OFFICIAL COPY

Nov 26 2019

PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Monday, October 7, 2019

TIME: 1:00 p.m. - 2:31 p.m.

DOCKET NO.: E-100, Sub 164

BEFORE: Chair Charlotte A. Mitchell

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

Investigation of Energy Storage in North Carolina

Presentation by:

Jeremy Twitchell, Energy Research Analyst,

Pacific NW National Laboratory

and

Kelsey Horowitz, Lead Researcher,

Sustainable Technology Analysis,

National Renewable Energy Laboratory

VOLUME: 1

OFFICIAL COPY Nov 26 2019

P R O C E E D I N G S

CHAIR MITCHELL: Good afternoon. Let's go ahead and get started, please.

I'm Charlotte Mitchell, Chair of the Utilities Commission. With me this afternoon are Commissioners ToNola D. Brown-Bland -- thank you Commissioner Clodfelter -- Lyons Gray, and Daniel Clodfelter.

Today will be the first in a set of presentations pursuant to the Commission's September 4th Order Initiating an Investigation in Docket Number E-100, Sub 164, in which the Commission has commenced a series of educational presentations by experts whom we've invited in to discuss energy storage related topics. We're happy to have with us today two such experts, both of whom have traveled a long way to be here. I will introduce those speakers momentarily, but first I'd like to talk about the structure and format for these presentations.

The speakers will be working from slide decks, which will be displayed on the monitors here in the room. So I see that -- that they're not up yet, but will be momentarily. The slides have also been posted on the docket on the Commission's website, so

OFFICIAL COPY

Nov 26 2019

you should be able to access the slide decks that way if you don't already have a hard copy of them.

We have our court reporter here today who will be creating a transcript of the presentations and those -- that transcript will be filed in the docket and available on our website as well. That way over time we will create a repository of information on energy storage that we think will prove insightful and helpful as we move forward.

These sessions are structured for the benefit of the Commission's learning and understanding, and the speakers will be asked to share their expertise and answer questions from the Commission. People in the audience will not have an opportunity to ask questions. However, if you want to file information in the docket in response to what you hear at any of these presentations, please do so, or if you'd like to suggest other expert speakers whom we should consider inviting to future presentations, please do so as well. Now, I'll get to today's speakers.

First up today is Jeremy Twitchell who comes to us from Portland, Oregon, where he is an energy research analyst at the Pacific Northwest National

OFFICIAL COPY
Nov 26 2019

Lab. Jeremy assists with distribution system planning research and provides technical assistance to states like North Carolina to help them analyze energy storage and other developing energy resources. Prior to his joining the lab, Jeremy spent five years at the Washington Utilities and Transportation Commission where he helped develop policies for the treatment of energy storage in utility planning. Jeremy has degrees from BYU and from Texas A&M.

Our second speaker today will be Kelsey Horowitz. Kelsey is with us today from Golden, Colorado, where she is a lead researcher in the Distributed Systems and Storage Group at the National Renewable Energy Lab. Kelsey has degrees in electrical engineering and her research interest include clean energy tech and their integration into the grid. Kelsey is going to provide us with an Overview of Approaches and Emerging Practices in the Interconnection of Storage and Storage -- Solar-plus Storage Facilities.

So Jeremy will be up first and I have checked with both of them and both have agreed to take questions along the way if the Commission has them, so please feel free to ask your questions of our

OFFICIAL COPY

Nov 26 2019

presenters as they speak.

Our next meeting is scheduled to be held on November 25th and we will hear then from Bob Schulte who is an energy consultant who lives here in Raleigh. And Bob will continue our discussion about how energy storage fits into integrated resource planning. Okay. With that, I will turn it over to Jeremy.

MR. TWITCHELL: Thank you. Thank you, Chair Mitchell. So as you pointed out, before joining the lab I worked for five years at the Washington Utilities and Transportation Commission, so I just want to preface my comments by saying I get it. You know, we -- I understand the unique issues and challenges the Commissions' face, and also I just want to point out that all the information that we present today is meant to be objective and informative. Our job is to help inform processes such as this so that you can decide how and where storage fits in your unique state's needs and -- and policies. We're not here to make recommendations or tell you what you should do, just to help you figure out what you want to do.

So all of the work that I'm sharing today was funded by the Department of Energy through the

OFFICIAL COPY

Nov 26 2019

Office of Electricity through the Energy Storage Program under the direction of Dr. Imre Gyuk. I also want to thank my colleagues, Vince Sprinkle and Patrick Balducci at PNNL, and Ray Burn and Dan Burney with Sandia National Labs, for their help in developing this presentation.

So what I'll be talking about today first we'll do a brief overview of the energy storage program, what we do, the work that we -- that -- that the DOE funds. Then technologies and trends related to energy storage, what kinds of technologies are out there, installation trends we're seeing. Then dive into a little bit the specific challenges that energy storage creates from a resource planning perspective. And then look at some of the emerging practices that we're seeing utilities around the country develop for fitting storage into those planning processes.

And then finally, this is more of a reference than anything, just an overview of state level policies on energy storages, just what's going on around the country. Again, not trying to say that one policy is better or more effective than another, but just helping you see that when it comes towards policy that's -- there's a lot more than just procurement targets.

So the energy storage program that DOE sponsors comes out of a 2013 report that the DOE released where they identified four key challenges to energy storage. First was a need for cost-competitive energy storage technology development. Second was a need for validated reliability and safety of various technologies. Third was an equitable regulatory environment for storage. And then fourth was industry acceptance.

And my slides are very much meant as a reference. If you -- you'll see hyperlinks on each of these to learn a little bit more about these research areas, but the point here is that I'm really just the tip of the spear. I work on policy and regulatory issues, but this program sponsors chemists, material scientists who are working on better storage technologies, codes and standards experts working on interconnection electric codes, safety codes for energy storage, develop or helping states identify regulatory challenges and potentially better solutions. And then industry acceptance is -- is economists. People who are doing very detailed analysis of various energy storage project and

OFFICIAL COPY

Nov 26 2019

OFFICIAL COPY

Nov 26 2019

supporting demonstration projects around the country as well.

So here's just a few examples of some of the work that the storage program does around the country. We engage with universities on the research side, utilities on the development and the deployment side and with various commissions around the country in helping identify new regulatory approaches for storage.

So technology and trends for energy storage. The information on this slide comes from the DOE's global energy storage database. I will caveat it by saying it is not right. It is a -- it is a Wiki site that Sandia National Labs put -- puts a lot of effort into verifying and checking, but it is directionally accurate.

So we have about 26 GW of storage on the grid in the US. The vast majority of that, about 94 percent, is all pumped hydro. Batteries, despite rapid growth in recent years, still only represent about 3 percent of the installed storage capacity in the country followed by thermal storage resources and compressed air.

And then pulling out those -- those battery resources to the right, most of what we have, about 85 percent, is lithium-ion followed by lead acid, and then nickel and sodium and flow chemistries. And then a little bit of ultracapacitor technology out there as well.

So pumped storage, there's a lot of that in the region, some here in North Carolina as well, so I -- obviously everyone knows generally how it works. You know, again, as you can see pumped storage is the vast majority of installed capacity in the country, but we haven't built any in a while now. There's a few challenges, a few particular challenges. You know, first obviously high capital cost. It is -- it is very expensive to build these facilities. Permitting requirements, very challenging to get them permitted. And then geographic restrictions. You can only build them in so many places.

But pumped storage does offer a lot of benefits. Once you overcome those initial high capacity or -- excuse me -- capital cost for installation, it does offer very cheap, long duration -- excuse me -- long useful life. You know, these things will go 50 - 60 years. It does offer long duration storage, eight - 10 hours, and it is high --

OFFICIAL COPY

Nov 26 2019

a very high voltage application so you can use it for things like transmission support.

So to get around some of these permitting and geographic restrictions around pumped hydro, Shell Energy North America has proposed this hydro battery idea, which is basically just kind of a modular approach to pumped storage where you basically just build -- think of it like a very, very large above-ground pool on a hill by a river, and then just a pump and a penstock to get the water back and forth. That -- the hyperlink there goes to some economic analysis that we did at PNNL of these facilities, found that they could be cost effective in a few market structures around the country. One of these has actually been permitted in Washington State and will be entering construction in the near future is my understanding.

So moving on to batteries. Just basic terminology for battery, you've got a positive cathode on one end, a negative anode on the other, and then an electrolyte which is some ionic mix that allows the electrons to flow back and forth to charge and discharge. And so one of the -- one of the -- the gauges of energy storage you'll hear a lot is energy

OFFICIAL COPY

Nov 26 2019

density. That's just a measure of how much energy you can store in a device relative to its size.

And then usually when you talk about capital cost for energy storage, it'll be expressed in dollars per kWh, per MWh, which is different than what we're used to for capacity resources, which are usually dollars per kW, dollars per MW or -- excuse me -- MW. The reason we do this is to serve a levelizing function. So if I had a lithium-ion battery that was two hours duration and a lithium-ion battery that was four hours duration, if I just look at the dollars per MW cost, I'm not capturing that difference in terms of two hours of duration and four hours of duration. So by doing it in terms of dollars per kWh or dollars per MWh, we can levelize across different chemistries, different sizes.

So lithium-ion as we -- as I mentioned the dominant source of battery storage in the country. You know, a lot of advantage for that, it does have high energy density. You can pack a lot of energy into a relatively small cell. You can get some pretty good useful life out of it. We have seen rapidly decreasing costs in recent years. I'll get to that in a few minutes, largely driven by the EV fleet and the

OFFICIAL COPY

Nov 26 2019

infrastructure that's gone into developing EV batteries. So we do have really strong supply chains, lots of vendors, lots of resources, which is translated to much lower capital costs, rapidly falling costs.

You know, but there are some challenges there. There's the reliance on rare-earth minerals. Lithium is so-so, but then you start to get into the cobalt and that becomes very, very challenging to source. Safety, we've all heard about the battery fires most recently in Arizona. And this last one performance varying with usage. How you use the device has very significant impacts, both on how much energy you'll get out of it in a given cycle but also the useful life. So the harder you push a lithium-ion battery, the shorter duration you'll get out of it, the shorter life you'll get out of it, and so we're really starting to understand what do those relationships look like and how do you build models that account for those relationships.

So lead acid, this is the -- the OG of battery storage, the -- the original source of storage. This is really good for light-duty applications like your car or backup storage. If you

OFFICIAL COPY

Nov 26 2019

go to a substation, any utility substation you'll probably see some lead acid batteries on site. Very, very cheap. The challenges that you do have, very limited life, you know, five to 15 years, and very few cycles, 500 to a thousand if you're lucky. And if you push it hard, you're going to really, really shorten the life of the battery we have found.

So again, you're -- you're usually only seeing this in places where it's -- you just need emergency backup power or you're just using it a little bit once in a while. There is active research going into lead acid batteries to deal with some of these challenges. You can see an example there.
So sodium -- excuse me -- sodium metal batteries. So these are interesting. They kind of invert the -- the -- the traditional battery structure. Usually you have an -- an anode and a cathode that are solid, and then liquid or semiliquid in between. Here you actually have the -- excuse me -- the anode and a -- and a -- excuse me -- the anode in a sodium battery is -- is molten and the electrolyte is solid.

So the advantages here, sodium is real easy to find, really cheap, decent energy density, and you can get long duration cycles out of it, four to six

OFFICIAL COPY

Nov 26 2019

hours. The challenges though is in order to keep that sodium molten, you've got to operate at a very, very high temperature, 300 to 350 degrees Celsius, and that -- that can be very difficult to manage and creates a lot of safety risks.

So flow batteries, this is still very much an area of active research. The difference with a flow battery, the unique characteristic they have is normally in a traditional battery structure you're limiting the energy and capacity based on the size of the cell. What a flow battery does is it decouples that relationship. So I'm -- I'm setting my -- my capacity, my power rating based on the regenerative fuels there in the middle, how much membrane I have. But then the energy component is in separate tanks, and so I can -- I can change the size of those tanks. I can make them bigger. I can make them smaller. So you've effectively decoupled the energy and capacity relationship with a flow battery.

Some of the advantages here, this is highly recyclable, so you could run a flow battery for 20 years and even though all the -- the equipment will eventually reach the end of its useful life, you can pull the electrolyte out of there and drop it into the

OFFICIAL COPY

Nov 26 2019

OFFICIAL COPY

Nov 26 2019

next battery and it will still run just as well. You know, there -- there's no fire risk here. You're talking about a weak acid operating at essentially room temperature.

Some of the challenges though, you know, we don't have a lot of experience in this area. We have deployed a few flow batteries around the country and what we found is that the idea of having pumps and all this machinery to move liquid around and move it through this membrane sounds like it would be relatively easy, but what we found is that it is not. The mechanical challenges of really putting these things together have proven fairly significant.

So there is a complicated design. You've got low energy density, so if you're talking about a grid application where you have a relative large amount of space, a flow battery might be a good fit, but you're -- you're unlikely to ever see a flow battery in a vehicle application, because you just can't get enough energy into that space. They also have to date lower round trip efficiency than a lithium-ion battery would have.

So R&D efforts at the Department of Energy. So DOE is very actively sponsoring as I said research

OFFICIAL COPY

Nov 26 2019

and development on battery storage. And the flow batteries what we're looking at is organic chemistries. Most of the chemistry here -- or the most popular chemistry right now for flow batteries is vanadium. And vanadium is one of those rare-earth minerals that can be difficult to find and has some -- some mining challenges associated with it, so what we're trying to do here is generate organic compounds for energy storage, carbon-based things that -- that don't have any of those recyclability challenges, don't have any of those mining environmental impacts. It's theoretically possible. There's proof of concept. But again, trying to figure out how to make it hold a lot of energy and have long -- long life. Multiple cycles is the -- the primary challenge.

For sodium batteries there's two fronts to this. One is reducing the operating temperature of that traditional molten sodium battery. We've had some good results pushing that temperature down to around 110 degrees Celsius; still obviously very hot, but significantly cooler than traditional technologies. And then also solid state, so it's effectively using just the sodium in metal form to store energy.

OFFICIAL COPY

Nov 26 2019

Similar challenge. We've demonstrated that it can be done, but figuring out how to do it in a way that holds a lot of energy and will give you hundreds or thousands of cycles is -- is where the work is being done.

And then finally metal air batteries. This is very, very early stage research. The goal is to use, you know, abundant or semi-abundant materials; zinc, lithium. And use them in a way that don't have -- doesn't have a flammability risk. The -- the -- the reaction is occurring in the -- in the metal and with the air.

But yeah, it's still largely theoretical. You know those -- like if you see those like rechargeable AA batteries that you can buy, those are usually zinc based, but you're only using about 5 percent of the potential capacity that's in that battery. Just like the top little bit is what you're using as you charge and recharge it each time and you're only going to get maybe a hundred, a couple hundred cycles out of it. So what we're really trying to do is figure out how can we get more of that capacity out of that battery and get it up to, you know, several hundred thousands of cycles.

So Installation Transfer of Energy Storage. This is from Wood MacKenzie. As we're all well aware, the -- the deployment of storage has rapidly increased in the last few years. I just want to point out one thing in 2018. What you really started to see for the first time in the last couple of years is significant deployment of behind the meter energy storage. In 2018 for the first time we had a quarter, I think it was quarter 2, where the was more behind the meter energy storage installed in the US than front of the meter energy storage.

So the Elements of Battery Storage. It's important to remember that when we talk about energy storage, we're talking about much more than just a cell. So that first column on the left, that storage, that's where we're talking about just the cell, the device that -- is actually storing and discharging energy.

But then you need a power control system. This is the hardware to connect it to the grid. You need an energy management system, so this is the software to manage the battery device itself, make sure it's operating within its optimal range. You need a site management system that governs how the

OFFICIAL COPY

Nov 26 2019

OFFICIAL COPY

Nov 26 2019

device interacts with the grid. And then you need your balance of -- balance of plant cost, so wiring, housing, cooling, whatever you need to actually get the thing in the ground.

And it's important to remember that when you hear like a quote for a battery cost, you know, like $200 per kWh, you're usually only talking about that storage component. Maybe depending on the vendor you might have the power control system in there. The important thing to remember there that -- in that bottom line is that once you really get this all-in cost for energy storage, you're really talking about 4X or higher from that -- that quoted cost for the -- just the storage device itself.

So this is from Bloomberg New Energy Finance. This is where the -- the -- the prices for lithium-ion storage have gone over the last few years. As you can see it's fallen down to about $176 per kWh, but that, again, that's just the cell and the pack, so just the device and what I need to interconnect the device. It's not -- it's not covering the software. It's not covering the balance of plant cost. So even though the cell costs have rapidly fallen in recent years, what we're seeing is that those balance of plant cost are not falling nearly as rapidly if at all. And so as the cell costs get lower and lower, it's not unreasonable to expect that the total install cost may be as much as six times higher than your quoted cell cost.

This is just an I-chart from a report that we recently did at PNNL where they looked at various energy storage technologies to compare them on -- on even terms accounting for their -- their different characteristics and their different performance. And I drew a line around the -- yeah, that did not work at all. I drew a line around the total levelized cost for each technology type dollars per kWh. And the -- the goal here was do it -- to do an all-in cost, an installed cost in accounting for life cycle cost, disposal cost, recycling cost, commissioning cost. You know, all-in costs.

And so you'll see there that in terms of dollars per kWh what we came up with for lithium-ion was about $362 per kWh. And then it ranged up from there to about $700 per kWh for some sodium technologies. And then similar for pumped hydro. Came up with an all-in cost of about $2,600 per kW there.

OFFICIAL COPY
Nov 26 2019

So Challenges for Energy Storage and Integrated Resource Planning. So I -- I want to caveat this before. My goal here is not to criticize IRP processes. I know we have utilities in the room. IRPs are incredibility complex exercises. If you think about it, what they're trying to do is for every hour over a 15-year - 20-year, whatever the horizon is, for every hour in that period they're matching up load and generation. And for each one of those calculations, there are dozens of variables. They have to look at all of their different sources of generation, they have to look at market interfaces and market prices. They have to look at fuel cost for the fleet. They have to look at changing load patterns for customers. You know, what's the impact of distributed generation, electric vehicles. And they have to take all of this and come up with a model that says okay, for every hour here's the bottom line; here's how much energy you'll have to provide to your customers and here's where it's going to come from.

So this is an incredibly complex exercise. And in order to make it manageable, we've basically as an -- as an industry just develop some simplifying assumptions.

OFFICIAL COPY

Nov 26 2019

OFFICIAL COPY

Nov 26 2019

So first we look at the system from an hourly basis. And again, as you can see there, for a 15-year plan even at hourly resolution I'm trying to solve for more than 131,000 data points. So if I'm trying to do sub-hourly resolution on my system, you know, every 15 minutes, every five minutes to account for the -- the variable -- excuse me -- to account for variable resources, to account for granular flexible resources like storage, I've just added hundreds of thousands of more calculations than my model is trying to solve for.

And traditionally we didn't have to worry about that as an industry. We didn't have model -- you know, computer software, computer models that could handle that kind of calculation, and we didn't really need to do it anyway, because we had predictable plants. We knew we could flip a switch and turn a generator on, ramp it up, ramp it down, turn it off. We knew when people were coming home, how many devices they had in the house, but what we've seen with the way the industry has evolved in the last few year is we've introduced unpredictability on both sides of that. We have unpredictable generators. We have customer load patterns that are changing rapidly and in ways that are really difficult to predict, because it's not just economics that's driving these decisions.

Another simplifying assumption we've done is we do reserve margins instead of calculating for -- for ancillary services. So all the model is saying for every -- for every hour here's how much energy I need for the hour. But we know that in order to keep the grid up and running we have all these other services we need to provide. We need to provide frequency response, voltage support. We need to provide spinning reserves, non-spinning reserves. But we've never really optimized for all that. Instead we just created a reserve margin and we just effectively overbuilt the system to have excess capacity to make sure that we can provide all those services.
Again, we didn't really need to optimize, because we didn't have models that could do it, we didn't have resources that can move around that quickly anyways. But now we do have -- we do have both of those things. We have models that can dive into that level of granularity. We have resources, you know, like storage, like demand response that can move that quickly.

OFFICIAL COPY

Nov 26 2019

And then, again, the last simplifying assumption, we've only focused on generation resources. So no looking at the -- well, limited look at the transmission system and nothing about the distribution system.

So Energy Storage, the point of this graph is just to show that energy storage can do a lot of different things at different places on the system depending on how you use it -- how you use it. But it can't do them all at once. You know, every time you -- you pick a service, you dispatch the device to do something, there's an opportunity cost, because now there's all these other services that I can't do during that period or when the device is recharging from the service that I selected. So really the key to optimizing energy storage is having a model that can understand, okay, what are all these values that the device can chase. What are the operational characteristics of the device and how can I optimize it in a way that will maximize the value?

Okay. So the idea here is to show that as you add all these services, you're changing the -- the way the device dispatches. So that top row energy price, that's the -- that's the market price that a

OFFICIAL COPY

Nov 26 2019

storage device is seeing. And what we've done here in the first row is allowed to chase arbitrage. So discharge when or -- excuse me -- charge when prices are cheap, discharge when prices are high.

And that third row we've added a frequency response use case. You know, balancing the system, and so you see it moving up and down very quickly. The fourth row we've added a T&D deferral opportunity where by discharging during a certain window it can defer the need for an enhanced or an expanded distribution line.

And then finally in that fifth row we've added a Volt/VAR, a real power application. You know, the point is just to show that as you add in these different services, these different values, it changes how the device is dispatched. And if you're looking at this from a traditional resource planning perspective, the only one of these uses that you will see is that arbitrage use case. Charging when prices are low, discharging when prices are high. All these other potential values are not going to be captured in that traditional IRP model.

CHAIR MITCHELL: Jeremy, have a question for you.

OFFICIAL COPY

Nov 26 2019

MR. TWITCHELL: Yes, ma'am.

CHAIR MITCHELL: I want to stay on the slide you were previously on.

MR. TWITCHELL: Okay.

CHAIR MITCHELL: And this goes back to a point you made very early on in the presentation. So as we look at these different applications of energy storage, as you indicated on this slide, which one constitutes working the battery hard? You talked about sort of working the battery in different -- in different ways which is --

MR. TWITCHELL: Yes.

CHAIR MITCHELL: -- which is a less -- and -- and I don't know if that's the exact right word to use, but --

MR. TWITCHELL: No. No, that's -- that's the right term.

So in like any good question, the answer is it depends. So it's going to depend on the battery chemistry you're using and it's going to depend on the resource, so --

CHAIR MITCHELL: So if you assume the lithium --

MR. TWITCHELL: -- let's -- let's assume

OFFICIAL COPY
Nov 26 2019

OFFICIAL COPY

Nov 26 2019

it's lithium-ion. So that -- lithium-ion does best when it's doing short shallow charges and discharges. You know, just a little off the top up and down. So that balancing use case is very good for lithium-ion. When you start to get in that T&D deferral, so if that's something that I have to do like to -- to shave a daily peak, and so I have that long three hour window where I'm discharging the device every day, something like that would constitute a hard use. Or I'm doing a deep cycle on a daily basis.

We're -- like I said, we're trying to understand exactly what those relationships are, but that -- that definitely would reduce the useful life of the battery. And depending on the value of deferring that distribution line, it may make sense to do that. You know, if I only get five years out of my battery, but I can defer that distribution line for five years, that may well make sense. But again, you need a fairly sophisticated model to understand what is the value of deferring that distribution line and what is the impact of my device by doing that -- that deep discharge cycle every day to defer it.

So we just did a report at PNNL, there's a hyperlink to it there, where we -- we looked at IRPs from around the country to understand, you know, are utilities recognizing these challenges in the traditional planning models and to what degree are they adapting their planning process to -- processes to account for flexible resources like storage, like demand response. Really the question we were asking is are utilities including battery storage and pumped storage as a resource option in their plans? And if so, how are those resources being evaluated?

And so what we found is that of the 21 IRPs we looked at, 15 of them included battery storage in the plan. Of those 15, eight plans did not select it, five plans did select it in their preferred portfolio or their -- their plan going forward, their most likely plan, and then two utilities selected it and a alternate portfolio where if -- if something happens, then storage makes sense. Usually it's in a portfolio that has high emissions costs or something like that.

For pumped hydro we found that 10 of the 21 utilities included pumped hydro. Only three utilities did select it. Two of those utilities included it in the preferred portfolio, but I should point out that those were both expansions of existing facilities. These are not new facilities. There was one utility

OFFICIAL COPY
Nov 26 2019

that did have new pumped storage in an alternate portfolio, again, with -- with high carbon cost in the future.

One thing we found as we looked at this is that utilities are much less certain about the cost for batteries. And, you know, this makes sense. If you look like a resource like a combustion turbine or pumped storage, that's something that's been around for a long time. Utilities have a lot of experience with that. They know what they're getting when they buy that. There's a lot of vendors for that kind of stuff, so the -- the costs are fairly well known.

When it comes to battery technologies, lithium-ion in flow, there's much less certainty about these costs. So, you know, you had utilities -- some utilities that were assuming that a battery cost nearly twice as much as what another utility assumed it would cost, which obviously has significant impacts on whether the battery will be cost effective in the resource planning process.

What I thought was the most useful or the most interesting finding from this in this report was so as we -- as I mentioned a couple of slides ago, the traditional IRP model is not capturing most of these

OFFICIAL COPY

Nov 26 2019

OFFICIAL COPY

Nov 26 2019

services. But what we found is that as utilities adapt their models or add processes into account for those additional services, they become significantly more likely to identify cost effective energy storage opportunities.

In that first group we had 12 utilities that had zero to two services for storage and none of them selected it in their plan. The next group there was -- there were four utilities that has three to four services and one of them 25 percent selected it. That final group we had five utilities modeling at least six services and three of the five 60 percent selected it.

So what are utilities doing to account for these benefits? How are they building in this additional valuation?

So this net cost approach, this is a great starting point. This is the one that is most likely or has the least impact on planning processes. This was pioneered by Portland General Electric back in 2016 and it's -- effectively what they do is they just run their traditional IRP model like any utility does, but then what they do is they use an external model and there -- there's a few of them out there. At PNNL we have the Battery Storage Evaluation Tool. EPRI has put out Storage VETs and there's -- those are both free. There are some that you can pay for as well.

But anyways, that external model, they run the battery through that and that external model captures all those flexibility benefits, those ancillary service benefits that aren't in the IRP model. And so -- well, you can't see my -- so that -- that light purple in the middle, that's what PG identified as the operational value, all these flexibility benefits that were identified by that external model. And so they took that and they basically said okay, what is the net value of those and they went back into their IRP model and deducted that net value from the assumed cost of the storage device, which lowered it to that -- that third purple line, you know, what is the -- the net cost impact of energy storage.

Then they did the same thing for a combustion turbine where they -- they looked at how much it would cost, that far right dark line. They looked at what the flexibility benefits are, that middle lighter gray line. And then came up with the net cost, the gray line on the left. And what you can

OFFICIAL COPY

Nov 26 2019

OFFICIAL COPY

Nov 26 2019

see is that this kind of analysis that brings in these additional values really narrows the gap between a traditional combustion resource and an energy storage resource.

Another thing that some utilities are doing is moving to sub-hourly planning models. So adopting planning models instead of using hourly granularity are now using sub-hourly granularity, five minute, 15 minute. There are several commercial models out there that can do that. This is more challenging. This does have much more impact on a utility. You know, these -- these IRP models utilities have spent a lot of money licensing those models, training staff over the years to use those models, so moving that whole process to a new model is -- is a complex and challenging and expensive process.

We have found utilities -- in that IRP report I mentioned we found one utility that's kind of taking a hybrid approach where they're using the traditional IRP model to get their preferred portfolio, but then they're using a sub-hourly model to optimize it. So there -- there are ways to do this.

And then finally Integrated Distribution

System Planning. You know, as -- as I mentioned, the traditional IRP is not really looking at the transmission system and it's definitely not looking at the distribution system. But we're -- but we're starting to see around the country, and there's a few examples of this, is when you do look at how storage can be used in a transmission or a distribution setting, there -- there is potential value there. And so the challenge is figuring out how do we adapt and evolve our traditional modeling practices to incorporate that look at as well.

And what you can see here is an example created by Paul De Martini about what that might look like schematically. There's also a few states that have started to look into how do -- how do we evolve our planning processes to do this as well.

And so the Overview of State-Level Policies on Energy Storage. I just wanted to point out this first slide. One of the things we do at PNNL is we try to track these state-level policies, and so we maintain this database, there's a link for it there, where we're trying to say okay, what is each state doing and what we've done is we've broken it up into five different types of storage policy, you know,

OFFICIAL COPY
Nov 26 2019

OFFICIAL COPY

Nov 26 2019

recognizing that it's more than just procurement targets. Certainly there are several states now that have done that, but we've also seen states where the Commission has taken the lead and instituted through rule makings, through policy statements increased expectations or guidance for how utilities should be looking at storage.

We've seen states support demonstration programs where the state is helping to provide funding for demonstration programs, and then assuring that there is some kind of analytical component to help identify what is -- what are the benefits of energy storage, what might -- might make sense for the state going forward.

And then financial incentives. These are state incentives to end-use customers for customers to install behind the meter storage. Maryland actually has a tax incentive. They're the only state that has that. We've seen other states that have provided funding or some other kind of assistance for customers to do behind the meter storage as well.

And then consumer protection. This is kind of a newer one. This is where a state has established that customers have a right to install behind the

OFFICIAL COPY

Nov 26 2019

meter storage, and then instituted certain expectations around interconnection processes and ratemaking to ensure that those resources are treated fairly.

And then the next few slides here are just a few examples with hyperlinks to where these policies have been done and what -- what some of the drivers were if you're interested in looking into that a little more.

There's a few more resources there for the storage program, some of the work we've done.

Again, as I mentioned this -- this program is very large. I'm just the tip of the spear. I've got a whole lot of very, very smart people behind me, so as you work your way through this -- this proceeding, you know, any technical issue that comes up, we'd be happy to help. Again, our goal is to be objective and informative and never to make recommendations about what should be done.

And with that, I'm happy to take any questions.

CHAIR MITCHELL: Questions from Commissioners? Okay. I think, Kelsey, you're up. Thank you, Jeremy.

MR. TWITCHELL: Okay. Yeah.

CHAIR MITCHELL: We appreciate it.

MS. HOROWITZ: All right. Hi. I'm Kelsey Horowitz and my background is in engineering, as Commissioner Mitchell mentioned, so I am not a policy person, but hopefully we can provide you with some good technical information that we'll be able to inform some of your decisions around storage and solar-plus storage.

So I'm going to start off by covering some issues around storage and solar-plus storage system configurations and interconnection issues. And then talk about potential issues of -- potential impacts of solar and storage on the distribution system, which is where I've been doing more of my research recently. And then considerations for storage and solar when they're co-located and potentially retrofit onto existing solar systems.

So I'm not going to go into much about what other states are doing in this particular talk, but I just wanted to call out that there are still -- everyone is still in the very early stages of trying to understand how to include storage in their interconnection rules and a few states including North

OFFICIAL COPY

Nov 26 2019

Carolina obviously are in the process of explicitly addressing this in interconnection rules. And if you're interested in learning more about what different states have been doing in the interconnection process for storage, we have a guidebook that's broadly about distributed energy interconnection. Then I have a link to here and also includes information about the IEEE 1547 standard, cyber security, technical screens, upgrade analysis, and other issues around managing interconnection applications for solar and storage.

So what's unique about storage is obviously that it can act as a load or a generation source and that the behavior and technology can be quite complex as Jeremy talked about in his presentation. So a key piece to adapting the interconnection process for storage is including provisions that address both different configurations of storage as well as how the storage will be used and what control technologies are actually in place to establish those parameters for use. And then specifically addressing what level of review each type of system might undergo, because those can have different physical constraints in how they're actually able to behave.

OFFICIAL COPY

Nov 26 2019

So we can kind of categorize storage in three categories. One of them is an exporting system with no limit on how much can be exported, so this provides more operational flexibility for the battery owner. But also potentially has larger or less predictable impacts on the grid. There's also a limited export scenario where there's a specific amount of power that that the battery is designed to operate and export up until. And then a non-exporting system that is not intended to export to the grid at all.

And those can be tested and certified to have those particular characteristics by nationally recognized testing laboratories or in some cases because the technology is changing quickly, if there is not a standard test yet developed, mutually agreed upon test and controls have also been utilized.

So if you do have a non-exporting system, these are lower risk to the grid if they function as intended, because they have more definable behavior not exporting, so several different states have either proposed or instituted expedited review processes for non-exporting storage systems. And in some cases they can even forego interconnection reviews completely.

OFFICIAL COPY

Nov 26 2019

But if you had a system where there isn't a load co-located, so a large solar system, utility-scale solar system for example, with storage, then the system will be exporting.

So just here are some examples of what different states are doing, and then, again, you can review these in the slides around expediting the interconnection process for non-exporting storage systems.

And if you're interested in learning more about different approaches where people are taking for protection and rating of storage systems in order to kind of define these different functionalities, IREC has published model interconnection procedures updated for this year that provide some examples of this. So one example is you may have a functionality for reverse power protection, which specifies that the system shall output no more than 0.1 percent of the service transformer's rating with a maximum of 2 second delay. Or you can have something where you have a -- a specific threshold of export over a different period of time.

So I'm not going to, again, go into the details on that, but that resources is available and

OFFICIAL COPY

Nov 26 2019

has a lot of great information on it if you're interested.

So -- but even in systems that are designed to be non-exporting, there is a potential for inadvertent export of the system and a lot of times people are dealing with this by just allowing up to 30 seconds of maximum export for any single event and trying to keep the total amount of energy in kilowatt hours that's exported to an acceptable limit. And the Utility can put in systems to monitor and verify that those energy export thresholds are met.

There's also a potential to include failsafes, so if something happens with the controls on a storage system or if it's a coordinated -- coordinated control through a communication system, if that system fails that the system will enter a specific predefined mode in that scenario, and so the Utility has some idea of how it may be impacting the system.

So inadvertent export is not currently fully addressed in the new IEEE 1547 2018 standard, so state standards instead have been working to address this issue. And there are also emerging UL testing procedures and standards around issues of inadvertent

OFFICIAL COPY

Nov 26 2019

export.

All right. So if you have --

CHAIR MITCHELL: I have a question before you --

MS. HOROWITZ: Oh, yeah.

CHAIR MITCHELL: -- before you move on. So technological controls that like specifically the one in the -- that -- that would be utilized in the context of the failsafe. Can you give us the -- what is the status of that technology? Is it -- is it -- is -- has it been implemented and would you say it's tested and reliable? Are we still in a research and development stage for that type of technology?

MS. HOROWITZ: No. There's a lot of different control systems that different vendors have, storage vendors have, and they're still developing those. But they do -- there are control systems that exist and can implement different types of failsafes, and so I think that the -- the current approach is just to test and verify that that functionality works in the field as expected and the -- the control system is actually implementing the desired control functionality. And I have some examples later, not around inadvertent export, but around capacity firming

OFFICIAL COPY
Nov 26 2019

OFFICIAL COPY

Nov 26 2019

and some modeling that we've done in the lab compared to how things work in practice. But I would -- I would say that the technologies are there, but they're still being tested to make sure that they're implementing the functionalities as expected.

So if you do have a solar system that you would retrofit with storage, it's possible that you could actually set the threshold for limited export to the same level that the PV would've been exporting it or that the PV -- the export level of the -- the PV system that was used during the previous interconnection process, so nominally that combine system would only be outputting the same amount of maximum power as the existing installed solar system or at some other level that has already been determined to be safe for the distribution system.

So there's also another potential option here if you are adding storage to an existing solar site. Rather than just going through a full new interconnection application process, because a lot of the storage behavior does depend on these controls and the specific configuration and failsafes, it's possible for the Utilities to try to instead just ask for changes iteratively and make those changes, and

OFFICIAL COPY

Nov 26 2019

then verify that that functionality has been implemented through these different testing standards and kind of working back and forth with the vendors to ensure that the storage system is operating in a way that will conform with what the Utility needs for integrating that resource onto their system.

And this is a, you know, practice that could benefit all technology types, but particularly for solar and storage, and storage systems, this is relevant since they're highly controllable.

So there are a few different ways that you can actually physically connect up solar and storage systems; AC coupled and then two versions of DC coupled systems, which I'll talk about here.

So this is an example of an AC coupled system where you have a solar system with an -- its own inverter, and then a battery system separately that has a bidirectional inverter and battery energy management system that goes to the grid. In this scenario the battery can charge from the grid and discharge from the grid as well as from the -- charge from the PV system.

In some cases retrofit systems are AC coupled, because you wouldn't need to replace the existing inverter, and in this configuration it's possible that the physical output of the plant could be equal to the AC capacity of the solar system and the battery system combined. Although in practice that may not happen very often, which I'll talk about later when we discuss some probabilistic screens of impact of solar and storage on the grid.

And again, you can put controls in place in order to limit the export to a different value than that maximum level. And I think I -- I bolded AC here just to try to point out the fact that there is both a DC rating on one side of the inverter and an AC rating on the other side of the inverter, and the system is -- output it based on what is on the AC side of the inverter that actually interfaces with the grid.

So I'll come back to this output of the battery and solar over time in a few slides.

So if in contrast you have a DC coupled system, this is where the solar and storage actually share some of the inverter system. On the top here this is showing a DC coupled system with more flexibility in terms of charging where the battery can charge from the grid from the solar, so you have a DC/DC converter, and then a bidirectional inverter.

OFFICIAL COPY

Nov 26 2019

In the other scenario which we called tightly DC coupled there's still a DC/DC converter, but the inverter only goes DC to AC. It's one direction. And so the battery can only be charged from the solar system and cannot charge from the grid.

So in the DC coupled systems, the output of the -- of the combined system is limited to the AC inverter rating.

If you are retrofitting DC coupled sites with -- or retrofitting solar sites with storage in a way that's DC coupled, you may need to replace the existing inverter. Although there are some inverters now that are being manufactured to be storage ready, so that you can have a solar system, and then have fewer things that need to be replaced when you add solar to it, and that's true for both sort of behind the meter, residential or commercial systems, as well as front of the meter systems. It's a relatively new set of products that have been developed, and so this is preparing things like the inverter or controllers to be ready to more easily add storage to them.

Another thing to note is that if you do end up having a solar system where you are adding storage to it and need to replace the inverter, there's a

OFFICIAL COPY

Nov 26 2019

potential opportunity to replace the inverter with a newer inverter that is capable of providing advanced functionality. So solar inverters actually don't last as long typically as the solar plant itself, and so they need to be replaced in the middle of the solar system lifetime anyway. And so depending on how old the plants are, there's a potential opportunity for kind of syncing up that replacement process. And if the inverters are legacy inverters, several years old, they may not have all the functionality in, for example, the IEEE 1547 standard and be able to provide some of the additional grid support that comes with that, for example, for frequency relation or voltage regulation.

So this is just an example, and there's many examples of this. I'm happy to provide additional resources if this is of interest to people. But an example from a laboratory study that we've done at NREL showing that storage can provide voltage support for the distribution network with these types of inverters. So what this is basically showing here is the profile of voltage over time and the line that you can't quite see but is below the pink line is without any type of additional controller -- it's reactive

OFFICIAL COPY

Nov 26 2019

power is it can regulate voltage in this specific scenario.

And then the other green, orange, and red lines are showing the voltage profile after specific controls have been implemented on the battery, so you get an improvement in terms of the -- the profile and -- but I think one thing that's -- that's helpful to know from this, which is why I included this slide, is that the improvement actually depends a lot on what kind of control mode is implemented on the battery. So those colored lines match up with the colored lines on the other panel of this figure. And so basically in this case the -- the specific curve of how voltage influences reactive power was very important for determining what the profile looks like.

So all that means is that it's important to check that the controls are what you think they are on the battery energy management system and confirm that the battery actually operates as expected, because a lot of this value depends on the specific curves that are used for control.

All right. So maybe we can shift now to talking about how storage could potentially impact the distribution system if there aren't other questions on

OFFICIAL COPY

Nov 26 2019

that portion of the presentation. Okay.

So one thing I wanted to note upfront is that all the impacts of storage on the distribution system like other distributed energy resources are very dependent on the specific feeder or distribution system as well as where the storage is on the grid, how it's being controlled or operated. We saw some examples of that from Jeremy earlier. What the loads are on that system. What the grid controls on the rest of the distribution system are. So for example, there's utility-owned devices that can regulate voltage as well and those may be controlled in different manners and depending on how they are that can affect how storage impacts the system.

And then if there is other solar on the system, where that's located, how big it is, how it's controlled, and how its inverters are operating, and then any other distributed energy resources as well. So that could include electric vehicles or other types of distributed generation.

But here are some sort of categories of ways that storage an impact the distribution grid. So there are kind of two subcategories of capacity firming that can be provided. One of them is

OFFICIAL COPY

Nov 26 2019

substation capacity firming. So this would be reducing the variability in such a way that at the substation the load tap changer, which is a piece of equipment often used to control voltage at the substation but not always, you may be able to reduce how many times that operates by decreasing the variability of the load and possibly lead to a reduction in operation and maintenance cost.

And substation equipment is particularly expensive, so in some cases this can be valuable. And this is something that storage can provide with or without PV, so it can actually provide a reduction in operations just by moving load as well.

There's also renewable capacity firming where you're firming variable renewable generation during critical load periods. And this could also help produce reductions in device operations and potentially O&M costs, which I'll give some examples for later. Storage can also effect voltage and thermal loading on the distribution system, so thermal loading just means, you know, are your wires or transformers getting overloaded. And that potentially has implications for their operation in their lifetime. So storage can actually go either way in

OFFICIAL COPY

Nov 26 2019

terms of improving voltages and improving thermal loading or making it worse depending on how and when it's operated.

So storage can, for example, reduce voltage and thermal loading problems without or with solar present and some people are using storage as a way to expand the hosting capacity of distributive solar.

It could potentially also negatively impact the grid depending on when and how it's operated. So for example, if the storage is discharging at a point of otherwise very high loads, it contributes to or -- I'm sorry -- it's charging at a point of otherwise high loads, it contributes to that load value and can potentially lead to lower voltages or thermal loading issues and vice versa for when it's discharging.

So here's an example that I mentioned earlier of trying to look at how storage can actually provide capacity firming both in models and in field measurements, and this is a study that was done at NREL.

So you can see here there are simulation results on the right of how the battery actually can improve the active power of variability, narrow the variability in this case providing the capacity

OFFICIAL COPY

Nov 26 2019

OFFICIAL COPY

Nov 26 2019

firming. So the far right is with the battery idle in the field, and then the far left is the simulation results, and the one in the middle is actually the field measurements wall the battery is active. So you can see that the battery is actually providing an improvement in variability in the field, but that in this case the model expected a greater improvement than was actually observed.

And part of this there's a lot of different reasons for this. It's hard to model reality perfectly, but there can also be a lot of data that's still being developed for both the storage systems themselves as well as the distribution networks. And distribution networks in particular can be hard to -- to model, because they have either missing data about the system topology or about how the system was operated before and after implementing the storage because of the lack of monitoring and visibility on most of those systems.

Other potential ways that storage could impact the distribution grid. Storage is able to limit reverse power flow from solar and other distributed generation at the substation, so this is actually a criteria that many utilities use to limit interconnection or define as a -- a limit on the hosting capacity of solar systems. So if you're able to limit that reverse flow, you could potentially expand the hosting capacity. It can also reduce loading on the distribution feeders and substations themselves, and like I mentioned before, the substation upgrades are expensive, so if you do end up in a scenario where you're overloading your substation due to load growth or to distributed generation, storage provides a potential alternative to those upgrades.

And then regulating the voltage on the feeder, which I provided some information about before, but this, again, really depends on what inverter is used and what operation and control modes are enabled on that inverter, as well as where the storage is located on the system.

So here's an example going back to issues around firming and decreasing the number of operations of utility grid equipment in order to try to extend the lifetime of that equipment and reduce operations and maintenance cost. So this is a pretty complex issue and I just included the slide to try to illustrate that.

OFFICIAL COPY

Nov 26 2019

So these are examples of how some grid device operations change when solar alone is deployed on the system. This colorful chart up here in the corner is showing weekly load tap changer operations with solar added to the system in different locations. So you can see in Oahu, which is that orange bar, there's a significant increase from 62 to 341 operations weekly with the system, which translates to a little bit over 17,700 operations per year and out of roughly 100,000 operations lifetime for that device. So that could potentially decrease the lifetime of the device significantly.

In other locations the increase is much smaller and would not actually, you know, materially impact the lifetime of the device.

Additionally there are a lot of other factors that kind of influence O&M besides just how many times the device is operating like environmental factors, so humidity, temperature, how much it is loaded overall.

And then the other figure that I'm showing here is for capacitor switches. Capacitors are also used to regulate voltage by some utilities on the distribution network. And this is an analysis where

OFFICIAL COPY

Nov 26 2019

we looked at different penetration levels of solar and you can see there's a lot of variability depending on the specific capacitor and how many more times the device actually switches and these are two different distribution systems here. So in one case the number of operations actually decreased or stayed flat. In other cases it increased pretty significantly for some capacitors, but not for others. And then increase was still not enough to necessarily result in a significantly lower lifetime.

And then this is a third example from a field study that NREL did as well and the information about the specific network tested in this case is here. So this looked at different value streams associated with trying to optimize the dispatch of storage systems, and so that included peak shaving, capacity firming, voltage support, and energy arbitrage. I'm happy to share this report as well.

And in this specific case they also found there was negligible operations and maintenance savings from reducing the number of load tap changer operations by optimizing the dispatch of the storage. So it depends. I think that's a good takeaway from part of this work.

OFFICIAL COPY
Nov 26 2019

So one of the ways that we've tried to deal with this looking at solar and then more recently storage and other distributed energy resources is by trying to have this holistic techno economic analysis of how it could affect this system. So one thing that you could look at is either upgrade costs that are triggered by the systems or potential deferral benefits. For example, if you're trying to use this a non-wires alternative I place of load growth and we've been trying to try understand this at different penetration levels for different resources, because that kind of gives you a sense of how much you could incorporate before things start to get really expensive, which either could give you a sense of how much could be hosted on your system for storage or if you're looking at storage as a way to increase the hosting capacity for solar trying to understand the penetration level at which that might become more economical compared to just traditional infrastructure upgrades.

CHAIR MITCHELL: Kelsey, I'm going to ask you to go back to slides 22 and 23.

MS. HOROWITZ: Yeah.

CHAIR MITCHELL: And will you just go

OFFICIAL COPY

Nov 26 2019

through those slides again for me?

MS. HOROWITZ: Yeah. Absolutely.

CHAIR MITCHELL: And -- and tell us the major points we need to take away from each of those two slides. Just want to make sure I caught everything.

MS. HOROWITZ: Yeah. Absolutely. I guess major points are the degree to which storage can provide firming that reduces -- so I guess we can start with this one. The degree to which storage and then optimally dispatching storage can provide capacity firming to reduce operations and maintenance costs depends a lot on what feeder you're looking at. So what specific distribution system you're looking at and there's not really a single answer for whether or not this is beneficial or not.

In some cases studies have found that this is beneficial and that you can potentially reduce operation and maintenance costs. In other cases they found that it's negligible. And that's not necessarily due to differences in methodology, but more just differences in -- in actual system -- like system by system variability as well as how the storage is actually dispatched.

OFFICIAL COPY

Nov 26 2019

And then for this slide the key takeaway is, you know, one -- one of the potential values of adding storage is helping reduce the variability from renewable generation and decrease potential O&M costs associated with that variability. So in some cases that can be a very significant value, because the -- the solar can create a lot more variability over time in certain locations. And in other cases it does not have as much of an impact. The value would not be as high because the devices on the grid are not operating that much more than they would otherwise compared to their useful life.

And that can have to do with location, weather, but also just the control and placement of everything on the -- on the grid.

And the actual cost associated with some of these systems that may need maintenance is also very different, so replacing a capacitor switch, for example, is a lot less expensive than replacing a load tap changer on a substation.

Okay. So what I just described is the second thing that we've been trying to look at. And again, doing some of this forward-looking analysis has been helpful for us to understand how like at what

OFFICIAL COPY

Nov 26 2019

OFFICIAL COPY

Nov 26 2019

point you start really incurring a lot of cost or benefit from these different resources as well as trying to kind of think about how different systems are contributing to those costs. So there may be a scenario, for example, where a solar system is contributing to potential issues on the distribution system, but then it is not enough to sort of trigger an upgrade during the interconnection process, but that at some point a new system comes online and it's kind of the straw that breaks the camel's back and is the one that actually is responsible for that upgrade cost. And so this is very interesting for looking at questions around cost allocation as well as maybe when storage would be most valuable to add to the system.

Another thing we look at is total energy losses as electricity propagates through distribution system and you can do this for the transmission system as well. And what often happens with solar is that there is initially a decrease in losses until the solar starts exceeding the load, and then the losses increase. And so that's what this figure here is showing. And storage is much more complicated and hard to kind of have a single rule of thumb for how it impacts energy system losses.

OFFICIAL COPY

Nov 26 2019

And then this isn't something that I'll get into too much, but also looking at potential curtailment from distributed generation and how that's impacted by storage deployment.

Oh, and then another thing is a -- a lot of these analyses it's hard to come to the same conclusions, because people don't have a full set of data and not all the analysis has been replicated or validated, so that's something else that we found to be really important, but also very challenging.

So, for example, if you're trying to validate how storage impacts the distribution system, in the field it can be difficult to do that if you don't have a good baseline of operational data for how the system was working before the storage was deployed, which is very often the case on a distribution system. So something that's helpful but challenging oftentimes in practice.

So another -- another thing that's interesting around the sort of charging load and discharging generation modes of storage is not that it can -- not just that it can impact the distribution system differently, but that it could impact how the -- the generator has to -- or the -- the storage

OFFICIAL COPY

Nov 26 2019

system owner has to pay for those upgrades. So oftentimes cost allocation may be different for upgrades that are associated with load versus generation, and so it's helpful to kind of clarify in the interconnection policies if the storage does trigger an upgrade based on both of those functionalities, how the cost will be allocated to that system owner.

And again, I think I kind of covered this on the last slide, but providing transparent screen and study results can really help move some of this forward because the behavior is so complicated and difficult to model and if there is just an understanding of the assumptions that go into it, it's a lot easier to kind of iterate on that and move forward with the process.

And again, sometimes the system may -- the -- the storage system may impact the distribution network in a specific way, but there could be simple modifications made to the controls or the site design that can help alleviate those concerns and there may be a potential opportunity for an iterative process to kind of clarify and implement those updates.

So I think this is already -- I've already

OFFICIAL COPY

Nov 26 2019

kind of like made this point many times, but determining the size of storage and how it's operated is really important for this type of analysis. And so if we try to think about what definitions of battery capacity and how it could potentially output are, there is a nameplate or nominal capacity both in amp hours and watt hours that's often cited for the battery. But then there's another -- another value that's the usable capacity or the operational capacity, and oftentimes as Jeremy alluded to in his presentation, this can be much lower than the nameplate capacities due to constraints on the -- the capacity around depth of discharge, efficiency, charge or discharge rates in order to ensure that the lifetime of the battery isn't just obliterated.

And so in some cases there are batteries that have this high durability label on them and they'll end up having a longer lifetime, but at the expense of some of that energy and capacity value, so that they don't discharge as deeply or cycle as quickly.

And so even though you may have a nameplate or nominal capacity or energy value on like a battery manufacturer's spec sheet, that may or may not be how much the system is really going to output in the field on your distribution network.

And the same is true for solar. So there's a potential to try to look at some of these issues in a time serious way and have different probabilistic screens, which we've been trying to do some research on at NREL and I'll talk about now.

So I'm going to start with solar as well, because this is a good example of kind of how the rated values of these systems may also differ from what's seen in the field typically. So this is an example that I made for Raleigh. And so solar panels are actually rated at a thousand watts per meter squared irradiance, so how much sunlight is falling onto the panels. And this is showing you that irradiance in Raleigh over the year hour by hour and you can see there's a couple of hours where it actually exceeds even in Raleigh a thousand watts per meter squared.

On the other hand if we look at average daily irradiance profiles, which are shown here, it's almost always much, much lower than a thousand watts per meter squared, and well below 800 watts per meter squared. So typically you aren't going to have the

OFFICIAL COPY

Nov 26 2019

solar panel actually outputting anywhere near the value that it's rated at.

And so that leads to that -- this idea of what we're calling dynamic hosting capacity or some probabilistic screening. So if you think about it over time, again, solar or storage or any type of distributed generation or load may only be reaching its sort of worst case bounding either consumption or generation during a few time points of the year. Typically the way that people determine -- determine the impact of storage or solar on distribution grids is by using a few bounding time points to kind of correspond to a worst case operational behavior. And then have sort of a strict interpretation of ANSI standards.

So, for example, there is an ANSI standard that says your voltage can never go above 1.05 per unit, which is the red line here. Or I'm sorry. The -- the ANSI standard says you can go above that, but only for a limited duration in time and that standard is sort of intended to represent the voltage actually at the customer where they're utilizing it.

But in reality a lot of these models don't even sort of include the systems that go out to the

OFFICIAL COPY
Nov 26 2019

customer, so they're mostly modeling something that's upstream where that standard doesn't really apply and there's a threshold that says if you go over this value, you're basically failing a specific requirement for the grid instead of well, if you go over this value but it's just for two minutes throughout the whole year, maybe that's totally fine and you could potentially be triggering the need for an upgrade that would not otherwise be needed.

So this is a study that we've done where we've looked at for solar if it's outputting at certain points of the year how does that actually potentially influence the -- the full annual loading on the distribution system. And so another example here is that if you have a transformer, a lot of times the threshold for interconnection analysis is that you don't want to load that more than a hundred percent, which you definitely don't want to do all the time, but if you load transformers depending on the type above a hundred percent for even up to 150 percent for a couple of hours, that's totally fine.

So the idea of this is just trying to kind of acknowledge both the fact that there is conservative interpretation of the standards if you

OFFICIAL COPY

Nov 26 2019

just use these very worst case time points, as well as a conservative interpretation of how the distribution system actually operates. And that the -- in reality the systems can also often end up in these operational regimes with or without storage on them.

So this is an example, again, when we're looking at solar where we saw that if you use this method, this dynamic hosting capacity method to try to estimate how solar impacts your system, you could potentially host 15 or -- sorry -- 10 to 25 percent more PV, so in these particular systems that was 200 kW to 1.84 MW, more solar at very little cost. But there's still a lot of ongoing effort to kind of develop this framework around probabilistic analysis in developing risk frameworks both for solar and storage.

And another kind of way to think about this is that you have this initial scenario that's like a static hosting capacity value for your distributed energy resource and that's based on a few bounding worst case time points and kind of these conservative interpretations of standards and doesn't really account for the fact that -- that the load and the generation changes a lot over time and may not always

OFFICIAL COPY

Nov 26 2019

be operating at its nameplate value.

And then there's another sort of level of thinking about this where all of the devices are operating on their own, so they all have local autonomous controls with no communications, and you're kind of doing these probabilistic screens to see how they could behave and impact the system.

And then there's sort of a third level of this where you could potentially host even more if you have communications based controls that can modify the output of devices in real time, or maybe not necessarily real time, but at some time point in order to be able to optimize the system and integrate more without having additional infrastructure upgrades. And so that is a scenario where the revenue is less predictable for the developers and potentially for the utility, but that depends on the contract structure. And there's a lot of work being done to kind of structure contracts in a way that help mitigate or share some of that risk.

So in addition to the lack of data in a lot of scenarios, which I mentioned before, there are also potential computational challenges to using some of these time series analyses for many, many scenarios

OFFICIAL COPY

Nov 26 2019

where you're trying to consider like lots of different possibilities about how the future may evolve or many, many different weather years, for example, but if you have a few different scenarios there have been studies that show those can pretty fast even just on laptops and NREL has actually developed with Sandia and other folks this fast time series analysis method where there was an 83.9 percent reduction in computational time associated from going with very high-time resolution, high spatially resolved data to much lower time resolution, less spatially resolved data and you're not getting really a significant error in the results.

There's also ongoing work that we're doing and others are doing just to try to understand how sensitive some of these metrics that you're looking at for interconnecting these resources are to having missing data or poor data quality or poor data resolution. So we don't unfortunately have an answer on that yet, but it's something that is continuing to be explored.

Okay. Talked a little bit about different considerations for co-locating solar and storage, but I'll dive into that more here. So this is a picture

OFFICIAL COPY

Nov 26 2019

OFFICIAL COPY

Nov 26 2019

that's actually showing a real distribution feeder in part of California that we've been modeling. So you can see here these different solar systems that are located on this particular feeder. So one thing that you can gain if you co-locate storage with solar as opposed to having it separated on the substation is that if you do have local overloading on these particular lines where the solar is, having a battery there can mitigate or some type of storage system can mitigate that local overloading issue. Whereas if you have the battery at the substation or somewhere else on the feeder, you may not be able to fully mitigate the local overload.

So, for example, if you would've otherwise needed to replace a transformer here or a line here, the storage can help avoid that. One thing to note is that those upgrades may be relatively low cost, so this is really a case by case evaluation on how much it would cost to add storage versus just doing those upgrades and looking at kind of the full value stack that Jeremy talked about earlier and if that make sense for the cost/benefit ratio in that particular circumstance.

However, if you don't have a case where you have some local overloading on lines or transformers triggered by the solar system, and if you have, you know, multiple solar systems on one circuit, you could add storage to another location that's not, you know, co-located with the solar system and mitigate the distribution system issues more effectively.

So there have been prior analyses on storage placement that kind of tried to optimize that for different services and they found that the optimal location is not always necessarily where the PV is depending on the circumstance.

And if you kind of think about, you know, economies of scale and storage systems, if you place, you know, five storage systems at five solar sites, in some cases that may be less cost effective than having one solar -- one storage system that you could kind of allocate the cost over those different generators. But again, this really depends on the specific -- the specific system and unfortunately there's not a generalizable answer for the best placement of solar on the distribution network.

So I think I already talked about this, but if you do end up adding a battery management system to the solar site either replacing an existing one or

OFFICIAL COPY

Nov 26 2019

just adding it in combination with the existing solar inverter, that can help provide additional voltage regulation and potentially thermal regulation features that were not at the site previously and if you install at the same time that you would be replacing the inverter anyway, that could be a potential way to minimize those costs.

Co-locating solar and storage can also provide an opportunity if it's at the same site for reducing losses associated with either clipping, which is basically power that's lost when the DC array for the solar system is oversized compared to the AC inverter rating or curtailment, which is often more sort of an -- an active reduction in power in order to regulate voltage that can be done autonomously through the inverter or based on the a utility signal. But today almost always the storage costs are must higher than the cost of lost revenue from clipping and/or curtailment.

We have seen some scenarios in modeling where you could get very high curtailment of solar if you're in particular locations in trying to curtail to address multiple grid needs where maybe storage at lower cost could make sense in that scenario, but this

OFFICIAL COPY

Nov 26 2019

is more just like one thing that could go into understanding the full cost benefit of storage for a specific solar site.

If you do build solar and storage at the same plant together, you can also get a potential installed cost savings. So this is a figure taken from an annual solar and storage cost benchmark report that NREL puts out and the link is here. This is a new version from 2019, will be released pretty soon as well.

And this is an example for utility scale storage. So there is the cost of individual PV and storage installed systems. The PV plus battery installed at separate sites here on this bar. And then you get some savings associated with co-locating the solar and storage at the same site. And a little bit of additional savings if you have a DC coupled system instead of an AC coupled system, because you can share that inverter.

There is also an opportunity to try something called Community Energy Storage, so this could be something where you are not necessarily -- you're not necessarily retrofitting an existing plant, although you could. And these can provide similar

OFFICIAL COPY

Nov 26 2019

services to what I described previously in this presentation as well as potentially backup power during outages for communities.

And then another piece that goes back to some of what I was saying before is that the value of storage on the distribution system as well as for the bulk power system really changes as penetration levels of variable renewable energy in particular solar increase. So as solar and wind penetration increases, the value increases. Although this is very sensitive, as you can see in this figure to a lot of other assumptions about the system, for example, what prices for natural gas are and how much of the system is comprised of other none renewable resources of different types.

So I think that the key takeaway from this is that even though in some cases the economics for adding storage only makes sense in certain scenarios at current penetration levels, prices of storage are dropping and in the future the value of those resources will increase in terms of both bulk and distribution system needs.

All right. So I am not an expert in metering, but I heard that you guys have questions

OFFICIAL COPY

Nov 26 2019

about metering, so I put some slides in here and then I am happy to point you to people who are more expert in this topic if you have additional questions. And I understand you have potential challenges with metering solar and storage site specifically if they were not installed at the same time and would not be subject to the same rate structure.

So just here are some examples of AC and DC coupled systems without backup and these slides are from SRP, Salt River Project, my colleague Mike Cottington worked on developing these with the -- with him, so I think he'd be a great resource if you wanted to talk to someone about this more.

But in a AC coupled system you have typically the battery, the inverter, and then a service entrance with a meter installed on the Utility side, and then a separate meter for the PV array specifically. When you have a DC coupled system, it's a little bit more challenging, because everything coming out on the AC side includes both the solar and the storage output, but you can install, you know, a bidirectional billing meter on the grid side, and then an additional meter for the PV that's coming out of this inverter here. But I think there is still a lot

OFFICIAL COPY

Nov 26 2019

of sort of challenges around how to think about metering systems that are DC coupled when you have different rates being applied to the PV and the battery system.

All right. So there are a lot of tools and data out there for looking at storage and looking at distribution, effects of different distributed energy resources. Jeremy shared a lot of those that PNNL has developed in his presentation. There's also other national labs like Argonne for example has some battery modeling tools, but I'm just showing you here some resources that NREL specifically has.

So this first one is a database of unit cost for different types of distribution system upgrades, so that won't tell you how much it -- it cost to upgrade a distribution system in total, but it'll tell you, you know, here's how much to replace a certain type of transformer or a certain type of line. In some cases we have data on emerging techniques for integration like Distributed Energy Resource Management Systems, but that data is a lot sparser.

We're also developing this tool that hopefully will be publically released at some point where you can actually model distribution systems, and

OFFICIAL COPY

Nov 26 2019

then get information out about what kind of upgrades may need to be in place, what your losses look like, what potential solar curtailment looks like, and what changes and the number of device operations could potentially look like as well.

These two presentations don't -- are not actually the links to the tools for the solar and storage modeling, but they provide really nice overviews of what tools are available, what their intended use is, you know, if you can actually download them yourself and use them or if you need to ask NREL to do that modeling work for you. So I included those links here for reference.

And then there's also a lot of different test facilities for storage, so we have something called Energy Systems Integration Facility that has lab testing. And then also hardware in the loop testing, so you can actually kind of in some cases test devices and then temporarily connect them to real grid systems. And then in other cases kind of like model the operation partly, and then actually do field test for other parts of the operation.

And then something called a Flat Iron Campus, which is you've ever been to -- to -- around

OFFICIAL COPY

Nov 26 2019

Golden, it's between Golden and Boulder, and they have some battery systems that are being tested there. And then we also have other publications on interconnection, storage grade integration analysis, and other issues that are in our publications database.

And that's what I have. Do you have additional questions?

CHAIR MITCHELL: Questions from any Commissioners?

(No response)

Okay. Thank you very much, Kelsey.

Thank you, Jeremy and -- and Kelsey for being here today. We really appreciate y'all coming all this way to help us firm up our understanding of these issues. And we look forward to seeing all of you again on the 25th. Thank you.

(The hearing was adjourned at 2:31 p.m.)

OFFICIAL COPY

Nov 26 2019

C E R T I F I C A T E

I, KIM T. MITCHELL, DO HEREBY CERTIFY that the Proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

Kim T. Mitchell

Kim T. Mitchell
Court Reporter II

OFFICIAL COPY

Nov 26 2019