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U.S. NUCLEAR REGULATORY COMMISSION

BRIEFING ON STEAM GENERATOR TUBE
DEGRADATION

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1:00 P.M.

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

APPEARANCES

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Director of Operations

Eric Leeds
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Senior Level Advisor, NRR Steam Generators and Material
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External Panel:

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Hitoshi Kaguchi
Project Director, Nuclear Plant Production Division,
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Jeff Fleck
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Damian Testa
Product Manager, Steam Generator Management and
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Daniel Hirsch,
President, Committee to Bridge the Gap

1 PROCEEDINGS

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

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

16 Let me say at the outset that it is important to stress that the
17 following issues should not be discussed with respect to the ongoing adjudicatory
18 proceeding associated with the March 27, 2012 Confirmatory Action Letter
19 issued by the NRC to Southern California Edison Company for the San Onofre
20 Nuclear Generating Station, two issues in particular: one, whether the
21 Confirmatory Action Letter constitutes a de facto license amendment that would

1 be subject to a hearing opportunity under the Atomic Energy Act, and if so; two,
2 whether Friends of the Earth's pending intervention petition satisfies the
3 procedural requirements for a petition to intervene.

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

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

10 CHAIRMAN MACFARLANE: Okay, great.

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

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

1 generator inspection and integrity issues.

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

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

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

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

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

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

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

21 One thing that makes steam generator tube rupture a little bit
22 unique is the reliance on operators. Traditionally, we rely on automatic actions,
23 but tube rupture requires operators to play an important role in plant recovery.
24 First, they have to diagnose the event and they have to identify the steam
25 generator. And they have to cool the plant down to reduce primary coolant

1 pressure below secondary pressure. The operators are obviously trained and
2 tested on this on a routine basis. Next slide, please.

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

10 We issued three generic letters: generic letter 8207, 8208, and
11 8211. And the licensees took action through an owners' group initiative to
12 improve steam generator tube rupture recovery capabilities. This involved
13 instrumentation for the operators, help diagnose the event, as well as the
14 equipment needed to dump valves with and without power so that they could
15 mitigate the event. And this is documented in WCAP-10698A, which is on
16 ADAMS. Next slide, please.

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

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

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

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

17 This slide has several illustrations of steam generators showing
18 both recirculating and once-through steam generators. The steam generator on
19 the left is a typical recirculating steam generator that would be used in a
20 Westinghouse-type plant. It has the traditional U-shaped tubes. The
21 recirculating steam generator in the middle is more representative of a steam
22 generator that would have been originally in service in a Combustion
23 Engineering-type plant. And if you look closely, in that steam generator, the
24 tubes are shaped more in a square rather than the traditional U-shape. They
25 have two 90-degree bends, especially in the larger radius tubes. The figure on

1 the right is an example of a once-through steam generator, just illustrating that it
2 has straight tubes. Next slide, please.

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

18 Steam generator tube degradation has led the industry to develop
19 various repair criteria and repair methods in order to extend the lifetime of those
20 steam generators. These review criteria and repair methods -- or repair criteria
21 and repair methods are submitted to the NRC staff for review and approval
22 because these requirements are contained in the plant technical specifications.
23 There are operating conditions and maintenance tasks that can affect the lifetime
24 of the steam generators. For example, plant can elect to operate at a higher hot
25 leg temperature, which may make the tubing material more susceptible to

1 corrosion-related degradation. From a maintenance standpoint, the utility can
2 elect to clean the deposits or impurities out of the secondary side of the steam
3 generator less frequently, which would make the tubing material more
4 susceptible to degradation. When the staff reviews implementation of a steam
5 generator program, it doesn't necessarily focus on the operating items or
6 maintenance items that may affect the lifetime of a steam generator. It focuses
7 on tube integrity and making sure that the tubes can perform their intended
8 safety function for the period of time between inspections. Next slide, please.

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

19 Since 1989, all of the steam -- licensees have evaluated their
20 replacements under the 5059 process to determine whether or not a license
21 amendment is required. In all cases, a license amendment has not been
22 required for the entire replacement project, although specific amendments may
23 have been required for specific aspects of the replacement. Although the design
24 of the steam generator may not have been reviewed by the staff, it is subject to
25 regional inspections. There's an inspection procedure in place that the regions

1 follow that addresses all aspects of the replacement project, including the
2 planning and design phase, the installation phase, and the post-installation
3 inspection and testing phase. Next slide, please.

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

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

25 In addition, cracking is a more difficult degradation mechanism to

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

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

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

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

20 Now I wanted to talk about two specific occurrences of tube wear.
21 The first is tube-to-tube wear and replacement once-through steam generators.
22 In the fall of 2011, a plant was doing its first in-service inspection, and they
23 identified some indications. They eventually attributed those indications to wear
24 as a result of tube-to-tube contact. Upon finding this information, they shared it
25 with the other utilities who have once-through steam generators, and it was

1 subsequently determined that four of those units also had -- or a total of four
2 units had wear as a result of tube-to-tube contact.

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

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

11 I now want to talk about the tube wear that has been observed at
12 the San Onofre Nuclear Generating Station. In 2010 and -- or San Onofre
13 Nuclear Generating Station Units 2 and 3 replaced their steam generators in
14 2010 and 2011, respectively. These steam generators were designed and
15 fabricated by Mitsubishi in Japan. In early 2012, Unit 2 shut down for a normal
16 refueling outage and performed a steam generator tube inspection. They found
17 wear at a number of different locations. They found wear that was attributed to a
18 foreign object in the steam generator. The number of tubes affected was very
19 small -- just a few indications -- and the severity of those indications was also
20 small.

21 Wear was also found at the tube supports. A large number of
22 indications were found at that location. However, the severity of those
23 indications was very limited. Wear was also detected at a structure referred to as
24 a "retainer bar." There were a few indications of wear at that location. That wear
25 was unexpected, and one of the indications was deep. Although the indication

1 was deep, that tube had adequate tube integrity. There were also two tubes that
2 were identified that had wear as a result of tube-to-tube contact. Those
3 indications were shallow, and those tubes had adequate tube integrity. Unit 2
4 had operated a full cycle at 100 percent power, and they had adequate tube
5 integrity at the time of that inspection. Next slide.

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

20 I now wanted to spend a few minutes talking about our regulatory
21 framework, our oversight of licensee steam generator programs, and steam
22 generator performance. The inspection and repair of steam generator tubes are
23 covered in the plant -- are addressed in the plant's technical specifications. The
24 original technical specifications were developed in the 1970s, when wastage and
25 wall thinning were the dominant degradation mechanisms. When cracking

1 started to occur, it became evident that we needed to enhance our regulatory
2 framework. So the staff embarked on a multiyear effort to improve that
3 framework. Ultimately, the staff approved new generic technical specification
4 requirements, which were risk-informed and performance-based. The technical
5 specifications are performance-based in that we specify the criteria that the tubes
6 must meet at the time of the inspections. However, we do not specify the exact
7 details of how to go about achieving that objective. Since 2004-2005, all plants
8 have adopted these new risk-informed performance-based technical
9 specifications. Next slide, please.

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

20 There are also a number of activities here at headquarters with
21 respect to steam generators. The headquarters staff will have calls -- or
22 discussions with select licensees during their outage to monitor the scope and
23 results of the tube inspections being performed at those facilities. In addition, the
24 plant technical specifications require licensees to submit reports summarizing the
25 results of their inspections. All those reports are reviewed by the staff. In

1 addition to these activities, the staff will, as on an as-needed basis, meet with
2 licensees to discuss their inspection results. In addition, there are semiannual
3 meetings with the industry to discuss issues that may be generic to the steam
4 generator community. These interactions are available to the public. The
5 meetings are available to the public, our review of licensees steam generator
6 reports are documented, and those reviews are publicly available; as is when the
7 staff has discussions with the utilities, we document those discussions and those
8 summaries are made publicly available. Next slide, please.

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

21 In addition to the staff responding to the emerging degradation in
22 the 1970s and 1980s, the industry also took a number of steps. They formed a
23 group referred to as the Steam Generator Owner Group, which addressed steam
24 generator issues. Today the industry has a standardized program for addressing
25 steam generator issues. They developed guidelines which basically cover all

1 aspects of a steam generator program. They have primary and secondary water
2 chemistry guidelines. They have inspection guidelines that govern the inspection
3 of the steam generator tubes. They also have guidelines on how to perform
4 integrity assessments for the flaws that are observed in the tubing. In addition,
5 they have primary to secondary leakage guidelines, which provide guidance on
6 how to monitor for leakage and how to respond to that leakage. Next slide,
7 please.

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

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

20 This next slide depicts the steam generator tube rupture frequency
21 as a function of year. Once again, you see a declining trend as a result of
22 improved performance. One question that we always get is, is the improved
23 performance a result of the steam generator replacement, or does it actually
24 reflect improvement in performance of the inspections that are being performed?
25 And so on this graph, we have two lines. The red line, or solid line, shows the

1 tube rupture frequency for the first generation steam generators, with the mill
2 annealed alloy 600. And as you can see, that line has a declining trend. And
3 that's attributed to improvements in the steam generator programs that licensees
4 implement. Next slide, please.

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

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

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

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

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

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

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

24 KEN KARWOSKI: The term "fluid elastic instability"?

25 COMMISSIONER APOSTOLAKIS: Yes.

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

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

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

13 COMMISSIONER APOSTOLAKIS: Thank you. On Slides 26 and
14 33, you talked about the risk significance of this tube rupture event. And you said
15 that there was an assessment regarding risk significance, but you didn't tell us
16 what the results were. What is the risk significance?

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

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

24 KEN KARWOSKI: Right.

25 COMMISSIONER APOSTOLAKIS: Thank you Madam Chairman.

1 No, you want to add?

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

18 COMMISSIONER APOSTOLAKIS: Thank you. Thank you Madam
19 Chairman.

20 CHAIRMAN MACFARLANE: Commissioner Magwood.

21 COMMISSIONER MAGWOOD: Thank you Chairman, and thank
22 you for your presentations today. As all this matter has evolved over the last
23 year or so, and as I've spoken -- haven't had a chance to sit down with you. I
24 look forward to doing that, but as I've talked to staff and I've talked to industry
25 people and other experts about all this, a lot of the discussion seems to be, I

1 guess, I would use the -- Commissioner Apostolakis, we talked about this earlier
2 today, empirically based. It's all experiential. You look at how things have
3 behaved in the past and that's how you design programs going forward. And to
4 some degree, a lot of our discussion has been empirical. You've talked in terms
5 of experience rather than physics, say. And that raises a question with me and
6 I'd like to hear your thoughts about this. It seems to me that as we design
7 sophisticated equipment these days, we rely a lot more on analysis than we do
8 simply on, you know, what's worked in the past. So I expect that vendors are
9 using very highly sophisticated codes and models to design their systems. Are
10 we using highly sophisticated models and codes to analyze those systems? And
11 I'd like to understand where are we on the regulatory side of this in terms of
12 understanding -- we see a steam generator design. What is our ability to analyze
13 that design from a physics standpoint, from a modeling standpoint as opposed to
14 simply referencing what's worked in the past?

15 CHRIS JACKSON: Well, you make a good point, and as we get
16 more, you know, we've redesigned many of the generators, mainly with like-to-
17 like replacements, but as we do, we use more modern tools. And by and large
18 as industry does that, that improves the plant design. So when we do our
19 reviews -- we call it the standard review plan -- so the standard review plan
20 outlines the entire scope of our review and we use those for new reactors, we
21 use them for operating reactors. As we learn, we update those. So if you look at
22 the design, typically we focus on the safety significance, on the safety analysis,
23 and on the consequences. So we rely on industry codes and industry standards
24 for the design. The diesels and the valves are designed to as ASME standard or
25 a concrete's designed to an ACI standard. So the design, rarely do we get into

1 the heavy details of the design itself. We look at the consequences and the
2 integrated safety. So, you know, obviously for fuel and some other components,
3 we look heavily at the design. So, for the steam generators, the thermal
4 hydraulic conditions on the secondary side are not something that's within our
5 standard review plan. We don't look at that in excruciating detail when we do the
6 review. So, that's something that's more financial based. If they make that
7 mistake it costs them money because the generators don't perform from a
8 financial standpoint. But from a safety standpoint with our defense-in-depth
9 approach, that's less important. Obviously if we learn the operating experience
10 when we go forward we may revisit that. But at the moment, the standard review
11 plan doesn't have us looking in detail at thermal hydraulic conditions in the
12 secondary side for the design basis.

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

22 JENNIFER UHLE: I think I can maybe help answer that question.
23 I'm Jennifer Uhle. I'm currently the deputy director for Nuclear Reactor
24 Regulation, but until about a month ago I was the deputy director of the Office of
25 Nuclear Regulatory Research where, as Ken has indicated, we've had an

1 extensive steam generator tube integrity research program for many years since
2 about the '70s. And I would say to help answer specifically your question,
3 Commissioner Magwood, areas that we have advanced our modeling has been
4 in looking at the -- the modeling that takes place once a crack or a degradation
5 has occurred, then there are analytical approaches that are used to determine
6 what the integrity of the tube would be if it would be challenged under various
7 operating conditions. And our approach so far has been to take a look at what
8 the industry has been providing. We model cracks. Cracks are hard to size and
9 to characterize specifically, so we have, you know, an approximation method to
10 model the geometry of the crack and then, you know, with an analytical approach
11 determine what pressures and temperatures and how much more cracking could
12 occur before it would become a problem during that next operating cycle. So
13 we've made some advances there, but as Chris has indicated, we do not use the
14 same level of design tools to take a look at the integrity of the tubes themselves,
15 largely because of the design process involving ASME type codes.

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

19 JENNIFER UHLE: Yes. Right.

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

25 JENNIFER UHLE: We have, in the research program, looked at

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

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

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

23 BILL BORCHARDT: Just to clarify one aspect, I think, of what you
24 were saying, there is a technical basis, I believe, for understanding crack growths
25 and different failures, that once detected through ISI, we can have a reasonable

1 expectation of how long that tube will last and whether or not it needs to be
2 plugged. So there is a very good, I think, basis for that. I think you're right
3 though about the internal thermal hydraulics of the steam generator.

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

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

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

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

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

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

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

25 KEN KARWOSKI: In terms of the steam generator design, most

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

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

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

25 BILL BORCHARDT: Yeah. You might want to ask the second

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

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

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

24 KEN KARWOSKI: Yeah, and that's the key. The industry operates
25 -- I believe they all follow the EPRI primary and secondary water chemistry

1 guidelines and stay within the limits and action levels within those guidelines.
2 However, when you're talking about steam generator tube degradation, you have
3 an integrated effect. So a steam generator that was put into operation 35 years
4 ago has the integrated effect of every chemical transient that it had experienced
5 over the lifetime of the plant, and that is very difficult to model on, you know, how
6 much deposits are on the secondary side, you know, what type of impurities may
7 exist in there because of the materials that are used on the secondary side of the
8 plant, which can vary from plant to plant. So that is very difficult to model on a
9 generic basis and make a generic type of conclusion.

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

14 CHRIS JACKSON: Yes, I was.

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

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

23 KEN KARWOSKI: Yes. So in terms of, you know, tube cracking,
24 they've observed tube cracking, they've had similar issues. They do have some
25 modifications in the designs which may make their steam generators more or

1 less susceptible to certain forms of degradation, but for the most part they're very
2 similar, as Chris indicated. And we share operating experience. There are some
3 differences, but we share operating experience and we factor that in.

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

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

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

24 JENNIFER UHLE: It's Jennifer Uhle from NRR, and I would add to
25 that that our -- the research program is heavily involved in looking at the

1 effectiveness of the various NDE techniques that are being deployed for those
2 parameters that we find important in affecting the tube integrity; so it's a very
3 active part of what we're doing in research.

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

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

14 COMMISSIONER OSTENDORFF: Okay.

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

22 COMMISSIONER OSTENDORFF: I understand. Thank you.

23 Thank you, Chairman.

24 CHAIRMAN MACFARLANE: Okay. Thank you. All right. Eric or
25 Chris, can you back up a sec -- and I know Chris, in your slides you talked about

1 a limiting event, and I think that's a bit deep into the lingo there, so I'd like to
2 clarify that. And I'd like you guys to explain what -- just put on the record here,
3 what's the worst that can happen during a steam generator tube rupture
4 scenario?

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

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

23 CHRIS JACKSON: Well, I mean, the worst that can happen is you
24 would -- I guess there's several scenarios. If your tube ruptures your limiting
25 event, the worst that could happen is you wouldn't have safety systems, you

1 would drain the reactor coolant system and fail the fuel and have a direct release
2 path to the environment. That would be a very bad event. You could have
3 another event, a steam line break that would result in fuel failure as well. So the
4 worst event would be a fuel failure with a containment bypass.

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

7 CHAIRMAN MACFARLANE: Yes.

8 ERIC LEEDS: -- tube degradation --

9 CHAIRMAN MACFARLANE: Yes. Yes.

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

12 CHAIRMAN MACFARLANE: Right. Right. Yeah.

13 ERIC LEEDS: And for that type of a scenario, very similar to a
14 single tube rupture, what you're doing is you rely on the operators to spot the
15 leakage -- and they have technical specification limits on leakage -- and shut
16 down the plant, and allow the pressure to equalize between secondary side, the
17 side that goes to the steam -- to the turbine, the money-making end, and the
18 primary side. So what you'd have is you'd have a bigger probability for a primary
19 to secondary leak, you get more of the primary fluid into the secondary fluid.

20 That could release more radionuclides into the secondary side, so the possibility
21 is there for more of a possibility for a release off site or within the turbine building.

22 CHRIS JACKSON: Yeah. I apologize. I don't think I answered the
23 question. So if you had multiple tube ruptures, that would be a more challenging
24 event from some perspectives but from other perspectives it wouldn't
25 necessarily. So one of the challenging things on a tube rupture, particularly a

1 small one, is diagnosing it. With multiple tube ruptures, you'd have an earlier
2 plant transient and you'd be able to identify the tube or the generator quicker,
3 safety systems would react; so multiple tube ruptures would challenge the
4 operators in a different way. But we have studied that from a risk perspective
5 and we chose not to take regulatory action or regulatory action wasn't necessary.
6 So in some aspects the operators were benefitted by automatic systems and
7 easier diagnosis, but the timing would create another challenge for them, so...

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

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

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

19 [laughter]

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

23 KEN KARWOSKI: I would say that the biggest challenge --
24 recognize the thermally-treated alloy 600 includes both original and replacement
25 steam generators. But I'd say the challenge I see in the future is managing the

1 cracking and that thermally-treated alloy 600 tube material. As far as I know,
2 none of those plants have plans to replace their steam generators. Right now,
3 there's only been a limited amount of cracking, but we know from past
4 experience cracking tends to follow an exponential curve, so I -- from my
5 perspective, I believe that the cracking in the thermally-treated alloy 600 is
6 probably the biggest challenge.

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

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

12 CHAIRMAN MACFARLANE: Yeah, I know. The thermally-treated
13 --

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

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

23 KEN KARWOSKI: Yes.

24 CHAIRMAN MACFARLANE: Okay. So then let me try to
25 understand. You guys talked about tube ruptures at other plants, maybe one in

1 particular. I want to understand a little bit more about other experience of tube
2 ruptures.

3 KEN KARWOSKI: There's been nine domestic tube ruptures, if my
4 memory serves me correctly. The last tube rupture occurred in the year 2000 at
5 Indian Point 2. Most of the tube ruptures occurred in the '70s and '80s, and in
6 1993 there was a tube rupture at Palo Verde Unit 2. So the last two tube
7 ruptures, one was in 2000, one was in 1993, and there were several in the '80s
8 and the 1970s.

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

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

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

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

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

23 KEN KARWOSKI: The tube materials have been enhanced, but
24 other things can affect the degradation of tubes. So the tubes support materials
25 have changed. They used to be carbon steel, they used to corrode and create

1 issues. They've been replaced with stainless steel. They've changed -- when
2 you bend a tube you put a lot of stresses in the tube; that can make it more
3 susceptible to cracking. They've -- for the tubes that are the most tightly bent,
4 the smallest radius tubes, they'll do a thermal stress relief to help reduce those
5 stresses. They've changed the method by which they expand the tubes within
6 the tube sheet to reduce the stresses in the tube sheet at the expansion
7 transition region. So there have been a number of design changes that have
8 taken place in order to limit the potential for degradation.

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

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

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

22 CHAIRMAN MACFARLANE: Okay.

23 CHRIS JACKSON: And from an operating experience standpoint,
24 the industry and us learned quite a bit from the 1982 Ginna event, where they did
25 have challenges bringing the plant down into a safe condition; so that's all been

1 implemented into the regulatory process for the owners' group initiative.

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

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

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

20 [break]

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

25 JIM BENSON: Well, good afternoon. I'm going to start by

1 providing a review of the EPRI Steam Generator Management Program, and if
2 we could go to Slide Number 3. So, EPRI was established in 1973 as an
3 independent non-profit organization to conduct research on key issues facing the
4 Electric Power Research Institute. And in 1975 EPRI established a steam
5 generator program first beginning with the Steam Generators Owners Group, and
6 now we're turning into the Steam Generator Management Program, which exists
7 today, one of the longest standing issue programs within EPRI. Next slide,
8 please.

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

17 The SGMP develops many documents, technical documents, and
18 guideline documents. The guideline documents come about by the research we
19 do as well as industry experience, and we have currently six guideline
20 documents that are put out to the industry. These documents, although called
21 guidelines, they do have requirements in them that the utilities do put into their
22 steam generator programs. Those guideline documents address secondary
23 water chemistry, primary water chemistry, examination, the techniques that are
24 used, as well as the period between inspections or the inspection interval. They
25 address primary to secondary leakage, monitoring for leakage, and actions that

1 need to be taken when leakage is identified. There are also tube integrity
2 assessment guideline documents to assess the current condition of the steam
3 generators, as well as making predictions for future degradation that may occur.
4 And the last document I'll mention is the in situ pressure test guideline to actually
5 assist in determining tube integrity. Next slide, please.

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

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

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

1 generators has been a focus on stress corrosion and cracking. Next slide,
2 please.

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

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

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

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

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

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

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

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

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

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

16 HITOSHI KAGUCHI: Thank you very much. My name is Hitoshi
17 Kaguchi. I am a project director with Mitsubishi Heavy Industries. My
18 presentation today describes MHI's experiences related to tube vibration and
19 wear in steam generators during a faulty case of plant operation in Japan, in the
20 U.S., and also in the other countries. MHI has manufactured 116 steam
21 generators in total, and six of them were for the U.S. plants. Our steam
22 generators have experienced two major issues. One was flow-induced vibration
23 wear between the joist and the anti-vibration bar. We call them AVBs. And they
24 were observed in several plants in Japan, in the 1980s to the early 1990s. The
25 other was the tube rupture event due to fluid elastic instability, or we call it FEI, in

1 one plant in 1991. Until 2012, MHI steam generators have not experienced tube
2 wear issues since the early 1990s.

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

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

22 Next I would like to explain about in-plane FEI in SONGS. The SONGS
23 steam generators were the largest steam generator fabricated by MHI. The
24 design, the SONGS steam generator was based on the established design
25 practices, ASME, and other industrial codes, and the detailed customer design

1 specifications. A major focus of the SONGS design -- SONGS steam generator
2 design was to minimize the tube wear. We changed the design nominal gap
3 between the tube and the AVB from our standard 3 mils to the 2 mils. This is the
4 -- 2 mils, is the cold condition and fixes the zero gap at the hot operating
5 condition. This was intended to reduce the -- prevent the tube wear caused by
6 out-of-plane FEI. MHI also confirmed a severity issue against the out-of-plane
7 FEI with conservative assumptions. The tube leakage at SONGS Unit 3
8 occurred due to tube-to-tube wear caused by in-plane FEI, and the in-plane FEI
9 discovered at SONGS is the first occurrence in the nuclear industry. It is also the
10 first evidence that the in-plane FEI conditions could be achieved in our operating
11 steam generator. For in-plane FEI to occur, three conditions must exist
12 simultaneously. The first one is the high steam quality. It means a very dry
13 steam. This is related to the tube damping. And the second is the high steam
14 velocity, flow velocity. This is related to the energy input to the tube. The last
15 one is the low contact force between the tube to AVB. This is related to the
16 effectiveness of the supports.

17 The steam quality and the velocity there depends on the size, and
18 the design, and the operating condition of steam generator. The low contact
19 force was the desire to the effort to minimize the wear due to out-of-plane FEI.
20 MHI applied tighter damage wear control and the process improvement to the
21 achieved uniformity distributed gaps. These actions result in unexpected in-
22 plane FEI. MHI has confirmed that the condition found in the SONGS unit do not
23 exist in other MHI design steam generators, including operating steam
24 generators and the proposed USABWR design. SONGS Unit 3 had significant
25 tube-to-tube wear by in-plane FEI, but Unit 2 did not. MHI examined the reason

1 for this difference in detail. The same hydraulic conditions in both units were
2 almost the same. The only difference was the support condition between the
3 tubes and the AVBs. After the completion of the Unit 2 assembly, MHI improved
4 fabrication processes. The main difference was the damage control of AVBs.
5 MHI recently developed a very detailed three-dimensional model shown on this
6 slide. Using this model we confirmed that the small change in damage control
7 resulted in the large change in contact force. Contact force in Unit 3 are less
8 than half of the dose in the Unit 2. We now understand that the AVB supports in
9 Unit 2 are more effective to prevent in-plane FEI compared to Unit 3.

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

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

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

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

1 Mechanical Engineering at AREVA. Mr. Fleck.

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

7 Next.

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

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

22 In the AREVA U.S. components, tube wear has been identified at
23 various locations, including anti-vibration bars, tube support plates, outer bundle
24 supports, and also wear from foreign object intrusion. The operating experience
25 with the AREVA recirculating steam generators has not shown any tube wear

1 due to in-plane fluid elastic instability. Tube to tube wear in the once-through
2 design, however, has been identified and was summarized in NRC generic letter
3 2012-7, as well as in Mr. Karwoski's presentation earlier today.

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

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

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

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

25 Included in the flow-induced vibration analysis, are stability

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

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

24 The industry framework defined by NEI 97-06 and the EPRI Steam
25 Generator Management Program establishes rigorous programmatic

1 requirements, especially in the qualification of people and techniques. It also
2 standardizes methodology for assessments and provides for operational
3 experience sharing and exchange. Finally, it also established the current steam
4 generator tech specs that were also referred to earlier. These tech specs are up
5 to date and appropriate for effective in maintaining safety margins, especially
6 those with tube wear.

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

19 In summary, historically tube wear has been a manageable
20 mechanism in operating steam generators. Cycle lengths and tube integrity
21 margins have not been challenged, even in cases where large populations of
22 wear scars are affecting the steam generator. A common strategy taken for the
23 management of tube wear is to preventively plug tubes that are less than the 40
24 percent threshold criteria established in the plant tech specs. This increases
25 margin in the tube integrity -- the calculations that are performed to support the

1 next inspection interval. Finally, in our experience, the current industry protocol
2 programs and requirements provide sufficient safety margins for all steam
3 generator tube degradation mechanisms, including tube wear. Thank you. That
4 concludes my presentation.

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

8 DAMIAN TESTA: Good afternoon.

9 CHAIRMAN MACFARLANE: Got to have the red dot there.

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

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

1 san has mentioned earlier, and also modifications made in pre-heater designs.

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

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

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

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

1 the feed water flow to reduce the velocities as seen by the tubes.

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

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

21 With respect to our experience at SONGS, we performed an
22 evaluation for SONGS Unit 2 addressing tube wear at AVBs, tube-to-tube wear,
23 and the potential for in-plane instability. We concluded that tube-to-tube wear
24 observed in tubes in Unit 2 resulted from proximity of the tubes and out-of-plane
25 vibration and/or in-plane turbulence, and not in-plane instability. How we came

1 to that conclusion is based on the following; Eddy current data showed that there
2 was no extension of the wear scars beyond the width of the AVB itself, and not
3 only in these tubes, but other tubes in Unit 2 as well. Also, vibration due to in-
4 plane instability will cause extension of the wear scars beyond the width of the
5 AVBs as observed in Unit 3. Additionally, the two tubes with tube-to tube wear
6 have no indications of the top tube support plate wear, as found with tubes that
7 had tube-to-tube wear in Unit 3. All this was included in our operational
8 assessment that we performed, and has been delivered to the NRC for review.

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

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

21 PETE DIETRICH: Thank you, Chairman. Good afternoon. I'm
22 pleased to have this opportunity to share our experience and explain what we
23 have learned at San Onofre regarding tube wear in our replacement steam
24 generators. Next slide, please. The tube wear we have observed at San Onofre
25 falls into two categories: what I will characterize and what we have characterized

1 as tube-to-tube wear; and what I will refer to as other tube wear mechanisms, the
2 normal wear that has been discussed in some of the other presentations. And I
3 will discuss each briefly in this slide to shape them. Tube-to tube wear occurs
4 when adjacent tubes vibrate and contact each other during operation. Other
5 plants have experienced tube-to-tube wear in the free span straight length of
6 tubes between tube support plates. At San Onofre, tube-to-tube wear has
7 occurred in the U-bend region for the first time in the industry. Other tube wear
8 includes more prevalent tube wear mechanisms occurring in the industry as well
9 as at San Onofre. This includes wear of tubes as they vibrate and contact anti-
10 vibration bars, and as they contact tube support plates. The SONGS
11 replacement steam generators also experience another tube wear mechanism
12 resulting from vibration of thin retainer bars on the periphery in the U-bend
13 region, as well as one instance of wear due to a foreign object. The wear rates
14 resulting from each of these other mechanisms are within the experience of other
15 operating plants and the industry steam generator management program
16 described by the previous speakers. More precisely, the wear rates from these
17 mechanisms at San Onofre have been determined to allow safe operation of the
18 Unit 2 steam generators at 100 percent power for a full operating cycle, based on
19 proven regulatory framework and established industry precedent. Now, because
20 the type of tube-to-tube wear observed at San Onofre is unprecedented, I will
21 focus the majority of the remainder of my presentation on this mechanism. Next
22 slide, please.

23 This slide compares the tube-to tube wear observed in the two San
24 Onofre units. The depiction is a plan view of half the tube bundle showing
25 damage or wear indications in the U-bend region for one of the steam generators

1 in each of the units. Unit 3 steam generator, on the left side, experienced deep
2 tube-to-tube wear in multiple tubes, including through-wall wear on one tube. By
3 contrast, Unit 2, which is on the right side of the slide, operated twice as long as
4 Unit 3 and had shallow tube-to-tube wear in only one pair of tubes. The deep
5 tube-to-tube wear in multiple Unit 3 U-bend tubes resulted from in plane vibration
6 caused by fluid elastic instability. As you have heard from the earlier
7 presentations, this phenomenon has not been observed previously in an
8 operating steam generator. For Unit 2, to be conservative, Southern California
9 Edison is assuming that the single case of tube-to-tube wear in Unit 2 may also
10 have been caused by in-plane fluid elastic instability, although as you have just
11 heard, there is another plausible explanation for this instance of shallow tube to
12 tube wear. Next slide.

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

25 As we saw in an earlier slide, deep tube-to-tube wear from fluid

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

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

25 We have learned quite a bit from the SONGS experience with our

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

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

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

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

25 MICHEL PETTIGREW: Michel.

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

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

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

7 ANNETTE VIETTI-COOK: Speak into the microphone.

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

22 Okay, the other concern, if you like, is the vibration excitation,
23 which is in this case, is in the form of flow velocity, high-flow velocities. It may be
24 a bit difficult to see on this slide, but on the right, at the top near the U-bend,
25 there is an area that's whiter than the rest. And this corresponds to a flow

1 velocity of about 6.5 meters per second, or 20 feet per second. So, there are
2 quite high-flow velocities in that region of the steam generator coupled with the
3 possibility of less-than-effective support. It's the kind of thing that can lead to
4 problems. Next slide, please.

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

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

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

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

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

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

25 Okay, so if you look at the upper part result, we have a column of

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

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

22 So, let's go on the left in here and get it going. You see on the left
23 this is the single row, but that's allowed to vibrate every which way in an
24 axisymmetrical fashion. And you see it goes unstable. Whereas, if the tube will
25 constraint to vibrate only in the in-plane direction, it would not go unstable as

1 we've seen before. Now, if we look at the two-column one now. You see the
2 two-column one does go unstable. That's really the interesting part in here is
3 that one column one does not go unstable; two-column one does go unstable.
4 What we've shown in here is that you can have fluid elastic instability in the in-
5 plane or the in-flow direction in two-phase flow, but sometimes it's not so easy to
6 do. It's a lot more difficult to get fluid elastic instability, to achieve fluid elastic
7 instability when the tubes are constrained to vibrate in the flow direction. If I
8 could have my final slide?

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

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

21 DANIEL HIRSCH: Chairman Macfarlane, members of the
22 Commission, thanks very much for the invitation to be here today. I am a lecturer
23 on nuclear policy at UC Santa Cruz and president of the Committee to Bridge the
24 Gap, but the views here are my own today. If I could have Slide 3. This is
25 obviously the San Onofre reactor. When it is operating, there are billions of

1 curies of radioactivity inside each of those domes, and outside of them reside
2 8.5 million people within 50 miles, about four times as many as reside near
3 Fukushima. Your job, that goes without saying, is to assure that that radioactivity
4 remains inside those domes and it never gets out to expose those people. Next
5 slide, please.

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

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

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

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

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

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

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

1 indications of wear, a thousand times more. Next slide.

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

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

18 Why does it matter? Well, for two reasons. San Onofre in just one
19 or two years has experienced more damage than steam generators normally
20 experience in decades. And in one to two years, they've chewed through nearly
21 half of their 8 percent plugging limit and they have thousands of indications of
22 wear on tubes that have not been plugged that if this wear continues, they'll have
23 to plug as well. They concede that the wear is due to random vibration, not the
24 fluid elastic instability causing the tube-to-tube damage, and it will continue to
25 concede if they restart. So, you have steam generators that cannot run for very

1 long even if there's no breakage, no disaster, no release. But gross failure is
2 clearly possible. Edison, as you've heard, claims that the reason Unit 3 is in
3 somewhat more trouble than Unit 2 is that the supports were more effective in
4 Unit 3 than 2, but supports are exactly what's getting worn down in Unit 2. And
5 so, that contact force is diminishing, that support is diminishing; and the problem
6 with the tube-to-tube wear is it's sudden and unpredictable. You have a nice
7 ramp function perhaps for other kinds of wear, but for the tube-to-tube it's a step
8 function. So if you allow them to restart Unit 2 and you get more of that support
9 wear loosening the fit, you are running the risk of this running out of control with
10 the damage that's not predictable or controllable. Next slide, please.

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

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

25 Now, last couple comments in the last minute or two I have. This

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

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

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

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

4 JEFF FLECK: Yes, sir.

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

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

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

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

25 COMMISSIONER APOSTOLAKIS: But you make it very clear

1 here. You say, "In-plane turbulence and not from in-plane instability," so that tells
2 me that they're different, and you're saying not different.

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

6 COMMISSIONER APOSTOLAKIS: AREVA, says that --

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

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

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

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

21 PETE DIETRICH: Yes. First, Commissioner, I want to be clear
22 that the two presentations that you're referring to refer to conclusions about Unit
23 2 --

24 COMMISSIONER APOSTOLAKIS: Yeah.

25 PETE DIETRICH: -- and actually what occurred in Unit 2. Both

1 companies have concluded that what occurred in Unit 3 was clearly due to in-
2 plane fluid elastic instability.

3 COMMISSIONER APOSTOLAKIS: Okay.

4 PETE DIETRICH: So these conclusions are about Unit 2.

5 COMMISSIONER APOSTOLAKIS: Yeah.

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

19 COMMISSIONER APOSTOLAKIS: Yeah, you agree?

20 JEFF FLECK: Yes.

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

24 MICHEL PETTIGREW: [laughs]

25 COMMISSIONER APOSTOLAKIS: But on Slide 6, if we can have

1 it back, you saw an animation there and it wasn't clear to me what was in-plane
2 and what was out-of-plane? Help me understand it. Slide 6 of Mr. -- or Dr.
3 Pettigrew's slides, please? Okay, so let's go to the animation. Are they now --
4 what's happening there? Which one is in-plane and which is out-of-plane?

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

6 COMMISSIONER APOSTOLAKIS: So, horizontal is out of plane?

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

10 COMMISSIONER APOSTOLAKIS: Okay.

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

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

17 MICHEL PETTIGREW: Yeah.

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

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

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

24 MICHEL PETTIGREW: No, the previous one is.

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

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

4 COMMISSIONER APOSTOLAKIS: So this is in-plane?

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

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

8 MICHEL PETTIGREW: There is a component out of plane.

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

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

18 COMMISSIONER APOSTOLAKIS: Thank you very much.

19 Chairman?

20 CHAIRMAN MACFARLANE: Okay. Thank you. On to

21 Commissioner Magwood.

22 COMMISSIONER MAGWOOD: Thank you, Chairman. Thank -- I
23 thank all of you for your presence today and your presentations. You've come
24 from all over to talk about this issue, so we appreciate that. I wanted to follow up
25 on my colleague's line of question with Mr. Pettigrew. I had some of the same

1 questions. I appreciate you going over that. But one -- you heard my dialog with
2 the staff earlier, I think, about our ability to model some of these phenomena.
3 They seem rather complicated, this instability. Is this something that you have
4 looked at modeling? Is this something that we can model? And, you know,
5 where are we in doing that?

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

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

1 in the tube bundle, and if you're looking at the mixture of the flow, it's really quite
2 a fine flow.

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

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

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

17 COMMISSIONER MAGWOOD: Really?

18 MICHEL PETTIGREW: Yeah. Yeah.

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

21 MICHEL PETTIGREW: Well, exactly. Well, what's being done
22 now, as you may know, we have a so-called share program at the Ecole
23 Polytechnique in Montreal. So we've set up a lab specifically devoted to look at
24 two-phase flow-induced vibration, and so we have developed instrumentation to
25 do that, and doing experiments, and some modeling. And to model two-phase

1 flow, then what you have to do is to look at the basics. So they're doing
2 experiments now on one bubble in a liquid environment and looking at what that
3 bubble is doing, and eventually, now they've added -- they've got five bubbles
4 now -- so looking at what's happening, you know, when you have a train of five
5 bubbles in the liquid. And I think this is all, you know, very exciting work to do,
6 but it's going to take some time before we can take the results of that kind of
7 work and fit it into design guidelines.

8 COMMISSIONER MAGWOOD: I appreciate that as a --

9 MICHEL PETTIGREW: Yeah.

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

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

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

23 DAMIAN TESTA: Only out of plane.

24 COMMISSIONER MAGWOOD: Okay.

25 JEFF FLECK: Same here. And our analysis codes also are based

1 upon testing that was performed in mockups and boilers in France, which is
2 where most of the design work occurs for the replacements. But they -- those
3 tests were performed in the late '80s and early '90s to validate some of the
4 design changes that they were making to the components.

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

12 DAMIAN TESTA: Want me to go first?

13 JEFF FLECK: Either way.

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

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

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

24 COMMISSIONER MAGWOOD: And Mr. Fleck, what's next in the
25 design?

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

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

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

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

25 DANIEL HIRSCH: I teach Introduction to Nuclear Policy, so this

1 was a useful project for them to try to accumulate some of the data that NRC has
2 but hasn't assembled itself, and in the process identified, I think, some useful
3 suggestions for you folks that you ought to be assembling these routinely on your
4 own rather relying on my students.

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

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

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

12 CHAIRMAN MACFARLANE: Thank you. Commissioner
13 Ostendorff?

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

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

1 criteria for design life?

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

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

16 DAMIAN TESTA: Yeah. Nothing in particular.

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

19 COMMISSIONER OSTENDORFF: Typically 20, 40, 60 years.

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

22 COMMISSIONER OSTENDORFF: Yeah.

23 JEFF FLECK: It depends on perhaps the life of the plant, for when
24 they reach that point in the economic basis when it's more appropriate to replace
25 the unit than it is to limp along with the, you know, a unit that has stress corrosion

1 cracking or some of these other mechanisms that we've talked about. It --
2 there's a wide range, but usually, or typically 40 years, similar to the original
3 component, is the design life that's asked for in the specification.

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

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

9 COMMISSIONER OSTENDORFF: Okay.

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

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

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

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

25 JIM BENSON: So from the standpoint of the chemistry, because

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

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

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

24 COMMISSIONER OSTENDORFF: Okay. Thank you. I want to go
25 back to a question that Commissioner Magwood asked, and as I understood that

1 question, he was commenting on Professor Pettigrew's work and to what extent
2 is that body of that work reflected in the design considerations for the vendors
3 designing steam generators. And I believe, Mr. Testa, you commented that you
4 use your own model. So can you comment briefly in a little more detail about
5 what model perhaps is used, the AP1000 design certification?

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

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

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

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

19 DAMIAN TESTA: I don't think there's a whole lot of approaches in
20 this particular area. There are differences with respect to design and
21 manufacturing. We have a lot of differences that we don't share with each other
22 --

23 COMMISSIONER OSTENDORFF: Sure.

24 DAMIAN TESTA: -- obviously.

25 COMMISSIONER OSTENDORFF: Okay.

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

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

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

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

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

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

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

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

24 CHAIRMAN MACFARLANE: [affirmative]

25 DAMIAN TESTA: -- in a support, relatively closely supported. It

1 will move, but it will not severely deform, as in -- as it was described by Dr.
2 Pettigrew.

3 CHAIRMAN MACFARLANE: [affirmative]

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

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

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

10 CHAIRMAN MACFARLANE: Change in the...

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

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

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

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

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

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

1 lot of damage. But that doesn't happen in steam generators.

2 Then you have what's been called buffeting or rendering
3 turbulence. There's been different terms for the same thing. This is coming from
4 the flow itself. There's always turbulence in flow, and two-phase flow in
5 particular, it's a very active flow, there's turbulence. This generates pressure
6 pulsation or -- pressure pulsation along the surface of the structure, and that
7 excites it to vibrate. But usually, this is a fairly mild mechanism, and we're
8 worrying about this one in the longer term. If you want a steam generator to last
9 60 years, then you have to do that kind of analysis and do it well.

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

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

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

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

4 CHAIRMAN MACFARLANE: [affirmative]

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

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

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

15 MICHEL PETTIGREW: Okay. In time.

16 CHAIRMAN MACFARLANE: In time.

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

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

21 MICHEL PETTIGREW: Yeah. All right. The vibration part of it
22 probably doesn't change too much in time. We're talking about the same fluid
23 velocities and the same kind of structures, so I don't think we get a big change in
24 time. From the wear point of view, our wear studies have shown that wear for
25 the same excitation is the same, remained the same in time. So the wear

1 calculations are based on the parameter, which is called the work rate.

2 CHAIRMAN MACFARLANE: [affirmative]

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

5 CHAIRMAN MACFARLANE: [affirmative]

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

7 --

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

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

15 CHAIRMAN MACFARLANE: [affirmative]

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

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

20 MICHEL PETTIGREW: Yeah.

21 CHAIRMAN MACFARLANE: Is there an experimental database?

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

25 CHAIRMAN MACFARLANE: [affirmative]

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

4 CHAIRMAN MACFARLANE: [affirmative]

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

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

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

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

1 CHAIRMAN MACFARLANE: Do you guys have any comments?

2 DAMIAN TESTA: No, I agree.

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

8 JIM BENSON: One point I wanted to make is that EPRI has done
9 some studies on wear coefficients of different materials, the -- a 600 material, the
10 690 support materials, stainless steels, carbon steels, and then made that
11 available to the industry in our published reports. So we do have those types of
12 studies that were done.

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

17 CHAIRMAN MACFARLANE: Okay. Thank you. Commissioner
18 Svinicki.

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

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

25 COMMISSIONER APOSTOLAKIS: I don't think we got a straight

1 answer whether research results like the ones that Dr. Pettigrew produces diffuse
2 into the design or -- you gentlemen said, "Oh, we do our own." I mean, are you
3 feudal lords and isolated and don't care what the professor in Canada does?

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

7 JEFF FLECK: Yeah.

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

11 COMMISSIONER APOSTOLAKIS: So you're aware of what the
12 literature is?

13 DAMIAN TESTA: Yes.

14 COMMISSIONER APOSTOLAKIS: To some extent.

15 DAMIAN TESTA: Yeah, yeah.

16 COMMISSIONER APOSTOLAKIS: Don't read it every day.

17 JEFF FLECK: I agree.

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

1 needs to be done, and sometimes we tell them what they should be
2 interested in.

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

5 MICHEL PETTIGREW: That's worked very well.

6 COMMISSIONER APOSTOLAKIS: Okay, this is better now.

7 Thank you very much.

8 CHAIRMAN MACFARLANE: Okay. Okay, great. Anybody else?

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

14 [whereupon, the proceedings were concluded]

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of)
)
SOUTHERN CALIFORNIA EDISON CO.)
)
) Docket Nos. 50-361-CAL
(San Onofre Nuclear Generating Station -) 50-362-CAL
Units 2 and 3))

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing **TRANSCRIPT of February 7, 2013 Briefing on Steam Generator Tube Degradation** have been served upon the following persons by Electronic Information Exchange and by electronic mail as indicated by an asterisk*.

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[Original signed by Herald M. Speiser _____]
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Dated at Rockville, Maryland
this 19th day of February, 2013