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MEREDITH BRASELMAN: Good afternoon. Welcome to Resilient Power Grids-- Strategically Undergrounding Powerlines. I'm Meredith Braselman with ICF. Thank you for joining us for today's webinar.

A few housekeeping items before we get started. This Webex meeting is being recorded and may be used by the US Department of Energy. If you do not wish to have your voice recorded, please do not speak during the call. If you do not wish to have your image recorded, please turn off your camera and participate by phone. If you speak during the call or use a video connection, you are presumed consent to recording and use of your voice or image.

All participants are in listen-only mode today. If you need to view the live captioning, please refer to the link that is in our chat. If you have technical issues or questions, you may type them into the chat box and select to send to host.

We are taking questions today, and you may submit them throughout the event using the Q&A function. We will have a Q&A session after each panel. When you submit your questions, please reference the speaker or topic so we can direct it to the correct person.

And finally, we will post a copy of today's presentations on the Resilient Power Grids web page by Monday. The slides will also have contact information for our speakers, and the recording of today's webinar will be available in about two weeks. So to get us started, we are thrilled to have Pat Hoffman, Acting Director of the Grid Deployment Office, joining us today and kicking off our event. Pat?

PAT HOFFMAN: Thank you, Meredith. And I want to thank everyone for participating in today's discussion. It is a very important discussion for us today to talk about strategically undergrounding power lines. And so your engagement and the information we present here are very important as we think about infrastructure as we move forward.

As you all are aware, investing in our T and D, our Transmission and Distribution infrastructure, is at the heart of our clean energy objective. We know it's very critical in supporting further electrification of the economy, but also really adding to the resilience that the economy needs moving forward.

So as most people think about it, undergrounding is, of course, more aesthetically pleasing, but we recognize that strategically undergrounding power lines can make a community more resilient by minimizing damages and hazards, such as extreme weather events, hurricanes, and wildfires that a community may face. We recognize that undergrounding power lines also can have some opportunities or issues with respect to rebuilding of the infrastructure or not having to rebuild infrastructure, but it does have potential as we think about expanding our infrastructure.

The question that we always struggle with is, where does undergrounding make sense? And we talk about strategically undergrounding our infrastructure, and that's part of the session that we want to have today, is really to think about how do we best do that and how do we best look at undergrounding moving forward. But let me take a step back and talk about the electric grid writ large.

We all understand the importance of reliable, resilient, and secure electric grid. A transmission system building out our transmission and distribution system helps get electricity where it needs to go. It helps with balancing supply across the United States, and it really allows for communities to be connected, taking advantage of distributed energy resources, and really allowing for capitalization of power, clean energy across the United States.

We also recognizing upgrading the power grid is necessary as we think about the weather events that we're faced with, whether it is more intense hurricanes, whether it's tornadoes, whether it's wildfires, that we must keep pace with the future. We must keep pace with the challenges that we're facing today. We also recognize that expanding the transmission system will help us integrate renewable energy and clean energy sources as we think about really expanding and meeting the President's objective of 100% clean energy by 2035 and net zero by 2050.

We also recognize that demand is going to grow as we think about the electrifying the building and transportation industries. We know that we need to continue to invest in our infrastructure to support electric vehicles and vehicle charging stations as well as electrified buildings. So this means that we really need to strategically invest in the future, plan for the future, and be very careful and thoughtful of how we do our investment.

So where can we take advantage of undergrounding our infrastructure? Where can we take advantage of expanding existing infrastructure moving forward? We recognize that we need both investments in the T and D system, but we also need to invest in the generation side of things, clean energy, distributed energy resources, energy storage solutions. They're all opportunities in investments moving forward.

We also recognize that there is not a single silver bullet, but we're going to have to invest across the system writ large. We all recognize that transmission is difficult. It is time consuming to build, it takes a long time to get transmission projects developed, permitted, sited, and constructed. So we know we need to focus on what can we do to expand our existing grid as well as look at new transmission lines.

But let me just take a moment and talk about our objectives and our philosophy. We want to really maximize the capacity on the existing transmission system and really lean in to take advantage of what the existing system has to offer. So that may be optimizing transmission lines to really take advantage of where can we utilize existing rights of ways, and to be able to capitalize on where we can expand or increase voltages, but really look at those opportunities and existing rights of ways.

The other thing that we're looking at is how can we take advantage of existing technologies, such as grid enhancing technologies, that really looks at going from static line ratings to dynamic line ratings to really take advantage of those opportunities of maximizing the capacity on the existing transmission system. As we also think about our infrastructure and existing rights of ways, we do also want to think about their wants, which is really taking advantage of once we disturb the ground, can we really maximize any sort of crucial infrastructure projects moving forward, whether it's broadband, whether it's power, whether it's other utility infrastructure, it's a philosophy. We really want to take advantage of that.

So I did want to let you know that, of course, why are we thinking about all this? Everybody is pretty much aware of the bipartisan infrastructure law that was passed that provides a significant opportunity, over $20 billion in federal financing tools that are available related to transmission, expansion, and resilience activities. Some of this includes loan borrowing authority to build transmission lines through the Western Area Power Administration's transmission infrastructure program, through the Department of Energy's loan guarantee program. We also have $2 and 1/2 billion in borrowing authority for a transmission facilitation program, and what this program allows is for us to either buy capacity online to do a loan or actually to directly invest in transmission lines.

In addition to that, the bipartisan infrastructure law has $5 billion that's dedicated to preventing outages and to enhancing the resilience of the electric grid. And it is Section 401.01, and that is actually the grid hardening provision. In addition to that, there is $5 billion for demonstration of innovative approaches to transmission storage and distribution as we think about regional grid resilience.

And then, finally, there is $3 billion that's associated with smart grid investment grants, similar to what was invested in under the Recovery Act programs. So there is a huge opportunity for communities, for utilities, developers to really think about how do we upgrade our transmission and distribution system.

And part of that is really getting into the discussion of what makes sense as we look at transmission and distribution infrastructure. What is the realm of the possible? And what is the strategic decisions that need to occur, whether you're talking about above ground lines or you're talking about strategically undergrounding transmission and distribution lines.

So in closing, grid hardening and transmission resiliency is very important as any community starts to think about their resilience objectives and what they want to do in support of a reliable and resilient electric system. Today, you'll hear from utilities about their experiences, their lessons learned, and the important decision process that one needs to consider as one evaluates different technology solutions.

You'll hear from state and municipal regulators about their real world experience, about some of the decision processes they have, and the rules of the road and regulations associated with undergrounding.

With this information, I'm hoping that communities can take a hard look and be very strategic about some of these investments moving forward. We recognize that undergrounding is an important tool and an important opportunity as we look to advance climate change. But it is not the only opportunity that's out there.

So with this, I really want to leave you a message that the discussions, the collaborations, the broad range of stakeholders that we have here today is going to be critical as we move forward and as we think about community resilience and investing in a resilient infrastructure. So with that, I thank you very much for your time. And I'm going to turn it back over to Meredith to lead us to the next session.

MEREDITH BRASELMAN: Thank you so much, Pat, and thank you for setting the stage for today's conversations. I am excited to introduce our next speaker. Peter Larsen is Staff Scientist and leader of the Electricity Markets and Policy Department at the Lawrence Berkeley National Laboratory and a research fellow at the University of Montana Bureau of Business and Economic Research. Peter conducts research and analysis on the economics of electricity reliability and resilience, energy service company industry and project trends, long-term electric utility planning, risk to infrastructure from extreme events, and islanded power systems.

Please join me in welcoming our keynote speaker, Peter, who will be available for questions after he speaks. Peter, I will turn it over to you.

PETER LARSEN: Thank you very much. I want to thank the ICF team for making this all possible from a technology perspective. And I also want to thank the Department of Energy, who supports our National Lab and supports a number of research projects that are directly relevant to our topic today.

So I'm going to share results of a pair of cost benefit analysis that I completed, one for Texas, what I call an ex-ante analysis, and one for Cordova, Alaska. And we have the privilege of having the CEO of the Cordova Electric Co-Op on one of our panels later today. So you're going to hear about Cordova from an ecologists' perspective.

So my interest in undergrounding really started from some Department of Energy funded research into reliability trends across the US. And we've published a number of papers where we looked at 200 utilities across the country and looked at how reliability is changing over time and what are some of the factors that are affecting reliability. And one of the things that we found is we got access to data, utility data, on the share of line miles that were actually underground, and we included those in a pretty sophisticated economic or an econometric analysis.

And lo and behold, we found out that, not surprisingly, utilities that had a larger share of transmission and distribution lines underground had a statistically significant correlation with improved reliability. And so that got me thinking, what is the value of having undergrounded lines?

One of the things you hear, I think kind of a knee jerk reaction you hear from some stakeholders is, well, undergrounding's too expensive. It's too costly.

But in my research, I found that there wasn't a lot of information about the benefits of undergrounding. So if it's really costly, what is that relative to in terms of benefits that undergrounding might provide? And a researcher at a consulting firm basically did an analysis of Texas and came up with a finding that undergrounding all of Texas's transmission distribution lines led to costs that were far in excess of the quantifiable storm benefits. And so I wanted to sort of explore this issue in a bit more detail, especially for Texas.

And so I've set up a cost-benefit analysis framework. And I'm going to move fairly quickly through all of this, so please feel free to ask me questions at the end. But I set up an analysis framework, and who was I really interested in exploring the decision around. And it turns out I was interested in basically a public utility commissioner in Texas, someone who cares about maximizing private benefits. There are a bunch of different stakeholders in Texas, if you're thinking about undergrounding the power system there.

And I looked at two different policy alternatives-- a status quo, meaning let's just maintain the existing share of underground line miles versus overhead line miles. And in Texas, about 20% of all transmission distribution line miles are underground right now. And a policy alternative-- what happens in the future if the public utility commission of Texas decided from now on every overhead line needs to be underground and all future transmission and distribution lines need to be built underground?

And I picked Texas because there was a wealth of information already out there in the public domain, including this consultant's report, so I had ready access to some really good assumptions to build a pretty sophisticated cost-benefit analysis. And I group the costs and benefit categories into these different categories by stakeholder, and so you've got the independent or the investor-owned utilities had some costs in my model. And we have ratepayers, and the ratepayers would pretty much bear a lot of the additional costs of undergrounding and converting the overhead to underground.

And then there are people that live in the service territory and beyond in Texas who get benefits. They may not be ratepayers, but they get benefits, like avoided societal costs due to less frequent power outages or, as Pat Hoffman mentioned just a second ago, avoided aesthetic costs. Not looking at a transmission distribution line actually has economic benefit that can be measured.

And so I built the model that basically took all of the transmission and distribution line miles in Texas and converted them over time, over the course of four or five decades. And then any new transmission or distribution line, my model assumed that's going to start underground, and you can start to estimate the lifecycle costs.

And not surprisingly, the lower graphic shows the net present value in billions of dollars. So it goes $10, $20, $30, $40, $50 billion. So under the undergrounding, not surprisingly, undergrounding the entire Texas system over the course of 40 some odd years is a very costly endeavor, exceeding $50 some odd billion. If you maintain the status quo of having the same share of overhead and underground that we have today, it's less costly, but still significant.

One of the things that I was able to model, then is, if you have a larger share of underground line miles you can actually show improvements in reliability. And under my modeling assumptions, I assumed reliability was actually going to get worse in Texas, which is sort of playing out in reality over the past couple of years. But if you have more underground line miles, it's not getting as bad as it would have been had you not been completely underground. And so you can start to put a dollar value on the avoided costs of power interruptions.

And so here in this lower graphic, the navy color is the cost of power outages because these reliability events, these interruptions happening in the future are lower under the undergrounding. And that makes sense because there are less lines exposed to the elements. You see the property value, if you're not looking at basically underground line-- if you're not looking at overhead line miles, there's an aesthetic benefit that you can measure in terms of property value.

One of the tools that we used or I used in this cost-benefit analysis is a tool that's been funded by the Office of Electricity called the ICE calculator. I'm sure many of you have heard of this before it's a tool to estimate the costs of power outages. So when I came up with the avoided costs of power outages because you have more underground line miles, I used the ICE calculator.

And I should mention to this audience. We are undertaking a major initiative, a public-private partnership with a large section of the country of utilities representing many, many different service territories who are actually funding Berkeley Lab to update the ICE calculator. So if you'd like more information about this big project, please let me know. This is an exciting emerging project that will be underway over the next year or two.

So if you put all this information together into this cost-benefit analysis table, the first three rows are really the costs. The total net costs, if Texas made the decision, if the public utility commission said, let's underground all of our existing overhead lines and all future lines, the cost would be about $28 billion in net present value. The benefits of undergrounding, this major mandate, not a strategic undergrounding, but a major mandate to underground everything, the net benefits were $7 billion.

And so as you can see, when you compare the costs of the benefits, the net social benefits are negative, and negative by a pretty significant number, about $21 billion. And that leads to a benefit-cost ratio 0.3. So for every dollar you invest, you get three $0.30, essentially, of societal value back.

And I ran this under a wide range of scenarios and what's called the Monte Carlo simulation. And every possible permutation of assumptions that went into this model showed pretty significant net social losses from this broad mandate.

One of the things I like to create are tornado diagrams, and this is a wonky way of just showing what's the model sensitive to. And it turns out discount rates, the costs of undergrounding, and the lifespans of the overhead lines are the three most sensitive parameters that went into this cost-benefit analysis.

So what did I conclude? Well, not that the public utility commission of Texas was ever considering this, but if they would have considered a broad mandate to underground everything, this is a bad idea because there are very significant net social losses.

So then the question is, what are the minimum conditions necessary for a strategic or a targeted undergrounding initiative to actually have positive net benefits? And what I found was that these, if these conditions here hold, you can see some net social benefits, meaning the benefits exceed the costs. First, there has to be a lot of customers per transmission distribution line mile. These have to be densely populated areas.

You also have to have an expected vulnerability to frequent and intense storms. And much of Texas, especially along the coast and in the tornado corridors up towards Oklahoma, these are places that fit that criteria. You also have to have the potential for economies of scale, and I think Pat Hoffman alluded to this in her comments earlier when she said, hey, if you can underground in parallel with fiber optic lines for other types of utility services, you can actually achieve cost savings and get these costs of undergrounding line miles down.

And then overhead line utility easements are larger than underground line utility easements. That essentially means that places where you need a larger right of way for the overhead lines, that's another candidate for an underground.

So now I have the pleasure of talking about my ex-post analysis, and this is for a place that's near and dear to my heart, Cordova, Alaska, and you're going to be hearing from the gentleman in the upper right picture here, Clay Koplin, here in a bit. I was traveling all across Alaska, maybe eight, nine years ago, studying rural power systems and the challenges and opportunities they face.

And I had the opportunity of traveling to Cordova. And as I was driving into town, I saw these workers digging a trench. And when I met Clay for breakfast, I said, what are those workers doing? And he said, oh, we are just completing undergrounding our entire power system.

And it was one of those moments in life where I was struck because I had just completed this Texas analysis. And I looked at Clay and said, hey, could I do a case study on your decision to go 100% underground? He said, of course. And so he helped me. So I'm going to report the findings from that study.

So in this case, it's the CEO, Clay, who cares about maximizing benefits for his community. There are a bunch of different stakeholders. And the policy alternatives are a little different.

In 1978, when the decision was made to underground Cordova's system, maybe they just never did that and they stuck with the overhead line model. And then the alternative is, let's underground all of our lines, and that's what Cordova actually did. So this is an ex-post analysis.

Here are the different costs and benefit categories, very similar to what I talked about for Texas. So I'm not going to spend too much time on this. This graphic in the upper left essentially shows my model simulating how this system went underground under different scenarios since 1978. And then, as you might suspect, the lifecycle costs of undergrounding exceeded the costs of overhead.

And then I modeled, and with a little help from Clay and his team at the Cordova Electric Co-Op, how much the reliability improved because of this very large share of having a nearly complete or complete underground system. And so the frequency of power interruptions dropped, and Clay even told me they dropped even more than I estimated. And my numbers, my estimates about how the duration of power outages decreased were actually quite in line with historical records that Clay provided me.

So when you put this all together, this is an amazing story. Cordova, my estimate of the costs of undergrounding their system, from 1978 to recent, it was about $4 million. This is a community of about 2,500 people. The benefits that I estimated were $69 million. That's a net social benefit for a community of 2,500 people of $65 million, and a benefit-cost ratio which is out of this world. You rarely see benefit-cost ratios this high, of 16 to 1.

The reliability benefits were very large, but it's important to point out they weren't even necessary for cost effectiveness. Same with Texas, I did a tornado diagram, the value of lost load, these customer costs of power interruptions courtesy of the Department of Energy funded ICE calculator. The results swing quite wildly based on the assumptions of value of loss load, and the reliability impact from undergrounding also swung the results quite widely. But you can see under all these scenarios, the net benefits are greater than 0, meaning the benefits exceed the costs.

Then I ran a sensitivity analysis through a Monte Carlo simulation. Again, every combination of parameters that are used in this model showed significant net private benefits. This is just a no brainer idea. Looking in hindsight, it was a very fortuitous decision that was made in the late '70s and then continued up until you know clay took over as the CEO. So this is a very good decision, and I had the opportunity of presenting these results to Cordova a couple of years ago.

So concluding, it's always been assumed the cost of undergrounding are much higher than the benefits, but there was very little information about what the benefits actually were. And so when you start to look at strategic undergrounding, which is the theme of this workshop, you can see that strategic underground and can actually lead to net benefits. It makes a lot of sense.

The cost effectiveness of these analysis depend on the lifespan of the existing overhead infrastructure, whether economies of scale can be achieved, and the vulnerability of locations to storms, and finally the density of customers per mile. These are really important things to be thinking about. This framework that I showed today could be adapted to a value the economics of other strategies to improve grid resilience and reliability.

So with that, I'll stop and I'm happy to take questions. Here's my email address and my phone number if you wanted to reach out to me independent of today's webinar. Thank you so much for having me.

MEREDITH BRASELMAN: Thank you, Peter. We are going to be taking questions now, so please put them in the Q&A. So we do have one questions submitted here, Peter, so I'm going to start with this one. Can you distinguish between transmission and distribution in your analysis? Distribution lines are generally relatively short and there are no significant technical reasons why they cannot be built. Transmission lines, on the other hand, are often quite long, and there are technical reasons why their links are limited. And the limits are more severe for high voltage transmission lines, which also carry the largest amounts of power.

PETER LARSEN: Yeah, very good question. So I basically collected information from-- I didn't get into all the nuances of the voltage ratings of all the different transmission. Certainly different voltage ratings at different costs, capital costs, and operations and maintenance costs, and obviously performance and losses and so forth. I really just collected information from the Department of Energy about whether the line was overhead, whether it was considered a transmission line with-- I don't remember what the minimum voltage criteria that was set to determine whether it was a transmission line or not.

But basically, EIA collects a lot of this information utility by utility about what the voltage ratings are, whether it's transmission distribution, what the replacement costs were, and the operations and maintenance costs were. So it's somewhat basic in terms of all the assumptions going into what is really meant by a transmission line versus distribution line.

But here, I did want to show that-- see if I have Cordova here-- I'm going to go-- I do have at the end of my deck just some of the assumptions around the different types of transmission and distribution lines. I am assuming much more costly per line mile estimates for transmission because we know that, obviously, it's much more costly to bury a transmission line relative to a local low-voltage distribution line. I hope I answered your question.

MEREDITH BRASELMAN: All right. Thanks, Peter. Another question here. Would your Texas study be similar in cost benefit to that of the Cordova study if you separated out transmission and only looked at distribution?

PETER LARSEN: Great question. I think that-- I don't know the answer to that. I have to think about that a little bit more.

One thing I could say is that-- and Clay, I think, is going to speak to this later today, so a plug for his work. But Cordova was able to achieve something remarkable in terms of economies of scale. They have the benefit of a small community, 2,500 people, that they were able to position resources and basically, like Pat Hoffman was saying earlier, a couple other types of utility services along the corridor, the undergrounding corridor. So Cordova has the advantage of being small and being very efficient in how they basically addressed the costs of installing these underground lines. When you talk about Texas, even if it's just distribution systems, and you throw out the transmission system, you're still talking about a pretty wide geographic area, and a lot of staging and logistics that have to be overcome to get those costs per line mile down.

MEREDITH BRASELMAN: How do you calculate or define aesthetic costs?

PETER LARSEN: Great question. So there's been a couple of studies, and I can point folks to these studies. I found three or four examples, and there may be some more in the last year or so that have basically done what's called a hedonic modeling effort where these researchers look at property values of like homes or like businesses that have views of transmission distribution lines versus similar homes and businesses that don't have views, and they can do an econometric analysis that then detects, essentially, the aesthetic cost of actually seeing a transmission distribution line. So they pick like properties, one that has a view of a line, one that doesn't, and then they're able to do a statistical analysis and figure out that basically 10% to 15% of a property value is actually impacted by the view of a transmission line. That's one of the studies I found that was published in the peer-reviewed literature.

MEREDITH BRASELMAN: All right. Thank you. Setting aside the benefits of undergrounding, can you estimate the average increase in the cost of electricity if all new and existing lines were put underground?

PETER LARSEN: Yeah. That would be, if that's specific to Texas or the whole country, the way you would do that-- I don't know the answer to that, but I can tell you how I would think about it is we'd identify how much conversion from overhead to underground is being considered in terms of line miles by different ratings of voltages for lines, whether new lines will be undergrounded. And then once you have an idea of the mileage and you can come up with the cost estimates, both the capital cost as well as the annual operations and maintenance costs, then you can take that value and basically, if it's a regulated utility, apply a rate of return, a cost of capital, on top, and you can come up with a proxy for what the additional costs to ratepayers might be from that major investment being made by the utility.

MEREDITH BRASELMAN: OK. Have you considered different repair times at different places for underground cables versus overhead lines? If so, how do they compare?

PETER LARSEN: Yeah. So this is a good question for Clay. I know that Clay has pioneered some techniques, at least in Cordova, that he's able to detect faults very quickly to his endocrine system. And I don't know the latest on where the science is on how fast it takes to conduct these sorts of determining where a fault occurs, if it's underground.

In some cases, I think Clay will talk about-- I think he laid parallel lines, where he's got two lines next to each other. So if one goes down, he can energize one immediately after. So there's all these different strategies you can do to basically reduce the restoration time for underground. And if the person who asked that question sends me a note, I can actually send a paper that gives more specifics about how duration of interruptions actually goes down with a larger share of undergrounding line miles.

MEREDITH BRASELMAN: All right, sounds good. I'm also hoping Clay is not having to rewrite his entire presentation right now while we're going through this. Next question. What construction methods were used in the modeling, traditional trenching, horizontal drilling, et cetera?

PETER LARSEN: Yeah, I didn't get into real specifics. I'm an economist moonlighting as an engineer. So I focused just on what are the cost estimates that are out there in the peer-reviewed literature that are here in row 1. Those cost estimates, my guess is they're mostly due to just regular trenching, traditional types of undergrounding, because the cost estimates that I collected were somewhat dated, both from the Texas analysis that I mentioned earlier, from this consultant.

But also, I believe EPRI or EDI also published a study where they had cost estimates of undergrounding, and based on the date of those studies-- my guess is that they were more the horizontal trenching type strategies to come up with the cost. But I didn't get into the details of all the engineering. I really focused on the economics of these different strategies.

MEREDITH BRASELMAN: OK. What were the life expectancies assumed for overhead versus underground for the economic benefit study?

PETER LARSEN: Yeah. So if you look here on row 8, these are the different life span assumptions for overhead. I have 60 years for overhead. I'd have to bring up my paper to see what the assumption was for the underground.

That's for Texas. So the base case was where I assume that the overhead transmission and distribution infrastructure would last 60 years with regular ongoing operations and maintenance. So it's not like you're-- you're still putting money into it to keep it maintained. For Cordova, I assume there, 40 years, so slightly shorter lifespan for the overhead for Cordova. And that's based on feedback from the Cordova Electric Co-Op.

MEREDITH BRASELMAN: OK, very good. A couple more questions here. Have you done analysis like this regarding avoided societal costs from power line-caused wild fires, including fatalities, smoke, lost homes, suppression expenditures, et cetera?

PETER LARSEN: I've really wanted to do that. I have pitched to a number of organizations over the past few years to look at how different strategies to avoid wildfire ignition-- undergrounding is one of them, covered conductors is another strategy, Public Safety Power Shutoffs, PSPS in California. I've thought about-- you could structure an analysis like this for other strategies to mitigate the impact of wildfire ignitions caused by the utility sector. But I haven't had any luck getting any funding in on that, but it's something that I've thought a lot about.

MEREDITH BRASELMAN: All right. Has any medium or large-sized city undertaken a large undergrounding project?

PETER LARSEN: Yeah. One place that I think is quite a fascinating case study, and we actually have a report funded by the Department of Energy Office of Electricity that looks at case studies of economic impacts of long duration widespread power outages. It's up on the LBNL website. I can send folks a link if they want to see it.

But we studied a bunch of different locations and some of their strategies to head off the risk from these long duration interruptions, power interruptions. And one case study sticks out in my mind is in New York, after Hurricane Sandy, a lot of investment took place to try to harden their system and reinforce and extend the underground line miles because of the damage that storm did. And so Consolidated Edison and some of the other utilities up in New York after Hurricane Sandy would be good places to check out. Places down in Florida, Miami, Orlando, some of the bigger cities in Florida have done a significant amount of undergrounding. The Washington, DC area has also done a significant amount of undergrounding. One of the reasons that they did it, though, is to avoid cutting down all these beautiful trees in and around the Washington, DC area. So there's an aesthetic element in the DC area as well as a natural hazard issue. So there are a lot of different places around the country that have been exploring undergrounding, and they tend to be in more urban areas than rural areas.

MEREDITH BRASELMAN: Very good. All right, that is perfect timing, brings us to the end of our Q&A. Peter, thank you so much for joining us today and for answering all of these questions.

We are going to take a quick break here. So we want everybody to get up, stretch your legs, grab some water. And we will be back here at 1:45 for our panel. Thank you.

Welcome back. Our next panel, we're going to be hearing about experiences from the field. I'm going to turn this over to our panel moderator, Eric Hsieh from the Office of Electricity at DOE. Eric?

ERIC HSIEH: All right. Thank you very much, Meredith. And thanks again to Dr. Larsen for his presentation. Undergrounding is a major tool kit in providing safe, reliable, and resilient electricity, and it's great to see the use of a quantitative cost-benefit framework applied to real communities. As Pat Hoffman mentioned, Congress recognized the importance of undergrounding and included it as one of the eligible solutions in several parts of the recently passed infrastructure law, including the resilience of the electric grid and hazard mitigation.

Now we're going to hear from several utilities on their experiences with undergrounding. We'll hear each of them speak about their experience, then go into audience Q&A, and then we'll end with a round of what they wish more people knew about undergrounding.

Our speakers today come from utilities in all four corners of the country, representing vastly different urbanization rates, terrain, and climates. We have East and West, North and South, large and small. If you were planning the longest possible road trips in the country, you would almost certainly pass through these service territories. And collectively, they're going to show us many of the most pressing needs for delivery infrastructure, and I'm excited and excited for our audience to hear their expertise.

So I'll introduce them from East to West. So our first speaker comes from New York. He's an expert who's been integral to many professional engineering groups on conductors and underground, including those at CEATI, CIGRE, and IEEE PES. His responsibilities include underground transmission cable system designs, failure analyses and restoration procedures, as well as standards. From Con Ed in New York, please meet technical expert in transmission line engineering, Arie Makovoz.

Our next pair-- Arie, if we can say hi. Our next pair of speakers--

ARIE MAKOVOZ: Hi, good afternoon.

ERIC HSIEH: Thank you. Our next pair of speakers come from the largest vertically integrated and regulated utility in the US, serving more than 11 million residents. Between them, they have almost 50 years of experience with the company. The first half of the duo leads operations and maintenance for distribution infrastructure, and leads a workforce of over 1,600 engineers, technicians, and union employees. Please meet Vice President of Distribution Operations, Michael Jarro.

The other half of the duo is responsible for the direction and execution of construction programs for distribution, transmission, and substations. He also leads the company's storm secure underground program. Please meet Senior Director for Project Development Power Delivery, Jerry Cook.

JERRY COOK: Hi. Welcome.

ERIC HSIEH: Our next speaker comes from a utility that serves 16 million people across 70,000 square miles in northern and central California. She oversees the company's program to underground 10,000 miles of electric distribution lines to reduce wildfire risk. Please meet Vice President of Undergrounding at Pacific Gas and Electric, Jamie Martin.

JAMIE MARTIN: Eric, thanks so much.

ERIC HSIEH: Nice to see you again. Our last speaker comes from the state of the last frontier. This utility may serve a small community of around 2,000 customers, but it has pioneered some of the most innovative storage and microgrid projects in DOE's Grid Modernization Laboratory Consortium. Please meet Chief Executive Officer of Cordova Electric Cooperative in Alaska, Clay Koplin.

So with those intros, I'm going to encourage our audience again to submit questions as they come up, and our behind the scenes producers will sort them out for the Q&A sessions. With that, I'll turn it over to Arie.

ARIE MAKOVOZ: Thank you, Eric. Good afternoon, everyone. My name is Arie Makovoz. I'm with Con Edison of New York. And today, I will share with you our experience with resilient power systems, specifically the transmission system.

So we are serving a great New York City, five Boroughs and Westchester County. We have 335 underground feeders, 754 miles. Average age of our system, our feeders, 47 years old, and some of them even older than 70 years and still in service. Most of our system, I would say 80% are pipe-type feeders, and rest of it solid electric feeders. We also have 51 overhead lines, totaling 569 miles. As part of our pipe-type system, we maintain 125 pumping plants and 76 cooling plants.

As majority of our feeders are pipe-type and they have the dielectric fluid, so our major challenge, it's the electric fluid leaks. Steel pipes get damaged, have corrosion, and that's how the electric fluid leaks develops. So what we do about that, we maintaining our reliable cathodic protection system. We use state of the art leak detection system to detect those leaks in the early stages. And based on cathodic survey, based on leak pattern, we proactively change a coating of the steel pipes, and in the last several years we start using a carbon wrap, which effectively protect the pipes and contain leak if it's happened.

Our second major challenge based on our mature system, like I said, 47 years old average, it's condition assessment of the system. So what we do, we periodically take a dissolved gas analysis of the dielectric fluid. We use regular and digital X-ray for joint condition assessment. And when I have a chance, during failure repair or proactive replacement, when we get out any cable we've installed in the system, we perform a degree of polymerization test, which can tell us the remaining life of the cable.

From 2010, we are no longer installing new high-pressure fluid-filled feeders. We instill only solid dielectric feeders. And when we started, one of the challenges was to create at the transition joint from high-pressure fluid-filled hydraulic system to solid dielectric system, which is completely at a dry and no pressure. Also, all of our terminations, the transmission terminations, they are fluid-filled. So another challenge was to start install composite to dry terminations.

And of course, when we decided to not install more high-pressure fluid-filled feeders, we need to have enough spare to maintain this system for whatever time is needed when we replace it completely with solid dielectric. So how we address those challenges? We developed already high-pressure fluid-filled solid dielectric transmission joint for 69 and 138 kv, and we are working right now to expand it up to 345 kv.

We start implementing dry-type terminations. We already install them for 69 kv and 138 kv. First installation will be next month. And of course, we're working with only one supplier in the world of high-pressure fluid-filled feeders in New Jersey, so we work with them to secure enough spare cable if we need it for our maintenance and operations.

Second part of challenge is same as for pipe-type, condition assessment and the dynamic rating for solid dielectric cable system. We believe when the future is going to be done implementing artificial intelligence, but artificial intelligence have many steps before you start to actually analyze the data. First of all, you need to have sensors to acquire all this data. Second, you need to have a data acquisition system to acquire and store all these systems, and of course, work through pretty complex utility system with all these firewalls and other electronics. So we already started that, and my next slide will be a case study and when I also will touch base of that artificial intelligence system.

So you can see there, in 2019 we energized a new feeder in New York City. Parameters of the feeder is 5.7 miles, 138 kv, six terminations, 17 joints. Challenges, of course, mostly construction challenges because during that project we cross three railroads, several major highways, elevated subways, and bridges. That was a major constraints when we work through the city of New York.

You can see there on the left side, evaluation criteria we use to evaluate the route. Some of them are pretty obvious, some of them new constructability, project cost, schedule, existing utility impact permits, especially in the city, land use impact and easements, surface disruption, and traffic impact.

As part of those studies, major study what we performed was, of course, a traffic study. Also during that study, we perform 120 field tests, extensive subsurface facility investigation, including a ground penetrating radar. And to benefit that, I can say, as a result of that, we have opportunity to short route using easement, and we shorten that feeder out by half a mile and at tremendous cost for the transmission feeder.

These are a few pictures from that installation. You can see that dark bank construction for transmission circuit, you see installation in the trenches. What I want to pay your attention, all 17 underground walls been prefabricated, which tremendously reduced the cost, and have significant impact to reduce the schedule of installation. To install that wall, it's take almost less than one day, even. But if you compare it to field pour, it's going to take more than a week, for example. So you can see there we install those underground walls during that project.

This slide, as I promised, it's reflect what sensors and monitoring system we install in each underground wall as a preparation for future artificial intelligent expansion. Partial discharge system help us to monitor condition of the joint and cable insulation. Any degradation in the future will alert that system.

Distributed temperature sensors allowed us to monitor the thermal environment around the feeder, any heat sources which may reflect on the rating of the feeder. Distributed acoustic sensors will help us to

monitor reconstruction activity on the feeder, any digging, piling, air hammering, and effectively can help us to eliminate route patrol. We also believe it will help us to find a fault if it's happened.
Also we installed video and infrared cameras, online cameras, in there in these walls. They all installed in IP68 enclosures, submersible. We are obligated by DPS staff to inspect our manholes every five years, and we do it every four. So to do that, we dispatch two crews.
Our walls located under the streets, so we need to stop traffic, we need to open the vault. We cannot enter because the plastic cable energized, we cannot go in. So it's take one wall a day, maximum two walls a day for them to inspect. By installing cameras, we believe we can reduce the time. And we can do inspection off their office desks, and that's a tremendous improvement. If it will work, that will help us with that.
Also, we installed local vibration monitoring and wall entrance alarm. All these sensors, and of course, subsequent data acquisition unit will help us with future IR system, which can analyze the data and tell us the condition of the feeder and assess condition of the feeder.
My last slide I want to share with you, it's our vision of how to make the system more resilient, transmission system. We believe it's a two major component of that-- one, spare part inventory, and second, complete resilient system for operational and catastrophic emergencies.
So spare part inventory, for mature systems like us when you have a lot of different feeders installed in different time frame with different suppliers, we must have strategy for type and quantity of various spare parts. We need to monitor inventory of replacement parts. Some of the parts have expiration date. For example, rubberized gasket, plastic components, solvents, any semi-conductive paint, it must be monitored because when you need it, they must be ready and be ready for use and not expired.
Part of that also, proper tools and the training of your personnel to be able to use spare parts, which can be spare for 10, 15 years. And people change, so you must have the training and tools available.
And last part of it is complete resilient system for operational and catastrophic emergencies. We find out sometimes you need to bypass equipment at the transformer of a single regulator or connect bus to bus, and we didn't see it's very easy to do it with existing spare parts because they are spare parts. They are not complete systems. So in order to try to assemble a complete system from spare parts, it's not very efficient operation.
So what we recommend is to have a for operational use small rails with flexible cables, pre-installed terminations, easy to assemble termination stands and pedestals. It's for operational needs when you need to quickly install the transmission line for the temporary use.
If you have more kind of emergency or catastrophic events and part of full substation is destroyed, you may use a system based on container-type. You can see it on the picture, left bottom picture. That container can act as the termination stand, and prefabricated termination and pre-install can be pulled out through the hatches on top of that container to be easy assemble.
And most important, you have everything what you need inside that container. So if emergencies happen, you can easily and quickly deploy that system. I think that's it, what I would like to share with you for that presentation. Thank you.
ERIC HSIEH: Great. Thank you, Arie. It's very interesting to hear how new technologies for conditioning and monitoring are being applied to undergrounding.
So now, moving from Northeast to Southeast, please join me in welcoming our next panelists from Florida, Florida Power and Light, Michael Jarro and Jerry Cook, when you're ready to go ahead.

MICHAEL JARRO: Thank you Eric. And good afternoon, everyone. Certainly appreciate the opportunity to give some insight into our story. And as many of us will present, and as you will probably hear through the Q&A, our history as really shaped our path forward and a lot of the initiatives that we've put forth in currently have underway.

And undergrounding is no different. And particularly for us at Florida Power and Light, obviously we contend with a lot of natural disasters that come from the Atlantic and the Gulf called hurricanes. And in the '04-05 season, we experienced seven storms in an 18-month period. So in that kind of time in our history, the commission that regulates us, the Florida Public Service Commission, our executives, our employees, our customers had essentially said, enough is enough, the impacts of those hurricanes and the outages associated to it. We had to do something different.

And that essentially set us forth on our Storm Secure Program, which really was focused on four key elements. One was hardening of our feeder lines or our major grids, increasing or actually standing up a more resilient pole inspection program, increasing the amount of vegetation management we did, both on feeders and laterals, and then a strategic community-based underground conversion program that would underground both feeder and laterals.

So since then, we had been investing a lot, doing a lot of work to increase the resiliency of our grid and executing our Storm Secure Program. And then 2017 presented us with an opportunity called Hurricane Irma. And our initial plan was to take the recipe and the work that we were doing on the feeders, and then once we were done there, apply them to our lateral infrastructure.

And a lot of our laterals are in the rear of customer properties. They have a lot of tree conditions. And though we do have a very robust vegetation management plan and our trim cycles keep the lines clear of vegetation, what it doesn't do is it doesn't clear all the way back and provide a large enough trim zone that could avoid trees kind of falling over and coming into those lines. And Irma proved that was an issue that we really needed to design or engineer out of our system, as you can see by all the photographs in our picture.

And as I mentioned, our history has shaped our future and the plans that we worked on, this prompted us to launch our Storm Secure Underground pilot program, which not only did we start as a program but now-- and you can go to the next slide-- now the commission the Florida Public Service Commission has essentially a proposal in front of the governor, which is now put it into law, requiring that utilities invest in the resiliency and improving the resiliency of our electrical grid for natural disasters and for storms. So along with that, we have to essentially submit our 10-year plan detailing all the work that we're going to do, both not only on the feeders and our Storm Secure Program, as I mentioned, but also as we move forward into undergrounding our laterals. And Jerry will kind of go into a little bit more specifics of how we're doing that.

It is a very data-based criteria by which we select which laterals we're going to underground. It's based on those laterals that were impacted during past hurricanes, laterals that we have vegetation-related outages associated to them, and then also those laterals that have been-- call it the thorns in our side and have bad or poor historical reliability issues. And the path forward is to underground the majority of our overhead laterals, and some of the discussions that were had earlier, underground lines perform 85% better during those catastrophic events, during hurricanes. But then also, beyond just the building the resiliency for those catastrophic events, it also provides a day-to-day improved performance, which for us is about 50% more.

We do work very closely with other utilities in our space. However, we do not underground there are lines along with ours. But we try to coordinate so they understand where we're going to be undergrounding and when so they can follow suit and do the same things.

And then lastly, in terms of the cost, all the costs are covered by the customers through their bill, and it's something that requires Public Service Commission approval on a yearly basis. So with that, I'll turn it over to Jerry, who's responsible for executing the plan moving forward.

JERRY COOK: Thanks, Mike. So onto the next slide, please.

So real quick, just to give people an understanding, we do almost exclusively all-directional boring. That's one reason why we don't work with other utilities much on this stuff, because we're going in at a level, and below them typically, and setting up and doing our bore. So it's not the same thing as doing open trench, where you just throw everything in the same trench. We do this because we're working in existing neighborhoods, so the restoration of the property is a lot less when you're only open up access pits for the actual bore set up and then down where you're coming up to the transformers or handholds. All right, next page.

So typical equipment, this is just to show our patent on our hand holds. Let's go on to the meat and potatoes, which is our successes. So wanted to give people-- we've run in this pilot since 2018, we've probably put about 600 miles underground to date, and we've got another 300 or 400 scheduled for this year to go underground.

But what we've learned is we first started to start out and try to get easements for all our lines along with the transformer locations, and that wasn't working. So we switched to just putting our lines into the right of ways and getting easements for the transformers, and the customers seemed to be a lot more receptive to that. So that ended up enabling us to move forward a lot quicker with the program.

We started to outreach. We were coming to communities either at city council meetings, homeowners meetings, any kind of community means we could go to, to kind of build a groundswell of support in Florida here. Early on, when people that know about the program, they were very skeptical. But after about a year or two, people are now calling us and saying, when can we get ours underground, and we want to be next because we don't want our stuff down during a hurricane. So doing these outreach sessions with the county commissioners, city commissioners, things like that, helps get a groundswell of support, really push the program forward, and that helps us get easements for our facilities.

We also implemented an augmented reality tool, which-- there's a picture there on the right side-- which shows the customer how a transformer will look in their yard when we're done. Of course, we're going to be removing poles, lots of times a service pole and all that out of their yard. So they'll see that gone and they'll just see the green box. And lots of times we would landscape around that also.

On the construction side, on the bottom right picture, you'll see, we don't touch the meter can. We basically cut off at the weatherhead and back feed the cable, and then we use this flexible conduit to come over to a junction box. So this saves times on the customer not having to get any permits or electrician fees. We just run it directly into our junction box and hook it up, which has worked really great for us.

And then another thing we learned which was successful is that we started out just looking at the worst laterals, and we ended up, we were jumping all around. And we would do one lateral here, 10 miles away or 25 miles, and we would do another lateral, and we realized that wasn't efficient.

So we started grouping laterals by feeders and said, all right, we're going to do all the laterals on this feeder, which enabled us to be in one location, have less demob and mob back and forth, less permit fees because we're just permitting usually from one agency or one location. And for our Maintenance Of Traffic, or MOT vendors, they could come out and set up and just move from street to street and not have to be jumping all around. So it was just way more efficient and more cost effective to do it this way.

Now moving on to some of our challenges I'll touch on. So as a lot of you are all experiencing, material and labor costs are going up quite a bit. We're on a steep ramp up here, increasing our mileage each year and increasing our spend and need for resources. So we've had a little bit of problem getting more equipment to handle all of our work.

Skilled labor now is becoming a problem, even though underground is less of a classification than an overhead lineman would be. It's still getting to the point where there's just so much from other utilities, whether it's AT&T or Comcast or all these other big companies doing underground, and we're all drawing from the same labor pool. And so that's starting to be a challenge. And wages are going up.

Along with that, the fourth bullet there is one that I think we've learned along the way, that you can't just go out and do this. You've got to get electrical clearances, you've got to work with the other work you've got going on the system and understand that you're going to be running into each other, on top of each other sometimes, and sometimes that delays us and causes us problems. So you've got to imagine, you're working in Miami, there's a lot a lot of other stuff going on. So you've got to be very careful with the way you schedule these things.

Permitting agencies, we've had a lot of backup in some agencies because, obviously and fortunately, our state is growing quite a bit. Given the amount of demand just from the permitting agencies from FPL and what we need to do, all the other home builders, all the other businesses, everyone's pulling permits, so it's become a bottleneck and it is a problem. So we have to do a lot of extra work in this area, which I think, if you're in a busy area that's growing, you have to experience the same thing if you try to undertake this kind of thing.

Lastly, we go out and after we're done we want to remove poles once our facilities are off and get those out of there. Obviously, the other telecommunication and cable providers, they don't have the same incentives that we do to do this, so they're remaining attached. And so we've tried to attack this through some legislation to try to get everybody on board to get them off the pole and get underground and make the system more resilient.

And lastly, we've experienced problems with, obviously, anybody that's doing a lot of underground work, digging, hitting things, you've got a lot of gas lines, sewer water, even other FPL lines. And so we're using a lot of different tools, including obviously a lot of ground penetrating radar and soft digs and things like that to try to get around this, but it's still a challenge.

So that's kind of what we've seen from our program. Like I said, we're doing about 350 miles this year. We're probably going to be going up to over 500 miles next year, and then probably 700 miles the following year is kind of where we're kind of targeting at this point in time.

So really, our total system is 23,000 miles of laterals. So we have a long way to go, but we're trying to push forward. And hopefully, if the economy and we can get the resources we need, we'll be able to be successful in doing that. So that's all we have.

ERIC HSIEH: Great. Thank you, Michael and Jerry. It's very interesting to see how FPL has been building its underground program using a data-driven approach and continuing to identify efficiencies as it scales up.

Just a quick reminder to the audience, please continue to submit questions to the chat QA function, and we'll get those routed to the right panelists at the end. Now, switching coasts from East to West, let's head to my former home, California. Jamie Martin from PG&E, when you're ready, please go right ahead.

JAMIE MARTIN: Thanks so much, Eric. And thanks everybody for making time to join today. It's a really important conversation that we're having. I'll offer just a little bit of context on our program, some similarities between PG&E's drivers and FPL's drivers, and then talk about what our program looks like over time and some of the things we're doing and focused on as we scale our program. And then we'll conclude with challenges.

So I'll take us ahead to the next slide, and to ground us all, PG&E is based in the state of California. And a lot of the West has faced catastrophic wildfires for the last few years at a pretty significant scale. And as a company, we've taken a stand that catastrophic wildfires will stop. And so last year, we announced our program to underground 10,000 miles of our distribution system in what we call high fire threat districts. 10,000 miles represents almost half of the number of miles in our high fire threat areas across our service territory. And the program is significant. 10,000 miles is a lot to put in the ground.

And if we click ahead to the next slide, we recently filed-- sorry. I'll pause and talk just a little bit more about the risk profile that we're facing from a wildfire perspective. There's a lot of data that we're looking at here, but there's a few takeaways with regard to the growing risk of wildfire in our service territory. Conditions have changed even just over the last four years. We've seen more than 80% of the state in extreme drought conditions and 39% of the state in exceptional drought conditions, which is significant.

In 2022, we had our second driest January in the past 128 years. This doesn't bode well for the upcoming fire season. And a fact, from our 2021 fire season in a state is that the vast majority of burned acres burned on what we call non-red flag warning days. Red flag warning days are days that typically present significant wildfire risk, and most of the acres burned on days that didn't have that profile. And that's compared to 47% in 2020.

All this to say that the threat of wildfires continues to grow and is really the foundation of our undergrounding program at PG&E. The need to reduce wildfire risk on a permanent basis and continue to serve our customers affordably, reliably is what we're after. So I'll take us ahead and talk about our overall program.

We recently filed a rate case, an update to our rate case to reflect what the next few years of our undergrounding program looked like. So from a mileage perspective, we're targeting at least 175 miles in 2022, and we're scaling that to 1,200 miles in 2026. It's a significant effort. We'll face many of the challenges that we heard from Michael and Jerry with regard to the ability to do this, but we have plans in place to mitigate those risks.

At the same time, we're focused on reducing the cost per mile of our undergrounding program. Our rate case indicated that we expect about-- these are unescalated dollars, but that this year will we'll see about $3.7 million a mile, and we want to decrease that over time to about $2.5 million a mile. Before I talk about how, just a little bit more about the benefits that we see from undergrounding. Once a line is underground the risk of ignition is nearly eliminated.

Additionally, there are resiliency benefits when a line is underground. We see fires occur in similar places, year over year, burning our overhead assets, even after they're hardened. On top of that, we still have winter storms, snow, ice, and underground lines provide a level of resiliency to the benefit of our customers.

It also will improve reliability. You may or may not know, PG&E has a fairly extensive program to shut off power in the event of high wildfire risk to protect public safety. Additionally, we've deployed an engineered enhanced power line safety settings to make our lines more sensitive to potential strikes, but these have a reliability impact and underground lines will reduce the need for those tools.

Finally, underground lines will reduce the need for vegetation management activities. PG&E spends upwards of $1 billion, $1 billion and a half annually on vegetation management activities. It's a significant amount of work and a significant impact to the trees in our service territory. And as lines go underground, we expect that vegetation management profile would change.

So as we think about reducing the cost, we think about optimizing our design and construction standards. We have traditionally focused on overhead hardening and undergrounding at a lesser scale than what I just articulated.

And our design and construction standards can be updated to reflect what we've learned through the undergrounding work that we have done over the past couple of years. We believe that that did build a lot of efficiency up front in the planning process, and then of course when we get to construction and execution. The scale of this program is going to allow us to bundle work strategically across our service territory, taking advantage of economies of scale and reduced mobilization costs, and then, of course, the opportunity to deploy new technology and equipment, to do the work safely but even more efficiently.

So I'll take us forward, and this is just a little bit more detail on what we see as opportunities to reduce the unit cost of the work that we're doing. One thing that I haven't highlighted yet is reducing the cycle time from scoping to completion of construction, and we have a team that we're standing up that's focused on that amongst the other things that you see here on the page. The picture that you see on the slide is a project that we did in the northern part of our service territory, where we used a plow to dig the trench. And then we're installing cable and conduit, as you see here, that's followed by a machine that basically pounds the dirt back in and the work is done.

This can't occur everywhere, but it can occur at a number of places. And from an efficiency and speed perspective, it provides a lot of benefit compared to places where you would perhaps do open-trench style construction.

I'll take us forward and just talk in conclusion about some of the things that we're focused on in our program. The community impact that we're describing, and as you heard from the FPL team, is real. Traffic management, outages, all of those things when you're undergrounding hundreds of miles of line in specific areas need to be managed, and so developing a program that puts our customers at the center and manages those community impacts will be really important to us.

Also, the cost of this program is real. We think our rate case that we filed didn't represent an incremental cost compared to the rate case that we previously filed that didn't have our undergrounding program. But nevertheless, demonstrating that the work is economic and delivering on our cost targets is important.

We've already heard about the resource and materials constraints. Those are very real for us as well, not just in construction, but also in design and engineering. We share the need to have a comprehensive joint trench strategy that will bring our joint pole tenants into the trench with us in ways that makes sense for them and for us, and most importantly, for our common customers.

Land rights and environmental are obviously a critical component of doing this work right, and our work is done in an area that has complex environmental and heritage considerations that are really important to address proactively and completely so that we're in a strong position with our agencies and other constituents who care deeply about doing this work right and in compliance. And then I've covered standards already. And so I'm going to stop there and turn it back over to you, Eric.

ERIC HSIEH: All right. Thank you, Jamie. It's illuminating the hear how PG&E is rapidly adapting to a changing environment with your major investments. Let's move on to Alaska with our final panelist, CEO of Cordova Electric, Clay Koplin. Clay, when you're ready, please go ahead.

CLAY KOPLIN: Hey, thank you, Eric. And good morning, at least on my end of the country here.

So just a little bit background. I was came up as a distribution engineer at Kodiak Electric Association. And they had done an urban renewal after the 1964 earthquake and built an underground system in the town core, and then they had the Coast Guard base there, the Navy base that was built in World War II that also had underground systems, delta, and some interesting design approaches that I drew from.

But Kodiak itself was a rapidly growing community. They call it the Rock because it's solid rock everywhere. And I found through a variety of approaches that I could actually reach cost parity and almost always improved cost performance in installing underground lines at a lower cost than overhead lines. And so I developed some frustrations there, as there was a lot of resistance to underground power lines.

So when I saw Cordova Electric with a policy to convert their entire system to underground power lines, that was pretty much the singular reason that I moved over to Cordova Electric as their operations manager, ran the line crews that installed underground power lines. And I would just say that when I arrived at Cordova Electric, about 75% of the lines had already been converted to underground. So what was left was all the very difficult stuff, the solid rock, the canyon crossings, the mountaintops. And I was really proud that I was able to finish that overall conversion and do it extremely cost effectively, sometime literally for dimes on the dollar compared to a conventional overhead or even conventional underground.

So Cordova, similar to Florida Power and Light, PG&E, we've got our weather challenges. What most people call a hurricane, we call a storm. We can have as much as-- we have had as much as 48 inches of rain in three days, as much as 30 feet of snow in three months, wet, heavy snow. So it's nice to have buildings collapsing and boats sinking, but the lights stay on.

The challenges with underground, and some of these I think are more paradigm than reality, but it's expensive to install, it's expensive to repair, and nothing is bulletproof. Just another storm-related event here that took out some underground.

We have some old legacy duct work. One of the questions in the presentation are, what are the technologies we need going forward? Well, I think our grids changing and we need some new approaches, and that offers challenges and opportunities.

But I honestly feel that most of the technologies that we have are in place, the hard technologies, in terms of design and routing, and so forth. It's really the soft technologies that pose the barriers, the permitting, the cost sharing, the trench sharing, the regulatory and rate cases for it. That's where you really get into the weeds into the delays and the costs. Again, the hard technologies, the frost, ground freezing, locating either existing or during outages or faults, and then addressing cost effectiveness, I think most of those can be mitigated.

So cost effective approaches, in my experience, at least, there's no silver bullet. Sometimes the value engineering mindset can actually work against you. Say, well, we're not going to oversize the wire or we're not going to put an empty conduit in the trench because that costs money. I found that making good investments and decisions up front and taking the long view of where your system might be in 10, 20, or 50 years pays huge dividends, and very often much more quickly than you could ever anticipate.

So if there's one thing I would highly advise, it's take care of your wire on the front end, your connectors, everything. Make sure that you handle it properly. So many wire failures are due to poor installations or damage in shipping that go unobserved or unnoticed, and they're extremely costly to mitigate after the fact. So the way that your wire is delivered, who handles it, how you store it, how it's installed, all very important.

Sharing trench, easily the biggest cost lever. When you're trenching underground in, I found that 90% of the cost was digging and back filling the trench. So if you can split that cost between three stakeholders, you've just gone from a 100% cost down to a 40% cost, for the electric utility anyway.

Find that almost every job, it really can or should be a custom design. There's always nuances to any individual job, and having a lot of flexibility and agility and experience in your design team is really important. You can find workarounds and eventually you can build a portfolio of approaches that you can apply strategically to individual jobs to make each job cost effective.

Strategic installations, highway projects we've found have been our absolute best lever. When we think about electrification and electric vehicles, as Pat Hoffman mentioned on the front end, strategically utilizing existing right of ways, not only utility right of ways, but transportation corridor, so forth, can make a big difference. But going into a highway resurfacing project, for example, and working between the time that the old surface is removed, getting in and installing all the infrastructure that you can anticipate needing for the next 20 or 30 years before they repave pays big dividends because you're not digging up and cutting up brand new asphalt to replace or install your facilities. Everybody wins, and you share the construction site.

And if you can, again, work through those soft skills of getting a highway contractor and Department of Transportation and an electric utility all playing nice together can be quite challenging. But there's a lot to be gained, though.

Piggybacking, again, with other projects, here in Cordova, the three utilities meet once a year. We look out on the horizon at our capital projects for the next two or three years. Very often, one utility will defer a project so that they can lean in and join one of the other utilities on their project, and it's just kind of a shared approach.

Locating and repair, I have a lot to say about that. We've used everything from some old school things that I'm sure have been quite forgotten to latest data technology. And then, of course, exercising the same care in repairs that you do during a greenfield or new installation.

I talked about proper handling, chain of custody. Handle the wire as little as possible and handle it well. If you get an engineer out of the office and out in the field, they will find that there are a lot of things happening in the installation that they don't actually realize is going on. It's important to really make sure that construction crews have the tools and the guidance they need to do quality installations, and there needs to be a capture, a way of measuring and making sure that's happening. Terminations, of course, are extremely critical in terms of hygiene and again the right application for the right job and handling.

This picture I took of this cabinet just to show that, again, in our snow environment, you can see all the working space around this where a lineman can operate it with a stick. It's elevated for drainage. We live in a rainforest climate, and it's located out of a normal snow plowing area, so strategically locating equipment where it'll be least likely to be damaged and has working space. I recognize we may have a little space than some municipal environments or whatnot, but still important to put thought into where you place and how you place things.

Talk about shared trench a little bit. This looks a little messy again, working in the rain snow and everything, but those are two different utility crews working side by side. And we very often have a blended crew. Two of you mentioned workforce issues in the labor environment. Well, if you have a telephone lineman, an electric lineman working side by side installing both utilities, or very often we've developed a trust and a specification sharing to where if telephone can install conduits for us and so forth, and we're familiar enough with each other that they'll install it properly, and even with their own crew, sometimes with a mixed crew with a representative or two of ours, but that sharing works all the way into the labor pool, and not just sharing the space and the right ways and so forth.

This may look a little unconventional and it is. This is actually a transmission line from a new hydroelectric project into the community. And in some ways, as important as it is to be careful with installations, in some ways it's amazing how forgiving wire can be and how forgiving underground can be.

So just a few misconceptions I wanted to run through. I like to get a little disruptive about underground. I know the conventional wisdom is to install wires in conduit. I actually think in most cases that's a misapplication because there are some paradigms that you can always pull wire out and install new.

In my experience, that's not the case. HDPE actually collapses over time. PVC and other conduits can be damaged and then covered back up by someone who doesn't want you to know they damaged it. Over time, pipes can fill with water and freeze. They can fill with sand. It's not as easy to pull a wire out as you think and to pull it back in, and this is speaking from having working second generation underground and whatnot.

So to me, there's a lot more value installing underground direct-bury cables, which are much easier to repair because you don't have to deal with conduit, and install an empty conduit next to them. Then you've got the flexibility of adding circuits, of pulling in new without competing, of fixing what you have in place easier than trying to do it in conduit. I know 99 out of 100 electrical engineers, distribution engineers, will say, it's better to put the wire in the conduit, but I want to push on that a little bit.

Armored cable versus hardened in the submarine environment. You can actually get thicker jackets, flat neutrals, and take some installation approaches. Again, armored cable is supposedly more hardened in the marine environment, and yet it does fail. And when it does fail, it's several orders of magnitude more difficult and costly to repair.

We've found that we've had very good success in installing almost conventional submarine URD cable in saltwater depths up to 100 feet in highly, highly trafficked and commercially fished zones. And we've got decades of experience without a single failure. So again, there's some paradigms out there and there are strategic approaches to mitigating some of the challenges, both on the front end and then as you manage the wire over time.

I think I was just trying to show here a highway project. I wish I had a better picture of this. This is a-- let's see, 6 and 1/2 by 13. This is 7 miles of URD installation, just an example of how we've done things cost effectively. I used a combination of boring-- we actually had to cross under 11 glacial rivers with salmon runs, most of them, from a distribution site out to a remote airport on a radial feeder. And I used a combination of boring under all the rivers and then plowing along the toe of the highway across the wetlands delta, critical habitat refuge.

And I got assistance from the FAA because it was serving an airport, we got $1 million and a half grants to upgrade the 40-year-old wire. I installed one spare 2-inch conduit and I later sold it to a telecom as a fiber conduit. Cost me $40,000 to install it. I sold it for $475,000 a few weeks later.

The net cost to Cordova Electric was $300,000 for 7 miles, I say, of underground distribution, much of that inside the congested airport core. And I fully anticipate that wire will be in service for 50 years without problems if no one digs into it.

Say it's hard to unpack 30 years in 10 minutes. We did have a large barge drug 2-foot chain link anchor chain back and forth across a submarine cable. They're not supposed to do that, but they got caught in the fog and were spinning circles. And they ground on the wire long enough to cause a failure.

And so I used a bunch of old school and kind of repurposed some old equipment. I didn't have an as-built or any information whatsoever on this distribution line, so I use my own raft and a handheld GPS and then this thing, an old Metrotel Hound Dog. And this is about a 60-year-old piece of equipment, and it's just meant to annunciate when you get over 60 hertz wire.

Well, I put 1,000-volt DC pulse on this 3 and 1/2 mile long cable, and it turns out that in my raft with my GPS in one hand and this annunciator in the other, I could stay within 10 feet of that submarine cable from the surface, even in 100 feet of water. So I as-built the whole thing, got the whole length.

And then to find the fault, I put a standard car battery on an insulating mat so I didn't have any leakage current. I used jumper cables to energize our 15 kv cable and then used a voltage divider to figure out the ratio of voltage, 3 point something, out to four digits, of the total voltage loop voltage 12 point something, out to four digits, and I pinpointed the fault within 10 feet and then used a local boat here that you can see in the background we repurposed our steel cables racks, which are too expensive to return for the deposit. So we just rebuilt one with four loops of cable on there because there are four phases there. They installed an extra.

And we could fit it on a standard [INAUDIBLE] boat. We put their same boom out and put a tarp over it so we had a clean workplace. We use these very hardened Raychem splices, a series of four heat shrinks and an armored outer jacket. We spliced a chunk of wire in. So we used divers, raised to the surface, spliced a chunk in, spliced on the other end, returned it to the water all in a day and re-energized it the next morning and had our submarine cable back in service. And it's been 15 years now.

This cable is almost 40 years old now. It has hooks hanging in it, anchors drug through it. It's standard URD cable and it's been in a saltwater environment for almost 40 years, as I said. And then this was the day we actually converted our last overhead to underground. It was a big day in our history.

And hopefully I baited a few little hooks. I have so much to share and there's so little time to share it. But Eric has asked a question at the outset. If there's one thing we could share about underground, what would we share? And packing it into one sentence, I would say, it's not as hard or as expensive as you think when you learn what you don't know and you just take the approach that there is a way to do this, we just need to find it. And I'd love to be part of a expanded conversation.

I would just add, I remember my first conversation with Peter Larsen a little differently because we got a little debative about the cost of underground. And he says, well, yes, you converted your whole system. How could you afford to do that? And I said, Peter, we couldn't afford not to. And it's paid huge, huge, huge dividends, as you saw.

And our customers, if there's one thing they appreciate most about their utility, it's the fact that, again, their buildings can be collapsing, they're shoveling themselves out of their second story windows to get in and out of their home, but their lights stay on.

MEREDITH BRASELMAN: All right. Thank you so much to all of our panelists. We have got a number of questions lined up for you all already. I'm actually going to start with Michael and Jerry. This is a good segue from what Clay just said. Does undergrounding save utilities money? And if so, what's the time horizon on the ROI?

MICHAEL JARRO: So I'll take it, and certainly Jerry can chime in. But absolutely. I think the cost, as been mentioned many times by the presenters, it certainly does in some instances cost more to underground, but the benefits of not having to do vegetation trimming, for us our pole inspection program, also the cost associated to storm restoration after a hurricane or an event will be dramatically reduced because there's not as much damage on the underground. So all of those elements drive out day-to-day costs, but then also costs that are recovered through our customers after a storm event. So it definitely saves customers money in the long run.

JERRY COOK: Yeah, and the one thing I'll add, which no one really wants to think about, this is bigger than just comparing the cost of overhead to underground or even putting it back up. For us, Florida's GDP for our service territory is $2 billion a day. So if we take an extra 10 days of restoration time, it adds up real quick. And so if you look at this holistically, from the point of view of the state and all the economics, it's a no-brainer.

MEREDITH BRASELMAN: Very good. I'll throw this question out to any panelist who wants to answer here. Are there concerns citizens would be less likely to evacuate if they believe that they won't lose power during big storms?

JERRY COOK: I mean, my thing is, from our perspective, we haven't had that issue yet. But again, we're only a couple of percent underground. So we'll have to see how it goes. But we have not crossed that bridge yet.

Obviously, I think people make their own decisions. I think that could happen. But obviously, that's obviously not the focus of what we're trying to do. We're trying to get people back on faster and quicker.

MEREDITH BRASELMAN: Got it. All right. This next question is for Arie. Do you augment your periodic condition assessment testing with models? And if so, do actual conditions change faster than expected?

ARIE MAKOVOZ: No. As based on our average age, you see, we have 47 years old and some of them much, much older, we don't see the condition deteriorate much faster. No, we don't see that.

MEREDITH BRASELMAN: OK, very good. Clay, this was a question that was actually asked of Peter, and I think he had mentioned you in this one. Have you considered different repair times at different places for underground cables versus overhead lines? If so, how do they compare?

CLAY KOPLIN: We just here about two months ago had one of the most extended outages we've had in 20 years, and it was just a combination of having exactly the wrong fault in exactly the wrong location. There was a gap in underground fault locators.

What I would say is this. We have a new piece of fault locating equipment, and it's just next generation. You don't have to know the propagation constants, anything. It's almost like magic. We just hook it up and it puts us right on the fault every time if it's a low impedance fault. If it's high impedance fault, that voltage divider method that I mentioned with a car battery and just a 30-year-old flute multimeter can be unbelievably accurate if you know how to apply it.

We've installed fault indicators. Schweitzer and others make indicators that can tell you if a fault has passed through a piece of equipment. Almost every piece of equipment in our system has those, so we're immediately able to narrow down the fault and isolate the section. Now that we're implementing an AMI platform that gives us better visibility to just which sections of our town are out of power, we may even be able to expedite that quicker.

But once you find the fault, yes, it takes time to dig it up and repair it, again, a reason I'm somewhat a fan of direct burial cable. The other thing is that we've been adding loop feeds all through our system so that we can isolate a fault and not have to have any customers out of service while we're doing the repairs.

And sometimes we-- in our environment, we're not real highly regulated. We will install sometimes cable and conduit. We keep a reel handy. In the winter, especially, we'll jumper from piece of equipment to a piece of equipment on a backlot line, for example, and leave it energized until the ground thaws in the spring. So we have some workarounds that we use. But again, we can get away with them in our environment.

MEREDITH BRASELMAN: Very good. Jamie, this next question is for you. Wildfires are often followed by flooding and landslides. Will the undergrounding program improve resilience to both disruptions?

JAMIE MARTIN: Thanks for the question. I think in our service territory the greatest risk is the landslide risk, just given the nature of where our lines are in the topography and such. So the short answer is, yes. There's challenges presented in the event of a mudslide or shifting earth, for example, in the event of an earthquake, which is certainly a risk in our service territory.

But from a design standard perspective and then a restoration perspective, in the event that those things occur, we feel pretty good right now about our ability to navigate that. Certainly in the event of a mudslide with overhead line, you're undoubtedly going out of service. We think the resiliency is greater with an underground system.

MEREDITH BRASELMAN: OK. Thank you.

JAMIE MARTIN: I see Clay raised his hand. I bet he has a part.

MEREDITH BRASELMAN: Clay, anything you want to add?

CLAY KOPLIN: If I could just add to that, we've had freshwater flooding where we had our distribution system under 8 feet of water and it ran just fine for eight days. So it can be-- we had to disconnect the meters to the customers because their homes were flooding, but our primary and secondary stayed in service just fine.

Also as a design approach, wherever there's an avalanche chute or a potential mudslide chute, I'll intentionally put elbow connectors on either side of that in a piece of equipment so that it can literally pull out of the cabinet and break away. I kind of design it to fail. If there's splices on either side of a landslide zone, it can propagate and damage a lot more severely than just a second. So maybe that's one of those things of the feature, that we actually design breakaway equipment.

Another thing is put plenty of slack cable in the ditch where you can and intentionally maybe lay it with a little extra lay. We had a place where a road subsided, and the wire was so tight and the road that it pulled on a splice and we had a high impedance fault there. If we'd had a little more lay in the water, it may have been OK with the road subsiding a couple of feet.

MEREDITH BRASELMAN: All right. Jerry, the next question is for you. Any challenges to speak of related to the quality and longevity of the underground cable insulation? They're specifically asking about the effects of salt water.

JERRY COOK: We haven't had any issues with that. We're pretty smart about where we run our underground, and we don't-- very rarely will we have saltwater intrusion. But where we do, we've been pretty smart about raising them, at least our pads and that sort of thing, and sometimes using double pads and things like that to keep things up and out so we don't get salt water down the pipes and everything. But it's not been a big issue for us at all at this point in time.

MEREDITH BRASELMAN: OK. Let's see. This is to all the panelists. Can you share any success stories with integrating utility infrastructure, broadband, and DOT roadway improvements in an efficient and coordinated manner? Clay, you want to go ahead?

CLAY KOPLIN: Ooh, how many hours do I have? Well, I actually mentioned it we do that by working in partnership. A lot of times, as soon as I see that there's a design for anything, whether it's a new facility, a new building, , when we have paving contractors in town or they're doing a highway project, for example, we'll advertise real heavily that anybody who's going to have their driveway paved and so forth, we'll get out in front of it and install empty conduits across their driveway ahead of time so that we don't have to be back five years later digging up their brand-new driveway to replace that 30-year-old electric service.

But I also forgot to mention-- I wanted to mention this is called interstitial filler, and it was designed by a couple of Alaskan engineers. They were using the packing around windowsills and putting it in conduits with wire-- and this is up in Fairbanks where they have permafrost and so forth-- so that when water gets in a conduit and freezes, instead of crushing the wire, it crushes this stuff. And this is designed with an outer kind of a Chinese hand grip so that you can pull it in.

But this sacrifices and takes up that extra volume in the conduit and then it rebounds in the spring. And they've had this stuff in service for 30 years, so this is going to be on the market very soon. But avoiding failures and using some mitigating techniques can really help.

MEREDITH BRASELMAN: This is for all of our panelists. What would you say is the number one thing that must be solved to reduce the upfront cost of undergrounding? And the same question for eliminating the fear of managing and operating underground assets.

MICHAEL JARRO: This is Mike from FPL. I think Jerry touched on it in our presentation. I really do think, when you talk about all the utilities that are investing in undergrounding, there is going to be a shortage of resources. So I think those costs are certainly going to be considerable. And also the limitation of equipment to execute that underground is also going to be one of those limiting factors. We all kind of what needs to be done, but having the ability to do it at a reasonable cost, without being priced out by our vendors and the workforce, I think is the biggest thing that we have to contend with right now.

MEREDITH BRASELMAN: Jamie, the next question is for you. How are you incentivizing other utilities to go joint trench?

JAMIE MARTIN: That's a great question. The answer is, we're working on it and we're taking a lot of different approaches. Our joint pole partners often talk about their business model and the economics of undergrounding for them and what's going to work and what they need. And so our traditional approach in California, and certainly in our service territory from a rate making perspective and tariff perspective has been a cost sharing agreement, a fixed cost sharing agreement, often not necessarily the most economic choice for other utilities.

And so we're considering things like incremental cost as a method by which to economically incent other utilities to join in the trench with us. There's certainly a lot of desire, I think, from our joint pole partners to be in the trench. But business sense for them and for their customers is top of mind, and so coming up with the right economic strategy that benefits everyone, including PG&E's customers, is what we're focused on. And so I'm pleased with the collaboration we've had thus far, and we kind of all recognize that there's more to sort out as we scale the program.

MEREDITH BRASELMAN: Very good. One more question, and then I'm going to hand it back over to Eric for a question and close us out. So this is for all panelists. What are the limitations of the current trenchless technologies that limit their more widespread use for undergrounding applications?

CLAY KOPLIN: Well, I guess I'll chime in a little bit. There's different ground materials. I've found that if there's a real heavy rock or hard rock, or even worse, big, inconsistent ground where you may have a lot of organics, but then you have the periodic large boulder, it's kind of hard to take a boring or trenching approach, at least with boring technology.

There's some limitations on you have to have set up room for a bore so that you have an angle of approach and an angle of exit, and that can pose some problems. But there are some opportunities as well. Very often, you have a lot bigger boring hole than you need to get your conduit in, so boring can be a tremendous opportunity to install additional conduits for other utilities and so forth. And Jamie, I would love to circle back and share some thoughts on the whole spectrum of sharing, right up to having joint easements and stuff that'll save your municipalities a lot of headaches and whatnot.

JAMIE MARTIN: I'll take you up on that, Clay. Thank you.

MEREDITH BRASELMAN: All right. That just about wraps us up. Eric, time for one last question from you to our panelists.

ERIC HSIEH: Yes. So great to see connections being made, but we'd like to give all of you a chance to give one last word out to the community. So what is one thing you would like more people to know about undergrounding? So we'll go in the same order, and Arie, if you'd like to go ahead, kick us off.

ARIE MAKOVOZ: Yep, thank you, Eric. So I just want the community to this is not as easy as it looks like. It's not just a wire in there, in the ground. I can speak for the transmission cables.

I can give you one funny story. In New York City, we're installing underground transmission, each cable, like, 4 and 1/2 inch in diameter, and we're putting it in the ground. And some pedestrians stop by and ask, why do we need so many water pipes?

So that's exactly what I would just bring it as example. It's not as easy as it look. It's not wire in the ground. It's not number 10, like you have it in your house. That's all.

ERIC HSIEH: Thank you. Thank you, Arie. Michael and Jerry, you're next.

JERRY COOK: I'll just take it real quick. I think we've always said this is how we kind of wrap their heads around it. But no matter how much you harden it, overhead, a tree is going to fall in and knock it down. The only way to truly mitigate these hurricanes and wind storms is getting the stuff underground.

And it's not a time of cost right in this moment, but it's a lifecycle cost 40, 50, 60 years of looking at all the stuff you're doing. And so and we firmly believe it's the right thing to do. That's it.

ERIC HSIEH: Thank you. Jamie?

JAMIE MARTIN: I think I'd say that what matters most is keeping an incredibly open mind to what's possible. Things change rapidly. New tools, new technologies are available. Old tools, old technology applied differently are an option. And I think there's so much possibility with regard to undergrounding and its benefits, and it just requires a really open mind. I'll stop there.

ERIC HSIEH: Great. Thank you. And Clay, I know you answered it already, but is there anything you'd like to add to your answer?

CLAY KOPLIN: Of course, especially the final word. I just have to say, we went through a rate case. We have a huge industrial economy. We're the 11th largest seafood delivery port in the country, and so we have huge industrial processor loads.

We increased their rates 20% this summer. And we sat down with each one of them, and I expected a violent reaction. And what every single, all five of them, said to us was, thank you.

They said, your power is so reliable, usually four or five years between outages during their processing season, that it is a tremendous value to them. They're fully automated now, they've got well-balanced loads. So don't underestimate the value of reliability, as was mentioned earlier.

The one thing that hasn't been mentioned, life safety. I know that that's a priority for all of us. And it is so hard to get between a high voltage in the ground when it's already in the ground. So I think that's a huge, huge benefit of underground power lines.

And in broad terms, I would just say that I think the value at the end of the day is broadly underappreciated, and it's worth the extra effort and working through to get methodologies to get it in the ground. Oh, sorry, and the future grid. I know we keep thinking bigger and bigger on transmission, but as we think about distributed resources and think about a future grid, distribution class gets clear up to 35 kv. We call it the grid, but it's not really a grid. It's really still kind of a radial and kind of a hub and spoke system. So think about what a 35 kv grid through a community looks like and all the alternate pathways for power flow that could represent, and start thinking about how we might architecture a new grid.

And also, I forgot to mention our underground power system has such good power factor-- we now have slightly leading and winter slightly lagging in summer-- we are running our hydro projects at 10%, 15%, sometimes 20% past their nameplate capacity because we have a balanced power factor. Huge, huge value stream we can measure in thousands and thousands of gallons of fuel savings a year. So just another little value stream.

ERIC HSIEH: Great. Thank you, Clay. Your insights are endless and always appreciated. Thank you again to all our panelists for that discussion. And Meredith, may I hand it back to you?

MEREDITH BRASELMAN: Yeah. I want to reiterate, thank you so much for sharing the work that you all are doing and the impact you're having on your community. So that was a great conversation.

We are now going to take a short break. We are going to come back here at 3:15. So take a few minutes, check your email, take a walk around, and we will see you back here for our regulator panel.

Welcome back. Thank you again to our utility panelists for talking about your experiences in undergrounding within your service territories. The presentations did an excellent job highlighting real world examples of the need to underground, what each of them are doing on an ongoing basis to maintain reliability and resilience within the systems in place, and the challenges they are experiencing as they scale up their efforts going forward.

Our next panel will focus on underground power lines from the perspective of regulators. I'm going to turn this over to Joe Paladino, Acting Director for Grid Technical Assistance with the Office of Electricity at DOE moderate this panel. Joe?

JOE PALADINO: Meredith, thank you very much. I appreciate that. And thank you all for being here. And today we will hear from Tom Ballinger, who's the Director of Engineering at Florida Public Service Commission, and Joey Chen, who serves as the Advisor to the Chairman of the Maryland Public Service Commission on efforts to harden their electric grids.

I am Joe Paladino, representing DOE's Office of Electricity, where I work with both regulators and utilities to evolve integrated planning practices for addressing myriad policy objectives, including decarbonization, resilience, and equity, and including how we incorporate grid modernization into that planning paradigm as well. As we know, ensuring that our energy systems are resilient is a significant and growing public concern requiring predetermined cogent strategies for investing in energy infrastructure, including the electric grid. This includes developing an investment portfolio that can satisfy multiple objectives, for example, reliability, energy efficiency, cost effectiveness, decarbonization, and equity in a balanced way. There are two major but interrelated components to resilience planning. The first is associated with emergency preparedness and improving our response capability so as to minimize the duration and impact of outages. And the second is associated with our decision processes for determining how to best eliminate and mitigate the impacts from threats. There's a wide range of mitigation strategies, including hardening strategies, for example, making assets less vulnerable to threats, or deploying microgrids or other technologies that require sophisticated automated coordination and control schemes, and using information platforms that can provide real time situational awareness to field crews and forensic data to planners.

There is still a lot of work yet to do to evolve the decision making process for determining mitigation strategies, especially as we begin to address greater levels of complexity associated with both technological advancements, especially at the grid edge, and the need to account simultaneously for social as well as economic concerns. So with that, today we'll hear from two gentlemen, Tom and Joey, who'll provide the approaches their respective states undertook or are undertaking to mitigate the impact of storms.

And first up is Tom Ballinger, who, again, is Director of Engineering at the Florida Public Service Commission. And just a little bit on Tom is that he graduated in 1985, which makes you almost as old as I am, Tom, with a BS in mechanical engineering from Florida State University and been employed with the Florida Public Service Commission since that time. And throughout that time, he's been involved with significant policy issues facing the electric industry, which is what makes it so interesting for all of us. Examples of the issues include open access to retail sales, promotion of renewable energy generation and energy conservation programs, and storm hardening efforts.

He oversees the technical staff of 41 in the area of electric utility planning as well as water and wastewater engineering issues and the commission's electric and gas safety programs. Tom will be speaking about storm hardening efforts in Florida and their process for continuous improvement over the years with regard to minimizing the impacts from hurricanes. And Tom, let me give this off to you now. Thanks.

TOM BALLINGER: Thank you, everybody, for joining this afternoon. Thank you, Joe, for that introduction.

What I will start with first, and hopefully it won't take the full 20 minutes, is give you a little overview, a little background. I don't know what the other panelists covered from the utility perspective, but the one from Florida Power and Light may have covered some of this, so it may be a repeat. But I will try to go through quickly.

A little background. As all of you are aware, electricity is a cornerstone of our economy. It powers everything these days. And commissions around the nation are charged with the balancing act of balancing reliability with cost, and that's always a give and take there.

And luckily or unluckily, in Florida we have quite a bit of experience with severe weather, mainly hurricanes. And the damages in 2004, 2005 really resulted in an eye-opening experience and an outcry from the public to do more about strengthening our infrastructure.

You see from this next slide, in the 2004 Florida was hit several times in the same year by multiple hurricanes. It was a busy year, a lot of damage. Central Florida really took the brunt of it. 2005 was a little better, but not much. We still had two or three hurricanes strike our coasts and again cause more damage. So after that, the commission took some action to try to encourage utilities to do more on strengthening and hardening. So in 2007, we filed a report with our legislature detailing some approaches to storm hardening.

Really, I probably should have flip these in order. Really, probably the first thing we should do is make sure that your customers are aware, to be prepared for storm readiness. In Florida, that's things of lashing down lawn chairs, things of that nature, that could fly for debris, making sure you have jugs of water in case you lose that. Prepare to lose power for 3 to 4 days, and that's a message that needs to be sent out to your customers, that that's what they need to prepare for, because it's the first two or three days after a storm, you probably will lose power. And be prepared so you're not out and hampering restoration efforts.

Again, our goal is to balance restoration, reducing restoration times, and mitigating rate increases. And this is something that's going to take years. It's not going to be something overnight that would happen. So we realized that it would be an ongoing process, it would take a long time.

What we've done during that period starting in '07, started having annual preparedness briefings by the utilities, would come in, brief the Commission on where they were in terms of inventory, practice drills they'd done, where they reached out to customers. We started our formal pole inspection and reporting for wooden poles. Before this, many utilities had the practice of leaving poles in place until they rotted and fell over before replacing them. Started to take a more proactive approach of inspecting wooden poles, looking for strength testing, and reporting those on a more cyclical basis.

We also encouraged and required enhanced vegetation, more frequent trim cycles. Florida is in basically semi-tropical climate zone, have a lot of vegetation, a lot of growth. Required utilities to collect forensic data for after storm events.

And this last bullet is very important. Increase coordination with local governments. That was to coordinate with local EOCs and to also help pinpoint critical infrastructure and critical facilities, such as nursing homes, assisted living facilities, hospitals, police stations, things of that, to make sure that both sides were aware of where the critical facilities were.

And as luck would have it, since 2007 we didn't have any hurricanes until 2017. So really, we had a quiet Florida. We were doing all this hardening efforts. And then in 2017, Hurricane Irma came along. And you see from this graph, it impacted the entire state, basically, with either tropical force winds or hurricane winds.

But the good news about this is that Irma gave us a lot of data to evaluate how our hardening efforts have worked. You see here, it affected 6.7 million customers, all 67 counties, and over 20,000 mutual aid personnel came into Florida to help with the restoration efforts.

But despite our hardening efforts, there is nothing that is a silver bullet. You see on the left, we had some underground facilities that were uprooted, would turn over trees. On the right was a concrete pole that had recently hardened, that fell down when the wires got caught up and pulled down. So there's not going to eliminate outages, but it will reduce outages.

Well, I said it gave us a forensic data to do a review. So in October, we opened the docket, collected information from utilities, also got input from customers and their reaction and their experiences. The objective was to identify damage mitigation options and restoration improvements. Again, we're always trying to improve our processes and procedures.

What we found in this report was it looks like our hardening programs are working. Still the primary causes of power outages, like I'm sure most utilities experience, come from outside utilities, right of way, falling trees, displaced vegetation, other debris, such as trampolines. Those tended to be a major factor.

These last two bullets, the length of outages were reduced, and hardened versus overhead distribution facilities performed better than non hardened. When I say hardened, I mean concrete poles versus standard wood poles, per se. But I have to caveat that we're saying that we really didn't get into were they compared on a meteorological basis similar. So it was a system-wide basis comparison of outage times, but not pinpointed down to similar wind speeds or rain amounts.

Luckily-- and this is where the hardening really paid off-- is very few transmission structures failed. In 2004, 2005 we had several transmission structures failed, and the focus of our initial hardening efforts were the more bulk system, to get the more bang for the buck, to harden things that impacted more customers. So that was a very positive finding here.

Also, underground facilities perform much better than overhead, in general. This is one that's good and bad. The customer expectations are still improving or still rising. They want it faster, quicker. They still weren't satisfied, even though hardening efforts have improved things. And you see there a link for the report on our website if you want to have further reading.

So after this, a couple of our utilities-- this gets to the topic of today's webinar-- is Duke Energy and Florida Power and Light started some pilot programs to target underground lateral conversions. This would be kind of like the last mile. Over the last 10 years, we had done a lot of hardening on the bulk system, but now they were going to the last laterals into individual subdivisions, things of that nature.

Projects were prioritized based on historic performance, so it wasn't about income level or location. It was more looking at do they have a history of poor performance, if you will, because of vegetation problems primarily. However, some projects have been delayed or canceled due to inability to obtain easements.

You remember, when you get to the lateral area, it requires all in the community to agree where the easement should be, where the green pad mounted transformer should go, things of this nature. Also you have other facilities on these poles, such as cable and telephone, and where will they be located. So there's been some glitches in the way as we go along, but they're just getting started.

This next slide shows kind of the progress we made. You see Duke is rolling out, started out with 12 projects, then three. And now in 2020 and 2021, they're starting to ramp up. Now, again, this is just a number of projects, but each project could vary. Some could be as small as three customers, some could be 100 customers, or a few miles or several miles. So it varies, but this is just done by projects.

And then you see Gulf and TECO are also starting to initiate targeted undergrounding programs as well. And I'm pretty sure the last presenter mentioned that FPL and Gulf have now merged, so they will be one and reported as one going forward.

And then finally, we've had some recent legislation passed in 2019. The legislature passed Section 366.96 of the Florida statutes. And what this did, it did two things. It required IUs to file transmission and distribution storm protection plans for a 10-year period.

Previously, we had had storm hardening plans with the pole inspections and all that for a three-year window. This now made it to a 10-year window, basically the same programs going forward. So a lot of that we just had a transition over to that, to calling it a different name, if you will.

But the real key in the legislation was it provided for annual cost recovery review, where prior hardening efforts were done as a utilities base rates and recovered through base rates. So any time we'd have a proceeding is when we would true up costs, if you will. Now with this new legislation, both capital and O&M costs can go through an annual review and annual recovery, much like fuel or other costs we do on an annual basis.

And the statute also requires to do an annual report to the governor and legislature, and that can be found here at our website. We just did our first one last year. So it's just starting to get rolled out to where it's on an annual basis. And that'll highlight the number of projects done and the cost, if you will, for each project. And with that, I will conclude.

MEREDITH BRASELMAN: All right, Tom. Thank you so much. We do have one question that's come in. It was regarding the picture that you showed of the uprooted system. They asked, was the underground that was connected, that was uprooted-- let me start over. Was the underground that was uprooted connected to overhead systems? There we go.

TOM BALLINGER: Yes, it was. And that's another thing that I mentioned, that undergrounding laterals and stuff like that is not a be all because your feeder may be overhead. So we've had that as well. And we've had that from customers complaining, oh, my systems underground. Why did I lose power? It's because the feed coming in. But actually, this photograph was taken down in the Keys, and much of their laterals were underground mainly for aesthetics, if you will.

MEREDITH BRASELMAN: OK, very good. Those are all the questions that we have at the moment. So Joe, I will turn it over to you.

JOE PALADINO: Thank you, Meredith. I just was curious as well, Tom. I just wanted to ask, there's undergrounding and there's also strengthening above ground, assets, poles, and things like that. Is there an advantage to undergrounding? And where would that advantage be that you're seeing more than that then would be a aesthetically?

TOM BALLINGER: Yes, and I think the Hurricane Irma showed that we found areas did perform better in undergrounding, and it's pretty intuitive that, obviously, you have heavy vegetation around, it will perform better. However, other areas, it may not, based on the water level table, proximity to the coast, because underground is subject to flooding. There's other pictures we've had of other hurricanes, especially in the panhandle, where pad-mounted transformers ended up 2 miles inland getting washed out.

So it's very site specific. It has benefits, but it's not the be all and end all for everything.

JOE PALADINO: No, I really appreciate that. Thank you. Thank you for that distinction. Great. Thank you. So let's continue to Joey Chen, who is a Senior Advisor to the Chairman of the Maryland Public Service Commission. And a little bit about Joey is that he received a bachelor's degree in neuroscience from the

University of Rochester. Joey, we can really use you in this utility landscape with a neuroscience degree, I'm thinking-- seriously, actually. And went on to get a master's degree in pharmacology.

While he was getting his graduate degree, he found that he really enjoyed discussing policy issues and particularly where policy meets law. Joey then went on and received his law degree from the University of Maryland School of Law. And afterward, he clerked for a judge in Baltimore City and subsequently joined a law firm practicing commercial litigation, and he joined the Maryland public Services Commission as the Assistant General Counsel in 2016 and has been a Senior Advisor to the Chairman since 2018.

And Joey will be speaking about Maryland's efforts to assess the impact of storms, including the 2012 derecho that many of us experienced and hit the East Coast pretty hard. And he'll be speaking about also the subsequent efforts as a result of that storm and others to underground based upon the state's risk assessment efforts. So with that, Joey, I'll hand this over to you. Thank you very much.

JOEY CHEN: Thank you, Joe. Thank you for that introduction. And thanks to the Office of Electricity and to the ICF team for the opportunity to participate today. As Joe mentioned, I'm Joey Chen, Senior Advisor to the Chairman of the Maryland Public Service Commission. And my portfolio of work at the commission ranges pretty broadly from electric vehicles to connected and autonomous vehicles, the siting of utility scale generation and high voltage transmission in state, as well as natural gas infrastructure replacement. I am also the chairman's staff representative on the Regional Greenhouse Gas Initiative, RGGI, and I lead the commission's public conference, or we call it PC, 44 work group on competitive markets and customer choice. And in that respect, we deal with accessing consumer energy data matters as well as supplier enhancements, as Maryland is a competitive choice state. Next slide, please.

Because I am part of Commission staff, I am, of course, obligated to share this disclaimer that any opinions that are expressed today are my own and do not necessarily reflect the positions or opinions of the Commission or any of the commissioners, get that legal disclaimer out of the way. Next slide, please.

So like Florida and other PSC, PUCs around the country, the Maryland Commission regulates the activities of public service companies that provide critical public services like electricity, natural gas, and telecommunications, water and sewage services in the state. And additionally, our Commission may be in the minority and also regulating for higher transportation motor vehicle services, including certain taxicab companies, transportation network companies like Uber and Lyft, limousine services, and passenger vans, just to give you a little introduction to the Maryland PUC. The Commission also has limited jurisdiction over retail energy suppliers and is the final siting authority for the construction and modification of utility scale generation and transmissions.

To give you an indication of our size, we have about 140 employees in our agency. The Commission's authority comes from the legislature, and while the Commission's main function is as an economic regulator, the Commission has broad authority over the supervision and regulation of these companies and is charged with the responsibility to supervise the companies in a manner that promotes the adequate economical and efficient delivery of public utility services without unjust discrimination. And as such, as you can see in the slide here, the Commission is guided in its decision making by the consideration of the factors, such as public safety, reliability, affordability, customer-centered service, conservation of natural resources, preservation of environment. Next slide, please.

So Maryland is a state with just over 6 million people, and it has 13 electric distribution utilities. There are four investor-owned utilities in the state. These are Baltimore Gas and Electric Company, Delmarva Power, Potomac Electric Power Company, PECO for short, and the Potomac Edison Company. We also have five municipal utilities and four rural electric cooperatives. You see their service territories roughly represented in the colored map there.

Under the state's electricity service quality and reliability act and the Code of Maryland Regulations, so our COMAR, electric utilities are required to provide customers with safe and reliable electric service at just and reasonable rates. And while our Commission, I'll say that we have not adopted a specific definition for resiliency per se, much of what we've done to address service quality and reliability do go to aspects of resiliency.

Service quality and reliability are measured by objective and verifiable standards in our COMAR, and each electric company is held accountable to those standards. And if it fails to deliver reliable service according to those standards, then they could be subject to [INAUDIBLE]. This regulatory requirement applies to our investor-owned utilities and our large electric cooperatives, with the exception of Choptank, and it does not apply to small rural electric co-ops or municipal electric companies.

So when promulgating rules and regulations governing service quality and reliability, the Commission must, among other things, ensure that the service quality and reliability standards are cost effective. So next slide, please.

So now that I've set the general regulatory landscape for our state, I thought I'd start by categorizing utility undergrounding activities in Maryland broadly, the two types. So first is basically extending new service to new residential and non-residential customers that is connecting them to the utilities and electric distribution grid. And the second type is really the selective undergrounding of electric lines to address problematic force performing feeders, and I'll get to that in a little bit.

The Commission has undergrounding regulations for new services, so for the former, but not for the latter, that is, not for selective underground. You see here, COMAR 208501 and 208503 are the two regulations that have been in place since 1969, and they apply to line extensions to these new residential and nonresidential customers. And by these rules, all new low voltage-- that's under 33 kilovolts-- electric and telephone distribution lines must be undergrounded. And this applies to commercial buildings, industrial buildings, multi-occupant buildings, and numerous [INAUDIBLE]

Modifications and exceptions from this requirement are possible, they're provided, however, they are subject to Commission approval. And the costs of undergrounding in this context are typically borne by the customer that requires it. And as I said, there's no comparable regulatory requirement for or undergrounding existing overhead lines, but the utilities do choose to do that, that is, underground certain segments of their overhead distribution lines on a case by case basis and a proven-- sorry. On a case by case basis and largely involving the lines that have overhead lines that are proven to be particularly problematic over time and subject to frequent outages.

So while there are no selective undergrounding regulations in the book as of yet, there have been extensive discussions in the state about possibly undergrounding overhead lines in the state. And earlier today, we heard one of the speakers on a previous panel say that his company's history helped shape their path forward. And I think the same can be said for Maryland, that these underground discussions largely did stem from the series of extreme weather-related outages, particularly in 1999 that we experienced, but then also after snowmageddon in 2010, Hurricane Irene in 2011, and then of course the 2012 derecho storm that went through Maryland and the states.

In 1999, after Maryland experience outages from Hurricanes Dennis and Floyd, as well as ice-related outages and heat-related outages also that summer, the Maryland Governor at that time, Governor

Glendening, requested an investigation to determine whether Maryland utilities are prepared to deal with such major natural disasters and emergencies, and also to restore service in the face of such events. And the Commission initiated an investigation in October of that year focused on extensive outages and rolling blackouts as a result of these events.

And from that proceeding, the Commission created several working groups on several topics, and directed the Maryland electric utilities to do self assessments and file reports with the Commission. The Commission directed the utilities to evaluate the benefits and the detriments of undergrounding specifically segments of their transmission and distribution systems. Specifically, the utilities were to consider costs, the durability of underground systems the risks of damage, the relative duration of outages compared to overhead facilities, and also aesthetics.

Baltimore Gas and Electric, BGE, reported that it would cost about $12 billion with a B to underground all of its overhead lines, all of which would then have to pass to BGE ratepayers. PECO, BGE's sister utility, estimated $10.5 billion, again with a B, to underground its lines. So it wasn't clear that undergrounding was the best or most practical solution to resolving electric reliability problems, especially when electric utilities are arguing that overhead facilities were at least as reliable as underground facilities, but 1/5 the cost to install.

What was clear to the Commission, however, was that undergrounding all distribution facilities would be too cost prohibitive. Moreover, the Commission found that as a practical matter, undergrounding these lines would not necessarily eliminate all the power outages. But the Commission did not want to rule out selective undergrounding, and it felt that this warranted further investigation and discussion, but through a collaborative stakeholder process.

And so the Commission directed the utility staff and other interested parties to evaluate and report their conclusions to the Commission regarding the benefits and detriments of selectively undergrounding segments of utility lines. The work group did just that and filed a report with the Commission including recommendations in this regard. And in July of 2001, the Commission adopted the recommendations of the working groups, including the recommendations from the selected undergrounding work group. And that work group concluded that undergrounding of existing overhead lines may be desirable or necessary for aesthetic or public policy reasons, but it should be on a project by project basis because of the high cost and the service reliability issues, because costs will vary whether or not we're talking about an urban or a rural area, and whether it involves disturbing rock or disturbing sand, what that topography is going to be.

And of course, the undergrounding costs, as you probably heard today, are typically estimated to be 5 to 10 times higher than the cost of installing overhead facilities. But even with technological advances that might even lower some of those costs and address reliability, the reliability issues, the work group still counseled the Commission against a widespread replacement of overhead lines. The Commission agreed with the work group ultimately, regarding taking a more cautious and deliberative approach to undergrounding facilities based on the cost and the identified service reliability concerns.

The Commission declined to mandate an increased use of undergrounding as a solution to reliability and restoration. That was around the time of the early 2000s. And of course, that derecho hit in 2012, kept coming through, and brought massive destruction-- sorry, devastation to the state, totaling more than $90 million in storm-related damages and causing widespread power outages that left nearly 2 million Marylanders without power.

So in July 2012, the governor, Governor O'Malley, stood up a task force to examine how to improve the resiliency and reliability of Maryland's electric distribution system in view of the derecho and the other severe weather events that preceded it, which caused widespread and prolonged service outages. And specifically, that task force was directed to evaluate the effectiveness and feasibility of undergrounding supply and distribution as well as other options for infrastructure investments that would improve reliability of the grid, and of course, costs were on the table for discussion. Next slide, please.

So the task force compiled data obtained from BGE and PECO, and created what you see here is a compiled storm outage map in their two respective service territories. And the map displays the location of each utility's inoperable substations and distribution lines during two of the three previous major storms. So that's the derecho, snowmageddon, and Hurricane Irene. The yellow blue outlines represent the boundaries of BGE's and PECO's service territories, respectively. And I apologize that the text may be a little small to see here.

The blue cross hatch that you see, areas, those represent substation loss of supply interruptions, whereas the solid areas in orange and red represent the neighborhoods where citizens were most affected by the frequency of outages. Neither company, interestingly, had a substation that lost supply in all three storms. BGE had one substation that lost supply in two storms and PECO had more substations [INAUDIBLE].

The task force found from this data, concluded from this data that underground lines offered better protection from the three storms. That is, again, 100% of the two companies' underground substation supply lines remain operational during all three storms. But by comparison, 64% of BGE's overhead substation supply lines remained operational during all three storms, and then PECO's number was 7%. On the distribution line side, 81% of BGE's underground distribution lines remained operational during all three storms, and for PECO it was 55% of its underground lines. So the task force made a number of specific recommendations, including but not limited to, number 1, improving utility reliability and reporting requirements, holding utilities responsible for liability standards, including major storm outages, tightening the poorest performing feeder standard, and providing simplified major outage event reporting from the public. And number 2, accelerating the commission's rulemaking efforts on reliability and utility investment in resiliency spending areas, such as vegetation management and poorest performing feeder remediation.

So in determining whether undergrounding overhead lines presented the appropriate solution, the task force did find that while utility undergrounding can provide benefits, there were also negative aspects to undergrounding lines. You've heard many of those already today-- significantly higher construction costs, shorter life expectancy due to chemical and abrasion conditions that can degrade cable insulation, for example, and longer repair times due to the increased need and time to locate and repair underground line faults.

Similar to-- next slide, please. Similar to the governor's own task force for grid resiliency, the Commission pocketed a separate proceeding, case number 9291, in connection with the electrical service disruptions from the derecho storm, and required the utilities to file major outage event reports. I won't get into that a whole lot. I think that if you wanted to follow up on that case, that's information that I can certainly provide to anyone who's interested. But you can also go to the Commission website and look up all the papers that were filed, the filings in that particular docket. Again, that's 9298.

The takeaways, there I would say, is that the Commission did call attention to the fact that Maryland's electric utility distribution grid was not resilient enough to withstand storms like derecho. The Commission looked at the performance data from the utility companies leading up to, during, and then after the derecho, and interesting, they found it made a number of findings, not the least of which was that an overall finding that the utility's general preparedness or specific responses to the derecho, even though the grid itself wasn't resilient enough, the utility companies did not act in a way that violated state law or commission regulations such as to warrant assessing a civil penalty at that time.

But in terms of path forward, the Commission did issue a number of directives aimed at improving reliability. For example, the Commission directed the utilities to take a number of specific actions, including developing a five-year plan for accelerating reliability improvements, perform detailed studies on their system to determine what investments would be needed to reduce the number of duration of service interruptions after major events, and then participate in work group activities for the purpose of gathering information that would then be leveraged and used to develop specific recommendations for regulatory and statutory changes down the road. The Commission also directed the Commission staff to draft proposed regulations to further revise service quality and reliability standards to include now major outage event data and to strengthen things like restoration times and Maryland's poorest performing feeder standard.

So now I've said Maryland's poorest performing feeder standards several times, and this will be the segue into a couple of examples I'm going to leave you with, approved utilities selective undergrounding activities in our state. And so as I mentioned, the Maryland electric utilities are required to file annual reliability reports, and where necessary, a utility may be required to file a corrective action plan in response to violations of certain performance standards. And as part of this reporting requirement, the utilities are required to include a list of their poorest performing feeders, and those poorest performing feeders are defined as those having circuit reliability performance 250% or more above the utility system-wide SAIFI and SAIDI indices.

Now, the important thing is that the feeder cannot remain on the utility's poorest performing list for three consecutive yearly reporting periods, unless the utility has undertaken reasonable remediation measures to improve its performance. So in the example of Potomac Edison, Potomac Edison reported a repeat feeder, poorest performing feeder, in its Little Orleans circuit from 2018 and 2019. And following the report in 2018, Potomac Edison completed a full circuit tree trimming in 2019, which included the removal of danger trees and an overhead circuit inspection.

But despite this remediation work, that circuit appeared again on the company's poorest performing feeder list the next year, and the outages were primarily caused by large incidents by off-right of way trees. In 2020, Potomac Edison completed another danger tree patrol and removed identified trees that had been susceptible to incidents, but it nonetheless filed a corrective action plan with the Commission and proposed to underground two segments of the Little Orleans circuit, which is a total length of about 5,000 feet in Washington and Allegheny counties.

Now, Potomac Edison had tried to identify none underground any solution, and this was important for the Commission. Potomac Edison had attempted to install reclosers at strategic locations along the circuit to more efficiently route the line crews to the problem area. But the issue with that was that the signal strength for communications was insufficient, and so that effort was discontinued. Potomac Edison also

considered the distribution automation scheme. But because of the circuit's, again, rural location and no adjacent circuit ties, it would have required extensive construction work.
And then the third thing that Potomac Edison tried to do, and Potomac Edison proposed an alternative, a non-wire alternative, to offer the New Orleans circuit as a candidate for Maryland's air energy storage pilot program. And that battery storage system would have provided a second source to that circuit, to that area, I'm sorry, in the event of an outage, and would have allowed automation to isolate the faulted circuit faulted section of the circuit and automatically restore power to the rest of the circuit. But during the design phase, it was then discovered that the battery storage system just wasn't compatible with the circuit because of the single phase nature. So the energy storage proposal was withdrawn.
But as I mentioned, this was important. The fact that the Potomac Edison considered several non-underground solutions that just weren't we're not going to work was not lost on our Commission staff. They found that Potomac Edison's remediation effort in this regard was, in fact, reasonable and noted that there are no other less costly options that would have been similarly effective.
Now, Baltimore Gas and Electric also that year reported its own problematic area of 16 multiple device activations, and these are protective devices that activated five or more times during the reporting period, which caused sustained interruptions in electrical current service to more than 10 customers. Now, by Commission regulation, companies are required to implement reasonable remediation measures to reduce the number of these multiple device activations and include them in their annual reports. And BGE included this repeat MDA, submitted a corrective action plan on it, identified a fuse on one of its feeders as the repeat device, dating back to 2018.
Again, as with Potomac Edison, BGE had tried other options. It had previously performed focused hotspot tree trimming in 2019 to address the issue, but this didn't resolve it. It also installed reclosing capable sectionalizing devices. But even after all of this, the multiple device activations continued [INAUDIBLE].
So then BGE ultimately decided to implement selected undergrounding, undergrounding the beginning portion of the tap where this fusion was located, and then removing the existing overhead equipment.
So since the completion of this work, BGE reported to the Commission that there's only been one outage recorded in the area, which in the company's view reflected the success and effectiveness of the undergrounding effort. So the Commission approved BGE's cap and found that BGE took prudent steps to address the problem feeder identified in 2018 when the feeder was first reported and improve that review.
So I think the one thing I will mention before I wrap up here is that the Commission is-- since I joined the Commission, and this is now post-derecho proceedings, the Commission has already considered several proposals that would present distribution grid resiliency benefits that do not involve undergrounding. One of them is on the energy storage front. And as I mentioned, this involves two energy storage projects proposed by BGE that would address what they simulated would be winter post-contingency overload if something were to happen and BGE lost two transmission circuits that happened to share a single right of way in a pole line.
And then the other proposal that I've seen come through the Commission relates to public purpose microgrids. So two of our utilities, BGE and PECO, proposed separate microgrid proposals. Ultimately, they were not approved by the Commission, but you can see how microgrids could present another alternative to undergrounding. But that would yield or could yield localized resiliency benefits.

So with that, I want to thank again the Office and ICF for this opportunity to present. And I'll be happy to take questions.

MEREDITH BRASELMAN: Yeah, thank you so much, Joey. We do have a couple of questions that we want to cover, and I know Joe Paladino has some follow-up for you all. But first, a quick reminder that we will be posting today's presentations on the website by Monday, and a recording of the webinar will be available in about two weeks.

So Joey one of the questions that was submitted here, did you say that underground cable has an inferior lifespan compared to overhead? If so, I'm familiar with the 1970s vintage cables that had manufacturing issues and only lasted 20 to 30 years. Did your study committee look at modern cable materials that can last over 100 years?

JOEY CHEN: So I think one thing to keep in mind is that the study that I was referring to in the efforts of those discussions are probably of the older order now. So this was reported in the grid resiliency report from 2012. So by now, I think that then the life expectancy from an undergrounded cable, as I understood it, was about 30 some years. I have not personally looked at longer life underground cabling, so I don't have any more recent data.

MEREDITH BRASELMAN: OK. Thank you. Joe Paladino, I will turn it over to you for some follow-up questions.

JOE PALADINO: OK, great. Well, I'll just pose a couple here, a couple that are very specific. Joey, I was curious about the energy storage devices that BGE proposed. Do you know what kind of duration they were looking at for those? Was it a four-hour duration? Was it eight hours? Do you know?

JOEY CHEN: Not of the top of my head, but I can try to find out for you real quick.

JOE PALADINO: OK, well, not immediately, but it's a curiosity because a lot of folks install four-hour batteries and things like that. But try to provide resilience from a major event, one would imagine that you might need backup power to last a fairly long time. So the curiosity, the question then, is how much time did you actually need from the battery? So that that's one question. The other question is, do you know why the public purpose microgrids were not approved?

JOEY CHEN: They were considered separately, and they came in time. BGE's came in first, and then I think PECO's proposal came afterwards. One of them, and I think it might have been BGE's, had to do more with the actual slate of resources that would be proposed in the portfolio. The Commissioners, I think several of the Commissioners at that time had identified or asked some questions as to whether or not, why the portfolio did not consider certain resources versus others, for example, lack of energy storage being looked into the project, the list of resources. And the other one, I think PECO's had more to do with cost.

JOE PALADINO: Cost, OK. And rationalizing that a utility could make a rational proposal for a public purpose microgrid, then. I'm just curious because there's always a question about what the utility can own versus what a DER service provider or customer can own right. And I know some utilities are really interested in owning and deploying their own microgrids and including energy storage devices. So I'm wondering if utility ownership had had anything to do with the final decision on whether the utility could build out something like that or not.

JOEY CHEN: It was something that was raised, I think, in some of the party filings, but the Commission did not-- I do remember this part. The Commission did not address that question head on, in terms of utility ownership.

But you raise a good point because in Maryland, being a restructured state, utilities are not-- they don't own generation. And then the reason why utilities are able to pursue the energy storage pilots are a creature of law. The law flows out of the legislature authorizing the commission to implement an energy storage pilot program, which then has provisions that solicit and obtain proposals from the utility companies specifically. But I think that to the side, yeah, the question of ownership is still one that's out there today.

JOE PALADINO: Got it. Got it. OK.

JOEY CHEN: So I just-- Joe, if I could circle back real quick to your first question about the energy storage pilot. So the scoping of our energy storage pilots is, by the legislature, again, was fairly small. We're not talking about big battery projects here. So I think that's one thing to keep in mind, is I don't think that-- the BGE proposal involved jointly utilizing both projects together, relying on both projects. It doesn't exactly answer your question about the hours, so I would have to see if I can get back to you on that.

JOE PALADINO: OK. I'm just going to continue to ask a couple of questions, Meredith, if that's OK, unless you're seeing some pop up.

MEREDITH BRASELMAN: We do have a couple, but go ahead, Joe.

JOE PALADINO: No, no. Go ahead, go ahead.

MEREDITH BRASELMAN: OK.

JOE PALADINO: I want to give other people a chance here.

MEREDITH BRASELMAN: All right. So Tom, this question is for you. How did the Florida commission handle rate increases due to undergrounding and pilots? Were there any considerations of rate class impacts or other considerations for low income and vulnerable customers?

TOM BALLINGER: OK, so the pilots when they first started, they were under the traditional rate making, where they would be rolled in with every other asset of utility in a general rate case. So there was no special treatment in terms of equity or cost sharing or income levels, things of that nature.

I failed to mention, too, that prior to this targeted undergrounding, that if a subdivision, let's say, requested undergrounding as a conversion, they would pay the differential between underground and overhead. So it would be a voluntary activity and that group would pay the incremental cost. These pilots now are going forward with all ratepayers paying the cost, even though it's impacting a smaller subgroup, if you will, of customers.

So to answer the first question, it was under normal rate making. And the same thing now going through with the clause that I mentioned, with the cost recovery clause going forward, I believe it's still being allocated on a cost of service basis capital based on 12, 13, and 1 CP, that kind of thing, between demand and energy. So it's still no special circumstance based on income or location.

MEREDITH BRASELMAN: OK. Joey, question for you. With the Maryland microgrid proposals, was there a diesel or gas generator included in the package?

JOEY CHEN: Oh, I do recall that there was one. I can't remember it was tied to which company, that was BGE or PECO. And there was some discussion about that in terms of also the weather impacts associated with the diesel. But again, I would have to dig out that order to tell you which company's proposal it was.

MEREDITH BRASELMAN: OK. For both of you all, given the realm of possible investments to improve resilience, what do you find so compelling about undergrounding? Where is it especially useful, and how does it compare to other resilience measures?

TOM BALLINGER: I'll go first, Joey, if you don't mind.
JOEY CHEN: Fine.
TOM BALLINGER: I think in Florida, like I mentioned, a lot of especially South Florida is basically a subtropical climate. So we have heavy vegetation growth, a lot of older houses, a lot of rear lot services, where the lines come in behind the houses and then branch off from there, and a lot of growth of trees and things of that nature. So I think we found it in areas like that, where there's heavy vegetation to be more helpful.
JOEY CHEN: And so for Maryland, we are susceptible to the big storms that will come through. We do have vegetation issues, downed trees, and so broadly, if you think about it from a big picture standpoint, undergrounding does provide enhancements to resiliency, especially when we are talking about this sort of trending up of extreme weather events. We're seeing more and more of them in recent years. And particularly where there are no feasible overhead alternatives and difficult to locate, then undergrounding can present, I think anyway, a possible candidate for that. It may be a better option in urban areas.
And one of the things that we've-- and I've been involved with more recently is a group discussions on compatible siting. That's siting of generating stations and transmission lines in a manner that's compatible with military operations. So the idea of other uses that would favor the undergrounding lines would also be a reasonable application.
JOE PALADINO: Meredith, I'd like to pose another question, if that's OK.
MEREDITH BRASELMAN: Yeah. I think we've got time for one last question, Joe, so that's perfect.
JOE PALADINO: OK. So beyond the reliability indices, like SAIDI, SAIFI, et cetera, do you folks apply specific resilience measures that either utilize those or are separate from those?
JOEY CHEN: So I can start us off there, Tom. I think my answer would be, at this time, outside of our reliability metrics, so SAIDI, SAIFI, CAIDI, no, because Maryland doesn't, as I mentioned at the beginning of my remarks, we haven't landed on a specific definition for resilience.
However, what we have done is recently the Commission docketed a grid-- sorry, distribution system planning efforts. Launched that. There will be a work group, stakeholder collaborative process that will probably address and bring up the topic of resiliency. And I also am aware that there is a effort, a forthcoming rulemaking that could also involve resilience indices. I can't say for sure because we'll have to wait to see what's actually proposed, but it is possible. Our staff has had opportunity to meet with stakeholders and utilities, and one of the things that they've talked about is the idea of using [INAUDIBLE].
JOE PALADINO: Great. And thank you very much, Joey. And Tom, I was wondering whether you guys had specific resilience-based metrics that you applied.
TOM BALLINGER: No, we look at the typical SAIDI, CAIFI, MAIFI, all those metrics. But I would say also a very important one is customer complaints. You have to balance those with-- you may have a system that's performing not as great as you'd like it to be, but very few complaints. So you have to balance that if customers may be more tolerant of momentaries especially, we found in Florida.
JOE PALADINO: Great. Tom, thank you. Joey, thank you very much. Meredith, thank you, and everybody. I'm handing it off to you, Meredith.
MEREDITH BRASELMAN: Yeah. Thank you very much. I'd like to now welcome Michael Pesin, Deputy Assistant Secretary for the Advanced Grid Research and Development Division at DOE's Office of Electricity. Michael?

MICHAEL PESIN: So thank you very much for having me. I'm just going to say a few words at the closing of this wonderful event. Actually, I had an opportunity to listen to many of the presentations today, and that was great.

So I don't have any prepared remarks. I just want to share some of the thoughts of mine and thank you for participating and sharing your thoughts. And just want to give you an idea of the vision, where I think electric grid is going in the future, what's the role of undergrounding topic in this, and what all we can do to enable all goals that we have for electric grid.

So one thing is certain, and I think Pat talked about this in the beginning. We need to make sure that the electric grid can keep with all future demands and future challenges, and we have a lot of new challenges facing the grid. We have weather changes, hurricanes, physical threats, cyber threats. We need to make sure that we can be prepared to mitigate all these threats.

Then we have changes in our generation portfolio composition. We're moving from the old centralized grid to fully distributed, or mostly distributed, with a lot of renewable variable generation. So how can we make sure that the electric grid can support this.

We need to make a lot of new investments, and those investments must be strategic. We can't just do one time, we need to have a holistic approach when we are making our investment decisions. So we need to significantly increase capacity of the electric grid.

But increasing capacity does not necessarily mean building a lot more transmission. There is a lot more untapped potential in the existing right of ways. So how do we prudently upgrade this so we can maximize value from this upgrade, so we can increase capacity while improving reliability and increasing resilience. So there is broad set of investments that we need to consider. There is no single silver bullet that we have, but undergrounding is definitely one of the solutions in our portfolio.

So I was really happy to hear a lot of the things that we discussed today, from technical analysis, that was very interesting. So I heard the presentation from Peter Larsen from LBNL. So it's utmost importance to make sure that when we make this decision about undergrounding we can make it in a way so it's economically feasible. So we can have a societal values and other economic values taken from the grid.

And then, of course, there is no substitute for real hands-on experience. So Clay had a lot of interesting ideas, I think, from you. So prior to joining DOE, I spent almost 30 years working in electric utilities. And when I was young engineer, many, many years ago, I spent some times with URD crews, with line crews, so I've seen how it's been done.

And there's certain things that kind of industry best practices, but this is why they're called best practices, not standards. For example, using conduits for undergrounding makes sense for many utilities, but as we just heard, not always. Sometimes what is given as a best practice may not be the best solution for specific applications. So unless you have this hands-on experience, you can't come up with the solution.

And another interesting discussion that I think I liked, and actually, I never heard this discussed for undergrounding, is design to fail. So we had a lot of discussions about design to fail for overhead lines. But under certain conditions, I think it makes perfect sense for undergrounding lines designed so they fail in the points where it's easiest to repair. So you know where they fail.

But even having said that, when we start undergrounding our power lines, we want to take advantage of all good things that come with this and minimize all the negative impacts of that. So one of the negative things of undergrounding is difficulty of locating faults. So one of the solutions that we are working on at DOE is developing sensors that can be embedded either at the strategic locations or along the entire cable so we can pinpoint the fault locations, so we don't need to even apply this wonderful car battery tools to locate the fault that the system, the SCADA or some other data acquisition system can report to you where the fault is located.

Some other things that we can consider is where these underground lines go, what other benefits we can get, so strategic locations in the right of ways. So for example, we all hear about big transportation electrification effort, which means we're going to have a lot of public charging stations in public infrastructure. So if when we're undergrounding our distribution lines, and even in some cases transmission, we can plan for taps for those charging stations and create those in advance. That will save us a lot of time and money later when we have to dig it out again and connect to a new distribution center for high level, high speed electric vehicle charging.

So there is a lot of many interesting topic. And undergrounding, of course, it's not a silver bullet. We all understand this. But it is a very important tool in the portfolio of all the industry solutions.

And this is the tool that can help those harden the electric grid, but it also can help to improve reliability, resilience. When it's done right, it can significantly contribute to decarbonization of the national economy. It also is very vital element in the evolution of electric grid. This is something I've been talking a lot about recently. So the grid that is designed today, similar to highway or water supply system, is evolving. So we have a lot more distributed resources. So it is evolving from this point-to-point delivery mechanism to something similar to internet, where we have multiple pathways to deliver energy from source to consumption. And it goes for both for transmission system and for distribution system.

So the radial lines will be evolving in looped radial lines, when you have open [INAUDIBLE] under normal operations, but you can reconfigure it and you can have more than one path to a single customer. So there is a lot of changes that are happening to the industry.

But from the electric grid that is designed around this large, centralized, mostly fossil generation, we need to move to the one that will have very high penetration of renewables. It will have widespread distributed energy resources, different types of resources, solar generation, electric transportation that can be managed with smart charging or even vehicles to grid, buildings that will be more electrified, and industrial and other laws.

And one thing we need to always keep in mind, that grid that we're creating, we need to be able to give all consumers the opportunity to participate in this clean energy economy. And very importantly, the grid were all consumers cannot only rely on electricity to be always been available, but they also need to be able to afford this electricity. So we need to make this investment decision very prudently and we need to plan them carefully.

And so, finally, I want to thank everyone for participating in this webinar and submitting your thoughtful questions with these very important topics. And I want to thank all utilities, regulators, National Lab participating in this. And we will look forward to working with you to understand what are the challenges that you're facing that industry sees much better than we can see from here in headquarters, and we look forward to working with you. And I think with that, I will turn it over to Meredith to close out. Thank you.

MEREDITH BRASELMAN: Thank you so much, Michael. This brings us to the end of today's webinar. Thank you for your participation today. We hope everyone enjoys the rest of your day.