FEDERAL ENERGY REGULATORY COMMISSION

MANAGING TRANSMISSION LINE RATINGS

DOCKET NO. AD19-15-000

TECHNICAL CONFERENCE

Day 1

Tuesday, September 10, 2019

8:45 a.m.

Federal Energy Regulatory Commission

888 1st Street NE

Washington, DC 20426

PANELISTS

Panel 1

Joey Alexander, Ampacimon SA and Elia System Operator

T. Bruce Tsuchida, The Brattle Group, Inc.

Rob Gramlich, Grid Strategies LLC, Working for Advanced Transmission Technologies (WATT), and the American Wind Energy Association (AWEA)

Jake Gentle, Idaho National Laboratory

Jack McCall, Lindsey Manufacturing Co. and WATT

Hudson Gilmer, Line Vision, Inc.

Panel 2

Swarj Jammalama, Apex Clean Energy Partners

Francisco Velez, Dominion Energy, Inc.

Babak Enayati, National Grid USA Service Company, Inc.

Chunchuan (Charlie) Su, New York Power Authority (NYPA)

Howard Gugel, North American Electric Reliability Corp. (NERC)

Shaun Murphy, PJM Interconnection, L.L.C.

Chad Thompson, ERCOT

Panel 3

Carlos Casablanca, American Electric Power Company, Inc. (AEP)

Dennis Kramer, Ameren Services Company

Dede Subakti, California Independent System Operator Corp. (CAISO)

APPEARANCES (Continued):

Michelle Pivach Bourg, Entergy Services, LLC

Rikin Shah, PacifiCorp

Mike Wander, Potomac Economics

Amanda Frazier, Vistra Energy

P R O C E E D I N G S

MR. KOLKMANN: We're going to get started. Good morning and welcome to today's Technical Conference, Managing Transmission Line Ratings. This Conference will explore what's transmission line rating and related practices might constitute best practice and what, if any, Commission action in these areas might be appropriate.

We have three panels today and two tomorrow. We'll allow up to 10 minutes for each panelist for opening statements on Panel 1, and up to 5 minutes on the following panels. We will follow this by question and answer.

All the materials received from speakers have been posted to the calendar page on ferc.gov and will also be posted on e-library under Docket Number AD19-15. In addition, on August 23rd, staff issued a paper on managing transmission line ratings to help frame certain issues for this Conference.

That paper is also available on the calendar page for this event. The first panel will include presentations from, and discussions with National Lab and industry experts in advanced transmission technology to introduce different approaches to transmission line rating.

Panel 1 will also discuss the ambient adjusted ratings and dynamic line rating implementation process, current R&D trends, the extent of current use and expected future adoption of these advanced transmission line reading methodologies.

Panel 2 will discuss benefits and challenges to DLR and AAR implementation. The panel features a broad array of industry experts, will share case studies, lessons learned, and best practice related to advanced approaches to transmission line rating.

Panel 2 will also touch upon DLR's on how DLR's might be incentivized and whether periodic studies of the cost effectiveness of dynamic line ratings on congested lines would be helpful.

Panel 3 will discuss whether transmission owners should implement ambient adjusted ratings. The panel features a broad range of industry experts bringing their unique experience, as well as the lessons shared from the prior panel.

Panel 3 will also discuss how any requirement for transmission owners to implement ambient adjusted ratings might be reflected in transmission service, both in ISO's and bilateral markets methodology requirements.

This panel will also address corresponding changes to ATC calculations, as well as software and communication. Finally, this Conferenced is complimentary to relevant responses to the Commission's inquire on transmission incentives and in Docket Number PL19-3 and in addition to the recently announced workshop on grid enhancing technologies in Docket Number 80-1919.

The purpose of that workshop will be to discuss grid enhancing technologies such as those that increase the capacity, efficiency or reliability of transmission facilities. Utilities, RTO/ISOs and other interested parties will discuss how grid enhancing technologies are currently used in transmission planning and operations, the challenges to their deployment and implementation and what the Commission can do regarding those challenges, including incentivizing or requiring the adoption of grid enhancing technologies by RTO/ISOs.

These technologies include those to be discussed today, but also include, but are not limited to, power flow control equipment, transmission switching and storage technologies. Speaker nominations and registration forms are now available on the Commission website.

I want to thank all of the Commissioners -- all of the participants for being here today for what I'm sure will be a lively and informative day of discussion. I also want to welcome Commissioner Glick who's here.

Prior to covering several housekeeping matters, I want to turn to Commissioner Glick and see if he has any opening remarks.

COMMISSIONER GLICK: Thanks Dillon, you know, and

I want to thank you and the staff for putting together this very important Technical Conference -- both for putting it together, the very helpful white paper. You know, one of the more important essential tasks or capabilities being in government is trying to take something very complex and making it more understandable, especially to those less technically inclined like myself. Line ratings don't come naturally but it's a very important issue.

And I'm very -- it's all -- the Commission is hosting this Technical Conference today, it's a very important issue. And you know, if this country is going to meet its clean energy target established by numerous states and corporations, we're going to need a more vibrant transmission system.

And part of that is we're going to need more transmission naturally, but also it also means using our existing system more efficiently and that's something I think we're going to take a look at today.

Certainly, the Commission needs to consider whether there are alternative mechanisms for establishing line ratings, such as dynamic line ratings and the ambient adjusted ratings that can squeeze more out of the transmission system without impairing reliability.

I will be in and out today, to attend a bunch of other meetings, but I hope to sit through as much as possible today and tomorrow, and hopefully learn as much as I can, so thank you very much.

MR. KOLKMANN: Great, thank you for your remarks and for helping to frame the issues. I'm going to close with a couple of housekeeping matters. The Conference is being webcast finally. After the Conference, the Commission will issue a request for comments. Please don't bring your food or drinks -- please don't bring food or drink, other than bottled water, silence your cell phones if you haven't done so already. There are bathrooms and water fountains behind the elevator bank on either end of the building.

So, we've got a lot of ground to cover in a short amount of time today. With that in mind, we'd like to keep panelists. We'd like to keep comments within the topics laid out for each panel. If discussion begins to stray outside the scope of the panel or outside the scope of the question, we may interject to bring things back to topic.

The panelists -- if you'd like to be recognized to speak, please put your name card on its side, any tent on its side. Be sure to turn on and off your microphone and speak directly into it. When you're not speaking, please turn your microphone off. Do your best to avoid a lot of acronyms, recognizing that there are lots. And with that I'd like to introduce FERC staff.

MR. KHELOUSSI: Can I say, I think because these microphones will probably remain on, unlike these, so I think you just leave your mic on, but pass it to whoever's speaking. Thank you, last minute change.

MR. KOLKMANN: Starting from my left to right, I'll introduce the FERC staff. We have John Rogers, we have Daniel Kheloussi, Tom Dautel, I'm Dillon Kolkmann, Jignasa Gadani, Eric Ciccoreti, Al Corbett, Vincent Le, Michael Gildea, Kevin Ryan, Alex Smith and Michael McLaughlin.

Our panelists for the first panel, reading in order of their presentation, audience is left to right would be: Bruce Tsuchida, Rob Gramlich, Joey Alexander, and I'm sorry, Bruce Tsuchida is from the Brattle Group, Rob Gramlich is from the WATT Coalition as well as a number of other places, American Wind Energy Coalition.

Joey Alexander, who is from Ampacimon. We have Jack McCall from the Lindsey Manufacturing as well as the WATT Coalition, Hudson Gilmer from LineVision, and we have Jake Gentle from Idaho National Lab.

With that I'll turn it over to our first panelist, Bruce.

MR. TSUCHIDA: Well, good morning. And first off thank you very much for assembling this meeting. We appreciate the opportunity in helping out the panel. This panel will be producing the introduction to the whole three-day or the two-day Conference with its members.

And I will be producing an introduction to the introduction to the presentation that I have provided. Is that going to be projected somewhere or?

Okay, thank you, if we can jump to slide, the third slide or maybe if there's a -- okay, my presentation will talk about roughly three topics. We're on the third slide named agenda. The first discussion will be what is line ratings? Just to get the concept straight among the audience, and the participants of the meeting.

Then we'll talk about what the difference is between static and dynamic line rating. Obviously, ambient adjusted line rating comes in between. We'll also talk about the potential benefits and then the last question is what is missing? So, it will all be an introductory to what we're going to be discussing over the next few years.

Slide four -- so, what are line ratings? Line ratings is how much you can pass through a given transmission line -- how much power you can pass through and the transfer capability of any given lines is largely defined by two factors -- the physical capacity of the individual lines is the mic working? And also, the network topology.

The physical capacity of the overhead line is basically how much can you pass power through until the line gets too warm? When the line gets warm it expands because of resistive heating and how much space do you need to maintain from the line from touching the ground or touching the neighboring line to keep the line temperature within the annealing of the conductor, aluminum by itself, limiting the aging effects of heating and so on and so forth, which is all technical and engineering stuff.

But the important thing is the heating of the line is not only defined by the amount of power that flows, it's also defined by the ambient conditions. So, for example, in a cooler temperature you can potentially heat up the line more, because the ambient temperature will cool down the line.

Obviously, when it's more windier, there is cooling effects of the wind, so you can also have that, even if it's the same temperature during the daytime you get a lot of sun heating up the line, so it's probably safe to say that at nighttime you get a little bit more cooling effect, just because there's no direct sunlight at it.

That's what defines the capacity of the individual lines, but at the same time the amount of flow on the line, which we will not be discussing a lot today, is also dependent on the network topology.

The network topology will actually tell you how much flow is going into each individual line based on where the injection point is and where the withdrawal point is and how complex the network topology is.

The technology options that deal with network topology includes the phasing regulators that are in practice today. There's a lot of flexible, alternative current transmission as it's called, the FACTS devices, and there's also topology control, but we will not talk about these technologies and today we will stick to the dynamic line rating, and ambient adjusted line ratings which we'll go on to the next slide.

Slide 5, I'll talk about the difference between static and dynamic line rating. So, today's practice of trying to figure out how much power you can flow on a given line is typically done on a static line rating basis. What it does, it uses a very conservative assumption such as low wind, high temperature, high solar radiance, and try to figure out what is the safe level of power that can flow in a given line.

Another way of saying it -- it's like saying that in the winter in Boston, where I'm from, you get a lot of snow, so the highway speed is limited to 40 miles an hour so that no one -- or the odds of you getting in an accident is pretty much limited.

But we all know that even in the same wintertime, if it's a nice and sunny day and the road is dry, you can drive safely at a lot faster speed than 40 miles an hour.

But when it's snowy, you may go down to 40. The effect of static line rating today is similar to saying that the entire winter the highway limit is at 40.

Dynamic line rating adjusts this limit based on the ambient conditions. The ambient conditions can be the line temperature by itself, which controls the line sagging, or you can measure the line saggings, or it can be measured by the ambient conditions like the temperature, the humidity, the solar radiance, or the winds.

All of those effects that have a cooling effect. And there's a range -- there's a wide range of applications between the static line rating and the dynamic line rating. You can just look at wind, you can just look at temperature, you can just look at temperature and humidity combined and there's multiple ways of doing it.

There are also multiple ways of cutting it. You can look at it on a minute-by-minute basis, you can look at it on an hourly basis, you can look at it on a daily basis -- so, there's a whole wide-range but let's just stick to the bookends. There's static where you say the highway can only be driven at 40 miles an hour because we're anticipating that should it snow, that's what you need.

Then there's dynamic line rating that says today it's sunny so you can do 60 miles, tomorrow it's raining, so let's bring it down to 55 miles, the day after it's going to be very, very windy, although it's sunny so we're going to bring it down to 50, and whatever it may be.

Now, as an example of the benefit of dynamic line rating is that the high wind can actually lead to a higher cooling effect which means you can potentially send more power to a given overhead line. This is very beneficial, especially in the Midwest when there's a lot -- where there's a lot of wind being developed, because when there's strong wind the wind turbines are producing more power, and you want more transfer capability on the line.

Some of the DLR studies that my colleagues here on the panel have -- may discuss in Europe show that in general, DLR implementation will actually reduce the wind curtailment by roughly 15%.

Going to slide 6 -- there's a lot of commonalities and differences between static and dynamic line rating. They both use conservative assumptions, because even if given a certain condition of the power flow, the wind radiance, the temperature and whatever else there is, you don't want to be overly optimistic about it because the last thing you want is the line going out.

The maximum allowable temperature is likely going to be the same. If it's different, there's a question whether you're measuring things correctly, or whether you're judgment is correct or whether you trust the experience that you've done, you've had in the past versus the theoretical limitation -- that's a different discussion that I will not like to go into today.

But there are differences. Dynamic line rating, unlike static line rating, will require individual line unit specific data, measured along the line at the corridor. It applies different conditions to each of the individual lines because the lines are located at different locations, the weather conditions differ and the loading of the line -- the amount of power that flows differs.

Just as an example, the DOE ONCOR study that was done in 2013-2014 timeframe, assumes that the DLR can increase the line ratings by 5 to 25% compared to static line rating. But because DLR is variable, you need a forecast to implement it into the operations plan. That is something that's new, and that's something that's not practiced today under the static line rating.

Slide 7 will talk about the benefits. In general, when we talked about the sample projects and the pilot's that done worldwide, they tend to indicate that the benefits are in the tens to 100's of millions of dollars. That is very, very similar to the operational benefits that the RTOs bring.

PJM assumes that they are saving 100 million dollars on ancillary services -- they call grid services.

They also assume that the benefits of nodal congestion compared to the transmission relief is about 100 million. MISO similarly estimates there's about a 60 million dollar a year savings from ancillary services.

Dynamic line rating, just because it increases the line rating of a given line, tends to reduce congestion. The U.S. annual congestion cost is assumed to be in the 6 billion dollar range. The DOE/ONCOR study that estimates that if you can increase the line ratings by 10%, most of the congestion in the U.S. will be gone.

Entergy confirms that -- although their dynamic line rating test is mostly in the offbeat time, that the average line rating -- dynamic line rating will increase the capacity by 10% or so, so all together, we're talking about a significant potential of benefits.

It helps with renewable integration. Also, as the pace of decarbonization or 100% renewable energy comes in and that accelerates you may not have enough time to build additional lines, or the wind pattern may change over time and therefore building a new line may not be the long term solution.

So, it helps with renewable integration. It also helps with keeping up with the pace of change and finally, it is not a competition to building new lines. It's a compliment. When you build the new line, the new line is typically an EHB line, very high voltage line that has a lot of capacity. But the underlying system may not allow that high voltage line to carry all the -- or to produce all the benefits that it's supposed to.

But if you can add these line ratings and other operational technologies for the underlying lines, that will actually help you get more benefit from the new line. And you can also use it for bridging the gaps. For example, if it's going to take you five years to get the environmental assessment permission, you can use these technologies for the first five years until the final project comes in, or you can use it during the outages of construction, or even during the maintenance outages.

And there are other benefits that the panelists here will talk about as we go. Finally, the question is if it's so good, why is it not being widely deployed? So, one thing is that these technologies are relatively new. We did not have them 10 years ago.

Now, that doesn't mean that you cannot deploy them. The next question is are the incentives aligned? First off, the congestion costs are specifically passed through to the end customers, so the operators and the transmission owners may not have the proper incentives to relieve congestion or reduce curtailment.

The industry typically awards maintaining reliability over operational efficiency, so if the industry sees that changing operations is taking a risk, that's also going to work against the operations. And the transmission owners who -- especially are gaining sufficient returns through larger investments, may not want to look into these relatively smaller projects because they know that they can make more money through the larger investments.

So, should there be a benefit sharing mechanism? We talk about these benefits and also the incentives in a white paper where there's a link to it on this slide, but my colleague Rob, who will follow, will talk a little bit more about these incentives.

MR. KOLKMANN: Thank you Bruce. We'll next turn to Rob Gramlich.

MR. GRAMLICH: Alright thanks Dillon, thanks Bruce and thank you to Commissioners and staff who created this event and for your interest. We're thrilled this is happening for all the benefits and reasons that Bruce described. We think there's a lot of opportunity to deliver more energy over existing wires and that's very important for consumers and for reliability.

I am appearing here today on behalf of Grid Strategies, working for Advanced Transmission Technologies. The companies are listed. Many of them are on the panel. The American Wind Energy Association, ACOR, Americans for a

Clean Energy Grid and Advanced Energy Economy.

I'm going to give your brain a little break before we get four technical panelists following me to talk just a little more general policy and the importance of this issue, and some of their kind of regulatory policy considerations. Generally, the point I'm trying to make is the demand for transmission delivery is high and rising and the supply is not growing, so any way we can deliver more over existed wires is going to be more beneficial which is essentially what Commissioner Glick said.

If I were back in the role of a Commissioner's advisor, I might modify a couple of words that the Commissioner said. He said without impairing reliability and I would strike that and replace it with while improving reliability as well. So, just a minor detail some of the other panelists will get into that.

So, on this point about demand for transmission increasing, we see congestion on the rise again. It's a little bit cyclical as folks know. This Commission was very involved in getting multi-value projects in the Midwest, similar projects in SPP and then you consider ERCOT, California, other places. You know, we built a lot of transmission in the last 10 years and that reduced some congestion and curtailment.

Well, I don't see those big lines happening now or really in the works, and yet a lot of the resources are being developed in some of those areas and so these congestion costs that were below 4 billion in 2016 and over 5 billion a year in 2018, I see this trend increasing. This is just the RTO areas, if you consider the other third of the country congestion is you know, maybe closer to the 7-8 billion dollars a year range at this point.

There is obviously a resource transition going on. Wind and solar are the low-cost energy sources. This is the Lazard slide and I'm sure you've seen before, but when we have wind and solar unsubsidized in the 30's and 40's, there's going to be a lot of demand for these resources, and they tend to be located in different places which is often remote from load.

And you know, with retirements and new generation, or really any time you have a capital turnover in the generation stock, you're going to have generation in different places, and this particular time in history is no different, particularly for a lot of the wind development in the Midwest, you'll see there, but even within sub-regional areas, let's say upstate New York to downstate New York, or within some of these regions you have the same dynamic -- that the wind projects are not in the middle of the city obviously.

So, with all that generation development, certainly those investing in renewable energy pay a lot of attention to congestion and curtailment. This slide -- and I guess for those on the webcast, this is slide 6 with the heading being, "Growing Need for Transmission Delivery Capacity" that shows wind curtailment which again, it does kind of go up and down over time.

And you see it, you know, it spiked earlier in this decade, but then a lot of those large scale regional transmission plans came in, MVP plans were energized et cetera, but again, that trend is starting to reverse now and unless we get an MVP 2.0 which is something I hope we do, and other transmission planning initiatives going, I think we're going to see growing congestion and curtailment.

And just to say I think most panelists here are going to say look, we need to expand the grid for a lot of reasons as well, and in fact if you think more broadly, if you look at more than 5-10 years, we're really going to need a macro grid, and so we not only need to look at Order 1000 for regional planning, but we need to look at interregional planning, and in fact we need to look at inter -- interconnect planning.

So, but obviously it's very hard to build such lines, we don't even have a regulatory structure anywhere near up to the task of this type of macro grid, so hopefully we'll get there someday and hopefully we'll be looking at intraregional planning within RTOs to connect remote generation to load, but again, even those lines are very difficult to permitting the cost allocation, the planning, all major challenges.

That leads us back to we have this great need for transmission delivery capacity, and we have somewhat limited supply and difficulty expanding that supply. So, any way we can squeeze more power over existing wires, will be beneficial for consumers.

These are a set of technologies, the WATT Coalition, that I'm here representative as power flow control, topology optimization and dynamic line ratings companies, you could say storage is transmission fits in that category. There could be potentially others, we're not trying to limit what is included. We provided a definition in the Notice of Inquiry proceeding -- the other related docket, to trying to be open to whatever technologies are out there or may come along, but these are certainly three technologies that are ready to go and as you'll hear from the next -- the other panelists, they're being deployed more rapidly in other countries, in other places.

So, that point gets to this other issue of well, if they are ready to go, and of course, some of these technologies -- I mean dynamic line rating was well-known 10 years ago, but it's the implementation, the technologies and the particular approaches to it that has changed dramatically, and these other technologies are newer, so when Congress passed the -- in the Energy Policy Act of '05 and talked about expanding our use of existing wires, some of these technologies were not really ready to go, and the Commission didn't hear a lot about any of these technologies at that point.

But now in other countries and other places, a lot of these technologies are being widely deployed and so you kind of scratch your head and you say well why not here? Why are they not widely deployed in the United States? And to me, perhaps its my economics bias, it's a fundamental incentive problem, not an unsolvable one, but it's an issue where I mean the famous, you know, if you're an economist and you start and you study regulatory -- regulated industries, on day one the first thing you'll hear about is the Averch Johnson effect, and that's just basically if you earn your money from a return on invested capital, you're going to want to expand that capital -- expand the rate base.

And of course, that's how transmission is regulated in this country. So, if you're comparing, you know, a large new line to some of these technologies that costs two orders of magnitude less -- 1%, you know, it's just obviously less in your interest to do the cheaper work approach cost technology.

And you know, and there's all this debate, including in that other proceeding about whether we're talking about performance base rates or incentive regulation and to me that's -- it's just all regulation is incentive regulation, that's sort of a meaningless question, yes, you have you know, cost of service regulation of formula rates as one set of incentives, you know, a shared savings approach as another set of incentives, so any regulatory approach has its own incentives, so yes, we're definitely talking about the incentives that are in the regulatory structure.

And then the last quote there is a Nobel prize winning economist who look at the U.K. grid and their approach to electricity where a lot of these technologies are being deployed and found that the different incentives there are leading to deployment of a lot of these technologies and reducing congestion costs.

So, there are other ways of doing things. A lot of the groups here have been looking at what Australia does, what the British system does, and finding there are some lessons, and so once again, I didn't know until yesterday about this November conference, but I'm thrilled to hear about that where I think incentives will be more the focus.

So, I'll maybe wrap that section up now, but we can talk more at that time. But it does seem like that's a real opportunity. And of course, you might also say it's an obligation if you look at the Federal Power Act Section 219 B-3 it talks about specifically about, increasing the capacity and efficiency of existing transmission facilities.

Of course, there's a lot more expelled on expanding facilities and FERC's implementation with 679 and all the later orders of the last 15 years have been really related to grid expansion but there is this section there that in my view anyway, was never addressed.

So, again, in that other proceeding and perhaps for the subject of the November conference, the WATT Coalition, and some of the other parties I mentioned do have a specific proposal on sharing the savings. Basically, ideas -- if you look out and you can estimate that the congestion would be reduced by X, well let's let the utility keep 25% of X.

So, that's the basic concept and that's being discussed and debated in that notice of inquiry proceeding. And then I'll just close with this last point. I was pleased to see some of the panel topics for later in the day, but increasing the transparency -- this is something I'm hearing more from women solar developers, increasing the transparency will be very important. Currently, line rating methodologies are very opaque and inconsistent. Some are even saying that whether it's opacity and inconsistency, there's room for discrimination and manipulation of those ratings, so getting more transparency on the methodology will help all parties.

It's certainly consistent with the tradition of this Commission in promoting open access to make available transmission capacity available to loads, so that more market participants know and can trust about what's out there, what capacity is there and for example, what are the reasons for congestion?

Is it a thermal limitation or stability limitation? Obviously, the former is more conducive to dynamic line ratings. So, I think this Commission can play a role partly through today. I think NERC, IEEE and others can play a role in helping with that line rating methodology. I'll leave it there, thanks.

MR. KOLKMANN: Thanks Rob. We'll next turn to Joey Alexander from Ampacimon and we'll load up your slides.

MR. ALEXANDER: Thank you Rob. Thank you, Dillon. So, as Dillon mentioned I'm Joey Alexander with Ampacimon and I'll tell you just a brief bit about Ampacimon. There's a DLR solutions provider based in Belgium.

Had quite a bit of success and have recently moved into the American markets two years ago, back in 2017. Ampacimon's largest deployment is with a utility called Elia. So, a little bit about Elia. Elia is Belgium's TSO. They have over 8,700 kilometers of transmission lines, a peak load of 13,000 megawatts in the wintertime and important to this case, they operate on a two-day ahead trading market with France to the south and Netherlands to the north, okay?

So, a big question here is why did Elia decide to implement DLR? So, they were under a lot of pressure and time constraints in 2014. In the summer of 2014 Elia was going to have to shut down three of their four nuclear generation plants, and that represented the loss of about 3,000 megawatts, and that was due to various technical reasons.

Elia had an existing import capacity from France and Belgium of around 3,000 megawatts, so one-to-one there was a replacement for that generation, however, during the winter peak load, they saw that that import capacity was at a higher risk than their previous nuclear generation capacity would have been.

So, in order to be with that, they wanted to further increase the capability to import power from France and Netherlands. And they also wanted to increase the capability to pass those flows from north to south throughout the country to make sure that the entire country could be -- could make use of the extra power, okay.

So, what Elia decided to do -- they had already piloted our solution, Ampacimon's solution -- oh, I'm sorry.

MR. KOLKMANN: Part of the reason we're in this room is because the Commission room is under construction, so we're going to hear some light construction.

MR. ALEXANDER: Do I need to talk louder?

MR. KOLKMANN: I think you're okay.

MR. ALEXANDER: Good, okay, I'll talk a little bit louder. Alright, so Elia had already piloted Ampacimon DLR technology back in 2011, so it had proved out that it worked for them, that it was accurate. And since they only had a few months before the winter peak load, they had to do something quickly in order to increase the import capacity from France and from the Netherlands.

So, all in all they deployed DLR over 35 lines, 167 devices, ranging from 70 to 360 kilovolts. So, if you look at the top here, or look at the whole map, everything that is either purple or red are lines that are equipped with DLR. So, their objective was to put DLR on any and all lines that were constrained at different times.

So, lines that imported power from the

Netherlands or down here from France, they wanted to make sure they could implement a two-day ahead forecast of the DLR because that's what that market traded on, it's a two-day ahead capacity price.

In addition to that, they were bringing on new wind generation from offshore. They had some capacity to bring that generation on, but they knew that they were going to have to curtail a big part of that wind generation once it was online. So, DLR was implemented here as well to increase the capacity there and avoid the wind curtailment.

Another important part of this deployment was a comparison that they did between DLR and ambient adjusted ratings. So, we'll look at -- next we'll look at how the DLR solution works. That comparison of ambient adjusted versus DLR, and also the final results of whether or not they were able to increase the capacity that they were looking to.

And by the way, there's Elia has a website dedicated to this project. You can go there, and they have a pretty good depth of information there on this deployment and what was done and how it's currently working, okay.

So, first just quickly how DLR works for my specific company. So, there is a sensor that is mounted on the conductor. Typically, at least 5% away from the tower, but otherwise it doesn't really matter where you put this sensor. It's equipped with three accelerometers, very sensitive accelerometers that are able to pick-up on small vibrations in the conductor.

And those vibrations allow us to measure both line sag and perpendicular wind speed, so two very important characteristics to dynamic line rating. In terms of how this device is powered, it has a current transformer that goes around the conductor, so it's basically just powered off the conductor's magnetic field so there's no need for a battery or solar power.

It solves very quickly in about 15 minutes. You can choose to use either 4G LTE to communicate or satellite to communicate if you're in some really remote areas, like some customers in Canada who don't have cellular everywhere.

We use IEEE-738 and the CIGRE Technical Bulletin 207 in order to calculate realtime DLRN, also to forecast DLR. And then that information is fed into Ampacimon's HMI or the data is integrated into the utility's SCADA/EMS system through TASE2 or DNP3.

Okay, so the biggest question I get about our product is how does a vibration sensor tell you about the sag of a line? It doesn't make a lot of sense when you first think of it. And the analogy I think, that works best for me, is to imagine taking out your shoestring and then holding it tight between your hands.

If you pluck that shoestring, it's going to vibrate a certain frequency. If you loosen it a little bit, pluck it again, it's going to vibrate at a different frequency. And fundamentally, that's how vibration sensing let's you ascertain how much a line is sagging -- differences in frequency vibration.

And more importantly, if you look at the science behind it, you know, the equation for frequency relating to line characteristics and then sag relating to line characteristics, and you solve those two simultaneously, you come out with a value for sag that is only dependent on the frequency of vibration and the constant force of gravity.

So, we can detect sag by knowing the vibration alone. It gets a little bit more complicated than that behind the scenes, so we take the frequency record. There is a wave form and a harmonic analysis of that data in order to determine what the sag is. So, it gets technical behind the scenes but basically that's how it works. This is patented. It's very accurate, so we validated the accuracy of the sag to within plus or minus 1%.

And you know, since this doesn't rely on any line characteristics, there's no need to ever calibrate the device. Once it goes on, it stays accurate for the life of the device.

Okay, oh -- this animation is working. I didn't think it would work, okay good. So, you can see a little animation here. The device on there. The wind is blowing the line, right? There are the acceleration records. That's going into a frequency spectrum, so wave form analysis and then that's calculated into a sag value. That's essentially how it works on the back end.

Okay, good. So, besides measuring sag, the other key factor to this solution is measuring wind. So, if you think about all the different things that could possibly impact the temperature of the conductor and the capacity of the conductor, ambient temperature, the solar radiation, wind, and of course the current going through the line, wind is actually the most influential variable in cooling the line down.

So, perpendicular wind of 1 meter per second or 3 feet per second is responsible for 44% of that line's capacity. So, it's very important to know accurately what wind is being experienced by that line. And this device measures it two different ways. So, this is a cross section of a conductor. As the wind crosses over the line, it produces a turbulent flow on the other side.

That turbulent flow causes the line to vibrate in a very specific way. The accelerometers inside the device can pick-up on that vibration and determine the wind speed based on that. At higher wind speeds, the conductor will actually start to be displaced -- to swing, there's a swing angle.

Those accelerometers inside our device can pick-up on the swing angle and calculate wind speed from that as well. Okay. And going to the comparison of AAR and DLR that Elia conducted, and the reason why this goes behind wind is because the big reason these are different is because AAR doesn't really give you an accurate measurement of wind on the line.

It's really more based on ambient temperatures. So, AAR gives a less gain, DLR you get about two times more gain in general -- at least this is what Elia found out on this specific line. They were able to get two times more gain on average with respect to AAR.

The other side of the coin is that there are some cases where the ambient adjusted rating -- that's here in blue will actually be above the dynamic line rating, which is representative of the real conditions. So, if you're running your system by AAR, you may think you have higher capacity than you really do. And in this particular study, that happened about 5% of the time where if the utility were operating under AAR, they were actually going to put the line in overcapacity, okay?

And a big reason behind this is wind speed. So, we know that wind is the highest contributing factor to impacting the capacity of the line and AAR does not capture any of that wind effect. DLR can capture wind speeds down to the .5 meters per second range. This might sound like really the wind speed, but it actually can cool the line quite significantly.

And you know, weather-based methods cannot account for wind speeds that low, okay. So, Elia was able to successfully integrate the system into their SCATA. This particular screenshot is one of their ABB screenshots showing the one hour DLR forecast that they operate off of.

There's also a screen that they have for a two-day ahead forecast that they use in trading between France and between the Netherlands.

And finally, the results -- so, there's five years of cumulative data collected over Elia's systems for DLR. You see there we have the static line rating marked at 100%, this is the original rating for their lines and then data for 2014 for 2018. And during those five years, the DLR system increased capacity on their system by around 30%.

90% of the time it increased it 110 to 116%. And, it's also notable to say that 2% of the time the DLR value was actually less than the static value and that's because and knowing what the real-time conditions are on that line, sometimes your rating is lower than your static rating.

And it's good to know that because then you know that you could be in a situation where you can overcapacity your line. So, DLR not only gives you what you need to get extra capacity, it also helps you improve reliability and avoid risk of overcapacity.

So, you know, in the end Elia was able to get their 30% increase in import and operate their system safely and reliably throughout their winter peak time, and they're still using this system today, alright.

MR. KOLKMANN: Thank you Joey. We'll next turn to Jack McCall from Lindsey Manufacturing.

MR. MCCALL: If you can do the 16 by 9 one, it will probably show up better on the screen, thank you. My name is Jack McCall. I'm with Lindsey, we're a supplier to the industry for over 70 years. We've been supplying dynamic line rating and transmission capacity forecasting solutions for a number of years as well.

For a brief introduction on the dynamic line rating product that Lindsey makes, and this will kind of serve as a background to talk about forecast, which I'm going to focus on here. The product we make is called Smartline TCF, which stands for Transmission Capacity Forecasting.

Basically, the product is, you'll find with most dealer products, provides real-time instantaneous, dynamic line rating. By using direct measurement technologies, we make sure that we maintain clearance to ground limitations for all the transmission lines and we make sure that we're not violating any of the thermal limits of the transmission lines either.

The system can provide forecasts of line capacity of an hour or greater within the day, or if you want multiple day it can provide one day to one week forecasts. We can also provide complex forecast packages or bundles as may be required by an ISO or a TSO.

And the forecaster developed the 98% confidence factor by default, that can be adjusted up or down, if a TSO, or an ISO desires to do so.

The line sensors directly measure the critical perimeters of the line. It's a cloud-based software which can provide input directly to an EMS system. And it's a cyber-secure system and soon it's also going to be a transmission line asset management capability added to this as well since we are monitoring the transmission line.

Basically the way it works is on this slide, which should be the fourth slide, for anybody that's following along, there are sensors mounted on the transmission line as you can see to the left where we're pulling in life data from the transmission line.

That information is then matched up with live weather data which does two things. One, we compute an instantaneous, dynamic line rating, but we also use it to start building a learned conductor behavior model, so rather than assuming that we know how the conductor is going to behave, we learn over time how the conductor actually behaves for different line loading conditions and the prevailing weather conditions.

This then allows us to go to the next step, which is to take weather forecast data and use that built-up line model to develop line power capacity forecasts. So, we've already discussed this, but I'm just kind of going to re-establish it here to build the ground to forecasting -- what are the two key parameters that limit line ratings?

They are the clearance to ground -- that is from the lowest point of a conductor span to ground that's required by law to maintain certain clearances, and as has been established in numerous other conferences, a line is not safely operated unless electrical clearances are maintained, so that's a key factor here.

And also, conductor temperature -- if a conductor is run at too high of a temperature, it will start to anneal, which requires the conductor to be replaced. And it can be weak, and then weakened after that process as well, which is why you want to replace it, you don't want the conductor breaking.

What effects these parameters? As we've

discussed its weather. Line static ratings we've already heard, are traditionally based on very conservative weather conditions, other techniques such as seasonally adjusted ratings and ambient adjusted ratings, recognize weather does have an effect on the line capacity but both of these techniques depend primarily and really only on ambient temperature.

Wind has a much more significant impact on the line rating than ambient temperature does. This should not be considered a general rule of thumb to apply, but for a very common type of conductor used, a two-mile an hour change in wind speed has the same rating effect on the line as a 15 mile an hour change, or -- excuse me, as a 15 degree change in temperature.

So, ambient adjusted, you know, from winter to summer, may have 15 or maybe greater degree temperature change, but that's really only the equivalent change to a couple miles an hour change in wind speed.

So, how do we do this? So, we again -- as all the DLR technologies have the ability to monitor the line's parameters somehow, the parameter that we are -- or the sensor that we have, has a built in lighter unit which is continuously looking at the ground from the line and it's continuously measuring the actual distance from the belly of the span of the transmission line to the ground, so we actually know the clearance.

We're also measuring the conductor temperature in the line, so we know actually how hot the conductor is. We're measuring the current that's flowing through the line, so we're not depending upon a remote current reading, and then there's other sensors built-in as well -- tilt and roll vibrations, so on and so forth. So, again it's a self-powered device. It can be installed on a de-energized or energized line very quickly and it can use -- and right now we use primarily satellite radio communications because sometimes where you wish to try and monitor the line may not necessarily be a place where communication infrastructure is strong.

Nobody likes the visual pollution of transmission lines. Everybody wants them routed as far away as you can get from population centers, but it may be that those particular spans, or those particular portions of the lines are the portions that need to be monitored for dynamic line rating, so the satellite really gives you the ability of not having to worry about what the communication infrastructure is.

So, again, we take real-time weather, and you look at the actual conductor temperature, the clearance to ground, we call those the critical parameters for what a line rating is, and then you can start to develop an equation which describes the way the line behaves, and this is what helps you move forward.

So, let's take a look at dynamic line rating. So, this graph up here is data from an actual 138 kV line here in the United States. The green line at the bottom is the actual amount of power flowing through the lines. The Y axis, by the way, is MVA, so it's the amount of power in the line.

The yellow line is the line static rating. The red line in this particular utility is a four hour emergency rating that they've established on this line. And the blue line up above is the instantaneous DLR. So, this particular one is updated every 10 minutes with a new dynamic line rating.

Now, a couple things to pull from this. One is you'll see that the dynamic line rating for at least this two-day period of time, which is shown here, is significantly higher than the dynamic line rating or even the four hour rating of the line. And studies have shown -- decades of studies have shown, for a dynamic line rating, for different experiments and techniques that have been done.

We've heard from Ampacimon how this was backed up in Belgium, but you have 10 to 25% additional capacity is available, usually 95% of the time or more, which is very useful. The big problem is that dynamic line rating changes very rapidly. It changes quite erratically and its real-time.

So, let's pretend we were looking at that graph here and now I've blacked-off the area that I know was ahead and if this is the point in time that I'm actually looking at, and I'm saying this is my dynamic line rating. Now, I want to operate my line to this actual condition, how do I do that?

Well, I don't know what my next 10 minute dynamic line rating is going to be. Is it going to be this rating? Is it going to be up here? Is it going to be down there? Is it going to be somewhere? We don't actually know. Utilities have found that using real-time dynamic line rating is operationally difficult. It's kind of the same thing, getting back to traffic analogies, it's kind of like you're stuck in a traffic jam here in this photograph, and you pull up your phone and you start up Google Maps, and you look at your phone and it says you're caught in a traffic jam and you're not moving.

And you're like, yes, I know that, I'm caught in a traffic jam, I'm not moving. The information is highly accurate but it's absolutely useless, you can't do anything with it. You wanted to know before you got on that road that I shouldn't have gone on that road, I'd be caught in a traffic jam, that I should have taken a different path.

So, for dynamic line rating, real-time is too slow, which seems like an oxymoron, but it is. So, let's take a look at forecasting. Utilities are used to forecasting. Ever since the beginning of utilities, they have forecasted load because it varies with the weather. They say what's the weather going to be tomorrow, am I going to have more resistive strip heaters turned on? Is my air conditioning going to be turned on? Is it a weekend? So, on and so forth, what's my load going to be?

Today with renewable generation, every utility is forecasting how much wind power am I going to have tomorrow, what's my solar forecast going to be. Forecasting is very common, but generally transmission capacity is generally assumed as fixed utilities.

So, the next step of dynamic line rating is to take that and move it into the forecasting realm, which we're terming "transmission capacity forecasting," which basically is an advanced statistical process, just like any forecasting process is, that looks and it forecasts from an hour ahead or a day ahead, or some combination in between.

It can be done with very high confidence factors. And the use of local line measurements avoids weather only type systems and the errors that come from that. All forecasting systems can provide input directly into EMS systems. Most EMS systems today will take forecasts as an input and they combine the learning-based conductor behavior models with continuous forecasting techniques.

So, what does this actually look like? Going back to that same graph that we had before where we have the dynamic line rating in blue, we've added two more lines here. A line in orange and a line in green, look at the line in orange first. This is a two hour line forecast, so every two hours a new forecast is generated that says how much power can this line carry for the next two hours, knowing that there is a 98% confidence factor that my instantaneous DLR will not drop below what that forecast is, okay?

So, I'm getting my little thing here -- so, again, so you have a two hour forecast. At that dot point, we generate a new forecast and a new forecast and so on. The green line is the same except it's a 24-hour forecast that's just generated once a day, usually 24-hour forecasts will be updated on a more frequent basis than this, it may be updated every hour, every two hours, or every six hours, what have you.

But the way this chart was drawn, and for explanation purposes, is that these forecasts were drawn as forecasts, and then the real-time DLR, the blue line, was drawn in after the fact as it actually occurred.

So, the way to think of it is that the orange line is what we predicted would occur, and then the blue line is actually what did occur. And you can see forecasting can be done very, very accurately with dynamic line reading and forecasting techniques which are very common.

This is what makes it operationally useful for utilities to be able to move forward with the deployment. And per the DOE report, and for the FERC report that came out, DLR and transmission capacity forecasting together can provide numerous benefits right out of the report. It can provide congestion relief, which we've heard on that, increased resilience -- there's a lot we can talk on that, increased reliability -- a lot we can talk on that, enhanced market operations, situational awareness, curtailment reduction for wind power.

So, that's my introduction for you guys for forecasting transmission capacity.

MR. KOLKMANN: Thank you Jack. We will next turn to Hudson Gilmer of LineVision.

MR. GILMER: Actually, just keep that slide up for one second, I just wanted to make one more point on that slide that -- so, when Jack talked about that forecast, that orange line, it's actually the lower bound of a confidence interval of that forecast. Can you hear me okay? I thought

I heard tapping, so can you just verify that mic is on? Yeah, I think it's not, maybe -- a green light goes on, okay, can you hear me now? Alright, thanks.

So, I just wanted to add one point to the comments that Jack had made earlier on this slide and I'm not sure if we have a slide number here, but this is the one entitled "Transmission Capacity Forecasting".

And just to be clear, the orange line here, and keep me honest Jack, is basically the lower bound of a confidence interval of the forecast where the midpoint is actually probably close to that blue line, but then there would be another band, another upper band, so what this is doing is telling the operator that you've got a 90% or a 98%, I believe, confidence interval that the actual dynamic rating will be at or above that orange line. So, you know, this is a very conservative forecast.

MR. GENTLE: A very quick question, for any confidence you want you can come up with a forecast?

MR. GILMER: Correctly, certainly for LineVision and I believe for Ampacimon and for Lindsey, these are configurable confidence intervals and it's maybe a slight digression but there's an interesting discussion around weather for a day ahead forecast it makes sense to have for example, a 98% confidence interval, or if perhaps in the same way that we forecast weather for the day ahead markets, a 50% confidence interval is more appropriate.

So, I just want to make that clarification and then if you can pull up my slides. And while he's doing that, I just want to introduce, my name is Hudson Gilmer, Co-founder and CEO of LineVision and thank Commissioner Glick and the FERC staff for pulling this event together.

MR. GENTLE: I don't see it in there. I'm sorry about that.

MR. GILMER: I said that last night.

MR. GENTLE: I know you did.

MR. GILMER: Yeah, do you want to go to Jake, and I can see if I can -- yeah, why don't we do that. Maybe while it's doing that, we like traffic analogies and I just want to reinforce the analogy that Bruce made earlier because I think it does a great job of characterizing our current situation.

The way we operate our transmission grid today is that we set rating limits based on worse case weather assumptions. And as Bruce indicated, this is really like operating our interstate highway system with a 40 mile per hour limit. And maybe that made sense 50 years ago when we didn't have sensors and we didn't have advanced cloud-based analytics, but we do have those technologies now.

These systems have come a long way over the past 10 or so years and we really think there's a unique opportunity to bring the industry together, to bring system operators, utilities and the regulators and the vendors together to get more out of our existing grid.

Okay, so we've got the slides up. I'll move to slide number 2 and provide a quick introduction to LineVision. So LineVision is a relatively new company. We spun out of a company called Genscape a little over a year ago back in May of last year, but we have been incubating the business within Genscape for the previous three plus years.

But we're built on a technology -- a non-contact transmission line monitoring technology that was developed over the last 18 years, and between Genscape and LineVision, we have deployed over 5,000 monitors on transmission lines worldwide, so this is a well-proven and robust technology.

And the logic for spinning out LineVision was really that we wanted to create a company that was solely dedicated to providing the asset owners, providing the electric utilities with solutions to increase the capacity, increase the reliability and increase the flexibility of their transmission lines.

So, what are the applications that we provide to our customers? There's three, and only one is really focused on ratings. So, the first is what we call LineAware, and this is extending situational awareness for the utility to the transmission lines themselves.

Situational awareness has been an area that utilities have invested in considerably over the last decade or so, and if you walk into any modern control room, you'll see a wall of monitors, and you'll see data from all of the substations, and generally that data is coming from equipment within the substations, such as transformers, such as smart relays, such as synchrophasors.

But to date they really haven't had any visibility on the lines themselves. So, what LineAware does with our continuous monitoring is detect anomalies on the lines themselves and provide real-time alerts to the utility whenever there are situations that may pose either a risk to the asset or to public safety.

Conditions like clearance violations, when the line is hanging below a defined threshold, things like storm damage to the tower structure, galloping or ice building up on lines. So, this can really provide that end-to-end situational awareness to the utility and improve the overall reliability of the electric grid.

The second application is what we call LineRate and this is leveraging our monitoring to calculate dynamic line ratings and increased capacity on existing lines, typically between 15 and 40% over the static or seasonal ratings. So, in much the same way as Joey from Ampacimon and Jack from Lindsey described, we're using the exact same industry standard, IEEE 738 line rating calculations to calculate a steady stage or a real-time rating.

We're able to calculate short-term emergency ratings and that we're also able to incorporate forecasted weather data to forecast ratings with a defined confidence interval over the coming several days.

And then finally, we offer LineHealth, so Brattle Group did a study recently showing that over 50% of all circuit miles of transmission in the U.S. were built 40 or more years ago. In fact, we did an installation on a couple lines recently on lines that were built back in the 20's, so they're actually nearing 100 years old.

And utilities really haven't had a good way of assessing the current health of those assets. They have to resort, if they do test those assets, to what's called destructive testing, which is a very cumbersome and expensive process. It involves de-energizing a line, dropping those conductors to the ground, cutting out a section of the conductor and sending it off to a lab for what's called destructive testing.

So, what we're able to do with LineHealth is with the monitoring, we get very fine grained time series historical data. We're able to see and compare the actual condition of that line to the as built condition when it was originally designed and installed. And so, we can see if over time the line has annealed or stretched. And we can also see events that contribute to the aging and the loss of tinsel strings of those conductors. Factors like thermal cycling. Factors like heavy winds or galloping on the lines, and also ice building up on the lines.

We've had utilities say hey, we know there have been wildfires in fields underneath our lines, and we're still operating these lines, but we don't have a good sense of whether they're safe to operate and you only need to look at the recent events in California with the wildfires and the PG&E bankruptcy to know that utilities need better information on the actual condition of their lines to help them extent the useful life of healthy lines, but also to prioritize maintenance or renewal decisions on lines that may need work.

So, how are we doing this? The system is a little bit -- it's a non-contact system that actually mounts on the tower. So, we're using two key sensors. One is a patented electromagnetic field, or EMF sensor that monitors the electrical properties of the line, most importantly the loading or the current on the line.

And secondly, we use an optical -- a scanning optical sensor, that looks up at the conductors as you see in this image and is able to get hundreds of data points on each of the conductors, so a single system is able to see all three conductors for a single circuit, or in the case of a dual circuit where you've got six conductors, it can see all six of those conductors and then we digitally reconstruct that entire caton area and create a digital twin of the asset.

And then very similar to the systems from Ampacimon and from Lindsey, we're able to take that data through typically an LTE data connection or satellite if necessary, bring it into our cloud, run the analytics and then deliver that data through either a secure web interface or an integration with the clients EMS system or pi historian.

So, now I want to switch gears a little bit and I think there's -- and talk about the differences between static ratings and ambient adjusted ratings and dynamic ratings. As you saw on the previous slide, ambient adjusted ratings -- they have the advantage that they're low cost, they're easy to implement, there is no physical equipment that's required at each site.

But if you actually consider the cost of dynamic rating, dynamic line rating systems relative to the cost of installing a new line or reconductoring a line, dynamic line rating systems are actually incredibly cost-effective relative to their benefits.

The number that we typically cite is a DLR system costs about 1% of the cost of reconductoring a line, or less than half the percent of the cost of building a new line. And then if we look at incremental capacity -- ambient adjusted ratings benefit solely from the adjustment of the temperature based on the nearest weather station, and so that can provide a few percent of additional capacity.

Generally, 1% additional capacity for each degree Celsius of reduced temperature below the static assumption. Whereas, dynamic line ratings -- because we incorporate wind, have typically between 15 and 40% additional capacity that we can offer.

And there's another point here that I think is often overlooked. It's not just about how much capacity is available, but the question is also is that capacity provided when the grid needs it the most?

If you think about ambient adjusted ratings, they take advantage of the reduction in temperature, but that reduction in temperature typically happens during the overnight hours when the grid is least loaded and least likely to be congested.

Whereas, dynamic line ratings actually have a beautiful coincidence of unlocking the additional capacity when the grid needs it the most. And this is because of two factors. One is that a significant percentage of congestion on the grid, and a growing percent is wind driven congestion. We have pockets of wind and when all those wind farms in a given region are spinning, then it creates congestion on the lines that bring that wind to the load centers.

But if we installed dynamic line ratings on those lines that connect the wind farms, that same wind that's spinning the turbines is also cooling the lines and unblocking or removing those bottlenecks.

And the second factor is that at the height of the lines, wind speeds are actually greater during the daytime hours than they are during the overnight periods, so we see higher dynamic line ratings during the daytime.

And then finally, the benefits of dynamic line ratings extend beyond simply the additional capacity. We're able to provide greater reliability, greater resilience on the grid through situational awareness and giving utilities that end to end situational awareness and also helping them move from traditional operate to failure, or time-based asset management approaches to condition-based asset management through our line health asset -- asset health monitoring.

So, I want to close -- one of the topics that was -- or questions that was raised for this panel was what we see as the expected future adoption of dynamic line ratings.

And if you look at a lot of the reports that are provided, it looks at DLR as a technique for addressing the most highly loaded or highly congested lines.

And while that's a great place to start, we actually believe it's only a matter of time before dynamic line ratings become standard on every transmission line. The vendors you see here are working to reduce the cost and improve the functionality and improve the benefits of these systems and I think for the utilities once they overcome that initial hurdle of the data integration and deployment, it becomes actually preferable for them to have very consistent deployment throughout the system.

So, we look forward over the next couple days to working on moving towards that adoption, thank you.

MR. KOLKMANN: Thanks Hudson, and we'll next turn to Jake Gentle from Idaho National Laboratory, thanks Jake.

MR. GENTLE: Hi, thank you. So, as you load the slides I wanted to thank the Commission for putting this together as well as FERC staff for not only assisting in pulling this together, but you know, shepherding all of the material and the people as we enter the building.

And I want to point back to a 2017 dynamic line rating workshop that we held at Idaho National Laboratory in Idaho Falls. I appreciate back then the ability for FERC and NERC and others to attend. I'm really sure that the conversation is not only continued but expanded, and so I think there's a lot of colleagues on this panel session that helped drive some of that pressure as well and I appreciate that because taking science to market is not always easy.

So, I want to thank my colleagues at Idaho National Laboratory, as well as the National Oceanic and Atmospheric Administration, so Ken Fenton is in the room here, so he can help answer any questions later as we talk about meteorology, as well as Department of Energy.

So, a couple of the reports that have been cited here were funded through the Department of Energy. And all of my work is funded by the Department of Energy Wind Energy Technology Office.

I'm not going to spend a lot of time on some of these slides because it's been talked about and I think we want to catch up and let the audience ask questions, so first off I want to say of all the technologies and approaches -- they all are based on standards.

And those standards have been around for a long time. They evolved over time as well, but they have a basis. There are many types of measurements that can be applied in a line rating use, whether it be direct or indirect, whether it be weather-based or conductor-based.

There are two questions. There's one question really that I posed under that third bullet for direct measurements, whether that would be weather, temperature, sag, distance to ground, are they placed at key locations? How do you know where to place those?

The second is testing and careful calibration of sensors are required. Are you asking the right questions? Prove to me that it works. And you look at -- if you look at weather-based only solution, one weather station is not enough. Going to a website and putting in that net longs and getting weather station date is not enough.

I'll explain why. This is where weather enters the equations. These are the same equations whether you look at IEEE 738 or C grade technical brochures, its throughout all of the equations. The physics behind how you rate a line require weather input.

We've talked about how you might use that out plan rating. Everybody in the room has a different use case guaranteed. You'll have a different driving force for why you would want to implement dynamic line rating.

Two points -- if you consider your static assumptions, where did they come from? How does current weather trends map back to when you established your static rating assumption?

Second -- how does preventing wind compare to transmission line direction? Using a normalizing of incidents, whether it be parallel perpendicular, your lines are not always the same line as met throughout your entire service territory.

So, consider applying your ratings at least to your lowest angled incidents, so more parallel. If you're not tracking where all of your lines and know what they are throughout your system, you may consider that angle of incidents.

The point of my talk today is to talk about forecasting and in order to forecast a rating -- because ratings can't be measured, you have to look at the weather conditions. You can ground truth that by operational technologies that look at direct conductor behavior and that's critical, you need that.

In order to forecast the rating, you need to forecast the weather conditions that would drive the rating. I'm going to talk about one particular model. This is the high resolution rapid refresh model. This is owned and maintained by NOAA. The data is free, so potentially you go to the website and extract it.

It's on a three kilometer grid spacing and then temporal resolution has been increased. It used to be 18 hours, it's now 36 hours, so from zero to 36 hours, you're getting an update every hour with 15 minute resolution within the hour.

There are other models that go out further in time, but they also increase in that spatial, so 12 kilometers versus 13 kilometers, et cetera.

We saw for right the HERR model is most applicable for dynamic line ratings because it allows you to have that day ahead and even a little bit further out within intra-hours as well, so if you want to go 15 minute interval updates, you can. If you want to go 24 hours, you can.

There's a timeline in which some of the different weather forecasts for regional mesoscale models can be applied. There are overlaps by design. To go to the details specifically of one of our studies use cases, this is based on 45 weather stations in an area within Idaho that has about 450 miles of transmission line.

All of our work presented here today has been published in various forms, whether it be C grade session or grid of the future or IEEE transaction journals or conferences, so the details behind all this can be found out there in literature. I'm just trying to show you the snapshots of those studies.

So, essentially, we've got four ratings here. We've got summer, fall, winter and spring. That's the gray bars. The red dots are effectively the 3 hour ahead daily minimum. So, if you take throughout the 24 hours all of the 3 hours ahead forecasts -- we want to go 3 hours ahead because we didn't want to look at 1 hour which, you know, is different than 24 hours.

We wanted to look farther enough out in time that the model starts to become more accurate. You know, zero to 1 hour, zero to 1 and hour, some of these forecast models aren't as good. You know, you might lean on persistence.

So, effectively we looked at the 3 hours ahead forecast, we've picked the daily minimum, and we've applied that over the course of a year. Each one of those red dots represents a single day. The minimum of all 450 miles of the line and you know, 2,600 square miles that we did the study on, that takes the daily minimum as calculated using a 3 hour ahead forecast.

We applied a 98th percentile threshold to all of the HRRR data points. If you look at 18 hours out, the way that the HRRR model operates, its error is about the same as the 3 hours. It's a really flat RMSE value as it goes out in time.

But we can do better, right? Physics-based models are getting better and better over time, better at continually being trained and updated and approved for applications. But we have local observations in a lot of instances, so why not apply them to do some bias correction?

Effectively what I'm showing here is the conductor -- the ambient air temperature bias correction applied to all 45 weather stations across that 1 year period, which leads to a new plot on the right.

Effectively you need local observations to remove those biases. Statistics will only get you so far. This is a blown up version of that and I added -- well, Ken added some real-time ratings based on the local observations. So, again this is the minimum of that same 1 year period of daily minimums, each circle, so that's the difference between the actual measured weather data versus the HRRR forecast data for the same period in time that you're forecasting to.

There are instances in there, which is hard to see, but there are instances in there where the actual weather data, even if you apply a 98 percentile, there is still 2% of the time that you should be below, right? So, there's measured local observations that would have led to a lower rating than you're forecasted.

It's not just weather that drives some of these conversations, its terrain. Terrain drives climatology. Terrain drives span distance, structure height, tension, et cetera. Whether you have dead ends every structure or you have dead ends every 50th structure.

All of that matters when you're considering a line rating. So, what these two plots show you on the left is the histogram for that same 1 year period of time in a different location where we've taken about 10 miles of transmission line over very complex terrain and we've identified each span, based on weather calculations, each span that would have been "that limiting span".

So, this helps you drive the conversation around where do you place your ground truthing, your direct measurement devices. This could be weather stations or anything else. With all this knowledge, where do you choose to monitor? Is it just easy access right-of-way? Is it the most critical span, meaning it's crossing a highway or some other sensitive area?

How do you know where that location is? If you're looking at line ratings, weather drives line ratings. At any given time, your weather conditions can be different across all spans, so the plot on the right is just a single instance snapshot. This would be the wind direction or the arrows, and you know, the magnitude of the wind speed would be the length of the line, or the length of the arrow.

So, within 10 miles of line you can see the angle direction -- the wind angle at that single point. There's a lot of case studies, you know, dynamic planning is not new, and I think all of these have a common theme -- it's valuable. It doesn't matter what methodology you choose to use, there are value adds by having dynamic line rating information.

The difficulty is each one of these case studies has a different set of conditions -- a different market, a different structure, a different conductor, a different year, a different climatology in general. Totally different terrain, surface roughness -- all of those parameters are different when you look at all these locations and they have to be different, right? There's no single instance of a conductor that's the same.

So, I want to drive into the physics basically behind some of the comments made today which is wind speed and wind direction matter most. I think that's been well documented. But I wanted to show you a couple plots that show you what those magnitudes could be.

So, looking on the top left plot, effectively that's as you sweep wind speed, hold all of the other parameters' constant from zero to 20 meters per second. You can see the increase in ampacity as you sweep that wind speed.

From zero to 5 meters per second is when you get the most change. After that you start flattening out the curve there. There's four plots -- two of them are for one conductor type, a draped, another two are for another conductor type, a bittern and they're each operated at 80 degree Celsius as its maximum operating conductor temperature versus 200 degrees Celsius as its maximum operating conductor temperature.

And I asked this question a while back. ACSR at 200 degrees Celsius -- are you kidding me? Those utilities are operating them right now at 180-190 degrees Celsius, so these curves are very valuable.

Compared to wind direction, you can see parallel wind versus perpendicular wind. It repeats itself as you flip on the other side of the wind rows, the angled then since matters. One thing I wanted to mention is the plots on the right, which are hard to quite understand without you know, probably 10 slides ahead of this, which are probably in a different slide deck.

But effectively, the reason why you have a shaded reason is because there are variances in the accuracy of the measurement types, whether it be a cup anemometer, lowest end possible, cheapest 80 dollar device versus ultrasonic anemometer, where you're measuring wind speeds at 1.% meters per second accuracy, .01 meters per second accuracy.

So, the ability to calculate a rating depends on the devices you install. So, when you ask, you know, whether service provides that are providing weather data, understand the equipment they're using because it matters in the rating, alright, so the precision of that device, or the accuracy of that device can vary over time.

Effectively the same scale to Steve's parameters. You can see the slope of the curve is different. Temperature and solar flex matter, but they don't have the same driver or influence over the ratings as wind speed direction.

We talked about ambient adjusted versus dynamic line rating and on a plot there's four lines up here. The first line I'll reference is the static rating based on the units here. If I'm correct, they should be feet per second, but and that shouldn't be amps per meter square, it should be watts per meter square, nonetheless.

So, you've got ambient adjusted using just ambient air temperature. That's the first plot there. The second one I added ambient adjusted with air temperature, plus ambient adjusted with solar, so if you take into consideration of whether it be time of day or measured, this is measured plots per square meter. You can see how they track. They tend over time to be very similar.

And I also added a 1 hour average over this one week period of using IEEE 738 study state rating, so if you take the instantaneous rating using dynamic line rating parameters measured within that hour and you average it, there are a lot of other ways, I just wanted to pick one. You can take the minimum. You can take some other 98% tally, you can do whatever, but I just wanted to take an average over that 1 hour period, and we plotted the dynamic line rating, if you will, or that one week period.

The thing I want to note is down here, right? All of these instances where, you know, I hand-picked a week where it did dip below, but if you're just looking at ambient adjusted, whether you use just temperature, ambient air temperature, or you add in some more complexity by adding solar or time of day calculation, you're more than likely missing some of these instances.

And the ability to include ambient adjusted versus full on dynamic line rating, you're just adding two more variables -- wind speed and direction. Where do you get that data? How do you trust it? That's the complexity. The ability to use it is no different.

Lastly, in the physics-based conversation, as you go from operating lines that say 80 or 90 degree Celsius as your maximum conductor temp to say 200 degrees Celsius as your high temp of low sag conductors come onto the market, this conversation about dynamic line rating needs to be revisited from your static rating assumptions, and your line rating assumptions because emissivity and abstractivity change at higher operating temperatures. The impacting which those two parameters matter.

Where are we headed now? We're continuing to work with all partners on the panel here as well as partners within the audience and on the phone. We really want to focus in on the physics and different regions of the country have different physics, different climatologies.

Here are four locations, there's multiple lines that we're looking at doing studies against and we're really mapping the performance of weather forecast models against local observations -- how do you apply them to line ratings?

Last but not least, cybersecurity is mentioned in here several times and I appreciate the FERC staff report commenting on NERC and other cybersecurity concerns. I think that's an area of necessity. As utilities are going to be basing their operations, whether it be real-time or forecasted off of technologies, advanced technologies, cybersecurity is a major concern.

And again, I want to thank the funders and those who have paid for me to be here.

MR. KOLKMANN: Thanks. Jake. I'll start off with the first question and we can go from there. Are panelists aware of any research or testing to reach the non-wires transmission equipment more dynamically? The substation equipment for example? Do panelists know of any research on that?

MR. GENTLE: I can definitely start from a research angle, yes. There is significant research being done, a lot of different technologies, you know, whether it be sub C cable for example, underground cable. They have different research angles if you will, things to consider, versus overhead lines which I'm going to guess almost everything on this panel is overhead barrel conductor as well as transformer ratings.

Transformer ratings -- they're a much more expensive asset, lead times are much more difficult if one were to be damaged, so the sensitivity around deviating from what's worked to maybe something a little more aggressive could be more aggressive, just the higher risk. There's a higher consequence if you're wrong.

MR. KOLKMANN: Did you want to ask a question? You can go, we're running behind time.

UNIDENTIIFED SPEAKER: Quickly, a couple of questions. Mr. Gramlich, you mentioned you talked about transparency and the need for it, the lack of transparency can actually impair actual engagement because of utility discrimination. Can you provide examples about how transparency can lead to discrimination?

MR. GRAMLICH: Well, I'm not offering specific examples, I'd probably share if I knew of them, but sure, I mean in theory, I mean if it's a total black box, I mean if you're giving utilities response to this whole conference is hey, this is my job and I'm not even going to tell you how I do it.

To me that's not acceptable if you're a transmission customer seeking access to that transmission capacity, you know, that violates 25 plus years of FERC tradition of trying to determine what the available transmission capacity is and make it available to the market and that was done for both you know, just and reasonable rate reasons, but also discrimination reasons.

And you know, depending on the utility's structure and incentives, they may wish to hold capacity back, and of course, utilities and RTOs are going to be, by nature, conservative, and hold capacity back as probably a general tendency. But again, if the actual capacity can really be measured, and if over time utilities can get more comfortable, making sure that reliability is upheld in the quality of the line and the line health. If it remains intact, then you know, that's going to improve efficiency.

MR. KOLKMANN: That's fine, we're running a little behind time, so we will close it there and we will resume again at 11 o'clock. And thank you to all the panelists for being here, this is a very informative discussion.

(Break).

MR. KOLKMANN: Please find your seats. We're going to get started. Welcome to Panel 2. Panel 2 will discuss the Benefits and Challenges to DLR and AAR Implementation. The panel features a broad array of industry experts who will share case studies, learn about the practice, to transmission lines, advanced transmission line rating approaches.

Panel 2 will touch on how TLR's might be incentivized and on whether periodic studies, cost effectiveness of dynamic line rating and adjusted lines would be helpful. I want to introduce the panelists. Thank you for being here.

Starting from my right, audience's left we have Swarj Jammalama, and I'm sorry. He's from Apex Clean Energy. We have Francisco Velez from Dominion. We have Chad Thompson from ERCOT. We have Babak Enayati, he's from National Grid. We have Charlie Xu, from NYPA. We have Howard Gugel from NERC and we have Shaun Murphy from PJM. Thank you all for being here. I'll start with Swarj.

MR. JAMMALAMA: So, the Apex team has been investigating advanced transmission technologies since 2015 to maximize available transmission capacity and enable the new -- as we looked at it from -- both being from a different perspective and also from market congestion relief perspective, and definitely based on what we're seeing in the changing fuel, and aging infrastructure, we see these technologies and a combination of just also local control devices, and other advanced technologies to accommodate the changing fuels and some aging infrastructure.

So, moving directly into the barriers and limitations, despite the lost potential for realizing cost savings and its ability to increase reliability, several barriers or limitations have existed that prevents a widespread option.

And in general, it is the hesitation mostly with largely utility -- in this field, they use unfamiliar technology. One common concern is the accuracy and the reliability of the DLR data, and the related lack of operation knowledge and experience with the technology with just changing quickly.

Also, in regulated markets and in vertically integrated environments, transmission is primarily seen as a median to serve load obligations, and no incentive exists to open up additional transmission capacity if no additional revenue is generated from its own generators load.

Talking about a few opportunities that we see either as a market participant or as a generation developer, is additional capacity for DLR's and relieve the congestion that results in congestion charges in the market. If the congestion is regular and consistent, DLR may also reduce our further need to replace our new construction or cap x projects.

Additional capacity also allows for larger transmission capacity which enables delivery to the more regions and settlement locations that wouldn't have been possible before, that also includes behavior and creates additional liquidity at some of those new settlement locations.

And the capacity about the static DLR rating can be monetized in multiple ways and one of them can be a simple new transmission product for the incremental transmission unlocked by the DRL facility.

So, the DLR in this light can be viewed as a non-transmission alternative, but any power transmitted down this virtual path can be monetized either as a scheduled market product, or as a bilateral product in markets in decentralized markets.

Why LSC can lead to cost savings, the savings may not accrue for the financial benefit of the transmission owners to sufficiently incentivize them to deploy such systems and other advanced technologies like power flow controls, et cetera. This is due in part to the financial regulated structure, rate regulated utilities.

Transmission owners generally can recover their expenditures for transmission under FERC rules, however, under the current regulatory after service model, it's more about the transmission owners receiving the return on the

Cap x investors rather than the quality of the additional capacity provided by the existing transmission system.

There really doesn't exist an incentive to maximize the transmission system. And from an ISO or RTO market perspective, most jobs the ISO philosophy is behind optimizing the structures to serve -- to bring the least path economic generator to the load with tender limitations of the transmission system, and this is where the transmission system needs to be a little more dynamic.

If you're thinking about optimizing generation resources to load, but we also have to think about maximizing, while maximizing the existing transmission system and the best ways to do it. And moving along to challenges and integration to a centralized system.

DLR as we have mentioned before, does have significant benefits, but it only does so on the centralized basis when dispatch operators can apply those maximized ratings to standard operations from their regional control centers.

Stand alone DLR solutions can provide both time and look ahead, a day ahead forecast. The ultimate destination for DLR solution obviously is integration of the control room for the systems. Typically, the DLR single server can be configured to send standard tele-control frames to the SCATA front and acquisition units. These frames can then be processed for display and calculation, and however utilities see that the associates use the data.

ISOs have evolved a lot on technology since they initially started operations. Today they have successfully implemented online or real-time stability analysis, or tools that can in real-time access the limitations of the system to maximize flow on key constrained facilities.

This has led to an increase on pre-established system operating limits and in some instances, interconnecting reliability operating that's on the system. The market has significantly benefitted from these tools, especially when in incentives, they have been exported to places that have been constrained on pre-existing calculating limits is real-time tools are brought in additional margin that the utilities have been able -- the ISOs have been able to work on and it's resulted in reduced congestion in the market.

From a communication's perspective, I'd just like to finish up with the communication's part and cybersecurity considerations, just to speak on a high level layer. The input data, such as weather patterns, their circuit load and infrastructure design and measurements are public domain. Proprietary, if not confidential, and must be managed accordingly.

Output data, like conditions, rating and forecasts are both proprietary and confidential. To ensure provisions of data confidentiality, integrity and availability, the utility -- the ISO and the vendor can implement secure communication with access control and restrictions and industry can have favored deployment of software of the service model, both of these are center secured costs.

Just to conclude, the DLR enabled by diverse technology has a potential to reduce costs to the American ratepayers and the businesses by alleviating congestion on transmission lines and improving safety and reliability for increased situational awareness.

Thank you for the opportunity for this Conference.

MR. KOLKMANN: Thanks for your comments. Before we go further, I do want to welcome both the Chairman and Commissioner McNamee, thank you for being here. Next, we have Francisco Velez from Dominion. Take it away.

MR. VELEZ: Hello, good morning, my name is Francisco Velez and I'm the manager of electric transmission reliability at Dominion Energy Virginia. As manager of electric transmission reliability, I am responsible for ensuring the electric performance of a transmission network and developing programs to improve our reliability metrics.

Dominion Energy would like to thank the FERC staff for organizing this Technical Conference on the potential use of dynamic line ratings and ambient adjusted line ratings. Dominion Energy Virginia appreciates the background information contained in the FERC Technical White Paper titled, "Managing Transmission Line Rating," and the effort that went into preparing the paper.

The pilots mentioned in the paper and the reports listed as references gives us a wide perspective of the benefits and challenges of using dynamic and ambient adjusted line ratings. Upon joining PJM in 2005, Dominion Energy Virginia adopted and currently uses PJM's ambient adjusted rating methodology.

The company's rating process for transmission line facilities take into account all the elements that comprise the line, including those at the terminal stations. The ratings process produces facility ratings for normal operating conditions, whereby facilities can be operated continuously with acceptable equipment loss of life for nine ambient temperatures between 32 and 104 degrees Fahrenheit.

These ratings information is communicated electronically to PJM.

In our system operator center, shift supervisors adjust line ratings under the highest temperature setting according to the temperature gradients across the service territory in real-time. The ambient adjusted ratings used in real-time operations are validated and implemented in a fashion that allows reasonable and necessary reliability margins for the safe and long-term operation of our system while allowing the maximum line capacity to be used going through ambient temperature.

The operational experiences at Dominion Energy Virginia system operator planning and operation procedures have shown its transmission system is more frequently voltage constrained than thermally constrained in real-time operations and the benefits of having dynamic line ratings might not materialize in real-time operations.

However, Dominion Energy Virginia does recognize the potential benefits of having dynamic line ratings on its most congested regions in terms of allowing more flow on the transmission line to obtain higher efficiency of those transmission assets.

Dominion Energy Virginia has partnered with different dynamic line ratings providers to install pilot sensors and assess to provide line rating data. The pilots have been focused on the evaluation of the sensor installation and validation of the dynamic data provided by these sensors.

Currently, we're testing two different line sensor products. The first one is a ground based sensor, manufactured by LineVision, which is currently providing measurements of ampacity loading, ground clearance, conductor temperature, power flow, and dynamic line rating.

We are also working with EPRI to install three sensors on three different 500 kV transmission lines for a 4 year long pilot program. These sensors would provide similar information as the LineVision unit but using a different methodology. With these pilots, Dominion energy Virginia expects to gain experience in the installation and data management/validation of the DLR systems.

Even with the execution of these pilot programs, Dominion Energy Virginia foresees some challenges in the implementation of a full DLR system. First, currently, Dominion Energy Virginia's EMS system, does not have the ability to incorporate DLR data.

And while we understand PJM has the capability, we believe PJM or none of the operators have actually tried to use this capability.

Second, a DLR system might introduce uncertainty to operations due to unforeseeable weather conditions and terrain discrepancies. Third, the opportunity to realize increased line facility capacity through the use of higher ambient wind speeds may be limited by substation terminal equipment.

Fourth, the line and terminal equipment that comprise a line facility, including line switches, line leads, wave traps, substation conductors, and underground line segments have different thermal characteristics than a line conductor which may make full DLR implementation difficult to achieve.

Dominion Energy Virginia supports the FERC staff on their intentions and actions to study the benefits that DLR can bring to the electric transmission industry. Dominion Energy Virginia believes that the experience and learning opportunities obtained from the pilot programs referenced in the staff white paper and Dominion Energy Virginia's own pilot programs can facilitate the adoption of this technology into our system operations.

However, Dominion Energy Virginia believes more pilot programs and studies are needed in order to gain more operating experience about the installation, reliability and use of DLR systems.

Dominion Energy Virginia is open to studying our most congested transmission lines to determine how DLR can be cost effective and feasible with existing system constraints. Thank you for the opportunity to provide comments.

MR. KOLKMANN: Thank you. We'll next turn to Chad Thompson from ERCOT. Thanks Chad.

MR. THOMPSON: Good morning, my name is Chad Thompson and I am the Senior Manager of Operations Support at ERCOT. In this role, I am responsible for outage coordination, next-day studies and engineering support for ERCOT's real-time operations.

ERCOT began using Ambient Temperature-Adjusted line ratings of AAR's in 2005, and these ratings are used in both ERCOT's real-time network analyses like state estimator and real-time contingency analysis, as well as its operational off-line studies.

Additionally, ERCOT's forward-market applications also consider dynamic ratings. The ERCOT Operations Model includes nearly 7,000 transmission lines which are 60kV and above higher voltage. And approximately two-thirds of those lines are dynamically rated.

For a line to be dynamically rated, transmission service providers submit a network model update request to ERCOT which includes a static table of temperature-adjusted ratings at 5 degree Fahrenheit increments.

ERCOT incorporates those model update requests through its weekly network model database load process. And dynamic rating update requests can also be implemented in real-time as needed. The temperature in the table is compared to the temperature in the ERCOT weather forecast for the region where that line is located, and the corresponding rating is used for that study or real-time condition.

TSP's have the option to use the static table for their real-time ratings or provide a telemetered rating value as calculated by their systems, currently the ERCOT. ERCOT will use the telemetered value first, and default back to the static table in the event the telemetry is interrupted.

As a result of this implementation, ERCOT has observed a decrease in real-time congestion, as additional transmission capacity on these lines is available during off-line periods. In 2010, ERCOT published an article in the IEEE Power & Energy Magazine, which illustrated some of the congestion benefits that AARs can provide.

By making dynamic line rating information available to market participants, the increased awareness of the additional capacity of these lines can help market participants make more informed financial decisions with respect to perceived transmission congestion.

AARs do have some challenges, however those challenges are very similar to those observed on non-dynamically rated lines. For example, when a dynamically rated line is upgraded, the TSP may fail to update the rating information in the network model or in the TSP's ICCP telemetry may fail as well.

As long as the rating information in the network model is correct, and the data's telemetry quality is good -- well, ERCOT's not going to have any indication that the rating is no longer correct.

But when these discrepancies are discovered, ERCOT quickly works with the TSP to correct the model, in real-time, but significant congestion may have occurred during that time.

Another issue is related to lines that have joint or co-ownership. For their own reasons, a TSP may rate its portion of a line different from the other ends that the other TSP may own, and ERCOT uses the most conservative of the ratings that are provided and that has caused some confusion with our market participants in the past with regards to which rating is correct.

Overall, ERCOT has experienced significant benefit to its implementation of AARs. ERCOT is pleased to be part of this panel and to share any further details of its experience with AARs. I would be happy to answer any questions you may have.

MR. KOLKMANN: Thanks Chad. We will next turn to Babak Enayati, from National Grid.

MR. ENAYATI: Good morning. Thank you for the opportunity to participate in this panel session. My name is Babak Enayati with National Grid. I'm the manager of the

Technology Deployment team.

With an electricity network of roughly 9,000 miles of lines and almost 400 transmission substations, National Grid is one of the largest transmission owners, operating in the OSO New England and New York ISO or NYISO control areas.

National Grid plans and operates its U.S. transmission network based on seasonal ratings in New England, on a case by case basis, upon request from ISO New England, day ahead forecast ambient adjusted rating or AAR, may be considered for reliable transmission operation.

In New York, National Grid's electric transmission operations may consider real-time temperature based rating for reliable grid operation of the transmission system, but this is not considered in the day ahead capacity forecast by NYISO.

To evaluate the benefits and challenges of dynamic line rating, or DLR, over static line rating or ambient adjusted rating, National Grid installed DLR technologies on two 115kV transmission lines. Preliminary findings and observations are as follows:

Challenges: Number 1 - Cyber Security. Not all DLR vendors have their equipment certified to meet utilities' digital risk and security requirements and so integration to Energy Management Systems or EMS may require additional time and resources.

Compliance with NERC Critical Infrastructure Protection, or CIP standards, for line and tower-based devices communicating with bulk power system substation RTUs can also pose challenges.

Number 2 - Ability of the ISOs to accept and utilize DLR data in their administration of electricity market and reliable grid operations.

Number 3 - DLR forecast data calibration may take a few weeks after the installation as the vendors utilize -- I should say, some vendors utilize neural network for their forecast models.   Number 4 - Risks or issues associated with the real-time variability of rating due to changing environmental conditions like the rating, wind speed, et cetera, and this can be summarized into three different categories.

A - Impacts to real-time security constrained dispatch. This is another variable with frequent changes impacting the electric system on top of the renewables that may require regulation and reserve to be re-examined long term.

B - Transmission Owners and ISOs need the correct tools to dynamically rate and redispatch in real-time adding complexity to market and grid operations.

C - Market tariffs may need to be changed to allow customers to be compensated for additional capacity. How will, for example, how will National Grid NY customers that hold Transmission Congestion Contracts be compensated for additional capacity and what are the financial risks associated with increased variability caused by real-time changes in ratings?

Back to the challenges, number 5 -- Need for adequate coverage of line segments with sensors to yield the right answer. The geographic location of line spans plays a key role in the DLR data estimation. Therefore, more than one sensor may be needed to adequately cover the line segments.

Moving on to benefits, Number 1 -- The DLR data associated with the two National Grid installations indicate that real-time line rating is generally higher than the seasonal static rating. The available capacity above the static rating is critical during operations and system contingencies.

However, there were limited periods when the dynamic rating of the line was lower than the static rating. This happened during hot days with little to no wind. This highlights the importance of DLR technologies as they provide better visibility over line capacity for TROs and ISOs.

Number 2 - Economic benefits and potential congestion relief: This potential benefit depends on ISOs changing market rules such that incentives are provided to those entities that create capacity above static ratings.

Number 3 - Renewable integration: Additional line capacity allows higher integration of renewable generation on the electric transmission system.

Last, recommendations: National Grid supports use of DLR where it can reasonably provide value to customers. We encourage the Commission to continue to explore the policies that would drive adoption to improve system operations and create economic benefits.

National Grid believes that the Commission's transmission incentives policy is an available mechanism to facilitate greater deployment. In our comments in response to the Commission's Notice of Inquiry on Transmission Incentives, we highlighted the trends changing the future of the transmission system, including the challenges of adapting to increasing renewable energy generation, ambitious state clean energy goals, evolving customer expectations, and role increased adoption of technology can play.

National Grid suggested that the Commission look specifically at new ways in incentivize advanced technologies that will make the grid more efficient, improve operational flexibility, and reduce congestion costs. We noted that the technologies like dynamic line rating could help fulfill the Commission's statutory mandate under Section 219 of the Federal Power Act to encourage deployment of transmission technologies to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities.

We highlighted that DLR could produce significant real-time capacity gains above static line ratings. Consequently, investments in dynamic line rating could improve transmission operation, utilization and flexibility, as well as maximize the economic value of the transmission system.

As the subject to this Conference is to consider appropriate action with respect to line rating, we would encourage the Commission to use input from these discussions in its assessment of transmission incentives.

Thank you for your time, and I look forward to participating in the Q and A.

MR. KOLKMANN: Thank you, we'll next turn to Charlie Xu.

MR. XU: Well first, thank you very much for having us up here and for organizing a meeting to discuss the transmission.

Okay, so we are New York Power, we are established in 1931. We are the largest state public electric utility in the United States. So, we are a power plant and power lines, we have like 1,400 hundred miles of high voltage lines. So, this is like bulk transmission substation power generation, so I don't want to talk about the details about where we are because I think the first panel already did.

So, this slide shows you know, how we have done for the DLR. We tried different technologies. We tried CAT, we tried like a weather station, we've had thermal rate, by different technologies, all these present to us, it goes to DOE back to 2009, 2010 and the slide, it's like project tasks sponsored by NYSERDA, you know, like the New York State DOE, so we tried all the different technologies.

So, this is some of the data we got from the -- actually from the CAT system. So, we tried different technology and we observe it. And so, this shows what we have done and what we are doing now ultimately with the OH DLR. We are now the bulk of the DLR that's what we discussed in the first panel.

It's not easy to adjust MDR because you know the rating can change very fast. So, to use the DLR you need to do some kind of forecast, so now we have a forecast DR person, it's sponsored also by NYSERDA, you know, like New York DOE.

And we're going to demo the DLR part to try the pressure at the 70 mile line and then we're going to get a real-time on the adjust rating, and the bulk rating for the pressure. So, I think I want to mention you know, for this pressure we are going to get a stand-by rating for the line, because I think that's critical for us, you know, I don't want to allow you to -- if you want to really operate the line you need to know every span rate, not only you know, some span rates, because you know when you do the rating you don't want the temperature higher in any single span, so that's why I think this is one advantage of this technology.

So, besides the OH dynamic rating, we are also looking to underground cable because we also have like about 40 miles of underground cable. Compared with overhead -- overhead you know, the driving force of the wind and the wind direction and the wind speed can change in 5 minutes, very dramatically, but for the underground cable the driving force or the dominant or similar property, earth ambient temperature and so it's much more easy to use because of the earth ambient temperature.

The earth like similar temperature, not changing in 5 minutes, so we are looking to this technology now. So, to summarize, we learned best on what we have done for the real-time DLR. In the past, maybe now it's better. We know the indication is not very reliable, so I think in the future if you know the winters can provide the DLR with more reliable information would be good because if you want to operate a line with DLR, only 100% of that basis must at least be 98-99% of reliability because the produced DLR projects.

I don't want them in the winter, I think overall the ability in communication is only about a 70 or 80% of reliability, so we cannot operate a line with this communication reliability. So, I think now we are also looking to ambient adjusted. I think for now the real-time DLR, is used for overhead lines, is kind of like they rely on wind, but you cannot adjust what wind speed and direction is going to be tomorrow like to maybe -- for forecasts.

So, I think the ambient adjusted rating now is like between real-time and so we are going to look into this technology. And so, as well we are looking to the underground cable DLR because you know, it's easier to implement it.

So, this is lessons that we learned from the past. Thank you very much.

MR. KOLKMANN: Thank you. We'll next turn to Howard Gugel, from Gugel -- sorry, from NERC.

MR. GUGEL: I get confused with the surgeons all the time. Good morning, my name is Howard Gugel, I'm the Vice President of Engineering and Standards at North American Electric Reliability Corporation, or NERC.

NERC's mission, as the Electric Reliability Organization, is to assure the reliability and security of the bulk power system in North America. I've been at NERC for about ten years and prior to NERC, served in areas of transmission planning, operations, and maintenance for several electric utilities at the U.S.

I have 30 years of experience working in the electric industry and am pleased to speak with you today about NERC's perspective on dynamic line ratings. I hope to appropriately communicate to you NERC's support for the benefit of dynamic line ratings, while simultaneously noting areas of caution that require attention and sometimes pre-emptory mitigation to avoid inadvertent compromise of reliability.

The first panel today did a really good job of explaining the history and the different technologies that are available for dynamic line ratings, but it's important to note that the overall rating of a transmission line goes far beyond just the conductor temperature and wind speed. All circuit elements must be included.

Other things that have a direct bearing on a circuit rating include current transformer ratings, in-line disconnect switch ratings, circuit breaker ratings, and system protection relay settings. Relay settings played significant roles in blackouts, including the 1965 Northeast

Blackout, and let to the development and implementation of NERC Standard PRC-023 on relay loadability.

Additionally, in the 2003 blackout, discrepancies in line ratings between some transmission owners and transmission operators, or reliability coordinators caused significant confusion. In one case, there were three separate ratings for one particular circuit. The discrepancies were further exacerbated by limitations of a short, approximately 10 foot copper strain bus within a substation.

Although it was very short, its lower current carrying capability, lower than the line's conductor, was recognized as the current carrying limit for the circuit. Disturbances like these demonstrated the need for standards to provide for consistent ratings. As I'll discuss, these standards allow the use of dynamic line ratings subject to the requirements of the standards, but some consideration should occur prior to implementation.

The purpose of NERC's Reliability Standard FAC-008-3 is to ensure that facility ratings used in the reliable planning and operation of the Bulk Electric System are determined based on technically sound principles. A facility rating is essential for the determination of system operating limits.

As such, the standard requires generator owners and transmission owners to have a documented methodology for determining facility ratings for its facilities that are consistent with at least one of the following:

Ratings provided by equipment manufacturers, or obtained from equipment manufacturing specifications, such as nameplate ratings.

One or more industry standards developed through an open process such as the IEEE, or CIGRE, or a practice that's been verified by testing, performance history or engineering analysis.

Further, they are required to document the underlying assumptions, design criteria, and methods used to determine the facility ratings, including identification of how ambient conditions were considered. While FAC-008-3 does not require entitles to vary facility ratings based on different ambient conditions, it does require the consideration of ambient conditions.

It further does not prohibit an entity from establishing dynamic ratings on any of its facilities, provided that the documented methodology explains how those ratings are established.

Another limitation for line ratings is found in the testing criteria for Standard PRC-23. Those criteria are used to determine if a circuit could ever get highly loaded enough under varying operating conditions as to require a mitigation of relay loadability limitations for that circuit.

Similar testing criteria would be appropriate for any transmission circuit being considered for application of dynamic line ratings. Some circuits cannot be physically loaded anywhere near their thermal limitations under any foreseeable operating conditions because of terminal equipment limitations.

While the NERC reliability standards allow for an entity to implement dynamic line ratings, there are many considerations that should occur prior to implementing those ratings. For example, an entity must know and understand how substation equipment may affect the capacity of transmission lines.

A 1200 amp switch or current transformer may be the limiting element of a transmission line rather than the conductor itself, and as such may limit the usefulness of implementation of dynamic capacity on that circuit. In addition, there are limitations on how dynamic ratings can be used in planning studies, since they are highly dependent on specific ambient conditions that are not available at all hours. This will also impact how system operating limits can be established, and how available transfer capability can be done.

Dynamic line ratings can be used to provide system operators a little extra margin that may only be needed a few hours out of every year. How those dynamic line ratings are communicated in real-time operations is a priority consideration.

Reliability coordinators, transmission operators, and the operational study groups supporting them must have ratings on adjacent transmission systems to understand interactions including parallel flow impacts. Clearly, they must have visibility of these ratings as they change up or down.

These communication and control channels will need to be cyber secure. Adulterating real-time facility ratings information could degrade the situational awareness of system operators, potentially affecting the reliable operation of the bulk power system.

Since information gathered would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise, and that information would be provided to a reliability coordinator and/or a transmission operator, it may cause a transmission line that was previously determined to be a low impact to be a higher impact.

Finally, the methodology for establishing line ratings often incorporate a margin into them that can accommodate may unknowns as well as some knowns that are not quantified exactly.

An adequate capacity safety margin is essential to ensuring that the bulk power system does not operate in an unknown state. This was a key finding in the investigation of the 2003 blackout and was a driver in the establishment of both FAC-003 and PRC-23. Thank you for your consideration and I look forward to providing input to the discussion.

MR. KOLKMANN: Thank you Howard. We'll next turn to Shawn Murphy of PJM.

MR. MURPHY: Good morning. I'm just going to jump around my prepared remarks a little bit and just call out the points that I think are relevant to this discussion. So, first of all through the remarks I mention that PJM has done a handful of pilot projects with some of the vendors in this room.

The first one was back in 2016 and that was working with AEP, one of our transmission owners, and Genscape, now LineVision, to pilot a project. The results from that were documented. I have my references here as well.

The results from that were very consistent with what we saw in the first panel as far as the additional capacity above the static ratings, the majority of the times, at a very small amount of time, we saw that that dynamic rating was lower than static and we'll get into that in a couple of minutes.

Following that analysis, from what we saw with the additional capacity on that line, we were really intrigued as far as what the economic benefits might be in an RTO environment. PJM conducted a production cost forecasting study. So, we used our PROMOD economic analysis tool to forecast the hypothetical dynamic line rating installation in PJM.

LineVision helped us out by looking at the historical weather data for our target line, developed what those dynamic ratings might have been. We loaded those ratings into PROMOD and compared it with a base case analysis.

Again, we published a paper and I think it's a really good read. It's got some real good detail in it. The takeaway is the 4.2 million dollar savings that we referenced, so the target line that we focused on PJM's footprint saw 11 million dollars of congestion on it through that year, 7 million dollars of that was off-flowed to downstream and parallel lines, which is really consistent with any other upgrade that you would do.

If you upgrade a particular facility that's adjusted, you're going to import power down and then it's going to run into the next limiting element, but the takeaway there is the 4.2 million dollar net savings per year.

We also conducted a pilot project with Lindsey, again in the AEP footprint. That was focused more on investigating co-convections and looking at the relationship between the dynamic line ratings and the output of a wind farm in the area and again, we saw a good correlation between those two things.

Technologically, PJM has implemented ambient adjusted ratings. This was mentioned earlier. We use that with the majority of our transmission owners. They communication what the ambient adjusted ratings are going to be. It's my understanding that we've implemented a dynamic line rating project in the past. It was a dynamically rated cable, it was a long time ago, but from discussions with our EMS engineers, we received a dynamic rating in the last and loaded it into our EMS.

I'm fully sure that to receive dynamic ratings now, we would need to take a look back at that implementation, but it is something that we're familiar with.

Getting back to my original comments on our initial study, looking at the additional capacity, we obviously see an economic benefit when we have a dynamic rating that's above the static rating. We looked at PROMOD and that validated our initial impact, but also, we see benefits from reliability.

When we do have a dynamic rating that's below the static, we're calling to attention that facility can't handle what the static rating might be documenting. So, we see in either case, there's a benefit to the transmission owner and to PJM by having a more accurate facility rating.

It's important to kind of differentiate what a transmission project might be implemented to address, so it's important to kind of differentiate between reliability needs and I think that was discussed earlier this morning as well.

We would not want to assess that the system is going to be reliable on a dynamic rating above the static in a future looking planning case. However, our market efficiency process seems like a logical fit for a dynamic line rating project to be submitted, and in that we would do a similar PROMOD analysis and look at what the market benefit is of that particular project that was proposed.

We definitely see the engagement of the transmission owner as you know, a top priority for PJM. Talking earlier today about the forecasting as something that we definitely see a need for, things like the confidence intervals, who decides that? You know, that would definitely need to be a discussion with the transmission owner.

Some of the things that Howard mentioned as far as the limiting elements, it might not just be the conductor, it might be substation equipment or something along the line that we need to be aware of. PJM doesn't have full visibility into that. We get the ratings from our transmission owners, so we would certainly need to engage them on implementing a dynamic line rating project, maybe its capped at the next limiting element on that same transmission facility.

There are two kind of areas of future exploration that we propose, the first of which being the incentives to build that have also been discussed earlier today, but comparing what the incentives are for building a new line or operating that line versus implementing a dynamic line rating project for other advanced technologies for that matter -- they really don't compare as far as what the economic drivers are from a business perspective.

The second area that we kind of propose for future exploration is engaging with NERC on some initiatives to develop -- I would say a more cohesive philosophy on static line rates, ambient adjusted ratings and of course dynamic line rating, and have that discussion with the industry as far as how would we implement this and what are all of the engineering concerns that the asset owner will be faced with if the dynamic line rating project was installed, thank you.

MR. KOLKMANN: Thank you. I'll start off today, if at any point you guys want to talk, and multiple people want to answer please feel free. Recognizing that the answer is going to depend on location and its going to depend on relevant conditions, how much of a ratings boost have you people seen with regard to implementing wind and sunlight precipitation relative to this temperature? What have your test results seen?

MR. VELEZ: So, this is Francisco from Dominion Energy. As I mentioned in my comments at this point we're still analyzing the data from LineVision, so presenters to provide any comments around that.

MR. GUGEL: I can provide a quick comment on that. So, in the distribution that we saw earlier on the earlier slide, it's easy to get excited by looking at the additional capacity that you get for a small percentage of the time. And our experience in talking with the vendors, you're going to see a moderate increase in the capacity, I would say between 5 and 10% additional capacity before you're going to run into the next limiting element either on the transmission aspect or downstream or in parallel.

So, and it's possible that a regional

implementation could be used for those, you know, multiple transmission assets or in parallel.

MR. JAMMALAMA: So, just from a developer's perspective, and in my past utility life we're exploring that. One of my first jobs was actually calibrating the technologies to establish those and generally the assumptions, the wind speed assumptions, those are between 2 and 3 miles an hour, generally speaking.

Most of them can't even -- at those speeds, they need 9 or 10 mile wind speeds. So, if you are presuming that some wind is blowing on the system between 9 and 10 miles an hour, you can usually see -- and just isolating that circuit itself, just for capacity can easily see 15 to 20% rising in the capacity, which is very reasonable.

And again, isolating that facility and not the natural impacts of completing the rating where the next, you know, natural limit will be. But when you just look at thermal ampacity on establishing -- and if your conductor was a particular element, you should be able to see at least 15 to 20% increase at a minimum, by moving it to a decent wind.

MR. ENAYATI: I mean I can add more. In terms of National Grid's experience, we're not ready to make a generic statement on the actual capacity increase because these pilots have been -- the project has been in service for a little over a month, but the data that we've received so far shows that the majority of the time an average I agree, so in average again 15 to 20% capacity increase is what we've seen on both lines.

And sometimes of the day capacity was higher, sometimes lower, but capacity would average.

MR. JAMMALAMA: Yeah, based on some of our products, the results, we actually have a sensor close to the wind pump, so I think there's some kind of like emulation between the wind pump output and the DLR. We do some kind of like relation between the two but we also see some kind of like exception, because you know the lines lie very long, so you know, if the line angle changes some location or some spot, the DLR number can also be low, so kind of we might need to put some sensor, or some kind of device there to monitor DLR before you can decide it, this is some of the things we learned.

MR. KOLKMANN: So, a number of you mentioned renewables. Building off of that point, and understanding that it's absolutely important to plan for the worst case conditions, both transmission planning interconnections, but are panelists aware of any approach that uses DLR's to take advantage of the correlation between wind generation and the cooling of lines?

Is there a possible symbiosis there?

MR. JAMMALAM: There is, but that is something that would not be in a conquered --

MR. KOLKMANN: Yeah, and I'm wondering like have we seen this, has anyone thought about this in the context of the interconnection process specifically?

MR. JAMMALAM: We have been pushing for that as interconnection. I mean someone who puts in a connection, a connection that goes across the system and yet as you can the ISOs have been saying that there isn't capacity on the system for a majority of the times when you hit the limit on the system, you just need an incremental amount of capacity on those lines.

And then we are starting, for example, when integration of interconnections, we're looking at the wind farm, the nameplates. And at that point you really cannot use a 2 mile or a 3 mile per hour assumption to calculate our use, we established that equation. So, we have seen a significant, you know, a facility is based on both static limits which we would like some kind of relief.

Because most of the facilities either need a 3 or 5% relief for additional incremental capacity and it just so happens that you know, you have to build a new line with just 50 to 100 million dollars for that newer facility, when you just needed an incremental amount.

Obviously, it depends on location and where it is, but the majority of the interconnection studies don't take into account, or in fact might be an exception in certain regions, but apart from that, most regions have interconnection customers have not seen that.

MR. JAMMALAMA: Yeah, I think as was seen in the information in Panel 1, the cooling effect that you would get from wind is highly dependent upon the angle of incidents, right? So, the wind farm may be situation such so they could take advantage of the wind blowing in a certain direction, but transmission lines take varying angles around and there's a good opportunity or a good chance that while the angle of incident may be 93 at one point, it may actually flow parallel on the line which would kind of compound it rather than cooling, it might provide an additional heating aspect.

MR. KOLKMANN: That's helpful. So, I have another question. Can -- we heard that there's a certain percentage of time in which either an AAR or a DLR might come in lower than the status quo. Like, what percentage of the time have panelists seen at this particular aspect? If you could provide some help.

MR. JAMMALAMA: Yeah, I'll go first. So, again, for this one month of data we just see some of the DLRs, the percentage we've seen is like 4% -- 4 to 5%, and but you know, as we get more information in for longer durations that percentage may change, but that percentage we've seen the past month.

MR. XU: Just the way they want to end up -- so before I worked for this utility, I worked with Wind Earth. We had a lot of projects in different countries, so from the data I saw, all different zones of assumption of the utility. If you assume a 3% wind speed versus 2% wind speed, it's much different.

So, I think from what I saw, I think most likely around 5% for a three feet per second assumption. Also, it depends on the ambient temperature as well as solar. You may cycle zero like the watts per minute square, some you're going to use 100 -- 1,000 to meet watts per minute square in all effects, so it all depends.

MR. THOMPSON: Yeah, and this is Chad, if I could just add to that. At least from the ERCOT side with regards to ambient temperatures, the majority of the line ratings that come in are rated based at -- they're static or their nominal rating is usually about 104 degrees Fahrenheit value and in parts of Texas, we get temperatures in the summer time that are well above that.

So, we do see periods of time where we actually -- if the actual temperature is above 104 degrees, the dynamic or that nominal static rating, because that can't happen.

MR. KOLKMANN: And you too raised the line?

MR. THOMPSON: Correct.

MR. KOLKMAN: And so, on building on that concern, what -- in terms of the use of either DLR's or AAR's in the day ahead markets, we spoke a lot about forecasting, obviously, in the previous panel. But what are your perspectives on whether or not a forecast can be made conservative enough in order to use a forecast in a AAR or a LDR in the day ahead market?

Recognizing that essentially can you make this forecast conservative enough? Any thoughts on that and then at the close of the day ahead market would be helpful.

MR. THOMPSON: Chad, I guess I'll start. The way we are utilizing our forecast vendor and we're taking the temperature data from that forecast in as one of the inputs to our day ahead markets. So, we're already sort of taking those risks into account when we enter our market, so you know, again from the AAR perspective, we try to make strides to implement that in a way that instead of just using that nominal, or that static rating in the AAR, we can actually utilize it in cooler weather to provide a little bit more transmission to be sold in the day ahead market.

MR. JAMMALAMA: So, the previous panel spoke a little bit about this on the level of confidence and the hours at which you can actually pay the margins, so you can have a 2 hour rating and now a 4 hour rating. You can have a day ahead rating. You just need to figure out what kind of margin you need to build, because today all day ahead markets have some kind of margins within their forecasts.

Wind forecasting has come a long way. They're forecasting loads to an error rate that has historically been the lowest, so it's not -- and same thing with these online tools that are running today. System operating limits are being also forecasted day ahead and they are -- they have a significant amount of margins within, in terms of transmission capability.

The same thing I don't think is very different. The way I look at it is if something happens with the DLR equipment, it's similar to a transmission, which is just one of the balancing market of what the real-time market is. They're actually to take care of that.

MS. GADANI: Thank you. A quick question. I'm just trying to think about the challenges that the utilities identified, or DOE has identified to implementation of DLR more broadly. A couple people mentioned EMS system limitations. Can someone talk a little bit more about that?

And then a second related question is in terms of visibility of a system, I would assume that each utility would appreciate knowing the line rating of their system and limitations. Would these sensors of this technology help with that visibility or be a challenge to deployment of those technologies? So, it's a two-part question, but folks can answer whichever.

MR. MURPHY: Yeah, I'll take a stab at it. But I would say technologically uploading the static rating, the ambient adjusted ratings for that matter in the EMS. You have to build that capability for you to be able to adjust obviously, but also the way that we adjust the rating at PJM is based on what the transmission owner has indicated for you to use.

Someone needs to go into the EMS and what that rating set might be. Now, they can do that for a zone, for a transmission zone within PJM, so it's not going through each line in setting the ratings, but that is a procedural task they need to perform.

To receive the dynamic line rating, we would now need to set up a data link from that transmission owner with that data point on it and then we would need to set up the automation to close that in. I know that there's also a concern with the volatility of the dynamic rating, you know, setting the ambient adjusted rating gives the operator an opportunity to kind of set what the ambient adjusted rating might be.

The dynamic rating automatically loaded in, that might cause concern.

MR. GUGEL: So, kind of a follow-up question on that. How would you communicate that information to adjacent reliability coordinators or adjacent ISO ROTs on lines that would be on the perimeter?

MR. MURPHY: I suppose we would use the same implementation of getting that rating from the utility itself that we do real-time data exchange. I'm thinking it would just be a SCATA point that we would communicate to our neighboring reliability coordinators.

MR. ENAYATI: Yes, just to add to what was just mentioned. So, in terms of EMS integration at my summary I talked about the cyber concerns. Right now, our concern is so, we have the bulk of our systems that you know, both physical and cyber protection requirements. And having these devices outside the station, like on the line or on the tower, and keep in mind you know, a device on the sensors of the tower they're like probably like 15-20 feet above ground and so, having these devices communicate with our DPS what are the cyber certifications needed.

As we went through these projects with the vendors, they had to go through additional certification to meet our requirements, so that's some of the concerns for us. Just to let you know, we have not connected our DLRs to our EMS yet, because the life portal, we want to see the benefits first through the analyses and then in the larger roll-out once the cyber issues are resolved and plus other operational challenges, then that will be the next step.

MS. GADANI: So, just to ask the follow-up question to that. So, in terms of the cyber deterrent, you have other devices on the system that you use. How do you -- basically, have you tested that and protected that?

MR. ENAYATI: So, typically -- well, not mainly on the line, it's more like you know, so the station communication that we have, you know, with our EMS. These are all new devices coming on the system and we do have a set of requirements for cyber, but we're also working with INL, those requirements need to be updated and there's a big -- I don't want to say unknown in our uncertainty, but concern that needs to be resolved as soon as possible before we allow, you know, the devices connected to our EMS.

MR. VALEZ: Yes, looking to our system operator sensors, right now our EMS system does not have the capabilities to access the line rating just by the time, but we are working on that upgrade eventually, one year - two years, to get it implemented and we can probably have DRL capability.

MR. XU: A real case for DRL implementation, but so I don't want to name the utility, actually they are now using underground DRL, what they're using for cyber security, all the issues. They have a serve outside connecting all the data to the DRL, and then there is a server inside to pull the data from outside the cyber to some costs for cyber security and then they put inside the firewall, they have a serve and check the number.

That's how you know sometimes, you know, the DLR has some issues, to check out and these numbers are good, that some of the data SCATA, and then to the ISO and this is how they do. And on the unit case, DRL systems fail. They were kind of like the operator has the options, they can choose, you know, like a switch, go back to static, that's what they do.

MR. MURPHY: Just to make one more quick point. So, in this family of I'll say non-wires transmission alternative, collecting the dynamic line rating technologically is the easy part because they just kind of passively collect that information and pass it along to the facility and to the RTO.

Some of these other things, like the next

Technical Conference on the power control, that's really complicated -- figuring out how do we dispatch a unit to make a direct decision and how do we communicate that as well?

So, these discussions of dealing with the cyber security and the EMS capabilities, are really going to be compounded when you look at something that you need to directly control that.

MR. KHELOUSSI: This is Dan, thank you for all the talent. Can I ask Chad to elaborate on Charlie's last point about reverting to static rating concerns which falls outside of a bounds or something like that? Because I know in the ENCOR test pilot, this is elaborated on a DOE report, so if you could just share some information.

MR. THOMPSON: Yeah, sure yeah, it's been a while since I looked at ENCOR's report. Yeah, so and what my recollection is they were able to take that DLR information to the field and bring it into their EMS and I believe they had a way to actually compare it against what they would have thought the ambient rating would have been at the same time and then they had the opportunity to make a decision on which value they want to send to ERCOT by ICCP Inc.

So, that decision was made really on the ENCOR side. For preliminary ratings that come into ERCOT, we do compare that value against the table and if there is a delta between what's the cable for that temperature inside that they're sending in. I believe it's 10%, and we would be kind of like just kind of an alarm to say hey, go check this out and make sure that this value is correct.

And we do have an opportunity to kind of -- for lack of a better stated term, this can inhibit that point and so just back to our temperature rating that we're calculating internally in the event that we believe that value is incorrect. If that kind of helps.

MR. GUGEL: I would say, this is Howard. I would say that while the data collection is probably fairly straight forward coming in to that data, especially if it's done, you know, outside of the fire wall, or just collected from the field to make sure that it's not moved, or to make sure that it's not changed.

You know, the concern would be if you had the ability to do that, you could certainly compromise reliability or do market manipulation if you wanted to, just by simply changing those data points.

MR. KOLKMANN: To build upon some of the experiences that we've had here. We've spoken about forecasting obviously, but to confirm, do you guys think that that's necessary to implement either AARs or DLRs? And, how far forward do you typically need for that to occur -- 24 hours, 2 hours, you know, for both real -time data.

MR. MURPHY: Forecasting is 100% necessary. Looking back on the first panel, I thought it was a good exercise, when we saw the slide with the big black box on it and we saw what the real-time rating was. That doesn't do me a lot of good because I need to know where it's going and also having the additional capacity in real-time is great, but my generation did that from the day ahead dispatch done yesterday.

They're getting that forecasting in. You know, we have to figure out the constant intervals, figure out how do we implement day ahead versus real-time, but yeah, without a doubt we need the forecasting.

MR. KOLKMANN: And constant intervals are determined in order, question?

MR. MURPHY: I don't know who, yes, certainly needs to be involved, yes. You know, in the line movement and the methodology of the static rating.

MR. XU: Yeah, I think now ISO relies on us to communicate to provide these numbers, but we are taking all the reasons, so yes.

MR. KOLKMANN: How often -- when you're implementing either AARs or DLRs, how often would you expect for the rating to change? Would -- this is getting back to forecasting, would you expect the rating to change 5 minutes, 15 minutes, hourly? What kind of granularity changes would you expect?

MR. VELEZ: This is Dominion. Again, so obviously the temperature changes throughout the day, right? What we do in our operating center right now with AARs, at least twice a day, with those ratings. I mean that depends on the, you know, level of activity in the brain center, with the shift supervisor on the floor.

He's taking a look at the temperature and he's deciding whether or not he needs to adjust those ratings. So, if he decides, you know, the ratings he selected an hour ago, two hours ago, needs to be changed because that's of the way the temperature.

MR. ENAYATI: In our experience with National Grid, our sensors send this data every 10 minutes and we are seeing some changes, you know, between the two measurements and we haven't changed that, so I can't give you the exact number what we would be comfortable with, but even with that 10 minute measurement frequency there are some changes we're seeing in terms of line rating.

MR. KHELOUSSI: Can I ask Shaun, so Francisco mentioned maybe twice today that's kind of the standards for their much more frequent, are there other facilities that move the rating around?

MR. MURPHY: So, from my experience that's about consistent. We do have transmission owners that use winter and summer ratings, so that's much less frequent.

I would also say when we have a line that's congested, that's when the conversation starts between PJM and the transmission owner. What is the ambient adjusted rating that we've applied, whichever one is more conservative is what we're going to operate to, and then we defer to the transmission owner, they want to take a look back at the ambient temperature specific, so that congested element, we may make a deviation from there as well.

MR. THOMPSON: Yeah, I was getting ready to put my card up. So, from the ambient side. We're running a real-time market every 5 minutes. We're running our state estimator in a real-time contingency now every 5 minutes. So, we would be able to respond to any change in the rating if it did come in that time period, and we're able to dispatch on it in real-time at 5 minute granularity needed.

Our day ahead market and our reliability unit commitment applications are running on an hourly basis. They would picked-up based on -- once you get outside of real-time, we're going to be defaulting to that cable that's going against our weather forecasting anyway, with regards to what the rating is to look for the rest of the operating.

MR. KHELOUSSI: Following-up on Shaun's point. You said, you know, when congestion gets to a certain degree, when you start that conversation. I'm not sure exactly, what I want to ask about that, but basically would it be valuable to the facilities if you -- anyone can answer, if you would like provide occasional study or comment not -- I don't want to call it mad hunt basis, but something a little more regular or where the RTO gives you some study, yeah -- anyone can answer.

MR. KOLKMANN: What line would be a good candidate for helping to form your own study?

MR. GUGEL: I don't want to speak out of turn, but I would suspect that the first areas folks would look at would be any lines that consistently showed up consistent operating limits, or IROLs and whether or not that was based on stability issues or whether it was based on thermal issues.

That would probably -- to me, that would be the first area that you could probably get the biggest bang for your buck.

MR. THOMPSON: So, this is Chad. I'll start by taking a little bit of a step back. When our real-time applications run, our analysis results are actually posted on our secure, our information system website. So, when the congestion shows it's starting, it's made available to them to see what's showing up in real-time, and that includes the facilities, hey one of my lines is showing up we're very overloaded, that rating doesn't look right.

So, it gives them an opportunity to actually go back and kind of trouble shoot it or evaluate whether or not they think those rates are correct. For lines that in real-time that we do have some issues in the management or coming up with operating plans and things like that to evaluate, one of the first things we look at typically is the rating of the line.

And if that line is one of the handful that we have in our model that isn't dynamically rated, we will reach out to them and to the impacted CEO and say hey, you know, is this a line you think is a candidate for making the grade? And they may take that back with their modeling folks and their engineering staff to decide if that's a feasible option.

MR. DAUTEL: So, this is Tom. A follow-up to that is that kind of study, would you feel that some kind of requirement for a periodic study that would examine the cost-effectiveness of implementing either AARs with DLRs on maybe even those congested lines, or some other way of identifying candidate lines would be appropriate or useful or not?

MR. JAMMALAMA: And maybe this is moving a little bit out of operations, entering into planning, but the planning processes are there to figure it out and part of the long-term assessment for PJM's, RCAP from MISO, NCAP, there needs to be a point where it should become, I mean as an alternative to transmission, so non-transmission, I think any of the economic issues that they're seeing in their economic study was part of the long-term transmission plan and process.

It's definitely something I think we should -- I'm told to look at. Right now, they're looking at storage, you know, that's the new thing as can it help fix any issues, but this has to be similar to that. If you're seeing congestion, economic studies are projecting congestion, what's the nature of that and if we can use the DLR on any kind of power flow device, you actually need that, that should be investigated in the planning process.

MR. ENAYATI: Just to -- I want to echo what was just mentioned. Recent studies should be added to the planning process, identify lines that you mentioned before, the actual rate current for the line is supposed to be the rating of the line's static rating so that those are the priorities in terms of reliability, but in addition to that in our service territory, we are seeing a high penetration of renewable generation on the distribution side.

And that actually back feeds -- well, through the transmission, it's high enough in some areas, we are seeing the power is getting close to the transmission line rating, the static rating. So, having the technology studies done to understand the benefits of DLR can be beneficial, because we went to solar, you don't have solar at peak all the time, so for those 2 hours, it's really just the rating of the line above what you see as static rating and can that defer capital investment, these are all of the questions that can be answered in the study.

MR. MURPHY: I think requiring that such a study would lead us down a path that if it's PJM identifying where those dynamic line ratings should be installed that we inform the transmission owner. The next question is going to be from the transmission owner -- are you requiring me to do this?

We need an answer for that. Or, if PJM is trying to say hey, it might be worthwhile for someone to do this, what's in it for the utility? What is the incentive for the utility to go out and do that? I think a more consistent process would be using our market efficiency process of letting the market propose whether it be DLR, whether it be battery transmission, or wire, what have you, for that project participant to propose what it should be and then we would analyze it.

MR. KOLKMANN: Yeah, I didn't mean to apply that it would be an RTO requirement. I think we're at the very early stages of thinking of that. Is there a reason that it couldn't be a TO that would do a study like that?

MR. MURPHY: I think they certainly could. I'm just -- what was the next line of questioning be? How would they fund it?

MR. KHELOUSSI: So, we touched upon this a little bit, but our understanding is that from time to time RTOs will -- they'll seek justice. And they will subsequently ask for -- ask a transmission owner for an updated rating if that's possible in real-time.

And actuall

y, I think this is typically done for reliability reasons. Obviously, t here are good reasons for this to happen. Taking advantage of different temperature, this is what the seasonal rating is, actual temperature is. Are you guys familiar with this?

And are there any other reasons why this might occur other than this reliability reason? Oh, sorry I can repeat it. We -- I understand that from time to time there -- in the event of a reliability concern that an RTO may have, you may have an RTO that reaches out to a transmission owner and says well, I understand that might be helpful to alleviate this reliability concern to have some kind of higher efficiency rating because I know that's what the planning says the temperature is supposed to be, and this is what it actually is.

And I'm wondering if people are familiar with this process, maybe it's occurred. And two, why else -- why might it be done other than reliability reasons, if at all?

MR. ENAYATI: So, this is exactly what's right now, so that's the process to go with static rating on a case by case basis. ISO New England, based on their operations, procedures and if they see any issues that come online potentially, overload is based on the static rating. They contact us, and then we'd have that discussion with them to provide the ambient adjusted rate.

MR. THOMPSON: So, I mean, for lack of a term, it never hurts to ask, right? And that's really what we do in real-time is we just ask the question because you know, there's a lot of going on in the ERCOT interconnection right now. There's a lot of things moving on, and people are always constantly observing their equipment and evaluating, you know, evaluating their system as normal ways to just do maintenance on their system.

And so, that's why we asked the question in real-time, is typically we're on our way to creating an operating plan for that particular operation because changes are there may not be a dispatch solution for that constraint.

So, if we're having to come up with an operating plan, if there's a higher rating that we can operate to, and if we -- what we do, we talked about this a little bit. You know, we manage our post constraints to 2 hours, we call it an emergency rating.

So, if there's a way that we can get a higher 2 hour rating, you know, that will actually help us kind of diminish the degree of effort that we need to go into with regards to creating an operating event. Maybe with fewer loads, fewer megawatts of load shed if we're creating a load, some thing like that. So, you know, ask the question first because you never know.

MR. CORBETT: Alright, I come more from the reliability side, so there's a few things I would like to get on the table here. First of all, would you like to speak to what is the minimum required wind speed, just for a wind facility to obtain its nameplate output?

MR. JAMMALAMA: So, the carton speeds are typically between just to pick on the power for it to get out what you need is between 20 to 25 miles an hour, that's almost ten times the standard assumption of the static basis.

MR. CORBETT: I would point out that most of these static ratings are basically based on possibly zero wind.

MR. JAMMALAMA: I'd like to believe that based on between 2 to 3 miles an hour.

MR. CORBETT: Well maybe if they switch it to like an emergency rating, but many for normal rating would be zero feet per second, 10 miles per hour for wind. So, I wanted to get that on the table first.

MR. ENAYATI: Maybe I can share our experience that for us it's 2 miles per hour static rating, 100 degrees Fahrenheit for summer, 50 for winter, that's how we rate the static.

MR. XU: We are just like 3 feet per second for the static.

MR. CORBETT: For the normal rating?

MR. XU: Yes, 3 feet per second.

MR. VELEZ: With Dominion it's 3 feet per second.

MR. MURPHY: Alright there would still be a natural connection that I referenced earlier the IEEE standards, the natural connection, I don't know what you've worked out, even if there's zero winds blowing, you're still going to have a connection.

MR. CORBETT: Well, I'm glad to hear that. My experience has been the less wind, so that's good. Number two is you know, we talk about release of capacity that we can anticipate by using either AAR or DLR, so released capacity relative to the transmission owner's rating methodology, correct? So, you know, we see instances in a few percentages of the time when the rating might be lower than what the rating -- static rating is in the summer.

However, during the winter periods, as many rate their facilities at 32 degrees Fahrenheit, I'm seeing the ratings being stated maybe possibly at 91% of the time. So, what do you see in regard to addressing this phenomenon during the winter season with the static rating is -- should we say, very possibly exceeded 91% of the time, or some type of percentage?

MR. JAMMALAMA: Maybe just to follow-up, so the question is that due to whatever reason, our ramping temperature during winter your experience has been that the DLRs are projecting much higher transmission capacity than the static ratings -- the 91% opposed to that within the DLR and the static rating.

MR. CORBETT: No, I'm just saying the temperature is exceeding let's say the 32 degrees Fahrenheit temperature.

MR. JAMMALAMA: So, I think Chad can speak a little bit. I believe they take that into account where they're using it and the temperature calculates what it would be with respect to what assumptions were and the static rating was calculated at.

MR. CORBETT: So, this would be pivoting away from the seasonal static rating of let's say just a flat out 32 degrees Fahrenheit?

MR. THOMPSON: So, I wanted to comment. So ERCOT only has -- we don't have like winter ones that are rating, that we use year 'round and that value is based on however it would be in the table, so we would be enforcing the rating at 32 degrees based upon what the table would be showing at the 32 degrees.

So, that's why I want to make sure you were thinking that the 32 degree rating, somehow you were exceeding the static rating of the line by 91%, so I want to make sure I understood the question.

MR. JAMMALAMA: Right, it's that ambient temperature and the conductor temperature. I just want to let you -- breaking, sometimes with DLR as the flow the static, you have a -- you also need some very good time.

You have to have -- like the wind speed is low and at that time ambient temperatures are high, but if you know, nature, sometimes they can now come and say to each other in summer when the temperature is high and you have some high wind, that kind of like compensate with each other, so that's why a lot of the time you see like only 5% of the time that you are at a high flow.

MR. CORBETT: Well yes, that's it, that there are compensating factors that we're not aware of, so that shall we say have created an actual path if you're a facility that exceeds maybe what the hard static break is based on that static break temperature. For example, like you're saying, load is rolling off. Maybe, load is falling, the load component of the seeing contribution is rolling off and in a 4 hour period.

Or like the wind speed is high, so we're talking about the true capacity of a transmission facility which is like where we're going with the ambient ARR. But, when you compare it to the static rate, they don't -- the static rating has a temperature with a static rating, so it doesn't necessarily change, it just stays constant.

MR. XU: I think like wind speed or induction, all these can occur, you have to rely on some real-time measurement sensor to measure all these things.

MR. CORBETT: And yes, it has what was mentioned just a little earlier, that's true for conductors. What I'm saying is a certain voltage class has a high concentration of equipment limited transmission, rather than the conductor circuit breaker line.

And they're not -- they don't necessarily get that rating advantage because of the ambient temperature sensor.

MR. XU: Yeah, that's true because with a transformer.

MR. ENAYATI: One of our projects in New England, we actually faced something similar to DLR, gave us higher data in terms of capacity but there was a limiting element of switch there that had the limiting capacity, so the limit -- if capacity is aligned with limited -- the rating of that switch. The next project for us really to see if that capacity is based on what we thought the DLR was the upgraded switch, so though we can have all the capacity available.

In terms of -- just to add what we do in New England in terms of temperature. So, for summertime we consider 100 degrees Fahrenheit. For winter, 50 and if you live in New England, normally you're going to get that level anyway in both summer and winter, so our AAR's are typically higher than static ratings most of the time.

MR. CORBETT: You're using a higher temperature in the winter that's something like 32 degrees Fahrenheit.

MR. ENAYATI: Yeah, it's at 50, that's what we do.

MR. CORBETT: The last comments that I have for you, it's we can talk about a confidence factor or we can talk about bandwidths that would be acceptable simply for forecasting. So, let's say we start out with we're going to 85 and 90 degrees, this is a forecasted peak of the day, could you see an algorithm for DLR to track the bandwidth performance so that it automatically makes ratings adjustments based on bandwidth?

MR. XU: I think one problem that you may have is we have summer at winter ratings, like in between. For example, our period from November 1st to March 31st, so from March like March 31st to April 1st you have a jump. The rating will jump from some kind of number to another one. So, at this time maybe when you have a concern, maybe there's some concern there because you know, the weather cannot change one day, but the rating number can be changed in one day.

And I think it is kind of a condition that everybody else is concerned, maybe we need to see it, I think.

MR. CORBETT: Would you also say that the wider your bandwidth for the confidence factor width, that the rating would change?

MR. XU: More about it like for a system with like static ratings, you would have this kind of concern. I think the temperature is very small but I'm just reading all the focus ratings, different issues.

MR. CORBETT: Thank you.

MR. KOLKMANN: I asked Jake the same, mostly Jake, I think the same question earlier. I'll ask, I'm curious to know if you guys had similar experiences. Are panelists aware of research testing or testing to read non-wires transmission equipment more dynamically? Have you thought of or heard of anything in research ratings for non-wires?

MS. CADANI: So, going back to something you said about incentives to get people to think about using more dynamic line ratings. I wanted to ask different facilities to provide us with some of the thoughts that they had concerning the pilots we did. And then also, in terms of what else could be done to help those, or even more ambient ratings.

MR. XU: Now as I mentioned, you know, we -- ISO can now rely on us to take the risk to provide numbers for them. So, if we upgrade the rating, so we are going to have the reason, so what now benefits we can get. I think we, of course the rating, we can get some benefits, but I think for most of you here, it would be more in it to do this, otherwise you know, why would I have risk.

MR. ENAYATI: And in addition to that, more like operational flexibility at the whole incentive structured needs to change, incentive-wise for the services. And plus, the congestion part is that you know, my opening remarks I mentioned the New York transmission congestion contract, so with DLR at showing more capacity in a particular area that will definitely impact the way that market works, the contract with the entities.

So, which requires again, significant changes to the way we're currently managing FTRs and NTP.

MR. VELEZ: So, then your question is why we collect the lines where we put the sensors for our pilot program and so in one of the cases we installed the sensors and the idea was just to test the data installation of the sensors first, and second the data that we get during that process for one of our pilots, it was not really for congestion, or it was not really for any other event constraint.

It was just to get experience installing the sensor and get the data and evaluate the data. The other three sensors we were installing, or two sensors we're installing with EPRI, one of them is for another different kind of measurement, these sensors can also give you other measurements than line rating.

One of them is when it gives us blowout, you know, when the transmission lines can actually move and approach a tree because of the wind, and we don't want that line to approach that tree. So, we have a long span in one of the transmission lines, we have installed these sensors in that location and another one -- request for galloping in the technician line.

And having oscillation and knowing they reduce the clearance from the conductor to underground structure, so that's the only reason why we connected that one. But I mean the thing is there's some incentive because I think the incentives are going to be self-imposed, the utility has some point or even now we are constrained in our system in terms of thermal constraints that we want to push more power and we cannot do it, so I think just because we went from the polling, we're looking into that ourselves.

MR. GUGEL: This is Howard, if I go back to Dillon's question a little bit earlier. I'm not really aware of any research on dynamic line ratings of terminal equipment, but I will say that there's IEEE standards. Most terminal equipment is amp year limitations, it's not really more of a thermal constraint, but it's limited by amp years.

And there is IEEE standards for pieces of equipment where you can take a loss of life calculation into account for that. And so, there are conditions where folks will, under certain scenarios, assume a certain amount of loss of life in order to increase a particular piece of equipment for a very short period of time.

I am aware of those types of scenarios, and certainly the IEEE standard allows for that.

MR. CORBETT: I'd like to follow-up. When you're looking at transmission lines versus equipment, do you see a value -- a strong value for that identification of what the limiting element is for each facility? What that limiting piece of equipment is? I believe that's standard 8.2.

MR. GUGEL: In fact, you're required to identify that and certainly the knowledge of whether or not it's a wave trap or a CT or as switch can give you some information about whether or not there are, you know, some additional loss of life calculations. I don't know that specifically for maybe like a reliability coordinator knowing that information is immediately a concern, but at least it can open up a conversation between the transmission owner and the reliability coordinator about whether or not they want to take any kind of a loss of life calculation into account to increase a rating for a specific period of time.

MR. CORBETT: Got you.

MR. KOLKMANN: I just wanted to see if any of the panelists who have done pilots could walk me through at a high level how and AAR or DLR into the emergency ratings, do those all shift along with these day ratings or have these been primarily kind of focused at the study day rating and one of the early emergency ratings, how does that work?

MR. MURPHY: So, for PJM pilot project we were looking at the static ratings. I wish one of them could explain how they come up with the emergency ratings, but that's what we would control to in a you know, sense where we would use this in production, so that's kind of the best

I can answer that question.

MR. KOLKMANN: Sorry, just to make sure I understand. When you say you control to the emergency rating?

MR. MURPHY: We would have a 45 minute emergency rating that we would -- that would be based on the current conditions and a hypothetical drop in the wind speed at that time to formulate what the emergency rating would be. How that emergency rating is actually formulated I'm not sure.

MR. KOLKMANN: That would come from the TO and?

MR. MURPHY: That would come from the dynamic line rating vendor, they would formulate how that works and the TO would validate what is the contingency that you're considering as far as the drop in wind speed.

MR. XU: I wanted to add, for a short-term emergency rating normally you need to also provide or have some idea about the correct temperature, normally about 15 or 45 minutes, so you need to use estimate to do that.

MR. KOLKMANN: Okay.

MR. DAUTEL: I just want to say, especially because the first panel got cut off early. There will be a comment period, right? Yeah, I was like we should really make 100% sure that that's true. So, you will be able to add any additional thoughts, including the audience who isn't actively participating, but there will be a forum for you to get additional information on the record. That's all I have.

MR. KOLKMANN: Well, thank you for your time. That's all I have. It's been very informative, so thank you for that. And we will resume up again at 1 p.m. -- sorry, 2 p.m.

(BREAK)

MR. KOLKMANN: Good afternoon, welcome back everyone. Welcome to Panel 3 where we will discuss whether transmission owners should implement ambient adjusted line ratings. As you'll find out, the panel features a broad range of industry experts bringing their unique experiences as well as sharing lessons learned from the prior panel.

This panel will also discuss how any requirement for transmission owners to implement ambient adjusted ratings might be reflected in transmission service, both in ISOs and bilateral markets methodology requirements. And the panel will also address corresponding changes to ATC calculations as well as software and communication.

Thank you all for being here. I want to start off with introducing our panelists. From my right to audience's left to right we have Carlos Casablanca from AEP, Dennis Kramer from Ameren, Dede Subakti from California ISO, Michelle Bourg, from Entergy, Rikin Shah from PacifiCorp, Mike Wander from Potomac Economics and Amanda Frazier from

Vistra.

Again, thank you for being here. We'll start off with Carlos, so kick us off.

MR. CASABLANCA: Good afternoon, can you hear me? So, I'm going to read from my prepared statement. Chairman Chatterjee, Commissioners, staff, and colleagues, thank you for the opportunity to participate in this important -- not on? Or Closer? There we go -- Thank you for the opportunity to participate in this important dialogue.

My name is Carlos Casablanca, and I am the Director of Advanced Transmission Studies and Technology at AEP Transmission. American Electric Power is one of the largest electric utilities in the United States, delivering electricity to more than 5.3 million customers in 11 states. AEP also owns the nation's largest electricity transmission system, a more than 40,0000 mile network that includes more 765 kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined.

AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, and approximately 11 percent of electricity demand in ERCOT.

AEP's experiences with real-time facility rating adjustment techniques, including ambient adjusted ratings and dynamic line rating technologies, have given us a good perspective on the benefits and challenges of these methods and the value that they can bring to transmission owners and operators.

It is our belief that ambient adjusted ratings that leverage real-time and next-day forecasted regional temperature differences can increase the value of a robust transmission system to the benefit of our customers and bring flexibility to the transmission operations environment.

A requirement for transmission owners and operators in all regions to implement ambient adjusted ratings on most, if not all, of their transmission lines, should be encouraged. The application of ambient adjusted ratings in real-time operational environments is something that APEP has been doing for over 10 years. We monitor various temperature zones in each of our regions and real time temperature data is retrieved with every state estimation process run to adjust facility ratings.

The facility ratings are adjusted by interpolating between the respective seasonal summer and winter ratings, following AEP's established facility rating methodology. In addition, temperature zone values can be manually adjusted when performing studies in our State Estimator; a feature that allows our operational planners to better analyze the system impact of anticipated near-term temperature changes.

In the PJM Interconnection, transmission owners are required to provide temperature adjusted values for normal, emergency and load dump ratings associated with the limiting equipment for each particular transmission facility.

Eight different ambient temperatures are used, with a set for the night period and a set for the day period; thus, 16 sets of three facility ratings are provided for each monitored facility and used for operational purposes.

In the Electric Reliability Counsel of Texas, transmission owners are required to provide temperature adjusted facility ratings from 20 to 115 degrees Fahrenheit in 5 degree increments for requested facilities.

It should be noted that not all facilities in the AEP ERCOT footprint have seasonal differences in operating limits, only circuits that were built after 1977 have temperature adjusted ratings.

In the Southwest Power Pool and Midcontinent Independent System Operator, AEP calculates temperature adjusted ratings within the AEP state estimator and uses those ratings operationally. Seasonal ratings are submitted in both regions and although not required, both regions have mechanisms in place to allow members to supply ambient adjusted ratings via Inter-Control Center Protocol.

Whenever there is a difference in the derived opera ting ratings, AEP and the respective regional operator will operate to the most limiting ratings unless the respective regional operator elects to defer to AEP's temperature adjusted ratings.

Although AEP has leveraged ambient adjusted ratings for a long time, it should be understood that not all transmission lines may benefit from ambient adjusted ratings. Still, as several regional operators and we have demonstrated, the principle and methodology around ambient adjusted ratings should be feasible to scale to all transmission facilities.

Entities that have not applied ambient adjusted ratings before will likely incur some start-up costs associated with internal process development and documentation, weather data subscriptions, software changes, and training.

However, given our experience and practice in the four regions that we operate in, and across two different EMS platforms over the last decade, these should be manageable.

AEP also recommends that the application of these ambient adjusted ratings be limited to real time and day ahead operational planning and studies. We believe that neither ambient adjusted ratings nor dynamic line rating technology should be considered as permanent solutions to address any thermal constraints identified in long-term transmission planning reliability assessments, as these long-term transmission planning assessments are meant to be deterministic and conservative and assume system peak load conditions that coincide with higher ambient temperatures.

After the conclusion of this technical conference, we would recommend that the FERC issue an order with an appropriate timetable, requiring transmission owners and operators in all regions to implement ambient adjusted ratings on most, if not all, of their transmission facilities and that the application of these ambient adjusted ratings be limited to real time and day ahead applications.

I would like to thank again the FERC Commissioners and staff for your time, for organizing this Technical Conference, and for allowing us to participate. I welcome your questions and look forward to the coming dialogue, thank you.

MR. KOLKMANN: Thank you. Dennis?

MR. KRAMER: Good afternoon. I am Dennis Kramer, Senior Director of Transmission Policy and Stakeholder Relations for Ameren Services Company, and appear today on behalf of the MISO transmission owners. The transmission owners thank the Commission for holding this Technical Conference on the concept of adjusting transmission line ratings and this panel specifically on ambient adjusted ratings for transmission lines.

Transmission line ratings are a significant factor in the long-term transmission planning, operation of the bulk electric system, and functioning of the organized markets. Transmission owners are responsible for determining the ratings of the equipment using established calculation methods and in compliance with NERC standards and requirements. An important distinction that needs to be drawn is that implementation of AARs will not alter the transmission system long-term planning horizon requirements as described in NERC reliability and operating standards.

The standards establish specific criteria that the transmission owner must satisfy in order to achieve compliance. AARs are not applicable when determining the line ratings used in studies and analysis required to demonstrate compliance with these standards.

The ratings that transmission owners determine for their facilities are a major factor in determining how the bulk electric system is operated and planned as well as how organized markets function. There are various types of ratings, including static, seasonal, emergency, AAR, and dynamic line ratings, DLR.

Regardless of the purpose of the rating or the method transmission owners use to determine, the ratings must maintain public and employee safety; ensure the bulk electric system is operated and designed in compliance with NERC standards; not operate equipment in a manner detrimental to its planned lifespan; and be available to parties that depend upon these values for safe and reliable operation of the bulk electric system, or making decisions that are vital to the success of their business.

At a high level, the concept of AARs sounds appealing and relatively simple; adjust line ratings based upon current or near-term environmental conditions that being ambient temperature and sometimes wind velocity, to increase the efficiency of energy flow on the bulk electric system.

The broad implementation of AARs however, is not simple and could be very complex with impacts on multiple existing procedures -- processes and procedures, as well as requiring creation of entirely new policies, requirements, obligations and capabilities.

For example, transmission control centers use sophisticated software systems to monitor the condition of the transmission grid in the operating horizon to ensure the bulk electric system operates in a safe and reliable manner. A necessary input for these systems is the ratings of the transmission lines.

In order to continue to provide safe and reliable operations, many of these systems would need to have some level of modification to accept AARs in the operating horizon.

Transmission line ratings are also essential for the efficient and cost-effective operation of organized markets whether they be real time, day ahead, or longer term, such as FTRs or transmission service requests. In order to take advantage of any temporary adjustment to transmission line ratings, market operators will need to modify their systems to accept and integrate adjusted ratings.

Likewise, many market participants will need to modify systems they use to participate in the markets to integrate this new information.

There are also legal obligations and liabilities to consider that may result from broad implementation of adjusted line ratings that must be discussed and resolved. For example, what happens if the forecasted weather conditions that were the basis for adjusting a rating do not occur and the adjusted rating is no longer available.

From an operations standpoint, the answer is relatively clear in that the applied rating must ensure continued public safety and bulk electric system reliability. From the market operations standpoint, the answer is far less clear because similar documented and understood rules and policies do not exist.

A particular challenge will be if AARs are applied in establishing available transmission capacity ATC, for use in FTR auctions or transmission service requests, including short-term non-firm requests. Ambient weather condition forecasts are much less accurate in future weeks and months compared to the next hour or next day forecast.

New rules and policies will be needed to address the situation when an expected line rating is not available and a change from the expected rating impacts markets and market participants.

Finally, there's the question and matter of cost. The needed modifications to processes, procedures and systems to obtain the potential benefits from implementing AARs will require financial investment. Therefore, it's important that any implementation of AARs be focused upon transmission lines where it can provide the most benefit.

For AARs to be cost-effectively implemented, methods must be developed to identify candidate transmission lines and evaluate the benefit that AARs may provide compared to the implementation cost. Before these investments can be made, it must be determined which entities receive benefits from AARs and how to equitably assign cost responsibility.

There is no one size fits all path forward. The Commission should recognize differences in how the transmission system is developed over time because of unique topology, specific system requirements and differing environmental conditions.

Before any new or modified rules or requirements are considered, it's critical that all aspects of AARs be identified and fully investigated. This Technical Conference is a good first step in that process. The MISO transmission owners look forward to the exchange of information during this Technical Conference, and future discussion on these topics. Thank you.

MR. KOLKMANN: Thank you. We'll now turn to Dede Subakti from California ISO.

MR. SUBAKI: Good afternoon, my name is Dede Subakti. I serve as Director, Operations Engineering Services at the California ISO. So, first I would like to thank the Commissioners and staff for the opportunity to share my thoughts on this implementation of DLR and specifically for AAR, which is the ambient adjusted line rating and see how many we can put in this thing.

I think we've been talking about this for the whole day, whole morning about the principle benefits of using AAR or adjusted line rating. One way or another I think we believe that the principal benefits of using AAR is really giving us a more accurate understanding of the truly transferability of the transmission line at any given point in time.

I think we also talked about this may actually include whether or not this actually increase rating or also decreased availability that the transmission grid has, but all else being equal, this information should promote more reliable and efficient transmission operations.

In the past, in California ISO we've done some pilot programmings with regards to AAR. We have implemented some AAR certain degrees and now with the new EMS that we have, we have the capability of implementing any type of an AAR or DLR, you name it.

But today I want to focus on a couple items that we should consider. Number one is the questions about weighing any requirement for transmission owners to implement AAR for all transmission, whether or not it is necessary or not.

For example, AAR for a particular transmission line may provide a greater TTC, the total transfer capability and permit a more efficient security constraint or dispatch in an area like California ISO so where we actually run an older market.

In this case, an adjusted rating has the potential to create or resolve congestion riding on the transmission system. On the other hand, if we calculate and implement AAR for a specific transmission facility that has never been congested, then you're just not doing anything.

And the other portions in the Western connections we do have a number of stability and voltage limitation, so for those areas in there you might not gain anything. So, just have to be very careful and selective in where you want to put the AAR in.

Secondly, I think as Dennis mentioned, so we should consider if the more accurate rating could actually impact more or distort market efficiency. Let me explain. Changes to the facility rating in the day ahead timeframe may create variances to how California ISO has modeled its system for the purpose of issuing congestion CRR, or some people call it FTRs, through our normal annual and monthly process.

So, similarly implementing AAR in the real-time market, maybe the various between the PPC that is used in the day ahead hour and a half scheduling process for all of our -- that is in there.

So, the reasons why I said this is the reaction we have the project, and we actually have an hourly, real-time PPC calculation that we implemented and when you put it in there, the PPC would actually change as the rating changes, which then recite that the APC also becomes changing.

So, this variance between this market process may result in pricing impact that create unexpected market outcomes. So, I would suggest that the Commission and staff would need to explore whether this is more efficient to reflect this rating variances, or if they agree unnecessary uncertainty with respect to how a market participant would end up scheduling and needing their resources.

So, accordingly, California ISO urge staff and Commission to balance the efficiency and the reliable benefits associated with AAR against the increased volatility that such a rating might create in the market outcomes.

We believe that transmission owners, transmission providers should continue to determine if whether it is operationally practical to use AAR for all, or even some transmission facility, and also the Commission should also provide this entity with the latitude to structure their system in a way that leverage existing technology to submit and receive this AAR and incorporate them into their EMS, and/or market system.

We've heard today that there are multiple ways of doing that. Of course, that's one way, AEP does it another way. Those are great and we have -- we encourage that the

Commission should allow the transmission owner and operators to figure out what's best for them.

Especially in the area where the transmission owner is a part of the ISO and when the ISO have a CRR, FDR, day ahead market, as well as real time market to figure out when is it the best time to actually put this adjusted rating in any of these markets in there.

That's because the -- this foundation of food for captive AAR and the real time AAR might impact the market outcome itself. So, I would like to thank you for the opportunity, looking forward to discussing more with this panel.

MR. KOLKMANN: Thank you, Michelle?

MS. BOURG: I'm sensitive to the microphones all day. Wonderful, can you hear me, good enough? Great. Well, good afternoon. My name is Michelle Bourg, and I serve as the Vice President of Transmission Asset Management for Entergy Services. So, I'm really excited to be here and on behalf of the Entergy Operating Companies, I want to thank the Commission and the staff for holding this Technical Conference and facilitating these panels on how we may use ambient adjusted ratings into the future.

So, as a transmission owner and as owners of transmission assets in MISO, the Entergy Operating Companies are responsible for determining ratings of our facilities and we heard earlier -- in compliance with NERC standards, right, FAC 8, Entergy originally began getting experience with ambient adjusted ratings in the 2009-2010 timeframe.

And based on this experience, Entergy began a formal program with MISO using both ambient adjusted ratings and short-term emergency ratings on certain transmission facilities. And this started in 2016.

This afternoon I'll provide an overview of Entergy's experience with implementation of ambient adjusted ratings and give you insight into Entergy's journey over the past several years.

I think it's important to note that throughout this journey Entergy has maintained an unwavering focus on balancing grid security, safety of the bulk electric system and safety of our assets with really the desire to maximize system efficiency.

So, Entergy's adopted the use of ambient adjusted ratings and specifically I'll talk about temperature adjusted ratings, to enhance system efficiency during periods when ambient temperatures are less than conditions assumed in the calculation of our static ratings. And just for reference, we use 104 degrees Fahrenheit for that calculation.

This temperature adjusted rating is calculated by updating the normal facility rating, the static rating, to account for more accurate ambient temperature conditions. We trend historical weather within the Entergy footprint, obviously.

And we found that rating adjustments based on ambient temperature deviations is really the most efficient way for us to get the gains. It's also really the most predictable, which is a factor we hold to be very important in the consideration of dynamic ratings.

Since the Entergy service territory is really a hot, humid summer environment, I'll emphasize hot, humid, summers and mostly very mild winters, and we really don't have very large swings in ambient temperatures throughout the seasons. It's been our experience that seasonal ratings really just aren't as effective for us as it may be for other transmission owners.

It's also worth noting that Entergy does not make any adjustments based on forecasted or actual wind loading due to that potential variability in the real-time environment. Entergy's methodology for calculating static transmission facility ratings, and adjusting certain facility ratings based on real-time or projected temperature information is documented in internal facility rating methodology standards and separate procedure documents that govern our temperature adjusted ratings process.

Next, I'd like to give you an overview of the scope of Entergy's temperature adjusted rating, or I'll call it the TAR program, another acronym we use internally. And the process that Entergy uses to calculate the temperature adjusted rating.

So, we have approximately 2,300 transmission facilities -- this is lines and autotransformers, rated from 69 kV to 500 kV in our operational planning model. Of that population of 2,300 facilities, there are roughly 1,000 Entergy transmission facilities or 40% of the total for which Entergy calculates a temperature adjusted rating.

These facilities are included in what we call another acronym, the WEBTAR database. So, as the name implies, WEBTAR is an internally developed database with a web interface that contains information for selected transmission elements capable of being temperature adjusted.

So, the information housed in the database includes, among other things, section name, the from to buses, zip code, city information and all of the limiting element ratings, including ratings for our terminal equipment in the substations, the conductor itself, and the protective devices.

Entergy uses a commercial weather service to obtain zip code level temperature data, and this information is mapped based on the zip codes of the terminal stations to each line in the WEBTAR database. We also use publicly available information via NOAA, as a back-up source for the actual and forecasted zip code level temperatures.

So, using all this information, our WEBTAR program calculates temperature adjusted ratings for these facilities every hour, so at 2 p.m. daily, this program calculates a day ahead and two day ahead temperature adjusted ratings for the same subject of transmission facilities.

These hourly, daily and two day ahead TARS are shared with our real-time folks for use in monitoring and assessing transmission system security. They are also provided to MISO for use in real-time operations and in the day of and day ahead MISO markets.

MISO and Entergy exchange in quite a bit of two-way communication related to temperature adjusted ratings, so we each have the opportunity to identify facilities for which temperature adjusted ratings may be beneficial, weather and real-time operations, or for market consideration and we talk quite a bit about that.

A process has been defined for both MISO and Entergy, real-time and operational planning personnel to request TARS for facilities outside of the automated process as well. So, it's, you know, the process began as an off-line tool, but as it stands right now, this program will automatically upload into the EMS tools used by both Entergy and MISO to monitor the transmission system and it's also communicated to various internal stakeholders via email.

We've incorporated logic into this database to identify any large temperature deviations, and we also perform a quality control assessment of the calculated temperature adjusted ratings.

The methodology that we use for calculating temperature adjusted ratings considers the equipment temperature, which is determined by adding the thermal rise caused by load current to the ambient temperature. So, for every degree Fahrenheit observed, or forecasted below the 104 degrees Fahrenheit that we use in our static rating, the rating for most substation equipment -- and I have to say we do not temperature adjust autotransformers or protective relays.

So, the forecasted or the new rating can be increased by about 8/10ths of a percent for that substation equipment, while the rating for transmission lines can be increased by about 4/10ths of a percent. So, for every degree Fahrenheit less than the 104 degrees.

By adjusting certain facility ratings for this ambient temperature condition, we have observed a significant increase in real-time and near real-time ratings for the facilities that are included in the database.

So, over a 19-month period, beginning January of

2018 through present, application of temperature adjusted ratings for these certain transmission facilities have resulted in anywhere from a 5% to 25% average increase over the static rating, depending on kV class.

So, as the kV class goes up, so for our 500 kV facilities, the inverse -- that's about the 5% increase. And for our 69 kV facilities, the 25% increase. Application of temperature adjusted ratings has resulted in a maximum increase, so before it was average -- maximum increase of 8% to 33% over the static rating, again depending on kV class.

Because the conditions that allow for the use of these temperature adjusted ratings are not readily predictable on a long-term basis, dynamic or ambient adjusted ratings are more useful in the operations and day ahead real-time markets than in long-term planning.

Entergy does not support the use of temperature adjusted ratings for transmission planning, economic planning, or generator interconnection studies. This process, while automated, requires a significant resource commitment. Several years ago, Entergy established a configuration management organization that is responsible for maintaining static ratings for all transmission facilities, including all component and settings information, and communicating this information to stakeholders within our organization.

This information serves as the basis for all temperature adjusted ratings. In addition to the IT resources required to support the automation, required for the calculation and dissemination of temperature adjusted ratings, an additional full-time engineer is responsible for maintaining the WEBTAR database, performing modeling updates, liaising with real-time system operations personnel and other associated activities.

I would say automation is required to support the efficient calculation in communication of approximately 1,000 temperature adjusted ratings per hour, and this is key -- while minimizing the risk of human error.

It's also worth noting that Entergy uses short-term emergency ratings in very limited circumstances, so for less than 10% of our facilities, to minimize the risk of potential load shed while balancing risk for potential equipment damage, short-term emergency ratings allow for the operation of a given transmission facility for a short period of time at a level that exceeds the continuous rating of the facility.

However, use of short-term emergency ratings carries a high degree of risk, due to the potential to degrade the applicable transmission facility, or reduce its operating life, risk and trade-offs that must be very carefully balanced.

Entergy acknowledges that the continued use of short-term emergency ratings may deliver additional value to the MISO markets, but Entergy remains very concerned about prioritizing market needs over the needs to maintain the integrity of the transmission system itself.

As such, Entergy is continuing to evaluate the use of short-term emergency ratings in the market environment. Entergy believes that there is no one size fits all approach to rating transmission facilities and it's incumbent on each transmission owner to utilize information regarding the design basis, the topology and other operating conditions, among others, in the development of such ratings.

Thank you very much for the opportunity to share Entergy's experience this afternoon.

MR. KOLKMANN: Thank you. Next, we'll turn to Rikin Shah from PacifiCorp.

MR. SHAH: I'll read from my prepared statement. Good afternoon Chairman Chatterjee, Commissioners and FERC staff. PacifiCorp appreciates the opportunity to participate in the Commission's Technical Conference on Managing Transmission Line Ratings.

PacifiCorp concurs with FERC's initiative to discuss this important issue related to different methods of transmission line ratings, whether it's static, seasonable, ambient adjusted, or dynamic line ratings being used in the industry and how the dynamic line rating and the ambient adjusted ratings could be enhanced.

Appropriately evaluated and applied DRL and AAR -- ambient adjusted ratings may be useful in a alleviating congestion, including transfer capability and addressing reliability concerns, particularly within integration of renewable resources such as wind where the resource is not in the near vicinity of the load, DLR or AAR could be used to address reliability concerns under outage conditions.

PacifiCorp has used DLR system on technology in order to alleviate congestion and address reliability issues under outage conditions which in turn has increased the transfer -- available transfer capability on transmission path. This DLR system is implemented in eastern Wyoming on the Standpipe to Platte 230 kV Line, approximately 32 miles long.

This DLR system measures the ambient conditions on the transmission lines at three different load cells, three different locations, communicates the data to the central master unit, which then communicates the data to PacifiCorp's Energy Management System.

Along with the ambient temperature and wind speed, the DLR system also measures tensions on the line segment as well as ice loading and thickness. Based on these measurements, the DLR system calculates the dynamic rating approximately every 10 seconds and updates the EMS system with the new ratings. Some of the potential benefits that -- and challenges of using this system DLR are listed.

The benefits could be potential to eliminate or delay capital investment requirements by optimizing the transmission line rating and the transfer capability without requiring the construction of new transmission lines, which everybody knows could take a lot longer than the 10 to 12 years just to get that line built.

Potential to mitigate reliability concerns -- thermal overloads under outage conditions, awareness of the real-time conditions and true transmission line capability that could impact the reliability of the transmission system.

But with the benefits also comes the challenges like the regular maintenance of the AAR ambient adjusted rating equipment, or DLR equipment. Other limiting elements, such as breakers and jumpers connecting to the transmission line to the substation, even though as everybody mentioned that is 5 to 25% increase in the transmission line rating if a jumper is only capable of 1,200 amps it's not going to be good enough.

So, recurring costs -- these are technology changes and replacement of existing AAR/DLR equipment. We have -- PacifiCorp has implemented this DLR and currently it's under the process of replacing that particular DLR system with a newer DLR system.

Malfunctioning of the AAR/DLR equipment affecting the data quality and the loss of communication. Many times, the operators do face instances where the rating -- the data coming from the DLR system is not accurate based on their operational experience and so they have to go back to the static ratings and all of the static ratings that are in the line.

Because of the AAR/DLR technology bring both benefits and challenges, the benefits are best realized when specific applications are identified, and the systems are evaluated and designed to maximize the benefit of the specific use case. Accordingly, transmission owners should not be required to implement AARs on all transmission lines.

Transmission lines in the western interconnection, in particular, may go through a variety of terrain due to line length which can be several hundred miles. And varying geography of the western United States and hence experience a variety of ambient conditions -- ambient temperature, wind speed, altitude, et cetera, on which the rating would be dependent.

This would require ambient conditions and measurements across the entire line lengths at certain levels -- at certain intervals. Also requiring transmission owners to implement AARs on every transmission line may not be an effective use of the technology as the ratings established on some lines now may already be adequate either due to minimal changes in the ambient conditions throughout the year or the loading observed historically along with future forecast.

If you look at a planning just going with the same analogy as the highway, if you're the planners or planners design the system for 10 years ahead, 20 years ahead, and they already build a bigger wire just like a five-lane highway where one lane gets shut down, still your congestion may not -- there may not be any congestion because of that.

So, requiring them to put AARs or DLRs on that specific lined may be an ineffective use of that technology at this particular point in time.

Individual transmission owners should be given an opportunity to determine whether implementing the AAR on a particular transmission line would be beneficial to the transmission system in either alleviating congestion or enhancing the reliability of the transmission system.

Requiring the transmission owners to implement AARs on every single transmission line may result in unnecessary investment without the return that was expected and put additional burden on the consumer rates.

The transmission owners should be allowed to determine the subset of transmission lines on which the AAR should be applied as they have access to and are in the best position to make this assessment. The planning/operational reliability analysis, historical information on congestion, causes of congestion, and limiting element information, LIDAR survey results, et cetera could be used as criteria for determining the subset of transmission lines best suited for the AAR/DLR application.

PacifiCorp does not operate under an RTO or ISO but believes that there would be both benefits as well as challenges for RTO/ISOs to incorporating the AARs into their energy management system. Widespread implementation of AARs, whether implemented under an RTO or ISO or non-RTO entity has the potential for significant communication network upgrades necessary to communicate the real-time ambient conditions to the energy management system as well as the new line rating and the changes to the ATC and share that real-time information to all participants and affected systems. This would be an added cost to installation and maintenance of the communication network.

Just to point out the real-time BLR implementation that PacifiCorp has done has almost a full screen worth of DLR data that comes into the EMS system that gets verified from the three different stations. Just imagine that was spread across every single line in the United States, so that is one concern that you have to consider.

Currently, the tools and software used to conduct power flow analysis incorporate static ratings provided by the transmission owner. These tools currently do not have the capability of handling ambient adjusted ratings to determine varying total transfer capability under varying ambient conditions.

The seasonal TTC, that total transfer capability, of a transmission system is established using these static ratings. If the TTC of a transmission system is based on a single transmission element and is limited due to thermal constraints, then the increase or decrease in the ACT available change of capability of the transmission element could be proportionally used in the markets.

But if the SOL, or as everybody says, system operating limit of a transmission system is based on a transmission flow gate, which is very much the case in the Western interconnection system where there are multiple lines that are forming a flow gate into a load sensor or anything, then the transmission full TTC analysis might be needed if an ambient adjusted rating shows that the rating is different for one line.

And so, the transmission flow analysis needs to be conducted in order to determine the increase or decrease in the ATC. This is due to the fact that the impact of the change in rating of one or multiple transmission elements due to the ambient adjusted rating on the transmission flow gate is unknown until the full TTC evaluation is done.

Network transmission service and the point to point transmission service irrespective of the bilateral markets or the RTOs/ISOs utilize the same transmission system hence both should be impacted pro-rata for the changes to ATC based on the AARs.

This is in response to the question whether a network service should be curtailed first or the transmission service should be point to point transmission service should be curtailed first. I think it's one transmission system, so the curtailment happens across the transmission system pro rata and so that would be the input to that.

Due to the intermittent nature of the ambient conditions which could change significantly within an hour timeframe and potentially increase or decrease the ATC in the market, AAR should only e used in markets that are operating in hourly or less time frame.

Also, the positive changes to the ATC should be available for non-firm products that could be easily curtailed if necessary, in the light of the changes to the ATC. Keeping it within an hourly timeframe -- hourly or shorter market, will not only help test the technology and process but also minimize the changes in the ATC due to unexpected changes in the ambient conditions.

Many transmission owners currently do not have the communication network and the tools in place to accept and use an AAR data stream and automatically calculate AARs and change the ratings in the real time EMS system. Significant communication networks to capture ambient conditions and calculate AARs would be required along with tools that would automatically update the ratings in the EMS.

Also expanded communication networks will be necessary to ensure that all data gathered to calculate the AARs by the transmission owners is communicated to the RTO respectively. Again, data quality check requirements would also be needed by the RTO/ISO in order to ensure that the quality of the data received by the RTO/ISO is usable.

PacifiCorp believes that the current FERC regulations and NERC standards adequately address the distribution of the transmission line rating methodology by transmission owners to entities concerned with the reliability of the interconnection and the transmission system such as the reliability coordinators, transmission operators, planning coordinators and transmission planners upon request.

Through its transmission planning process, PacifiCorp continues to consider possible applications of DLR and AAR on its system for reliability enhancements and transmission customer needs. PacifiCorp does not see a need to revise the existing FERC regulations and NERC standards covering distribution and coordination of facilities ratings methodology as part of any effort to advance more widespread adoption of AAR and DLRs.

Consideration should be given to how the protection of the thermally protected transmission lines will be handled in light of AAR and DLR. For example, if a real-time rating, if it's a thermally protected line, the line is going to trip at 1,200 amps, but if the AAR says it's 1,600 amps, the line is still going to trip at 1,200 amps. Should that be changed or not changed? And how should that be protected, that line?

So, that would be given. Also, consideration should be given on how the interconnection procedures could be modified such that the transmission provider could identify an AAR/DLR as a mitigation to the thermal constraint as part of the interconnection cost.

The reason I put this statement in here is because while going on through the standard interconnection process, the transmission planners or the transmission providers does not have the opportunity or the timeframe to do a real-time study to ensure whether DLR or AAR mitigation is adequate mitigation or not, or whether they still need to rebuild the line or not.

So, that's the part where I think to identify that as a mitigation this is a very -- it can be a very good tool, but an adequate timeline should be provided. And additional outreach with regards to the benefits and challenges of implementing AARs/DLRs involving a wide variety of stakeholders throughout the interconnection is warranted.

Finally, I thank you for the opportunity to provide comments on this important issue of managing transmission line ratings. I would be happy to answer any questions that you may have.

MR. KOLKMANN: Thank you, Mike Wander from Potomac.

MR. WANDER: Hello, that works. Okay, my name is Mike Wander, I'm with Potomac Economics. We are the market monitor for the inter-continent ISO. We work around the country but most of my comments pertain to just MISO given the experiences we've had with MISO.

So, I guess I'm ending the suspense. We do believe a requirement should be put into place. I didn't want to bury the lead, and we believe that really based on our experience over the last maybe 5 or 6 years primarily. And so, we have done the studies that we've published for the last 2 years at least. And those studies are built up from real-time data looking at all the binding constraints on a 5 minute basis.

And we've mapped those constraints to the nearest weather station and where people are providing ambient adjusted ratings. We wouldn't show, and in fact we calibrated and found very little benefit and our back casted benefits match very well with the actual experience from TOs, but the bottom line is that we're showing benefits of about 150 million dollars a year.

That's split between ambient adjusted and short-term emergency ratings about 50/50. And those results quantitatively are very consistent with the results that Entergy has reported, at least the last stakeholder presentation that I'm aware of was end the 2018, and the quantity changes that were just reported a moment ago also match pretty closely with those numbers.

But, the vast majority of TOs in MISO do not voluntarily provide ambient adjusted ratings and we and MISO have tried with limited success over the past few years to get more participation in some very detailed discussions after a lot of you know, learning about the methodologies at the end of the day it appears that many TOs, it's simply their policy not to provide ambient adjusted ratings.

It's not based on reliability that at least on some elements when we've gotten into the details. So, as noted there, TO agreements, the open access tariffs, NERC, IEEE standards that have been talked about today don't require ambient adjusted ratings, but importantly they don't preclude them either.

And then I think the bottom line that the benefit of requiring this seems like a reasonable solution. And I guess I already referred somewhat to Entergy, but they're not the only one in MISO that has ambient adjusted rating programs and we show significant benefits with all the programs.

And I didn't hear any today and to date I haven't heard of any. You know, there's legitimate reliability concerns notably with the short-term emergency ratings as discussed. But no actual reliability issues to date in the ambient adjusted programs.

Then the next point -- I'll explain a little bit, it's maybe a little obscure but we think there's also significant reliability benefits simply in the RTO/ISO world. The TOs provide the ratings based on a methodology known primarily only to them, so we think there's true significant benefit in the RTO/ISOs or any transmission provider being more aware of those methodologies.

And in terms of transparency to a wider audience, I think there's likely benefits there too. There might be security concerns, those can be dealt with. And then the next point under there -- it may come as a shock, somewhat of a shock to me, that the RTO/ISO world does not generally keep a comprehensive database of the most limiting elements and most surprising that that would be -- limit the ability to identify really low-hanging fruit in the planning processes.

So, if you have a -- and this case to light in MISO's vetting all of our analysis where they said, you know, you're calculating significant benefits and the limiting element here as was researched, found to be something else. But that information does not get into the planning process.

So, if you have a wave trap or a current transformer that you know could be upgraded at pennies on the dollar, compared to the conductor -- that knowledge is not currently getting into the planning process.

So, there's a number of side benefits to expanding our requirement for AARs. So, I think as I note here at the end, you know, we think the requirement should certainly consider adding to the STEs or short-term emergency ratings.

What would the requirement look like? So, I hesitate to say it should be on a subset or I agree with the notion of prioritization and in fact, Entergy's done just that, it seems to be a reasonable approach. I don't think it would be feasible to implement a requirement on all facilities right away.

But if you leave it to sort of an opaque process where TOs are deciding where to put the emphasis, I don't think that brings us very far from where we are today and again, based on four or five years -experience, we've made very limited progress today, so.

And then in terms of precision and uncertainty, there is a concept in the industry transmission reserve margin. We don't expect TOs to take changes. You know, we think with uncertainty in terms of resolution of the information without DLRs, you know, DLRs can solve a lot of that but we're talking AARs here.

We expect them to use a transmission reserve margin or something equivalent to that in a safety margin on AARs. I think those should be transparent -- those reserve margins, and they themselves could highlight where DOR investment might be warranted and be most cost-effective.

So, that kind of gets to the prioritization question. We think it should be a general requirement.

There could be a showing on why the requirement shouldn't apply to this or that. I mean that could be up front. And then, so TOs would -- in our world as today, they would be responsible for the ratings, transmission owners and transmission operators, that convey them to transmission providers -- a lot of terms.

So, that would not be changed. It would just be that the transmission provider would be responsible for understanding what goes into the methodology and verifying. So, we've covered that.

And short-term emergency ratings -- what we see in the industry is a lack of clear standardization on what the timeframe of those short-term emergency ratings are. And MISO doesn't have a database -- I think it may be true of all RTO/ISOs, they don't have a separate database that says this is a 45 minute rating, a 1 hour rating, a 4 hour rating, and that actually should be something that's conveyed and would be enhancing to reliability.

Not perhaps, I know FERC has dealt with the topic of predictive adaptive ratings. I think that I'm not arguing that should be a requirement but in the discussion, if you did have that capability, that would also allow greater utilization of short-term emergency ratings, and less reluctance on parties like Entergy, you know, who, you know, they -- I think it was 10% was the number.

You might get more robust participation.

On the question of ATC/AFC and I threw in TLR there, I think I share the views that have been expressed that in ISO/RTO markets, most of the benefit is in the day ahead and real-time market and trying to roll in the AARs into the current ATC and MISO AFC leads to ATC might be counter-productive. If the TOs necessarily and rightly would be more conservative in providing those values since the further you go out the more uncertain those values could be.

So, I think we simply think in the RTO/ISO world, the focus should be on day ahead and real-time and the markets at least MISO has something called a spot in service which is already going to capture all the benefits of the AARs in real-time. Now in the non-ISO/RTO world, it should get in there. That's the only way to get the benefits of AARs is through incorporating them into ATC.

And then I added the twist -- the transmission line loading relief should definitely incorporate AAR values. It seems unjust and unreasonable to have a TLC called on a facility where AARs could be calculated. So, that concludes my statements, thank you.

MR. KOLKMANN: Thank you, Amanda?

MS. FRAZIER: Good afternoon and thank you Commission staff for hosting us today. I think this is an interesting and meaningful topic and my name is Amanda Frazier. I am the Vice President of Regulatory Policy for Vistra Energy and I think I represent a unique perspective on this panel, but I'll keep it short.

Vistra Energy has competitive generation and competitive retail companies in six of the seven organized markets in the United States. And I primarily want to talk about my experience in the ERCOT market.

Specifically, in 2013, Oncor, which is a distribution and transmission company in ERCOT, did a pilot program with their transmission system to implement dynamic line ratings that was incorporated into the RTO as you heard Chad Thompson talk about this morning.

Both, day ahead real-time markets and also the financial transmission markets called the CRR markets, it's not part of the planning process. I heard a couple of the transmission providers warn you against incorporating it there and I think that's probably prudent not to include it in the planning process.

But it has made a big difference for the generation fleet. In ERCOT you hear a lot about congestion relief benefiting customers and loads saving money. But it also relieves generation trapped that could be available to serve load and allows generators to optimize the deliverability of their energy.

And so, from that perspective we strongly support AARs and DLRs being incorporated into all of the competitive markets.

MR. KOLKMANN: Thank you. I'll start off with the first question. One of the things that I'm struggling with, hopefully you can help me -- so, once you've implemented a program to rate lines on an ambient adjusted basis, what's the incremental cost to rating another line at an incremental basis?

I ask because it sounds like most of the costs that are associated with an initial upgrade to EMS is software and I understand that obviously, many lines are not congested all the time but I also don't understand what the cost is to rating lines on an ambient adjusted basis once you've already started the process.

So, if people could help me out with that, that would be helpful.

MR. CASABLANCA: So, I can't really speak to the dollar figures, but I think what you can maybe takeaway from what I've shared, and other panelists have shared is there are different ways of implementing ambient adjusted ratings, so even for us right?

In one case we used the PJM approach is through a website where you submit sort of tickets where you provide different ratings for different facilities. ERCOT, I think it's more of a spreadsheet method where all is submitted all at once.

SPP and MISO at least for us, right now what's available for us to use is uses the ICCP protocol, which is more real-time, so I think that incremental cost is going to vary depending on the implementation that is chosen, either by the utility or the RTO.

So, I think that's -- I mean the point I probably want to make sure you take away is there are different ways of implementing AARs. They have maybe some pros and cons in terms of maybe how frequently the data is updated and maybe how good or real-time quality it is, but then also the implementation costs will also vary.

I don't think there is a one single approach will do it and maybe that's another takeaway is you need to leave the different regions and transmission owners to figure out how to implement the AARs, but there's ways of doing it and I think we've shown it.

MR. KRAMER: Yes, just to elaborate on that a little bit more. There are different methodologies, there's technologies. You've got to remember there's over you know, 30 transmission owners within the MISO footprint, and therefore each has different sets of technology, so you may add one line, however that may be the only line that that particular transmission owner has that would be subject to

AARs.

There's also the question of the availability of data. Now, I know Entergy is using zip code level data. Some areas have better monitoring facilities and better forecasting capabilities than others, some of those are better and like I said just because you're near a zone of urban area, as opposed to very remote, and very rural where they may not be the temperature sensors.

MR. SHAH: I think as Mr. Kramer pointed out, if it's in a diverse just like for example a couple hundred miles of line which is going through an area which is not like you know, there are no temperature sensors. We have to specifically install temperature sensors now.

The other thing to keep in mind is that to keep that communication established from that point on to the EMS system, that it is coming, it is accurately coming in and because of weather changes and stuff, if that communication gets unestablished, you've got to go back and the technician would have to go back and do that maintenance on that particular temperature sensor, so.

MR. KOLKMANN: Michelle and then Mike.

MS. BOURG: I was just going to very simply add, you know, its been our experience, and that's what I can speak to here and everyone's journey and experience is different. But because we're using commercially available weather information, we're not deploying discrete sensors or any kind of any facilities out in the field to capture information.

And because we already have the infrastructure built, not only to manage the calculation process, but we also have the information available for all of our facilities, that next incremental facility to apply a temperature adjusted rating for us is very incremental and really is not material.

But we're further along, perhaps, on the journey than others, and we have the infrastructure built to accommodate that.

MR. WANDER: Well I don't know if I'm allowed to ask questions of the panelists myself, but I'm interested if we don't have these resolutions --

MR. KOLKMANN: Can you speak into the mic, please?

MR. WANDER: Oh, I'm sorry. Whether when you don't have the resolution in place today, maybe you want it or are considering it, but you don't have it today, whether the concept of transmission reserve margin makes sense.

Where you do have some temperature, you know, you have a national weather map. You have a, you know, a broader forecast. Your rating is based on 104 and you know, the national map is not going to get above 80 anywhere. You know, with some concept of an ambient adjusted rating based on some conservative value be applicable, you know? What's the rationale for not being able to consider even when you don't have zip code or more resolution?

MR. KOLKMANN: Who wants to take it?

MR. KRAMER: Yeah, just for the record, Dennis Kramer for the MISO TOs. There is a lot of different locations that transmission lines traverse. They go literally tither and yon, so transmission lines go uphill, they go downhill, they go into valleys. They go into areas where local temperatures can be much different than you know, 3 miles - 5 miles away.

Other locations have micro-climates and, you know, you can talk about those near lakes and things of that nature. So, to say that the national level of temperature is going to be no higher than 80, is really not applicable when you're talking about a transmission line that's running through a valley in the middle of, you know, Missouri through the hills where there is no error, there is no really wind in the summer usually.

And maybe on both sides have heavy growth of trees through a national forest. So, to say that 80 degrees is not going to exceeded in the nation really is simply not applicable. So, in those situations the challenge is the critical span -- if you're going to assume that the transmission line itself is the rating -- is a limiting factor, not the transmission terminal equipment.

But the limiting span can literally move depending upon as the sun moves across and is there wind and things of that nature. I'm not advocating for DLR, but what I'm saying is there needs to be a recognition that these lines do not all traverse in straight lines across open fields where there is solid topology. That's where there's a need for no one solution fits all.

So, if you're going to establish requirements, you have to give the flexibility for people to adjust to the fact that a line going across say, southern Illinois, in our domain, is on flat land. You could see for miles. If I go into Missouri, I'm talking about a very different topology with craigs and valleys and hills, thanks.

MR. KOLKMANN: Does anyone else want to address that? Okay. I'm curious about the connection to short-term emergency ratings also. It sounds like all of you have experience rating at an ambient adjusted basis, but only sometimes provide short-term emergency basis, I'm sorry -- short-term emergency ratings.

Could you talk me through why you choose sometimes but not always, rate on a -- provided emergency ratings and how those are calculated as well? What's the cost benefit thinking there?

MS. BOURG: Sure. So, I talked about a small subset of our facilities where we do calculate short-term emergency ratings. Those are typically calculated on an hourly basis and go through the same program that I talked about that's automated and has all of the interface and connectivity with the EMS system to provide the information.

When needed, because of system reliability issues, we obviously have the capability to calculate a short-term emergency rating outside of the automation and provide that to both our real-time system operations personnel and to MISO for their use.

MR. KOLKMANN: Okay.

MR. DAUTEL: Michelle, I had a follow-up question to the statement you made in your opening statement. I think we've heard in our outreach a lot of the things you've talked about in terms of AARs and DLRs not being very helpful during planning.

The caveat we often heard after that is of course, for economic projects that are being planned, they may be of some use. I think you said the opposite of that, and I just wanted to unpack that a little bit and understand if we're thinking about the same thing or you're talking about something different or what the rationale is behind that.

MS. BOURG: Yeah, I mean my comment was just simply related to the time, domain and the time horizon and the fact that yeah, we really only have certainty around what that weather or that temperature information is going to look like right now, here and present and reasonable certainty like in the near future.

As we think longer term around transmission expansion, reliability planning, economic planning, generator interconnection, that level of uncertainty for us is not something that we're comfortable with. You know, making an assumption around temperature information as we think into the future. Does that answer your question?

MR. DAUTEL: Okay, I think so.

MR. KOLKMANN: Does anyone else have any comments on that or? Thank you all for your presentations. I do not want to cause any drama, but I think I heard a direct disagreement between the gentleman from PacifiCorp and the gentleman from Potomac Economics. I understand you represent different types of organizations.

But perhaps we should first establish that there is a disagreement? It sounded right towards the end of your presentation that everything is working fine and no change in requirements, et cetera. Okay, go ahead you can --

MR. SHAH: So, PacifiCorp believes that AAR and DLR does have benefits. But the benefits should already concentrate in the sense that a broad spectrum of applying this to every single line segment may not be an effective use of the technology as compared to a very focused method of this is why this line, we are using AARs and DLRs on.

That is the approach, I think that's why. And again, the information about congestion is with the transmission planner based on their transmission planning studies or the RTOs on the real-time operations, but those are the information points that we should be taking in order to consider which lines are there, should be.

But what PacifiCorp does not believe is that -- is to mandate it for every single transmission line.

MR. KOLKMANN: Okay, that's totally fair.

MR. WANDER: Can I jump in?

MR. KOLKMANN: Yeah, of course, of course.

MR. WANDER: I don't think we would generally disagree with that. I think it's rather that you cast a wide net on a requirement to go through some steps. And those steps could include demonstrating that oh, it doesn't make sense here because. And that "because" could be a micro-climate where temperature spikes, if that's, you know, if that can be verified.

Or that could be the limiting element is not subject to ambient adjustment, but even that as I said, would have the residual benefit that then we can zero in and say there's huge benefits in upgrading that limiting element.

So, I think it's just on the initial set of requirements that that should be broad. But within that there can be exclusions and prioritizations.

MR. KOLKMANN: Okay, and that's great. I'm glad everyone's getting along. But --

MS. BOURG: I was wondering what the disagreement was.

MR. KOLKMANN: So, I going to -- one of the last paragraphs of the PacifiCorp statement was, "PacifiCorp does not see it needs to revise existing FERC regulations and NERC standards covering distribution and coordination of facilities rating methodology as part of any broader effort."

MR. SHAH: So, let me clarify that statement. It's more reflecting of the question that one of -- it's, there is a claim being made that there is opacity in the -- or there's less transparency in sharing the transmission rating methodology because of different entities.

Again, as I -- and the paragraph pointed before is the entity's related to the reliability concerns like their reliability coordinator or the transmission operator, transmission planner, was designing the system. They have an ample opportunity to request that transmission rating methodology and use that.

And with that specific concern, PacifiCorp believes that there is no additional regulation required. Again, there might be examples where a developer may -- a generation developer may think that the transmission rating methodology is opaque to that particular developer, but that really goes into -- it might be related to interconnection, but the transmission owner or the transmission provider is looking at the entire system and the reliability concerns with that.

So, that's -- that doubles the point being driven with that particular paragraph, that no additional regulation is required.

MR. CICCORETTI: I think I want to follow-up on some of that discussion and direct my question to the two gentlemen who advocated for requiring AARs. You said that it shouldn't be required on all lines, but as you said most lines. How do you draw that line? Where would that requirement fall? Which lines would be exempt, Mr. Casablanca, do you want to start?

MR. CASABLANCA: Yes. So, from our perspective I think my statement, there are some historical design practices that you know, in a sense we've grandfathered. I mean we've got some assets that are over 100 years old in some of the regions and based on maybe how some of the clearance criteria was applied when those assets was designed, we don't think it may be safe or prudent to apply it in some facilities, right?

So, I would say design methodology, rating criteria, probably are some factors that should come into play when we select which facilities, we would implement AARs and which not. I think some examples have been made as well here in the panel where there are some facilities where they are, let's say coming up a lot in day to day operations or in the market, and maybe that should be your radar.

Maybe that's the way of taking -- that should be our radar. Maybe we should look at some specific subset of facilities that are implementing AARs may give us the most benefit for the investment we need to make and whether it's an RTO or transmission owner and kind of going through the burden and cost of implementing the AAR methodology to actually get the benefit from AARs in the real-time environment. So, I think those are maybe some guidance I would give on how to make that selection.

MR. CICCORETTI: Mr. Wander?

MR. WANDER: So, I think I would say I think having it as a broad requirement to go through a process and that process itself would then eliminate facilities that are inappropriate. We use the word feasible for AAR but just you know, it would be you know, if a professional engineer puts his name on something and says this cannot be temperature adjusted, or this is not suitable, we would tend to believe him.

But that would be the process. The process would be identifying which ones were suitable, which ones weren't, and they would have to affirmatively -- the TO's would be responsible for affirmatively saying this is inappropriate.

Now within that, I think there should be a prioritization. We, you know, a market-based prioritization, administered probably by the transmission provider or ISO/RTO, but outside ISO/RTOs maybe the transmission provider.

MR. KOLKMANN: So, you're suggesting a process that includes both technological and economic factors?

MR. WANDER: Well, the initial set would be a broad requirement to affirmatively state which facility is ambient adjusted. If we're starting from a set that you know, we're agreeing or starting from, you know, 104 degree conservative seasonal rating, and you could establish how that response would come to you or who would sit in a position to determine which facilities are exempted effectively.

But so, I'm saying that initial requirement would be broad. And the benefit of that would be that you'd start to develop a database of -- for the planning process, a database of potential upgrades that are very cost effective to make a facility ambient adjustable. You know, if it's lacking some attribute. But I'm not suggesting that we compromise our liability at all.

And I'm not suggesting that TO's take a chance. I'm rather suggesting that we come up with the metrics of how much conservatism they're applying, and what's the nature of the need for that conservatism. We all agree the planning, you know, the longer the horizon, the more conservative you need to be.

But it could be the nature of that conservativism is lack of a temperature gauge somewhere nearby. And that might be a very cost-effective solution.

MR. CICCORETTI: And we'll open it up to any other panelists that want to comment on where to draw that line, bright or otherwise, Mr. Kramer?

MR. KRAMER: Thank you. I guess the comment I have with the broad process is that it's just that, it's broad. You're talking thousands of transmission lines that would have to be dozens of man hours spent to justify why this line that hadn't had congestion in decades would suddenly need to be looked at and reviewed, specifically to see -- well maybe if it will sometime tomorrow, we need to do something.

It would seem as though it should be much more cost effective to focus on those that answer the two questions of how much and how often? If you're talking about economics here, and you're not talking liability, we're only talking economics, then it would seem as though there should be flexibility built in to work with the TO and the RTOs and ISOs, to determine what is a level of congestion and economic impact of certain lines, and then screen for that.

That to me seems to be a relatively simply process to at least get that initial screening. Because once you get that screening, then you need to look at what's the root cause? Okay, we've already heard that there is in some cases, terminal equipment -- in many cases, actually, that are limiting factors.

There are limits of what we can do and what temperature adjustments can do on terminal equipment. Switches don't normally temperature rate very much quite frankly, from our experience. However, then you run into okay, I've identified a line that would be a potential economic, you know, maybe AARs would be applicable, then you need to look at what's called the next limiting element.

Because these systems have been developed over the years to be relatively concise and consistent. In other words, the RTO -- I can only speak within the RTO arena. The RTO arena, at least in MISO, is there's been efforts made to I guess I could use the term harmonize, make them consistent across the footprint on the different systems that have been upgraded so that the ratings would be if you make a change to one line, you may quickly within a very short increase, hit the next limit.

So, you need to look at that from a holistic viewpoint rather than just one line at a time. You need to look across the entire system to which, as Potomac Economics says, you want the most bang for the buck. So, there may be two lines, there may be three lines that need to be looked at and identified for an upgrade to get the full benefit. Thank you.

MR. KOLKMANN: Miss Frazier and then Mr. Shah.

MS. FRAZIER: Thanks. I don't have a suggestion on a bright line in that I think there's a tendency in this arena to let the perfect be the enemy of the good and so, we've heard a lot of discussion around, you know, you have to include every line all the way to you should let us cherry pick any line or not required to make any requirements at all.

Because the incentives are not aligned for transmission providers to voluntarily do this, I think it would be helpful to have the regulators say this is the right thing to do. This is the way to optimize the system, but I would not want to see that fall into a situation where in order to get it perfect, we miss the benefits of the easy solutions and the low-hanging fruit.

MR. SHAH: So, a couple of things. So, the question was about what can be the criteria for determining the subset of lines. So, from the transmission planning perspective, the planners perform a 10-year out study. If there are congestions being identified in those kinds of studies, you can potentially look at the performing a real-time study based on the ambient conditions to see whether that mitigation is going to be a fruitful mitigation or not.

Or, you can use the LIDAR surveys that have been done to determine the FACH ratings of every single line that determines which are the most congested lines and which are the lines sagging the most. Those kinds of criteria could be very beneficial in determining which ones should be focused on -- which line should be focused on.

MR. KOLKMANN: Thank you.

MR. CORBETT: Just to follow-up on the short-term duration ratings, I kind of reflect back on this car scenario where it's driving down the road 65 and then you get increased risk on the path and you slow down to 40. With regards to operating the transmission system, we're operating this system to a normal rating and then as the system develops additional risk, we speed up, okay.

So, what I'm wanting to know is when you're operating the system at an operational rating and you need more capacity and you could pivot towards ambient adjusted ratings, or you can pivot towards short-term durations, so what is the trade-off? Can you speak to what are the trade-offs, what are the risks that you're willing to inherently absorb for this additional capacity through short-term ratings when maybe the line is rating because of the sag of the conductor?

Okay, rather than shall we say, the risk that you would anticipate from applying AARs, yes Rikin, yes.

MR. SHAH: That was from my last.

MR. CORBETT: Okay, Carlos?

MR. CASABLANCA: My understanding is we, I think, maybe is to try to avoid to apply short-term emergency ratings on facilities. When we do, I think it's been more associated with substation equipment. I think for us, AAP, the ambient adjusted ratings are easy, right, as I've already explained we're kind of already doing it for the most part in many locations.

The one challenge that I see, and I know we've discussed it internally around short-term emergency ratings is the fact that this is a rating that essentially exceeds what you normally would consider your maximum rating. And then let's assume that you actually consume or operate to that limit, to that short-term emergency rating.

Now, you have to essentially account for and track the fact that you consume some life on the asset. And now for that asset, how many times are you going to do that? And tracking the history of the number of times that I have actually operated this asset, sort of beyond the normal emergency rating that I would normally apply, that becomes sort of a burden documentation. Plus the fact that when we do, I think there's been a few cases where we actually have done short-term emergency ratings, but it's not an automatic process essentially.

You have to engage a subject matter experts internally, an analysis has to be done, it has to be documented, I think for NERC compliance reasons, so it's a multi-hour process to come up with a short-term emergency rating versus what, at least for us, adjusted ratings is sort of like almost automatic.

So, there's a burden to it and then the tracking of it long-term that becomes a challenge as well, so that's what I can comment on that.

MR. CORBETT: Yes, so you don't use the short-term? You're not inheriting the risk. You're pivoting towards the ambient?

MR. CASABLANCA: Normally, yes.

MS. BOURG: Yeah, it's normal conditions for Entergy use, the temperature adjusted rating, when you really see that it's very -- there are benefits to your benefits to use in the temperature adjusted rating throughout other ratings for us and foremost, increased operational studies, operational plans, outages in the form of operating guides, tension bearing load sheds and operational constraint where it can be gives us that ability in that perspective.

And certainly, it is not our attention or it's not our desire, it's not to operate, in short-term emergency rating, they're there for a reason. They're there obviously to give time to upgrade a line or to plan and mitigate the issue, but it's certainly not our preference short-term emergency rating.

So, there's a burden to the tracking of it long-term, I think that's a challenge as well, that's my comment on that.

MR. KOLKMANN: Because you don't -- in the short-term you're not inheriting the risk, you're pivoting towards ahead.

MR. CASABLANCA: Normally, yes.

MS. BOURG: Yeah, under normal conditions for Entergy as well that we would use the temperature adjusted rating, and we really see that really as a very low risk proposition. There are advantages to using the temperature adjusted ratings in the form of increased operation flexibility and outages on the system in the form of you know, operating to prevent central pollution, we find ourselves in operational constraint, that DMV, they're temperature adjusted so it can give that flexibility in that perspective.

And certainly, it's not our intention or it's not our desire to plan to be operating to a short-term emergency rating, they're there for a reason, obviously, to invest some time to create a plan to mitigate the issue, but it's certainly not our preference in the operating tools for a short-term emergency rating.

MR. SUBAKTI: In California, there are 3 to 500 proposed kV proposed on the cells, right? And we actually have to make one long-term positions every single time. It appears on the transmission line it's a more efficient way, or, I think we all know in the NERC family, in the FERC approved standard, we have to do it as N minus 1, right? What would happen if -- and that could be a trade off on how much oil that you could allow in that transmission line in the normal continuous stated versus how much would you be willing to allow for the N minus 1 contingency rating.

So, in our experience by working with it, that's how we know it's real, every single day, so you could suffice that you could re-inspect your system to have a lower pre-contingency to allow the use of emergency N minus

1 or N minus 2 ratings, and in which case we think that you could actually use something for an emergency rating versus you're just going to say you know what, we're not going to go all the way to the emergency rating, therefore I'm actually allowing more flow in the normal continuous rating.

That pre-load easing element that occurs when you are reinspecting your system, that the pre-contingency flow is actually in the system. So, the other portion that we have to think about after that is that in the event that you have something in it, you'd actually have the resources to actually reinspect your system within 30 minutes to actually bring that flow down, all the way down because you're allowing so much more maybe to enter, now you're actually having to have more to reinspect your system in an appropriate timeframe.

And we actually, in California, I think we actually embark on what we call the corrected capacity in our market to figure out how much capacity do we have that will allow, you know, that the emergency rating is working, because sometimes you may end up having a wide, more ramping capability to get off of that emergency rating if you're not careful.

So, it's a line day-to-day position that I think the operators are cognitive, they have to make those decisions, whether or not they're allowing more megawatts in the normal pre-contingency and expansible not using the emergency rating the other way around.

MR.KRAMER: Yes, as we covered, just recapping, the way I'm using short-term emergency ratings is it is post-contingent and so, you know, before those contingencies happen, you're maintaining the normal continuous rating as a separate monitor tone, so you're not pushing over that limit.

It's only post-contingent, so you know, if that contingency actually occurs, then you're going to go over that normal continuous rating, so the question becomes to what extent do you know for certain that your poste-contingent actions can get you down to that normal continuous rating in the allotted time period, and I think that's the problem that utilities have.

MR. SUBAKTI: Like, you know, even for one of the cases for the emergency ratings, why they all conform, and it gives the operators a time to get the system under normal by continuous ratings for the terminally constrained element and take action.

And, so that action may equate whether it's a 30 minute emergency rating, or a 4 hour emergency that is what operators should do to get the system back to normal.

MR. KOLKMANN: Thank you all for this discussion. I want to turn to the extra emergency if I can. In implementing either AARs or DLRS, at least when there's a connection that creates congestion, I asked so how do you manage this? What are your thoughts on that, what are the connections and one of the things I wonder is would transparency fully help out on this?

If market participants are aware of how introducing line ratings aren't being calculated, they can make decisions based on how the rating is accordingly, or -- any research on that would be helpful. Mr. Subakti first, and then Amanda.

MR. SUBAKTI: Yeah, what I'm still wondering the same way, for best reasons right now, for our FDR, or as we call it, our STRR, we use the flow rating. We use the flow rating that is in there and we know that you know, the seasonal rating is more over time.

And then when the end of the day ahead, we actually got some of our transmission owners to give us trend uses, it's the high open data, if you actually -- it's a small area, a compact dense area. We know that in that area there's going to be a high of 80 degrees tomorrow, we use 80 degree temperatures instead of the usual seasonal summer rating at 104.

So, that's why to create a difference between what the DLR model versus what is in the day ahead model, that you may end up not having congestion in the day ahead and you collected something in the CRR or the FTR process.

Actually, the same questions could be made because when we use that day ahead for the Agency rating, and we create that congestion based on the 80 degree rating, and then real time it's actually 78 degrees rating, and the congestion disappears. So, somehow, we corrected the congestion in the day ahead and it's not there in the real-time. So, this is actually one of the things that maybe comments about we might want to take a look at it -- I know that PJM and ERCOT had just done this, and frankly will look at what is the impact of the DLR and the congestion offset as well as the differences in there and it was very interesting.

Before us right now, we don't do that in the FDR and the CRR and we do that in the day ahead and the real-time and we do see that difference you know, both directions, that is in there. And even beyond that, I think when somebody's asking about planning, if the same question occurs for people who are, especially in California where we have a high density area where we assume that we need the generation in the area, right, because we have a conservative rating for planning.

But then every time in real-time that generation never runs because it's never needed, because the temperature goes higher. So, that's what happens with that investment with the generator that's in there. So, that's mainly why, you know, my comment is asking maybe before we make any -- it's good for reliable, for transparency, but at the same time not quite sure what the impact in the market and if it's going to create efficiency in the market or distortions in the market, what have you in there, so.

MS. FRAZIER: So, in ERCOT, the CRR market use a monthly high rating which is not perfect. But they also, CRR markets don't sell 100% of the transmission capability, even up until the month ahead market. So, there's always conservatism in those forward markets.

They don't include all of the outages that occur in real-time, so you're always going to have discrepancies between the forward market and the day ahead market and the real-time market. And those are discrepancies and variances that get accounted for and there are different winners and different losers, but that doesn't mean that you shouldn't try to make the market more reflective of the actual capability.

So, a monthly rating is not perfect, but it's certainly better than 104 degree rating in February. And so, I would you know, I would again suggest don't let the perfect be the enemy of the good and bring these dynamic or really, it's just ambient adjusted temperatures in the forward markets.

But put those into the forward markets and allow the markets to adjust to that information.

MR. KRAMER: Thank you, I think what you're hearing is that every one of the markets are different. They all have different terms for the different products that are used. And I think that points to the fact that there needs to be flexibility in allowing each of these markets to work out how these impacts would apply to them.

The FTRs, as we just heard, at least in MISO, the farther out you go, the less certainty as we've said before, you have in forecasting the weather. We don't use the Farmer's Almanac, thank heavens, because if you've been reading it, it would be very extreme coming up.

So, those are the things that we're most concerned about is making sure that all of these factors that would impact or be impacted by ambient adjusted ratings, we have a chance to review them, to examine them, to make sure we have a full understanding of the impacts of any ambient adjusted ratings that we may be applying.

MR. KOLKMANN: Mr. Wander?

MR. WANDER: I think this just puts more of a premium on it, just so the markets can see this before you know, the rights are sold. They know the process. But we couldn't be -- and I think Amanda's points go to this right away. We're not arguing that because the financial markets and the options assume an outage, that we better impose that outage in real-time. We're clearly not assuming that right? So, I think it just gets back to transparency. That the increased need for transparency.

MR. KOLKMANN: One of the other things we heard in the morning panel was regarding forecasts. So, I wanted to touch upon it here as well. And this is really a question in regard to the application of AARs to the day ahead market.

We've heard different opinions here. And so, the question is essentially how -- why aren't you more -- why not -- is it possible to set a confidence interval conservative enough that might alleviate some of your concern about applying ambient adjusted ratings to the day ahead market as well?

MR. KRAMER: I'll start. Let me understand when you say confidence interval, what are you referring to?

MR. KOLKMANN: What I mean is you can set -- we're not talking about a 50/50 forecast. We're talking about certain standard deviations more conservative than what you would typically expect to happen. So, it would -- it could be for example, 98% confident we heard this morning that load will be -- that the temperature will not exceed a certain point.

I think I asked this morning one of the experts whether for whatever confidence you want, you can get a conservative forecast for that, and I thought I heard yes. So, a follow-up question I have is if you can get whatever confidence you want and even in the day ahead timeframe, why not use that forecast in the day ahead market?

MR. KRAMER: Okay, I'll do my best to what I think the question is. As I've said I think in my statement, when there was a discrepancy between real-time and day ahead, and you say a day ahead of 100 in real-time, the temperature is 110 and so, you know, you have to reduce the rating.

The operators are going to do what's necessary to keep the system safe. So, that's a given, that's going to happen. So, now you're talking money. And you're talking the difference between what someone expected would be the dispatch pattern, and the day ahead market when they ran the commitment schedules versus real-time.

That's where we think that that needs to be thought of very carefully. I know some are doing it already. MISO is somewhat and I guess you could say we're not as -- AAR as Mr. Wander said, isn't that popular, at least yet and MISO is not that prevalent.

But there needs to be a discussion around what do you do with that data you said in their market, with that difference in the dollars? In other words, in the day ahead you may have collected money that in real-time doesn't need to be paid or vice-versa. So, those are the things that we have that in certain cases which will make whole payments and things of that nature.

But none of that that I'm aware of, reflects or incorporates what could be a driver such as ambient adjusted ratings. Did that make sense? In other words, we have adjustments between day ahead and real-time, but I'm not aware of anything that incorporates or captured impacts, potentially from the ambient adjusted ratings that would drive those.

MR. DAUTEL: There's a possible analogy, the forecast we currently do between per load between the day ahead and real-time market? That's a forecasted value that could be accurate or not accurate and be different in real-time.

MR. KRAMER: I think there could be. We'd have to look into the forecasts for the ambient adjusted ratings because here again, you do have depending on what is the particular binding constraints, because you're going to have a different set and we understand that, between day ahead and real-time already.

Just we are using -- the impact of some of the weather already, so to speak, because as you just said, load is incorporated. I don't think it's impossible, but it's something that we need to have time to evaluate in how to best reflect that and capture those impacts.

MR. SUBATKI: In California ISO we have multiple transmission owner and I can think of two transmission owners right now that are actually giving us you know, a so-called dynamic plan rating adjustment or adjusted rating in some sort. So, in the day ahead they would forecast the temperatures and they say it's going to be 80 degrees, I'll plug in whatever the 80 degree reading in that, and it's in there and some -- the other transmission owner would say that hey, you know, tomorrow is going to be a little bit windy, so we'll put whatever, 4 foot per second instead of 3 feet per second, so then it's you know, it gives us something in the day ahead.

And then in the real-time that number is adjusted again. So, we are doing that, and I think it's a valid question for us at least, and I think this is different for every single market as well. They're very similar. I used to work for another ISO in eastern connection, but it's very similar because for us, at least in California ISO, when there's a different within load for example, right, within load forecast in the day ahead and the real-time, those are kind of like an imbalance.

There's an imbalance that's within a day and a half and the real-time, then it becomes you know, there's a sufficient guarantee or BCR, or whatever, micro-payment that is for the energy portion that is in there.

Now, for the limit changes, it's a little bit different in California ISO when we have a limit changes, where for a transmission line that is binding, those are kind of like what we often call real-time congestion offset, which is, you know, a different bucket of money that is in there.

So, you're right, I think in a sense, it becomes very similar, but you know, one way or the other it's going to impact the economic on it. And I think I agree that whatever that we do -- there's an economic impact in there, but whatever that we do is also give the system operator a better awareness of what is the truth of the transmission capability of the system, and I think a lot of us are somewhat -- I mean it's kind of always challenging is trying to -- how do you value this increased awareness of the reliability because that is actually a good value and a good benefit that we could actually see all this stuff, but it does impact, you know some of the markets.

And I agree it's put a premium on the transparency. So, in California ISO, we always publish what is the limit that we are using in any given market run. So, this -- there will become more data. I mean there's a lot of data that's out there, so market participants are more than welcome to grab all those data, but it's a lot of data.

If you get all these limits that are in there, but the data is out there for some ISO maybe, hopefully for all ISO, for all this limit that is out there. And because for every market run when the limit changes, it will impact all of those.

MR. KOLKMANN: Our understanding is that, and I asked this of the previous panel too. I'm curious to know what you guys think of this. Our understanding is that RTOs at times asked TOs for an updated rating in real-time. Typically, this is for reliability reasons, it's done for good reason.

And it takes advantage of differences in temperature between what is planned for using the static rating and what actually is occurring at a given moment. Do you guys -- are you guys familiar with this process and would -- it would seem like implementing ambient adjusted ratings would be able to capture a lot of the benefits which might be occurring on a one-off basis. So, what are the benefits there, if at all.

MR. SUBAKTI: Let me start, I think, you know, Mike Wander touched a little bit on this as that as a system operator, you know, California ISOs or maybe other ISOs, the first and foremost thing is being able as a system operator is to be able to have this information right in front of them, that's very important -- that's premium for us.

California ISO has been an ISO for some time and we just become an RC, a reliability coordinator, and our footprint of ISO and our footprint of reliability coordinator is actually different, right? The reliability coordinator footprint is actually bigger than the ISO footprint.

The reason why I'm saying this is because for ISO footprint, for California ISO footprint through our tariff, we actually have an operational control for some of these transmission lines that is turned over to us.

For those transmission facilities that is turned over to us, we actually have a requirement through our tariff that allows us to have what we call a transmission registry. The transmission registry is actually a requirement for every single equipment within our control grid to have all the facility ratings for every single one of the bus, the CT, the disconnect, the jumper, the limit there and everything, which then allows us as the California ISO to be able to know exactly what is the most limiting element at what any given point in time.

And I think that's probably pretty unique for California ISOs because we have the ability to do that through our tariff, to kind of ask and request and mandate that information from our transmission owners. For that particular reason, our operators really like the idea, but I know exactly what is the most limiting, and if it is a conductor, then they can actually call and ask if we actually have a transmission adjusted rating.

And we actually made the requirement for all those transmission owners if they do have a transmission adjusted rating, at the very least you've got to give me an Excel spread sheet that has all the ambient temperature, similar to what ERCOT does and what not.

Now, that's not the same for maybe other ISO, it's not even the same with the RC portions of California ISO that is not part of the control grid portion that is in there. But I'm familiar with the process, and I can see actually in both directions, which one the operators really like, but at the end of the day, the operators need to know what is exactly the most limiting element and what is the major of that limiting element, so that they actually know right away to make an informed decision and know what the risks are that they are getting.

So, I think that's very good, but I think that's a lot of data as well.

MR. KRAMER: Dennis Kramer for MISO TOs. Yes, MISO -- the process that you described is accurate. MISO will contact our operating center and ask if the rating of the line could be adjusted upwards, so the engineers on the staff -- on the line, would check the rating, make sure that is the limiting element, number one, as we talked about. It's not a circuit breaker or something of that nature, or a wave trap.

And then I think in most every case we would agree to the change. MISO would put it in its system. I assume their dispatch system, and also their state estimator would do the same with theirs, so yes, those adjustments do occur at the request of MISO.

MR. KOLKMANN: Anyone else want to say something -- oh, sorry, Amanda?

MS. FRAZIER: I was just going to add -- and they would happen automatically if you incorporated AR's into the system.

MR. KRAMER: Exactly.

MR. KHELOUSSI: We're definitely focusing, just for discussion purposes on the proposal for AARs, but I did want to ask just to get opinions. Are there even limited circumstances where the benefits of the DLR would be so obvious and so overwhelming that they should just be required? Yes or no? Opinions? And if so, how would we know that? What would a process be that would allow us to figure out what facilities those might be?

MS. BOURG: I guess, you know, in the spirit of there's not a one size fits all approach for everybody, I just think about Entergy's journey and the experience that we have had with applying temperature adjusted ratings sort of in a scaled fashion for -- but they are relatively substantial subset of our facilities.

And I think about the benefits that we've derived in terms of you know, average and maximum temperature adjusted ratings above that static facility, and we've done that using the information that we have internal to our organization, right? Institutional knowledge and the understanding of all of the elements that are in series that make up that transmission facility knowing what those limiting elements are and having the visibility into our system to be able to make informed decisions as to how temperature may or may not make that facility adjustable.

And then I think about the deployment of technology that has to happen to get that recognizance from the field for dynamic facility ratings, you know, the deployment of capital, you know, the maintenance associated with it, the telecommunication.

Someone earlier on one of the panels talked about potentially some of the cyber security concerns with the transmittal of all of the information about the status of the bulk electric system, so I'm sure there's risks and trade-offs with both, but based on you know, some of the gains that we've seen through our process, using temperature adjusted ratings, you know, I think we're pleased with what we see and would certainly not advocate for any type of you know, requirement to do one over the other, because I think, you know, either/or may have some place, but certainly I think we've demonstrated that this one has been very successful for us.

MR. KRAMER: Yeah, and just to echo what Michelle said. The one size does not fit all, especially when you're talking about dynamic line ratings. Because you'd have to not only go through the expense of identifying where it should be, but then implementing it, maintaining it secure, keeping that data.

And also, you need to really examine the value of a number that's changing, possibly every minute or every two minutes. In other words, what are you going to use that data for? Just because you can gather it, just because it's obtainable, does not mean you're going to be using it for decision-making.

And I think that's what we're really trying to strive for here is what are the information sets and data sets that's most impactful to make the benefits available to our customers at a reasonable cost?

The cost of the DLR would, I think, would be something we'd have to look at very, very closely before we'd ever move into that arena where it would be -- you'd have to have a discrete value to looking at something every minute, or every t wo minutes as opposed to possibly every hour. Thank you.

MR. CASABLANCA: And I'll just echo as well, the similar statements. In spite of all the pilots, the federal pilots we've done on DLR technology, you know, we're nowhere near comfortable in applying it in a real-time operational environment. I think our concerns -- it's an interesting technology, it probably has some short-term niche application today, but you know, long-term deployments, the processes around all that and the challenges with the security communication maintenance operation, I think there's a lot of questions for us to try to answer internally.

So, I don't think we can give any guidance on how would we select which circuits to apply it to today.

MR. SHAH: It just again, like on the same points but similarly stating that you know, it's the tail is the best fitted position to determine those ratings for where the DLR's, for example, just giving the same example that I said in my opening statement.

The source behind that constraint was wind energy and so, in order to enhance the transmission capability across that corridor, that's where the DLR system was implemented and so, I agree that you know, not one size fits all would kind of apply to the DLR technology itself as well.

MR. WANDER: So, as Rob said, you know, everything comes down to incentives. A requirement is an incentive. I don't think we were as comfortable going with the DLR, you know, concept. We thought you appropriately scoped this panel, the folks on the ambient adjusted. To me, I think again, back to the sort of opportunity to collect more information so that we're making informed decisions and there's transparency, that could be part of the requirement is to you know, if you can't ambient adjust to the full extent, you know, you have to apply significant transmission reserve margins, or whatever you want to call it, you know, DLR's could solve that.

So, I think we would stop short of saying requirement, but it definitely should be part of the discussion. And I know you are, with the next you know, additional NOI-type discussions.

MR. KOLKMANN: Okay, thank you. It's now slightly after 4 o'clock, so I want to be respectful of everyone's time. Thank you again very much for joining us here today. It's been very informative.

There will additionally be a request for notice of request for comment afterwards, so to the extent we didn't cover anything, please feel free to say that in your comments and we look forwards to those, so thank you. We'll convene tomorrow at 8:45.

(Whereupon the Technical Conference concluded at 4:03 p.m.)

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceeding before the FEDERAL ENERGY REGULATORY COMMISSION in the Matter of:

Name of Proceeding: Managing Transmission Line Ratings

Docket No.: AD19-15-000

Place: Washington, DC

Date: Tuesday, September 10, 2019

were held as herein appears, and that this is the original transcript thereof for the file of the Federal Energy Regulatory Commission, and is a full correct transcription of the proceedings.

Charles Hardy

Official Reporter