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U.S. NUCLEAR REGULATORY COMMISSION

BRIEFING ON STEAM GENERATOR TUBE DEGRADATION

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TRANSCRIPT OF PROCEEDINGS

Public Meeting

Before the U.S. Nuclear Regulatory Commission:

Allison M. Macfarlane, Chairman

Kristine L. Svinicki, Commissioner

George Apostolakis, Commissioner

William D. Magwood, IV, Commissioner

William C. Ostendorff, Commissioner

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P R O C E E D I N G S

CHAIRMAN MACFARLANE: Good afternoon. The Commission meets today to discuss information about steam generators, including recent operating experience and the NRC's regulatory oversight. While ongoing steam generator tube degradation issues at the San Onofre Nuclear Generating Station have made recent news, the NRC has been evaluating and addressing steam generator tube issues for decades.

First we will be hearing from the NRC staff about some of that history, the agency's oversight of licensee steam generator programs, recently observed tube degradation mechanisms, operating experience, and details on the design basis accident for steam generators. Following the staff presentation, we'll hear from seven external panelists representing the Electric Power Research Institute, Mitsubishi Heavy Industries, AREVA, Westinghouse, Southern California Edison, Atomic Energy of Canada, and the Committee to Bridge the Gap.

Let me say at the outset that it is important to stress that the following issues should not be discussed with respect to the ongoing adjudicatory proceeding associated with the March 27, 2012 Confirmatory Action Letter issued by the NRC to Southern California Edison Company for the San Onofre Nuclear Generating Station, two issues in particular: one, whether the Confirmatory Action Letter constitutes a de facto license amendment that would be subject to a hearing opportunity under the Atomic Energy Act, and if so; two, whether Friends of the Earth's pending intervention petition satisfies the procedural requirements for a petition to intervene.

Before we get started, let me ask if any of my fellow Commissioners would like to make any comments. No? Okay. In that case, we will turn it over to the NRC staff, in particular to the Executive Director of Operations, Bill Borchardt.

BILL BORCHARDT: Thank you, Chairman. Actually, Eric's going to begin the presentation today.

CHAIRMAN MACFARLANE: Okay, great.

ERIC LEEDS: Thank you, Bill. Thank you, Chairman. Commissioners, good afternoon. Today the staff will be giving you a presentation on steam generator tube degradation and its significance. Certainly steam generator tubes are important to safety because they serve both as a reactor coolant pressure boundary as well as a containment boundary. If not managed effectively, steam generator tube degradation can be risk-significant. As the Chairman mentioned, the NRC staff expends significant resources monitoring steam generator performance across the industry, and we focus our oversight on the safe operation of steam generators.

Personnel in the Office of Nuclear Reactor Regulation are responsible for reviewing licensee proposals related to steam generator tube integrity and for reviewing licensee inspection results. In the regions there are inspectors that inspect licensee steam generator programs at every nuclear power plant. And in addition, the Office of Nuclear Reactor Research has an active steam generator research program which looks primarily at steam generator inspection and integrity issues.

We have two staff presenters today. Chris Jackson, the branch chief of the Reactor Systems Branch in NRR, will be discussing safety analysis related to steam generators. Chris will be followed by Ken Karwoski, the senior-level advisor for steam generators. Ken will provide an overview of steam generator degradation, including some recent issues, and the staff's oversight of licensee steam generator programs. So at that, let me turn this over to Chris.

CHRIS JACKSON: Good afternoon. My name's Chris Jackson. I'm chief of the Reactor Systems Branch. My branch is one of several branches in NRR responsible for accident analysis. Next slide, please.

Here's a cartoon of a reactor, but just to make a point, we focus in the accident analysis in the fission product barriers: the fuel, the core in the middle, the reactor coolant system pressure boundary, and the containment. If you look off to the left is the turbine and the money-making side of the house, and those are inputs to the accident analysis. And you'll see that the steam generator is a kind of in between. They fit in the middle there. Next slide, please.

When we talk about safety analysis, we talk about the chapter 15 safety analysis. These are in the final safety analysis report. They cover anticipated operational occurrences as well as design basis accidents. These range from turbine trips and reactor coolant pump trips all the way to double-ended guillotine of a major pipe in the system or steam line break. The objectives for the design basis accident are protecting the fuel design limits. The RCS pressure boundary cools the containment. And then, of course, onsite and offsite doses. Dose consequences remain within the limits. Next slide, please.

Steam generators transfer heat from the reactor to the turbine. Steam generators also form a barrier between the reactor coolant system and the steam system. This creates the possibility of a containment bypass situation, so they're of significant importance to us. Next slide, please.

Steam generators provide an input to many of the accident analysis. For example, RCS flow, heat removal, steam generator pressure, core inlet and exit temperatures, power -- all are directly related to the steam generators. And obviously, the failure of the steam generator tube is a design basis accident as well. Next slide, please.

So steam generator tube rupture with regard to design basis accidents. This is described in Standard Review Plan, Chapter 15.6.3, and it's evaluated from a dose perspective. And this is because the steam generators can form a barrier or a bypass scenario around the containment. We evaluated -- if you follow the instructions on 15.6.3 -- from a conservative standpoint. The flow characteristics are conservative. You assume the maximum RCS activity, which is quite conservative, and you'll also assume an iodine peak. And it's evaluated from a dose perspective. From a fuel design standpoint, it's not limiting. It's much less significant than the major rupture of a reactor coolant pipe, and from a containment, the containment's not challenged at all. So next slide, please.

One thing that makes steam generator tube rupture a little bit unique is the reliance on operators. Traditionally, we rely on automatic actions, but tube rupture requires operators to play an important role in plant recovery. First, they have to diagnose the event and they have to identify the steam generator. And they have to cool the plant down to reduce primary coolant pressure below secondary pressure. The operators are obviously trained and tested on this on a routine basis. Next slide, please.

We have had steam generator tube rupture events in the United States. We have learned from that operating experience. Principally in 1982, there was a tube rupture event at Ginna. In this event, the steam generators filled with water. Water entered the steam lines, and water was discharged to the steam relief valves. Steam lines aren't designed for water solid conditions, and the steam relief valves aren't designed to relieve water. So the operators were challenged on this event. So we took action -- so 1982. Next slide, please.

We issued three generic letters: generic letter 8207, 8208, and 8211. And the licensees took action through an owners' group initiative to improve steam generator tube rupture recovery capabilities. This involved instrumentation for the operators, help diagnose the event, as well as the equipment needed to dump valves with and without power so that they could mitigate the event. And this is documented in WCAP-10698A, which is on ADAMS. Next slide, please.

So in conclusion, the steam generator tube rupture event is not a limiting event from a fuel perspective or from a containment pressure perspective. Additionally, the steam generator tube rupture event isn't analyzed from a dose perspective, and the doses are well within regulatory limits. With that, I'll turn it over to Ken Karwoski, who will talk about steam generator design, steam generator degradation, as well as inspections and assessments.

KEN KARWOSKI: Good afternoon. My name's Ken Karwoski. I'm the senior-level advisor for steam generators in the Office of Nuclear Reactor Regulation. There are two major types of steam generators in use in the United

States. There's recirculating steam generators and once-through steam generators. There are 62 units with recirculating steam generators. These steam generators have the traditional U-shaped tubes. These types of steam generators have been used in plants designed by Westinghouse and Combustion Engineering. There are seven units with once-through steam generators. These steam generators have straight tubes instead of the U-shaped tubes, and these steam generators are used in plants that were originally designed by Babcock and Wilcox.

We usually group steam generators based on the tube material and the heat treatment that that tube material has received, and that's because that determines the corrosion resistance of the tubing to degradation. There are three types of tube materials and heat treatments used in the United States. The first generation steam generators have mill annealed alloy 600 tube material. The second generation steam generators had thermally treated alloy 600 tube material. And the current material of choice for the replacement steam generator is thermally treated alloy 690. Next slide, please.

This slide has several illustrations of steam generators showing both recirculating and once-through steam generators. The steam generator on the left is a typical recirculating steam generator that would be used in a Westinghouse-type plant. It has the traditional U-shaped tubes. The recirculating steam generator in the middle is more representative of a steam generator that would have been originally in service in a Combustion Engineering-type plant. And if you look closely, in that steam generator, the tubes are shaped more in a square rather than the traditional U-shape. They have two 90-degree bends, especially in the larger radius tubes. The figure on the right is an example of a once-through steam generator, just illustrating that it has straight tubes. Next slide, please.

Steam generator tubes have degraded with time. We usually bin steam generator tube degradation into two broad categories: corrosion category and a mechanical degradation category. In terms of corrosion, that's usually cracking or pitting or some type of -- form of corrosion. The mechanical type of degradation is typically wear. In plants with the original mill annealed alloy 600 tube material -- the first generation steam generators -- they've observed both cracking and mechanical type degradation along the entire length of the tube. And the examples that are illustrated on this figure have basically been observed in -- all these examples have occurred in mill annealed alloy 600 tube material. In the second generation steam generators, thermally treated 600, they've observed some cracking, but the dominant degradation mechanism in those steam generators is still wear. In the thermally treated alloy 690 steam generators, the dominant degradation mechanism is wear. There has been no corrosion-related degradation in thermally treated alloy 690 steam generators, either domestically or abroad. Next slide, please.

Steam generator tube degradation has led the industry to develop various repair criteria and repair methods in order to extend the lifetime of those steam generators. These review criteria and repair methods -- or repair criteria and repair methods are submitted to the NRC staff for review and approval because these requirements are contained in the plant technical specifications. There are operating conditions and maintenance tasks that can affect the lifetime of the steam generators. For example, plant can elect to operate at a higher hot leg temperature, which may make the tubing material more susceptible to corrosion-related degradation. From a maintenance standpoint, the utility can elect to clean the deposits or impurities out of the secondary side of the steam generator less frequently, which would make the tubing material more susceptible to degradation. When the staff reviews implementation of a steam generator program, it doesn't necessarily focus on the operating items or maintenance items that may affect the lifetime of a steam generator. It focuses on tube integrity and making sure that the tubes can perform their intended safety function for the period of time between inspections. Next slide, please.

Steam generator tube degradation has led to replacement of steam generators at a number of units. Fifty-seven of the 69 currently operating pressurized water reactor units have replaced their steam generators. All of these replacement steam generators have incorporated design enhancements. They took the lessons learned from the original steam generators, and they made modifications to the steam generators to limit the potential for degradation in their replacement steam generators. Some of the design enhancements include changing the tube material, changing the tube support plate material, changing the design of the support plates in order to limit the potential for corrosive impurities to accumulate by the tubing.

Since 1989, all of the steam -- licensees have evaluated their replacements under the 5059 process to determine whether or not a license amendment is required. In all cases, a license amendment has not been required for the entire replacement project, although specific amendments may have been required for specific aspects of the replacement. Although the design of the steam generator may not have been reviewed by the staff, it is subject to regional inspections. There's an inspection procedure in place that the regions follow that addresses all aspects of the replacement project, including the planning and design phase, the installation phase, and the post-installation inspection and testing phase. Next slide, please.

This figure depicts the number of pressurized water reactor units in operation as a function of year. It also shows the tube material in those steam generators at those units. As you can see in the red, in the '70s, '80s, and '90s, the majority of plants had mill annealed alloy 600 tube material, the tube material that has been susceptible to degradation the most. Starting in 1980, plants began to install steam generators with thermally treated alloy 600 tubing, and then starting in 1989, plants began installing steam generators with thermally treated alloy 690 material. Currently there are 48 units with thermally treated alloy 690 steam generators in service, 17 units with thermally treated alloy 600, and four units with mill annealed alloy 600. Next slide, please.

I now want to talk about two current steam generator issues. The first issue is cracking in thermally treated alloy 600 tube material, and the second issue is tube wear. As I just mentioned, there's 17 units with thermally treated alloy 600 tube material in the United States. The average age of these steam generators is approximately 25 years. In 2002, the first instance of cracking was detected in this tube material. Since 2002, additional cracks have been detected at various locations along the tube length. The number and severity of the cracking, however, has been minor. However, we still have concerns with this because cracking is a time-dependent phenomenon, and it tends to accelerate with time. As a result, there's a possibility that significantly more tubes will be affected by this degradation mechanism.

In addition, cracking is a more difficult degradation mechanism to manage than a lot of the other degradation mechanisms such as wear. Cracking is harder to detect, it's more difficult to size, and prediction of the growth rates of the cracks is more difficult than other mechanisms. Next slide, please.

The second issue I wanted to discuss is steam generator tube wear. Tube wear has been detected both in original and replacement steam generators. It has been found along various lengths of the tube. It's been found in the free span region of the tube as a result of the tube interacting with a loose part or foreign object. It's been found in the free span region of the tube as the result of tubes interacting with other tubes. It's also been found at the tube supports, including the support plates and the U-bend supports. That's the location where most of the tube wear has been found -- at the support locations.

The number of indications of tube wear detected varies from unit to unit. Some units have virtually no wear; other units have thousands of indications of wear. However, it's not the number of indications of wear that is important. It's the severity of the wear: how much tube material has been removed and whether or not that tube can perform its intended safety function.

Unlike cracking, wear is more easily managed. Wear is easily detectable in most cases. It's readily sized and it's easy to predict the growth rates of wear. Next slide, please.

Now I wanted to talk about two specific occurrences of tube wear. The first is tube-to-tube wear and replacement once-through steam generators. In the fall of 2011, a plant was doing its first in-service inspection, and they identified some indications. They eventually attributed those indications to wear as a result of tube-to-tube contact. Upon finding this information, they shared it with the other utilities who have once-through steam generators, and it was subsequently determined that four of those units also had -- or a total of four units had wear as a result of tube-to-tube contact.

This wear is shallow and appears to be slow growing, and a root cause evaluation is currently underway. It's important to note that this wear has been detected in steam generators designed and fabricated by two different vendors. Next slide, please.

This next slide is just a graphic showing that the wear is located in the free span region of the tubing. The wear -- at least one plant -- ranged up to at least 8 inches in length. All the tubes with this type of wear have had adequate tube integrity. Next slide, please.

I now want to talk about the tube wear that has been observed at the San Onofre Nuclear Generating Station. In 2010 and -- or San Onofre Nuclear Generating Station Units 2 and 3 replaced their steam generators in 2010 and 2011, respectively. These steam generators were designed and fabricated by Mitsubishi in Japan. In early 2012, Unit 2 shut down for a normal refueling outage and performed a steam generator tube inspection. They found wear at a number of different locations. They found wear that was attributed to a foreign object in the steam generator. The number of tubes affected was very small -- just a few indications -- and the severity of those indications was also small.

Wear was also found at the tube supports. A large number of indications were found at that location. However, the severity of those indications was very limited. Wear was also detected at a structure referred to as a "retainer bar." There were a few indications of wear at that location. That wear was unexpected, and one of the indications was deep. Although the indication was deep, that tube had adequate tube integrity. There were also two tubes that were identified that had wear as a result of tube-to-tube contact. Those indications were shallow, and those tubes had adequate tube integrity. Unit 2 had operated a full cycle at 100 percent power, and they had adequate tube integrity at the time of that inspection. Next slide.

Unit 3, in January of 2012, had operated for approximately half a cycle when they observed primary to secondary tube leakage. The leak rate was less than their technical specification limit, but the utility elected to shut down the facility because the leak rate was increasing and the leakage was unexpected. Like Unit 2, Unit 3 performed an inspection. They also identified wear at a number of locations. They identified wear at tube supports, at the retainer bar, and they also identified wear due to tube-to-tube contact. Unlike Unit 2, however, some of the wear indications were significant; in particular, the wear indications in the tubes affected by tube-to-tube contact. In all, there were eight tubes that did not have adequate tube integrity. All eight of those tubes failed the performance criterion in the technical specifications due to tube-to-tube contact wear. The tube-to-tube contact wear has been attributed to the aggressive thermal hydraulic conditions on the secondary side of the steam generator, coupled with a lack of effective support in that region. Next slide, please.

I now wanted to spend a few minutes talking about our regulatory framework, our oversight of licensee steam generator programs, and steam generator performance. The inspection and repair of steam generator tubes are covered in the plant -- are addressed in the plant's technical specifications. The original technical specifications were developed in the 1970s, when wastage and wall thinning were the dominant degradation mechanisms. When cracking started to occur, it became evident that we needed to enhance our regulatory framework. So the staff embarked on a multiyear effort to improve that framework. Ultimately, the staff approved new generic technical specification requirements, which were risk-informed and performance-based. The technical specifications are performance-based in that we specify the criteria that the tubes must meet at the time of the inspections. However, we do not specify the exact details of how to go about achieving that objective. Since 2004-2005, all plants have adopted these new risk-informed performance-based technical specifications. Next slide, please.

The NRC oversees and monitors the implementation of licensees steam generator programs. We have a multi-tiered approach, which involves both regional and headquarter activities. From a regional perspective, they have onsite resident inspectors. And from a steam generator tube integrity standpoint, those inspectors would monitor reactor coolant system leakage and primary to secondary leakage, which are indicators of possible loss of tube integrity. The regions also have region-based inspectors who, from a steam generator tube integrity standpoint, would go and monitor the licensees and service inspection program for the steam generator tubes. In addition, as I indicated previously, they would also inspect the steam generator replacement project.

There are also a number of activities here at headquarters with respect to steam generators. The headquarters staff will have calls -- or discussions with select licensees during their outage to monitor the scope and results of the tube inspections being performed at those facilities. In addition, the plant technical specifications require licensees to submit reports summarizing the results of their inspections. All those reports are reviewed by the staff. In addition to these activities, the staff will, as on an as-needed basis, meet with licensees to discuss their inspection results. In addition, there are semiannual meetings with the industry to discuss issues that may be generic to the steam generator community. These interactions are available to the public. The meetings are available to the public, our review of licensees steam generator reports are documented, and those reviews are publicly available; as is when the staff has discussions with the utilities, we document those discussions and those summaries are made publicly available. Next slide, please.

The NRC has had a research program since the 1970s, when it became evident that the steam generator tubes were susceptible to extensive degradation. We look at three broad areas in that research program. We look at the capabilities of the in-service inspection program to detect degradation. We look at the assessments of tube integrity and the models that are used to evaluate the flaws that are identified in the tubes. And in the past, we've looked at the various corrosion mechanisms in place in the steam generator. The Office of Nuclear Regulatory Research also has an international steam generator tube integrity program, where a number of foreign entities are a part of that. That program has been invaluable in ensuring that we keep abreast of research that's going on overseas and also the operating experience in other countries. Next slide.

In addition to the staff responding to the emerging degradation in the 1970s and 1980s, the industry also took a number of steps. They formed a group referred to as the Steam Generator Owner Group, which addressed steam generator issues. Today the industry has a standardized program for addressing steam generator issues. They developed guidelines which basically cover all aspects of a steam generator program. They have primary and secondary water chemistry guidelines. They have inspection guidelines that govern the inspection of the steam generator tubes. They also have guidelines on how to perform integrity assessments for the flaws that are observed in the tubing. In addition, they have primary to secondary leakage guidelines, which provide guidance on how to monitor for leakage and how to respond to that leakage. Next slide, please.

Steam generator performance has improved since the 1970s. In the next few slides, I'll show you a couple graphs that depict that improvement in performance. Prior to 2012, the last time a plant did not have adequate tube integrity was 2003. So in general, the performance has been very good, especially over the last decade. Over the last 25 years, most of the losses of tube integrity have been a result of cracking type degradation rather than mechanical types of degradation. Next slide, please.

This slide depicts the forced outage frequency as a result of primary to secondary tube leakage as a function of year. And as you can see, there's a general declining trend with time. In the last few years, there have only been a few primary to secondary leaks that have resulted in a forced shutdown. Next slide, please.

This next slide depicts the steam generator tube rupture frequency as a function of year. Once again, you see a declining trend as a result of improved performance. One question that we always get is, is the improved performance a result of the steam generator replacement, or does it actually reflect improvement in performance of the inspections that are being performed? And so on this graph, we have two lines. The red line, or solid line, shows the tube rupture frequency for the first generation steam generators, with the mill annealed alloy 600. And as you can see, that line has a declining trend. And that's attributed to improvements in the steam generator programs that licensees implement. Next slide, please.

We have a defense-in-depth approach to address steam generator issues. And it starts with the design phase. We try to achieve a high-quality design where the steam generator tubes are resistant to degradation. However, we recognize that steam generator tubes may degrade. As a result, as Chris Jackson indicated, a steam generator tube rupture during normal operation is a design basis accident. In addition, in the unlikely event of a tube failure, licensees train their operators to respond to primary to secondary leakage and also to steam generator tube ruptures during normal operation. Even though we try to achieve a high-quality design and have degradation-resistant materials, we still require tube inspections to be performed on a periodic basis, and we require assessments of those findings.

Tube inspections are performed when the unit is shut down. However, the tubes normally degrade when the plant is operating. As a result, we have various operational parameters that monitor to give us an indication of a possible loss of tube integrity. These include reactor coolant system leakage and primary to secondary leakage. In addition, we've assessed the risk significance associated with steam generator tube degradation. We've assessed the risk significance associated with single and multiple steam generator tube ruptures during normal operation, design basis accidents. And we've assessed the risk associated with tube degradation and severe accidents. As a result of these reviews, we have not identified the need for regulatory action. Next slide, please.

In summary, steam generator tubes may degrade. However, this degradation can be managed. The NRC staff monitors steam generator operating experience, and our focus is on tube integrity. In general, the steam generator performance has improved since the 1970s. That concludes my presentation.

ERIC LEEDS: All right. That concludes the staff's presentation, and turn it over to the Chairman.

CHAIRMAN MACFARLANE: Okay, great. Thank you. Thank you very much. It's very clear presentations. Appreciated that. We will start with questions with Commissioner Apostolakis.

COMMISSIONER APOSTOLAKIS: Thank you, Madam Chairman. And thank you for your presentations. My interest in today's topic is very high. And I very much value the information that we are getting from you and will get from the second panel. However, as the Chairman mentioned, there's an ongoing adjudicatory proceeding, so that limits the number and nature of questions I can ask. And I can assure you, however, that perhaps the shallowness of my questions does not reflect my interest in this topic.

Ken, you mentioned that there's degradation or the possibility of degradation of tubes when there are aggressive thermal hydraulic conditions on the secondary side. And I guess the result of that may be another technical term that I see in all the documents: fluid elastic instability. Now, not all of us have spent a career studying steam generators, so can you explain in simple terms what that means?

KEN KARWOSKI: The term "fluid elastic instability"?

COMMISSIONER APOSTOLAKIS: Yes.

KEN KARWOSKI: That's a condition when the velocity of the water on the secondary side of the steam generator causes the tubes to become unstable and vibrate excessively in different modes of operation. And so in the case of that specific condition, the tubes will start to vibrate excessively. There's two forms -- that vibration can be both in the plane of the U bend or it can be out of the plane of the U bend. In the case of San Onofre, for example, it was in plane fluid elastic instability that resulted in a lot of the tube-to-tube contact.

COMMISSIONER APOSTOLAKIS: And that instability, as I understand it, is related to the natural frequencies of the tubes, right?

KEN KARWOSKI: Yes. The support conditions of the tubing would affect the susceptibility of the tubing to fluid elastic instability. The more well supported a tube is, the less susceptible it will be to fluid elastic instability.

COMMISSIONER APOSTOLAKIS: Thank you. On Slides 26 and 33, you talked about the risk significance of this tube rupture event. And you said that there was an assessment regarding risk significance, but you didn’t tell us what the results were. What is the risk significance?

KEN KARWOSKI: Steam generator tube degradation, if not effectively managed, could be risk significant. However, we performed various risk assessments that have looked at both tube ruptures during normal operation and design basis accidents and have concluded that the risk associated with that is within acceptable limits.

COMMISSIONER APOSTOLAKIS: Okay. So it’s the totality of everything we do and so on that results in a lower risk.

KEN KARWOSKI: Right.

COMMISSIONER APOSTOLAKIS: Thank you Madam Chairman.

No, you want to add?

CHRIS JACKSON: Yeah. I mean, in Ken's presentation he was discussing globally, we had generic issue 163 and generic issue 188, which looked at risk, you know, from a broad perspective -- accident induced tube ruptures, multiple tube ruptures, severe accident -- and based on all the work above and beyond the significant work we were doing with the performance degradation, performance-based approach, we chose not to do any additional work. With regard to San Onofre and the risk significance of the event itself, the operators -- leakage was detected, primary to secondary leakage was detected, and the operators chose to shut the plant down. They chose to shut the plant down well below the tech spec limit. You know, they were at a procedural limit and they chose to shut the plant down. That's exactly what we would look for in the performance degradation. You identify the leakage before it's a rupture. So they were well below tech spec leakages of 150 gallons per day, so this is quite a small amount of leakage. The plant was shut down safely. The operators took appropriate action. So from that perspective, the public wasn't put in any risk from the event when the leakage was discovered.

COMMISSIONER APOSTOLAKIS: Thank you. Thank you Madam Chairman.

CHAIRMAN MACFARLANE: Commissioner Magwood.

COMMISSIONER MAGWOOD: Thank you Chairman, and thank you for your presentations today. As all this matter has evolved over the last year or so, and as I've spoken -- haven't had a chance to sit down with you. I look forward to doing that, but as I've talked to staff and I've talked to industry people and other experts about all this, a lot of the discussion seems to be, I guess, I would use the -- Commissioner Apostolakis, we talked about this earlier today, empirically based. It's all experiential. You look at how things have behaved in the past and that's how you design programs going forward. And to some degree, a lot of our discussion has been empirical. You've talked in terms of experience rather than physics, say. And that raises a question with me and I'd like to hear your thoughts about this. It seems to me that as we design sophisticated equipment these days, we rely a lot more on analysis than we do simply on, you know, what's worked in the past. So I expect that vendors are using very highly sophisticated codes and models to design their systems. Are we using highly sophisticated models and codes to analyze those systems? And I'd like to understand where are we on the regulatory side of this in terms of understanding -- we see a steam generator design. What is our ability to analyze that design from a physics standpoint, from a modeling standpoint as opposed to simply referencing what's worked in the past?

CHRIS JACKSON: Well, you make a good point, and as we get more, you know, we've redesigned many of the generators, mainly with like-to-like replacements, but as we do, we use more modern tools. And by and large as industry does that, that improves the plant design. So when we do our reviews -- we call it the standard review plan -- so the standard review plan outlines the entire scope of our review and we use those for new reactors, we use them for operating reactors. As we learn, we update those. So if you look at the design, typically we focus on the safety significance, on the safety analysis, and on the consequences. So we rely on industry codes and industry standards for the design. The diesels and the valves are designed to as ASME standard or a concrete's designed to an ACI standard. So the design, rarely do we get into the heavy details of the design itself. We look at the consequences and the integrated safety. So, you know, obviously for fuel and some other components, we look heavily at the design. So, for the steam generators, the thermal hydraulic conditions on the secondary side are not something that's within our standard review plan. We don't look at that in excruciating detail when we do the review. So, that's something that's more financial based. If they make that mistake it costs them money because the generators don't perform from a financial standpoint. But from a safety standpoint with our defense-in-depth approach, that's less important. Obviously if we learn the operating experience when we go forward we may revisit that. But at the moment, the standard review plan doesn't have us looking in detail at thermal hydraulic conditions in the secondary side for the design basis.

COMMISSIONER MAGWOOD: I wanted to let Jennifer jump in, but just let me make sure I understand what you just said because it sounds a bit like -- and just give me a chance to clarify this a little bit for me -- because it sounds a bit like -- because as I think it is, as both you and Ken indicated, the tubes are -- they are a containment barrier, basically. So one would expect that there would be some analysis that would go with this to assure that that barrier will remain intact during the operating life of the equipment. So is that not how we look at that? Can you clarify that a bit for me? Because it sounds like you were saying we don't analyze that and --

JENNIFER UHLE: I think I can maybe help answer that question. I'm Jennifer Uhle. I'm currently the deputy director for Nuclear Reactor Regulation, but until about a month ago I was the deputy director of the Office of Nuclear Regulatory Research where, as Ken has indicated, we've had an extensive steam generator tube integrity research program for many years since about the ‘70s. And I would say to help answer specifically your question, Commissioner Magwood, areas that we have advanced our modeling has been in looking at the -- the modeling that takes place once a crack or a degradation has occurred, then there are analytical approaches that are used to determine what the integrity of the tube would be if it would be challenged under various operating conditions. And our approach so far has been to take a look at what the industry has been providing. We model cracks. Cracks are hard to size and to characterize specifically, so we have, you know, an approximation method to model the geometry of the crack and then, you know, with an analytical approach determine what pressures and temperatures and how much more cracking could occur before it would become a problem during that next operating cycle. So we’ve made some advances there, but as Chris has indicated, we do not use the same level of design tools to take a look at the integrity of the tubes themselves, largely because of the design process involving ASME type codes.

COMMISSIONER MAGWOOD: And another observation I would make is that we focus, and I think most of the discussions focus on the tubes themselves, as opposed to the mechanics of the structure.

JENNIFER UHLE: Yes. Right.

COMMISSIONER MAGWOOD: But even, to some degree, thermal dynamic behavior, because I think a little bit of what Chris was saying, the thermal dynamic behavior is more of an economic issue as opposed to safety issue. But it does have safety implications obviously because that leads to fluid elastic instability and other --

JENNIFER UHLE: We have, in the research program, looked at more physics-based corrosion approaches. I can point to, well, what we call the model boiler program, that we found because we -- because each of the plants have a different chemistry on their secondary side, we could not possibly come up with correlations specific for each plant. So at this point in time, we use more of the -- or as Ken has indicated, the integrity approach. And so if the crack growth rate is a certain amount, as long as it can continue operating until the next inspection cycle, then we find that adequate protection.

BILL BORCHARDT: Just as a non-expert in many of the technical aspects, our concern has always been public exposure. I mean, we wanted to make sure that we had a program in place so that if a tube did develop a problem, it wouldn't result in release off-site that exposed the public unacceptably. It wasn't to make sure that there would never be a tube problem, right? So the fact that a tube develops a leak, there's a tech spec which governs that, requires the plant to shut down, do in-service inspections and plug tubes that look like they won't make it until through the next cycle, that's our interest.

COMMISSIONER MAGWOOD: That's interesting, and I think that certainly leads you to -- and I know the tech specs allow for a certain amount of leakage, but it does lead to a lack of an analytical basis for any changes in design. You know, we rely on the experience that we've had in the past to design our inspection program, and without an analytical basis, if there are changes in, you know, steam generator design, how do we know that those -- had experience that applies to the new designs? How do we sort through that?

BILL BORCHARDT: Just to clarify one aspect, I think, of what you were saying, there is a technical basis, I believe, for understanding crack growths and different failures, that once detected through ISI, we can have a reasonable expectation of how long that tube will last and whether or not it needs to be plugged. So there is a very good, I think, basis for that. I think you're right though about the internal thermal hydraulics of the steam generator.

COMMISSIONER MAGWOOD: I mean, if someone were to have a, I don't know, a helical steam generator say, just to pick something at random, how would we analyze that? What's -- how do with do that? Do we do that? Here comes Jennifer again.

JENNIFER UHLE: Sorry. This is Jennifer Uhle again from Nuclear Reactor Regulation. I would, in case of large deviations from the state of practice, then we would obviously invest more time in analyzing the structural integrity -- I mean, the overall behavior of the structure of the steam generator. And I would expect that all of our methods that we currently use to look at tube integrity, we would revisit under the research program. For example, these types of simplified analytical approaches to determine the effect of a crack and its impact on structural integrity, when we saw the changes to 690 -- excuse me, the Alloy 690 material, we've gone back and just verified that, in fact, these approaches are still valid.

COMMISSIONER MAGWOOD: Okay. Well thank all of you for your -- Chris, did you want to --

CHRIS JACKSON: Well, yeah, just to follow up, I mean by and large when we don't have a lot of information, you know, for new reactors, you just go conservative -- or where we lack information. I think in this instance, the thermal hydraulic conditions in the secondary side surprised the utility and surprised us. And the consequences were what are surprising and that this was a new degradation and we're going to study it, so, you know.

COMMISSIONER MAGWOOD: Appreciate it. Thank you for your answers. Chairman, for the meeting -- SRM, it might be worthwhile to ask Research to give us some thoughts about what direction research in this area should take going forward with all the experience that we've recently accumulated. Thank you.

CHAIRMAN MACFARLANE: Thank you, Commissioner Magwood. Commissioner Ostendorff.

COMMISSIONER OSTENDORFF: Thank you, Chairman. Thank you all for the presentations. I'm going to start out, Ken, with you. I remember back in the Navy in the 1970s we had a significant problem with steam generator tube cracking associated with stress corrosion cracking phenomena, chemistry control sludge, chemical hideout, pH phosphate control issues that were of significant concern, resulted in a lot of special inspections. I remember doing one as engineer of a submarine back in 1980 in Charleston, and we plugged the tubes routinely at that time. It was like Bill said, very straight stick approach. You go in there, you do an inspection, see cracks, you plug the tubes. Something that was said earlier today, and your presentation led me to ask this question, these generators were basically used for 30 years. That's was the service life of a submarine. The ones that are in -- you know, the generators that are in service in PWRs today, what kind of a time period are they designed for? Is there a standard? Is it 40 years? Is it something more than that? How do we look at that as far as standardization or expectation of life? Because I was looking at all the ones that have been replaced as opposed to just ones that had tubes plugged, and there's a big difference between those two evolutions.

KEN KARWOSKI: In terms of the steam generator design, most steam generators were originally designed, I believe, for 40 years based on general corrosion of the tubing. They did not anticipate cracking, and as a result, a lot of those steam generators did not make 40 years; some replaced, I think, the earliest was like after seven years of operation, and some have operated over 30 years. So in the design phase usually what you're looking at is general corrosion of the tubing. If cracked, then you try to select materials that are not susceptible to mechanisms such as stress corrosion cracking.

COMMISSIONER OSTENDORFF: Okay. So as these -- let's say for generators replaced in the last 10 years. Are they still being nominally designed for a 40-year period based on general corrosion or for cracking or tube-to-tube wear? Is that thinking design methodology evolved with experience and if so, how?

KEN KARWOSKI: Okay, our replacement steam generators were thermally alloy 690. In general, I don't want to say that that material is immune, but it is more resistant to corrosion and in particular stress corrosion cracking. So it's difficult to model the lifetime of a steam generator on whether or not it may or may not be susceptible to cracking. So, a new steam generator would still have, you know, a licensee can specify in their specification for a replacement steam generator 30 years, 40 years, and I think some of the new reactors, the design might be 60 years and that would be based on fatigue, analysis, and general corrosion of the tubing material. So in some respects, it's up to the utility to determine what the lifetime is. But as I indicated in my presentation, our focus is making sure that the tubes have adequate tube integrity for the period of time between inspections. The lifetime is more of an economic issue.

BILL BORCHARDT: Yeah. You might want to ask the second panel this. They certainly have better information. But I don’t think you can look at the number of steam generator replacements that have been made to date and assume that those generators were in a condition of failure or had reached the maximum number of tube plugs allowed. But rather, the decisions, were in a number of cases made, along with the license renewal decision, and once the authorization was granted or the decision was made to operate from 40 to 60 years over the life of the plant, then they had a 30-year-old generator and said, “Well, we’ll just replace the generator now and that’ll get us to the end of life.” And so that decision was made more -- I can’t say more -- but influenced by the business economic decision of having a new generator with enhanced performance that would relieve some operator burden, that would reduce dose exposure during outages because of the number of tubes that were required to be plugged and the ISI programs. And so there were a lot of factors, I think, that went into the steam generator replacements that have been conducted so far.

COMMISSIONER OSTENDORFF: Okay. Thank you. That’s a very important distinction and I appreciate your identifying that. One comment that Jennifer made that kind of caught my attention if I understood her correctly -- you want to come back to the podium. You dealt with chemistry, I guess -- or did I understand you to say that the chemistry varies significantly even for the same type of generator being installed at different plants? You might see different approaches to chemistry control?

JENNIFER UHLE: I would say over time they have evolved, but I’ll ask Ken to say, but yes, they vary between plants.

KEN KARWOSKI: Yeah, and that’s the key. The industry operates -- I believe they all follow the EPRI primary and secondary water chemistry guidelines and stay within the limits and action levels within those guidelines. However, when you're talking about steam generator tube degradation, you have an integrated effect. So a steam generator that was put into operation 35 years ago has the integrated effect of every chemical transient that it had experienced over the lifetime of the plant, and that is very difficult to model on, you know, how much deposits are on the secondary side, you know, what type of impurities may exist in there because of the materials that are used on the secondary side of the plant, which can vary from plant to plant. So that is very difficult to model on a generic basis and make a generic type of conclusion.

COMMISSIONER OSTENDORFF: Okay. Thank you. Let me shift gears a little bit. Ken, you mentioned -- and I'm going to direct this question to you and to Chris -- you talked about the international exchange of information and I believe that Chris you were over at ASN for a while --

CHRIS JACKSON: Yes, I was.

COMMISSIONER OSTENDORFF: -- and I was curious since the French have a lot of PWRs, I'm curious about what experience the French have had with similar issues on tube degradation or cracking. Whoever wants to take that.

CHRIS JACKSON: Well, I'll start and then I'll let Ken follow up. But I think the French steam generators are very similar to ours. The original designs were very similar to our designs and they've evolved. So we use the same constructors and vendors; so they are very similar and we share information.

KEN KARWOSKI: Yes. So in terms of, you know, tube cracking, they've observed tube cracking, they've had similar issues. They do have some modifications in the designs which may make their steam generators more or less susceptible to certain forms of degradation, but for the most part they're very similar, as Chris indicated. And we share operating experience. There are some differences, but we share operating experience and we factor that in.

COMMISSIONER OSTENDORFF: Okay. Let me shift gears and stay with Ken and Chris, and Eric, feel free to add in here if you want to, or Bill, I want to talk technology. I was out at SONGS in July of last year and I believe it was AREVA that had -- was coming in to look at tube-to-tube gap, looking at different dimensional checks of their tubes. I wanted -- I think, as I understood at the time, that there's some very specific technology being used for non-destructive evaluation of those tube-to-tube gaps. Are there standard practices from where we sit as regulators that would suggest there's a proper way of looking at this as far as the gaps to measure for proper clearances?

KEN KARWOSKI: When a specific issue comes up at a plant, frequently there's no generic techniques. There have been two proximity signals in other steam generators, so utilities have developed various techniques to try to ascertain, you know, are tubes in closer proximity and could there be a potential issue there. But in terms of have we reviewed and approved a specific technique for measuring those gaps, no, that would normally be up to the licensee. And to the extent that that's relied upon in our decision-making process, then we would ask for the appropriate technical basis and then review that if it's subject to, you know, our review and approval.

COMMISSIONER OSTENDORFF: I think you have some backup here at the podium.

JENNIFER UHLE: It's Jennifer Uhle from NRR, and I would add to that that our -- the research program is heavily involved in looking at the effectiveness of the various NDE techniques that are being deployed for those parameters that we find important in affecting the tube integrity; so it’s a very active part of what we’re doing in research.

COMMISSIONER OSTENDORFF: But is it the staff’s general impression that there’s reliability in these gap measurements that are being reviewed across industry, not just one plant --

KEN KARWOSKI: Well, in general, we know that the current technique is capable of seeing outside the tube wall, detecting loose parts that are metallic that might be next to a tube wall. We do know that utilities do use various techniques to monitor different things like the ovality of the tube or the diametrical expansion or the profilometry. In this particular case, part of the AIT, or our technical evaluation report, we may look at that specific aspect, depending on how it’s used in the specific review.

COMMISSIONER OSTENDORFF: Okay.

JENNIFER UHLE: But I would just add to that that if there was a parameter that a licensee was going to rely on to then feed into their analytical approach to determine whether or not the tube was likely to have integrity over that continued operating cycle, then we would be very interested in understanding the reliability of that NDE technique. The parameter that you are citing, I do not personally know if that parameter is currently used. So I think that’s -- you’re getting some of the --

COMMISSIONER OSTENDORFF: I understand. Thank you. Thank you, Chairman.

CHAIRMAN MACFARLANE: Okay. Thank you. All right. Eric or Chris, can you back up a sec -- and I know Chris, in your slides you talked about a limiting event, and I think that's a bit deep into the lingo there, so I'd like to clarify that. And I'd like you guys to explain what -- just put on the record here, what's the worst that can happen during a steam generator tube rupture scenario?

CHRIS JACKSON: A limiting event. I apologize. That is lingo. It comes so naturally. But the fuel is designed for various challenges, and a reactor coolant system is designed for various challenges, and so is the containment. And this event doesn't approach any of the limits. There's other events that are much more significant. So from a fuel standpoint, this is not a challenging event for fuel. Many of the other design basis accidents do challenge the fuel when you approach limits, and they don't exceed them, but this is not a challenging event for the fuel. So other events will uncover the fuel, will cause cladding to raise temperature, oxidize the fuel, which can be acceptable, depending on the type of event. This one does not. There's no temperature excursion, so the fuel remains intact for the design basis event. The same goes for the containment. The limits, other events, the steam line break, the large break LOCA will challenge the containment, you can approach limits; but this one doesn't, so it's not a challenging event from that perspective. But what makes it challenging is the operators have to take action and you have the containment bypass scenario; so that's what makes this event more interesting.

CHAIRMAN MACFARLANE: So then explain what's the worst that can happen during a tube rupture scenario.

CHRIS JACKSON: Well, I mean, the worst that can happen is you would -- I guess there's several scenarios. If your tube ruptures your limiting event, the worst that could happen is you wouldn't have safety systems, you would drain the reactor coolant system and fail the fuel and have a direct release path to the environment. That would be a very bad event. You could have another event, a steam line break that would result in fuel failure as well. So the worst event would be a fuel failure with a containment bypass.

ERIC LEEDS: I'm not sure if that's what you're asking for, Chairman. I think that what you're talking about is for steam generator --

CHAIRMAN MACFARLANE: Yes.

ERIC LEEDS: -- tube degradation --

CHAIRMAN MACFARLANE: Yes. Yes.

ERIC LEEDS: -- is it possible to have multiple tube ruptures? How would the plant react to multiple tube ruptures?

CHAIRMAN MACFARLANE: Right. Right. Yeah.

ERIC LEEDS: And for that type of a scenario, very similar to a single tube rupture, what you're doing is you rely on the operators to spot the leakage -- and they have technical specification limits on leakage -- and shut down the plant, and allow the pressure to equalize between secondary side, the side that goes to the steam -- to the turbine, the money-making end, and the primary side. So what you'd have is you'd have a bigger probability for a primary to secondary leak, you get more of the primary fluid into the secondary fluid. That could release more radionuclides into the secondary side, so the possibility is there for more of a possibility for a release off site or within the turbine building.

CHRIS JACKSON: Yeah. I apologize. I don't think I answered the question. So if you had multiple tube ruptures, that would be a more challenging event from some perspectives but from other perspectives it wouldn't necessarily. So one of the challenging things on a tube rupture, particularly a small one, is diagnosing it. With multiple tube ruptures, you'd have an earlier plant transient and you'd be able to identify the tube or the generator quicker, safety systems would react; so multiple tube ruptures would challenge the operators in a different way. But we have studied that from a risk perspective and we chose not to take regulatory action or regulatory action wasn't necessary. So in some aspects the operators were benefitted by automatic systems and easier diagnosis, but the timing would create another challenge for them, so...

CHAIRMAN MACFARLANE: Let me ask Ken a question. So I'm interested in alloy 690 and 600. You said there are still some plants that use alloy 600, the TT one. What's the compositional difference between those?

KEN KARWOSKI: In general, it's the chromium content of the alloy. Alloy 600 has lower chromium. Alloy 690 has higher chromium. The mill annealed versus thermal treatment refers to a heat treatment that those materials receive that make them -- that may change the micro-structure in terms of -- the carbide distribution around the grain boundaries, which may make it more or less susceptible to stress and cracking.

CHAIRMAN MACFARLANE: I understand that. Limiting events, no. but that, yes.

[laughter]

Good, okay. So what do you think then is the biggest challenge right now facing the replacement steam generators? Is it tube wear, or not? Or is there something else?

KEN KARWOSKI: I would say that the biggest challenge -- recognize the thermally-treated alloy 600 includes both original and replacement steam generators. But I'd say the challenge I see in the future is managing the cracking and that thermally-treated alloy 600 tube material. As far as I know, none of those plants have plans to replace their steam generators. Right now, there's only been a limited amount of cracking, but we know from past experience cracking tends to follow an exponential curve, so I -- from my perspective, I believe that the cracking in the thermally-treated alloy 600 is probably the biggest challenge.

CHAIRMAN MACFARLANE: Okay, so once -- so have any steam generators been replaced that -- so there were replacement steam generators but they have the alloy 600 in it?

KEN KARWOSKI: Yes. Recognize we usually distinguish two different forms of alloy 600.

CHAIRMAN MACFARLANE: Yeah, I know. The thermally-treated --

KEN KARWOSKI: The mill annealed alloy 600 and the thermally-treated alloy 600. There has been one plant, because of the timing and the replacement, actually replaced their original mill annealed alloy 600 steam generators with steam generators with mill annealed alloy 600 tubing. There's been one unit that has done that. There have been approximately eight units that have replaced their original mill annealed alloy 600 tube material with thermally-treated alloy 600 tube material.

CHAIRMAN MACFARLANE: Okay. So there's -- there are some plants that have done that. All right.

KEN KARWOSKI: Yes.

CHAIRMAN MACFARLANE: Okay. So then let me try to understand. You guys talked about tube ruptures at other plants, maybe one in particular. I want to understand a little bit more about other experience of tube ruptures.

KEN KARWOSKI: There's been nine domestic tube ruptures, if my memory serves me correctly. The last tube rupture occurred in the year 2000 at Indian Point 2. Most of the tube ruptures occurred in the '70s and '80s, and in 1993 there was a tube rupture at Palo Verde Unit 2. So the last two tube ruptures, one was in 2000, one was in 1993, and there were several in the '80s and the 1970s.

CHAIRMAN MACFARLANE: Okay. And then what about international experience with tube wear and tube cracking? I mean, is there -- some countries plagued more than others?

KEN KARWOSKI: I would say in general these steam generators are very similar, and as Chris indicated, a lot of the designers and fabricators are used throughout the world. So the experience is comparable from country to country.

CHAIRMAN MACFARLANE: Yeah. Okay. Good. And Bill, you mentioned something about the new generators have enhanced performance. What does that mean?

BILL BORCHARDT: Well, I was just referring to the improved materials that are inside.

CHAIRMAN MACFARLANE: Okay. So that's pretty much the only thing that's been improved or changed in the new generators is the materials?

KEN KARWOSKI: The tube materials have been enhanced, but other things can affect the degradation of tubes. So the tubes support materials have changed. They used to be carbon steel, they used to corrode and create issues. They've been replaced with stainless steel. They've changed -- when you bend a tube you put a lot of stresses in the tube; that can make it more susceptible to cracking. They've -- for the tubes that are the most tightly bent, the smallest radius tubes, they'll do a thermal stress relief to help reduce those stresses. They've changed the method by which they expand the tubes within the tube sheet to reduce the stresses in the tube sheet at the expansion transition region. So there have been a number of design changes that have taken place in order to limit the potential for degradation.

CHRIS JACKSON: Water chemistry has changed for the better, too, in many areas. So, you know, I know plants are working quite a bit to remove things in their feed water system that could --

CHAIRMAN MACFARLANE: What are the problems in the water chemistry that different --

KEN KARWOSKI: Different chemical species can cause accelerated corrosion. There's certain chemicals that you never want to get into your steam generators, like lead. Lead can lead to stress corrosion cracking very quickly. So there are certain chemical species that utilities definitely try to avoid their use anywhere on the secondary side, and then they monitor those species that can be detrimental to the tubing and keep the concentrations of those species below limits that are normally specified in the EPRI water chemistry guidelines.

CHAIRMAN MACFARLANE: Okay.

CHRIS JACKSON: And from an operating experience standpoint, the industry and us learned quite a bit from the 1982 Ginna event, where they did have challenges bringing the plant down into a safe condition; so that's all been implemented into the regulatory process for the owners' group initiative.

CHAIRMAN MACFARLANE: Okay. Okay. Great. Thank you. Commissioner Svinicki.

COMMISSIONER SVINICKI: I'm batting cleanup today, and I was thinking about Commissioner Apostolakis began this round of questioning by referring to the fact that although there are a lot of important dimensions of the topic we're talking about today, not all of them are appropriate for pursuit and resolution in this venue, so that makes it difficult for us to -- even the technical information is being used as the bases to resolve certain investigatory and adjudicatory matters. So I think I will just compliment you all on your presentations, and I will tease Eric and Bill a little bit by saying it's easy to look good when you have people like Chris and Ken and Jennifer, who took a very wise position near the podium, just so I compliment -- it's easy to look good when you have people that have such an impressive command of all of the history and the technical details. So thank you for the work you do and I will yield back. Thank you.

CHAIRMAN MACFARLANE: Great. Thank you. Thank you all. Thanks very much for excellent presentations. We will now take a five-minute break before we convene the external panel.

[break]

CHAIRMAN MACFARLANE: All right. I think we're had a bit of a break, and now we're back, and to get us started with the external panel, I'm going to turn to Jim Benson, the program manager for the Electric Power Research Institute Steam Generator Management Program. Mr. Benson.

JIM BENSON: Well, good afternoon. I'm going to start by providing a review of the EPRI Steam Generator Management Program, and if we could go to Slide Number 3. So, EPRI was established in 1973 as an independent non-profit organization to conduct research on key issues facing the Electric Power Research Institute. And in 1975 EPRI established a steam generator program first beginning with the Steam Generators Owners Group, and now we're turning into the Steam Generator Management Program, which exists today, one of the longest standing issue programs within EPRI. Next slide, please.

The specific objectives of the EPRI SGMP include identifying and prioritizing and conducting steam generator research to address materials degradation. Additional objectives include performing a long-term R&D in various technical areas such as water chemistry, non-destructive examination, materials and thermal hydraulics; all of those that have a significant impact on the steam generator operation. And the last objective I'll mention is the development of necessary technologies, processes, procedures, and tools to support the assessment of steam generator tube integrity. Next slide, please.

The SGMP develops many documents, technical documents, and guideline documents. The guideline documents come about by the research we do as well as industry experience, and we have currently six guideline documents that are put out to the industry. These documents, although called guidelines, they do have requirements in them that the utilities do put into their steam generator programs. Those guideline documents address secondary water chemistry, primary water chemistry, examination, the techniques that are used, as well as the period between inspections or the inspection interval. They address primary to secondary leakage, monitoring for leakage, and actions that need to be taken when leakage is identified. There are also tube integrity assessment guideline documents to assess the current condition of the steam generators, as well as making predictions for future degradation that may occur. And the last document I'll mention is the in situ pressure test guideline to actually assist in determining tube integrity. Next slide, please.

At this point, I'm going to change over to look at some of the historical degradation mechanisms that have been observed in the industry. Next slide, please.

This slide here, I just wanted to mention that there was a previously identified in the NRC presentations, just identifying the various tube materials and the trends toward the alloy 690 material for the replacement steam generators. Next slide, please.

This slide provides a snapshot of causes of steam generator tube repair, and by tube repair I don't just mean plugging up tubes, but also consider any degradation that exceeds a repair limit. So, sleeving of tubes, rerolling, and alternate repair criteria; basically trying to capture the more significant degradation that's been observed in this particular plot. And I'm plotting the percentage of tubes versus the year. And it's on percentage, so from this chart you can't tell numbers of tubes, just the percentage on a given calendar year. And it identifies the reasons for the repair, going from the early repair, which would be the thinning, and then in the early 1970s, followed by preventive repair or denting of the tubes. Then there was pitting type of repairs performed. So, the degradation mechanism that you see on here mostly in the blue shaded area is stress erosion and cracking, and that has been one item that has affected the industry to monitor, and inspect for, and maintain the operation of steam generators has been a focus on stress corrosion and cracking. Next slide, please.

So, the next three slides are going to talk about the three different tubing materials that are used in the steam generators here in the U.S. The first chart here is showing the number of tubes repaired versus year, and in this chart we're actually showing the actual number. And you look at the scale on the left side. It goes up to 9,500 tubes repaired in a given calendar year, and that's important to point out now because when I talk about the 600 thermally treated and the 690 thermally treated on the following slides, the scale is going to go down from a 9,500 down to 200 or 300 tubes repaired. And the only thing to point out on the mill annealed tubing is the stress corrosion cracking, is the numbers, the larger numbers, that is shown in the chart in the gray shaded area. Next slide, please.

This slide shows the alloy 600 thermally treated tubing experience relative to repair. And you'll see a lot of middle color blue, the mid blue in the center, and that is reflecting structure wear, and the structure wear has been a large number of repairs that have been performed on the 600. And I say large number; that's relative. This chart, looking at this, it's showing maybe 200 repairs is the maximum for the fleet of the 600 TT tubing which has in the order of 17 units that are shown on this particular plot. One thing to note in the brown or tan colored boxes to the right is the occurrence that has begun on stress corrosion cracking in the alloy 600 thermally-treated tubing. Not all plants have experienced the cracking that have thermally-treated tubing; however, we are noticing that that is an occurrence that is starting to be observed. The next slide, please.

This slide is showing the repairs on the alloy 600 TT. This is the material of choice to date for the replacement steam generators. Represents different numbers of plants that are represented by this chart. As the plants are replaced in the early 1990s, mid 1990s, we were averaging maybe one to three plants that are replaced per year. So, when we get to 2011, that represents a far greater number of plants on the order of approximately of 50 or so represented on the far right, in 2011. And we're seeing from this chart that the predominant mechanism, the yellow really stands out here, is the tube structure where that's been observed at AVBs and support plate locations. Next slide, please.

This chart, I'm switching from previous charts, we're talking about tubes. This chart is talking about indications. The number of indications -- there can be many indications -- any current indications of tube wear that occur in one tube, because there's many support locations along a tube length. So, what I've done here is I've taken those steam generators and those plants that have observed the greatest number of wear indications, and I plotted that here in this chart. So, the chart goes up from zero to about 12,000 indications reported for any given plant, and I'll focus on plant A to start with. For plant A in the lower left, I'm comparing the first ISI to the second ISI, and I'm showing the change between the first and the second to be very small. Realizing that -- and if we look at the depths, there are depths of -- flawed depths of these, and only the largest flawed depths tend to be repaired, usually over 35 or 40 percent through wall. So, there are very few tubes that are repaired that are shown on this chart. Most of these remain in service, are monitored, and have a very controlled growth rate for the wear. And so the only difference from one inspection to another is the change in the height of the bar showing in plant A, showing very little change;

meaning the same indications that were present in the first inspection are there in the second and with very little new indications that were reported.

Now on plant B, there's a little bit of a change there. We see an increase in the bar by about 50 percent of the height, going from about 6,000 indications to maybe 9,000 indications. So, that's showing an increase. And then we'll jump over to plant E at the far right showing basically a threefold increase in the number of indications. I wanted to point out one item on this particular bar is that the blue on the far right, on plant E, which has the most number of indications, less than 10 percent through wall. So, less than 10 percent through wall is very, very small, just able to be detected by the Eddy current. It's very shallow. So, these will be monitored over time to determine if they grow and at what rate they are growing, but you can see from this chart on the percentage through wall.

The last plant I'll talk about is actually plant C and D. This unit has actually only had one inspection, and I'm putting this down here just to show because of the numbers, and it fits the category of the top units for seeing wear, that after one inspection of each of the two plants there just to show the differences in the wear and the distribution of flaws. Next slide, please.

This is a chart that was shown earlier in a different format from the NRC presentation showing the forced leak or outage was reduced. And I just wanted to point out that except for the leak or outage in 2012, there was a period of six years that had proceeded without any forced shutdowns due to tube leak. And the trends of this going down, we talked about the improved inspection programs to control leakage, and then also obviously the replacement of the steam generators. Next slide, please.

And for conclusions I'd like to say that the SGMP provides the tools to develop technically strong steam generator programs which focus on maintaining steam generator tube integrity. The tools include results of EPRI research, guidance documents, and access to the worldwide steam generator operating experience. The steam generator programs are continuously updated based on new industry experience, industry guidance, and research results. And, for example, I'd like to mention that the industry guidance has been flexible, flexible enough to address emerging issues that might not have been observed before. We were able to handle the stress corrosion cracking observances, foreign objects that get in the generators and cause wear of the tubes, as well as tube-to-tube wear that's recently been observed, and that concludes my presentation.

CHAIRMAN MACFARLANE: Thank you. Okay, next we're going to hear from Dr. Hitoshi Kaguchi, project director in the Nuclear Plant Production Division for Mitsubishi Heavy Industries. Dr. Kaguchi.

HITOSHI KAGUCHI: Thank you very much. My name is Hitoshi Kaguchi. I am a project director with Mitsubishi Heavy Industries. My presentation today describes MHI's experiences related to tube vibration and wear in steam generators during a faulty case of plant operation in Japan, in the U.S., and also in the other countries. MHI has manufactured 116 steam generators in total, and six of them were for the U.S. plants. Our steam generators have experienced two major issues. One was flow-induced vibration wear between the joist and the anti-vibration bar. We call them AVBs. And they were observed in several plants in Japan, in the 1980s to the early 1990s. The other was the tube rupture event due to fluid elastic instability, or we call it FEI, in one plant in 1991. Until 2012, MHI steam generators have not experienced tube wear issues since the early 1990s.

At first, I would like to explain about the early tube to AVB wear. The wear was caused by fluid-induced vibration. The vibration occurred because of the too large gap between the tubes and the AVBs. The nominal gap at the time was over 10 mils. To prevent this tube to AVB wear MHI set the design gap of the later steam generator to approximately 3 mils. For already installed steam generators MHI replaced the existing AVBs with expandable type AVBs in 36 steam generators on-site in Japan. Similar repairs were also performed by the other vendors in the United States.

The second major operating experience was a tube rupture event that occurred in 1991, at Mihama Unit 2 in Japan, after 19 years of operation. The direct cause of the rupture was a fatigue failure of a tube because of a out-of-plane fluid elastic instability due to improper installation of the AVBs during fabrication. Over the time sludge accumulated between the tube support plate hose and the tubes. This resulted in the tube became tightly fixed at the tube support plate. Damping of the tubes decreased and the out-of-plane FEI studied. After this event, based on the extensive research under the development program, new design guidelines were developed by the JSME, Japanese Society of Mechanical Engineers. And the standard was implemented by Japanese MHI. Of course, the control of the AVBs becomes more strict after that.

Next I would like to explain about in-plane FEI in SONGS. The SONGS steam generators were the largest steam generator fabricated by MHI. The design, the SONGS steam generator was based on the established design practices, ASME, and other industrial codes, and the detailed customer design specifications. A major focus of the SONGS design -- SONGS steam generator design was to minimize the tube wear. We changed the design nominal gap between the tube and the AVB from our standard 3 mils to the 2 mils. This is the -- 2 mils, is the cold condition and fixes the zero gap at the hot operating condition. This was intended to reduce the -- prevent the tube wear caused by out-of-plane FEI. MHI also confirmed a severity issue against the out-of-plane FEI with conservative assumptions. The tube leakage at SONGS Unit 3 occurred due to tube-to-tube wear caused by in-plane FEI, and the in-plane FEI discovered at SONGS is the first occurrence in the nuclear industry. It is also the first evidence that the in-plane FEI conditions could be achieved in our operating steam generator. For in-plane FEI to occur, three conditions must exist simultaneously. The first one is the high steam quality. It means a very dry steam. This is related to the tube damping. And the second is the high steam velocity, flow velocity. This is related to the energy input to the tube. The last one is the low contact force between the tube to AVB. This is related to the effectiveness of the supports.

The steam quality and the velocity there depends on the size, and the design, and the operating condition of steam generator. The low contact force was the desire to the effort to minimize the wear due to out-of-plane FEI. MHI applied tighter damage wear control and the process improvement to the achieved uniformity distributed gaps. These actions result in unexpected in-plane FEI. MHI has confirmed that the condition found in the SONGS unit do not exist in other MHI design steam generators, including operating steam generators and the proposed USABWR design. SONGS Unit 3 had significant tube-to-tube wear by in-plane FEI, but Unit 2 did not. MHI examined the reason for this difference in detail. The same hydraulic conditions in both units were almost the same. The only difference was the support condition between the tubes and the AVBs. After the completion of the Unit 2 assembly, MHI improved fabrication processes. The main difference was the damage control of AVBs. MHI recently developed a very detailed three-dimensional model shown on this slide. Using this model we confirmed that the small change in damage control resulted in the large change in contact force. Contact force in Unit 3 are less than half of the dose in the Unit 2. We now understand that the AVB supports in Unit 2 are more effective to prevent in-plane FEI compared to Unit 3.

The following two slides show the improvement of the hydraulic condition by changing operating condition. This graph shows the quality. Power reduction show -- power reduction to 70 percent, for example, it would improve the steam quality in SONGS steam generators by more than half. This would bring the steam quality where it's in a range in other steam generators fabricated by MHI.

The similar result obtained for the flow velocity. Flow velocity would also be less than half, as reached in other steam generators.

My conclusion today, first, the in-plane FEI observed at SONG is the first occurrence in operating steam generators. The second, MHI has identified technical causes of tube wear from the in-plane FEI. Third, based on the technical causes, we can say in-plane FEI can be prevented by reduced steam quality, reduced flow velocity, and/or greater contact force between the AVBs and tubes. Thank you very much.

CHAIRMAN MACFARLANE: Thank you. Okay, now we will move on to hear from Jeff Fleck, who is manager of Nuclear Steam Supply System

Mechanical Engineering at AREVA. Mr. Fleck.

JEFF FLECK: Good afternoon. Today I would like to share with you the background and experience that AREVA has in the area of tube vibration and wear, starting on Slide 3. Since 1989, AREVA has designed and manufactured replacement steam generators. And as a global organization this experience includes components for both international and domestic utilities. Next.

The components are different due to the overall size and design of the plants for which they were designed, and include 67 recirculating steam generators, and four once-through steam generators. However, the materials of construction and the fabrication techniques are essentially the same, utilizing advanced and higher performing materials than the original components as well as enhanced fabrication practices and techniques. In the U.S. there are four plants with a recirculating design currently installed, one more to be installed this fall; and two plants with the enhanced once-through steam generator design installed.

For the U.S. replacements, in-service tube inspections have been performed, with most of the components receiving at least two. The U.S. inspection methodology and techniques provide for identification of tube wear at low depth thresholds as was shown previously, which allows for trending and larger data sets for use in engineering assessments. Next.

In the AREVA U.S. components, tube wear has been identified at various locations, including anti-vibration bars, tube support plates, outer bundle supports, and also wear from foreign object intrusion. The operating experience with the AREVA recirculating steam generators has not shown any tube wear due to in-plane fluid elastic instability. Tube to tube wear in the once-through design, however, has been identified and was summarized in NRC generic letter 2012-7, as well as in Mr. Karwoski's presentation earlier today.

The root cause for this mechanism is still in progress, but instability is not a factor, based on the results of the three inspections performed at the oldest plant and little to no increase in the flaw depths over time. Next.

As the designer of these components, AREVA has performed studies and evaluations to determine the causes of the wear, in order to ensure corrective actions have been identified and implemented as appropriate. Next slide.

Moving into some considerations that AREVA takes when designing a component, we work to an owner certified design specification that defines the design requirements that must be met. As a class one vessel, the component must also meet ASME requirements as well as industry and best in-house practices. Next.

Among the design requirements are those related to tube vibration and wear, therefore the following conditions must be considered during the design phase: thermal hydraulic, including flow rates, steam pressure, and void fraction; support configurations, the numbers and the design of each; the tube bundle configuration, for instance the tube spacing and the U-bend, otherwise known as incrimination; material selection related to wear resistance, and the coefficients of wear associated between material interaction; and flow-induced vibration of responses of the tubes and other internal components of the steam generator.

Included in the flow-induced vibration analysis, are stability determination, turbulence, and nonlinear wear calculations, all of which must meet the established acceptance criteria. In all cases conservatism is utilized in the analysis to ensure adequate design margins are maintained in the component. AREVA's design codes have been benchmarked through either laboratory testing or comparative analysis with other established codes. If during the design process changes are proposed or suggested, they are compared to previously proven technology and thoroughly evaluated for any detrimental effect. As a learning organization, AREVA utilizes lessons learned, corrective actions, and operating experience for applicability, and we incorporate them as appropriate. The final component design is certified as meeting the spec by a professional engineer, and owner acceptance of the component is established.

Now I'd like to move into our experience in the steam generator and inspection and repair business that we have been engaged with for the past 30 years. This work also includes engineering functions associated with steam generator assessment work. Our experience includes many of the challenging mechanisms that existed in the original alloy 600 steam generator components presented by Mr. Benson. Most recently, however, tube wear is one of the most common mechanisms affecting the replacements. However, it's been observed, based on our experience, that tube wear is detectible at low levels using EPRI qualified technique, has size uncertainties that are well quantified, has structural correlations that are conservative and based upon laboratory testing of real specimens, and typically has large margin to the tube integrity performance criteria.

The industry framework defined by NEI 97-06 and the EPRI Steam Generator Management Program establishes rigorous programmatic requirements, especially in the qualification of people and techniques. It also standardizes methodology for assessments and provides for operational experience sharing and exchange. Finally, it also established the current steam generator tech specs that were also referred to earlier. These tech specs are up to date and appropriate for effective in maintaining safety margins, especially those with tube wear.

For over a year AREVA has been involved in support of steam generator activities at the San Onofre site. Tube-to-tube wear as a result of fluid elastic instability and in-plane vibration is a new phenomenon that has required significant inspections, engineering, and conservative tube repair strategies. In Unit 2, the majority of the tube plugging was preventative and used conservative decision-making based on the Unit 3 characteristics to establish margin for return to service. Our condition monitoring and operational assessment was complete and was submitted as part of the SCE CAL response letter. Based on our calculations, at 70 percent power, there is margin to in-plane instability, which will then mitigate the potential for additional tube to tube wear, as well as place Unit 2 into an operating regime that has demonstrated successful performance relative to this phenomenon as presented by Dr. Kaguchi.

In summary, historically tube wear has been a manageable mechanism in operating steam generators. Cycle lengths and tube integrity margins have not been challenged, even in cases where large populations of wear scars are affecting the steam generator. A common strategy taken for the management of tube wear is to preventively plug tubes that are less than the 40 percent threshold criteria established in the plant tech specs. This increases margin in the tube integrity -- the calculations that are performed to support the next inspection interval. Finally, in our experience, the current industry protocol programs and requirements provide sufficient safety margins for all steam generator tube degradation mechanisms, including tube wear. Thank you. That concludes my presentation.

CHAIRMAN MACFARLANE: Thank you very much. Okay, next we're going to hear from Damian Testa, who is project manager for Steam Generator Management and Modification Programs at Westinghouse. Mr. Testa.

DAMIAN TESTA: Good afternoon.

CHAIRMAN MACFARLANE: Got to have the red dot there.

DAMIEN TESTA: Okay. Thank you. Good afternoon. Today I'd like to share with you some of Westinghouse's experiences with respect to flow-induced vibration. With respect to design of Westinghouse steam generators, we've manufactured generators for over 40 years. The potential for flow-induced vibration is routinely analyzed in every steam generator that we design and manufacture. This includes vibration in tubes, and also moisture separators in dryers.

The input parameters for the methodology used in the FIV analysis are documented in technical literature, and there's been also extensive testing performed to support this analytical methodology and literature. Improvements in the analytical methods have been made as operating experience and test data have evolved over the years. Replacement steam generators have incorporated enhancements in the U-bend assemblies and in all these generators manufactured. Field modifications have also been performed and they have been effective in resolving original steam generators' flow-induced vibration issues; things like complete anti-vibration bar replacements such as Dr. Kaguchi-san has mentioned earlier, and also modifications made in pre-heater designs.

Westinghouse manufacturing processes have improved for the RSGs and also our new design steam generator such as the AP1000. The advanced AVB design since 1990s have been incorporated in these models, and that consists of tighter dimensional controls on compounds and improved assembly oversight in the documentation at our manufacturing facilities.

With respect to our original steam generators, we've had relatively good performance with a few observed issues. We've had a limited amount of AVB wear in different models. We've had some short-term rapid wear early in life due to manufacturing issues, but over the long term, with the few exceptions, AVB wear has not challenged the pressure boundary or the tube integrity in these generators.

I mentioned AVB replacements. We've replaced AVBs, anti-vibration bars, which are the supports of the tubes, in 19 original steam generators between the years of 1985 and 1993. This process was effective in minimizing the AVB wear in the Model 51- and Model F-style steam generators. This modification consisted of incorporating expandable AVB design into the generators, which reduce the gaps. Other Westinghouse models during this timeframe did not experience such issues as those two models.

With respect to our Model D3, we have an FIV issue that resulted in a tube leak in a Westinghouse pre-heater-style steam generator. There were field modifications made to that generator, to divert flow in the pre-heater. Also our models D4 and D5 that are also pre-heater designs, the wear was not as severe as the D3. There were no tube leaks; however, we did do tube expansions to better support the tubes, and we also made modifications to split the feed water flow to reduce the velocities as seen by the tubes.

With respect to replacement steam generators, there's been no significant operational issues observed. A fraction of one percent of the tubes have experienced AVB wear, which is a very low number, and many Westinghouse RSGs have no AVB wear indications after one or more cycles of operation.

Some significant events that have occurred; in 1983, we had AVB wear that resulted in a tube leak in a Model 33 steam generator. That was determined to be related to a manufacturing issue. We had a Model D3 pre-heater wear issue. It was caused by turbulence in out-of-plane fluid elastic instability, and that was resolved by flow control in modifications to improve tubing support. Also there was a tube rupture due to high cycle fatigue in 1987 in a Model 51 generator. This was caused by denting at the top tube support plate and a variation in the AVB insertion depth. It was addressed by analysis and the installation of sentinel plugs, and stabilizers in a few tubes in this particular plant. And there was an NRC bulletin that resulted in that -- 88-02. A rapid wear event occurred in 1992 in a Model F. It was determined to be related to a manufacturing issue. It was one steam generator in a three-loop plant. That was resolve by replacement of all the AVBs in that particular generator, and the utility decided to replace the AVBs in the other remaining generators at the same time.

With respect to our experience at SONGS, we performed an evaluation for SONGS Unit 2 addressing tube wear at AVBs, tube-to-tube wear, and the potential for in-plane instability. We concluded that tube-to-tube wear observed in tubes in Unit 2 resulted from proximity of the tubes and out-of-plane vibration and/or in-plane turbulence, and not in-plane instability. How we came to that conclusion is based on the following; Eddy current data showed that there was no extension of the wear scars beyond the width of the AVB itself, and not only in these tubes, but other tubes in Unit 2 as well. Also, vibration due to in-plane instability will cause extension of the wear scars beyond the width of the AVBs as observed in Unit 3. Additionally, the two tubes with tube-to tube wear have no indications of the top tube support plate wear, as found with tubes that had tube-to-tube wear in Unit 3. All this was included in our operational assessment that we performed, and has been delivered to the NRC for review.

So in summary, we have observed issues related to FIV in the past with our original steam generators. As a result of our experience with this wear and fatigue issue over the past two decades, we've incorporated enhanced designs, manufacturing and oversight into our RSG in recent new steam generator manufacturing. We strive for zero wear for our design in manufacturing, and as a result, we have minimal wear. Tube wear in the original steam generators in service currently is managed in accordance with NEI 97-06, and as a result of that, we feel that they are very safe to operate. That concludes my presentation.

CHAIRMAN MACFARLANE: Good, thank you very much. Next up is Pete Dietrich, who is the senior vice president and chief nuclear officer of Southern California Edison.

PETE DIETRICH: Thank you, Chairman. Good afternoon. I'm pleased to have this opportunity to share our experience and explain what we have learned at San Onofre regarding tube wear in our replacement steam generators. Next slide, please. The tube wear we have observed at San Onofre falls into two categories: what I will characterize and what we have characterized as tube-to-tube wear; and what I will refer to as other tube wear mechanisms, the normal wear that has been discussed in some of the other presentations. And I will discuss each briefly in this slide to shape them. Tube-to tube wear occurs when adjacent tubes vibrate and contact each other during operation. Other plants have experienced tube-to-tube wear in the free span straight length of tubes between tube support plates. At San Onofre, tube-to-tube wear has occurred in the U-bend region for the first time in the industry. Other tube wear includes more prevalent tube wear mechanisms occurring in the industry as well as at San Onofre. This includes wear of tubes as the vibrate and contact anti-vibration bars, and as they contact tube support plates. The SONGS replacement steam generators also experience another tube wear mechanism resulting from vibration of thin retainer bars on the periphery in the U-bend region, as well as one instance of wear due to a foreign object. The wear rates resulting from each of these other mechanisms are within the experience of other operating plants and the industry steam generator management program described by the previous speakers. More precisely, the wear rates from these mechanisms at San Onofre have been determined to allow safe operation of the Unit 2 steam generators at 100 percent power for a full operating cycle, based on proven regulatory framework and established industry precedent. Now, because the type of tube-to-tube wear observed at San Onofre is unprecedented, I will focus the majority of the remainder of my presentation on this mechanism. Next slide, please.

This slide compares the tube-to tube wear observed in the two San Onofre units. The depiction is a plan view of half the tube bundle showing damage or wear indications in the U-bend region for one of the steam generators in each of the units. Unit 3 steam generator, on the left side, experienced deep tube-to-tube wear in multiple tubes, including through-wall wear on one tube. By contrast, Unit 2, which is on the right side of the slide, operated twice as long as Unit 3 and had shallow tube-to-tube wear in only one pair of tubes. The deep tube-to-tube wear in multiple Unit 3 U-bend tubes resulted from in plane vibration caused by fluid elastic instability. As you have heard from the earlier presentations, this phenomenon has not been observed previously in an operating steam generator. For Unit 2, to be conservative, Southern California Edison is assuming that the single case of tube-to-tube wear in Unit 2 may also have been caused by in-plane fluid elastic instability, although as you have just heard, there is another plausible explanation for this instance of shallow tube to tube wear. Next slide.

This slide depicts the critical elements in an operating steam generator required for fluid elastic instability to occur. The three components needed to act concurrently to cause the in-plane fluid elastic instability are loose or ineffective support conditions, high steam velocity, and high steam dryness which results in low damping. The size of each circle is indicative of the relative presence of each. In Unit 3, all three conditions existed concurrently for a significant number of tubes. The anti-vibration bar support conditions at Unit 2 were more effective than in Unit 3, therefore this circle is smaller in the three-ball diagram on the right. I will discuss the reasons for this in the next slides. Consequently, the overlap of the three conditions required for fluid elastic instability was minimal for Unit 2, at 100 percent power, and deep tube-to-tube wear did not occur in this unit. Next slide, please.

As we saw in an earlier slide, deep tube-to-tube wear from fluid elastic instability occurred in multiple tubes in Unit 3 but not in Unit 2. This difference in performance was caused by differences in fabrication between Unit 2 and Unit 3. The anti-vibration bars that support the U-bends are long, flat, and relatively thin. They are formed into a V-shape, and thus can be subject to twisting and bending. The Unit 3 anti-vibration bars were flattened after the forming, using a press, and the force applied to the Unit 3 anti-vibration bars was three times that of the force used in the Unit 2 forming of the anti-vibration bars. The resulting contact between tubes and anti-vibration bars was thus minimized. The effective of this difference was confirmed in pre-service measurements of contacts between tubes and anti-vibration bars. Unit 2 had many more such indications of contact. Next slide, please.

Mitsubishi Heavy Industries has developed a very detailed full tube bundle model, which calculates the effect of the fabrication differences on contact forces between the individual anti-vibration bars and tubes at steam generator operating conditions. In the Mitsubishi Heavy Industry’s presentation, you saw that the effect on contact forces, and thus the relative looseness of the tubes is substantial. Unit 2 has increased contact force and reduced looseness, and is therefore less susceptible to fluid elastic instability. The more effective anti-vibration bar support in Unit 2 resulted in a full run cycle at 100 percent power for approximately 12,500 hours with minimal tube-to-tube wear. Anti-vibration bar wear was also less extensive in Unit 2. For example, the total number of anti-vibration bar wear indications in both Unit 3 steam generators was about 50 percent greater than in Unit 2, even though Unit 2 had run twice as long. Next slide, please.

We have learned quite a bit from the SONGS experience with our replacement steam generators, and particularly that in-plane fluid elastic instability can occur in operating steam generator U-bends. As importantly, we have learned how to mitigate and avoid this new phenomenon in our operating plants, namely prevent the concurrent presence of inadequate supports, high-steam velocity, and high-stream dryness. Ensure acceptable stability ratios for in-plane fluid elastic instability using conservative inputs and assumptions. And lastly, we provide adequate justification through testing when extrapolating beyond proven operating experience. Next slide, please.

As a plant operator, I have operational control over two of the three components needed for in-plane fluid elastic instability. Specifically, reducing power can reduce steam velocity and reduce steam dryness sufficiently to preclude in-plane fluid elastic instability since the conditions for fluid elastic instability no longer occur concurrently. Next slide.

The previous slides summarize some of the specific technical understanding gained. Finally, I would like to reaffirm the context for this understanding. At San Onofre existing industry and plant measures, specifically operator response, for detecting a leak and shutting down the plant promptly worked effectively at San Onofre. The existing steam generator management program, as discussed by previous presenters, is effective and broad enough to address emergent issues such as in-plane fluid elastic instability, as well as the more prevalent anti-vibration bar and tube support plate wear. And also independent and open expert participation is very important. Thank you.

CHAIRMAN MACFARLANE: Thank you very much. All right, next we'll hear from -- is it Michel or Michael?

MICHEL PETTIGREW: Michel.

CHAIRMAN MACFARLANE: Michel Pettigrew, who is adjunct professor at Ecole Polytechnique, Montreal, and a principal research engineer Emeritus for the Atomic Energy of Canada Limited, Chalk River. Mr. Pettigrew.

PETE DIETRICH: It’s on. Yes, sir. You’re ready to go.

MICHEL PETTIGREW: Good, all right. Could I have the first -- yes, thank you.

ANNETTE VIETTI-COOK: Speak into the microphone.

MICHEL PETTIGREW: Yeah, I’ll get closer, yeah. My talk is going to be about vibration and in particular fluid elastic instability. On the left of the figure, you see a steam generator. I think you all know enough about steam generator. What I’d like to do is to focus on a peculiarity of a steam generator. So, on the right you see a steam generator being assembled. And what you see there is U-bends that are being inserted in the steam generators. So, you notice the U-bend -- the plane of the U-bend is being installed, and on top of the U-bends are bars. They are anti-vibration bars. And so you can see here that from the point of view of out-of-plane motion, the tubes are really very well supported because you have a large number of bars all around; but from the point of view of in-plane motion, there’s really no positive restraint here to prevent the tube to move in the in-plane direction. Essentially, it relies on friction forces to limit the vibration. And that is one part of the problems that we are discussing here. Could I have the next one?

Okay, the other concern, if you like, is the vibration excitation, which is in this case, is in the form of flow velocity, high-flow velocities. It may be a bit difficult to see on this slide, but on the right, at the top near the U-bend, there is an area that’s whiter than the rest. And this corresponds to a flow velocity of about 6.5 meters per second, or 20 feet per second. So, there are quite high-flow velocities in that region of the steam generator coupled with the possibility of less-than-effective support. It's the kind of thing that can lead to problems. Next slide, please.

Now, we've taken a very pragmatic approach to these problems. Essentially, we have subjected various section or markup of various parts of steam generators to operating conditions. So, in this case in here we have, on the right-hand side, there is a test section here and it's essentially a cantilever tube bundle. And we are subjecting it to flow and we can, with this loop in here, we can have air, water, or a mixture of air-water, so we can simulate liquid, two-phase and gas flow. And we subject the tube bundle to these flow conditions and we reach instability that way. And if I could have the next slide.

Okay, so this is now looking at the end of the tube bundle and there is a Plexiglas porthole there, if you'd like that allows us to look at the end of the tube. That's the free end of the tube. The other end is clamped. And you'll see, if you can get the simulation going -- okay. You see what's happening in here. This is condition of instability. It's a square tube bundle. The flow is going up; it's liquid, so in that case it's water. Okay, so now what we're going to do is increase the flow velocity by 10 percent. We're not changing anything at all; we're just increasing the flow by 10 percent. So, could you -- would you do it, okay. Can you -- yeah. You see, now, we have instability. It's the same condition except 10 percent more flow velocity, and you see we have instability now in a completely different mode of instability, all right?

Okay, from an academy point of view, this is all very interesting. From a practical point of view, you'll really want to avoid this in your component.

There's no question about it. You have amplitudes here where you have tubes contacting each other, meaning vibration amplitude in the order of a quarter of an inch or more.

Okay, can I have the next one? Here, we analyze this information of fluid elastic instability. We present it in the form of an instability diagram, which you can see now. So, on the Y-axis, you have the dimensionless flow velocity; it's flow velocity divided by frequency, diameter. And on the X-axis is a mass-damping parameter, it's a dimensionless mass-damping parameter. So, what I've done here is over the years I've reviewed the literature and come up with something, like 500 data points, which I have analyzed and put on this graph in here. And the message is clear here. If you're below the lines -- there's a line there, if you're below the line, that's stable; if you're above the line, it's unstable. So, you want your component to be below the line, not above, you know, it's that simple.

Okay, the next slide is going to -- next one -- is going to be what's happened now in two-phase flow and in in-plane direction. Now, I'd like you to focus on the figures on the right; Figures C and B, okay? In this case the tubes -- that's a cross section across a test section, and the tubes that are numbered are instrumented tubes and they are flexible tubes. All the tubes that are not numbers are essentially rigid. In C you have a column of tube, which we could constrain to vibrate only in the in-plane direction, or allow it to vibrate in the axisymmetrical fashion in every which way. On D we have two half columns there, and they are constrained to vibrate only in the in-flow direction or in-plane direction. So, the next slide shows the results.

Okay, so if you look at the upper part result, we have a column of tube that is constrained to vibrate in the in-plane. And on the right, top right, you see the response. There is really no evidence of instability; whereas, if for the same column, I allow it to vibrate every which way, then it really goes unstable as it shows on the left-lower diagram. In the left-lower diagram you have the vibration response times the velocity, starting by the left, it's in liquid flow. And on the very right, it's at 95 percent void fraction, and then in between -- in between. But clearly, you know, you do not have instability for a single column that's constrained to vibrate in the flow direction, the in-plane direction, and you do if they are un-constrained, although the frequency in that case was a lot higher, meaning that the rigidity of the tubes were much higher. So, in spite of that, it really goes unstable.

Now, the next slide shows a comparison between one column and two columns. One column is on the left and the top, two columns is on the right at the bottom. And in both cases here, we're only allowing the tube to vibrate in the in-plane direction. And of course, for the one column, then it doesn't go instable, as we've shown before; but if you have two columns, then it does go unstable, as you can see on the drawing on the left bottom. On the left bottom, you have vibration amplitude versus flow velocity. And there's three lines, and here one is void fraction of 80 percent, the next one is 90 percent, and the last one is 95 percent. Now, we're going to see an animation of this, if I can get the next one.

So, let's go on the left in here and get it going. You see on the left this is the single row, but that's allowed to vibrate every which way in an axisymmetrical fashion. And you see it goes unstable. Whereas, if the tube will constraint to vibrate only in the in-plane direction, it would not go unstable as we've seen before. Now, if we look at the two-column one now. You see the two-column one does go unstable. That's really the interesting part in here is that one column one does not go unstable; two-column one does go unstable. What we've shown in here is that you can have fluid elastic instability in the in-plane or the in-flow direction in two-phase flow, but sometimes it's not so easy to do. It's a lot more difficult to get fluid elastic instability, to achieve fluid elastic instability when the tubes are constrained to vibrate in the flow direction. If I could have my final slide?

Okay, so this is a similar diagram of instability on the Y-axis; there's a dimensionless flow velocity on the X-axis in the mass-damping terms. And the bottom line is for results from two bundles that were allowed to vibrate axisymmetrically; whereas the upper line is really to look at what happens when you are constraining the vibration into the in-plane direction. So, you have to go to a higher velocity to achieve instability when the tubes are on constraints. So, it's more difficult to get in-plane instability, but it's possible to happen. Thank you. That's all I've got to say.

CHAIRMAN MACFARLANE: Okay, thank you very much. And then our final speaker this afternoon is Daniel Hirsch, president of the Committee to Bridge the Gap, and lecturer at the University of California-Santa Cruz. Mr. Hirsch.

DANIEL HIRSCH: Chairman Macfarlane, members of the Commission, thanks very much for the invitation to be here today. I am a lecturer on nuclear policy at UC Santa Cruz and president of the Committee to Bridge the Gap, but the views here are my own today. If I could have Slide 3. This is obviously the San Onofre reactor. When it is operating, there are billions of curies of radioactivity inside each of those domes, and outside of them reside 8.5 million people within 50 miles, about four times as many as reside near Fukushima. Your job, that goes without saying, is to assure that that radioactivity remains inside those domes and it never gets out to expose those people. Next slide, please.

Steam generators are an absolutely critical safety feature for assuring that that happens. They perform two vital functions. One is they are necessary for cooling the core, preventing the fuel from melting or releasing its radioactivity. Secondly, they provide a direct pathway out of containment to the environment. So they're unique. They can both cause the melt and they can provide a pathway for that radioactivity to expose people. That must never happen. Next slide, please.

The steam generators at San Onofre are of the recirculating type. And so, as you've heard before, there are four basic places where you can have wear. There's a free-span area in the U tube region where the tubes can bang against each other, if the thermal hydraulic conditions are bad, but there are also tube support plates, anti-vibration bars, and retainer bars where they can rub against those supports. Unfortunately, we're having all four kinds of damage at San Onofre. Next slide, please.

Edison makes two claims, and you've heard their entire team pushing for this restart of Unit 2 at 70 percent power. The two fundamental claims that they make to support that -- the first -- next slide -- is that the wear in Unit 2 is far less extensive than the wear in Unit 3, that there were 300 tubes with unexpected tube-to-tube wear in Unit 3 and only two tubes with minor wear in Unit 2. Next slide, please.

For months, however, Edison and NRC staff refused to release the actual data about the degree of damage within Units 2 and 3. It took Senator Boxer's intervention for these data to be revealed. And you'll see very quickly why when you look at these tables. Yes, there were only two tubes showing tube-to-tube wear in Unit 2, but there were thousands of indications of wear at the anti-vibration bars in the tube support plates. There are 1,600 tubes that have been damaged just in this first cycle of operation in Unit 2. And as you'll see from the next slide, there are about 1,800 tubes that have been damaged in Unit 3. And the next slide you can just see this graphically that there's very little difference. The number of tubes damaged between Unit 2 and Unit 3 are very similar. Unit 3 has a slightly higher fever, but both of these are very sick reactors. They both need to be in intensive care. Next slide.

So, when those data were released, Edison made a second claim that the nature of the support structure wear is not unusual in new steam generators and is part of the equipment settling in. So, I asked NRC staff if they have any data about this. They said they've heard the same claim, said it was based on anecdotal information that they had no data. So, my students and I went and assembled the data that, frankly, the NRC staff should have, and the results are quite extraordinary. Next slide.

You will see and in the slides that follow that rather than being a normal amount of wear it is very much beyond the norm -- orders of magnitude beyond the norm. Next slide.

You will see, for example, here that the number of indications of wear for the steam generator tubes, the median is four nationally. And for Unit 2, the one that's supposed to be better and good to go, they have over 4,700 indications of wear, a thousand times more. Next slide.

The number of damaged steam generator tubes in Unit 2, again the good one to go supposedly, is about 1,600. The median nationally is four. And lastly, the next slide, you'll see -- one more slide, yeah, that's it, I'm sorry -- that there are 510 tubes that have been plugged in Unit 2 when the median nationally is zero. There were more tubes plugged in one cycle of operation for the new steam generator in Unit 2 than in all of the new steam generators in the country combined.

So, an additional claim has now been made by Edison that's saying, "Yeah, we have a lot of wear in Unit 2, but this levels off over time." I asked NRC staff if they have information as to whether that's true, they said, again, they've heard it anecdotally, but they had no data. So, I had to have my students accumulate the data once again. And to just give you one example, the Palo Verde plant, which Edison has identified as one that they claim is similar, for Units 1, 2, and 3, the number of tubes damaged don't level off. They continue to increase, and indeed the rate of increase continues to increase, generally, from one in-service inspection to the next. So, there go those claims.

Why does it matter? Well, for two reasons. San Onofre in just one or two years has experienced more damage than steam generators normally experience in decades. And in one to two years, they've chewed through nearly half of their 8 percent plugging limit and they have thousands of indications of wear on tubes that have not been plugged that if this wear continues, they'll have to plug as well. They concede that the wear is due to random vibration, not the fluid elastic instability causing the tube-to-tube damage, and it will continue to concede if they restart. So, you have steam generators that cannot run for very long even if there's no breakage, no disaster, no release. But gross failure is clearly possible. Edison, as you've heard, claims that the reason Unit 3 is in somewhat more trouble than Unit 2 is that the supports were more effective in Unit 3 than 2, but supports are exactly what's getting worn down in Unit 2. And so, that contact force is diminishing, that support is diminishing; and the problem with the tube-to-tube wear is it's sudden and unpredictable. You have a nice ramp function perhaps for other kinds of wear, but for the tube-to-tube it's a step function. So if you allow them to restart Unit 2 and you get more of that support wear loosening the fit, you are running the risk of this running out of control with the damage that's not predictable or controllable. Next slide, please.

Perhaps the most extraordinary aspect of Edison's restart request is found in the following three sentences from their transmittal letter. First -- next, please. They -- keep going, sorry. Again, again, again, again, here we go. They say that they plan to run at 70 percent power for five months is not a fix but an interim compensatory action. Next slide.

They say after those five months, they want to shut down and see if their theory is correct. This is clearly experimenting with safety. But the critical one is the next sentence. They say, "In addition, Edison has established a project team to develop a long-term plan for repairing the steam generators." So, Edison knows that those steam generators need to be repaired or replaced and is asking you to let them run without repairing or replacing them. And I would say to you, and it's in this next slide, that you should simply say no. It would be unwise to permit San Onofre Unit 2, with its critical steam generators that need repair or replacement, to operate without repairing or replacing them.

Now, last couple comments in the last minute or two I have. This episode has demonstrated not simply that the steam generators at San Onofre are damaged and need repair, but they've exposed some breakage in the NRC's regulatory structure itself that needs to be repaired. I am told that it took the NRC staff a total of only one day, when they finally looked at this matter, to determine that the computer code projections were wrong. One day of review, a billion dollars of expense, and a steam generator that had eight tubes that would have burst that wouldn't have been safe. One day of review that was bypassed. And Edison is now asking you to do the same thing. They want you to rely on the computer models. They're now relying on the ATHOS model, which also failed to predict the problem. The same people that designed the steam generators that failed, that operated and approved them, the two other companies that have okayed this, the consultant all telling you, "Yeah, maybe it wasn't done right, but trust us, we can do it again." There are 8.5 million people on the other side of those containment domes. And the only way it would be appropriate would be to make sure that that is really safe. If you had a car that had brakes that were failing, you would not get away with saying, "I'll just keep it off the freeway and drive at 50 miles an hour." You'd have to get the brakes repaired. With a car you can only kill a few people. There are hundreds of millions of curies of cesium and strontium and iodine inside those domes that you've got to keep in. And letting them run with damaged steam generators without repairing them would be very unwise. Thank you.

CHAIRMAN MACFARLANE: Thank you very much. Okay, we'll move on to questions and start with Commissioner Apostolakis.

COMMISSIONER APOSTOLAKIS: Thank you very much for the presentations. There were a couple of statements that confused me a little bit.

Mr. Fleck, on your Slide 15, you say that at San Onofre tube-to-tube wear due to in-plane fluid elastic instability is a new phenomenon, but you're implying that this is what happened, correct?

JEFF FLECK: Yes, sir.

COMMISSIONER APOSTOLAKIS: Okay. Then we go to Mr. Testa, who says on Slide 14 that Westinghouse concludes that the problem was the result of out-of-plane vibration and/or in-plane turbulence and not in-plane instability. And then Mr. Dietrich says that -- you heard of their alternative interpretations -- SCE goes with instability. Well, first of all is there a disagreement as to what caused the wear? I mean, you're saying it was in-plane turbulence, and you say it was in-plane instability. And I'm not an expert on these things, but the words are different.

JEFF FLECK: I don't think there's a disagreement. I think what we have done in our operational assessment and our strategy is to conservatively assume that it is tube-to-tube wear, based on the results from a similarly designed and operated unit next door. So, we were not -- based on the Eddy current results that we have available to us, it was determined that we would conservatively assume that those two tubes did experience some level of instability and as a result wore against each other during that operating time period.

COMMISSIONER APOSTOLAKIS: What's the difference between in-plane turbulence and in-plane instability, Mr. Testa?

DAMIAN TESTA: I would call those two the same, in-plane. The question is in-plane or out of plane.

COMMISSIONER APOSTOLAKIS: But you make it very clear here. You say, "In-plane turbulence and not from in-plane instability," so that tells me that they're different, and you're saying not different.

DAMIAN TESTA: Yes, well, yes, that's correct. We do not believe, based on the evidence, that you had in-plane instability. And that was just based on --

COMMISSIONER APOSTOLAKIS: AREVA, says that --

DAMIAN TESTA: -- any current evidence that I quoted in my presentation. It's an approach we took that's less conservative than the approach that AREVA took, which is a more conservative approach.

COMMISSIONER APOSTOLAKIS: Why is it more conservative to assume instability? I mean, Mr. Dietrich said the same thing. It's more conservative in what way?

JEFF FLECK: Well, from the standpoint that Unit 2 falls into the realm of being susceptible despite having differences between Unit 2 and Unit 3, fabrication and other things that were mentioned earlier. That's --

COMMISSIONER APOSTOLAKIS: Yeah, but if I decide that the cause was in-plane instability, you're telling me that -- no, if actually, -- if there is a question whether is due to in-plane turbulence versus in-plane instability, you're telling me it's more conservative to assume in-plane instability. Mr. Dietrich, you have a comment on that?

PETE DIETRICH: Yes. First, Commissioner, I want to be clear that the two presentations that you're referring to refer to conclusions about Unit 2 --

COMMISSIONER APOSTOLAKIS: Yeah.

PETE DIETRICH: -- and actually what occurred in Unit 2. Both companies have concluded that what occurred in Unit 3 was clearly due to in-plane fluid elastic instability.

COMMISSIONER APOSTOLAKIS: Okay.

PETE DIETRICH: So these conclusions are about Unit 2.

COMMISSIONER APOSTOLAKIS: Yeah.

PETE DIETRICH: Westinghouse concluded that perhaps during the installation process of the steam generators, these two tubes, where we saw the very minimal indications, just at the edge of detection, might be because of what we call tube-to-tube contact, where the tubes came into contact with each other after fabrication, during shipping, and during installation. And that is as the steam generator went into service, they wore as they moved apart. We feel that that is not as serious a degradation mechanism as in-plane fluid elastic instability. So, in my comments where I said we have assumed the conservative route that Unit 2 is seeing very small amounts of fluid elastic instability in these two tubes, that’s what helped us shape our proposed corrective actions, the corrective actions for our proposed period of operation. So, that is how we managed the differing opinions about Unit 2, but again, both companies agree on what occurred and caused the deeper damage on Unit 3. Does that help?

COMMISSIONER APOSTOLAKIS: Yeah, you agree?

JEFF FLECK: Yes.

COMMISSIONER APOSTOLAKIS: Mr. Pettigrew, your presentation was what I used to see in my previous life. You spoke to the slides, which I congratulate you for.

MICHEL PETTIGREW: [laughs]

COMMISSIONER APOSTOLAKIS: But on Slide 6, if we can have it back, you saw an animation there and it wasn't clear to me what was in-plane and what was out-of-plane? Help me understand it. Slide 6 of Mr. -- or Dr. Pettigrew's slides, please? Okay, so let's go to the animation. Are they now -- what's happening there? Which one is in-plane and which is out-of-plane?

MICHEL PETTIGREW: They're mostly out-of-plane.

COMMISSIONER APOSTOLAKIS: So, horizontal is out of plane?

MICHEL PETTIGREW: Yeah, yeah, that's right. The flow was upward in here and that's mostly out-of-plane. And more of the time in single phase flow -- that's in single-phase flow --

COMMISSIONER APOSTOLAKIS: Okay.

MICHEL PETTIGREW: Okay, more of the time when you get instability, it's in the out-of-plane or what is called the lift direction, that's the terminology that's used.

COMMISSIONER APOSTOLAKIS: And this is something that people knew -- people in the business knew that you could have out-of-plane vibrations?

MICHEL PETTIGREW: Yeah.

COMMISSIONER APOSTOLAKIS: My understanding is that in-plane is a new phenomenon as people claim, correct?

MICHEL PETTIGREW: Well, certainly in two-phase flow, yeah, it is a new phenomenon, yeah.

COMMISSIONER APOSTOLAKIS: And then is the next slide animated, too?

MICHEL PETTIGREW: No, the previous one is.

COMMISSIONER APOSTOLAKIS: Five, let's look at 5.

MICHEL PETTIGREW: Yeah. Okay, 5, essentially, the first sign of instability. And what we did from the -- the vibration in this case is mostly in the in-flow direction, which is a little unusual. Most of the time it's in the --

COMMISSIONER APOSTOLAKIS: So this is in-plane?

MICHEL PETTIGREW: This is vibrating in-plane, but if you look carefully enough, there is a component out-of-plane.

COMMISSIONER APOSTOLAKIS: I'm sorry, what? That?

MICHEL PETTIGREW: There is a component out of plane.

COMMISSIONER APOSTOLAKIS: You're right, you're right.

MICHEL PETTIGREW: Okay. So, in the next slide then all we did is increase the flow by 10 percent. Everything is all the same, and we get a different mode of instability. And the point that I'm making is that there's, you know, possibly and quite a number of different modes that you could have. And from an academic point of view, that's all very interesting. But from a practical point of view, you just want to avoid all of this. And so essentially, it's the first one that's reached, okay, we can't go any further. So we use that as a guideline. We want to be below the lowest critical velocity for instability all the time.

COMMISSIONER APOSTOLAKIS: Thank you very much. Chairman?

CHAIRMAN MACFARLANE: Okay. Thank you. On to Commissioner Magwood.

COMMISSIONER MAGWOOD: Thank you, Chairman. Thank -- I thank all of you for your presence today and your presentations. You've come from all over to talk about this issue, so we appreciate that. I wanted to follow up on my colleague's line of question with Mr. Pettigrew. I had some of the same questions. I appreciate you going over that. But one -- you heard my dialog with the staff earlier, I think, about our ability to model some of these phenomena. They seem rather complicated, this instability. Is this something that you have looked at modeling? Is this something that we can model? And, you know, where are we in doing that?

MICHEL PETTIGREW: Yeah. Yeah, well, that's a good question. We've been trying to model these phenomena for quite a number of years, and I guess we've made some progress, but so far we haven't been able to predict what we have seen in the lab, you know, within plus or minus 10, 20 percent, and we're out by a factor of 50 percent or more. And it's particularly difficult in two-phase flow, because in two-phase flow, you have an extra parameter, which is void fraction or steam quality, if you like.

And then you've got also to talk about flow regime. What kind of flow regime exists inside the tube bundle? Okay, so very little work has been done on that, because it's very difficult to do, for one thing, and in cross-flow in particular. So you -- we've made an attempt at looking at the tail of this with -- experimentally to start with, and we've built test sections with tubes about twice the size of steam generators so that we can look at the detail of what's happening as the flow goes through the tube bundle. And this was revealing actually. What you find is that the flow tends to create a path between the tube, which you could represent by a series of 60-degree elbows. And you find that the void fraction distribution across that gap -- we took 19 measurement points across the gap at every millimeter. And what you find is that the void fraction distribution goes from being high on one tube and low on the other tube, and the next tube is the other way around. So there's a tremendous mixing taking place in the tube bundle, and if you're looking at the mixture of the flow, it's really quite a fine flow.

Now, between -- now I'm talking about the flow going between the tube, but between -- so the -- an upstream and downstream tube, if you like. Then there's a region here of more stagnant flow and more -- lower void fraction tends to be mostly liquid. So what's happening is that the flow on one end is streaming between the tube and the tube bundle, and in between, between upstream and downstream tube, there's an accumulation of liquid there and some cyclic activities as well, which, again, is something that we were not expecting. We were expecting random turbulence excitation to be quite broad banded, and what we found is that there is some periodicity in this two-phase, flow end tube bundle.

COMMISSIONER MAGWOOD: Right, when you were running your experiments, was -- were you able to identify transition points where the flow took you either to in-plane or out-of-plane instability?

MICHEL PETTIGREW: No, I don't think so.

COMMISSIONER MAGWOOD: Really?

MICHEL PETTIGREW: Yeah. Yeah.

COMMISSIONER MAGWOOD: So that sounds like an area of -- for additional --

MICHEL PETTIGREW: Well, exactly. Well, what's being done now, as you may know, we have a so-called share program at the Ecole Polytechnique in Montreal. So we've set up a lab specifically devoted to look at two-phase flow-induced vibration, and so we have developed instrumentation to do that, and doing experiments, and some modeling. And to model two-phase flow, then what you have to do is to look at the basics. So they're doing experiments now on one bubble in a liquid environment and looking at what that bubble is doing, and eventually, now they've added -- they've got five bubbles now -- so looking at what's happening, you know, when you have a train of five bubbles in the liquid. And I think this is all, you know, very exciting work to do, but it's going to take some time before we can take the results of that kind of work and fit it into design guidelines.

COMMISSIONER MAGWOOD: I appreciate that as a --

MICHEL PETTIGREW: Yeah.

COMMISSIONER MAGWOOD: May have to put you on my visit list, I think. Yeah, let me turn to Mr. Testa and Mr. Fleck. I mean, is work like this part of your everyday lives? I mean, do you look at work such as Professor Pettigrew's as you're thinking about future designs? Does -- do you get that level of detail in your work? Yeah, you please go first, Mr. Testa.

DAMIAN TESTA: We've performed similar tests in the past, and that's what our analytical codes are based on, the data from the tests we've performed in the past. They may not be as extravagant as Dr. Pettigrew's, but yeah, we perform tests, and that's what our models are based on.

COMMISSIONER MAGWOOD: I think you mentioned during your presentation that you model -- routinely model fluid instability, you know, fluid-induced vibration, and you didn't really specify whether you modeled both in-plane or out-of-plane. I'm assuming you just model out-of-plane or is --

DAMIAN TESTA: Only out of plane.

COMMISSIONER MAGWOOD: Okay.

JEFF FLECK: Same here. And our analysis codes also are based upon testing that was performed in mockups and boilers in France, which is where most of the design work occurs for the replacements. But they -- those tests were performed in the late ‘80s and early ‘90s to validate some of the design changes that they were making to the components.

COMMISSIONER MAGWOOD: Let me stay with the vendors for a moment. What -- recognizing that, you know, all of you are focused very much on what’s happened with the fluid -- with the in-plane fluid-induced instability, but looking -- sort of looking down the road, what’s the next step? Where are we going with steam generator design? I mean, have we -- we still have some to replace there are new reactors on the drawing board. What’s the next step? Where do we go from here?

DAMIAN TESTA: Want me to go first?

JEFF FLECK: Either way.

DAMIAN TESTA: Basically, we’re using the same tools that we’ve used. We’re just staying within our comfort levels. We’re not pushing our design limits. We’re staying with what we know, what’s been proven to work in the past.

COMMISSIONER MAGWOOD: So we’ve seen the apex of PWR steam generator design? This is it? This is as good as it gets for that?

DAMIAN TESTA: Well, you can always improve on fluid elastic or thermal hydraulic codes; and there’s some new codes that are in the works, and we’re looking at those. They’re currently being developed, but whether they’ll be as good as what we’re using or not, we’ll have to evaluate them when they come out.

COMMISSIONER MAGWOOD: And Mr. Fleck, what’s next in the design?

JEFF FLECK: In the same context, we are in France developing a new thermal hydraulic code. That's been underway, but as you might imagine, the development of a code that has to handle so many variables and these conditions that are very uncertain, it's time -- you know, you have to vet the process and make sure that, again, you're staying in the bounds of what you've known and your technology that you've used, and continually use that to benchmark anything new that you're working on or that you're developing. But as far as the pinnacle of the replacement market or the replacement design, I would say that most of it is fairly standard, you know, at this point. I don't think there's anything outside of the norm that anyone is looking at.

COMMISSIONER MAGWOOD: So pretty much the same as with MHI?

HITOSHI KAGUCHI: Yeah, we have all sorts of experience here at SONGS, and the, as I said, the three factor flow and the quality, dryness, and also the contact forces. So we have to be careful about these three things. And two things -- and the flow and the quality is based on the TH, thermal hydraulic condition, so it can be more precisely analyzed. And also we have to be very careful because we are very concerned about the gap between the tube and the AVB -- to vibrate in this direction. Now, if the contact force is very weak, tube can't start this way, so we have to also be careful in the manufacturing in this point. Yeah.

COMMISSIONER MAGWOOD: All right, thank you very much. And just -- Mr. Hirsch, you mentioned your students several times. What kind of course was it that was --

DANIEL HIRSCH: I teach Introduction to Nuclear Policy, so this was a useful project for them to try to accumulate some of the data that NRC has but hasn't assembled itself, and in the process identified, I think, some useful suggestions for you folks that you ought to be assembling these routinely on your own rather relying on my students.

COMMISSIONER MAGWOOD: Always curious, but people know I sort of like education -- even though I'm not a professor, I like -- but what kind of students are they? Are they technical students?

DANIEL HIRSCH: They're many disciplines. They're interested both on the policy side and the technical.

COMMISSIONER MAGWOOD: Okay, so it's multidisciplinary. Sounds interesting. Thank you. Thank you, Chairman.

CHAIRMAN MACFARLANE: Thank you. Commissioner Ostendorff?

COMMISSIONER OSTENDORFF: Thank you, Chairman. Thank you all for your presentations. I want to add my comments to those of my colleagues, Commissioner Apostolakis and Svinicki, who indicated that though we may not ask particular questions, it does not mean we're not interested, consistent with the Chairman's comments at the opening of the hearing today. So I thank everybody here for your presentations.

Let me go to Mr. Benson here for a minute. You know, talking at a high level, I asked the first staff panel comments or question concerning design considerations for the life of a steam generator. And I wanted to ask you from your EPRI standpoint, what are some high-level -- not focusing on any particular design, but just across the industry, can you talk a little bit about design life considerations and what goes into looking at a particular set of optimization criteria for design life?

JIM BENSON: Yes. The work that we've done thus far in specifications for steam generators was mostly focused on the tubing, and we've done numerous studies on tube material and corrosion studies, and we've put out documents on specifications for the manufacture of tubing and requirements on the cleanliness, ovality, and Eddy current noise as well. So that's pretty much the extent as far as a design standpoint on specifications. However, what we do provide is information that we gather from the utilities on operating experience and similar to some of the information I've provided today. And that is shared amongst the utilities and the vendors, and then from those experiences, they can determine where the weaknesses are in their designs and strive to improve those designs.

COMMISSIONER OSTENDORFF: Okay. I want to give our three vendor representatives any opportunity if you want to add to Mr. Benson's comments, if you had anything else you want to say on that.

DAMIAN TESTA: Yeah. Nothing in particular.

JEFF FLECK: If your question would evolve or revolves around the design life of a replacement steam generator,

COMMISSIONER OSTENDORFF: Typically 20, 40, 60 years.

JEFF FLECK: Minimum 20. I've seen them 40, I've seen 60. It's very plant-specific.

COMMISSIONER OSTENDORFF: Yeah.

JEFF FLECK: It depends on perhaps the life of the plant, for when they reach that point in the economic basis when it's more appropriate to replace the unit than it is to limp along with the, you know, a unit that has stress corrosion cracking or some of these other mechanisms that we've talked about. It -- there's a wide range, but usually, or typically 40 years, similar to the original component, is the design life that's asked for in the specification.

COMMISSIONER OSTENDORFF: Dr. Kaguchi, anything you want to add that?

HITOSHI KAGUCHI: To design, we need, anyway, design life. The design life, influence of the design life on fatigue or something is linear to the design. So 20 years, 40 years is just a linear double of the number.

COMMISSIONER OSTENDORFF: Okay.

HITOSHI KAGUCHI: So it's not so tremendous. Design itself is the same.

COMMISSIONER OSTENDORFF: Okay, thank you. Going back to Mr. Benson here, in one of your slides, in your Slide 8, you showed -- I understood from the causes of steam generator tube repair, if I'm looking at the color-coding correctly and I understood your presentation, the most common cause of tube repair has been stress corrosion cracking.

JIM BENSON: Yes, that's the blue color.

COMMISSIONER OSTENDORFF: So I'm looking -- you know, that continues to be the case over recent years, and I think this -- our NRC staff panel earlier has made a comment along the lines of, "Perhaps there's variability in the industry as to chemistry practices," and I was curious from an EPRI standpoint, do you see -- is there a consensus on chemistry to lessen stress corrosion cracking for a particular design of steam generator, or are there any different viewpoints on that?

JIM BENSON: So from the standpoint of the chemistry, because obviously there's also stress considerations of the tubing, but from the standpoint of the chemistry, that is being considered in the guidance that was put out to the industry based on the corrosion studies that have performed, numerous corrosion studies on the various tubing alloys. So the cracking that we're seeing in this particular chart is from the 600 mill annealed -- just the few plants that are left have a significant number of cracks that they're observing, and the newly identified, thermally treated 600 tubing in the cracks that's identified in that material as well. So this cracking that we're seeing now is from the -- not from the 690 material, but the chemistry that we've developed to assist in minimizing the cracking, slowing the rate of cracking, and not just the chemistry itself but also processes through a chemical cleaning to keep the tubes clean and the crevices cleaned out, and that also is technical documents that are provided to the utilities on optimization of chemistry practices and cleaning practices.

COMMISSIONER OSTENDORFF: Do you have any feel as to what extent the utilities are actually following that guidance?

JIM BENSON: Well, the guidance that we put out is for the U.S. utilities. They are all following the guidance we provide. If there are any exceptions to that guidance, because there are many, many requirements in our guideline documents, then they would identify through a technical write-up that they would provide to both the NRC and to EPRI, and there are a couple of instances where the technical information has been provided, but it's very rare to have that deviate. So for all of the many requirements, they're followed pretty much to the letter.

COMMISSIONER OSTENDORFF: Okay. Thank you. I want to go back to a question that Commissioner Magwood asked, and as I understood that question, he was commenting on Professor Pettigrew's work and to what extent is that body of that work reflected in the design considerations for the vendors designing steam generators. And I believe, Mr. Testa, you commented that you use your own model. So can you comment briefly in a little more detail about what model perhaps is used, the AP1000 design certification?

DAMIAN TESTA: The same models that are used in the replacement steam generators. We refer back to the testing that was done numerous years ago. Mr. Fleck even referred back to some testing that was performed in France, and that work is still used today.

COMMISSIONER OSTENDORFF: And on the vendor side, is there a consensus viewpoint on that modeling as to its applicability?

DAMIAN TESTA: We don't have any challenges with it. It's worked well for us. Our track record is very good with it. I --

COMMISSIONER OSTENDORFF: I'm not trying to challenge your -- you know, I'm just trying to see to what extent you guys are – we've got a number of different vendors at the table here. I'm trying to see, is there generally a consensus, or are there very different approaches by one vendor approach to the next?

DAMIAN TESTA: I don't think there's a whole lot of approaches in this particular area. There are differences with respect to design and manufacturing. We have a lot of differences that we don't share with each other –

COMMISSIONER OSTENDORFF: Sure.

DAMIAN TESTA: -- obviously.

COMMISSIONER OSTENDORFF: Okay.

DAMIAN TESTA: But I think when it comes to FIV, I think our roots are very similar.

COMMISSIONER OSTENDORFF: Okay. Do you want to add anything, Mr. Fleck, or...

JEFF FLECK: No, I think that that adequately covers it.

COMMISSIONER OSTENDORFF: Okay. I'll give a last chance for Professor Pettigrew. Is there anything you want to comment on and the -- from your perspective as to how you see the academic-type work that you've been doing being reflected in vendor applications?

MICHEL PETTIGREW: Well, usually what we do, whenever we come up with something that is significant and can improve things, then we put them in our specification for flow induced vibration; so there is a direct path here between what's done in the lab and what goes into the specification.

COMMISSIONER OSTENDORFF: Okay. Thank you. Thank you, Chairman.

CHAIRMAN MACFARLANE: Thank you very much. Okay. Got a couple of questions here. Can you just go back to -- for Mr. Testa's Slide 14, and pick up on the question that Commissioner Apostolakis was asking when you say "in-plane turbulence and not from in-plane instability," and can you just explain to me -- I must be a little thick -- what the difference is between turbulence and instability?

DAMIAN TESTA: I'll try to do that. Turbulence would be similar to a tube rattling around --

CHAIRMAN MACFARLANE: [affirmative]

DAMIAN TESTA: -- in a support, relatively closely supported. It will move, but it will not severely deform, as in -- as it was described by Dr. Pettigrew.

CHAIRMAN MACFARLANE: [affirmative]

DAMIAN TESTA: So structurally, it will not bend or deform significantly. It's more or less just a rattle around in a tube, in a support case. I guess that's one -- best way I could --

CHAIRMAN MACFARLANE: And what's instability? That was [inaudible], right?

DAMIAN TESTA: Instability is a change in the mode shape.

CHAIRMAN MACFARLANE: Change in the...

MALE SPEAKER: In the mode shape of the structure of the tube.

CHAIRMAN MACFARLANE: So a change in the structure of the tube. The tube itself is deforming as opposed to moving.

DAMIAN TESTA: And I've deferred it – Dr. Pettigrew to see if --

CHAIRMAN MACFARLANE: And do you all agree to those definitions?

MICHEL PETTIGREW: Well, they -- if I may say something here, there are basically four vibration excitation mechanisms. One is called periodic wake shedding, you know, where you may have a cylinder and flow, and it would generate vortices, and these vortices can excite the structure to vibrate or excite other structure to vibrate; so that is periodic wake shedding.

Second one is acoustic resonance. It's usually not a problem in steam generators, but if you have a situation whereby the frequency of the vortices that are being shed by the tube bundle coincide with the acoustic natural frequency of the container, then you'd have a resonance problem, and it can do a lot of damage. But that doesn't happen in steam generators.

Then you have what's been called buffeting or rendering turbulence. There's been different terms for the same thing. This is coming from the flow itself. There's always turbulence in flow, and two-phase flow in particular, it's a very active flow, there's turbulence. This generates pressure pulsation or -- pressure pulsation along the surface of the structure, and that excites it to vibrate. But usually, this is a fairly mild mechanism, and we're worrying about this one in the longer term. If you want a steam generator to last 60 years, then you have to do that kind of analysis and do it well.

And the last one is fluid elastic instability. To have fluid elastic instability, you've got to have a coupling between the motion of the structure and the fluid. So if you imagine that you have a tube inside a tube bundle and there's flow; if you displace the tube a little bit, then the hydraulic forces around that tube are going to be affected. They're going to change. If you get a situation whereby the displacement of the tube causes hydraulic forces to change -- so you may have, you know, a change in position of the structure, which changes the flow and increases the fluid forces on the structure, so you get a situation where you have -- the more you have motion, the more you have hydraulic excitation. The more you have hydraulic excitation, the more you've got motion. And it goes unstable more and more until everything breaks down or is limited by age in tubes or supports.

CHAIRMAN MACFARLANE: So when you see in-plane tube-to-tube wear, which of those four mechanisms is it?

MICHEL PETTIGREW: Well, okay, I divide this thing in two. First of all, you go from the flow and then you calculate the response of the structure.

And once you've got the response of the structure, then you calculate the wear that will take place the -- if the structure responds to that level. Okay? So there are two different things here. There is vibration, and there is vibration damage.

CHAIRMAN MACFARLANE: [affirmative]

MICHEL PETTIGREW: Okay, so you do the vibration response calculation first, and then you go through your wear analysis and see how much damage will result.

DAMIAN TESTA: And the point I was trying to make in my Slide 14 was that these tubes were not assumed to be very much in close proximity to one another, possibly even touching, which is not the design condition.

CHAIRMAN MACFARLANE: Okay. So then, just -- let's take this a little bit further, and so I'm trying to understand these processes, which actually sound pretty complex. And I'm trying to understand how well we know them and whether we can understand whether they progress linearly or not.

MICHEL PETTIGREW: Okay. In time.

CHAIRMAN MACFARLANE: In time.

MICHEL PETTIGREW: In time, yes, yeah. Well, that's a very good question. [laughs] Yeah, maybe I could comment on this a little bit?

CHAIRMAN MACFARLANE: Maybe somebody else has a comment, too? Go ahead.

MICHEL PETTIGREW: Yeah. All right. The vibration part of it probably doesn't change too much in time. We're talking about the same fluid velocities and the same kind of structures, so I don't think we get a big change in time. From the wear point of view, our wear studies have shown that wear for the same excitation is the same, remained the same in time. So the wear calculations are based on the parameter, which is called the work rate.

CHAIRMAN MACFARLANE: [affirmative]

MICHEL PETTIGREW: And this work rate, to put it very simply, is the integral of the contact force times the sliding distance.

CHAIRMAN MACFARLANE: [affirmative]

MICHEL PETTIGREW: Okay? So the greater is your impact force --

CHAIRMAN MACFARLANE: You don't take into account the properties of the material?

MICHEL PETTIGREW: Yeah, you do that, yeah. But that's another step. Okay. So this work rate, you can calculate it and estimate it. And the wear damage, the wear volume damage according to our chart, the theory -- so the wear volume is really the product of a wear coefficient times a work rate. Okay? The wear coefficient, this you have to obtain experimentally.

CHAIRMAN MACFARLANE: [affirmative]

MICHEL PETTIGREW: It's the wear properties of the material combination that you have.

CHAIRMAN MACFARLANE: Are there -- is there experimental data --

MICHEL PETTIGREW: Yeah.

CHAIRMAN MACFARLANE: Is there an experimental database?

MICHEL PETTIGREW: Yeah. There is a limited amount, not greatly, because you have to do those tests at high temperature and high pressure –

CHAIRMAN MACFARLANE: [affirmative]

MICHEL PETTIGREW: -- so it means in a pressure vessel. If you do things in a pressure vessel, it gets very costly and very complicated, and to go and try to measure inside those --

CHAIRMAN MACFARLANE: [affirmative]

MICHEL PETTIGREW: -- what you need, you need to measure the contact forces and the sliding distance. We're talking about measuring microns at 300 degrees C, measuring fraction of newtons at 300 degrees C. You need something like $80,000 worth of transducer just for one such test facility. So -- but to answer your question, there is some data available. Some come from the EPRI program, and some have come from Westinghouse, because they have asked us to do that work for them.

CHAIRMAN MACFARLANE: And it's been done -- it's been collected on the alloy 690?

MICHEL PETTIGREW: I cannot speak for what Westinghouse has done with test data. Ours has been generally published, so it's available to everybody. Yeah.

PETE DIETRICH: Chairman, what we have concluded, getting to, you know, how does fluid elastic instability propagate over time – the wear -- that's why it's critical to prevent it, is because we do think that it starts with a set of tubes and propagates to tubes around it and can grow if the phenomenon is allowed to occur. And that's why, as we depicted in our presentation, not allowing the three components to occur concurrently is very important. It's critical. And by preventing fluid elastic instability, you prevent -- or by preventing those three conditions from occurring concurrently, you prevent the onset of fluid elastic instability.

CHAIRMAN MACFARLANE: Do you guys have any comments?

DAMIAN TESTA: No, I agree.

JEFF FLECK: Yeah, I agree, and I'd also add that, you know, that when we changed materials from 600 thermally treated to 690, and stainless steel supports that, you know, the common practice would be to do wear testing to understand what the coefficients are in order to, you know, perform some of the wear analysis that Dr. Pettigrew referenced.

JIM BENSON: One point I wanted to make is that EPRI has done some studies on wear coefficients of different materials, the -- a 600 material, the 690 support materials, stainless steels, carbon steels, and then made that available to the industry in our published reports. So we do have those types of studies that were done.

HITOSHI KAGUCHI: We also referred EPRI data and also some material slightly changed from the -- for the -- especially AVB material is for viable use, the use of 410. So we confirmed that the data is adequate or not. We did our own test.

CHAIRMAN MACFARLANE: Okay. Thank you. Commissioner Svinicki.

COMMISSIONER SVINICKI: I just want to add my thanks for all of you traveling here today and for sharing your information and perspectives. I appreciate also your responses to my colleagues' questions, and I don't think I have anything further. Thank you.

CHAIRMAN MACFARLANE: Okay. Any further questions from my colleagues? No? Yes?

COMMISSIONER APOSTOLAKIS: I don't think we got a straight answer whether research results like the ones that Dr. Pettigrew produces diffuse into the design or -- you gentlemen said, “Oh, we do our own.” I mean, are you feudal lords and isolated and don’t care what the professor in Canada does?

DAMIAN TESTA: No, we care. We listen to what he says. He publishes papers along with other academics. And our engineers read the published papers out there, and it’s considered in the design.

JEFF FLECK: Yeah.

DAMIAN TESTA: We’re just referring back to the data that we have based on our own tests and staying within the comfort levels of certain parameters.

COMMISSIONER APOSTOLAKIS: So you’re aware of what the literature is?

DAMIAN TESTA: Yes.

COMMISSIONER APOSTOLAKIS: To some extent.

DAMIAN TESTA: Yeah, yeah.

COMMISSIONER APOSTOLAKIS: Don’t read it every day.

JEFF FLECK: I agree.

MICHEL PETTIGREW: Maybe I would -- in the light of your question, maybe additional comments. We -- in Canada, we work through a research chair that is called an Industrial Research Chair, meaning it has industrial partners; so in our case, it’s Babcock and Wilcox Canada, and Atomic Energy of Canada are the chair sort of supporter, if you like. And this allows to create a research group and a lab with two-phase facilities and so on, and they’re very active in the process of this chair. We have meetings twice a year, and sometimes they direct the work that needs to be done, and sometimes we tell them what they should be interested in.

COMMISSIONER APOSTOLAKIS: Well, but you also publish in international journals like the Journal of Pressure Vessel Technology and so on.

MICHEL PETTIGREW: That's worked very well.

COMMISSIONER APOSTOLAKIS: Okay, this is better now. Thank you very much.

CHAIRMAN MACFARLANE: Okay. Okay, great. Anybody else? No? Okay. All right, well, I want to thank you all very much, both the external panel and our NRC panel, for excellent presentations. This is a very technical topic, and I commend everybody for their patience, and I think we've learned quite a bit this afternoon. I really appreciate, again, all of you for coming out here, and I will now say that we are adjourned.

[whereupon, the proceedings were concluded]