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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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731ST MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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OPEN SESSION

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THURSDAY

DECEMBER 4, 2025

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The Subcommittee met via Video-Teleconference, at 8:32 a.m. EST, Walter Kirchner, Chair, presiding.

MEMBERS PRESENT:

WALTER KIRCHNER, Chair

GREGORY H. HALNON, Vice Chair

VICKI M. BIER, Member

CRAIG D. HARRINGTON, Member

ANNIE KAMMERER, Member

ROBERT P. MARTIN, Member

SCOTT P. PALMTAG, Member
DAVID A. PETTI, Member
THOMAS E. ROBERTS, Member
MATTHEW SUNSERI, Member

DESIGNATED FEDERAL OFFICIAL:
LAWRENCE BURKHART

ACRS CONSULTANT
RONALD BALLINGER
ALSO PRESENT:
KATHY BARNES, Public Participant
ALAN BLIND, Public Participant
JESSE DEER, Public Participant
JACQUELYN DRECHSLER, Public Participant
ARNIE GUNDERSON, Public Participant
ANDREW JOHNSON, NRR
KEVIN KAMPS, Public Participant
MICHAEL KEEGAN, Public Participant
PAUL KLEIN, NRR
APRIL NGUYEN, Region III
KARL RABENHORST, Public Participant
KRAIG SCHULTZ, Public Participant
ANN SCOTT, Public Participant
SPENCER TOOHILL, Public Participant

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

8:32 a.m.

CHAIR KIRCHNER: This morning's topic is the Palisades Steam Generators Operational Assessment. We have received quite a few written comments from interested members of the public and at least one request to make an oral statement from Mr. Arnie Gunderson. There will be opportunity for these statements and other public input after the committee has heard from the staff on the subject.

And with those introductory remarks, I will now turn to my colleague, Greg Halnon, who is vice chairman of the ACRS and our lead member on this topic. Greg.

VICE CHAIR HALNON: Thank you, Chair Kirchner. During our 728th full committee meeting on September 3rd through the 5th, we discussed the Palisades restart activities. Since the documentation was not available at the time, the operational assessment of the steam generators will be discussed today as one topic, one sole topic, of this morning's meeting session.

As part of the interaction with the committee, the NRC staff will present and discuss their thoughts on the subject and the document. Once this is complete, we will have approximately 15 minutes for public comments. Unless previously allocated more time, comments will be limited to two minutes to ensure that as many individuals as possible have the opportunity to speak about the operational assessment of the Palisades steam generators. As you make your comments, I do ask that you please focus your comments accordingly.

The committee will then discuss what we've heard today, and I anticipate that we will provide a short write-up through our deliberations of the meeting's summaries.

So with that, I'll turn the presentation over to Paul Klein of the staff. Paul.

MR. KLEIN: Thank you. Good morning, ACRS. Paul Klein from NRR staff. My colleague seated off to my right here is Andrew Johnson, and we're both in the Division of New and Renewed Licenses in the Corrosion and Steam Generator Branch, and we're happy to be here this morning presenting the results of the Palisades steam generator OA.

CHAIR KIRCHNER: Paul, just pull your microphone a little closer.

MR. KLEIN: Is that better?

CHAIR KIRCHNER: Yes.

MR. KLEIN: Thank you. We just want to put a list of the acronyms upfront to help members of the public that might be joining and those that aren't as familiar with general nuclear and more steam generator-specific acronyms to better follow the discussion this morning.

Some of the ones on the list that we'll probably touch on the most during the course of this morning's presentation on the left side would be CM, which is condition monitoring; eggcrate, which is the term for the horizontal lattice tube supports in the steam generators at Palisades. On the right side, we'll be speaking quite a bit about SCC, or stress corrosion cracking, and OA, the operational assessment, which is the forward-looking projection of tube integrity to the next inspection.

Next slide. So we recognize the focus for today is the Palisades Steam Generator Operational Assessment for Cycle 29. We did want to start, however, with a summary slide to provide a high-level perspective upfront of the Palisades work as a whole. And since it's been a few months since September, since we last presented at ACRS, we thought it would also be beneficial if the OA discussion was preceded by some slides that relate to the steam generator design to some of the results from the tube inspections, the subsequent tube sleeving; and then we'll follow that up with some of the condition monitoring and operational assessment work that was done. And then we'll wrap-up with some information related to recent steam-generator chemical cleaning at Palisades and provide concluding remarks.

So this slide is really intended to be a high-level summary, and we'll get into more details later on in the presentation. We previously have briefed the committee about degradation was detected during 1D28 at Palisades, the D designating a defueling instead of a refueling outage. The big surprise during the steam generator tube inspection was detection of over 1,200 axial ODSCC indications at the horizontal eggcrate supports. And because in steam generator A, if all of the tubes with ODSCC indications at the supports would have been plugged, it would exceed the 15-percent plugging design limit in the tech specs, so the licensee instead submitted a license amendment request to install sleeves as a repair method in lieu of plugging; so, at this point, there's been a total of almost 300 sleeves placed that will be -- oh, thank you. Sorry. Almost 3,000 sleeves will be placed in service to preserve the plugging margin. And it's worth noting that, of that almost 3,000, about 900 of them are what they term corrective sleeves, which means they were placed over locations where ODSCC was present. The other, roughly, 2,000 were preventative sleeves that tended to be placed in locations where cracking could occur in the future. And we can discuss that strategy in a couple of slides when we see the steam generator schematic.

In terms of condition monitoring that showed that tube integrity was maintained, as part of that effort, 23 indications passed in-situ pressure testing as part of the condition monitoring. There was no burst or leakage detected.

And we did want to correct one mistake that was on preliminary slides. In that third bullet, I think the preliminary slides had 23 tubes. It was actually 23 indications and 22 tubes. So I just wanted to note that.

VICE CHAIR HALNON: This is Greg. Before you go on, can you describe what the no burst or leakage criteria is? What is that test and how is it done?

MR. KLEIN: Well, as part of the in-situ pressure test, there's usually two points of interest.

One would be a pressure representative of main steamline break, and so you would be wanting to check for any potential leakage at that point.

And then the burst would be to test against the structural integrity performance criteria, which, in this case, was three times the normal operating pressure differential. And then they add some margin for related to testing at ambient temperature and also for the account from the AGR and other type things.

VICE CHAIR HALNON: And these indications that they tested, they were worst case or at least indications that would be expected to --

MR. KLEIN: Yes, they are the worst-case indications. In terms of the eggcrate supports, they would be the ones that, analytically, would be most likely to burst, if that were to happen during one of the tests.

And then for the circumferential indications, they were tested for leakage. At the top of the tube sheet, there were a number of circumferential indications that we talk about on a later slide that were tested for leakage. And then if you detect leakage, then you would test those for burst at that point; but there was no leakage during any of those tests or with the other tests.

VICE CHAIR HALNON: So just in summary, the licensee took the worst-case known cracks, subjected them to pressure three times the design pressure, and there was no leakage or burst; is that correct?

MR. KLEIN: That is correct for the eggcrate indications for the circumferential ones at the top of the tube sheet that were tested to the main steamline break conditions. And since there was no leakage at that point, there was no need to test them to burst.

VICE CHAIR HALNON: But just to clarify, you said three times the design pressure. Is it three times the normal operating normal pressure? Okay. Slightly less than the design. Well, not slightly. Less than.

MR. KLEIN: That's correct.

VICE CHAIR HALNON: Yes. Okay. Thank you.

MR. KLEIN: It's a good clarification.

MEMBER HARRINGTON: This is Craig. It's a differential pressure.

VICE CHAIR HALNON: Differential.

MR. KLEIN: All right. Should I continue?

For the last bullet here we're on, Cycle 29 Operational Assessment, we have Revision 2 that we took a look at. That Revision 2 was for 1.5 effective full-power years.

The bottom line, and we'll discuss this in more detail later, the analysis results did meet all the performance criteria. There was a little margin for eggcrate structural integrity performance criterion. But there are some very key conservative assumptions as part of that analysis. One is that the crack growth rates at the eggcrates are based on assuming all cracking at 1D28 was just below the detection threshold level at 1R27. And we'll discuss that later, but that is clearly a conservative assumption. And it also assumes no improvements from the chemical cleaning that was just performed on both steam generators.

We did have a verification call with the licensee. And based on that call and some of the discussions, they indicated that a OA revision is in progress, and we're expecting to receive a Revision 3 at some point here in the near future.

This just shows the Palisade's Model 2530 steam generators. I think, in one of our earlier presentations, we were asked if we could show some schematics to give the committee a better understanding of the generators. And as you can see on the left side, the horizontal supports are labeled, once you get above the tube sheet level, 1H up to 8H. The actual sleeves were inserted from 01H up to 05H. And in terms of the preventative strategy that they used, because, once you sleeve a tube, you can't get in in the future to a higher elevation to sleeve at a higher support, they tended to sleeve from 01H to 05H and a lot of the tubes where they had indications. And that's how they ended up with approximately twice as many preventative sleeves as corrective type sleeves.

Overall, the steam generator has 8,219 tubes, 0.75-inch diameter, 0.042-inch wall thickness, combination of lower row U bends and then higher row square bends, as shown on the right here. And I think that is most of the highlights we want to cover.

This next one shows schematically on the left side a more blown-up schematic of the upper support structure, the vertical supports, or vertical straps are sometimes also called. And then you can also see the diagonal bar hot and diagonal bar cold in that schematic, and that's referred to oftentimes as a batwing support. And then the lattice type support on the bottom right of the left side, which then on the right side schematically lays out the eggcrate-type support arrangement. I think we can move on.

VICE CHAIR HALNON: I think we have time to set for clarification on this chart you just put up. There's the vast majority of the axial educations are actually two supports. Go back to the previous picture. Where in this picture were these cracks within the -- I'm sorry -- the length of this? You know, on the right you got the eggcrate, and where are the cracks?

MR. KLEIN: So they would be within that width of that a eggcrate support on the tube in an axial direction. You can imagine there would be a number of deposits around the tube. And this schematically also doesn't show the tube density, so the actual tube bundle would be a 0.75-inch tube arranged on a 1-inch triangular pitch so that there's a much denser packing of tubes for heat-transfer purposes.

VICE CHAIR HALNON: Okay. Thank you. So the cracks tend to occur where the deposits that are trapped by those various structural injuries?

MR. KLEIN: That's correct. The deposits help to trap impurities, which then also promote cracking at those locations.

So this slide's a summary of some of the more important SCC indications and volumetric wear indications at support structures that exceeded the 40-percent wear plug-in criteria during the 1D28 inspection. In terms of the total number of SCC cracks, you can see that the tube supports, by far, have the highest numbers. In terms of the actual wear, we're just showing the indications that exceeded 40 percent, but, of course, there's actually thousands of wear indications, which is not unusual for steam generators to see some type of wear at support structures.

MEMBER HARRINGTON: This is Craig. The high number of wear locations in the condition monitoring table like this, that's not just newly observed ones, that's cumulative over time?

MR. KLEIN: Yes, that's correct. So in the condition monitoring, you would assess all the indications, all the historical ones, plus any new ones. And you, typically, for a generator that's been in service for a number of years where it tends to attenuate over time and so the wear growth rates drop over time and it becomes a stable situation. And I think that's reflected by the relatively few number of indications that you see that were greater than 40 percent here.

MEMBER MARTIN: Question here. Bob Martin. Previously, when you visited us, I think you talked about some cleaning activities. I mean, I can't remember whether they had to clean at the time or plan or, I mean, obviously you've already, you know, if you haven't said it, you've implied debris matters and contributes to the stress corrosion cracking at these eggcrate locations. They've gone in and cleaned them all up so that at least they're ready to go.

MR. KLEIN: Yes. So last time we were here, that was a planned activity at the plant. And, at this point, it has been done and we have a slide that will speak to that later on in the presentation. But, yes, they did a chemical cleaning and there was thousands of pounds of deposits removed from the generators.

MEMBER MARTIN: Okay.

MR. KLEIN: I think the final thing I'll highlight here is shown in red, and that would be the effective plugging percent. So that that would represent the tubes that were plugged, plus accounting for the sleeves that were installed, to come up with an effective plugging percent. And you can see where the steam generator A and B are relative to the 15-percent criteria.

CHAIR KIRCHNER: Can we ask the participants to mute their phones and computers. Thank you.

PARTICIPANT: But could we ask the speakers to say who they are? Thank you.

CHAIR KIRCHNER: Okay. We're just, again, we're having a presentation from the staff. It's Paul Klein and Andrew Johnson. Go ahead.

MR. KLEIN: All right. Thank you. So this slide talks about the condition monitoring. I just want to remind everyone that that is a backward-looking process where you determine if you have maintained tube integrity during operation up until the inspection point. So it uses the inspection results, and you assess whether your tube integrity performance criteria were met.

So, typically, you pre-establish CM limits for each degradation mechanism and location so that you can rapidly evaluate that during the inspection process. Once you begin to receive any EE results, the flaws that are detected can either clearly meet the CM limit with initial ND sizing, some of the larger flaws might require enhanced A-current flaw sizing, which is also termed profiling, to determine if condition monitoring is met. And then if you're analytically unable to demonstrate that condition monitoring was met, the next step would be the in-situ pressure testing.

So all tubes met condition monitoring during 1D28. We previously mentioned there were 23 indications that did require in-situ pressure testing, and there's a breakdown below the third bullet, that the locations of those 23 were at eggcrate supports, there were two axial indications at the top of the tube sheet, 11 circumferential indications at the top of the tube sheet, one axial ODSCC at a diagonal bar hot, and there was one obstructed tube that was tested since they couldn't pass the eddy current probe through the tube. And as we previously mentioned, no leakage or tube burst or an in-situ pressure test.

MEMBER PALMTAG: This is Scott Palmtag. So I have a question on the timeline. So the plant was laid up, and I assume that condition monitoring was done after they decided to restart in terms of the timelines.

MR. KLEIN: Yes. So the condition monitoring would have been done following the inspection that was performed.

MEMBER PALMTAG: Okay. And then, in a condition monitoring report, it says degradation exceeded what was expected, and there were some questions about how the plant was laid up after these latest inspections. Is there any indication of, you know, why there was -- degradation was exceeded or expectations were exceeded?

MR. KLEIN: Well, I think they clearly under-predicted the amount of cracking that was occurring at the eggcrate supports. If the question is whether it would occur at temperature in the last cycle or occur during shutdown; is that what you're asking?

MEMBER PALMTAG: Or why, if they could have some indication of why this occurred.

MR. KLEIN: I mean, I think it occurred because of the axial ODSCC, right? So the question is when it occurred. And I think, you know, the last time we were before the committee, we made a statement that we couldn't for a certain rollout. There was some contribution during shutdown, but the more that we thought about it and the more we've looked into some of the precursor eddy current signals, it seems more likely to us that degradation occurred at temperature. And we'll talk about that in a couple of slides here why we think that.

MEMBER PALMTAG: Okay. That's important because, you know, now you have a better explanation of why this occurred over shutdown. All right. Thank you.

MR. KLEIN: Okay. This schematic shows an example of how the more detailed eddy current or flaw profiling is used as part of the condition monitoring process. So this is a snapshot of condition monitoring of steam generator B for axial ODSCC at eggcrate supports. And if you look on the left chart, each of those data points would indicate an indication that was detected in size by eddy current. On the right side, this would show that same data but now with the benefit of the flaw profiling. So you would essentially take each slice of data and try to develop a flaw profile so that you can better map the actual crack profile. And when you do that, you'll oftentimes find that initial sizing oversized the flaw and you can see that there's relatively few flaws at this point at or above that condition monitoring line, which is shown by the red dashed line. And those indications and the similar ones that would occur in steam generator A then would be candidates for in-situ pressure testing.

VICE CHAIR HALNON: This is Greg Halnon. Real quick. The flaw characterization and the profiling, is that a new process that Palisades came up with because of these generators, or is it part of a well-established industry process that every PWR goes through?

MR. KLEIN: It's part of a well-established process that every PWR would use as part of any inspection of their steam generators.

VICE CHAIR HALNON: So this is not a new methodology or unproven methodology?

MR. KLEIN: Not at all.

VICE CHAIR HALNON: Thank you.

MEMBER ROBERTS: Paul, this is Tom Roberts. Can you speak to the condition monitoring limit? Does that assume one cycle of operation after the inspection, or is that based on the time at the inspection, or is it something else?

MR. KLEIN: The condition monitoring limit is backward looking, so it's not assuming any forward projection of one cycle or two cycles or anything. So it's really to say, at this point in time, based on your previous operation, did you maintain tube integrity?

And so for a given mechanism at a given location, they'll develop a combination of flaw depth and length that would meet that condition monitoring. And so for a different top of tube sheet indication that was axial, you'd see a different condition monitoring line.

And I think it's important to point out that the condition monitoring line is also a conservative line. So it's not intended to indicate that flaws above that line would necessarily lead to burst. And I think that's confirmed by the fact that they had 23 indications that were above the condition monitoring line tested, and there was no leakage or burst from any of those flaws.

So it's intended to represent a conservative flaw above which you need to pay more attention to and below which you're confident that it met tube integrity.

MEMBER ROBERTS: Right. But it's some other analysis that projects forward in time and acceptability. This just says that, as of today, they do expect to operate, but you have to do more analysis to conclude where they are in a cycle or two cycles.

MR. KLEIN: Yes. So the second half of the process, the operational assessment that we're going to get to in a few slides, that that is the forward projection of tube integrity until the next inspection point.

MEMBER ROBERTS: Okay. Thank you.

MR. KLEIN: The next slide here shows a profile of outside diameter deposits from steam generator A. And in this case, this schematic shows deposit loading of 20 mils and thicker, as shown in the yellow highlights on the left chart here. And so deposit mapping is done in most plants to understand the condition of the tubes and to determine when it might be appropriate to do chemical cleaning. And I think what you see here on the left side shows that the highest deposit loading tended to be from above the third support up to about the seventh there.

The right part of this slide, which was taken from the apparent cause analysis from the plant, shows the support number with the bottom support, 01H up to 05H, in terms of the number or percentage of total eggcrate cracks that occurred at that location. So you can see from the chart to the right compared to the highest deposit loading on the left, the chart on the right suggests that it's a temperature-driven mechanism, which is consistent with cracking at temperature at the eggcrates. The 01H and 02H have combined about six out of every ten eggcrate cracks in the steam generator.

So that leads us into the operational assessment part, which we just had a question on a minute ago. So that is the forward-looking projection, and that provides a technical basis for tube integrity until the next steam generator inspection. And that's done for all tube degradation mechanisms, so it includes not only the SCC at the eggcrates, but anywhere in the steam generator plus wear structures, such as vertical straps or diagonal bars.

This process is a pretty mature process, and it is addressed in the EPRI guidelines. And degradation can be projected using a number of different techniques, from fully deterministic to fully probabilistic, and we'll cover these methods in a little more detail in the Palisades-specific results coming up in the next few slides.

CHAIR KIRCHNER: Paul, this is Walt Kirchner. Just going back one slide, on that -- I know you have a slide coming up on the chemical cleaning. So going back to those deposits, those are mainly on what I'll call the hot side of the U-tube.

MR. KLEIN: Yes, that's correct.

CHAIR KIRCHNER: Yes, at the lower support levels for the eggcrates, so to reinforce your temperature-driven mechanism.

MR. KLEIN: Yes. I think in terms of this particular cut, which was for 20 mils and thicker, I think it's shown that the highest deposits are actually a little bit higher than where you're seeing the most cracking. So they don't necessarily line up.

CHAIR KIRCHNER: They don't line up on through one.

MR. KLEIN: So that would suggest that temperature has an important part, which is typical for SCC and steam generators.

CHAIR KIRCHNER: I know you're coming up to this, but, post-cleaning, was another scan done to look at deposit, depositions?

MR. KLEIN: I don't know if they've gone through that step or not.

CHAIR KIRCHNER: Thank you.

MR. KLEIN: So in terms of OA options, there's different approaches that are available. One would be a full bundle probabilistic approach. I won't read all the details here. Some of the more simplified techniques include arithmetic, simplified statistical mixed techniques, which are a combination of the above. And, typically, two integrity engineers start with the most conservative and simplest and then work their way towards a probabilistic, if needed.

So this schematic is taken from the EPRI Integrity Assessment Guidelines and, since that is a proprietary document, I want to note that the staff did obtain written permission from EPRI to present the slide in this ACRS meeting since it is open to members of the public. Having said that, the idea shown here is that you go through and perform a number of iterations on your full bundle. And for each run, you have an outcome that is shown as a plot here and then, in red, it shows the worst possible tube. And after you go through a number of these Monte Carlo iterations, you can construct a plot on the lower right of all the worst cases from each of your runs. And then they take the lower fifth worst pressure and compare that to the Structural Integrity Performance Criteria in order to determine if the analysis was successful or not, or met the criteria I should say.

Next slide. We are aware that ACRS did receive some public comments challenging the use of the 95/50 acceptance criteria for steam generators, instead of a 95/95, so we thought we would provide some comments on that. And first is that the industry consensus for steam generator OAs is the 95/50, and it's been that way for quite some time. There's an EPRI report on the Technical Basis for Tube Integrity Performance Acceptance Standards from 2006 that discusses that, and it's incorporated into the EPRI Integrity Assessment Guidelines.

The public commenter did provide some instances of where 95/95 was used as an acceptance criteria and that typically was related to either leakage or dose, not the Structural Integrity Performance Criteria. There are some cases like the H amendments that relate to tube cracking deep within the tube sheet where a 95/95 criteria was used for the alloy 600 TT fleet, and there are individual cases before the consensus approach was developed.

The 95/50 criterion has been in use now for quite some time, 20 years, and it has been shown to be very effective. And we do want to note that that criterion is used in conjunction with the deterministic safety factor, so either 3 times the normal operating pressure differential or 1.4 times the design basis accident level, depending on what's more conservative for a given unit. But using that 95/50 in conjunction with the deterministic safety factor does provide multiple layers of protection.

So we'll turn it now to --

MEMBER ROBERTS: This is Tom Roberts. I was wondering if you could give some perspective on the 95/50. One interpretation is that there's a 50/50 chance that 5 percent of your tubes will rupture. Is that the right interpretation? Obviously, there's conservatism in the conditions under which that would happen, but is that the right way to interpret it or should you interpret it some other way?

MR. KLEIN: No, you should not interpret it that way. It's related to whether you're going to meet the three times the normal operating pressure differential structural integrity performance criterion, so it's a very conservative value that you're comparing against.

MEMBER ROBERTS: Right. Yes. That's what I think I'm trying to say is that if you had conditions of 3 times the normal operating pressure differential or 1.4 times the DBA pressure, then there's a 50/50 shot that 5 percent of your tubes will rupture. Is that the right interpretation, or is that not right? I'm expanding the conservatism of the pressure margin.

MR. JOHNSON: This is Andrew Johnson. I would say that you still have a probability of 0.95 of meeting 3 delta P or 1.4 delta P.

MEMBER ROBERTS: Sure. If there's 1,000 affected tubes, that would lead to, roughly, 50 would be the mean value of the number of ruptures at those conditions, if I'm understanding this right, put a 50/50 chance. So, in reality, it's the 3 times, you know, operating differential pressure and the 1.4 times actual pressure that's really the margin; is that right? But you don't expect to meet those conditions in the real world.

VICE CHAIR HALNON: This is Greg. I thought that was like a confidence level, not a deterministic number of tubes. You don't take 1,000 tubes and put 0.95 on it and multiply them together and get the answer. It's 95-percent confidence level or 50-percent confidence. It's 50-percent confidence that there's a 95-percent chance the tube won't rupture. That's how I interpret it. That's not a chance. It's a probability.

MEMBER ROBERTS: Right. But if you apply it 1,000 times, like flipping a coin with a 0.5 probability, you get heads half the time.

MEMBER MARTIN: It depends on how the analysis is done. If it's a simple analysis, it might just be one tube. That has a 95 percent with a 50-

percent confidence. But, anyway, obviously, it doesn't appear you know the details of how the statistics was applied. But 5 percent of tubes, one tube either way, it's a pretty conservative type perspective. Three times differential pressure.

MEMBER ROBERTS: Well, conservative is in the 3 times --

MEMBER MARTIN: That's a margin kind of argument there.

MEMBER ROBERTS: Do you have any sense of what the probability would be at a more reasonable level of pressure? Is there some sort of extrapolated curve that you've seen or could judge?

MR. JOHNSON: This is Andrew Johnson. So you say a more reasonable pressure. I guess are you saying a pressure less than 3 delta P?

MEMBER ROBERTS: Yes.

MR. JOHNSON: Well, then, I mean, clearly, the probability would be much lower if you're going to have any problems.

MEMBER MARTIN: You've got to think of a linear no-threshold theory. That might be a conservative model.

MEMBER ROBERTS: Yes, exactly. I was thinking about it a lot from the EPRI document a couple of slides ago. That might give some, you know, perspective on how quickly that probability falls off as the pressure goes down. Is that, like, a legal way to look at it? Because that curve fell off pretty quickly. Going from 3,500 to 3,000 psi, at least from the readability of the curve, it comes to basically no probability, no chance of -- so that would -- again, just try to get a perspective. If you had 1.4 margin of design basis acting on differential pressure, that 1.4 would be quite a bit to the right of that bottom red point with a 5-percent degree of the anchor.

Anyway, I was just trying to get perspective on this. My sense is that you're not right on the cliff edge. I'm just trying to get an understanding, you know, whether the pressure margin really does support that view, you know, given the margin and the pressure that you use for things. Again, this plot is a representative plot, I assume, not specific to palisades, but it would seem to support that the probability would be extremely low at design basis pressure differential or something closer to the operational differential pressure. Again, I was hoping to see if I understood that right.

MR. KLEIN: It seems to me you have the right understanding.

MEMBER ROBERTS: Even though, if you were to get the pressures at a 95/50, you would, you know, presumably be in, I guess, a hard-to-justify condition because there would be a lot of tubes potentially rupturing with a large population of available tubes.

MR. KLEIN: I don't think we can provide exact probabilities, but I think you can take comfort in the fact that they tested the worst flaws from the steam generators and they all met the 3 delta p criteria. So that's one measure of the conservative nature of the approach. Another is that since this approach has been implemented industry-wide there's been no tube ruptures.

MR. JOHNSON: And this is Andrew Johnson again. I guess another point that might give you confidence is that historical testing performed many years ago that we have records of showed that, you know, brand-new virgin tubes, when tested for rupture, they were, the vast majority, rupturing around 10,000 PSI. So that's significantly more than what we're looking at here.

MEMBER ROBERTS: Okay. Thank you. The conservatism and the strong capability in addition to conservatism in the assumed pressures. Okay. Thank you.

MEMBER MARTIN: Another point here, like, how many would go? Once you have one go, the pressure drop or the differential pressure would, of course, drop, as well. So you probably wouldn't have a cascading type condition, you know, 5 percent or whatever. It would probably be one, maybe two, depending on how rapid these things were. And, of course, that's still within, I think, operating history fleet, having one.

VICE CHAIR HALNON: That would be undesirable.

MEMBER MARTIN: Undesirable.

VICE CHAIR HALNON: Let's establish that. This is Greg. We're not advocating that it's okay to have one rupture.

MEMBER MARTIN: No, but it has happened.

VICE CHAIR HALNON: True. It has happened.

MEMBER HARRINGTON: And this is Craig. It's also, just to reiterate the point, this is in condition monitoring space. The next step after, not strict timeline but this doesn't mean that the tube passed and, therefore, it necessarily stays in service. Some of those that were evaluated would still be maybe taken out of service or sleeved.

So condition monitoring doesn't say the tube is fine to continue operating necessarily. It depends on the degradation mechanism and other people.

MR. KLEIN: Well, it's probably good, at this point, to mention that, in terms of the approach that's taken, it's plug-on detection for cracks. So due to the challenge of sizing stress corrosion cracks, you know, the conservative approach is taken in industry, and that's to plug-on detection. So any of those indications that you saw in that CM plot would either be sleeved or the tube plugged.

MR. JOHNSON: And this is Andrew Johnson. As a point of clarification, each plant has to have specific approved procedures to sleeve, right, or perform an alternate repair criteria. If they don't have that specifically approved, then they have to plug.

MR. KLEIN: Slide 15. In terms of the Palisade's specific operational assessment shown here in the two bullets or the degradation mechanisms that were addressed by a fully probabilistic OA approach and those that use some type of mixed arithmetic Monte Carlo approach.

So this slide kind of gives a summary of Revision 2 Cycle 29 OA for Palisades, which was for a

1.5 EFPY duration. Probabilistic full tube bundle method was used for most of the degradation mechanisms, including ODSCC, at the eggcrate supports. And then what we tried to show was the lower 95th percentile burst pressure versus the three times NOPD acceptance criteria for some of the mechanisms here. For the top three, I'll address probabilistically. And for the U-bend, it was a mixed arithmetic Monte Carlo approach.

It's worth probably noting for the one of most interest, the ODSCC at eggcrates, they simulated ten outages in the modeling that was performed, so ten outages 50,000 times, in order to address that particular mechanism. And we included the U-bend stuff just because there was some discussion the last time we were here with respect to Indian Point tube rupture, but I don't think we need to spend too much more time on that unless you have questions.

VICE CHAIR HALNON: So, Paul, this is Greg. Earlier, you said that the probabilistic method was used if, for lack of a better term, simpler methods could not be utilized. Is that implying here that this was a very complicated set of indications such that probabilistic had to be relied on to characterize these?

MR. KLEIN: I mean, it's common for plants to use probabilistic assessment for a number of mechanisms. So I would say the complicating factor here that they had to deal with in modeling was just the unanticipated jump in the number of indications at the support plates, and the next few slides will get into how they try to account for that. And so that was probably one of the more difficult parts of the OA model. But the use of probabilistic approach is not unusual at all in OAs.

VICE CHAIR HALNON: So the type of indications and the actual characterization of indications was not unusual. It was just the amount, the volume, of the step change and the numbers; is that correct?

MR. KLEIN: That is correct. I think the OA process is a mature process. I think there are options that can be used for each mechanism, and, because of the large number, they did make some assumptions that we'll discuss here in the next few slides to try and fit the Weibull function to the results when they wanted to benchmark the results of 1D28.

VICE CHAIR HALNON: So would you say there's nothing unusual about the indications other than the increased numbers? I mean, the numbers, we didn't find any mechanisms or things we didn't understand with the eddy currents?

MR. KLEIN: No. I would say axial ODSCC at the eggcrate supports and combustion engineering plants is a well-known degradation mechanism.

So the next slide kind of speaks a little bit to what we just discussed in terms of what was different for Palisades. And so what we tried to do on this slide was just show some of the degradation mechanisms on that left column, and then we compared the projections from the previous OA. So how many of each of these degradation mechanisms were expected at 1D28, if you will, and then the projection from Revision 2 of the current OA for 1R29.

And so you can see for most of these mechanisms, there's some increment increase in the number that's projected, which is not unusual as the plant ages, particularly a 600-millimole plant. But for the first row here, the axial ODSCC, you can see a significant underprediction on the number of indications. And so that really was probably the one thing that created the greatest challenge in terms of updating your model so that you reflected the 1D28 special results.

MEMBER HARRINGTON: This is Craig again. In the projections from the previous outage, why was the axial PWSCC in the tubesheet not performed? Is it because they hadn't seen that condition yet or --

MR. KLEIN: They had seen it, but it had been intermittent and not a great number. And so I think, in this particular outage, they found more PWSCC indications within the tubesheet compared to historical. And so, because of that, you see that reflected in the projection then for 1R29. And that may be -- this is just speculation, so I should make that clear. But some of the detections may have been because of the cleaning that was done in the RCS at the plant and maybe that allowed for improved detectability. I guess the next inspection or two will determine whether that was a one-time jump or whether it's part of a trend.

MEMBER PALMTAG: This is Scott Palmtag. I just want to clarify, 1292 indications is a high number; but that's what you use to decide whether you sleeve it, or is that the number of indications after you sleeve it?

MR. KLEIN: That's the total number of NDE indications. So in both steam generator A and steam generator B, that's the total number of ODSCC indications that the eggcrate supports.

MEMBER PALMTAG: Before sleeving or after sleeving?

MR. KLEIN: Well, it's the same number of indications, so that number caused them to pursue sleeving instead of just plugging each of those tubes.

MEMBER PALMTAG: Right. Okay. So now you don't expect to get 1292 because you sleeved, because you did sleeving?

MR. KLEIN: No. The sleeving should not affect that because locations that were sleeved as a preventative method, you already have a crack there. In terms of sleeve locations that were preventative, you could develop a crack in those locations in the future, but, since they're already sleeved, there's no safety concern with that.

MR. JOHNSON: Paul, you said preventative the first time. You meant correct.

MR. KLEIN: Oh, thank you, Andy. Yes. I don't know if I addressed your question. You look like I didn't address your question properly.

MEMBER HARRINGTON: Scott, this is Craig again. That is a projected number. That's a big number from condition monitoring, as well, but that's not necessarily a real number. It's a projected number.

MEMBER PALMTAG: It was projected, and then they sleeved, or is this projected after?

MEMBER HARRINGTON: The sleeving was based on the condition monitoring and other things.

MEMBER PALMTAG: Okay. So some of the projections even with this is for next outage.

MEMBER HARRINGTON: What they might see next outage as part of their operational assessment to make sure that they can go, you know, to determine when they have to inspect again, in part, and that they can make it at least to the next inspection without having the failure.

MEMBER PALMTAG: Okay. Thanks. That answers the question.

VICE CHAIR HALNON: So this is Greg. In a perfect world then, in 1R29, the condition monitoring would say you have 1292 indications that you have to assess going forward for the next operational assessment.

MR. JOHNSON: This is Andrew Johnson. You could, you know, if your model was exactly right and matched reality, you would find 1292 in the next inspection. You could very easily find 292 in the next inspection or you could find more, right? You just -- this is a model.

MR. BALLINGER: This is Ron Ballinger, a consultant. Were that to actually happen, and they were to sleeve every one of them, what would the margin be?

MR. JOHNSON: The margin to what, sir?

MR. BALLINGER: The 15 percent. I haven't done the math.

CHAIR KIRCHNER: You're at 11 and 6.4. So you're currently -- effective plugging for steam generator A is 11.1 and B is 6.4. This is, roughly, 1,000 tubes out of 16,000 total, so you're probably still under your 15 percent, but it depends which steam generator.

MR. JOHNSON: Right. Well, and you also have to consider that there's a variable number that affects sleeving, right?

CHAIR KIRCHNER: Right, yes.

MR. JOHNSON: When you first start installing sleeves, every 10 or so sleeves is equivalent to plugging one tube. As you keep installing more sleeves, that number goes up. Eventually, it goes to 11, then a little bit more than 11, right? As you keep restricting flow, right, each additional sleeve has a greater effect. But that's kind of the range, between 10 to 12 sleeves, per plug.

MR. BALLINGER: You also have an imbalance in flow now between the steam generators.

MR. JOHNSON: Well, that's true. And there's a certain limit between what you can have between the generators. That's right.

MEMBER PETTI: This is Dave. You can have more than one indication in a given tube.

MR. JOHNSON: That's true.

MEMBER PETTI: So, again, that's not necessarily directly translatable.

MR. JOHNSON: Right.

MEMBER HARRINGTON: And, of course, the other -- this is Craig. The other key point is that the operational assessment helps assure that you can operate safely until the next inspection. If you arrived in the condition that Ron's describing where you have to respond to all these and sleeve them and maybe you approach your plugging limit, that's an economic problem. It's a life of plant problem, but it's still not a safety problem because you haven't tripped the safety wire.

MEMBER ROBERTS: Tom Roberts. What's the role of the proactive sleeving in this projection? Presumably, all the tubes they thought would show cracking or most likely should crack in the next cycle, they'd proactively sleeve. Is this 1292 in addition to this, or does that count all tubes, including those that are sleeved?

MR. KLEIN: So I think there's a little confusion between the sleeving and the projections for the number of crack indications at the next outage. They probably don't necessarily overlay with each other. So in terms of the approach for the leaving, the idea was if you -- let's say most of your cracks were at O1H and O2H, well, you can put sleeves in one of those locations, like O1H. And then if you did an inspection at the next outage and you found a crack at O2H, for example, you would need to plug the tube at that point. So a lot of the sleeving that was performed would quickly become null and void at the next inspection, so they tried to go up to the next few elevations and put a sleeve in place so that, if cracking were to occur at that location, it would already be sleeved and the tube could remain in service.

MEMBER ROBERTS: So that number is not indicative of cases that are unsleeved? That's all tubes?

MR. KLEIN: That number is all tubes, yes.

CHAIR KIRCHNER: So that's just kind of a statistic --

MR. KLEIN: I think if we get to two more slides, we'll be able to see the projection on a plot and maybe it will make more sense.

CHAIR KIRCHNER: Before you go on, Paul, could you just loop back and address this? So, roughly, there were 1,000 tubes that were corrected sleeves and 2,000 preventative sleeves. So would those preventative sleeving of tubes address these projected indications? Is that where they did the preventative sleeve installation?

MR. KLEIN: They did the preventative installation in tubes that already had an eggcrate crack indication. If you look at the tube bundle as a whole, you don't really know where your next cracks may show up, so it's really difficult to try to look at the projections on total number indications and relate that to sleeve or unsleeved location.

CHAIR KIRCHNER: This is Walt again. The preventative sleeving was if you find a crack now at 01H, the preventative sleeve above that because you can't do it later, and so it's not that they said, well, that's a tube we're going to preventatively sleeve. It was a tube with a problem and there's --

yes, understood.

MEMBER MARTIN: This is Bob Martin. A number of these questions kind of get to the heart of the model you have. I assume it's relatively simple. Numbers like 1292 is more of a statistical derived. Actually, it's not a 3D, you know, solid model. You don't have all of that. So, I mean, you're nodding your head.

MR. JOHNSON: This is Andrew Johnson. You're absolutely correct. That number 1292 is a purely probabilistic number. It's derived. It has no relevance to any location in the generator.

MEMBER MARTIN: And as you described, it's a conservative model overall. You know, whether it's 1292 or 2, I mean, it really could be anywhere. But, you know, you take a conservative approach to kind of assess where you're at from there and whether actions taken at the site are appropriate.

MR. KLEIN: I think it's probably worth following up that comment to note, earlier, it was asked if the model was exactly correct to be 1292 indications at the next inspection. 0Ideally, the tube integrity engineer wants to model conservatively, so you want a model such that your number of actual indications is less than your projections. And if you look at the non-eggcrate locations where there's cracking in the generator, you can actually see the plots where they've consistently been able to overestimate the number of indications and the model continues to be conservative over time.

And so, in this case, in the eggcrates, they needed to make an adjustment in modeling. And the expectation is those adjustments would create conservative predictions moving forward.

MEMBER HARRINGTON: Right. This is Craig again, too. It's noteworthy steam generator B in the CM and what half the number of indications for the projection, they took higher numbers for steam generator A and applied them to B. It's conservative.

MEMBER MARTIN: And this would drive maybe a unique inspection or early inspection, or what decision would be coming out of this analysis?

MR. KLEIN: So this particular analysis was for 1.5 EFPY. Later on, we're going to discuss -- and we've mentioned several times that they are in the process of revising, so it's possible that that 1.5 EFPY could become shorter.

Okay. So moving on, a little more specifics about the modeling of ODSCC at the eggcrates. So the way that they treated it, they modeled it with the Weibull function, starting with 1R27, and then the model parameters were adjusted. You typically iterate these models until you benchmark them or you're able to reproduce the current inspection in your model, and then it's considered benchmarked.

They made a very conservative assumption that, to fit the large increase in detected indications in 1D28, they treated outages prior to 1R27 as having perfect ODSCC detection. In other words, all ODSCC cracks at eggcrates in those prior outages were perfectly detected by NDE and taken out of service.

MEMBER BIER: Excuse me. A question on that. I just want to make sure I'm understanding properly. My mic seems to have gotten much more sensitive for some reason. Sorry. Vicki Bier.

So you're saying this is conservative because the new indications are treated as representing brand new problems and, hence, a large increase, whereas, in reality, some of them probably pre-existed and the increase was less dramatic; is that correct?

MR. KLEIN: That is correct. Historically, with stress corrosion cracks in steam generators, it takes some time before they reach an level where the eddy current will pick them up.

And then the other conservative assumption that they made with respect to growth rate was that all flaws detected on 1D28 were at the threshold of detection in 1R27. And the result of that assumption is that it results in a very large average growth rate of 9 percent through wall per EFPY. And if you compare that, the EPRI integrity assessment guidelines have two sets of growth rates for alloy 600 mill and yield tubing. And those growth rates and integrity assessment guidelines are based on a total of about 35 plants over a period of decades, so it's a pretty robust database.

And so if you took the EPRI default average growth rate and adjusted that for the Palisades operating temperature, which is on the lower side, it would suggest a 2.15 percent through wall per EFPY. And I think in the last OA, I think they modeled the average growth rate at this location as 3 percent through wall per EFPY. That 9 percent is also greater than the growth rate that EPRI uses to conservatively bound any alloy 600 unit or temperature, and I'm not going to provide that number since it's proprietary.

MEMBER HARRINGTON: This is Craig. I assume, though, that that assumes that cracks were right at the threshold of detection. But if they had not even initiated yet, the growth rate would be remarkably higher, right?

MR. KLEIN: If the cracks detected in 1D28 had not initiated at 1R27, it would be extremely high growth rates. And I don't think that's very plausible.

MEMBER HARRINGTON: Yes, unrealistic.

MR. KLEIN: It's unrealistic for a number of reasons, including the fact that, when they went into the 1D28 locations and then performed any current look back, they could see precursor signals in prior outages. And so as they went further back in time in those outages, they could see that the percentages of those detections dropped over time. But that would suggest a growing population of flaws that eventually reach a detection level during 1D28 were detected. So this is not as conservative as it could be, but it's judged reasonably conservative under the circumstances of --

MR. KLEIN: I think it's conservative because, if you look at the Palisades T-hot temperature from the last operating cycle, it's about

583. And that conservative EPRI upper bound, I mean, you can apply that to plants that are operating at any temperature, so, say, 650 degrees, for example. So to exceed that upper bound rate with your average, to me, is a conservative approach.

MEMBER HARRINGTON: I don't know about ODSCC or PWSCC. That's a very susceptible temperature range, but, okay, sufficiently conservative under the circumstances. Thanks.

MEMBER ROBERTS: Hey, Paul, Tom Roberts. What is the role of the sleeving to this analysis? Is the sleeving accredited, or is this assuming that these are, you know, cracks that grow on unsleeved tubes?

MR. KLEIN: Well, I think cracks can grow on both sleeved or unsleeved tubes. I mean, really, the sleeving is on the ID, and it's put there to maintain tube integrity. The cracks are propagated from the outside based on the chemistry associated with deposits, et cetera.

MEMBER ROBERTS: I'm trying to understand why it matters if the tube is sleeved. If the tube is sleeved, doesn't the sleeve take the structural --

MR. KLEIN: Well, if you have a tube that is sleeved and then a crack develops at that location behind it in the future, yes, you've already accounted for that, and the sleeve is the pressure boundary. So you're right.

MEMBER ROBERTS: So this analysis then must assume correct crack growth in unsleeved tubes? What you said, if the tube is sleeved, it doesn't matter. That's what I'm trying to understand.

MR. KLEIN: I don't think the modeling, again, I don't think the modeling is trying -- it's taking a population, which is the entire tube bundle, and it's taking the number of detections from the current inspection, and then it's projecting that forward, and sleeving is not part of that modeling assessment.

MEMBER ROBERTS: So that would seem to be a significant conservatism; is that right? It's essentially assuming that you haven't sleeved anything, and so you're susceptible to all of the crack growth in your confidence model, whereas, in reality, well, the sleeved tubes have been protected.

MR. KLEIN: Okay. I would consider some of these other items listed here as more conservatisms than that, but that could be considered as some of those locations where they might develop are already pre-sleeved.

MEMBER HARRINGTON: Yes. This is Craig. It would be a statistical conservatism, but not a mechanistic conservatism basically.

MR. KLEIN: Correct. So this slide is figure 610 from the operational assessment, and this shows the probabilistic modeling for steam generator A, which, of course, bounds steam generator B. And so what you see on the plot here are a number of different inspections shown by the red dots. And if you look at prior to 1R27, which is shown here on the vertical line, it's close to about 24 EFPY. So prior to that it assumed perfect detection, and then at 1R27 is when it first initiated. You can see in the green triangle here shown at the top that the model now initiates a large number of new indications, cycle between 27 and 28. And because of that, you then have this large increase in number of indications that is benchmarked by the model here shown around EFPY 26. You can see that the predicted detections and actual detections match at that point, and that's part of the benchmarking process.

And then so the third vertical line to the right then would be the projection out to the next inspection point, and you can see what the model is predicting in terms of number of detections at that point, which is a significant increase from the current inspection.

So in terms of staff comments for the Section 2908, the OA did meet all the acceptance criteria for the 1.5 EFPY. We didn't know that there was a small margin for meeting the SIPC at the eggcrate supports. We noted some of the conservatism is already about the average SCC growth rate, assuming that all cracks are present at the detection threshold and only grew during the last operating cycle.

One of the questions that was outstanding was what if the cracking occurred also during the extended shutdown when the chemistry was being controlled. So if you included that as part of your model that cracking occurred both over that last operating cycle and/or shutdown, that would give you a longer time from crack growth, which would result in a lower number and also assumes no benefits from chemical cleaning. And we'll talk about chemical cleaning, I think, in the next slide or two slides maybe.

We did have a clarification call with the licensee and their vendor on the 14th of October. The purpose of that was to obtain clarification on portions of the Cycle 29 modeling. So, as you know, these are not simple documents to generate or to review. And so we did have a number of questions just to have a better understanding of their modeling approach and the OA model that was used in this case, the assumptions that were made. And, in particular, we asked about the upper tail growth and how well their model accounted for the upper tail growth that was seen during the 1D28 inspection with the assumptions that they made. And we also talked to him about, you know, whether they had done sensitivity analysis to understand how much small changes and different assumptions would affect the overall OA results.

Based on those discussions, the licensee vendor is performing additional sensitivity analysis. A new OA will be issued and our understanding is that, at this point, it has been received at the site. The NRC staff has not yet had a chance to take a look at it.

MEMBER PETTI: Paul, this is Dave. Just a question. The issue of the chemical cleaning and any benefits, the models don't take that into account, or is it that, since there's sensitivity study, they could look at where they kind of normalize things?

MR. KLEIN: Yes, I don't want to speculate about what the Rev 3 is actually going to do because they may make a number of changes. But the Rev 2 that we reviewed, there's no credit for chemical cleaning and that's definitely --

MEMBER PETTI: I thought you, in your discussions with them, you wanted them to pursue some additional sensitivity analyses. I mean, like the chemical cleaning, is the model that sophisticated that it could take that into account?

MR. KLEIN: Well, the way you could try to take that into account, and I'm not suggesting that they are, is there might be a change in the number of initiations or the crack growth rates. Later on, in the chemical cleaning sides, we're going to show that they took a significant amount of copper out of the generators, and so that should have a beneficial effect in terms of initiations and growth rates. But they're modeling based on what was detected in 1D28 without any effect from chemical cleaning.

CHAIR KIRCHNER: Paul, before you go on, could you elaborate on bullet two on this slide? Small margin for structural integrity performance criterion.

MR. KLEIN: Yes. I think that's reflective of the 95th lower value for burst from the probabilistic modeling is above the SIPC value, but it's not above that value by much. And so that's something that we pay attention to. But having said that, you could make less conservative assumptions and provide for more margin also.

So it really is a combination of how they model and what the results are, not necessarily just a given number. That's one of the reasons, you know, that kind of led to the discussion about modeling the upper tail growth and making sure that that was well represented in your model and also understanding maybe in a more formal sensitivity type analysis of how some of the parameters affected. When they develop the model, they get a sense of that, you know, by changing parameters and seeing the effects, but we were hoping to see something a little more formal.

MR. BALLINGER: This is Ron Ballinger, consultant, again. You may not know the answer to this, but a lot of plants spend a lot of effort to get rid of copper. Have these guys done that?

MR. KLEIN: They have. And I'm going to address that in the next slide.

MEMBER ROBERTS: This is Tom Roberts. Before you go on to the next slide, I want to follow up on the previous question. The credit for chemical cleaning, I certainly acknowledge that they didn't take any credit for it, but your earlier slide showing where the deposits were compared to where the cracks were would seem to indicate that a chemical cleaning wouldn't have as big an effect as you might think because there were deposits where a lot of the cracks were. Is that right?

MR. KLEIN: I wouldn't say there's no deposits there. Keep in mind that that slice of deposits was for 20 mils or greater based on eddy current, and so I would think there are deposits at all elevations, maybe just not to that same thickness.

MEMBER ROBERTS: Okay. Thank you.

MEMBER KAMMERER: This is Annie Kammerer. I have a question. So what I'm understanding from this presentation is that you do the inspections, you see the condition, you do the modeling that we saw first, and then you do a forward modeling to try to assess what, I guess, the timeline or what you would see in the future, and that that sort of is stepped forward in time in a periodic basis. And so, first of all, I hope that's the correct situation. Please correct me if I'm wrong. And I guess my question is has this cleaning happened in the past? And if so, is there some data or information that could be used or some sort of assessment done on how big of an impact it made in the past to understand how much of a difference it could make at this time? Thank you.

MR. KLEIN: It's a very good question. I think your understanding is correct. So there's a backward-looking process called condition monitoring that makes sure you maintain tube integrity and then the forward-looking process or operational assessment that models the future. Palisades has not performed a hard chemical cleaning prior to this past October. It was recommended that the plant do that, I think, back around 2008 - 2009 timeframe. Had it done it at that point, we probably wouldn't be sitting here is just my guess.

But there is data from other plants that show the effects of chemical cleaning, and I think we tried to hit on that on our third bullet on the current slide, which is it does show a clear improvement, but it's hard to quantify. Some plants have seen greater benefit than other plants, but there, no doubt, will be a benefit from removing all that copper from the steam generators. The degree, I think, will be determined moving forward by looking at the rate of new indications and crack growth rates.

MEMBER KAMMERER: Thank you.

MR. KLEIN: Some of the plants with data also that complicates it. When you get to a large number of cracks and you do chemical cleaning, some plants also would drop the temperature in order to get a benefit from that, as well. And so that makes just assessing the chemical cleaning by itself a little more difficult.

MEMBER BIER: I have a follow up question, and this is a hypothetical. It's not something I'm raising because I think it's happening but just, conceivably, you could imagine that chemical cleaning could actually increase the risk either by damaging the tubes themselves or by removing debris that is covering up a crack and, you know, preventing problems. I assume that, you know, we have enough experience from past cleaning at other plants that this is not a concern; is that correct?

MR. KLEIN: That is correct. And the chemical cleaning process has been around for quite some time. They're very careful in the steps that they take, and they include coupons in the generator at the time of cleaning to make sure that, if they were to have a transient or something they didn't expect, that it would be represented in the coupons that would then be removed and assessed. So we have no expectation that chemical cleaning would be detrimental.

MEMBER BIER: Okay. Thank you.

MR. JOHNSON: This is Andrew Johnson. I would add the comment about removing deposits and revealing more cracks, you know, I wouldn't call that a risk increase, right, because that's greater detectability. And I think that's actually likely as a result of this cleaning.

MEMBER BIER: Okay. Thank you for the explanation.

MR. KLEIN: So continuing on with the chemical cleaning slide, it was performed in October. Second bullet here shows the amount of material removed, which was substantial, and one of the things to point out is the amount of copper that was removed, which is between 80 and 90 pounds per generator and that's a lot of copper. So that will be beneficial moving forward in terms of crack growth and crack initiation. And I'd also note that these are preliminary amounts, so they are subject to change.

MR. BALLINGER: This is Ron Ballinger again, but you say they have removed -- when I say removed copper, I mean feedwater heaters and stuff like that to eliminate copper that's put in the steam generator.

MR. KLEIN: I didn't understand that at first. So the copper heat exchangers, I think, have been long removed from the plant. They had, I think, 90/10 copper-nickel condensers, and they had some brass feedwater heaters, and I think those type of things have long been removed because people understood a long time ago the detrimental effects of copper.

MR. BALLINGER: So this copper had been in there for a long time?

MR. KLEIN: Yes, that's correct. Next slide. So in terms of concluding remarks, we did want to note that the sleeve amendment we talked about the last time we were here, the safety evaluation was completed and the amendment was issued on October 30th. That session number is shown in that first bullet.

In terms of safety issue related to Palisades startup, we thought it was important to say that we don't have a safety issue related to tube integrity and startup. We do have some questions about the operational assessment and modeling, but we would characterize those more as a longer-term question, not an immediate Palisades startup issue.

They are performing additional OA analysis; and Revision 3, we believe, is at the site and in the process of being reviewed there and, at some point after the site accepts it, we expect it will be sent to the NRC for review.

That, I think, concludes our remarks.

VICE CHAIR HALNON: Thank you, Paul. This is Greg. Any other discussion at this point? We'll have another chance to deliberate after public comments, but any other discussion or questions?

MEMBER PALMTAG: I just had a quick question. Do you know when the startup is planned for Cycle 29?

MR. KLEIN: I'm going to defer that to April if she's listening.

MEMBER PALMTAG: And the question is related to the timing on Rev 3.

MS. NGUYEN: Yes. So this is April Nguyen with Region III. I'm the team lead for the restart oversight activities. So, currently, the plant is still undergoing activities to prepare for the startup sequence. So there's still a good amount of maintenance and testing activities that need to be completed, including loading fuel into the core, which has not been completed yet. So, you know, as the schedule moves along, we continue to follow the schedule.

MEMBER PALMTAG: So there's plenty of time for Rev 3 to get finished and evaluated before the startup is the conclusion there?

MS. NGUYEN: That is correct. And as mentioned previously, we do anticipate to see that in short term.

MEMBER PALMTAG: Just to go back to Craig's point, you made the point in there, but I think it's important to stress, especially for the public, that we did pass the OA, that there is a large crack indication, but it is acceptable under the OA. I just wanted to stress that. Thank you.

VICE CHAIR HALNON: Thank you, Scott. Yes, I wanted to, you know -- they've been doing a lot of conservatisms, taking the present condition of the generators, the tubes. Probabilistically, statistically, deterministically, added a lot of conservatisms and projected that there would be a number of tube indications, and the next inspection will tell us where we are based on that sliding scale of how conservative that is.

And then, from a structural integrity perspective, we passed what I would call the go-no-go, which is all the worst-case case tubes passed very conservative structural integrity. So, given that, I can see, you know, that can align with your concluding remarks, of course, adequate justification.

When Rev 3 does come out, I will ask that if there's anything that takes any concern, other than, you know, outside of your concluding remarks, that you would come back and inform us from that perspective. We don't plan on reviewing Rev 3 unless we get a flag from you all that says something unusual or something different at this point. It may change by the end of the meeting, given the comments from the rest of the members.

Again, questions from any of the members or consultant?

MEMBER HARRINGTON: This is Craig. Do you, relating this to the rest of the plant, do you see any connection between what's been observed here and, in particular, the fact that the plant is implementing weld overlays in PWSCC susceptible locations elsewhere in the piping of the plant? Do you see any connection there at all?

MR. KLEIN: We did speak to members of our piping branch about the weld overlays. I think one of the public comments that was received suggested that

that was due to active crack at that location. And based on the information that was provided on the docket that those are preventative overlays that are being performed and the licensee has not detected cracks at those locations, so that's worth noting. I think, as part of their analysis, they do postulate cracks, though, as part of the case that allows the structural weld overlay, so it's a postulated flaw.

In terms of how it relates to steam generators, we do stay abreast of other locations, but I think the steam generator kind of stands on its own because the degradation assessment that's performed prior to each outage, those look at all potential degradation mechanisms in the steam generator, including primary water, stress corrosion cracking, and outside diameter stress corrosion cracking. So in terms of that impacting the steam generator processes, I think the degradation mechanisms are already considered and it doesn't have a large impact.

MEMBER HARRINGTON: Okay. Thank you.

VICE CHAIR HALNON: So Dr. Ballinger, as part of our consulting staff and expert in materials, what's your impression of the OA and the work that was done by the contractor to establish it?

MR. BALLINGER: Yes. I mean, I think that they did a very good job, very thorough, given the uncertainties that were doing this. Anybody that knows anything about the definition of mill and yield will understand the difference between A and B. That's not surprising at all.

It's also not surprising that, once you start detecting these things, you start detecting a lot because these tubes are what, 50 mils, round numbers, thick? The cracks start responding to stress at 50 microns. Personal experience. And so the initiation process is multiple sources of initiation that eventually link up. But if the initiation is at 50 microns, it starts responding to the stress, it's not surprising that you see the kind of behavior, and that's why they use a Weibull distribution in the first place.

So it's well accounted for in the EPRI guidelines, in the EPRI procedures, they know what's going on. To my knowledge, I think there was a test program, maybe funded by the NRC, a long time ago where they looked at the effect of a tube rupture on adjacent tubes and the possibility of additional rupture, and they found an L-set. So there was no issue related to if they had a rupture impacting another tube.

So, again, overall, I'm sure we'll see what happens at the end of the next cycle.

VICE CHAIR HALNON: Thank you, Ron. Last chance before I go open for public comments.

MR. KLEIN: I think one thing that I probably didn't note but it's worth mentioning, during the clarification call with the licensee and their vendor, at that point, they expected the Rev 3 OA to be more conservative.

VICE CHAIR HALNON: Certainly, as I mentioned, if that's not the case, then at least inform us so that we can make a decision if we need to look at it.

Okay. I'm going to, at this time, open it up for public comments, and we'll start with the person who pre-applied, if you will. Mr. Gunderson, your two minutes is starting. Are you there?

MR. GUNDERSON: Yes. Hi, this is Gunderson here. Can you hear me?

VICE CHAIR HALNON: Yes, sir. Go ahead.

MR. GUNDERSON: Okay. I've witnessed the Palisade's resurrection by Holtec for several years. Despite steam generator tube hideout damage caused by Holtec's neglected chemical treatment during wet layup, it's unlike any other reactor in history. It's clear to me that the NRC is going to do nothing to stop the Palisades from restarting. I no longer consider the NRC to be protecting Michigan's health and safety. The Trump administration's executive order requiring the NRC to speed up licensing has turned the NRC into a sock puppet for Holtec.

I'm sure your committee is aware that I was retained as an expert and have on numerous occasions expressed well-documented concerns about the deterioration of the steam generators. The evidence suggests the steam generators will fail before the next refueling outage, releasing radiation into the state of Michigan. And what's been the response to my concern? Holtec has said that my concern should be discounted because, quote, Gunderson left the nuclear industry decades ago, yet continues to hold himself out as an expert in nuclear power plant operations, closed quote. This from a company with no operating experience. And the NRC has ignored my concerns, like the Moai statues on Easter Island.

The question remains how much radiation will spew from Palisades when a generator fails? Today's slide 17 suggests that the NRC expects 1,000 new indications if Palisades runs for 18 additional months. Rather than proving that the reactor coolant pressure boundary is safe and strong, the NRC seems content to place its faith in mitigating systems after the leak.

Is it too late to change course on Palisades? The reality is that the NRC's Palisade train has not left the station. Events in the last year make it clear that the NRC's train barreled right through the station without ever intending to stop. Thank you.

VICE CHAIR HALNON: Next on the list, Mr. Kraig Schultz.

MR. SCHULTZ: Can you hear me?

VICE CHAIR HALNON: Yes, sir.

MR. SCHULTZ: Yes. Good morning, and thank you for the opportunity to speak. My name is Kraig Schultz with Michigan Safe Energy Future.

What is happening at Palisades is novel and noteworthy. Restarting a plant from formal decommissioning has never been done in this country. This is completely new ground, and new ground calls for higher standards, not lower. A new plant, a new plant, would never be licensed with margins this narrow or with this level of unresolved uncertainty. Yet, somehow, the first restart from decommissioning is being done with a steam generator that has passed its age-degraded cliff, and we are expecting a heightened crack indication after the next operating cycle. That's your slide number 17. That mismatch is the core issue.

The question before the ACRS is not whether the calculated probabilities can be made to pass. The real question is, what should the standard be for the very first restart of a decommissioned plant. Whatever is decided here becomes the precedent for every future attempt. This decision will shape the reputation of nuclear energy, the trust of the public, and the credibility of the regulator.

The good news is that there's no financial or political pressure to take unnecessary risk. Federal funding is available. Replacing the steam generators would bring more jobs and more economic activity, and it would set a clean foundation for the proposed SMR project next door. There is simply no reason to accept a just barely adequate performance as a -- I mean, we're starting with the steam generators as a huge problem here. So the repair campaign was an honest effort, but noble attempts do not change physical limits. The results show that the repaired steam generators do not meet the appropriate standard for a first-of-its-kind restart.

This is the moment for the ACRS to define that standard and, if the committee takes the conservative prudent path, you will not be remembered as the group that slowed a restart. You will be remembered as the group that protected the long-term future of nuclear energy by ensuring the first restart was one worth emulating.

Thank you for your time.

VICE CHAIR HALNON: Thank you, Mr. Schultz. Mr. Kamps, Kevin Kamps.

MR. KAMPS: Hello. Can you hear me?

VICE CHAIR HALNON: Yes.

MR. KAMPS: This is Kevin Kamps with Beyond Nuclear, and I'm speaking to you from Kalamazoo, Michigan, which is 35 miles downwind of Palisades. I've heard the term cliff edge and cliff mentioned by the previous speaker but, also, I believe, by an ACRS member. We live on that cliff edge here in Kalamazoo.

Full disclosure: Beyond Nuclear is a legal intervener against the relicensing, the restart, unprecedented, of Palisades. We represent our members and supporters, some of whom live less than a mile from the atomic reactor. And I wonder where Entergy is today because I've heard a lot of blame about the year 2009. How have these problems been unknown for what is it? Sixteen years? There are some disconnects. There are some elephants in the room that are being ignored.

If a single tube bursts, that will result in a release of hazardous ionizing radioactivity into the local environment. Alan Blind had to correct an NRC staff person last January on that.

Another important part of that January 2025 meeting was an NRC staff admission that Holtec had neglected to implement proper wet layup on the steam generators for two solid years, and I just hear denial that this damage was a result of that. And I'd like to point out that Consumers Energy, the original owner and operator of Palisades, testified to the State of Michigan in the spring of 2006 that the steam generators needed replacement. NRC didn't require it, so consumers didn't do it, Entergy didn't do it, Holtec is not doing it.

There is a requirement in the Atomic Energy Act for reasonable assurance of adequate protection of public health, safety, and the environment. I'm not feeling it. So if I'm right, NRC is violating the law and our organization, our environmental coalition, has taken NRC to court so far on the exemption request, but we intervened on the steam generators, and we were shut down quickly --

VICE CHAIR HALNON: Mr. Kamps, I need you to wrap up your comments. You're well past two minutes.

MR. KAMPS: Yes. Quit experimenting at a grand scale with this nuclear monster on the lakeshore. Us guinea pigs downwind do not appreciate it. Thank you.

VICE CHAIR HALNON: Thank you for wrapping your comments up. Any other public comments? I have no one online. If you're on the phone --

MR. RABENHORST: Yes.

VICE CHAIR HALNON: State your name, please.

MR. RABENHORST: My name is Karl Rabenhorst.

VICE CHAIR HALNON: Go ahead, Karl. Please keep your comments relevant to the meeting today.

MR. RABENHORST: Yes. I served as a FEMA Region 5 rep program site specialist for the Palisades Nuclear Plant, and I provided written comments documenting both the NRC and FEMA have failed to enforce 44 CFR 350 off-site rep program regulatory mandates for over a decade. In September 2014, I reported Michigan emergency management failure to produce required radiological emergency response staff rosters and was overruled by Sean O'Leary, the Region 5 regional assistance committee chair. During an annual letter of certification staff assistance meeting in February of 2016, O'Leary verbally granted blanket waiver to 44 CFR 350 requirements in favor of the Michigan Emergency Management Act and routinely waives 44 CFR 350 requirements.

At 3 p.m. on October 10, 2018, I provided documentation of the above to NRC OIG Special Agent Joseph Lee at the Alexandria, Virginia Public Library. I was also FEMA Region 5's rep to the 44 CFR 351 Part B mandated FRPCC --

VICE CHAIR HALNON: Excuse me, Mr. Rabenhorst. Could you get more specific to the steam generator operator's operational assessment, please?

MR. RABENHORST: Well, okay. The concern becomes any discussion of restarting the plant needs to consider the ability to implement an off-site response. If any response is similar to the chemical spill at East Palestine, Ohio, which is a Beaver Valley-supporting jurisdiction, or a Hurricane Helene response, it would undermine public confidence in the nuclear power enterprise. Collapse of public confidence after Fukushima resulted in the German government prematurely decommissioning the entire German fleet.

Any public support of the nuclear power industry is an essential national security concern, and a decision to restart the plant needs to consider off-site radiological emergency preparedness, regulatory compliance, and the ability to implement an off-site response. Thanks.

VICE CHAIR HALNON: Thank you. Next on the list is Kathy Barnes. Kathy Barnes, unmute yourself. Looks like you're having a little trouble. We'll give you a second. She's got her hand up. Kathy, I'm going to give you a couple more seconds to get your mic taken care of. If not, then you can supply written comments to Quynh Nguyen of the ACRS staff, and he will enter those into the record if you can't make them verbally.

I see you now. Yes, finally got you. Go ahead, Kathy.

MS. BARNES: Yes, I'm sorry. I had to go into my settings and turn my microphone on. For some reason, the meeting app turned it off.

Anyway, I wanted to say thank you for all your research, but it is based on risk and probability. And probability statistics and all that, that's a lot of mathematics, but you're not taking into account that you just don't know everything.

And if some of these tubes get clogged, et cetera, it's going to increase pressure and temperature on the other ones. You just can't stop these tubes from functioning because that would be a meltdown, correct? If all the tubes, if they did not function right, if they burst, if they were clogged, it would be a meltdown because you couldn't pump the water in, and I don't think you should take that risk.

And even if you totally replaced all of those tubes and put in new tubes, you still have an aged, embrittled nuclear reactor there that you've run out of -- you know, you talked about core samples. You ran out of those. You don't have those. That's also based on risk and probability.

And talk about downwinders, that goes a long range. At one former meeting with the NRC, I asked about evacuation zones and about what would happen. Basically, if there was a meltdown at Palisades, it would affect agriculture. It would affect people's residences. It would be probable deaths. Cancer rates would go up. It would be horrendous. Is that something that you're willing to be responsible for? Is that something that you're willing to take a risk that it might happen?

Another thing is that that plant needs to be cleaned up. It's got tritium underneath the plant that needs to be removed, and that hasn't been done. And, eventually, it's going to contaminate the water of Lake Michigan as it tritiates the water and the groundwater. I believe it's already contaminated the groundwater, and eventually it will go out in the lake.

VICE CHAIR HALNON: Kathy, you're past two minutes. Can you wrap up your comments, please?

MS. BARNES: Pardon?

VICE CHAIR HALNON: You're past your two minutes.

MS. BARNES: Oh, keep it to the tubes? Oh, okay.

VICE CHAIR HALNON: I need you to wrap them up, so I have other people waiting to make comments.

MS. BARNES: Okay. Okay. One more thing. Fukushima is still melting down. That's still contaminating the ocean. They're pumping that contaminated water to cool it down into the ocean.

They haven't been able to stop that meltdown. Is that something that we want for Lake Michigan?

So those are my comments. Please, please, take them seriously. I do not think it should be restarted. I think it should be shut down and cleaned up. Thank you.

VICE CHAIR HALNON: Michael Keegan, you're next up. Two minutes, please.

MR. KEEGAN: Hello. Thank you. So Michael Keegan with Don't Waste Michigan. We're interveners to prevent the restart of Palisades, and we've had multiple contentions and we're on appeal with the NRC Commission themselves. And we're also in federal court.

I'm a sociologist by training, and a colleague of mine, Charles Perrow, has written a book called Normal Accidents, and what he does is he goes through complex systems and shows where there are failures that are baked into the cake. Now, the steam generators just happen to end up in your lap, and that's in the limelight. But there are a multitude of problems at Palisades.

To previous ACRS commissions, the utility had promised to change out the strainers on the reactor, on the steam generators, on the whole system.

There are five metric tons of calcium silicate as an insulation, and it's a GSI-191. It's a generic issue. It's been known about since 2000. There have been promises to remedy it. It's not been remedied.

There's just layer upon layer. The control rod drive mechanisms, in August of '24, the public was promised that those systems would be changed out. Well, then they're in a hardship, and now they have to do overlay welds. You've got band-aid upon band-aid. Every system you look at is compromised.

What's special about Palisades? There's no regulator ever been regulating at Palisades. Everything goes. So you're way out there probabilistically, risk assessment, all these systems are compromised. Normal access. What's the probability something's going to happen? Catastrophic failure. One over one. It is going to happen. You baked it into the cake.

So do not allow the restart. Step forward. Previously, you were promised that that strainer issue would be resolved. It is not resolved. Thank you.

VICE CHAIR HALNON: Okay. I still have a few minutes. Is there any other comments?

MS. DRECHSLER: My name is Jackie Drechsler, and I would like to make a comment.

VICE CHAIR HALNON: Go ahead, Jackie.

MS. DRECHSLER: Thank you so much. I appreciate this meeting. I've been to just about every single meeting regarding the restart of the Palisades Michigan plant. I've been to the big meetings, the small meetings.

This is what I would like to say: There have been so many years of lack of oversight, and there is documentation that shows the real possibilities of the steam generator failure due to cracking of the tubes. All I have heard today is supposition, probabilistic, and risk modeling. It's all speculation.

The NRC fellow said earlier, we need to make it to the next inspection without a fail. And then another person said -- or it might have been the same because I can't necessarily know who's speaking. The other person said large crack indications, but they're acceptable. Well, this plant, first of all, needs to be cleaned up. And the lady who talked about the tritium in the waters, that, you know, that changes DNA. There is the possibility of a real meltdown, should there be, you know, a failure.

This is high risk, pollution of waters, land, and health damages to people and wildlife. Why would the NRC approve a restart based on speculation? Thank you very much.

VICE CHAIR HALNON: Thank you. It looks like we have Alan Blind for the next question.

MR. BLIND: Yes. Hi. Thank you. Do you hear me okay?

VICE CHAIR HALNON: Yes, Alan. You have two minutes. Go ahead.

MR. BLIND: My comment, actually, comes from the Nuclear Regulatory Commission in their October 23, 2000 report, 25 years ago, on their summary of the Indian Point steam generator tube failure. Let me read it: The task group concluded that communicating the safety significance of the Indian Point experience is difficult. During the NRC significance determination process, the staff found that the tube condition during the last cycle was risk significant due to the degradation of safety margin. And I want to emphasize that, due to the degradation of safety margin, and there's been so much discussion today on margin.

Back to the quote: Notwithstanding the loss of safety margin, Indian Point 2 was designed to mitigate the effects of a steam generator tube rupture. I digress. Palisades is not designed, as Kevin Kamps quoted me earlier as correcting the NRC. And I think the committee needs to consider that's the consequence that stands Palisades apart.

Let me come back now to the NRC quotation: This distinction may not be understood by all stakeholders. Now, this is the most important point, so let me finish. NRC will probably face this communications challenge again because steam generator tube failures and ruptures -- and notice they say failures and ruptures -- have occurred before and will occur again. Let me repeat: will occur again. Therefore, the task group recommends that the NRC should incorporate experience gained from Indian Point in the significance determination process into planned initiatives on risk communication and outreach to the public.

VICE CHAIR HALNON: Alan, you're over your two minutes. Can you wrap up and conclude?

MR. BLIND: Yes. I'll just conclude that we need to put these margins back into the allowed operating period of time. Why allow Holtec to operate all the way up to 1.5 effective full power years with little margin, rather than a reduced period of operation and regain operating margin? And then let's take a look at what the inspection results tell us. Thank you.

VICE CHAIR HALNON: Okay. I don't see any other people in the queue. No public in the room here that I can see. Oh, okay. So Jesse Deer. Oh, is that the second comment? If you have another comment, please put it in writing and send it to Quynh Nguyen of the ACRS staff. His email is on the agenda.

So I think this is it. Jesse Deer, have you made your comment already or is this your first time? You keep on muting and unmuting. Try again. Yes. Go ahead, Jesse. Go ahead.

MR. DEER: Good day, you all. Pardon me, I'm a little under the weather. Got a little flu, but I still am tuning in. My name is Jesse Deer In Water. I live in Redford, Michigan, basically on the other side of the state, but work on different nuclear issues. You know, I'm no technical expert like some of you all are, but I just wanted to come here and, basically, after the presentation here and kind of following what's going on, I just wanted to reaffirm some of the things I heard, you know, that 1,200 tubes are at risk at Palisades. There's tons of tracking and degradation at critical support components, and the operational assessment, the OA, the degradation is projected using different determining factors.

And I just wanted to, you know, just reaffirm what everyone's kind of said here. You know, I know some of it was, you know, this and that. But I've known about Arnie Gunderson since I was a child and the different analysis and the work that he's done and followed. And so I would just like to just uplift Arnie's messages, his comments and everything that he had said. I mean, this is a big issue. You know, I mean, as an indigenous person with relatives who are Potawatomi and live over there in the area, I can say that there is tons of concern for safety and the future and that every possible thing needs to be looked at, every possible thing that needs to be fixed needs to be fixed. I mean, and if these steam generators are compromised, they should just be replaced and fixed.

I mean, I'm against the reactor reopening in general because, you know, I come from a community impacted by nuclear issues in Oklahoma. So I have, you know, this lived experience with it. And so, basically, I just want to uplift Arnie's comments and work and then also, at the same time, just give my honest thing that a nuclear meltdown could impact the lakes terribly, you know. I mean, bad. And the land I love over there in the western part of the state that my relatives fish, forage wild rice, manoomin, all that's at stake.

VICE CHAIR HALNON: Jesse, you're past your two minutes, so go ahead and please wrap up.

MR. DEER: All right. Sorry. I'll wrap up. But the United States owes a moral debt to the indigenous people here on Turtle Island and in Michigan to do the right thing. And you all are part of that, you know what I mean? You have this opportunity to do the right thing. If there's the money there, if there's all this other stuff to fix it, man, freaking fix it. I mean, you know, make them fix it. Don't run tests that, you know, they could -- yes, yes, just fix it. Just fix it. That's all. Just fix it.

VICE CHAIR HALNON: It's 10:30. I'm going to close public comments at this time, and we will -- okay. I'm going to allow two minutes just because you got in just before I said I was done. So go ahead.

MS. TOOHILL: Hi. Can you all hear me?

VICE CHAIR HALNON: Yes.

MS. TOOHILL: Okay. Great. Sorry. My name is Spencer Toohill, and I'm with the Breakthrough

Institute. I just wanted to give a very brief comment.

I am in support of the Palisades restart. And we are as the Breakthrough Institute. I just wanted to point out we are very big believers in public engagement and public comments. And, you know, these public meetings are very important forms of public engagement with the NRC and with the ACRS. So I think that this meeting is scheduled until noon, and I just wanted to encourage to allow this important forum of public engagement. And if people had more comments, I would just encourage to allow people to provide their public comments, their verbal public comments, in this forum for as long as they can.

So that's all I had. Thanks.

VICE CHAIR HALNON: Okay. No other hands are raised. I'm going to declare an end to public comments. It seems like we've received quite a few. I appreciate it.

If anyone beyond this has a comment, please enter it into the record, email Quynh Nguyen the ACRS staff, and we will try to get that into the public record. So I'm going to ask the members is there any additional thoughts or questions before we recess out of this period? Don't see any.

So with that, Chairman Kirchner, I will pass the meeting back to you. I want to thank Paul Klein and Andrew Johnson for your time and efforts. And, again, I want to reiterate that we will probably include a summary and probably, in that summary, I'll just ask that you, as part of the meeting minutes, provide us a notification if there's anything non-conservative or of concern in Rev 3 of the operational assessment that comes out.

So with that, Chairman Kirchner.

CHAIR KIRCHNER: Thank you, Greg. So we will capture our activities here in our meeting summary. Are you looking for further input from members for that?

VICE CHAIR HALNON: You know, I just need to take some time to draft some thoughts, and then I can probably, if you want, after taking a break -- if we take a break now, I can draft some thoughts up, and then we can iterate on that.

CHAIR KIRCHNER: Reconvene and iterate on that. So with that, we'll take a break until 10 minutes of 11. That's 10:50 Eastern time.

VICE CHAIR HALNON: I wasn't watching carefully, and it appears that we've got one more person that would like to make a comment, given the fact that we do have a few minutes prior. We need to take a break, granted.

CHAIR KIRCHNER: Let's take the comment.

VICE CHAIR HALNON: Yes, let's take the comment. Ann Scott, I'm going to give you two minutes. I apologize for missing your hand before I stopped. I assumed you had it up before I stopped; otherwise, I probably would not have had it up. But I want to give you two minutes. Go ahead, Ann. Ann, can you unmute yourself and take your two-minute comment? Ann Scott, we still don't see you unmuted.

MS. SCOTT: Hello. My name is Ann. Can you hear me?

VICE CHAIR HALNON: Yes, we can. Go ahead.

MS. SCOTT: My name is Ann Scott. I live in Palisades Park. I consider my home Palisades Park. I consider the plant Palisades Park. I live walking distance from the plant. I've grown up there. I watch it built. I watched it with all of its failures and the fines against it and the attempts to protect all of us who live near the plant, who live in Michigan, who live on Lake Michigan, who live in the United States, who live in the world. I've watched the NRC panel. I know their jackets. I know their faces. I've heard them tell me over and over again that they're here to protect us, they're here to protect our country, our state. I don't believe that. And I just want to acknowledge that you're not being honest with us and you're not taking the proper precautions. And I feel so badly for you and for all of us.

And the idea that you're giving two minutes to these important people. I'm not. I'm just an emotional human being. But there have been important people trying to get a message across, and the suggestion that they're allowed two minutes. That's shameful.

That's all. I'm done. My husband will have to turn off the microphone but really let down, really let down.

VICE CHAIR HALNON: Okay. Back to you, Karen.

CHAIR KIRCHNER: Okay. Thank you. So let's take a break now to the top of the hour, 11 o'clock, and we'll come back and discuss next steps forward at that period. So we're recessed until 11 a.m.

(Whereupon, the above-referred to matter went off the record at 10:38 a.m. and went back on the record at 11:01 a.m.)

CHAIR KIRCHNER: Okay. It's 11 o'clock, and we are back in session. And I'll turn it back to my colleague, Greg Halnon.

VICE CHAIR HALNON: Thank you, Chair Kirchner. So I wanted to thank everybody for the process that we went through today, and I wanted to also thank the public for the comments that they made. I know it's been a long process, and we clearly see some frustration in the results of how the process is coming out, and we certainly understand many of us have either worked or lived near nuclear plants ourselves and certainly understand that frustration.

We, as the ACRS, are an advisory committee; and, accordingly, we provided the commission our thoughts on the restart process in the September 22nd, 2025 letter, which is available on the public website of the ACRS. And we continue to stand by our conclusions that the steam generators' integrity is of concern in that the condition monitoring and operational assessment reports are essential to ensure integrity and that the NRC staff should continue to scrutinize the performance of the steam generators, both during the operational period and during the next inspection period, very closely.

And we did ask the staff to come back and tell us about Rev 3 if there is a non-conservative or some other concern that approaches that.

So with that, that's what our summary will reflect. And we're not going to continue to -- we're not going to let loose of this, but we're certainly at a point where, unless the staff comes back and tell us otherwise, we'll stand by our September 22nd one.

So, with that, Walter, I will send it back to you.

CHAIR KIRCHNER: Any comments from the members? Obviously, we'll monitor closely the next phase of the startup, which will include hydro testing once the system is buttoned up. That will be another check on the integrity of the steam generators and the tubes.

Anyone else at this point? Any new business for this meeting? Hearing none. Then we can let the court reporter go, and we will adjourn the 731st meeting of the ACRS.

MEMBER BIER: Were we going to finalize written statements, or that's going to be done offline? Written summaries for today and yesterday.

VICE CHAIR HALNON: We're going to discuss, Bob, the write up --

CHAIR KIRCHNER: No, we already finalized that yesterday. Thank you for the reminder, Vicki. For anyone listening in, that was on the full-spectrum LOCA topical report from Westinghouse, so we finalized our summary of that yesterday after yesterday's discussions. No new business.

Okay. Then we are adjourned.

(Whereupon, the above-referred to matter was concluded at 11:05 a.m.)

Advisory Committee on Reactor Safeguards Full Committee Meeting December 4, 2025

Palisades Steam Generator Update - Operational Assessment

Paul Klein and Andrew Johnson

NRR/DNRL/NCSG

Acronyms

- 1RXX – refueling outage number
- AILPC – accident induced leakage performance criterion
- BOC – beginning of cycle
- CIRC - circumferential
- CM – condition monitoring
- DBH – diagonal bar hot
- Eggcrate – horizontal lattice tube support
- EOC – end of cycle
- EPRI – Electric Power Research Institute
- FSAR – final safety analysis report
- ID – inside diameter
- NDE – nondestructive evaluation
- NOPD – normal operating pressure differential
- OA – operational assessment
- OD – outside diameter
- PW – primary water
- SCC – stress corrosion cracking
- SG – steam generator
- SGOG – Steam Generator Owners Group
- SIPC – structural integrity performance criterion
- TEH – tube end hot
- TSH – top of tubesheet hot
- TTS – top of the tubesheet

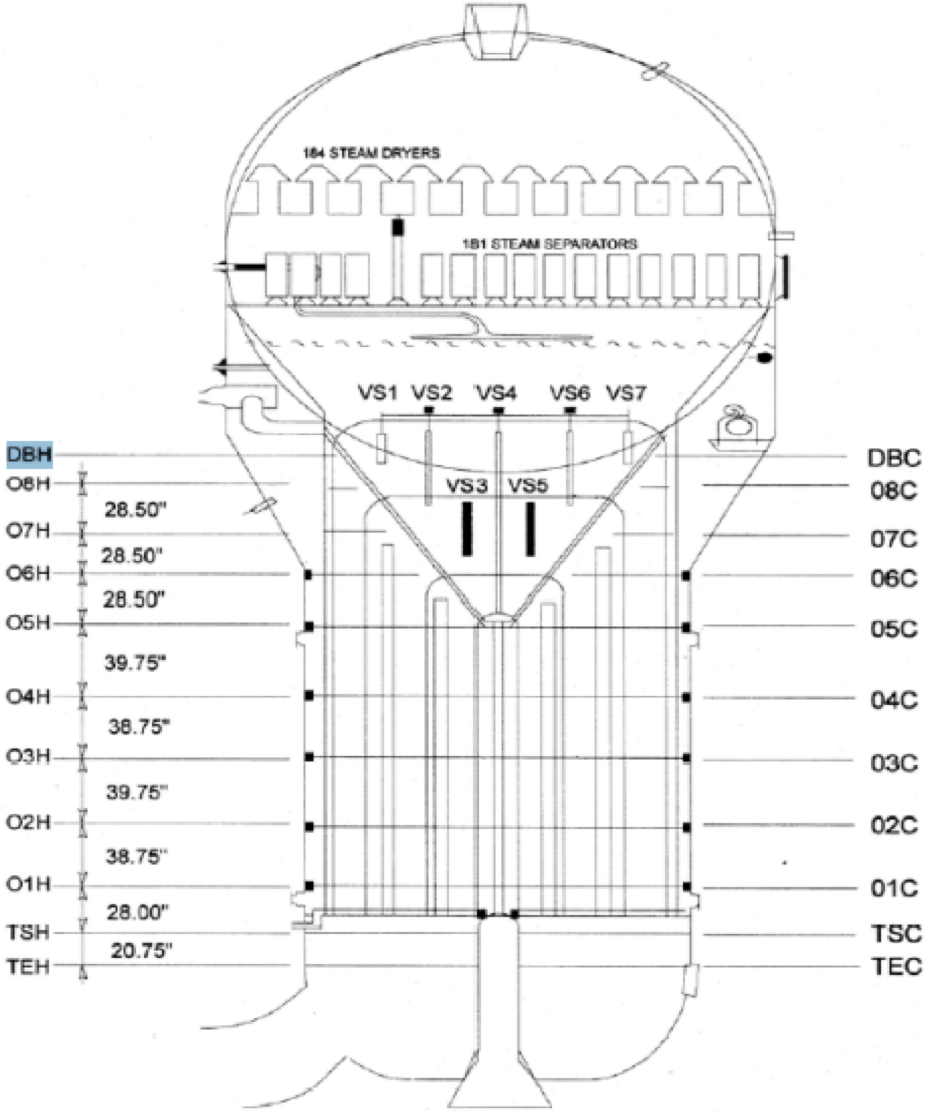
Agenda

- Summary Up Front
- Palisades SG Design
- SG Inspection (1D28) Results
- CM OA Process
- 1D28 CM Summary
- Cycle 29 OA Review
- SG Chemical Cleaning
- Concluding Remarks

Summary - Palisades SG Tube Degradation

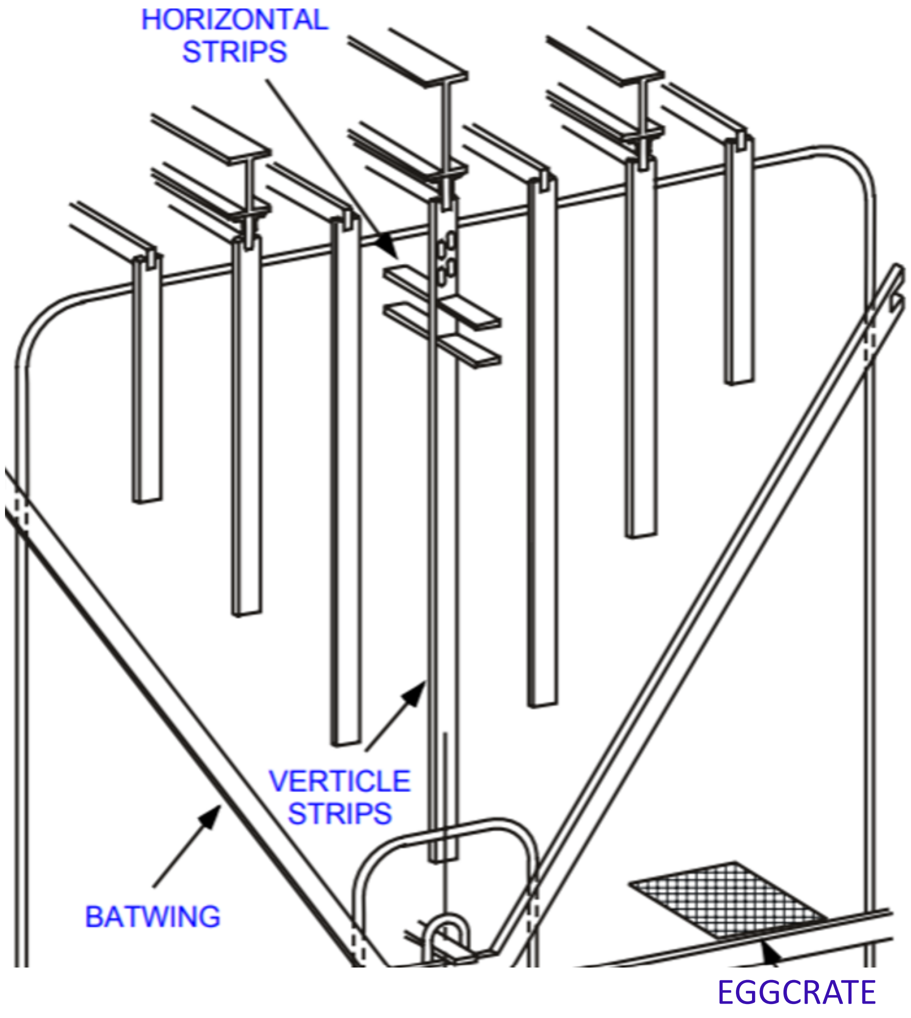
- 1D28 SG inspection: Over 1200 axial ODSCC indications at eggcrate supports
  - Plugging would exceed 15% SG A design limit; licensee submitted LAR to install sleeves
- A total of 2971 SG sleeves will be placed in service to preserve plugging margin
  - 906 corrective sleeves (SCC present), 2065 preventative sleeves (no SCC present)
- Condition Monitoring (CM) showed tube integrity was maintained, 23 tubes passed insitu pressure tested as part of CM (no burst or leakage)
- Cycle 29 Operational Assessment, Rev. 2 - 1.5 Effective Full Power Years
  - Analysis results meet all performance criteria, little margin for eggcrate SIPC
  - key conservative assumptions: (1) crack growth rates for ODSCC at eggcrates based on assuming all cracking at 1D28 was just below detection threshold at 1R27
    (2) assuming no improvements from EPRI SGOG chemical cleaning of both SGs
  - Based on NRC-licensee clarification call, OA revision is in progress

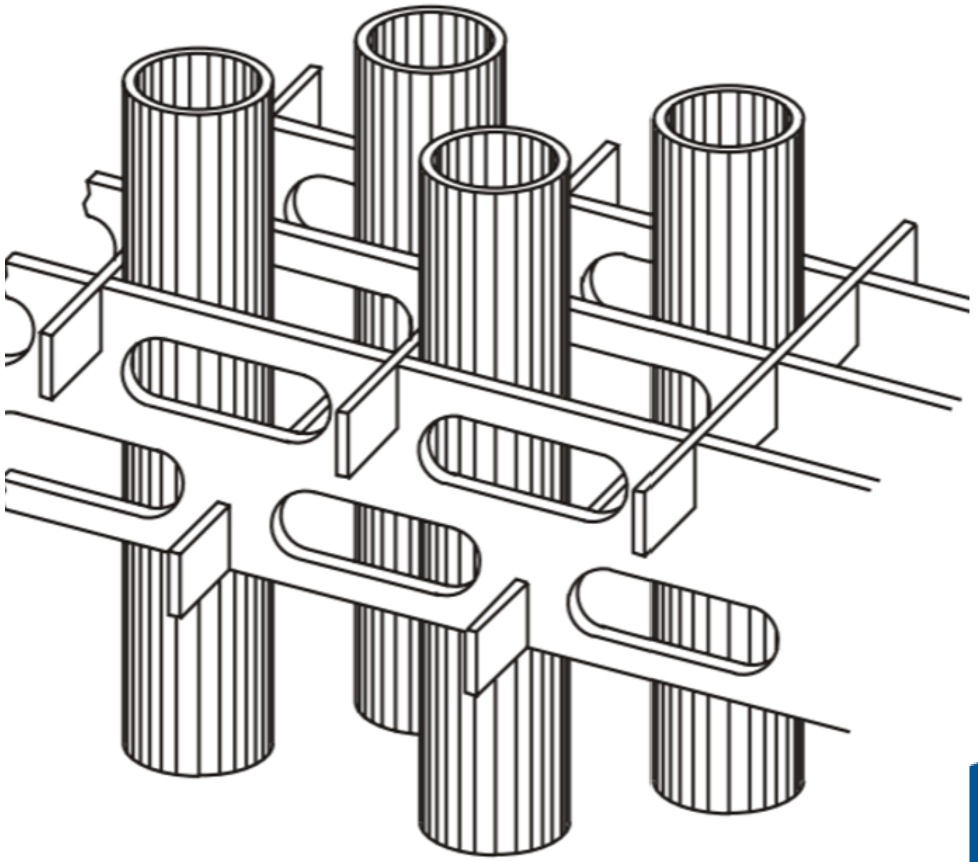
Palisades Combustion Engineering Model 2530 SGs



- Installed in 1990, each SG has 8,219 tubes
- Alloy 600 mill annealed tubing
- Nominal 0.75 inch diameter, 0.042 inch wall thickness
- Rows 1-18 U-bend, Rows 19-138 square bend design
- Horizontal stainless steel lattice type “eggcrate” support plates
- Sleeves installed 01H to 05H

Vertical and Horizontal (Eggcrate) Supports





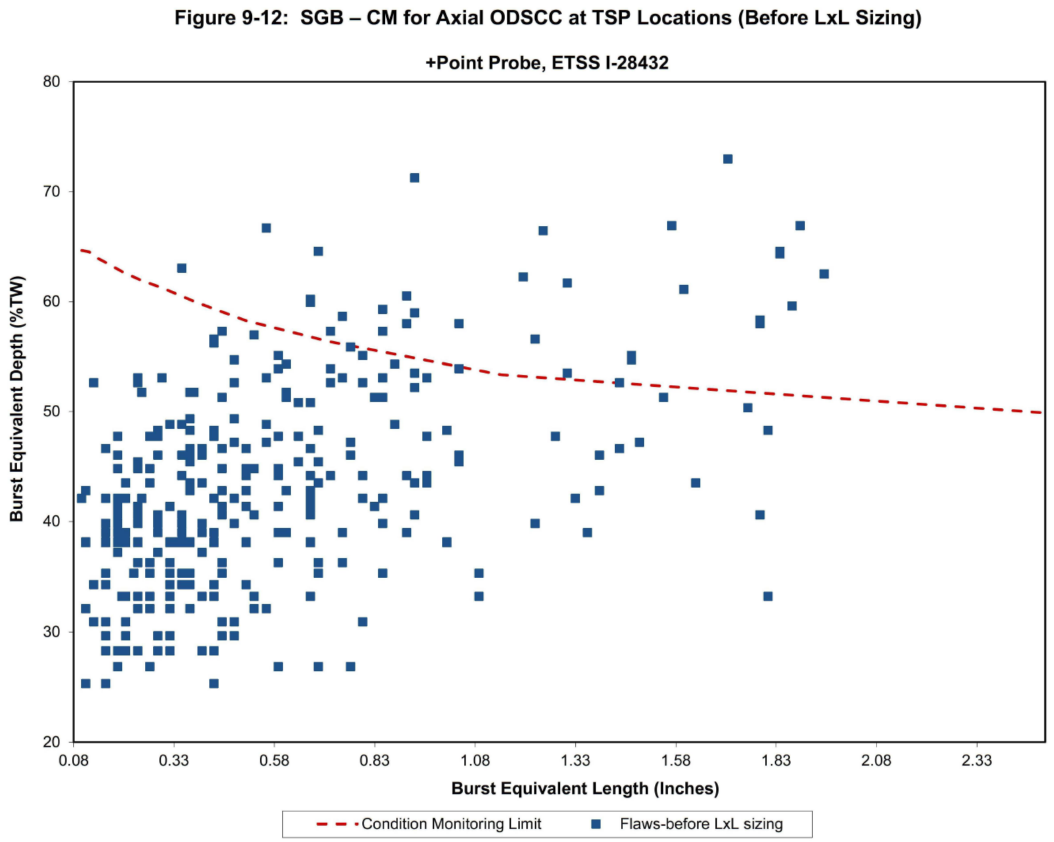
1D28 SG Inspection – Final Results

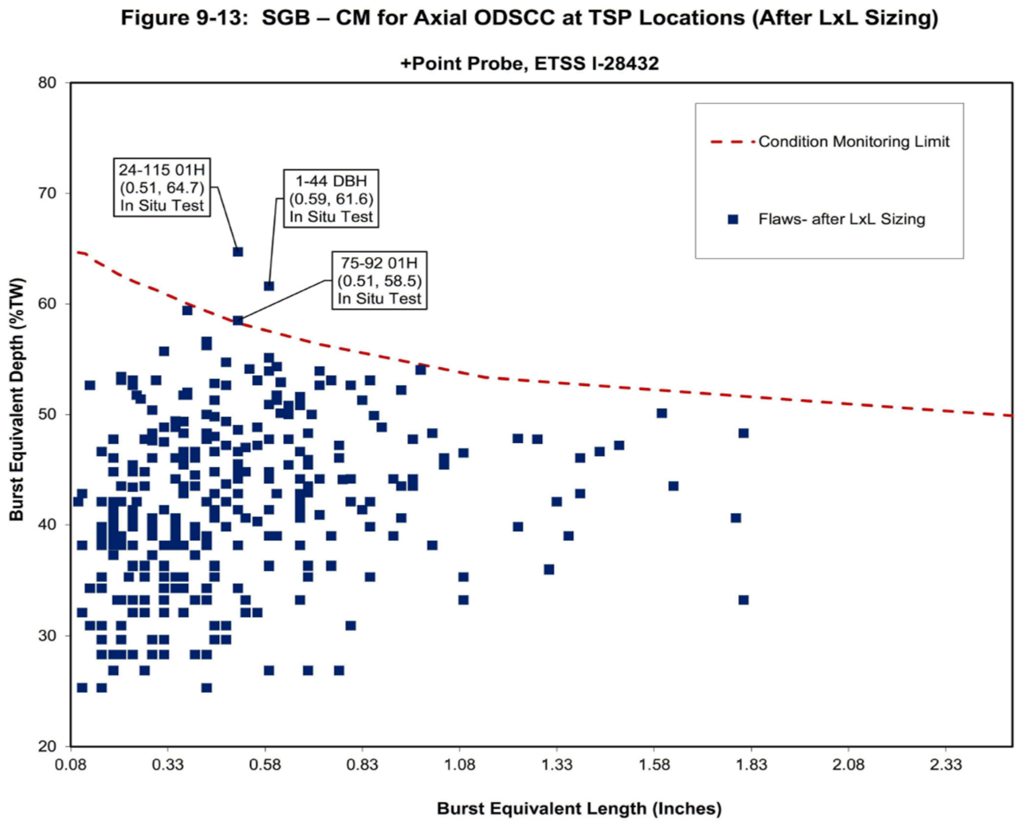
SG	Location	Type	Indications	Tubes
A	TSH	Axial ODSCC	17	16
A	TSH	Circ PWSCC	29	10
A	TSH	Circ ODSCC	73	60
A	Tube Supports	Axial ODSCC	900	608
A	TEH to TEC	Wear > 40%	5	5
A			EFFECTIVE PLUGGING PERCENT	11.1%
B	TSH	Axial ODSCC	10	9
B	TSH	Circ PWSCC	10	10
B	TSH	Circ ODSCC	1	1
B	Tube Supports	Axial ODSCC	313	220
B	TEH to TEC	Wear > 40%	3	3
B			EFFECTIVE PLUGGING PERCENT	6.4%

1D28 Condition Monitoring

- CM uses inspection results to assess whether tube integrity (SIPC, AILPC) was maintained until the inspection
- CM limits pre-determined for each degradation mechanism/location for rapid evaluation:
  - Flaw clearly meets CM limit with initial NDE sizing
  - Flaw needs enhanced eddy current flaw sizing (profiling) to determine if CM is met
  - Insitu pressure testing (ISPT), if NDE alone cannot confirm CM is met
- All tubes met CM during 1D28, ISPT needed for 23 indications
  - 8 eggcrates, 2 axial TTS, 11 circumferential TTS, 1 DBH, 1 obstructed tube
  - No leakage or tube burst during ISPT

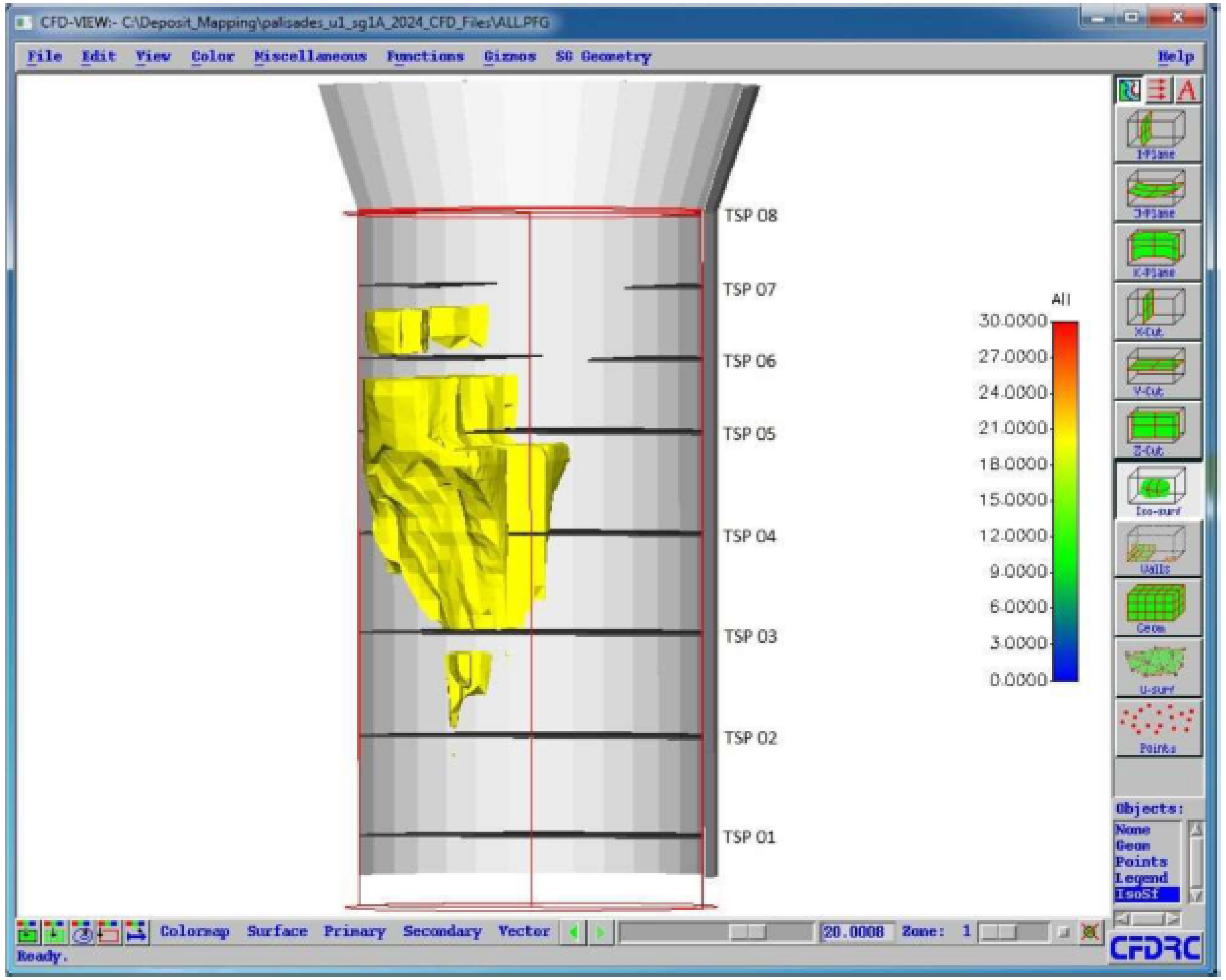
CM – Axial ODSCC at Eggcrates SG B





Eggcrate Support Cracking SG A

Figure 8-4: Palisades SG A Tube OD Deposit Loading 20.0 mils and thicker



Support Number	Eggcrate Cracks
05H	7%
04H	10%
03H	8%
02H	24%
01H	37%

~ 70% (03H, 02H, 01H)

ODSCC Distribution at Eggcrates is Consistent With a Temperature Driven Mechanism

Operational Assessment (OA)

- Forward-looking projection of SG tube degradation, OA provides the technical basis for meeting tube integrity until the next SG tube inspection
- Addresses all tube degradation mechanisms such as wear at support structures, SCC at the lattice supports, SCC at the top of tubesheet
- The OA process is addressed in EPRI SG Integrity Assessment Guidelines
- Degradation can be projected using deterministic (worst case tube), mixed, or fully probabilistic methods

OA Options

- Two general approaches

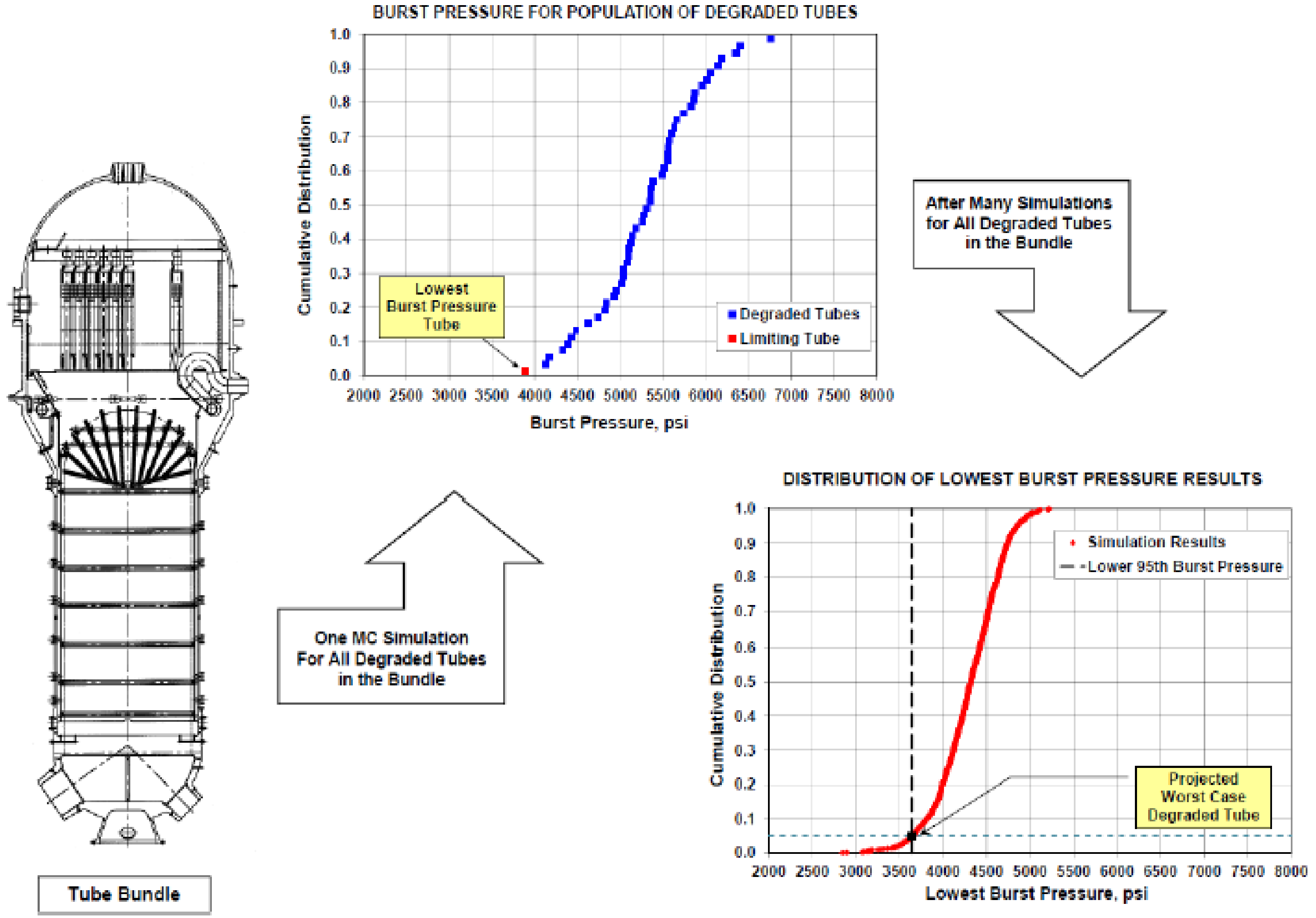
  Full bundle probabilistic

  - Monte Carlo simulation methods are used to predict the future distribution of the structural integrity parameters at the end of the next inspection cycle (EOC), so that the lower 95th percentile of the worst case burst pressure values may be obtained. Similarly, the upper 95/50 total bundle leakage is also calculated.

  – Simplified techniques, including:

    - Arithmetic
    - Simplified Statistical
    - Monte Carlo
    - Mixed techniques – a combination of the above.

OA - Full Bundle Probabilistic Process



95/50 Criterion vs 95/95

- 95/50 Probability/Confidence is the industry consensus for OA:
  - EPRI Technical Basis for SG Tube Integrity Performance Acceptance Standards, 2006
  - EPRI SG Program Guidelines – Integrity Assessment Guidelines
- Some uses of 95/95 acceptance criteria, typically related to leakage and dose, not the structural integrity performance criterion
  - H* amendments for tube cracking deep within tubesheet, Alloy 600 TT fleet
  - Individual unit examples before consensus approach developed
- Note the 95/50 criterion is used in conjunction with deterministic safety factors, (3 x NOPD burst normal operation, 1.4 design basis accidents) providing multiple layers of protection

Palisades OA for Operating Cycle 29

- Full tube bundle probabilistic OA model used for:
  - Axial Outside Diameter Stress Corrosion Cracking (ODSCC) at Eggcrates, Vertical Straps, and in the Freespan
  - Axial ODSCC and PWSCC at Top of Tubesheet (TTS)
  - Freespan Axial Intergranular Attack (IGA)
  - Circumferential (Circ) ODSCC at TTS
  - Tube Support Wear

- Mixed Arithmetic/Monte Carlo method used for:
  - Circ PWSCC at Expansion Transitions and Expanded Tubesheet Locations
  - Axial ODSCC at Dents/Dings
  - Axial PWSCC at Dents/Dings and Small Radius U-bends
  - Tube-to-Tube Wear

Palisades Cycle 29 OA, Rev. 2 (1.5 EFPY)

- Probabilistic full tube bundle method used for most degradation mechanisms, including ODSCC at eggcrate supports
- A lower 95th worst case tube calculated burst pressure that is greater than 3 times NOPD meets structural tube integrity

Mechanism	Lower 95th Burst (psi)	3 times NOPD (psi)	Comments
ODSCC at Eggcrates	3978	3960	Simulated outages 1R20 to 1R29 50,000 times
Axial ODSCC at TTS	4340	3960	50,000 trials
Circ ODSCC at TTS	7499	3960	50, 000 trials
Axial PWSCC U-bends	BOC structural depth from 95th POD, upper 95th growth	EOC Lower 95th Flaw Burst pressure is 4180 psi (3960 psi 3DP)	Mixed Arithmetic/Monte Carlo approach

OA Indication Prediction Comparison

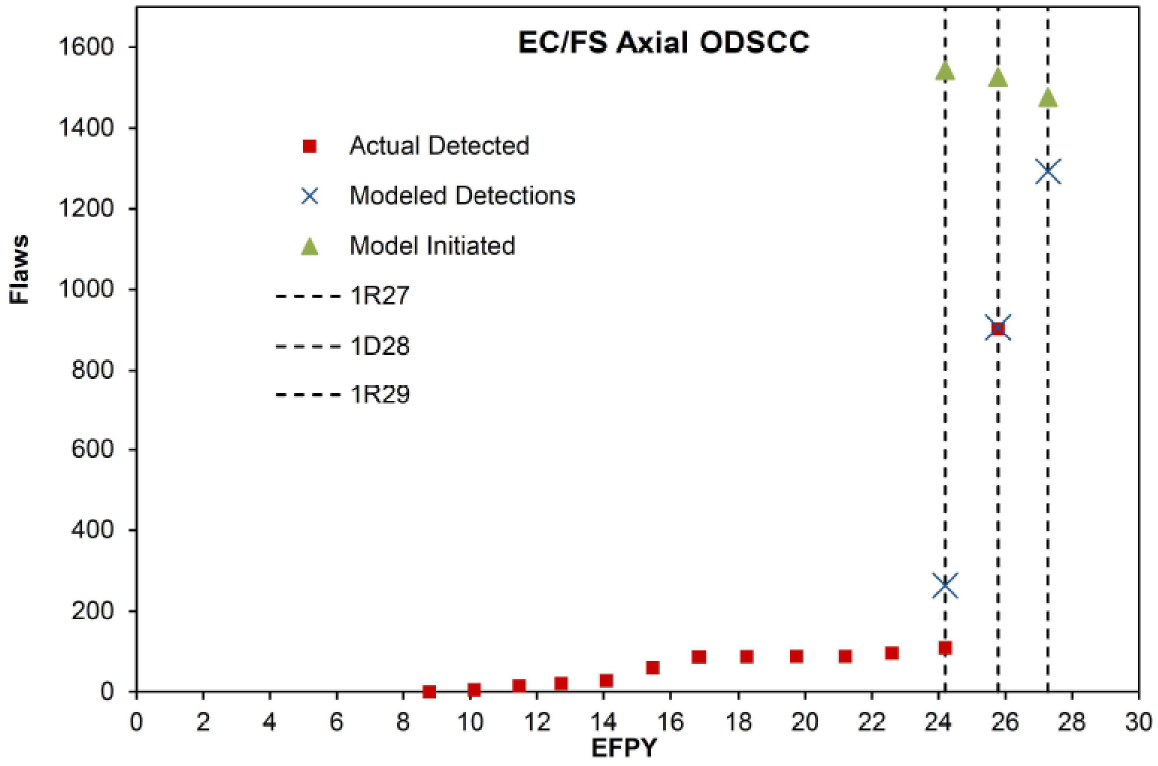
Damage Mechanism	Projections for 1D28	Projections for 1R29
Axial ODSCC at Supports (Evaluated Probabilistically)	22 indications/SG	1292 indications (SG A bounding; used for SG B)
Axial ODSCC at Top of Tubesheet (Evaluated Probabilistically)	16 indications/SG	21 indications/SG
Axial PWSCC within Tubesheet (Evaluated Probabilistically)	NOT PERFORMED	68 indications/SG
Circumferential ODSCC at Top of Tubesheet (Evaluated Probabilistically)	23 indications/SG	35 indications/SG
Wear at Supports (Evaluated Probabilistically)	3372 indications (both SGs)	3408 indications (both SGs)

Modeling of ODSCC at Eggcrate Supports

- Crack initiation modeled with a Weibull function starting with 1R27, model parameters adjusted until 1D28 results were benchmarked
- To fit the large increase in detected indications in 1D28, outages prior to 1R27 were treated as having perfect ODSCC detection
- OA input for SCC growth rates assumed all flaws detected during 1D28 were at the threshold of detection at 1R27
  - Results in average growth 9% TW/EFPY
  - Conservative to both the EPRI Guidelines default average growth adjusted to Palisades operating temperature (2.15% TW/EFPY), and the EPRI average growth rate meant to conservatively bound any Alloy 600 unit/temperature
  - Cycle 29 upper limit growth of 19.23% TW/EFPY

OA Model Results

Figure 6-10: Model Indications and Detections vs. Actual Detections: Eggcrate, Vertical Strap, and Freespan Axial ODSCC



- Probabilistic model of SG A bounds SG B
- Wiebull distribution with parameters adjusted to benchmark 1D28 (~26 EFPY)
- Assumes perfect detection prior to 1R27 (~24 EFPY)

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NRC Staff Comments, Cycle 29 OA

- Cycle 29 OA meets all acceptance criteria
- Small margin for meeting SIPC – ODSCC at eggcrate supports
- OA conservatively calculated average SCC growth rates by assuming all cracks were present at detection threshold and only grew during the last operating cycle (assuming cracking also occurred during the extended shutdown period decreases crack growth rate)
- OA assumes no benefits from chemical cleaning
- Clarification call with licensee on October 14, 2025
  - Obtain clarification on portions of Cycle 29 OA modeling
  - Upper tail growth and sensitivity analysis discussion
- Licensee's vendor is performing additional Cycle 29 OA sensitivity analyses; a new OA (Revision 3) will be issued

Palisades SGs Chemical Cleaning

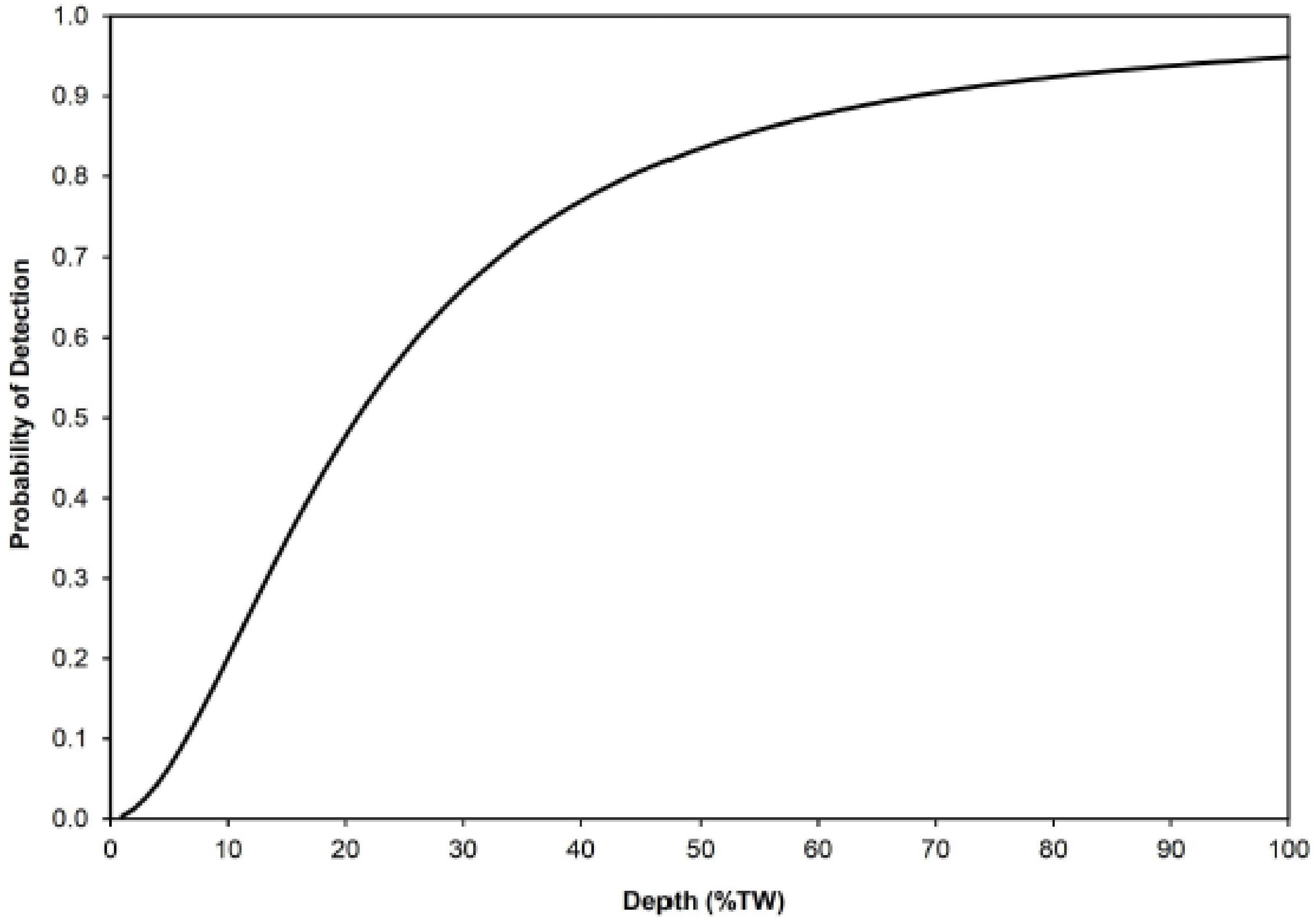
- EPRI SGOG (Hard) chemical cleaning performed in October 2025
  - Separate cleaning steps for copper and magnetite deposits
- Preliminary amount of material removed:
  - SG A: approximately 3000 pounds total deposits
    - 88 pounds elemental copper, 2000 pounds of elemental iron
  - SG B: approximately 3100 pounds total deposits
    - 85 pounds of copper, 2100 pounds of elemental iron
- Alloy 600 MA tubing fleet operating experience shows a variable but clear improvement in tube cracking from hard chemical cleaning

Concluding Remarks – Path Forward

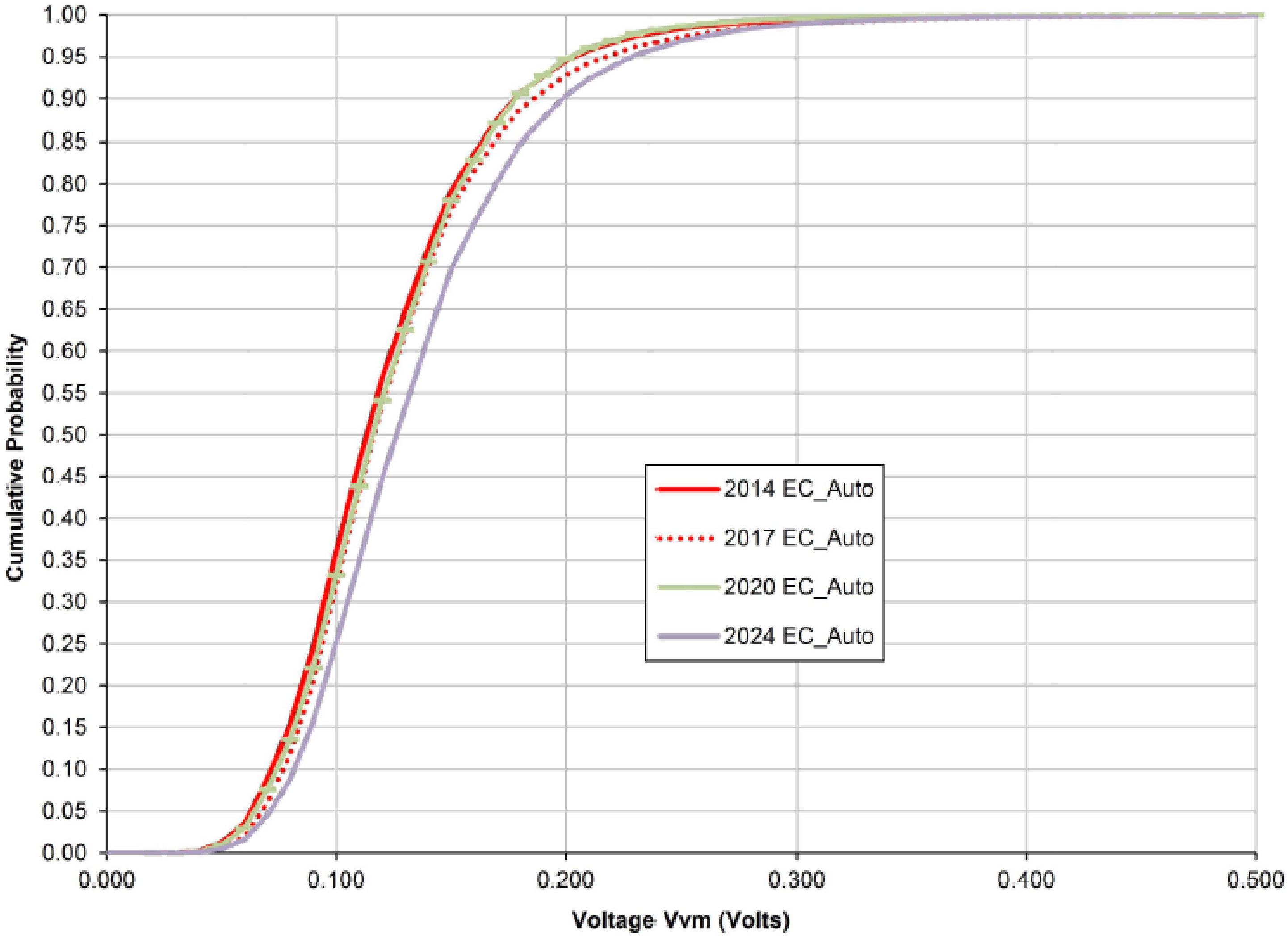
- NRC SG Sleeve Amendment issued October 30, 2025 (ML25303A280)
- NRC staff have no safety issues related to Palisades start-up and initial SG tube integrity, however, staff has questions related to OA modeling of cracking at the eggcrate supports
- Palisades is performing additional OA analysis based on NRC staff questions about the OA
- NRC staff evaluation of Palisades Cycle 29 OA continues, OA revision (Rev. 3) will be submitted to NRC after licensee review

Back-up slides

Bobbin POD Curve: Eggcrate, Vertical Strap, and Freespan Axial ODSCC



Eggcrate Support Bobbin Noise Comparison



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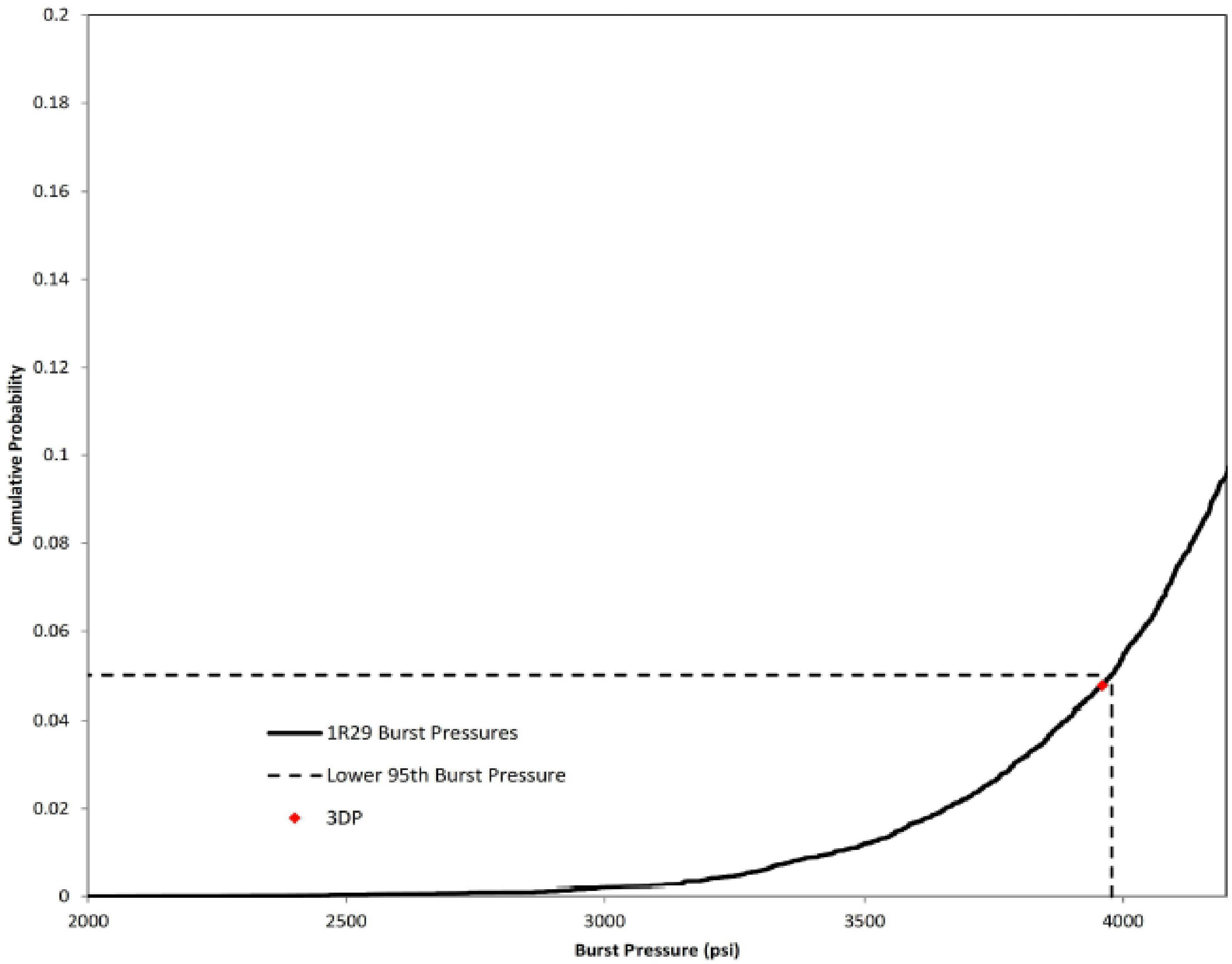
Burst pressure Evaluation - Eggcrate



Palisades SG Tube Sleeving Amendment

- Issued October 30, 2025, ML25303A280
- Sleeve life is limited to 10 years
- Sleeve installation limited to hot leg only
- License Condition (LC) related to sleeve inspection:
  - LC establishes a minimum sleeve inspection scope, the actual scope will be determined by the degradation assessment and OA
  - 100 percent of in-service sleeve/tube assemblies by the end of 1R29
  - 50 percent sleeve/tube assembly inspection by the end of each RFO thereafter, with scope expansion per EPRI Integrity Guidelines if flaw detected in pressure boundary portion of sleeve or parent tube
  - LC intended to maintain high probability of detecting structurally significant parent tube flaws should they initiate

Gundersen ACRS Comments 12/4/25

I have witnessed Palisades "resurrection" by Holtec, an inexperienced decommissioning contractor. Despite Palisades steam generator damage caused by Holtec's neglect and long history of exemptions to other licensing issues, it is clear to me that the NRC will do nothing to stop Palisades from restarting.

I no longer consider the NRC to be protecting the public's health and safety. The Trump Administration Executive Order requiring the NRC to speed up licensing has turned the NRC into a sock puppet for the nuclear industry

I am sure that your committee is aware that I was retained as an expert and have, on numerous occasions, expressed well documented concerns about the deterioration of the Steam Generators. The evidence suggests that the Steam Generators will fail before the next refueling outage, releasing radiation on the State of Michigan.

And what is the response to my concerns? Holtec said that my concerns should be discounted because "*Gundersen left the nuclear industry decades ago yet continues to hold himself out as expert in nuclear power plant operations"*[1]. This by a company with no operating experience! And the NRC has ignored my concerns, acting like the Moai statues on Easter Island.

The question remains "How much radiation will spew from Palisades when the steam generators fail?" Rather than proving that the reactor

[1] ASLBP No. 25-988-01-LA-BD01, APPLICANT'S ANSWER OPPOSING BEYOND NUCLEAR ET AL.'S PETITION TO INTERVENE AND REQUEST FOR HEARING, July 11, 2025. Page 19

coolant pressure boundary is safe and strong, the NRC seems content to place its faith in mitigating systems after the leak.

Is it too late to change course at Palisades? I have given up hope that the NRC will even read, let alone acknowledge, my steam generator safety concerns concerns. The reality is that the NRC's Palisades train has not "left the station". Events of the last year make it clear that the train barreled right through without ever intending to stop!

ACRS October 10 Meeting
Palisades Nuclear Power Plant
2 Minute Verbal Presentation by Arnie Gundersen

You are meeting today behind closed doors to review the supposedly non-public "proprietary" operational assessment of the safety of Palisades. I am not confident that the public's health and safety are well served by your top secret process.

My technical position on the integrity of the Steam Generators is already on the record. After I presented my concerns to the ACRS, new information became available that is deeply concerning. Holtec asked the NRC for eight relief requests because it has now detected stress corrosion cracks in eight dissimilar metal welds in the reactor coolant system! Two in the hot legs, four in the cold legs and two in the pressurizer.

EIGHT reactor coolant welds have experienced SCC in addition to the 3000 flaws that were sleeved in the steam generators. The entire reactor coolant system is degraded because Holtec chose not to maintain EPRI reactor coolant standards for two years.

Those of us who have appeared before the ACRS to criticize NRC Staff decisions have a joke about the ACRS: The ACRS asks the Staff great questions. The problem is that the ACRS accepts crappy answers! Since I only have two minutes, here is just one "good question" the ACRS might want to ask the Staff:

> Good Question: What is the probability that the Steam Generators will spring a leak before the next refueling?

Poor Answer: We don't know but there are systems in place to mitigate the leak when it occurs.

That answer is an admission that the Staff is relying on mitigation when a Reactor Coolant breach is almost inevitable.

Will you accept that crappy answer? After this meeting is finished, will you be able to say that you put safety before expediency on the Palisades "resurrection"??

Additional Written Information to The Advisory Committee on Reactor Safeguards
Concerning the Safety of the Palisades Nuclear Plant
October 10, 2025
Arnold Gundersen

In January 1986, two NASA contract engineers identified that the Challenger Space Shuttle was endangered if it were to be launched in cold weather. Those engineers used all the professional channels available to prevent the launch. But the bureaucratic inertia within NASA to maintain the launch schedule caused those NASA engineers to be overruled. We all know the outcome of that safety lapse. I write to you today in the spirit of those two NASA engineers as I continue to express my safety concerns to the members of the ACRS. You provide the last possible public safety oversight before resurrecting the Palisades nuclear plant.

First, I wanted to thank you for allowing me to share my concerns about the condition of the diminished integrity of the Reactor Coolant System at Palisades for five minutes during the Palisades subcommittee hearing on August 21, 2025. And I also want to thank you for your thoughtful Steam Generator questions to the NRC staff during the full committee meeting of September 3, 2025. I appreciate that the ACRS appears to be taking its oversight of the Palisades "resurrection" precedent seriously.

That said, new information just placed on the Palisades docket has amplified my previously expressed concerns. I know the NRC staff has not been forthcoming with information for me to analyze as an expert. I fear that the NRC staff has not been forthcoming to the ACRS either. Never in my 54 year professional career have I been more concerned about the integrity of the reactor coolant pressure boundary than I am about the condition of Palisades. Please let me explain.

All operating nuclear reactors are required to provide detailed Steam Generator (SG) Tube Inspection Reports to the NRC identifying flaws discovered during eddy current inspections. Six months after the inspections are completed, these detailed tube inspection reports become available to experts like me in the Public Document Room (PDR). Based on my prior industry experience, I knew that prolonged corrosive chemical exposure from extended shutdowns is deleterious to the metal components in both the Reactor Coolant and Secondary systems. I suspected that degradation was occurring at Palisades after it was permanently closed by Entergy in May 2022 and acquired by Holtec in June of 2022. But I had no hard data from the PDR to support my concerns. The last detailed Palisades SG tube Inspection Report in the PDR is from the 2020 SG inspections performed by Entergy. Five years of tube inspection data on both the primary and secondary systems is lacking from the PDR.

Since Holtec acquired Palisades, it appears to have used regulatory loopholes to avoid filing years of detailed Steam Generator Tube Inspection Reports indicating the extent of the damage. The NRC Staff has even acknowledged that Holtec has failed to provide some Steam Generator inspection details, which is why the NRC staff delayed issuance of the SG sleeving LAR. Here is the NRC's statement about the cause of that schedule delay:

> NRC staff has estimated that this licensing request will take approximately 940 hours to complete. The NRC staff expects to complete this review by September 30, 2025. Due **to the eddy current qualification data not being provided by the licensee**, the review date is beyond their originally requested date of August 15, 2025. (March 20, 2025, https://adamswebsearch2.nrc.gov/webSearch2/main.jsp?AccessionNumber=ML25076A177)

There are only two publicly available documents that discuss the condition of Palisades SG tubes. The first is the September 18, 2024 Preliminary Notification of Occurrence (PNO) (ML24262A092) issued by the NRC staff based on their concerns after the shocking August 2024 Holtec SG inspection results. The second is a letter containing meeting notes from October 1, 2024 (ML24262A092) between Holtec and the NRC that summarize the August inspection and make vague promises about follow-up analyses. That's it. If additional information is in the possession of the NRC staff, it should also be in in the PDR, and there is no such information. That leads me to the conclusion that the NRC staff is not in possession of some critical Steam Generator tube inspection data from 2024 and 2025 or that the staff does not want the public to analyze the condition of the SGs.

In your September 3, 2025 meeting, the NRC staff told the ACRS that approximately 3,000 sleeves were inserted into about 700 tubes since May of 2025. Each sleeve is 18 inches long, which means that 4,500 feet of sleeves (0.85 miles!) were installed. That is an astounding length of sleeving and is not supported by the publicly available flaw data from the September 18 and October 1, 2024 PDR documents. For an expert like me, it would be a simple matter to compare the existing 2020 Entergy Inspection with both the 2024 and 2025 Holtec Inspections to search for trends and their root cause of the increased cracking indications, but none of the 2024 and 2025 inspection data is available. However, it appears likely that the tube damage that was identified and sleeved in 2025 exceeded the tube damage that was identified in 2024.

The general rule for plugging is that tubes are sleeved or plugged when an indication has reached or exceeded 40% through wall. So a 20% indication will not be plugged but will be reexamined during the next refueling outage based on Electric Power Research Institute (EPRI) water chemistry guidelines. But the chemical hideout at Palisades is anything but normal. When Holtec did examine the tubes in 2024, it found some previously unaffected tubes had Stress Corrosion Crack indications exceeding 80% through wall cracks after remaining in cold unpressurized water for two years. Slow, anticipated crack growth that EPRI assumes is not realistic for Palisades. Hence 3,000 sleeves, already a huge number, may be inadequate to prevent additional tube failures because of hideout before the next Palisades Steam Generator inspections.

Traditionally, eddy current testing begins several inches above the tube sheet. The tube sheet is part of the reactor coolant pressure boundary which is where chemical hideout would be expected to be most prevalent. Because of this hideout, it is not clear that either the SG tubes or the SG tube sheet will survive for even half a year after Palisades "resurrection" is complete.

Now, new information of degradation has become available. In addition to all the steam generator tube and tube sheet indications indicating both SCC and PWSCC in the steam generator, on August 20, 2025 Holtec filed a series of relief requests (ML25232A195) indicating that it has discovered Primary Water Stress Corrosion Cracking (PWSCC) in at least eight dissimilar metal welds within Palisades Primary Coolant System. The affected welds include indications in two hot leg welds, four cold leg welds and two pressurizer welds.

The record indicates that Holtec did not take samples of either primary or secondary water chemistry at Palisades for two years and also that it is aware that Palisades was not in compliance with EPRI water quality guidelines. Clearly the absence of adequate water chemistry control at Palisades and its effect on the primary coolant system boundary are issues that deserve the thorough attention of the ACRS before allowing Palisades to set a new licensing precedent. This is a generic issue, as there are other decommissioned reactors now in the queue to be resurrected that have also not maintained adequate water chemistry during closure.

The existing evidence suggests that the reactor coolant pressure boundary degradation detected was caused by inadequate water chemistry control at Palisades, which places the facility in violation of two General Design Criteria:

> *Criterion 14—Reactor coolant pressure boundary*. The reactor coolant pressure boundary shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.
>
> *Criterion 15—Reactor coolant system design*. The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

The last time a steam generator tube completely ruptured was at Indian Point more than two decades ago. The condition of both the Primary Coolant System and the Steam Generators is even worse at Palisades with extensive SCC and PWSCC already identified. Luckily Indian Point's design allowed it to dump the radioactive steam into the condenser where it was contained. Palisades does not have this feature and would use Atmospheric Dumps to discharge radioactivity directly into the atmosphere.

Previously, I have seen the ACRS advise the NRC staff and vendor (General Electric) of its concerns that regulatory expediency was placed before public safety. About two decades ago, I was one of a few experts who petitioned the ACRS to evaluate Net Positive Suction Head concerns relating to the request for regulatory relief on Containment Overpressure during Boiling Water Reactor Power Uprates. The ACRS did the right thing then by refusing to allow for the containment overpressure relief which was championed by the NRC staff and GE. I have previously applauded the ACRS personally for making that decision.

My concern initially started with SCC and PWSCC discovered in Palisades' SGs but new Holtec relief requests have identified significant PWSCC corrosion at eight other locations within the reactor coolant system. The loss of the reactor coolant pressure boundary can lead to previously unimaginable impacts to the general public. The ACRS must be keenly aware of what could happen in the event of primary coolant system failure or a Steam Generator tube failure due to years of neglect from improper wet layup by Holtec at Palisades.

I pray that you will thoroughly question the integrity of the reactor coolant pressure boundary and steam generator tubes caused by Holtec's failure to meet EPRI primary and secondary water chemistry standards before allowing Palisades to set a new licensing precedent.

Thank you,

Arnie Gundersen
Expert Witness for Beyond Nuclear, Don't Waste Michigan, *et al.*

Written Comment for the 729th ACRS Full Committee Meeting
October 10, 2025

ACRS Written Comment – Palisades Steam Generator Life Cycle Considerations and Chemical Cleaning Considerations—Alan Blind

Dear Members of the Advisory Committee on Reactor Safeguards:

In your September 3, 2025 session, NRC staff, in response to your detailed questions, placed significant weight on the planned steam generator cleaning and emphasized the two-year period during decommissioning—when chemistry was not programmatically maintained—as the primary path forward to ensure public health and safety. Staff also appeared to rely heavily on Framatome's technical evaluations, and that reliance—without clear evidence of independent expert review—should itself be of concern to the ACRS.

While the decommissioning lay-up period deserves consideration, I respectfully urge the Committee to maintain a broader view that accounts for the full thirty-plus years of operating experience with the current Palisades steam generators. Too much emphasis was placed on assuming that two years without chemistry controls were the sole cause of the unexpected rate and severity observed in the 2024 inspection results. The longer history clearly shows that degradation mechanisms were active well before the recent lay-up period, and it is essential that the operational assessment reflect those cumulative effects. **NEI 97-06 requires that all degradation mechanisms be evaluated and that uncertainties be summed in determining the appropriate period of operation—meaning the full prior life cycle of the steam generators must be considered.**

Also, There must also be a questioning attitude about the specific chemical cleaning technique selected, its practical contribution to the operational assessment inputs, and whether it can realistically address the full life-cycle challenges of these steam generators—including the embedded copper and lead deposits that have historically, up until 2010, and maybe beyond, proven difficult to remove.

My perspective comes from direct responsibility: in 2010, while serving as Engineering Director at Palisades, I was asked to lead an evaluation of whether secondary-side chemical cleaning could meaningfully extend the life of the replacement steam generators. That study—completed more than a decade before Entergy elected to shut the plant down, and before many additional years of chemical deposit accumulation—reached conclusions that remain directly relevant today.

In 2010, we concluded that without a proven chemical cleaning technique capable of removing the embedded and historically difficult copper and lead deposits, outside diameter stress corrosion cracking from these mechanisms would continue. Even if cleaning could reduce the rate of degradation, it could not, by itself, assure operation through the 2031 license renewal period. We decided to not chemically clean the Steam Generators.

That finding remains directly applicable today. While chemical cleaning may contribute to life extension, it cannot be viewed as a stand-alone solution. The NRC and the Committee must weigh the broader record of operating experience, the persistence of copper and lead contamination, and the historical difficulty of fully removing hardened deposits when judging the adequacy of the operational assessment.

Operating History

The Palisades replacement steam generators, Combustion Engineering Model 2530, were installed in late 1990 and entered service in 1991. The tubing is mill-annealed Alloy 600, a material widely recognized in industry for its susceptibility to corrosion. From the outset, over 300 tubes in each generator were preventively plugged, with additional plugging accumulating in every refueling cycle. By 2009, effective plugging rates reached ~5% in both units. Predictive models in the 2010 Entergy study showed that without chemical cleaning, Palisades would likely exceed its 15% plugging limit by the mid-2020s, short of the 2031 license renewal period.

Unique Issues Identified in the 2010 Study

The 2010 chemical cleaning evaluation identified several unique challenges at Palisades:

- **Persistent sludge pile** on the tubesheets containing hardened deposits of copper and lead, historically at Palisades, resistant to mechanical lancing.

- **Copper transport legacy** from admiralty brass and copper-nickel condenser and heater tubing, which was replaced only after the steam generators were already in service.

- L**ead contamination** originated from low-pressure turbine rupture discs, which were not replaced until 2012—more than 20 years after the steam generators entered operation.

- **Top of tubesheet collars** and tube scale deposits, containing copper and lead, nearly impossible to remove mechanically.

The report concluded that unless copper and lead deposits were removed, long-term service to 2031 was unlikely.

Chemical Cleaning Techniques
Four principal methods were reviewed in 2010:

- **EPRI-SGOG process**: most thorough and documented, capable of targeting copper/lead/iron; but costly and operationally intrusive.

- **ASCA (Advanced Scale Conditioning Agent)**: less expensive, widely used, but originally intended for maintenance rather than full sludge removal.

- **High-temperature chemical cleaning (HTCC)**: aggressive but risky; prior use at Waterford 3 created iron redeposition issues.

- **Deposit Minimization Treatment (DMT, AREVA, now Framatome)**: newer, lower cost, but limited operating experience and uncertain effectiveness against copper/lead.

Unique Considerations at Palisades
Because Palisades' replacement generators entered service with pre-existing copper/lead contamination and hardened deposits, not all cleaning methods may be fully effective. The ACRS needs to question NRC staff on the particular cleaning method Holtec plans to use. The ASCA and DMT methods in particular may not penetrate hardened sludge piles or collars, raising questions about their adequacy

for the Palisades application. Even the most effective process (EPRI-SGOG) was predicted to provide only partial mitigation, not a guarantee of service through 2031.

Conclusion and Recommendation

As you meet with NRC staff on October 10, I urge the Committee to:

1. Acknowledge, as you have already done, the role of poor lay-up chemistry during decommissioning, but also weigh the prior three decades of degradation mechanisms that are equally important to today's operational assessment.

2. Question the NRC staff closely on the basis for confidence in the specific cleaning method selected, particularly whether it can address Palisades' hardened sludge piles and copper/lead contamination.

3. Probe whether staff has critically evaluated vendor claims and benchmarked outcomes from other Alloy 600 plants.

4. Ask the NRC staff how it expects the wide range of degradation mechanisms and they uncertainties to be quantified in the operational assessment.

Closing Remarks

In closing, I urge the Committee to keep in mind the unique circumstances at Palisades. Steam Generator Life-cycle management must be considered in full, not just the two-year period of unmaintained secondary chemistry during decommissioning, but the entire thirty-plus years of operation that preceded it. The upcoming operational assessment will necessarily be far more complex than those at other plants, with a wide range of uncertainties for each degradation mechanism. As required by NEI 97-06, these uncertainties must be treated quantitatively—summed as the square root of the sum of the squares—not minimized or considered in isolation. Finally, Palisades' licensing basis for a steam generator tube rupture accident relies solely on the atmospheric dump valves for rapid depressurization when offsite power is available, and on primary system feed-and-bleed—an operator-induced LOCA—when it is not. While this approach is licensed and permissible, it must weigh heavily on any judgment about the acceptability of additional operating periods given the condition and age of these steam generators.

Respectfully submitted,

Alan Blind, Retired

Baroda, Michigan

Written Comment for the 729th ACRS Full Committee Meeting

October 10, 2025

Re-Examining NRC Staff's Tube Integrity Assessment Response to ACRS: A Thought Experiment for ACRS Consideration

Alan Blind

At the September 3 meeting, in response to the ACRS request to NRC Staff to address the most severe cracks found in the October 2024 inspection, NRC staff stated that Palisades met tube integrity requirements during its last cycle because all 22 suspect tubes passed in-situ pressure testing, showing no rupture or leakage at three times normal operating differential pressure.

While NRC staff's statement is an assessment of tube integrity on the inspection date, I present this **thought experiment**—a back-of-the-envelope review of the most degraded tube, R73C94—not as a definitive analysis, but to highlight that the staff's response to the ACRS appeared to lack in-depth intellectual curiosity and focus on conservative decision making. **I respectfully suggest that the Committee probe this issue further in your October 10 meeting.**

During Holtec's 2024 inspections, Tube R73C94 was identified as the most degraded and stood out with its long axial and deep penetration crack. It exhibited a **73% through-wall axial crack, 1.7 inches long, located at a tube support plate**—a known site for corrosion and flow stagnation.

Crack Origin and Timing of Degradation

Outer Diameter Stress Corrosion Cracking (ODSCC) requires three elements: a susceptible material, an aggressive environment, and sustained stress. The stress component is particularly important, arising from operating pressure differentials across the tube wall as well as thermal stresses from repeated heat-up and cool-down cycles during normal plant operation. During the shutdown and decommissioning phase, when Palisades' steam generators were depressurized and at ambient conditions, these stress drivers were absent—even though water chemistry controls had also lapsed. This means that the severe crack found in Tube R73C94 could not have grown significantly during the decommissioning interval; instead, it must be conservatively assumed that the defect was already present at the time of plant shutdown and entry into decommissioning. This point is important within my thought experiment because it indicates Palisades ended power operations already carrying a tube in near-failure condition, making the margin to rupture even smaller than NRC staff acknowledged.

Basic Concepts: Failure Mechanics and Stress Environment

- **Stress Orientation and Crack Growth:** Hoop (circumferential) stress is the dominant stress in thin-wall, pressurized tubes and acts perpendicular to axial cracks. Axial ODSCC forms along the tube axis due to stress concentration, stagnant chemistry, and thermal conditions near the TSP. In R73C94, the crack approached through-wall depth. As the wall thins, remaining ligament stresses increase non-linearly, leading to imminent structural failure.

- **Likely Failure Characteristics:**

  • *Burst-Type Rupture* – Failure would occur rapidly, resulting in a high-pressure rupture. Though the crack is axial, the final rupture would be circumferential due to internal pressure acting radially.

  • *Leak-Before-Break Unlikely* – The high crack length and depth offered minimal opportunity for detection via small leaks before full rupture. Standard LBB assumptions do not apply.

• *TSP Effects* – The crack at TSP H01-0.4 could obscure leak detection and contribute to a redirected rupture path, and again, make early LBB detection difficult.

Crack Growth and Time-to-Failure Estimate

As outlined in my back of the envelope analysis, a bounding time-to-failure estimate for Tube R73C94 can be derived using the industry default crack growth rate for Alloy 600 mill-annealed tubing: [redacted] **inches per year** (per EPRI Steam Generator Integrity Assessment Guidelines, Rev. 3, 2011). Although this is not a predictive model, it illustrates how little margin remained.

- Tube wall thickness = [redacted] inches
- Crack depth = [redacted]
- Remaining ligament = [redacted] inches
- Growth rate = [redacted]/month
- **Time to 100% through-wall = [redacted]**

This 4.5-month estimate represents a bounding upper limit. It does not account for the non-linear intensification of hoop stresses as the ligament thins, which could plausibly accelerate failure and lead to rupture **sooner under actual operating conditions**.

Key Implication

Tube R73C94 was approaching structural failure with **insufficient margin for detection or operator intervention**. The most probable failure mode was a sudden, circumferential rupture at high pressure—a scenario that would have posed a serious challenge for operator response and triggered a **General Emergency declaration with potential offsite evacuation** under Palisades' licensing basis.

Thus, while tube integrity could be demonstrated at the time of the October 2024 inspection, the underlying data show Palisades was operating on the **edge of a steam generator tube rupture**. Continued operation for only a few additional months could have resulted in a markedly different outcome.

I respectfully submit this perspective for the Committee's consideration: **tube integrity assessments should not be viewed only as point-in-time**

demonstrations, but also in the broader context of time-to-failure and the limited margins shown in the October 2024 results.

Alan Blind

Written Comment for the 729th ACRS Full Committee Meeting October 10, 2025

Reassessing NRC Benchmarks for Palisades' Steam Generator Tube Integrity: CE Fleet Experience, 2024 Inspection Results, and the Role of Copper/Lead Oxides and Metal Deposits For Future At Power Operations

Alan Blind

Introduction

In this comment, I will first explain why Beaver Valley is not a valid benchmark for Palisades' steam generator performance, given the major design differences between Westinghouse and Combustion Engineering (CE) units. I will then compare Palisades' operating history to the broader CE fleet, showing that Palisades has already exceeded the end-of-life service years of all other CE steam generators. Next, I will discuss why the extensive tube degradation found during Palisades' 2024 inspection should not have been unexpected, based on known Alloy 600 behavior and the well-documented exponential growth of cracks.

Finally, I will highlight the unresolved issue of copper and lead deposits in Palisades' steam generators, including the risk that these deposits may have oxidized during the uncontrolled chemistry period in decommissioning, and propose specific questions for the ACRS to raise with NRC staff at the November 10 meeting.

> ***Note:*** *This paper refers to copper and lead deposits in Palisades' steam generators. For a more complete explanation of this issue—including chemical cleaning considerations—I respectfully direct the Committee to my separate comment titled* ***"Palisades Steam Generator Life Cycle Considerations and Chemical Cleaning Considerations"***

Benchmarking

At the September 3 meeting, an ACRS member asked NRC staff what other plants inform the Palisades' design and SG tube evaluations. Staff replied that only one other plant with Alloy 600 tubing remains for benchmarking: Beaver Valley. The staff appeared to place some weight on this benchmark as a validation of their evaluation of Palisades' vendor's analysis of steam generator tube condition.

This comparison is deeply problematic. Beaver Valley is a Westinghouse three-loop PWR, not a CE two-loop plant like Palisades. That difference matters technically when thinking about ODSCC mechanisms:

- **Loop & system layout:** Westinghouse SGs at Beaver Vally are designed for three-loop primary systems; CE plants like Palisades operate with two large steam generators and four reactor coolant pumps, a different hydraulic and thermal environment.
- **Support structure architecture:** Westinghouse SGs use broached or quatrefoil tube support plates; CE SGs (including Palisades' Model 2530s) use egg-crate lattice supports with vertical/diagonal straps and a stay-cylinder region. This geometry dictates how and where ODSCC initiates, as well as how inspections and repairs must be performed.
- **Tube bundle geometry:** Westinghouse SGs use all U-bend tube bundles, while CE SGs combine both: at Palisades, rows 1–18 are U-bends and rows 19–165 are square bends, supported by egg-crate lattices, vertical straps, and diagonal straps. This difference in tube geometry creates very different stress and wear environments, as well as distinct inspection challenges.

- **Tube scale and collars unique to CE:** At Palisades, tube scale and top-of-tubesheet (TTS) scale collars remain in place on the outside of tubes. These collars, along with copper/lead scale, are extremely hard deposits nearly impossible to remove mechanically because of the CE designed tri-pitch tube geometry. They directly promote ODSCC in dents, freespan, and egg-crate regions. Westinghouse SGs do not face this same combination of tri-pitch geometry and persistent areas of scaling, including for Palisades, copper/lead collars.
- **Materials:** Both plants may have Alloy 600 tubing, but Palisades' specific mill-annealed Alloy 600 (0.75" OD × 0.042" wall), coupled with CE support geometry, has shown a much higher susceptibility to ODSCC than most Westinghouse designs.

Because material, geometry, and scale/collar buildup drive ODSCC progression, Beaver Valley cannot be considered a technically valid benchmark for Palisades.

A More Meaningful Benchmark: The CE Fleet Experience

Rather than relying on Beaver Valley, the more meaningful benchmark is the actual fleet history of CE plants with steam generators of similar mechanical design. Following are the nominal steam generator effective full-power years (EFPY), **as of the year 2010**, at which other CE units reached end-of-life and replaced their steam generators:

- Palo Verde 1 – 15 EFPY
- Palo Verde 2 – 14.8 EFPY
- Palo Verde 3 – 20 EFPY
- Arkansas Nuclear One 2 – 15.5 EFPY
- Calvert Cliffs 1 – 19 EFPY
- Calvert Cliffs 2 – 18 EFPY
- St. Lucie 1 – 16 EFPY
- St. Lucie 2 – 20 EFPY
- Fort Calhoun – 25 EFPY
- San Onofre 2 – 21 EFPY

- San Onofre 3 – 21 EFPY
- Waterford 3 – 23 EFPY

In every case, CE units retired their steam generators well before reaching Palisades' present replacement steam generator operating age. Palisades today is estimated at ~28 EFPY of operation on its replacement steam generators, already exceeding the highest steam generator service life of any other CE unit.

Note: I do not indicate the tube alloy used at each of these CE plants, as that information is not always reliably available. It is well understood that allow 600 tubes, like Palisades', are the most susceptible alloy. However, regardless of alloy differences, the fact remains that the entire CE fleet reached end of SG life well before Palisades' current estimated EFPY age. This makes the CE fleet record the most meaningful benchmark for ACRS consideration of Palisades tube condition.

Why the 2024 Palisades Inspection Results Were Predictable

Viewed against this fleet record and the well-established behavior of Alloy 600 tubing, Palisades' 2024 inspection results—showing widespread and exponential increase in cracking and tube degradation at roughly 28 EFPY—should not have come as a surprise.   Let me explain:

- **Established damage modes:** Alloy 600 steam generator tubing is prone to both mechanical wear (caused by interaction with support structures such as egg-crates, straps, and tube-to-tube contact) and stress corrosion cracking (both primary water SCC and outside-diameter SCC). These modes are well documented across the CE fleet.

- **Exponential growth of cracks:** Once initiated, cracks do not grow in a linear fashion; instead, they accelerate, often increasing dramatically after a relatively quiet incubation period. This behavior aligns with industry findings—for example, *A Review on the ODSCC of Steam Generator Tubes* by H. Chung et al. (2013) describes ODSCC as a thermally activated process that accelerates once initiated. See Summary of Literature Search.

- **Role of deposits:** At Palisades, persistent copper and lead deposits in sludge piles, tube scale, and TTS collars have created a corrosive environment that promotes ODSCC. These deposits act as stress concentrators and chemical initiators, ensuring that once cracking began, its progression would be rapid.

Summary of Literature Search: End-of-Life and Rapid Exponential Crack Growth

Increasing Stress Intensity Factor

The growth of a crack is primarily driven by the stress intensity factor (K) at its tip. Because K depends directly on crack size, as a crack becomes longer or deeper the stress at its tip increases. This accelerates the growth rate and creates a positive feedback loop: a larger crack produces a higher stress intensity, which in turn drives the crack to grow even faster.

Crack Coalescence

During the incubation period, numerous small, isolated microcracks can form in high-stress regions, such as tube support plate crevices. As these microcracks extend, they begin to link and merge into larger, more significant cracks. This coalescence dramatically increases the effective crack size, producing a sudden surge in growth rate and a rapid increase in the number of detectable defects during inspections.

Worsening Chemical Environment

The aggressive chemical environment within crevices—necessary for ODSCC initiation—intensifies over time. Localized boiling, driven by heat transfer from the primary coolant, concentrates impurities inside the narrow crevice region, sometimes by factors as high as 10^8. Continued tube operation allows sludge and deposits to accumulate, restricting water flow and further concentrating chlorides, sulfates, and caustics. The result is a progressively more aggressive microenvironment that accelerates crack initiation and growth.

Sources

- Chung, H., Hong-Deok Kim, Seungjin Oh, et al. *A Review on the ODSCC of Steam Generator Tubes in Korean NPPs*. Nuclear Engineering and Technology, Vol. 45, No. 4, August 2013.
- Cizelj, L. *Trends of Degradation in Steam Generator Tubes,* 1998.
- U.S. NRC, *NUREG/CR-5752, ANL-99/4, Assessment of Current Inspection and Monitoring of Steam Generator Tubes*.

Palisades Copper and Lead Deposits: The Unresolved Question of Oxidation

Beyond these fleet-wide degradation patterns, Palisades faces an additional, unresolved risk: the extent and persistence of copper and lead accumulations within its steam generators. These deposits are concentrated in precisely the locations most vulnerable to ODSCC—dents, freespan regions, egg-crate supports, and the tubesheet transition. Historically these deposits were present in metallic form—hence hard to remove.

Basic chemistry shows why this distinction matters. Metallic copper and lead are relatively stable, but when exposed to oxygenated water or uncontrolled secondary-side chemistry, they can oxidize to form compounds such as copper oxides or lead oxides. In oxidized form, these compounds are well known to promote electrochemical reactions that degrade Alloy 600 tubing and accelerate ODSCC initiation and growth.

During Palisades' decommissioning period, for nearly two years, secondary-side chemistry was not controlled or monitored. This raises a critical unresolved issue: whether some portion of the long-standing copper and lead metallic deposits in Palisades' steam generators may have shifted from metallic to oxidized form under these conditions. If so, the potential for localized aggressive environments around the tube surfaces will be a factor for future power operations, when stresses are again introduced.

This is an important consideration that requires further explanation. Specifically, NRC staff should clarify to the ACRS:

- Whether copper and lead deposits at Palisades have oxidized following the extended period of uncontrolled secondary chemistry;
- What impact any such oxidation would have on ODSCC progression during the approved operating interval; and
- How these risks will be addressed in the upcoming operational assessments before the next full inspection of the steam generator tubes.

In short, the chemistry of these deposits is no longer an academic question. It is central to whether Palisades can reasonably be assumed to maintain tube integrity until the next mandated inspection.

Conclusion

Taken together, these factors meant that Palisades—operating beyond the demonstrated steam generator service lives of all other CE plants—was virtually certain to experience extensive tube degradation by the time of its 2024 steam generator tube inspection. Perhaps, in 2020 Entergy understood this very well, and it was a factor in their decision to discontinue future operations?

The October 2024 inspection results validated long-standing industry knowledge about Alloy 600 tubing rather than representing an unforeseen development. They confirm that the aging process for these steam generators follows the well-documented trajectory of slow initiation followed by rapid, exponential crack growth.

When viewed through the broader lens of CE plant steam generator experience clearly showing the industry end of CE steam generator life, and the extensive research on rapid, exponential crack growth after prolonged years of operation, the ACRS must press the NRC to explain how continued operation in this high-risk region of accelerated crack growth can be considered acceptable in the operational assessment when defining the permissible operating period before the next shutdown and inspection.

Moreover, the current 2024 Palisades data available today indicates that these accelerated growth rates are continuing unabated, as the research indicated. The literature shows that little can be done to halt degradation once it has been set in motion years earlier, given the inherent metallurgy, tube geometry, and crevice chemistry conditions driving the process. This reality underscores the urgency of adopting truly conservative decision-making goin forward.

Suggestions for ACRS Questions at the November 10 Meeting

Given the CE fleet experience, the unique design differences of Palisades, and the predictable progression of ODSCC, I respectfully suggest that the Committee ask NRC staff at the November 10 meeting to address the following questions:

- **Benchmarking Basis:** Why is Beaver Valley—a Westinghouse three-loop plant with fundamentally different steam generator design features—considered a meaningful benchmark for Palisades, when the CE fleet record provides a more relevant basis for comparison?

- **Fleet Experience Envelope:** Does NRC staff agree that Palisades, at ~28 EFPY, is already operating beyond the demonstrated service lives of all other CE steam generators, and if so, what technical justification supports allowing further operation?

- **Deposit-related Degradation:** How is NRC staff accounting for the persistent copper/lead scale, tube scale, and top-of-tubesheet collars unique to CE SGs—features that are absent in Westinghouse designs but known to accelerate ODSCC at Palisades?

- **Predictability of ODSCC:** Given the well-established, non-linear progression of ODSCC once initiated, does NRC staff agree that Palisades' 2024 inspection results were predictable, and if so, how is this being factored into the operational assessment and inspection interval planning?

Alan Blind

Five-Minute Verbal Comment – ACRS Full Committee, October 10, 2025

Alan Blind

Good afternoon, Members of the Committee.

I appreciate the opportunity to speak. I will summarize my written comments today. Let me emphasize up front: the October 2024 Palisades inspection results confirm that accelerated crack growth is continuing unabated. There is nothing Holtec can do now to reverse this. The literature shows this is exactly what happens once the degradation process has been set in motion years earlier. Given the inherent metallurgy, tube geometry, and crevice chemistry of Alloy 600 steam generator tubing, very little can be done to halt it once underway.

By way of background, I served as the Engineering Director at Palisades. In that role, I managed the benchmarking of Palisades' steam generator remaining life against the full population of Combustion Engineering plants. That benchmarking effort, completed in 2010, showed clearly that Palisades was at the front edge of the CE fleet experience curve, where the rate of outside-diameter stress corrosion cracking accelerates dramatically — what we described as a third-derivative growth curve.

We also accounted for plant-specific history. Decisions made in the 1990s introduced persistent lead and copper deposits into Palisades' steam generators. These scale collars and sludge piles are extremely difficult to remove and created localized conditions that exacerbated ODSCC. Combined with the known morphology of Alloy 600 cracking and the CE fleet benchmarking, we projected that Palisades would reach the **15% tube-plugging limit around 2025.** The Holtec October 2024 inspection results confirmed that projection almost exactly.

Those results show rapid expansion of both the rate and severity of ODSCC cracks. Several tubes approached or exceeded 90 percent through-wall depth, with one tube — R73C94 — within months of rupture under operating conditions. This is not random chance, and not simply the result of the recent period without secondary water chemistry controls. It is the textbook exponential growth phase of Alloy 600 cracking — a progression that began decades ago, and one we already understood and anticipated in 2009.

I applaud the Committee for shining a light on the Operational Assessment, and I recognize that in your September 22 letter to the Commission you highlighted the uncertainties introduced by the extended layup without chemistry control. That is indeed a concern, and perhaps one that chemical cleaning may help address. But the broader and more fundamental issue is this: the accelerated crack growth rates documented in 2024 show that Palisades has entered the high-risk, end-of-life phase where failures can occur suddenly and no credible mitigation strategy exists. The lack of proper wet layup during decommissioning did not cause this — the process was already well underway.

Fleet experience we reviewed in 2009 confirms this. Every other CE plant replaced its steam generators well before reaching this point. None attempted to continue operation in the exponential growth region of Alloy 600 degradation. Yet here we are in 2025, and Palisades is the outlier.

So the central question before you, as advisors to the Commission, is this: how can continued operation in this region of accelerated crack growth be considered acceptable in an Operational Assessment that defines the permissible interval before the next inspection? The slope of the exponential curve is approaching infinity.

In my view, conservative decision-making is the only defensible path forward. The data, the published research, the CE fleet benchmarking, and now the Palisades 2024 inspection all point to the same conclusion: once initiated, this degradation cannot be arrested. Palisades has crossed into a region of unacceptable risk, and that fact must shape both NRC staff's review and the Committee's recommendations.

Thank you.