FEDERAL ENERGY REGULATORY
COMMISSION

TECHNICAL CONFERENCE
UTILIZATION IN THE ORGANIZED MARKETS
OF ELECTRIC STORAGE

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P R O C E E D I N G S

(10:00 a.m.)

MR. AMERKHAIL: Thank you, good morning everyone and welcome to the Commission Staff's Technical Conference on the utilization of electric storage resources as transmission assets compensated through transmission rates for grid support services that are compensated in other ways and for multiple services.

My name is Rahim Amerkhail from the Commission's Office of Energy Policy and Innovation and seated with me are Heidi Nielsen from the Office of General Counsel and Michael Herbert from my office. A final agenda is available for attendees at the meeting room entrance and we have a few housekeeping items to note.

Our first -- to avoid interfering with our sound system please turn off your mobile devices or at least put them in airplane mode while in the Commission meeting room. Also there is no food or drink other than water allowed in the Commission meeting room. If needed, we have arranged for spillover space in Hearing Room 3 which is past the elevators to the right as you exit this room.

We will break for lunch at approximately 11:45 A.M. for about an hour. Speakers -- please be sure to turn microphones on and speak directly into them so that the audience and those listening to the webcast can hear you and

please turn your microphones off when you are finished speaking.

The format of the panels will be roundtables. No opening presentations -- just facilitated discussion of the issues raised in the Supplemental Notice and Agenda though panelists have been permitted to bring materials or presentations as handouts if they wish -- and we will also post such materials on our website after the Conference.

Depending on which direction the conversations turn we will not necessarily try to cover every single question from the published agenda. During the discussion panelists should stand up their name tags -- their name cards if they would like to speak.

Our goal is to discuss electric storage issues from a broad perspective and to avoid ex parte concerns. Speakers should avoid discussing the specifics of any pending cases. Now we are lucky to have on our panel some very distinguished experts from the industry and the National Lab and in the interest of saving time we ask that each panelist introduce him or herself the first time he or she responds to a question.

The panel will be moderated by Heidi Nielsen. I will moderate panel 2 and panel 3 will be moderated by Michael Herbert. Commissioners -- Mr. Chairman, is there anything that you would like to say that this time?

CHAIRMAN BAY: Good morning everybody. I would like to thank all of our panelists for coming here today as well as staff for putting together this great conference. Today's topic is I think an especially important and timely one -- it's of personal interest to me. One of the things that we are seeing is increasing deployment of electric storage resource driven by significant decreases in cost and advancement from technology.

So we are seeing the virtual cycle of innovation, deployment and cost reduction. And so I think it is very important that FERC continue to work on removing barriers to entry -- barriers that prevent the participation of energy storage resources. And FERC has certainly been following this area with great interest.

Last November we hosted a Technical Conference -- not a Tech Conference I'm sorry, Energy Storage Panel of one of our open meetings last April. We issued data requests to the arduous ISOs and request for comments on barriers to participation and electric storage resources in wholesale electricity markets.

And in today's Technical Conference we will explore issues associated with the compensation of electric storage resources for the different services they can provide from transmission services to grid support services and multi-use applications. I look forward to the

informative discussions today and on hearing how FERC can be helpful in this important area, thank you.

COMMISSIONER LAFLEUR: Thank you Mr. Chairman. Welcome everyone thank you for traveling here and thank you to the staff for putting together such an excellent agenda with so many thoughtful questions. I have already heard my first excellent policy proposal which is to have a one day suspension of the no coffee rule which I would certainly cast my vote for that.

But I am excited to hear the conversation because we all know that storage is a really a group of technologies that is evolving and has abilities to contribute to the provision of electric service to customers -- and I'm not sure we even fully understand. It seems not to fit neatly within the kind of holy trilogy of generation transmission distribution which we took to be the world but rather to supplement or maybe bridge those categories in ways that are unique.

And I think staff has done a good job posing questions that bring out some of that and what we might do about it. I am going to be in and out because we are in an agenda cycle and balancing other meetings but I look forward to seeing the recommendations that come out of the Conference, thank you.

COMMISSIONER HONORABLE: Good morning everyone.

Thank you to our staff for your tremendous effort in pulling together what I know will be an informative day and as the Chairman and Commissioner LaFleur have indicated this too is an area of not only interest for me but an area of excitement.

And I'm not sure quite what we were thinking to set this up today of all days and I know some of you didn't sleep well and the expressions on your faces I really should take a picture of it -- some of you. But we have important work to do today and I want to thank not only the participants, all of you who have endeavored to educate us about the tremendous world and what lies on the horizon with regard to storage and all of the attributes that it possesses but also the participants -- thank you to the RTOs and ISOs who have also expressed their opinions and helped to shape our work going forward and all of the stakeholders, thank you for your presence today -- on a rainy day but also for your willingness to help in this important effort.

As some of you have heard me say I don't believe we are on the cusp of dynamic change, indeed we are in the midst of it even now. And so really this discussion is one that is not only timely but I'm grateful especially to our Chairman for -- pushing our work in this area because as you have seen and as the Chairman has stated in his remarks we have been on this journey to get better educated about what

to do with storage and really how to maximize what it has to offer so I look forward to learning as well.

And I also agree that as regulators and policy-makers and decision-makers we must not only foster innovation and technological advances but also work to remove barriers and so I am hopeful that you all will aid us in finding the best way forward to do that.

Today we are discussing the value that storage resources can provide and also how they can be adequately compensated. And I also appreciate that storage may need multiple revenue streams to succeed in wholesale markets and I am hopeful that you all will educate us and really help us elevate our thinking about how to treat storage going forward.

But really in my mind compensation is only one barrier to participation. As I often say from the south when we learn better we do better. And so it is incumbent upon us to resist the urge and to be disciplined to not treat storage like other things because it simply isn't. It's the one thing that is not like any other thing and it is something I think in as much as we embrace and appreciate adversity throughout the country in so many ways that we absolutely must adhere to that with regard to storage.

I saw a tweet from Jason Burwen last night saying he was trying to work on his comments and watch results.

I'm sorry Jason that we did that to you last night but I look forward to as Cheryl mentioned it is certainly a busy week for us, we will be in and out our staff will be here.

Thank you for the comments that you will provide however you pull them together -- it will come from the heart Jason. And thank you again for your aid in this effort.

MR. AMERKHAIL: Thank you Mr. Chairman and Commissioners, over to you Heidi.

MS. NIELSEN: Good morning. The purpose of our first panel is to discuss issues related to the utilization of electric storage resources as transmission assets compensated through transmission rates including when they may also provide services other than transmission.

In Western Grid the Commission accepted a proposal to use electric storage resources as transmission assets based on the particular use proposed which was voltage support, a thermal overload protection for relevant transmission facilities and on other conditions proposed by the applicant including a commitment to forego any sales into organized wholesale markets.

This later condition was primarily intended by the applicant to address the Commission's concerns with respect to the impact to one -- the impact on competition, when one market participant may recover its costs through

cost-based rates on file with the Commission while others may not.

And two -- the impact on RTO's independence if the RTO is made responsible for the profitability of the electric storage projects charging and discharging activities rather than simply carrying out the market participant's instructions.

For purpose of this panel -- the purpose of this panel is to discuss first additional potential modes of electric storage resource operation beyond providing voltage support, a thermal overload protection that could be characterized as transmission service.

Second -- additional methods of addressing concerns about competition due to cross-subsidization in RTO and ISO independence, and third -- operational considerations when using electric storage resources as both transmission assets and providers of other wholesale electric services.

Let's start at the beginning. The pro forma Open Access Transmission Tariff defines "Transmission Service" as "Point-To-Point Transmission Service," which is the reservation and transmission of capacity and energy on either a firm or non-firm basis from the points of receipts until the points of delivery.

Our first question is -- Beyond providing voltage

support or thermal overload protection for relevant transmission facilities, as addressed in Western Grid, what other modes of electric storage operation can be considered transmission service that supports the reservation and transmission of capacity and energy from the points of receipt to the points of delivery and why?

So I would like to open for discussion. If you would like to start -- yes Tom and please remember to introduce yourself the first time you speak.

MR. KASLOW: I'm Tom Kaslow. I'm the Director of Market Design and Policy for FirstLight Power Resources. FirstLight owns and operates about 1400 megawatts of generating facilities in New England and approximately 1200 of that is pump storage including possibly the oldest pump storage facility in the United States, it was commissioned in 1928.

So storage was continuing to evolve. It's been around for a while. Our focus just at the outset is on avoiding adverse impact to competitive markets. All of our 1400 megawatts rely on competitive market revenues to support ongoing operations as well as new investment. In the past several years 88 of the 1200 megawatts of pump storage is new capacity that was brought to the marketplace on new investment. So even the existing facilities have to face some questions on investment and hence my focus on the

markets.

Other than one thing -- I had provided some written comments -- I don't have written copies with me but certainly I know they will be posted later. I think our approach to this is that the provision of transmission service or supporting grid -- the operation of the grid goes well beyond the planning exercise of whether or not there will be thermal overloads upon a contingency, or whether or not there will be voltage problems to the day ahead of planning of energy and operating reserves and to the real-time dispatch.

So our company finds it difficult to really separate the transmission support functions into what might be classically called transmission equipment functions and so we really think that the whole spectrum of these services are the grid support services and it certainly does raise the question of what unique contribution of storage needs to have compensation beyond the markets.

I will offer from our own perspective we provide performance on just the currently defined ancillary services and I'll pick operating reserve contingency protection as one. Currently our facilities can provide performance well beyond what those markets define as the minimum level of performance. We can come online -- the whole station within 10 minutes. We can provide single unit response in much

shorter time frames.

So to the extent there are you know further barriers to representing the full value of storage it may actually get into the market products as opposed to transmission rate-based type compensation, thank you.

MR. KORMOS: Good morning I'm Mike Kormos with Exelon. I'm the Senior Vice President of Wholesale Markets and Transmission Policy. Probably a couple of different points I would make. I think as the Chairman of the Commissioners said I think we are at a very unique opportunity and I think batteries are a fairly exciting new technology and potentially where the cost may go -- I think it is something that we definitely need to be looking at now.

I do agree they are different and in some cases I think may provide us some unique opportunities. So first I would say you know regarding transmission service I think when you look at the ancillary services -- schedule 2, 3, 4, 5 and 6 I mean a battery can provide any one of those services, whether it is voltage support, whether it is energy imbalances, whether it is regulation or whether it is operating reserves -- batteries are as able to provide those services as both generation and demand response.

And I think it is sort of interesting that they are in fact transmission service, why would we not let a

transmission asset provide a transmission service? So I think there is the ability for those to do that. I think there will be you know, it will be interesting as to when they can do it and how they can do it. I mean you cannot do everything at once.

So I think as we talk further I think that will be where the issue is. I don't think it is a technical issue. I think batteries can obviously perform these functions. It's more going to be a regulatory issue -- as to just ultimately how they are handled through the regulatory process because you are mixing costs of service with potential market based services as well.

So I think there are multiple opportunities for batteries to participate in those markets and in fact as we know they are participating in many of those markets today -- particularly at least the one I am most familiar with in the PGM market. The other thing I think batteries bring is a unique opportunity to even change the way we potentially operate for thermal and voltage overloads.

And I know you said beyond just thermal and voltage overloads but I'd also ask you to consider one of the things batteries can do as a transmission asset is I think be able very uniquely to provide potentially a different way to operate. Today we operate everything -- what we call pre-contingency. We start moving generation,

we start spending money before the actual contingency happens -- because we need a certain amount of time to make sure that if the contingency happens we can move in fact generation and/or load to get the system back into within normal limits.

Batteries will provide you really interesting opportunities in that they can be instantaneous and that we may be able to move for some things -- I don't think we are going to radically change it but for specific applications looking at using batteries post-contingency that rather than worry about moving the generation ahead of time you can use the battery in a charged state and if the contingency happens at that point the battery can basically respond immediately and basically back off. I think that is a very unique transmission opportunity that exists for batteries that a lot of other potential infrastructure investments just don't bring us.

You have some similarities with phase angle regulators and HVDC that have that kind of capability and I know in PJM we did use particularly the parts -- the phase angle regulators in that capability, being unable to operate to higher ratings because you could in fact take advantage of that fast response that batteries would bring.

So I think that's why it's very exciting is I think it goes beyond just the classic controlling for a

thermal or voltage overload. I think we can really challenge ourselves as with any new technology you have to challenge yourself how you are going to operate -- because the technology will allow us hopefully, to operate more efficiently.

So I think there is a lot of opportunity. As I said I really think it is more a regulatory issue than a technical issue. We have technical experts here who can speak to it but I think they are able to provide a vast amount of the services we know.

MS. NIELSEN: Thank you. Just to clarify we will be getting into the issues of cost base, transmission recovery and market, service recovery -- so just at this point we just really wanted to focus on the transmission issue, how these assets can be -- if they can be considered assets that provide transmission services.

MR. KUMARASWAMY: Thank you, thank you gentlemen, Commissioners and staff for organizing this great panel today we appreciate the opportunity to present our perspectives on this important issue. At AES we do consider energy storage to be a foundational element for us to create a clean, reliable and resilient electric grid and we are honored to work with entities and operators across the world to apply energy storage solutions to meet the challenge that we are facing.

We do see the obligation of energy storage and the transmission system as one that can increase the efficiency of the overall system and one that can help us make smart investments into the grid. It can provide targeted transmission relief in a matter of months and not years, it can delay expensive major transmission upgrades that we are planning for the system and it can cost effectively dissolve many of the transmission constraints that we face in regional markets across the country.

If you step back and think about how we have done transmission planning until now -- in the last 50 or 60 years the behavior of the performed transmission planning analysis has remained pretty static right? We know through the minus 1 and then minus 1, minus 1 contingency analysis and I identify violations in the curve -- the thermal and voltage violations.

And for the violations that we identify we try to remedy them with concrete projects that will underscore states. But you have got to remember that this type of analysis has two types of drawbacks. The first one is it does not account for the fact that if you have a lurid value that you are modeling in each of these snapshot simulations off that cooperation and that there is a particular value for beyond which a violation is triggered that necessitates an upgrade project.

And there is a particular value for it below which the violation disappears -- so that is one of the drawbacks that we face in a deterministic planning work right? The second issue is that all the upgrades that we think about are also traditional upgrades right and so the transmission upgrades come in block sizes so we try to reconnect the lines, we try to operate lines to a high voltage level -- so those are traditional upgrade projects.

The way energy storage fits into that piece is it is a new solution that is available for transmission planners and utilities across the country. To address both of those drawbacks right -- many of the traditional transmission infrastructure that you would apply to address the overload issue tend to be severely under-utilized because they don't provide additional services beyond providing that particular relief during the factual attack.

In contrast though energy storage has the capability to resolve the violation during the times when the load level exceeds a certain critical threshold value, and it can also be used for other applications for providing grid services during the demand.

The second part where it is a peer advantage for the storage of the transmission application is that it can provide rapid power injections into the grid following a contingency route. This is along the same lines as Mike was

describing and how we thought about it is that it is the capacity of the least idea to free up capacity from constrained transmission lines that interfaces it.

And so in sort of holding back capacity across key lines and interfaces based on deterministic and minus 1, minus 1 -- limits can you use storage to actually provide those post contingency injections to keep the library of the system at the same level -- but in return get higher capacity through across key lines and interfaces. So that's another key application that I just wanted to highlight for the staff here.

And you see that in this mode of operation the grid can be significantly utilized much better from where we are today and we see that as a huge opportunity for storage.

MS. NIELSEN: Okay thank you, Paul?

MR. MCGLYNN: Good morning my name is Paul McGlynn, I'm from PJM. Just from the vast majority of the rate-based transmission assets that we have in the RTEP anyhow are to address voltage issues and thermal issues. You know beyond that there are only a couple of other categories or things that we would put a rate-based asset into the RTEP 4 whether it be a short circuit issue or a stability issue.

So from an opportunity to participate as a rate-based transmission asset that anyhow would seem that

there is beyond voltage and thermal -- there's probably not as many opportunities. You know that being said though there may certainly be certain niche applications where a storage device could be used as a transmission asset. Some of the other comments around using those devices on a post-contingency basis, pre-contingency basis -- whatever, however you want to look at it to me seem like our application issues that maybe go one step beyond -- at least the threshold issue about as to whether they should be considered a -- you know, transmission rate-based asset.

You know that being said within PJM although again most of the rate-based transmission assets are -- there aren't any storage devices that are in that category. That's not to say there isn't a place for storage in PJM -- as a matter of fact there is I think well over 300 megawatts of storage that has interconnected to PJM and is participating in various markets providing you know different, various ancillary services and things like that.

So there is certainly a place in our markets for the storage devices and as I said there may be certain -- perhaps more limited applications where a storage device could be useful as a rate-based transmission asset.

MR. SUNDARARAJAN: This is Raja Sundararajan from AEP. I'm the VP of Regulatory Affairs for AP. I'm delighted to be on the panel here. We actually have done

this and primarily in Texas where AEPS put this Presidio battery as part of our joint venture in -- .

And frankly it is the same concept that I think Kiran and others are talking about and in Presidio where we had a 69 KV line, a radial line that served a load -- we had two issues, obviously the line was getting old and we had an option to either rebuild the line or B -- use the storage to satisfy the incremental capacity that you need as opposed to solving for the violation of the old load.

And we actually called to the Commission the fact about is if you are looking for the option of -- you ask two questions, how much capacity do you need for how long -- and that's when it becomes economization in terms of what technology do you want to use. It's not a binary decision in terms of whether you -- whether you know, re-building the line for the capacity for the next 40 years -- is that what you want to do? As opposed to building a storage device which gives you the incremental capacity that you need for the next 10 years where you are actually forecasting the violation for -- every RT has a planning horizon -- in PGM it is a 15 year planning horizon.

And that is a solve for the planning horizon then I think that storage does come into the mix. And then there is the storage for a 40 year horizon which most argue don't do today then obviously you determine that the transmission

line options become more cost effective. So it really depends on what effective solution you are looking for.

And in my opinion that's a question in terms of whether -- if RTOs are looking for the incremental capacity that solves for the planning horizon or are you actually looking for a longer term horizon that actually solves the contingency for a longer period of time then that becomes -- and for that -- that led to the determination in the Presidio case where they actually picked the storage as a solution.

And then on top of it, it also provides island and cable release in case you actually have the line that completes the out -- then you can actually you know instead of our crews, and trying to get the line as fast as possible, the storage gives you an option to solve the islanding issues and to provide the necessary support from a customer point of view.

And maybe in a broader context I mean if you know, the transmission service definition is -- and depending on how you look at it, it can be interpreted broadly. I mean it is data and everything else in the substation are they all providing point-to-point increasing transmission capability?

I think we kind of put a lot of assets as transmission because they enable at the end of the day

assets that actually provide the transmission service and we believe storage should be noted from that. I mean the third thing is -- and maybe I'm getting into the cost analysis -- the revenue space here -- I came from a transmission background and I have been even in my new role I kind of apply the principle set -- depending upon what you plan for the storage is you know the limitations that you put on storage in terms of what benefits it can provide is going to effectively you know choose which resources are selected in the planning process.

If you ignore the benefits of storage that goes beyond just the transmission, if you ignore the ancillary service benefits then effectively yes, you are going to hamper storage solutions at the expense of other traditional transmission solutions because storage typically is more expensive than A -- any of the planning horizon that you consider and --

B -- if you ignore the benefits. We actually think that storage is a tool that needs to be considered and how you plan for it and what benefits you take in account of the planning process goes a long way in terms of taking storage solutions.

MR. TATUM: Hi good morning I'm Ed Tatum with American Municipal Power and we are public power -- 135 members, 9 states. We have about 1800 megawatts of capacity

that we own. We have about 3400 megawatts of load that we need to serve so we take a customer perspective.

We are very concerned about keeping the lights on. I am going to do my best Heidi just to answer your one question and assuming that I will I do want to speak to the costs on that. As I read the first question I was burdened by two things -- one I'm an engineer and two -- I remember back in '95, '96, '97 Newark was talking about interconnected operation services and what they were.

So I thought I knew what we were talking about until I got your question and we started talking about transmission service and that seems to have morphed and evolved. So as I wrestle with that for days I finally said you know what we really need to think about here is what is a basic transmission function?

And you know we have ancillary services and I think the panel would agree but for scheduling storage can provide all of those ancillary services. Do we want to separate regulation and frequency? I don't know that we need a Technical Conference to talk about that.

But if we get down to talking about it as a transmission asset and it is out there on the wires I think FERC has done a good job saying, "Hey things that are out on the wires are on the wires and what are they trying to do?"

Well we are trying to keep the lights on with

these assets. And so if we are going to have something out there that is a low cost, more-effective solution than actually throwing traditional transmission wires in the air, we need to think about it and treat it in the same way and so we want to make sure that we have storage out there that would be just as reliable and just as available as transmission.

We would expect that if it is going to serve a transmission function that we would be thinking about it being under the control of the transmission provider. And then we would have to worry the technical issues -- if we are trying to serve two masters, which is kind of hard to do if you have one foot in the competitive world and one foot in the regulated world -- I mean in the competitive world you are supposed to maximize those profits.

The regulated world -- well you get a fair rate of return. How do you balance those back and forth, how you make sure if you are in both worlds that the competitive aspect is not using up all the storage such that when the transmission contingency comes -- whatever it is, the minus 1, and the minus 1, minus 1 that the storage is actually available to act as that asset and I look forward to your questions on cost.

MR. EMNETT: Hi Mason Emnett, Next Era Energy, sorry I slipped in and let everybody else talk first. So

Next Era Energy is a holding company for Florida Power and Light and Next Era Energy Resources are our primary two sides of the house. Florida Power and Light is developing battery projects on the FPL system for multiple uses but my comments here are focused on the Next Era Energy Resources side which has resources, battery projects that are participating in the PGM market and we are developing in all the other RTO's as well.

So focusing on RTOs given the scope of the Conference -- and to kind of pick up on what Ed and Raja were saying, I think it is interesting to start the question with transmission service because along the lines of what they were saying I think there is a difference between transmission service and transmission assets.

Transmission service is provided by the RTO using the whole group of assets -- transmission assets being a primary one but ancillary services sit in the open access transmission tariff because they are a piece of transmission service even though they are not provided directly by the wires although the wires enable them to be provided and therefore transmission service to be provided.

As soon as you think of storage or frankly any type of resources, but storage is the question today -- could it provide a transmission function or a function that is needed for transmission service? Clearly it can. And so

how should that resource, how should the participation in the RTO process and the ROT market be structured to take full advantage of everything that the storage asset has to offer which the Chairman and the Commissioners started us off with that framework of what are the barriers and how do we maximize the participation of the resource.

So from our perspective and I don't know whether you are going to the next question on differently or kind of sticking with follow-up questions on the first of transmission service -- in our mind a transmission asset is what it is. It is you know wires, sometimes capacitors and other stuff but a storage resource could be -- you could call it non-transmission alternative or you can call it a storage class.

I don't think the nomenclature matters from our perspective. It's more of putting a storage -- to the extent that a storage resource is supporting a transmission function, enabling the transmission service. It is not by definition therefore a transmission asset and subject to all of the rules and requirements that transmission assets are subject to which are there for a reason which then takes us to kind of more complicated questions that Ed raised.

If you have a storage resource that is receiving cost of service recovery for providing a transmission functioning, enabling the transmission service, how does

that asset then operate within the market structure? Who bids, who controls, who manages state of charge -- those are all complicated questions that need to be answered but the threshold question that I hope the Commission can address is can a storage resource provide the transmission function, receive cost of service compensation for providing that transmission service?

Not necessarily a transmission asset -- but if the answer to that is yes then we can answer all the other complicated questions. They might be different RTO to RTO but unless we get through that threshold question -- unless we get the threshold question as yes I don't think we get very far.

MS. NIELSON: So I think what I have heard so far is that in terms of providing the transmission service other than voltage support or thermal overload protection, that the main category is ancillary services if I heard correctly? Do you all agree?

MR. KUMARASWAMY: The position of the post contingency -- so --

MR. MCGLYNN: In PJM I think for the most part batteries are that they are the types of service market-based services that batteries are providing.

MS. NIELSON: Okay.

MR. SUNDARARAJAN: I think terminal and voltage

violations are more on the planning scope. You also have operational issues where you actually see actual outages on the line you know for various reasons whether it is weather related, whether -- and it sort of does provide in cases of -- especially in the Presidio example that we had that it can actually run off a radial line -- it does provide the capabilities that traditional transmission lines might not provide.

If there is an outage on the line it is not that it is a new line or an existing line, the storage does provide additional capability and additional options of transmission service that traditional alternatives don't provide.

MS. NIELSON: Okay, Ed?

MR. TATUM: Thank you and I like the way Mason put it as an asset. It has the ability to do a lot more but we do have to be very careful with how we are treating it and back and forth and if it truly is an asset I would like Paul McGlynn and his folks to really weigh in and tell us how -- and Paul you have this answer, but how could it work? How could we make it just as reliable and just as available?

But if we are in the transmission planning space we would need to talk about or OR-890 and we need to talk about this being the best and most effective lowest cost alternative to putting some transmission in place and then

we could actually start getting into if it is indeed a regulated asset.

And if it is indeed, provide additional services, how do those dollars flow but I'll wait until you ask the question.

MS. NIELSEN: Okay thank you. Go ahead Paul.

MR. MCGLYNN: Again I think from a planning perspective that there is perhaps -- I'm sorry from you know from a planning perspective there certainly may be niche applications for batteries and for storage devices. I also agree with many of the other panelists that there would appear to be capabilities -- well there certainly are capabilities that storage devices have that you know that could also be used to efficiently run the grid and manage the grid.

We have lots of batteries that are participating in our markets today and again it is conceivable to identify a place where they could be used for a transmission planning application anyhow. I think the challenge is dealing with the -- you know, dealing with the instances and where the money is going to go, how the money flows basically from the periods of time when you need the asset available for dealing with whatever transmission and planning function you had to deal with versus when the storage device may be able to you know provide other benefits to the operation of the

grid.

MS. NIELSEN: Okay Mason?

MR. EMNETT: Yes I just wanted to follow-up in a yes, clearly thermal support ancillary services we discussed but there is also economic transmission projects, market efficiency projects the goal of which is to address congestion and enable you know less cost provision of energy on the system and batteries can clearly do that as well, right?

Which then raises questions about how you operate -- do you bed the resource into the market, what are the conditions under which the RTO would have control -- again those are complicated questions but the threshold of can the battery achieve the same function or goal that the transmission facility -- that the wire would have -- yes.

MS. NIELSEN: Okay thank you, Tom?

MR. KASLOW: Thank you. I've been listening to the discussion and I certainly would agree that storage can provide the transmission services that were identified. I think the difficulty that our company has is that isn't necessarily distinct from other resources in the system.

And I appreciate Mason's comments that today in New England, as an example, other resources are given signals of where it would be useful to locate for the purposes of reducing transmission investment in a market

reliability alternative. I believe that is the term you referenced Mason, and in that type of an approach it avoids some of the issues that Ed raised about mixing cost of service and markets.

And so the perspective that we currently have is all of the services that were discussed could really be provided from other types of resources as well. And believe me -- we own storage so we would like storage to be valued properly but we also want it done in a way that makes sure that there isn't disruption to the other market revenues that the other storage resources are going to rely on, thank you.

MS. NIELSEN: Thank you, Rahim?

MR. AMERKHAIL: Thanks Heidi. So I have a couple of follow-up questions so if the theory is that providing ancillary services should qualify you as a transmission asset then how do we single out storage from all the other traditional generators, coal-fired power plants that provide ancillary services and kind of related if there actually are markets for these ancillary services, why aren't those enough?

Why is there a parallel need for payment through transmission rates? I think Raja went up first and then we will -- I'm sorry Ed.

MR. TATUM: Thank you much. I think storage can

already provide all put maybe one of the ancillary services. I think that we have markets for that. What your question is what do we need to do with the markets to do that? In PJM I think we have opportunities for those things to already work out.

I want to be very clear that from Amp's prospective we would not suggest that transmission assets be used as ancillary services. We see generation provided ancillary services, we get that but storage can be an ancillary service but in that situation it would be hard to classify the transmission asset.

And I hope I didn't confuse from that standpoint because I think what I am coming from is if you are defined as a transmission asset we are going to finally get to Heidi's question about how the cost is going to work.

MR. SUNDARARAJAN: I think the question is not whether you know clearly storage has a unique capability of not only solving for transmission issues, transmission service that you define as thermal or voltage violations but also has a benefit of providing transmission services similar to how you call it ancillary service market which is sold to a market.

I don't think we are saying that if storage wants to participate or any other asset wants to participate purely in the ancillary service market, you call those as

transmission assets. I mean the definition is, "In addition for solving for traditional -- what transmission assets historically provided, to store thermal and voltage violations, if they also happen to solve and provide other benefits on the ancillary service market why stop them." And does that limit your traditional definition of transmission service or transmission asset definition.

But to go beyond and providing other benefits -- is the question before we get to the cost aspect of it.

MR. MCGLYNN: I would agree with Raja's and Ed's comments. I think you know storage devices clearly participate in PJM's markets and provide ancillary services in PJM's markets. They compete with other resources in PJM's markets to you know to provide those services. So I think that comes first however there may again be some applications where you could consider a storage device to somehow help you to mitigate and manage some kind of transmission planning type of an issue but I wouldn't put that first and suggest that a planning solution is also providing some other ancillary service. That to me is a market function.

MR. AMERKHAIL: Are you saying it should not try to do more than one thing at a time or we have to find ways to make sure it can do the transmission function without being impacted by whatever else it does on the side?

MR. MCGLYNN: I think you have to be able to -- you have to figure out ways that you can manage both. If it is going to provide both services you have to figure out the instances that it would be able to be operating in one world and the other instances when it is providing the function that it needs to -- to deal with whatever the planning issue is.

But we'll save that for questions 2 or 3 I guess.

MS. NIELSEN: Please go ahead Kiran?

MR. KUMARASWAMY: No I agree with Raja and Paul's comment. Like as been said before it is not an issue, technical or operational issue for storage to provide all of these functions right and so you know if you put some regulatory constraint on the system for it to provide only a transmission-like service, say for instance, you are using storage for a peak load relief-type of an application -- when you are providing that peak load relief for a specific portion of the day for the summer months alone -- for the asset to remain idle for the remainder of the time just results in an economic sub-optimal solution.

But with respect to what we pay for the system we would like for assets to be utilized for all of the services that it can provide. And that is one of the things that differentiates storage also is that it is a 24 by 7 connected resource and so there is no starting and shutting

down with respect to storage.

And so from that principle -- from that economic benefit maximization principle we would like for asset to be providing for all of the services that it can provide under the system and so we think that there are lots of arrangements in which we can address some of the Commission-related concerns and cost subsidization and I know it is getting to the second question but we do think that there are reasons which we can address to all of those concerns, but still fully utilize all of the capabilities that storage provides in the space.

MR. MCGLYNN: I think it's hard to answer that question without getting without getting into the second or third one. I mean I think I agree with everybody. I mean I think we are not suggesting this is the only reason a battery should be brought on to the system -- there are a lot of merchant commercial reasons why a battery may be used and if it is just to provide purely ancillary services we would agree.

That's not something that should be rate-based, that is a market function. But I think if you are going to look at it as an infrastructure deferral of -- and that is going to be its primary reason that it is being brought on to the system. I think at that point it makes perfect sense to allow it to provide these other functions when it is not

providing its reliability function and we will talk about how you can do that.

So maybe I disagree with Paul -- I don't know if I do or don't, but I would think when you evaluate if it is the best cost effective answer for the transmission problem the violation you are seeing either in operations or planning, you should in fact take account of these potential additional revenues.

Now I think they can participate in those markets, I will talk about it. It is going to be as a cost-based you know market priced taker. I don't think anybody is going to suggest on this panel they should profit outside of that. I think it is just a revenue neutral kind of function but why would you not take advantage?

I think the end of the day all of our goals will be to provide the service in the most cost-efficient manner. And if the batteries are able to provide these other services, provide a rate of revenue in a competitive fashion because they are the most cost-effective resource at that time they should provide that service, they should receive those revenues and that should off-set the transmission cost.

I think that should be taken -- I think that it should A -- number one be allowed. I think we need the regulatory to figure out how to let that happen and B -- I

would also suggest in the planning process or in operations that should be part of the consideration when you are looking for what is truly the most cost-effective resource.

MS. NIESLEN: And I appreciate your comments. I think I know we are all trying to get to this other question but I guess we are really trying to focus here on can this fit into the cost base rate transmission bucket -- recovery. So just really I know that there are market issues that are coming up but if we could just try to really stay narrowly focused on this question, taking into consideration what Raja said as well, if you want --

MR. KASLOW: I wanted to clarify. I don't want to take it out of sequence. I thought the question was why couldn't a battery or other storage resource base its investments on participation in the existing ancillary service and other markets, was that the question? Because if that is the question I think that is the question. I think that is the real question about this Technical Conference from our perspective.

Why is that necessary? We have close to 2,000 megawatts of pump storage in New England at least from our own resource, 88 megawatts was recently invested. We see that we are probably going to have some other investments from battery storage and we have run into some of these same problems with traditional generators too and we are talking

about the amount of lock-in times that are required.

Generally developers will want the most stable revenue stream that is possible but we found out in our market that we get a lot of investment based on not giving quite everything that they were asking for. We just had 1100 megawatts investment in the last auction in New England based on a 7 year lock-in at a $7.00 kilowatt month price.

So a lot of things can happen in the market and one thing I certainly agree on the comment that was made was we all want the most cost-efficient outcome. The question is how it is achieved. Is it achieved through market-based compensation or is it achieved by providing rate-based treatment for certain storage applications?

But our concern is you can't have it both ways and you know we have experienced some of this before. I have a long history in it so I guess that means I'm older but in New England I lived through the years when we had 28% of the capacity in New England on reliability must run agreements and the Commission appropriately scolded New England and said enough, you really need to value it in the market and we were forced into a long series of changes which led to the current capacity market that we have that does seem to be successful at achieving new investment.

And the reason I asked to be here is I am afraid of going down a road that will lead to a similar outcome

where -- at least in New England, the pace of the capacity market was undermined by the reliability must run agreements and it is not clear that what is currently contemplated by mixture of cost of service and markets isn't essentially the same thing.

MR. EMNETT: So let me try and connect the dots between the two question and Tom's comments -- that our focus is on whether a storage resource can be cost-based transmission. In my mind can it have cost-based recovery for meeting a transmission need which is a different thing than cost-based transmission -- it is not transmission, it is not a wire.

But if the answer to that is yes then it takes you to questions about ancillary services and provision of other functions that are related to the provision of transmission services, all within the transmission service umbrella but there are different mechanisms that the RTO uses to provide that transmission service -- that uses a transmission planning function and construction designation process for the transmission wires.

It uses markets to procure most of the ancillary services, not all and there are cost-based mechanisms for some of the ancillary services. So where does storage fit in there? And in our mind yes the existing market mechanisms are the energy and ancillary services or capacity

where they exist are sending the signals for when resources should be coming in or out of the market.

But then the transmission planning function comes in behind and says given those decisions that have been made I saw a problem. I had problems that wires are going to need to fix and they can be reliability or economic or could be public policy and so I think what we are asking is when you are in that conversation -- where the market has already spoken as to where the resources would otherwise be and the RTO is considering what change in my wires do I need to make in order for the system to be reliable and economic and meet all the policy requirements that a storage resource should be able to say, I can do that too.

And if the evaluation of comparative economics of the two -- comparative benefits and costs of the various alternatives, the RTO ends up selecting and saying, "Yeah the storage asset makes sense." Now there will be complicated questions about the operational parameters for that storage asset when it is selected, how it will participate in the market, who has control, is it bid, is it effectively going to dispatch the outside of the market -- we can get to those questions and we have thoughts on that.

But if you can't get past the first threshold -- can the RTO select the storage resource and provide a cost of service recovery based mechanism that is similar to the

approach to the transmission but it is not the same thing because it is not a transmission wire, maybe cost allocation is different -- maybe, but if you can't answer yes to that then I don't think we get very far.

MS. NIELSEN: Thank you, Michael?

MR. HERBERT: Yeah I was wondering if we could talk about the concept of the post-contingency service a little more? The way you describe it, it sounded I think similar I guess from a planning perspective to providing congestion relief or infrastructure deferral from an operational perspective. So I guess my first question is -- is that true?

And then from an operational perspective how would it work differently? Would you hold that capacity in reserve in the event of a contingency event and then I guess the final question would be kind of probably for Paul a little bit -- I mean is there actually a demand from a transmission-planning perspective for that type of service.

And then for the developers is there the desire -- or would you be willing to forego any sort of market revenues to receive sort of cost of service for a kind of post-contingency storage asset?

MR. KUMARASWAMY: Let me probably take it one question and then Mike and Paul can probably add. The answer to your first question is yes. So it is operating on

an autonomous work in that type of situation. It is actually on standby for it to provide for you know rapid injections into the current if a contingency happens.

Because again think about it -- if you take a look at a lot of the interfaces that are constrained, they are constrained for a minus 1, minus 1, minus 1 type of events. You can really achieve a lot more power across an interface if you had the ability to actually to overload a stability problem with rapid injections immediately right.

And so that is where we are going with this type of an application and it is one that has significant potential right. It has potential that you could have storage in the order of hundreds of megawatts at a grid connector that is sensing it happening and then be capable to provide for those rapid injections.

In return for it you are actually seeking higher capacity on a particular interface that it makes economic sense for all of us right. And so how will you achieve that is sort of like the second question really. I mean what type of rate structure would make sense? Would that asset then be under our control, all of that is subject that needs to be discussed but again like Mike has said previously -- I think what we need to do is at least open our mind to thinking about solving an issue that we have using the technology that we have today, right.

We have storage that can act so quickly in being able to provide the service and we have to be able to figure out ways in which we can use that in our system and use it in a manner that can help us increase the overall utilization of the grid.

MS. NIELSEN: Rahim wanted to add on and then if we can have our final comments and we will move on to our next question.

MR. AMERKHAIL: I just thought this would help you guys with whatever you are about to say. So we talk about things like islanding the load of the -- retail load of Presidio with Raja's distribution battery or perhaps -- okay -- but isn't it a radial line out to this? Leaving that aside for now -- and possibly peak shaving -- Kiran mentioned it as though it were a transmission service to shave peak so I guess that raises a fundamental question for me.

Why are either of those things a transmission service -- they are clearly valuable but I am not sure they are valuable to the same range of transmission customers that the deferred transmission upgrade might have been valuable to. They are clearly valuable to the customers in Presidio but what about all the other transmission customers in Texas for example?

So I'll leave it at that.

MR. TATUM: So if I may and it is Ed Tatum, from AMP -- there's two things that we are trying to do here. One is we are trying to keep the lights on. The other is we are trying to make sure consumers get just and reasonable rates. So let's imagine a situation where we are using storage as a transmission asset and what that means is if it is not there the lights will go out.

So then that begs the question as to how would it be controlled, how would it be specified, how much storage would have to be there in order to truly mimic that and it would have to be there for a long time. Because what happens if it is not? We have gone through a FERC order 890 -- best plan, this is the least cost alternative but do you know what -- it wasn't.

Because for some reason somehow, it did not provide the same level of reliability and availability that the wires could have provided. And so we have storage which is a transmission asset but all of a sudden we are having to build more transmission because it wasn't sufficient. So that's kind of one of the concerns I wanted to raise there.

Can it provide additional ancillary services? Absolute -- I think that everybody here is thinking about that and I would say is in agreement on it. But you have to be very careful as to how we are mixing it. I don't think of peak shaving as a transmission service, I think that's a

result of how a load serving entity may react to the rates of the local transmission owner.

I think it is almost a demand-side opportunity that LCE's perhaps could avail themselves of -- to me it seems like a market thing. So as we talk about transmission assets, keeping the lights on, just and reasonable rates to the consumers, I think are our guiding principles in that regard, thank you.;

MS. NIELSEN: Paul?

MR. MCGLYNN: Regarding the issue of post-contingency operation to the devices just to me that goes beyond, that's one step beyond the threshold question as to whether a storage device should be considered a transmission asset or not. You know certainly it has capabilities -- those things would need to be explored.

I know just from an in general -- in PJM we don't like things to operate post-contingency or wait for things to operate post-contingency. To me that starts to sound like a remedial action scheme that we would need to you know, that in general we would not use as a first choice for trying to address some type of a transmission -- you know, some kind of transmission asset.

But again I think the question of how you operate the device, once you get beyond the threshold question of whether a storage device should be a transmission asset then

you know there may be other ways that you are going to use it, there may be applications for it that you know, could and should be investigated and discussed but I think that's again the next step anyhow for the next question.

MS. NIELSEN: Mason and I think we will wrap up this question and move on to the cost subsidization and RTOs own dependence, if you don't mind. Do you think your comment could be included in the next question? Okay.

MR. EMNETT: I'm sorry one suggestion would be to come at it from the perspective of needs and process/evaluation. So Rahim to your examples you know peak shaving -- as the RTO is going through its normal process of let's pick an eastern RTO for example -- the capacity for procurement of capacity energy ancillary services markets running to you know efficiently use the resources on the system and then it has the transmission planning process where it is deciding what are problems that have otherwise not be solved by my market mechanisms.

And it is in that conversation that at least I think of storage participating as an option. And so it would -- I think be unusual for the RTO to be solving a transmission need based on peak shaving as a primary goal. Most of the projects are reliability driving and so if the focus is really on what is the need that the RTO is trying to solve and can the storage asset solve that need then it

doesn't -- you know a couple of folks have referred to as a storage, you know, being a transmission asset or acting as a transmission asset.

In my mind I think if you call it a transmission asset simply because it's resolving a transmission need, you don't need to do that. It can be a storage resource, battery or bulk that solves that transmission need and it is not a transmission asset instead it is a storage asset.

I think you get out of some of the difficulties that you have if it is actually a transmission asset used and useful for transmission use or conduct applied -- instead of a storage asset and there will be rules around how that storage asset is used to implicate its participation in the market and doing other things.

But the threshold is did it -- does the storage resource provide or resolve that transmission need -- yes or no? Yes it does, then the question is well it is not needed to resolve that transmission need in every hour of the day. What does it do outside of those other hours and it takes us to complicated questions about market participation and offsetting and whether there should be to Rahim's earlier question just a crediting back of the revenues or should there be some kind of market-based revenues for the resource owner.

From our perspective no you would have a

crediting mechanism with a little caveat that management then becomes important because if the RTO, if the resource owner is the one who is having to make sure that its resource is positioned to solve that reliability need and not the RTO then when that resource is taken into the market there is a risk that that resource owner has and is that risk managed/compensated for -- that's just something that you would have to resolve.

MS. NIELSEN: Thank you, that's all very helpful. Now to moving on with the question we all want to answer. So turning to the next issue which focuses on concerns about competition due to cross subsidization RTO and ISO dependents -- if we were to assume that electric storage resources were allowed to receive cost base, cost recovery for the transmission services and/or transmission deferral of avoidance benefits that they provide while also participating in wholesale electric markets, then how would the cross subsidization and RTO independence concerns raised in the western grid and Nevada hydro be addressed?

For example could the electric storage resource use only a portion of its total storage capacity to provide the cost-based rate transmission services and include the costs of only that portion of its storage capacity in its cost-based transmission rates while using the remainder of its capacity to provide market space rate services in the

wholesale electric markets?

Or alternatively, if electric storage resource uses the same storage capacity to provide both cost-based transmission and market-based services in the wholesale electric markets, how should these concerns be addressed? What additional steps might be needed to address these cost subsidization concerns? So Mike would you like to start?

MR. KORMOS: I've been trying to answer the question all day. So I guess in my mind I think you know there are multiple methods and we could probably sit here for the next couple of hours talking about different ways of handling that. I think the most simple is if it is the primary purpose -- is to avoid a transmission problem well you know whatever criteria violation it is, I think we should handle it like any other transmission asset at that point.

In that it is turned over to the ISO/RTO and the ISO/RTO has the information which no market participant will have to use that asset primarily as it was designed for for the reliability function. So first and foremost that's got to be what's it is held for -- I agree with Mason I don't want to get into this putting this state of charge of the reliability function auto market participant.

I think that may be a little bit of an issue. I think as with any transmission asset they are turned over to

the RTO for operational control. I think these assets would be turned over to them. The RTO is in the best position to make sure that it is there for its primary reliability purpose first. They have that visibility that nobody else has but then the RTO can look at where it could also be potentially used, most likely in ancillary services we talked about.

Again my suggestion is it would purely be a price-taker, cost-based, not suggesting any kind of market participant and only it would be taken if it is the most cost-efficient resource able to provide the service at that time and it is available.

I think simply then any revenues that would be received through those markets are used to offset the transmission rate. So this is what I think to keep it more clean -- I understand where Mason wants to go with a separate category, I think that may add more complexity than is necessary at this stage.

I think leaving it as a transmission asset, putting it in as a revenue requirement but then using whatever revenues it receives from the non-transmission function so to speak, to offset those. I think we have lots of similarities where we install cell phone towers on our transmission lines, we get revenue for that, we refund that revenue back against the revenue requirement.

It is just the ability to use the transmission asset as an alternative use. There is no reason we shouldn't capture that value. We want to capture that value because we want to basically provide the least cost transmission service. So to me I think the fairly easy model -- and I don't think it's again much different than collecting non-firm transmission revenues. When gas gets put in for firm service but if it is used for a non-firm purpose you collect those revenues you refund them back to the firm customers.

I think that is the model we would look at is, particularly by having it under an independent -- nobody is suggesting profit maximization, nobody is suggesting that would be the RTO's test. The RTO would use it in the most cost-effective way to control the grid as it is needed just like they use a generator. I mean they don't profit and maximize for a generator but they do use it in the most cost-effective manner.

I would see the battery basically falling under that very similar category going forward.

MR. AMERKHAIL: A quick follow-up Mike. So hypothetically if there were a market for cell phone towers and independent cell phone tower developers and you got subsidized cell towers that don't need the full tower because you are adding it to transmission towers -- why

would they think it was fair to have to compete with your cell transceivers?

MR. KORMES: But I think that's the nature -- I mean the ability to repurpose an asset. You are right, it provides an advantage -- I don't think it is an unfair advantage. And that's why we put cell phone towers on transmission lines, you are right. You could force somebody just to build an entire cell phone tower right next to it if that was the desire -- and there are plenty of locations where that is the right answer.

But if the ability is there to take advantage of that and it benefits the customers who have paid for that infrastructure why would you not take advantage of that, and in fact the industry does. That is what we do today.

MR. EMNETT: Sure you know I largely agree it is about efficient use of the resource which again going back to process -- if you -- what point is the RTO considering the storage asset or really any non-transmission alternative right -- in the process as an alternative to the wire to solve the problem.

And so it decides on a non-transmission alternative solution. Why would you not maximize the capabilities of that resource back to you know statements that were made at the opening. Like it is just yes there are implications for operations in the market and in our

mind that resource would be a price taker, you just bid on and be available and the energy and ancillary services market mechanism would figure out when is the optimal time to use the resource.

The state of charge management is a complicated question. As a developer we like the idea of the RTO to Mike's you know suggestion. The RTO managing state of charge because it is the one that has the most information but we appreciate that there could be concerns in terms of affecting market prices associated with decisions on when to -- you had to posture the resource.

I'm charging and discharging for a battery or pumping you know for bulk storage -- and so we can see and understand a structure where the battery or the storage resource developer both the battery would have to be responsible for that and that's a risk that bears as part of a cost-based structure where it is getting this capacity -- I'm sorry credit back from our participation.

MR. KASLOW: Thanks, first a quick response to the last two conversations and then I will get directly to the questions that you have on this one. A follow-up to Mason -- I think there is a lot assumed here that's easy in terms of when to use storage and not in terms of participating in the energy and the ancillary service markets.

At least from our company's experience it is not an easy task -- it is very complicated, there is a lot of art to it actually in terms of trying to forecast when the use of storage is best because you can't necessarily economically charge immediately after you discharge prices may still be too high relative to what would be economic for the system as a whole.

And so there is a lot of management at the state of charge that I don't know how the RTO would do other than just trying to clip prices with perfect knowledge. And if that were the case I think you would definitely have a challenge on any market-base storage resource wanting to come in because who can compete with the ISO? So that's a general response now your two questions.

I'll start with the alternative first because I think the alternative one in my view is a common use for both market and transmission purposes. And that one to me looks precisely like reliability must run agreements that we have had a bad experience with in New England on generators. So it just doesn't look any different.

And I think if that road was taken then the need to -- how do you deal with the cost base subsidy of that resource and the capacity, energy and ancillary service markets? The capacity market we currently have minimum offer price rules for anything new that comes in that

currently would not be transmission rate based -- how do you deal with that if it is a transmission asset?

I don't have a good answer on the energy and ancillary services because it is a problem actually the markets face today from investments that are made outside of transmission. They come into the market with a little bit more assistance beyond the competitive market forces and so that's a problem and I don't know how you solve that.

It just places greater reliance on the capacity market when that happens. What I would call the segregated use -- you have a battery or a pump storage facility and you know I think the question is the pump storage is easier to visualize -- is at the top or the bottom of the upper reservoir that is used for the transmission service -- since it is used infrequently benefits the bottom of the resource, how much duration is used for that relative to the duration that's used.

We have a facility that has a convenience flat out for 8 hours -- if we were to do this type of service is it one hour that is devoted to the transmission service since it is not really a reliability function versus a market function? And how you slice up that upper reservoir, is it just the storage medium whether it be water or electrical chemical -- or is it the equipment, the common use equipment to convert that charge into a discharge into

energy on the system.

It isn't clear how the division of the capital and the recovery of the investment of what's rate-based and what isn't rate-based would happen in that type of segregated function and I would expect that there would be significant challenges to any method that was given to set up a formula for how that storage would be segregated, thank you.

MS. NIELSEN: Sure, Kiran?

MR. KUMARASWAMY: Sure I agree with many of the points that have been said here. From my perspective we think differently commercial structuring arrangements that can be put in place to mitigate a lot of concerns of cross optimization. And it's possible that it is not going to be a one size fit all type of solution. You have got different types of utilities, different types of entities that actually double up storage projects and so it has got to be evaluated on a case-by-case basis.

But we do think that there are definitely opportunities for us to pursue both of those types of services in a manner that doesn't impede market operations or result in cross optimization.

I mean just to highlight it --let me talk about two scenarios, one where you have battery storage that's providing a transmission service and it's owned and operated

and actually participate in the wholesale market and so some of the traditional cost allocation methods are probably appropriate here right?

You allocate a portion of the cost for providing that library service and that any profits or monies that you make through the wholesale market operation flows back through revenue credit mechanisms through the data mechanism back to reduce the cost of the off-rate price in that case right.

And the one thing is that the thing we have to be cognizant of is an operating plan for you to operate the asset and that's going to take a little bit of work to figure out what the type of a plan might look like but putting together that type of an operating plan will help you mitigate a lot of these concerns. And then when you use an asset for a particular type of service and when you don't use that asset for a different type of service.

The second scenarios is where similarly what Mike was describing the storage resource gets selected as a transmission asset in an ISO RTO planning process right and in that case you know, if it is an -- the transmission costs can be allocated to a zone then the mechanism is pretty similar. You are going to use the same construct in terms of using that resource to participate in markets and that those monies and revenues actually flow back to the original

set of customers with whom absorb -- actually paid for that asset based on an allocation factor.

And so how we again double up the allocation factor in terms of the cost of the system and the monies that you receive through the market operation have to be worked out in that particular case but in construct it seems like that's doable as well.

MS. NIELSEN: Thank you, Paul?

MR. MCGLYNN: So I think from a -- from an efficiency perspective trying to parse out these storage device -- to have a portion of it set aside for dealing with whatever the transmission issue is that you know would have been a regulated kind of -- transmission asset, it just seems inefficient to me.

You know from a planning perspective we figure out what the needs are on the system for you know, peak load conditions and things like that and there's lots of times throughout the year that you are not at peak, that you are not going to potentially have this planning violation.

So there would appear to be lots of opportunities for storage devices to then participate in other -- and provide other ancillary services to the grid. I think you know once you get there I think then you have to figure out how you are going to operate and who is going to be in control of operating it if you will.

You know I know that the Commission has had some concerns about turning that over directly to the ISOs or RTOs you know because of concerns potentially how they could impact the market. Another alternative and certainly a transmission owner, you know you wouldn't want to -- I suspect you wouldn't want to just have the transmission owner being responsible for it and playing into the other markets because then it would be market participant which you know obviously would be problematic.

So an alternative would be to set up a third entity perhaps that the transmission owner would and could be an affiliate of the transmission owner, but they would contract to this third party to provide a you know -- some kind of contract-based reliability service to the transmission owner.

And then the transmission owner then could -- for whatever those contract fees are they could be the subject of the rate-based rates perhaps. And the rest of the time the third party would be able to use that device, use the storage device in whatever market may be available to them.

MS. NIELSEN: Thank you, Raja?

MR. SUNDARARAJAN: From an AEP point of view I think we kind of view this as a fundamental question of what you are asking here is -- is more of a planning question because in our opinion planning decides how you allocate the

cost -- being transmission or on the wholesale market.

The planning consideration was primarily driven to solve the voltage violation and one of the decisions why the storage was chosen as a cost efficient solution or cost-effective solution than other alternatives was that because it provided ancillary services and you actually had a forecast of ancillary service revenues -- then that becomes how do you make sure that wholesale transmission rate fairs are not back-stocking the cost for the revenues that are being forecasted in the transmission planning process for ancillary services.

So you can solve that through multiple ways -- one is to say either you know in absence of the storage solution you will build something else. It is a traditional transmission asset you have to have a cost construct that you can use to say in absence of building a storage device for example, a traditional transmission line or some other transmission asset to solve for the violation.

So then you have some mechanism to allocate the cost that would be borne purely by the transmission rate-payers given the assumption that the remaining portion of forecast of ancillary service revenues is negotiated through some kind of commercial contract as Paul mentioned -- either you other third part provide or it is not borne by the transmission rate-payers. That could be a commercial

arrangement for being the transmission owner or somebody else and the transmission owner doesn't take that risk for the cost that is not allocated to the foundation rate base.

So we believe that that could be a more efficient construct as opposed to an allocation of well I'm going to consider in my planning process that any refunds of transmission revenues and ancillary service revenues will be an off-set to the transmission costs -- puts a burden on the transmission cost to be a back-stop for the revenues and then effectively they are taking some kind of a market risk for lack of a better word.

And then we believe that the later construct lends to a better proposition that A -- a cost-effective solution is being chosen in the plan. Secondly, the wholesale rate payers -- the wholesale transmission rate payers are not providing any back-stop mechanism for according to your market revenues.

It will be very difficult for a transmission planning organization to forecast transmission and ancillary service revenues for the next 15-20 years and incorporate that as part of your planning process. So that's why a commercial arrangement that either a third party or somebody else can negotiate -- fully understanding that the first rights of the assets is by the transmission owner or the transmission provider in this case so that they can call

upon the assets for liability needs, provides a better construct and kind of mitigates this cross subsidization issue.

MS. NIELSEN: Okay Ed?

MR. TATUM: So I think we are getting a flavor here from the discussion as just how complicated this could possibly be if we do go down this route. I think you know, especially after the last 24 hours nothing is impossible but the question is what is practical and what are we trying to do? And again keep the lights on and have just and reasonable rates.

We have two paths we can go by -- we can do the regulated transmission which apparently is a pretty good business, okay? And folks can make decisions as to whether or not they wish to be a transmission asset and recover their storage asset from that way and have that guaranteed rate of return for umpting ump years or we can rely upon markets.

AMP believes in markets and if we are currently not having enough value from the markets provided to storage in order to get the storage that we need, we should address the markets from that standpoint. But when we get in our feet in both worlds it is going to get complicated and the thing that we would worry about is the lights going out.

And we could see that as very well happening --

we are talking about split usage back and forth, if you have a transmission -- if we are avoiding a transmission construction because we need 20 hours of storage and we have a device that can do 30 by giving that device to be able to play with the additional 10 will all the 20 be there? You don't know unless it is under the actual absolute control of the RTO or the transmission provider.

And then Paul and his team were not too comfortable one with the solution -- this post-contingency rule to keep the lights on, is PJM or any other RTO going to be making win/lose calls as part of how that device is operating?

It seems that we would be in a very difficult situation. What makes markets work are the different views that various folks have going to that market. And if folks think that they can make a better return from a market, then they should be in that market, that's good. But they also could have a choice to be within the regulated environment and still doing a pretty good business. I agree with others if we are going to somehow mix and match these two revenues that do come from this regulated asset, we'd go back to those who are paying for it which would be the customers.

I would worry about surrogates for the investment and the value because again if we are having a storage asset be the least cost transmission solution, that's the solution

that ought to be put into place as opposed to a higher priced surrogate.

MS. NIELSEN: Michael, please?

MR. KORMOS: Just a couple of things that I think were said -- I think you know, we looked at Raja's model and again not that I disagree that it is not a workable model -- I think the issue there is the amount of discounting that would go on by the entity -- the third party entity taking. You are losing a lot of value that could be returned to the transmission customers.

And so why it is workable I don't know if anybody is comfortable they have enough information on how contractually that would work that I think there are some downsides to that model that I think we should consider before we go there. You know I think as far as the transmission customers taking "a market risk". I think they take that no matter what.

Any time the RTO chooses a transmission solution they think it is the most cost effective. I guarantee we could go back and look at many of the decisions that were made and they were not the most cost-effective. You are looking at a 15 year forecast, there are going to be things that change and things that are going to be wrong.

It is what it is, the transmission customers that pay that -- that's an accepted paradox for us so I don't

think that should be a real problem for us in that the ISO assumes some level of reserves. I am sure they would be very conservative. They make those decisions every time they try to decide what is more cost-effective.

How hard is this siting going to be? It's a guess. I mean it's an educated guess but it is purely a guess. Until the line is actually being built you don't really know so I don't worry about that. I understand the issue that a cost of service based asset being in the market but again I would suggest that we have that today. We have a lot of rate-based generation that plays in the market that is in the market and the market works perfectly fine.

They are still choosing the most cost-effective resource in that matter. We have resources that are receiving out of market payments -- I get it, it's an issue. But I don't know if it is one that this one is going to necessarily cause that much more concern in particularly to markets they will play in.

So and the other thing is I think the ISO RTO's I'm surprised to come and have -- PJM actually does schedule resources. They already do provide that service to the pump service resources on the PJM system if they want that. They will schedule it, the pump and what they believe is the cheapest cost areas they will generate it in the most expensive areas.

It is because overall they have information that the market participant doesn't have -- and overall that is the most efficient thing for the system. And so they are never 100% right but they are probably better at it than the market participant if they had to do it themselves.

So I think there is that balance that continually has to be struck. We are all about price formation and we believe price formation is one of the most important things on the Commission plate and I know you are dealing with that and I don't think we are suggesting anything should try to distort their prices.

But I do think we have to balance making sure the system is run as most cost-effectively as we can with the assets that are being provided out there and I think batteries will require changing the way we think. I would be happy to talk more about M minus 1 because I can talk for a long time about that, but I think there are unique opportunities that we can really bring some efficiency.

That will cause changes in the market. But I think that's part of technology and that's part of going forward.

MS. NIELSEN: Thank you, Kiron, do you want to continue you.

MR. AMERKHAIL: Maybe I could jump in. Just to help maybe guide the rest of the discussion -- so there are

to my mind the cross subsidization issue that was raised in Nevada Hydro Western Grid was actually two-fold. One you are worried about transmission customers but two you are worried about the impact on competition in the market itself.

Many of the solutions -- in fact I will go so far as to say all the solutions I have heard so far about sharing revenues from the market with transmission customers definitely seem to address the first part -- making sure transmission customers aren't harmed. But many of your companies also have non-storage resources that presumably derive some revenue from the ancillary service markets.

Would they really feel like it was in -- and I recognize there are other cost-to- service assets but that's actually one of the most controversial things in the market today. We have minimum offer price rules, would they really feel it was fair that they are competing with resources that are providing essentially the same service in the markets but can go in as price takers because they are at no risk because they get their costs recovered in transmission rates, even if they make no money in the market.

So I'll leave it at that.

MR. EMNETT: So for me it kind of comes to a process. Like at what point did the RTO choose the storage resource or something other than the wire? It was after all

other -- I mean transmission itself is a last resort. I mean the market has tried to respond to whatever the particular need is and has not. The energy market, the cost of service regulated, vertically integrated, development hasn't. There's a need that needs to be resolved.

And so to me the question is who is allowed to solve that need? Only wires or someone else and Order 890 they said non-transmission alternatives get a place in that discussion but didn't include any sort of recovering mechanism. And so the question now is should that recovery mechanism exist when the resource that is selected is meeting whatever that transmission need is? And then that will take you places -- you will have to sort of decide what to do with that asset and I think there's generally agreement that if the Commission -- sorry if the RTO were to make the decision to select the storage resource you should then optimize the use of that resource.

It is similar to the RMR concept which I mean I know there were concerns expressed about in a volume of RMR's that the Commission was clear as recently and that your ISO cases and not to get into the substance of anything that is pending but the current Commission policy for RMR is that if a unit is needed for a liability, it is a price taker in the markets because of the reliability commitment based on the RMR compensation has resolved a need that was

otherwise unresolved by the market.

And so it is a similar question here and I don't think that you get to the kind of volume concerns that Tom had on RMR's -- it's more of a conceptual thing. Should an RTO be able to make -- choose among multiple options and if so then you would optimize the use of that resource just like you do in RMR.

MR. KASLOW: It was very timely to wait. A couple of things I just want to respond to. The RMR solving a need that the market has not solved -- I think that has happened and probably will happen in the future. I think Ed had mentioned earlier though the question there to ask is why didn't the market solve that? Why do I need to resort to an RMR? Is there a way to improve that?

That is what happened in New England, we had a lot of them and the solution to that was a locational capacity market where some of that locational value could be reflected through the capacity price. The other comment was if a resource is contracted or rate-based the RTO should optimize it.

I don't know how you can avoid maximizing the impact on competitive markets if the RTO is participating in the market. And I would argue that that would undermine confidence in the competitive market and it means if you still get additional investment the risk premium is going to

have to be higher.

Finally I did want to respond to a prior comment from Mike was you know a lot of the assets are currently part of vertically integrated companies -- that is not true in New England. In New England most of the states have restructured and the utilities not only do not own generation, but with limited exception for renewal resources, they are not allowed to build or buy them.

So this would be a change and potentially if it were considered as transmission equipment might somehow get around state laws that were intended to keep them out of the generation business and the reason that was done in restructuring is because the states saw the wisdom in having investors take the risk of investments and not the rate-payer. So I think there are a lot of hairs on this one and my point in raising it is New England may be much different than some of the other areas.

I think one of the last larger vertically integrated utilities is New Hampshire and currently undergoing a process to divest their assets, thanks.

MS. NIELSEN: So Tom if you don't think RMR is a good structure and you are concerned about the RTO ISO being involved, do you see a path forward?

MR. KASLOW: I think the path forward is having the storage resources such as ours which we currently do --

recover their investments through the competitive market. If there are additional premium values that are provided -- and I mentioned earlier that I think we and other storage resources provide very fast, contingency response or other ramping needs in the case of having a lot of renewables.

Then having a product values that. I understand in the U.K. that they actually do have a very fast or maybe it is called fast reserve but it is a premium reserve product. If that is what is needed then do that but our fear is jumping to a regulated solution has a lot of ramifications that could actually cause barriers to further our investment if you are not part of whatever RTO planning exercise identifies your storage resource.

MS. NIELSEN: Michael do you want to continue to dive on and then add your comment okay, so please do ahead.

MR. KORMOS: I think the concerns are very legitimate and one of the things that I would suggest is that I think the process is how the decision has been made would have to be very transparent to the market. I think those that are in the market fully understand that risk and we understand things will change.

We will have to react to those changes. They are not always within our control and many times they are due to externalities. So I do think one of the benefits here is that if you are being very clear and very transparent of how

the batteries are being selected -- as Mason said, well in advance -- how they ultimately would be used and what the rules would be of using them -- making it clear they are not being forced into the market simply to lower prices.

They are only being used when they are in fact the most cost-effective solution. I think the market can respond to that. I think the market can react to that and I think it is something doable. But it will go down to the RTO will have to have clear and transparent rules as to how those decisions will be made.

But again, I think that's the benefit of having that independent entity to do that. I'm all for markets solving every problem but I think we have learned that that's just not feasible. There is some societal benefits -- there is some social benefits that the fact of the matter is the regulated services are maybe a better model.

And that is why transmission is where it is. There are ways to add competition to that -- we have Water 1000, I think Water 1000 will be a great way that anybody can provide these kind of solutions -- better solutions and whether it is a pump storage provider or whether it is a generator for providing -- not necessarily be just transmission owners doing it so I think there is a lot of value there.

And I think again to sort of go back to the

concerns, I think they are legit and they are real but I think transparency really is the best answer at this point.

MS. NIELSEN: Thank you, Kiran?

MR. KUMARASWAMY: I just wanted to say that on the subject of cost-effectiveness for some of these applications like peak flow relief right here -- I want to go back to Mason's point which he made pretty well which is often times what we see is the storage solutions aren't even considered in the planning process. So that if you take the shape of the load variation curve and find all the critical load level beyond which actually trigger violations to the system -- we actually systematically see when those time charts actually happen in the system and how often are we exposed to that type of load level that triggers the violation need.

So I think the first step is for us at least to get to the point where we know exactly where the trigger point happens for an upgrade project. And then the second point really is that when that happens storage also has the capability to be extremely modular in terms of how you slice the system right -- and that can be really helpful in periods of uncertainty right.

And I think -- my topic with this -- we've all seen this, transmission projects get planned and we have a device load grill because of various reasons and then we

have different plans right -- so in periods of uncertainty if you don't want to sink in big capital expenditures on a single project, it is a great way that you can actually provide for the relief that you need.

In blocks system it is very modular right with an option to scale over time right -- and that actually helps you it really makes smart investments into the needs that we see in the transmission grid. That's number one.

The other advantage that it also brings us -- you are only paying for what you are using right and so any capacity that you add in the future it gets augmented over time -- depending on whether the load grows or whether you can keep the capacity where it is. And if you are buying the solutions in the future the cost of storage is also coming down right and so there is definitely a bridge also that you actually have in terms of effectiveness of storage for peak type relief types of applications.

MS. NEILSEN: Thank you, Raja?

MR. SUNDARARAJAN: I thought the question was to the extent any of the storage is compared to other transmission alternatives for solving a transmission need -- i.e. solving a thermal or voltage violation or any other consideration that you impose on and then on top of that given the fact that storage can provide other benefits given the fact that the thermal violation actually -- the

mitigation of that only happens a few hours in a year in some small segment.

And the storage is basically sitting there idle to provide other benefits -- that's the issue here as opposed to where you predominantly are using storage for ancillary services only. The predominant use of storage in this case is to solve for thermal or voltage violation and this is just happens to be an ancillary benefit that you derive out of it.

The problem becomes when you are in the planning process and you are considering this compared to other non-traditional alternatives, storage becomes more or less cost-effective when you don't consider those benefits. And so that's why how you -- when you plan for this, what assumptions do you derive on the revenues from the fact that storage actually provides other benefits.

It is an important determination of why storage is more cost-effective than other transmission alternatives. And given that that is the main reason why you made the consideration you have to factor into account that that revenue can somehow be relied upon as opposed to imposing that on the transmission rate fares.

Either you can rely upon that through some kind of a commercial contract with the generator plant and the ancillary service provider to say that make sure that the

pro storage asset is available for transmission needs first and to the extent you are not there are penalties associated with it.

And then you find out what the true value of ancillary service is assuming the reliability violations are solved first. That's in our opinion, a more-cleaner contract that solves more the issue of cross observation and B -- not having the wholesale transmission rate as a back-stop on these revenues.

And to the extent you can do that you say then you can make an apples to apples comparison between the storage that is being allocated to transmission rate payers is comparable to transmission owners and the planning process in our opinion makes it a little simpler.

If you don't do that, how you forecast these ancillary benefits and imposing that and then incorporating it as part of the planning process becomes your single most criteria. Because that's where you know either you would solve the transparency that every stakeholder can argue on those assumptions and make sure that when you are imposing that as a back-stop make sure that the very news that the violation providers is reasonable, that's one way to solve it.

Otherwise you let the market decide what the value of the storage for a non-lineup assuming the provider

has a right to call upon assets first. And then let the costs -- subtract the costs of those revenues and then allocate the cost for the violation rate-payers.

MS. NIELSON: Thank you. Ed?

MR. TATUM: Thank you, so I think we clearly could use a little bit more imagination in our transmission planning. I like the idea of taking a look at the load shapes and I think there could be opportunities there for storage to be used as a transmission asset. One thing that I would be concerned about from a consumer and a customer perspective though is we talk about cost-effective you know we try to think of the lowest possible cost for a reliable system.

I don't know but is the premise here that there is currently not enough revenues for storage assets? That they need more revenues that we have to get them more money to actually get them in there? If that is indeed the case are they currently where we need to be? We made great technological advances on storage, the price has come down, the capabilities have come up but for consumers, what are we trying to do here?

Transmission as I said earlier is a pretty good business and that's not a shabby rate of return and return on equity for a long term. A lot of folks would like to be able to have that type of certainty and return on their

investment. In the same way though we have got markets and we have the ability to make sure those markets are working, we have the ability to become more sophisticated with them.

I think you guys have asked a question earlier about regulation and frequency response. I think that we still might need to talk about that if there is additional value that storage can provide there.

We can certainly try to storage provide both but as you have heard from this discussion here today there's a whole lot of additional steps and processes and things that we need to think about and talk about and work through and ensure that the lights would indeed stay on if we truly have that as a transmission asset.

MS. NIELSEN: Thank you, Mike did you want to add a question?

MR. HERBERT: Yes regarding the sort of the model we talked about where you have got the storage asset you know it has been chosen to provide some sort of transmission benefits or transmission need and then potentially participating in the wholesale markets as well. I think assuming we have overcome the threshold question we have an asset that has been chosen in the transmission planning process.

I think all of this is kind of hypothetical for you so maybe you will have an answer maybe you won't. How

would the operator actually decide to dispatch that asset in real time? I mean if you -- if it was providing congestion relief into a load pocket would you dispatch that asset as the first, lowest cost generator up or would you only dispatch that asset when there is no other generator in that load pocket that can potentially provide energy and you just absolutely have to get something else in there.

Because I wonder -- I guess I wonder how the dispatch of that resource and the hypothetical situation would differ from the dispatch of that resource if it was just a market participant and then you know potentially whether or not making that resource also being a market participant is even necessary.

MR. MCGLYNN: So your question is a good one. I think you know to me to Ed's point the first thing is about keeping the lights on right? So we would need to make a decision about whether the storage device was going to be needed to address whatever -- I'll call it a planning related thing -- item issue. Short of that issue being you know expected or anticipated within the next dispatch period you know it would appear that the device, the storage device would be available to be used for other -- in other markets.

Your question then about who gets to decide when it is going to be dispatched at that point I suppose the RTO could decide at that point to do it but again I think

there's potential issues there with the RTO then having impacting the market and other market participants and things like that.

So you know I think perhaps an alternative to just turning that decision right over to the RTO would be to have again a third party providing you know kind of this reliability service if you will that they could provide but then otherwise the device could be used for -- in all of our other markets whatever that may be.

You know fundamental though, one thing that I haven't said before is that obviously if the device is -- the storage device is going to be there and needed and required for providing some kind of reliability service -- transmission service if you will, clearly the RTO would be to have a right to recall it.

You know so if the unanticipated thing did happen and if the device was you know, operating in the market doing something else you know we would need to have -- clearly need to have the ability to call upon it to provide the service, the reliability service, that it was you know intended for.

MR. KORMOS: Probably just to build off of that a little bit because I think probably one of the interesting things about this is there is multiple ways to use the battery so it is very specific to the application you are

trying. I think you know if you are going to actually try to discharge the battery to cover an overload, it really would be an operating procedure. It would be the last thing, it would be the reliability.

You would kick it in when all other cost-effective means are done you would then use the battery. One of the reasons I like when we talk about using it post-contingency versus pre-contingency is you are not actually dispatching the battery until the contingency happens. So you have the defining event that says until the contingency trips you are not.

So the only thing ISO has to do is make sure the battery is charged and ready to go under the circumstances I think that's more clearly. If we are talking about dispatching it outside of the reliability need, the ISO knows it's not needed. I think the easiest answer again it is a cost-based thing.

The battery -- there is a cost to charge the battery. So if it is going to then just be dispatched as an energy resource it would fit right in the bid stack based on its cost. And again its cost was whatever the price was when it charged, or whatever it expects the price to be when it recharges.

And again this is very similar to what we do with pump storage plants as to how you dispatch them. So I don't

think again you have to worry about how the RTO would dispatch. There's a pretty clear precedent as to how you dispatch storage resources based on the cost to store the energy in the first place.

MS. NIELSEN: Thank you, Tom?

MR. KASLOW: Thank you. First of all I think we do have examples of cases right now where the RTO activates a resource or directs it to active and it is not price-based. In New England that is currently the only way that real time demand response is activated and it happens when the system experiences an operating reserve deficiency which is when you start to hit scarcity pricing.

So what does happen on occasion is when you activate a block of unpriced megawatts -- sometimes it actually removes the deficiency and so you go from scarcity to no scarcity even though the action itself may have been relatively expensive and it interferes with that pricing and caused a lot of uplift, all the inefficiencies that you have probably heard before.

I would like to approach the question a little differently. I would like to -- getting back to if a storage resource participated as a competitive market resource -- it puts in the bid prices which are instructive to the economic dispatch of the resource, but the RTO always has the ability to either turn the resource on, if necessary

to meet transmission reliability needs even if the economic dispatch wouldn't do it and it always has the opportunity in the case of limited energy resource to -- what New England refers to as "posture the resource".

You want to generate -- I don't want you to generate because I know something that you don't, I'm taking over your dispatch basically and you are going to hold on to that energy and I am going to make you whole for it. So I am not complaining about that the provision is actually relatively fair now.

So I don't know what it is that we are trying to solve with this particular one. I think the only time you have something to solve is if you are trying to dedicate a storage resource to solely transmission use which I think from earlier discussion raised the question of why would you do that if there is additional efficiencies that can be provided by the resource and if additional efficiencies can be provided why can't they support themselves on market based compensation, thank you.

MS. NIELSEN: Thank you, Mason?

MR. EMNETT: Just one quick think to add because I know we are running out of time but I think the core of the question is how would the posturing/state of charge management operation -- how does that all fit into the RTO bidding in offered perimeters and dispatch algorithm. Well

I think you have got that problem regardless of the last two hours of discussion on whether the asset can initially provide a transmission need, that storage resources are asking those questions in the separate docket on the RTO market rules.

That the way that the offered perimeters and dispatch algorithms are set up now is they are defined, they are set in a way that is trying to achieve or extract the maximum value from the use of generation resources. And then over time they have been tweaked for command response.

As Mike said pump storage, kind of taken care of in PJM to fit within there. But the question is do those offer perimeters and the dispatching algorithm do they need to change further for other types of storage technologies to extract the full value of its resources and whether it means that the RTO is more involved in state of charge management or less involved or what the set point perimeters are -- that will be figured out.

It has got to be figured out independent of this question on you know solving the transmission need.

MS. NIELSEN: Thank you, Ed a final comment?

MR. TATUM: Well thank you. The algorithms Mr. Kormos was talking about with regards to the ability to go ahead and use energy storage as a transmission asset but also the ability if it is doing other things. And the

question is -- and we are talking about the reliability aspect of it and the lights are going to stay on or now. What happens if that transmission storage asset was completely discharged at the time?

We don't have -- I don't think Paul the level of clairvoyance yet to really be able to foresee and predict the transmission outage. I think that you can get a transmission outage just like that and so if we are doing that, we are going to have to be thoughtful about minimum levels of charge required.

You know we would have to actually get into the technical requirements of what was the characteristic of that storage device that solved the transmission constraint to assure somehow it would indeed be there for all those unforeseen and unpredictable events that could occur. So I just want to put that reliability point on the discussion.

MS. NIELSEN: Okay we need to wrap up. So if Raja and Kiran could be very brief then we will close our panel.

MR. SUNDARARAJAN: Yes, from our point of view, AEP's point of view, just because it is complicated to solve doesn't mean you get out of it. So I know Ed and the panelists raised extremely important points of terms of yes it is typical to solve an issue but in our opinion there are constructs that we can provide to solve the issue of both

cost subsidization and the impact of comparative markets construct.

The aspect of the specific question that Ed raised -- I want to make sure that the existing foundation, if I rely on energy storage as a foundation asset how do I make sure it is there? It is no different from any other transmission asset that you built and you know you incorporate that as part of the planning process, that's part of the M minus 1, minus 2 then this becomes your M minus 1 scenario.

So the moment you classify this is a transmission asset it becomes the closest to the planning process of seeing what happens if the design is out and you have the same thing that you do with everything else. I think it incorporates a different element of the planning process but that doesn't mean that should be the only reason you stay out of it.

UNIDENTIFIED SPEAKER: But you are already a contingency.

MR. NIELSEN: Kiran?

MR. KUMORASWAMY: Yes I will be pretty brief. I completely agree with Raja that's the same perspective that we have at AES. I mean we came into the space long ago, 9 years ago, we have several assets that we operate globally and we have a level of the confidence that these are

extremely reliable assets right and to the extent that they are pretty close to the availability factors that you actually see on the transmission system.

And I want to quote what Raja said which is that, "There's a learning process that you will go through in terms of integrating this into the planning process, but you have to make an entry point somewhere," right -- I think as we see the traditional transmission planning processes that only consider traditional solutions for fixing every terminal overload issue -- we see that as a great opportunity for us to use storage to solve it in smarter ways given that the technology is mature.

And given that we are living in a period of uncertainty with respect to many factors that influence it. And so that's a great opportunity that we have and I also want on Ed's comment which is very true that it is great that this discussion is actually getting to that point where we are talking about operations right?

In that type of a mold I do agree with Ed that you have to have the storage unit completely charged up and its capabilities for it to provide that post-contingency relief right and so it is an important aspect, I think that's part of like designing the system for providing that application. And if you are able to do that the significant benefits that the system realize because of doing that,

because again the way we operate the system is based on those deterministic contingency events.

Regardless of how often those contingencies really happen in the system -- we posture ourselves -- those contingencies really happen. We never go back and look at if those contingencies happened at all in the last 10 years or 20 years and so the point that we are trying to make here together -- offers here is that you can leave the technological advances in the storage space for you to get to a point where you derive more efficiencies the way we operate the grid today.

MS. NIELSEN: Okay thank you very much. Anyone on staff have any questions -- no. Well thank you all very much for the discussion today it was very helpful. We will break now for lunch. We are running a little behind but I think we will be able to catch up later this afternoon so let's plan on reconvening at 1:00, thank you.

(Whereupon a lunch break was taken to reconvene this same day at 1:00 p.m.)

A F T E R N O O N S E S S I O N

MR. AMERKHAIL: Alright folks we are going to need to get started pretty soon so if I could ask the panelists to start moving toward their chairs please thank you.

Alright I think we would like to begin with our

second panel now please. And again we would ask that everyone turn off their phones or set them to airplane mode to avoid interference with the sound system. Also there is an overflow room in Hearing Room 3 on the other side of the elevators if anyone needs that.

So the purpose of this panel will be to explore potential models to enable an electric storage resource to provide grid support services under rates other than transmission rates. We hope to hear about existing processes that might already be considering resources such as storage devices for this type of non-transmission cost recovery, such as transmission planning processes that consider non-transmission alternatives but then feed the resulting projects into local resource adequacy or other processes for cost recovery.

We also hope to hear about processes that may not have been used this way in the past such as reliability must run contracts otherwise known as RMR contracts and black start procurement processes where stakeholders could perhaps consider expanding the process to permit competition from new resources like storage devices.

But let's start with the non-wires -- with how non-wires alternatives are considered or better yet may already have been considered in transmission planning and what happens or happen next. Neil I understand that Caiso's

transmission planning process has some experience with this so could you talk about that for the benefit of the panel? Thank you.

MR. MILLAR: Thank you I would be pleased to. Yes in the ISO transmission planning process we look both for opportunities for transmission alternatives as well as identifying the requirements that we would have that could perhaps be met by either non-conventional, non-transmission alternatives.

Our best example of this actually goes back to the loss of the 3.06 for nuclear generating station where in order to allow the continued retirement of a number of gas-fired generators on the coast as well and not be impacted by the loss of generation. We ended up looking at an integrated solution that drew on some conventional resources, some preferred resources including storage as well as some local transmission upgrades.

If we hadn't had the first two the transmission operates would have had to have been far larger, far more serious upgrades than those that we were able to move forward with. Now the resources that have been procured -- that's taken place through the state's capacity procurement mechanisms and through bilateral contracts with the utilities with the resources themselves.

And that's worked -- putting it bluntly both for

conventional as well as these preferred resources both batteries, energy efficiency programs and other types of products -- so we see by the end of the year we should have close to between 2 and 300 megawatts of battery storage connected to the system, largely as part of those programs.

There's also a state mandated program that is broader calling for battery storage to be developed inside the state. These local programs count towards those broader programs so they are not instead of -- they layer in under part of that procurement.

On the other hand over the last 4 or 5 years we have studied 17 different battery storage proposals that were made to us as transmission assets. Those tended not to be successful, either due to a combination of the cost or the necessary characteristics, the requirements that we had to impose on those devices, they simply didn't measure up to meet the needs we had.

We have two more to look at in this planning cycle so that's a continuing evolution but we certainly had far more success through the capacity procurement framework than looking at potential battery storage projects as transmission assets.

We have considered the RMR type model but that for us has normally worked more where we are retaining some requirement out of an existing resource as opposed to a

mechanism to get new capability actually developed and built. So those are sort of the key points we have been looking at.

So I have to admit we have actually been both appreciative of the flexibility we do have, to look at products as transmission products in those narrow cases where the requirements would really require us to lock down what the unit is doing but also to rely on the capacity procurement framework where we have resources and a basket of resources that we can be more open to letting the market run with the resources and only step in and dispatch outside of market when we absolutely have to.

So that's been minimizing the impact on the market but still allowing these resources to move forward.

MR. AMERKHAIL: Thank you Neil. Follow-up I assume you may have seen the prior panel and there is discussion at the end of the fact that in planning you would look at the M minus 1 contingency, whatever reliability issue you were trying to address and that you would put appropriate limitations on the resource.

And it sounds like that's exactly what you must have done in your planning process with the transmission battery proposals. Could you talk about what kind of limitations those were?

MR. MILLAR: Actually it's close to that but we

actually started the other way around. The first thing we did a few years ago was to develop basically what we saw as being the generic characteristics that these resources would have to provide and we really identified the three factors of how much notice do they have to get dispatched, how many times a year would we realistically expect to call on them.

And when we do call on them what's the duration? How many hours of output do we require? And we put out some generic information that would generally meet our needs just as guidance and then in the transmission planning process when we have a particular need we will sharpen our pencils a bit and try to provide a bit better picture of what is required in that area.

That also happened in the other procurement that I was talking about with the loss of the -- generation. We provided more detailed characteristics to the utility to use as part of their procurement decisions and that material was then debated through regulatory processes approving their contracts.

So we tried to provide the rough characteristics in advance so that people can propose projects into our processes that meet the needs.

MR .AMERKHAIL: Thank you, would anyone else like to comment on either their experiences as a developer in a process like that if you have any or on things from your own

RTO -- John?

MR. FERNANDES: Thank you and good afternoon, John Fernandes from RES Americas. I think generally speaking most of your ISO's RTO's right now have an open mindedness towards storage as a non-transmission alternative. I think though that there might be -- not everyone might be far enough along to really do the complex modeling that is needed to optimize the system, charge, discharge based on what could be extended needs as an operational resource.

And that's where we the developers are certainly building those capabilities quite quickly so I think there is possibly a little bit of a disconnect between -- sure we are willing to take a look and yes we will actually deploy this for those purposes, treat it as a transmission asset, give the appropriate kind of rate recovery and until the development community has some level of certainty that there is at least some likelihood that non-transmission alternatives will be selected it is hard for us to justify spending the time, the resources, the effort to really put together viable projects -- so more certainty would be helpful there.

MR. AMERKHAIL: Thank you, does anyone else have anything or anyone from staff on this topic? Well again I guess we should move on to existing processes that may be

leveraged. Let's talk about RMRs. The way I look at them they are generally executed in order to support the grid in some way yet their cost as far as I know are not recovered in transmission rates -- Eric can you confirm that?

MR. HSIA: This is Eric Hsia from PJM, confirmed.

MR. AMERKHAIL: Okay would you say that they are recovered more locally generally than transmission rates?

MR. HSIA: Yeah so this is Eric Hsia from PJM -- so the current allocation for our market at least at PJM there's a cost recovery, cost of service, it is allocated to the network load customer, to the zone or zones to actually -- eventually it will pay for the transmission upgrade as that is how it is currently being allocated within PJM.

MR. AMERKHAIL: Okay thank you. Do either of the other RTOs have anything to add on that?

MR. DESOCIO: This is Mike DeSocio, from New York ISO. So our filing contemplates very similar cost allocation to those that are benefitting from that asset being retained on the grid.

MR. AMERKHAIL: Okay thank you.

MR. MILLAR: It's Neil here with the California ISO. Yes, those costs in our system are also recovered from that local transmission area, the same as the local transmission charges would be.

MR. AMERKHAIL: Thank you. So in the past when

your RTOs or ISOs identify a need like this do you or have you ever opened a competitive process where resources that may be very rapidly deployable could compete with the departing generator or has that just not been an option up until now so it never came up? Do you want to start Eric?

MR. HSIA: Sure, at PJM we haven't had the opportunity to open up as a competitive bid for that service. We would look at -- our planning department will look at every option possible, also look at existing transmission upgrade and see when that will be in service and available to essentially alleviate the concern that we have.

But at PJM we are certainly not opposed to potentially open that up as a possible option. Certainly we do recognize that there is a lot of benefit from energy storage assuming that they have the capability to provide the service we would certainly consider that as a possible option.

MR. AMERKHAIL: Thank you, Mike?

MR. DESOCIO: As we contemplated RMRs in New York we really thought about dealing with a short-term need. And as we thought through that you know we really thought that the purpose to deal with that potential it can happen in reliability and retaining an asset that is already there to deal with that gap.

And then leverage the markets to really deal with the longer term issue so the planning processes are really designed to typically be focused on that short term issue. We haven't really had that opportunity yet where we have been faced with a situation where storage could participate in an RMR yet.

MR. AMERKHAIL: Thank you, Neil?

MR. MILLAR: We have had the situation where we saw the need collectively -- I shouldn't say just the ISO but collectively to move on additional storage procurement to help mitigate the impacts of the outage of the Aliso Canyon Gas Storage Field and the CPUC issued additional procurement requirements for the utilities to pick up additional battery storage to be online by year end of this year.

So that was probably the most expedited procurement of storage that we have seen and we have been working with the utilities to make sure that's moving forward, properly represented in the market and online by year end. That will be just under 110 megawatts of storage.

MR. AMERKHAIL: Thank you. Let's turn to the developers for a minute. I'm sorry Anuj?

MR. KAPADIA: So while we are talking about the planning and the operations and I think Eric you said that you did look at other alternatives for planning. Can you

explain a little bit more about what are the different planning aspects you guys looked at, how did you model it versus in operations?

I think John mentioned that you guys are modeling something with the operations which kind of you can turn it on and turn it off when there is an internal project, can you talk a little bit more about that I guess?

MR. FERNANDES: Sure, so as far as the modeling processes that we have been using -- I can just talk about projects that we are actively developing. A lot of them are for utilities for grid services but you are talking about down at distribution -- that's where a lot of these guys are starting. And there are several examples of this around the country.

The modeling gets interesting though because the utilities that are coming forward already and deploying these projects are also using the storage for other purposes on the system, grid balancing -- if they are in a market they can realize the value of something like frequency regulation. If it's a vertically integrated non-market utility it is just a lot of cost offsets whether it is peaking energy or the same type of balancing services.

And so that's where the modeling starts to get a little interesting because you are looking at what has been historically considered a wires service even if it is at

distribution and then your non-wire services. So when I talk about the modeling that's really what I am referring to. A lot of your standard sign PSSE, whatever they may be -- your standard utility software platforms aren't necessarily doing both so that's where we need to start shuffling them together if you will.

MR. HSIA: So from a planning ground when they do the study they actually look at more of a reliability concern within the zone so we look at AMI's to contingency voltage issue or thermal issue and see if there are available resources that we can actually dispatch around the control position.

So that's part of the kind of planning study process to ensure that we can potentially have an option to control. Now if we don't have that option we don't have an impending transmission upgrade that will be in service we would offer the generator to retiring the RMR contracts to see if they want to continue to generate, to help us with that issue.

MR. AMERKHAIL: Okay so returning to the idea that in the past when you are faced with an issue like this it is often because generators made a decision unexpectedly to leave the system and you have to address this temporary reliability concern until you can put in place more permanent solutions.

And I would think in the past there was no real option to have anyone compete with the retiring generator so my next question to the developers is just how fast could you move a storage resource from a warehouse or some earlier location to wherever it might be needed on the grid? Load it on the truck put in place many modules that are necessary for the particular concern?

Maybe we will start with Jason because you represent the whole range of the industry and you could talk about different technologies perhaps.

MR. BURWEN: Sure, thank you and thank you to the staff obviously for putting together this Technical Conference. I appreciate it. In terms of this particular question certainly containerized storage is made in such a way that there is portability to it and certainly we have seen examples of containerized storage being moved from for example New York ISO into PJM.

So we know that that redeployment is possible and I think that certainly -- when we think about the timeline of that it comes down to in some respects, the sort of nature of the interconnection not simply just the time it takes to load it on a truck and drive it.

But also sort of in line with that idea as referenced certainly by Neil we are seeing very rapid deployments of energy storage as well at this time in part

as a response to the Aliso Canyon Reliability issue and this is something that we expect to be a continued capability of the industry and of developers in the tens of megawatts to one hundred megawatt availability and something that certainly we think asks the question of the ability for storage to be a competitive alternative bid for RMRs in the situations where it makes sense to do so.

And I can speak obviously a little further about that when you would like us to.

MR. AMERKHAIL: Bill or John, do you have any thoughts on this?

MR. CAPP: Sure, background -- the last time I appeared here I was representing Beacon Power CEO involved in trying to open the market for storage so I appreciate the opportunity to be here with you again on one of my favorite subjects obviously.

But to the subject of portability I agree with what Jason said and that is the interconnection process or other limitations of the equipment quite voltage or whatever may be the longer term issue than just taking a container full of batteries and installing them in one place or another.

The largest data system in the world is actually in Japan. It came online early this year, it is 300 megawatt hours and it was made up of 20 foot containers, 252

20 foot containers that were shipped to the site and we brought it online -- it was about 9 months from the time of the order to the time it was operational.

And those systems can easily be you know rigged to another location along with part of the electronics but it is likely that it would be something else besides just that equipment that will be not quite right that might require some adjustment. It is possible to have flexibility built in if you think about that being a goal of this kind of equipment you can imagine there being a lot of portable generators today that are designed in a way so that they can be easily adapted to a location where they get installed.

You can order up to 2 megawatt portable generator from Caterpillar and you would probably have it here tomorrow if you wanted it.

MR. AMERKHAIL: Thank you John.

MR. FERNANDES: Yes I mean just in terms of the timeline you are talking months. We would for an actual plant deployment to meet a need like this you would be talking in terms of months and if there were a way to expedite an interconnection and permitting process, things like that -- if there were a site to interconnect because of the very specific localized need you are talking about even fewer months, so less than a year.

MR. AMERKHAIL: So if it is a departing generator

obviously and there is already interconnection facilities you are saying it may be faster to just plug into the existing, okay thank you. So then back to the RTOs -- months or less fast enough to address the interim need that comes up in a situation like this -- do you want to start Neil?

MR. MILLAR: I didn't think there would be a race for the microphone on that one. The -- I think the bottom line is it depends on the various specific circumstances and especially the voltage level of the interconnection. If we are talking a smaller battery storage project connected to the sub-transmission the ability to interconnect that project more quickly is higher.

Once you start looking at a much larger installation and especially if you are in an area that by definition must already be having some issues or else we wouldn't be expediting the procurement. Just getting through the technical work to be convinced that the unit can be safely, reliably connected -- it is not going to interfere with any of the other operations in the area and also that there is adequate opportunity to charge the battery, that's actually part of our standard interconnection process for batteries is to study them as a generator but also to test that there is some reasonable opportunity for charging.

And especially if it is a larger facility then it is necessary to get it properly reflected in a market model and EMS systems, so that also can add some time. So months is very tight -- we were able to move in about a 9 month period for some generators -- some storage projects coming on by the end of this year but that was working in parallel with the design teams working on sites that they had previously identified as potentially good interconnection sites, developing the models for how the control systems would work on the batteries themselves, getting those models to us so that we can probably study the implications.

So cutting it down to a couple of months I would say that might work for smaller projects but if you are looking at the larger transmission system, high voltage grid, and especially in an area that has something that is challenging already or you wouldn't be dependent on the resource. A few months is pretty optimistic to get through that to make sure that you are not doing something that is going to promote or deteriorate their liability in the area.

MR. AMERKHAIL: Okay thank you.

MR. HERBERT: Neil and potentially Eric and Michael as well -- can you give us a sense of sort of the time frame of the retirement process for generators? Like when they submit that request, when the RTO or ISO determines you know whether or not they are going to need to

stay online and at what point in that process you could sort of say you know how many months before that retirement do you determine whether some sort of RMR arrangement is necessary?

MR. HSIA: Right so at PJM if the resource is a capacity resource they are required to notify us three years in advance so into account from a BRA but if you are not a capacity resource typically it is a 90 day notification and PJM has 10 days to respond to the request -- I should say 30 days.

MR. AMERKHAIL: Sorry repeating -- to state the obvious for a capacity resource in PJM at least with a three year notice requirement there might be plenty of time to look at alternatives and obviously for a non-capacity resource it might be a lot tougher although at the lower voltage level it is not impossible. Does anyone disagree with that? Okay.

MR. HERBERT: I guess is that similar in California and New York?

MR. MILLAR: I think -- I shouldn't be quoting this from memory but I believe it is 60-day notice if it is not a unit that has any other strings attached. One thing we have been trying to do though is looking at out of that concern for what our exposure is to any -- we think we understand our exposure to any single generator around what

the implications are.

So when those notices come in it is pretty straight-forward that we have already considered the implications. One thing we are starting to look out now -- I'm actually starting in this year's transmission planning cycle, is looking more for where we have clusters of generators that are similarly situated both in terms of age, technology, the economic pressures they are facing and starting to do more study in advance about what if two or three of those units all come to the same conclusion or their owners all come to the same conclusion at the same time.

So that to us has been the larger risk. Most of the retirements we have been dealing with that were in a reliability challenged area were the ones through cooling generation along the coast and for those we generally have years of notice. The plans have been developed in advance and we were working towards a measured plan for those.

MR. DESOCIO: So in New York we are looking for about a year notification and then from there we give ourselves about 90 days to complete any studies for need and then from there we are really working through contracts and things like that.

MR. AMERKHAIL: Thank you so I would like to explore the customer side of this issue. We heard a little

on the last panel from one of the panelists that RMR contracts are frequently controversial. Charlie -- am I right that some of the members of your association cooperatives are located in RTOs and maybe assigned RMR costs at times?

MR. BAYLESS: We have six members out of 26 members that operate in PJM in the northeast corner of North Carolina and yeah depending on where the retirement of the plant is they could conceivably be charged RMR costs.

MR. AMERKHAIL: Okay so my impression of part of the reason why RMR contracts -- I mean to me the need makes sense. Transmission planners don't have guide-like access to perfect information so there are always going to be interim issues that come up that they weren't ready for but part of what makes people dislike RMR contracts is it feels like the generator should be in the market instead of getting you know -- it shouldn't have the choice of cost recovery and some other fashion.

So I am wondering from a customer perspective would you -- do you think people would be more accepting of an RMR contract if it resulted from a competitive process? Even if it ends up being the same departing generator at the end of the day they had to bid against somebody else who could be deployed in the timeframe needed so the customer would at least know it is the cheapest cost alternative?

MR. BAYLESS: Yeah I think that's -- one of the things that we are looking for is a competitive process. I mean we want to make sure that reliability is maintained, the best technical solution is maintained, but to do it at the lowest and most efficient cost. You know looking at all the variables, if energy storage meets that cost at the lowest methodology then you know that's fine if we go with energy storage but if some other technology can meet the same solution at a lower cost then you know we would favor that.

It just is the lowest cost for customers and it still maintains reliability on the grid. The technical aspects of whatever solution you are looking for.

MR. AMERKHAIL: Absolutely and I assume there could be other resources that could be deployed in the timeframe needed?

MR. BAYLESS: Yes.

MR. AMERKHAIL: Jason do you have follow-up?

MR. BURWEN: Sure I just wanted to also raise a sort of related note and when we start talking about the cost of RMRs and what alternatives might look like. What are we comparing also is I think an important conversation. Certainly you know we see RMR contracts as sort of managing around market inefficiency for unit retirements and there is not therefore, any sort of demand signal or compensation for

flexibility.

There is certainly one thing that I think should be borne in mind with this but to that end what does that signal? Is it the cost of the RMR contract, recognizing that there are also transmission upgrades that have to occur after that unit effectively finishes its contract and so when we think about what the value is here, particularly if that storage unit can be managing for an extended period of time -- then I think it raises the question of are we talking about just storage versus the short-run cost of an RMR contract or storage versus the short-term costs of an RMR contract and transmission upgrades that follow if it is able to stay in service and provide the reliability functions it needs to.

MR. CAPP: I guess I would be a little bit concerned about the competitive nature of that if you are essentially providing additional payment to the generator to make the economics extend a little bit longer. I mean the classic one is an old generator in a load pocket and you are just trying to get voltage control.

You try to find an energy storage equivalent that could show up in what could be a congested area and go through all the process of the design and the interconnection to make that an equivalent -- there's a lot of additional costs that would come along with that,

although I favor the idea conceptually I just think I might be a little bit skeptical that it could work in many occasions.

MR. AMERKHAIL: Thank you, Mike?

MR. DESOCIO: So there's a couple of things in New York that might be a little bit different than other places and I am not really familiar with the other areas but in New York when New York is doing its' planning -- its comprehensive planning process, it really is going through a reliability needs assessment every two years. And in doing that it is looking to determine whether or not there are good needs. And from that determination we are really looking for market-based solutions to help meet those needs.

We will look to the que to see if the project is already in the que that could solve the need and if not solicit other projects. To the extent that we don't find the project that could meet the need then there is a back-stop where the transmission owner can participate and deal with the reliability needs themselves.

If we then move to the RMR, the RMR is really focused on -- we have a generator or a resource on the grid and it has told us, "Hey I am going to retire, I'm not making a go of this anymore," and then we go through a process of looking at whether or not we have reliability needs after that retirement happens and if show should the

contract for that generator stay on until we can solve those needs.

Making this a competitive process I think extends the timeframe for the notice because it is going to take us longer to go through all the projects to figure out viability and sufficiency and whether or not we can deal with all of those things. Not a bad idea it will add time to those processes.

MR. AMERKHAIL: Thank you. Does anyone have anything to add? Okay -- well let's just ask then assuming people explored opening up competition in this particular product would developers find it to be an attractive opportunity to compete, John?

MR. FERNANDES: Yes absolutely. I mean we always welcome solicitation processes like that. We welcome the chance to compete. I think before -- especially for energy storage before we even get to that point though and I'm pretty sure this came up on the first panel -- I'm sorry I missed it, it was a busy day for renewable energy guys this morning.

There needs to be an examination of storage resources being able to capture value across all spectrums in which it can provide a service. And so I wouldn't be necessarily looking to come in with a storage plan and just collect revenue or a value stream for this one offset of an

RMR. I might also want to participate in the real-time market at certain times. We still need to discuss how exactly would this be a cost of service type arrangement -- transmission rates and so I think -- I think there needs to be just -- I'm debating whether it is a general understanding or a specific agreement that storage needs to be able to cross asset classes that allows us to make it affordable, make it economical and make it just a more efficient resource than a lot of the alternatives that are currently either being put in place or just started like RMRs.

MR. AMERKHAIL: Thank you, I believe Jason is next.

MR. BURWEN: Thank you, on that point I think that in terms of the interest in these kinds of potential competition procurement here certainly one of the problems we face right now is that RMR arrangements aren't really necessarily executed in a transparent manner. They are almost obviously never bid out but they are also not necessarily -- I mean I'm glad to hear Cal ISO's are sort of looking ahead at these generation clusters and starting to take this into account that they are generally not considered a part of transmission planning in terms of thinking ahead where those unit retirements may be showing up in a way that accounts for the cost of RMRs in these

processes.

But in recognizing that there are reasons for that I think that the point I would make is that a competitive process is of interest if we 1 -- can agree on a manner in which it is able to happen expeditiously but also 2 -- that certainly as my colleague at RES says, we should be looking at this as a manner that is in fact adding value by reducing the cost of this particular solutions to the system.

We know that in CAISO RMR specification in the tariff rule says that condition 1 units can enter into market transactions for energy in the ancillary services as long as they don't impair their ability to meet the reliability needs and that those revenues offset their CAISO cost recovery.

In PJM the generator that chooses to operate under a deactivation of voidable cost credit can operate in the PJM markets with those revenues subtracted from the credit. So we know that model is there and I think it is just a matter of insuring that we are looking at that when we talk about the kind of value that these kinds of storage adds an alternative competitive bid can offer.

MR. AMERKHAIL: Thank you Jason. How about Neil and then Charlie after that?

MR. MILLAR: Thank you. I probably should have

jumped in earlier but I just wanted to add that we are down to one generator left in the ISO under RMR agreement. We also have a synchronous condenser -- generators converted to synchronous condensers but that is a short term running another year.

But I think the point about running a competition for a short-term interim solution our preference has been to focus the efforts on the long-term solution as opposed to getting caught up in the huge amount of redesign and system reconfiguration on an interim basis. And when you are looking at the competitiveness of this we are talking about some very old units looking at imminent retirement, maintenance is running down quite low.

So it is going to be very difficult for any new resource to compete with something that is already essentially heavily depreciated. So we haven't seen a huge value in that. If the opportunity arises we are not going to foreclose it but I think we have to be realistic about what a new resource would actually be competing against on an interim basis.

If you only need 6 more months out of one of these older units I just think we need to be realistic about expectations.

MR. AMERKHAIL: Thank you, Charlie?

MR. BAYLESS: I'll agree with what was just said

about looking at the long-term planning and making sure that things are planned correctly. As far as North Carolina we have actually got two pilot projects going on right now. One which was put in service in Ocracoke Island this past summer -- it's a 1 megawatt battery and you know it is a demonstration. We are trying to figure out how to use it now.

We are looking at balancing and frequency, reliability, peak shaving the whole range of things to try to figure out how best to use this battery in a solar facility micro-grid out in Ocracoke Island. But you know -- to the extent one of these pops up in the PJM market, NCMC would be you know thinking about an opportunity to sell ancillary services or you know things like that into the market.

So you know it is conceivable that we would -- some of the load would actually be competing in these to the extent that we have micro-grids.

MR. AMERKHAIL: Thank you, John?

MR. FERNANDES: Yes, thank you John Fernandes from RES. Just one point of follow-up -- my answer doesn't change based on well this is going to be more of a long-term needs assessment as opposed to just a short-term. We need a quick fix. In fact from an investment standpoint it is much easier for me to justify and finance a project if I have a

long-term outlook and especially with storage.

I mean this is what we are doing -- at least on distribution with customers right now. We are not just deploying the storage resource to address a need for the next two or three years. Jason already referenced the long-term transmission upgrades that might be required. I wouldn't be looking to offset those needs for an extended period of time as well. That's -- and granted that might make it a little more challenging to say we need to deploy this thing in a few weeks -- it is going to extend the modeling and studies and things of that nature but my answer stands.

Yes we would want to compete, we would want to address both that short-term reliability need and any long-term infrastructure that could be off-set with this. And all at cost -- I just want to make sure we are also clear on that. We were looking to compete at cost with all the other resources being considered, we are not looking to shoulder rate-payers with a neat little experiment here.

We are justifying this in front of regulators everywhere.

MR. AMERKHAIL: Thank you. Alright I think we have beaten that horse enough. Are there any other potential processes we could look at such as black start procurement or anything else you can think of that might be

open to competition from new resources including electric storage resources? I'll start with you Mike.

MR. DESOCIO: So in New York storage resources can participate and compete in 90% of the markets. Black start being one of the exceptions but filter support service, storage can participate in that market -- it can be an energy provider if they are energy limited they can be an ancillary service provider, both terminate and 30 minute reserves.

They can provide regulation. To the extent they can produce a megawatt of output for at least 4 consecutive hours they can be a capacity provider. If the resource doesn't have that long a duration and can only discharge for less than an hour they can be a regulation provider as a limited energy storage resource.

In one of the areas that I think you know we need to think -- we are considering how to expand is when the grid is evolving and we are adding more intermittent resources, more variable resources to the grid you know we think about what other grid services may be necessary for the capacity market to deal with.

And so in markets or areas where you have got large men-gen issues, having a dispatchable negative load is very helpful to a grid operator. We have used pump storage in that manner for decades and it is a tool that grid

operators just love to have. That said, I think this is a regional issue and it depends on what that mix is in that region to determine whether or not there is value for having that extra service.

And so I think there are opportunities. I think we need to let the regions kind of move in that direction as their grid is evolving. I know New York is thinking about these things because of public policy goals that New York has which are probably different than issues in other parts of the country.

And so I think if we try to deal with this through you know a regulatory process that says one size fits all, you get a little bit worried about that. I think there is a lot of good dialogue happening in the marketplace. Let's continue that dialogue and work through where it makes sense to add these products, whether it be fast ramping or new capacity type of product.

MR. AMERKHAIL: Thank you, Eric?

MR. HSIA: So the PJM is very similar to New York. Currently I think the first panel offered that we have a 300 megawatt for storage installed at PJM mostly participating in the regulation market right now. We have had a storage device respond to a black start peak issue.

Certainly so they are looking at those different options. For us for black start we require 16 hour minimum

run time so again with battery storage type devices, if you give them the sector you need, certainly they can deal with it. But the thing you need to look at is the cost. So and we have other opportunities within the market.

Our market role is very neutral to all asset types so again if it could run for 5 hours it could compete or participate in a capacity market. All of our ancillary service markets have no restrictions to storage type devices. So I do agree with what Mike said, I think we all agree that there is a lot of benefit with storage. They do offer great services, it's quick -- it's really let the marketplace tell us where is the best to utilize storage type devices as their technology continues to advance as well I think there are other opportunities for them within the marketplace.

MR. AMERKHAIL: Thank you, Neil?

MR. MILLAR: I'll just add in I really agree with what we have just heard. And that's one of the reasons actually that we believe the first choice should always be to have these devices unconstrained in the market as opposed to being locked down through transmission asset models.

I think the only thing I would raise though is that we are probably skeptical about battery storage as a viable black start source because we have had experiences where we have to look at how much volt current the battery

storage can produce when you are starting up systems because the rest of the transmission system is counting on adequate volt trend to be able to tell the difference between running load versus if there has been a fault on the system.

And without enough fault current the protection challenges really climb. So that is something that a conventional resource provides as a matter of course that might be a challenge for storage.

MR. AMERKHAIL: Thank you. I'll open it up oh I'm sorry Bill?

MR. CAPP: I think we are all looking at applications where storage makes sense and provides a compelling value. And one of those I would want to reinforce -- obviously it's one that the Commission has expressed some concern about in the past and that's frequency response in the sense that it is diminishing and every time a cold unit comes off line you have less inertia and you are going to need more frequency response.

To me it is an ideal application for storage because it is much more economical than providing it from generation. It takes a longer answer to fill that one in but it is certainly true and because as you improve frequency response you can reduce ancillary services. It funds itself in a very attractive way.

Because there is no market for frequency response

today, there is no -- by cross subsidization -- even though you may be reducing a market for frequency regulation in the organized markets, it is not a direct competitor. It is just influencing the total size of that market which we can expect to go up over time as more renewables get deployed anyway.

And with a slight change in power electronics you can provide voltage control and frequency response with the same asset again looking at multiple uses. So I think it really hits a lot of the checkboxes in terms of things that would be of interest.

MR. AMERKHAIL: Thank you Bill. Does anyone else -- I'm sorry?

MR. BURWEN: Just a quick follow on in terms of taking a step back here. You know I think that when we think about what we are talking about here and what we are trying to accomplish it's an idea that we have an asset -- like there is a concern that storage be locked down as a transmission service being desired to be avoided.

You know you are going to have an RMR, you are going to have something that is going to fill that gap anyway and you are going to be spending on keeping a generator in service or you can spend it on something else. And maybe you can spend it on something else that has avoidable cost to load, particularly again as we have talked

about if there is a sense to which you can defer or even avoid a transmission upgrade for a significant period of time.

If you are just thinking about a six month gap, I think that it is a different conversation and there might be business models that arise in the future but fundamentally if we are talking about flexibility of the system, particularly with exit of units on short-term basis, we are trying to provide a way of seeing that this is an opportunity to enable that and that through the multiple uses of that technology the locks down as a transmission service I think is less concerning at least from a cost standpoint.

I am totally agreed that markets for storage are good things and what we should be focused on but we know these RMRs are going to continue to get done and they are not going to go away necessarily so we are looking for some way to insure that we can help with market efficiency in some manner.

MR. AMERKHAIL: Thank you. Are there any other questions from staff? Michael?

MR. HERBERT: It's kind of a two-part question I guess. The first part for the ISOs and then probably for the developers as well -- so for the -- I guess from a planning perspective for these RMR contracts, short-term

contract is there anything that might prohibit a storage resource that is procured just from or for just being online for 6 months, a year or two years to provide that specific service that is needed to fulfill whatever the RMR contract would be procuring?

Is there anything that I guess would stop that resource from just staying online and being a full-scale market participant after that? And then I guess also from sort of the developer's perspective would that be a model that you guys would be interested in, sort of agreeing to a very limited set of services for you know "X" amount of time but then just being allowed to kind of remain on the system where you are at and being able to be a market participant after that and relying on those revenue streams afterwards?

MR. HSIA: So currently we don't have a lot of RMR, I think we have one RMR contract remaining. I think it is getting down to almost a termination date. But as far as resources currently they do participate in order market services so they do capacity into services, assuming that they can provide it.

So I think to your question if it is a short-term RMR asset and they are already competing and participating in other market services, certainly there is no reason why they can't stay on and continue to be an integrated generation asset, continue to participate in those purposes.

But as far as the RMR payment obviously that will go away once the term is ended, but certainly that is an option they could stay on and continue to participate in the markets.

MR. FERNANDES: So I'm a developer so obviously I like long-term contracts, we will just state the obvious first. Conceptually no, I don't think I am opposed to what you just put forward. A short-term contract of a guaranteed revenue and then I can operate under more market-type structures after that -- the only thing that gives me pause when it comes to storage and all of these guys sitting at the table are making a lot of progress but all the market structures are not necessarily in place for me to be able to fully leverage the capabilities of storage to capture revenues from multiple different market services.

You still have constructs that require double digit hours of service to get a capacity or a reliability value on. There's very limited intra-hour flexibility to move from one market service to another and so those are all being addressed by this Commission which is outstanding. It is all steps in the right direction.

So again not a problem -- there's just other changes that need to take place first.

MR. DESOCIO: I think back to your question about any issues with starting with a short-term contract and then releasing the resource to go participate in the market -- I

think you know as we thought about the structure of the contracts we expect that any revenues made after we have paid for the asset get refunded back to the load, to the customers that bought the resource.

So I don't know how we would come up with a contract to deal with that kind of paradigm we would have to rethink how our RMR contracts are structured.

MR. MILLAR: I was just going to add that one of the issues for us would be well how much of the capital cost of the battery is being paid off in that interim period. Is the expectation that we are largely covering it or not -- I think also pragmatically once you have actually built a solution that's working I wouldn't be optimistic about our chances of getting a permit to build the transmission line to replace the functioning asset that is already working.

Once a need has been addressed, I think we would be starting to think that's going to be a long-term solution.

MR. FERNANDES: Exactly.

MR. AMERKHAIL: Okay well I think we have exhausted our topic for now. Of course you are free to file post conference written comments and I think we will donate the rest of our time to the last panel. Thank you panelists and we will take a short break. Let's reconvene at let's say 5 after 1. I'm sorry -- 5 after 2.

(Whereupon a brief recess was taken to reconvene at 2:05 p.m.)

MR. HERBERT: Alright good afternoon everyone, welcome back. So let's go ahead and start Panel 3. As always housekeeping stuff first -- turn your cell phones off, turn your mic on when you want to speak, turn it off when you are not speaking and raise your little tent card if you have something to say.

So for Panel 3 the purpose is to discuss any practical considerations for electric storage resources providing multiple services at once. Multiple entities are the same entity and particularly for our interest if one or more of those services are wholesale electric services into the RTO and ISO markets and others are retail and/or end use services.

So on this panel we hope to delve into exactly what services can be provided simultaneously, whether they can be provided by the same electric storage capacity or different portions of the total electric storage resource capacity and what the technical limitations may apply in those situations. So we will kind of start broadly and then kind of hone in on some specifics.

So the first question is what if any services can be provided simultaneously from the same storage capacity. We can start go ahead, you win.

MR. NELSON: Thank you, first thank you very much for having me here today. It's Jeff Nelson from Southern California Edison. We see as the grids evolving and technology is changing much more potential and multiple use applications for distributed storage as well as other distributed resources.

We have been doing a whole slew of experimentation and actual infield implementation. We have got about 500 megawatts worth of contracts signed for storage just within our utility and we have used it in a whole host of applications. Certainly they can provide dual use and I'm glad you defined that because there really is a spectrum of what is meant by dual use or multiple use.

But at the retail and wholesale they have both the ability to provide voltage support and reactive power simultaneously and more than that they have the ability to provide things like resource adequacy capacity in the process of providing this and then beyond that at a retail level function such as shaving peak demand off to reduce retain demand charges and possibly energy arbitrage with an even time of use rates.

Arbitrage might be a strong word. So further than that they have the ability to provide distribution reliability services such as reducing voltage constraints or overheated constraints and even providing voltage quality --

so done properly and simultaneity is an interesting question what you really mean by that -- but then properly they can provide all of those services to a certain grid at once, so that's our view.

MR. HEBERT: And that's I mean we will get in to sort of you know the same service -- or different services from the same capacity at different times in the next question but yes this question focused exclusively on things that the resource can do at the same time with the same capacity.

MR. NARANG: Hi so my name is Aparna Narang and I'm with Pacific Gas and Electric and I oversee our scheduling coordinator functions at PG&E and so I really just wanted to share kind of our real life experiences associated with our multi-use storage resources in our portfolio.

We have two resources right now that I would like to talk about. One is the 1200 megawatt Helm's Pump Storage facility that is in our portfolio and then also they are kind of very different types of technologies here -- we are looking at also the 4 megawatt Yerba Buena battery. It is a sodium sulfur battery.

And similar to the earlier comments I do want to recognize that it has been kind of complicated to manage multiple-use storage but the level of complication really

varies based on the numerous dimensions associated with each of the storage devices, including the duration of the resource, the services it provides, whether there are multiple users, whether it is on a transmission or distribution system, whether it is predictable amongst others. And I realize we will get into a lot of those topics as part of this panel.

So definitely the details really matter. So in regards to Helms so I just really want to talk about specifics here -- so in regards to Helms it is providing energy and ancillary services in the market so it is providing regulation, it is providing spinning and non-spinning reserve in the markets. Though I do want to highlight that in terms of the simultaneous nature of it, it is really the regulation and of course the spinning reserve is the simultaneous nature -- the non-spinning really is not of the simultaneous kind of nature product.

I also want to mention that it has the ability to essentially produce or absorb bars when it is generating so that's what I would consider non-market type service that it is providing from a simultaneous use. I recognize we will go into the non-kind of simultaneous uses later but I do want to highlight that it does get exceptionally dispatched for voltage support in the pump use -- so and that means then the other ancillary services really aren't available

for market participation.

In regards to our Yerba Buena asset which is the 4 megawatt battery it has 7 hours of essentially utilization and here it is also providing energy and ancillary services in the market. It is predominantly regulation it has the potential ability to provide also the spinning capacity in there, but from a non-market perspective it provides islanding services, but that is not simultaneous and I will get into those details at a later part of this discussion.

MR. HERBERT: Troy?

MR. MILLER: I'm Troy Miller, the Director of Grid Solutions for the S&C Electric Company. We manufacture and install integrated energy storage systems, including the aforementioned Yerba Buena Project for PG&E and I would like to talk today in the beginning here about a project that we did for the Village of Minster, it's a public power utility -- small city in the middle of Ohio, 2800 people, probably 20 megawatts of peak load there.

We have installed a 7 megawatt, 3 megawatt hour energy storage system that is participating in the PJM Reg B frequency regulation market on a daily basis, an hourly basis. And simultaneous with that it is providing voltage support by providing 5 M-bar of reactive power to support the voltage so they were able to basically defer the purchase of large capacitor banks to get their power factor

up.

The third thing that it is doing there is avoiding coincident peaks, so there is a PPA that exists between our developer partner, Half Moon Ventures and the Village of Minster for a 4 and megawatt portable tech and we were able to modify the PPA to help them to avoid 10 or 12 days a year, to avoid these coincident peaks in the PLC, the peak load contribution charge that they might be getting from PJM and AMP.

So as far as what can be done simultaneously -- it's frequency regulation and voltage support or coincident peak avoidance and voltage support and then also investigating utilizing the asset for islanding one of their larger customers, so that would be the fourth thing, but that would be the only thing.

MR. HERBERT: The voltage support and peak shaving is for the municipality?

MR. MILLER: So the voltage support is for the municipality correct, yes. And so Half Moon Ventures takes the frequency regulation revenue, the voltage support and the coincident peak avoidance is for the Village of Minster and both of those are wrapped into a PPA standard PPA, the voltage or the portable tech PPA.

MR. HERBERT: Ted?

MR. KO: Ted Ko, Director of Policy with Stem.

We are the country's leading provider of commercial and industrial battery storage. So I think just agreeing with what Troy was just saying my only comment was the simultaneous nature is really just a physics question so these are you know so for our battery systems we are using four quadrant, full four quadrant converters.

We don't call them inverters we call them converters because they are four quadrants and so whatever you can physically do with four quadrant behaviors on a converter you can provide simultaneously on a physics basis.

In defining different simultaneous services on a kind of physical action basis the finding of simultaneous services on any kind of market basis then it is you know whatever they are physically -- they are physically the same thing alright and you can't do you know one service that causes you to charge and one service that causes you to discharge at the same time which just doesn't make any sense.

So that's just the basic physics question and we will get into the other kind of market rules around simultaneous and multi-use which are much more economic and market based than physics based.

MR. HERBERT: Okay we'll go to Michael and then we will come back to Sarah.

MR. KINTNER-MYER: Good afternoon my name is Michael Kintner-Myer from the Pacific Northwest National Laboratory which is one of the U.S. Department of Energy National Laboratories and we are working on technical as well as economic evaluations of energy storage system and I would like to just offer something technical -- a little bit more finer detailed technical discussion on the simultaneity.

The pitfall of it is that we are just adding up too many services at the same time and falling into the pit of double counting. That's the challenge -- double counting and so if you really look at it what can actually physically be delivered simultaneously at the same time without disregard of physics it is both of our control which usually may not really access the DC, the direct current storage medium which is more a phase angle arrangement in the inverter while at the same time providing real power.

So those go fairly well together. We also have seen in some of the construct strategies that we are evaluating some simultaneous provision of balancing services and energy however we still have to obey the law of physics and cannot go over the rate of capacity in terms of power as well as in terms of electric energy.

But these two can work fairly well together as well. As far as provision of capacity value for adequacy is

concerned of the transmission level that too can actually coincident with some more local deferment opportunities in the distribution system. Again if the local peak is simultaneous to the system peak then I think we can deserve -- I think that the machine can deserve to be counted both for deferment of distribution system assets as well as contributing to what system adequacy.

So those are -- a few pairs there, the challenge really is how you maximize that value at all times and so this is one of the current state of the research to look at controlled strategies, to look at all of the provisions and then optimize the code of value.

MS. VAN CLEVE: Sarah Van Cleve, I manage energy storage policy at Tesla. So I agree with the comments that have been made so far on providing services from storage simultaneously so I wanted to address a different issue -- take a step back before we get too into the weaves of these questions.

And that's on exactly what we are talking about when we say multi-use storage. For example in the initial notice for this workshop it referred to multi-use storage as storage that is providing transmission functions as well as wholesale market functions and then customer-sided resources that are also providing wholesale market functions but I think it really goes beyond that.

So the way I look at multi-use storage it is storage that is providing services across the four traditional buckets of services that can be provided. So those four buckets would be transmission services, distribution services, wholesale market services, or customer located service -- you are providing back-up power or any of the arbitrage et cetera as Jeff said.

So any combination of two or more of those services would be a multi-use storage asset and I think it is really important that FERC is addressing this and thank you for doing so because every single one of those combinations with the exception of distribution service, combined with customer service, do fall under your purview so really it is important that FERC help clarify how we can cross these traditional asset classes you know -- of transmission distribution wholesale market and customer located, so I just wanted to put that out there as a high level to help set the rest of the conversation.

Thank you again for having me.

MR. HERBERT: Yeah I think that's kind of what we had in mind as well. We might not have defined it as clearly in our Notice but it is -- sort of any time those resources providing any services, I mean it could be multiple services to the same entity even -- but I think as all-encompassing as we can be for this conversation would be

helpful.

So let's move to the next question and so -- oh Lorenzo, I didn't mean to leave you out.

MR. KRISTOV: Thanks Michael and thank you all for inviting me to participate in the panel. I think it is excellent that FERC is taking these questions up. I wanted to 1 -- affirm what a number of panelists have said already that there are numerous possibilities for multiple use applications of storage devices.

And also pick up on Sarah's sort of expansion of the scope and just mention a little bit about how the ISO is looking at this because several years ago we created the NGR model, non-generator resource specifically thinking about storage. That is a device that sometimes consumes and sometimes produces.

And picking up on Commissioner LaFleur's comment this morning that storage doesn't fit nicely into the GET or D-buckets it is a fourth bucket because it is something that consumes sometimes and produces sometimes and does a lot of variations on that.

Our sense is that that model is going to become more and more prevalent in the coming years and that notion of consuming sometimes and producing sometimes can also apply to a micro-grid, to a smart building, to an individual end use customer so storage-like resources on the grid we

think have the potential to really multiple in their volume and variations and scope.

Many of the questions you are asking here will apply even if it is not strictly a battery storage device but it is some combination of things that at its points of interconnection sometimes consumes and sometimes produces. And what that does is it throw into question the old duality between a resource and a load because now all loads can become resources by putting stuff behind the meter and having this storage-like behavior.

So I just wanted to frame things out a little broadly that way and say again within that context there are lots of possibilities for multiple use applications.

MR. HERBERT: Yeah I think that's right and I think that is consistent with how we have defined storage in sort of the proceedings we have had here at the Commission, basically anything that can receive electricity or inject it back to the grid would be of a storage technology so that is helpful.

So the next question is if two or more services can be provided by the same storage capacity at different times what, if any are the technical implications of making simultaneous sales of those services from the same capacity? Manal let's start with you.

MS. YAMOUT: Alright good morning everyone. I'm

Manal Yamout, Vice President of Policy and Markets with Advanced Microgrid Solutions. AMS specializes in aggregating fleets of behind the meter storage for a variety of services. And what I was hoping to do is actually give another example because I know that you all are very keen on projects that are actually doing this.

I think we have some of the few, probably along with Stem, examples of projects that are actually in the ground doing multiple services across the four buckets that Sarah mentioned today. And there's one in particular that I think will be helpful context for this conversation and it is a project that we are doing with Southern California Edison.

We currently have 120 megawatts under development in California. 90 megawatts and 360 megawatt hours of those are the contracts that provide resource adequacy with Southern California Edison in the West LA Basin.

So what I wanted to do is give an example of a project that provides in addition to resource adequacy and customer services is also providing some distribution services to SCE as part of a collaboration we are pursuing with DOE. So 1 megawatt, 6 megawatt hour system at a water treatment facility in Southern California -- it is part of a 50 megawatt, 200 megawatt hour resource adequacy commitment that we have at SCE.

So the primary function of the system is to provide resource adequacy to the utility as often as they would like it. In addition to that we use the system to manage the customer's energy bill. We lower their demand charges using the system when we are not otherwise using it for utility capacity. So that is an example of simultaneous -- multiple use of the battery but not simultaneous use of the battery which is an important distinction.

In addition to that in this case at this particular site we are going to be providing full bar optimization and powerful optimization for Southern California Edison. And then on top of that as soon as the ISO is done with its -- Phase 2 process and proxy demand resources are able to bid into the reg-up, reg-down market we will be able to use that same system to provide reg-up, and reg-down with an ISO market.

And then in addition to that there are other services that SCE is interested in using it for like a virtual microgrid being able to dispatch it within seconds to help with local feeder problems. So it is not a direct answer to your question Michael so I was kind of hoping you would call me third, but I do think it is a really helpful example to frame up this discussion because as far as I know this is the only project that is under construction that is doing -- well it is not doing them yet, but is going to be

doing all of these things.

And as we found with many of our projects along with many of our developer colleagues around the table, it is often once we start putting projects like this in the ground that we run into a lot of challenges that you know we didn't anticipate two or three years ago and we signed contracts so I'll stop there and I'm happy to weigh in again later.

MR. HERBERT: Thanks Manal, let's go ahead and let Jeff go next since SCE was mentioned already.

MR. NELSON: So multiple use not simultaneous -- you have to start with what services are being provided here and to the extent -- let's imagine it's a distribution located resource that is some time providing ancillary services to the ISO. The first and the premise of the issue here is safety and liability and the source of distribution operator when people are interconnecting they go through an interconnection process and the interconnection is designed to allow them to safely operate.

But as they start providing multiple types of uses there may be restrictions or limitations that happen that prevent them from participating in the wholesale market in order to maintain a safe and reliable distribution grid. So the number one principle of multiple uses has to be safety and reliability.

We view that there is sort of a premise argument that depending on where the resources connected the distribution side, the transmission side, the direct connector in these types of premises they need to have the ultimate say in what is safe and not safe to operate.

Then when you are starting to mix wholesale and retail participation across time we think it is important that there is a clear accounting or delineation of energy that is being let's just say consumed at wholesale, it needs to then be returned back to the wholesale market. We run into very hairy issues if parties are allowed to consume at wholesale and then serve that to retail load so it is another sort of principle that we think is important.

Now with that said we think it is possible -- we are not quite there yet, things are under development to do with metering and accounting the ability to sometimes you are charging at wholesale and selling at wholesale. Sometimes you are buying at retail and selling at retail from the same device.

We are not there yet, we think it is possible and we would like to see that happen. So those are more regulatory and safety considerations rather than sort of technical considerations of the battery strip. But those should apply to any technology or any resource like Lorenzo was say, or Dr. Kristov was saying.

MR. HERBERT: Aparna do you want to go ahead?

MS. NARANG: So actually kind of segwaying over from Jeff's comments over he touched upon the multi-use not simultaneous concept, he also touched upon prioritization which I will touch on with the two resources that we have.

So for Helms what's interesting is that it is a multi-day type utilization resource -- it can actually -- it has a really large upper and lower reservoir so you are actually optimizing the "state of charge" for this hydro asset over not just within a day but over multiple days, months, over the year.

So when we are providing essentially non-simultaneous communalization of the resource whether it is through kind of an exceptional dispatch with the California ISO -- essentially it might not have been planned, it is unpredictable and so then it can impact of course it's really a state of charge.

But there essentially because they have such large reservoirs it is actually fairly reasonable to manage. We can manage that day over day over day. So that can be done. It's also you know interconnected to the transmission system so the services -- not necessarily sow the services but the services it is providing both in the market and through the kind of voltage control from an exceptional dispatch perspective are really all within the ISO kind of

footprint. They are really watching that, they are managing it so they recognize what is happening in terms of what Helms can provide at different periods of time.

Kind of on a different note going to the Yerba Buena battery it is interconnected at the distribution system and with 50% of its -- approximately 50% of its capacity over a two year period was actually reserved for customer islanding and 50% was actually in the market.

So because we had a commitment to provide these islanding services and we didn't know when that was going to happen we always had to maintain that 50% state of charge and not enable -- not have that participate in the markets so that the other 50% was in the market.

But then when the islanding occurred the entire resource was essentially separated from the grid because you are actually -- you're islanding right? So in those cases what that means is then okay we are participating in the ISO markets but then what that can result in is exposure potentially to deviations or potential risks associated with the ability to provide essentially future, ancillary services products that were planned for it for the rest of the day.

And because it is a 7 hour battery, 4 megawatts, unless you do the 4 megawatts kind of the 7 hour kind of duration you are not managing this intraday kind of resource

and at a much more granular level than you would let's say a resource like Helms, so that's just a little bit more complicated.

MR. HERBERT: Troy do you want to go ahead?

MR. MILLER: Yes I was just going to make the same point that if you are going to do multiple uses with a single asset it is a matter of prioritization which should come first, second and third and those can change on a daily, seasonally, monthly basis -- it doesn't have to be the same forever so you could -- islanding in the case of Yerba Buena, you can take islanding as always the most prioritized asset.

If something comes up there's a net reliability event it islands automatically no matter what. There is demand management, voltage support, you can do frequency regulation, fast frequency response, there are all different things that you can do. So it is prioritization as frequent a basis as you would like to have it done that's the first thing and then the second thing is reserving these pieces of energy state of charge to be able to do your number one priority whatever that might be.

If it's transmission support, reliability at the retail level or you know resource adequacy at the distribution level, if you are going to do other things then you need to have a large enough energy capacity and hold

some back for whatever your primary prioritization might be.

MR. HERBERT: Lorenzo go ahead.

MR. KRISTOV: Yeah I'll pick up on the state of charge question that was mentioned because that becomes especially important with the battery and we are looking at it from the ISO perspective to provide a certain function for us. And I think what a lot of this will come down to is specifying the terms under which performance is measured and the consequences for non-performance.

That that would be part of the calculation that a resource operator is providing multiple services -- we'll say, "Well what happens if I bid and balance energy into the ISO market and then I don't deliver it?" Well that's not such a big deal if it is a tiny resource and it has to buy back the energy.

But if it is providing a more vital function then we may need to define non-performance penalties of incentives in some way that insure or maybe capture the priorities that Troy was talking about and the priorities could change at different times. So I think that question really needs -- and then also around state of state I would mention that in our NGR model we have made modifications to allow options for how the resource operator can do that -- whether they bid the state of charge to us as a perimeter and we take their word for it then it is their

responsibility to have the capability to deliver what they are offering.

Or, the ISO has actually got telemetry to monitor state of charge and we are optimizing over a long time horizon. So I think allowing options for how to manage that and then thinking about well how serious is the impact of non-performance and how strong are the incentives we need to have?

MR. KO: I'd like to add to what the panelists have said starting with the example of a project and thanks to Manal for calling us out -- actually doing this. The example that is actually in operation today in California is the behind the meter customer services with wholesale market participation bidding into the wholesale market multiple use case -- that's the one that is actually being operated today.

And we have systems and a couple of other developers have systems in the California Demand Response Auction Mechanism is the one that was in pilot before now we are actually in more full operation and we have been doing -- getting into the wholesale market with Cali ISO for about 2 years now and in the real-time market in the Cali for about a year.

So that's a huge case that is actually being operated right now and to what Manal said we are -- you

learn a lot when you actually start operating these things, then you start actually bidding in and looking at the prices and deciding what your bids are and actually dispatching when they are getting awards.

And to kind of pull up what everyone here just previously said there's this idea multi-use we talk about value stacking -- so we are stacking different value streams of the same battery and the same storage system can do. Then the privatization is what we might call an obligation stack.

So you the storage operator are managing both. You are managing the value side where you can monetize and you are managing your obligation stack. And to what Lorenzo was saying it is about what's the contractual you know -- cost benefit. What's the penalty if you don't provide, what's the level of performance requirements you have based on your contract or based on the market rules and so I think it's ultimately the storage operator's job to manage those, to figure those out and not have the market determine what those necessarily are.

The most extreme case in the -- say a liability function that has to show up and you set very, very high penalties and one of the things -- and this came up in our conversation on multi-use in California and the California CPC proceeding is what levels of kind of performance

penalties do you need?

Are there different levels at the dissipation level? Is it all -- you have to show up or are there certain situations, certain parts of the grid where it is okay, you know -- we have alternatives if you don't show up, these kinds of things. So all of that has to be captured in the obligations and then it becomes an economic risk calculation for every hour of the day for the battery to decide what to do about it.

And I just wanted to add on the one thing we didn't talk about -- capacity and reserving capacity in your battery, one thing in the rules you have to understand is the rules for a fleet of batteries is going to be different than the rules for a single sect, right. So you are managing the state of charge of a single site is a whole different idea than managing the state of charge of a fleet of 50 sites.

And so the rules will likely be a little bit different for those two things and then with the state of charge management and like Lorenzo called out with the NGR and the state of charge if the grid operator is directly managing your state of charge, then you have pretty much eliminated your ability to do multi-use. Because unless the grid operator can know all the different things that you want to use the battery for, this just came up on the first

panel I think about whether the grid operator can put you in the market or not, but if it is behind the meter storage then the grid operator is not going to know what to do that is going to be best for the end customer.

So -- direct management of state of charge doesn't really allow multi-use in that scenario.

MR. HERBERT: That's a good segway to another question that we have and that is staying on the prioritization theme. There is sort of this apparent uncertainty if there are services that are being dispatched and you don't know when that is going to be necessary so you know, how can that prioritization be meaningfully accomplished without knowing when the higher priority service would be dispatched relative to the lower priority service, and how could the storage resource insure it was maintaining sufficient state of charge to serve the higher priority service? Sarah?

MS. VAN CLEVE: Thanks Michael that's a really good question and one that we have been thinking about a lot and we think that over time is our forecast gaining confidence in both of these resources as well as the needs get better, we will be able to get more granular. But just now for at the forefront I think we can all agree that it is possible to switch resources in and out of say market function and reliability function widely.

And the CFIST version of that that you could start with is if you are using a storage resource say for distribution reliability off-setting the peaks in summer you could say, "I really need to have this resource here so for the four months of summer it is not going to play in markets at all, it is just going to sit there and be ready to discharge when we need it for the liability on the grid."

However, we know that we don't have any of those peaks in winter so the other 8 months of the year that's when we are using it in the market. Then we go when we are confident and we say, "We have a pretty good day ahead predictions, we'll know when we are going to have a peak day." So that's when we decide on the day-by-day basis. Okay tomorrow we are going to need this for reliability let's not bid it in the market at all tomorrow.

And then especially as we get more visibility down on the distribution system in particular, hopefully, we can do an hour ahead or even real-time optimization of should I play this resource in wholesale markets or keep it for reliability, so I think that that's still a question we need to work through but certainly there are ways to have multi-use resources that we can absolutely insure provide reliability and hopefully as we move along we can even more closely optimize and efficiently use those resources.

MR. HERBERT: Thanks, Manal do you want to go

ahead?

MS. YAMOUT: Sure, Sarah gave a great example. I guess my question is the point of prioritization -- I guess I'm not sure what the point of prioritization is right so if prioritization changes to Sarah's point from season to season or from site to site or from hour to hour, so in our case we have a 50 megawatt fleet operating, we have 100 buildings in that fleet.

There might be a day when I use 100% of that battery for utility capacity and another day where I'm behind on my demand charge management obligation and I decide to use the whole battery for demand charge management obligation. I let other buildings in the fleet step up and meet that obligation.

So I think the point made by others on the panel about setting the rules right and getting the penalties right is really, really critical. So if we focus on the service being provided and we insure that that service is distinct and incremental from other services to avoid you know perception or actual double counting.

And in addition to that we make it very clear what the penalties are and they should be commensurate with severity situation. If we are at the end of a line and if we are not available for capacity if we are called, it should be a very, very high penalty versus other situations

where the ISO might have a back-up.

And if those rules are set right and the obligations are clear and the services are distinct and incremental, I'm not sure why we would want to determine or state what a priority of a particular building is or a particular fleet because it changes all the time and you know part of the reason I am sensitive is this is in the California PUC discussions there has been a big focus on you know what is the primary function of the system. And I guess from a developer perspective I am not so sure that it should matter to the market as long as we are there when you need us and if we are not you are able to hold us accountable.

MR. HERBERT: Jeff go ahead.

MR. NELSON: Well I want to combine sort of both of those themes, the points that I wanted to talk through. I am imagining first it depends on what applications you are committing to do -- if you are just making you know voluntary energy, ancillary service sales, not such a big deal if you make one or the other. But imagine a hypothetical where someone has been selected and we are doing this right now for distribution deferment, rather than building traditional wires for the RFOs to say that there needs to be specific performance under specific conditions, and without that we don't have a reliable distribution

system.

And that type of agreement, there needs to be a clear understanding of what the terms and conditions, what the expectations are and people need to live within those expectations. Now outside of those -- right -- there may be flexibility.

Something Sarah said, we've learned through some of our market demonstrations that the better visibility, the better control, the more direct knowledge and situational awareness we have with what's happening on our grid lets us be more flexible with resources, let's us really say you know we thought this was going to be a problem today but the telemetry is saying it is not so that can allow us to free up and get extra value out of the resource.

So hand in hand of premisy and who does what should be a discussion of are we trying to get the most efficiency out of the resources from the get-go or are we on a big grid modernization sort of philosophy now to do that, to be able to extract more value and actually provide more flexibility to the resources so it is only in pre-targeted situations in this example.

It would be a red light that day, that you have to do exactly what we say and maybe it is just a couple of hours on that day and the rest optimized.

MR. QUINN: So Jeff I think what I heard you say

at the very end there is there might be a small set of hours where there is no penalty that you would say is big enough to kind of measure the value that the resource is providing to the grid and so there would be maybe a cut-off at which you would say -- because infinite penalty isn't available to you.

You, as the grid operator for the distribution system would say penalty structure very good for most situations but for these -- defined set of situations we are not going to rely on a penalty situation and I am going to require that the distribution system has first priority. Was that what you said?

MR. NELSON: I think that would go back into earlier principles. The number one principle has to be safety and right after that reliability. So to the extent that we have an issue that we believe is going to create a safety or reliability issue financial incentives may not be sufficient and may require direct command and control under those situations. I hope that answered the question.

MR. QUINN: Yes that answered. I would be interested to know if PG and CAISO have the same point of view on that because I think connect the dots to the first panel today I heard a lot of discussion in the first panel from the grid operators as if I'm a give-something cost recovery through the transmission rate base, whether or not

I give that resource -- the grid operator wants operational control and that's how we think about transmission facilities in the ISO context.

MR. NELSON: And as a distribution operator I think there's a spectrum. I think there may be some assets that are so integral and so constantly used that they will be treated just as a traditional distribution asset and be in sort of full control of the distribution operator. And then there may be these others that really this is a two-hour a year problem and I think those will be treated differently.

MR. KO: To follow-up, to add on to what he was just saying -- this came up in the discussions at the CPC exactly you have the gradations of types of service you are trying to go for right and so even in SEU territory like the contracts that Manal referred to and Stem also has with that in that grid were essentially local capacity and for reliability on the west LA Basin but it was at such a large enough grid area that there wasn't a requirement in those contracts for them to take to get control of those things, right.

So you define the service by how much the need is. If there are certain hours, then we the developers will then decide if they want to take on that risk.

MS. NARANG: I was going to try to help answer

Arnie's request for us to comment which is a general agreement here with SCE but recognizing everything is on a case-by-case basis really in terms of what utilization of the asset is and what services it really needs to provide.

But coming back to safe and reliable operations is being really a number one priority.

MR. HERBERT: I think Rahim had a quick follow-up as well.

MR. AMERKHAIL: So I think several of you mentioned this. Sarah for example mentioned that as you get more and more experience with the asset you may be able to predict some things like when the peak may come along and so that you can avoid it and I guess Troy's Minster project does the same thing.

But then there are -- so that's -- I can understand that very well but do any of these projects seek to be -- to have some of their, one of their services be contingency reserve where almost by definition you can't predict when the contingency happens at the same time as they are doing other things and how does that impact the calculation list, I'll start with you Jim.

MR. NELSON: Well we are exploring the many uses of storage on the grid. One of them is handling in M minus 1 condition and that would be a classic example of it has to -- almost like a -- it has to stand ready in the event that

the M minus 1 happens and that might put severe limitations on what else it can do.

MR. HERBERT: Okay thank you.

MR. KRISTOV: Given CAISO perspective some of the things that are just being raised now and both Rahim's question and Arnie's and Jeff's point about safety and reliability may arise even without multiple services being provided. In other words once you start getting these devices on the distribution system something that we really need to think about and we are in California about the future is what's the new coordination framework between distribution operators and the ISO?

We issue a dispatch instruction and it could be that instantaneous conditions on a distribution circuit may make it impossible for that resource to respond to our instruction or it may cause a problem if it tries to respond or it may be providing multiple services and this question of prioritization is a real-time instantaneous decision.

And these circumstances right now, what do I need to do for the next five or ten minutes -- so we can't spell all of these things out in advance but I think a piece of what needs to happen if we really want to see the expansion of storage devices, much of which will be on the distribution side of the system and participating in wholesale markets, then this question of how do ISOs and

distribution companies coordinate?

What information do they need to exchange? How do we get current information about grid conditions that may affect the capability of a resource to respond? Who needs to know that? When do they need to know it and if it is a constraint on distribution that prevents the resource from responding, well how do we treat that in settlement? How do we use our outage notification process?

These are a lot of the questions that we are asking but I think the central notion of coordination is a big part of this whole inquiry.

MR. KAPADIA: So since we are on the topic of kind of dispatching where you get the dispatch signal but you are not being able to do it as Lorenzo said but with your -- the PG&E application where you have the islanding thing where you have 50% of islanding and 50% for something else and as you mentioned when you are called upon and if you have an island and the CAISO calls upon you, how did you plan that?

MS. NARANG: I wish it could be planned but such is not the case. So what we do is we do participate in the markets at all times for that 50% capacity that is not reserved for islanding just because we just don't know when the islanding needs are going to happen and the frequency of those islanding events is about like two times a month over

the course of that two year period so in the event that islanding happens, what happens is then we are essentially at risk for deviations where we are typically providing let's see a regulation product.

So now we are not able to provide that product and then also the question is will the battery be at the right kind of state and position in order to provide then the residual ancillary services needed kind of for the rest of the day or post islanding condition?

So these are some of the challenges that we face with managing it and I think you know to Lorenzo's point a lot of it is going to hinge on kind of that coordination in terms of that team D kind of coordination and efforts with visibility and understanding across the distribution and transmission systems.

But that is how we are handling it today because of the unpredictability nature of it we do want to make sure that it is available for market use when it is available.

MR. HERBERT: Troy you have had your tent up for a while so maybe you'll let us know what issue you are responding to.

MR. MILLER: No problem. So just to the point that everybody has been making about if the rules are defined properly and the penalties for not -- so in the case of the Yerba Buena project taking a penalty for deviation

that works into the pro forma. We have got a project in the U.K. that's for -- the primary use was to avoid the build of another transmission line so it was 20 kilometers at 400 KB transmission for winter peak and during that time, actually there is about 6 to 8 weeks where it is doing nothing else but doing peak shaving to provide these services for that.

But in the other times there are enhanced frequency response and FFR that they are also providing and all that gets baked into the pro forma. If the rules are known well and the energy storage is allowed to cross these asset classes because the most efficient use of the system is for it to be providing like all four buckets that we talked about previously.

If all of those are known you don't have to worry about prioritization because it works in the pro forma and we are constantly reordering on a daily or hourly basis, based on our interpretation of the rules and the penalties. So defining those markets tightly and then coordinating across all the four classes is huge, so.

MR. KO: Just summing up a lot of this -- if you think about the risk calculation that we make as developers -- if we have say a 50 megawatt come in, we are going to put a fleet out there, probably 60-75 megawatts if we want to use multi-use. Because we are doing a calculation of risk about times when there is need versus when the customer is

going to need us and how much do we need to keep in the tank.

The more the risk is in the markets like the more the risk is the more we have to overbuild. So the extreme cases -- the one which Rahim was just saying is like if you have to be at any moment you have to have your full capacity available, then you have to overbuild by that much. You just have to have that available and that is what you have to have that reserved right?

But if you -- if the rules aren't set up that way so that you can you know, gauge your fleet, see what's available and you don't have that much risk, then you don't have to overbuild as much. And so it is really just that whole risk calculation along that spectrum and then to what Sarah was saying -- the smarter your software is, the smarter your software is about predicting and anticipating risk, figuring out what times -- the smaller the overbuilt can be.

So it is kind of what we say, more brains less batteries. Like the smarter your system is the less you know hardware you have to put in place to actually provide those services.

MR. HERBERT: I'm going to try and summarize what we heard here really quick and maybe you guys can fill in any gaps but it sounds like as far as prioritization of

multiple use applications you have to -- sometimes there are sort of contractual arrangements that you can't get out of.

If it's resource adequacy, if it is islanding, those sorts of things come first and that is sort of established what you will execute that contract with. And then after that it is sort of a condition of economics, what's the most valuable service that I can provide at a particular time and then sort of part of that economic calculus is also penalties and you know what penalties am I going to incur for not showing up to provide this other service.

And then as Lorenzo talked about a little bit to the extent there can be coordination between multiple entities then we can potentially avoid those penalties and better optimize those systems so that they can provide sort of all of the services that they are most capable of doing. Is that kind of a good summary of what we have heard or would anybody like to add to that, Manal go ahead.

MS. YAMOUT: I think that's a great summary. Just a point of clarification you mentioned resource adequacy as a use case example where you were going to dedicate the resource and I would just say that that is not always the case, especially at a fleet level, so someone made the point earlier about a distinct set of rules for an individual project versus an aggregated fleet.

So in the case of an aggregated fleet where we have a 200 megawatt hour resource adequate obligation SCE half of that -- not half of that, 10% of that fleet at any given time could be providing zero resource adequacy and that might change every single day.

So just a point of clarification there it is different for hundreds and hundreds of sites versus one.

MR. HERBERT: Thank you, go ahead Jeff.

MR. NELSON: And for the sake of sounding like a broken record I think I didn't hear the safety issue on that and I think there really is when it comes down to a safety issue that the economics have to be put to the side and safety has to be maintained.

MR. HERBERT: Would that be captured -- I mean is that why you would -- is that the sort of thing that would be captured in a contract you know, a contract between AMS and STE to provide resource adequacy? Do those kind of contractual obligations insure the safe operation of that resource?

MR. NELSON: I think it shows up in potentially multiple places. For example in the ISO's tariff generators that are interconnected to the transmission levels have a PGA and the PGA obligates them to follow dispatch instructions basically for this whole safety reason. Similarly in our interconnection to our distribution grid

there are certain requirements that they have to follow the instructions of the distribution operator.

And then above and beyond that specific contracts may have specific terms on top of it.

MR. HERBERT: Lorenzo?

MR. KIRISTOV: Yeah I would just pick up on what Jeff said, I think that's right the PGA -- it's not just what the market dispatches but it also allows the grid operator to give an emergency operating instruction and the resource has to follow that. So that's the kind of prioritization that happens instantaneously and I think some of the problem to work out will be where you have an aggregation of resources or -- say a fleet that creates a virtual resource, one of the different responsibilities between say the entity that is receiving the service, the ISO or the distribution operator -- and then the aggregator who is the visible entity that the ISO sees and gives a dispatch to.

And then the relationship is down to those individual resources which they could be say dispatched to give 10 megawatts but depending on the geographic pattern of that dispatch it may or may not cause a distribution system problem. So how does that level of coordination happen and I think for you know -- we drew a map of existing information and coordination activities between the various

components of the utility and the ISO and scheduling coordinators.

And what you see in today's world is the distribution operator has almost no interaction with the ISO. And I think -- and that's something that we are starting to talk about how to remedy, how to fill that gap. I think in the future that's going to be hugely important.

MR. HERBERT: Thanks guys. Let's change gears a little bit and we are going to take a step back to simultaneous use of the same capacity. So assuming that it is technically feasible, we have heard some examples of how it is technically feasible -- how could or should the costs of that electric storage resource capacity be shared among those services that are being provided simultaneously?

And do those cost sharing arrangements only matter if one or more of the simultaneous services are provided under cost-based rates to captive customers -- that is to say basically alleviating -- if it is all market based do you alleviate the potential for cross subsidization.

MR. KO: I think I would say that knowing that some of the discussions that we had earlier. If it is all market based and again I am using the example that I am familiar with which is the behind the meter resource, also bidding into the wholesale market. There isn't a cost-sharing question there -- it is more just how you are

getting compensated right?

So if you are getting compensated for what Manal was saying, incremental distinct services and you know how to measure and count those incremental distinct services, then there isn't really a cross subsidization problem there.

MR. KRISTOV: Yeah and I would add as an example I think going back to Manal's case as well -- that last year in Asder 1 we created a Commission approved using meter generator output as a measure of demand response so that we were participating as a PDR resource. We are measuring the demand response actually at the storage devices, not at the customer meter.

But we are comparing that response against baseline measurements which look at similar hours in which the resource was not dispatched for demand response. So whatever services the batteries are providing the customers on an ongoing basis are essentially captured on this baseline and subtracted out and I think you know that's at least one useful way to approach this.

On the other -- on a related question if the performance of a resource simultaneously satisfied two performance requirements that are services to two different entitles. I don't know whether we care about that. I guess I would question well they are doing the same thing and they are getting paid by two people but they are satisfying their

obligations for what they are providing to those two entities so maybe that's okay.

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

MR. NELSON: Yeah I'm not aware and Lorenzo might be able to correct me, of the ISO sort of entering into any sort of cost-based contracts at this stage for these type of items. I know that was an earlier panel discussion as Stem was talking about. We do a lot of -- hey will buy resource adequacy tags from you, this is how much money we are going to give you, we are done.

If it is not sufficient we will find money somewhere else or there is no deal but we are done. We do a lot of contracts like that. Something Lorenzo did talk on -- we should try to minimize uplifts or cost-shifting in the wholesale designs. We are working on -- I'm not sure where it is in the FERC process but I will just say that in general our design of markets should not result in uplifts to implemental use.

MR. HERBERT: Sarah?

MS. VAN CLEVE: So I think that the cost allocation question you are getting at really is only relevant when you have a device that is providing both services that are attritionally some cost-based rates as well as services that are in market services, whether that be getting revenues from the wholesale markets or from

individual customers that they are serving.

In those cases I think there are a few models, a few of which were discussed this morning, in particular the two models that were discussed this morning -- one was where the system operator operates the device and when it is not using the device for reliability needs it participates in wholesale markets, it dispatches the resource and then any of those revenues get credited towards the cost of the resource.

Another model that was mentioned was sort of the opposite where there was a contact where it is a merchant storage device that basically contracts out the reliability service to the ISO. I think there's one more model that wasn't discussed in detail that could also be very useful and that's sort of a combination of the two.

Where the device could be owned by the network operator, there's the distribution operator, transmission operator and then the wholesale portion is then contracted it out. So it is different than just having the wholesale market operator dispatch in the market -- we are talking about as a price seeker earlier because there would be a long-term contract for use of that capacity with a third party participant.

So the transmission operator/owner wouldn't actually be participating in wholesale markets they would

simply set times you can use this storage device you know, during winter months or whatever else. And I know this is getting a little bit in the weeds but I would suggest if folks are interested in this issue that they look at the Brattle study that was done in Texas, I think it's called the Value of Distributed Storage in Texas.

And it is a pretty long report -- 70 pages or so released last March of 2015 I think but the last 10 pages gets into these different types of models where you do have this competitive concern when the resources are also providing services by cost-base rates. So I think there are a few models that are worthy of discussion, particularly with FERC.

I think this is going to be one of the main issues that we need you all to weigh in on to make it clear to transmission distribution operators throughout the country how they can make these multi-use resources that are clearly efficient work from a regulatory perspective.

MR. KO: Yes and to give some specific examples of what the models that Sarah just mentioned is one -- where the revenues get credited back is actually in our contracts where they -- it is not where the cost recovery is under kind of a DR demerits cost recovery but the cost recovery is that Edison gets is the cost of the contract with us minus whatever revenues they get from the wholesale market because

they bid our resources into the wholesale market.

So that's one model that is actually in contract right now and we are building out at the moment. The other one -- the one, the hybrid model is actually one that we have been in discussions with one of the utilities about and it didn't result in an actual contract yet but it is exactly that idea.

Even where the utility would actually own even the behind the meter storage resource in this case and would you know contract and own it for specific additional reliability function with a specific defined set of obligations for distribution and liability but then would contract with a third party like us to actually operate the battery into the wholesale market.

And where we the operator could actually get the wholesale market revenues separate from the distribution, the sale of the asset. So these models are out there and they are being discussed right now.

MR. HERBERT: Anybody else on that question? I want to do a little time check, we are running over but we also started this panel a little late. We can go another 10 minutes -- 15 minutes or so if everyone is okay with that, okay. So the next question and this one might pick on you a little Lorenzo but what concerns do the RTOs and ISOs and other grid operators have about allowing electric storage

resource to sell services to other entities with the capacity that is already participating in their markets or providing a transmission service, or grid support service?

MR. KRISTOV: Well I think it comes down to things that we have talked about already. One is that we need this degree of coordination between us on the distribution system operator particularly -- I mean specifically for resources that are below the ISO grid level. I think spelling out the performance requirements and the penalties for failing to provide them and then the ability say under emergency conditions to be able to give an instruction and have a physical requirement that they have to follow it.

I think those are the main things. And we have you know right now we just basically have imbalanced energy. If you are providing balanced energy or no pay if you fail to provide AS but we do have to deal with those situations where it is an emergency and we need you to do this right now.

And that again may still involve a degree of coordination with the distribution operator because conditions on that system may be in the way. So that's kind of a summary but I think you know that's the things we are working on.

MR. HERBERT: Any other thoughts on that -- ways

to alleviate these concerns?

MR. KO: I just wanted to echo what was said before about this idea that if you know if we are providing services in a multi-use situation and we are providing services to them -- the wholesale operator, and we are providing it to another entity, maybe the distribution operator and we are providing the performance that we are being compensated for -- they almost don't care about you know, double counting of these kinds of questions.

It's like it should be and it is more of a high level principle of the market -- they should design the markets and the products around what it needs and then let the developers you know figure out how to work it.

MR. HERBERT: So I think we are going to skip ahead and talk about sort of the segregation of storage capacity a little bit and so as an alternative to simultaneous use, what issues may arise in connection with segregation of storage capacity for different services that would be separately compensated?

So as an example could a transmission connected electric storage resource be capable of providing multiple services using different portions of the capacity and if so would any special metering or telemetry requirements be necessary in order to allow tracking of the portion of the storage capacity that was used for each service.

MS. YAMOUT: I'd like to answer the question more broadly and then talk a little bit about behind the meter resources specifically if that's okay because that's essentially what we do. But I think that at the highest level the main consequence of segregation, especially for a customer-sited resource that can do several things is that it is extremely inefficient.

And it is very expensive and you get to the point where you are not putting in these systems at all, certainly not at this point of the market's development. And so from the AMS perspective where we need multiple revenue streams in order for us to install battery systems -- so if we aren't able to use the same system for more than one thing in most cases we don't build it.

That said, we do have situations where we do have separate battery packs, battery cells, we test the batteries and we share an inverter. So in some cases on certain customer sites we do separate out the energy that we have set aside for the utility versus what we have set aside for the customer's use, but they share an inverter.

But those are decisions that we have made for business reasons but generally speaking I think Ted said -- what did you say, more brains less battery -- I think that's really the goal and what we are seeing -- what most of us on the developer side started out as developers but ended up as

software companies for a reason. There's a lot we can do with the proprietary algorithms that everyone in this space has developed that allow us to meet all the obligations with less battery.

And the less battery is the single most expensive piece of this whole thing so if you can put in less and meet everyone's obligation, you have a much more efficient system.

MR. HERBERT: Go ahead Jeff.

MR. NELSON: So my technical folks say technically you can do it, it is an issue of costs. But something that's related that is turning out to be interesting and economic, they are calling it enhanced GT's or enhanced combustion turbines where you can have an existing generation resource that is already interconnected and pair it with storage and depending on how the interconnection is arranged you can put restrictions that the two can never simultaneously output or you could put restrictions such that the combined output of the generator plus the storage doesn't exceed what was interconnected before.

And this provides some additional flexibility to the generation of -- for example that stone cold CT can now sell spinning reserve because the battery that is paired with it is synchronized to the grid. There's also ways you

can manage emissions and start up and shut downs with that sort of enhanced GT scenario.

So it is not directly at your issue but these are transmission interconnected -- you have sort of got two devices, you can separately meter both devices and have a single meter in the front. So we are seeing some interesting flexibility the batteries are creating for existing generation.

MR. HERBERT: And so -- go ahead.

MS. VAN CLEVE: I was just going to add that I think the reason that you heard silence from the group is because the metering solutions are absolutely there. It's something that we need to be cognizant of in particular with the question about you know the difference between retail services and wholesale services. Obviously we have to meter that appropriately but the metering capability is there -- we want to make sure it is cost effective, especially when participating in ISOs but it is not a barrier at this point.

MR. MILLER: It is just a matter of market design and if you are rate-basing a product and you want it to be credible -- like was being talked about with Encore they are a wires company they can't really you know participate in ancillary services markets, it is not the most efficient use of those resources.

The market really hasn't caught up on the rates,

hasn't caught up on what we could do with it so the metering does exist and you can segregate the assets and have them flow to different areas it is just a lot of times they are not allowed to currently.

MR. HERBERT: That's helpful. And so one final question and this is you know the further downstream the storage asset gets the more complicated this issue becomes. And so the last question is you know if you do have a battery or storage asset on the distribution grid or behind the customer meter that is also providing multiple services to multiple entities -- how if at all can you sort of segregate the energy that is discharged to sell wholesale electric service from the energy that is discharged to serve and end use load.

I know Jeff you kind of eluded to this concern earlier but practically speaking is that possible and how is that possible if so?

MR. KO: One of the issues we came up with in the double counting discussion in California was well -- let me step back a minute. In the -- Phase 2 proceeding that we have been talking about the discussion came up around being paid to charge. So this idea that we can -- there's a market where we do demeris except you are charging instead of discharging and you know are there kind of retail rate, wholesale rate implications or jurisdictional questions that

you have to deal with.

And it turns out that actually for most cases there aren't any actual issues because the retail meter pretty much takes care of what the retail meter is going to take care of and you can directly meter the battery like Lorenzo was saying -- for the wholesale, whatever the wholesale market participation was at the time and it would be, you know, they have that approval earlier this year.

So there isn't actually -- there doesn't have to be any kind of reconciliation against the retail meter in that case because we are going to -- we'll get paid to charge but we are also going to pay the retail rate for that energy at the retail meter, which is fine because we are going to discharge later and we will offset that at some other point.

So we will lose a little about in the round trip efficiency but from a market participation point of view there doesn't need to be any kind of accounting to unwind that later.

MR. HERBERT: Jeff go ahead.

MR. NELSON: Yes, so we kind of crossed into some of the principles of concern here -- the concept of charging at wholesale and discharging at retail. That's something we think is just not allowable for multiple dimensions, the lock-in part of it. But technically we think there are --

you know we haven't done that but the concept is sort of inventorying -- keeping account, the time of use metering, we need to know what's happening, when it is happening and they need to know more of the actual reason why someone is doing something.

But the concept of being able to inventory with time of use so that wholesale is charged in and then wholesale is returned is conceptually possible.

MR. KO: I do want to point out that in the -- meter case we would never be charging at wholesale, we would be charging at retail yes.

MR. NELSON: There are charging issues with baselining and some of those baselining issues get into whether you trade up flux or not so it is doable you need to be very careful, you need to work the math from a couple of different angles to make sure that you end up with you know credits and debits equaling each other at the end of the day but we think it is doable.

MS. NARANG: Yeah it just raises the complexity of settlements quite frankly in terms of compensation and payments and what not so but yeah it's just all part of the process I think.

MR. HERBERT: Great anyone else? I think I'll hand it over to Rahim for some short closing remarks then.

MR. AMERKHAIL: Thank you Michael and thank you

to all the panelists. I was going to try and summarize what we heard but I think it is beyond me at this moment and the three panels. Staff is going to think about what we have heard. We plan to issue a Supplemental Notice -- if we come up with additional questions they will be in that Supplemental Notice, if we don't the Notice will just ask for comments.

And we hope that the panelists and anyone else who is interested will submit written comments and help us decide where if anywhere, to go with the information we have heard today. Again I want to thank everyone. I think we had some very interesting discussions. We learned how difficult some of these issues are in some cases and maybe in a few cases saw our way forward.

But with that unless anyone else has anything to say I think we will adjourn this Technical Conference, thank you.

(Whereupon the meeting was adjourned on November 9, 2016 at 3:22 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:
UTILIZATION IN THE ORGANIZED MARKETS
OF ELECTRIC STORAGE

Docket No.: AD16-25-000
Place: WASHINGTON, DC
Date: NOVEMBER 9, 2016

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.

Gaynell Catherine
Official Reporter