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UNITED STATES NUCLEAR REGULATORY COMMISSION'S
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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FUELS, MATERIALS AND STRUCTURES SUBCOMMITTEE

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WEDNESDAY

OCTOBER 18, 2023

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The Subcommittee met via Video Teleconference, at 8:30 a.m. EDT, Ronald Ballinger, Chairman, presiding.

COMMITTEE MEMBERS:

RONALD G. BALLINGER, Chair

VESNA DIMITRIJEVIC, Member

GREGORY HALNON, Member

JOSE MARCH-LEUBA, Member

ROBERT MARTIN, Member

DAVID PETTI, Member

JOY L. REMPE, Member

THOMAS ROBERTS, Member

MATTHEW SUNSERI, Member

ACRS CONSULTANT:

DENNIS BLEY

STEVE SCHULTZ

DESIGNATED FEDERAL OFFICIAL:

CHRISTOPHER BROWN

ALSO PRESENT:

JONATHAN BLACK, EPRI

ROB CHOROMOKOS, EPRI

DYLAN CIMOCK, EPRI

KURT CRYTZER, EPRI

ILYA GOLDBERG, EPRI

SAMUEL JOHNSON, EPRI

DAVE OLACK, EPRI

JEREMIE VARNAM, EPRI

RYAN WOLFE, EPRI

C-O-N-T-E-N-T-S

P-R-O-C-E-E-D-I-N-G-S

8:30 a.m.

CHAIR BALLINGER: Good morning, everyone. The meeting will now come to order. This is a meeting of the Fuels, Materials, and Structures Subcommittee of the Advisory Committee on Reactor Safeguards. I'm Ron Ballinger, chairman of today's Subcommittee meeting.

ACRS members present are Bob Martin, Dave Petti, Dennis -- our consultant Dennis Bley, Greg Halnon, Jose March-Leuba, Joy Rempe, and I expect we'll be joined by others shortly.

MEMBER SUNSERI: Hey, Ron, this is Matt Sunseri. I'm on.

CHAIR BALLINGER: Ah, okay. Well, I probably missed -- sorry about missing Matt Sunseri. I'll probably miss somebody else as well, but hopefully we'll get that take care of.

MEMBER ROBERTS: Hey, this is Ron Roberts. I'm on, too.

CHAIR BALLINGER: Gee whiz. I have my list of participants that don't show you folks. Oh, well. Some days you win, some days you lose.

Okay. Christopher Brown of the ACRS staff is the designated federal official for this meeting.

This is our fourth Subcommittee meeting with EPRI this year. So far we have had a Subcommittee meeting on the materials, reliability issues, instrumentation control, and fuels. I might add this is the last of the meetings. I might also add that the Sharepoint site or the site on which the slides for all of these meetings will be plus I guess the transcripts constitute a wealth of information related to the materials area and we expect that -- we know that this will be very useful going forward in committee reviews for -- committee reviews in general.

During today's meeting the Subcommittee will receive a balance-of-plant information briefing from EPRI. The Subcommittee will hear presentations and hold discussions with EPRI and other interested persons regarding this matter. I might also add that when we have been doing subsequent license renewal reviews very, very often the AMPs and things that are in place related to subsequent license renewal often are related to balance-of-plant issues. So while they're not -- this presentation will not deal with primary stress corrosion, cracking, and other primary systems and things, it's very relevant for subsequent license renewal.

This meeting is open to the public. The

rule for participation in all ACRS meetings were announced in the Federal Register on June the 13th, 2019. The U.S. NRC public website provides the ACRS charter, bylaws, agendas, letter reports, and full transcripts of all full and Subcommittee meetings, including slides. The agenda for this meeting was posted there along with the MS Teams link. We have received no written statements or requests to make an oral statement from the public.

The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions as appropriate. I also might add that this is an information briefing. It's not -- we're not expected to produce a letter related to this. A transcript of the meeting is being kept and will be made available.

Today's meeting is being held over Microsoft Teams. There is also a telephone bridge line as well as the MS Teams link allowing participation of the public. When addressing the Subcommittee the participants should first identify themselves and speak with sufficient clarity and volume so that they may be readily heard. When not speaking we request that participants mute your computer microphone or phone by pressing *6, otherwise we get sometimes feedback and things like that.

We will now proceed with the meeting. And I'd like to call on Kurt Crytzer to provide opening remarks from EPRI.

Are you there, Kurt?

MR. CRYTZER: I am. Can you hear me?

CHAIR BALLINGER: Yes.

MR. CRYTZER: Okay. Wonderful. Thank you.

Okay. Thank you for your time. My name, as was mentioned, is Kurt Crytzer. I'm a senior --

(Audio interference.)

CHAIR BALLINGER: Yes, as I said, somebody better mute something.

MR. CRYTZER: All right. Give me one second. I want to make sure that -- okay. My name is Kurt Crytzer. I'm a Senior Principal Team Lead within the Plant Engineering Group within EPRI Plant Engineering. Next we'll be part of the EPRI's Plant Reliability and Resilience Program, which we'll talk about on the next few slides.

My personal background, I've been in nuclear since 2001. I've worked for Westinghouse, I've worked for Duke, and currently work for EPRI. I do manage the balance-of-plant group within EPRI and my technical areas of expertise right now are heat exchangers and thermal performance.

We've put together a pretty thorough agenda, so I won't spend too much time on my background, but thank you so much for this opportunity.

So as I mentioned, we'll becoming Plant Reliability and Resilience, and we're going to talk a little bit about our research, which you can see is in the area of components systems, which includes maintenance and engineering. This also includes process guides and best practices.

As we roll into one group; you've mentioned Instrumentation Control has presented to you in the past, we will all be under one program. We'll cover active mechanical, which is rotating and moving equipment; balance-of-plant and all passive mechanical systems, which also includes thermal performance; electrical, which includes medium and low-voltage cables, switchyard relays, instrumentation and control, which You're familiar with; and engineering maintenance and processes. These would be something like single point vulnerabilities or various maintenance processes.

So really the whole idea of bringing everybody together is to be able to cross-collaborate on engineering and the subsequent maintenance that goes along with components with systems.

We're aligning our research focus areas with industry issues that we're seeing and hearing about. So as you mentioned before, plant life extensions, power outbreaks. Our research touches on those.

Resiliency, both in climate, environment, and social resiliency. So most recently supply chain issues, but obviously the impacts of climate change on ultimate heat sink. You'll be hearing some things moving forward on that.

Efficient and intuitive access to EPRI information. So to get the information out as cleanly and as quickly to the end-user as possible in a manner that is convenient, not only for those who have English as their first language, but using illustrations to have those who perhaps English is not their first language access the information conveniently. So we're making a real mindful approach to doing that.

Risk-informed and graded approaches. And then modernization, the use of data, both gathering and data analytics, and online monitoring. So all these will bubble up through Plant Reliability and

Resilience.

So I have a team put together today that will hopefully touch on topics of interest including balance-of-plant corrosion, low and medium-voltage cables, plant resilience, intakes and heat sinks. And then we'll hopefully have a really good open discussion on some of the research.

As just a point, please feel free to ask questions or interject at any time during these presentations.

So with that I'm going to introduce the first set of speakers. I'll let them introduce their backgrounds themselves, but the first presentation that we have is on buried piping, cathodic protection research activities. We also have a new flow-accelerated corrosion initiative along with this presentation that we're going to be talking with. And this will be Dylan Cimock; Dylan is a senior technical leader within my group, Jeremie Varnam, and Sam Johnson, who will be joining from NDE.

So with that I'll turn it over to Dylan and let Dylan start it off. Dylan?

MR. CIMOCK: Good morning. Is my microphone coming through okay?

All right. Good morning. So as Kurt

said, my name is Dylan Cimock, Senior Technical Leader in the Plant Reliability and Resilience Group. And for the last probably six, seven years I've been with EPRI I've been leading a lot of our research activities in the area of buried piping, cathodic protection, and more recently on selective leaching. Prior to joining EPRI I was with one of the nuclear utility companies and primarily doing license renewal work starting around 2009 until 2016.

Kurt, did you want to introduce the rest or progress through?

Kurt, can you go to the next slide?

Okay. So in addition to the research activities that we do in buried piping and cathodic protection one of the other areas of responsibility that we often have for many of these topical areas is managing a number of industry-wide user groups. Specifically I've been involved with our Buried Piping Integrity Group, BPIG. So it's a group of utility engineers mostly associated with buried piping program owners, cathodic protection system engineers. We have an annual meeting once a year where we have probably about 100 attendees, anywhere from maybe 40 to 50 utility people and 50 to 60 members from either NRC staff, INPO, as well as technology suppliers and vendors.

I thought I would maybe highlight a few of the topics that we've been hearing about recently at our annual BPIG meetings. So the three topics here: one is on selective leaching degradation, specifically as it applies to cast iron components. The other topic we've seen presented a lot and discussed in the industry has to do with different internal pipe repair methods using non-metallics, things like carbon fiber composites, cured-in-place piping, spray-in-play piping. And then the third topic is cathodic protection. A lot of discussion around performance and reliability issues, system overhauls and replacements, and some of the EPRI resources and activities that we have available for the industry on that.

Next slide? The first one we'll talk about is selective leaching and some of the research that we've been doing on this. So we've mentioned to start this that there are a lot of aging management programs in the BOP space that are coming through for license renewal and second license renewal, and one of those is the selective leaching AMP.

I'm not sure how familiar everyone is with it, but selective leaching is a specific form of corrosion where one element of an alloy is preferentially removed. It's also referred to as de-alloying. And the unique aspect of this is even though the material is losing material, it may not necessarily undergo any changes in dimension or shape. So visually the component will look to be in near nominal or completely satisfactory condition even though it has actually lost some amount of material and have some inflamed graded material properties in the affected region.

So some of the materials that are susceptible that we commonly find in nuclear power plants and documented in both the GALL, GALL SLR, and even IAEA IGALL report is grade ductile cast irons, aluminum bronze with more than eight percent aluminum, and then other copper alloys with at least 15 percent zinc.

And some of the systems that we commonly find these materials in, a lot of them are in the fire protection systems with some as well in the Service water condensate systems, and then even in some of the cooling water aspects of the emergency diesel generator, and sometimes even safety-related systems like auxiliary feedwater.

So the picture on the right is an --

DR. BLEY: Dylan, this is Dennis Bley.

MR. CIMOCK: Yes?

DR. BLEY: I've heard of this, but I'm not completely familiar with it. Since this structure hangs together and probably on the inside looks pretty good for a long while through this process, what kind of failure modes do we get? Is it sudden holes in the pipe, or what's it look like when this leads to failure?

MR. CIMOCK: Good question. It varies based on the material. So with cast iron what we have seen is oftentimes it will result in a crack of the pipe, either circumferentially or even spiral and longitudinally down the pipe typically emanating from an area that's affected by the leaching. We have seen other cases where the leaching actually penetrates full through-wall. And then during some sort of a system surge it actually kind of blows out a graphite plug and it will leak. So those are the two mechanisms that we see often with cast iron.

With the copper alloys they tend to kind of weep, so it's kind of a porous microstructure that eventually goes through a wall and water slowly kind of migrates and diffuses through and begins to weep out.

But the picture on the right, that's an example of a 12-inch diameter cast iron pipe that experienced selective leaching. So the photo on the left is actually after we wire-brush cleaned it and it appeared to be in pretty much near nominal condition, completely smooth, no indications of any form of material loss. And after we had completed doing some of NDE exams we subjected it to an abrasive sandblast. And the extent of wall thinning there in the photo on the right probably ranges anywhere from about 30 to 50 percent through-wall and there were some localized areas, as much as 70 percent, through-wall, none of which was seen during the initial exams.

Kurt, next slide? So why is it important? It is a slow-acting mechanism so as plants continue to operate beyond their original 40-year lives out to 60 and 80 years of operation, this form of degradation composed a greater threat to the plants and to the components. Many of the utilities have gone through the license renewal and now second license renewal processes or beginning to implement aging management programs specifically for this.

And the recommendations for the quantities of inspections have kind of gone up through the progression of the original GALL, GALL Rev. 0, Rev. 1, Rev. 2. And so some of the utilities have been faced with an increase in quantity of inspection sometimes in the hundreds of inspections. So it's becoming a kind of costly endeavor to manage this as well. Some of them upon discovery of adverse findings have had to implement periodic programs. And I'll talk about the inspection difficulties a little bit on the next slide.

DR. BLEY: Dylan, Dennis again. Have there been any observed failures in the first 40 years of operations from this mechanism?

MR. CIMOCK: I believe so. I don't have a specific reference for it, but yes, I believe so.

CHAIR BALLINGER: This is Ron. One of my other hats was as a corrosion consultant and I can tell you that there have been many failures related to this in the past.

MR. CIMOCK: Yes, it's also not unique to the nuclear industry. We have a lot of cast iron infrastructure in our water municipal infrastructure and gas transmission pipelines, so this is not something specific to the nuclear industry. A lot of our buried infrastructure has been dealing with this for many years.

CHAIR BALLINGER: Yes, this is Ron again.

I have a house that's built in the early 1800s and it had cast iron pipe for its heating system, hot water, and I removed it to replace the heating system. And one way to remove it is to take a ball-peen hammer and just whack the elbows. And because of the selective leaching graphitization the pipes would just fall apart.

MR. CIMOCK: Yes. So this picture here is kind of an example. You can see in the cross-section of a valve body as -- the leaching is kind of progressing its way through the thickness of that component even though the dimension kind of remains intact. So you can kind of see a darker gray area where it's mostly graphite, and then even the red. It's kind of oxidizing as it progresses through the component wall thickness.

All right. Kurt, next slide? So some of the challenges that we've been observing in the industry from the standpoint of implementing these aging management programs: One is just general knowledge and training. It's not a really well-understood or even known about mechanism, so the aging management program owners that inherit it don't necessarily start off knowing a whole lot about it.

There's also been some questions about

when implementing a sampling-based inspection program how to maybe go about choosing your components or locations for inspecting based on things like severity of the operating environment, relative susceptibility.

And then from a technique perspective I mention that visual exams have definitely been challenged by being able to adequately detect the mechanism. GALL Rev. 2 introduced hardness testing as an alternative and that has had somewhat mixed results. Some components, their size and shape are just not conducive to using portable hardness testers. On the other hand, some have had success using that as a detection-based technique. You'll find that the leached areas exhibit a reduction in hardness, but it doesn't necessarily tell you anything about the depth of penetration.

And particularly until recently there hadn't really been some objectively demonstrated NDE techniques for leaching, and this has led to a lot of utilities implementing a process of relying on destructive examinations, sometimes just proactively going in, selecting a component, removing it from Service, and cross-sectioning it and looking within the cross-sectional area for any evidence, which while effective isn't necessarily the most efficient.

Next slide, Kurt? So from an NDE perspective we've been looking into this matter for some time. We started off back in 2009 issuing a couple of reports that initially showed some promise for ultrasonics and electromagnetic techniques. The problem was we were somewhat limited in the availability of samples that we had to test on and some of the field testing that we did do wasn't necessarily fully conclusive.

So we followed that up with looking at some additional techniques in 2016, but really beginning in about 2019 or 2020 we put a more concerted effort into trying to procure some field-removed samples exhibiting more significant amounts of selective leaching. And we were lucky that we had a number of utilities volunteer some removed components in the form of both valve bodies as well as piping. And that's really what's led to some of the progress that we've seen over the last couple years in the three most recent reports in 2021 and this year.

Next slide, Kurt? So in 2021 we published two what we call technical briefs. These aren't full EPRI technical reports. They were actually designed in Microsoft PowerPoint, full of lots of images, graphics, and a lot shorter text descriptions so that the reports were NDE-based, but maybe a little bit easier to digest by the typical system program engineer.

But the first one we documented the results and the successes that we had using three different ultrasonic techniques to detect selective leaching inside of gray cast iron valve bodies. So those exams were performed from the outside surface of a valve body that was relatively clean looking for degradation initiating from the inside surface.

The second project we look at four different electromagnetic techniques to examine gray cast iron piping. It included three techniques from the outside surface and one technique actually applied from the inside surface of the pipe.

And I'll pause. I think I just saw a hand up.

CHAIR BALLINGER: No, that was a mistake.

MR. CIMOCK: Okay. So based on the results of the electromagnetic techniques we did publish an update and a more thorough EPRI technical report earlier this year. It includes a lot more detailed analysis of the original four techniques that we used on each of three different piping samples. And then we looked at two additional techniques in

2022.

And just to give you guys kind of an idea, Kurt, if you'd go to the next slide, a lot of people are familiar with ultrasonics, but electromagnetic techniques not necessarily as much. So this is just some examples of what these slides -- or I'm sorry, these tools look like. So the first four techniques that we evaluated were pulse steady current, low-frequency electromagnetic technique, LFET, a through-transmission bracelet probe, and then the internal remote field testing. So this is a tool that can be pulled through the inside of the pipe and detect degradation on either the inside or outside surface. And then the second two techniques are magnetic flux leakage and saturation eddy current.

Next slide?

DR. BLEY: Can I ask two quick questions? Dennis Bley again.

MR. CIMOCK: Sure.

DR. BLEY: The one you showed on the last slide where you can pass that through the inside of the pipe certainly makes testing easier. Is it reasonably effective? How does it stack up with the others? And related sort of, you've mentioned valve bodies several times. Are the valves more susceptible or it's just a place that's obvious to check because of the bends or connections associated with it?

MR. CIMOCK: So I wouldn't say the valve bodies are necessarily more susceptible. They're just part of a component population. Often what we see is they represent a component that can maybe be more easily removed from Service and replaced or perhaps they have other issues such as properly seating and sealing just do to raw water debris build-up. And so they're proactively replaced due to isolation concerns and then they're opportunistically evaluated for selective leaching at the same time.

But from a detection point of view this is some examples of what the qualitative view of the results look like. So again on the left is the pipe sample that we did the abrasive sandblast on. The image next to it is actually what's called laser profilometry. It's a technique to basically scan the surface of a component and measure kind of the contour, the surface of it. So it's not actual wall thickness measurement, but rather a surface contouring temperature.

The next are our qualitative images of the corrosion maps generated for each of the first four techniques.

DR. BLEY: Are these all of the same pipe section?

MR. CIMOCK: That is correct. So when we initially collected the data the pipe was not sandblasted. We had no indication of any degradation present on the pipe. But each of the four techniques showed us that there was something going on in the pipe, some indication of wall thinning and it was being displayed in kind of a consistent pattern, shape, and location on the pipe. And that's what led us to doing a destructive evaluation on one of those pipes to confirm those findings.

So next slide, Kurt? So where we're kind of at from an NDE point of view, with cast iron components we demonstrated three different ultrasonic techniques for when the degradation is occurring on the opposite surface from the exam and six different electromagnetic techniques, all commercially available that can be used on piping.

One of the outstanding gaps that we still have is that ultrasonics are still challenged when the exam is performed on the same surface that the leaching is progressing from. The material just seems to be kind of porous in nature and difficult to get the ultrasonic energy to couple into the piping material and get a back wall response. So we're still having challenges with coming with an ultrasonic technique for that application.

With copper zinc alloys we see this mostly in small valves as well as some heat exchanger tubing. And unfortunately we haven't really had any field-removed tubing known to have selective leaching that has allowed us to do some objective demonstrations on eddy current testing, but what we have seen is some industry operating experience which indicates that the utilities have had success in detecting it either directly or in any pitting that results from the leaching.

Aluminum bronze is the third material type and the industry has had some successes in developing and advancing techniques like time-of-flight diffraction and even phased array testing for that material type for certain component geometries.

But based on the results that we've seen as well as the industry operating experience we did provide a recent comment during the open comment period for NUREG-2191, Rev. 1, the GALL SLR update. So we did provide a comment I believe it was last week recommending that the NRC staff consider the results of this research, the industry operating experience, and possibly include NDE as a viable option in the XI.M33 selective leaching AMP. What we're seeing is that these are more or less field-ready techniques and offering a lot of advantages from a detection capability as well as the surface area component that can be examined.

Yes, Dennis?

DR. BLEY: Sorry. I couldn't get my mic open. I was just wondering, quite a few -- well, almost everybody now has aging management programs and this sounds really arduous in time spent, not just testing, but digging up the pipes so you can see it. Has any of the licensees decided over the time they expect to operate it's not worthwhile and begun switching over to non-suspectable materials?

MR. CIMOCK: Yeah, they have. Sometimes it's kind of informed based on results that you have. If You're not finding a lot, you may elect to stick with what you have. But if based on the inspections you begin to see issues, utilities have absolutely begin to implement a process of either replacing the material with perhaps like-for-like material but extra coatings on the inside of valves or improvement materials like high density polyethylene or just a material not susceptible to selective leaching. So it's a little bit more on a case-by-case basis.

MR. BLEY: Okay. Thank you.

CHAIR BALLINGER: Yeah, this is Ron Ballinger again. This kind of sheds a little bit of light on what we see in SLR. A lot of times when it comes to buried piping and the like, applicants have simply resorted to basically digging things up at locations which they, in their judgment, feel that they would be susceptible as opposed to using some of these inspection techniques.

MR. BLEY: Yeah, Ron, that's why I asked that question. I seem to remember 10 or 15 years ago as we were looking at license extension. Quite a few people were opting to go susceptible materials. And I didn't have any idea how far that's progressed.

MR. CIMOCK: Was there a question?

MR. BLEY: No.

MR. CIMOCK: Okay. Could you go to the next slide? So I just want to highlight the materials uses one are that we've been looking at from the perspective selective leaching research. We have put out a state of the art report to try to improve the level of knowledge and understanding on the mechanism.

We did do a project that we published in 2021 where we've looked at a literature review on factors affecting susceptibility, including some limited lab studies. And we're currently collaborating with one of the national labs on furthering that research. We also have a report coming out just in probably another week or two from general programmatic guidance on implementing these programs.

We put out training. And then we've also done pilot studies on the selective leaching as part of the larger EPRI and industry effort on leveraging risk insights for aging management. So next slide, Kurt. So we'll touch a little bit more briefly on some of the non-metallic repairs that we've been seeing used in the industry. Kurt?

This would include materials like high density polyethylene, carbon fiber reinforced polymer or CFRP, and spray in place pipe lining. So I don't know how much you've guys have seen this. But we have observed a lot of utilizes moving towards rehabilitating buried pipes, particularly large diameter using CFRP.

So it's essentially woven carbon fiber fabrics saturated a polymeric resin and then hand applied inside of the pipe. Because it's hand applied, the diameters usually required manned entry, so greater than 30 inch. When they're designed, they can be either designed to simply reinforce the existing pipe or they can actually be designed such that the pipe really just serves as a form to install the system.

And once fully installed and cured, the carbon fiber composite actually is the new pipe that's credited with taking all structural and pressure loads. And the host pipe doesn't rely upon any more with the exception of what's called the terminal lens. This is the end of the composite repair.

And those terminal ends are what's credited with transferring the loads between the repaired and unrepaired regions. So the lower right-hand corner, you can kind of see what a cross section of these composites look like. You have a steel substrate there at the very bottom of that. The black layers are five layers of carbon fiber fabric sandwiched between the blue epoxy resin after it's been fully cured. So we can see this used a lot in pipes that are larger diameter, buried deeper into the ground, and where it might not be very economical to actually excavate and replace all this large diameter pipe due to the depths that it's at and underneath other buried assets.

MR. HALNON: What's the thickness in that lower right corner?

MR. CIMOCK: That one there is probably around 0.6 inches.

MR. HALNON: Okay, thanks.

CHAIR BALLINGER: Does this complicate inspection down the road? Or does it basically eliminate the requirement for inspection?

MR. CIMOCK: Largely, it eliminates the requirement for inspection as basically a new pipe. The one exception has been the ASME code case that's in development for carbon fiber composites. The N-871-2 that's in progress right now, it has introduced some volumetric requirements at these terminal ends to ensure that degradation doesn't continue to progress on the back side of the original pipe. If it's strictly reinforcement, then yeah, there is still a concern about monitoring the degradation beneath that composite. So Kurt, next slide.

(Simultaneous speaking.)

MR. CIMOCK: -- right now is spray in place polymeric linings. So using robotics to spray in basically a polymeric lining solution. It's not necessarily new, but what is new is the fact that these are now being installed at a much higher dry film thickness, somewhere on the order of about a tenth of an inch up to a quarter of an inch.

And they're using new polyuria resins which offer significantly faster curing times. Kurt, next slide. So some of the research that we've been doing on carbon fiber, we published a report last year actually on NVE of the metallic substrates beneath the CFRP to your point. So previously, these were too thick and too attenuative for conventional ultrasonics.

But we did identify two different techniques that can still penetrate through that carbon fiber and measure the remaining substrate thickness. We have an ongoing project ran out of our NDE group by Sam Johnson who's on this call related to NDE of the carbon fiber composite system itself. And we continue to score ASME code case every quarter and include and identify any potential research gaps for follow up.

With the SIPP solution, we have a report coming out in a couple weeks looking at kind of technology landscape assessment and the gap assessment against using SIPP in the nuclear industry. And we're working with the utilities on developing guidance on testing and qualification of these systems for slake related piping, including solicitation of interest in using SIPP as a fully structural repair methodology and what material properties need to be developed in order to continue progressing that. Next slide. So particularly with the CFRP, I wanted to note that we have been working collaboratively with members of the NRC staff on some common areas of interest with respect to research gaps on carbon fiber.

And we actually held a workshop this past July including members of the staff, national labs, universities, and some NDE technology suppliers and CFRP designers and installers. And currently right now, both NRC staff and EPRI have two independent projects where we're looking at the NDE of the composite systems. So we've been collaborating on understanding kind of the flaw types and sizes that are of interest, the NDE technologies that are out there that might work, and then setting up the fabrication of actually mock-ups. So that's some work in progress going on right now and into next year. Next slide. So with that, I'm going to turn things over to Jeremie.

MR. VARNAM: Thanks, Dylan. Can I do a mic check?

MR. CIMOCK: Yeah, You're good.

MR. VARNAM: Thank you. So I'm Jeremie Varnam. I'm a senior technical leader at EPRI, approaching my one-year anniversary with joining the team. My career in nuclear started in the mid-2000s with Progress Energy at the time. And then I've also spent a good portion of my career in the consulting world, mainly in the realm of chemistry and chemical engineering.

I currently have some leads with working with heat exchangers and condensers. But also I've held out with some backup poles and buried pipe in which one of the projects we're talking about here with slake detection using ERT and also serving as a backup in the area of flow accelerated corrosion. Next slide. This is a conceptual measurement of the electrical resistivity tomography application.

This concept was originally used at the Hanford site where there's an electrical current that is injected into their subsurface. And they use a near tank well work casing that has an electrode. And then they measure the corresponding electrical potential within the tank. So as you start developing a leak near the tank casing or around the tank, the electrical connectivity of the soil in that vicinity is altered.

And you essentially get a change in the electrical potential within the tank. Essentially, this concept has been adapted using an array of cost effective electrodes. So the ERT measurement essentially requires four electrodes that you put in direct contact with the subsurface or the soil.

So you start out with applying a current between the positive and negative current electrodes. So essentially, now you've got a source that's considered a battery. And the current source is a potential gradient in the subsurface which causes the flow from the positive to the negative electrode.

We could measure that current conceptually using an ammeter. And then we have two other electrodes that are used to measure the potential in the ground induced by the current source. And we do this by essentially connecting the positive and negative leads to a voltmeter to those electrodes and measuring the voltage.

And this you simply use here with the four electrodes, this ERT measurement. It's simply the voltage normalized by the current. And we call this transfer resistence.

So essentially, we're taking this application here and we're applying it to many electrodes and many measurements in the ERT system. But it makes a very simple system that makes ERT robust, customizable, and applicable to pretty much any scale where you can reasonably connect a series of wires and electrodes and get them into the soil. Next slide. So for this project, we wanted to develop an autonomous technique for monitoring leaks in buried pipe and tanks to allow for early identification.

Not only with early identification being important particularly with lines that may contain radioactive fluids, but also being able to narrow down, like, the portion of piping that would be required for excavation. As far as our current research activities, the project commenced with a Phase 1 feasibility study where we essentially with that modeling technique to see if ERT could be a viable approach to use in our nuclear fleets. And then we've recently completed Phase 2 and published those findings this year where a small pilot was conducted using the PNNL.

It was conducted at a BWR site where they had their Service water piping discharge in a facility that contains both saltwater and freshwater type sources. In this project here, we did simulated leaks of both saltwater and freshwater components. And we were able to distinguish these leaks from major rainfall events that occurred during the demonstration period.

So with appropriate electrode spacing, essentially we can minimize the area that would require excavation to be minimized from a risk standpoint. Next slide. This is the demonstration setup. This considered the Setup No. 1 where we put the -- the electrodes were buried about six inches beneath the surface and spaced in between four discharge lines for circulating water discharge.

There was a leak simulation tube. Look at the photo on the right highlighted in the yellow circle. That was our leak simulation tube that we put on top of the pump bravo discharge line.

What we found out and I'll discuss these results later is that this particular space in here that was utilized, the lines were not close enough to the leak source. As you move away from your leak source, the sensitivity to detection decreases. But this was the initial set up here that was deployed at the site.

The ERT instrument and the control computer, these components were stored inside in one of the pump houses. So we completed two leak injection tests, one using potable water which was around 388 microsiemens per centimeter and then also using the nearby canal water which has a conductivity of greater than 3,000 microsiemens per centimeter. The injection rate was set to approximately one gallon per minute, and the ERT survey time which was the time to pulse between the four series of electrodes is about 20 minutes.

This test was conducted over the course of two days where day one was about 170 gallons or approximately three barrels of canal water used and then followed by 2,000 gallons of a potable water flush. And then day two was more the agility type testing where we started with 57 gallons of barrel water near discharge pipe C and 278 gallons of canal water on pipe B. Essentially what we found there in this first leak test was that the electrodes were too far away from the leak.

Looking into the failure of this, it was a design mistake based on incorrect assumptions and lessons learned. So what could be done here is prior to deploy the ERT technology is looking at doing baseline measurements. So you have an understanding of the background soil conductivity and use a sensitivity study so you can help develop a map of sensitivity away from the components of interest, whether it be a tank or a pipe to help with selecting appropriate electrode placement.

So that was done after this first leak injection test here. And if you'll get to the next slide, Kurt, the electrodes were moved closer toward the -- to be over top of the discharge pipes, and in this case here, closer towards the leak injection pipe. So these temporary surface electrodes, when you use two lines of the eight electrodes each at about one meter spacing, again, we use the same water sources and potable water with a lower content in canal water essentially being saltwater.

Use similar injection rates. And this time, the ERT survey time required, we reduced down to ten minutes. And for this test sequence, we used approximately 100 gallons each of the potable water source and of the canal water.

And the results were extremely promising as shown on the next slide. You can start these animations here. On the left-hand side is the potable water, and on the right-hand side is the canal water.

And essentially what we were able to do with these simulations is even with the potable water at a very low connectivity, the leak was identified after approximately 15 gallons were injected into the soil. For the canal water which has a much higher connectivity, the leak was identified after approximately ten gallons. You see with these visuals here, this data could be fed in to the software that's utilized and help develop tomography of the area.

So again, this are extremely promising results for this demonstration here. Your next steps are to put the technique through some of its paces, looking at influences from a cathodic protection system and also assist in other issues which could be, how does it work around non-insulated reinforced concrete? Or in the presence of grounding grids, are there other seasonal variations that need to be considered beyond like heavy rainfall events, particularly in regions that may contain a lot of (audio interference) surface if sod is used. So there's still some gaps that we're looking to do with Phase 3. But the Phase 2 results show that with appropriate sensitivity studies in advance, the plain electrode placement, this is an extremely viable technology to identify leaks that occur extremely early and at low rates.

MR. CIMOCK: All right, Jeremie. Thank you. So real quick and just for the sake of time I'm going to touch on a few of the reports and research that we've been doing around the cathodic protection tanks. So Kurt, if you can go to the next slide. Kind of summarize CP and what we're seeing in the industry as kind of issues that maybe falls under three different categories.

One is just general training and knowledge, understanding how cathodic protection works. Second is applying CP inside nuclear facilities is immensely more complicated than was commonly done inside the gas transmission pipeline industry. We have a lot of pipes in close proximity.

They are crossing one another at different depths. They are different materials. And they are all electrically bonded together and connected to the station grounding grid which is uncoated and more favorable for CP than the steel piping that's typically there.

And so trying to apply CP in such a complex facility is complicated from trying to balance areas that are overprotected to under protected in getting it to the assets that need it everywhere. And then the third challenge really stems from simple maintenance prioritization with CP. At the end of the day, it is not a safe-related system.

It doesn't affect generation, and it doesn't result in any LCOs when it's not performing correctly. So from simply a prioritization issue, it is a lower priority system. But to address a lot of these gaps, we hasn't done some research historically developing thorough guidance on how to manage the system.

We've developed training that we are actively upgrading this year and into next to try to get the training into the hands of the engineers sooner. And then we've also looked at developing software for the industry to use to help with managing their data and trimming it to forecast the need for systemwide upgrades. So right now, it's a little bit less research oriented and more in training an knowledge transfer and retention.

And from a tank perspective, Kurt, if you go to the next slide, we have published a couple of reports on tank inspections. One is guidance for performing tank inspections and different types of tanks including above grade and buried tanks. And then we've also looked at different NDE techniques and methodologies.

A lot of what we're seeing, the industry interest in right now is underwater inspections of the tank floor plates for above ground storage tanks whose bottoms sit on the soil. There's often a lot of challenges with trying to coordinate draining of these tanks and performing inspections. So being able to perform them using robotics underwater is highly desirable.

And there have been some vendors offering these services. And we have evaluated some of these techniques in the past and the report referenced there. But we'll also continue to do some research here looking at techniques like guided way to look at the bottom of the tank floor plates from the outside surface and possibly some reference guides about different technologies, different deployment options for each of the different types of tanks, above ground storage, buried tanks, indoor horizontal cylindrical tanks.

So different techniques for different applications and from different services that they're applied from. And so that's another project that we'll be trying to pull together as more of, like, a reference and resource guide for both engineering and NDE personnel. So with that, next slide. Jeremie, this is back to you.

MR. VARNAM: Thanks again, Dylan. This

next project was following a finding from one of our utility members from one of their inspections related to a wall fitting on a feedwater bypass line which is this is a line that comes off one of the main feedwater lines that is in operation less than 2 percent time of the year as considered a stagnant location. So Kurt, if you kind of clip through, it'll bring up some of the text and the highlighting here.

But essentially, what one started with was an inspection of the Charlie feedwater bypass line. This line was inspected following some questions by one of the newer system engineer at this particular site where they were questioning as the 14 inch line that comes by for the charted line is a non-susceptible material. So it's P22 chrome alloy material.

And then the Charlie bypass line is a susceptible material, carbon steel. So there's some questions on whether or not there could be an inverse effect having to go from a non-susceptible to a susceptible material. So there known specs in history as these bypass lines were categorized as non-susceptible as they are in operation for less than 2 percent operating time.

The findings were unexpected where the

actual thickness was 100 mils versus a coded mil of, excuse me, 213 mils. So this led to some scope extension for the alpha and bravo bypass lines. And the metal and thicknesses identified there were even lower where the alpha bypass line having a thickness of 52 mils and bravo having a thickness of 92 mils.

These bypass lines were emergently replaced with a P22 chrome alloy material which allow for some examinations of these specimens. And all of these bypass lines exhibit a rippled or an orange peel surface which is pretty consistent with single phase flow accelerated corrosion. There were --

CHAIR BALLINGER: This is Ron Ballinger again. That minimum thickness, how close were they to rupture?

MR. VARNAM: I'm not sure if we had that information from the utility as far as what kind of burst criteria would've been with that wall thickness. Ryan Wolfe is also on the phone. He's our fact lead here. Ryan, do you have any additional insights if that information was shared?

CHAIR BALLINGER: I'm reminded of the incident they had in Japan at Miyajima where they did have a rupture. And 52 mils, boy, that seems pretty close.

MR. VARNAM: It does. But yeah, I'm not sure how that was in relation if there was any formal evaluation. At least I'm not aware of one that was shared.

MR. WOLFE: Yes, this is Ryan Wolfe. I'm a technical executive at EPRI in the area of balance of plant and also flow accelerated corrosion. I'm not aware either of an evaluation that was done regarding a week before break of this particular defect.

CHAIR BALLINGER: Thanks. I just thought maybe somebody would have it. Seems awful thin.

MR. VARNAM: The next slides show some of the visuals from one of the specimens that was removed. So the utilities actually did contact EPRI and coordinated with our Checkworks users group advisory committee to help define the extended condition. So the factors that were looked at were operating time, erosion and leak by.

Those were eliminated as likely not factors. Interest effect and water chemistry were assessed. And while they may have been factors, there was not enough history for certainty.

The area of high interest that warranted additional investigation that led to our project were looking at flow conditions. So we did decide to tackle this using a computational fluid dynamics as a project. Next slide, Kurt. So to help determine whether in fact thinning was the likely cause of this wall thinning here, we did deploy computational fluid dynamics.

One of the things that we want to also inform is whether or not similar effect thinning of those lines could occur at other plants and wanted to change to the EPRI guidance. So what we're looking to do here beyond the model of the actual plant conditions is also doing a variety of parametric studies to help characterize different conditions of these branch bypass line connections. Next slide. So some of our preliminary results are shown here.

So on the right-hand side is an animation showing all the velocities. One thing that we, early on as we were setting up the model, noticed that we're not getting a monotonic convergence at residuals. So we're really dealing with a very unsteady state here. So instead of being able to look at potentially, like, 1.0 time as determining the resonance time to the system here and taking an average of results to the system.

But essentially, this system was modeled here. We started with the initial boundary at the 18 inch lines. The two 18 inch lines feeding into a common 14 inch header.

The three 14 inch lines are the feedwater lines. And then the branch connections there were all 4 inch lines. Beyond looking at the flow velocity for these systems, we were able to use this share stress model to also look at the turbulence kinetic energy and wall shear. And Kurt, if you go to the next slide. Looks like we're getting stuck with some of the videos here.

MR. CRYTZER: Yeah, Jeremie, right now I'm having -- have to restart the program.

(Pause.)

MR. VARNAM: So I was mentioning beyond looking at the flow velocities through these different sections, we also looked at the turbulence kinetic energy and the wall shears. And the one thing that we noticed although it's kind of hard to see using Microsoft Teams here is that where we're seeing, like, the highest velocities, the wall shears, and the turbulence kinetic energy, they match extremely well to where the actual wall thinning was observed on the samples from the utility. So it gave us a good competence that when developing an appropriate CFD model that it could inform us of different parameters that could influence fact finding and gave us confidence that the flow turbulence, add that rotation, was the likely contributor to the wall thinning observed at these particular locations. Next slide.

This next slide will show some of the correlations that we're working on here where we're looking to correlate the wall thinning with some of the different parameters. In this case on the right-hand side, You're showing a correlation of the CFD simulation in the blue line. In the gray line is some of the inspection data from the plant.

And it looks like we can develop a fairly decent correlation between wall thinning and the turbulence parameters that are predicted. So our next steps are looking at parametric analysis to help prioritize additional locations and help define an extended condition for the industry. And in doing that, we're looking at the information such as bypass line size.

And so instead of having, like, a 4 inch into 14 inches is adjusting that bypass line. We did lower sizes and all the way up to 14 inch, taking a look at the bypass entrance. Where does that bypass entrance occur?

Is it two diameters away from the header all the way up to about four diameters away? Also looking at a variety of pipe connection geometries. So in this example here, this particular connection was a welder let. So it's kind of a fairly sharp entrance into that branch connection.

We've also adjusted the model to mimic like a forged tee with different blended radii on the elbow piece of it. And then other considerations that we're looking at are bypass operation, whether or not it's been in use for more than 10 percent of the time and potentially looking at the fluence, if there's bypass valve leakage. How does that influence some of the turbulence and wall shears that are expected at that entrance location.

MR. VARNAM: All right. Thanks, Jeremie.

MR. CRYTZER: All right, Ilya, You're next up on our agenda unless there are any questions.

MEMBER HALNON: Before we move on, this is Greg Halnon. Jeremie, did -- I'm sorry. I had to step away just for a second. Did any fundamental changes get made to the industry-wide fact program because of what you found here?

MR. VARNAM: As of this time, not yet. With the parametric study, you know, we're looking to see if that would result in the need of changing some of industry guidance, so we're -- you know, the positive thing is that, you know, we were able to kind of mimic, you know, some of the, you know, at least with CFD modeling.

You know, where the plant actually saw the wall thinning is where we're seeing the highest turbulence of kinetic energy, so we're looking to play with a variety of stuff that's more indicative of what may be out in the industry, you know, for like a force feed connection instead of being like a 14-inch to a four-inch, doing 14 to 14, because that's, you know, kind of a common type of how some of these branch connections are made, to help inform to see if it does warrant a change in the guidance. So, we're still -- the parametric study piece is still ongoing, but near to wrap up.

CHAIR BALLINGER: Yeah, this is Ron Ballinger. A related question, these inspections are oftentimes time consuming and expensive, and has this additional analytical capability been able to inform operators as to reducing the number of locations that they have to inspect, narrowing the susceptible population?

MR. VARNAM: Right, yeah, and that was,

yeah, as we worked through this and, you know, I think, one, developing the higher confidence level and the use of CFD and how it's, you know, actually shown here to be pretty applicable to the plant findings with wall thinning.

You know, some of the future work that we have identified here, it is for something such as that where, you know, maybe we apply it to, you know, to the heat exchangers, and, you know, are there other particular components around the shell where, you know, the higher turbulence is where we need to focus our inspection studies versus, you know, at another link of the component itself.

CHAIR BALLINGER: Thank you.

MEMBER HALNON: So, Jeremie, back to my question before Ron jumped in, in my previous experiences, I do remember the CHUG membership coming back and have been doing some interim actions based on industry operating experience. Is the CHUG still active enough that people brought this back?

Because it's clearly a safety issue from the standpoint of potential, as we talked earlier, rupture, or even a leak at that pressure and temperatures. Is it -- the next available outages, are people thinking about this and inserting this into their inspection programs?

MR. WOLFE: Jeremie, if I could jump in here, this is Ryan Wolfe again with EPRI. I'd just like to say that evaluation of operating experience is one of the key elements of an effective flow-accelerated corrosion program. It's one of the main sources of inspections.

In this situation, this operating experience was made known to the CHUG membership, and each of those CHUG members will have separately evaluated the operating experience to determine its applicability not only to the feedwater piping bypass lines, but also in other lines that may be excluded from the flow-accelerated corrosion program due to having low flow conditions. I would say in that case, the information has been considered by other folks.

MR. CRYTZER: All right, thank you, Ryan, and thank you, Jeremie. Ilya, do you want to take over?

MR. GOLDBERG: Sure, thank you. Can you hear me all right?

MR. CRYTZER: We can hear you well.

MR. GOLDBERG: Great, thank you, and thanks for passing it on. So, my name is Ilya Goldberg. I am a senior technical leader at EPRI with a few areas of coverage, but one of the main ones being cable aging and cable condition monitoring.

I have about 13 years prior experience in the cable industry. I started off in fiberoptic systems and then transitioned to downhole medium voltage cables in oil and gas before joining EPRI about three and a half years ago to work on cable programs for nuclear power plants. Go ahead, next slide.

We're going to talk about both medium voltage and low voltage programs, but we are going to start off with the medium voltage cable installation condition monitoring program and some of the developments that we've had in that over the years. Go ahead to the next slide.

So, let's start off with some background. Cables were initially classified as long-lived passive components, so things that, you know, that really did not require maintenance and testing, and that was the position endorsed by NUREG 1526, et cetera, and the majority of cables will, in fact, last for plant life, but there are some exceptions, and the biggest, you know, the first big primary one is cables that are exposed to adverse local environments.

So, good examples of adverse local

environments, you know, you have your thermal exposure, water exposure, electrical, mechanical, chemical, radiation. There are also considerations for cables that are damaged during installation or maintenance, or any latent damage that occurs and then comes up over the years and becomes more problematic.

Now, specifically in medium voltage cables, your primary adverse local environment, your most important ones are the ones with dielectric impact, and that is primarily water aging. There are thermal aging situations, impacts that have occurred, but they are relatively rare. So, a lot of the focus goes into water aging and water exposure aging.

Successful programs are ones that identify these adverse local environments and manage how the cables age in those environments. Aging management programs are typically designed to do that, to find which cables are going to be exposed to these environments and to test, monitor, and manage their aging. Next slide, please.

So, let me continue on with some background. Medium voltage cable, the failures really started to occur during the mid-1970s, and GL200701, the summary report, was provided with data that had been collected on the failure rates and failure occurrences, kind of a summarization of what had been seen in the industry at that time.

There was a wide range of failures and a wide range of cables that had been captured, including in-Service and test barriers, about 188 of the 269 cable failures were medium voltage, so rated 5kb to 46kb. Now, it's important to keep in mind though what the population sizes are when You're looking at that.

So, although you see quite a bit of low voltage cable failures, you have to keep in mind that a typical plant is going to have about 30,000 to 40,000 low voltage cables and maybe a few hundred medium voltage cables. So, in terms of population impacts, you can really see why there's been focus on the medium voltage cables.

The leading causes were attributed to water and moisture, and failures were pretty common across the types of insulations that were in use, you know, the butyl rubbers, EPRs, and XLPEs. And, you know, there was some characterization, but of course, you know, that characterization also has a large presence of unknown categories. So, again, your data quality is what you can get out of it. Next slide, please.

There were some NRC staff conclusions and recommendations that came out of that summary. Two of those, that many utilities did not at the time have cable-specific testing and monitoring programs, and that there was increasing trending of these failures, you know, increase in trends as plants aged.

So, the recommendations were reasonable preventatives should be made to keep cables dry, but there were also some conclusions that came out of the GL that really begged for more research, including cables are designed or qualified for submergence, and concerns that a common mode failure of cables could occur. And these are some of the -- you know, some of these ideas informed the research that went on after this. Go to the next slide? So -- yes?

MR. BLEY: This is Dennis Bley. My memory is over the last many years, people who were coming in for a license, you know, reported to the community these kind of problems, and I seem to recall that there were more failures associated with cables that got flooded, dried out, and then rewetted multiple times than ones that were just submerged. Is my memory right on that?

MR. GOLDBERG: We mention this a little bit later on, that essentially if cables can be dried out and then kept dry. I don't have the information to say that repeated wetting versus consistent wetting. I can't say that offhand.

MR. BLEY: Okay, thanks.

MR. GOLDBERG: So, continuing on, a need for research of commonly used EPR and medium voltage cables was identified. A lot of the research up to that point had looked at XLPE insulation, and that failure mechanism research really began in 2006, with the first reports being issued in 2007.

EPRI harvested and collected thousands of feet of previous in-Service medium voltage cable that either had in-Service failures or had poor test results, and evaluated them to look at what the cause of that failure was. Between 2000 and 2015, eight reports were issued on those findings and what was identified in those cables. Next slide, please?

So, first off, to describe the approach of this research, and then what essentially we did is once those samples were pulled in, there was a systematic methodology for finding the faults in those medium voltage cables.

So, it starts off with VLF Tan Delta, and then you section you cable into increasingly small pieces and use combinations of VLF and AC breakdown to try to find the weak points in them, all the way down to, and this is an image shared on the right showing the use of a pin-type, you know, a pin-type tool to really identify where that leakage, where that weak point is in the cable. Once those weak points were identified, the cables are sections and analyzed to see what kind of understanding, what kind of knowledge can be gained about the nature of the failure.

So, at the bottom right here, we see a few of those points are weak points that were sectioned and then photographed to show exactly what had gone inside the insulation at that point, and it shows the presence of a water tree underneath it. We can go ahead to the next slide, please.

So, from that large body of samples, we were able to make some findings to address some of the initial concerns. So, one of the primary ones was that VLF Tan Delta testing, so very low frequency Tan Delta, identifies the degraded insulation, and it can sort out, using some criteria, cables that fit into a good category, an action required or failed category, and a further study category in between those two.

And what this does is it allows you to sort your cable populations and identify where your problems are through this testing to know where you need to take action in order to get ahead of any issues you may have.

Now, one of the other outcomes here is that these water tree developments, they were not homogeneous, and what it means, you know, what that practically means is that when you look at parallel sections of cable that were pulled and you look for failures in the same portions of those parallel section, you don't see them across all of the phases.

And what You're doing there is You're essentially demonstrating that this is not a common cause failure mechanism because you don't see it across multiple sections that are all exposed to the same adverse environment, adverse local environment, in that adverse local environment. We can go ahead to the next slide.

So, from that research, there were some guidances that were issued. Two that I wanted to call attention are Report 1020805 was the aging management program guidance for medium voltage cable systems for nuclear power plants.

There is a Revision 1 that was issued in 2013 under number 3002000557. This is the general aging management criteria, and that also includes these Tan Delta sorting tables and condition, you know, evaluation criteria that we identified from the previous cable sample inspection program.

Another component to that is 1021070. That is the medium voltage cable aging management guide, also in Revision 1, and that is more -- pulls in some initial insights into how Tan Delta is applied. These are both -- the most commonly used one, the most commonly, you know, referenced one is the 3002000557 with those criteria.

These reports recommended some actions for medium voltage cables in wetted conditions, whether they are in those conditions presently or whether they have been wetted in the past and that condition has been corrected, or rectified, or addressed.

There are recommendations to perform inspections for inaccessible cables and to keep the dry where possible, and then also there were some guidelines for how that VLF Tan Delta testing, which had been shown to be able to identify these issues, how to apply it, that essentially you start off after certain initial periods of aging with a six-year test frequency for cables that are testing good so you can trend them, and then that frequency gets increased to two to three years if those cables fall into a further study test condition, and then as soon you start falling into repair/replace, once you hit the actual required range.

So, once You're in the actual required range, that's where you really should be starting to look at things you can do to take action about that cable system. Go ahead to the next one, please.

So, there has been some follow-up work since then. We have collected seven years of data over two different reports. They're listed down here. 1025262 was the initial report and then 3002005321 was the follow-up report where more tests were collected.

We initially had 700 different phases tested from 198 circuits in the first report, and then there were, in the second report, we stepped that up to 541 circuits comprising approximately 1,800 individual cables, so this is a fairly large sample size.

What I wanted to call to here in this slide is that this was a pretty good cross-section of the different types of cable that are installed. So, we saw different kinds of EPRs and XLPEs represented, as well as some, you know, rubbers represented in this test sample size.

The other thing I wanted to call attention to is that when cables from the first study phase were retested in the second phase, we did not see further progression. And what we did with that is that we are -- what we were showing is that VLF Tan Delta is effective at finding the problematic cables, and once your problems are eliminated, you know, the cables that have been exposed to those adverse local environments, once you've addressed that, you don't see a further progression.

The remaining population remains healthy, and that was one of the reasons why there was this initial large population sample and then this even larger follow-up sample was to really look at how these cables had progressed and done. Next slide, please.

So, here I wanted to address something specific. So, this is, this was the RL2021O11. This was essentially a letter issued that looked at the Tan Delta methodology, and the NRC had noted some findings with regard to it.

The NRC generally found the methodology of Tan Delta testing was sound and the criteria were sufficiently conservative. However, it was not endorsed due to insufficient data for some specific types of cables, so brown EPR and XLPE as an example.

Now, one thing to note there though is that these cables make up, brown EPR and XLPE made up relatively small portions of the population, and with that, of course, they're going to make up smaller portions of the data collected. You can kind of see what our test results broken out by cable type are here on the right, and these are relatively small portions of the population that was received.

But the biggest message, you know, the bigger take-away that we saw is that the failure mode and progression had been consistent across the insulation types. So, for us looking at this, that body of evidence really needs to be evaluated as a whole.

And the capability of this test method, Tan Delta, had been demonstrated on the whole and on different types of populations, cable populations, and since we're not seeing a different progression or failure mode within specific insulation types, this method still -- you know, this method is still a very capable and powerful tool for identifying degradation across all types of insulation based on what we've seen through the data so far. Please go ahead to the next slide.

So, just to get a little bit more into how Tan Delta testing is applied today, you know, where we are with this methodology today and how it's applied today. Tan Delta tests give you three different parameters about the cable system that you are testing.

They give you a combination of your mean Tan Delta, your delta Tan Delta, which is essentially how that Tan Delta changes as you step up your voltage, and then your standard deviation percentage, which is how steady your reading is at any given voltage.

These readings come in in the criteria and each one tells you something a little different about the cable system. So, our evaluation criteria looks at all three and applies all three, and in situations where you start seeing a failed or further study required result, you can actually gain some insight into what's happening based on which one of these parameters is showing the problem or if it's all three.

Now, some other take-aways with how this testing is applied today that I wanted to highlight, testing is typically done every six years and is sufficient to prevent cables from transitioning from a good test to a degraded test, which is another way of saying that we're catching the problem cables before they traverse all the way to, you know, to real issues, that we get indications of those with the testing cycle.

When combined with withstand testing, which is another term for hipot testing, it gives you a reasonable confidence to prevent immediate in-Service failures, which is another way of saying that typically, when you start seeing progression, one of the ways, one of the recommendations that comes out is to apply withstand testing to make sure that you can return your cable to Service immediately and give you some confidence for the near term, while also stepping up the monitoring campaign for that cable circuit and prepare to replace it as, you know, as you can.

And one other thing that I wanted to mention is that when you do identify degradation, if you can use what I mentioned about how different parameters reflect different aspects of the cable system, you can sometimes use it and some other test methods to figure out exactly what portion of the cable system is giving you trouble and make repairs.

You know, oftentimes you can find that there is an insulation issue, I'm sorry, there's an installation issue with one of the splices or termination, and those typically present in specific ways in Tan Delta testing, and when you can make repairs that fix that issue, or even in cases of degraded insulation due to an adverse local environment where you can correct that environment and replace the cable system section with a new section, you can restore the cable test results to good. Once you've rectified that issue, then you can continue to use that testing to monitor the condition of your cable circuit. Next slide, please.

So, highlighting a few pieces of ongoing work, you know, at this point in the presentation, we've gotten to where we are today. Where are we going tomorrow? So, a few things that are out now and, you know, really kind of came out recently on the cutting edge, we're looking at applying VLF testing with motors attached and also VLF testing with your transformers.

The intentions here is, in other words, is to show how this testing can be applied on full circuits with, you know, your equipment load, and whether we can differentiate effects within the cables within the motors or transformers, and whether that testing still provides useful information.

This is often useful because in some cases in some circuits, it's really difficult to disconnect the load, and any insight you can get into your cable system before going in to disconnect the load is going to be very useful in terms of planning for, you know, what kind of issue you need to address.

There have been two pilot sites and several others that have applied for using this research, you know, and it's starting to come out and be applied, and we're starting to glean some useful information out of it. There are two reports that have been issued from laboratory testing and some initial looks on how to use this technology.

There is some other research currently in progress. One of the key ones that's going through right now is evaluation of insulation shields' attenuation effects on high-frequency test signals. Now, this is important because VLF Tan Delta is a low-frequency test technique, but there are other high-frequency test techniques, you know, TDR/FDR for example, that have some promise to be useful.

Well, there are some questions around how shield attenuation plays into the usefulness of those testing techniques, and there's been some research, you know, kind of going in several different directions, but there hasn't really been certainty yet.

So, we're looking at how to really, you

know, to characterize that attenuation and understand how it impacts these high-frequency test techniques because we see the need to apply them in the future and we want to lay the groundwork for application of those high-frequency test techniques.

Now, in line with that, you know, we saw a few slides ago that there was a large body of data collected for medium voltage cable test results. We are not formally, through a formal program collecting further test results, but we continue to collect them, you know, informally.

It's done now through member input. Oftentimes, this is for me or some of my colleagues with the cable program, get requests from a member that say, hey, we got a test result. We're not exactly sure what this means. Can you take a second look at it?

And, you know, we do everything we can to help with that, but we're also collecting those. You know, we're also collecting that data so that we have an understanding of what is happening, what kind of test results are being gathered from the industry, and what kinds of trends we're seeing as time goes on.

Another big part of that is, you know, the meetings we have, the cable user group. You know, we get feedback on how these testing and other emergent issues have progressed and how these techniques are being applied, and what kinds of results we're seeing with them. This all feeds into, you know, a good understanding of what the state of the industry is at the moment. So, if we could proceed to the next slide, please?

So, in review, just to kind of very briefly cover some of the things we've talked about as well, post-GL200701, we've applied VLF Tan Delta testing, and that has really led to improved operating experience. We've had very few in-Service failures since 2015, in part attributable to these monitoring programs and VLF Tan Delta as a tool.

Important to remember to that, medium voltage cable insulation typically degrades from dielectric stressors, and VLF Tan Delta as, you know, as shown by the results above and previously has been proven capable of identifying cable degradation for both wet and thermal aging. Now, thermal aging, we saw it as part of the, you know, test sample, but it's very rare.

To kind of re-highlight what the progression, the damage progression is, water trees form at stress points, typically manufacturing anomalies or latent damage from installation. The insulation degradation sites are not -- I'm sorry. And because these sites are typically, you know, almost random in nature, they are not really a common mode concern.

We talked about that when we looked at how circuits that lay next to each other that are parallel and are exposed to the same adverse local environments don't necessarily develop the same failure mode across those locations.

And then also keeping cables dry or even wet then dry is better than being submerged continuously, and that testing will identify issues, and what that -- that in some ways gets back to the question that was asked earlier, but your best bet is to keep it dry. Your next best bet is to dry out the wet cable rather than just repeatedly, rather than just continuously submerging it.

And in the close to the medium voltage section, I just wanted to say the medium voltage cable insulation will be long-live because dielectric stressors can be managed by the above strategies. So, everything we've talked about is the tool for managing the dielectric stress, and that the degradation can be corrected through the methods we've talked about here.

And the last thing to highlight is that thermal oxidative, you know, thermal aging is not a typical factor in medium voltage cable, and I specifically put that at the end of this summary because we are next going to move to low voltage cable insulation testing, and there the things change a little bit.

So, progressing onto the low voltage aging management and some of the tools and work that we are doing here, before I do that, are there any questions before we move to low voltage?

MEMBER HALNON: Yeah, this is Greg. Just one quick question. Is the lack of NRC endorsement hindering in any way the use of this, and if so, what benefit could we gain from getting full endorsement?

MR. GOLDBERG: There were some questions initially about what the progression of this testing will be and kind of what the future of it will be. That being said, the testing has already proven so useful and effective that it's still seeing very regular implementation. You know, it's almost become the go-to to do Tan Delta testing on these cable circuits.

One thing I will say is that I think it's going to be very important to reevaluate as we gather more and more data and we see more and more how effective Tan Delta testing is and that, you know, if we periodically look back at that assessment and see how the body of evidence has grown behind how useful this testing is, we could really get some more confidence if there is a reevaluation.

And that if, you know, once that requirement for, you know, the more, I would say the more, sorry, the less frequently existing cables is really, you know, met, there would be so much extra confidence, especially internationally for use of this testing, that it would be important.

MEMBER HALNON: Okay, so are we going to go back and try to get endorsement at some point in the future or is that still kind of an open-ended question?

MR. GOLDBERG: I think it's going to be informed by, you know, the needs, and what amounts or data we get back, and what we see as this testing evolves. I think it's going to be, you know, evidence that, hey, we should take another look at this and we could really forward this, use of this testing to even more places and more conditions if we had that endorsement under reevaluation in the future.

MEMBER HALNON: Okay, thanks.

MR. GOLDBERG: Okay, if there's anything else, we can move onto low voltage. Okay, so going into low voltage, once again, low voltage cables are long-lived, passive components, but once again, you have a situation where adverse local environments can accelerate stress and cause issues.

The difference between medium voltage and low voltage cables though is that the primary driver of adverse local environmental aging in low voltage cables is thermal in nature. So, specifically we're talking about external heating. That typically is where you see the most problems, the biggest cause of problems, and identifying those areas where that external heating can produce some issues and managing them has been the focus of cable aging management for low voltage cables.

In other words, what you really want to do is you want to know which cables are seeing localized thermal heating, external heating. You want to correct that if you can. And, you know, you also want to monitor that to see what the progression of aging has been. So, I'm sorry, there's a question now?

MR. BLEY: Yeah, it's Dennis Bley. I'm going to take a guess, but, I mean, will you explain why there's a difference between low and medium cables in this cause? And I'm kind of guessing that it's because water is more of a problem for the higher voltage cables or is there something else going on that's making a difference?

MR. GOLDBERG: Yeah, absolutely, so the reason for that is that in wet aging, that progression of water exposure to water trees to then electric trees, which is the manifestation of failure in the insulation, it's a voltage-driven process. You need a driving voltage behind it, and low voltage cables, they just don't put enough of a voltage grading across the insulation to drive that process forward.

The thermal aging process is not one that needs a voltage driver behind it. The presence of external heat does the work, so that's where you see, you know, the degradation path occurring.

MR. BLEY: Okay, and that leads me to the next question, which is are medium and high voltage cables just as susceptible to thermal aging and it's just that we have a more likely source driving failure with the water or are they not exposed to the same temperature regime? And I don't know why that would be.

MR. GOLDBERG: Well, we actually do see rarely, but we see some external heating issues driven in medium voltage cables, and that was mentioned as a cause that does happen. It's just fairly rare and I suspect that's because of a combination of factors, part of them being where and how they're installed and just, you know, the size and type of cables that are used, that it's just, it's a rarer cause of failure in the medium voltage population.

MR. BLEY: Okay, I'm not sure I fully understand that, but maybe they're not packed as densely in the cable trays or some such thing?

MR. GOLDBERG: Yeah, that's part of it, but just where they're typically installed, and also the actual population sizes play into it. You know, as we mentioned, there's thousands and thousands of low voltage cables installed everywhere in plants. There's typically only several hundred medium voltage cables in some specific areas.

(Simultaneous speaking.)

MR. GOLDBERG: Well, it's an opportunity for exposure as well.

MR. BLEY: Okay, that seems to be a certain effective rate, but the numbers would be much lower, okay.

MR. GOLDBERG: Okay, all right, so popping to the next slide, in terms of how this thermal aging has been addressed up to now, so the background of what's been done so far, typically, these terms of degradations are identified and, you know, quantified visually.

So, through walkdowns, through periodic inspections, visual inspections of these cables, you can identify the adverse local environments and you can look for effects of those adverse local environments on the cables. Visual indicators are usually, you know, they're present and they're important.

A lot of this is because your jackets start to degrade initially, and then you start to see the effects later on the insulation material. Your jacket is external. The heating source is, again, typically external, so that's where you see your first impacts.

And depending on your jacket material, that can be cracking, you know, full circumferential cracks, weeping of plasticizer. There's really a whole host of different things that can occur that are going to clue in that hey, there's an adverse local environment here, and that something is happening to these cables that needs further inspection and monitoring.

We also see discoloration, just a whole host of visual indicators, and typically these precede the insulation beginning to degrade underneath them. However, once you start seeing that insulation degradation in the jacket materials, you want to start thinking about getting an understanding of what the condition of the insulation underneath is because this jacket is kind of sounding a warning bell that hey, something is -- you know, there's an adverse local environment here. Something is going wrong. You need to start thinking about looking deeper and understanding what the condition of the cable is overall. Go ahead to the next. Next slide? Thank you.

There have been some quantitative tests that existed in the industry before and that currently exist that have seen some use, and these tests tend to be very common, but they're rarely applied, which is a differentiation in terms of how often they're actually used. A lot of these tests are either destructive or they require laboratory processing of the materials exposed to those adverse local environments.

So, a good example of those on the destructive side is elongation of break, and that is a very good typical indicator of thermal aging, but it's also one that's hard to collect, and then some laboratory testing that can be used alongside, you know, oxidation induction is a good example of that, but these, again, are tests that require a lot of, you know, effort and work to implement, and also that are not necessarily applicable, that they're hard to apply because in part you need to know where your adverse local environment is and you need to be able to get samples out of it, and that's not always the case for circuits as an option that's available.

That's really the big problem behind some of these existing techniques is the ability to harvest samples. It's not always present and it's not, you know, something you can do constantly. You are limited in how often you can do it and in places that you can do it.

So, that really puts a limitation on some existing techniques that are more material based. You know, we call them mechanical and physicochemical techniques. Next slide, please?

Now, looking at commonly used current electrical techniques, one of the most commonly applied ones today is insulation resistance, what's commonly called Megger, Megger testing. The problem with Megger testing, especially in dry cables, is that you can often have pretty severe degradation, you know, all the way almost up to exposed conductor, and in a dry air environment, you may not see indications of that in a Megger.

That's pretty common to see that a cable is fairly, you know, significantly damaged, but it doesn't show up in that Megger test as a problematic test result. And the reason for that is that air is a good insulator, and if you have a proper air gap around your degraded region, your Megger test is not necessarily going to show you a problem, and that's a big gap. That's really something that, you know, limits the ability of this test method to find issues.

Another common sets of tests that is used, time and frequency domain reflectometry, so TDR/FDR we'll hear as an industry term that gets used for FDR, is one that can indicate anomalies in insulation. Not all of those anomalies are degradation, and what that essentially means is that there's a lot of false positives.

There's a lot of instances where an FDR will show you where your cable is going around the bend, and You're not sure if that's a problem or if it's just a cable going around a bend. That limits the applicability of that test method. I think I saw a hand go up?

MEMBER ROBERTS: This is Tom Roberts. Just a quick question on the problem with the Megger. Do we have the same problem with the Tan Delta type of measurement which is relying on finding resistance in kind of a static voltage?

MR. GOLDBERG: Well, Tan Delta is looking at your difference in lag between your voltage and current waves, so it's not really looking at resistance, and You're also, when you use that methodology, You're looking at how steady that measurement is and how much of a voltage dependence there is to that measurement. And then finally, of course, you know, it's typically being -- you know, You're looking for issues in cables that are in wet environments on the medium voltage side. Did I see a couple more hands go up?

MEMBER ROBERTS: Yeah, just a quick follow-up. So, the reason why you get the angle change in a Tan Delta is because of resistance, right, so You're counting on the high voltage, seeing a resistance that shouldn't be there between the insulation and, you know, ground, or shield, or whatever it is You're comparing to. So, just how is it different that the Megger doesn't find that resistance, but the Tan Delta does?

MR. GOLDBERG: Well, part of it is that you look not just at the Tan Delta value itself, but how much of a voltage dependence there is to that value, and also how steady that value is within the same voltage. So, you know, it happens where you see an acceptable Tan Delta value, but man, that reading is not steady or that reading is getting higher and higher between your voltage steps, and that tells you that there are issues as well, and that's not something You're necessarily doing with a Megger.

Now, we're going to get to it in a few slides, but there are variations on the Megger test that reflect something similar to that I-pole versus ID-pole that look at essentially how your reading steadies out over time that are providing useful information, and that is part of a methodology that we're working through to help evaluate this situation. So, if you look at more than just the value You're getting back, there is useful information that can be extracted.

MR. BLEY: This is Dennis Bley. That last thing is pretty interesting. I look forward to when you have some results in that area to share. The thing I'm wondering about is I always assumed that the highest temperatures were deep inside the cable trays, especially for power cables, and the visual inspection is only going to see the cables on the outside.

The pictures you've shown have been in cabinets and places like that where, you know, maybe it's control cables in there that are getting damaged. Can you say anything about that?

MR. GOLDBERG: Sure, what that points to is the difference between what you would call ohmic heating and external thermal heating. What we've seen is that the biggest, most frequent driver is external heating. So, there is, you know, a common example of that is a cable that's coming, you know, a cable tray that's coming close to a pipe carrying hot steam that doesn't have insulation or that the insulation was removed and not replaced, or cable trays that were routed through areas of a plant that are very hot.

There, you see degradation on the exteriors, specifically the places that are closest to the heat source. Ohmic heating, from what we see, is less common, and there you would have a concern that you may -- you know, you can have ohmic heating inside, but there is plays into, you know, that goes into, back to the design of the cable system to make sure it's sufficient to carry the current load that it's asked to carry, as opposed to external heating which is typically, you know, something that maybe changed in a plant where a cable that wasn't initially exposed to excessive heating is now exposed because a piece of insulation, a piece of thermal insulation was removed from a pipe. So, those tend to be on the external side closest to what's emitting the heat.

MR. BLEY: Interesting. It makes sense. Thank you.

MR. GOLDBERG: Thank you. Okay, go ahead. So, jumping into this next point where we're going to talk about the testing, low voltage cable testing methodology that EPRI is working through and piloting right now, the first thing I wanted to do is just briefly highlight the difference between a global assessment test and a local evaluation test.

So, your global assessments are giving you a look at the overall condition of your whole insulation system. So, good examples of this, you know, going back to what we talked about the insulation resistance test method, dissipation factor, which is Tan Delta, dielectric spectroscopy, which looks at similar results, but over a wider band of frequencies, and polarization/depolarization current, which is what I had briefly alluded to in terms of gathering more data from a Tan Delta, or from an insulation resistance test based on how it performs over time, but those are all assessments of the insulation system as a whole for that cable.

Now, as opposed to that, the second pillar, the second part of the cable test methodology are localization methods. What these do -- and good examples of them are TDR and FDR, LIRA. These methods are meant to help you figure out exactly where in the cable you are seeing your problem, so to localize the area of concern. Go ahead to the next slide.

So, let's get into the actual research. This research product, 3002020818, test protocol for condition monitoring of low voltage cables using dielectrically-based methods, it's what we -- I mean, that's a mouthful. It's what we commonly call the low voltage test methodology, and the thinking behind it is to take an array of tests rather than just one test to try to do everything with, and use that array of tests to achieve a specific set of goals for a cable system.

So, you start off with identification. You know, is there a problem with my cable system or is this a green test result that I don't need to be concerned with it for the next period of time?

Proceeding through that is discrimination. Is this an internal and real problem? What is the nature of the problem? You know, this is something I alluded to a little bit where you see issues with FDR/TDR where You're not sure whether the, you know, whether the echo that You're seeing on the chart is actually a problem or just a bend in the cable or a change in the environment there. Part of this test methodology aims at that discrimination function.

The next one is localization. We talked a little bit about that in the last slide between global methods and local diagnostic methods, in order to help you understand where in your cable system you do have a problem once you've identified that there is a problem.

And finally, assessment. What is the nature of this problem? We saw that approach to assessment on the medium voltage side where we used Tan Delta to sort cables into good, action required, or further study required. Well, we want to do that as well on the low voltage side. We want to be able to sort our cables into these categories.

And the way we've achieved it, the way we've gone about it is we started off by applying both global and local diagnostic techniques to these cable systems. On the global side, we're looking at low frequency dielectric spectroscopy, which is kind of a neighbor of Tan Delta, but it's across a set of frequencies, and polarization/depolarization current.

This gets back to extracting more information from a test that's similar to a Megger test, an insulation resistance test, but looking at it over time and how the current reacts as you first apply voltage and then take that voltage away. What is the reaction of that current and how does it apply to the previous reaction when you applied voltage? You can glean some information about the cable condition from that.

And then you apply your local diagnostic techniques, advanced TDR and FDR, and what we'll see here in a little bit is the necessity to really look at both of those as a body of data to help you zero in on problems rather than trying to rely on one or the other without having a full picture of the condition of the cable. Can we hop to the next one?

So, and hopefully my little animations here come through pretty well, but what you do when you apply these tests, so what You're seeing here is a population of test samples that was collected as part of that previous test report that I mentioned. And once that population is collected, on the left side of the chart, you see a Tan Delta value across a fixed frequency.

On the right side, you see that response across multiple frequencies. But once you collect that, your goal to make this test useful, and we're using LFDS as an example, is to try to sort it into good, action required, and intermediate, further monitoring, you know, further testing or further monitoring required categories.

So, if you can click once, it should show the sorting. There we go. Now you see we've taken the test results and we've really broken those populations out across to see where they fall out, and it's really clear when you take a look at the whole body of evidence, again using low frequency dielectric spectroscopy as an example, on this little right-hand chart where you see your green, your good cables not really showing a frequency dependence in their Tan Delta values, and your red sorted valued showing a pretty strong frequency dependence in their Tan Delta values, and then the yellows are in-betweens, the ones that are transitioning from the lower frequency dependence to the higher frequency dependence, and that's the approach we use to really grade populations within that test report.

You can go ahead to the next one. Yeah, click through them. This is just exactly what I explained with anomalies observes versus no anomalies and an intermediate. Go ahead to the next one.

So, let's apply that same test technique to another test that is part of this methodology, polarization/depolarization. This is the outgrowth of insulation resistance when You're looking at your leakage current over time, first as you apply your voltage, so I-Pole, and then as you take away your voltage, what happens to it, so ID-Pole, and then you ratio them to each other and you compare them to your line, which is where you expect that ratio to fall out.

And as you can see now, there is a population of distribution relative to that line of I-Polarization versus ID-Polarization, and when you apply -- when you look at that population and you look at where it falls out -- go ahead and click.

You can once again start to sort it into results that fall near your expected line in the green, way away from your expected line in the red -- yeah, go, click forward more -- and then this transition in the yellow as You're transitioning from good test results to degradation is starting to occur and you need to keep a closer eye on these particular populations.

And this is just a large body of results that we collected that shows exactly, you know, that shows how that populational study was gathered and broken out. Go ahead.

Going back once again, so if you remember, I mentioned that those were our global condition test techniques. Now we can take a quick look at what some of the local techniques are telling us. So, this is FDR and TDR.

And if you click through, we'll see a couple examples of results. Here, You're seeing an FDR trace, and You're seeing one that's good here on the left side. In the middle, You're seeing possible anomalies in the yellow, and on the right, that's where You're seeing significant anomalies and then echoes of those anomalies on the right-hand FDR trace.

Now, what I wanted to do with this slide through is up top, you now see the corresponding TDR trace, and what that's showing you is more information about the issue that You're seeing, that's really forcing what you are seeing.

So, when you look at that bottom right FDR and you see a set of peaks, but now you look at the TDR above it and you see a defined peak in a specific location that's then backed up what your FDR is seeing, followed by some echoes of that, then it makes it really clear that hey, we have a problem and it's probably in this specific region because the two test techniques, which are slightly different, are giving you reinforcing results.

A similar thing in the middle point, the anomalies observed investigation required result where you see an anomaly both in the TDR and FDR, and it's one that may not be as clear or as indicative in any one of the two tests. When compared to each other, you say hey, these tests are both telling me that there's maybe something. It's not, you know, full significance, full visibility yet, but there is something going on here, so anomalies have been observed in this cable in this specific region.

And on the left-hand side, you know, you just see a clean trace TDR/FDR, and You're getting good confidence on both that what You're seeing is, in fact, a clean result, it makes, that cross-correlation makes the results more interpretable, more usable, and that's another piece, foundational piece of this low voltage test methodology. So, let's go to the summary. Next slide?

Just to summarize what we've talked about, thermal degradation is the most common cause of insulation degradation in low voltage cables, and it is the most common adverse localized environment that we've seen, external heating to those cables. The current monitoring techniques, you know, what's typically done today is not always catching these degradations as they occur, and we really need something to augment and improve our ability to catch those.

The physical test methods were very difficult to apply. They rely on having samples that you can pull and do physical testing on, and rely on knowing where your adverse local environments are. The electrical tests that are commonly applied today, they can often provide false indications of issues in the case of TDR/FDR where there's really just changes in the environment or changes in cable routing, and then you can also, with insulation resistance just by itself, often miss things that are, you know, that are going to turn into larger issues as time goes on.

And what we wanted to show in this presentation is that EPRI is, you know, has developed and has piloted and is currently piloting in even more places a low voltage test methodology that combines multiple methods to give you an overall assessment of this cable from a set of different techniques to really get at, you know, what, the condition of that cable.

And the status of it now is we've already demonstrated it for some members. Other members are requesting demonstrations, and throughout next year and the following years, we're going to demonstrate it more and more, and we're going to gather more and more data just like we did with the Tan Delta in order to show this method's applicability and impact. So, I think I see one question from Dennis?

MR. BLEY: Yeah, where I'm kind of hanging up -- this is very interesting and it's a great step forward, but your discussion that most of this heating comes from your plant changes after the original design makes me think that, in addition to having ways to test for it, providing guidance to mechanical and electrical designers at the plants to include consideration of this issue for any plant mods would be a very helpful thing.

MR. GOLDBERG: Yeah, absolutely, and that is already a consideration. What it comes to is, you know, sometimes the impact isn't fully understood, and the intention here is to have an ability to verify and really understand especially if there was, you know, already an exposure to external heating to a cable, to understand the condition of that insulation.

And, you know, you can do a visual walkdown. You can look for the extent of these conditions, and they're often found and corrected, but then, you know, often the question comes up is what's the impact to the cables that were exposed to it? And that's where a good bit of this work is aimed at, is to be able to evaluate the condition of those cables.

And also, we want to be able to prioritize, you know, where you see -- you know, which cables require the most, you know, the most testing work, you know, have a method that can give you an idea of the condition of your system and find, you know, conditions that you may not know exist.

CHAIR BALLINGER: Okay, thank you very much. We're a little bit behind, but I don't -- it's not terminal, so this is a point at which I'd like to take a, let's say a ten-minute break. By mine, it's 10:40. Can we take a break and come back at 10:50? We'll try to get a shorter break. Unless there's an objection to that, we'll recess until 10:40.

(Whereupon, the above-entitled matter went off the record at 10:40 a.m. and resumed at 10:50 a.m.)

CHAIR BALLINGER: Okay, it's 10:50 a.m. Boy, it seems like time flew. So let's --

MR. CHOROMOKOS: All right.

CHAIR BALLINGER: -- let's pick up where we left off. Thank you.

MR. CHOROMOKOS: All right. Kurt, you want me just to drop in, or you want to transition in.

MR. CRYTZER: No, please, go ahead and start.

MR. CHOROMOKOS: Right on. Okay, good morning. My name's Rob Choromokos, from EPRI. I work in the Risk and Safety Management Group, RSM, and we have -- actually, my role within the RSM Group, focuses a good bit on external hazards.

I think you'll see, through this discussion that, that kind of, falls in line with external hazards. I've been at EPRI about three years now, and I've been in the nuclear industry a little over 36 years, mostly on the consulting side, and my background is predominantly design engineering. I'm a civil engineer, at the University.

Today's topic is nuclear resilience -- is resiliency and, while resiliency can pertain to numerous threats, namely, our ability to respond to weather-related hazards, from chronic weather changes and extreme events and -- and how these might change in the future.

So one last part of the intro, in the last few years we've had an increased focus on the effect of changing future climate. It's been in the news quite a bit.

I'm seeing quite a few articles and publications with a focus on how the power grid assets are -- are -- are going to be challenged, potentially, challenged by climate risk, specifically, related to extreme heat, weather events, and in our extreme events, such as storm, drought, and hurricanes and such.

The primary concern is -- is that historical weather events that we've used in our original plant designs may not adequately capture or bound the impact of future climate change, on our weather-related hazards.

So additionally, we've got some aging nuclear fleet out there that will have a shortened horizon from making any investments, and what we want to do right now is -- is -- is see if we can help inform some decisions, regarding how to become more resilient to the change in climate.

And we -- we certainly have some recent examples of weather-related challenges that we could all point to, deep freeze last Christmas, power outages in Texas a couple of years back, heat domes out in the northwest, and even in the upper-Midwest. These have all challenged resiliency to the grid and the components to the assets on the grid, including nuclear power plants.

So as the climate is changing, science is now telling us that there will be warmer average temperatures but, also, a potential increased frequency in magnitude of extreme weather events.

So that's today's topic, and I'm going to give you a little bit of what we're doing, currently, related to the nuclear and safety design basis, but I want to quickly pivot to what we're doing on operational side, what we're seeing and then what we're going to help focus our research on, in terms of -- of increasing our resiliency. So next slide.

So what is resilience? Resilience is the ability to withstand and recover from a disruptive, or unplanned, event. In today's discussion, we want to ensure that the nuclear plant's prepared to withstand the impact of the changing weather-related events, with minimal, if any, disruptions in operations.

So if you look at that figure, on the right-hand side, we're kind of rolling along operationally, at normal power, and then an unplanned event occurs.

And it's really how we respond and get back up to normal operations that it is the measure of our resiliency. So how deep we -- we go down that drop, we'll say, is a d-rate.

And then, all the way down is a trip. And, you know, depending on how prepared we are and how well we've planned and how well we're hardened helps -- helps with the -- the amount of -- of loss of power, but also, the time of recovery, and our efficiency helped shorten that time period, as well.

So while reliability is about reducing the frequency of a disruption, resilience is about the capability to avoid functioning during recovery of that.

So you see the figure on the right, I think most of us seen that, you know, we've got high-capacities in our industry, we've got robust design margin and we've had relatively minimal impacts from unplanned outages, with respect to internal events.

And, based on these current capacity factors, you know, unplanned outages account for about three percent. There's a refueling component in there, but unplanned outages, which include weather impacts, account for about three percent of the total availability.

And we're going to, kind of, take a deeper dive into that. You know, the consensus -- hold on a second -- well, consensus is that, that the weather has -- you know, likely to worsen in the next couple of decades.

It is regionally-based and severity is by region and I'll talk a little bit today about what we're providing, in terms of tools to -- to the sites, to the -- for understanding a little bit more about how those climate hazards may change in the future. Next slide.

So just a little bit on what we're currently doing, the current research, related to design basis, extreme events, looking at external hazards over the past ten years, what the significancy of the -- the great East Japan earthquake and tsunami and the accident at Fukushima, basically, provide us two -- two key lessons learned implement -- related to external hazards.

The first, being portable equipment, you know, we kindly refer that to, as flags, in the U.S. And the second is, we -- we need an understanding, we needed a continuous, systematic approach to monitor for changes in external hazards, to make sure we're staying current and how, either, the hazard, itself, may change, or understanding that that hazard may change.

So we've implemented a process based on a recommendation, where we can continuously monitor changes in, either, external hazards, themselves, or -- or get an understanding.

It is very similar to a process that the NRC has, it's called POANHI, and here we are, both, the industry and regulator alike, monitoring for changes and external hazards. Next slide.

One last bullet. I mean, our -- our process has been in place for about, almost, seven years now, since 2016. The process contains the following, we develop a catalog. It's, kind of, illustrated, on the right.

But we developed a catalog of credible information sources of our external hand search, namely, our seismic extreme heat, cold, extreme wind, high winds, and flooding.

So we're -- we're constantly monitoring changes in those key hazards, but keeping an eye on -- on what's potentially coming down the lines, in terms of new hazards, or new understanding of hazards.

We have reviewed over 1,100 pieces of new hazard information, over the last six years that we've been doing this. These encompass new precipitation studies, a tsunami potential.

Recent one on NIST tornado maps, climate change studies, and observations are creeping in more and more. There's been some -- a -- a quite bit of -- of activity in the seismic hazard in MJ East and with -- and are releasing some -- a NUREG on site implications.

And so we -- we have some new information on seismic hazard that we've been reviewing, over the last year, and then every year we go through all the operational experience that we see, from the INPO's IRIS database, to see, you know, what's changing.

And, although, it may not impact the design basis, it -- it certainly can give us a better understanding of the types of challenges plants are seeing. So the durational, for example, in Iowa, is one. Frazzle ice hurricanes are -- are captured in our operating experience.

As I said, we have some new information for 2022 and 2023, related to seismic hazard information, with MJ East, site amplifications, and we also have some new information that we've passed on to the plants, relative to the mismatch that got folded into the ASAE '07 and '22, I believe, it was, related to the new wave maps.

So we are seeing new information and we are evaluating that information for relevance, credibility, significance, and if it passes our significance threshold, we -- we pass it on to the plants for further evaluation. Next slide.

So just a quick snapshot of the -- of the -- the volume of information that we're looking at, you can see, on average, we're reviewing about 100 pieces of new information.

Divided amongst those five external hazards, some of the evaluations you see completed are where we actually take a look at the significance of the change.

And we've had some wind pressure loads from ASAE, in 2018. A new PMP study in 2020, MJ East subjunction, 2022. And then, in this year, in 2023, we -- we've had MJ East, a recent reel that was released by NRR, and we were in -- on site amplifications, as well as, the NIST tornado maps. So it gives you some sense of the volume.

Next slide. Next slide. We've packaged all this up in a report that we publish once a year, pass it on to the -- to the sites, for them to basically capture meeting the commitment that they've committed to in -- in the INPO Recommendations, so it allows them to complete that.

Next slide. The next area focus is -- is really climate risk, now, so we're going to move over to a little bit of the operating side and not so much the nuclear safety side.

And -- and this question is really related to how climate change may present a physical risk of the utility assets, primarily, on the operations side, and what strategies are available to minimize future consequences.

So if you think about the -- the resiliency curve, it's all about trying to manage the depth and the duration of that curve. Also, looking at what existed in their research and help answer these questions, with a good focus on -- on what are the current -- what's the current OE telling us, then, what is the climate signs telling us how those weather impacts are going to change in the future.

So next slide. Oh. Sorry. I forgot, You're on that one. A little -- back -- back up. So we put together a -- a white paper, actually, and there's two versions of the white paper, one -- one is, kind of, to the Members, themselves, and then it has a couple additional topics to it.

But, we've published one for the public that, basically, goes through and -- and reviews the OE, on ten years' worth of weather-related events, for the nuclear sites in the U.S.

Our goal was to provide some independent research on nuclear resiliency, using our knowledge of how plants are designed, how they're operated, to kind of, at least, get that in context of what we're getting in the more public publications of climate impacts on plants. We wanted to do something within EPRI that gave us a good basis for any future research.

A couple of key points we wanted to make in the paper was a clear distinction between nuclear safety and operational impacts. Plants are a -- have significant margins and -- and what we're talking about, when these impacts occur, these plants always prioritize nuclear safety over operational, and the plants always have the ability to, basically, derate, or trip the unit.

But, what we're talking about, today, in terms of resiliency is -- is how do we minimize those impacts and become more reliable on the grid? So we've put together a -- a review of the operating experience, as I said, and I'll go through that, in the next slide.

In -- in the paper that we provided to the plants we -- we also presented some climate modeling to get them some insights into how various regions in the United States may change, in the -- in the next 20 to 50 years, and give them a sense of how those may impact those hazards that are regional to those plants.

We'll, also, finish the paper with how climate data could be used by plants to really evaluate future vulnerabilities, and that was going to end up being the -- a little bit of our future research on vulnerability assessments. So this was all published in the paper, on the bottom that's downloadable.

Next slide. So as I said, we've reviewed ten years of weather-related operating experience, about 200 items, and we categorized them into each of our external hazards, high winds, flooding, heat, and cold.

And we, also, added a couple more that were showing up, and then we -- while following -- and lightening, were showing considerable impacts. We noted, not only how many events occur over that time period, but how the plant was impacted, either, a derate, or a trip.

And then, really, for how long, so using its capacity we could get loss-production days and some frequency of the magnitude of these events. Not all of the reported items resulted in loss of generation.

So they -- sometimes, they were managed and the other important point is, not every event is reportable to INPO, in terms of their IRIS database. So there is a certain amount of, I'll say, derating that can be managed at the -- at the plant level, and is not reportable. And --

MR. BLEY: And I'll just --

MR. CHOROMOKOS: -- you know, this is just -- that we looked at, only 120, you'll see that in the top table, where it resulted in loss of generation, high winds, storms, and lightening impacts represent over half of those 120 events.

Obviously, extreme storms and tornadoes

and hurricanes tend to impact less-robust transmission and distribution. I'll stop, in a second. All right. In --

(Simultaneous speaking.)

CHAIR BALLINGER: -- Dennis has a question.

(Simultaneous speaking.)

MR. CHOROMOKOS: Sure. Dennis.

MR. BLEY: Yes. In just terms of the page -- I mean, there might be other things like this, 2013 and 2014 have no biofouling events, which just seems surprising that there would be none, in two years. The other stuff, I can understand why there would be none, occasionally, can you explain it?

MR. CHOROMOKOS: Without pulling the report open, I -- otherwise, I couldn't explain exactly why that just didn't occur those years. It could be for a number of reasons, in terms of the reporting. Like I said, it -- it may not have amounted to a magnitude that was reportable. But --

MR. BLEY: Okay.

(Simultaneous speaking.)

MR. CHOROMOKOS: I appreciate the question and I -- I -- I had -- I knew something was going to pop up on this slide, so I was trying to have it open, but you caught me on why it didn't happen, not why it did, so I can't speak to that.

CHAIR BALLINGER: Yes, this is -- this is Ron Ballinger. What does strike me is that, we only go from 2010 to 2020, how far back do you go?

MR. CHOROMOKOS: I -- I went from '10 to '20. We picked a ten-year time frame, just as a -- just a figure of merit, to be honest with you. We could have gone back, you know, another ten years, as well.

A lot of things have changed, I'll say, in -- in -- in -- from those ten years, so I -- I don't know that I wanted them to show a trend, as much as I wanted to show the types and the -- of events we were seeing, in terms of significance. So I guess, I could go back another ten years.

CHAIR BALLINGER: Thanks.

MR. CHOROMOKOS: Sure thing. All right. So where I left off was just kind of distinguishing between the top and bottom, and it was really around the -- the high winds and storms, really, taking out the grid, itself, in terms of the plant's reliance on outside power, would generally trip the plant.

So although, the plant was derated or -- or tripped, it wasn't a result, necessarily, of the plant, itself, it was the result of the -- the grid, itself, the TMB infrastructure wasn't able to deliver, or receive electricity, the plant had put itself in the safe condition.

So what I did is I removed those frequent-related impacted and I wanted to get a good sense of the plant, itself, and the loss-production days goes down significantly, almost, to a factor of two.

So clearly it -- what's not surprising that the grid is the weaker link, and I think we all know that, but it did allow me to focus a little bit more on what our -- what is actually happening at the plant.

So in the end, I was able to basically look at the lost generation. If you recall, at the beginning, I was trying to understand the impact of -- of weather-related events on the unit, itself, in terms of its capacity effect, and I found they were less than one percent, which is extremely good.

But, as you know, past performances are not indicative of a future return. So what we wanted to do and -- and given the -- the science is telling us that these could change, in frequency and magnitude, beyond what we've traditionally seen, and so what -- what can we start to take away from this and what can we begin to work on?

So next slide. So the take-aways are, you know, from a safety standpoint and I -- I think everybody on this call would -- would largely agree wit that, they're -- they're designed quite robust and able to withstand the events far more significant than most critical infrastructure, given our fuel type.

But, based on OEE and the high-capacity factors, the power plants have demonstrated resilience to extreme events. Most major loss of production events come from grid-wide challenges, as you -- we all know, we maintain a significance amount of OE and knowledge to build upon.

As he just said, we can go back many years to see the types of events that have happened. We have numerous seasonal readiness programs, lessons learned programs, corrective action programs that we're able to draw upon, in terms of our OE.

And, you know, the climate impacts can effect operational resilience. Forward looking assessments could be a benefit and allow them to have a more strategic response to the future chronic changes and -- and I'll say, just changing ambient temperatures and events, as well as, extreme weather events.

So I -- I think OE's been good and the -- the reality is here, how do we maintain that high level, given that plant fossil retirements are happening, the public is going to rely, even more, on us for producing reliable, available generation, and what can we do to ensure that we're always there?

So before that, any questions on past OE, or -- or impacts that -- or -- or recommendations on things to, maybe, include in going forward?

If not, we'll keep going. Next slide. So as I said, you know, maybe, a future opportunity is to -- is for climate risk assessment, and I'll talk a little bit more about the -- the institute level, the upper-institute level, not just nuclear, but across the entire grid.

So the question is, what does climate change mean for a -- a nuclear station, or any asset on -- on the grid? It's really a sense of looking at the hazard, itself.

What's exposed, what's in harm's way, how is it vulnerable and how might it respond, and then, how do we manage that vulnerability and how do we make decisions, regarding managing that risk, and it all begins with how climate change may effect that hazard.

So that's the model we're going to use going forward is, primarily, how did climate change effect the hazard, what's in harm's way, what's exposed, what's the vulnerability, the critical thresholds that we're looking at, and then, how do we manage that?

And then, I think, you'll see a question at the very end that, I am still working through, is -- is how do we manage that in a way that -- that can, basically, be integrated with the existing priorities the plant has, in terms of reliability and resiliency?

So next slide. So this was a -- a starting point that we just published, about a year ago, I believe, and -- what's today, 2022 -- and it, just at a high level, started to look at, really, what are those systems that, probably, have a -- a high impact in -- in their cooling systems, right, those come to mind, steam turbine and condensers, and then physical impacts, as well, from the -- or changing hazards.

And, really, they were involved around our air temperature or humidity changes, water temperature changes, flooding, precipitation, in terms of operations, so these are the ones that quickly came to mind.

And, in the last column, there is, it's you know, very impact on plant performance and operation. I don't need to go into the details on all those, because I think folks on this call probably understand that, pretty well, in terms of derating or tripping the plant.

So just looking at a high-level of how to start that climate risk assessment and, what we want to do now is take it into a deeper dive. So next slide.

So the -- kind of an illustration, we've been communicating with, in -- in terms of looking at the future weather projections, on the left, is how the climate will become and whether it will be changing, it's really geared around, you know, ten -- out beyond ten years, 30 years, 40 years.

It's when you have to make some storm decisions, in terms of investment, and not working on the seasonable readiness aspect. That's, kind of, well-in-hand, but really looking at beyond ten years.

Although, there is a gap right now, where we're trying to cover, I'll -- I'll say, projections out, you know, two to ten years that -- that, really, climate models don't do well at, and I think there's a gap we need to fill, in terms of that time period, and we're working on that.

But it's those weather projections, how they impact the asset, in terms of exposure and vulnerability, and those vulnerabilities may show up, in terms of margin reductions, as I've showed you, impact on capacity factor, they -- they could effect life expectancy of components, environmental permitting on discharge.

They could effect maintenance and when we decide to run the failure, or decide to change our maintenance interval, and then health and safety. And then, really, when we see those thresholds, or see those impacts, how do we park them in the existing plant programs, to make sure they're being prioritized and acted upon, in a way that helps reduce that backed up curve that I showed you earlier, in terms of resilience.

I think we're really good at -- at the systematic process of looking at exposure and vulnerability and we've got a lot of programs, at the plant level, in terms of -- of -- of plant health and long-term asset management, is making sure that we get climate risk the right context, so that it can go within those decision-making programs to build this. Still working on that a little bit.

Next slide. We did publish some recent climate vulnerability assessment guidance, they're focused on how to develop your climate hazards, at your site, in your region, and your site, using climate models, probably, a little bit beyond the -- the capabilities of a -- a normal site, with mere engineer. I can speak to that.

What I'd like is to have the hazards put into context, so that I can go ahead and evaluate critical thresholds with, but we wanted to, at least, lay out what and how you would go about standardizing, or establishing, a climate hazard.

And then, exposure and vulnerability, it's really a screening process of how to identify those critical assets to, either, safety or reliable generation, and how do you identify those structure systems or components that may be impacted by weather-related variables?

So you can really think of a matrix of critical systems and then, across the top, the various climate hazards that impact those systems, and then drill down and find out the limiting components and work through those critical thresholds, so it's been, kind of, the process.

So that's exposure and vulnerability, and after vulnerability would become really managing that risk and we're -- we're not quite there, yet, but we are working toward that.

I will say that, the INPO is -- is actively involved in -- in this, as well, and has come up with a resiliency -- or she's coming up with a resiliency standard -- and they're also coming up with some resiliency, I'll say, vulnerability assessment guidance and we worked, somewhat, together, in terms of giving plants the right tools and methods to -- to respond to questions, regarding vulnerability.

(Simultaneous speaking.)

MR. CHOROMOKOS: So next slide. We did publish a literature review on how to perform a climate vulnerability assessment. Went out to the DOE, to various system operators, to asset owners, beyond nuclear and some within nuclear, in terms of how to do a vulnerability assessment.

I'm going to talk a little bit about ready, at the very end, but our -- our goal is to help develop a consistent way of assessing vulnerability and then, assessing and proving resiliency, rather than individual side-by-side isotope-by-isotope approach, so we're looking for some consistency in establishing that framework.

However, some plants have undergone, or are planning vulnerability assessments. I know a lot of the fleet is, it's -- it's starting to think about that.

In fact, some have completed it and some are doing it right now and we're also helping a plant do a pilot of our vulnerability assessment guidance. So our goal, with the pilot, is to get some lessons learned and what's the -- or what -- what can be improved?

What's the most efficient way, and how are we actually proceeding through the vulnerability assessment, so that we can perhaps incorporate some lessons learned and -- and refine the guidance, itself.

And then, last -- that last bullet is just making sure we're producing measured results, we're adding value, and we're increasing resiliency. Finding the -- the vulnerability in the INPO threshold.

Understanding the climate change to that threshold is -- it's not, necessarily, the whole story, with respect to resiliency, but that there is a response component to it, how the people respond and -- and, depending on some investments, you may want to wait -- make.

So I think, even the vulnerability assessment, there's still more work to do in the future, in terms of incorporating that into your decision-making. Next slide and --

(Simultaneous speaking.)

MR. BLEY: It's Dennis Bley, again. One thing you haven't mentioned is smoke and, over the last three years, there have been some really massive forest fires, here and in Canada that have effected people in the States.

I don't know if they've any nuclear plants, or other industrial facilities, but I'm wondering, if you know of any cases where it had an impact on operators, or other personnel, or even was thick enough to cause problems with the solid state of electronics?

MR. CHOROMOKOS: I -- I'm not personally aware of that, and interestingly enough, I'll be on a call, this afternoon, with Bruce Power and OPG, and I'll be sure -- I'll bring that up to them, as well, but I'm not personally aware of any.

MR. BLEY: Okay. Thanks.

MEMBER HALNON: Hey, Rob, this is Greg Halnon, just a quick question, as we go through this.

There's -- there's really two impacts has on plants. One, is the physical aspect, which is obvious, the freezing and -- and other things.

But the other one's the -- the regulatory impact, and sometimes, extreme heat causes a ultimate heat sink to be inoperable, and then there's a shutdown, or -- or a derate, and -- or, some other tec spec issue.

Had -- is there a distinguish -- I mean, a -- a -- a line between that and your studies on what is a physical impact versus a regulatory impact?

MR. CHOROMOKOS: If they're both captured, probably, could categorize -- I mean, I can -- I mean, I could shift the data, but --

MEMBER HALNON: Because, when we're talking about resiliency of a -- of a nuclear plant -- I mean, clearly, it's -- there's a -- physical limits, probably, predominant.

I mean, I'm -- I would imagine, the regulatory impacts are much on the small subset, but it would be interesting to -- to see how you might deal with the resiliency, through analysis and regulatory change, or license change, versus a physical modification to the plan or procedure.

So I -- just a thought, as I was going

through this, that -- that -- the -- I've had both happen to me, in the past, and probably equally, so I was just curious, if there was something distinguishing in this study, or not, but it sounds like you've --

CHAIR BALLINGER: No that's a good point, an ultimate heat sink, I -- I think a lot of the plants have that type of mind, in terms of -- I mean, that's part of the goal of the vulnerability assessment is tell me -- project out, when I may be encroaching on my -- my discharge limit?

Or I, you know, when do I need to have them in OED and -- and those type -- when do I need to go in for a license amendment to change a tec spec limit? I think, those are all the questions that we would want to be able to answer through such --

MEMBER HALNON: That's in the vulnerability assessment process then?

(Simultaneous speaking.)

CHAIR BALLINGER: That -- that should be an outcome of it, right, finding out where those are, vulnerabilities were --

MEMBER HALNON: Okay.

(Simultaneous speaking.)

MEMBER HALNON: Thanks.

CHAIR BALLINGER: Yes.

MR. CHOROMOKOS: So -- so I'll -- getting back to the assessment, the vulnerability assessment, again, we started with climate hazard projections, EPRI has offered up a, what we call supplemental, which is, kind of, ala cart.

Clients can pick and choose, if they want to participate in some projects, and this project was all around getting those plants that are starting on their vulnerability assessment, what are the inputs they're going to need, what are the projections, what are the key variables that are impacting their location, their site, and how will those variables change, over time.

A nice opportunity for plants to get, kind of, a, I'll say, introduced to -- to climate hazard projections, climate change, understand a little bit of the science, the uncertainty, the inputs that are used.

And it was a really good opportunity for the engineers to get with the climate science folks and make sure that the data is coming across and usable, in terms of looking at vulnerability, from an engineering standpoint.

So a really good project, in terms of

climate hazard projections, for the plants doing those assessments. Next slide.

MEMBER MARTIN: Oh, this is Bob Martin.

MR. CHOROMOKOS: Sure.

MEMBER MARTIN: I just wanted to ask a question, on the previous slide. Does your assessment also consider, say, maybe, increased -- maybe, an increase in the likelihood of grid instability?

You know, certainly, the Texas cold weather event, from a couple of years ago, you know, showed the, you know, the impact from, you know, the loss of other power sources, you know, and -- which, of course, where the nuclear power plant is good, you know, be translated into a loss of off-site power. It seems like --

MR. CHOROMOKOS: Yes --

MEMBER MARTIN: -- that the focus is mostly local, than site-specific, but also, the relationship to the grid, overall, is that captured it in the -- in the report?

(Simultaneous speaking.)

MR. CHOROMOKOS: No, it's not. And -- and it -- it's a -- and, if I'm understanding it correctly, I -- I -- I think I talk a little bit about the -- a -- the system, the power flow analysis, the system analysis that's going on, right now.

But I -- I think the plants are, largely, reacting to the grid impacts. Certainly, you know, if the -- if -- if a -- a hurricane's going to happen, or an extreme event's going to happen, the client can be asked to derate, or asked to down-power, but I -- I think, when a lightening hits, or they trip for a loss of off-site power, I -- I think that's more of a reaction than a planned -- planned -- plan known, I'll say, maybe. But I think that's a good question on -- on -- on how the plants respond to that, but I -- I think they're more reactionary than anything else.

(Simultaneous speaking.)

MEMBER MARTIN: Sure. Thanks.

MR. CHOROMOKOS: Sure. Next slide. So yes, I -- I talked about the vulnerability assessment steps, so you know, this is exposure and -- and what's in harm's way. I'll quickly go through this.

It's really the process of identifying all plant SSEs, important stable reliable operation to plant, we want to focus on those system that can trip and derate the plant.

The real question is, you know, we don't have a -- a nice -- a nice list to pull from, so we -- we're, kind of, going through that process, right now.

In fact that's my aim this afternoon with several plants, is how can we provide enough guidance so that, systematically, you guys can go through and identify all those SSEs that are potentially exposed to weather-related impacts that can, basically, trip, or derate the plant.

And it seems straightforward, but we just want to make sure that we're providing all the guidance and tools that they -- that we can, to make sure they can do this in a consistent way.

Next slide. So the vulnerability assessment, again, I just spoke to that, plants are kind of in the process of doing that, they're looking at those systems.

They've, kind of, identified the systems important to generation, and now they're going through each one of those systems and looking at the vulnerable components, the -- the operating limits and thresholds.

And then we can go ahead and take a look at how those weather variables are challenging those thresholds, in a way that can negatively impact a plant.

And, we're still working through a little bit of how we present that, you know, damage functions, fragility curves, are -- are at somewhat comfortable to us, we -- we know how to do those, as nuclear unit, as a nuclear industry, trying to do those in a consistent way, across all great assets, is something we're looking at.

But, again, I -- I'll probably have more to share on that, the next time, relative to what -- how we present the risk, in -- in terms of each key thresholds and the uncertainty of associated with the -- the climate variables.

But, we're in the process of identifying all the critical thresholds through our vulnerability system and, again, how do we prioritize with -- with these results, is the next step, in terms of plant health committee and asset management, and we're, kind of, in the process of working through that, still, still -- still on a journey here.

Next slide. So as I said, for -- for 2024, we're on -- we're looking at that next step, already, so we're -- we're looking through practical implementation of vulnerability assessments.

And we're starting to look at adaptation strategies, how do we monitor them, how do we make sure that we're getting the -- the -- the climate risk incorporated into the programs, to build this IMC.

This may include developing strategies for planning implementation. It does definitely interface with existing plant programs.

And, I think, our goal is to leverage all the existing programs that plants have today, just making sure that we're giving climate risk the right context to be, I'll, I'll say, appropriately considered in -- in terms of, all of their decision-making, as they allocate resources to plant upgrades, or modifications.

Next slide. So I have two more slides and, again, I wanted to just touch on, you know, Climate READi, which is resiliency and adaptation issue, R-E-A-D-I.

It is across the institute, so it's not just nuclear, it covers all grid assets. And it, basically, the -- it -- it's goal is to develop a common framework, across the power system, develop a comprehensive, informed, consistent approach.

And then, really, it's -- it's tailored toward physical risk assessments, so it's really making sure that we can get comparative answer relative to investment strategies.

It's broken down into three work streams, which are very similar to the climate physical risk assessment on exposure and vulnerability that I showed you, earlier.

But, the first work stream is -- this is, both, climate data and guidance, it's where your climate 101, it's where You're aggregating all your data, your climate models, to really get through best -- best science, in terms of how these weather variables are changing, over time.

Work Stream 2 is, really, the vulnerability assessment, it's what I've talked about a lot today and where nuclear is primarily focused and we, kind of, pipe up through Work Stream 2 and so is our non-nuclear, our renewables, our transmission distribution, all of those physical assets, kind of, come up through Work Stream 2, in terms of a -- a vulnerability assessment.

And then, Work Stream 3 was, well, what we talked about, in terms of, how does that all feed a power flow, or a system analysis, knowing that what -- what they're looking for is to model the grid.

They're looking to know, what is the generation output, as a function of a weather variable and, basically, put those in, as knows, and then model climate change and demand a response to the system and see how it reacts, and hopefully it will give insights into where you need to invest to -- for the future, for increased resiliency.

So that's, kind of, Work Stream 3, a -- a pretty good initiative. But we're primarily focused on Work Stream 2, at the moment, but I'm really interested to see how the power flow and the system analysis goes in Work Stream 3.

Our deliverables are actually in the guidebooks. Again, it's what we're trying to promote a consistent way across all the asset classes, on how to do these physical climate risk assessments and identify research gaps, and then fill those gaps in the future.

Next slide. The last slide, here, is just showing who some of the climate-ready numbers are, mostly, system operators, but a fair number of them have a nuclear units in there, so we've got a fair bit of nuclear participation.

You can see AP, or D.C. Cook, BG&E, FirstEnergy, Ameren, Vistra, so TBA, Southern Company, so we've got quite a bit of nuclear representation and Climate READi, as well.

Climate READi is scheduled to take about three years, and we're about half-way through, and right now, we're kind of in the thick of looking at vulnerability assessment, so more to come.

So that brings me to my last slide, any questions, I'd be happy to take them.

MR. SCHULTZ: Rob, this is Steve Schultz. Just looking -- looking at your last slide, interested to see that, you don't really have full utility participation, especially, in some of those areas of the country, where you might expect readiness to be a -- an important factor in their overall planning.

Do you anticipate additional utility participation, as you move forward with your program? I'm thinking of Louisiana, Texas, Carolinas, Florida.

MR. CHOROMOKOS: We'd love to have them participate, but I -- I can't speak to them, you'd have to ask them, for sure. But, you know, I -- there are -- I know, there are plants that are not in ready -- there are utilities that are in ready that are undertaking, I'll say, their own studies.

So I -- I -- I think, they're happening, because it may not be happening through READi, in terms of developing the consistent framework. And I'll -- one thing I will add is, we have members that I showed you, on the -- that graph.

We also have a group of stakeholders, we'll call them, we call them Affinity Group Members, which are stakeholders, such as academia, PLE, -- the labs, for example, consultants, so we've got a -- a fair number.

I mean, almost over 80 of these Affinity Group Members that are supplying some of their knowledge and -- and insights into developing this framework, so I think we're getting the benefit of industry knowledge, it's just we're not getting full participation.

MR. SCHULTZ: Okay, and I thought there might be a way to fold in the information that could be gathered from those utilities that may have been working on this for a few years already and could include their experience in the overall program.

(Simultaneous speaking.)

MR. CHOROMOKOS: We'd love to have them.

MR. SCHULTZ: I hope you get it. Thanks.

MR. CHOROMOKOS: As you know, it's a voluntary, not a mandatory, so.

MR. SCHULTZ: I understand those programs, yes.

CHAIR BALLINGER: Thanks, Steve.

MR. CHOROMOKOS: All right. So I'm going to pass it over to -- to -- to John Black. I didn't know it was Job. John, did you change your name, J-O-

B, that -- but, we're going to talk about, ultimate heat sink, a little bit. So, John, take it away.

MR. BLACK: Thanks, Rob. So I'm John Black and I've run our Aquatic Resource Protection Programs, so I'm -- I'm the odd one out here, as probably the only Fishery Biologist on this call.

And so you may be asking, well, why is a Fisheries Biologist involved in ultimate heat sink? Well, it really stems going back to about 2004, when EPA was drafting requirements for fish protection, under 316(d).

We started spending a lot of time at cooling water intakes, thinking about how you would go about retrofitting for fish protection technologies. And in so doing and talking to operators, it really became evident that, issues around debris and biofouling were really a much greater concern and that, actually, this offered an opportunity, perhaps, to kill two birds with one stone and protect fish, while at the same time addressing some of these debris and biofouling issues.

So we started a -- a -- an internal interest group, which I'll tell you about, here in a minute, and -- that focused on those operational issues and that is still going on today and that --

that's how I became involved on -- on this side of the house.

I've always worked closely with engineers. I was 17 years a consultant, mostly, with Alton Research Laboratory, and a consultant to EPRI, and then, seven years ago, I joined EPRI.

So thanks for letting me speak today and -- I -- I think Rob did a really great job, sort of, setting up how we're thinking about climate risk and improved resilience, here, at EPRI.

And, now, I'm going to just, sort of, focus in on the intakes and the cooling water. And with that, I will, in trying to catch up to a little time here, I will go quickly through a couple of slides, at the beginning, and then, because I really want to get to the research that we're actually implementing.

So next slide, please. We can skip that, next slide. So we know that this long-term ecological change is happening, it is something we need to get our arms around.

And it's hard, again, as we look at the specific level downscaling, we have these great big wonderful climate models, at a much higher scale, but as we start trying to figure out what this is going to do, at the individual power plants, and how that might effect reliable sources of cooling water that's where -- that's where we're -- I'm focusing my efforts in research, here, at EPRI.

Next slide. So yes, we know that keeping reliable sources of cooling water, today, is a function of making sure that the cooling intake system equipment is ready to operate.

That the operators are responsive to events that are happening, and that there is adequate preventative maintenance happening to these systems, so that when they're needed, they're easy to operate.

So in general, as you saw, from Rob's slides, on the number of outages, as a result of debris events, while they're somewhat manageable, in quotes, today, we are seeing very -- increase in frequency, intensity, and duration, there are new types of debris showing up at intakes that weren't there, previously.

As the species composition and abundances in the source water bodies is changing, what's showing up at the intake is also changing. And so many of these systems were designed and optimized for very specific types of debris and biofouling, they now need to reconsider what's happening.

And, as Rob mentioned, these systems are aging, as well, a lot of the equipments may need, it's a balance, right, between life of the plant and how much You're willing to invest, but it may also be important to do so, to make these plants resilient to these new types of challenges.

So understanding this, then, requires that we evaluate the current operation and -- and OE, for these cooling water intake systems, upgrade aging equipment, as necessary, develop and test new novel approaches.

And, as you'll see, in a minute, we've also been focusing on developing forecasting systems, so that operators can be prepared ahead of time for these events, before they actually happen, which allows them to, you know, scramble and -- and -- and make, either, operational changes, or just have equipment and -- and manpower ready to address them, when it occurs.

Next slide, please. So on the right, here, you know, this is what I think about, when I think about intake reliability. It's going to be -- it's the function of the structural, functional, and operational design of the equipment.

You have to have -- make sure you have

adequate maintenance and that the staffing is well-trained and prepared for the types of events. In the first, main bullet, here, we're talking about current conditions.

You would -- you need to maintain compliance with your -- any regulatory requirements, and that includes, both, on the intake side, but also, as we were talking, earlier, on the discharge side, them changes in -- in the temperature, at the outfall, and what that might do to your 316(a) requirements.

You need to be mitigating for fouling and managing debris, and you need to be performing O&M and preventative maintenance. That's under normal operations.

You're also prepared today for these upset events, these abnormal operations, you need to be able to anticipate and then manage them when they happen. But again, as we think about it, into the future, we want to be monitoring long-term data trends and observational data, so that we can help predict changes and evaluate the existing equipment, under these new scenarios that we're anticipating.

Next slide. So as -- well -- this is the time, now, to be thinking long-term. It's not about the issues that are going to happen next week, or next month, this is about things that are going to be happening on a decadal scale, sometimes.

We want to be having good communications. When we understand some of these changes, what we're anticipating, that needs to be communicated throughout the -- the staffing, so that the -- we can review the operational capacity and performance and existing operational experience, not just from here, in the U.S., but also internationally.

And then, if -- if necessary, take action and revisit the design basis. And this may not happen, in all cases, depending on what the -- the estimated level changes might be, but examples of this might be changes in water quality that might change the corrosion potential of that water and -- and the selection of materials.

It might include changes in water levels and what that might do to pump habitation and the like, so there are many things that we can be doing, if we have a clear guidance, as to where things are headed that we can anticipate and -- and implement, going forward.

Next slide, please. So many of you are probably familiar with the imposed SOER 2007-2. Part of that, we've been talking with operators and power companies and most of this is fairly straightforward, but we're getting feedback, especially, on Recommendation 1, which is, sort of, monitoring these long-term environmental changes that, that has been a real challenge.

Because the question is, what are you looking for, so which parameters should you be evaluating, how do you go about monitoring them, at what frequency would you do that, how would you analyze those data?

So there's a -- there are a lot of questions, and so -- yes -- a project we would like to initiate, going forward, would be to help develop some guidance on -- on what that might look like.

And, of course, this might change on a site-specific basis, based on the types of water body from which You're withdrawing and other factors. So -- but there certainly can be a -- a framework under, which this would be much easier to develop. Again, the -- as these things change, we have to be prepared to -- to implement these, going forward.

Next slide. So one of the documents that we just published, in 2021, is the best management practices for preventing cooling water intake blockages.

This is a guidance document that we had previously, but it was several years outdated, and a couple of things that have changed, since then, we've now included a lot more international experience and -- and data from international events.

There are also a lot more new screen designs that are available for travel and water streams, downstream of the bar racks, upstream of the circ water pumps, these -- the -- the screen types now include polymer screen, multi-disc screens, and others that you wouldn't have seen implemented, in the field, ten years ago.

And the -- I -- what I think is also nice, here, is we've included, both, successful and unsuccessful mitigation attempts, lessons learned from unsuccessful application, is often, as beneficial, as successful applications. It just adds to the body of knowledge we have available, for operational experience, or debris management, at intakes.

Next slide. I also want to tell you about an intake maintenance guide series that we've put together. We can go to the next slide, please. So yes, this is another guidance document that was -- it used to be a single volume and was quite outdated.

We took that and we've divided it, now,

into three separate guides, and they roughly travel from upstream to downstream, through the intake structure.

So the first volume covers stop gates, trash racks, and trash rakes. The next volume, Volume 2, covers the travel and water screens, or whatever your fine screening technology, in Europe, it's often drum screens, and then the final one is, once that debris is removed, what are your options for debris disposal?

So again, there's a lot of new technologies out there that weren't in there, in that other one, there wasn't much in the way of international information that's, now, in there.

And, in talking with providers of technologies, we've recognized that the maintenance practices have also changed. This has been a cross-sector collaboration.

So we brought in information from fossil plants, as well as, nuclear power plants, because in many ways, a cooling water intake is a cooling water intake, and we've developed preventative maintenance templates that are being added and updated.

And so members are able to get a framework under, which they can figure out their preventative maintenance schedules, which components need to be replaced, how to determine those, and make inspections, so some information, there, as well.

Next slide. So to put these maintenance series guides together, we looked at publicly-available information, we made interviews with different vendors, we talked to architectural engineering firms, who are working on cooling water intakes.

We reviewed a bunch of equipment manuals, for O&M, and again, these -- these -- this series of guides provide description to the different technologies, how -- what the PM recommendations are.

And in the next slide, you'll see, what we found, to be the primary modes of failure for -- I'm -- I'm focused here, on the traveling screen, so Volume 2, and I just wanted to point out a couple of these things, and I'm not going to read through these.

But, if we think about biofouling, of course, that's now being changed, as global climate change happens. If we think about corrosion, that's also changing, as a result of water chemistry changes.

So a lot of these are dynamic. The -- the way that things were handled, the way that they were -- the maintenance that was done to these systems, ten years ago, may not be the same today and, certainly, won't be the same going forward.

So new -- different -- this may be selecting different materials, it may be the frequency of inspections, there's -- and there's guidance in there about -- about all of these aspects.

Next slide. So just a couple of other examples of intake-related research that we're doing that I wanted to share with you. The first, is we're working with one of our utilities, at a -- at one of their stations, in -- in the -- in the Southeast U.S., where they have a major issue with aquatic floating vegetation that has caused some derates and shutdowns, historically.

That seems to be up-ticking, over time, which may be partly due to climate change. It also has to do with the establishment of the new aquatic vegetation in the reservoir.

They have gone about and changed their screens and they also changed their bar racks and raking system with more narrowly-spaced bar racks and a -- and a racking system that can operate continuously.

But, despite that, they want this to never happen again, so they are exploring additional measures they can do. So we are engaged in a multi-year evaluation of air bubble curtains to -- the divert some of that debris, before it gets to the intake structure.

So we just completed the first phase of that, which was primarily just getting -- gathering an analysis and understanding the -- the issues. We are now doing hydraulic modeling and an evaluation of engineering designs and, eventually, we'll put together a pilot test, hopefully, for 2025. So that's that project.

Next slide, please. I mentioned that we had -- we started that interest group, back in 2004, when we were talking to operators and realized that debris and biofouling issues were a major concern.

This is a informational exchange forum. We bring together the members, we help develop EMP, to address emerging issues. We transfer information, through Webcast, workshops, newsletters, and tech briefs.

Our next upcoming workshop will be in -- in Pennsylvania, in November, so we're looking forward to that. Our hope here is that, we can minimize, or prevent, unscheduled outages, keep everybody up to date on the newer technology that are out there.

We're available on-call, to help when issues arise and, hopefully, it's an opportunity for members just to be able to network and stay informed. Next slide.

And I wanted to point out that we have several tech briefs that have come out of here, on different types of biofouling, or debris, issues and, each one of these, they, you know, they range in length, but they're all about a dozen pages, or so that, pretty succinctly pull together information about those species, what -- what the issues are, what kind of problems they can present, and then, potential solutions for those issues.

There's also information in there, about experts in the field. So there are ways you can reach out, use that information to reach out to people if -- if necessary.

So next slide, please. We also -- so one of the things that we're very interested in doing is developing a forecast -- oh -- forecasting systems, so a way for operators to get some amount of heads-up, ahead time, before these debris and biofouling issues arise, which is more debris-focused than biofouling.

But we -- if we think about some of the major upset conditions, these are often like jellyfish blooms, or large debris -- aquatic -- aquatic floating vegetation that comes in and overwhelms the screening systems.

So we have, if we move on the finger, on the right, from right to left, we have far-field, mid-field, and near-field. In the far-field, we want to be looking for the first indication that there may be the development of material in -- in the water body.

So this could be done, remotely, through satellites, it could be done through hydro-acoustics, or other in-water sensors, as we get closer we -- we also had sensors in the water.

These can then help tell, actually, calculate the amount of biomass that might be present, it can start to tell you about the route, in which it is -- it is moving, and the timing, in which you think it might actually be there.

And then, in the near-field, we're actually confirming the arrival of the events, and this may give operators several days' notice about these events, again, to prepare, start looking at the screens more frequently, whatever it is they might have, as their backup plans.

And we're -- we're working on other pieces of this and, depending on the system and the types of debris, there may be biological pieces that could be included in here.

For example, if you know that, when water temperatures drop below a certain amount, the organisms would've rooted to the bottom, die off, and they float to the surface and then become that mass.

So you know, or it could be wind direction, so meteorological data, there could be all sorts of pieces that could be fit into these models.

What you would do, in theory, is you would look at data sets, where you -- where you have conditions, under which these -- the debris events happened, previously, and try to hind-cast, or understand those trends.

But, it only happened at certain temperatures, or when the wind direction is from a certain direction, or when -- whatever those conditions are, so that you can then develop your model.

And these, of course, have to be site-specific, based on each plant's unique set of circumstances.

MR. BLEY: All right --

MR. BLACK: Next slide.

MR. BLEY: -- this is Dennis Bley --

MR. BLACK: Oh.

(Simultaneous speaking.)

MR. BLEY: Can I ask you a couple of questions about this one? This is a --

MR. BLACK: Sure.

MR. BLEY: -- reference manual, so I suppose it's a -- a plant owner, but some -- especially, the far-field thing, seem like things that, perhaps, the Government ought to be doing.

I don't think that it's within your purview of what -- what EPRI might do, but you can correct me on that, far-field, maybe, even mid-field, are things that would effect multiple facilities, not just one particular nuclear plant, and require some technologies that -- that, based on the surface, and a little unlikely to be done, by an individual plant, it could be done by a group of plants, or by the Government, trying to protect our infrastructure, is there any effort going on with Government agencies to participate, or anything along the lines that I was just talking about?

(Simultaneous speaking.)

MR. BLACK: Yes that's a great questions, and I'll -- I'll just preface my answer to say, it also really depends, a lot, on the complexity of the hydraulics of a -- of a system, whether it's, you know, unit directional river, for example, or in a estuary, where you -- where you have ebbing and flowing tides.

But, certainly, tapping into publicly-available data sets is -- is -- is an option. So for example, in -- in some systems, the National Oceanic and Atmospheric Administration may have buoys that have sensors, or -- including, meteorological data, but some of them also have flow sensors on them.

And tapping into, you know, satellite data, I don't know how much of that Government stuff is available. There are certain private entities that can supply that information, at a nominal cost, You're not launching your own satellite system.

So the -- the guidance, here, it really just lays out a framework for deciding how you would go about putting together a forecasting system and things you would consider.

Again, each system is going to be a little unique and -- and really need to -- some thought put in and understanding, sort of, how that system works, in terms of, what are the fouling You're likely to encounter and, how does it travel through that system.

But that's a great question. Yes that --

we don't have any active conversations with the Government, to try to tap into those, but I think there probably are some data sets that could be used.

MR. BLEY: Are you providing any guidance on how to access those data sets in this manual?

MR. BLACK: No, sir. This is -- this is just explaining the -- the types of data that would be beneficial, not how to access them.

MR. BLEY: And, I guess, the last thing, along this line, is have -- have the members shared, you know, have you had discussion groups with the members, about how this might progress in the future?

MR. BLACK: Yes. In fact, I'm going to tell you about another project here, if time allows. I know we're short on time, about -- about a follow-on project to this.

But we are also -- this whole intake resilience and reliability work that we're launching, we -- we will be -- we are having conversations one-on-one with utilities and, also, at our upcoming annual meeting, we're going to have, very much, a discussion session focused on where do we need to be, focusing our efforts to bring -- to bring this technology forward for more broad-scale application.

MR. BLEY: Okay. Thanks.

MR. BLACK: Next slide, please. Go ahead and see -- let's skip ahead. We can skip that. So I want to tell you, another project we are working, we have some internal EPRI funds, to evaluate a drone, fitted with clean equipment for cleaning bar racks.

Our bar racks get covered in barnacles and oysters and muscles and all sorts of other biofouling organisms, if you really disrupt the flow into the power plant.

Traditionally, you need to clean these with divers, and it -- there are automated cleaning systems, racks and rakes, but the really hard, attached biofouling requires some literal scraping.

You can remove racks and -- and put -- put on then, in their place, but often times, if You're using divers, that is a real risk to the divers, human health and safety risk, but it's also, often, it has to be done under -- when the plant's not operating, because again, for diver's safety, you don't want them in there, under full-flow conditions.

So we are looking at using drones to take the place of divers, for -- for doing this type of cleaning. We have selected a -- a site for a demo. We will be going down there -- I'll be heading down there, in November, to Florida, to see the site and --

and figure out the support that we can get from the station and our plan is to actually demo that technology in early-2024.

I should just add one other thing, here. It doesn't necessarily have to be a free-floating drone, like you see in the top, right picture, it -- really, we just need a stable platform, from which, these, either, jets, or blasters, or -- or -- or brushes can be deployed.

So it -- it may be a rack that goes in front of the bar rack and it's -- and it's on that -- that it -- that the bot moves around and does the cleaning.

But, anyway, this is a -- this is a really exciting opportunity. I -- I think it has great potential to blow up, in terms of O&M cost savings, but more importantly, for human health and safety. Next slide.

MR. BLEY: Jonathan, Dennis, again. Any thoughts on coatings, of any sort that might help this problem?

MR. BLACK: I -- I -- so coatings is an area of active research, at EPRI. Dave Olack is on the line and is -- runs our coating program. And, Dave, did you want to say any words?

MR. OLACK: Yes. Thanks, Jon. Yes, coatings from -- for, you know, many immersed surfaces, is it on -- is ongoing, you know, research work with EPRI.

And there are -- we have done some hydrophobic-type coating projects, in the past, and -- and that work will continue into the future. But -- yes, coatings are -- are definitely of -- of interest in -- in the intake system, overall, whether it's hydrophobic, or any other coating product.

MR. BLACK: So I think is my last slide, and this is a project that Dave and I are working on. Again, this is, sort of, the next step in this whole forecasting system.

Depending on the complexity of the system, you may have a lot of different data inputs into -- into this forecasting system. Again, it could be meteorological data, hydrological data, it can be biological data, it could be all -- all -- all sorts of different pieces here, including possibly, either, an overlaying on a computational fluid dynamic, hydro -- hydrodynamic model.

And, one of the big questions is, really, a -- a data analytics question and that is, how do you take all of these data sources and integrate them into a way, one, you want it to be near real time, because you want to be able to make decisions quickly.

And, second, you -- You're dealing with this geo-reference data and sometimes 3-D data that's been -- can we integrate those into a single model output that would then be used, as part of this larger forecasting system.

So the goal is, 3-D real-time visualization of all of these data inputs. And this first phase, we are just looking at the -- the feasibility, understanding the types of data that these different sensors are going to be providing?

And then, is it realistic, from a computing powers endpoint to actually integrate all of those in -- in that near real-time, if that's successful, then we may actually go to the lab and -- and demonstrate this and test it out, but that's down the road. The short-term, here, is just a -- a feasibility assessment. And I think that's -- that's it, for me.

CHAIR BALLINGER: Thank you, Jonathan. This is Ron. Oh. But, we're -- to do -- if you used carpenter's dimensions, we're really on time. So that, I think, is the last presentation, so I'd like to ask the Members and Consultants, if they have any comments, or questions that -- that need to be asked?

MR. BLEY: Well, Ron, it's Dennis, again. I go back to my last question, since you have a minute, here, and ask the gentleman, who was discussing the coatings, that -- is these screens underwater structures, or is there anything really encouraging that you've been working on?

MR. OLACK: So I guess, I need to be careful, regarding encouraging -- yes, our -- there are some products that happened fairly successful. It's the -- more of the longevity of them. Of course -- and -- and that work continues.

You may be aware of one of our member sites, I've been testing it on, since Service water pump bowl assemblies, where they've applied a hydrophone of coating and they've worked through that, over the past, probably, three to four years of continuing to do their inspections and working with the manufacturer to -- to improve the quality and the longevity, or the long-term performance of the coating products. A number of different, you know, products are out there, again, it's just how well -- what the durability of them are.

MR. BLEY: Thank -- thank you, very much. And, Ron, I guess, I just say, I found today very enlightening. We've known about these problems for -- for years and I wasn't up to speed on what's being done, currently, to improve the situations, so it was a great day.

CHAIR BALLINGER: Thanks. I -- it was -- I've -- pretty much predictable, who would ask the questions, mainly, it's somebody like you and the operational people, like -- like Greg and -- and others. So hopefully that -- the presentations today will serve, as a, sort of, capstone of the four -- the four presentations that we've had, so if there are no other questions, and I don't see any hands, or anything, it's -- it's too bad that the other EPRI folks may, or may not, be listening from the other presentations, but I would like to speak, if I can, for the subcommittee and -- and -- and thank the EPRI folks, big time, because these four presentations were, I'm sure it took a lot of time to put together, but were extremely informative and will, at least, to my mind, constitute a -- a, kind of, a library that we can -- we have access to, and so if there aren't any further questions, I think that the -- we're probably done. So I think we -- the -- the meeting -- Oh, okay. No, no, go ahead.

(Simultaneous speaking.)

CHAIR BALLINGER: Yes.

MEMBER HALNON: Public comment.

CHAIR BALLINGER: Oh. Oh. Oh, shoot. Sorry. Are there any public -- members of the public that would like to make a comment? Please, identify yourself, and make your comment.

Ah, sorry. Since there are no public -- no -- no public comments, once again, I'd like to think I can speak for the Subcommittee and, thank you very much, for the presentations, and once again, the -- we are adjourned. I guess, we'll see a lot of people at about 1:30 p.m. Thank you, again.

(Whereupon, the above-entitled matter went off the record at 12:08 p.m.)

Full Name	User Action	Timestamp
Christopher Brown	Joined	"10/18/2023, 7:54:49 AM"
"Olack, David"	Joined before	"10/18/2023, 7:54:49 AM"
Kelli Voelsing (EPRI) (Guest)	Joined	"10/18/2023, 7:58:58 AM"
Tyesha Bush	Joined	"10/18/2023, 8:01:01 AM"
"Crytzer, Kurtis"	Joined	"10/18/2023, 8:01:49 AM"
"Crytzer, Kurtis"	Left	"10/18/2023, 8:02:35 AM"
"Crytzer, Kurtis"	Joined	"10/18/2023, 8:03:31 AM"
Shandeth Walton	Joined	"10/18/2023, 8:01:50 AM"
Court Reporter - Sam Wojack (Guest)	Joined	"10/18/2023, 8:03:45 AM"
+1 704-614-3889	Joined	"10/18/2023, 8:04:32 AM"
Jose March-Leuba (ACRS) (Guest)	Joined	"10/18/2023, 8:04:36 AM"
Dave Petti (Guest)	Joined	"10/18/2023, 8:06:24 AM"
"Golberg, Ilya"	Joined	"10/18/2023, 8:08:03 AM"
"Cimock, Dylan"	Joined	"10/18/2023, 8:09:23 AM"
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Weidong Wang	Joined	"10/18/2023, 8:23:21 AM"
Tammy Skov	Joined	"10/18/2023, 8:24:02 AM"
Stephen Schultz	Joined	"10/18/2023, 8:24:58 AM"
Sandra Walker	Joined	"10/18/2023, 8:25:18 AM"
Thomas Roberts	Joined	"10/18/2023, 8:25:27 AM"
Bob Martin (He/Him)	Joined	"10/18/2023, 8:26:03 AM"
Gregory Halnon	Joined	"10/18/2023, 8:27:09 AM"
Michael Snodderly	Joined	"10/18/2023, 8:27:31 AM"
Michael Snodderly	Left	"10/18/2023, 8:36:14 AM"
Dennis Bley (Guest)	Joined	"10/18/2023, 8:27:46 AM"
mattsunseri	Joined	"10/18/2023, 8:28:10 AM"
mattsunseri	Left	"10/18/2023, 8:29:19 AM"
Matt Sunseri	Joined	"10/18/2023, 8:29:10 AM"
Derek Widmayer	Joined	"10/18/2023, 8:30:08 AM"
Stephen P O'Hearn (Services - 6)	Joined	"10/18/2023, 8:32:15 AM"
Vesna B Dimitrijevic (Guest)	Joined	"10/18/2023, 8:33:07 AM"
Janet Riner (Guest)	Joined	"10/18/2023, 8:35:49 AM"
Janet Riner (Guest)	Left	"10/18/2023, 8:39:59 AM"
Thomas Dashiell	Joined	"10/18/2023, 8:43:02 AM"
Edwin Lyman	Joined	"10/18/2023, 8:52:28 AM"

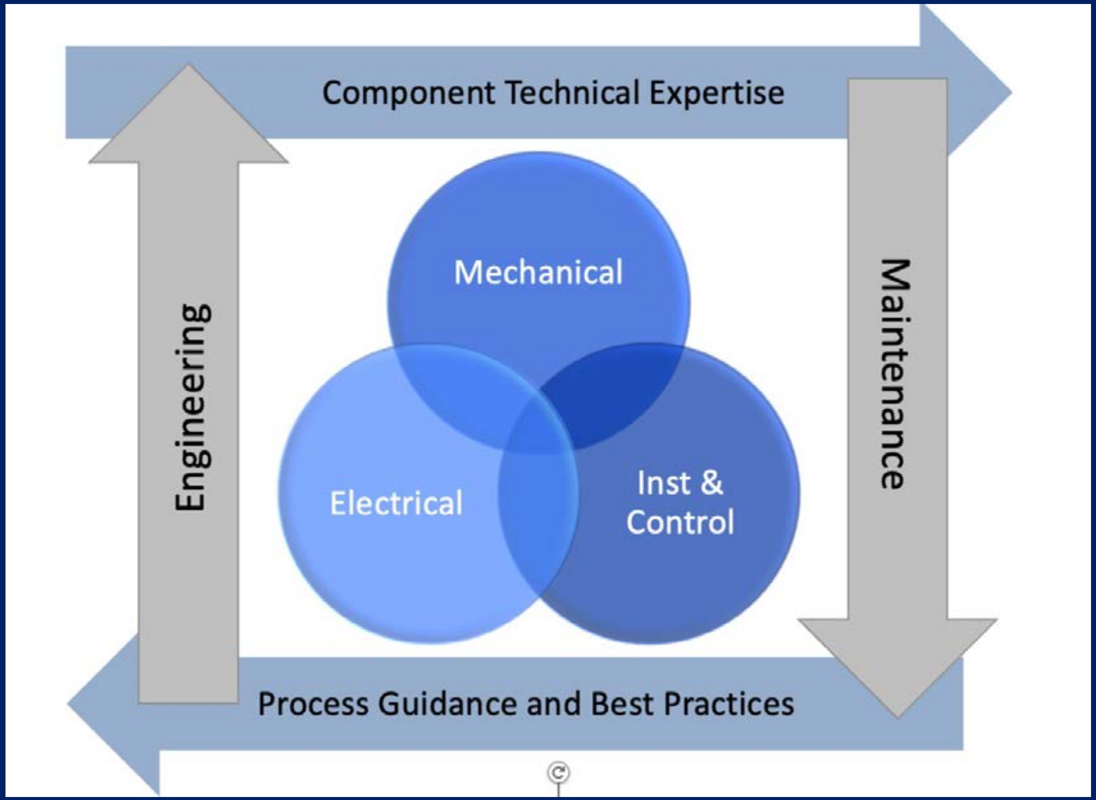
EPRI's Plant Reliability and Resilience Program: Information/Update

BOP Update – Topics of Interest

Kurt Crytzer, Senior Principal Team Lead

Advisory Committee on Reactor Safeguards
October 18, 2023

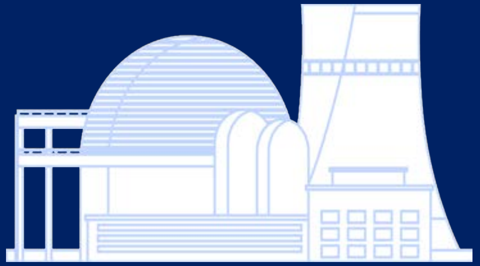
Plant Reliability and Resilience Research



2024 – One program covering areas:

- Active Mechanical
- BOP/Passive Mechanical
- Electrical
- Instrumentation & Control (I&C)
- Eng/Maint Processes

Plant Reliability and Resilience (PRR) Program allows integration maintenance and engineering research to address broad industry initiatives



Research Aligned with Critical Industry Issues

Plant Life Extension and Power Uprates

Resiliency
(to Climate Change, Supply Chain Issues, and Other Factors)

Efficient and Intuitive Access to EPRI Information

Risk-informed and Graded Approaches

Modernization, Data, and Online Monitoring

Agenda

Item	Topic	Presenter(s)	Time
1	Opening Remarks and Objectives	Prof. Ballinger, ACRS	8:30 – 8:35
2	EPRI Opening Remarks	Kurt Crytzer, EPRI	8:35 – 8:40
3	Nuclear Aging management and Corrosion Monitoring Research (BOP) • Buried Piping (NDE, Programmatic, and Cathodic Protection) • Integrity of Tanks • Selective Leaching NDE and Programmatic Research • Use of CFD for FAC of isolated piping	Dylan Cimock, EPRI Samuel Johnson, EPRI Jeremie Varnam, EPRI	8:40 – 9:25
4	Low and Medium Voltage Cables • Reliance on VLF tan delta testing for Medium Voltage Cables • Advances in Low Voltage Cable Condition Monitoring	Ilya Goldberg, EPRI	9:25 – 10:05
5	Resilience • Weather impacts on nuclear plant operations • Considerations of future climate impacts	Rob Choromokos, EPRI	10:05 – 10:50
6	Intakes and Heat Sink • Recent Intake Guide Research • Silting management research • Changes to flora and fauna impact to UHS • Innovation	Jonathan Black, EPRI	10:50 – 11:30
7	Open Discussions	All	11:30 – 11:50
8	Committee Discussions	Prof. Ballinger, ACRS	11:50 – 12:00
9	Adjourn	All	12:00

Please feel free to ask questions or interject at any time during the presentations

Nuclear Aging Management and Corrosion Monitoring Research (BOP)

Buried Piping and Cathodic Protection Research Activities

Dylan Cimock, Sr. Technical Leader
Jeremie Varnam, Sr. Technical Leader
Sam Johnson, Sr. Team Lead

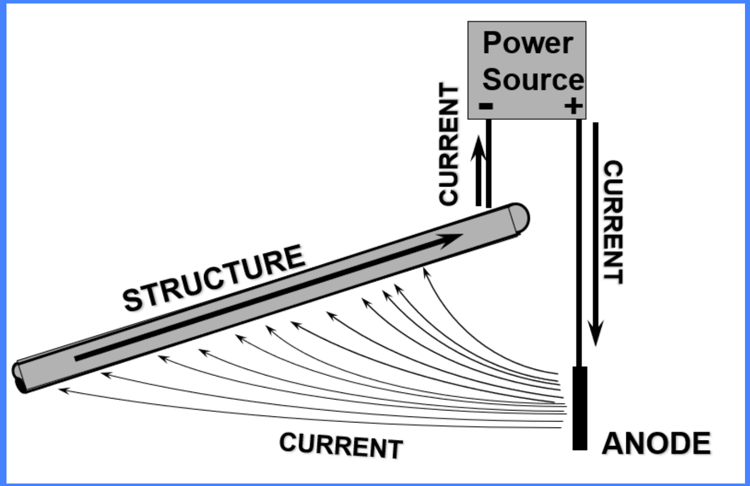
Advisory Committee on Reactor Safeguards
October 18, 2023

Recent Buried Pipe Meeting Topics of Interest

- Selective Leaching (graphitic corrosion) of cast iron piping & valves
  - Cannot detect visually
  - Multiple recent leaks / failures
  - Impacts and regulatory scrutiny on license renewal (life extension) applications

- Internal Pipe Repair Methods
  - Carbon Fiber Reinforced Polymer (CFRP)
  - Steel Composite Liner (SCL)
  - Cured-in-Place Piping (CIPP)
  - Spray-in-Place Piping (SIPP)
  - Mechanical Joint Seals

- Cathodic Protection
  - Important to mitigating external corrosion of buried piping
  - Finite life
  - Performance / reliability issues
  - EPRI Resources and Activities



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Selective Leaching

Selective Leaching Background

Selective leaching (SL) corrosion preferentially removes one alloying element from the parent matrix, enriching the remaining elements. Typically associated with exposure to untreated internal or external aqueous environments.

→ **Affected material may stay in place with wall thickness remaining nominal**

- Relevant susceptible materials (NUREG-1801 & -2191, IAEA I-GALL)
  - Ductile iron & gray cast iron
  - Aluminum bronze with >8% aluminum
  - Copper alloys with > 15% zinc

- Examples of affected plant systems
  - Fire Protection
  - Service Water
  - Emergency Diesel Generator
  - Condensate
  - Auxiliary Feedwater

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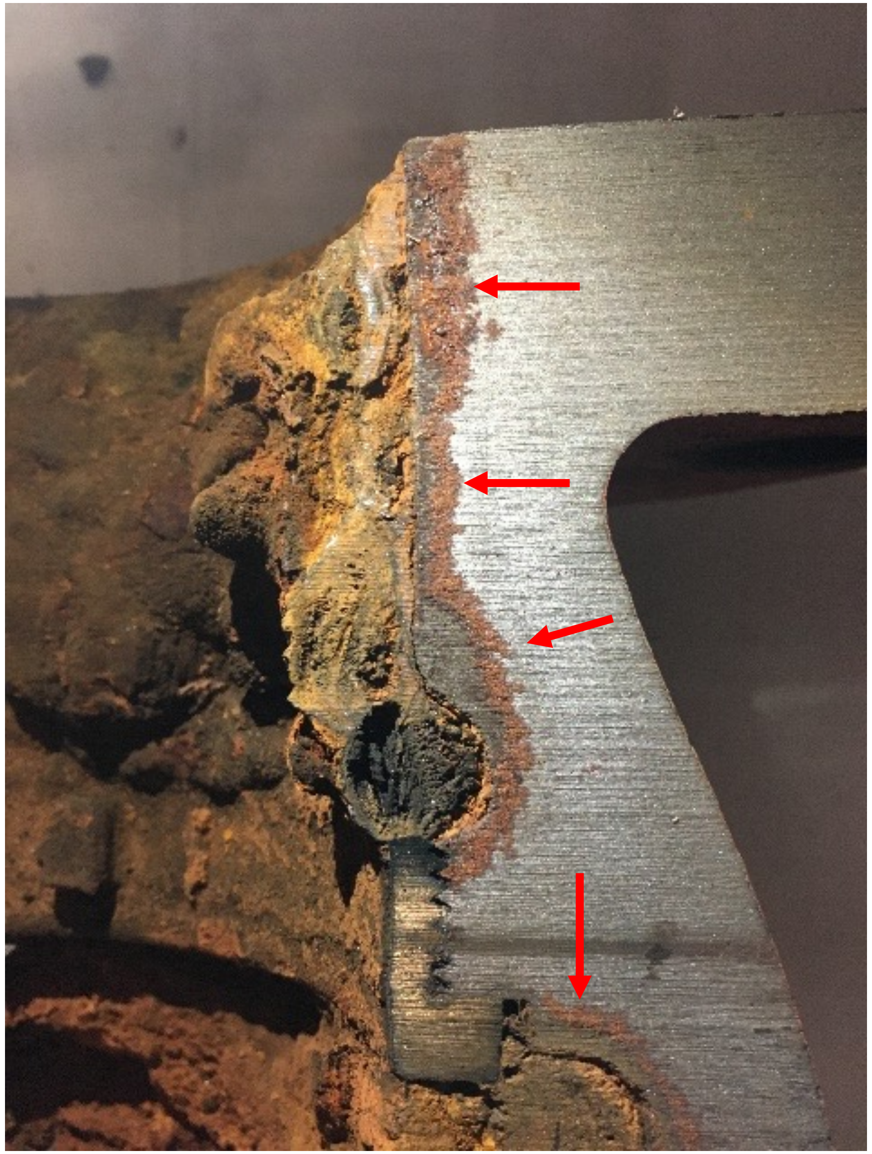
Why Selective Leaching Research is Important?

- Impact on power reactors licensed to operate beyond 40 years (and even more so for those licensed beyond 60 years)

- Industry incurs significant expenses to meet aging management commitments for long term operations
  - Large inspection population sample sizes
  - Development of periodic inspection programs

- Inspection Difficulties
  - Corrosion features are complex (local plug type and uniform)
  - Susceptible components are difficult to inspect (e.g., valve & pump casing)



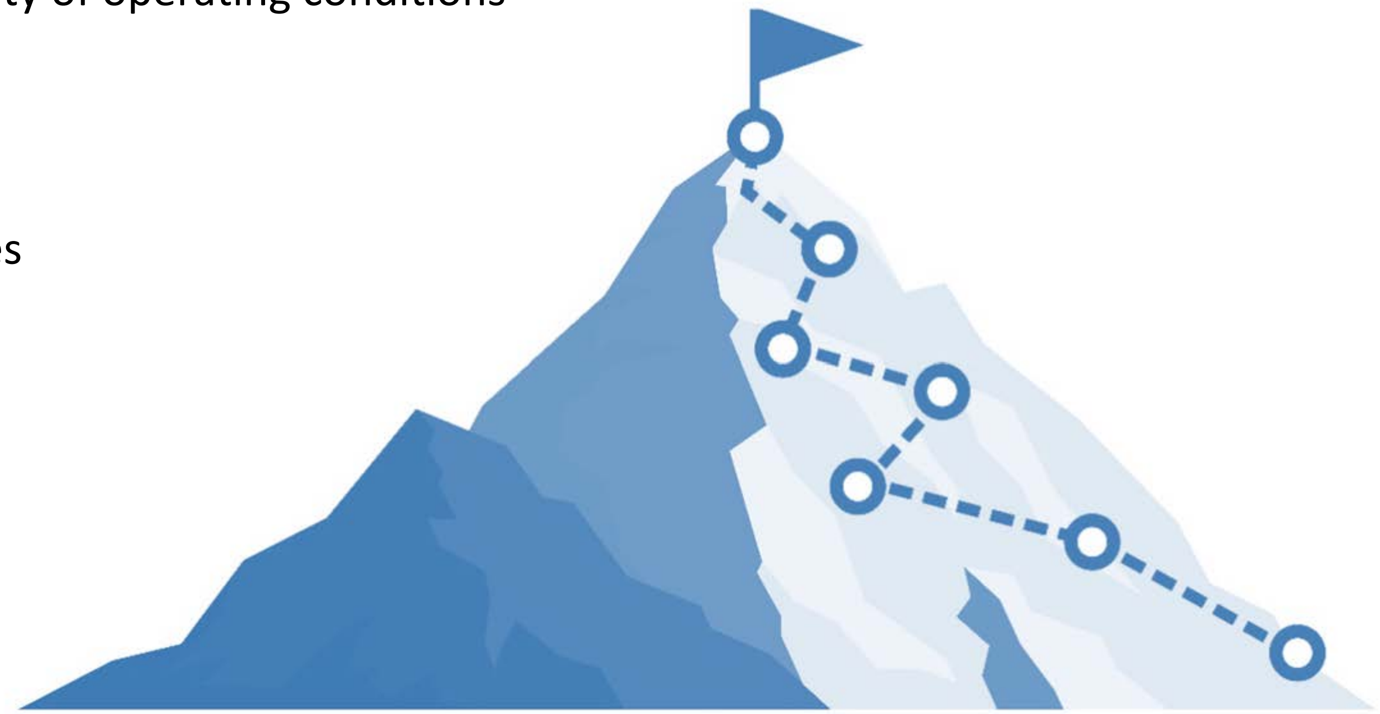
Aging Management Program Challenges

- Knowledge & Training

- How to choose sample components amongst populations?
  - GALL & GALL-SLR recommends to focus on “lead components most susceptible… based on time in service & severity of operating conditions”

- Inspection Techniques
  - Effectiveness of visual examinations
  - Accessibility of susceptible component surfaces
  - Effectiveness of hardness testing
  - Demonstrated NDE techniques (e.g., UT)
  - Efficiency of destructive test

- Dispositioning of findings
  - What is relevant? (depth vs superficial)
  - Fitness-for-Service rules for brittle materials
  - Postulating growth rates



EPRI Research on Selective Leaching NDE

Report Number	Title	Year Published
3002023785	Evaluation of Electromagnetic NDE Techniques for Detection of Wall Thinning Due to Selective Leaching Degradation in Gray Cast Iron Piping	2023
3002020832	Electromagnetic NDE Techniques for Gray Cast Iron Piping	2021
3002020830	Ultrasonic Techniques for Selective Leaching in Gray Cast Iron Components	2021
3002016057	Selective Leaching: State-of-the-Art Technical Update	2019
3002013168	Nondestructive Evaluation: Guidance for Conducting Ultrasonic Examinations for the Detection of Selective Leaching	2018
3002008013	Assessment of Available Nondestructive Evaluation Techniques for Selective Leaching: Technology Review	2016
1025218	Nondestructive Evaluation: Correlation of Selectively Leached Thickness to Hardness for Gray Cast Iron and Brass	2012
1019111	Nondestructive Evaluation: Update to NDE for Selective leaching of Gray Cast Iron Components	2009
1018939	Nondestructive Evaluation: NDE for Selective leaching of Gray Cast Iron Components	2009

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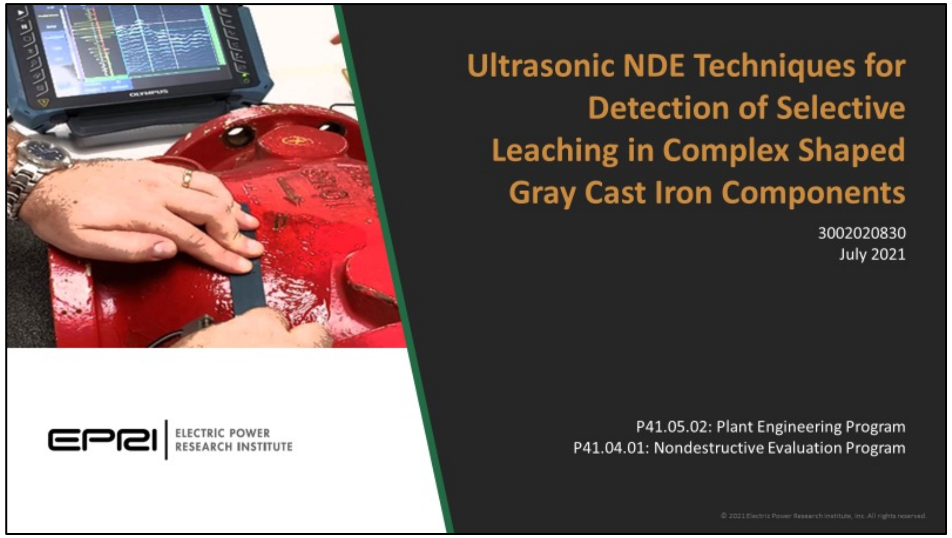
Selective Leaching NDE Reports

“Inspection Techniques” Research

- Technical Brief: 3002020830 “Ultrasonic Techniques for Selective Leaching in Gray Cast Iron Components”
  - Scope: detection of internal selective leaching from outside surface examination (opposite surface)
  - 3 techniques successful demonstrated on field removed components for detection and characterization of opposite surface SL

- Technical Brief: 3002020832 “Electromagnetic NDE Techniques for Gray Cast Iron Piping”
  - Four (4) different techniques evaluated on field removed piping components
  - Includes both internal and external techniques

- Technical Report: 3002023785 “Evaluation of Electromagnetic NDE Techniques for Detection of Wall Thinning Due to Selective Leaching Degradation in Gray Cast Iron Piping”
  - More details and analysis of results from EM techniques
  - Includes results for two (2) additional techniques evaluated in 2022



Reports Provide Techniques and Quantitative Results of Demonstration

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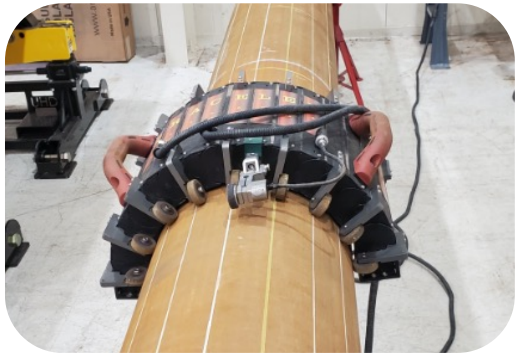
Examples of Electromagnetic NDE Techniques

Pulsed Eddy Current

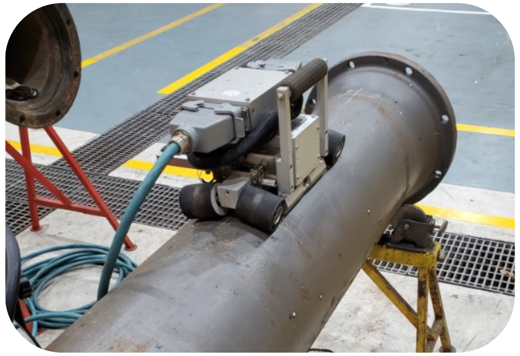
Low Frequency Electromagnetic Technique



Through-Transmission

Remote Field Testing

Magnetic Flux Leakage



Saturation Eddy Current

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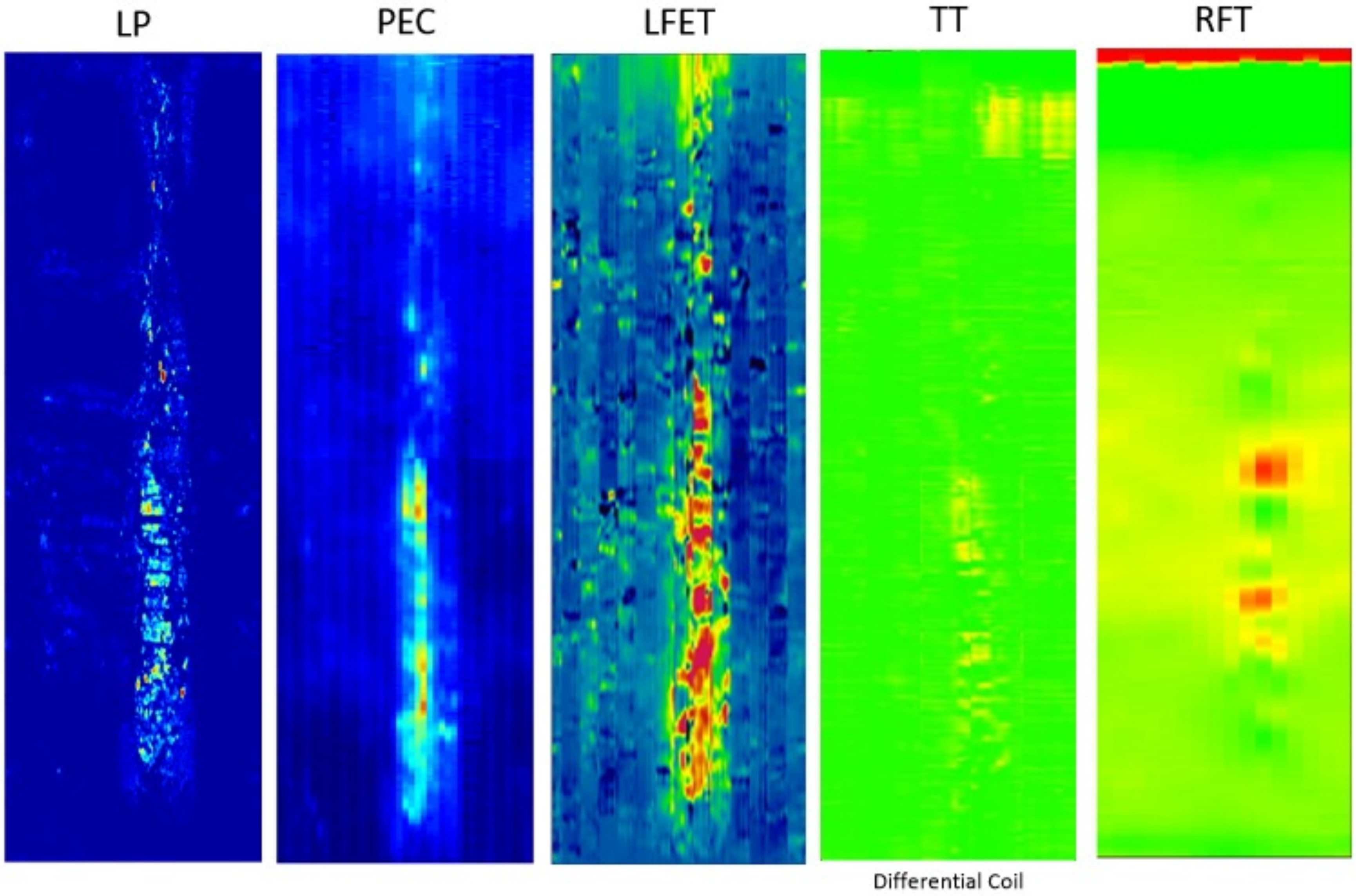
Example Results from Electromagnetic Techniques



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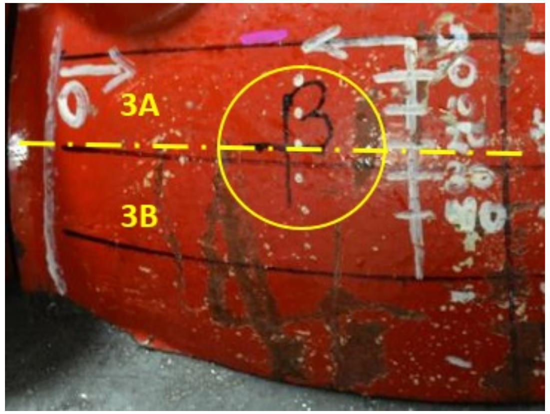
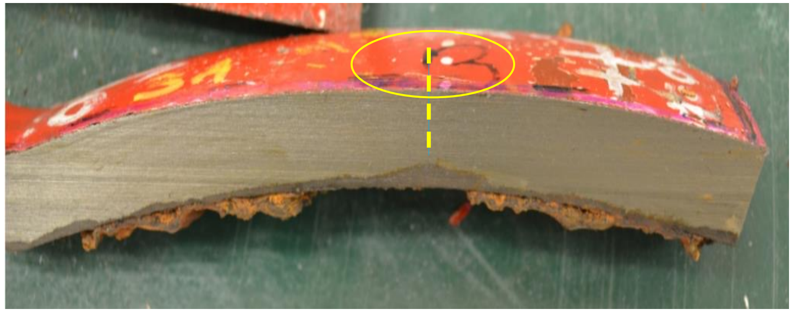
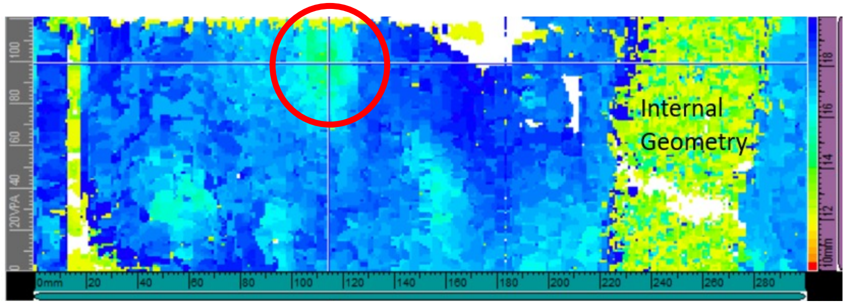
Summary: Selective Leaching NDE

- Cast Iron
  - Recent EPRI Research has demonstrated NDE capabilities to detect wall loss due to selective leaching in cast iron materials
    - Six (6) commercially available electromagnetic techniques for piping
    - Three (3) Ultrasonic techniques for opposite surface detection
- Copper-zinc alloys
  - Past industry OE indicates success in detecting SL in copper-alloy heat exchanger (HX) tubing using eddy current testing (ECT)
- Aluminum Bronze
  - Industry demonstration and advancement of advanced UT (Time-of-Flight Diffraction and Phased Array)
- *EPRI has submitted comments on Draft NUREG-2191 Revision 1 (GALL-SLR)*
  - Recommend NRC Staff consider results of recent EPRI reports and include NDE as viable options for the XI.M33 Selective Leaching AMP
- Outstanding Research gaps:
  - Objective demonstration of ECT on HX tubing
  - Applicability of ultrasonic techniques to same surface SL is progressing from in cast irons
  - Evaluation of surface eddy current (array) sensors to multiple materials for detection







Selective Leaching R&D Tasks

Report Number	Topic	Publication Year / Status
3002016057	"State-of-the-Art" Report	2019
3002020822	Susceptibility Evaluation	2021
3002020830 3002020832 3002023785	NDE Technique Development • Tech Brief ultrasonics • Tech Brief electromagnetics	2021 2023
3002020713	Selective Leaching: Leveraging Risk Insights	2022
N/A	Development of Analytical Techniques	Project: 2024 (tentative)
*3002026340**	Recommendations for an Effective Selective Leaching Aging Management Program	Project: *November 2023*
3002015155 3002018468	Development of SL Training	2019: Instructor-Led Training 2020: Computer Based Training (CBT) 2023: Updates

*Report in publication process at time of presentation

Non-Metallic Repairs and Rehabilitation of Piping

Repair / Rehabilitation / Refurbishment Approaches

HDPE

Source: ML20014E476, Structural Technologies

CFRP:
Carbon Fiber Reinforced Polymer

CIPP:
Cured-in-Place-Pipe

Photo Credit: Elite Pipeline, 2017 EPRI NUCC Meeting

SIPP:
Spray-in-Place-Pipe

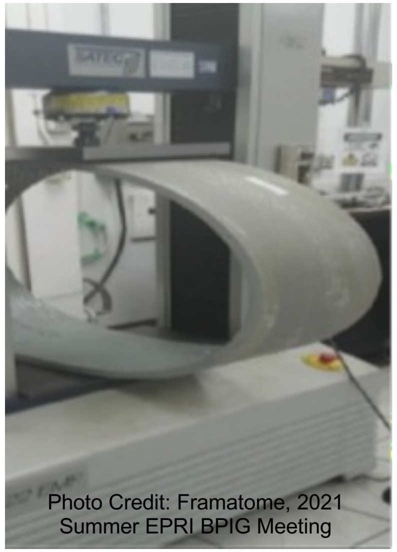
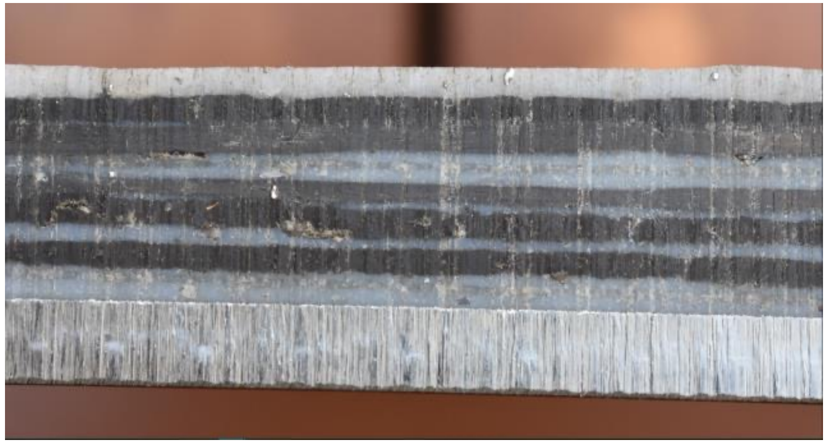


Photo Credit: Framatome, 2021 Summer EPRI BPIG Meeting

Carbon Fiber Reinforced Polymer (CFRP) Composites

- System is comprised of multiple layers of woven carbon fiber fabric, saturated in polymer resin, hand applied to pipe
- Can be installed on the inside or outside of piping
  - Inside: diameter requires manned entry (>30 inch)
- Can be designed / installed to structurally reinforce the existing pipe
- Alternatively – can be designed/installed as a stand-alone repair
  - CFRP credited for all structural and pressure loads
  - No reliance on the original host pipe, except at “terminal ends”
  - Host pipe serves only as a “form” for installing
- Can be applied to multiple material substrates, including carbon steel and concrete

Photo Credit: Dominion Energy & Structural Technologies, 2018 EPRI Summer BPIG Meeting



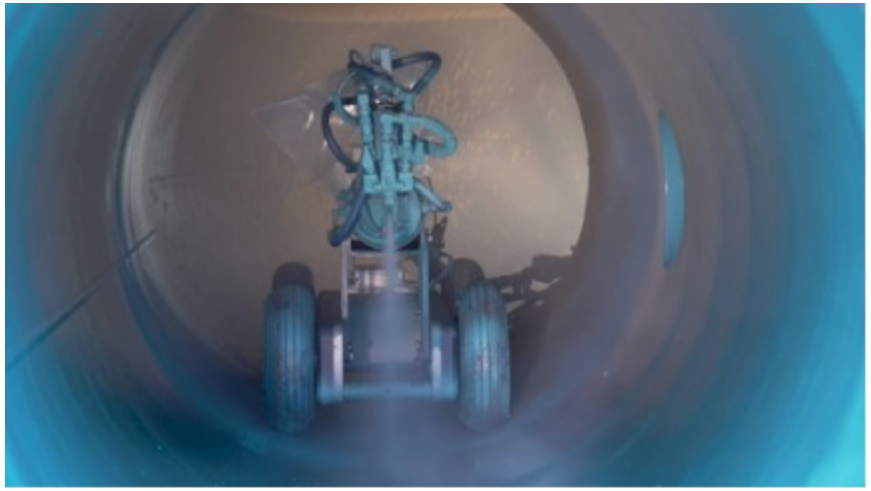
Cross-Section of CFRP Mock-up: 0.375-in steel with 5 layers of CFRP

Spray-in-Place Polymeric (SIPP) Linings

- Internally spray-applied corrosion barrier for piping
  - Thermoset pipe within a pipe
  - Epoxy, polyurethane, or poly-urea are most common materials

- Has been used as structural or semi-structural repair in non-nuclear industries
  - AWWA C620, “Spray-in-Place Polymeric Lining for Potable Water Pipelines 4-inch and Larger”

- Recent products presented at EPRI Conferences:
  - Use fast-curing poly-urea resin
  - High build dry film thickness (>0.10 inch)
  - Multiple utilities pursuing as internal corrosion liner option
  - Interest expressed by vendor(s) and utilities on potential pathway for structural repair



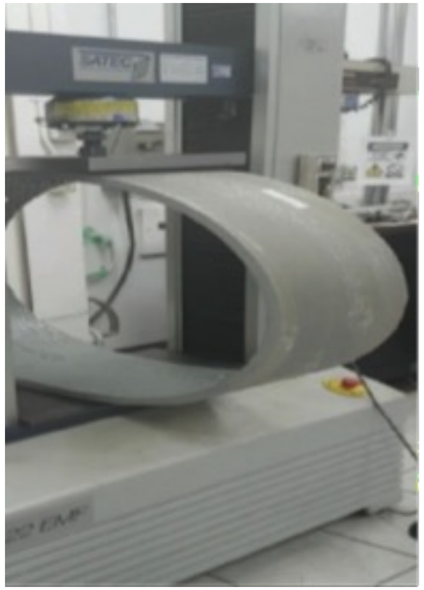


Photo Credit: Framatome, 2021 EPRI Summer BPIG Meeting

EPRI

EPRI Observed Gaps and Projects: CFRP-SIPP

CFRP

- 3002020823 "NDE of Metallic Substrates Beneath CFRP Materials"
- NDE of Carbon Fiber Composite Materials
  - 2023-2025 project
- ASME Code Case support
  - On-going
- Projects Under Consideration
  - Appropriate margin between CFRP glass transition temperatures and maximum system design temperatures
  - Cure temperature adjustment factors for material properties
  - Stress Intensification Factors (SIFs) / Fatigue Factors

SIPP

- SIPP Technology and Gap Assessment (Nov. 2023)
- Guidance on testing & qualification of SIPP as a corrosion lining for Safety-Related Piping
- Material properties to support structural credit of SIPP

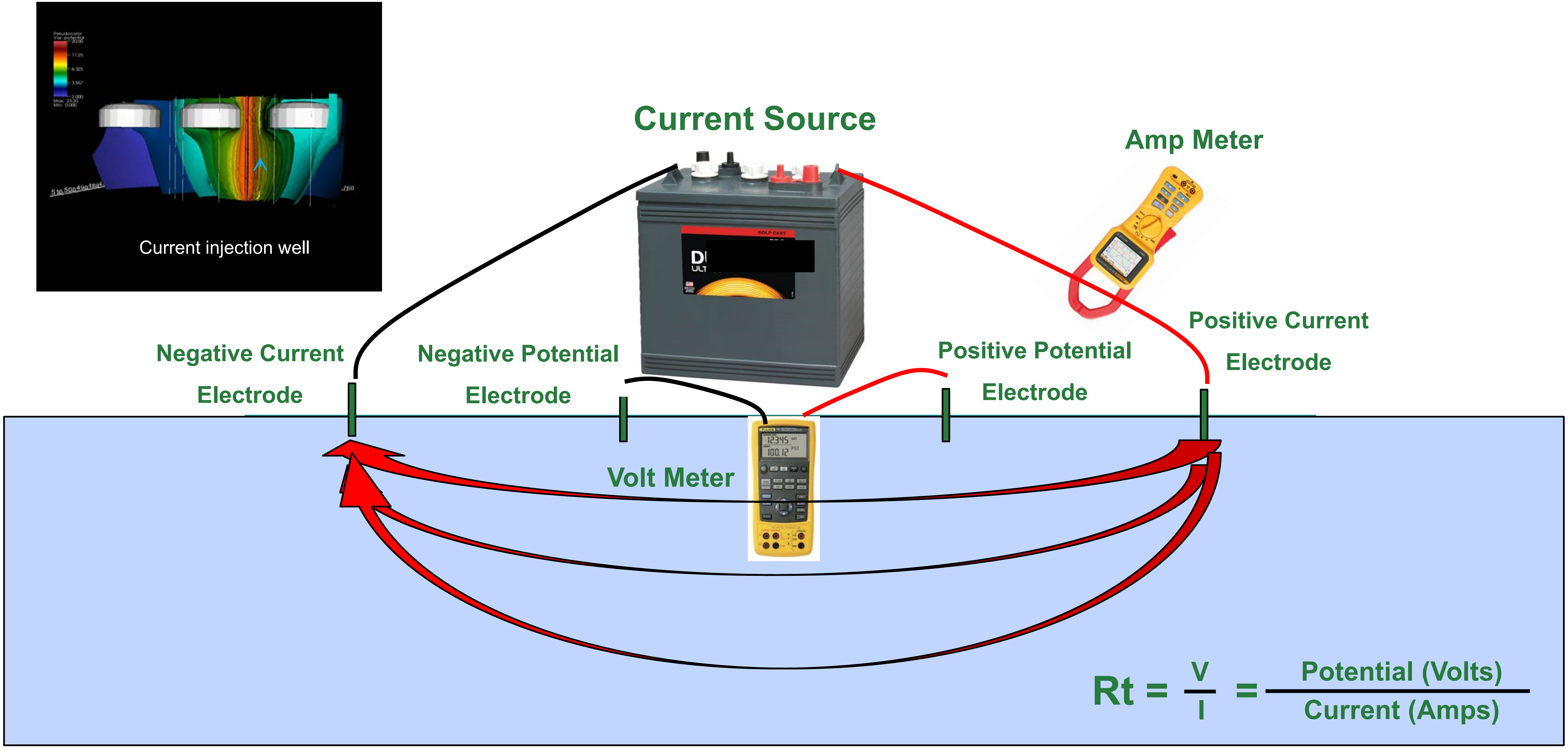
CFRP Workshop – Technical Information Exchange

- EPRI held in-person CFRP workshop July 25-26, 2023
- Attendees:
  - CFRP repair designers & installers
  - NDE technology suppliers
  - US NRC and US national labs
  - Universities
- Topics
  - Overview of CFRP applications, designs, processes
  - Flaw types and flaw evaluation
  - Current quality assessment technologies
  - New NDE inspection technologies
  - Fabrication of mock-ups and intentional defects

Leak Detection Using Electrical Resistivity Tomography

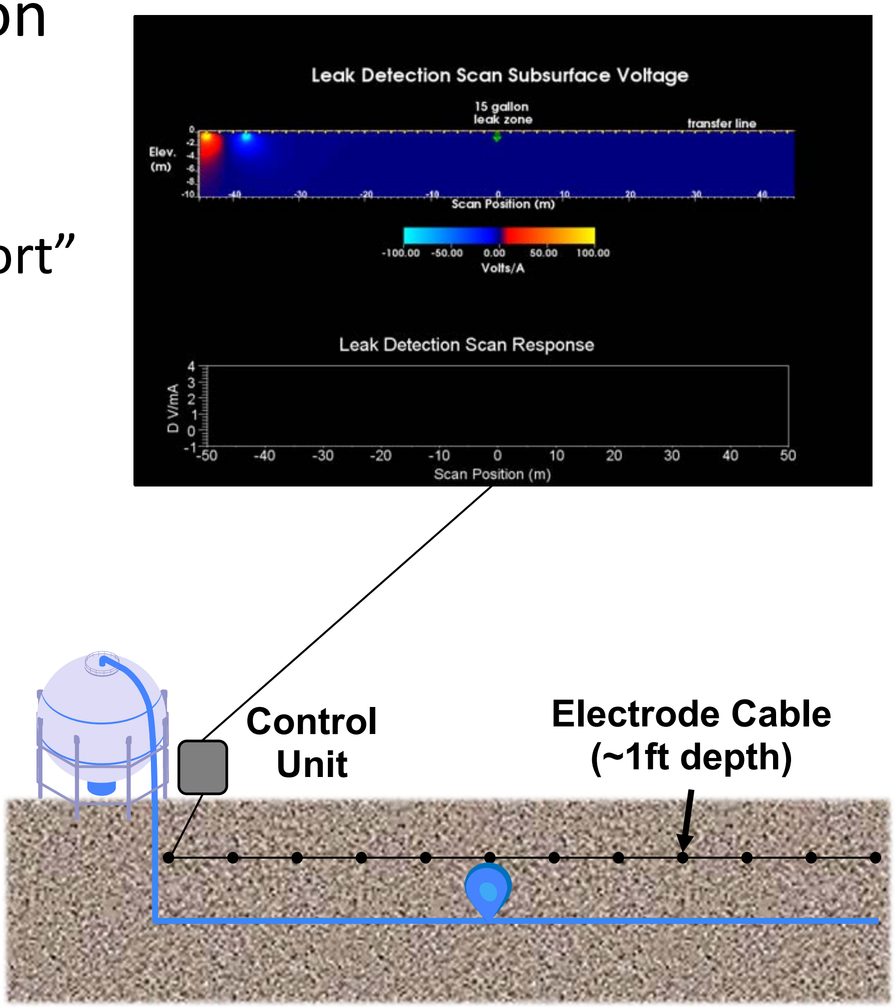
EPRI

Conceptual Measurement



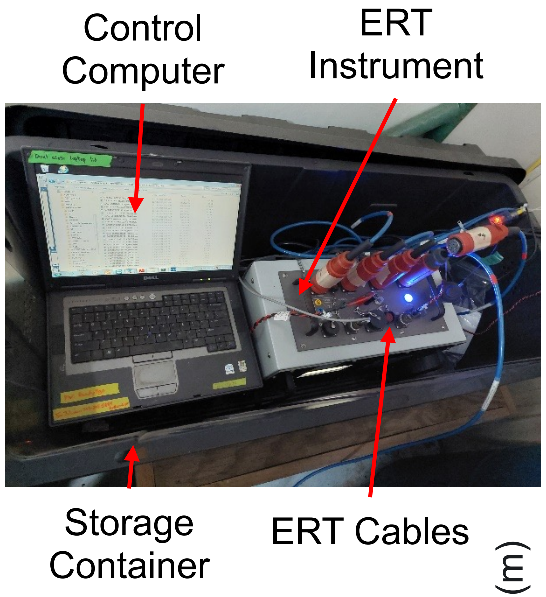
Electrical Resistivity Tomography (ERT)

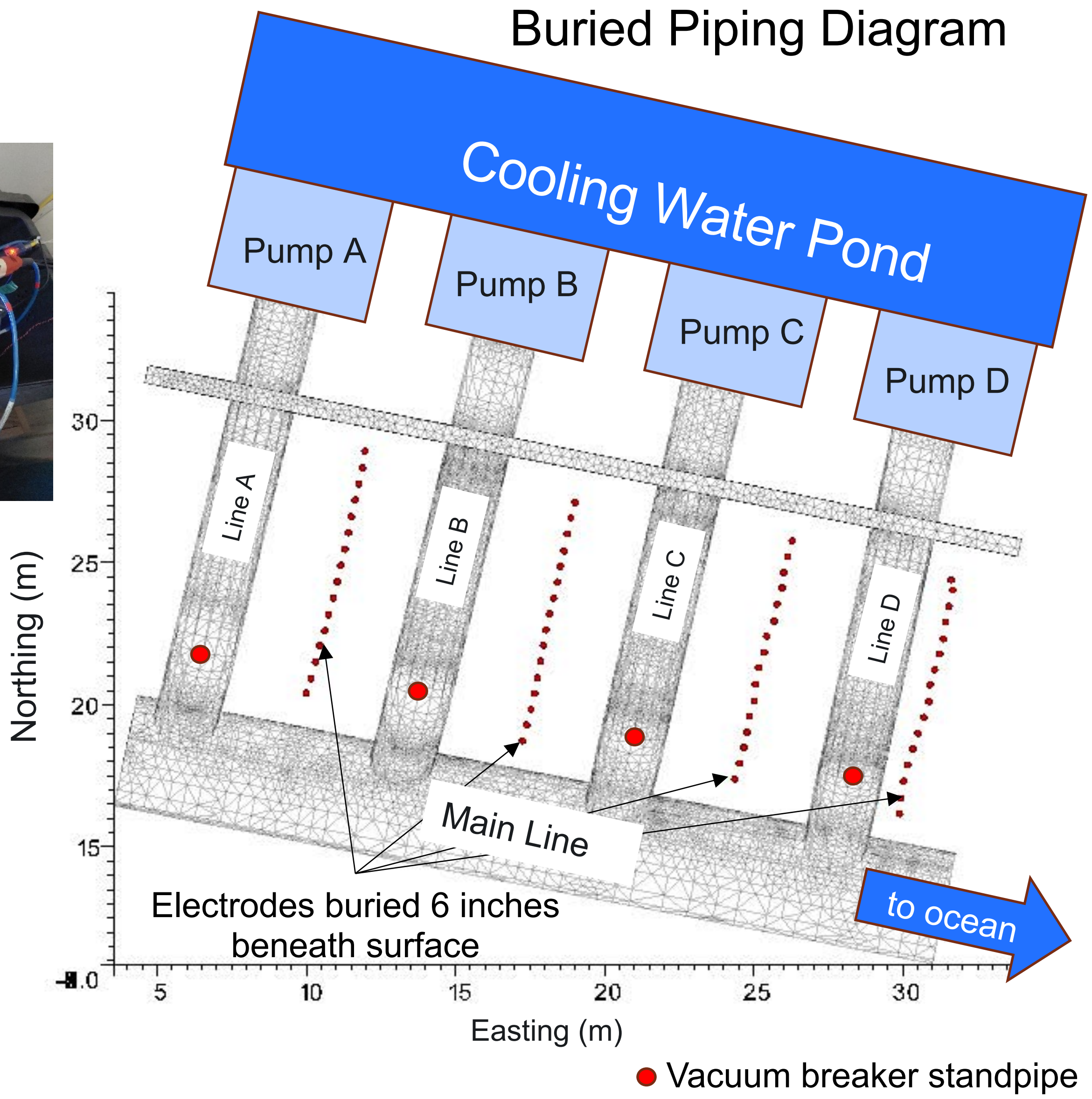
- **Project Objective:** Autonomous monitoring for leaks in buried piping and tanks allowing for early identification
- Current Status
  - 3002010596“Geo-Electrical Subsurface Leak Detection and Monitoring at Nuclear Power Plants: Phase 1 Feasibility Report”
  - 3002023782 “Electrical Resistivity Tomography for Leak Detection and Imaging at Nuclear Power Plants: Phase II Demonstration”
    - Small Pilot with PNNL at BWR Service Water Piping from 2020-2022
      - Simulated leaks detected (Salt Water/Freshwater)
      - Major rainfall event monitored to distinguish leaks

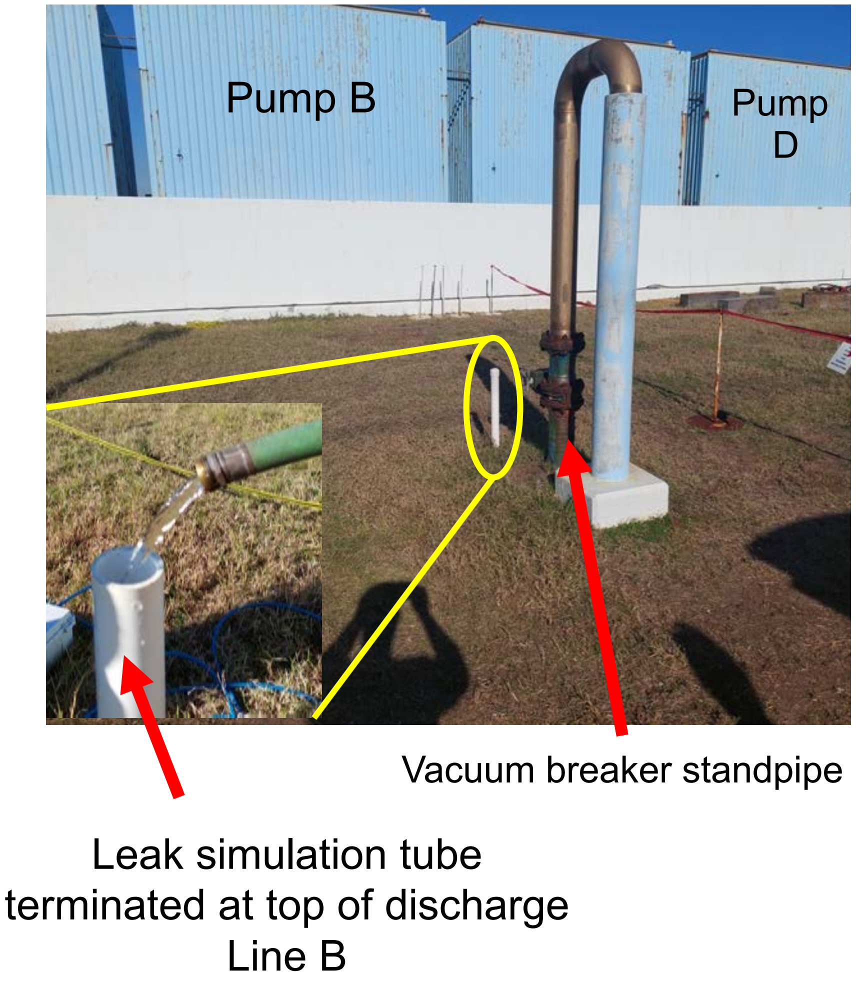


With appropriate electrode spacing, the area requiring excavation can be minimized

Demonstration Site Setup







Leak Injection Test A

Two water types were tested:

- Potable water @ 388 uS/cm
- Canal water @ 31530 uS/cm

Injection rate set to 1 gpm

ERT survey time required ~20 minutes

Test sequence:

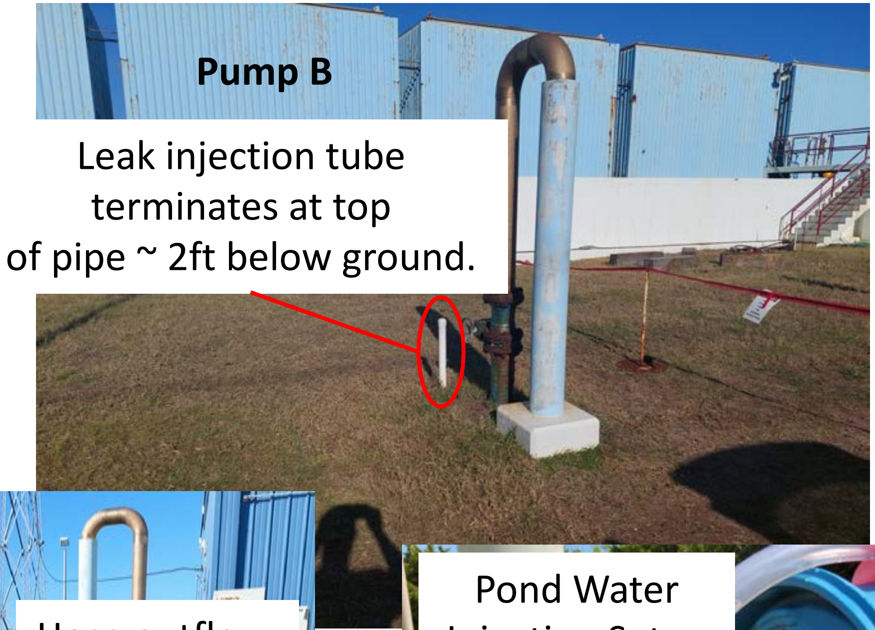
Day 1 Pipe B

1. **171 gallons (3 barrels) of canal water**
2. **2090 gallons of potable (flush) water**

Day 2 (agile testing, troubleshooting, Pipe B,C)

1. **57 gallons (1 barrel) of canal water on C**
2. **278 gallons of canal water on pipe B**

Conclusion:
*- **Electrodes were too far from the leak***
*- **Design mistake (based on incorrect assumptions) and lesson learned***



Leak Injection Test B

Temporary Surface Electrodes

2 lines of 8 electrodes @ 1m spacing

Two water types were tested:

- Potable water @ 388 uS/cm
- Canal water @ 31530 uS/cm

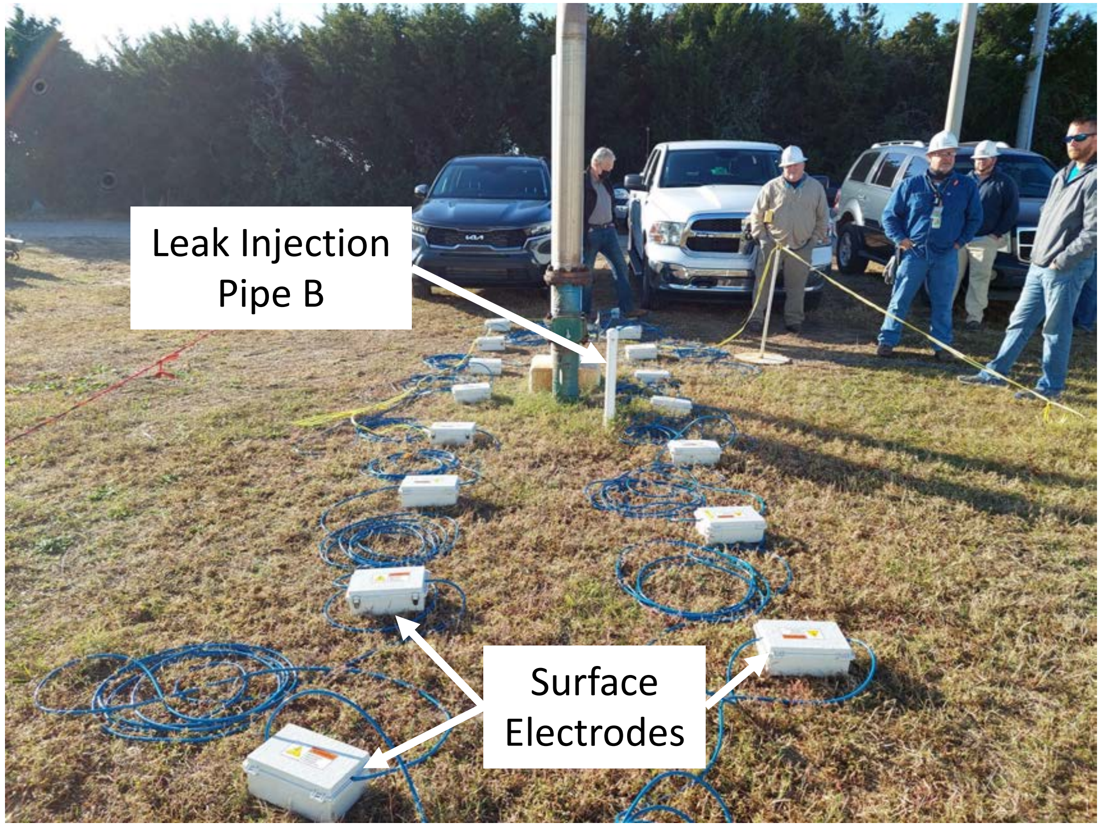
Injection rate set to 1 gpm

ERT survey time required ~10 minutes

Test sequence:

Pipe B

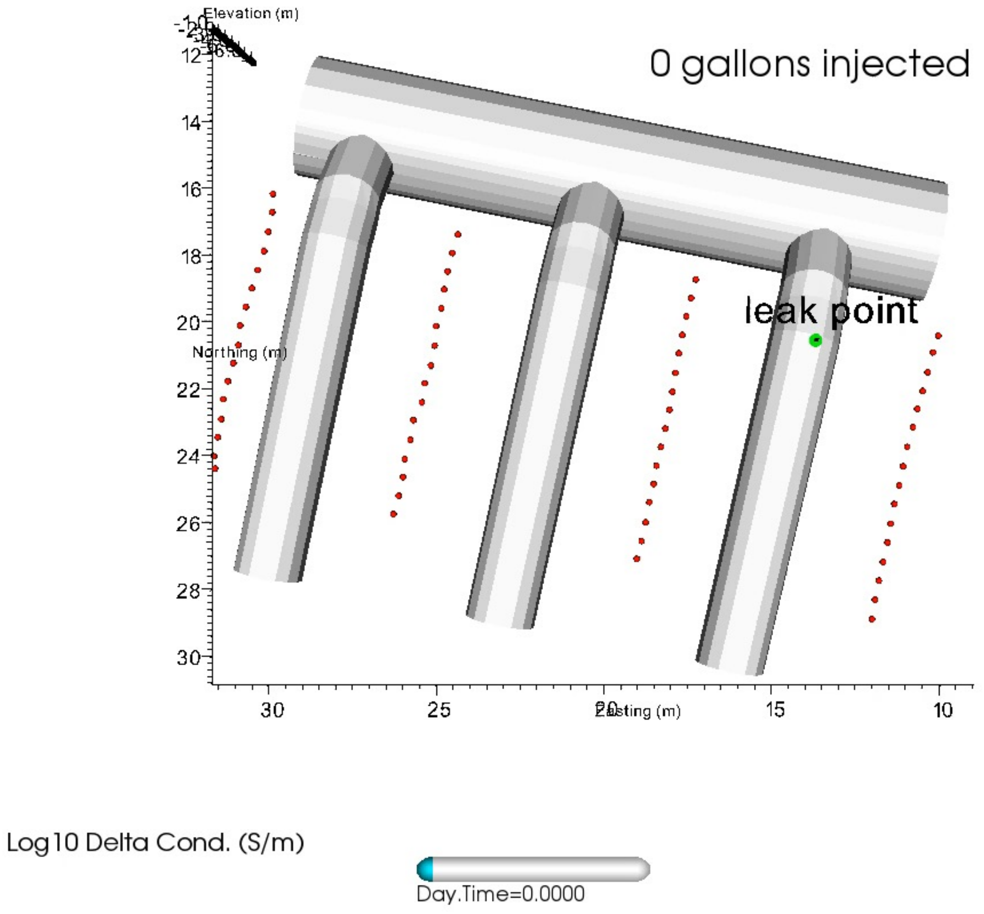
1. **~100 gallons of potable water water**
2. **~100 gallons of canal water**

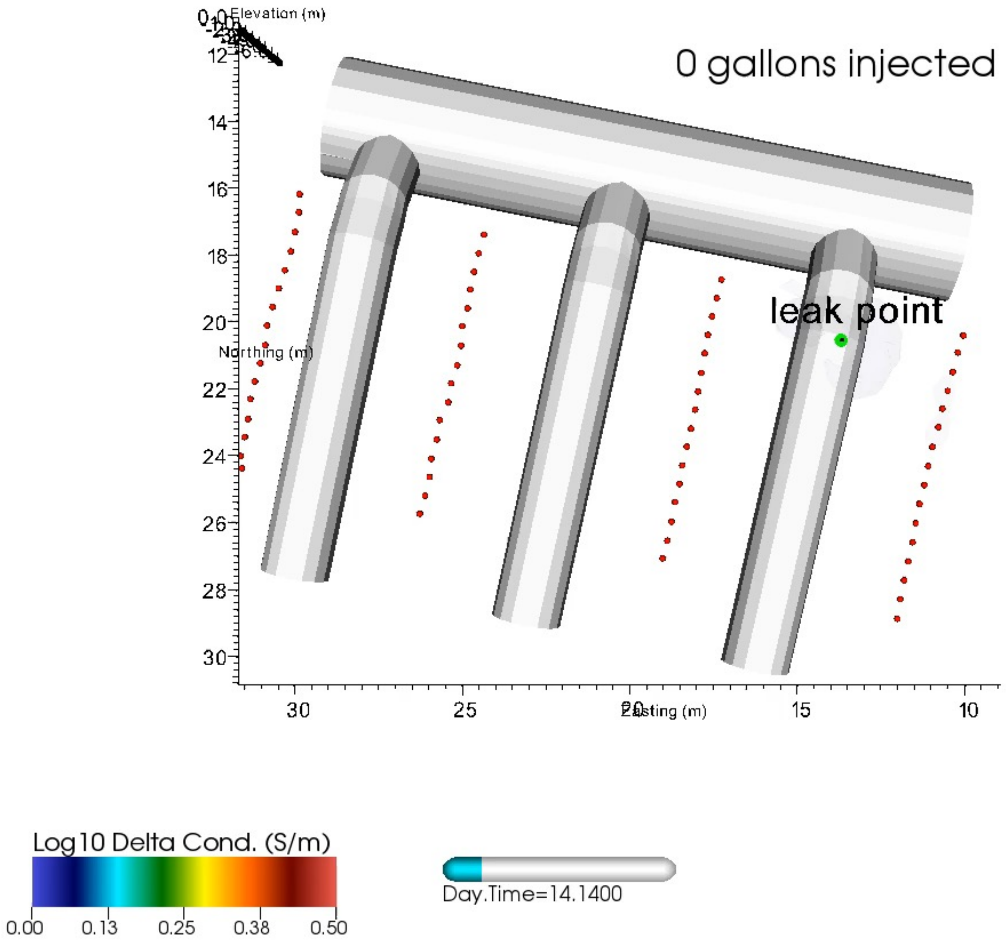


Leak Injection Test B

Potable Water: 388 µS/cm

Canal Water: 31530 µS/cm



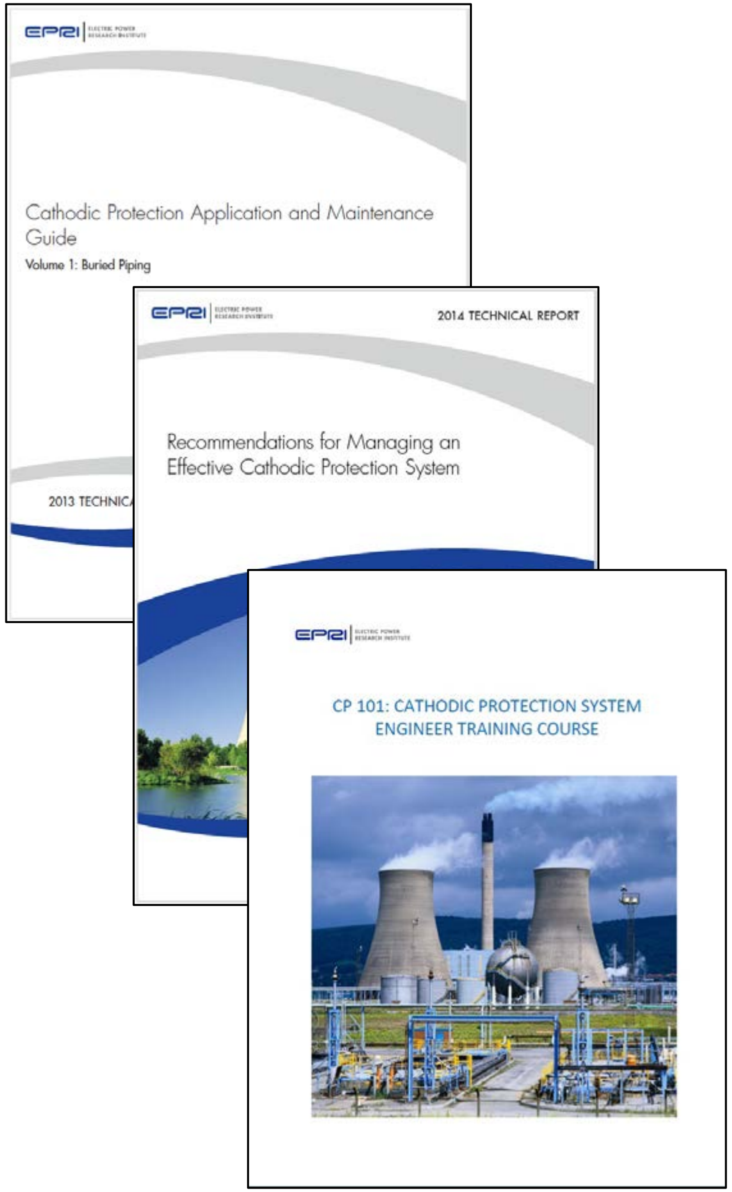


Potable water leak found after 15 gallons
Canal Water leak found after 10 gallons

Cathodic Protection and Tank Inspection Resources

EPRI Cathodic Protection Resources

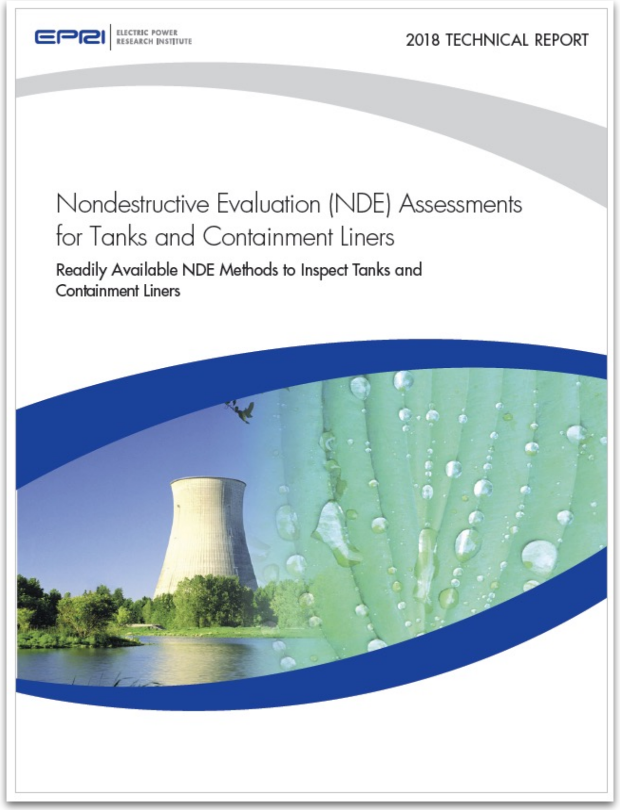
EPRI ID	Title	Year
3002000596	Cathodic Protection Application and Maintenance Guide	2013
3002002949	Recommendations for Managing an Effective Cathodic Protection System	2014
3002005067	Evaluation for Installing or Upgrading Cathodic Protection Systems	2015
1025252	Cathodic Protection System Design Specifications	2012
3002010674	Cathodic Protection Effectiveness: A Review of Protection Criteria, Threshold Values, and Evaluation of Alternative Methods	2017
3002015460	Cathodic Protection Data Management and Trending Software (CPWORKS)	2020
3002007627 3002010678 3002013202	State-of-the-Fleet Assessments of Cathodic Protection Systems (2015-2017)	2016 2017 2018

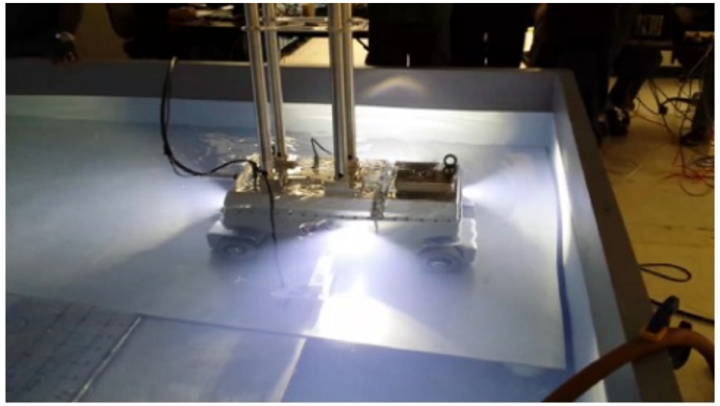


EPRI Research on Tank Inspections

- Previous Projects:
  - 3002013172 “Nondestructive Evaluation (NDE): Assessments for Tanks and Containment Liners: Readily Available NDE Methods to Inspect Tanks and Containment liners”
  - 3002003071 “Guidelines for Tank Inspections”

- Current and Future Projects
  - Guided Wave UT Deployed from the Exterior of Tanks
  - Robotic Platforms for Deploying NDE for Tank Inspections
  - Comprehensive Tank Inspection Reference Guide





Computational Fluid Dynamics Analysis of Stagnant Lines for Flow Accelerated Corrosion

Significant FAC Observed in Unexpected Location

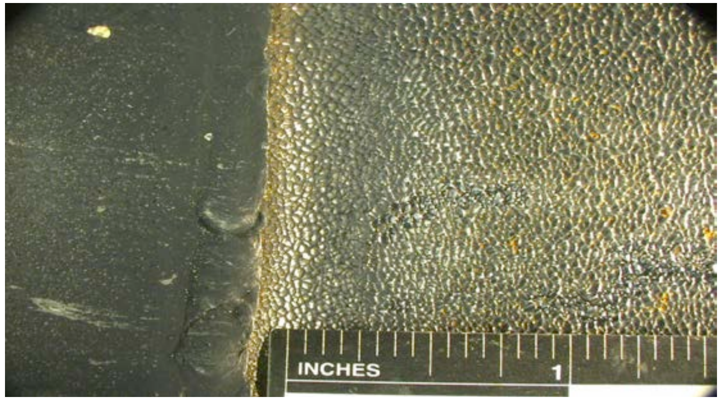
Ref: K. Burke, CHUG Meeting, January 2023

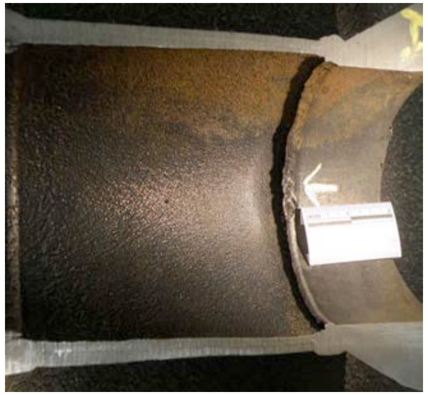
- Unexpected wall thinning of the ‘C’ Feedwater Bypass line was below T_{min}
  - No inspection history as bypass lines were categorized as “non-susceptible” due to less than 2% operating time
  - Actual thickness of **0.100"** versus code minimum of **0.213"** (T_{nom} = 0.337")
- Scope expansion for ‘A’ and ‘B’ bypass lines
  - ‘A’ minimum thickness of **0.052"**
  - ‘B’ minimum thickness of **0.092"**
- All exhibited a “rippled” or “orange peel” surface typical in single-phase Flow-Accelerated Corrosion (FAC)
  - No anomalies in chemical composition, hardness, and microstructure
- Emergent replacement of thinned components with P22 chrome-moly material

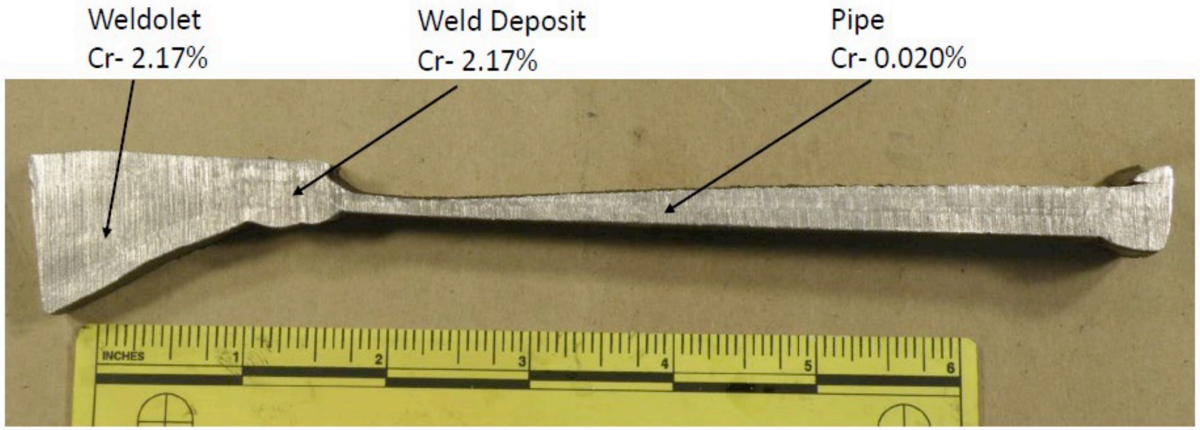
Causal Factors and Extent

Utility's FAC lead contacted EPRI and coordinated with the CHUG Advisory Committee to help define the extent of condition

- Operating time, erosion, and leak-by were likely not factors
- Entrance effect and water chemistry may have been factors but not enough history for certainty
- Turbulent flow conditions warranted additional investigation



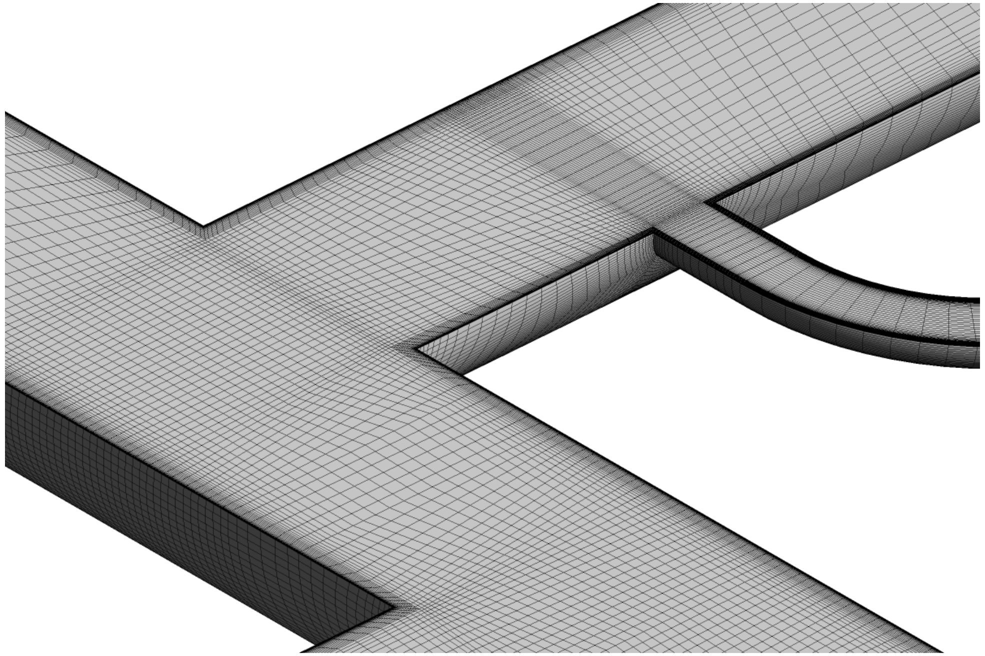


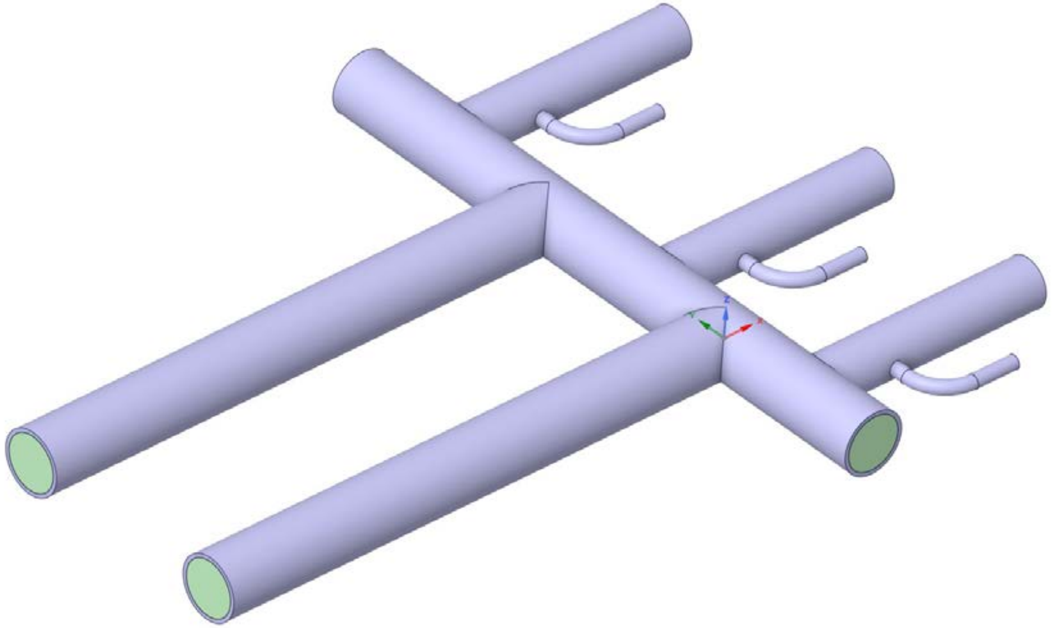


Ref: K. Burke, CHUG Meeting, January 2023

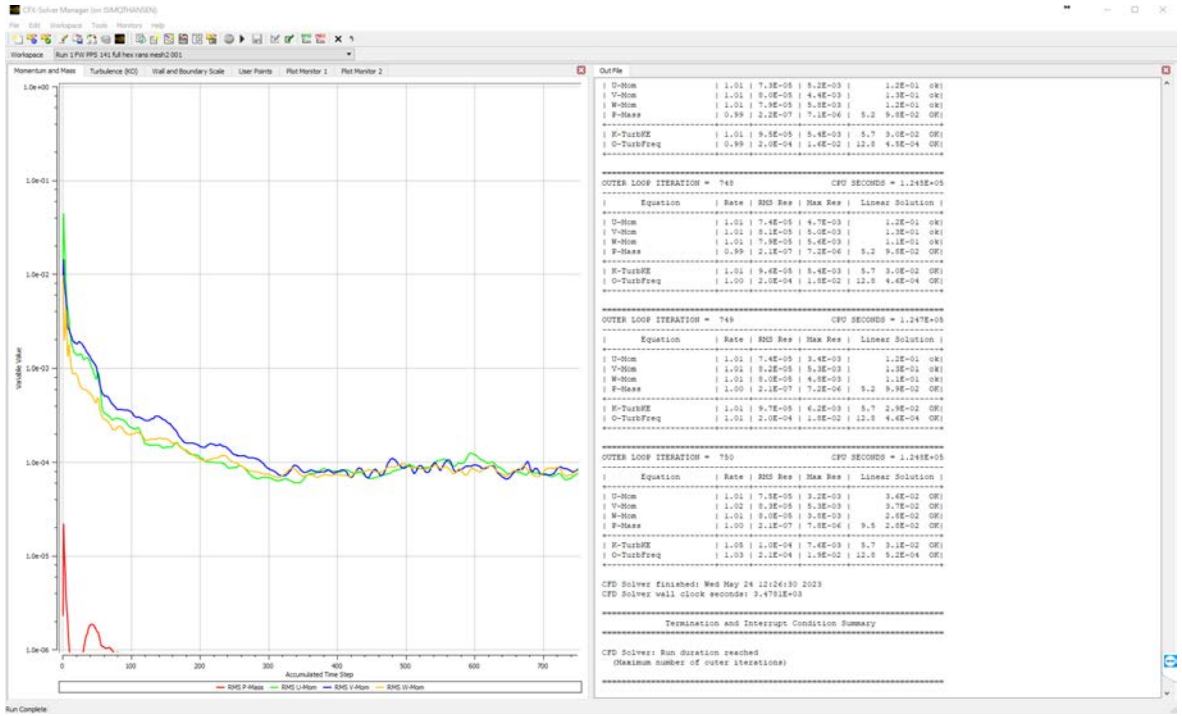
CFD Analysis of Stagnant Lines

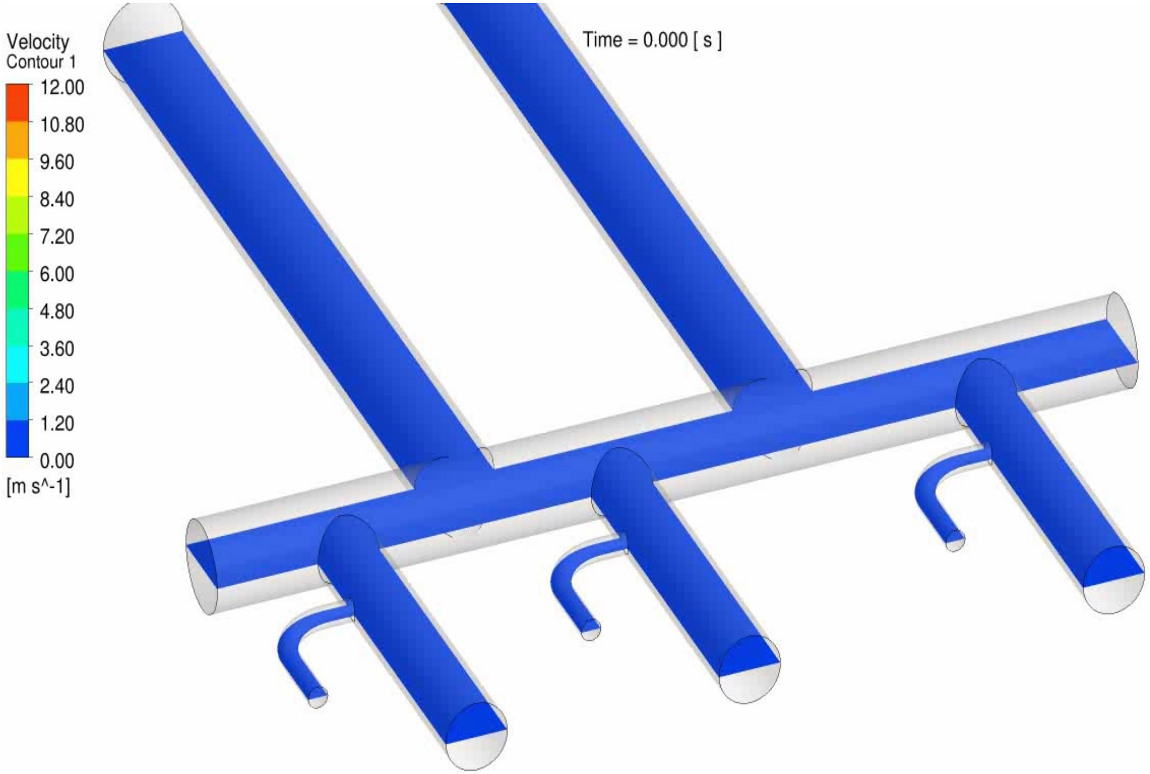
- To validate whether FAC thinning was the likely cause
- Could similar FAC thinning of stagnant lines occur at other plants and warrant change to EPRI guidance, Computational Fluid Dynamics (CFD) modeling will be used to characterize conditions at the branched bypass line connection





CFD Modeling: Preliminary Results



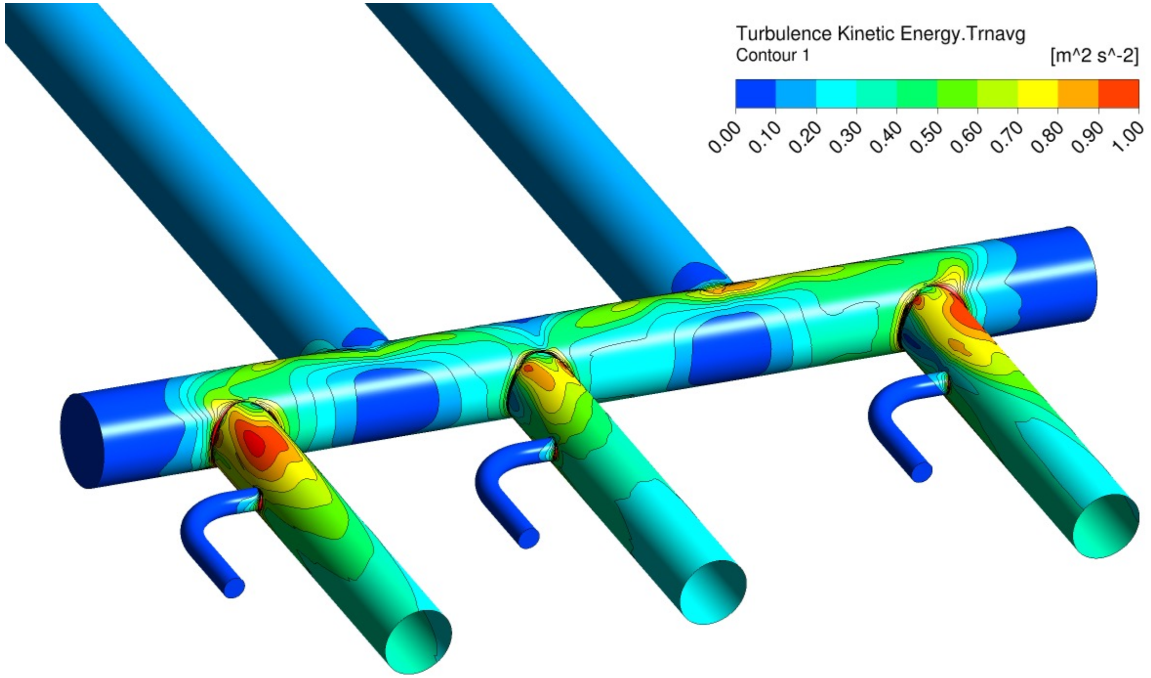


Variable	Value	Unit
Velocity components C_x, C_y, C_z	0	m/s
Pressure	57.23	bar
Turbulence intensity	1	%
Eddy viscosity ratio	10	-

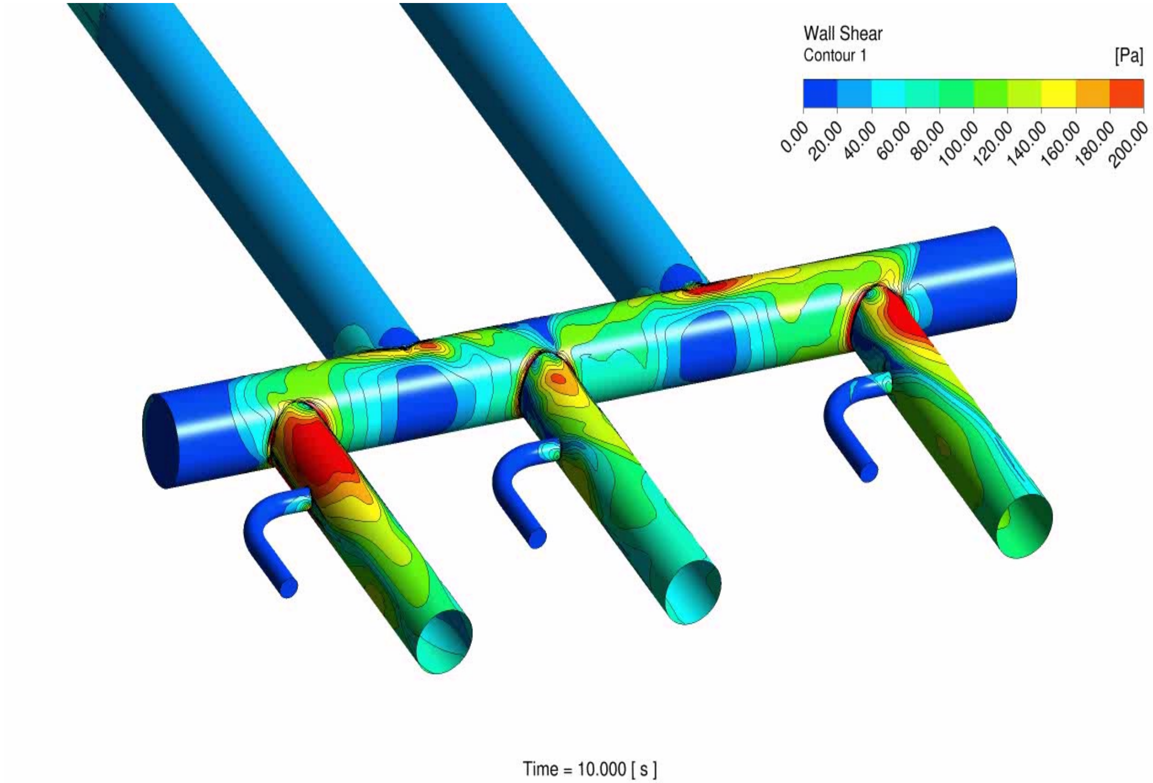
No monotonic convergence at residuals

CFD Modeling: Preliminary Results

Turbulence Kinetic Energy



Wall Shear

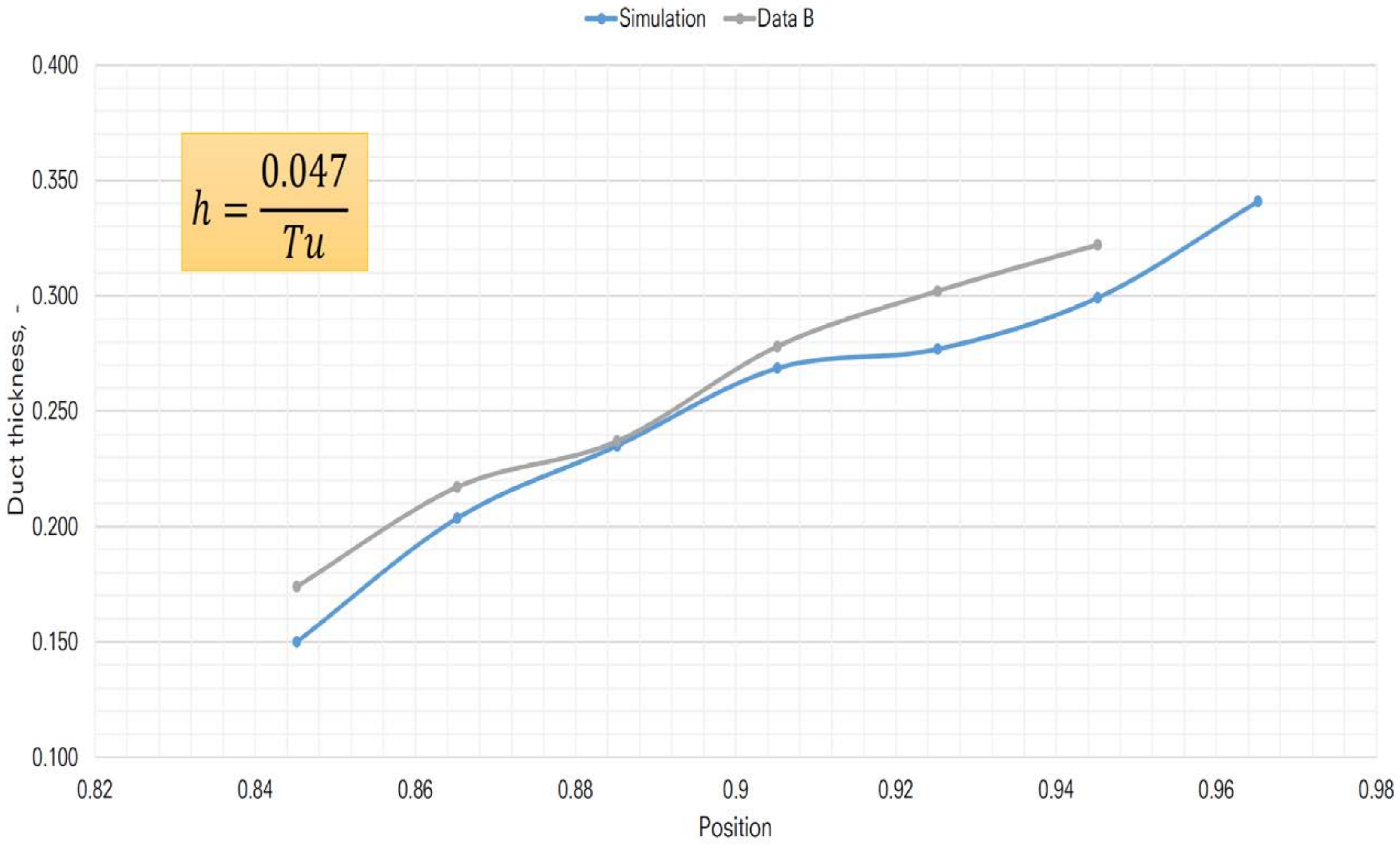


Model results are consistent with locations of thinning

Next Steps: Correlations and Parametric Analysis

Parametric analysis is being done to help prioritize additional locations and define extent of condition for the industry

1. Bypass Line Sizing
2. Location of Bypass Entrance
3. Pipe Connection Geometries
4. Bypass Operation
5. Bypass Valve Leakage



Cable Condition-Monitoring for Aging Management Programs

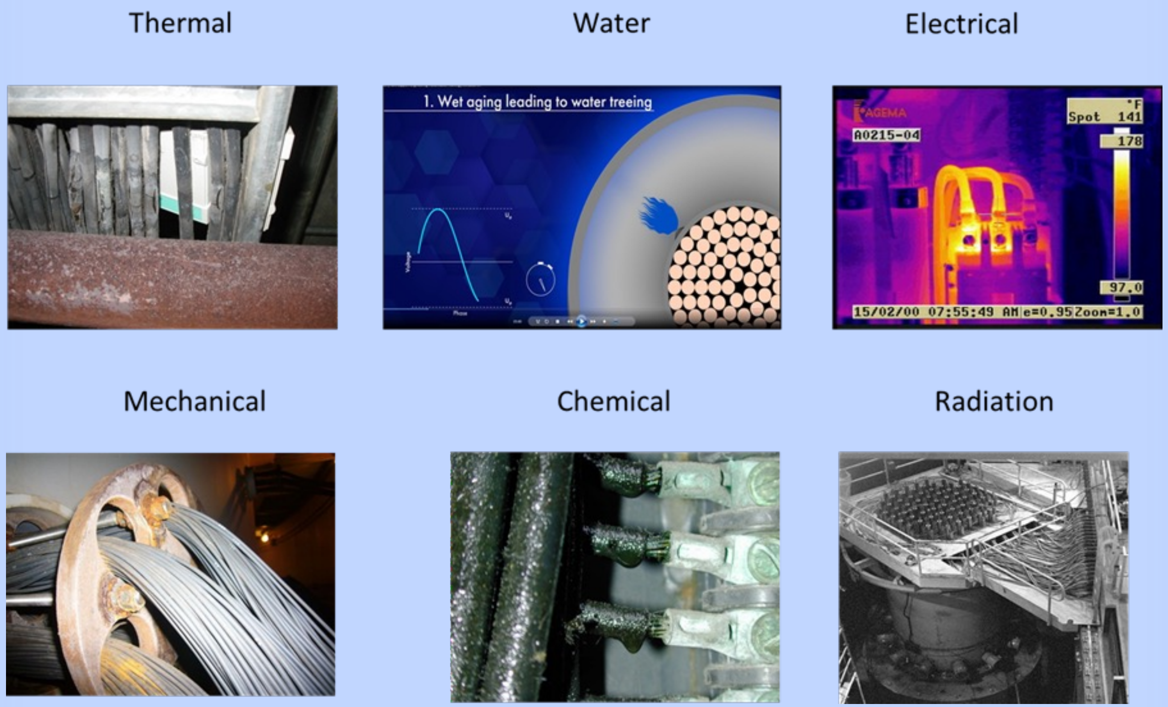
Ilya Golberg, Sr. Technical Leader

Advisory Committee on Reactor Safeguards
October 18, 2023

MV Cable Insulation Condition-Monitoring

Cable Aging Management During LTO

- Cables initially were classified as long-lived, passive components that did not require maintenance/testing (position was endorsed by (NUREG 1526) and the NRC endorsed NUMARC 93-01, Maintenance Rule Implementation Guide
- MV cables degrade primarily due to **dielectric effects** (water treeing, partial discharge) not thermal aging (there are known, but rare instances)
- Majority of cables will last for the plant life except:
  - Cables that are exposed to adverse local equipment environments (ALEEs)
  - Cables damaged during installation or maintenance
  - Cables degraded over time due to poor installation practices, or maintenance induced damage
- Successful cable aging management programs identify and managing cables in ALEEs
- The AMPS for cables in GALL/SLR-GALL are designed to manage aging

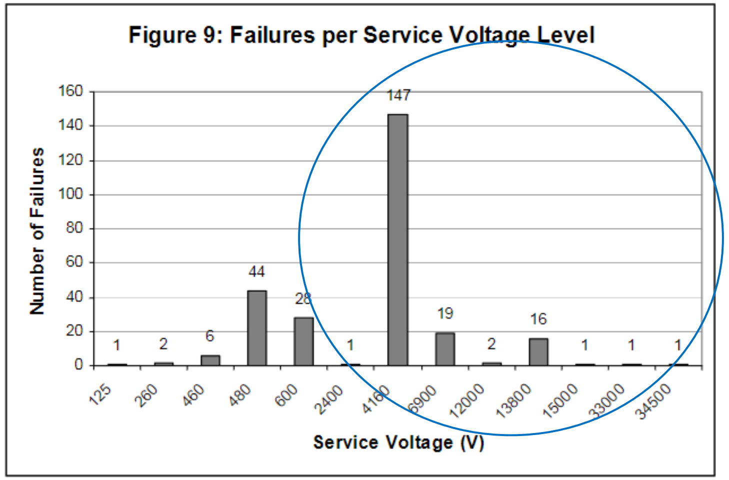


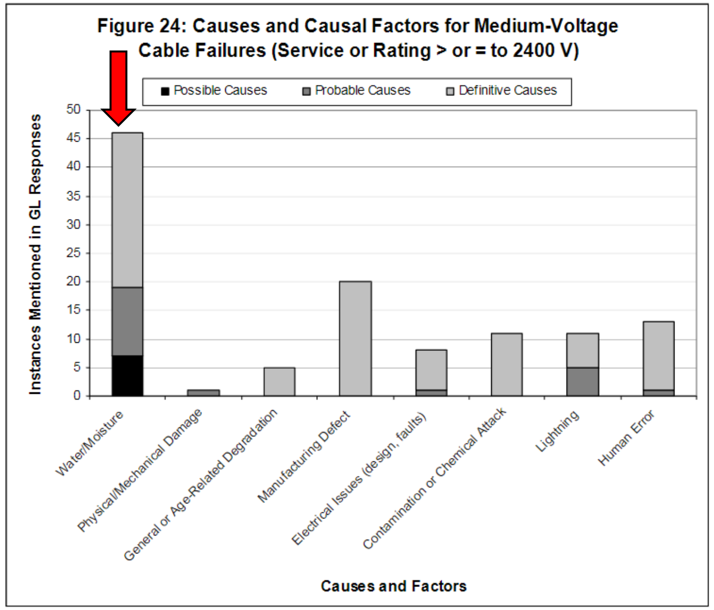
Common Cable ALEEs

Background – Medium Voltage Cables (MV cables)

- MV cable failures began occurring in mid 1970s
- GL-2007-01 summary report provided data on MV cable insulation degradation that the staff reviewed and summarized
  - 188 of the 269 cable failures* in the industry responses were MV cables (rated 5kV to 46kV)
  - Water/moisture was the leading reported cause of degradation (approximately 50%)
  - Failures occurred on all commonly used insulation types (Butyl Rubber, XLPE, EPR)
    - Unknown, Butyl rubber, and black EPR made up the highest incidence of failures

* Includes in-service and test failures





NOTE: Low voltage cable failures by number was the highest contributor to all industry failures, but that is insignificant when you consider they represent the larger population of cables in a typical plant (30,000 – 40,000 LV cable versus a few hundred MV cables)

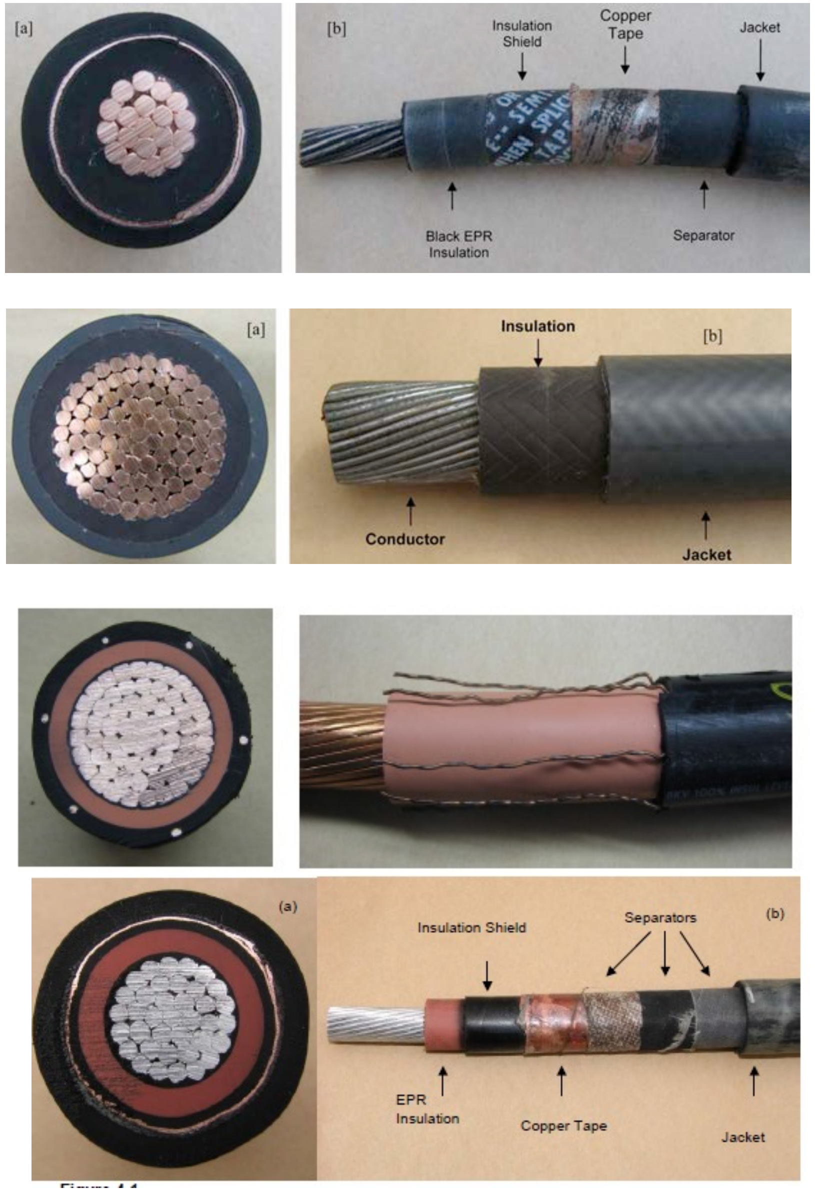
Background – Medium Voltage Cables (MV cables)

- The NRC staff conclusions and recommendations based on GL-2007-01 industry data included the following:
  - Many utilities did not have cable specific testing programs
  - There was an increasing trend in failures and/or plant upsets as plants aged
  - Reasonable provisions should be made to keep cables dry

- Some assumptions evolved out of this GL
  - Cables are not designed or qualified for submergence
  - Concern that a “common-mode failure” of cables could occur

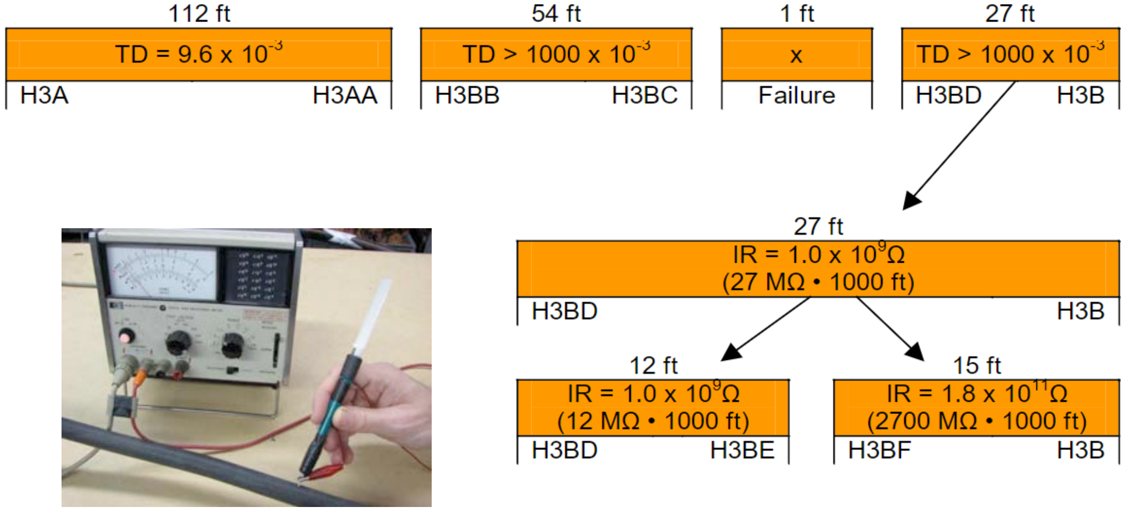
EPRI Research to Address MV Cable Aging

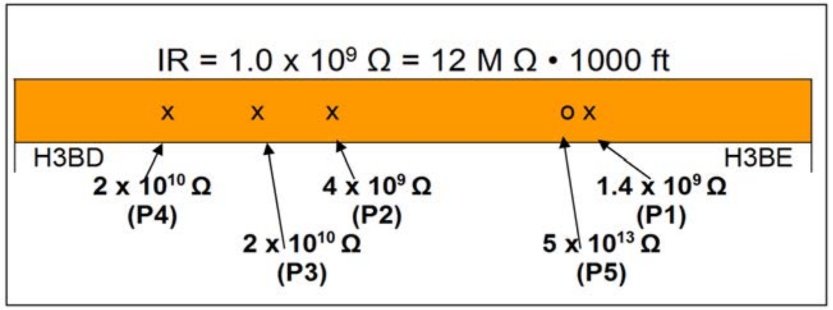
- A need for research of commonly used EPR MV cables was lacking (most research focused on XLPE insulation)
- MV cable failure mechanism research began in 2006, the first report issued in 2007
  - EPRI collected thousands of feet of harvested MV cables that had in-service failures or were replaced based on poor test results to support research
  - Evaluation was performed on all insulation types installed in US NPPs
  - In total 8 reports were issued between 2007 and 2015 (all are available at no cost)



MV Cable Failure Mechanism Research Results (continued)

- A systematic approach to isolate degraded insulation was developed
  - VLF tan delta results capable of identifying degraded insulation
  - Using ever smaller size test probes the degraded areas were isolated
  - AC breakdown testing was used to determine the change in insulation condition compared to other sections of the same cable that were not degraded
  - Wafering and inspection of degraded areas showed locations of the water trees





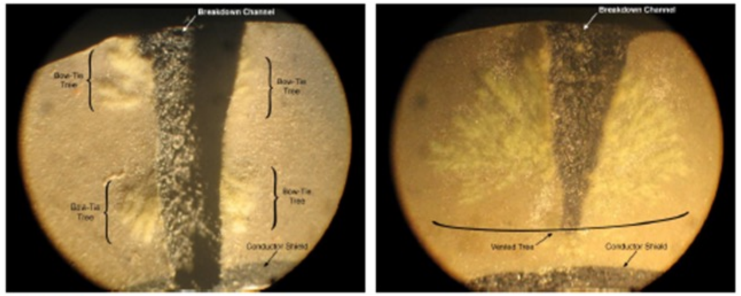
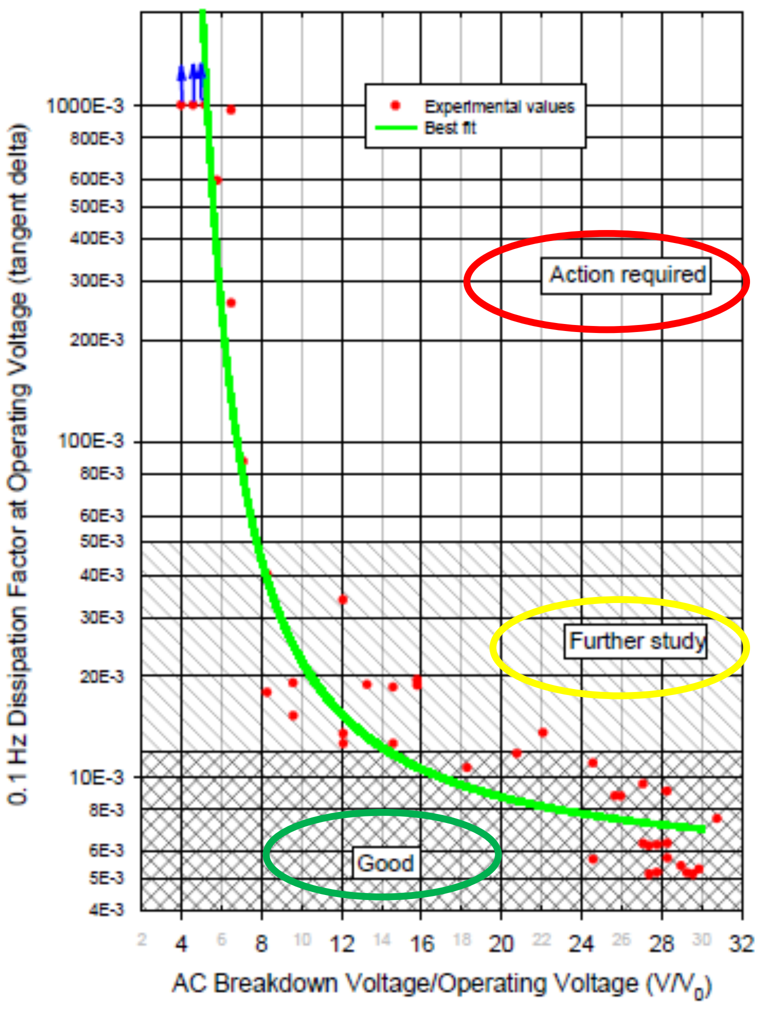


Figure 4-3
Photomicrograph of water-swollen wafer of pink EPR insulation of compact design at the location of laboratory AC voltage breakdown indicating the presence of water tree

MV Cable Failure Mechanism Research Results (continued)

- Key research findings
  - VLF tan delta testing identified degraded insulation, and it also showed the EPRI criteria for good, further study and action required correctly identified the degree of degradation (i.e., higher the mean tan delta, lower the breakdown strength of the insulation)
    - This allows cable repair/replacement decisions to be made before the cable could potentially fail in-service
  - Water trees do not develop homogeneously or even in parallel sections of the other cables for the same equipment being fed (not a common mode failure mechanism)



EPRI Research to Address MV Cable Aging

- Program guidance issued for aging management of MV cables
  - Report 1020805, "Aging Management Program Guidance for Medium-Voltage Cable Systems for Nuclear Power Plants" issued in June 2010. Current guidance: 3002000557 "Aging Management Program Guidance for Medium-Voltage Cable Systems for Nuclear Power Plants, Revision 1" issued in 2013.
  - 1021070 "Medium Voltage Cable Aging Management Guide, Revision 1" issued December 2010
- These reports recommend the following actions for MV cable in wetted conditions (presently or in the past)
  - Perform inspections of inaccessible cables to determine the frequency of pump-outs would be required to keep the cables dry
  - Performing VLF tan delta testing
    - On a six-year frequency for cables that tested "good",
    - Increased frequency (2-3 years) if "further study"
    - Repair/replace as soon as reasonable if in the "action required" range

Table 5-1
Preliminary Tan δ Assessment Criteria for Butyl Rubber (in terms of x 10^{-3}; 0.1 Hz test frequency) (Note 1)

Condition	Tan δ		Absolute Value of the Difference in Tan δ Between 0.5 V_o and 1.5 V_o (Notes 2 and 3)
Good	≤12	and	≤3
Further study required	12< tan δ ≤50	or	3+ to 10
Action required	>50	or	>10+

Notes:
1. This is based on Figure C-13 in EPRI report *Plant Support Engineering: Medium-Voltage Cable Aging Management Guide* (1016689) [15] and in-plant test results and consultation with tan δ testers.
2. Differentials may be taken at 1 V_0 and 2 V_0 at the user's option. See text preceding this table.
3. The difference in tan δ is normally positive. Negative differences should be treated as very significant and may indicate a problem with a test or an indication of the presence of a significant defect.

Table 5-2
Preliminary Tan δ Assessment Criteria for Black EPR (in terms of x 10^{-3}; 0.1 Hz test frequency) (Note 1)

Condition	Tan δ		Absolute Value of the Difference in Tan δ Between 0.5 V_o and 1.5 V_o (Notes 2 and 3)
Good	≤12	and	≤3
Further study required	12< tan δ ≤50	or	3+ to 10
Action required	>50	or	>10+

Notes:
1. This is based on Figure C-1 in EPRI Report 1016689 [15] and associated in plant results and consultation with tan δ testers.
2. Differentials may be taken at 1 V_0 and 2 V_0 at the user's option. See text preceding these tables.
3. The difference in tan δ is normally positive. Negative differences should be treated as very significant and may indicate a problem with a test or an indication of the presence of a significant defect.

VLF Tan Delta Effectiveness Evaluations

- EPRI collected industry test data between 2008-2015
- Two reports evaluating the test effectiveness in identifying good to severely degraded insulation were issued
  - 1025262 “Evaluation and Insights from Nuclear Power Plant Tan Delta Testing and Data Analysis”
  - 3002005321 “Evaluation and Insights from Nuclear Power Plant Tan Delta Testing and Data Analysis – Update”

Table 2-1
Problems identified by insulation type for ethylene-propylene rubber cables evaluated to date

Insulation Type	Circuits Tested*	Number of Circuit Issues	Deteriorated Component Identified		
			Termination	Splice	Insulation
Butyl rubber	12 (6.1%)	0	0	0	0
EPR, black	57 (28.8%)	11 (45.8%)	0	4**	7**
EPR, black, compact	16 (8.1%)	2 (8.3%)	0	1	1
EPR, brown	19 (9.5%)	1 (4.2%)	0	1	0
EPR, pink	54 (27.3%)	6 (25%)	1	2	3
EPR, pink, compact	40 (20.2%)	4 (16.7)	1	1	2
Totals	198***	24 (12.1%)	2 (8.3%)	9 (37.5%)	13 (54.2%)

* Cables tested are not identified by phases in this table. It is possible that more than one phase tested was degraded.
** One circuit had deteriorated insulation and a deteriorated splice.
*** The 198 circuits comprise approximately 700 individual phase cables.

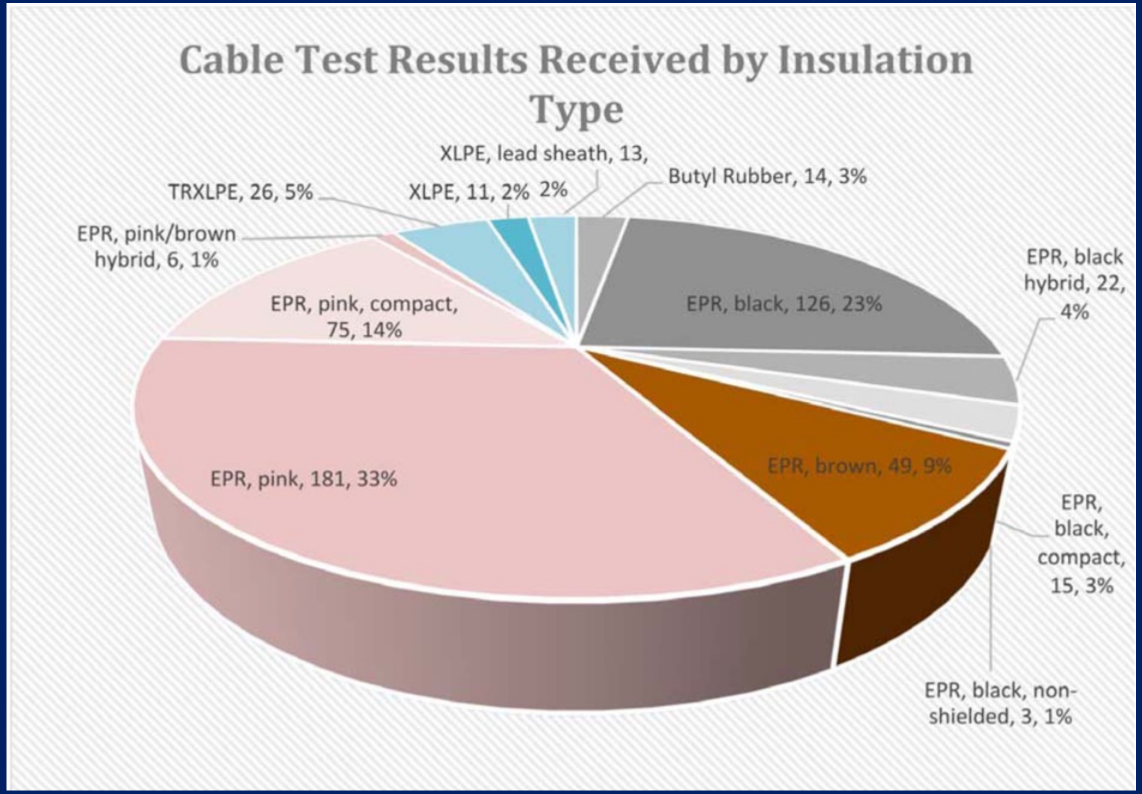
Table 3-2
Tan δ test-identified cable issues summary table by insulation type

Insulation Type	Circuits Tested (Percent of Total Circuits)	Number of Circuit Issues	Deteriorated Component Identified		
			Termination	Splice	Insulation
Butyl rubber	14 (3%)	0	0	0	0
EPR, black	126 (23%)	13 (38%)	2	4*	7**
EPR black, hybrid	22 (4%)	1			
EPR, black, compact	15(3%)	1 (3%)	0	0	1
EPR, black, non-shielded	3(<1%)	0	0	0	0
EPR, brown	50 (9%)	2 (4%)	1	1	0
EPR, pink	181 (34%)	12 (35%)	5	3	4
EPR, pink, compact	74 (14%)	5 (17%)	1	1	3
EPR, pink/brown hybrid	6(1%)	0	0	0	0
TRXLPE	26(5%)	0	0	0	0
XLPE	11(2%)	0	0	0	0
XLPE, lead sheath	13(2%)	0	0	0	0
Totals	541***	34 (6.3%)	9 (26.5%)	9 (26.5%)	15 (47%)

* One circuit had deteriorated insulation and a deteriorated splice.
** Three cables were replaced due to historical issues, not high tan δ results.
*** The 541 circuits comprise approximately 1800 individual cables.

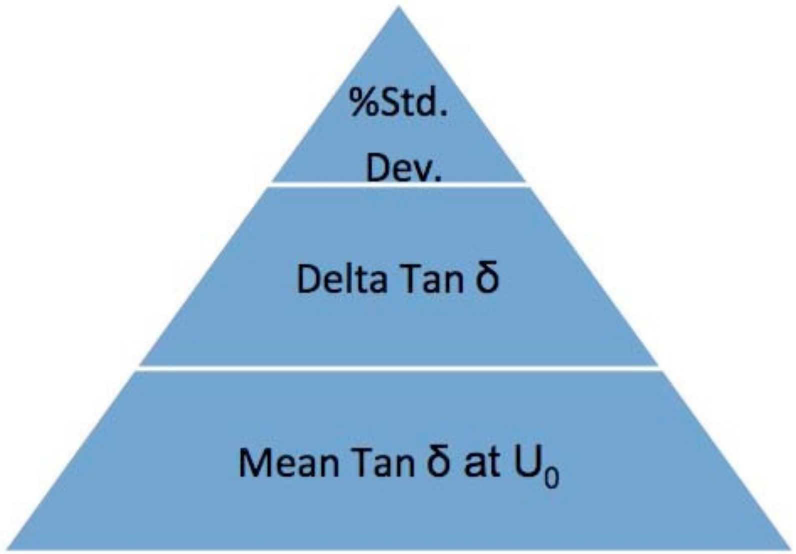
RIL 2021-011 Response

- NRC found methodology of EPRI Tan Delta testing was sound and criteria were sufficiently conservative relative to IEEE 400.2.
- NRC did not endorse EPRI VLF TD methodology due to insufficient data populations of some cable types (Brown EPR and XLPE).
- Failure mode is consistent across insulation types and when data is taken evaluated as a whole, it demonstrates the capability of the test to identify degradation regardless of insulation type.



VLF Tan Delta Effectiveness Evaluations

- Key Findings of Test Data Evaluations
  - VLF Tan Delta can be used for condition assessment of all commonly used insulation types
  - Testing every 6 years was sufficient to prevent cable degradation from “good” to "degraded".
  - When combined with VLF withstand test (hi-pot test) provides reasonable confidence to prevent immediate in-service failures
  - Data indicates a hierarchy of the three acceptance criteria, but all three are useful to determine what part of the insulation system is degraded
  - If a degraded part of the cable system (insulation, splice, or termination) can be isolated as the cause; replacing it can restore the cable to “good”



Phase A Summary: 0.1 Hz, 549.8 nF

Voltage [kVrms]	1.2	2.4	3.6	7.0
TD Value [E-3]	75.67	69.89	72.20	40.89
Std. Dev. [%]	0.64	0.25	0.31	0.59

Phase B Summary: 0.1 Hz, 554.8 nF

Voltage [kVrms]	1.2	1.2
TD Value [E-3]	177.52	192.17
Std. Dev. [%]	0.18	0.16

Phase C Summary

Voltage [kVrms]	-
TD Value [E-3]	-
Std. Dev. [%]	-

Phase A Summary: 0.1 Hz, 548.4 nF

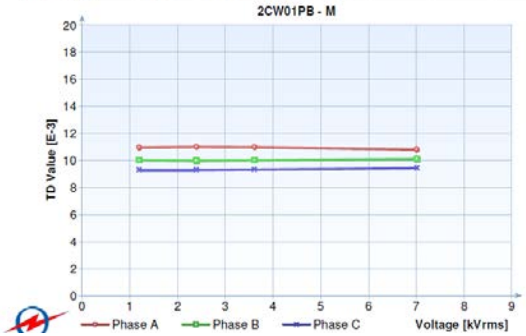
Voltage [kVrms]	1.2	2.4	3.6	7.0
TD Value [E-3]	10.97	11.00	10.99	10.81
Std. Dev. [%]	0.00	0.00	0.00	0.01

Phase B Summary: 0.1 Hz, 554.1 nF

Voltage [kVrms]	1.2	2.4	3.6	7.0
TD Value [E-3]	10.01	9.99	10.02	10.13
Std. Dev. [%]	0.00	0.00	0.00	0.00

Phase C Summary: 0.1 Hz, 553.6 nF

Voltage [kVrms]	1.2	2.4	3.6	7.0
TD Value [E-3]	9.30	9.31	9.33	9.46
Std. Dev. [%]	0.00	0.00	0.00	0.00



Other EPRI MV Cable Research (continued)

- More recent research has focused on VLF testing of
  - 3002013161 "Field Guide for Very Low Frequency Tan Delta Testing of Medium-Voltage Motors and Cables from the Cable Terminations"
  - 3002018284 "Medium-Voltage Transformer and Cable Very Low Frequency (VLF) Tan Delta Testing from the Cable Termination: VLF Testing of Transformers"
    - Both reports show that degradation of the end device and/or cable insulations can be detected
    - Two pilot sites and several others have applied the research with motor or motor lead degradation being identified
- In-progress: Evaluation of cable insulation shield's attenuation effects on high frequency test signals (partial discharge, frequency and time domain reflectometry)
- EPRI continues to evaluate member tan delta test data, but unlike the 2009 – 2015 period where we collected all data, it is now done on member request for input

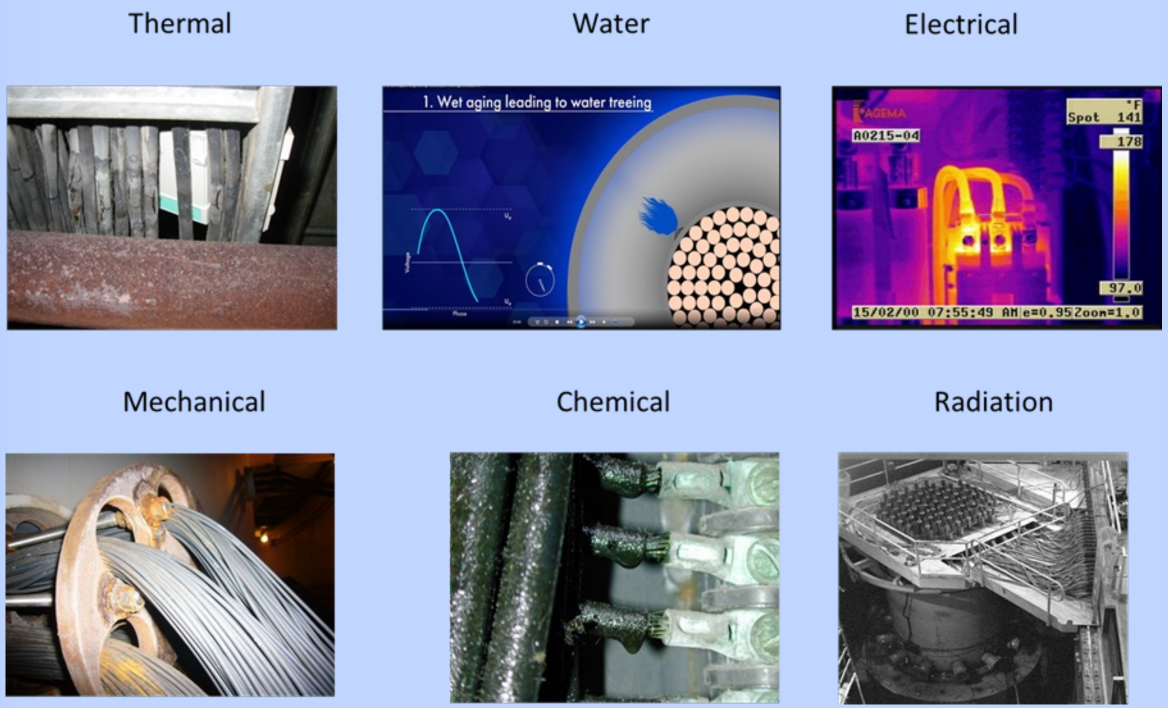
In Review

- The adoption of manhole monitoring and VLF tan delta testing post GL-2007-01 has resulted in improved OE (very few in-service failures since 2015)
- MV Cable insulation degrades from dielectric stressors, not thermal
  - VLF tan delta testing analysis has proven capable of identifying cable degradation for both wet and thermal aging (although much rarer)
  - Water trees form at stress points caused by manufacturing anomalies or latent damage from installation
  - Insulation degradation sites are not due to aging, they are not the result of homogeneous degradation in EPRs. Thus, they should not be considered as a potential common-mode concern
  - Keeping the cables dry or even wet and then dry is better than being submerged continuously and testing will identify issues
  - MV cable insulation will be long-lived because
    - Dielectric stress can be managed by the above strategies and degradation can be corrected to restore cable condition to “good” via partial or full cable replacement when necessary
    - Thermo-oxidative aging is not typically a factor in MV cable as a contributor to insulation degradation

LV Cable Insulation Condition-Monitoring

LV Cable Aging Management During LTO

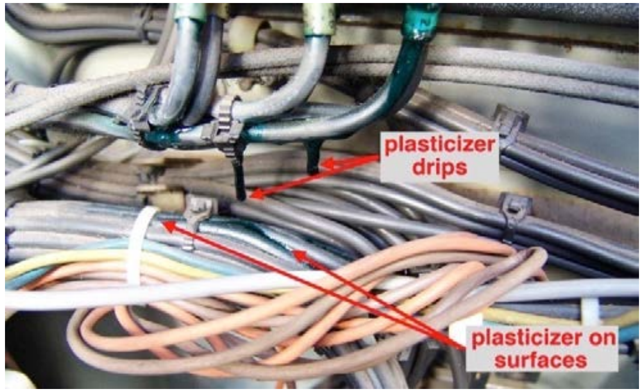
- LV Cables are also long-lived passive components
- All the common ALEEs shown have been seen in plants, but thermal oxidative aging from external heating(not ohmic heating) is most common cause identified for cable degradation
- Identifying ALEEs and monitoring and managing those cables is key to the aging management of these cables



Common Cable ALEEs

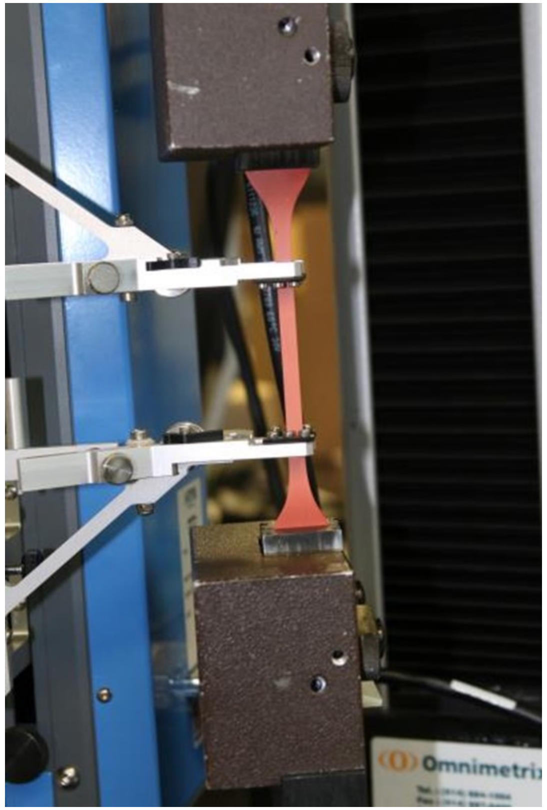
LV Cable Test Methodology – Background

- LV cables in adverse local equipment environments (ALEEs) can typically be visually identified and qualitatively assessed.
- Walkdowns pre-Period of Extended Operation and thereafter at least every 10 years are required for LTO to identify ALEEs
- Thermal degradation from high temperatures in ALEEs is the main cause of LV cable aging
- LV cables do not degrade by water treeing due to their low operating voltages
- Visual indications can be seen on the cable jackets including weeping of plasticizers, spontaneous cracking, or jacket discoloration
- External visual indications on jackets typically precede insulation degradation, however a quantitative assessment of the insulation condition will be warranted at some point



Background (continued)

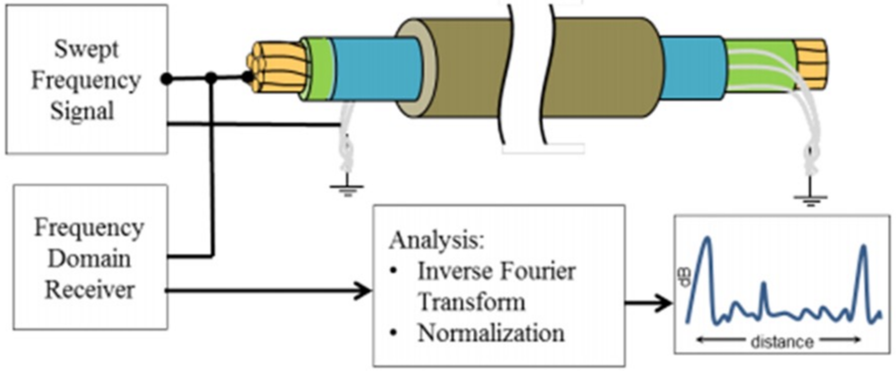
- There are many quantitative test available that fall into various categories
  - Destructive, non-destructive (e.g., elongation at break versus indenter modulus)
  - Laboratory versus In-situ (e.g., Oxidation Induction Time versus insulation resistance)
  - Mechanical, Physio-Chemical, Electrical
  - Global versus localized
- All mechanical and physio-chemical tests but indenter modulus require harvested materials to perform the test technique



Condition Monitoring Gap

- Insulation resistance for dry cables is not always reliable indication of insulation condition
  - Dry cables, even when severely degraded often have high Megger values as air is a good insulator

- Time and Frequency Domain Reflectometry results indicate anomalies in insulation, not all are degradation



Research Gap: How can low voltage condition be more reliably identified?

EPRI

Electrical Testing: Global vs. Local

- Global Evaluation - determination of the insulation condition along entire length of a cable
- Local Evaluation - determination of the condition of a material at a specific location on the cable

Local

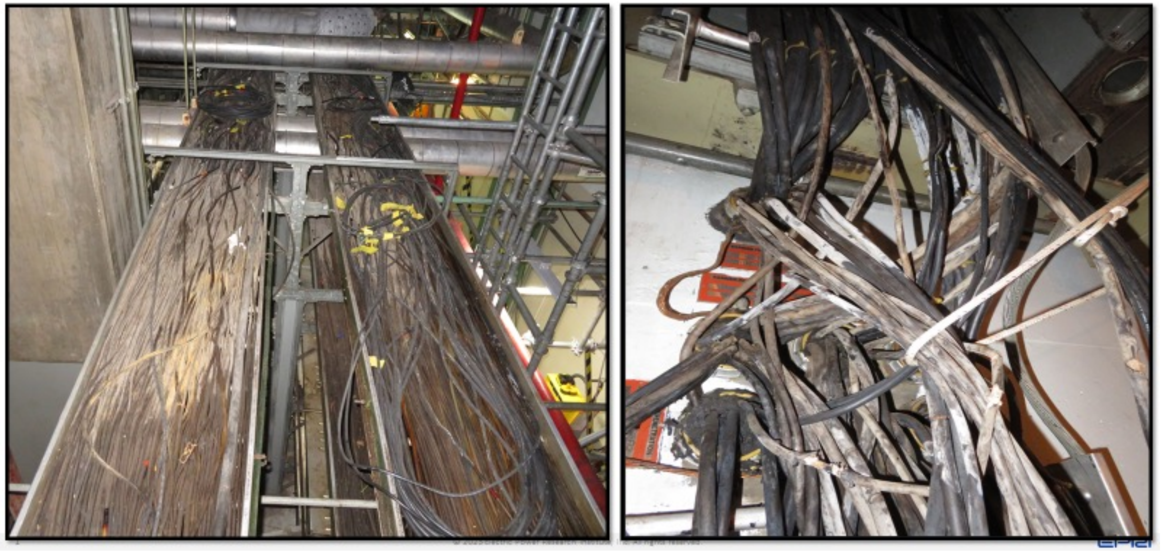
Test detects defects at discreet point(s) along the cable like Time Domain Reflectometry (TDR) or Frequency Domain Reflectometry (FDR)

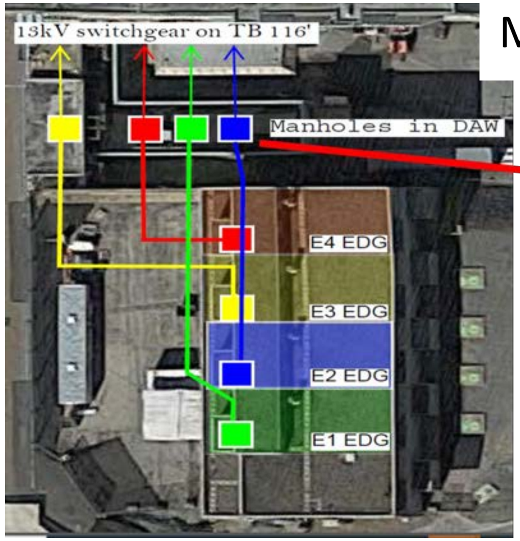
Global

Test provide a global assessment of the insulation condition like Insulation Resistance, Dissipation factor/Tan Delta, Dielectric Spectroscopy and Polarization/Depolarization Current

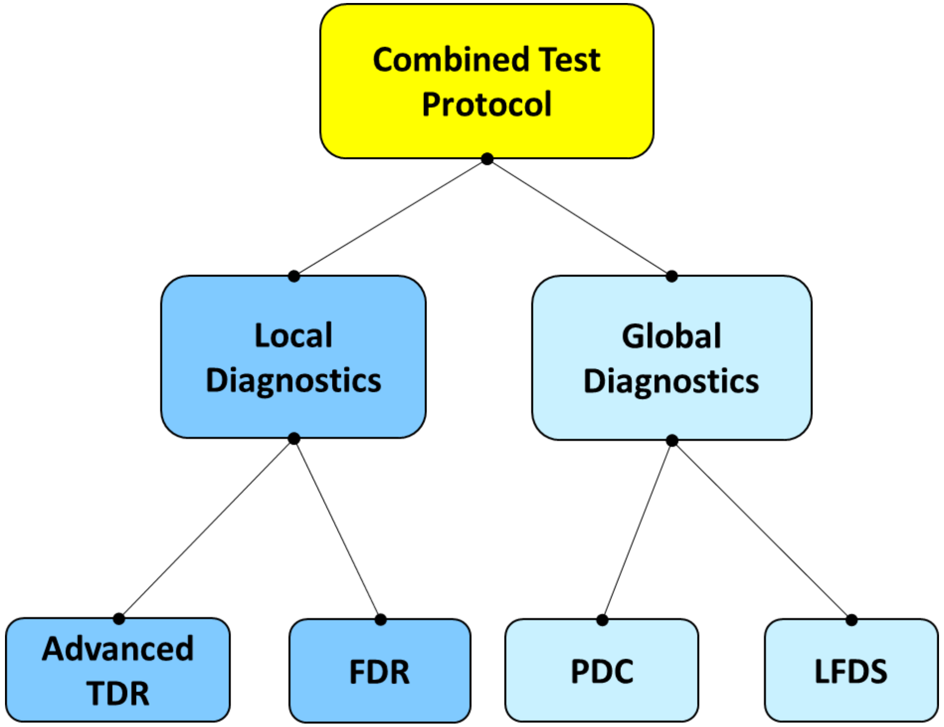
3002020818 "Test Protocol for Condition Monitoring of Low Voltage Cable Using Dielectrically Based Methods"

Thermal Stress Area – Moisture Separator Area (BWR)





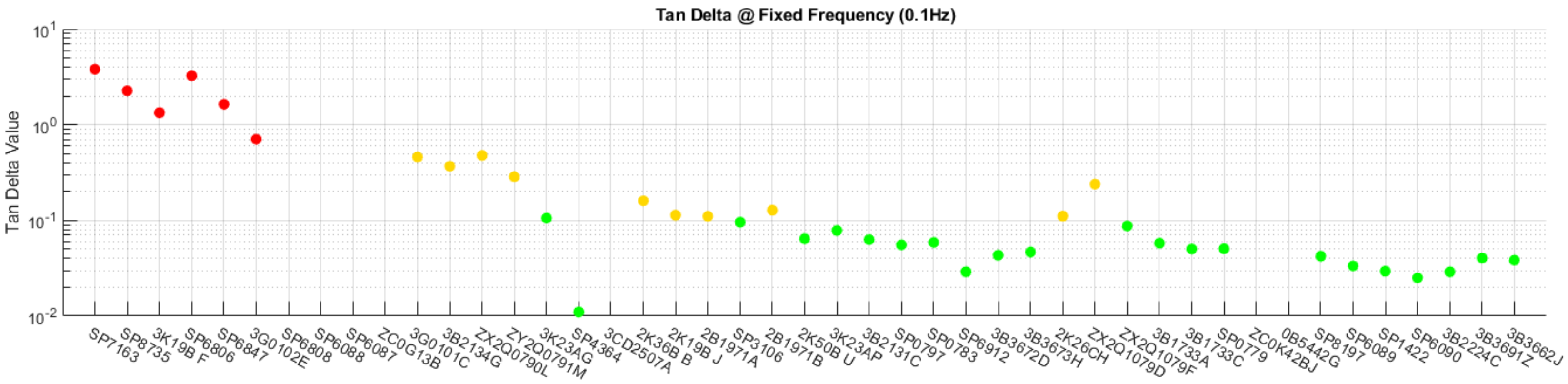
Manhole with Spliced Cables

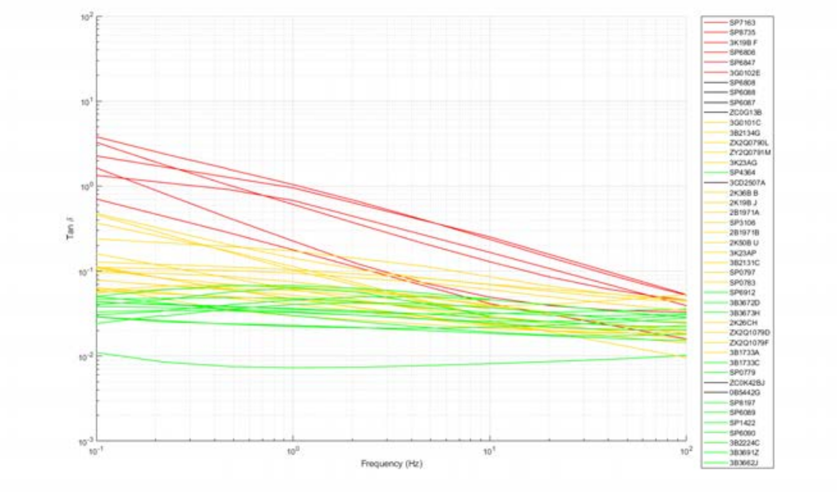


Diagnostic Function / Objective of Testing Strategy	
Identification	Is there a problem?
Discrimination	Is it an internal and real problem? What is the nature of the problem?
Localization	Where is the problem?
Assessment	How bad is the problem?

Example LFDS Results

Population - Tan δ at Fixed Frequency





No Anomalies Observed

(i.e., 'Good')

Moderate Anomalies Observed

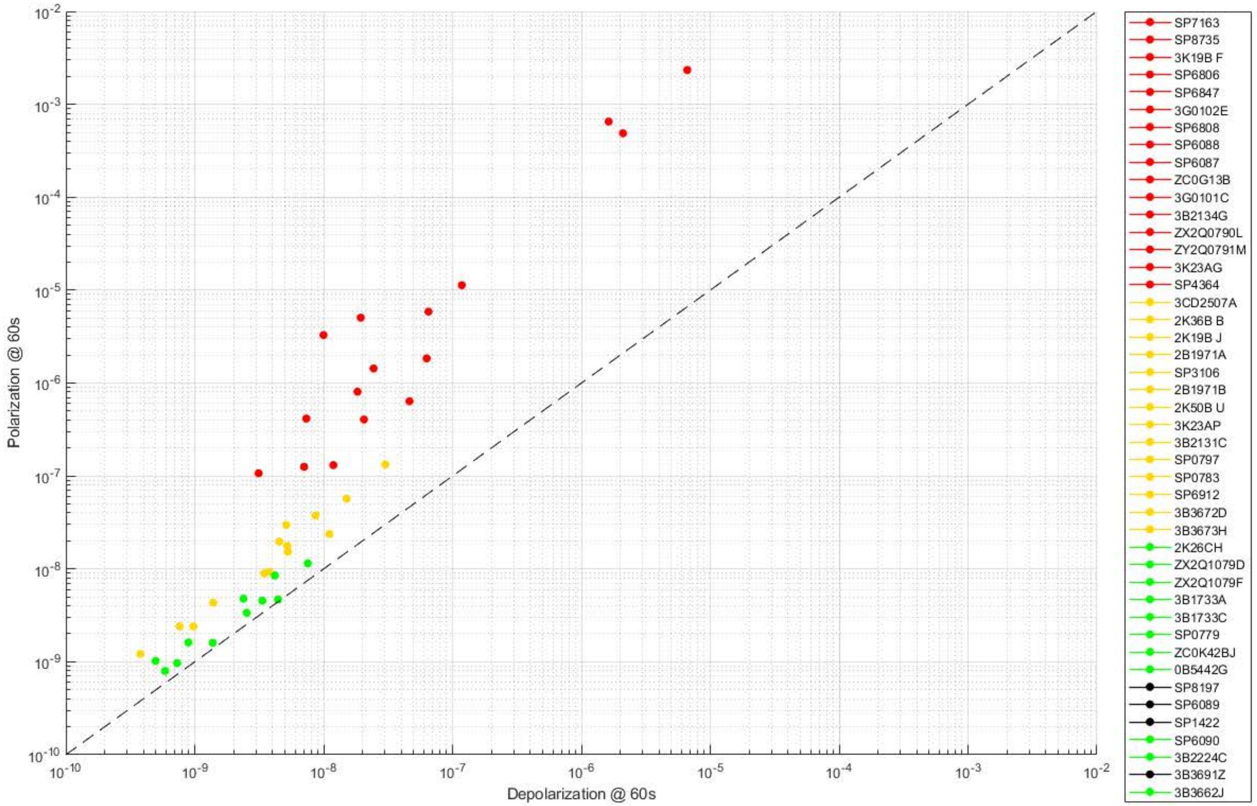
(i.e., 'Further Investigation')

High Anomalies Observed

(i.e., 'Action Required')

Example PDC Results

PDC – I_{POL} vs. I_{DEPOL}



No Anomalies Observed

(i.e., 'Good')

Moderate Anomalies Observed

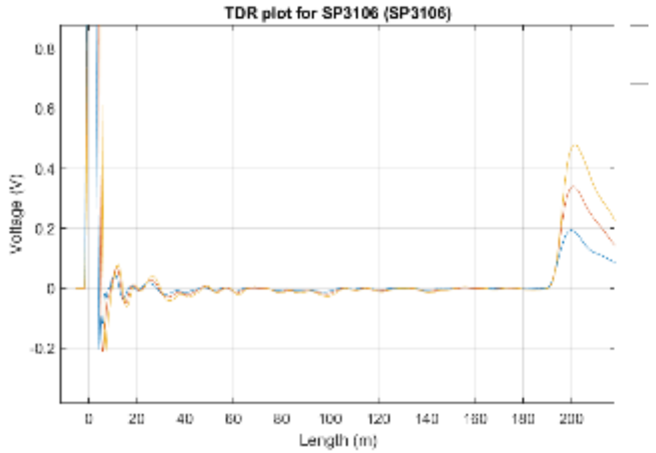
(i.e., 'Further Investigation')

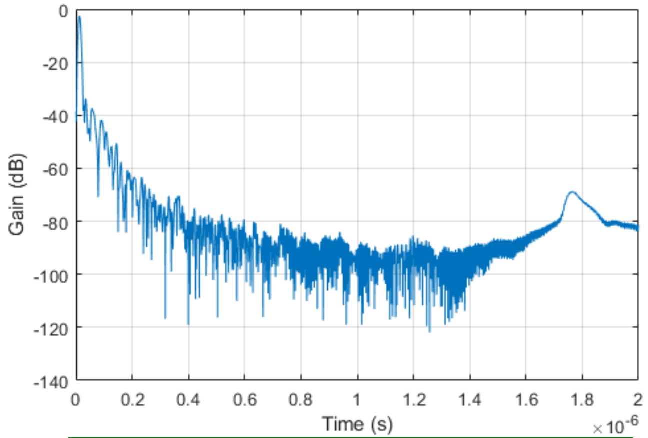
High Anomalies Observed

(i.e., 'Action Required')

Test Results – FDR and TDR

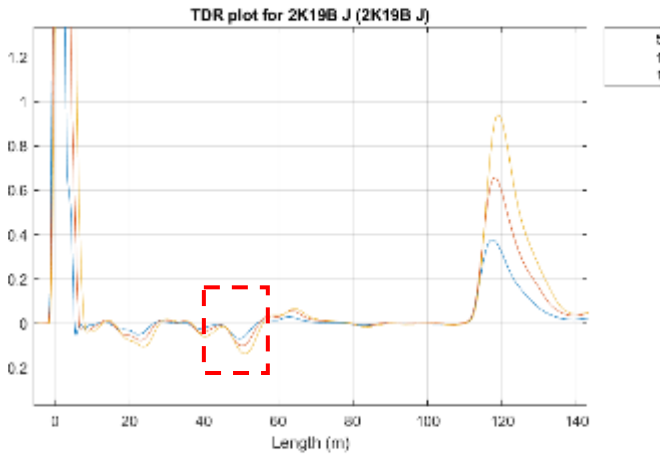
- Cross-correlation with TDR results used for increasing accuracy

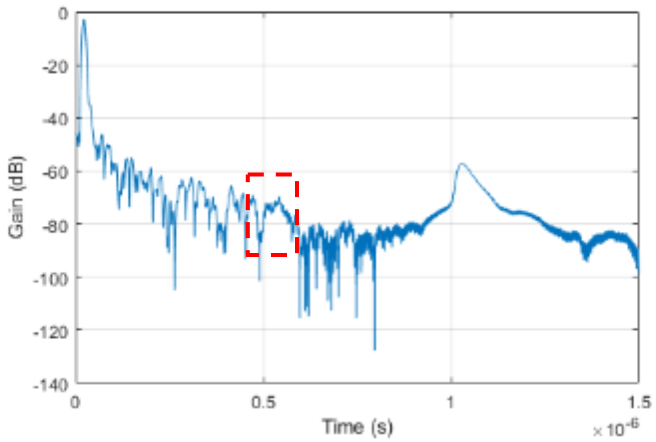




No Anomalies Observed

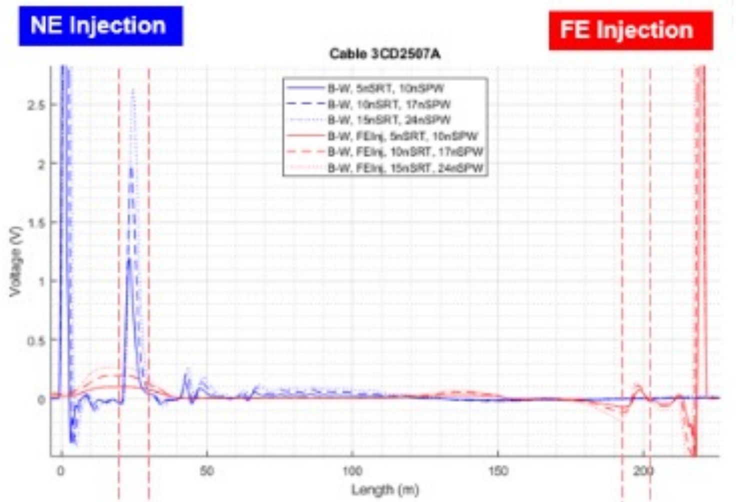
(i.e., 'Good')

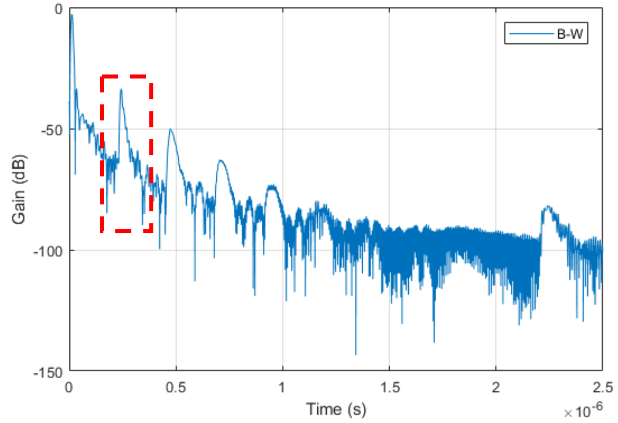




Anomalies Observed

(i.e., 'Investigation Required)





Significant Anomalies Observed (Indication of Fault) – 'Action Required'

Review – LV Cables

- Thermal degradation in ALEEs is the leading cause of insulation degradation
- Current condition monitoring improvements are needed because once degradation requires quantitative methods the current options are either
  - Difficult to implement mechanical, Physio-Chemical test methods
  - Electrical tests can provide false indication of insulation degree of degradation
- EPRI has provided a new test methodology that has proven capable of identifying thermally degraded or wet insulation degradation
  - Verified via pilot at a member site and ongoing testing there
  - And promoting it via demonstration at members sites on request

Nuclear Power Plant Resilience Research

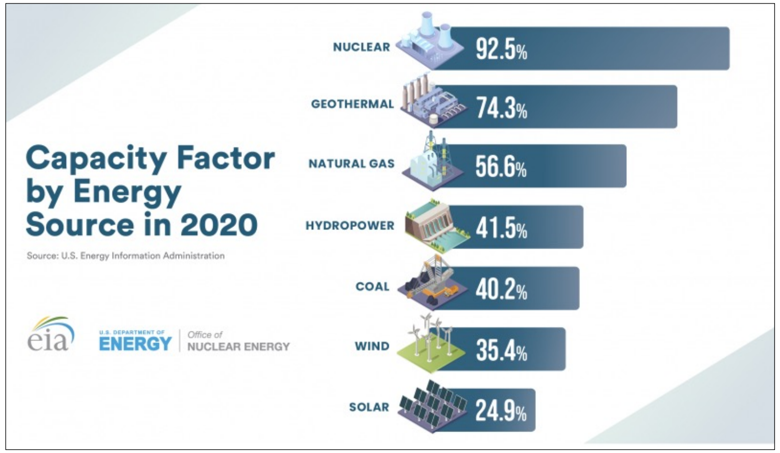
Rob Choromokos, Principal Group Leader

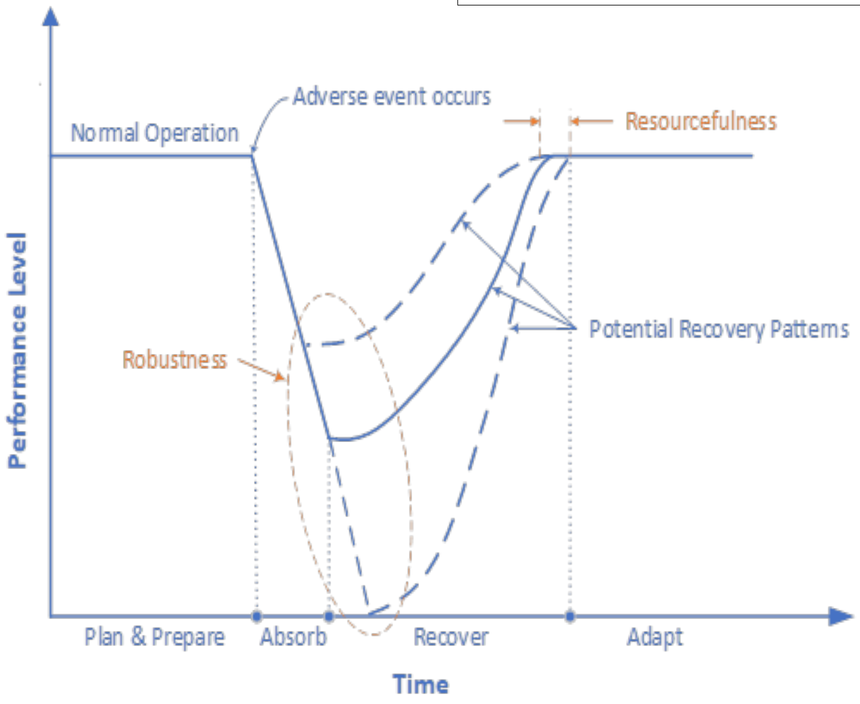
Advisory Committee on Reactor Safeguards
October 18, 2023

Resilience

Nuclear Resilience to Weather Events

- Nuclear plants have robust design margin and a historically high capacity factor even when challenged with weather-related events
- Weather-related hazards are likely to worsen for nuclear power plant operators over the next two decades as a result of climate change, with severity varying by region
- Nuclear plants must remain resilient in the face of extreme weather events to contribute to grid stability and remain a part of a low-carbon energy future





Global climate change and extreme weather events

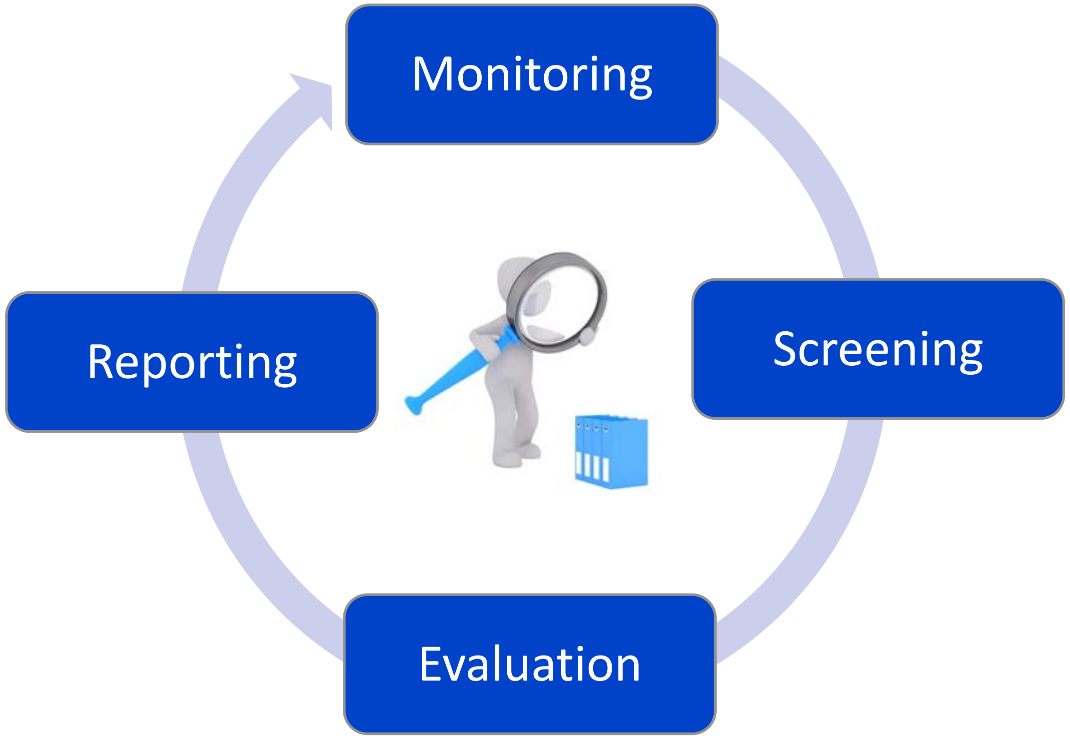
External Hazards Information Compilation and Analysis

- Benefits nuclear power plants who commit to the implementation of Recommendation 2 of INPO Event Report (IER) L1-13-10 or similar external hazard monitoring program
- Broadened participation worldwide in 2021
- Current scope of changes to hazard required by the US are seismic, flooding, high winds, extreme heat, and extreme cold/snow/ice
- International hazards maybe be different and need to go through the screening process
- Project been in place since 2016

“An efficient, shared resource for understanding changes in external hazards”

External Hazards Information Compilation and Analysis

- Reviewed over 1100 pieces of new hazard information over the last 6 years
  - New precipitation studies
  - East Coast Tsunami potential
  - NIST Tornado Map Changes
  - Climate Change Studies/Observations
  - Seismic Hazard (NGA East Earthquake)
  - Operating Experience (Derecho, Frazil Ice, Hurricanes)
- New information identified in 2022/2023
  - Seismic hazard information
  - Wind hazard information



Nuclear plants maintain a robust design margin for safety

Summary of Recent Years' Project Work

Project Year:	2018	2019	2020	2021	2022
New information items reported	0	0	0	0	0
Evaluations completed	1	0	2	0	1
Potential new information items requiring consideration of additional technical information	11	9	15	12	16
Individual items screened requiring no action	109	109	98	87	107
EPRI Report Number	3002016048	3002018235	3002020757	3002023811	3002026415

2022 External Hazards New Information Report

Technical Report [3002026415]

"External Hazards Information: Compilation and Analysis: 2022 New Information Report"

Objective of this Report

This report is a product of EPRI's External Hazards: Information Compilation and Analysis Supplemental Project and presents credible new information, identified during the 2022 calendar year,

Annual Summary Report for Responding to INPO Recommendation

New Research Area – Climate Risk

- How climate change may present a physical risk to utility assets and operations and what response strategies are available to minimize future consequences?
- What existing and new research can help can answer this question?
- OE in Weather impacts on nuclear plants operations
- Considerations of future climate impacts

Identifying Potential physical impacts of a changing climate

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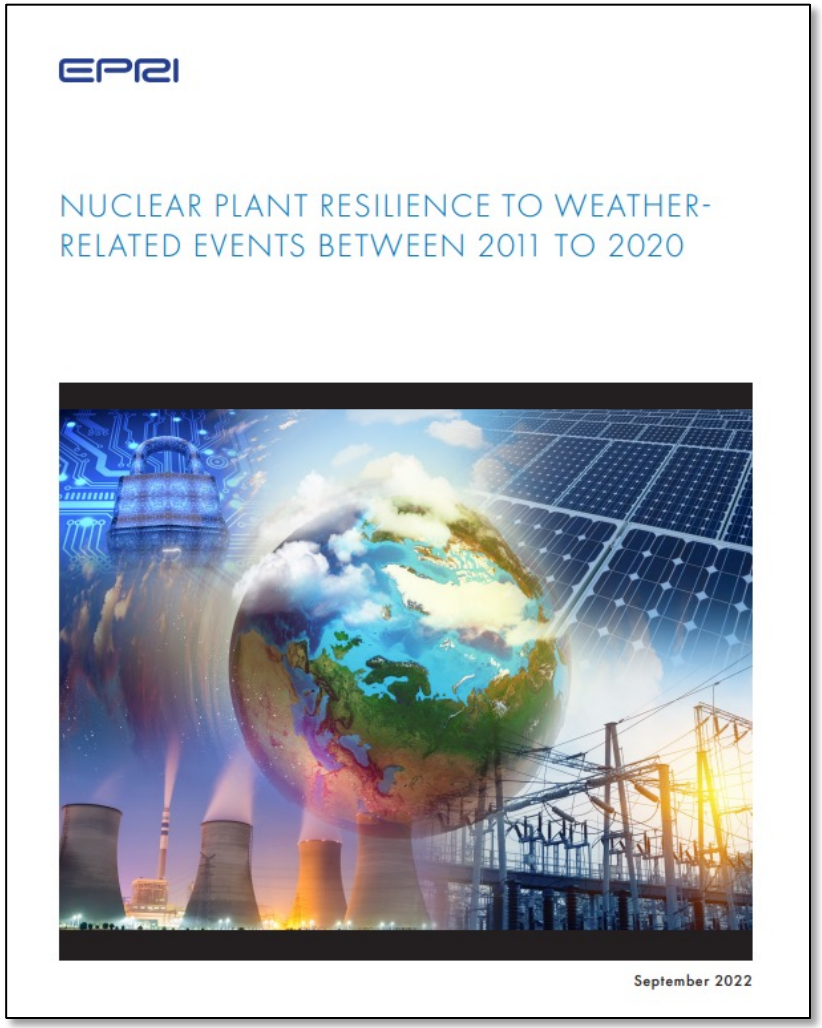
Recent Operational Experience

- Highlight distinction between nuclear safety and operational impacts
- Historical review of available US nuclear operating experience to weather-related events over past 10 years
- Impact of weather-related events on capacity factor at US NPP plants
- Discuss future research regarding forward looking climate vulnerability assessments



SCAN ME

"Nuclear Plant Resilience to Weather-related Events between 2011 to 2020"
3002025519 – EPRI White Paper

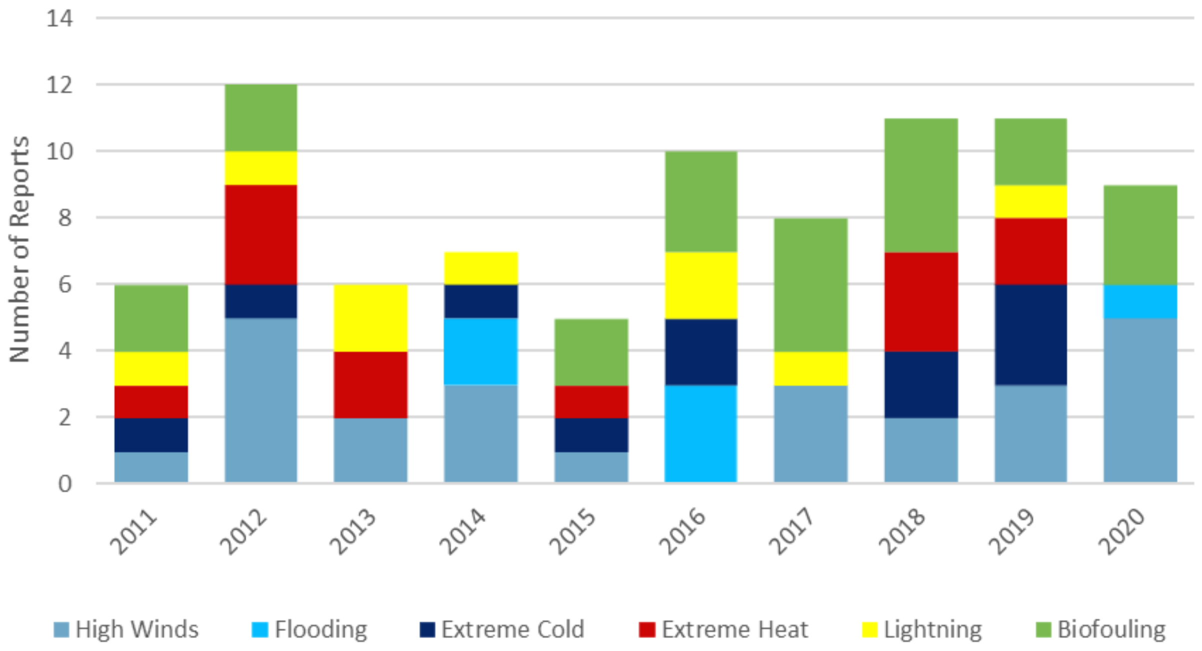
Weather Related Operating Experience (2010 – 2020)

Events including Grid Impacts

Weather Events	Average Recovery (days)	Range of Recovery (days)	Number of Events over 10 years	Total Number of Production Days Lost (days)
High Winds / Storms	4	0 to 32	48	207
Extreme Cold	3	0 to 10	17	55
Flooding	7	0 to 16	6	44
Biofouling	2	0 to 6	22	34
Lightning	1	0 to 6	15	22
Extreme Heat	2	0 to 13	12	22
		Total	120	384

Events excluding Grid Impacts

Weather Events	Average Recovery (days)	Range of Recovery (days)	Number of Events over 10 years	Total Number of Production Days Lost (days)
High Winds / Storms	2	0 to 18	25	52
Extreme Cold	3	0 to 10	11	19
Flooding	7	1 to 16	6	44
Biofouling	2	0 to 6	22	34
Lightning	2	0 to 6	9	19
Extreme Heat	2	0 to 13	12	22
		Total	85	190



Lost generation due to weather-related events in the US nuclear fleet is less than 0.1%.

Nuclear plants are currently very resilient and need to maintain this performance

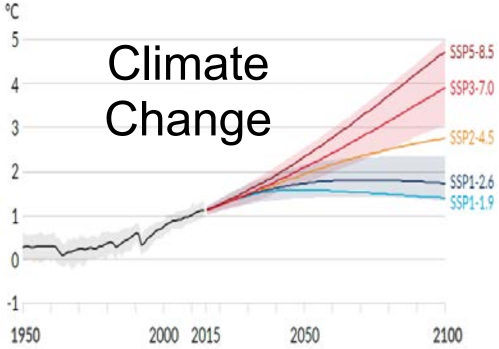
Key takeaways

- NPPs are specifically designed to safely withstand events far more severe that most critical infrastructure.
- Based on OE and high capacity factors, NPPs have demonstrated resilience to extreme events. Most major loss of production events come from grid-wide challenges.
- NPPs maintain a significant amount of OE and knowledge to build upon in addressing weather-related vulnerabilities.
- Climate impacts can affect operational resilience. Forward looking assessments could allow plants to have a more strategic response to chronic changes and extreme weather events.

Plants currently maintaining high degree of availability

Climate Risk Assessment

What does climate change mean for a nuclear station?



Hazard?
Are physical conditions changing?

Past and potential global climate change

Past and potential local climate change

Exposure?
What's in harm's way?

Structures, systems, components, operations, supply, infrastructure

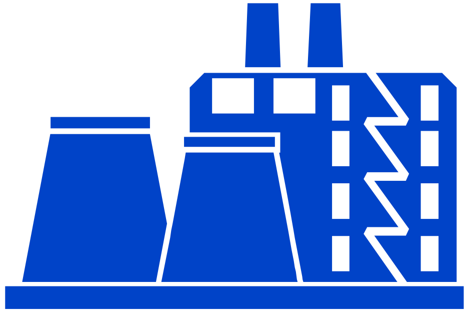
Vulnerability & Response?
Does it matter? How might we respond?

Current and potential climate impacts and responses

Risk & Risk Management?
Is the risk large? What are robust and resilient strategies?

Current and potential risks and risk management

Nuclear Generating Asset



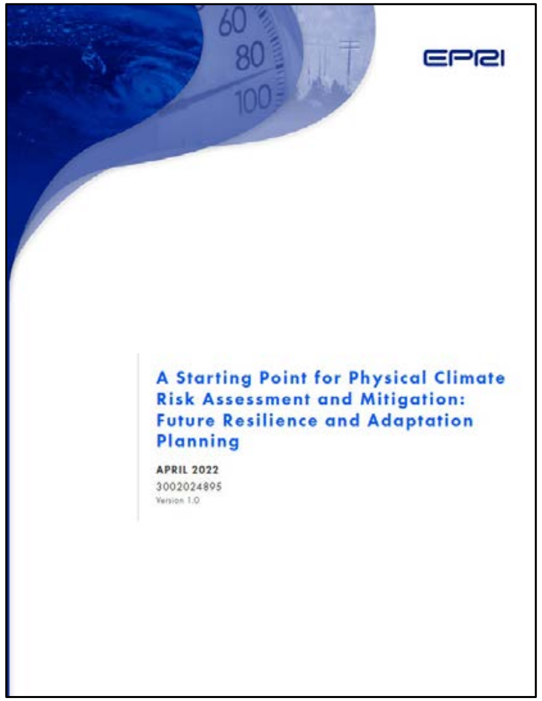
Starting Point for Physical Climate Risk Assessment

Table 3. Nuclear Generation Summary: Plant Performance

Nuclear Power Plant Component		Primary Climate-Related Variables	Potential Climate-Related Impacts on Nuclear Power Plant Performance and Operation[1]
Plant Operational Impacts (Efficiency and availability)[2]	Cooling system	Air temperature Humidity Water temperature Precipitation	• Plant performance is a function of cold cooling water temperature. Higher water temperatures can reduce electric (turbine) cooling efficiency and reactor cooling efficiency (decay heat removal). • Increased water temperatures can increase bio-growth and lead to de-rating. • Discharge limits can be impacted by higher water temperatures. • Drought can reduce cooling water levels below inlet (performance penalty) and reduce cooling water flow rates (fouling and corrosion).[3]
	Steam turbines and condensers	Air temperature Humidity	• Increased air temperature can reduce generation capacity and increase heat rate.
	Cooling towers	Air temperature Humidity Wind speed Wind direction	• Higher air temperatures can result in higher cooling water temperature, reducing tower efficiency. • Cooling towers experience performance penalties with increased in wind speeds. High winds can cause physical damage to cooling towers.
Direct physical infrastructure impacts		Air temperature Precipitation Wind	• Extreme weather conditions and storms like hurricanes, derechos, extreme heat, and extreme cold events pose physical and operational threats to plant infrastructure and grid components. • Loss of grid power during storms may trigger plant shutdown. • Debris from severe storms can clog cooling water intake structures.
		Sea level rise (SLR)	• Rising sea levels can worsen nuisance flooding and storm surge with potential to impact infrastructure or operations at plants through flood risk and/or coastal erosion.[3, 4]

Notes for Table 3:

1. Many of the operational impacts identified for nuclear plants are similar to other thermoelectric plants. See Table 1 for additional references.
2. For analysis of potential operational impacts at nuclear power plants, see: Linnerud, K., Mideksa, T.K., and Eskeland, G.S. (2011). The impact of climate change on nuclear power supply. The Energy Journal. DOI: 10.5547/ISSN0195-6574-EJ-Vol32-No1-6
3. Brockway and Dunn, 2020.
4. For more detail on sea level rise projections, see the Fourth National Climate Assessment, Chapter 2 (https://nca2018.globalchange.gov/chapter/2/) or Sweet et al (2017).



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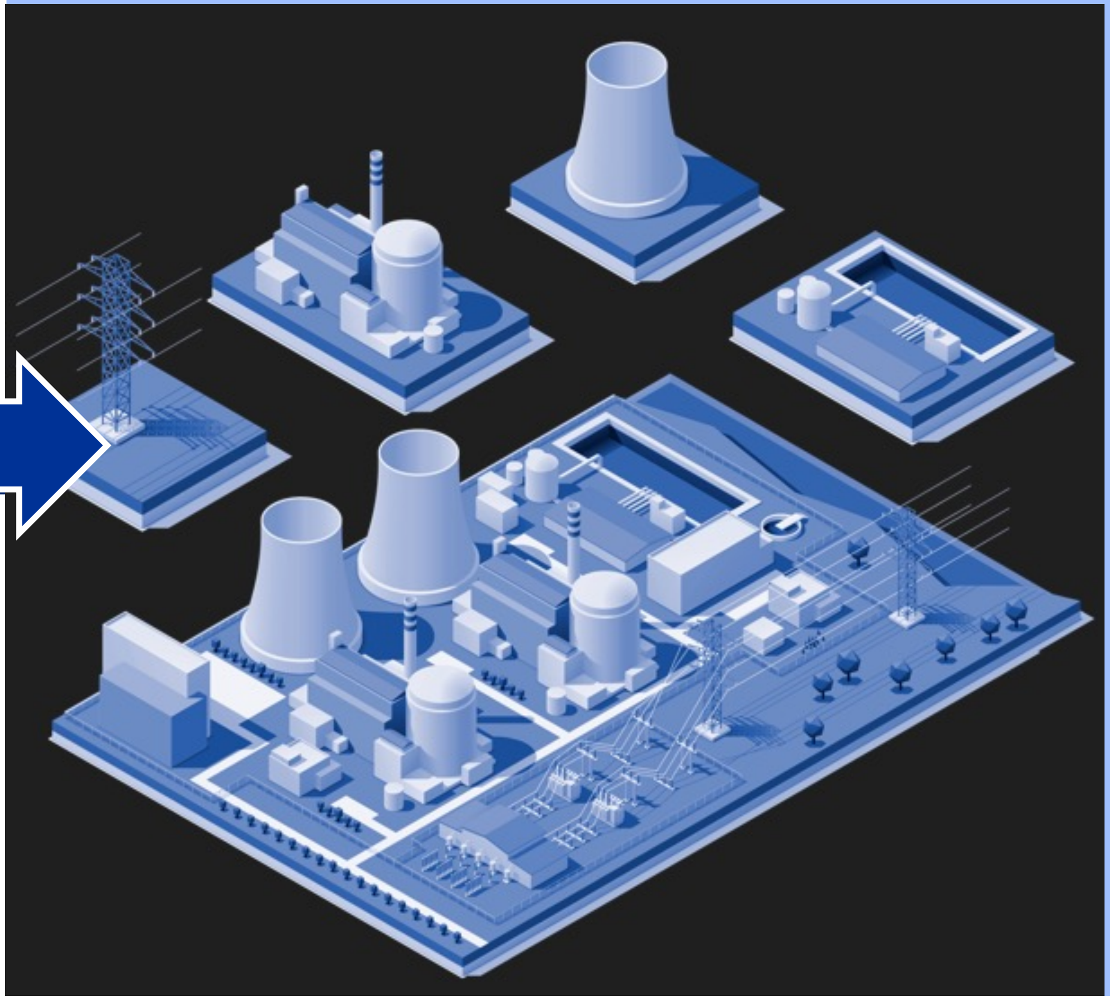
Future Weather Projections

- Temperature
- Precipitation
- Ice
- Extremes

Impact on Asset - Exposure & Vulnerability



- Margin Reductions
- Impact on Capacity Factor
- Life Expectancy
- Environmental Impacts & Compliance
- Maintenance
- Health & Safety

Planning & Investment Prioritization

- Asset Management Program
- Informed Design Approach

Adaptation Strategies

Physical climate risk assessment

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Climate Vulnerability Assessment Guidance

1. ***Climate Hazards*** – how to establish future climate change-related trends and extremes at the local nuclear plant
2. ***Exposure*** **–** how to identify and screen critical assets, systems or components likely to be impacted by weather-related variables
3. ***Vulnerability*** **–** how to establish design and operating margins, potential impacts and potential risks

"Climate Vulnerability Assessment Guidance for Nuclear Power Plants"
***3002023814** – EPRI Technical Report*

Climate Vulnerability Assessments

- Several NPPs have undergone or are planning vulnerability assessments
- More work to do on consistency of assessments
  - EPRI and INPO guidance should help
  - More guidance on selection of climate variables, modeling, uncertainty, etc.
  - How to present findings
- How to ensure we are producing measurable results and increasing resiliency with existing plant programs

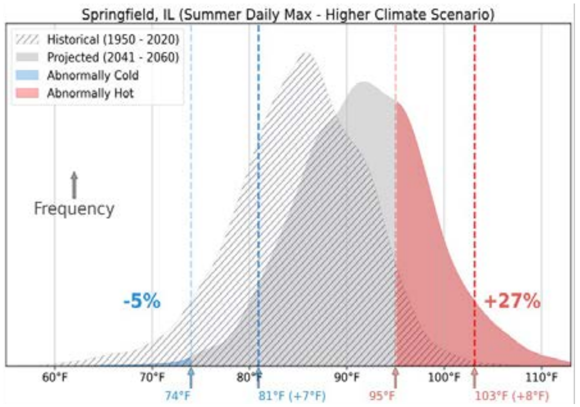
Site-specific Climate Hazard Projections

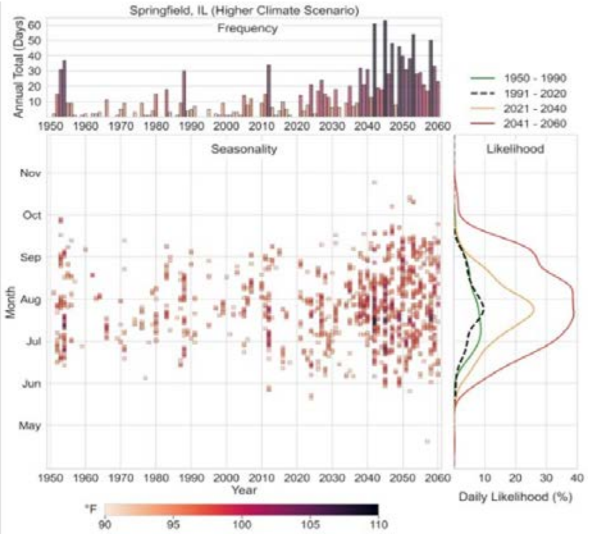
Challenges:

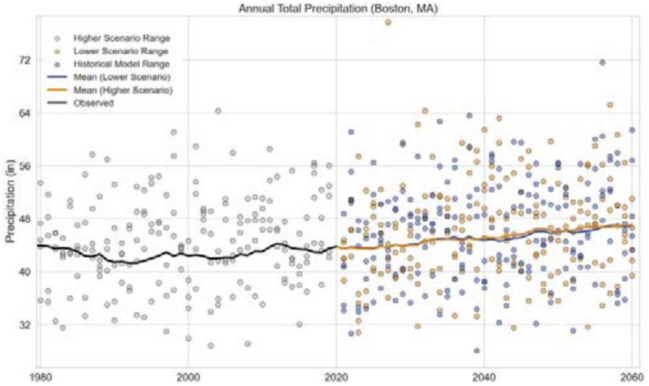
- ✓ *Changing Weather and Extreme Events*
- ✓ *Climate Vulnerability Assessments*
- ✓ *What climate data to use and how much margin?*
- ✓ *What are my specific climate related challenges?*

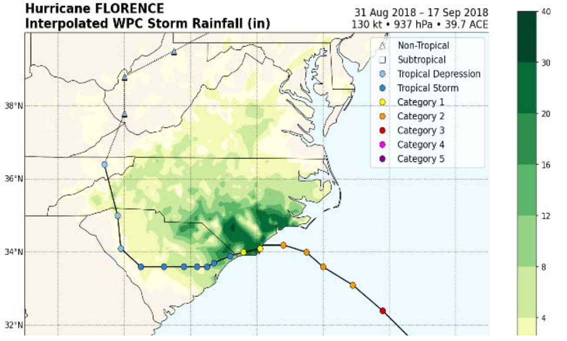
Improved Climate Hazard Information:

- *Site-specific estimates* of key climate-related variables based on latest generation climate model projections
- *Interpretation and analysis* of climate information to support technical insights and clarify potential uncertainties or limitations associated with current climate modeling state-of-practice
- *Workshops* to enhance understanding of climate hazards, data, timeframes, resources, and applications
- *Documented guidance* and technical basis upon which to conduct climate risk and vulnerability assessments









Anticipating Climate Change Impacts to Nuclear Power Plants (3002023431)

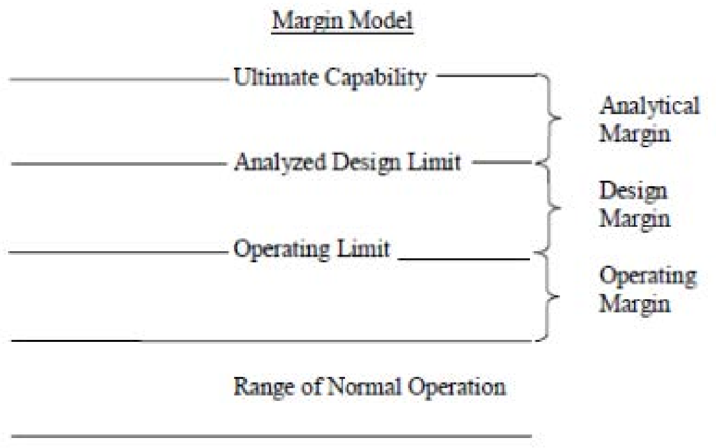
Critical Asset - Exposure Assessment

- *Identify what might be in harm's way* - Identify all plant SSCs important to safe and reliable operation of the plant – focus on those systems that can trip and derate the plant
- Identify those SSCs that are potentially exposed to weather related impacts
  - Could the weather event cause an LCO?
  - Does the weather hazard impact the safety analysis?
  - Is there OE from these weather events? Derate or trip?
  - Are key operating parameters impact by this weather hazard?
  - Could the weather event have an impact on a supporting SSC?

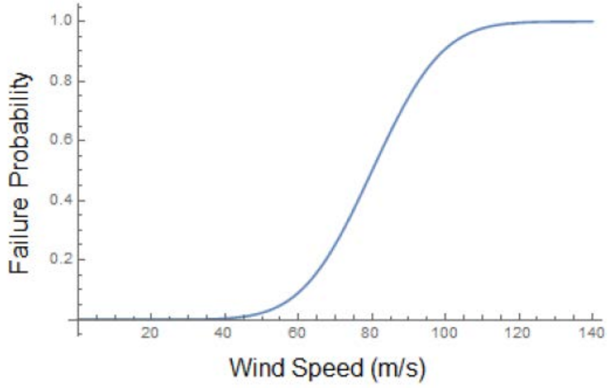
Identify Critical Assets and Infrastructure for Climate Risk Assessment

Vulnerability Assessment

- Identify potential consequences of exposure to a changing climate and options for responding – *derate or plant trip*
- Damage functions, fragility curves for impacts on generating asset
- How to factor in the risk-informed approach?
- How do plants decide how to prioritize with these results?



Ref: INPO 09-003



Ref: ORNL/TM-2019/1252

Assess the vulnerability of nuclear assets to climate scenarios

Adaptation and Monitoring Guidance (*new for 2024*)

- Response Prioritization
- Identifying adaptions to maintain or improve resiliency
- Develop strategies for planning and implementation
- Interface with existing plant programs
  - Maintenance and Reliability
  - Plant Health Committee
  - Asset Management Program
  - Enterprise Risk Management
- Monitoring & Evaluation

CLIMATE
READi
RESILIENCE AND ADAPTATION INITIATIVE

Workstream 1	Workstream 2	Workstream 3
Physical Climate Data & Guidance	**Energy System & Asset Vulnerability Assessment**	**Resilience/Adaptation Planning & Prioritization**
• Identify application needs • Assess data available and provide recommendations on data suitable for different analyses • Address data gaps	• Develop risk framing • Assess vulnerability at the component, system and market levels • Identify mitigation options • Enhance design / hardening	• Assess power system and societal impacts: resilience metrics and value measures • Identify optimal investment priorities • Develop cost-benefit analysis and adaptation strategies

EPRI Climate Resilience and Adaptation Initiative (READi)

- Development of a Common Framework across the Power System
- Comprehensive, informed, and consistent approach to climate risk assessment and strategic resilience planning
- Applicable to the assessment of physical risk at the asset, infrastructure, and operational level

Deliverables: Common Framework "Guidebooks"

- Climate data assessment and application guidance
- Vulnerability assessment
- Risk mitigation investment
- Recovery planning
- Hardening technologies
- Adaptation planning
- Research priorities

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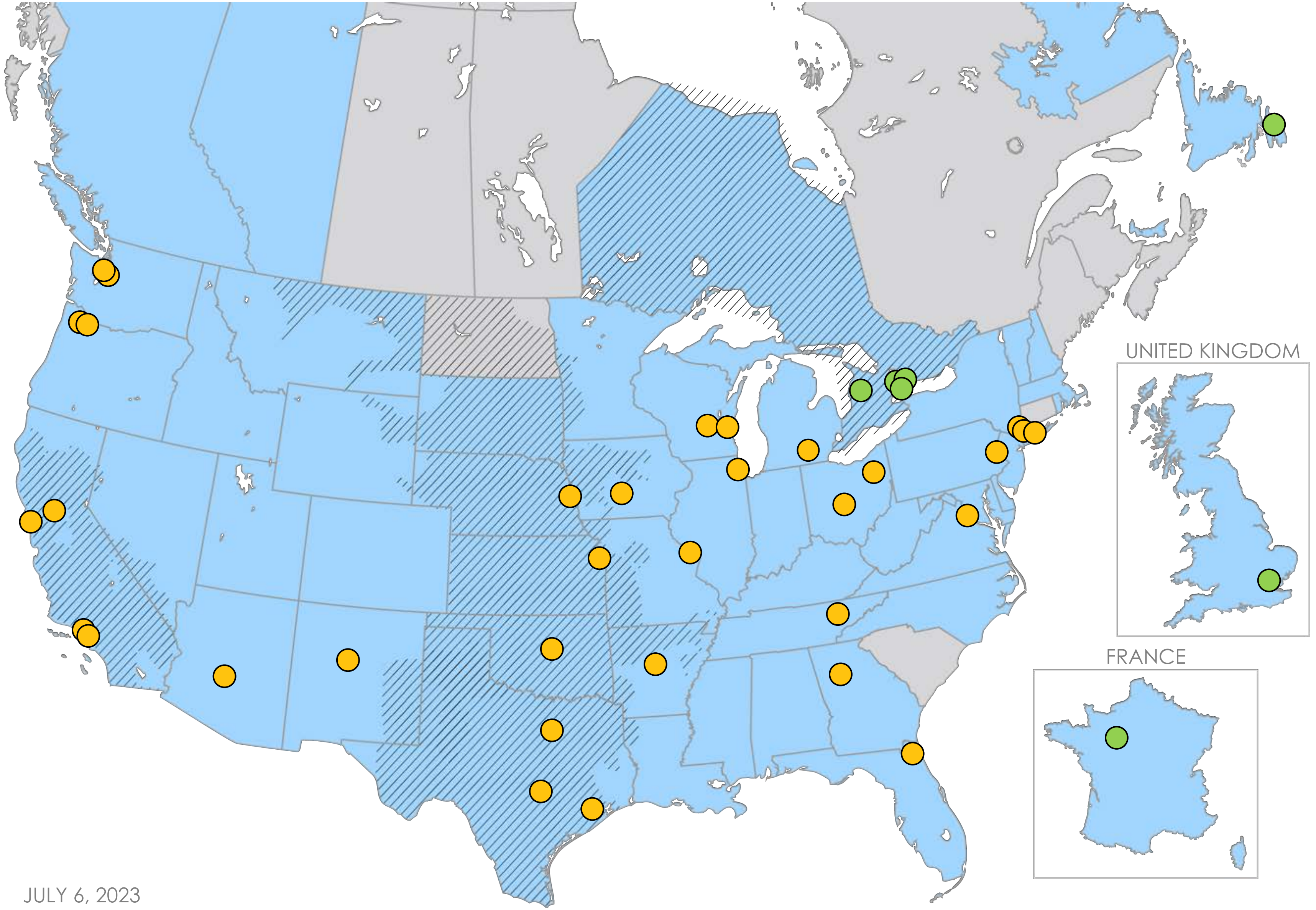
Climate READi Members



◯ Member Headquarters ▢ Member Operating States/Provinces ▨ ISO Service Territories *(only HQ location shown for IPPs)*

AES Indiana
AES Ohio
Alliant Energy
Ameren
American Electric Power — Boundless Energy
Berkshire Hathaway Energy
Bonneville Power Administration
Bruce Power
California ISO
CenterPoint Energy
Consumers Energy
conEdison
ercot — Your Power. Our Promise.
evergy
exelon
FirstEnergy
FORTIS INC.
hydro one
ieso — Connecting Today. Powering Tomorrow.
JEA
LA DWP Los Angeles Department of Water & Power
LIPA Long Island Power Authority
nationalgrid
New York State of Opportunity. NY Power Authority
OG&E
your energy partner — OPPD Omaha Public Power District
Ontario Power Generation
PGE
PG&E
PNM
ppl
PSE Puget Sound Energy
Rte
SRP
Seattle City Light
Southern California Edison
Southern Company
SPP Southwest Power Pool
TVA Tennessee Valley Authority
VISTRA
WEC Energy Group

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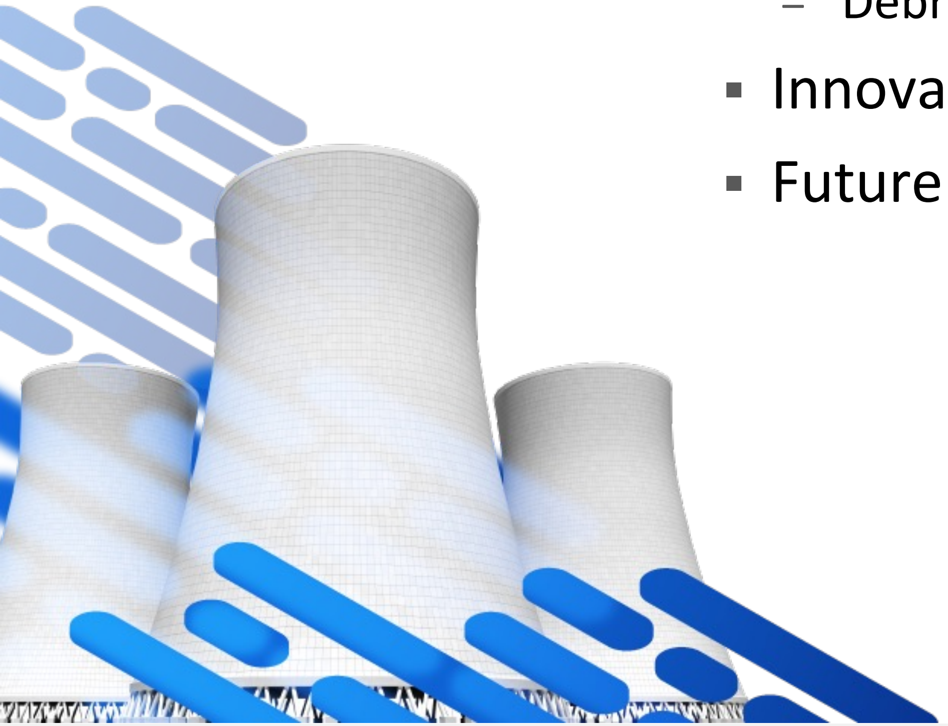
Intakes and Heat Sink Research Update

Job Black, Technical Executive

Advisory Committee on Reactor Safeguards
October 18, 2023

Agenda

- Long-term Ecological Change and Impacts to Ultimate Heat Sink
- Recently completed research
  - Intake Guides
  - Preventing Cooling Water Intake Blockages
  - Intake O&M and Optimization Interest Group
  - Debris Forecasting
- Innovation and Ongoing Research
- Future Directions



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Long-term Ecological Change and Impacts to Ultimate Heat Sink

Environmental conditions impact CWIS requirements

Changes in environmental conditions:

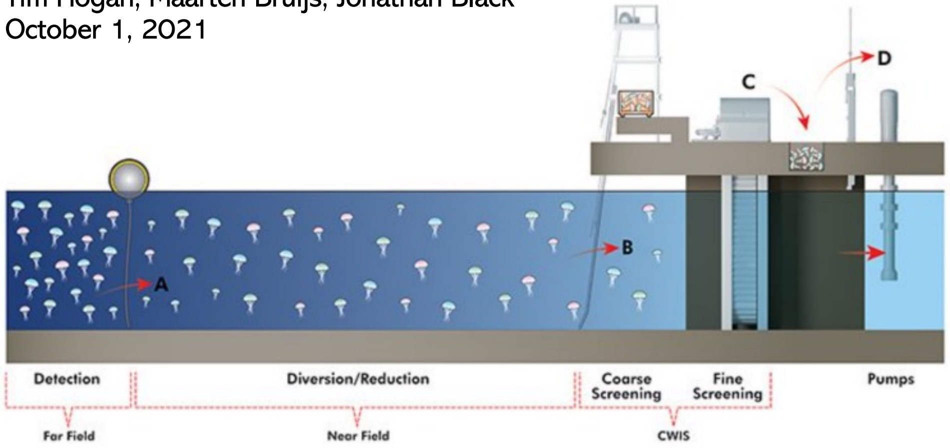
- Currently require
  - CWIS equipment readiness
  - Adequate responsiveness of operators during events
  - Adequate PM (e.g. structural integrity, operation settings, etc.)
- While most events are still ‘manageable’ today, these will
  - Increase in frequency, intensity and duration
  - Be of new types of debris not experienced previously
  - Challenge the reliability of current (ageing) intake designs
  - Require
    - evaluation current CWIS designs OE
    - upgrade of ageing equipment
    - develop and test novel approaches
    - ability to forecast

POWER

Water Intake Reliability in the Age of Environmental Uncertainty

Thermal power plants need a continuous supply of cooling water to operate, but as the natural environment changes, more and more screen blockages are occurring at cooling water intakes. Maintaining intake equipment in good order and having a sound program to mitigate problems when events occur is important for intake reliability.

Tim Hogan, Maarten Bruijs, Jonathan Black
October 1, 2021



https://www.powermag.com/water-intake-reliability-in-the-age-of-environmental-uncertainty/

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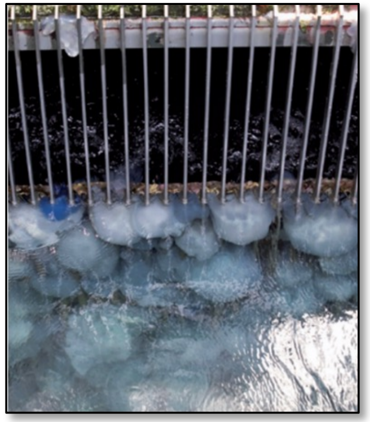
Importance of Intake Reliability

- Readiness for current conditions
  - Normal operation
    - Maintain compliance
    - Mitigate fouling and manage debris
    - Perform efficient O&M/PM
  - Abnormal operation
    - Ability to manage
    - Ability to anticipate
- Preparedness for future conditions
  - Monitoring long term data/trends and observational info
  - Predict changes
  - Evaluate CWIS design and equipment requirements (and retrofit as anticipated)



'Intake Reliability' is a function of the structural, functional, and operational design of equipment; adequate preventive maintenance; and the preparedness/training of competent operating staff

The screening assembly must

- be designed to operate under the expected environmental conditions,
- capable of managing the debris type(s) expected, and
- properly maintained to assure good working order

Anticipating Future Challenges – a Today Task!

The nature of the intake issues 'as we know them' will change

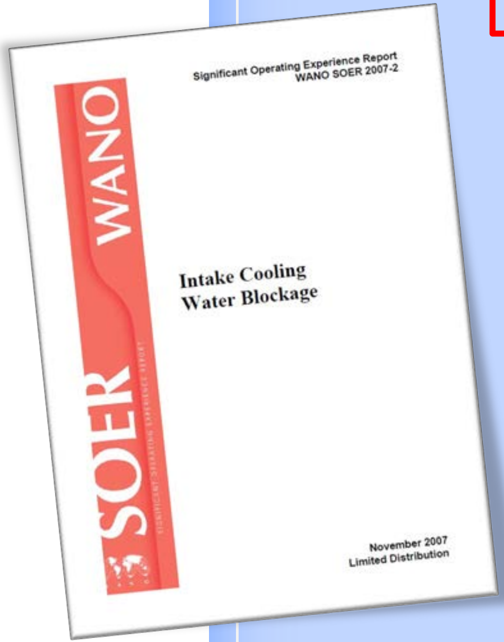
As changes are gradual, power plant operators need to:

- Think long-term
- Communicate among team
  - observed & expected changes
  - review intake operational capacity and performance
  - review international OE
- Act
  - Revisit design basis – e.g.
    - water levels in relation to operating margins,
    - water quality in relation to material selection,
    - equipment and operational settings (and assumptions) in relation to debris types

EPRI provides a framework and expertise to launch new research in support of adaptation to gradual changing environmental conditions

Monitoring Long-term Environmental Changes

- SOER 2007-2 recommends monitoring changing environmental conditions
- Long-term ecological change can be challenging to monitor
- EPRI is interested in developing guidance on which parameters are best to monitor, at what frequency, and how they should be analyzed
- Data from other climatic regions, acting as reference site for future conditions, could be used as example
- Data can be used for hindcasting and developing / improving forecasting tools
- Expected enviro changes may include:
  - Increased storm-related debris events
  - Increased nuisance species (e.g., jellyfish, hydrozoa)
  - Water conditions (temp, chemistry) impacting equipment integrity



- **Recommendation 1: Identify and periodically (at least once every three years) update station information on site-specific environmental conditions that must be addressed in the design bases of the intake cooling water structure, equipment and associated systems, to prevent or minimize obstructions and degradation that may affect cooling to the plant.**
- Recommendation 2: Develop monitoring and predictive methods to anticipate site-specific environmental parameters and initiate appropriate mitigating actions.
- Recommendation 3: Verify that plant operating and design features of intake cooling water structures and equipment and associated systems minimize the likelihood and consequences of intake blockage or degradation- this requires validation every two operating cycles.
- Recommendation 4: Implement maintenance strategies and work control processes to maintain the functional capability of intake cooling water structures, equipment and associated systems.
- Recommendation 5: Prepare operators and other support personnel to anticipate and respond to cooling water blockage and degradation in a conservative manner.

"Intake Best Management Practices"

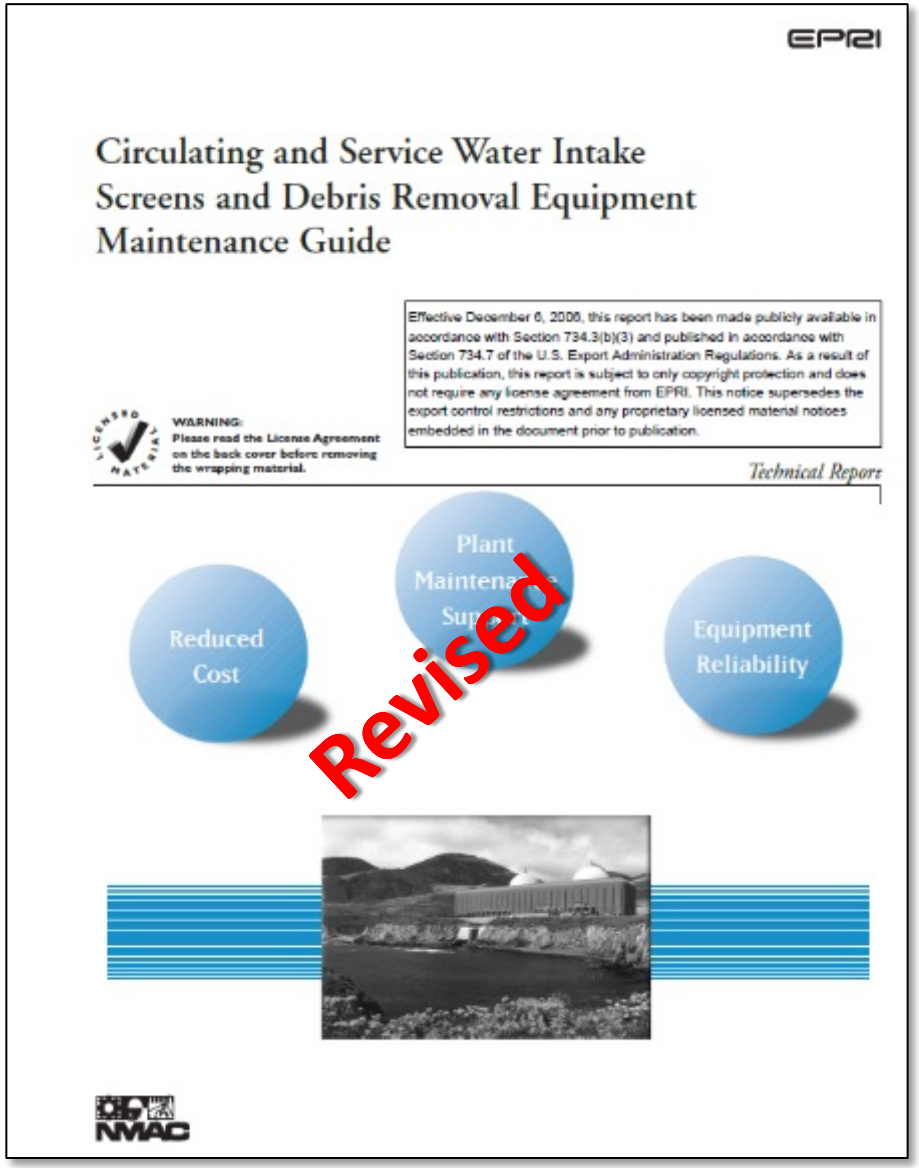
3002019660

- "Best Management Practices for Preventing Cooling Water Intake Blockages"
- Guidance published in June 2021
- Guidance includes international events
- New screen types and designs
- With international input, we increase knowledge
  - Both successful and unsuccessful mitigation/forecasting efforts
  - Application of specific (novel?) intake system types
  - Add to the body of OE related to debris management at intakes

Intake Maintenance Guide Series

Intake Equipment Maintenance

- Existing guide (2004) was outdated:
  - Addition of new technologies
  - Missing international relevance
  - Changes in maintenance practices
- New guide divided into three volumes:
  - Vol. 1 – Stop gates, trash racks, & trash rakes
  - Vol. 2 – Fine screening (TWS, drum screens)
  - Vol. 3 – Debris disposal
- Cross-sector collaboration
- Preventative maintenance templates are being added/updated



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Approach

- Review publicly available info
- Interviews with vendors
- Interviews with A/E engineers
- Review equipment O&M manuals
- Reports designed to provide:
  - Technology descriptions (operation, common failure modes, recommended maintenance)
  - Technology graphics
  - Technology animations
  - PM recommendations
  - PMBD templates (Preventive Maintenance Basis Database)

Common Failure Modes/PM Needs for Fine Screening

TWS

- Biofouling
- Mesh panel damage
- Corrosion
- Faulty seals
- Carrier chain wear/tension
- Sprocket teeth wear
- Spraywash system clogs
- Poor lubrication

Drum Screens

- Biofouling
- Mesh panel damage
- Corrosion
- Faulty seals
- Central bearing wear
- Spraywash system clogs
- Poor lubrication

Passive WWS

- Biofouling
- Screen damage
- Corrosion

Active WWS

- Screen damage
- Corrosion
- Brush wear

Additional Recent Intake Research

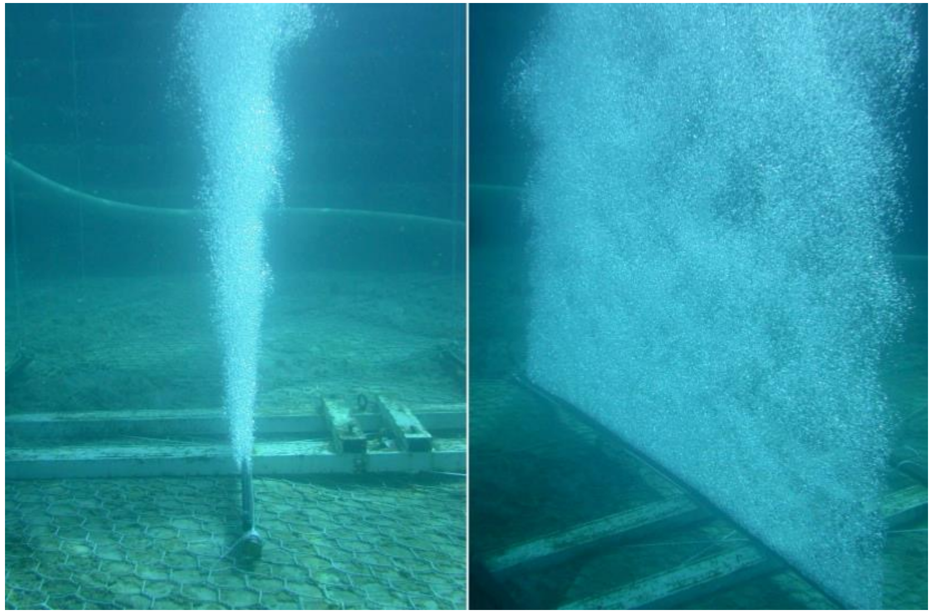
Air Bubble Curtains for Aquatic Vegetation

- EPRI is working with a nuclear facility in the Southeastern U.S. where floating aquatic vegetation has overwhelmed intake screening and forced outages or derates
- In addition to intake screening upgrades (new narrower spaced rack and raking system & new traveling screens), the facility is exploring additional measures to reduce exposure
- Multi-phased project to evaluate air bubble curtains as a potential mitigation measure

Phase 1
Data Gathering and Analysis

Phase 2
Hydraulic Modeling, Laboratory Evaluation, and Engineering Designs

Phase 3
Pilot Testing



Intake O&M and Optimization Interest Group (OMOIG)

Objectives and Scope

- Forum to discuss intake blockages, operational impacts, O&M and screen optimization
- Develop BMPs to address emerging debris and traveling screen issues
- Support nuclear reporting requirements
- Webcasts, workshops, newsletters and technical briefs to disseminate information

Value

- Minimize or prevent unscheduled outages or reduced operating efficiencies
- State-of-technology on intake screen design, operation and optimization
- On-call assistance for emergency intake management issues
- Contribute to and benefit from a network of informed peers

Project Description- EPRI 3002017668

Practical Solutions for Power Generators
Tech transfer through webcasts, newsletter, tech briefs, and annual meeting

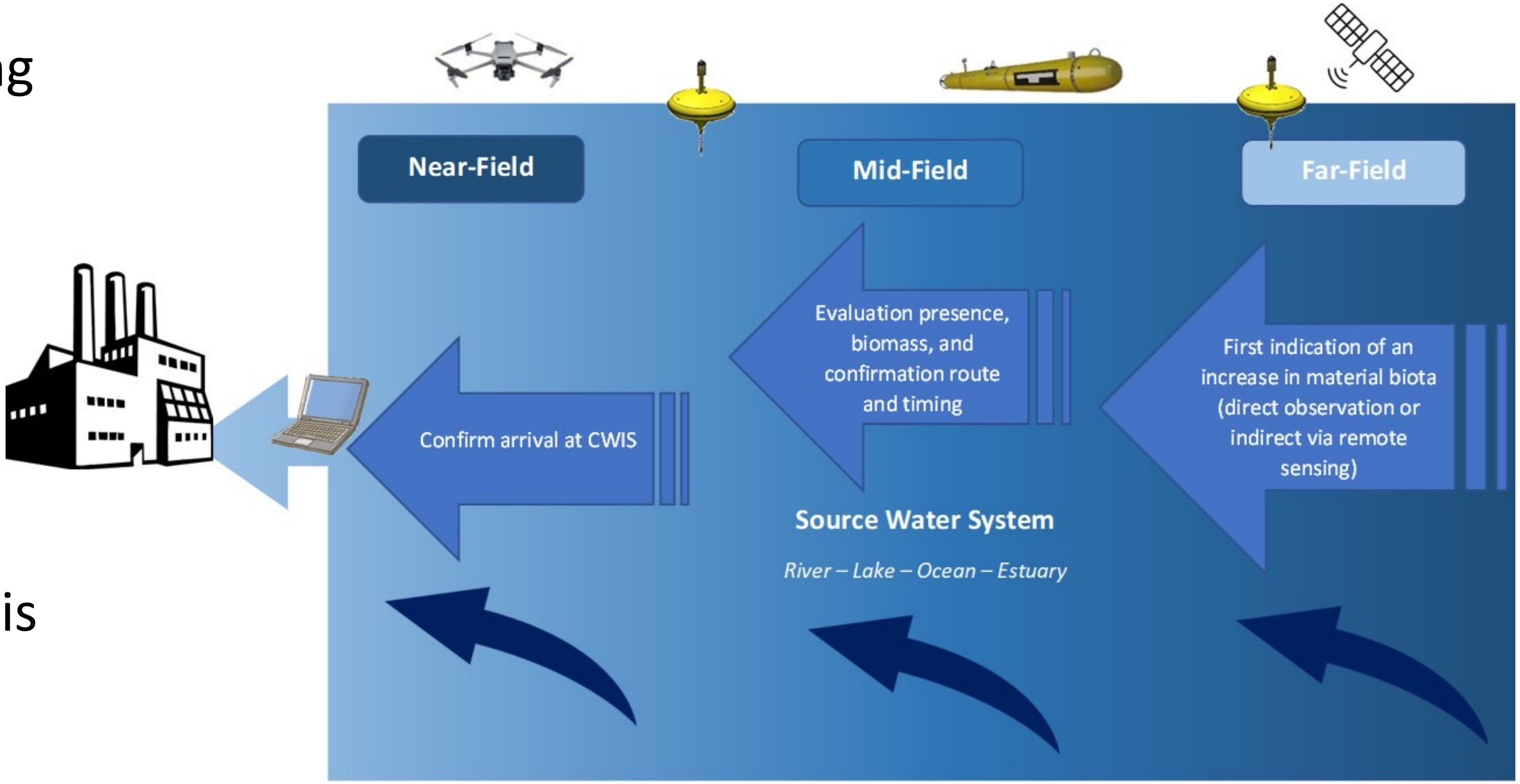
Relevant OMOIG Technical Briefs

Several tech briefs on different types of biofouling and debris types that can force outages

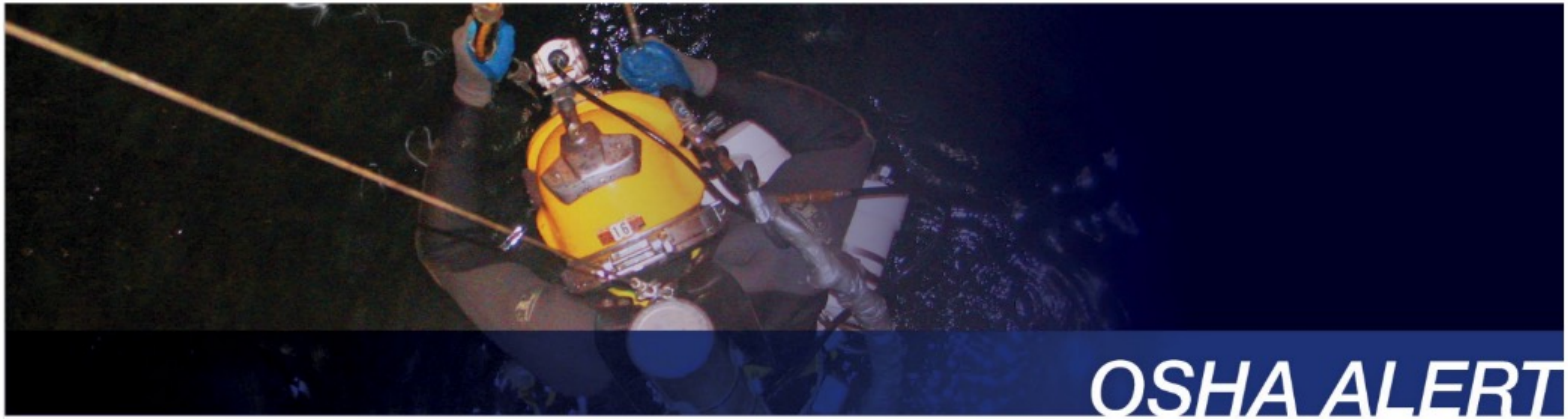
- Hydrilla (3002002526)
- Bryozoans and Hydroids (3002003052)
- Jellyfish (3002014362)
- Frazil Ice (3002004233)
- Fish Kills (3002004640)
- Cooling Water Intake Debris Management: Coatings for Biofouling Control (3002007621)
- Marine Debris: Issue, Modeling, & Detection (3002016687)
- Harmful Algal Blooms (3002018397)
- Results of zebra and quagga mussel member survey (3002025119)

Reference Manual on Forecasting

- Describes major components of forecasting system
- Step-by-step guide illustrating integration of key components
- Hypothetical case study for illustration
- 3002024512 "Reference Manual for Forecasting Debris Events at Cooling Water Intake Structures"



Innovation and Ongoing Research



Keep Workers Alive During Diving Operations

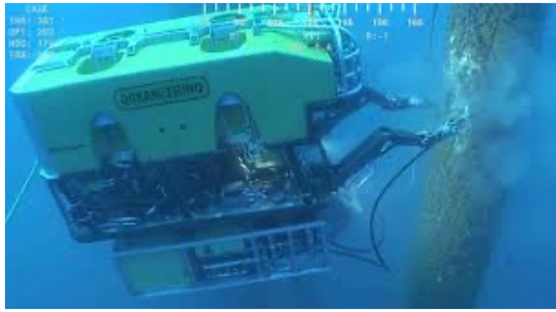
Divers working around drains, tunnels, pipes or valves can suffer fatal injuries when differential water pressure, commonly known as Delta P, creates forces quick and strong enough to entrap them.

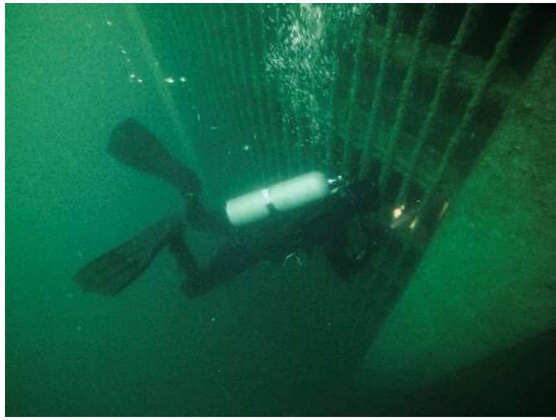
EPRI Technology Innovation (TI) is funding a multi-year research project to evaluate the use of remotely operated vehicles to clean intake structures under full flow conditions to improve diver safety and reduce O&M costs

From June 2019 to July 2021, 5 of the 6 Delta P fatalities occurred at power generation facilities

Remote Technologies for Cleaning Trash Racks

- Key task:
  - Understand how well the cleaning tools work for a variety of biofouling (e.g., hydroids, bryozoans, barnacles, oysters, mussels)
  - Test platform ‘stability’ under full flow conditions
  - Test (custom) tools developed for fouling removal
- Variables include: intake hydraulic characteristics, biofouling types, minimum trash rack cleanliness to be achieved, degree of fouling at which cleaning is initiated
- Study design based on demo site characteristics
- Testing
  - Field testing of selected technologies (platform and cleaning tools) at a selected demo site
  - Power facility in Florida in early 2024
  - Potential estuarine site in 2025, if results from 2024 are positive





EPRI

New TI Project: Data Integration for Event Forecasting

- **Background:** Forecasting debris events at CWIS requires an understanding of debris types (e.g., macroalgae, jellyfish), debris density, timescales, and physical behavior of debris (area, depth, trajectory)
- **Issue:** A forecasting model is data intensive and includes multiple data types (e.g., surface and submerged sonar, unmanned aerial vehicle, satellite imagery, hydrodynamic, meteorological)
- **Research:** Assess the feasibility of an information technology system that can collect, store, and process multiple data streams from various monitoring technologies and produce a 3D/real-time visualization model of the cooling water source waterbody. Can be incorporated into a forecasting system.

Open Discussion

Together…Shaping the Future of Energy®

BACKUP SLIDES

CFD Modeling

- Solid and fluid geometry models have been developed using design information from the Surry Power Station
- Boundary condition locations have been defined
  - Inlet: 18" lines feeding into 18" header
  - Outlet: 14" lines, prior to motor-operated valves
- Mass flow rate, pressure, and temperature data from the plant was used
- Mass flow rates of 18" feed ducts assumed to be the same
- Menter's Shear Stress Transport (SST) model with automatic wall functions used

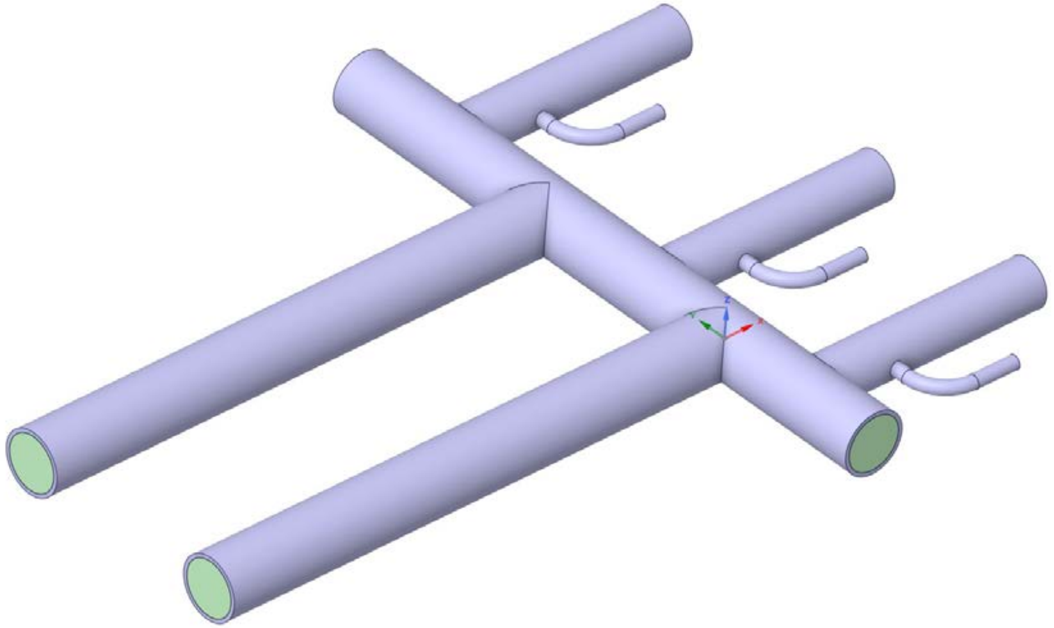
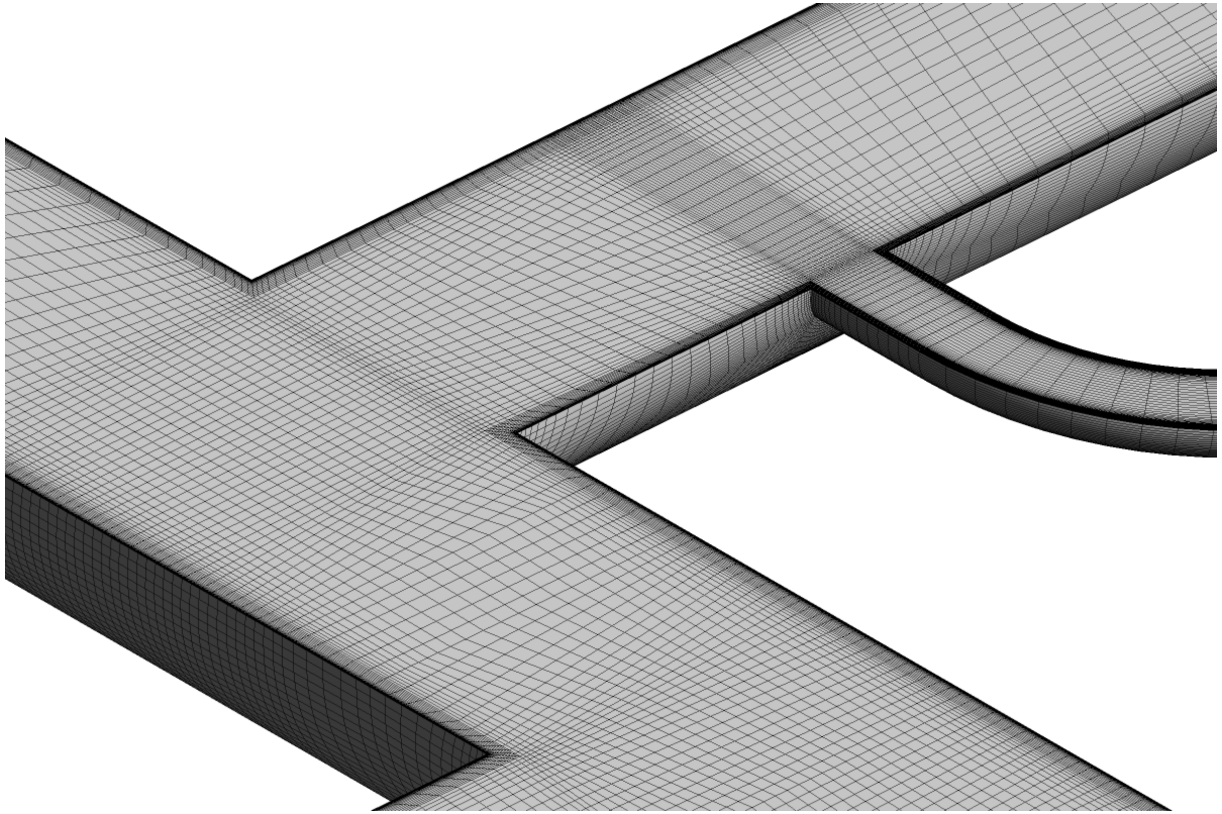


Photo courtesy of Surry Power Station

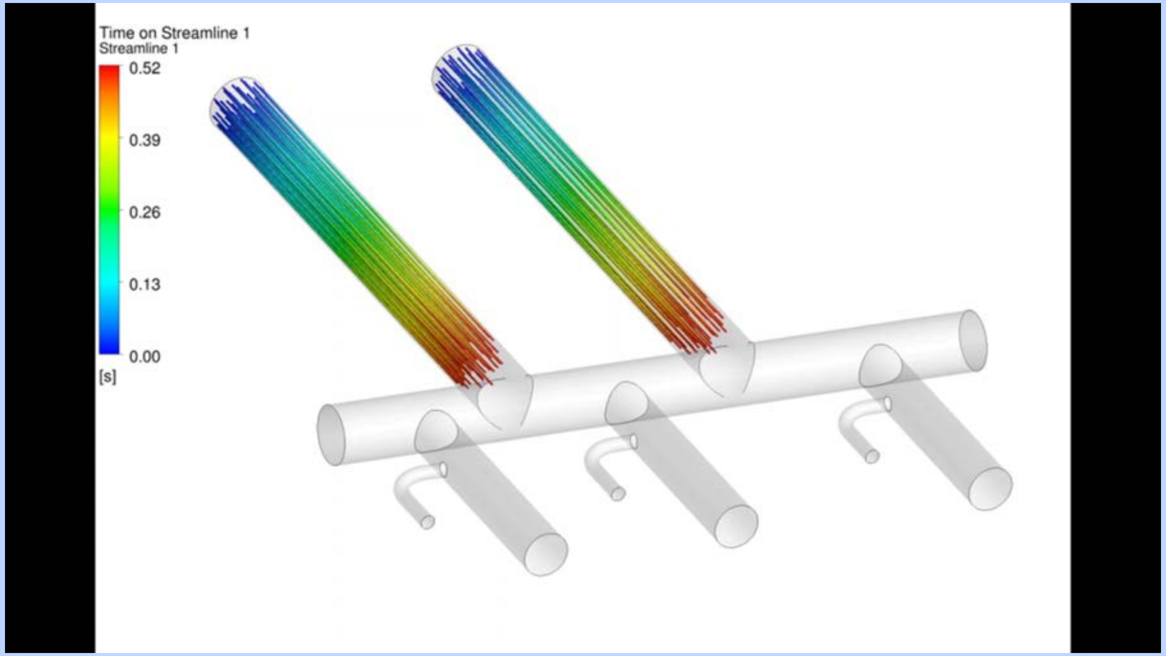
CFD Modeling

	Mesh 1
Nodes	2,986,315
Elements	2,919,432
Minimum orthogonality angle, º	31.2
Mesh expansion ratio	5
Mesh aspect ratio	1,051
Area-averaged n^+	280



Residence Time to Determine Simulation Time

- Residence time of 1.5 s
- Performed 8 times for total simulation time of 12.0 s
- Time increments on 0.001 s
- 12,500 total time steps for each simulation
  - ~32 hours to complete



Other CFD Applications in the Balance of Plant

- Refinement of prior CFD studies examining entrance effects
  - Include the pipe wall in the model and investigate non-steady flow based on this work
- Evaluate design modifications to improve heat transfer or flow distribution
  - Investigate velocity distribution along heat exchanger shell to identify areas of possible high wear
  - Identify areas of potential vibrational issues

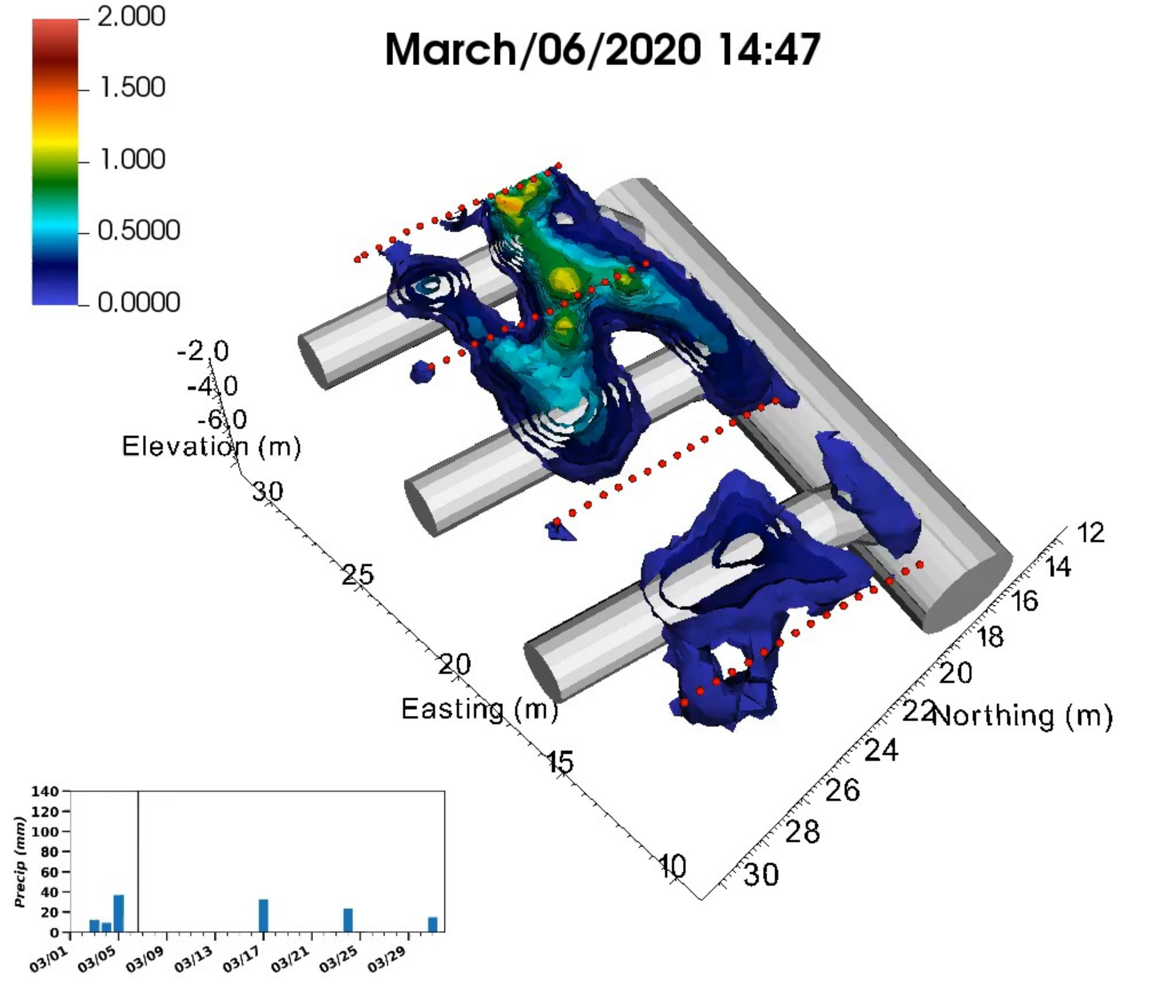
- Heat exchanger tubing integrity with adjacently plugged tubes
- Revisit Condenser Performance Evaluations using CFD
  - Last EPRI study performed in 1998

Future Options

- **Full-scale pilot**
  - Look for active (non-simulated) leaks
  - Evaluate influence of man-made noise
    - e.g., cathodic protection, non-insulated reinforced concrete, grounding grids
  - Assess seasonal variations
    - e.g., rain/snow events, salt treatments for icing
  - Current discussions with host sites for leak detection in fire protection and other buried piping
- **Deployment strategy**
  - (i.e., commercialization, common design package)
- **Stretch Goal:** Can the leak detection system detect a coating holiday?

Significant Weather and Potential Saline Discharge

- In March 2020, Pump 'C' was offline for maintenance
- Two large, anomalous increases detected in soil conductivity near Line 'D' vacuum-breaker pipe during precipitation events
- Suspected storm-induced backpressure on Line 'D' resulting in saline water overflow of the vacuum breaker line saturating the soil.



Other EPRI MV Cable Research

- 3002010591 "Effects of 0.1 Hertz Withstand Testing on Medium-Voltage Cable Insulation"
  - Research question, is withstand testing destructive?
  - A control group and a group of cables that were subjected to 60 consecutive days (78 hours total) of 30 minute withstand testing at 7kV, then at 12 kV for 30 minutes, 21 kV for 30 minutes and 23 kV for 30 minutes
  - Results showed the test was not destructive (degrades good insulation) because there was no difference in AC breakdown strength between the control group and the test group
- 1025263 "Plant Engineering: Dewatering Effects on Medium-Voltage Ethylene Propylene Rubber Cable" - Study of wet, wet-dry, dry effects on cable insulation condition showed that drying wet cables improved cable condition but keeping them dry is better
- Two studies for accelerated wet-aging were attempted, but were unsuccessful in "aging the insulation"
  - Use of high frequency voltage (450 MHz and 900 MHz) did not give the expected aging effect as no increase in tan delta occurred after 1-3 years of aging

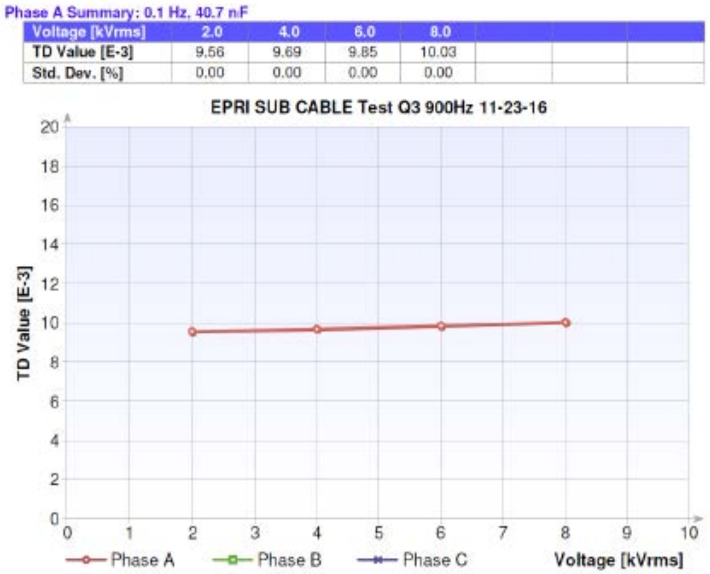


Figure 4-15
Tan Delta vs. Voltage plot and summary for year one quarter three 900 Hz cable