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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 SUBCOMMITTEES

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WEDNESDAY

NOVEMBER 16, 2022

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The Subcommittee met via hybrid in-person and Video Teleconference, at 1:00 p.m. EST, Ronald Ballinger, Chairman, presiding.

COMMITTEE MEMBERS:

VICKI BIER, Chair

RONALD G. BALLINGER, Member

CHARLES H. BROWN, JR., Member

VESNA DIMITRIJEVIC, Member

GREGORY HALNON, Member

WALT KIRCHNER, Member

JOSE MARCH-LEUBA, Member

DAVID PETTI, Member

JOY L. REMPE, Member

MATTHEW SUNSERI, Member

ACRS CONSULTANT:

STEPHEN SCHULTZ

DESIGNATED FEDERAL OFFICIAL:

MIKE SNODDERLY

ALSO PRESENT:

RYAN HOSLER, Framatome

ANDREW MORLEY, Public Participant

CAROL MOYER, NRR

DAVID RUDLAND, NRR

CHRIS WAX, EPRI

T-A-B-L-E O-F C-O-N-T-E-N-T-S

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

1:00 p.m.

CHAIR BALLINGER: Okay, 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 Jose March-Leuba, Dave Petti, I think Matt Sunseri will be here, is here.

MEMBER SUNSERI: Yeah, I'm here.

CHAIR BALLINGER: He's here. Joy Rempe, Vicki Bier, Greg Halnon, Charlie Brown was here, I think he'll be here, and let's see who else is here. Vesna Dimitrijevic, and if I've missed anybody, I -- Walt Kirchner, and that probably should cover it, that covers it. Mike Snodderly is the ACRS staff member that's designated federal official for this meeting. During today's meeting, the subcommittee will have an information briefing with the NRC staff, and EPRI on the French PWR safety injection system cracking.

I need to say ahead of time, this is an open meeting. Nothing that we are going to have presented here today is not publicly available. Personally, I was on the committee in France for EDF, along with another person who is here today, and we will -- I will refrain from making any comments related to the presentations, because for fear that I might say something that's not open.

So, just to be careful with that, and we would be happy to send these presentations to our colleagues at EDF, just so that they know what was said here. The rules of participation in all ACRS meetings including today's were announced in the Federal Register on June the 13th, 2019. The ACRS section of the U.S. NRC public website provides our charter, bylaws, agendas, letter reports, and full transcripts of all full, and subcommittee meetings including the slides presented here.

The meeting notice, and agenda for this meeting were posted there. 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 positions, and actions as appropriate for deliberation by the full committee. The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register.

Today's meeting is a hybrid meeting, is being held in person, and over Teams. The bridge line allowing participation of the public over the meeting has been made available. A transcript of today's meetings is being kept, therefore we request that meeting participants on Teams, and on the Teams call in line identify themselves when they speak, and to speak with sufficient clarity, and volume so that they can be readily heard.

Likewise, we request that meeting participants keep their computer, and, or telephone lines on mute, otherwise we get feedback, and things. The chat feature on Teams should not be used for any technical exchanges. Okay, make sure everybody's muted, okay. So, Dave? At this point I'll turn it over to Dave Rudland of the NRC staff for initial comments.

MEMBER SUNSERI: Thanks Ron. For those of you who don't know me, my name is Dave Rudland, I'm a senior technical advisor for materials in the division of new and renewed licenses in NRR. And first off, I want to thank you for the opportunity to come here, to talk to you about this very important foreign operational experience. And I wanted to let you know that the NRC staff have been heavily involved in the evolution of this issue.

We were first informed of it about a year ago with the first cracking at Civaux Plant, and we have been following it with the help of our counterparts at ASN, the French regulator, as well as at IRSN, ASN's technical service organization. So, again, I just want to say thank you, the staff have been following this, and we're happy to present some of the things that we've learned over the last year.

And to hear from our EPRI counterparts about their efforts, and how this relates to the U.S. fleet. So, thank you very much.

CHAIR BALLINGER: Okay, I guess Carol, are you on?

MS. MOYER: My name is Carol Moyer, I'm a senior materials engineer in the Nuclear Regulatory Commission Nuclear Reactor Regulation Office --

CHAIR BALLINGER: You're sounding like you're a little bit in, and out, these microphones are highly directional, so.

MS. MOYER: Is that better? Okay, I have to slouch. Great, so thank you for this opportunity to discuss this topic. As Dave already explained, this is not our firsthand knowledge, this is a compilation of what we've been able to glean from various sources, and so we hope that we can add value by pulling these facts together. But we're looking forward to the discussion.

Okay, a quick overview of the operating fleet. There are 56 reactors in operation, all of them are pressurized water reactors built in the 70s, through the 90s. They're in three main styles, roughly classed as the 900 megawatt, 1300 megawatt, and 1450, and up megawatt. The original 900 megawatt version was based on a Westinghouse design, and the others have been an evolutionary development from there with some modifications to make them fit well in the French grid.

Okay, so this is an overview of the time line of these observations. As David mentioned earlier, this was first discovered a little over a year ago in last October. Flaw indications were detected near welds in safety injection lines during their scheduled ten year safety inspections. So, they were first discovered at Civaux One and Civaux Two and Poly One, and I'm going to try not to butcher the French names too much.

Civaux One and Civaux Two, then at the end of last year. The indications that were found in the safety injection lines, and residual heat removal lines on the IDF pipes circumferentially located oriented -- jumping to the end. The laboratory analysis confirmed that these were intra granular stress corrosion cracking cracks. So, the regulator ASN decided to expand the inspections, and reevaluate prior NDE data to get an idea of the extended condition.

MEMBER HALNON: This is Greg, is that near welds, or in the welds, flaw indications? Is it a heat affected zone?

MS. MOYER: Yes, adjacent to welds would be a description.

MEMBER HALNON: Okay, so it is a part of the weld essentially, issue.

MS. MOYER: Essentially, yeah. And you'll see in the cross section that most of the cracks were associated with welds, but not all. This was a nice photo that I lifted from an EDF slide with permission that shows that layout of the affected loops. This diagram at the bottom, you'll see again, if I can point at things. So, there are welds at elbows, and various sections of pipe, and the cracking, as I said, has been mostly associated with welds throughout the injection lines.

So, with four separate loops, they're stainless steel pipes, they are roughly an inch thick, and eight inches diameter, give, or take.

MEMBER MARCH-LEUBA: One thing I'm reading on the slide is that the long pipes with the stagnant flow, or no flow at all.

MS. MOYER: Yes, we're going to get to that too. Yes, there are pipelines of varying lengths, and that we think is important.

MEMBER PETTI: Which alloy of stainless steel is it, do you know?

MS. MOYER: 316LN. So, this is another just blow up of -- well, a hand drawing, and a for real photograph of the location of some of these cracks. So, again, they are at the connections between pipes, and elbows for example. Okay, so as I said, they expanded the inspections, and tried to understand the extent of condition. EDF was asked to accelerate their plans to inspect safety injection piping for similar degradation from the spring, and through the summer.

The regulator also requested additional information to assess the degradation in its extent to determine whether it was a generic issue. Starting with this summer, EDF deployed a new NDE method to detect, and size flaws, and we'll talk about that a little bit more also. So, they used a couple of different methods to detect flaws, and to characterize what was found.

The stress corrosion cracking indications were mostly found in the 1300 megawatt, and 1450 megawatt type reactors, that I believe only one crack was found in the 900 megawatt plants, and that we think is also important. So, there is a list here of plants that either had confirmed flaws, or had results that suspected flaws that needed to be further evaluated.

The list is not comprehensive, because it kept changing as I looked at different reports, and things, because no one was quite sure what was confirmed, but let's say it's a lot. So, the pipes were at -- the cracks were at pipe ID, located at all those. When they did destructive examination of pipe sections removed, they confirmed that these were intragranular stress corrosion cracking in the base metal 316L, or LN I later learned, and heat affected zone adjacent to the welds.

Coming up in a couple slides I have a photo, it seems in many cases the cracks started in the heat affected zone, and grew to the weld, and then stopped. But in some cases the extension could reach the full circumference of the ID. Because of the design of these lines, and the stagnant, or intermittent flow, there was a suspicion that they could be susceptible to thermal fatigue cracking, and that's really what they were looking for with the ultrasonic test that they were doing on these pipes.

Although I'm told that they did not really expect thermal fatigue cracking at this stage of life, and the plant, for defense in depth reasons, they were inspecting anyway, and were somewhat surprised to find -- obviously were surprised to find the SCC cracking. Most of the cracks were shallow, around a millimeter deep. A few at heat affected zones were as much as six millimeters deep. So, about an inch, or about a quarter of the way through the wall of the pipe.

And yes, stagnant flow, and thermal stratification are potential contributing conditions. Okay, so it's our understanding that over 100 of these faults have now been examined, either with a sensitive penetrate test, or destructive examination, cutting them apart, and actually opening the cracks, looking at them. Cracked elbows were sent to the EDF's hot lab.

Some were also examined by IRSN, the technical support organization to the regulator, and they were able to confirm then that there were IGSCC cracks in the base metal, and heat affected zone, as

I said, max depth was about a quarter of the way through wall. They also found elevated hardness in the vicinity of the weld root pass. Not extreme, but somewhat elevated, enough to have that noted I guess.

They also found unusual weld geometry in some cases. There was the first pass, the root pass of the weld in some of the cross sections was unusually deep, or high. Without really a good explanation for that, so it is possible that some off normal welding conditions led to unexpected residual stresses. However, there was no evidence of chemical contamination.

You always look for chlorides, and things like that that might exacerbate a CC, that was not found. Okay, so here's a cross section. So, the center picture shows one of these cracks that's five, or six millimeters deep, and it's in the heat affected zone adjacent to a weld, the crack tip goes up to the fusion line, and then stops.

MEMBER MARCH-LEUBA: So, for us, the people who don't know exactly what we're looking at, the connect is the little hair line that we see at the top of the cone, or where is it?

MS. MOYER: Yes, I'm sorry, if I can figure out how to point on this. There we go, okay.

So, this is the pipe ID, the pipe inner wall, outer wall, weld crown, weld root pass is here, and then this small dark line beside the weld is the crack.

MEMBER MARCH-LEUBA: And the cone, the thing that looks like a mountain is the weld?

MS. MOYER: That's the weld, yes. So, this is the cast elbow on the left I believe. I don't have an annotated picture in front of me, but I'm pretty sure this is the cast elbow on the left, and this would be a wrought stainless pipe on the right.

MEMBER HALNON: Was it always on the vertical section that side of the elbow, on the vertical?

MS. MOYER: I don't know the answer to that, I don't think so, I think they were distributed throughout these loops. And there were some that were cracked on both sides of the same weld.

MEMBER KIRCHNER: This is Walt Kirchner, I'd like to ask, you said the elbow is cast?

MS. MOYER: That is my understanding.

MEMBER KIRCHNER: That's -- when you lay down a weld like this next to a cast, I don't know Ron, that's not surprising to me.

CHAIR BALLINGER: I know nothing.

MEMBER KIRCHNER: Okay, you're our expert.

CHAIR BALLINGER: Can you say something?

MR. RUDLAND: I'm actually not sure if they're cast, or not.

CHAIR BALLINGER: I don't think so, but --

MEMBER KIRCHNER: I would be surprised, that's why I raised the question. Because the difficulty of welding with castings is well known, but --

MR. RUDLAND: But there's a sufficient number of cast elbows in the French plants, because they had an awful lot of thermal embrittlement issues with their elbows, that they actually went through a replacement.

MEMBER KIRCHNER: Yeah, of course.

MR. RUDLAND: But I'm not sure about these to be honest.

MS. MOYER: It's second hand information, but I think these are 316 elbows as well, not CFAs like that, so perhaps they are -- nevertheless. So, this is a cross section of a butt weld. So, you have -- sorry for the folks online, it's a pipe, and an elbow, and the weld, you start at the root pass, and then grow out. So, the ends would have been dressed at an angle, and then that gap is filled with weld metal as you increase the circumference.

So, then these cracks occurred at the ID surface, at the inner surface, and grew towards the outer surface, but not very far.

MEMBER MARCH-LEUBA: It's easy to see how you would leave a seal on the stresses there. Is there any treatment afterwards, or? Because this is --

MS. MOYER: It's my understanding that these were plant welds, not shop welds. So, there is likely not any post weld heat treatment applied, they would be in the as welded conditions.

CHAIR BALLINGER: That I can say, you don't post weld heat treat stainless steel welds, otherwise you'd sensitize them. So, it's one of those things where you just can't. It's good news, and bad news with stainless steel, that's the good news, the bad news, it's stainless steel.

MEMBER MARCH-LEUBA: I'm going back with the CRE, with the professional, since the suspicion is that this is stress corrosion cracking, it makes sense that the internal, where you have the water. Can you say yes for the record?

MR. RUDLAND: Yeah, the cracks are on the wet surface.

MEMBER MARCH-LEUBA: On the wet surface,

where you will have the corrosion mixing.

MR. RUDLAND: That's correct.

MEMBER BROWN: That means the inside of the pipe?

MR. RUDLAND: That's correct.

MEMBER BROWN: How in the world did you find them in the first place then? You had to drain everything, and then inspect it? I'm an electrical guy, so I've got to ask.

MS. MOYER: They're inspected by ultrasonic.

MEMBER BROWN: Okay, so exterior you can pick it up?

MR. RUDLAND: They inspect on the outside.

MEMBER BROWN: I got that part. My memory goes back 20 years --

MS. MOYER: They're running a probe down the outside of the pipe.

MEMBER BROWN: So I'm starting to remember some stuff.

MEMBER MARCH-LEUBA: This is actually an ultrasonic picture, right?

MS. MOYER: No, this is a destructive examination. They found the crack by ultrasonic, so non-destructive examination, NDE, and then once they had located a crack, they cut that section of pipe out, replaced it with a new one, and took the broken one to the lab.

MEMBER MARCH-LEUBA: So, that's a microscope picture.

MS. MOYER: This is a cross section, polished.

MEMBER SUNSERI: This is Matt, I have a question, Matt Sunseri.

MS. MOYER: Yes?

MEMBER SUNSERI: So, maybe I don't remember this correctly, but my recollection is for in a granular stress corrosion cracking that occurs, you need three things to happen. One is to have susceptible material, two corrosive environment, and three high temperature. So, it sounds like one, and two are met, but the temperature seems a little low to me, this is something south of 600 degrees Fahrenheit, 300 degrees C, so are these welds exposed to higher temperature than that?

MS. MOYER: No, the essential requirements are susceptible material, environment, and stress, not necessarily temperature. You can get to stress by temperature perhaps, and we may have here by differential heating, but temperature alone doesn't necessarily alone get you to SCC.

MR. RUDLAND: This is Dave Rudland, it's more the environment, the chemistry of the water that could cause that. So, there's certain chemicals in the water that can cause susceptibilities to be worse. So, if you have a high oxygen content in the water, it makes that location more susceptible. So, when they talk about the environment, they're talking in this case more about the water chemistry than they are about the temperature.

The temperature feeds into the growth rate more so than the --

MEMBER MARCH-LEUBA: Asking questions about the theory, 100 percent theory, is this an accident event, I mean a transient, of having a crack in a second, or is it a very long corrosion that goes crack, crack, crack over months?

MR. RUDLAND: Yeah, it's a time dependent cracking event.

MEMBER MARCH-LEUBA: It's a long time?

MR. RUDLAND: It took a while for the crack to initiate, and a while for the crack to form.

MEMBER MARCH-LEUBA: So, it was not like a surge of some very hot water.

MR. RUDLAND: That is correct.

MEMBER HALNON: Matt, go ahead if you need to finish your question.

CHAIR BALLINGER: I think it was done.

MEMBER DIMITRIJEVIC: I have a question, this is Vesna Dimitrijevic. My question is we usually don't see IGSCC in the pressurized water reactors in the U.S., right? That's a more BWR problem. I mean we might --

MS. MOYER: I think the answer to your question is --

MEMBER DIMITRIJEVIC: You know, when we analyze the degradation mechanism in class one piping in the PWRs, that was never damage mechanisms. It was the damage mechanism we saw in the BWRs.

MS. MOYER: Yeah. IGSCC has been reported in BWRs primarily. When we see stress corrosion cracking in pressurized water reactors, we tend to call it primary water stress corrosion cracking, PWSCC, but it's not really that different.

MR. RUDLAND: Yeah, and actually I think -- this is Dave Rudland again -- the susceptibility of the stainless steel in pressurized water is not as high as it is in the water in BWRs, because of the chemistry again. And so the cases in the U.S. where we have seen stress corrosion cracking in stainless steel have been kind of limited to locations where there's something special going on.

There's been excessive grinding, or something that really increases the stresses at the ID surface, or in stagnant conditions, where you may have water chemistry issues.

MEMBER DIMITRIJEVIC: I see, I mean I was a little surprised to see this, but you know, I know we have IS, integration stress corrosion cracking program for BWRs, but -- all right, thanks.

MS. MOYER: Okay, as I was starting to say, cracks were detected by manual ultrasonic testing. So, in this case you're putting a sound wave into the pipe from the outside, and listening for, checking for a response, a reflection back to the transducer. They use a 45 degree sure wave at 2.25 megahertz. This is pretty normal for looking for thermal fatigue cracks, which is what they were doing.

It's manual scanning, which means there is a human actually moving the transducer over the pipes. Part of the story I think, the conjecture is that may have been a contributing factor in the sense that there's a dose implication to putting a human there to do this examination. And one of the modifications that was made in the later designs was to increase certain piping run lengths.

Putting the person farther away from the exposure, but also changing the configuration of the pipe, so again, there's a trade-off. This ultrasonic procedure, as I said, was designed for thermal fatigue cracks, not really optimized to detect, nor to size, or as we would say, characterize SCC cracks. But when they did start to find some indications, they confirmed the SCC cracks with destructive examination.

MEMBER HALNON: Carol, does that mean that the SCC cracks had to get big enough beyond what normally you would expect in order to see them? Or is it just something that the inspector needs to be cued into?

MS. MOYER: Yeah, SCC cracks tend to be slow growing, and they tend to be very tight. And sometimes they have adherent oxide in them that's still somewhat conductive, and so it's not an easy kind of flaw to find in the first place. But yes, they do tend to be small, and tight, and a sure wave that's just looking for a big sound bounce may look past it.

MEMBER HALNON: They had to get bigger than what we -- if we had a probe designed, or optimized to detect SCC cracks, it would have caught them a lot earlier?

MS. MOYER: Conceivably.

MEMBER HALNON: I guess that's the inference, okay.

MS. MOYER: The other interesting thing is, as I showed --

MEMBER DIMITRIJEVIC: I'm sorry, I have another -- how does the extracting exams, you know, which piping they have been performed on? I mean what does --

MS. MOYER: I'm sorry, I don't understand.

MR. MORLEY: They've cut the pieces out of the plant, and destructively examined those.

MEMBER DIMITRIJEVIC: Cut the pieces from some retired plant?

MS. MOYER: No, the pipes that were found to be cracked were cut out, and taken to a laboratory, and replaced with new pipe sections.

MEMBER DIMITRIJEVIC: I see, so they have to drain RCS?

MS. MOYER: Yes, this was done during their ten year inspection.

MEMBER DIMITRIJEVIC: Yeah, but inspection is done with the water in the piping, and the stress exam, they don't have installation valves, so they have to drain the RCS to do this, right?

MS. MOYER: That's my understanding, I don't know for sure how extensive that was, but yes, that was part of the problem, and why it has taken a long time for them to recover from this experience.

MEMBER DIMITRIJEVIC: I mean I -- so, that's something I didn't see there, replacing the class one piping. So, I mean okay.

MR. HOSLER: Yeah, this is Ryan Hosler, they would have to drain down to the level of the cold leg, and hot leg, clearly to get this done. But that would remain above the majority of the reactor vessel.

MS. MOYER: Right, the injection point for these lines is the cold leg.

MEMBER MARCH-LEUBA: Can you show us slide four? Very clear.

MS. MOYER: Okay.

MEMBER MARCH-LEUBA: You can see the level right there, right? It's the copper pipes, which are not made of copper, but copper colored pipes in there.

MEMBER KIRCHNER: Yeah, you can't drain the whole primary system with the core still in it, so either they have to take the entire core out to drain the primary system, before they drain the primary system. Or, they take suitable precautions to -- if the fuel is still in the core, to ensure that the system doesn't drain out. Can you give us more information on how they actually did the repairs?

MS. MOYER: I cannot, I have just been looking at the materials implications of it, but I think we'll get to that later in the meeting.

MEMBER KIRCHNER: Okay, thank you, yeah.

MEMBER HALNON: This is Greg, the industry has cold leg plugs they stick in the cold legs, and you go to mid loop operations, and that's how they can drain the pipes.

MS. MOYER: So, all of the pipes that are shown in this diagram, this cartoon, are here at the hot leg, and cold leg level. So, all of the welds of interest are in these loops, and in these pipes that feed them. So, the vessel itself would not have to be drained any lower than the hot, and cold leg level.

MEMBER HALNON: Correct.

MEMBER DIMITRIJEVIC: They go to mid loop operation, my guess would be they had the fuel outside, so.

MEMBER HALNON: Yeah, they had to defuel the reactor, I mean you can't do this with fuel in it, the dose rates would be too high anyway to do that. The experience of this, cutting out the hot leg, was paramount in figuring out how to do this probably.

MR. RUDLAND: Before Carol moves on, I'm getting live emails from my French friends, and I just wanted to point out that the elbows are forged, they're not cast.

CHAIR BALLINGER: And now you said it, okay.

MR. RUDLAND: Yeah, the elbows are forged. And also there was a comment about the 900 megawatts, there was a defect found in one of the reactors in the RHR system, but it was due to lack of fusion, and not due to SCC. So, there were no SCC cracks found in the 900 megawatts.

MR. MORLEY: I think it was emanating from a weld defect in the 900.

MEMBER REMPE: We need to have whoever just spoke say their name for the transcript please.

MR. MORLEY: I'm sorry, Andy Morley here, Rolls Royce.

CHAIR BALLINGER: Say again?

MS. MOYER: Andy Morley from Rolls Royce.

CHAIR BALLINGER: Okay.

MS. MOYER: So, as Dave said, looking more closely at all of the NDE data that they had in history also might find other things along the way, like this weld defect in one of the 900 megawatt plants, and other non-relevant indications. So, that was one of the things that was a concern too, was whether it was possible that some other indications from prior NDE examinations had been improperly characterized, and were in fact cracked.

So, they looked again at some older data. I don't have a breakdown of how those results came out, I just know that these are complicated joints. There's geometry, there's counterbore, there's the weld tow, the welds were not crowned, so there's a weld crown, which means it's difficult to inspect right up close to the weld, because the transducer just doesn't physically fit flat against the pipe because of the crown on the weld.

So, some of these challenges may have impacted the inspectability of some of the pipes. And so, it was worth looking again just to make sure nothing was overlooked. And then EDF developed a plan for an accelerated schedule to inspect all of the analogous piping. Okay, as I mentioned we were told that there were inspections by remote penetrant test, or ultrasonics, then some by destructive tests.

I've been informed that the new, and improved, if you will, NDE procedure that was rolled out is something called total focusing method full matrix capture, and plain wave imaging. Total focusing method plain wave imaging. So, this is still a manual technique, but it's encoded, so you keep track of the location, and there's a bracket that goes around the pipe, and encodes the location information.

It's a very sensitive technique, it is a developing technique. It is not fully qualified, at least not in the U.S., and to my understanding, it's not qualified in France either, by their standards organizations. It's an emerging technique, and again, as I said, very sensitive, and creates a great deal of data. We among the NRC staff, when we were discussing this, had some questions why a qualified phased array ultrasonic technique was not selected.

Not to second guess anyone, but just in the course of conversation, we said I wonder why they went to such a sensitive technique, instead of a well known phased array UT technique, but there we are. Okay, so a little bit more about the root cause analysis, as we've been saying, IGSCC was not expected. It really didn't line up with international operating experience, there was no SCC on the French 900 megawatt plant series after 30 years.

There was no contamination observed, like chlorides, or something that didn't belong in the water chemistry. However, there were some weld repairs, and there were some unusual weld geometries that were found. Again, I don't know a lot about this, it is second hand somewhat, but EDF, I know did a welding simulation to estimate hardening, and residual stresses that were observed near the ID of these pipes.

And found that there was an area of limited depth on the ID that was subject to tensile stress. But the stresses weren't compressive within the weld, which does line up with the observation that the cracks started in the heat affected zone, and then grew to the weld, and stopped. That was confirmed by their destructive examination.

MEMBER KIRCHNER: Carol, this is Walt Kirchner again. Did the 900 series plants have those cast elbows for those lines?

MS. MOYER: They apparently were forged elbows, that was my bad information, sorry. Dave Rudland has now confirmed those were forged stainless elbows in both cases.

MEMBER KIRCHNER: Forged, not cast.

MS. MOYER: Right.

MEMBER KIRCHNER: Okay, thank you. But it was the same material selection, same fabrication for the 900s as the larger techniques?

MS. MOYER: Yes, as far as I know, it's 316LN, possibly with a nitrogen strengthening, so a very common place material.

MEMBER KIRCHNER: Okay, thank you.

MS. MOYER: Okay. So, the regulator was aware of some weld repairs. I think they knew which welds had been repaired, or at least which pipes had had weld repairs, but they weren't necessarily sure of exactly where. Weld repairs may leave the pipes in unusual, or unknown residual stress condition, that's always a possibility. So, those welds were especially, carefully reinspected.

Another thing that could be a contributor, so it's worth checking out, is oxygenated water. Chlorides certainly are very bad news for stress corrosion cracking, but oxygen can be a contributor. This is something that we learned from our colleagues at IRSN, that some of the flows, like from core makeup tanks, the boric acid tank, and then peroxides injected at shutdown for various good reasons may also bring along with them some oxygen that would potentially throw off the chemistry in these lines.

Especially given that they are stagnant, or mostly stagnant, so that's one other possible concern. Thermal stratification is another concern that could impose its own cyclic loading on the pipes. As I mentioned, in the M4 type reactors, there were some horizontal runs of pipe that were extended, had a good justification for inspectability, but may have contributed to having longer pipes that were stagnant, and that had thermal stratification.

So, uneven temperature because of thermal expansion means uneven stresses in those pipes. So, I think IRSN has been doing some work to estimate just how much of an effect that might have been. Okay, mitigation plans include, as I mentioned, cracked sections have been removed, and replaced with new. From this fall, through 2025 EDF has a plan for a complete examination program on all their operating reactors on areas that might be affected by this concern.

They're using this advanced UT procedure that is optimized now for IGSCC detection. And I'm told that they plan to seek qualification of that technique, but anybody who's worked on standards knows that's not a quick, or one step thing. That's usually a protracted effort. The reactors that were considered most sensitive, just based on the population of flaws found so far are the N4 type, and those have been stopped to carry out inspection, and repairs where needed.

And looking forward, there is a plan for a periodic reinspection program, with periodicity based on the sensitivity of the NDE, the crack growth rate of IGSCC, and mechanical, plastic fracture mechanics analyses to try to stay ahead of it. So, at present, and this at present is probably a week, or so old, so it might not be quite accurate. There are 26 reactors down, 15 for stress corrosion problems, and 11 for other scheduled maintenance.

The repair work has been completed for six reactors, and repairs on this problem are underway at four.

MEMBER MARCH-LEUBA: When you say currently, you mean today, or you mean --

MS. MOYER: About a week, or so I think.

MEMBER MARCH-LEUBA: I mean it's not nine months ago.

MS. MOYER: Right, this is -- my notes are this is from World Nuclear News Daily on November the 4th.

MEMBER MARCH-LEUBA: At what speed are they testing them, do they have more than one sensor, one machine?

MS. MOYER: There are multiple machines, but keep in mind, that you need operators, and you need welders, and if there's an exposure component, those folks have limits on how much they can do.

MEMBER MARCH-LEUBA: I'm kind of asking what's your projection of when they'll be up, and running?

MS. MOYER: I wouldn't even hazard a guess.

MEMBER MARCH-LEUBA: Is it a matter of weeks, a matter of years?

MS. MOYER: The whole inspection program I was told was to be done by 2025. So, going all the way through every plant ensuring that these lines have been fully inspected, and repaired if needed may take a couple of years. But when they can get to a point where they can operate these plants, that's probably a different answer, and I don't have enough information to say.

MEMBER DIMITRIJEVIC: This is Vesna Dimitrijevic, so, when you say the 15 for stress corrosion, I know this is also outside information for you too, so does that mean that they're doing testing, or that means they've identified problems, and they have to do the pipe replacement? What does it mean for stress corrosion problems, is it for testing, or for replacement?

And what does -- for maintenance, is that totally independent of IGSCC, or sorry, I have a problem pronouncing this for some reason. Or is this for the independent maintenance, or these are also related to this? So, the maintenance, is that independent of this problem, or it's for what?

MS. MOYER: It is my understanding that 15 of the plants had some indication of cracking in these lines that was being further investigated, or repaired. So, 15 of these were suspected, or confirmed stress corrosion cracking, and 11 of the plants were down for other maintenance, whether scheduled, or unscheduled. Does that help?

MEMBER DIMITRIJEVIC: That gives me some information. And my other question is also is your understanding that the testing related to this will be done in -- they will be scheduled on all these plants in these couple years independent of the regular service testing, it will be just for this, so they will be shutting down all plants to do this testing?

MEMBER DIMITRIJEVIC: You were --

(Simultaneous speaking.)

MS. MOYER: I would have to ask --

MEMBER DIMITRIJEVIC: In order to perform these tests, are they going to perform them on all the plants, or are they just going to do them on the plants where they have the most suspicion that this corrosion cracking can be? And also I have a question, do you have an idea what percentage of welds they think is in the region which can be exposed to that?

Because let's say that we have within 400, 600 welds in the cross run piping, what percentage of those welds will need to be tested, do you have an idea about that too?

MR. RUDLAND: This is Dave Rudland, if I go back to your first question, I really need to emphasize that this is still an ongoing, developing issue in France. And discussions between EDF, and the regulator are continuing to be ongoing. So, I hate for us to speculate too much about their plans on what they do, and when they plan to be up, and things like that.

That really needs to be left to those discussions between the EDF, and their regulators. In terms of the number of welds, I know that them being very conservative in the number of welds that they're looking at. I think Carol pointed out earlier that they were doing a lot of penetrant testing on a lot of the welds that had any types of suspicion at all, so they're being conservative in how they're looking for these.

And so, I think they're suspecting that most of them that are in the same lines as the ones where they've had cracks before are considered susceptible enough that they want to do some kind of non-destructive evaluation. In a lot of cases it is this penetrant that they're planning to use.

MEMBER DIMITRIJEVIC: I'm really curious, because that's a really terrible timing with this energy crisis in Europe, they're shutting 50 percent, or more of their plants, it's just really bad timing.

MS. MOYER: Certainly.

MEMBER MARCH-LEUBA: Yeah, I'm reluctant to put unverified data on the record, but Google says that France intends to restart 27 of the reactors by December of this year, and they're still working on five more, they expect to be restarting in February, but of course that's Google.

MS. MOYER: Okay, thank you.

MR. MORLEY: Andy Morley, Rolls Royce here, do we now, have they only looked at these branch lines, the SIS, and the RHR system, or have they looked at the main loops as well? And if they haven't looked at the main loops, is there a reason why?

MEMBER REMPE: I'm sorry to interrupt, and I'm chairman of the ACRS, and this is not a time when the public can ask questions.

MR. MORLEY: I'm sorry, I didn't realize that.

MEMBER REMPE: I realize that it's a different country, and all that, and I don't mean to be rude. But at the end of this meeting, I assume the supplementary chairman will ask for public comment, and if you have a comment, you can state it for the record at this time, but that's all we can do.

MR. MORLEY: My apologies.

CHAIR BALLINGER: My apologies, I thought that you were one of us in some respect, so that's the reason why I said okay. And nobody corrected me until now. Now we can keep going.

MS. MOYER: Okay. As a regulator, I found it interesting that the utility, that EDF in this case performed a stress analysis, and proposed a flaw evaluation criteria for continued operation. That is they essentially requested permission to restart a reactor with known cracks saying well, they're very small, and we know where they are, and we can show by a stress analysis, and crack growth data, that we can operate to the next outage, or something like that.

The regulator, with support from their PSO, evaluated that proposal, and the level of uncertainty associated with the data that went into it, and decided that that was not prudent, and as a result, that reactor was not given permission to come back online with flaws in place. I found that interesting.

CHAIR BALLINGER: I can say, I might add that the rules in France are different than the rules in the U.S. In the U.S. my guess is that it's allowed by the code, they would have done a risk analysis, and probably be able to operate, but in France, the rules are much more final if you want to use that word.

MS. MOYER: Right, that's true.

MR. RUDLAND: To add to what Ron said, I agree, I would suspect that we would probably prefer it to be mitigated, and not an -- an SCC left in service. By mitigated, a weld overlay, or something like that.

MS. MOYER: Okay, so we talked about extent of condition, we talked about root cause. One of the other things that we would normally look at is similar operating experience. What have we seen that looked anything like this in any other reactors? A similar appearing crack was found in the Japanese plant, OE unit three pressurizer spray weld in August of 2020.

That flaw was attributed to hardening from high weld stress on the inside diameter surface. Again, as Dave mentioned earlier, we've typically seen this kind of cracking when you have a lot of grinding, or a really unusual weld upset, a weld procedure that was off normal in some way. And you would have unusually high residual stresses. So, that was essentially the conclusion in that case.

In the U.S., PWRs have observed stress corrosion cracking in 316 only when there was cold work, grinding contamination, very oxygenated water conditions, something like that, that you can really point to. Okay. So, in the U.S., we have the ASME code, American Society of Mechanical Engineers Boiler and Pressure Vessel Code. Section 11 covers in service inspection.

That code is mandated by U.S. regulations, by 10 CFR 5055A. Most plants use an NRC approved risk informed in service inspection plan as an alternative to section 11. So, they have to meet at least one of those. U.S. plants examined 10 to 15 percent of the class one safety injection, and RHR piping under their programs. So, they do inspect these class one pipes looking for this kind of flaw.

They do apply a sampling, they don't necessarily look at 100 percent of the welds every outage, they cycle through them --

MEMBER MARCH-LEUBA: So, you have a population, this number, 10 to 15 percent is every year, or ever?

MS. MOYER: Every inspection interval, which is ten years.

MEMBER HALNON: There is an escalation aspect to it.

MS. MOYER: Certainly, if anything is found, then you have to expand --

MEMBER HALNON: This 10 to 15 percent has got to be clean.

MEMBER DIMITRIJEVIC: It is not certain, they always inspect the same 10 percent, or 15 percent. There is no -- I mean they don't cover every ten years, the same ten percent, more than that is inspected.

MS. MOYER: I'm sorry, was there a question? No, okay, I missed the beginning of that.

MEMBER DIMITRIJEVIC: My point was if we're inspecting the same ten percent, and we have seen here that higher power, the plants, we can be missing this in United States, because we are not looking for that, we are looking for thermal fatigue, and inspecting ten percent of the valves. Or this is something which will be lessons learned from this French situation.

MEMBER HALNON: But we also, the experience here shows that a small leak will occur. We won't get a catastrophic failure, so it's you will leak before break.

MR. RUDLAND: And this is Dave Rudland, let me also point out that the risk informed programs are designed such that the ones that they are looking at are the most susceptible locations, be it stress, or geometry, or whatever it happens to be. So, they are looking at the most susceptible.

MEMBER HALNON: One thing we do miss in this is the weld records. I was at the D.C. summer plant when the hot leg was found, and until you went back, and looked at the actual records of construction, you didn't realize that you had excessive grinding, and excessive rewelds on that root pass. And this 10 to 15 percent, it may be most susceptible from a system condition perspective, but not necessarily the most susceptible from a rework perspective.

So, I don't know how you factor that in, but again, it's like the previous slide said, the most cases in the U.S. it's excessive grinding, and excessive rework, but that's not factored into the section 11, is it?

CHAIR BALLINGER: I feel compelled.

MEMBER HALNON: Go for it Ron.

CHAIR BALLINGER: My personal opinion is that stainless steel of this type is fundamentally unstable in 300 degrees C water. So, the material has to maintain that protective film. There are so many variables involved, everybody says there's too much grinding, there's too high stress, but this material will crack if you violate that film. And so, anything that violates that film will probably result in cracking.

The reason the difference is between PWRs, and BWRs is one operates as an oxygen over pressure, the other one operates as a hydrogen over pressure, so the potential is much lower, but they're still susceptible. So, that's one of the reasons why we're having this meeting, to kind of warn people that we need -- 80 years is a long time. Thanks.

MEMBER MARCH-LEUBA: You came in on that, what film are you talking about, is this put in on the inside?

CHAIR BALLINGER: It's a Faustian bargain that we play. You've got a chromium oxide based film that's on the surface that isolates the material from the environment. But the material is fundamentally unstable, it wants to convert to an oxide. So, if you breach that film, then the underlying material is exposed. And if you do it in the right way, you crack.

So, in that respect, plain carbon steel would be better than 316 stainless steel because it doesn't stress corrosion crack.

MEMBER MARCH-LEUBA: I don't know anything about this, why I'm asking the question. Chromium oxide is generated when you put water inside --

CHAIR BALLINGER: Yeah, it's a film.

MEMBER MARCH-LEUBA: It's in itself something --

CHAIR BALLINGER: I'm being a little fast, and loose with the chromium oxide. It's an oxide based film that's tough, and adherent, and it is a strong function of the chromium content, which is the reason why the higher nickel chrome, and higher chrome alloys, 690 for example, nickel based, that has 30 percent chrome, that's much more stable. But this material is right at the limit where you need to be very careful about stress, and grinding, and all that kind of stuff.

MEMBER MARCH-LEUBA: But isn't that film self-generated, so grinding won't get rid of it, you will generate a new one?

CHAIR BALLINGER: Yeah, it reforms very quickly.

MEMBER MARCH-LEUBA: Anyway, you guys are the experts.

CHAIR BALLINGER: But you can create conditions in a crack which make the environment more aggressive. And if the stress is five millimeters deep, you're driving this crack through. So, again, we just need to be careful.

MEMBER MARCH-LEUBA: And would the stress be dependent, I mean if we have much more stress inside the pipe than outside?

CHAIR BALLINGER: For a single V weld, typically what happens is you have a tensile residual stress on the ID, but it goes compressive right away, which is what they see here.

MEMBER MARCH-LEUBA: So, the probability of the crack growing more than a quarter of an inch is small?

CHAIR BALLINGER: Low.

MEMBER MARCH-LEUBA: Low.

CHAIR BALLINGER: But again, the weld, you've heard the expression, is it a Friday weld, or is it a Monday weld? There are all kinds of things, parameters that affect welding. And these are -- look at the multi, these are like 20 pass welds. And the code allows regrinding. In other words you do an inspection part way through, and if you see a defect, the code requires you to grind it out.

So, once you grind it out, you change the whole residual stress pattern, and everything. So, there are a lot of variables that can affect this, and you just have to be mindful of that.

MEMBER MARCH-LEUBA: Would it be a good application for artificial intelligence to review all those records that we're talking about, and identify which of the records?

MS. MOYER: Especially with a new NDE technique that's going to generate boatloads of data, an AI technique would be very --

MEMBER MARCH-LEUBA: We have a separate

subcommittee on artificial intelligence, and --

MS. MOYER: Machine learning is being looked at it for it.

MR. RUDLAND: The repairs haven't been documented, a lot of them haven't been well documented. And again, like Ron mentioned, the stresses are a function of the number of passes in the thickness, but also if there's any repairs, and the depth of those repairs on when this thing may go into compression. You have a large inter diameter repair, you can have even very high stresses through much of the wall because of that repair, so.

CHAIR BALLINGER: But the N4 reactors were the newer ones.

MR. RUDLAND: In reality the smaller the pipe, the harder it is to do an internal repair, right? So, for this size pipe, it's a lot less likely than it is for some of the hot legs, where they've had issues where they had to grind, and do welds.

MR. HOSLER: This is Ryan Hosler, just wanted to make a quick comment. Inspection coverage for these branch lines, the safety injection RHR lines, so as was mentioned, the risk informed inspection program looks at susceptibility, but also consequence. And obviously the non-iceable portion, which is what we're interested in, is going to have a higher consequence, and is going to get a focus of the inspections.

On top of that, as discussed previously, thermal fatigue is a big part of a potential issue in these non-iceable portions of the piping, and there's an MRP-146 inspection program that also looks there. So, there is focus at this particular branch connection, so you don't have to necessarily -- the specific condition isn't necessarily the entire class one, it's just the non-iceable portion of the piping. End of comment.

CHAIR BALLINGER: Just one, or two more.

MS. MOYER: Just one, or two slides more, yes. I know we are on time. Okay, as Ryan just mentioned, there is MRP-146 guidance document, I guess, what do you call it, white paper? That enhances owner's voluntary programs of inspection to look specifically for cracking in these lines. That's enough of that. Okay, class one pipes are examined using multiple ultrasonic angles, or scanning directions.

So, these are well inspected in U.S. plants, in any of the plants there are class one pipes. Personnel procedures, and equipment used on piping welds must pass rigorous performance demonstration testing under ASME code section 11 appendix 8. The examinations in the U.S. are optimized for thermal fatigue flaws also, but are capable of detecting stress corrosion cracking.

And the UT examinations have a current ability to detect cracks 5 to 15 percent through wall with a very good probability of detecting larger cracks. Challenges, there are the same metallurgical challenges of metal grain structure, geometric features like counterbore, and weld crowns, and the well geometry itself that complicate the inspection procedure, and the interpretation of the inspection data.

But NRC continues also to do research on both SCC initiation, and growth, and NDE capabilities. Okay, so ASM has concluded that stresses caused by thermal stratification were one of the major contributors to the root cause of this IGSCC. The older French reactors appear to be less affected, possibly due to design. So, we talked earlier about this is a developing kind of degradation.

This is a time dependent degradation, so one might deduce then that the older plants would be more susceptible than newer plants, that's why this was a bit puzzling at first. And so we think that design had a bigger effect than age in this case. After the inspections have been completed on all the reactors, there's a periodic inspection program that will be defined, and implemented across the French fleet.

The U.S. fleet configured similarly to the older French plants, continues its regular inspections, no similar degradation has been observed in the U.S. plants. So, due to the past U.S. operational experience, the continued robust ASME section 11 exams in these locations, and the follow up by the U.S. industry, the staff concludes that there is no immediate concern for a similar issue in the U.S. fleet.

MEMBER HALNON: Is that taking into consideration comparable position, and places on the pipe? I know we did 10 to 15 percent for the NDE, but was there a concerted effort to go look at this specific line? I guess this is the high pressure injection, or low pressure injection line, what line is this comparable to the U.S. line, do you know Ron?

CHAIR BALLINGER: High pressure injection.

MEMBER HALNON: So, we had the high pressure injection.

(Simultaneous speaking)

MEMBER HALNON: So, we have the high pressure injection nozzle issues, and some valve issues, but have we specifically checked to make sure our records are giving us what you said, that there's been nothing found at the U.S. plants? Is that because we haven't seen anything in our general inspections, or is that because we've actually gone, and looked at these pipes?

MS. MOYER: We have not changed our inspection plans for U.S. plants in response to this observation. We are taking it into account as we do all operating experience, but we have not changed anything in the near term. I think we have another presentation that I would be stepping on if I injected about --

MEMBER HALNON: Okay, we can wait, thanks.

MEMBER DIMITRIJEVIC: This is Vesna Dimitrijevic, I work on the development of EPRI for my side, and we apply this to over 30 plants in the United States, so I have some experience with that, and I can really give you some previous ASME section 11, which is using France's inspect 25 percent every 10 years in class one, and that 25 percent is the same 25 percent every 10 years.

In United States, with the risk informed ISI, which is now applied almost in every plant, I think only maybe a couple don't have a risk informed ISI, actually that was changed at this location, 25 percent were selected based on stress, temperatures, changes, and things like that. So, in the risk informed ISI what happens is the valves were spreading risk, high risk, medium risk, and low risk.

High risk corresponds to high consequences, and high degradation mechanism, and only one high probability of the pipe fail to degradation mechanism, and only flow oscillated corrosion is one of those mechanisms. All other degradation mechanisms, including IGSCC, and the thermal fatigue are considered medium failure probability degradation mechanism.

But when combined with high consequences, like once when somebody just said, the pipe cannot be insulated, they will come in the medium category, where they inspect ten percent. Those ten percent are selected based on presence of degradation mechanisms. Based on all this ISI data up to that moment, only degradation mechanism identified in about 20000 inspections in the class one was thermal fatigue.

And therefore those ten percent are put in those thermal fatigue locations, and that's always the same ten percent. However, the risk informed ISI program has, if ever a different degradation mechanism has been discovered, then the program has to be reevaluated. So, the question is can the current inspection (audio interference) thermal fatigue, also identify IGSCC, I don't know.

But I bet if this information comes from some outside programs, we'll also require plants to look in their risk informed ISI programs, that would be my understanding of that. There is also ASME court cases covering, I think one just covering class one is N760, but I'm not sure, I forgot those numbers. So, covering risk informed inspections.

CHAIR BALLINGER: Okay, well thank you. Other questions from members? Okay, we have -- we're way ahead of scheduled, we're scheduled for a break at 2:40, but I think we can probably just pick it up, and keep going. And so if there aren't any other questions, can we just pick it up? Your name tag has been changed twice already. You were an EPRI guy, and now you're a Framatome guy.

MR. HOSLER: Yeah, somebody is moving me around.

CHAIR BALLINGER: I don't know what's

going on here.

MR. HOSLER: I'm Framatome. So, yeah, someone is going to have to drive the presentation for me, I wasn't able to get my computer hooked up to Teams. So, all right, while he's getting it up, I'll introduce myself. I'm Ryan Hosler, I'm the materials, and fracture mechanics supervisor at Framatome, that's the U.S. part of Framatome, but still part of the mother company.

I'm also the technical lead of the focus group that is addressing this issue, or addressing the potential impact of this issue in the United States. That focus group is developed by the PWR Owners Group in collaboration with EPRI. This focus group is the auxiliary piping stress corrosion cracking operating experience, and -- there we go, coming up here.

So, this focus group includes experts from the industry, utility members, also the vendors, and also EPRI as well, including materials experts, welding experts, NDE experts. A quorum to come together to try to see how this may impact the United States. Actually the focus group is also looking at Owners Group members outside of the United States, but for this presentation we'll focus on the U.S.

One thing I want to briefly cover that's not in my slides, I probably should have added, is just why is this stress corrosion cracking atypical, why are we sitting here? So, historically, stress corrosion cracking in PWRs has been found in isolated locations beyond the first isolation valve, or clearly stagnant conditions, or up in the control audit drive mechanisms.

Where especially for certain designs, with certain plants have a very large volume. So, when you start up you get a lot of oxygen up there during start up. So, you have those off chemistry conditions, you'd see stress corrosion cracking there. Also for cases of stress corrosion cases in PWRs, and well controlled water chemistry, it required heavy cold work. So, imagine pressurizer heaters that were assuaged, and not stress relieved afterwards.

We saw stress corrosion cracking in those, and some chemical volume control system heat exchanger tubes, thin wall tubes that were bent as part of the design. As high cold work, and cracking in those. Now, and so for the non-iceable portions of the branch connections, we haven't really seen stress corrosion cracking prior to this EDF OE. So, that's -- so, looking at this EDF OE, the first factor is it seems like that the weld stress is a primary contributor to initiation.

Meaning there's no evidence cold work, the destructive exams haven't shown any slip planes, or you wouldn't be able to grind the inside of these pipes anyway, it would not be normal practice to grind the inside, and the destructive exams, as mentioned earlier, shows that the weld crown is there, there is no -- at the root, I'm sorry, there is no grinding afterwards.

So, and also this is 316L, so you wouldn't expect sensitization, we haven't really seen any evidence of sensitization, and in destructive exams we've seen indications close to the flowing line, and also far from the flowing line. So, water chemistry does not seem to be a big factor in my opinion, from what I've seen. It seems like exceptionally high stress at the root is what's the primary driver.

And that's what makes this unique, is we have not seen that previously, typically it requires high cold work for this to happen. So, that's one piece, the other piece is the flaws have a large flaw aspect ratio. Meaning they're very shallow, and can be very long, which is again not typical of what we see with stress corrosion cracking. And that's, in my view, primarily driven by, as you discussed earlier, the stress profile you typically see for weld residual stress.

A high ID weld residual stress, and then quickly becoming compressive. So, I just wanted to start off, the Japanese OE that was mentioned, one flaw has been found there, that appears very similar, has all those same characteristics. So, those being the cases that we're aware of, that have this atypical stress corrosion cracking. I just want to kind of give that as a lead in.

So, that comes to the agenda here, which is what are the industry actions to consider this operating experience, and how it may impact the U.S. fleet? So, first, as I said, it's a collaboration between the Owners Group, and EPRI. So, EPRI completed a white paper, which I'll talk a little bit about. We're in the process of revising MRP-236, revision one, which is among other things, a database of the PWR stress corrosion cracking operating experience.

So, that was last revised in 2017, so we're adding new operating experience to it to understand the new trends, and what they may mean. And then lastly I'll talk about the effort in the focus group itself, and the two main efforts are a safety assessment, and applicability assessment. Next slide please. Okay, so for the white paper, the MRP letter, and number is listed there if you'd like to take a look at it.

CHAIR BALLINGER: We have it.

MR. HOSLER: So, it was developed by experts in the field of stress corrosion cracking, Peter, and Jason, Peter Scott I believe. So, here are a few of the inclusions from the paper. The first is that the most important factors that accelerate stress corrosion cracking to higher levels than expected in PWR primary water are residual deformation from cold work, or welding stress.

And then stress from welding, and pressurization fit up, etcetera, and environment, oxidants, and contaminates in creviced areas. Also there's a good deal of discussion of a newly developed crack growth rate for stress corrosion cracking that's discussed, MRP-458, which is also available for review. And also last point being stress corrosion cracking, and stand still components exposed to flowing PWR primary water will continue to occur.

But there is no evidence of aging that accelerates stress corrosion cracking in raw stainless steels, and no sudden increase in stress corrosion cracking initiation growth is expected after decades of operation. I'm happy to take questions on this paper, but I didn't write it, so I can only say so much.

CHAIR BALLINGER: That statement is almost self-contradictory. I mean you take up before the comma, and keep everything after that, everything is fine. If you take everything out after the comma, the meaning changes.

MR. HOSLER: So, you know, I know Peter, so I'll try to interpret what I believe it's saying. What I believe it's saying is stress corrosion cracking is going to happen. As you said earlier, it's hot water, and stainless steel, if you give enough time, it'll happen. If the three components, if they're minor enough, then it might not happen in the life of the plant.

But if one, or two of the components are severe enough, then it'll happen at some point. I think he's trying to hit that point, but he's saying there isn't a late blooming phase, or something, there's no sudden increase expected, I think is what he's saying.

CHAIR BALLINGER: Got it.

MR. WAX: Yeah Ryan, that point you made

at the very end is really what that statement's trying to imply there. And I'm Chris Wax from EPRI. That statement is saying there's no significant increase in propensity for stress corrosion cracking as you age these plants, it's there from day one, it'll be there in day infinity.

CHAIR BALLINGER: I rest my case.

MR. HOSLER: All right, next slide please. Okay, so this is going to discuss a little bit in the next couple slides, the preliminary results of the provisioned MRP-236. So, as I said earlier, this report contains information concerning stress corrosion cracking of primary circuit pressure boundary stainless steel, including an operating experience database.

The last revision was completed in 2017, which found no cases of stress corrosion cracking in the non-iceable portions of the branch piping. The new revision, which is in progress, is reviewing the operating experience since 2017. The only confirmed cases of stress corrosion cracking in the non-iceable portions of the branch piping have occurred in the EDF fleet, and the one case at the Japanese unit.

Also, we've also been reviewing the thermal fatigue OE database, and that's MRP-85, and

MRP-468. And the reason for this is that in some cases you'll be looking for thermal fatigue, you'll inspect, you'll find the flaw, and then perform an overlay, and you'll never actually do a destructive exam, so you can't know with 100 percent certainty, it's just because you were looking for thermal fatigue that it was in fact stress corrosion cracking.

Like with EDF, they were looking for thermal fatigue, and then they ended up finding stress corrosion cracking. So, we reviewed that database for the purpose of seeing if we could find any potential cases of this atypical stress corrosion cracking that was believed to be thermal fatigue. And the way we went about doing that was first looking at the OE database, there's about 34 cases over the last several decades, and look for cases where they did not perform a destructive exam.

And in cases where there was a flaw with a large aspect ratio, meaning shallow, and quite long, similar to what we (audio interference) events in this category. And so, we went through our database, and identified 2 of the 34 cases where it met this criteria. Does that mean stress corrosion cracking? Can't say, because weld overlays were performed, but it does meet the criteria.

So, those will be summarized in the revision to this report. Next slide please. So, this is again, preliminary results, I'll try to walk through this figure here. So, this figure is showing at the bottom, X axis is number of events, stress corrosion cracking events for PWR stress corrosion cracking of stainless steel. And on the left side is the stress driver. Whether it be weld residual stress, cold work, cold work, and residual stress.

Just operating stresses, or depending on operating stresses, and so the blue represents stagnant conditions, and the red represents well controlled conditions. And I'll explain that in a little bit. And saying it might be better to look at it as the blue represents cases where we believe aggressive environment was a significant factor in the stress corrosion cracking.

And the red cases represent events where we believe the environment was not a primary contributing factor in the stress corrosion cracking. Okay, so that being said, as I mentioned earlier, so the top right there, you see the weld residual stress, the big blue block there that is being driven by residual stress. Again, CRD, and CED housings, and fuels, and valve drain lines in iceable piping is where we see the most issues.

And for cold work, in the cold work case, we do see there's some stagnant conditions, but the well controlled conditions, we also would see driven by cold work, I mentioned the pressurizer heaters, and also the vent heat exchanger tubes. What's new is that now there's well controlled water chemistry events that are driven by residual stress, that top right.

And those are the new events, that's the EDF OE, and the safety injection RHR piping, and also the one case in pressurizer spray piping at the Japanese plant. So, that's kind of a visual look at the outlier here, and why we're focusing on this, and how it may impact the U.S. fleet. All right, I think I hit that there. Next slide. Okay, so now I'm going to go over where we are currently with the PWR EPRI focus group addressing this issue.

So, first, I'll discuss the safety assessment, the purpose of the assessment is to assess the potential safety impact of this operating experience in the industry, and then the applicability assessment is to assess the applicability of this OE to the industry. Next slide. The safety assessment's in progress, so this is all preliminary, but the approach essentially, to determine safety impact is based on risk.

And risk is a function of likelihood, and consequence, so what is the likelihood of this type of stress corrosion cracking being present in the United States? And we're going to determine that by reviewing inspection data to determine if applicable locations are being inspected. Review the UT method to determine if these type of flaws would be identified.

And then also review the operating experience database, which I have been discussing, to determine if this type of stress corrosion cracking is occurring outside of EDF. Then we'll also look at the consequences of this type of stress corrosion cracking. So, we'll review the available flaw evaluations to determine if a flaw could reach a critical flaw size, and then also compare design basis analysis breaks to branch line breaks.

And then after all that's done, if appropriate, we'll issue recommendations. Next slide. All right, so this picture on the right here is an example of a branch line within EDF stress corrosion cracking -- I'm sorry, EDF safety injection piping from an N4 design plant. And the reason I'm showing this is in order to determine whether we're inspecting the right locations, we have to define what is the area of interest?

And so, looking at the EDF OE, all of it is in the safety injection RHR branch lines, non-iceable portions, and elbow welds, or heat affected zone adjacent to those elbow welds. And there was discussion of this earlier, but all these are large diameter pipes, 8 to 14 inches. The safety injection is passive, and the RHR is the big RHR suction, sometimes it's 14 inch diameter pipe.

And so, that's the main area of focus for the OE review, or I should say the inspection review I will cover in a moment. Next slide. Okay, so the preliminary results for the likelihood of stress corrosion cracking being present in the fleet. So, I've reviewed the inspection results for 56 units, and focusing on each unit's last inspection that occurred in the last ten year period.

And so going through each of these, the passive safety injection piping, large diameter, it was about 130 welds inspected with no reportable indications. Have the other SI piping, which is high pressure, smaller diameter pipe, could be one, and a half to maybe six inches in diameter. About 250 welds have been inspected with no reportable indications. We'll go to the double asterisk there.

And I'll note that historically some indications have been identified, and attributed to thermal fatigue. But again, these results are the last time they inspected, and the thermal fatigue they observed was prior to that, and some repair replacement was performed. Then lastly, the pressurizer spray -- I'm sorry, the RHR piping, large diameter, we looked at 180 welds that were inspected with no reportable indications.

And also the pressurizer spray piping with 60 welds inspected with no reportable indications. So, there's still 17 units in the U.S. I have not reviewed their data yet, we're still gathering. It's a big effort to gather all that information, to go through it. So, we're looking, and we're not seeing it, at least not in the last ten year period.

And we looked at the OE database, and we're not seeing -- before the last ten year period, the OE database goes up to 2017, we're not seeing stress corrosion cracking in these locations. We look to the thermal fatigue database, there might be two units that meets the criteria, but we're not sure, because there's an overlay. So, then the question becomes well, are we using the appropriate UT method to see it?

So, talking with ND experts, UT experts at EPRI, and the vendors in the industry, the conclusion was that the UT methods employed were appropriate. Meaning that while the techniques used may not be specifically designed for IGSCC protection, they do provide reasonable assurance that if a significant cracking was present, it would be detected. So, there are new UT methods, and qualifications for personnel, and methodologies specific for identifying IGSCC.

They've been used for years in BWRs, and so we are considering those methods here potentially for the future. At least to some, maybe a one time, or maybe something else. It's part of what we're considering as far as the safety assessment.

MEMBER HALNON: So, what if we missed it, what happens?

MR. HOSLER: That gets to the consequence, which is the next slide here.

MEMBER HALNON: Okay, I knew that.

MR. HOSLER: All right, good lead in. All right, so for the consequence evaluation, this is a preliminary result, it's in process. A branch break line is bounded by a break, considered by design basis analysis, that's no surprise. Design basis analysis consider large break LOCA, and those lines are clearly more limiting than a break in a branch line. So, considering could simultaneous breaks happen in multiple branch lines.

Given the paucity of this type of OE, and the extent of inspection coverage, simultaneous breaks in multiple branch lines is highly unlikely. We don't have the statistics to put a number on highly unlikely, but that's where we are right now.

MEMBER HALNON: Is a break in any line likely? Or, I mean less unlikely? In other words if this is left to crack, are we going to expect a catastrophic break?

MR. HOSLER: What makes this -- I talked about why this stress corrosion cracking is atypical, and part of the reason is the large flaw aspect ratio. Typically you would expect a flaw to be driven through a wall, and then leak, and so worse case it would leak, and you would identify it, because stainless steel is highly ductile, and flaw tolerant.

In this case it's less clear, because as EDF has observed, you can have a 360 degree flaw, that so far they've only seen them go the duct to the root pass wall, maybe 20 percent through a wall. EDF has performed flaw evaluations under those criteria, and concluded that faulted events would not cause that to rupture. And as part of this focus group, we have not yet done an analysis like that.

MEMBER HALNON: Okay. Are the cracks arrested, or are they just growing slower, and slower because of less stress?

MR. HOSLER: The residual stress profile that is driving the flaw is highly tensile at the ID, and then drops off very quickly to become compressive. The stress intensity factor, the K driving the crack won't go to zero, it will flatten out to --

MEMBER HALNON: It'll continue to crack, but just maybe at a slower rate.

MR. HOSLER: Correct.

MEMBER HALNON: If it's going all the way around, that slow rate doesn't give me any comfort.

MR. HOSLER: Right. And ideally, that is correct.

CHAIR BALLINGER: I mean the good news is that the maximum amount of unidentified leakage would easily be detected before you got to a case before you had a real problem. The bad news is that at no time during the Davis-Besse event, did the leak rate ever exceed the unidentified leakage limit.

MEMBER HALNON: And that's the same in D.C. Summer, we never, it was a third of a gallon a minute, which is less than the one -- we found it was 400 pounds of boric acid crystals hanging form the hot leg. So, the boric acid is the key, keep boric acid in your system so you can find the leaks.

CHAIR BALLINGER: That's part of my argument about the tactile business of walking through the plant.

MEMBER HALNON: That's right.

MR. RUDLAND: This is Dave Rudland, I have one comment about the stability of these types of flaws. And realize that we're talking about mainly just the membrane type of stresses. If the type was under just totally, membrane stress, you might get to a condition where you might get a crack that continues to grow evenly around the circumference even. But under bending, which a lot of these pipes have bending stresses on them.

Of course it's going to favor one side, or the other to wherever the bending tensile stress is. Which again would lead to a leakage behavior probably before it ruptured.

MR. HOSLER: All right, next slide. Okay, so applicability assessment. This is also in progress, this is preliminary. But the approach being applied is identify, or consider the root causes to find for the EDF stress corrosion cracking operating experience. So, the primary is elevated stresses in the elbow weld region, and through a thermal stratification, I should say that it's identified as the primary by EDF.

And EDF has identified the secondary as weld residual stress. The IRSN has suggested that elevated dissolved oxygen due to dissolved oxygen in makeup water may be a contributing factor. EDF does not consider this to be one of the root causes, but it has been brought up by the IRSN. I can briefly give my thoughts on that. I agree with EDF on this.

Dissolved oxygen in the makeup water would, if that was a contributing factor, you would see stress corrosion cracking in the cold leg. Not only that, we're seeing stress corrosion cracking at the EDF branch lines near the flowing line, and down the branch line far from the flowing line. So, there doesn't seem to be -- oxygen doesn't seem to be a big driver in my view.

CHAIR BALLINGER: The question has been asked in another setting, with respect to the U.S. fleet, on makeup water tanks, some of them are inerted, some of them are not, is that true?

MR. HOSLER: That's my understanding.

CHAIR BALLINGER: And has somebody checked to see which ones are, and which ones aren't? If somebody claims that oxygen is an issue, would that be a discriminating?

MR. HOSLER: If the applicability assessment concludes that oxygen is one of the main drivers, then that could be a way to focus inspections potentially. But we're not going that direction currently for the reasons we discussed. Oxygen can certainly aggravate stress corrosion cracking absolutely. Especially when the material is sensitized, and there's no evidence of sensitization.

And again, we would expect to see cracking elsewhere if oxygen was really an issue. And beyond that, there's also been IGSCC found in the RHR branch line, which comes out of the hot leg, so clearly whatever makeup water you had after it's through before, it's gone. So, there's no oxygen you would expect in the RHR line.

CHAIR BALLINGER: Got it.

MR. HOSLER: All right. So, considering those root causes, assessed whether these conditions are present in the industry so we can consider the potential for thermal stratification in industry branch lines. This has been considered for quite a few years for concerns with thermal fatigue. And so MRP-146, which has NEI0308 guidelines for performing inspections specifically in these elbow welds, looking for thermal fatigue.

So, stratification is definitely something that's been a focus historically in the U.S. For the residual stress aspect, which as I said earlier is, in my view, the main driver, partially because of how the flaw is growing. I think as mentioned earlier, if the thermal stresses, or stratification is going to be preferential on the bottom of the pipe, so you would imagine the flaw would preferentially grow, and go through on that side.

But looking at the EDF OE I haven't seen that. So, that being said, for the applicability assessment, considering weld residual stress, it would be very beneficial to be able to review the weld procedures used, and weld records at the EDF units, and compare that to the U.S. fleet. That is easier said than done. You don't have access to the EDF records.

And also in the U.S. it's highly varied in how it was done, because it's done differently all over the industry. The branch lines weren't welded by the OEM of the reactor, or the primary loop, or the steam generators, they were all done by other organizations. So, I can't go look at the Framatome, or the BMW fabricated plants, and pull those records, because the branch lines were done by other companies.

So, gathering those records is very difficult, so making that comparison is still being considered how feasible it is. Lastly, so we can -- as we discussed, review common practices for makeup water control, and monitoring programs. If we do end up feeling the oxygen is a primary contributor, that's a path we're going to have to go down, but right now we're not going that direction.

Next slide please. All right, so been working on this for a little while, it's going a little slower than I like for two reasons. One is gathering all this inspection data for the fleet has taken some time. And also as mentioned earlier, it's very much an ongoing investigation in France, identifying where there are flaws, determining the extent of the condition.

And so, it's taken some time to gather up that information, and only so much is available to the U.S. And so at a point now where we've discussed in the focus group, said okay, this is the information we have now, or do we take what we have, and write our safety assessment, and then revise it later if we get more information later? So, that was what we've decided to do.

So, now we're moving forward, going to put out the safety assessment in January, and if additional information comes out later, we'll just revise it, and update it. And then applicability, assessment sometime in the first quarter of next year. I'll leave that as my last slide there.

CHAIR BALLINGER: Questions from the members, or consultants? I apologize.

MEMBER PETTI: I just had a question given these French units, are there any designs similar to the French units in terms of the way the piping runs?

MR. HOSLER: So, the N4 design that seems to be most affected, the EDF type design, there are passive safety injection lines, large diameter safety injection lines, which for the vast majority of their flaws, are in those lines are in kind of a downward horizontal configuration, which is not true with the U.S. fleet. The U.S. fleet, pretty much all the passive safety injections are either up horizontal, or horizontal.

CHAIR BALLINGER: Thanks.

MEMBER BROWN: Is that good, or bad?

MR. HOSLER: If thermal stratification, as identified by OE, is a primary driver, then that would mean that the safety injection lines in the U.S. fleet are not affected by the issue.

MEMBER BROWN: Less susceptible.

MR. HOSLER: Correct.

CHAIR BALLINGER: So, then you tumbled to the idea that subtracting all that out, all that's left is residual stress, weld residual stress, and if that's the case, what's the difference between welding procedures in the U.S. versus France?

MR. HOSLER: Besides the operating experience -- besides seeing the types of flaws being observed at EDF, and not seeing those flaws in the U.S., that is the indirect comparison. The direct comparison would be actually reviewing the weld procedures, and weld records. And if those were made available, then that would be useful.

CHAIR BALLINGER: Because there's obviously a difference, one cracked, and one didn't.

MR. HOSLER: I believe, and maybe this is me talking, Ryan Hosler, and not representative of a consensus, but I definitely see a correlation between the branch line configuration, and the amount, the extent of stress corrosion cracking in the EDF fleet. Certainly the N4 design has the most indications, and it has the most stratification. So, there's a clear correlation there.

I'm not seeing the cause effect, but everything I've seen, much of what I've seen is similar to others, which is press reports, some PowerPoint presentations, not a full report. And maybe if I saw a full report, I'd say clearly, I see how they got from A to B. But right now I don't see how they got from A to B, I see a correlation, but not a cause effect right now.

MEMBER BROWN: Is there -- I was looking at the age of the plants. Our plants are older than theirs by not an insubstantial decade, or so.

MR. HOSLER: Yeah, the U.S. fleet is certainly older than the N4 design branch point.

MEMBER BROWN: Yeah, based on the statistics, you're talking 20 years, and these aren't cracking, and those are.

MR. HOSLER: Correct.

MEMBER BROWN: And their materials are still the same? Was it 316LN, or whatever the name was?

MR. HOSLER: Yeah, the materials vary in the U.S., but much of it is 316, sometimes 316L, for the larger diameter pipes, 316 seems more common. For the smaller diameter, 304 seems more common. But they're all stainless steels that are generally similar.

MEMBER BROWN: So, the U.S. plants have had more stress applied to them over a period of time you would think, just from normal operations.

MR. HOSLER: I wouldn't say -- the stress is imparted during fabrication, the weld residual stress. The thermal stratification --

MEMBER BROWN: I wasn't thinking about thermal stress, but just due to operations, and flow usage.

MR. HOSLER: Right. Yeah, I'd say the time is a factor, and temperature is a factor, but all other conditions being equal, higher temperature will make it occur more quickly, but temperatures are similar in both designs, U.S., and EDF. All other components being equal, then yeah, it's just a matter of time. So, clearly we're not seeing -- in the EDF fleet, their older plants, they're only seeing it in their newer plants.

MEMBER BROWN: The 900s.

MR. HOSLER: In the 900s they're not seeing, they had one that was really associated with a weld defect, doesn't seem to be part of this extent of condition. The extended condition at EDF, they defined it as the N4 plant safety injection RHR. And then for the P Prime4, which is new, but not their newest plants, they've seen stress corrosion cracking at one unit.

So, they've included the safety injection lines for those 12 units as well as part of their inspection destructive examination program. But yeah, generally the EDF, they've only seen it in their newer plants, and not their older plants.

MEMBER DIMITRIJEVIC: Yeah, but those are also coming up --

MEMBER BROWN: There's a benefit to being old.

MEMBER DIMITRIJEVIC: Those are higher power plants, over 1300 megawatts. So, I mean in United States, if we look at this, it would have to be in higher power plants. I don't think that aging is maybe such a big part. It's your opinion, the aging is an effect, or the power of the plant?

MR. HOSLER: I don't see a cause effect between the power of the plant, and susceptibility to stress corrosion cracking. It's certainly an aging effect question --

MEMBER DIMITRIJEVIC: No, not the progression, but the temperatures could affect thermal transfer, so.

CHAIR BALLINGER: Nobody really knows when initiation occurred, and these plants are 40, 30 years.

MR. HOSLER: For the EDF fleet, they performed inspections ten years ago, and they didn't see anything, they performed inspections this time, and they did see something. Was it there ten years ago? It's possible it may have been to a small degree, and they just weren't able to detect it. But to them, it appears as though -- I mean it's their 20 year life is when all these started popping up at the N4 design.

Which, now U.S. plants are hitting their 50 years around this time, some of them are. And they're not seeing it, which indicates that clearly there is, in my view, a significant difference between the weld practices that were used at those two designs.

MR. RUDLAND: This is Dave Rudland, if I can make an observation, the NRC, and EPRI a few years back did a very extensive weld residual stress validation program, where we made welds in plates in small diameter pipes, and very large diameter pipes, and looked at how these residual stresses are formed. And something that struck me when I first saw this, and looked at it was the micrographs that I saw definitely showed the root pass of the weld was very large compared to the fill passes.

And again, typically in these multi pass welds, the secondary, the second, and third passes kind of anneal the first pass a little bit, and reduce the stresses slightly. In the cases that we've seen the root passes are very large, indicating to me it's going to have very high residual stress because of how big that root pass is. And that evidence is further brought forward by how deep the crack went.

Which, the crack went to about the depth of the root pass, suggesting again that it's some weld procedure, or some issue with the residual stresses that come from that particular weld. And those were -- granted, we've only seen a very small sampling of the weld sections, but that was an observation that we had from those weld sections.

MR. HOSLER: And that was true for the EDF destructive exam results I've seen, and also the

Japanese one as well.

MEMBER HALNON: I wanted to ask Carol, given all this information, what are the plans for the NRC? Is it leveled effort with research to the SCC, and NDE research, or are you guys finding a generic communication, and you're working up towards that? What's the NRC engagement as they finish their safety assessment?

MS. MOYER: This is an emerging experience, and response. None of that has been decided for sure yet. I will restate that we had already research in place on SCC initiation, crack growth rate, NDE techniques, and their sensitivity, and their reliability, including some of these newer techniques that EDF is employing now. So, we will continue those works to better understand what tools we have, and what susceptibility we may be looking for.

I'm not aware of any plans for a generic communication. I'm looking at Dave because I don't know the answer to that one.

MR. RUDLAND: Yeah, so this is Dave Rudland. Just coincidentally this morning, the NRC management, and the industry management had a materials meeting, and this topic came up of course.

And the status of the industry's focus, effort stuff came up. We asked that when they finish their effort, that we have another public meeting to kind of go over their final results.

And then I think any action we take will have to wait until after we hear their final results.

CHAIR BALLINGER: Yeah, that's good, thanks.

MR. RUDLAND: We suspect, and correct me if I'm wrong, but we suspect sometime this spring, early summer, we would have that meeting.

MEMBER KIRCHNER: Ron, this is Walt, may I ask a question?

CHAIR BALLINGER: Of course.

MEMBER KIRCHNER: Going back to the earlier presentation with that nice picture of the crack, so we have Carol, and David, and Ryan who are metallurgists, I'm not. I look at that kind of crack, and that doesn't look like stress corrosion cracking. I shouldn't have said that. How would you describe that crack from the picture, from the inner elbow picture from EDF.

MR. HOSLER: So, this is Ryan Hosler. The main indicators that it's stress corrosion cracking, and it's hard to see in that picture I agree, but there's some better pictures where it's closer up, and it's etched, so you can see the grain boundaries, and you can clearly see that the flaw is following the grain boundaries. Also some other destructive exam results did in fact break open some of the flaws, and look at the fracture surface with an SEM.

And you can clearly see that the faceted type intra granular stress corrosion cracking indicative surface.

MR. RUDLAND: And this is Dave, one of the first questions I asked was were these things initiated by thermal fatigue, and then grown by SCC? Transitioned, and grown by SCC, and from what I've heard, and read through my counterparts in France, that the SCC is across the entire crack face. So, it's not something that was transitioned, it was purely stress corrosion cracking.

MEMBER KIRCHNER: So, how do you reconcile that with looking at root causes, and saying it's residual weld stress?

MR. HOSLER: Residual stress is historically primary driver for stress corrosion cracking. For the BWRs, all the issues they had in the 80s, they were all weld residual stress driven.

MEMBER KIRCHNER: Okay, thank you.

CHAIR BALLINGER: I might add, there's kind of a rule of thumb, Vicker's hardness number for initiation, the Vicker's hardness number, if I recall, exceeded these numbers.

MR. HOSLER: They're very close to the ID, the hardness is quite high.

MR. RUDLAND: And just to be clear, stress corrosion cracking is a constant load mechanism crack. Fatigue is an alternating load, on, off. For stress corrosion cracking you need to have constant load, and so that's why residual stress is so detrimental to those that are susceptible to stress corrosion cracking.

MEMBER KIRCHNER: Great, thank you, thank you.

MEMBER BROWN: Earlier I asked a question, not being a metallurgist, where we're going now, it seems to me, the way I take away this is our ASME standards, and everything else in the weld requirements for Part 50, and Part 52, whatever we do to build plants seems to have put us in good stead. Is that a reasonable conclusion?

MR. HOSLER: I think what we've been doing has worked very well. Stainless steel generally has been -- stainless steel welds have been extremely well performing.

MEMBER BROWN: Is anything changing with the Part 53 with risk informed stuff, does that get applied to welding? I know a wide variety of plants, and light water reactors could use Part 53 if they wanted to, I presume. Do we still have special --

MEMBER PETTI: It still pushes the section level.

MEMBER BROWN: Okay, I didn't remember that from our previous --

MEMBER PETTI: Yes, but again, in some cases they're not going to use stainless steel, they're going to use high end nickel alloy, it depends on the reactor.

MEMBER BROWN: Yeah, stuff of that nature. I just needed to make sure it was clear in my mind.

MEMBER PETTI: Yes, and the code, and such is actively evolving for some of these more advanced reactors, and the newer materials, and higher temperatures, so they're in the process of evolving to try to meet those needs.

MEMBER BROWN: Just worry about you don't want to see the standards not meet the tests, we've been building these things since the late 50s, and that's a long time to have some of the very, very early plants, which have been decommissioned already, but it just seems to have put us in good stead, that's why I asked the questions.

CHAIR BALLINGER: Stainless steel has produced a number of bad hair days, and expenses, but it hasn't resulted in anything really bad.

MS. MOYER: As we've been saying, it is a resilient material, corrosion resistant, stainless, but corrosion resistant anyway. And between the design, and the inspection of section 11, leak before break has been maintained, and yes. So, if there are problems, typically they can be detected before they become big problems.

MEMBER BROWN: My point is inspection requirements, and things like that are costly, but they have at least been able to ensure that we're okay, which is the good news to me.

MS. MOYER: Fair enough.

MEMBER BROWN: I'm not criticizing anybody else, it's not the point, it's just a matter of whatever standards people have, and people complain about, they seem to have worked. Thank you.

MR. SCHULTZ: Carol, this is Steve Schultz. You mentioned that the inspection techniques that have been newly developed in France had the advantages of more rapid testing, and also other opportunities for testing, and you said that we were going to be looking further with that. I'm not sure if this is a question for you, or for the Owners Group. Is there --

MS. MOYER: That's not quite an accurate portrayal. I would say the techniques they're employing are very sensitive, and they find they're capable of detecting flaws, they're also capable of detecting geometry, they're capable of detecting grain structure, and weld micro structure. And the difficulty with a sensitive technique that is capable of detecting many things is it can be challenging in the interpretation of those results.

So, while EDF has selected an inspection technique that will give them a lot of information, turning that into actionable information will be a challenge for them. We are continuing to look at those inspection techniques, as I'm sure a lot of other people are. I mean there are systems available that you can buy, then take to your power plant of whatever sort, and employ that kind of an inspection.

But there are not ASME section 11 appendix 8 qualified procedures that say if you do this, you will get that predictable result. You see what I mean? We're in that somewhat sort of grey area with these new techniques.

MR. SCHULTZ: I thought you mentioned that there would be a dose reduction off (audio interference) technique, did I miss that?

MS. MOYER: That's not true.

MR. SCHULTZ: Okay, thank you.

MR. WAX: This is Chris Wax from EPRI. From a inspection perspective, we do have the performance demonstration institute within our EPRI NDE Center of Excellence. So, we do require folks to come, and actually qualify on these procedures to prove that they can actually go find an indication in a plant. They get their qualifications there, they get their approval, they get the -- essentially the thumbs up that they can actually go perform these.

And following the IGSCC experience from the BWR plants, we have a pretty extensively well put together IGSCC procedure that has been utilized in the past to look for these types of indications. And like Ryan mentioned in our presentation, that's one of the things we're looking at for future inspection needs. Do we need to go to that route, to that level, and have this IGSCC procedure deployed on these inspections?

And that's something that will come out of our findings, and our discussion from our focus group.

CHAIR BALLINGER: Thank you.

MEMBER DIMITRIJEVIC: Do you mean, okay, are you talking outside of the current ISI program, outside of these ten years, ten percent? You mean additional inspection for IGSCC, is that your meaning?

MR. WAX: I mean we have the thermal fatigue programs that we have required the thermal fatigue procedures to be utilized on in the past, and we're looking at some of those inspections, and the periodicity that they are utilized on. And potentially providing input that we propose the use of the IGSCC procedures. Again, that's in conversation, it's not formal yet, but that's just a thought we're having.

MS. MOYER: And I would want to reiterate that the newer techniques that I mentioned earlier, I'm not going to say the letters, because I'll say it wrong, but you can look back at the slide that mentions these matrix type things. They are very challenging to deploy in a real power plant at this time. They require a transducer that is very large. And so, a large transducer on a small diameter pipe means you don't always get very good sound connection between the transducer, and the pipe.

So, unless they can shrink the size of the transducer with additional technology development, I mean trying to get something that's three inches square to meet against a pipe, and give you a predictable sonification of that volume is just hard. It also produces, as I said earlier, vast quantities of data that will be an interpretation challenge. So, this is why we've chosen not to go this direction just yet.

CHAIR BALLINGER: Are there questions from members, or consultants? Well, that's the end of your presentation, right?

MR. HOSLER: Correct.

CHAIR BALLINGER: So, I'm sure the other members would thank you very much for the presentation, it's been very informative. We are hopefully going to get more presentations as this evolves. This was for information only, and I think you provided us with as much as you can by way of information that we can -- to give us a perspective on the issue, which is really important for us.

So, if there aren't any -- I have to go out -- excuse me. Now we can ask, are there any members of the public that would like to make a comment? If there are members of the public out there that would like to make a comment, please state your name, and then make your comment. Hearing none, again, I'd like to thank you guys very much for coming, and talking with us. And this meeting is adjourned.

(Whereupon, the above-entitled matter went off the record at 3:05 p.m.)

Stress Corrosion Cracking in French PWRs: Operating Experience Discussion

Carol Moyer, Sr. Materials Engineer, NRR/DNRL/NVIB

David Rudland, Sr. Technical Advisor, NRR/DNRL

November 16, 2022

French Operating Fleet

- 56 reactors in operation, all Pressurized Water Reactors (PWRs)
- Built during 1970s – 1990s
- 3 main styles
  - 32 are 900 MW (CP0 and CPY types)
  - 20 are 1300 MW (P4 and P'4 types)
  - 4 are 1450^{+} MW (N4 type)
- Based on Westinghouse design, modified for French grid

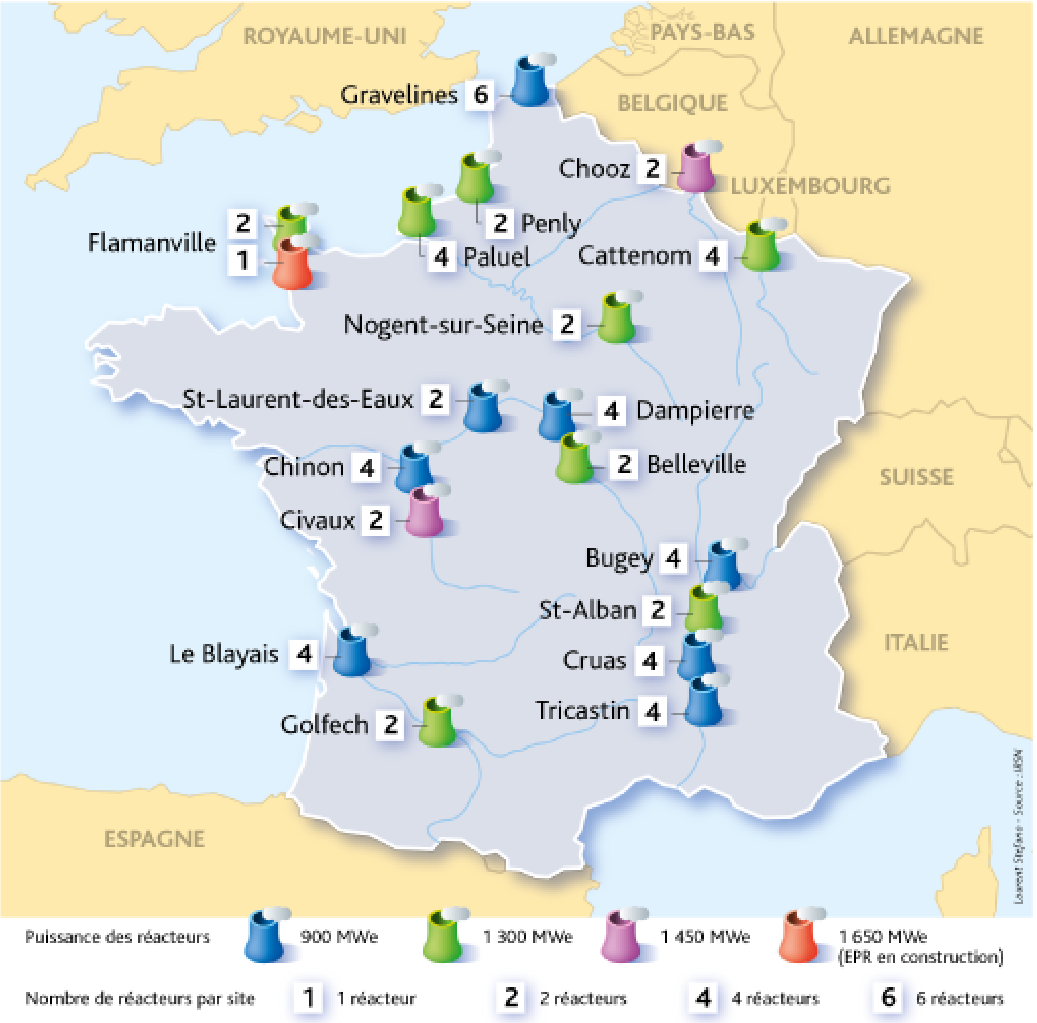
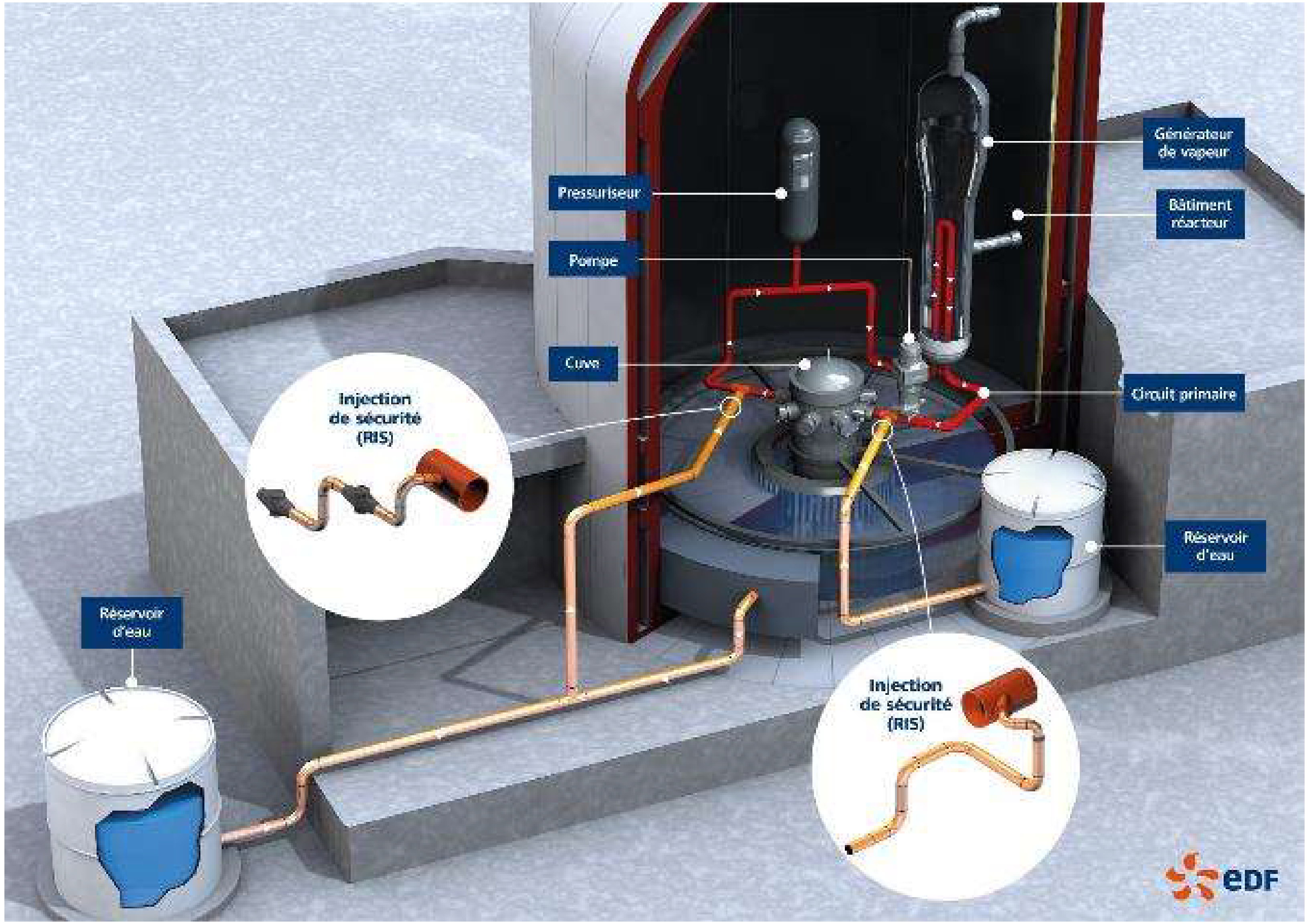


Figure courtesy of ASN

Timeline of Cracking Detected in French NPPs in Fall 2021

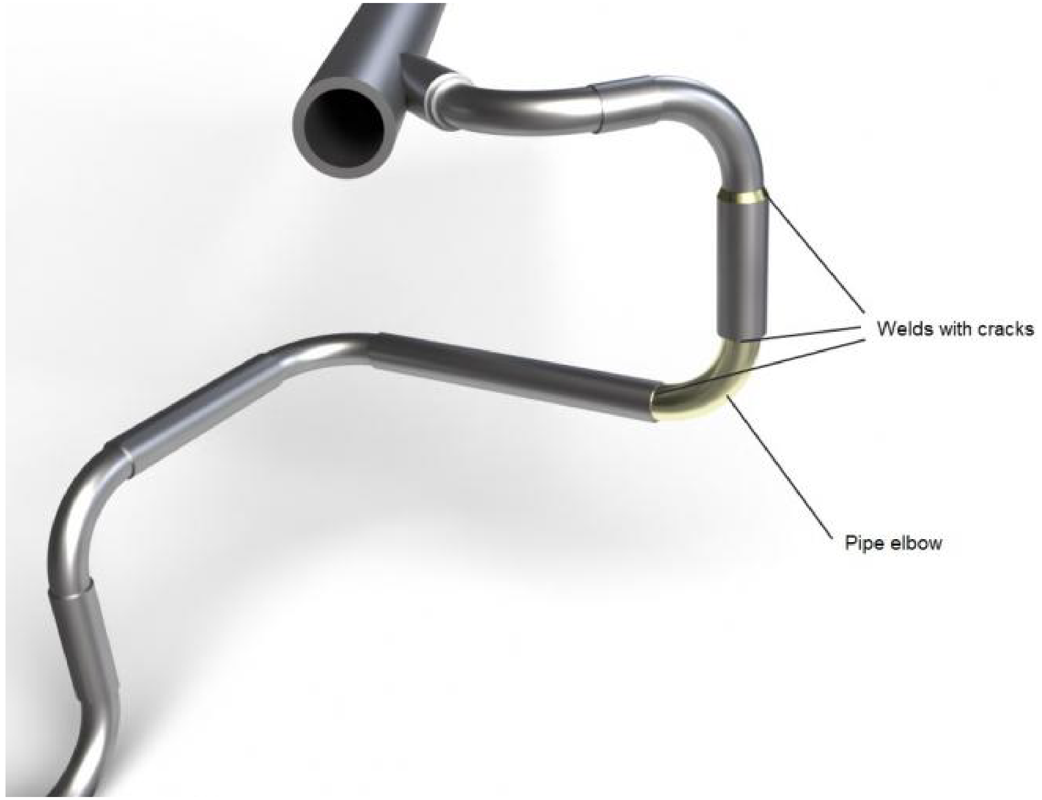
- Flaw indications were detected near welds in safety injection (ECCS) lines during scheduled decennial safety inspections
  - 10/2021 – Civaux-1 (N4)
  - 11/2021 – Civaux-2 (N4) and Penly-1 (P4)
  - 12/2021 – Chooz-B1 and Chooz-B2 (N4)
- Indications found in safety injection (SI) lines and residual heat removal (RHR) lines
- Laboratory analyses of Civaux-1 cracks identified intergranular stress corrosion cracking (IGSCC)
- Regulator (ASN) decided to expand inspections and reevaluate prior NDE data

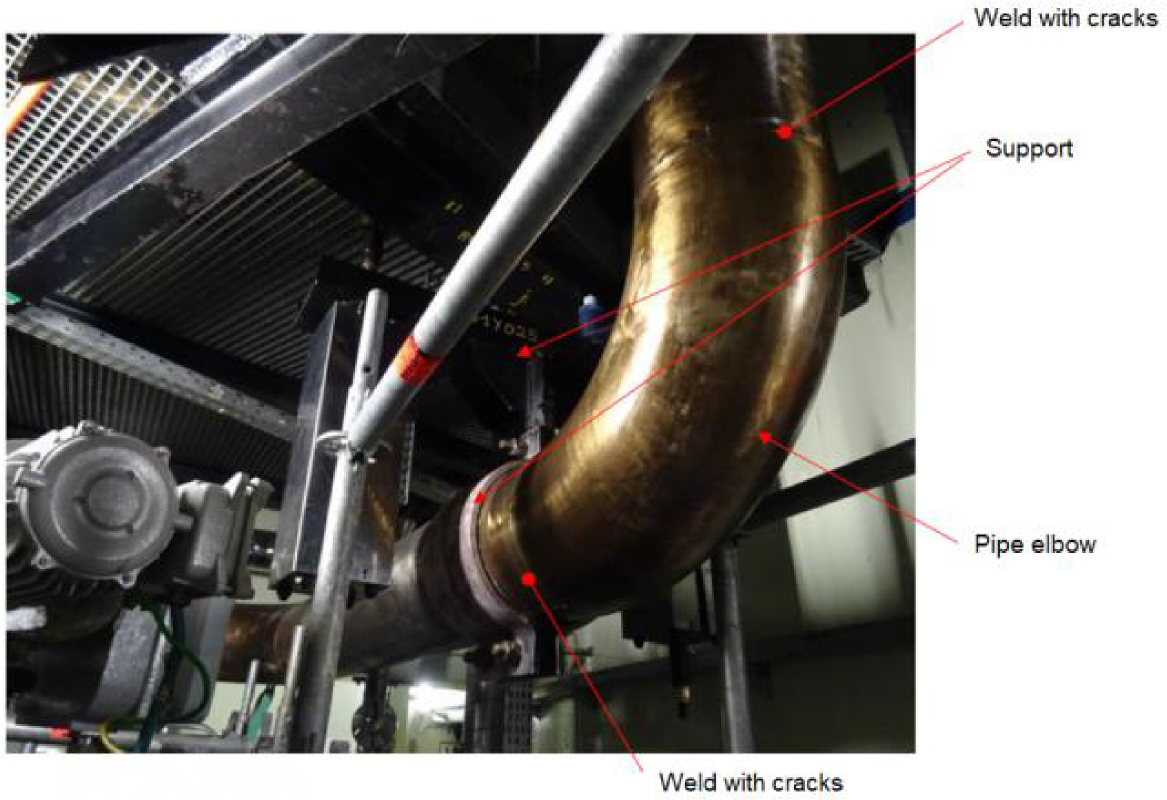
Affected Piping Loops



- 4 separate loops, connected to the cold leg of the primary circuit
- Stainless steel piping
  - Diameter: 25 to 30 cm
  - Thickness: 2.85 cm
- Design modifications increased the length of piping runs in the safety injection circuits to reduce inspector dose.

Cracking Locations in Safety Injection Piping





Nominal pipe sizes are 8” – 14” diameter, 1” wall thickness

Figures courtesy of ASN. https://french-nuclear-safety.fr/asn-informs/news-releases/stress-corrosion-phenomenon-detected-on-reactors

Additional Indications of SCC in Spring 2022

- EDF accelerated plans to inspect safety injection piping for similar degradation in Spring 2022
- The regulator (ASN) requested additional information from EDF to assess the degradation and its extent – whether a generic issue.
- Summer 2022 – EDF deployed new NDE method to detect & size flaws
- SCC indications were mostly in 1300 MW and 1450 MW type (newer) reactors, not in 900 MW (older) plants
- SCC indications have been reported at these reactors:
  - Civaux-1 & -2 (1561 MW)
  - Chooz-B1 & -B2 (1560 MW)
  - Penly-1 (1382 MW)
  - Cattenom-3 (1362 MW)
  - Flamanville-2 (1382 MW) (unconfirmed)
  - Golfech-1 (1363 MW) (unconfirmed)

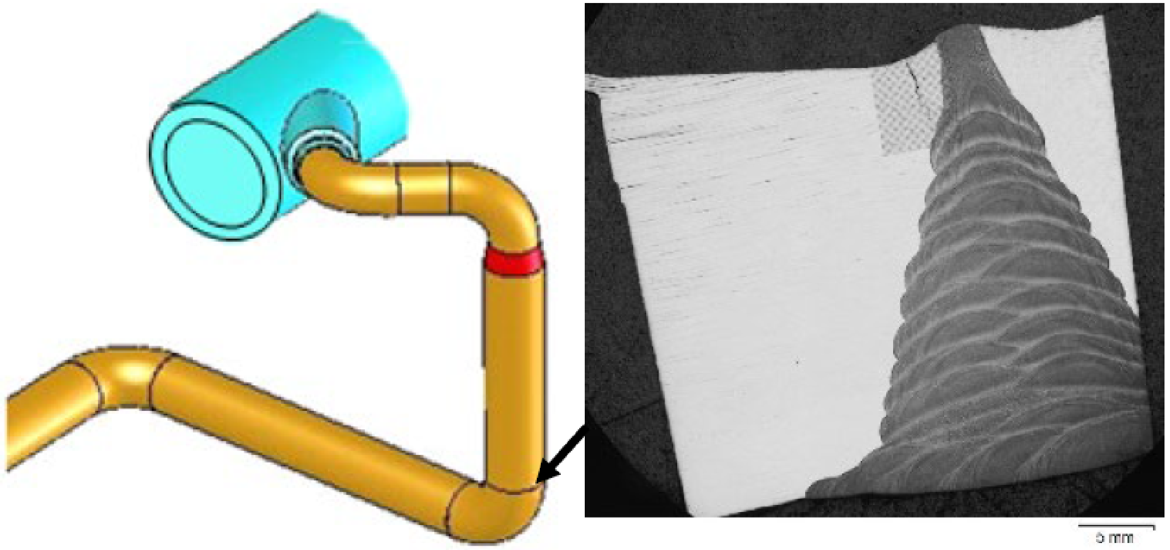
Characterizing the Crack-like Indications

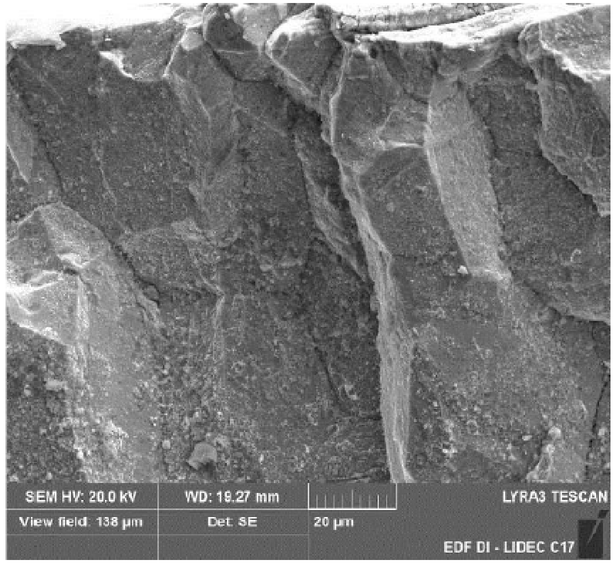
- Indications were at pipe inner diameter, located at elbows.
- Through destructive examination, the cracks were confirmed and attributed to intergranular stress corrosion cracking (IGSCC).
  - In the base metal (AISI 316L) and heat affected zone (HAZ) adjacent to welds
  - Crack depth varies
  - Crack extension can reach 360° (the full circumference)
- Thermal fatigue cracks had been anticipated.
  - Stagnant or intermittent flow is expected in affected lines.
  - Thermal stratification in affected lines is postulated.

Destructive Examination

- Over 100 welds have been examined with either penetrant test or destructive examination.
- Cracked elbows were removed and sent to EDF hot laboratory for assessment. Cracks were confirmed, attributed to intergranular stress corrosion cracking (IGSCC).
  - In the base metal (AISI 316L) and heat affected zone (HAZ)
  - Max. depth confirmed ~1/4 through-wall depth
- High hardness detected in the vicinity of the weld root pass
- Unusual weld geometry (height of the weld root pass) or weld repairs detected in some cross-sections
- No evidence of chemical contamination

Destructive Examination of Civaux-1 Crack





“Susceptibility to IGSCC of cold work austenitic stainless steels in non-polluted primary PWR environment,” T. Couvant et al., EDF, Fontevraud 10, Sept. 2022

- Non-sensitized 316LN
- Non-polluted hydrogenated primary water at ~300°C
- 20 years in service
- Elevated hardness (~270 HV) at ID surface
- Fully IGSCC

Non-Destructive Examination (NDE) (1/2)

- Cracks were detected by manual ultrasonic testing (UT)
  - Procedure used 45° shear wave at 2.25 MHz
  - Manual scanning has worker dose implications
- The UT procedure was designed to detect thermal fatigue (TF) cracks. It was not optimized to detect or size SCC cracks.
- Destructive exams have confirmed intergranular SCC cracks, with depths up to 6 mm (0.25”), up to 360° circumference.
- EDF has reanalyzed prior NDE data to look for missed calls, data characterized as “non-relevant indications.”
- Re-inspection of plant ECCS piping is using an advanced NDE procedure and accelerated schedule.

Non-Destructive Examination (NDE) (2/2)

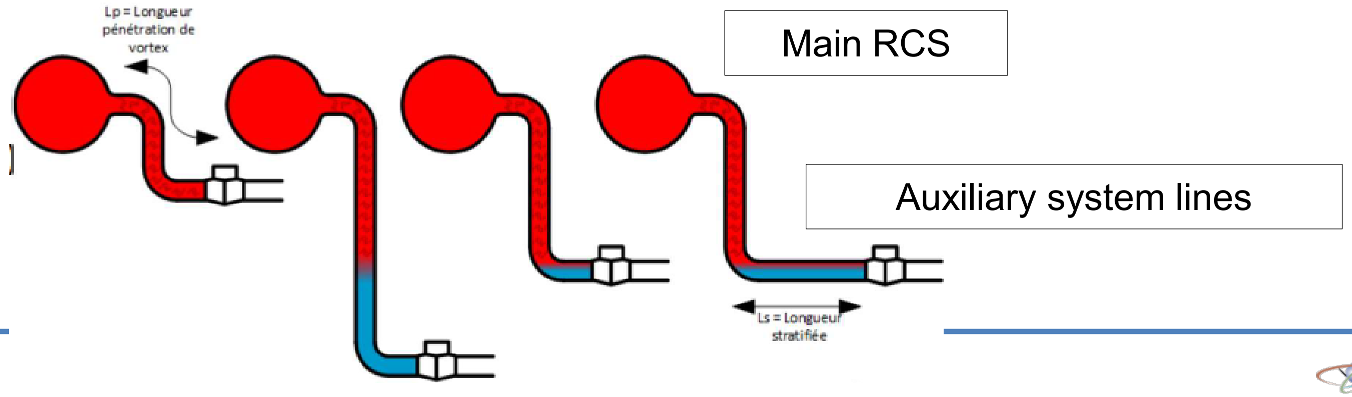
- Safety injection lines are being inspected by remote penetrant test or by ultrasonic test (UT)
- Total Focusing Method/Full Matrix Capture (TFM/FMC) Plane Wave Imaging (TFM/PWI)
  - Scanning is still manual but encoded for location
  - EDF claims flaw depth sensitivity is +/- 1mm
  - TFM/FMC is a research technique, not qualified – will pursue RSE-M
  - Why a qualified phased array UT (PA-UT) technique was not selected is unclear.

Root Cause Analysis (1/2)

- IGSCC degradation was not expected, not in accordance with the international operating experience. No SCC on the French 900 MW plant series after 30 years.
- No evidence of contamination was observed
- Weld repairs and deviations from normal weld procedures may have influenced cracking.
- EDF has performed a welding simulation to estimate hardening and residual stresses in the areas where IGSCC is observed.
  - An area of limited depth on the inner side of the weld is subject to tensile stress.
  - A compression zone exists within the bulk of the weld. This compression zone could significantly slow down the propagation of the cracks.
  - Destructive exams confirmed hardening near pipe inner diameter

Root Cause Analysis (2/2)

- Weld repairs may contribute to SCC susceptibility
  - Residual stress changes and localized hardening may occur
  - Regulator asked for all repaired welds to be re-inspected
- Oxygenated water may contribute to SCC susceptibility
  - Oxygen ingress in reactor coolant system might come from non-deaerated fluids (core make-up tanks, boric acid tank) or H_2O_2 injected at shutdown.
- Thermal stratification is expected to impose cyclic loading on the pipes
  - Increased in N4-type reactors, associated with longer horizonal runs for inspectability
  - Modeling by IRSN shows more stratification than previously expected



U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Mitigation Plans - France

- Cracked piping sections have been removed and replaced.
- From September 2022 through 2025, EDF intends to carry out a complete examination program on all operating reactors, on the areas that might be affected by IGSCC.
  - Advanced UT procedure optimized for IGSCC detection
    - Technique is based on Phased Array Ultrasonic Testing (PAUT) combined with the Total Focusing Method (TFM)
    - EDF plans to seek qualification of the technique in 2023
  - All reactors considered as most sensitive (N4 type, reactors with indications that may have been considered as non relevant) have been stopped to carry out inspection and repairs where needed.
- A periodic inspection program will be defined, with a periodicity based on the sensitivity of the NDE, the growth rate of IGSCC, and mechanical elastic-plastic fracture mechanics analyses.

Status of the French Fleet

- Currently 26 reactors are shut down: 15 for stress corrosion problems and 11 for maintenance.
  - Repair work was completed at 6 reactors
  - Repairs are underway at 4 reactors
- EDF performed FEA stress analysis and proposed flaw evaluation criteria for continued operation.
  - For Cattenom Unit 1, EDF requested continued operation for 8 months without repair of cracks (4mm and 6mm).
  - On advice of IRSN, ASN denied a re-start authorization due to uncertainties in crack sizing and pipe stresses.

Similar Operating Experience

- A similar crack was found in Japanese Ohi Nuclear Power Station Unit 3 pressurizer spray weld in August 2020, which was attributed to hardening from high weld stress on the inside diameter (ID) surface.
  - Unusual heat input at the weld
  - Restriction of weld deformation (constraint)
  - Residual stress would be expected
- Operating experience in U.S. PWRs has shown that stress corrosion cracking of 316 stainless steel is unlikely without significant abnormal conditions, e.g., cold working, grinding, contamination, oxygenated water conditions.

USA Operating Experience

- The use of ASME Code Section XI is mandated by 10 CFR 50.55a with most U.S. plants using an NRC-approved risk-informed inservice inspection (RI-ISI) plan as an alternative to Section XI.
- U.S. plants examine ≈10-15% of the ASME Class 1 SI and RHR piping welds under their RI-ISI programs.
- No SCC has been found in analogous welds in U.S. PWRs.
- Welds are susceptible to thermal fatigue cracking.
- There have been ten incidents of thermal fatigue cracking since 2013, with seven found through UT examination and three by leakage.
- EPRI updated MRP-146 in 2018 to enhance the owner's voluntary programs of inspections to detect thermal fatigue cracking.

More on U.S. NDE Examinations

- Class 1 stainless steel pipes are examined using multiple ultrasonic angles from four directions.
- The personnel, procedures, and equipment used on piping welds must pass rigorous performance demonstration testing under ASME Code Section XI, Appendix VIII.
- The examinations in the U.S. are optimized for thermal fatigue flaws but are capable of detecting stress corrosion cracking.
- The UT examinations have a current ability to detect cracks of 5-15% through-wall depth and a good probability of detecting larger cracks.
- Challenges include the metal grain structure and geometric features of the pipes and welds.
- NRC continues to conduct research on SCC initiation and NDE capabilities

Conclusions

- ASN concludes that the stresses caused by thermal stratification are likely the most significant factor in the root cause of the IGSCC.
- Older French reactors appear less affected, possibly due to design.
- French fleet inspections will be carried out with advanced UT.
- After inspections have been completed on all reactors, a periodic inspection program will be defined, with a periodicity based on the sensitivity of the NDT, the expected growth rate of IGSCC, and elastic-plastic fracture mechanics analyses.
- The US fleet, configured similarly to the older French plants, continues regular inspections. No similar degradation has been observed.

PWROG
PWR Owners Group

Global Expertise • One Voice

Ryan Hosler – Auxiliary Piping SCC OE Focus Group Update

ACRS Meeting 11/16/22

Agenda

Industry actions to consider EDF OE

- EPRI white paper (complete)
- Revision to MRP-236R1 (in progress)
- PWROG Focus Group (in progress)
    - Safety Assessment
    - Applicability Assessment

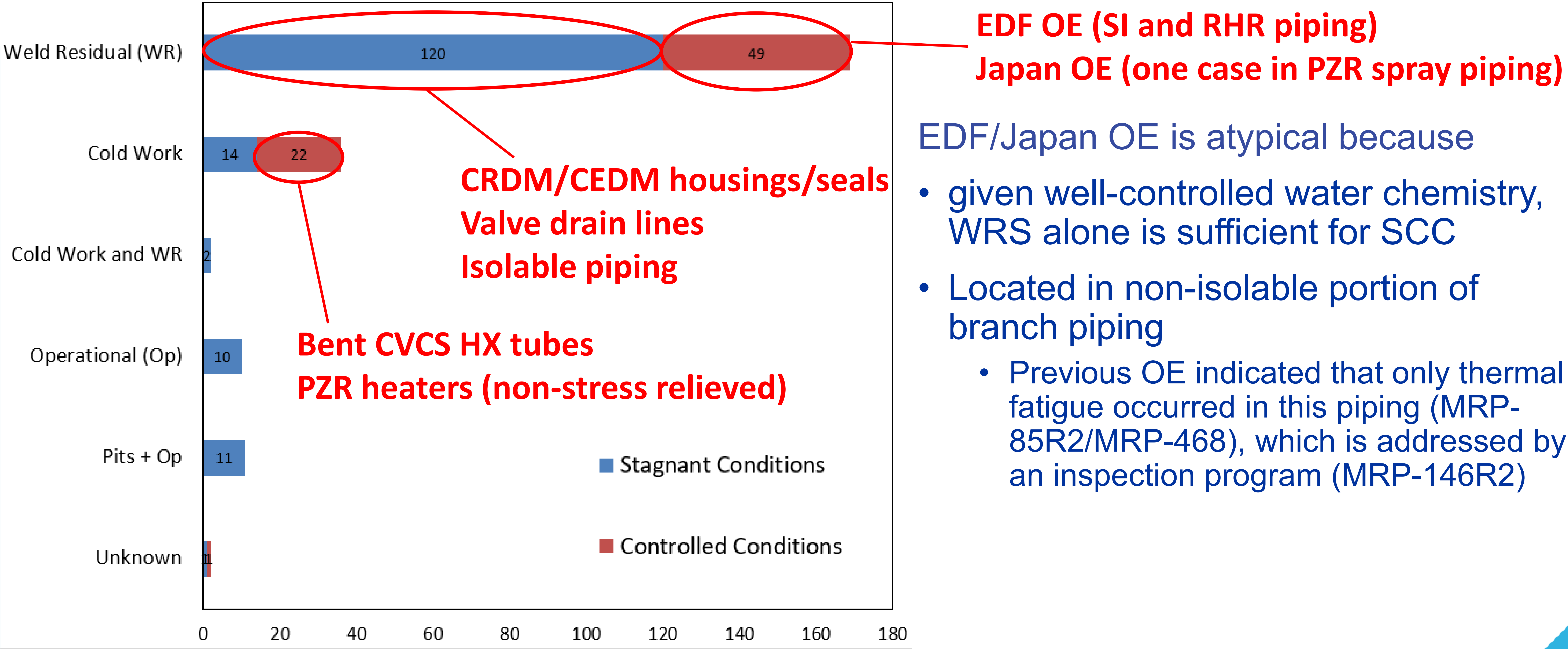
EPRI White Paper (MRP Letter 2022-018)

- Developed by experts in the field of SCC in LWRs
- Conclusions:
  - The most important factors that accelerate SCC to higher levels than expected in PWR primary water are residual deformation (from cold work or welding), stress (from welding, pressurization, fit up, etc.) and environment (oxidants and contaminants in creviced areas)
  - There is a newly developed empirically-based SCC CGR equation (MRP-458)
  - SCC in stainless steel components exposed to flowing PWR primary water will continue to occur, but there is no evidence of aging that accelerates SCC in wrought stainless steels, and no sudden increase in SCC initiation and growth is expected after decades of operation

Revision to MRP-236R1 (1/2)

- MRP-236 contains information concerning SCC of primary circuit pressure boundary stainless steel, including an OE database
- Last revision was completed in 2017, which found no cases of SCC in the non-isolable portions of branch piping
- New revision (in progress) is reviewing OE since 2017
  - Only confirmed cases of SCC in non-isolable portions of branch piping have occurred in the EDF fleet and one case at a Japanese unit
  - Revision will also include a review of the thermal fatigue OE database (MRP-85R2/MRP-468) for cases that have the potential to be EDF-like SCC
    - Focused on flaws with large aspect ratios and where a destructive exam to confirm mechanism was not performed
      - Two units have presumed thermal fatigue in RHR piping with these characteristics

Revision to MRP-236R1 (2/2)



EDF/Japan OE is atypical because

- given well-controlled water chemistry, WRS alone is sufficient for SCC
- Located in non-isolable portion of branch piping
  - Previous OE indicated that only thermal fatigue occurred in this piping (MRP-85R2/MRP-468), which is addressed by an inspection program (MRP-146R2)

PWROG/EPRI Focus Group

- Coordinating efforts between PWROG and EPRI
- Safety Assessment
  - Purpose: Assess potential safety impact of EDF OE on the industry
- Applicability Assessment
  - Purpose: Assess applicability of EDF OE to the industry

Safety Assessment (1/4)

Approach

- Safety is based on risk, which is a function of likelihood and consequence
  - Likelihood of SCC
    - Review inspection data to determine if applicable locations are being inspected
    - Review UT method to determine if EDF-type flaws would be identified
    - Review SCC OE database to determine if EDF-type SCC has occurred elsewhere
  - Consequence of SCC
    - Review available flaw evaluations to determine if a flaw could reach critical flaw size
    - Compare design basis analysis breaks to branch line breaks

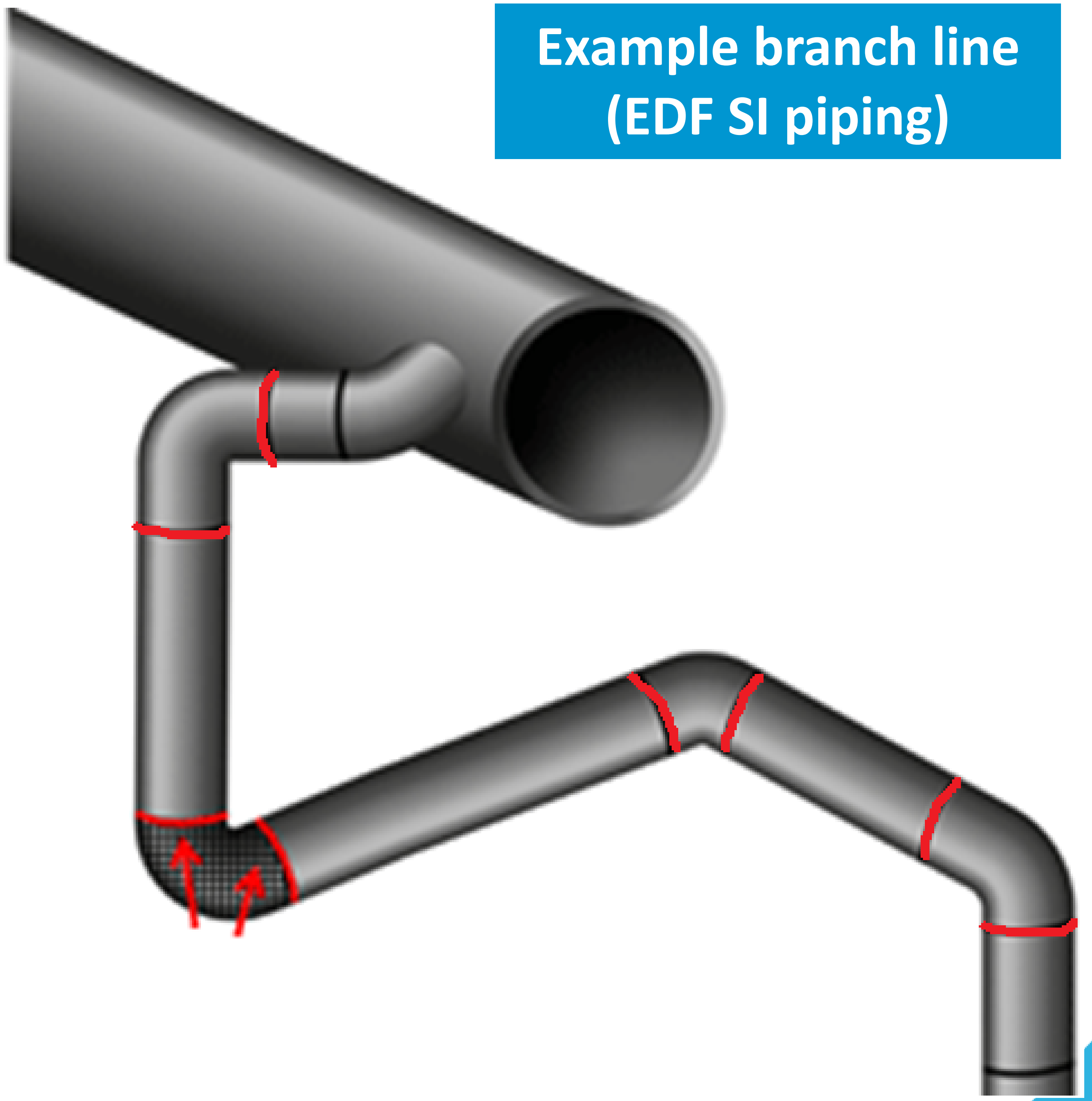
Issue Recommendations (as appropriate)

Safety Assessment (2/4)

Areas of interest per EDF/Japan SCC OE

- Red highlighted welds indicate weld HAZ locations of interest (i.e., elbow welds)

Example branch line (EDF SI piping)



Safety Assessment (3/4)

Preliminary Results for Likelihood of SCC

- Inspection results reviewed for 56 units*
  - Passive SI Piping (large diameter): ~130 elbow welds inspected with no reportable indications
  - Other SI Piping (small diameter): ~250 elbow welds inspected with no reportable indications**
  - RHR Piping (large diameter): ~180 elbow welds inspected with no reportable indications**
  - PZR Spray Piping: ~60 elbow welds inspected with no reportable indications
- Gathering of inspection results continues (17 units remain for US fleet)
- UT methods employed were appropriate
  - While the techniques used may not be specifically designed for IGSCC detection, they do provide reasonable assurance that if significant cracking was present, it would be detected
- UT methods specific to IGSCC are being considered

*Results from last inspections performed during most recent 10-year interval

**Historically, some indications have been identified and attributed to thermal fatigue

Safety Assessment (4/4)

Preliminary Results for Consequence of SCC

- A break in a branch line is bounded by breaks considered by design basis analyses
- Given the paucity of this type of OE and the extent of inspection coverage, simultaneous breaks in multiple branch lines is highly unlikely

Applicability Assessment

Approach

- Consider root causes defined for EDF SCC OE
  - Primary: Elevated stresses in the elbow weld regions due to thermal stratification
  - Secondary: Weld residual stress
  - Suggested by IRSN: Elevated dissolved oxygen due to dissolved oxygen in makeup water*
- Assess whether these conditions are present in the industry
  - Consider potential for thermal stratification in industry branch piping
    - This is a primary focus for existing thermal fatigue inspection requirements (MRP-146R2)
  - Compare weld procedures
  - Review common practices for makeup water control and monitoring programs

***EDF does not consider O2 to be a root cause**

Schedule

Report	Projected Completion
Safety Assessment	January 2023*
Applicability Assessment	March 2023

***Safety Assessment may need to be updated in the future as more information becomes available**

Questions?

Full Name	Timestamp
Court Reporter1	11/16/22, 12:45:20 PM
Russell Cipolla Intertek	11/16/22, 12:45:20 PM
Larry Burkhart	11/16/22, 12:45:20 PM
Thomas Dashiell	11/16/22, 12:45:20 PM
Michael Snodderly (DFO, ACRS)	11/16/22, 12:45:20 PM
Christopher Brown	11/16/22, 12:45:20 PM
Carol Moyer (NRR)	11/16/22, 12:50:09 PM
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Carol Nove	11/16/22, 12:52:31 PM
Beth Kehler Haluska (Services - 6)	11/16/22, 12:52:52 PM
Vesna Dimitrijevic (Guest)	11/16/22, 12:54:12 PM
PETIT Marc	11/16/22, 12:54:18 PM
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Dennis Bley (Guest)	11/16/22, 1:09:16 PM
Matthew Mitchell	11/16/22, 1:10:12 PM
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R (Guest)	11/16/22, 1:16:40 PM
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David Rudland (NRR)	
Chris Wax (EPRI)	