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BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

Investigation of Energy Storage in North Carolina

Presentations by:

Patrick Dalton, Manager, Distributed Energy Resources, ICF, Inc.

and

Charlie Vartanian, PE, Technical Advisor, ES Integration, Pacific Northwest National Laboratory

and

IEEE 1547 Working Group Interconnecting Battery Storage Under IEEE 1547

Volume 5

P R O C E E D I N G S

CHAIR MITCHELL: Good afternoon and welcome. I'm Charlotte Mitchell, the Chair of the North Carolina Utilities Commission and with me this afternoon are my colleagues Commissioner ToNola D. Brown-Bland, Lyons Gray, Daniel Clodfelter, Kimberly Duffley, Jeffrey Hughes, and Floyd McKissick.

This is the fifth in a series of presentations pursuant to the Commission's September 4th, 2019 Order Initiating Investigation in Docket Number E-100, Sub 164 in which the Commission has initiated a series of educational presentations by invited experts on energy storage related topics.

We're happy to have with us today Patrick Dalton and Charlie Vartanian. Patrick is the Distributed Energy Resources Manager for ICF in the Minneapolis area. And Charlie is the Senior Technical Advisor for Storage, Reliability, and Integration at the Pacific Northwest National Laboratory near Seattle.

Our speakers will be working from slide decks that will be displayed on the monitors here in the hearing room. The slides have been posted on the Commission's website in this docket. And our court reporter is also creating a transcript that will be filed in this docket and available on the Commission's website.

These sessions are structured for the benefit of the Commissioner's education and the speakers will be asked to share their expertise and answers -- and answer the Commissioner's questions should they have any. People in the audience will not have an opportunity to ask questions. However, if you'd like to file information in the docket in response to what you hear or if you'd like to suggest other speakers that the Commission consider inviting please file those comments and suggestions in this docket for our future planning.

Gentlemen, if it's okay, we'd like to be able to ask you questions as we go if that works for you.

MR. DALTON: Yes.

CHAIR MITCHELL: Okay. With that, we appreciate y'all being here today and we'd like to move forward. And I assume that you all have worked out among yourselves who will present first.

MR. VARTANIAN: Yes. I'll start with the IEEE 1547 standards overview.

CHAIR MITCHELL: Okay. And if it works for you, please proceed to the witness stand and you can present from there. That way we can -- we can see you face on.

And just for everyone's benefit, please provide an overview of your bio if you're willing to do so.

MR. VARTANIAN: Sure. Thank you, Chairperson Mitchell and Commissioners and also staff for setting this up.

The majority of my background is I spent 15 years at Southern California Edison starting as a Transmission Interconnection Specialist during deregulation, the initial open-access process and then that evolved into being the point person for distributed resource interconnection. As part of that starting back in early 2000s until now I've been a member of the IEEE 1547 Interconnection Standard Working Group.

The reason I left Southern California Edison I did their first rate-based energy storage project and that was so inspiring that I went to the World of Energy Storage for the last 10 years working with manufacturers and consultants and now with the Pacific

Northwest National Lab with a tasking to help fill gaps in performance -- technical codes and standards for energy storage. The Department of Energy Storage Program has identified several times codes and standards as a barrier to adoption and a barrier that's addressable.

Also in the audience is another lab counterpart, Mr. Chris Surles of Sandia National Lab, Safety Coach and Standards Lead as well as the past chair of the IEEE Energy Storage and Stationary Battery Committee and a true expert on the challenge of safety of energy storage systems. So I come with a lot of interconnection background.

For those who may have been involved in the era of the first open-access transmission tariff compliant interconnection studies, and there are some parallels all the way through today where if all sides have an agreed upon set of minimum performance requirements, it really just reduces cost and time to make sure assets are interconnected prudently, but again, with minimum cost and time involved has been my experience when there are a common set of standards to refer to.

There is a challenge with that. IEEE 1547 which is the interconnection standard for distributed resources was significantly updated in 2018 after its initial adoption in 2003. With -- and you will hear today from perspectives of what changes have happened in the standard and then Patrick will put that in context of how that's implemented within smart inverters which is really where the rubber meets the road for most assets today. Primarily PV and storage are mostly coming online as inverter connected.

And so what I hope to do is hit the high points of what changed. Give a little bit on the drivers of those changes and what it implies in terms of updating interconnection review and approval processes to incorporate the changes.

This is a disclaimer IEEE boilerplate. ICF Patrick's -- his site as well. He had input to this presentation. But these are not the positions or the work of the DOE labs or IEEE.

So that's an outline of what I plan to hit today. I'll jump right into it.

The red are the changes that happened from the 2003, the last approved version that most markets and jurisdictions are working from. Number one, an added requirement for interoperability and that comes down to defining the minimum communications interface and the minimum information that needs to be exchanged between a distributed resource and the connected power system. That was one of the larger changes.

You'll see there's no mention of ride-through, islanding. Those are some of the technical details that were updated, but not called out in the scope change.

This isn't new information to your jurisdiction or many others. We used to have a one direction power system from central station plants through the transmission system down through to the distribution, one direction to end load. Now we have a very dynamic power system where resources and active loads have the ability to let's say push back impact if not outright energy and power back onto the grid.

And some of the earlier markets that had high penetration really drove the new requirements. And what are the impacts of high penetration that were revealed early on? Places like Hawaii, California. First impact voltage did a challenge for utilities to hold primary their side of the transformer, hold that primary distribution within acceptable range when you have an abundance of resources connected down at the distribution level.

The second impact hasn't been as frequent, but frequent, or is it that it happens at higher penetrations and that's actually driving system frequency. At very high penetration you'll see system frequency, the shared system, the wider utility power system frequency can be moved at a high enough DER penetration. That's a day-to-day challenge on smaller systems with high penetration. Kauai, Maui, it's not as common, but even the whole west coast had an event where the sudden loss of 1,200 MW of PV caused the whole western interconnect frequency to deviate to an immeasurable amount and that let's say helped motivate even more the need to get ride-through, which we'll describe coming up as an added requirement of this technical standard.

Now, this doesn't have the animation, but it's showing safety and reliability weighted. So the safety and reliability are still the underpinnings of 1547, the safety being don't back feed to a utility system that's out of power. You don't want distributed resources pushing voltage or current back on a grid that's otherwise out. That's a worker safety issue.

And then the other do no harm aspect is to not interfere with the primary voltage regulation. And regulation meaning holding that voltage within an acceptable bandwidth on the utility side, the shared voltage.

But as you get higher penetration, you need some amount of grid performance support. You do need the voltage support from distributed resources. You do need ride-through. So there's a balance that needs to be considered. It was considered. And within the IEEE technical working group we believe that balance has been achieved with the update.

Again, in 2003, the rule was you shall not actively regulate voltage and you shall trip if you self-detect abnormal voltage or frequency. And here's another key aspect, the default was, and you will wait five minutes until the system is stable both in terms of frequency and voltage. And that has been an aspect of some of the early experiences where large amounts of PV have dropped off the grid, that's delayed return. I'd say it was considered in updating the criteria.

In 1547 the 2014 amendment was in large part driven by California and Hawaii where their retail tariff rules for interconnection had to -- they updated those ahead of 1547's update, so those local jurisdictions called for ride-through. They called for voltage support. So we did an amendment so it wouldn't be in conflict with 1547. There was an amendment that designated you may. So if it was called out by your local authority having jurisdiction, you may actively regulate. By 2018, the decision was made you shall. That was the default, being you shall be capable of regulating primary voltage, you shall be capable of riding through a great disturbance. And that is the new approved technical standard for distributed interconnection.

Other modifications that have impact I'll say jurisdiction wide is in part at the request of FERC and NERC. The update removed the 10 MVA. That's the total apparent power. Megawatts would be the real power. But removing a defined limit, because that had been a barrier in some jurisdictions. They want to refer to 1547 I'll say regardless of where it connects or the size of a project. So the updated 1547 in 2018 removed any reference to a maximum capacity, so there is no capacity limitation to 1547 with a 2018 update. I think that's probably the most dramatic.

While this is not applicable to transmission or network sub-transmission, it is a distribution-oriented standard. It can be used by reference and it is in settings where you do have network portions of your system.

All of this is intended to point out that there's a minimum amount of volt amperes reactive or VARs that need to be included as well as your kilowatt or megawatt real power rating. And it's giving the percent VAR capability.

So, in general, this calls for about a 10 percent increase in total inverter capacity to achieve these ratios of reactive power to real power. Why the reactive power? Reactive power has the greatest effect on local voltage versus real power. Also while you can regulate voltage with real power, real power is a side of the inverter that's delivering the energy produced, the usable energy, so this way you're not sacrificing the ability to deliver real power, real energy let's say from a PV panel or an energy storage system. You're using the VAR capacity of an inverter to provide that voltage regulation support.

Patrick, you probably have very concise ways to describe VARs.

MR. DALTON: There's a slide or two on that.

MR. VARTANIAN: Okay. I like the beer mug, so you're going to size your conductors and transformers for the size of the foam plus the liquid. The more liquid though is the real power. You want to minimize the foam. I bet you Patrick has a more technical description than that.

I'll just also share an anecdote. As PV penetration increased in certain markets and inverters only delivered real power, there were cases that I dealt with at the utility where let's say someone took an incentive, put a bunch of PV on their roof at a commercial building, suddenly they're only really taking VARs from the power system or a larger proportion that triggers a VAR penalty, so a lot of retail tariffs have a limit. If you take so many -- if too large of a percentage of your total kVA from the utility exceeds -- if the VAR proportion is over a certain defined amount, in some jurisdictions there's a penalty. So it is an example of an unintended consequence by the PV inverters only delivering real power. It exposed the customers to VAR violations.

One complication in the good old days of do no harm there were two major tables that AHH just had to refer to. The main point here I want to highlight is both for the VAR capability and the ride-through, there are going to have to be decisions made on which set of requirements apply within any particular jurisdiction or setting.

There is -- so there are multiple tables and graphs that really go to increasing levels of performance requirements, that are more aggressive, more demanding requirements here aligned with as the operating environment gets more challenging as you get more distributed resource penetration.

Category B was developed to conform with the high penetration rules already in place in California and Hawaii. And I'd say most markets that are planning for a high penetration future -- I'll call it -- I'll characterize it you're somewhat future-proofed by going with Category B.

Category A gives a traditional using VARs to set a power factor or adjusting your VARs are proportional to get a voltage response. You'll notice that it's the active power getting that involved to hold voltage to a minimum as the extension from going from category to Category A to Category B.

Response to abnormal conditions. So the VAR capability is considered a general requirement when the grid is in normal condition and you're operating. The VARs are there to be available for the support of voltage regulation, and ride-through is tightly aligned with abnormal conditions. And the abnormal condition is defined in 1547. If frequency or voltage as measured at the project location at their plug goes outside of defined ranges, those are "abnormal conditions for which there are a defined set of responses." It used to be if you self-detect voltage or frequency outside of a bandwidth, get off. Wait five minutes to get back on. And the five minutes is you self-monitor as voltage and frequency back within an acceptable bandwidth.

Here's another anecdote. After Sandy, Hurricane Sandy hit, there were a lot of constituents within New Jersey, New York with PV on the roof that wouldn't carry a load. And part of the REV process in New York, other activities in the Northeast I know were influenced in part by the fact these inverters were out there, they had PV connected, but by design they were complying to the standard. The grid wasn't present, so they couldn't come back online. They couldn't carry any load. But with a modification with the right set of rules set for the 1547-2018 compliant inverters could carry local load.

Again, Category I to the -- are increasing levels of complexity, more demanding performance requirements. Part of the challenge is anti-islanding that get off if there's a problem that still remains. The challenge is you just can't get off immediately anymore. You must ride-through from let's say T=0 of self-detecting of frequency voltage deviation. There's now a gap that you have to sit and wait and observe before dropping off the grid.

And the more aggressive you get, typically the longer you have to wait, so you got less time to determine whether that was a temporary grid event or is it going to be an ongoing sustained grid event.

And, Patrick, maybe you're -- do you touch on that, the smart inverter discussion on ride-through implementation?

MR. DALTON: Yeah, a little bit.

MR. VARTANIAN: I'll just say there was a robust set of manufacturers and consultants involved in this update and there was consensus among a range of manufacturers that this was not a barrier to them manufacturing inverters. In fact, the products built for Hawaii and California today have this capability, but there's a lot of devil in the detail -- devil in the details aspects to that.

And this chart just sort of maps that going from one, two, three, they were modeled on different levels of market requirements. Category II is consistent with bulk power grid ride-through requirements that have been present for a decade. The PRC-024 is a set of curves used for bulk power system ride-through, so Category II of this distributed resource standard is a nice middle ground. It's consistent with the NERC requirement.

Category III goes farther partly because on distribution systems grid events will transpire for longer duration before protective equipment take action. If there's a problem on the transmission grid, protective relay will tend to isolate quickly within six cycles, two to six cycles.

On transmission or distribution systems, you're going to -- they will let these events evolve much longer. So Category III accommodates the more demanding scenarios where you have distribution protection schemes that are running it much longer.

And they're consistent with California Rule 21 and Hawaii Rule 14 requirements.

Interoperability is, I'll call it, it's a challenge for the industry at large. It's really the purview of what's lumped in as smart grid issues. So I'll characterize this. This is bringing smart grid into the interconnection standard. We took a subset of the wider world of smart grid communication and controls, and the 1547-2018 working group defined a minimum set of what information should be exchanged and what are the acceptable communication interfaces. And in particular there are three protocols called out that if you can talk these three languages you're complaint with 1547.

The good news is there's already wide industry adoption, one of them being DNP 3.0, which is one of the go-to languages of utility. SCADA-type controls, SunSpec Modbus is another one of the criteria called out and then the smart energy profile, the new ZigBee. So depending on what it -- most of those are usually present within the industry within most jurisdictions.

Since this is an energy storage investigation and actually this is the focus that I'm taking right now as I'm a member of the 1547.9's working group, the P for IEEE speak designates it's a draft standard in process. Patrick is a member of 1547.9 working group writing the standard as well as Chris, as well as many utility stakeholder members from your jurisdiction.

This is an anecdote. In developing the mandate AB2514 Energy Storage Mandate in California, they had built the economic framework around a large number of potential use cases value propositions. The red to green just show that but for the update of the standard you would not have been able to do a handful of the more aggressive use cases.

Black start right at the top, it's one of the keys. If you want inverters participating for let's say support of isolated load home through a hardened community center, hospital, the update of the standard removes a lot of barriers to doing that.

Outage mitigation microgrid. So a lot of the more, you have double-dutying of assets for local load support during emergency as well as when the grid is there doing its everyday business. It's really -- it was opened up or a lot of barriers were moved by updating 1547.

Scoping of this has been -- it's still an active debate point. But a key item to point out is 1547.9 as scoped right now applies if a device gets an active power. That's the liquid or the real component in the mug back to the power system. So true UPS's meant to just supply emergency load are out of scope right now.

A quick comment on another item where this working group is going to give some guidances. That first scenario is I'll say a retrofit, when you bring energy storage to an existing PV project jurisdiction to jurisdiction there is no standard to how you calculate that capacity, so there are a range of approaches starting from simply add up the nameplate capacity and that's the new interconnection capacity.

Some markets are getting more sophisticated. The general term is control-based compliance whether it's for setting a capacity limit or setting performance compliance, for example, ride-through. For example, you might have 1547-2003 compliant inverter, but you can bring ride-through, other capabilities with a retrofit with an energy storage system.

One of the challenges, again, the more --

the real point of this though is how you come up with a total capacity at the point of common coupling. There are a number of ways to approach it.

Part of this from the industry side, the ITC is the investment tax credit. This gets into the whole world of metering and that's also driving the far right, the DC coupling. It simplifies both the metering to prove that the energy going to the battery was sourced by renewables and not the grid system power as well as that's one just physical -- I'll call it a physical way to limit the total power if you couple it on the DC side.

A quick comment. There was discussion of a possible follow-up or a staff discussion. This is an example where I can see going into a little bit more deeper technical detail.

This guide, it should be out by 2021, but, I'll say a lot of the insights being developed now can apply and you have stakeholders on the utility side working on 1547.9. A number of the southern company utilities are very active.

For jurisdictions, so 1547-2018 was approved in 2018 but for true industry adoption inverters need to be manufactured and certified to the standard. That's still in progress. The test procedure should be approved this year. Once the test procedure is approved this year, then UL will update their UL 1741 as a certification for 1547 capabilities. SA is a supplemental amendment that was written in large part for Hawaii and California. For those markets they do call for UL 1741-SA. That's for the grid support functions.

I'd like to highlight beyond California and Hawaii, a number of different states and programs have referenced this as a way to access grid support functions now in a way that all, you know, developers, owners, manufacturers have a way to deliver grid support capability today.

CHAIR MITCHELL: I'm going to -- may I interrupt you and ask you a question right there? So I want to make sure I understand what you just said. I think I heard you say that inverters have to be manufactured to the standard; is that correct? And there is this interim solution that's been proposed until we get to the point of having gone through the testing necessary to manufacture inverters to this standard. So what about all of the existing inverters on the grid now? Can they not be -- can their settings not be changed to comply with 1547-2018? I mean, what is the -- what is the implication for everything that's tied to the grid now?

MR. VARTANIAN: There are numerous inverters that would be literally a matter of firmware adjustments to add ride-through and voltage support. The challenge is their interconnection agreement. Number one they've been certified so when they were certified to UL 1741, the 2003 version, those functionalities were disabled, so that's actually how it's UL listed and labeled today is to have those off. So you would no longer be a UL 1741 listed certified product if you turn that on.

I think the second complication depending on how the interconnection requirements for interconnection approval, if they called out 1547-2003 you could be in violation of your interconnection agreement depending on how specific that was called out. But to your point, yes, there are inverters.

While I was at SoCal Edison I got letters from developers saying inverter manufacturers are ready to turn capabilities on if we could just sign off. And it was all those second and third order impacts where we generally -- well, actually not generally -- had to say no, because a whole sequence of approvals all the way from certifying listing that device to how it was presented to the utility in the application to meeting a spec if there was a, you know, a spec in the interconnection agreement. That's where the complexity lies.

There is another aspect of -- so let -- did I answer your question?

CHAIR MITCHELL: I think so. So is the response it is possible to make changes to existing inverters to -- in the interest of compliance with 1547 the 2018 version but there may be other hurdles like the interconnection agreement establishes certain standards and the UL listing could be a limiting factor as well?

MR. VARTANIAN: Hawaii is a great case where all stakeholders got together and did it within a regulated environment --

CHAIR MITCHELL: Okay.

MR. VARTANIAN: -- such that nPhase actually did it over the wires, over the intranet, and within a couple of days updated every nPhase built inverter within Hawaii to add ride-through and VAR capability.

And Ken Fong who is available to do the staff discussion was the head of transmission planning at the time and worked that from the utility side and has some lesson learned on how he would do it today.
So that has actually happened, but that was not an easy -- it was a multiyear process, but once all -- everyone came together it was I'll say an approved agreement.

John Burdener (spelled phonetically) who works with us -- my recollection -- doesn't he -- it was days, wasn't it?

MR. DALTON: I think so.

MR. VARTANIAN: A matter of days whereas in Germany they didn't grandfather their inverters when they added grid support. This was 10 years ago. They spent multibillions of dollars and I don't think they ever completed it because they inverter to inverter had to go back and implement these changes.

So the good news is between UL, IEEE, significant stakeholder groups, they've gone through that exercise of if you're in a market that may not be able to wait the two years for all of these pieces to be in place so manufacturers are building inverters to this new standard, UL is testing and certifying. I do like to point to California and Hawaii have come up with approaches that I think are worthy of consideration if you wanted to -- if any market had to model something similar.

Any additional questions?

CHAIR MITCHELL: Kim.

MS. JONES: That was really interesting. Thank you. A couple. So am I getting it right? We're on the verge of taking on 1547-2018. When we get done with that, which is for solar we need to do it again for storage. Am I understanding it right?

MR. VARTANIAN: No. 1547 applies to all distributed energy resources. A key aspect is it's technology neutral and nonprescriptive. So even all -- any resource that's connected to the distribution essentially and especially if it's third-party owned not utility-owned, it applies to that.

MS. JONES: Okay. So what's the 1547.9?

MR. VARTANIAN: That's a guide. So there are aspects of energy storage like even this in-scope versus out-of-scope argument, .9 will be a guide to the standard that just expand on these aspects like how do you determine what's in-scope/out-of-scope will probably speak to this DC versus AC coupling when you got PV plus energy storage. And that will be done two years from now.

MS. JONES: Okay. And then one that's totally other. Is the fact -- if you are in an environment like a Hawaii or a California where you have a lot of PV on the grid, would you go fast or slow at investing in Volt/VAR or controlled-type technologies? Do they become redundant or unnecessary in that environment?

MR. VARTANIAN: Prudently quick. And working through the list. So having adjustable power factor versus locking it at unity buys you a lot in the interim until you work out how do you want this sort of dynamic, you know, continually changing VAR. I think there's a lot to be said even just having the ability for utility let's say the bias that the VAR attributes of an asset by saying hey, we want a range of power factors and we'll tell you what it is when you make an interconnection request.

MS. JONES: Okay. So you would go after Volt/VAR control aggressively?

MR. VARTANIAN: Yes.

MS. JONES: Okay. Thank you.

MR. VARTANIAN: Yes. Quickly. And I think -- but again, that A to B, go after the A stuff first quickly and that buys you some time.

And now for a technical expert I'll hand off directly to Patrick.

CHAIR MITCHELL: Please come on up, Patrick. And before you step down though, any additional questions? Okay. Commissioner Duffley.

COMMISSIONER DUFFLEY: It's really not a question, just to make sure that I heard this properly.

MR. VARTANIAN: Yeah.

COMMISSIONER DUFFLEY: You talked about Germany and how they rolled out trucks and it cost a lot of money, and what I thought I heard you say to avoid what happened in Germany that you have to do a stakeholder process? Or can you state how do we avoid what happened in Germany?

MR. VARTANIAN: The biggest difference is they didn't have the ability to remotely access the control's interface. So number one, I do -- I'm a real fan of -- so Hawaii and California were good examples of all stakeholders came together. My understanding in Germany, it was the standard setting body that from top down, so there are two aspects. It was top down directive and there was no grandfathering, so every connected asset had to retrofit to be compliant.

But some of this motivation for the interoperability standards, you know, they didn't have a defined communication interface to send new settings over the phone or internet. With 1547-2018 there are minimum communication interface requirements such through -- that this -- an update to an inverter could be sent remotely and nPhase in Hawaii I think it was a real -- they had a big chunk of that total market's inverter fleet and yeah, they updated everyone to the new Hawaii Rule 14 when it was approved as soon as it was -- not long after Hawaii regulators said, you know, this is approved grid support services.

COMMISSIONER DUFFLEY: So let's just take North Carolina for example. Are there some inverters that have been put out in North Carolina that do need to be manually changed, or do they have that capability, or do you know?

MR. VARTANIAN: I can't say with absolute certainty, but I'm very confident there are inverters that do not have let's say defined open standard communication interfaces today. The new standard though doesn't set a size limit, so even a 3 kW single-phase rooftop inverter if it's 1547-2018 -- when it is 2018 compliant, will have that communication's interface that speaks three languages and it'll be ready.

The other solution is 2018 allows for a system solution versus making it equipment specific. So someone could deploy and -- a communications interface separate of the inverter and with the 2018 going to a system as allowable to be compliant versus has to be equipment -- you know, equipment by equipment, that's another, I'll call it way out of Dodge, in the new standard is those that don't have a communication interface or certain capabilities you could deploy collocated equipment as long as on the customer side of the interface. That from a systemic approach then meets the compliance.

COMMISSIONER DUFFLEY: Thank you.

CHAIR MITCHELL: Welcome, Mr. Dalton.

MR. DALTON: Thank you. Hello, Chair, Commissioners and staff. Thank you for having me here today. My name is Patrick Dalton. I'm with ICF. My background is in utility engineering. I was with Xcel

Energy for over 11 years in Minnesota in various planning and operational roles. The last three or four years of that time I really focused on leading a group that was integrating distributed energy resources across states that Xcel Energy served.

Through that time we implemented a large community solar program over 500 MW of large-scale solar that was installed through that program. I took part in the statewide process in Minnesota to write new process and technical requirements that included the implementation of IEEE 1547, so Minnesota was one of the early movers. Through that process we worked with the ISO, RTO, MISO to look at how the bulk system impacts might be included in the statewide rules update as well as the local system impacts, and it's my pleasure to be here today to speak with y'all.

So I'm going to cover a few of the same topics that Charlie touched on in terms of process. How do these standards come about? How are they implemented in statewide rules? How do they flow down to interconnection agreements? Talking about some of those types of questions.

I'm going to spend just a few minutes on general capabilities that in the standards update there's a grouping of capabilities that apply to all DER; they're in the general section. But when I talk about the standard I really break it down into three main areas and these are the next three bullet points.

The local distribution system support. So how is voltage managed at a very local level, a neighborhood level, so that if you have rooftop PV on your roof you're not causing your neighbor's lights to be too bright and burn out early? You know, that's a type of local impact that we're talking about with these Volt/VAR functions and some of the other active and reactive power control functions.

The next is bulk system support, and this is really talking about the interconnected nature of our entire electric system where something that happens -- a big event on one part of the system can really cause trouble in other parts of the system and let's think about like wide-area blackouts for these types of events. Those are the bulk system events that we want DER to at least not contribute to that event being worse than it would've been, but really what we would want is this DER to support the system to help kind of hold it together if there is some sort of disturbance on the system.

And then the final topic area is interoperability and this comes down to future-proofing like Charlie was mentioning that if you need to change something on this DER later, how do you do that? And what you really want is some sort of communications interface that has standard functions and standard parameters and speaks a standard language that if you need to talk to that inverter later you could do some sort of update like we were talking about. Or it might be on a more dynamic basis where you actually want to modify the setting based on something that's occurring in real time and that -- so that's more about the operational use case. So we'll talk a little bit about all of those.

Starting with sort of what changed from the previous version. The previous version kind of talked at a high level about this interconnection system. It was this sort of abstract here's the performance characteristics between the DER and the grid. And it wasn't as detailed as the future -- well, I shouldn't say future anymore -- the 2018 revision of IEEE 1547 which was prescriptive in that it defined two interfaces. A power interface, so the electrical connection, how should the DER behave and interact with the system; and then also a communications interface and that goes to the interoperability. So one way that I think about this is it -- the previous standard was sort of an interconnection standard. I think of that from, well, you're bolting a piece of equipment onto the system and it needs to work with it. The new standard I view more as an integration standard where both the DER and the system are sort of pulling to the same goal here. So it's not that, you know, you have something hanging on the side that's along for the ride. The DER is really contributing to the local and bulk system goals and the functions that are defined by the standard are really aimed at furthering those objectives of the grid.

So Charlie had a similar slide like this. I just think it's worth mentioning one more time that the 2003 standard basically said you shall not participate in the grid. If something goes wrong on the grid, we would like you to get off as quickly as possible so that we can use our normal standard operating procedures that have been established over decades to put the system back together and then we'll connect the DER after everything is restored and we're comfortable that the system has stabilized.

Where we move to today is with DER becoming a larger part of the energy supply resource on the system is that it really does need to actively participate or at least have the capability to actively participate and that's what's occurred in that shift from you shall not participate or actively interact with a grid to this new paradigm where you shall have the capability to be able to interact with the grid.

So we were talking a little bit about this towards the end of Charlie's presentation. So what really is the process for turning standards into equipment in the field that can benefit the grid? And it starts with 1547, just the baseline standard, which defines the requirements for interconnection and interoperability. That one is another standard. So we talked a little bit about the distinction between standards, recommended practice, and guides. These are both standards meaning that they carry the most weight.

The .9 that we were just talking about is a guide meaning that it establishes practices that are optional to follow and alternate good practices that you may want to consider, but it's not -- it's not really saying these are the functions that need to be followed. Those are going to originate in the baseline standard 1547 and the test standard .1.

That test standard is then incorporated into that UL 1741, which is a little bit broader than just interconnection. It takes into account some safety, fire, kind of consumer protection type of considerations in addition to the strict interconnection interoperability requirements. And it rolls those all up into a process that nationally recognized testing laboratories can follow and result in a certification for equipment that's able to pass those tests.

From there these standards and certifications often flow into statewide interconnection standards. So 1547 isn't automatically adopted. It's usually by action of a policy or regulatory body. And this is similar to what was done in Minnesota and many other states is just to say we follow 1547-2018.

And then making the decisions along the way that come with adopting a standard and there are a number of decision points that need to be made.

Charlie mentioned performance categories, that's a key one that happens early on. The type of ride-through response that you would like to see. Those are a few examples, but just saying that the state is going to follow IEEE 1547-2018 isn't the end. There are key decisions that need to be made. Some of them it makes sense to make immediately when adopting the standard and others could likely be pushed further on down the road without really a consequence in the market.

And I'm thinking more of the interoperability type of communication standards that it's likely not necessary to communicate with every single DER today, you know, the neighbor's rooftop unit. But somewhere down the road we probably want to get there when the grid needs and the drivers arise. So that's just an example of some things you want to adopt now. Ride-through performance, I think that's something that you adopt immediately when you're deciding to implement 1547. But things like interoperability perhaps there's room to push some of those decisions further on down the road. And that might be a practical consideration based on the complexity and the breadth of what's involved in a 1547 implementation and adoption.

MR. McDOWELL: Patrick, who's making that decision? You say that decision could be made. At what level is it? Speak to that.

MR. DALTON: Yeah. Thank you for that question. The decision to adopt and implement is largely done within a regulatory body. There are a number of decision points within the standard that say it's up to the utility but, of course, in the environment, the regulatory environment, there's always the option to be more prescriptive with some of those decision points. And I'll give you an example of that.

Volt/VAR in the standard, it says that it's the utility's decision to use Volt/VAR or not to use Volt/VAR. Some states have said well, we think that there's a public policy reason to object -- to adopt Volt/VAR across the entire state. It could be to increase hosting capacity to allow, you know, the next DER to be interconnected to the system with less costly upgrades or no upgrades at all. So there's a little bit of ambiguity in that the standard says some of these decisions are up to the utility and I think that a regulatory body may decide to take some of those decisions and issue requirements on those as well.

MS. JONES: Just to clarify, in our -- in the North Carolina Interconnection Standard right now the utilities and the developers are required to comply with 1547 but it's not the 2018 version at this point. So it is laid out in the standard.

MR. DALTON: Thank you for that clarification.

The final point on this slide is just that the generator interconnection agreement often houses some of the more detailed specific requirements that might originate from the standard. So, for example, if it's a large solar installation that needed custom Volt/VAR settings or some sort of custom settings that are within the confines of what 1547 says is allowed, that could flow into the generator interconnection agreement. That might be specific to that unit whereas other requirements are broad and cover any DER in the entire state.

In terms of the timeline for adoption and implementation, we talked a little bit about how the flow of 1547 to .1 to 1741 to equipment adoption occurs. Currently .1 is being balloted on or I guess it's approved at this point in terms of it passed the ballot. It's not officially an approved standard, so the end is in sight for .1. UL 1741 is expected to start the revision process shortly thereafter and the experience from California Rule 21 that UL 1741-SA that we were talking about a little bit ago that Charlie mentioned, that's expected to expedite the process some for revising UL 1741 based on the new .1. But that could still take nine months, six months, nine months, a year. It's sort of anybody's guess. But those are the types of timeframes I would think about when we're talking about revising UL-1741.

And then after that certification is complete, there's still the time that manufacturers need to change over their process lines and just sort of revamp their manufacturing, so that they can produce inverters that are capable of these -- meeting these requirements and certification. So even after all of the standards and certifications are complete, there's still some time on the manufacturing side to actually change over these lines. So I said, you know, will equipment be available late 2021? That's just a personal guess, but that's the timeframe that I would think about.

I just wanted to offer a few other thoughts on that discussion regarding do you implement UL 1741-SA now or do you wait for this full revision to be complete? I think that the penetration in the state and what you expect the impacts on the grid to be is a major factor. That can also be balanced with the expected lifespan of this equipment. So we're talking about power electronic equipment here and it doesn't last as long as a lot of the traditional utility assets; poles, wires, those types of things. I sort of think of maybe a 10 or 15-year lifespan on some of this inverter equipment. And so there is that aspect of it that equipment out there today is going to need to be replaced on the -- the PV panels might last twice as long as an inverter, so --

When I was approving interconnection applications and talking to developers, I would hear sometimes that they would expect an inverter replacement about halfway through the lifespan of that PV plant and they would build that into their budget, whereas the panels would maybe last a full 20 - 25 years. So this stuff won't be out there forever, the stuff that is out there today, and the expense that's involved in trying to upgrade it based on the penetration that you may have today.

My personal viewpoint is to not try to upgrade anything that's out there today and that the standards adoption and the certification to the smart inverter functions is best done on a go-forward basis. But that needs to be balanced with the specific context of the penetration that you have in the state, the expected impacts on the grid.

CHAIR MITCHELL: Can you just expand on that point just a little bit? Help me understand why it's your opinion that updates should only happen on a go-forward basis. Other than -- I mean, I understand the basic point that the inverter is only going to be out there half as long as the panel is.

MR. DALTON: Yeah. It's -- thank you for that question. It's mainly driven by cost and complexity based and balancing that against the expected benefit that you're going to gain from that, so it can be an expensive process. And if there isn't like a bulk system need, for example, that you know you really need ride-through or you expect that you're going to have some of your large bulk plants tripping offline because DER is making the situation worse, that would drive a need to say, well, maybe we need to dig a little bit deeper. But even in that you might want to consider alternate solutions as well compared to upgrading inverters.

So in most environments that aren't Hawaii and aren't California, I think that there is the opportunity to look at this on a go-forward basis, but it's when making that decision it's really worth diving into the specific context and asking what are the grid needs that would drive us to want to do retrofitting.

Okay. And I'm going to start with some of the general requirements now and I'll cover these fairly quickly, because Charlie did a great job of discussing many of these.

The first one is the performance category selection. This is a decision that I think will be in most -- will be brought forward to most commissions in the implementation of 1547. It's just one of those early decisions that you need to decide at a basic level. How do we want inverters to perform out there? It's, again, based on the context, the environment of what the penetration is. And if you have high penetration now or you expect that to happen in the next 10 years or so, I think that looking at these performance categories with higher capabilities makes a lot of sense.

And for normal performance, again, that's the local grid support, that would be Category B to support voltage regulation. Excuse me. And for abnormal performance Categories I, II, or III that would be III.

It's worth mentioning briefly that there is an amendment to the base standard that has been approved officially that modifies Category III to allow it to be a better fit for a wider set of states. So there were just a couple of aspects and I'm not going to go into the technical details on it, but there are a few aspects of the ranges of adjustability or ranges of allowable settings for this function that made it a concern for some utility participants in the MISO and PJM processes. The amendment expands that range of allowable settings, resolves those concerns, and makes Category III potentially more suitable for a wider set of environments.

So I talked a little bit about the normal functions voltage regulation and abnormal just to kind of drill into that point one more time. The normal performance functions are for when the grid is sort of it's a sunny day, your voltage frequency, which are the two main parameters that the inverters are going to look at, when your voltage infrequency are within a fixed band that's acceptable, that per the standard is considered normal. When it's outside of that range of voltage infrequency, it's considered abnormal. So in the normal region your Volt/VAR function applies, those kind of voltage regulation functions. In your abnormal region is where your ride-through applies. So there aren't requirements to do Volt/VAR when you're in an abnormal region, because it just -- it doesn't make sense. You have a major issue on your grid, so you're looking to these ride-through functions and that's the set that applies in that state.

Okay. Well, I'm going to try another analogy on an active and reactive power here. We'll see if this one resonates with anyone.

These tow boats used to be a big thing prior to the industrial revolution, I guess dating all the way back to the Romans. In the UK they used to use these horse-drawn boats along canals. And so if we think about a horse pulling a boat from the side of a canal, there's really a force that's directed right at the side of that canal, and that's not doing any work, because it's not moving anything. We assume that maybe the boat has a rudder so you know it's pushing back, but the boat is not moving towards the side of the canal. That's just reactive power that it's real force, you know, it takes -- work isn't the right word for it, but it takes force to accomplish this, but it's not doing any work. It's not moving the boat forward.

The force that is leading to work is in that forward direction and that's, you know, you apply a force and the boat moves forward and that's -- that's like the watts or your real or active power. Real and active power are the same words for this quantity of power that does work. So, you know, watts are generated by a power plant and sold to end customers or generated by DER and compensated over net metering. VARs -- there isn't a financial value in retail markets let's say generally, because it's just not -- it's not doing work, but it's required as part of the system.

And not to get into too many details here, but the VARs are really related to the magnetic component of all the circuits that we have, so there's a cost of keeping the circuits magnetized so that we can transfer power. And that's really what the VARs are, reactive power element, that's its role in the power system. But really what most parties are going to be interested in in terms of compensation is the watt component of it, the piece that really does work. So there was a long debate during the standards-making process about should we build in overhead, should we require overhead in all DER so that when it's doing a hundred percent of the work it's capable of doing, you know, producing a hundred percent of the watts, should it still be required to have that headroom to be able to produce VARs or consume VARs? And the reason that that's important is say that you have a Volt/VAR curve and your rooftop PV plant is generating a hundred percent of its power, but all of a sudden something happens with the voltage that now the inverter is trying to output reactive power or VARs. If there wasn't any headroom in that inverter, the watts are going to need to be reduced in order to accommodate that reactive power.

The standard ended up staying silent on this and really saying that you have two options here. You can do what I just said, reduce that active power, because you haven't built in headroom, or you can oversize that inverter. And so when you're designing the plant, you can add in an additional -- you can add in additional headroom so that that same situation you're producing a hundred percent of your active power and now your Volt/VAR curve calls on some reactive power. Well, you can still stay at a hundred percent of your active power production, get compensated for all of those watts.

In some state proceedings I've been following the compensation on reactive power. It has become an issue and that's where this type of design consideration that DER developers need to make upfront becomes relevant, because if a developer is going with the reduced active power option, Option 1 on the screen, and not expecting that these functions might reduce the power that they're compensated for, that can be an issue down the road. So I think that it's just something to consider early on in the process.

CHAIR MITCHELL: Can you -- sorry, Kim. Can you comment on how the majority of jurisdictions handle this issue to the extent that there is sort of some --

MR. DALTON: Yeah.

CHAIR MITCHELL: -- pattern or consensus

among jurisdictions?

MR. DALTON: So I can speak to how Minnesota has handled it. I think there haven't been enough states that have gone through this process to really develop a fact pattern on it yet. But what Minnesota did was to flag this issue in the statewide rules to say hey developers, this is a choice that you're making upfront, so it wasn't prescriptive about saying we shall follow one of these options but just informing that this is a choice that's being made and if you don't want power production to be affected, please consider oversizing your inverters right off the bat.

MS. JONES: Kind of a related question. Given the PURPA requirements basically that utilities must take power, is it even conceivable that they could be forced to forego energy sales?

MR. DALTON: That's a good question. And I'm not quite sure how to answer that in the context of if you have an interconnection agreement that says that this DER shall participate in some sort of voltage regulation scheme. Let's just use the Volt/VAR since we're talking about Volt/VAR a lot. If it's saying that the DER has the obligation to regulate voltage in that manner, I guess my question back might be how would you prioritize or view those two different requirements and does one take precedent over the other would be sort of how I would view working through that. But I don't necessarily have an answer of how that works.

I guess briefly on this new concept in 1547 called the reference point of applicability, the key point on this is that the RPA is where all of the interconnection and interoperability requirements apply. And the standard tried to differentiate small units from large units, because of the influence of -- excuse me -- let me say that again, differentiate large units and small units and include the influence of load. So I won't get too detailed into this, but it makes a break point at 500 kVA for saying that the -- if it's larger than 500 kVA and it meets these other requirements, chances are the point of applicability is going to be at a meter where it's been for the last 15 years based on the previous standard.

What 2018 did that's different is said sometimes the requirements might apply at that inverter device itself, so that's sort at a high level. What this reference point of applicability says is either the requirements are going to apply at the meter, the point that is the demarcation point between the utility and the customer's system, that's a point of common coupling which is usually the revenue meter. Or it could be just at the terminals of that inverter device is the other option.

Along with that are these control capability requirements. And this first one is really relevant for energy storage that all DER must be required to control its active power. And depending on where that reference point of applicability is that could either be a limit on sort of that nameplate value or what the DER is capable of producing or it could be an export limit which is the difference between the load and generation at that meter is essentially what an export limit is.

Export can be used to assure that energy storage is complying with net metering tariffs. If there is some sort of requirement for a DER in a net metering arrangement to be producing renewable energy. So it has relevance to sort of tariff compliance. It has relevance to determining the process track for a DER to follow in an interconnection process. If you're able to limit the nameplate value below a certain value, let's say you have a simplified process with a 20 kW level, do you want to consider power limiting as one way to get below that 20 kW and follow the simplified process track.

So these capabilities interact with both process types of eligibility and screening requirements, but also with compensation and tariff compliance requirements such as the net metering example.

I just briefly want to mention that there is a new response for DER besides just tripping and staying offline for five minutes. And that's this momentary cessation capability which just means for some bulk system responses if you choose Category III, you can get that DER back online really quickly. So in under half a second 80 percent of the production from the DER needs to be back online and that can be important for supporting bulk system needs. And that's different from just this traditional trip requirement where even in the new standard if a unit trips and it's set with a default settings, it's going to stay offline for five minutes, and then it's going to ramp up over another five-minute period. So you could have 10 minutes before you get full power production back under the tripping paradigm even with the new standard.

All right. Let's dive into the local system support functions and these are often of interest in the proceedings. Which functions do we pick? What are the default values? These are some of the decisions that you may be contemplating as you look at implementing 1547-2018.

So I'm just going to start with a pretty simple example about how DER impacts voltage on a feeder. What we're showing here is just a typical radial feeder and down below is a graph of the voltage declining as the distance increases from the substation. So with load on a feeder, you just expect a declining voltage profile due to kind of the physics of that line and current being drawn over it.

Now, if you add a DER at the end of the line and your current is now flowing in the reverse direction, that same -- the same physics that caused your voltage to decline in the forward direction are going to cause a voltage rise in that reverse direction. And it's possible that that voltage can rise so much that the voltage near the end of the line goes outside of the standard allowed ranges and it's pretty typical for utilities to follow a specific voltage range called ANSI C84.1. It's typically in their utility handbooks. It might even be in your statewide rules. But what we want to assure is that voltage is always maintained within that bandwidth.

And at a fundamental level there's really only two ways to make sure that that's accomplished and all of these, you know, fancy functions that we're going to talk about, Volt/VAR, Volt-Watt, Fixed Power Factor, they're all relying on these two fundamental methods of accomplishing voltage regulation.

The first one, and this is what we would prefer to do because there isn't a real cost in terms of lost production, but you can have that DER consuming reactive power or drawing VARs down the line. So what you have then is you have VARs being drawn towards the DER and that's counter to the flow of the power, the active power that it's producing, and there's a cancellation effect between those two quantities since they're going in reverse directions across the line.

Characteristics of large line causes a leveraging effect on the reactive power. So a typical like mainline conductor you might only need one unit of reactive power or VARs to cancel out three units of watts or that active power. So you can get this leveraging effect just because of the characteristics of the line and that makes this a very effective means in some locations, but it also means that it's not effective in all locations, because the response that you get is dependent on that line and if you don't have that leveraging effect, you could be using a lot of reactive power and not actually getting a reduced voltage.

The second method to reduce voltage is to simply back off the watt production or that active power, the power that's compensated for. This is going to be less desirable from almost everyone's perspective, because there's energy that's left on the table that's not being produced that could be used.

There are five of these functions defined by the standard, five functions that use one of those two methods to affect voltage. There is the constant power factor which has been around for many, many years. It's probably used on a lot of the large installations that you have out in the field today and that's still allowed in the future. There is adjustable constant reactive power just commanding a given level of reactive power. Not a lot of people have found uses for that today. Maybe as we move into the future with like advanced distribution management systems and DERMS and some of these more advanced types of systems you might use that.

Volt/VAR is getting a lot of attention because it's an autonomous function that dynamically adjusts. We'll look at a few responses of that Volt/VAR function.

And then there is Watt-VAR which I sort of think of as just like a smart power factor function. We won't get into that again. It's not one of the most prevalent, but it is an option.

And then there's this Volt-Watt function which I tend to think of as like a back-up function or a soft shutdown. It shouldn't be the primary means of regulating voltage, but you can stack it on top of one of these other functions and it can be very effective and we'll look at an example like that.

Okay. So now we're going to look at a couple of these functions in their graph form and I'm going to try to break it down, but please stop me if any of this isn't making sense and clarification would be helpful.

What we're looking at on this Volt/VAR function graph is a function that's going to absorb reactive power when the voltage goes high and produce reactive power when the voltage goes low. So see the voltage on that X axis and the level of reactive power consumption or absorption on the Y axis and that point right in the middle that's labeled V Ref that's where your hoping your system voltage is operating.

So normal response you have what we call a Dead Band there and that's that line that's not producing or consuming any reactive power right around your reference voltage. But then when your voltage goes low, you may be pushing reactive power into the system and that's that sloping line up on the left-hand side of the chart. And when your voltage goes high, your DER is going to be consuming reactive power and that's your sloping line on the right-hand side of the chart. So from a kind of graphical perspective that's what a Volt/VAR function looks like that is going to be consuming reactive power to lower voltage or producing reactive power to try to raise voltage.

So I have an animation here and we'll see if it works. Kind of explaining these graphs quick before we set it in motion. In the upper left-hand corner is a load profile on a feeder. So we think that, you know, there's times of low load when everyone is perhaps going to bed or, you know, they're -- people aren't at the office and in the home. And then in the morning the load can start to rise. So this is just kind of a simplified hypothetical chart.

Without voltage regulation, your voltage profile is going to basically be the inverse, so that is to say at times of very heavy loading, high load, you're going to have low voltage, so that sort of tracks inversely that voltage profile in the lower left-hand corner. And then over in the right-hand side is that Volt/VAR curve that we just described.

So I'm going to set in motion over time and you can see, I'd suggest focusing on the right-hand side to kind of show how when the voltage changes over time that we have -- so voltage is going up, you're consuming VARs. Voltage is going down, you're producing VARs. And then you reach kind of back within that steady state band. So it really is a dynamic function that's trying to track the voltage of the feeder over time and dynamically adjust the reactive power to compensate accordingly.

The other function we'll look at in detail or other function we'll look at -- we're only going look at two out of the five here. So this is the last graph I think on smart inverter functions. But this is a very, very useful function I believe, this Volt-Watt, in future proofing your system and having a system that is flexible to be reconfigured without needing to manually go and manipulate the DER.

So what we're looking at here is on the X axis, again we have voltage, so similar to the previous function. But now on the Y axis we have active power or watts. You know, the power that's compensated for. What we're seeing is that when you're at voltage that's normal, full output of power. So we don't want to reduce power unless we're seeing voltage that's high. And not just high, but high enough that it's outside of that acceptable band. So that is to say that this function isn't to be used for regulating voltage when it's within that normal standard ANSI Range A band that we looked at on that feeder voltage profile.

But when voltage does get high, that sloping down to the right is just going to be like a soft shutdown on the power, so you're producing at full power output, voltage goes too high and the power output just starts to droop essentially and it will go down to zero if it gets too high or some other predefined level.

So here's an example of why this function might be useful. We have a hypothetical system over on the right-hand side that has two substations, so these are two sources of power. The red breakers are closed so that means that this alpha substation up top is feeding all the way down to that green box and that's an open breaker. We assume that there's all sorts of, you know, residential customers, commercial and industrial along this line. Those aren't shown just to simplify the graphic.

But we do have this DER system that's close to that top substation in the normal configuration. But now let's assume something happens to that substation, it goes out; lightning strike, animal, transformer failure, you know, one of the common things that may happen to a substation. We're going to assume that this system is automated, and so it recognizes the fault is there. It isolates it. That top breaker opens up, and then this bottom substation Bravo closes through. And so that DER that used to be at the head end of a substation is now way at the tail end of a different substation.

If we think back to that voltage profile of DER way near the tail end can cause high voltage, that's what happening in this case. So we were within a normal voltage and we're producing 1 MW of power, but now that we're at the tail end, our voltage goes up to 107 percent, which is outside of that acceptable range, and that DER is going to automatically adjust so it's down in this hypothetical example. It's now producing a quarter of the power that it was in its normal state.

So this is really useful on automated circuits, areas where -- well, I guess just in general, as planning engineers we typically in distribution study the normal configuration, and there are so many of these abnormal configurations. For a typical circuit you might have five or 10 different ways to feed it, so you can't necessarily study every single abnormal configuration, and this is a way to say well, whatever state the system ends up in, this DER is going to automatically adjust and try to help protect voltage so that customers' equipment doesn't burn out, that voltage stays within an acceptable range there.

So if we think about how these functions might play together, this is one potential example, and I think that this is how a lot of states will end up viewing the stacking of these functions where under normal voltage conditions you're going to want to use a function like the Volt/VAR. There isn't that cost of reducing the real power, the active power produced that we talked about, so that's the preferable function to use to the extent that it actually does help the voltage. But if your voltage continues to shoot up beyond that range, then we want that Volt-Watt -- that Volt-Watt function to kick in and start to back off that power production.

So it kind of goes back to those two ways that we talked about of managing voltage. The first one you're going to use as a primary option is the reactive power with say a Volt/VAR function. If that doesn't work and it's still an issue, then the back-up option is Volt-Watt, which will start to back off the power production.

If you go above what the Volt-Watt function can even handle, then we're in that abnormal operating region that we talked about and the ride-through functions start to be the dominant consideration. Okay.

So that's it on the local systems for -- and we'll just pause there if there's any questions on Volt/VAR, Volt-Watt functions.

Okay. Seeing none, we'll jump right into the bulk system. So again, this is thinking about wide area transmission systems that are all interconnected together and trying to keep the system intact and not having any major issues.

Starting with the historic perspective of -- and this is looking at voltage tripping requirements. You'll see in the similar charts for voltage and frequency, I'm not going to get into the details of these charts, but I will point out that they all have time on the X axis down below and either voltage or frequency on the Y axis. So it's basically saying depending on how severe an event is and the duration of that event, we're going to classify a specific action should take place based on severity and duration is basically how these ride-through functions are defined.

This particular graph is going back to the 2003 standard, and I just wanted to put this up there for motivation of why it's important that we've defined new ride-through functions. And really the biggest issue with this previous function -- well, one of the biggest ones is the ambiguity for that may-trip region. It didn't say that you had to stay connected to the system and producing which is what you expect of a ride-through function that's supporting the bulk system. Continue producing power. That's a way to not make the fall through the disturbance any worse. This said well you may trip but it's not defining whether you do or don't. Outside of that region was more prescriptive. It said you must trip and clear. But as we go to the future function, we'll look at how that may-trip region was clarified and why that's important.

And this is an example of why we -- why bulk system response is important for DER these days. An event out in California -- there were actually two of them in 2018 -- there were disturbances on the transmission system and there was a large amount of inverter-based resources that tripped. Most of these resources were bulk plants, so kind of large-scale plants connected to the transmission system. But these events were the first time that DER tripping was noticeable for a bulk system event.

So in the first event, the Angeles forest fire, there was 130 MW of DER tripping, so a sizable amount of DER tripped. And in the second event there was about 100 MW. This equated to about 13 percent of the total generation, so even from a percent of all of the resources that tripped, it was significant. And I think that as DER penetration continues to increase in the future, we could only expect these numbers to go up. And there is some threshold where the amount of DER that trips becomes too great and it leads to instability of the bulk system.

And so that's really what's driving why do we want these ride-through functions for DER in the first place. Why is it important? They're on the distribution system and we're talking about supporting the transmission system in these bulk plants. And it really is that we've started to see that DER is responding to the bulk system events and it could have a material impact on how the system operates.

This is an example of what one of those events looked like, and I like this because it kind of just --

CHAIR MITCHELL: Can I -- may I interrupt you?

MR. DALTON: Oh, yeah. Absolutely.

CHAIR MITCHELL: Just going back to the point about the threshold, the point you just made about that threshold. The point at which it becomes too impactful to the bulk system.

MR. DALTON: Right.

CHAIR MITCHELL: What do we know about where that threshold exists?

MR. DALTON: That threshold often is going to depend on detailed studies. So every transmission system is different and based on -- you could find a worst-case fault, so in North Carolina we could find the line that causes the worst-case voltage depression for example, and then the severity of that voltage depression would inform where that threshold is. So I can't really say today that there is -- it's at 1,000 MW. It's really dependent on --

CHAIR MITCHELL: So there's no general rule --

MR. DALTON: There's no general rule.

CHAIR MITCHELL: -- or relative number at this point?

MR. DALTON: Right.

CHAIR MITCHELL: Yeah.

MR. DALTON: And some of the studies that have been done to try to find that threshold do just that. They're kind of detailed transmission studies. So initiating a study such as that could help inform where our threshold is, but it's going to be very system dependent from location to location.

Yeah, just briefly looking at the response of these inverter systems, this graph and it's from a NERC paper that's cited down in the lower right-hand corner, but I think it does a nice job of sort of illustrating the response of DER that you would see following an event.

So way at the left-hand side the -- we have full power output, just everything is normal, sunny day. There's a disturbance on the system. We lose most of the DER or most of the generation for a very brief second. The generating resources that are set up for that momentary cessation function that I mentioned where the output is restored very rapidly, those will all bounce back online and so that's that restore output labeled number 1.

But then any DER or generation that's not set up that way kind of exhibits this response that we're familiar with from the 2003 standard of waiting for five minutes, waiting for normal conditions on the system, normal voltage and frequency. Once that normal voltage and frequency has been established, there's a ramping period. 2018 standard says it's over another five-minute period.

So basically if the default settings are used, this is what you could expect to see. It's about a 10-minute period before you get all of your generating resources back unless the defaults are modified. So if there's a transmission study that says we can't afford to lose the level of DER that we expect to see for 10 minutes, then there would be a reason to push more of the DER to either that restore output rapid response or shorten the time delays or shorten the ramping periods. So these are decisions that are being contemplated by ISOs, RTOs, and states when implementing 1547.

MISO in the process that we went through over in MISO decided to stay with defaults, but they would've like to see a quicker response. The default was sort of balancing the distribution needs, which would like to see a little bit more time for things to stabilize out.

COMMISSIONER DUFFLEY: And what did PJM, have they decided anything on this issue?

MR. DALTON: I believe PJM was silent on this. I would need to double check but that's my recollection.

This is the voltage ride-through characteristic that's defined for Category III. And not going to get into the details of the settings, I think that what I'd like to point out from this is just that those regions that were defined in the 2003 standard as may trip and it wasn't prescriptive, now they're very prescriptive of we have a continuous operating region where you're expected to operate as normal if you're a DER. A mandatory operation capability where it shouldn't trip, there shouldn't be anything inherent in the DER that causes it not to be able to operate in this region. And then that momentary cessation capability which would lead to that rapid restoration of power if it enters this region and then goes back into the normal operating region.

Charlie showed this chart, so I don't think

I'll mention this one.

And then that brings us to the interoperability, the requirements surrounding that local communication interface. Charlie also showed a similar chart as this. I think what I'd like to build on from what he presented was that the scope of 1547 is actually pretty narrow and it's only at basically a communication port for that device. So all of the network, field area networks, how that information gets back to the utility or a third-party aggregator or whoever is managing that DER, that's not standardized.

What is standardized is the language that that port can speak, kind of the physical plug that that port is, you know. So can you fit an ethernet jack into that port kind of like we're used to plugging our internet into? That's defined. And then also information models, which is basically just a way to structure all of the functions and settings in a standardized way so regardless of if you're speaking French or German an apple is an apple essentially. So you can translate between different languages, but you have a common way about speaking about the functions and manipulating the functions.

A few reasons why we might want to use this interoperability interface of this local communications port. It can be used for monitoring or controlling the real-time status of the DER. So we just want to know what is it outputting or we want to change a function from Volt/VAR to a fixed power factor, it can be used for that. If there's some sort of emergency situation where you want to change the settings, or if it's a Hawaii situation where you want to do a wide-area setting. Something came up in the future we didn't anticipate. We got the ride-through settings wrong. We want to change all of those for DER that's connected to the communication system. This is a means of doing that.

And then looking a little bit further into the future, well, today ADMS is becoming more widespread, these Advanced Distribution Management Systems. I think of them just like the energy management systems transmission has been using for a long time. It provides greater visibility and control down to the distribution system and we could incorporate DER into these. And actually a lot of the commercially available products do have DER modules that contemplate interacting with advanced inverter functions.

As DER becomes more widespread, the DERMS systems may live within an ADMS or they may be a separate system that integrates with the ADMS. And really I think of these as a way to manage large, large quantities of DER. So if you want a response out of a 1,000 rooftop units in the field, you don't want to have to go through the trouble of saying what am I going to send to every single one of these units to get that response. You want to say here's the response I would like to see; now DERMS system you go figure out how to most efficiently implement that. So there are basically four different types of information that the DER needs to be able to exchange. There is the nameplate information. So the basic, what type of DER am I? What are my capabilities? What are my power ratings? Those types of quantifies.

There's the configuration settings and these are meant to be long-term settings that modify the operation of the DER. This isn't Volt/VAR. This is like if you wanted to take a 1 MW solar unit and permanently have it be a 800 kW unit, you can use a configuration setting and you can do that through the interoperability port.

There's monitoring. I mentioned like real-time monitoring of the operational status of the DER, the voltage frequency reactive power. That's one of the four categories. And then the last one is management, and that really does get to the Volt/VAR or the configured -- or configuring a set amount of power to be output at some given time. These are the ones that you would modify more dynamically as a utility or a third-party aggregator.

There are options of how you implement interoperability. I won't get into the technical detail of what these four options are, but I think the takeaway is that each of these options defines a physical layer. As I mentioned the ethernet plug, you know, what does that physical port actually look like? A transport layer which is a little bit more abstract, but it's sort of like how does information flow across the internet. What is the protocol that, you know, systems can communicate with each other over the internet? And then the application layer which is like a communication protocol, and that's more just like the language. And Charlie mentioned that these options, DNP3, SEP 2.0, and SunSpec Modbus.

This is a decision point that some states are choosing to make upfront and others are not. I think there are advantages to both. On the side of making this decision upfront, California was one of the early movers on that. They decided to go with SEP 2.0. as their protocol and there is something to be said about the interoperability of their system now that they've clasped on a single protocol. They don't have to try to translate between these. Basically they can expect that this is the stack, this one in the middle. That's how information is going to flow to them.

On the other side, the manufacturers haven't really coalesced around a single protocol yet. The standard requires that they support at least one of these. They may support all three. They may decide that they're going to support one and deal with translating the protocol if that's needed. So until the industry really does decide, you know, this is the protocol that all DER is going to use, and I think some in the 1547 working group would've really liked us to get there. That would've made this a simpler decision for people that are in your position for example. It would've been nice, but there were just too many competing interests and too many of these protocols and widespread use that we ended up with three of them, so a decision point to be made.

I guess I'll briefly mention sort of the information model perspective. And this graphic just shows that if you have a common information model, you can have sort of a channel that you are directing all that common information to and any system can pull from it, because it knows what format to expect it from. So it's a way that helps integrating different systems together sort of having that common information model.

Okay. So that's all that I had on interoperability. I wanted to just share a few thoughts about potential approaches as you're thinking about adopting these different components of smart inverters. So we talked about there's a lot of different functionality and not all of it necessarily needs to be figured out on day one, but there are certain aspects that could be figured out sooner than others and they're sort of like the no-regret type of decisions.

I see ride-through capabilities, if we think about this in a stepped approach, I see ride-through capabilities as one of those decisions that can be made immediately with the adoption of 1547-2018. So picking performance categories and then determining the response that you want to see within that, those performance categories. It's important to coordinate with the ISO and RTO in those discussions.

So picking ride-through functions and settings is a balance between distribution and bulk system objectives. So it's really important to have all of those voices in the room, those being distribution engineers, transmission engineers, ISO, RTO engineers.

MS. JONES: Excuse me, Patrick.

MR. DALTON: Yeah.

MS. JONES: In an environment where we are where most of North Carolina is not in an RTO, where would that coordination happen?

MR. DALTON: It would be with the transmission operator then. Yeah. So thank you for that clarification. If not in an organized ISO or RTO, it's really the transmission operator that would be the relevant party on the bulk system side.
The next step that I see is the use of real power control. So that's Volt-Watt. I think that Volt-Watt is a no-regret function to implement right away as

well. It's sort of this protective back-up function that when voltage is within the normal bounds, nothing happens. If it goes outside, it's going to start to operate.

One thing to consider with this is there is a consumer protection angle that customers' voltage may be just slightly above that acceptable range if the utility is riding that upper edge, so they may experience some loss production. And, you know, there are proceedings. I've seen consumer advocacy groups talk about that angle and I think it's an important one to consider. How I've seen it addressed to date so far is mostly been tracking. So requirements for utilities to track how often that function is being activated.

But most parties that I've spoken with or been involved with in these types of proceedings see the value in the Volt-Watt, so setting aside that there is sort of this small -- this consideration, an important consideration, but sort of an edge case that this function does make sense to implement early on in the process.

At a similar time I think it makes sense to consider what reactive power function, so do you set a default Volt/VAR function like we talked about? I think that there are a lot of reasons to consider a default Volt/VAR function due to its flexibility to adapt to different conditions on the feeder. It's sort of more of a future-proof function. It works well for small units that you don't want to necessarily come up with custom settings for the default Volt/VAR function in the standard. It was meant to be not too aggressive, that it won't have a lot of interactions with other inverters or other voltage regulation equipment. So I think that considering that type of function implementation at the same time makes sense.

Then further on down the road, maybe initially as well, but I see interoperability as a more complex topic to address. When do you apply it? Is there a certain size threshold that you're going to require that that interoperability interface is made active and communications are established to it? There's a real cost involved since the rest of that network isn't in scope for the standard, so the standard defined of basically, you know, a way to talk to the DER, but establishing all of that communications isn't in scope, so that needs to be done and there is a cost to that, so --

Some of those considerations we talked about protocols not being a hundred percent standardized on or at least the industry hasn't picked one protocol yet if that is to happen. There's a chance it won't, but I do tend to think that the industry will start to coalesce around a single protocol. So some of those types of issues make the interoperability issues a little bit more complex. And then like custom settings and approaches using something non-default of deviating from the defaults and the standard, I think is also more of an advanced topic.

That's just one potential stepped approach. This isn't like out of the official IEEE 1547 or out of any best practice, but just based on my experience with some of these discussions, something to consider.

So I guess just to summarize those three kind of key areas again. From my perspective when I think about the standard, it comes down to this local system support, the Volt/VAR, Volt-Watt, the bulk system support, the ride-through types of functions, and then the interoperability. And that's not to set aside many of the other important aspects of the standard. I just think of this as one way that I can wrap my head around what's in the standard is that there are sort of these three pillars that are really core to the revision and also are interwoven with the decisions that are typically made through regulatory proceedings to adopt and implement the standard.

And that's all I had. I'd be happy to take any additional questions if you have any.

CHAIR MITCHELL: Questions for Mr. Dalton? All right. I think it looks like you've gotten off easy. No additional questions.

MR. DALTON: Thank you.

CHAIR MITCHELL: We appreciate y'all spending your time with us today and sharing with us your experience and the work that you all have been doing. It's invaluable for us and we appreciate your engaging with us in this opportunity for shared learning. So thank you very much for being here today and helping us as we continue on our journey.

If there is nothing else from the Commissioners or from Commission staff, we will be adjourned. Thank you very much.

(The proceedings were adjourned.)

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