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

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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588th Meeting

+ + + + +

OPEN SESSION

+ + + + +

THURSDAY

NOVEMBER 3, 2011

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ROCKVILLE, MARYLAND

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The Committee met at the Nuclear
Regulatory Commission, Two White Flint North, Room
T2B1, 11545 Rockville Pike, at 8:30 a.m., Said Abdel-
Khalik, Chairman, presiding.

COMMITTEE MEMBERS PRESENT:

SAID ABDEL-KHALIK, Chairman

J. SAM ARMIJO, Vice Chairman

JOHN STETKAR, Member-at-Large

SANJOY BANERJEE

DENNIS C. BLEY

1 CHARLES H. BROWN, JR.

2 MICHAEL CORRADINI

3 DANA A. POWERS

4 HAROLD B. RAY

5 JOY REMPE

6 MICHAEL T. RYAN

7 WILLIAM J. SHACK

8 JOHN D. SIEBER

9 GORDON R. SKILLMAN

10

11 NRC STAFF PRESENT:

12 PETER WEN, Designated Federal Official

13 RICH GUZMAN

14 IAN JUNG

15 GENE EAGLE

16 RICHARD STATTEL

17 PAUL PIERINGER

18

19 ALSO PRESENT:

20 SAM BELCHER

21 DALE GOODNEY

22 PHIL AMWAY

23 GEORGE INCH

24 PHILIP WENGLOSKI

25 RICHARD WOOD

I-N-D-E-X

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

8:27 a.m.

CHAIR ABDEL-KHALIK: The meeting will now come to order. This is the first day of the 588th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting the Committee will consider the following. One, Nine Mile Point Unit 2 Extended Power Uprate application.

Two, Branch Technical Position 7-19, Guidance for the Evaluation of Diversity and Defense-in-Depth and Digital Computer Based Instrumentation and Control Systems.

Three, Preparation for Meeting with the Commission. And four, Preparation of ACRS Reports. This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Mr. Peter Wen is the designated Federal Official for the initial portion of the meeting.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's sessions. There will be a phone bridge-line. To preclude interruption of the meeting the phone will be placed in a listen in mode during the presentations and Committee discussions.

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1 A transcript of portions of the meeting is
2 being kept and it is requested that the speakers use
3 one of the microphones, identify themselves and speak
4 with sufficient clarity and volume so that they can be
5 readily heard.

6 At this point we will move to the first
7 item on the agenda, Nine Mile Point Unit 2 Extended
8 Power Uprate. Dr. Armijo will lead us through that
9 discussion. Sam.

10 VICE CHAIR ARMIJO: Okay. Thank you Mr.
11 Chairman. Our subcommittee on power uprates reviewed
12 this application on October the 5th of 2011. Nine
13 Mile Point Unit 2 is BWR/5 Mark II containment. And
14 it, I believe, is the BWR/5 to apply for an extended
15 power uprate.

16 The matters that we reviewed at the
17 subcommittee are similar to the matters we reviewed in
18 the past. There was one new technology that there was
19 some discussion at the subcommittee meeting. It's a
20 proprietary technology related to jet pump mixer
21 coatings. I've asked the applicant and the staff to
22 cover that information.

23 They have provided us a report at our
24 request. And so they will cover that but that will be
25 in a closed portion of the meeting, closed session.

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1 With that I'd think I'd like to just turn it over to
2 Rich Guzman of NRR to lead us through the
3 presentation.

4 MR. GUZMAN: Thank you, Mr. Vice Chairman.
5 And thank you, Chairman. Good morning, my name is
6 Rich Guzman, I'm the senior project manager in the
7 Office of NRR, assigned to the Nine Mile Point Nuclear
8 Station. During today's full committee meeting you
9 will hear from both the licensee and the NRC staff in
10 providing you with the details of the EPU application.

11 The objective is to be able to present it
12 to you in a clear concise way. And to do so we'd like
13 to also present the staff's evaluation supporting our
14 reasonable assurance determination that the proposed
15 EPU will not endanger public health and safety.

16 Before I cover the agenda items for
17 today's meeting I would like to provide some
18 background information related to the proposed EPU.

19 On May 27th, 2009, the licensee submitted
20 its License Amendment Request for Nine Mile Point Unit
21 2 for an EPU which would increase the maximum
22 authorized thermal power limit from 3,467 megawatts
23 thermal to 3,988 megawatts thermal, which represents
24 and increase of approximately 15 percent from the
25 current licensed thermal power.

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1 And approximately 20 percent from its
2 original licensed thermal power. The NRC staff's
3 review effort involved several pre-application
4 meetings with the licensee, starting as early as
5 September 2008. The NRC staff also performed a
6 detailed and extensive acceptance review before
7 initiating its full review of the application.

8 During the course of the review the staff
9 had frequent communications with the licensee, both
10 public and closed meetings, as well as two staff
11 audits. And numerous conference calls to discuss the
12 EPU application and supplemental responses to several
13 rounds of requests for additional information, or
14 RAIs.

15 The RAIs covered multiple technical
16 disciplines. Overall there were approximately 27
17 docketed supplemental responses from Nine Mile Point,
18 which supported the staff's completion of its safety
19 evaluation.

20 And finally, the staff projects completion
21 of its review by December of 2011, which would support
22 the licensee's scheduled implementation of its EPU
23 which is projected for the second quarter of 2012.

24 This slide shows the topics for today's
25 discussion. In the interest of time and staying

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1 within our two hour time block this morning Nine Mile
2 Point will be taking the lead in presenting these six
3 topics. And the staff will be supporting the dialogue
4 as necessary as it pertains to our safety and
5 technical review.

6 First the licensee will provide an
7 overview of the proposed EPU, which will include a
8 description of their proposed plant modifications and
9 their power ascension testing.

10 The anticipated transient without scram
11 and stability. Fuel methods topics will then be
12 covered. And that will be followed by a materials
13 presentation. And these four topics will be in open
14 session, that is the intention.

15 At the conclusion of those four topics we
16 can then switch to closed session to go over the
17 remaining two items, which would be the steam dryer
18 analysis as well as the open item that Mr. Armijo had
19 mentioned and the jet pump mixer coating. And with
20 that that concludes my presentation.

21 I would like to also mention on behalf of
22 the Division Director, Michelle Evans, as well as
23 Louise Lund, our Deputy Director in the Division of
24 Operating Reactor Licensing, who is here today, and as
25 well as the NRR staff members involved in this review

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1 we'd like to say a special thanks to the ACRS staff
2 who helped in the preparation for the subcommittee and
3 this full committee meeting. Particularly Mr. Peter
4 Wen.

5 And I'm going to now turn over to Mr. Sam
6 Belcher who will provide the opening remarks as well
7 as a overview of the proposed EPU. He is the Senior
8 Vice President for Site Operations at Constellation.

9 MR. BELCHER: As Rich mentioned I am Sam
10 Belcher, the Senior VP of Site Operations for
11 Constellation Energy Nuclear Group. I'll go through
12 a brief overview and then turn it over to my staff for
13 a more in-depth discussion on a number of topics.

14 Dale Goodney is the lead engineer on the
15 project. Dale will walk us through plant
16 modifications required for the extended power upgrade.
17 Phil Amway is a senior reactor operator on the project
18 and he will take us through discussion on power
19 ascension testing as well as the anticipating
20 transient without scram and stability methods
21 discussion.

22 Phil Wengloski will talk us through our
23 fuel methods discussion and then George Inch will take
24 us through our materials, mechanical/civil discussion
25 as well as the two closed session that were mentioned

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1 earlier regarding steam dryer as well as the jet pump
2 inlet mixers.

3 As has been previously mentioned it is a
4 BWR/5 technology with the Mark II containment. We are
5 proposing a 15 percent power increase above existing
6 current licensed power, but an overall 20 percent
7 increase from the original licensed power that the
8 plant was originally constructed to.

9 It is a constant pressure power uprate and
10 there is no credit being taken for Containment
11 Accident Pressure for ECCS suction pressure. As well
12 as no new fuel introduction as a part of this. The
13 core is currently all GE 14 fuel and will remain GE 14
14 fuel for the power upgrade cycle.

15 Also the alternative source term for the
16 accidental radiological consequences was previously
17 implemented using the EPU power level as the base
18 assumption for that submittal. Nine Mile Point Unit
19 2 has implemented MELLLA as well as the New York State
20 ISO has already received and approved the uprated
21 power condition with no grid modifications necessary.

22 So at this point I will turn it over to
23 Dale Goodney to walk us a through a discussion on
24 plant modifications.

25 MR. GOODNEY: Thank you, Sam. As

1 mentioned earlier I'm Dale Goodney. I'm the lead
2 engineer for the EPU project. And this will be an
3 overview of plant modifications related to the Nine
4 Mile Point extended power uprate.

5 The balance of plant systems effected by
6 the uprate were analyzed in accordance with the
7 generic methodology outlined in the constant pressure
8 power uprate Licensing Topical Report. This analysis
9 included an assessment of the impact on design and
10 operating margins at EPU conditions to identify
11 modifications needed to support the uprate.

12 Based on these reviews over 20
13 modifications are identified and are described in the
14 License Amendment Request. The primary objective of
15 these modifications are to recover design and
16 operating margins at EPU conditions. Restore material
17 condition. And install instrumentation to support the
18 engineering analysis as well the power ascension
19 testing.

20 At Slide 3 we show the basic plant process
21 parameters that changed due to the uprate. It
22 compares the EPU to current licensed thermal power.
23 As mentioned earlier, this is a 15 percent increase in
24 core thermal power. In addition this will result in
25 a 17 percent increase in nominal steam flow and

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1 feedwater flow. And 158 megawatt electric increase in
2 generator output.

3 Slide 4 is the installation time line,
4 this table lists the modifications that are described
5 in detail in the License Amendment Request.
6 Modifications in the two left-hand columns have been
7 installed and the remaining modifications will be
8 installed before startup in the 2012 refueling outage
9 scheduled to begin next April.

10 Most of these modifications shown here
11 directly support the increase in feedwater flow, steam
12 flow and electrical output of the station. And I'd
13 like to highlight some of the modifications on the
14 next slide.

15 The feedwater system flow capacity is
16 being increased by upgrading the existing feedwater
17 pumps. This was accomplished by replacing the
18 rotating elements and the step-up gears. In addition
19 the heater drain pumps and motors were replaced in
20 2010 with higher capacity pumps to support the uprate.

21 In terms of steam path upgrades the high
22 pressure turbine will be replaced to achieve higher
23 steam flows. The six cross-around relief valves
24 located on the piping between the high-pressure and
25 the low-pressure turbines will be replaced with new

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1 valves to increase the steam relieving capacity.

2 Heat exchanger rerates include the
3 moisture separated reheaters and the high pressure
4 feedwater heaters. In addition the steam dryer will
5 be modified to provide additional design margin at the
6 higher steam flows. And we'll be providing additional
7 details relative to the steam dryer modifications
8 during the closed session.

9 MEMBER BANERJEE: Were there any other
10 modifications between the steam dryer and the high-
11 pressure turbines, in the piping?

12 MR. GOODNEY: With regard to the steam
13 path?

14 MEMBER BANERJEE: Yes.

15 MR. GOODNEY: Well, as I indicated the --

16 MEMBER BANERJEE: So in the, yes you
17 indicated between the high-pressure and the other
18 stages. But in the piping itself? Does it go into
19 the high-pressure?

20 MR. GOODNEY: No, physical plant
21 modifications included just the high-pressure turbine.
22 Thank you. There are two electrical modifications
23 needed to support the increase in generator output.
24 First of all the isolated phase bus between the main
25 generator and the step-up transformers will be

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1 upgraded by installing a higher capacity plume system.

2 And in addition the coolers on the main
3 transformers are being replaced with larger coolers to
4 provide additional thermal margin to offset the higher
5 loading under EPU conditions. Tech-spec related
6 instruments affected by the power uprate include the
7 APRM flow-biased scram and the main steam high-flow
8 isolation.

9 New tech-spec allowable values for those
10 two functions will be implemented as part of the EPU
11 License Amendment. Also the balance of plant
12 instruments affected by the uprate will be rescaled as
13 required to accommodate the higher flows, pressures
14 and temperatures at the uprated conditions.

15 Slide 6 covers the --

16 CHAIR ABDEL-KHALIK: The feedwater reg
17 valves are not going to be changed at all?

18 MR. GOODNEY: Excuse me?

19 CHAIR ABDEL-KHALIK: The feedwater reg
20 valves?

21 MR. GOODNEY: The feedwater reg valves.
22 We are upgrading the feedwater flow control valves
23 with a new trim to provide additional, optimize the
24 controllability and provide, you know, accommodate the
25 additional flow.

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1 CHAIR ABDEL-KHALIK: How far are you from
2 fully open and when they are modified how far will
3 they be from fully open?

4 MR. GOODNEY: Okay, Phil, can you address
5 this? Thank you.

6 MR. AMWAY: Good morning, my name is Phil
7 Amway. I am the operations lead for extended power
8 uprate. Currently the valve positions, we normally
9 have two feedwater pumps in service. Each one has
10 their own feedwater reg valve and LV-10. And those
11 valve positions right now are at about 48 percent open
12 at 100 percent power.

13 With the new valve trim changes that we're
14 doing we should expect a similar response to the valve
15 in terms of where that valve position will be at
16 extended power uprate.

17 CHAIR ABDEL-KHALIK: Forty-eight percent,
18 is that typical for the industry?

19 VICE CHAIR ARMIJO: Yes.

20 MEMBER SIEBER: The real issue with those
21 valves was electric turbine pumps tends to be flow
22 control at low power levels. And that's where a lot
23 of trim adjustments are made so that a little bit of
24 valve movement does not give a large increase in flow.
25 And so you try to get it as sort of a V-shape curve.

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1 I presume that's the purpose of your modification.

2 MR. INCH: Yes, we redesigned the trim.
3 My name is George Inch, I'm the principal engineer
4 from mechanical. The trim was redesigned to maintain
5 the flow gain on the system the same. So the full-
6 open characteristics, C-V characteristics, were
7 increased and then the trim adjusted to maintain the
8 flow control characteristics the same as it was. And
9 to be able to achieve the flow, rated power condition
10 at the same point.

11 There's a small change in the first 15
12 percent open, there's a small slope change there, but
13 that's in the start-up range.

14 MEMBER SIEBER: Yes, the ideal situation
15 is to have valve position literally proportional to
16 feedwater flow, which is what I think you're trying to
17 do.

18 MR. INCH: Yes, we have maintained that.

19 CHAIR ABDEL-KHALIK: So if the valve were
20 to fail fully open, what would be the increase in
21 feedwater flow?

22 MR. INCH: The feed pumps are sized for
23 approximately that the run out condition, that's
24 around 115 percent for the run out scenario where,
25 it's usually called the feedwater control to failure,

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1 which sets the minimum critical power ratio limits for
2 the reload. And that assumes both valves go to full
3 open conditions.

4 CHAIR ABDEL-KHALIK: Okay.

5 MEMBER SKILLMAN: I'm Dick Skillman and
6 would like to ask a question, please, to Dale. In
7 your list of modifications and in your explanation,
8 the modifications really focus on secondary plant
9 feedwater, drain pumps --

10 MR. GOODNEY: Primarily pumps, and plant,
11 correct.

12 MEMBER SKILLMAN: -- bust up cooling,
13 transformer cooling. Where have you addressed
14 necessary changes in all of the systems that are
15 required for decay heat removal. You've bumped this
16 plant four percent and then 15, you're up 20 from your
17 original design.

18 And my curiosity is what is your approach
19 is decay generation rates that are accompanying this
20 very large power increase?

21 MR. GOODNEY: Right. I understand you're
22 asking where we analyzed or accommodated the
23 additional decay heat removal required due to power
24 upgrade.

25 MEMBER SKILLMAN: That is in the core, in

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1 the spent fuel pool. Anywhere the fuel is you've got
2 an abundantly greater heat load.

3 MR. GOODNEY: Right. We did, again this
4 uprate was analyzed in accordance with the LTR for
5 constant pressure power uprates and that provided a
6 generic methodology for evaluating those types of
7 impacts. We did perform a series of technical
8 evaluations that looked at the effected increase in
9 decay heat removals.

10 And those are summarized in the License
11 Amendment Request. And George could probably provide
12 additional details to the specific changes and how
13 those were accommodated. But, as I said, there were
14 not physical modifications required as a result of
15 those evaluations.

16 MEMBER SKILLMAN: Thank you. Thanks.

17 MR. GOODNEY: Ready to continue? Okay.
18 So we're back on Slide 6, which shows other plant
19 improvements. In addition to the EPU modifications
20 described earlier, the station has implemented, or is
21 planning to implement prior to the uprate, a number of
22 other plant improvements to restore margin, improve
23 equipment reliability and reduce risk.

24 Some examples include the 3rd Point
25 Feedwater Heaters, which were replaced in 2010 to

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1 restore material condition. The standby liquid
2 control system was upgraded to a higher pressure. And
3 the relief valve set-point was raised. This provided
4 additional margin between the pump discharge pressure
5 and the relief valve set point.

6 Cooling tower upgrades are being
7 implemented to optimize tower performance. In
8 addition the station has also implemented several PRA
9 related risk reduction improvements consisting of
10 procedure changes and other plant modifications.

11 The feedwater pump seals are being
12 upgraded in 2012, in conjunction with the feedwater
13 pump upgrades I mentioned earlier. And all 20 jet
14 pump inlet mixers will be replaced during the 2012
15 refueling outage to address inlet mixer fouling and
16 restore the performance of the jet pumps to original
17 design.

18 As mentioned earlier, as requested by the
19 ACRS subcommittee, we will be providing additional
20 information regarding the jet pump inlet mixer anti-
21 fouling coating, that will be presented later in the
22 closed session.

23 We also provided a detailed report on the
24 coating process to the ACRS subcommittee in a separate
25 submittal prior to this meeting. The main reason

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1 we're installing the jet pump mixers is to recover
2 core flow operating margin. And to illustrate the
3 effects that the new mixers have on core flow
4 capability I'd like to turn this over to Phil Amway.

5 MR. AMWAY: Thank you, Dale.

6 VICE CHAIR ARMIJO: Before you go there,
7 just one quick question. On the modifications to the
8 steam dryer. When will those be completed, is that
9 going to be in April of next year?

10 MR. GOODNEY: Yes, those will be during
11 the 2012 refueling outages in April.

12 VICE CHAIR ARMIJO: Okay. I'll defer any
13 further questions to the steam dryer.

14 MR. GOODNEY: Okay.

15 MR. AMWAY: Good morning. My name is Phil
16 Amway and I am the operations lead for ascension power
17 uprate. Before we get into the startup test program
18 I'm going to lead off with a discussion of the plant's
19 power flow operating map.

20 This first slide here is really just to
21 show you the entire map. The region of interest for
22 extended power uprate is in the upper-right corner.
23 So the following slide shows that region that we want
24 to talk about this morning.

25 The 87 percent line along the left axis

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1 represents our current operating state, 100 percent of
2 current licensed thermal power. And it shows our flow
3 window between 80 percent and 105 percent core flow.
4 If we were not going to replace the jet pump inlet
5 mixers our maximum estimated core flow was 99 percent.

6 And, as Joel was showing with the mouse up
7 there, that puts us with a single operating point at
8 the 100 percent EPU power level at 99 percent core
9 flow. That would be sufficient for periods of time if
10 we wanted to come up in power and do our power
11 ascension testing.

12 But it doesn't give any core flow window
13 for the operators to effectively maintain 100 percent
14 power operations with a normal cycle reactivity
15 variations at the core throughout the site to length.

16 And that is why we made a decision to
17 replace the jet pump inlet mixers is to restore that
18 core flow margin. We anticipate through our analysis
19 that that would regain a five percent core flow margin
20 at 100 percent EPU, which is sufficient to operate the
21 entire cycle at EPU conditions.

22 In our power ascension testing program the
23 preparation, we have several test objectives. And
24 those are to satisfy equipment performance that meets
25 the design requirements and to ensure that we have a

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1 careful monitored approach to extended power uprate
2 power levels. And we also want to make sure that we
3 meet all established requirements.

4 We have defined roles and responsibilities
5 and included that in our startup test program in the
6 forms of procedure. And we have also included a
7 number of industry benchmarking activities for plants
8 that have already implemented EPU to make sure that
9 our startup test program is consistent with other
10 plants that have already done so.

11 We are currently working on our test
12 procedure development. And our test plans have been
13 established. And before we actually implement the
14 test procedures we will make sure that the operators
15 and technical staff are trained on those procedures
16 prior to implementation.

17 In terms of schedule, we will ascend to
18 the EPU power level in one percent intervals and we
19 will perform data collection at each of those one
20 percent intervals. At two and half percent intervals
21 we will collect and evaluate data. And then our major
22 testing plateaus occur every five percent.

23 During those five percent power intervals
24 we will perform a combination of passive data
25 collective and active control system stability dynamic

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1 testing. Those active control system dynamic tests
2 include pressure regulator step testing and feedwater
3 level control step testing.

4 As completion of the active and passive
5 testing, data collection, we'll analyze that data.
6 Review it by our Plant Operations Review Committee and
7 forward that on to the NRC staff for review.

8 The next slide shows a pictorial analysis
9 of all the testing that's required along the left
10 column and the various power levels at which we'll
11 perform that testing where Xs in the boxes show what
12 tests are performed. And you can see some of those
13 are repetitive at the various power levels.

14 The red shading across the top indicates
15 those test plateaus where we will be forwarding test
16 data reports to the NRC for review. Those highlighted
17 in blue shading across the bottom indicate those
18 tests, which is really just the data collection,
19 that's done every one percent interval.

20 Moving on to the next topic, the long-term
21 stability solution, Option III and ATWS stability
22 events. Nine Mile Point Unit 2 installed and armed
23 the NUMAC PRN OPRM system as an active RPS trip
24 function in the year 2000. And it was done under Tech
25 Spec Amendment 92.

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1 In 2002, we implemented a plant-specific
2 DIVOM curve to address the concerns of GE Safety
3 Communication 01-01. And in 2003 we made additional
4 changes to the filter frequency and period tolerance
5 settings to address Safety Communication 03-20.

6 The effects of extended power uprate on a
7 long-term stability solution includes no methods
8 changes for extended power uprate. The maximum rod
9 line remains the same, and that is the MELLLA
10 boundary.

11 The OPRM arm region maintains the same
12 level of stability protection. That was done by
13 changing the Tech Spec Requirements from 30 percent.
14 In which we armed the system at CLTP down to 26
15 percent, which is the same equivalent megawatt thermal
16 value, so it provides that same level of protection.

17 We developed cycle-specific sub-point
18 analysis to capture core design variations. And we
19 are maintaining the Option III Long-Term Stability
20 Solution, which is the period based detection
21 algorithm.

22 The Option III OPRM set-points are
23 developed based on plant-specific DIVOM curves for the
24 EPU cycle-specific reload analysis.

25 Moving on to the ATWS mitigation design

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1 features. Unit 2 has a redundant reactivity control
2 system, which is designed to mitigate at loss events.
3 That system is largely automated in terms of it is
4 actuated on RPV high pressure.

5 And the immediate response of that system
6 is to independently try to insert control rods using
7 the Alternate Rod Insertion. And to perform an
8 Automatic Reactor Recirculation Pump trip to slow
9 speed.

10 The system allows those first two
11 immediate responses to effect a reactor shutdown. If
12 that is unsuccessful, after time delays, it will
13 initiate an automatic feedwater runback, a trip of the
14 reactor recirculation pumps to off.

15 And then, after a further time delay, if
16 those actions are unsuccessful in bringing the plant
17 to hot shutdown, we receive an automatic boron
18 injection.

19 The effects of extended power uprate on
20 ATWS mitigation strategies. NRR conducted a staff
21 audit at Nine Mile 2 in 2009. And that audit
22 confirmed that our existing procedures, operator
23 action times and strategies are effective at
24 mitigating ATWS and at loss instability transients.

25 The design feature of an automatic recirc

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1 pump trip results in a transient power level that's
2 primarily based on the maximum control rod line, which
3 is unchanged for extended power uprate. The automatic
4 feedwater runback rapidly and effectively dampens
5 thermohydraulic instability during the ATWS transient.

6 And again, we confirmed through the
7 simulator demonstrations that operators can perform
8 actions in a timely manner to bring the plant to safe
9 shutdown.

10 MEMBER STETKAR: Phil, looking at your
11 previous slide a lot of the ATWS responses are now
12 automated, or all automated, what in particular
13 operator actions does that last bullet on your Slide
14 22 pertain to?

15 MR. AMWAY: The operator actions primarily
16 are one, to confirm that the redundant reactivity
17 control system has indeed actuated as designed. And
18 to confirm that the boron injection time occurs at the
19 appropriate time.

20 Once those initial actions are done then
21 we proceed on to our level control strategy and the
22 automatic feedwater runback terminates high pressure
23 feedwater injection. However, the operators have to
24 take action to manually control feedwater to maintain
25 RPV water level in the desired band after the runback

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1 is completed.

2 MEMBER STETKAR: Okay. Thank you.

3 MR. AMWAY: You're welcome.

4 MR. WENGLOSKI: Good morning. My name is
5 Philip Wengloski, I'm the general supervisor for
6 nuclear field services for Constellation Energy
7 Nuclear Group. This morning I'll spend a few minutes
8 talking about the fuel design and fuel methods
9 utilized for the Unit 2 power uprate.

10 On my first slide you heard Sam mention
11 earlier that we use GE14 fuel, we have a full core of
12 GE14 fuel that was introduced in 2004. We only are
13 using GE fuel types through EPU implementation. In
14 particular they have Pellet Clad Interaction or the
15 Barrier Liner Cladding and an integrated debris filter
16 feature.

17 We don't have any test assemblies, test
18 rods, lead use channels in Unit 2 core. The energy
19 requirements for EPU have been met by changes to the
20 bundle enrichments, bundle loadings and bundle loading
21 patterns. Just as a figure of merit, prior to EPU we
22 utilized batch advents enrichments of about 4.18
23 weight percent and 276 feed assemblies.

24 For the power uprate safe analysis report,
25 4.21 weight percent and 552 feed assemblies. And a

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1 cycle 14 which will start up in the spring of 2012.
2 The first EPU cycle 4.23 weight percent and 332 feed
3 assemblies. Of course as you make the --

4 CHAIR ABDEL-KHALIK: The middle number
5 that you gave is 552?

6 MR. WENGLOSKI: Five hundred and fifty-two
7 was used in the PUSAR, that's correct.

8 CHAIR ABDEL-KHALIK: In the what?

9 MR. WENGLOSKI: In the PUSAR, in the power
10 uprate submittal.

11 CHAIR ABDEL-KHALIK: Okay. And the actual
12 number of feed assemblies in the upcoming --

13 MR. WENGLOSKI: The actual number for the
14 upcoming cycle is 332. So 20 feed assemblies less
15 than what was analyzed as part of the equilibrium
16 study.

17 MEMBER SIEBER: That's a pretty
18 conservative fuel management strategy.

19 MR. WENGLOSKI: That's correct.

20 MEMBER SIEBER: In my opinion.

21 MR. WENGLOSKI: That's correct. I was
22 just going to mention the core to zone limits that we
23 use for Nine Mile Unit 2, with respect for design for
24 minimum critical power ration, minimum heat generation
25 rate we're maintaining the same margins pre-EPU to

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1 post-EPU and they're very conservative.

2 MEMBER SIEBER: Well it causes a greater
3 balancing of enrichments across the core and therefore
4 reactivity, because you are changing out a fairly
5 large batch size with just a modest enrichment.

6 MR. WENGLOSKI: That's correct.

7 VICE CHAIR ARMIJO: Now, at EPU you're
8 peak linear heat generation rate is going to be 12
9 kilowatts per foot?

10 MR. WENGLOSKI: Correct.

11 VICE CHAIR ARMIJO: Now, most BWRs operate
12 at 13.4, has Nine Mile 2 been operating at 12 or 13.4
13 in their prior cycles?

14 MR. WENGLOSKI: It's been closer to 12.

15 VICE CHAIR ARMIJO: It has?

16 MR. WENGLOSKI: Yes, it has. We've been
17 fairly conservative in our field management
18 strategies.

19 VICE CHAIR ARMIJO: Okay. And so you
20 basically distributed that extra power more uniformly
21 throughout the core?

22 MR. WENGLOSKI: That's correct.

23 VICE CHAIR ARMIJO: In this design?

24 MR. WENGLOSKI: That's correct.

25 VICE CHAIR ARMIJO: Okay.

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1 MEMBER SIEBER: I would say the bulk of
2 your discharged fuel is twice burned.

3 MR. WENGLOSKI: For the EPU cycles?

4 MEMBER SIEBER: Yes.

5 MR. WENGLOSKI: That's correct. We'll
6 have fairly large batch fraction that will be part of
7 the feed assemblies.

8 MEMBER SIEBER: Okay.

9 VICE CHAIR ARMIJO: And your peak noble
10 burn up, what will that be?

11 MR. WENGLOSKI: The peak noble exposure
12 that we have for the EPU was around 52 gigawatt days
13 for a short time.

14 MEMBER SIEBER: That's the thrice-burned
15 assembly, right?

16 MR. WENGLOSKI: That's correct.

17 VICE CHAIR ARMIJO: Fifty-two --

18 MR. WENGLOSKI: That's correct, yes.

19 MEMBER SIEBER: Does that impact your fuel
20 storage capability? Spent fuel storage capability?

21 MR. WENGLOSKI: For wet or for dry
22 storage?

23 MEMBER SIEBER: Yes, the wet. Obviously
24 this strategy is going to fill up your spent fuel pool
25 faster.

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1 MR. WENGLOSKI: Right.

2 MEMBER SIEBER: And force you into
3 probably on-site storage outside the spent fuel pool,
4 correct?

5 MR. WENGLOSKI: That's correct. The dry
6 storage will be initiated at Nine Mile next year. And
7 the additional loadings have been factored into that
8 strategy to maintain full-core offload.

9 MEMBER SIEBER: How fast, how many
10 assemblies per refueling would you expect you would
11 need to move to dry cast storage per refueling cycle?

12 MR. WENGLOSKI: Well, for a full-core, to
13 maintain full-core offload we need to balance
14 obviously the 332 that come in. So 61 assemblies per
15 dry storage can, we can do the math. And we would
16 have to do those every two years to make sure we
17 maintain a full core offload.

18 MEMBER SIEBER: Doesn't sound like you
19 have a lot of margin right now. As far as empty
20 space.

21 MR. WENGLOSKI: Both units, that is
22 correct, both units do not have a lot of margin for
23 full-core offload.

24 MEMBER SIEBER: Thank you.

25 MR. WENGLOSKI: I mentioned changes to

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1 power distribution. Next presentation by George Inch
2 will talk about how fluence changes in reactor vessel
3 have been addressed in EPU.

4 CHAIR ABDEL-KHALIK: Did you just say that
5 both units don't have much margin for a full-core
6 offload? Are you required to do full-core offload for
7 one unit?

8 MR. WENGLOSKI: This spring will a full-
9 core offload for Unit 2 and we'll be able to obviously
10 discharge the entire batch to the spent fuel pool.

11 CHAIR ABDEL-KHALIK: Okay. Would you be
12 able to do a full-core offload while the other unit is
13 in a refueling --

14 MR. WENGLOSKI: They're separate units.

15 CHAIR ABDEL-KHALIK: So they have separate
16 pools?

17 MR. WENGLOSKI: They have separate pools,
18 that's correct.

19 CHAIR ABDEL-KHALIK: All right.

20 MR. AMWAY: If I could add a
21 clarification. Again, my name is Phil Amway. We plan
22 to maintain a strategy such that we would maintain
23 full-core offload capability at each unit.

24 CHAIR ABDEL-KHALIK: Okay.

25 MEMBER SIEBER: Aren't you required to do

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1 that? I mean you could end up getting stuck?

2 MR. AMWAY: That's correct. That's
3 discussed in our safety analysis.

4 MEMBER SIEBER: If you have to do
5 something with reactor internals you're finished.

6 MR. AMWAY: That's right.

7 MEMBER SIEBER: If you don't take that
8 strategy.

9 MR. WENGLOSKI: With respect to methods.
10 We utilized only NRC approved methods to do the core
11 design and safe analysis. In particular the Topical
12 Report on Applicability of the GE Methods to Expanded
13 Operating Domains was implemented. The SER for that
14 Topical Report imposed 24 limitations and conditions
15 that we needed to evaluate as part of the EPU.

16 And all of those conditions that were
17 relevant to the EPU were implemented and fully
18 addressed. We also demonstrated that the fuel
19 performance is consistent with the EPU plant
20 experience database.

21 So in conclusion, only GE fuel types will
22 be used throughout our EPU implementation. And cycle
23 14 will be the fifth consecutive GE14 reload. And we
24 only utilized NRC approved methods for the core design
25 and safety analysis. All of the applicable

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1 limitations and conditions from the Topical Report
2 were addressed and fully implemented.

3 And our fuel performance is consistent
4 with the plant experience database. And the analysis
5 confirm safe operation of the fuel under EPU
6 conditions.

7 Next George Inch will discuss the
8 mechanical, civil and material aspects of the power
9 uprate.

10 MR. INCH: Good morning. My name is
11 George Inch, I'm the Principal Engineer on the EPU
12 project for mechanical/structural. I'm going to
13 summarize the evaluations that were done for the
14 reactor vessel and the internals for the impact due to
15 the power uprate.

16 One of the major things that are impacted
17 with the core higher batch fractions and the
18 additional power is that the neutron fluence that it
19 exposes the core shroud and vessel is increased
20 roughly 40 to 60 percent depending on where the peak
21 locations are.

22 And those higher power bundles are not on
23 the periphery but they're within two rows of the
24 periphery. And the evaluations were done looked at
25 what components might be exposed to a fluence level

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1 where irradiation assisted stress cracking risk may be
2 increased because of those higher fluences.

3 And the evaluation concludes that the
4 components that currently exceed that fluence remain
5 the same. The top guide, core shroud and core plate.
6 Those components are addressed by the AWR Vessel
7 Internals Project Guidelines. The NRC approved
8 guidelines for that.

9 To give you an idea the top-guide location
10 is, you know, the highest fluence location in the
11 core. At the end of 60 years the peak fluence is
12 approximately $3.3 \text{ E}22 \text{ n/cm}^2$. Did I say that right?
13 E to the 22. The core shroud at the H-4 weld, which
14 is about mid-height, is at $4.1 \text{ E}21 \text{ n/cm}^2$. And the
15 core plate at $6.3 \text{ E}20$.

16 MEMBER BROWN: What is the core plate
17 material?

18 MR. INCH: That's 304 now.

19 MEMBER BROWN: It's 304.

20 VICE CHAIR ARMIJO: Is that the same width
21 for the top-guide and the shroud? Are they 304?

22 MR. INCH: Yes.

23 VICE CHAIR ARMIJO: Now you did, we asked
24 a question at the subcommittee meeting about the
25 piping. And that was fortunately a low carbon 316.

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1 MR. INCH: That's correct.

2 VICE CHAIR ARMIJO: But, that did not get
3 into the internals? You didn't use the same material
4 in the internals?

5 MR. INCH: No, that's not in the
6 internals.

7 VICE CHAIR ARMIJO: Okay.

8 MR. INCH: Our conclusion is that the
9 program that is addressed in the VIP remains an
10 effective way to identify any potential degradation
11 due to fluence effects or degradation of the
12 internals.

13 And the other conclusion we reached dis
14 that hydrogen water chemical and noble metals process
15 that we use to mitigate stress corrosion cracking will
16 remain effective for 60 years for these components,
17 even at the fluence level.

18 It is important to note the top-guide
19 really isn't mitigated by those mechanisms. And the
20 fluence level is above a threshold where you wouldn't
21 expect that to be effective.

22 MEMBER SIEBER: In your in service
23 inspection program for reactor vessel internals, have
24 you found indications, so far, that would, or defects,
25 you know, cracks or what have you, that would, well

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1 have you found any? And secondly have you done any
2 remedial action for what you might have found?

3 MR. INCH: Yes, our internal inspections
4 programs has identified cracking on the core shroud.
5 It's not unusual, consistent with the OE on it.

6 MEMBER SIEBER: That's right.

7 MR. INCH: On the top-guide we have not
8 identified any cracking. OUu inspection sampling is
9 at the beginning, because of the age of the unit, we
10 haven't achieved our full sample requirement of
11 approximately five percent yet.

12 And the core plate, that inspection hasn't
13 identified any issues. That inspection is currently
14 in an update process, generically. As part of the VIP
15 because it requires some inspection of core plate
16 bolts.

17 For that one we are not really required to
18 do any inspections until approximately 40 years. So
19 we're --

20 MEMBER SIEBER: That could be a sensitive
21 issue.

22 MR. INCH: The core plate bolting, for the
23 core plate, our margins and stress relaxation for
24 those bolts, analytically are shown to be remain
25 effective even with potential cracking. Consistent

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1 with the generic guidance.

2 MEMBER SIEBER: Okay.

3 MR. INCH: So the core shroud cracking is
4 on the OD, it's shallow on the H4 and H5 welds. And
5 we've got an aggressive inspection program with
6 ultrasonic. We've done a recent reinspection in 2008,
7 which was a six-year interval since our last
8 ultrasonic. And prior to that there was a four-year
9 interval. So it's a very aggressive program.

10 And it's shown that the mitigation
11 measures for hydrogen water and noble metals are very
12 effective, the cracking is not --

13 VICE CHAIR ARMIJO: So as far as the
14 length of the cracks and the depth of the cracks on
15 your shroud. It's been many years since you've first
16 detected them. And you've been operating with
17 hydrogen and noble metals. And have you found that
18 these cracks have grown either in length or in depth?

19 MR. INCH: Since the implementation of
20 noble metals there has been no significant change.
21 There is variation on ultrasonic measurement
22 techniques, and we attribute the change to within the
23 noise of the measurement.

24 VICE CHAIR ARMIJO: How about new cracks,
25 maybe that hadn't been detected before?

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1 MR. INCH: We don't believe there's any
2 new cracking. Again, you have different coverage
3 regions. So if you looked at a map it doesn't match
4 up exactly. But there's placement errors. So
5 essentially when you take the aggregate, our
6 assessment is is that there's no significant change in
7 the amount of cracking. It's approximately 70 percent
8 of the circumference on the H4 weld.

9 And it's shallow, less than a half inch,
10 it's a two-inch shroud. It's been stable since we
11 implemented hydrogen water chemistry. When they were
12 first identified in 1998 with UT. We went back in
13 after two years, just prior to noble metals, and
14 reinspected and it was a normal water chemistry.

15 We did observe what we considered growth
16 at that time, under normal water chemistry. It was
17 well bounded by the normal water chemistry crack
18 growth rates of 2.2 E to the minus five inches per
19 hour. And that was important information from our
20 perspective.

21 And that's why we implemented a much more
22 aggressive reinspection after noble metals to make
23 sure we've stabilized it, because we were considering
24 at that time other mitigation measures.

25 VICE CHAIR ARMIJO: So you didn't have to

1 apply these clamping techniques or do that other
2 people would have to do on the shrouds?

3 MR. INCH: Yes, we determined that the
4 core shroud tie-rod modification was not warranted at
5 this time. It is a contingency that we've looked
6 into. But with the cracking stabilized at a half inch
7 there's a large margin to allow.

8 VICE CHAIR ARMIJO: Thank you.

9 CHAIR ABDEL-KHALIK: What was the current
10 fluence level for the top guide?

11 MR. INCH: The current fluence level for
12 the top guide. I don't have that number at my
13 fingertips, I can get back to you on that.

14 CHAIR ABDEL-KHALIK: But it is greater
15 than 5 times 10 to the 20th?

16 MR. INCH: Yes. It's in the 21 range,
17 high 21s.

18 CHAIR ABDEL-KHALIK: And you have not
19 found any cracks in the top-guide, as far as you know?

20 MR. INCH: No we have not identified any
21 cracking in the top-guide. We've done approximately
22 six cells. We've inspected six of the control cells
23 with enhanced visual techniques consistent with the
24 new guidance. And in that sampling we have not
25 identified any cracking conditions.

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1 CHAIR ABDEL-KHALIK: Okay.

2 MR. INCH: Moving on to the bulk of the
3 internals, looking at the, you know, the impact of the
4 power uprate. There are two things we evaluate, flow
5 induced vibration and the basic structural effects due
6 to temperature and differential pressure changes. The
7 evaluations performed by GE Hitachi apply scaling
8 methods that are extrapolated from data from prototype
9 plants and actual plant data.

10 And that scaling applies velocity squared
11 for the internal components, such as the steam
12 separator and other components. The results show that
13 continuous operation at EPU conditions doesn't result
14 in any detrimental effects on the safety related
15 internal components.

16 Structural standpoint. The evaluation
17 stress reconciliation was performed consistent with
18 Design Basis Analysis. Load increases were evaluated
19 by scaling the governing stresses and then compared to
20 ASME code allowable limits. There's large margin on
21 those internal components.

22 All stresses and fatigue usage are within
23 the design ASME Code allowables. And the internal
24 components have been demonstrated as structurally
25 qualified for EPU conditions through the end of the

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1 license renewal term.

2 The fatigue monitoring program, fatigue is
3 one of the things that is impacted through the power
4 uprate because of the temperature changes. The
5 current licensing basis for Nine Mile Unit 2 is cycle
6 counting for fatigue monitoring for the design
7 calculations.

8 And so for each event the maximum usage is
9 accumulated. And for the stress based monitoring for
10 the feedwater nozzle is planned for managing the
11 feedwater nozzle location below 1.0 for the license
12 renewal term.

13 EPU evaluations have concluded that cycle
14 counting usage does remain below 1.0 for 40 years
15 consistence with the current licensing basis. And
16 that the current plans for stress based monitoring for
17 the feedwater nozzle remains required for the license
18 renewal term.

19 The Nine Mile Point 2 commitment is to
20 implement stress based monitoring in accordance with
21 the ASME Section II, NB-3200 and that's consistent
22 with the RIS-2000-30 to make sure that we include all
23 six stressed components, and stress based monitoring
24 is implemented for the licensing basis.

25 That's all I had on the on the vessel on

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1 the internals. But the next subject was going to be
2 the steam dryer.

3 VICE CHAIR ARMIJO: George, before you go
4 there. I think it was a feedwater nozzle, or one of
5 the nozzles it would be above the 1.0 accumulative
6 usage factor at EPU conditions unless you do something
7 different. What would it be, one point what?

8 MR. INCH: At the end of the 40-year term
9 for EPU conditions the peak location is at a usage of
10 0.9. And the standard rule of thumb, if you, for
11 scaling for license renewal is to multiple by 1.5. So
12 approximately 1.4 or something.

13 VICE CHAIR ARMIJO: So you have to go to
14 a different methodology or actually do a repair or
15 replacement or something in order to stay within that
16 limit?

17 MR. INCH: Right. Correct, if the usage
18 were actually that high, corrective actions would have
19 to be taken for the nozzle. And stress-based
20 monitoring allows us to get accurate predictions of
21 what the actual usage is for the nozzle and then take
22 appropriate action. Long in advance of approaching
23 usage of 1.0.

24 VICE CHAIR ARMIJO: Okay. And that's your
25 final bullet on that chart, right?

1 MR. INCH: That's correct.

2 VICE CHAIR ARMIJO: Thank you.

3 CHAIR ABDEL-KHALIK: Well the first bullet
4 says you conservatively assume the design base of
5 stress for each event. How far are you from this
6 design basis stress now, and how far will you be at
7 the elevated feedwater flow conditions?

8 MR. INCH: I think you're asking me what
9 the current usage is --

10 CHAIR ABDEL-KHALIK: Right.

11 MR. INCH: -- for the feedwater nozzle?

12 CHAIR ABDEL-KHALIK: No, no, no. The
13 design basis stress level.

14 MR. INCH: Well for the fatigue usage it's
15 really just the cumulative usage factor. Which will
16 accumulate that usage, what we're referring to there
17 is for each event, a maximum thermal event, the
18 accumulated usage for each one. So off the top of my
19 head I don't know what that actual stress is for each
20 one of those events.

21 CHAIR ABDEL-KHALIK: But I'm just trying
22 to talk this thing into meaning of the very first sub-
23 bullet. And how conservative is that assumption. How
24 close are you to the design basis stress? How close
25 will you be to the design basis stress at elevated

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1 feedwater flow conditions?

2 MR. INCH: I think I understand the
3 question. Is the severity of the design basis
4 transient that we're assuming in accumulating the
5 usage for the nozzle.

6 CHAIR ABDEL-KHALIK: Correct.

7 MR. INCH: How conservative is that
8 compared to the actual events?

9 CHAIR ABDEL-KHALIK: What you expect to
10 have. Correct.

11 MR. INCH: The limiting event for,
12 example, a feedwater nozzle is actually one of the
13 transient events that occurs during hot standby where
14 they assume some rapid cycling. And that's a design
15 basis assumption.

16 And the duration of how long that occurs.
17 And that is, there is significant conservatism in that
18 in that there's operating procedures that try and
19 mitigate severity of the conditions.

20 So I don't have a exact number for you.
21 But our evaluation and trending shows that there's
22 significant conservatism in the assumptions that go
23 into like the feedwater nozzle. Some of the events
24 are just the normal startup and shutdown.

25 And there's not very much conservatism in

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1 that heat-up cycle. It's just the conservatism is in
2 how many cycles you have.

3 But for the stress based monitoring
4 condition there is quite a lot of conservatism,
5 because it assumes the maximum possible and the actual
6 event is procedurally mitigated by operations.

7 CHAIR ABDEL-KHALIK: Have you ever had a
8 feedwater reg valve control failure?

9 MR. INCH: That's -- Phil?

10 MR. AMWAY: A feedwater, we've had some
11 events. At the level valves have been very good
12 operating performance in terms of failure. I mean
13 we've had minor issues where, you know, it may not
14 behave quite like we would expect it to. But not such
15 that it resulted in a level excursion.

16 MEMBER SIEBER: You have electric-driven
17 feed pumps, right?

18 MR. AMWAY: We have electric-driven feed
19 pumps for all three, that's correct.

20 MEMBER SIEBER: So the plant stability
21 depends far more on the operation of the feed reg
22 valve than you would have if you had steam-driven feed
23 pumps. Steam-driven feed pumps, feed reg valves
24 pretty much stay at the same place.

25 MEMBER STETKAR: Do you have variable

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1 speed feed pumps though?

2 MR. AMWAY: No, they are not variable
3 speed.

4 MEMBER STETKAR: Right.

5 CHAIR ABDEL-KHALIK: Right.

6 CHAIR ABDEL-KHALIK: So you say you had a
7 feed level reg valve controller failure, and yet it
8 didn't result in a vessel level excursion, is that
9 what you said?

10 MR. AMWAY: That's correct. What I'm
11 talking about is we'll notice, because we monitor the
12 motion of the feedwater reg valves and there's
13 normally two in parallel at 100 percent.

14 So if you had a failure in one the other's
15 going to try to compensate. Okay? So the failures
16 that I'm talking about is you'll have some kind of
17 LP10 will just fail on an as-is condition.

18 And you'll see that by when the operators
19 do their rounds they're looking for that valve motor
20 to be turning on some of a frequency to show that it's
21 actually responding to the feedwater level control.
22 So they have that.

23 And we also have alarm settings that will
24 warn us of an actuator trouble, you know, so as long
25 as we were at steady state operation we wouldn't see

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1 anything in the level control side of it. We would be
2 looking at the actual LV10 performance, that detects
3 --

4 MEMBER SIEBER: That's because they're
5 reset controls?

6 MR. AMWAY: Yes.

7 MEMBER SIEBER: They will grind that until
8 they get to the right point.

9 MR. AMWAY: Right.

10 MEMBER SIEBER: If one fails the other one
11 will take up the --

12 MEMBER SKILLMAN: This is Dick Skillman
13 and I understand you to say that with your current
14 cycle counting program and for what you project in
15 terms of future cycles, with the power uprate, your U
16 will remain one or less. Your U session factor, the
17 1.0?

18 MR. INCH: That's correct.

19 MEMBER SKILLMAN: What changes have you
20 made to your cycle counting program to ensure that you
21 have accurate cycle count and an accurate cycle
22 description? You've changed your feedwater about 15
23 degrees Fahrenheit. You've boosted feed flow and
24 steam flow. It appears as though you've addressed the
25 vibration and the other issues related to the higher

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1 mass flow rates.

2 But what have you done in your cycle
3 counting program to make sure you're on the money for,
4 if you will, the press towards your 1.0 U for the
5 power uprate, please?

6 MR. INCH: That's a good question, because
7 when we did the license renewal it was recognized that
8 we were going to have to get much more accurate in
9 managing the usage. At that point in time, in 2008,
10 we did implement the FatiguePro Software, which was
11 epi software that was developed.

12 What it allows us to do is it
13 automatically records all the processed computed data
14 and then has triggers for counting the cycles. So it
15 doesn't rely on someone to go back and figure out what
16 it was. So there's, actually all the data is recorded
17 for the actual severity of the event.

18 And then each one of the locations is then
19 sorted in the software as to which ones you're
20 counting the cycles and which ones you want to also
21 count with stress. So that program was implemented in
22 2008 and is currently being used to track the usage.

23 We're also double tracking the feedwater
24 nozzles so we have a usage based on stress based and
25 cycle counting.

1 MEMBER SKILLMAN: Thank you. I'd ask,
2 please, if the individuals who are monitoring that
3 program are sensitive to how important that program is
4 to your utilization?

5 MR. INCH: Oh, yes. The program is
6 managed through our Design Engineering Group,
7 expressly because it's computationally intensive.
8 You've got to understand the sensitive locations. And
9 so that's well understood.

10 MEMBER SKILLMAN: Thank you.

11 CHAIR ABDEL-KHALIK: What would be the
12 usage factor for 60 years of operation? Second
13 bullet.

14 MR. INCH: For 60 years. Our usage is
15 less than 1.0 for 60 years for all locations. And the
16 location for the feedwater nozzle we expect to be able
17 to maintain below 1.0 with a stress-based --

18 CHAIR ABDEL-KHALIK: Even for 60 years?

19 MR. INCH: Even for 60 years, yes.

20 CHAIR ABDEL-KHALIK: Okay. So why --

21 VICE CHAIR ARMIJO: But you'll be below
22 one for 40 years without stress-based?

23 MR. INCH: That's correct.

24 VICE CHAIR ARMIJO: Okay. But not for 60?

25 MR. INCH: If you were to have all the

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1 design events with the same design severity and then
2 you simply did a projection with the 1.5, that's where
3 you would predict you would be above 1.0. That's what
4 mandates having to more accurately track that.

5 MEMBER STETKAR: George, I don't recall
6 the license renewal. And I didn't look it up. Did
7 you guys look at a trending on your cycle counts in a
8 historical trending back through day one? Just to see
9 how the slopes were heading.

10 You know, the questioning about
11 extrapolating out through 60 years is a straight
12 linear extrapolation, that depends on the shape of
13 your operating history basically.

14 MR. INCH: Yes. What is showed is in the
15 first five years of operation we accumulated a lot of
16 usage. And there was a lot of startup, shutdowns and
17 transients. And since then it's really plateaued and
18 the usage has plateaued out. So there was a lot of
19 usage in that first five years.

20 MEMBER STETKAR: Thanks.

21 MEMBER SIEBER: One thing you need to look
22 out for though is that there is that there is a so
23 called bathtub effect. Where when a unit first starts
24 out, particularly if it's a first of a kind or the
25 first for that particular licensee, the cycle rates

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1 are pretty high. Then operation becomes steadier,
2 more experienced people, better repair programs. And
3 so the cycles go down.

4 However, at the end when everything is
5 wearing out your cycles go back up. So that's where
6 you really have to pay attention. Is to watch your
7 maintenance history and your failure rates. And as
8 the plant gets older, some plants see that in a
9 pronounced way. Other plants not so much. But you
10 have to pay attention to it.

11 VICE CHAIR ARMIJO: I'd like to bring up
12 a couple of items that came up during the subcommittee
13 meeting that I think the full committee might
14 appreciate. And, George, I'd like to ask you about
15 the hydrogen water chemistry techniques that you'll
16 use to compensate for the higher radiolysis rate in
17 the core.

18 And the other question is what mitigation
19 have you done for the indications of cracks that you
20 found in your nozzle dissimilar metals weld so that
21 the fatigue doesn't have to worry about some
22 preexisting crack. So if you'd expand on those two
23 points.

24 MR. INCH: Okay. I'll do the latter
25 first. We've done for our feedwater nozzle dissimilar

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1 metal weld, there were indications identified in it,
2 oh it must have been about six years ago, we did an
3 overlay on that location. We have implemented the
4 Performance Demonstration Initiative to properly
5 inspect the dissimilar metal welds.

6 And there was one other indication that
7 was originally identified back in '92. It was on a
8 HPCS line that a mechanical stress improvement was
9 done in that year. And it has been monitored since
10 repeatedly and there's been no growth. So we've
11 carried a contingency for an overlay on that location
12 for many years, it's still on the books, but it looks
13 like --

14 VICE CHAIR ARMIJO: How about the core
15 spray nozzles?

16 MR. INCH: The core spray nozzles?

17 VICE CHAIR ARMIJO: Yes, the core spray
18 lines. Did you have any --

19 MR. INCH: To my knowledge I don't believe
20 there's any indications in the core spray nozzles.

21 MEMBER SHACK: Those are carbon steel on
22 the BWR/5 aren't they?

23 MR. INCH: I would have to check that.

24 VICE CHAIR ARMIJO: And the hydrogen water
25 chemistry. You're going to do something different I

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1 know that. You're going to, as far as you're going to
2 increase the hydrogen, right?

3 MR. INCH: Oh, yes.

4 VICE CHAIR ARMIJO: Commensurate with the
5 increase in --

6 MR. INCH: Yes. For noble, we perform
7 noble metals with the online technique. So every year
8 we reapply. And currently our hydrogen water
9 chemistry program implements a molar ration of 4:1 for
10 the upper shroud location on the OD. And that results
11 in an injection rate of 15 SCFM.

12 For power uprate our plan is to maintain
13 4:1 at the upper shroud location and to implement 17
14 SCFM to maintain that same molar ratio. The required
15 molar ratio for mitigation is 3:1 but we've
16 implemented 4:1 because of some uncertainty associated
17 with the radiolysis modeling predictions.

18 And we hadn't recognized any significant
19 change in operating dose rates because of it. It is
20 something that we might want to consider in the future
21 to drop it to 3:1, if we're seeing any effect
22 associated with the higher injection rate. But we
23 don't anticipate that.

24 VICE CHAIR ARMIJO: What's the basis for
25 that 3:1, where does that come from?

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1 MR. INCH: That's a guideline that has
2 been developed primarily by the industry and General
3 Electric and NRC has endorsed as an acceptable molar
4 ration for mitigation.

5 VICE CHAIR ARMIJO: Okay. Thank you.

6 VICE CHAIR ARMIJO: Okay. At this point
7 I think we're, well we need the staff. So we're ready
8 to go into closed session and address the steam dryer
9 and the jet pump mixer coating or any other questions
10 the committee may have that might deal with
11 proprietary information. So let's just go ahead with
12 that.

13 (Whereupon the meeting of the open session
14 went off the record at 9:35 a.m. and went back on the
15 record at 10:40 a.m.)

16 VICE CHAIR ARMIJO: We can now go back
17 into open session. At this point I'd just like to get
18 some feedback from the Committee members. Any closing
19 remarks, observations, comments. And I'll just go
20 around the table quickly. Jack, nothing?

21 MEMBER SIEBER: None.

22 VICE CHAIR ARMIJO: Dr. Banerjee. Pass.
23 Harold, pass. David?

24 MEMBER BLEY: Nothing more.

25 VICE CHAIR ARMIJO: Dennis? Dr. Powers?

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1 MEMBER POWERS: Compliment them on their
2 conservatism and the care with which they've done
3 this, it's quite impressive to me.

4 VICE CHAIR ARMIJO: Thank you.

5 MEMBER STETKAR: Nothing.

6 VICE CHAIR ARMIJO: Mike.

7 MEMBER RYAN: Nothing else, thank you.

8 VICE CHAIR ARMIJO: Bill. Well, I really
9 have nothing else. We had a very good meeting today.
10 I think you were very well prepared. The subcommittee
11 meeting was thorough and you addressed all the
12 questions we raised at the subcommittee meeting so I'm
13 satisfied. I think it's now up to us to go into our
14 session and prepare our letter on the subject.

15 We did not get the chance to hear from the
16 staff here at this meeting in more detail. But we did
17 get a lot of detailed review on the part of the staff
18 at the subcommittee meeting and I'd like to compliment
19 both the licensee and staff on their preparation for
20 this application. And with that I turn it back to
21 you, Mr. Chairman.

22 CHAIR ABDEL-KHALIK: Thank you. At this
23 time we're scheduled for a 15 minute break. So we
24 will reconvene at 11:00 a.m.

25 (Whereupon, the meeting went off the

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1 record at 10:42 a.m. and went back on the record at
2 10:58 a.m.)

3 CHAIR ABDEL-KHALIK: We're back in
4 session. At this time we will move to the next time
5 on the agenda. Branch Technical Position 7-19.
6 Guidance for the Evaluation of Diversity and
7 Defense-in-Depth in Digital Computer-based
8 Instrumentation and Control Systems.

9 And Charlie Brown will lead us through
10 that discussion.

11 MEMBER BROWN: Okay, I'm not going to go
12 through a big introduction. Just to let everyone know
13 the staffs not really required to present the staff
14 review plan. That we normally get after it's been
15 issued but this one they gave us a heads up. We were
16 interested in seeing it, so I appreciate that
17 courtesy, I wanted to let the staff know that.

18 We had delayed a little it on coming to
19 the full committee and they, again delayed issuance of
20 this. Until after full committee to see if there were
21 any other continents that would be good to put in. So
22 I'm wanted to thank the staff for that and with that
23 I will turn it over. Who's leading this, Gene?

24 MR. JUNG: Thank you, Charlie. Good
25 morning. My name is Ian Jung, Chief of the

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1 Instrumentation Controls and Electrical Engineering
2 Branch to Digital Engineering. And thanks committee
3 for taking time to go over this particularly important
4 copy.

5 And this particular guidance is to
6 implement the Commission Policy 93-087, regarding the
7 software common-cause failures for digital systems,
8 for of course safety systems.

9 And that we've gone through a sub-
10 committee meeting in September, also ISG which is
11 being incorporated into this particular revision, ACRS
12 have retained that document earlier.

13 So the particular scope of change is to
14 incorporate those currently what's in IGS-02 which
15 will be added to Revision 5 forming a Revision 6.

16 With that I'll turn it over to Rich
17 Stattel and Gene Eagle.

18 MEMBER SHACK: Let me just ask a quick
19 question? What is the regulatory status of acceptance
20 like 93-087, it's not a fuel but you all have followed
21 the guidance in it.

22 MR. JUNG: It is not a regulatory
23 requirement but SRM Commission set out as a policy, in
24 general that is considered still the document. We
25 considered that as a policy, I think applicants not

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1 addressing the policy should testify why the policy is
2 not being addressed.

3 And Gene Eagle from Office of New
4 Reactors. Both of them were, led this part of the
5 effort, Gene.

6 MR. EAGLE: Okay, thank you. Today as we
7 are approaching lunch we'll try to keep our
8 presentation as short as possible. And some slides
9 I'll only put up and not necessarily read everything
10 on it and we'll try to hit the highlights or the key
11 points.

12 The crux of the briefing today is to
13 highlight and identify the key elements from
14 incorporating ISG-02 Revision 2 into BTP 7-19 Revision
15 5 to form Revision 6, and the action items from the
16 ACRS subcommittee presentation.

17 The current status is presented here, we
18 would like to note that BTP 7-19 has received OMB
19 concurrence as a non-major rule under the requirements
20 of the Congressional Review Act. This is primarily,
21 based on the fact that as we mentioned above the BTP
22 7-19 Revision 6 is the incorporation of the approved
23 and issued ISG-02 Revision 2 into Revision 5 to create
24 Revision 6.

25 Slide 3 presents the agenda for our

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1 presentation today. First we'd like to review the
2 purpose and general basis of BTP 7-19. BTP 7-19
3 applies to software Common Caused Failure and we will
4 simply refer to it as CCF on the screen and often in
5 this presentation.

6 The Interim Staff Guidance, ISG, documents
7 were in an NRC method of rapidly getting further
8 needed guidance on digital I&C to the staff and
9 stakeholders in preparation for the new reactor
10 designs.

11 The original concept was that all the
12 ISG's would be incorporated into the appropriate
13 standard review plan document. It forms the purpose
14 in general, I'd like to read the summary notes in red.

15 In summary, while the NRC staff considers
16 software Common Cause Failure in digital systems to be
17 beyond design basis. Nuclear power plants should be
18 protected against the effects of anticipated
19 operational occurrences,, and postulated accidents
20 with a concurrent Common Cause Failure in the digital
21 protection system.

22 Slide 5 has our background. That's first
23 we had Revision 2 which answered the initial comments
24 that were presented by the ACRS during the
25 presentation of Revision 1. And in particular the

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1 main thing was the idea of operator manual action to
2 be able to be credited as part or some basis in the
3 diverse means.

4 We then created, the decision was made to
5 merge Rev 2 into the standard review plan, Rev 5 to
6 create Rev 6. Seventy comments were received and the
7 presentation was made to the subcommittee on September
8 7th.

9 As the result of several public comments
10 on the paraphrasing of the NRC Four-Point Policy on D3
11 in Revision 5 the staff decided to quote the NRC Four-
12 Point Policy directly as noticed on these slides.

13 Points 1 and 2 emphasis performing a D3
14 analysis on the proposed I&C system. The direct
15 quotations of the four-points were followed by simple
16 specific items or significant interpretations that the
17 staff wanted to emphasize under concerning points.

18 One thing the four-points used the term
19 best estimate methods. We thought a better term
20 would be realistic assumptions. That then included a
21 definition.

22 By the way the corresponding event here
23 when we talk about zero power, this means that if the
24 Chapter 15 covers any kind of thing that goes down to
25 maybe a zero power that's included when we say

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1 corresponding to the event.

2 The Safety Analysis report id specified by
3 .2 must be addressed. Concerning Point 3, if the
4 analysis indicates a potential for Common Cause
5 Failure, Point 3 directs the applicant to identify or
6 add a diverse means to perform either the same
7 function or a different function.

8 You also want to notice that the phrase
9 "Safety Computer System" identified in Items 1 and 3
10 above, from Point 4 clearly indicates primary
11 application is to the automated safety-related reactor
12 trip system and the engineered safety features.

13 Point 3 also applies to manual initiated
14 methods for the reactor protection system if subject
15 to the Common Cause Failure

16 A diverse means may be accomplished by
17 automated, manual, or a combination of these for
18 initiating mitigating functions.

19 The staff wanted to emphasize that it is
20 Point 3 that directs the identification or creation of
21 a diverse means. If the D3 analysis identifies a
22 Common Cause Failure.

23 The critical safety functions are more
24 accurately defined as the plant critical safety
25 functions and are the ones from the NUREG-0737,

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1 Supplement 1.

2 Also the safety parameter display system
3 provides indicators and implementation to support
4 these plant critical safety functions. They are
5 listed in Revision 6.

6 Assume for a moment that a current nuclear
7 power plant is upgrading with a digital I&C system.
8 If certain panel alarms and instruments are retained
9 but the input signals are derived from the new
10 upgraded digital I&C system that is subject to a
11 postulated Common Cause Failure. Then these retained
12 I&C instruments would no longer qualify as independent
13 and diverse point-four displays.

14 Public comments made a case that once
15 manual activation from the main control room using
16 point-four controls had achieved the initial
17 objective, there may be, and I repeat, there may be a
18 need later to use controls outside the main control
19 room. An example might be actions needed in the long
20 run beyond 72 hours.

21 However there may need to be in the short
22 period use of these controls. An example might be the
23 realignment and operation of manual valves to set up
24 an alternate flow path to recover from failed or
25 damaged equipment. The key point here is that it may

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1 be on a case or specific basis.

2 MEMBER BROWN: Before you flip off of
3 that, don't forget the last line. "When supported
4 by."

5 MR. EAGLE: Yes. Okay. Once manual
6 action from Main Control Room, using point-four
7 controls is completed, controls outside Main Control
8 Room may be used for long-term and/or perhaps
9 short-term management when supported. I like the
10 last point, when supported by suitable Human Factor
11 Analysis and Procedures.

12 At this time Rich Stattel will be
13 presenting and discussing the independence of the
14 diverse means.

15 MR. STATTEL: Yes, good morning everyone.
16 Yes, I just wanted to say a few words regarding the
17 independent means. Because although the primary
18 objective of this revision to the BTP was to
19 incorporate what the Working Group 2 had come up with,
20 and the ISG-02. We also identified the need to
21 clarify certain aspects of the guidance.

22 Regarding the independent requirements for
23 the diverse actuations of the automatic diverse
24 actuation system. This was an area that received
25 quite a bit of feedback from the industry.

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1 And we decided to add some clarifying
2 language to the BTP to address allowances for both
3 safety related and non-safety related diverse
4 actuation systems.

5 Prior to this revision there was kind of
6 an assumption that the diverse actuation would be non-
7 safety-related and would be separated in that manner.

8 As you may know, there are basically
9 different requirements for separation between
10 divisions of safety and between safety and non-safety
11 related systems.

12 And basically, we didn't want to change
13 any of that guidance really, because that's something
14 that they have to conform to the regulations that
15 exist for those systems.

16 But the BTP also has to acknowledge that
17 a licensee can choose to incorporate a diverse system
18 within a safety related system. So for example if a
19 plant chooses to have a diverse safety system. Like
20 a four channel diverse safety system which several
21 plants have done this.

22 Then it's really unrealistic to expect
23 separation between the primary safety system and the
24 diverse safety system.

25 So Channel A would be powered by the same

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1 1E power source for example. But of course the
2 divisional separation would still apply as it does for
3 all safety systems.

4 For non-safety systems there's a different
5 set of criteria, and those are defined in other
6 standards, for example ISG-04. So as the slide states
7 here the diverse means it could be safety related or
8 could be non-safety related.

9 In the final analysis though, in either
10 case regardless of how the licensee chooses to
11 implement a diverse actuation. It should be
12 independent of the safety system in the manner such
13 that the Common Cause Failure of that primary safety
14 system would not adversely effect the diverse system
15 itself.

16 So that was really the goal, and I just
17 wanted to explain that that was the reasoning for that
18 clarification.

19 MEMBER BROWN: Just one point, the
20 clarification I mean. If you look at BTP, trying to
21 calibrate myself again here. That did not have as
22 much explanation, well to get to this point. So there
23 was a considerable amount of clarification to make
24 these differentiation points which was a pretty good.

25 MR.. STATTEL: I was actually very

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1 challenging to establish the criteria, knowing that
2 plants are going to implement the diverse systems in
3 different a different manner. But I think we came to
4 an agreement and I think the language as it is in the
5 new Revision, really addresses that issue.

6 MR. EAGLE: I also wanted to point out
7 that, for instance, when they talk about the point-
8 four displays and controls. They use the term
9 independent and diverse and originally we had started
10 using that.

11 And then during the industry comments they
12 brought up some of these things and therefore we then
13 addressed the independence with more detail.

14 Thank you Rich.

15 MR. STATTEL: Yes.

16 MR. EAGLE: The driving motivation for
17 ISG-02 was the nuclear industries representatives
18 presentation of a list of concerns and questions.
19 ISG-02 addressed seven of these problem statements.

20 While we don't plan on going into all the
21 details of each problem statement as we did in the
22 sub-committee. We would like to look at the key
23 issues and present some of these and discuss these.

24 The first one, was the automatic versus
25 manual diverse means. Originally there was a hard

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1 limit that manual operator action could only be used
2 if not required for at least 30 minutes. This was in
3 line with guidance or regulations from other countries
4 that were major generators of electrical power from
5 nuclear power plants as learned in a major
6 international meeting in this very room. Actually the
7 room next door.

8 MEMBER STETKAR: Which were probably
9 derived from very, very early, US NRC specifications
10 of 30 minutes.

11 MR. EAGLE: I'm glad to see we're a
12 leader.

13 MEMBER STETKAR: No, just don't rely on
14 that survey of other international experience.

15 MR. EAGLE: As being independent.

16 MEMBER STETKAR: As being independent, or
17 diverse. It's in fact derived from guidance from the
18 US NRC in the '70's.

19 MR. EAGLE: I would hope the NRC is one of
20 the key leaders in the world for power. Industry
21 presented a strong dissent to not having an option to
22 use manual operator action as all are part of the
23 diverse means for actions required in a short period
24 of time.

25 And the ACRS at the time agreed that it

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1 should be considered. And the result is we went to a
2 Revision 2 in which it was considered and was included
3 as an option.

4 Now in the automated versus manual, first
5 you perform a D3 analysis of the Reactor Protector
6 System using realist assumptions. If subject to
7 potential Common Cause Failure you need a diverse
8 means to perform the safety function subject to the
9 Common Cause Failure.

10 The diverse means may be automated or
11 manual or actually even a combination. Now the
12 automated diverse means is preferred. And it's stated
13 in REV 6 that way and also in ISG-02.

14 If the manual means is selected as the
15 diverse means, acceptability is based on Human Factors
16 analysis.

17 MEMBER BROWN: That's reflected in 1.6 to
18 Reg to 1.62 also isn't it?

19 MR. EAGLE: Yes, that's right.

20 MEMBER POWERS: Why is it human factors
21 and not human reliability?

22 Mr Eagle: Well, Human Factors Engineering
23 is, that's the term we usually use for it. Human
24 Factors Engineering.

25 MR. JUNG: Charlie, just little

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1 correction, it's the IGS-05.

2 MR. EAGLE: Well I know it's an ISG-05 but
3 Reg Guide 1.62, maybe it was another one but I thought
4 we also had this discussion available time required.
5 Did I get it wrong?

6 MR. JUNG: Manually in ISG-05.

7 MR. EAGLE: Oh, I got it wrong.

8 MR. JUNG: Manually in ISG-05, which has
9 been incorporated into Chapter 18, Appendix A.

10 MR. EAGLE: Oh, that's Appendix A, I'm
11 sorry.

12 MR. JUNG: Subcommittee.

13 MR. STATTEL: We plan on talking about
14 that in a little bit more detail in slide 14.

15 MEMBER BROWN: All right, lets go on then.

16 MEMBER POWERS: I mean doesn't the Human
17 Factors, oh it's going to tell you that's it's
18 physically possible to do this thing?

19 MR. STATTEL: That is the primary
20 objective there, so it's basically a process that
21 identifies what time is needed to perform an action.
22 And it also establishes how much time it takes for the
23 operators to accomplish that action.

24 And all the factors involved with that.
25 And basically compares those two times and comes up

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1 with a reasonable assurance that the operator will be
2 able to accomplish the required safety function. In
3 that amount of time.

4 MEMBER POWERS: You mean it just tells you
5 that it is physical possible to do within the required
6 time?

7 MR. STATTEL: Right.

8 MEMBER POWERS: It doesn't tell you
9 actually can happen.

10 MR. STATTEL: There was an aversion to
11 actually establishing a firm time restriction on that,
12 right? In other words, in the past, you know, if the
13 operator had an extended period of time to perform an
14 action it was just assumed that yes, he'll be able to
15 do that.

16 And if it was shorter than another time he
17 would not be able to do that. But unfortunately
18 that's a very simplistic approach. That really
19 doesn't work because the complexity of the action and
20 the amount of analysis that the operator has to go
21 through to take that action varies a lot, depending on
22 the action.

23 So the action may be as simple as I get an
24 alarm, I push a button. Or it may be as complicated
25 as I look at ten different indicators. And if they

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1 align in a certain pattern then I will initiate a
2 procedure that actuates 50 different components within
3 the plant.

4 So those are two extreme examples. So
5 with that in mind we felt, and we came to the
6 conclusion that a Human Factors Analysis could support
7 either of those cases.

8 And the amount of time whether it was 15
9 minutes or 72 hours was really not relevant to that.
10 As long as that analysis took all of those factors
11 into consideration.

12 MEMBER BLEY: I think, to Dr. Powers'
13 original question, and I could be corrected on this.
14 I know if Paul were, is Paul going to be here?

15 MR. STATTEL: He is here.

16 MEMBER BLEY: He is here?

17 MR. STATTEL: In the back of the room,
18 yes.

19 MEMBER BLEY: He might correct me on this,
20 but I think the traditional view of human factors
21 aligns with what Dr. Powers said.

22 I believe in human factors engineering as
23 it's been defined for design certification, it
24 incorporates human reliability analysis as part of
25 that whole discipline the way they've defined it.

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1 MEMBER STETKAR: At least up to the point
2 of, I think in terms of traditional human reliability
3 analysis it does not include the actual quantification
4 of the air raid. It includes everything up to that
5 point, I believe.

6 MEMBER BLEY: That's not the way I read
7 that.

8 MEMBER STETKAR: Okay, maybe Paul can --

9 MEMBER BLEY: It's on my HFE.

10 MEMBER STETKAR: -- help us.

11 MEMBER BLEY: But in any case, if it
12 doesn't then I certainly agree with what Dana said in
13 the beginnning. What you're talking about is human
14 reliability analysis, and I think the way you've
15 defined thing, that's part of --

16 MEMBER SHACK: Is it feasible, or is it
17 feasible and reliable?

18 MEMBER BLEY: I think it's the latter.
19 It's what it better be.

20 MR. EAGLE: Paul, do you want to comment
21 on that? He's our human factors expert.

22 MR. PIERINGER: Paul Pieringer, Human
23 Factors Technical Reviewer from DCIP. Feasible and
24 reliable is the big picture and that's what we always
25 go back to, and we do that by integrated system

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1 validation.

2 And I can stick to that more, we get into
3 more details. It's my understanding that the way we
4 interface with human reliability analysis right now is
5 that the PRA group identifies risk-important human
6 actions.

7 And there's criteria that they use to
8 screen actions that are being taken by the operator
9 that impact the PRA in a manner that makes those
10 actions important.

11 And they use Fussell-Vesely and RAW scores
12 to establish a criteria that selects those out. Those
13 risk-important human actions go into the Chapter 18.

14 Now what I would tell you is that most,
15 well, it depends on which design center you're working
16 with, but many DAS Manual actions are not risk-
17 important human actions.

18 So they would not necessarily get the full
19 treatment of the Chapter 18 program. What we see
20 currently is that most applicants are committing to
21 manage their DAS Manual actions using the fundamental
22 pieces of Chapter 18, the most critical piece being
23 the integrated system validation.

24 And so a lot of the evaluation work that
25 we do in HFE, we do an up-front review to make sure

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1 there's no fatal flaws, but we much prefer to see the
2 proof demonstrated in the integrated system validation
3 program.

4 MR. EAGLE: Thank you, Paul.

5 MEMBER POWERS: Well, now I'm confused.

6 PARTICIPANT: Yes, me too.

7 MEMBER POWERS: I mean it seems like, I
8 mean I think what you told me is that we don't do
9 this. We don't consider it an important action in the
10 PRA.

11 MR. STATTEL: I think we're talking past
12 each other in a little, what we use this for, this
13 review plan guidance for is to perform safety
14 evaluations on the acceptability of this
15 instrumentation.

16 And when, for example, if a licensee has
17 performed a D3 analysis and we're reviewing that it
18 basically falls through, right?

19 So they assume a certain failure, a common
20 cause failure mode and then they identify what the
21 backup means for performing the safety actions are,
22 right, and they relate that to each of the accidents
23 that are considered in Chapter 15.

24 And if it falls through to a manual
25 operator action, right, then we basically, you know,

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1 from a logistics point of view the NRR would basically
2 turn that over to the HFE group and they would perform
3 the human factors safety evaluation to support that.

4 MEMBER POWERS: So I got the impression
5 that he'd come back and say it's not important to PRA
6 so we're not going to look at it.

7 MR. STATTEL: Well, we issue our safety
8 evaluations and we consider them to be risk informed,
9 but not risk based.

10 MR. EAGLE: I think it's important to go
11 back to the actual documents themselves starting with
12 ISG-02 Rev 1, we have in there a hard line dimension.

13 If the response to an event with a common
14 cause failure postulated, if the response would
15 require, had to be done in less than 30 minutes, it
16 had to be on automated diverse means.

17 If the response required in greater than
18 30 minutes, operation action was acceptable. That was
19 Rev 1. In Rev 2, we went back and said diverse means
20 can be automated, manual or a combination, but the
21 automated means was preferred.

22 Now if it was manual chosen or even
23 partial manual, justification by human factors
24 analysis using ISG-05 Rev 1.

25 Now this was the document that would then,

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1 if you made a choice to use manual operation as part
2 of this diverse means, then it would switch over and
3 the ISG-05 Rev 1 would then provide the procedure or
4 how you would go about analyzing if this was
5 acceptable.

6 Now in BTP 7-19 it simply rolled the ISG
7 in. At this point in time, remember we mentioned that
8 also this ISG was in the process of being rolled into
9 a new document. It was called Appendix 18A, which
10 would cover the same thing that ISG-05 Rev 1.

11 So that would be the --

12 MEMBER POWERS: You're still not getting
13 to my point. When do you do the human factors
14 analysis, and is it perfunctory or is it something
15 that I can chew on?

16 MR. EAGLE: If you had chosen --

17 MEMBER POWERS: I don't know anything
18 about ISGs.

19 MR. STATTEL: We don't do that within our
20 division, so basically we would create an activity for
21 the HFE group and they would, for instance, for the
22 Ocone application there were several short-term
23 manual operator actions that were required for action
24 at mitigation.

25 And the HFE group performed a safety

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1 analysis that supported and it made a reasonable
2 assurance conclusion that those actions could be
3 performed in the required time.

4 And that was backed up by actual V&V tests
5 that were done with operating crews at the plant. So
6 they had demonstrated through simulations that the
7 operators could reliably perform those actions within
8 the required time.

9 But as far as the details of what go into
10 that human factors and safety evaluation, I guess Paul
11 would have to answer that because we don't perform
12 those on our side.

13 MR. EAGLE: The point is, as soon as the
14 decision is made, you've determined that you now need
15 a diverse means because there is a postulated common
16 cause failure of your automated system.

17 And once you make the choice to use manual
18 action as part of the diverse means then you have to
19 go to one of these, and it's completely procedurized
20 as Appendix 18A or ISG-05.

21 Paul, can you comment on that any?

22 MR. PIERINGER: I'm confused to what the
23 question is.

24 MEMBER SHACK: Let me just go, in ISG-05
25 there's a statement. "To credit operator actions,

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1 vendors/licensees should demonstrate that the manual
2 actions in response to a BTP 7-19 software common
3 cause failure are both feasible and reliable given the
4 time available."

5 I don't find that feasible and reliable in
6 the BTP except in the note, and there it's not sort of
7 required to demonstrate it, it's kind of a, you should
8 note that.

9 And I like the stronger language in the
10 ISG-05 that says you demonstrate that it's feasible
11 and reliable. And that to me was always the intent
12 when you dealt with things that were less than 30
13 minutes, was to have both the feasible and reliable
14 part in there, and somehow that seems to have slipped
15 out of the current version of the Branch TP.

16 VICE CHAIR ARMIJO: Thanks for your
17 comments. I think we are, I think the staff's not
18 disagreeing with that, I think we'll work with the ISG
19 folks and we'll try to incorporate to be consistent.

20 MR. JUNG: I don't think the intent of 7-
21 19 was to have a disagreement with the HFP. I think
22 fundamentally the Commission policy clearly stated
23 that once you have a situation where it is subject to
24 common cause failures and the potential consequence
25 being not acceptable to meet on the Part 100 limit,

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1 that is, you know, applicants should have a means to
2 be, you know, either automatic and manual if be
3 feasible and reliable.

4 VICE CHAIR ARMIJO: We'll take that time
5 and we'll provide the direct markup.

6 MR. STATTEL: I mean I believe the intent
7 was to provide a hand-off. ISG-19 is guidance on
8 performing diversity D3 analysis, not for performing
9 a human factors analysis.

10 So it identifies that the manual operator
11 actions are required and it identifies the need to
12 perform an additional safety evaluation, but it
13 doesn't give guidance on how to perform that
14 evaluation.

15 So I'm not sure we're within the scope of
16 the BTP 19.

17 MR. EAGLE: Correct. That is, once the
18 decision's made to use manual then the justification
19 of it has to come out of the procedures we mentioned,
20 the Appendix 18A of the Standard Review Plan.

21 It was brought up in discussions that
22 there were a number of manual functions in current
23 plants that must be performed within a short period of
24 time.

25 However, there are two important points to

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1 reiterate on this statement. First, the focus is on
2 the automated protection system subject to postulated
3 common cause failure, not just any operational
4 function.

5 Second, if a protective function has
6 normally performed by a manual action, then it was
7 expected that that function or an alternate function
8 would still be performed manually even in the presence
9 of a common cause failure.

10 Further, I&C associated with the normal
11 manual action is postulated to be subject to a common
12 cause failure, then the manual action may have to be
13 performed using different equipment.

14 We have a note that was added to describe
15 special emphasis on being aware. For instance, as the
16 difference between the time available and time
17 required for operator action decreases, uncertainty in
18 the estimates of both of these times must be evaluated
19 carefully.

20 These uncertainties could invalidate or
21 reduce the level of assurance of a conclusion that
22 operators can perform the action reliably within the
23 time available.

24 For actions within a limited margin of
25 time to act, such as less than 30 minutes between the

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1 time available and the time required, additional staff
2 review will be performed.

3 This statement was put in to put special
4 emphasis as these uncertainties develop. I would
5 also like to, I thank Mr. Stetkar's suggestion on how
6 to correct that, to make a change. We had addressed
7 that by making a change, and this is the latest
8 version of this statement.

9 Another item that was brought up was the
10 concern is that a potential common cause failure could
11 result in the loss of measure of portions of the
12 automated protection system, the operator's custom of
13 depending on them at a time of crisis as an
14 anticipated operating occurrence or an accident.

15 Now if one considers, however, that the
16 staff expects a quality software development process
17 for digital I&C systems and expects a quality
18 verification and validation process, further
19 considering that the digital I&C system goes through
20 factory acceptance tests, site acceptance tests,
21 start-up testing on the equipment, then the
22 probability of a software common cause failure will be
23 significantly reduced.

24 Further, the staff believes that because
25 of this extensive testing, the trigger that causes a

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1 common cause failure and perhaps the results, will be
2 something the operator is not expecting.

3 While not the CC type, there are already
4 examples of the quote "unexpected" taking operator by
5 surprise and then even scrambling the plant.

6 Despite emergency operating procedures and
7 abnormal operating procedures, which may include some
8 common cause failure related actions, operators will
9 likely be under significant pressure to respond
10 appropriately to mitigate unanticipated plant events
11 in coincidence with a common cause failure.

12 Good human factors dictate that this
13 pressure to perform should be minimized, thus the
14 inclusion of this warning note.

15 Some interested representatives advocated
16 the use of component actuation versus system level or
17 division level actuation. Actuation on a division
18 level or a system level was retained.

19 Again, at the time when the operator may
20 be under a lot of stress, actuation on a division
21 level or a system level depending on the design, was
22 retained to minimize the actions the operator would
23 have to initiate in an emergency.

24 Another area of interest is spurious
25 actuations. There are two types of spurious

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1 actuations to consider. One is caused by the common
2 cause failure itself, and the second is caused by the
3 diverse means.

4 The staff and industry representatives
5 spent considerable time discussing this issue and came
6 to a consensus as reflected in the next slide.

7 A spurious actuation is a lesser safety
8 concern than failure to actuate because the challenges
9 presented by spurious actuations are not considered to
10 be as significant as failures to respond to AOOs and
11 design based events.

12 MEMBER STETKAR: Okay, Gene, let's just
13 stop here because there's a lot of words on this
14 slide.

15 MR. EAGLE: Yes.

16 MEMBER STETKAR: Can you tell me the basis
17 for that statement? That's a statement presented as
18 if it's a fact and I'd like to understand why
19 spurious, and I don't want to call it RPS, because
20 that connotates shutting down the reactor.

21 I want to call it an integrated safeguards
22 actuation system, which is what we're talking about
23 here. Why is spurious actuation of an integrated
24 safeguards actuation system always of lesser safety
25 concern than failure to actuate?

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1 MR. EAGLE: The basis is this is basically
2 engineering judgment. And I can ask, you know, which
3 --

4 MEMBER STETKAR: In my engineering
5 judgment, here's another engineer, is that it's not.
6 So now we have a difference of opinion.

7 MR. EAGLE: Different opinion. In other
8 words, if you have a nuclear reaction that's running
9 away with a positive period very rapidly, what is
10 worse, for the failure to scram or a failure to -

11 MEMBER STETKAR: Let me pull you back.
12 I'm not talking about the scram function, I'm talking
13 about everything else that these systems do. For
14 example, new integrated digital safeguards actuation
15 systems automatically blowdown the plant.

16 They open up big holes in the plant
17 creating LOCAs. Okay, a LOCA is a design basis
18 accident. And in many cases they also blow open the
19 secondary side of the plant simultaneously creating
20 something that looks like oh, a fairly large steam
21 line break.

22 There is no design basis event that looks
23 at a simultaneous steam line break with a large LOCA.
24 It is not looked at. It is not part of the design
25 basis evaluation. It's not an AOO.

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1 Although there may be systems, there may
2 be common cause failure modes of these integrated
3 safeguards actuation systems that could conceivably do
4 that to you.

5 So now I'm concerned about why that is of
6 lesser safety significance than an already analyzed
7 design basis event or an already analyzed AOO.

8 MR. EAGLE: Here's one of the things, I
9 think when we go into some of these other points
10 we'll have to point this out. Further, spurious
11 actuations are annunciated and thereby immediately
12 detected.

13 MEMBER STETKAR: Okay, I am an operator in
14 the plant and I know it's a really bad day.

15 MR. EAGLE: Yes.

16 MEMBER STETKAR: Because auto took over
17 for me.

18 MR. EAGLE: Okay.

19 MR. JUNG: Gene, Ian Jung. And, I mean a
20 couple of comments. It's for, we are beyond design
21 basis space here, common cause failures.

22 So my response to Mr. Stetkar's comments
23 is, the current safety system requirements and
24 guidance for safety system software developments and
25 digital systems development has been, that's where

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1 we've spent a lot of focus on.

2 So the goal for staff review and industry
3 applicants, their main focus is really providing the
4 high quality software that minimizes, and then
5 hopefully to get completely eliminate the possibility
6 of common cause failures.

7 And that's why the other day there was a,
8 you know, the DAC procedure, the reason that we focus
9 on those processes in life cycle for the element
10 there's a reason for it.

11 Major common cause failure based on
12 operating experience have shown that major cause has
13 been development of requirements and translation to
14 specific occasions.

15 So their current requirements, current
16 staff guidance in other areas clearly try to re-
17 achieve that goal. So I want to point that out.

18 But in terms of those multiple spurious
19 actuations or possible scenarios, remember it goes
20 back to the D3 analysis when so far most of the
21 applicants coming in, when they use the same software
22 for all scope of safety systems from RPS or ES
23 effectuation, what they postulate so far has been
24 completely, all safety systems that use the same
25 software, all four divisions assume to have failed to

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1 perform the safety function.

2 So based on that assumption, when you come
3 up with the diverse backup means, either manual or
4 automatic, they provide an independent and diverse
5 means.

6 Diverse means we'll have a completely
7 different way of looking at symptom based app
8 approach. There we'll see different parameters are
9 being measured by different software, different analog
10 system or digital systems.

11 (Crosstalk)

12 MR. JUNG: I think there's a defense in
13 place, but in terms of postulating different spurious
14 actuation causing it, staff and industry significantly
15 discussed, and we couldn't come up with the situations
16 where current overall D3 guidance we have would not be
17 sufficient to cover the type of scenarios there would
18 be represented as part of spurious actuations.

19 MEMBER BLEY: It's a nice speech and I
20 appreciate what you guys have done.

21 When you go back to that first bullet
22 which is a reflection of the text, it's the same text,
23 it doesn't say that spurious actuations is less
24 frequent, therefore we're not as concerned with it, it
25 says the challenges are not considered to be as

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1 significant.

2 And I think that example that John gave
3 points out that, you know, if you don't look for the
4 challenges you don't know.

5 The idea that the worst thing that could
6 happen is it doesn't do what it ought to do, doesn't
7 acknowledge that maybe the worst thing it does is
8 something that wasn't supposed to do. And that's the
9 point that's being made.

10 And I don't think, I understand all the
11 other things you're saying. You could also say, well,
12 it's not in the design basis so we're not going to
13 look as hard, which is kind of what you're saying.
14 But just the statement I don't think has any basis.

15 MR. EAGLE: Well, I think that I'd have to
16 disagree with you on that. For instance, and we
17 talked about the scrambling, you know, that if you have
18 a runaway nuclear reaction versus, that is worse than
19 --

20 MEMBER BLEY: There are certainly examples
21 on each side. I don't think you're acknowledging each
22 side.

23 MR. EAGLE: Okay, well, we were looking
24 at, during this process we went through a lot of these
25 and we didn't see places where that the failure to be

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1 able to actuate when it was really needed, you know,
2 for instance, the water is dropping in the boiling
3 water reactor. It's coming down and getting ready to
4 uncover the fuel, something needs to be done.

5 MEMBER BLEY: Nobody disagrees with you on
6 that one.

7 MR. EAGLE: Okay, if that is worse than
8 suddenly the failed common cause failure and
9 electronics suddenly deciding to throw extra water in
10 there, and we looked at a lot of these, and basically
11 the key point is that it's annunciated and the
12 operator can now take action.

13 In other words, if something is spuriously
14 turned on or is starting then he has a warning about
15 it, and that's because even with common cause failure
16 taking out the automated systems you still have your
17 diverse systems.

18 And you remember the Point 4 displays are
19 independent, and the controls and displays are
20 independent of the automated protection system. So
21 he's going to have an indication if we've had a common
22 cause failure in this automatic system, he's going to
23 have a clear indication.

24 And at that point in time you're depending
25 on the operator to take action.

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1 MEMBER STETKAR: Gene?

2 MR. EAGLE: Yes.

3 MEMBER STETKAR: Let me try something
4 else. This is guidance for reviews and by
5 implication, performance of a D3 analysis, Diversity
6 and Defense-in-depth analysis.

7 If a person, an applicant who performs
8 that Diversity and Defense-in-depth analysis doesn't
9 look for these types of complex spurious actuations
10 that, you know, I mentioned, they then don't have the
11 opportunity to install either automatic or manual
12 diverse mitigation systems.

13 In other words, you know, my example about
14 blowing open a hole in the primary side and blowing
15 open a hole in the secondary side, if someone hasn't
16 identified that vulnerability they may not have
17 installed a diverse way that the operators can somehow
18 mitigate that, you know, manually closed valves that
19 may have been opened if they weren't squib valves or
20 something like that.

21 So that's my whole point about if people,
22 and I think Dennis raised it also, if people don't
23 look for these things, they don't have the opportunity
24 to identify a potential vulnerability and perhaps
25 design into their system a diverse way of dealing with

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1 that as they are doing now for the failure to acuate
2 either manual or automatic failures, you know,
3 capabilities.

4 The other point, getting back to a little
5 bit of what Ian said, is that there are some analogies
6 for other guidance for beyond design basis events that
7 do require explicit evaluation of multiple spurious
8 actuations, and in particular for fire events.

9 Both deterministic and probabilistic
10 guidance don't have any limits on the number of
11 multiple spurious actuations as they're characterized
12 there that need to be considered.

13 In other words, that there's no limit on
14 the number. And it's absolutely required that
15 applicants do that evaluation and that the staff
16 review those evaluations.

17 So there's kind of precedent, you know,
18 legal precedent, if you will, for beyond design basis
19 events to address this issue of multiple spurious
20 actuations.

21 If it's considered to be important enough
22 from the fire perspective, why isn't it considered to
23 be important enough from the software perspective?

24 MR. STATTEL: If I may, I was a member of
25 the working group and we had extensive discussions on

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1 this.

2 This language basically resulted from a
3 discussion regarding the consequences of a spurious
4 actuation, and a much better example is the
5 depressurization system in boiling water reactors
6 obviously.

7 The consequences being worse and have a
8 higher probability of occurring than the common cause
9 failure that we're all about here in this BTP that
10 we're trying to avert.

11 And an argument was being used by industry
12 at that time to basically use this as an argument for
13 not putting in a diverse system or not incorporating
14 diversity because it would have a down effect of
15 increasing the probability of a spurious actuation.

16 It's really not the intent of the guidance
17 in the BTP to downplay those consequences, and it's
18 really not the intent to imply that a licensee not
19 consider the effects of spurious actuations.

20 In actuality that they have always done
21 that. In the boiling water reactors, as you know,
22 there are significant design features that are added
23 in to prevent spurious depressurization signals from
24 occurring because they realize that those cause LOCAs,
25 basically the spurious actuation would cause the LOCA

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1 that you're trying to prevent.

2 Those need to be considered, and the
3 current position is that as before, as the design
4 guidance that we had prior to this BTP and its
5 existence, the licensee would consider those
6 eventualities.

7 The other thing I'll point out is that
8 this was language that was approved in ISG-2 and
9 really our effort was to incorporate that guidance
10 into BTP 19, and not to rehash or question what the
11 working group's conclusions were, because those had
12 already been presented to the Committee.

13 MEMBER STETKAR: Yes, and I think we had
14 the same comments when we talked to the working group
15 on ISG-2.

16 MR. STATTEL: Yes, it's a stretch to say
17 that we have total consensus on these.

18 MEMBER STETKAR: It would be a stretch.

19 MR. EAGLE: By the way, talking about
20 fires, this is partly attributed to the fact that
21 fires have a proven record of destroying cables,
22 creating short circuits and disrupting operator and
23 automated controls as at the Browns Ferry fire event.

24 Thus, four physical and often widely
25 separated divisions are used as part of the defense-

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1 in-depth.

2 Further, in modern digital data
3 communications and networks using fiber-optic cables,
4 the cable may melt, the path of logic may be lost, the
5 division logic may be destroyed, but unless the signal
6 is simply an on/off signal, it is unlikely the fire
7 damage would cause a legitimate recognizable but false
8 message frame that would cause the further down
9 systems receiving this to react.

10 Anyway, this is one of the reasons that we
11 looked at the idea of fires, but the main thing is it
12 comes back to the bottom line that we looked at in
13 making these various statements. And the consensus
14 was is the fact that it will be self-announcing and
15 the operators then can take action.

16 For example, in Chapter 15 you have an
17 inadvertent opening of a safety relief valve is one of
18 the things that I think, and if the software, a common
19 cause failure caused the software to suddenly said
20 open up these safety relief valves, that is an item
21 that is handled or taken care of in the Chapter 15.

22 But the big thing about it is, for
23 instance, in an ESFAS if the water level is dropping
24 and the operator recognizes it and the automatic
25 safety systems of ESFAS don't start putting water in,

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1 he's going to be able to recognize it and then take
2 action.

3 And that's a worse condition than being
4 able to, suddenly water starts pouring into the
5 reactor from suddenly the common cause failure, on
6 effect on instrumentations suddenly making a false
7 assumption and starting to put water in, maybe too
8 much water in.

9 Anyway, I think we probably have a
10 disagreement on that but I think on that, a lot of my
11 experience has been with the BWR and if more
12 simplified areas there, when that water level starts
13 dropping something has to be done.

14 MEMBER STETKAR: I think we need to move
15 on.

16 MR. EAGLE: Okay. There is a second type
17 of spurious actuation that we -

18 MEMBER BROWN: Before you do, have you
19 gotten at least the interchange you want in the
20 dialogue?

21 MR. EAGLE: Yes.

22 MEMBER BROWN: Okay, Dennis?

23 MEMBER BLEY: Yes.

24 MEMBER BROWN: Okay.

25 MEMBER BLEY: I understand.

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1 MEMBER BROWN: Okay, all right. We do
2 have some time and there's not a whole lot of slides,
3 you know, left. So I wanted to make sure you all had
4 adequate time to -

5 MEMBER STETKAR: I think we understand it.

6 MEMBER BROWN: Okay, all right. Go ahead,
7 Gene.

8 MR. EAGLE: Thank you. Charlie said his
9 lunch bill goes off somewhere -

10 (Crosstalk)

11 MEMBER BROWN: Theoretically we've got
12 until 12:45, but it's not, if we finish before that
13 that's perfectly satisfactory as long as we get
14 everything covered.

15 MR. EAGLE: The second spurious actuation
16 is that actually caused by the diverse means. And
17 remember we went back to talk about how that
18 industry's, one of the objections they had to some
19 adding diverse means was the fact that there could be
20 a higher probability of a safety concern than it would
21 be if you didn't have the diverse means, and we talked
22 about that for a moment.

23 So the way this was handled is the design
24 of diverse automated or diverse manual means should
25 address how to minimize the potential for spurious

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1 actuation of the reactor protection system caused by
2 the diverse means. In other words, quality of design.

3 Another item that came up of interest was
4 the combining of two manual initiations. There's two
5 manual initiation systems that may be needed. First,
6 there's a requirement in IEEE 603-1991, that there has
7 to be a safety related manual ability to initiate the
8 automatic protection systems.

9 One independent and diverse safety or non-
10 safety is then needed per BTP 7-19, if the reactor
11 protection systems manual initiation safety system
12 would be subject to the postulated common cause
13 failure.

14 So in other words, there would have to be
15 two manual initiation methods. Now how do you get
16 this down just to one? These two can be combined
17 under the following conditions.

18 The reactor protection system manual
19 initiation of the automated reactor protection system
20 is independent and diverse from the automated
21 protection system.

22 It has to be safety related and it has to
23 be not subject to the same potential common cause
24 failure as the automated reactor protection system.
25 In that case then you can have one.

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1 In case this may sound confusing this
2 diagram should help make it clear. Notice on the one
3 on the left you have a manual trip system that goes
4 directly into the reactor protection system, into the
5 electronics.

6 Both of these are a safety system, but you
7 notice that if the, on the left if you have a common
8 cause failure you won't be able trip the reactor with
9 a manual trip.

10 You have to then have our requirements BTP
11 7-19 Rev 6, you have to have a diverse manual system
12 as represented in the green. It can be non-safety.

13 On the right hand side, you notice that
14 now is a completely independent and diverse manual
15 trip that is safety related and comes down and blow
16 and is not part of the common cause failure
17 electronics.

18 MEMBER BROWN: Are you all going to put
19 the picture in 7-19?

20 MR. EAGLE: No, we never did. That might
21 be an interesting idea.

22 MEMBER BROWN: Can I request that?

23 MEMBER STETKAR: It might be a good annex
24 or something, you know.

25 MEMBER BROWN: Go ahead.

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1 MR. EAGLE: BTP 7-19 Rev 6 was sent out
2 for public comments and there were something like 70
3 comments and there were a lot of the, were received
4 from four sources.

5 Now NEI provided 90 percent of these
6 comments, each with their basis and a suggested
7 rewording. The public comments and the task working
8 group response to each comment was documented in the
9 spreadsheet and included in materials provided to the
10 ACRS in advance.

11 Each comment was given careful
12 consideration, a response was prepared to each comment
13 and documented, and some of the notable comments are
14 in this slide.

15 One of the things that got brought out,
16 the staff agreed that not all reactor protection
17 system safety functions may be disabled by a common
18 cause failure, but pointed out that assuming that all
19 reactor protection system functions are disabled is
20 considered a worst case bounding condition.

21 The staff accepted the comment, expressing
22 concern that after a actuation of the engineering
23 safety feature functions from the main control room,
24 the need may exist, and I repeat, may exist, for some
25 use of local controls later.

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1 And we discussed this a little bit
2 earlier, like the realignment of equipment or perhaps
3 after 72 hours before the action has to be taken in
4 the passive plants.

5 There were many other items, but just to
6 keep things short I just want to throw up a few
7 examples. We also included some notable
8 clarifications and a considerable amount of rewording
9 to improve the English and improve the presentation
10 and clarification.

11 A couple of interesting points was that
12 the system level was changed to system or division
13 level depending on the design.

14 Since single failures concurred with a
15 common cause failure not required to be postulated, a
16 normal equipment alignment is assumed, diverse
17 actuation of one division is sufficient provided that
18 that division will be in service.

19 Diverse design may need more than one
20 division. Also, the use of the term "diverse backup
21 method" was replaced with the words "diverse means" to
22 match with the four-point D3 policy and because some
23 current nuclear power plants portions termed primary
24 and backup even in the main system.

25 A CCF that affects normal displays or

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1 controls should not prevent an operator from manually
2 initiating safety functions.

3 In summary, once again would like to
4 mention that the guidance of ISG-02 Rev 2 was merged
5 into the Standard Review Plan by incorporating ISG Rev
6 2 guidance into BTP 7-19 Rev 5 to create Rev 6.

7 This Rev is an extensive revision
8 providing significant specific guidance for a number
9 of stakeholder concerns. It addressed the seven
10 questions and concerns that were presented.

11 It's hoped that we can issue this by
12 November 30, and any additional advice, like Charlie
13 said on the diagram, would be welcomed. I thank you
14 for your attention today. Are there any questions?

15 MEMBER BROWN: I'm just going to look
16 around. Are there any questions before, we have one
17 other public comment that we were going to get to for
18 a few minutes.

19 CHAIR ABDEL-KHALIK: Could you go to Slide
20 14, please?

21 MR. EAGLE: Okay.

22 CHAIR ABDEL-KHALIK: This 30 minutes deals
23 with the margin, not the total time available,
24 correct?

25 MR. EAGLE: It's the difference between

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1 time available and time required.

2 CHAIR ABDEL-KHALIK: Right.

3 MR. EAGLE: I have a diagram. I wish I'd
4 put that in here.

5 CHAIR ABDEL-KHALIK: I understand this.
6 But isn't this a little too restrictive?

7 MR. STATTEL: It's just an example. It's
8 just intended as an example, it's not really providing
9 the direct guidance. The direct guidance is in the
10 previous statement.

11 CHAIR ABDEL-KHALIK: So this particular 30
12 minutes statement is not going to be included?

13 MR. STATTEL: It is, this is a quote out
14 of the BTP, the new revision.

15 CHAIR ABDEL-KHALIK: Right, so I mean it's
16 there. I mean the fact that 30 minutes is used for a
17 lot of other things.

18 (Crosstalk)

19 MR. STATTEL: Originally we had a 30-
20 minute as a rule. Basically if it's less than 30
21 minutes do this, if it's more than 30 minutes do that.

22 CHAIR ABDEL-KHALIK: But that's related to
23 the total time, not to the difference between the
24 available and the time required.

25 MR. STATTEL: Yes.

1 MR. EAGLE: But once again, when we said
2 30 minutes, basically it's the time available. In
3 other words, you're supposed to have an action take
4 place.

5 So water levels dropping the BWR, all of
6 sudden the automatic system detects it, said level 3,
7 and it's supposed to start some kind of action. It
8 doesn't happen because there's been a common cause
9 failure.

10 Now something has got to be done. The
11 clock is measured usually from the time that action
12 should have taken by the automated system and now
13 something has got to be done. That water level's
14 dropping.

15 Something has to take care of that safety
16 function or you're going to uncover the fuel. That's
17 that time period that we looked at when we said the 30
18 minutes originally. But actually the difference is
19 the real thing, it's being used here.

20 MR. PIERINGER: This is Paul Pieringer,
21 Human Factors Reviewer. We use that 30 minutes only
22 as a guideline, and that is because if the time
23 between event initiation and the first manual action
24 is less than 30 minutes that's a very critical period
25 where diagnostics have to be evaluated, and we always

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1 provide a very detailed assessment of whether those
2 actions are really feasible and whether they are
3 reliable.

4 However, that doesn't address all of the
5 critical actions. You could have a remote action that
6 brings in a lot more variables that could be outside
7 of the 30-minute window, and you would certainly want
8 to look at those remote actions to make sure that
9 communications and environmental factors,
10 accessibility and all those other variables are
11 addressed.

12 And then there's another category that
13 deals with when the criteria are established for
14 initiating the action occur versus when the operators
15 take the action.

16 So example, here's safety injection. You
17 don't get safety injections, tight conditions for
18 safety injection until usually later in a scenario.
19 Well, so the operator's working in there looking at
20 many other things.

21 What we are sensitive to is, once he
22 reaches those conditions and the alarms and controls
23 indicate that they're there, then you have to look at
24 whether the operator can still reliably take those
25 actions regardless of whether it's 30 minutes or not

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1 from initiation time.

2 CHAIR ABDEL-KHALIK: All I'm saying is
3 that if you read this statement, the available time is
4 one hour and the operator is able to do this function
5 in 30 minutes, you still are going to consider that
6 something that needs further review.

7 MR. STATTEL: That's right.

8 MEMBER RAY: Let me ask before he steps
9 away, supposing the diverse actuation has the
10 horrendous consequences that John described awhile
11 ago.

12 In fact, if you look at the stress levels
13 on core support structure, for example, they're even
14 more horrendous than that in my opinion. When you
15 look at the reliability, the operator action, do you
16 reflect on the reluctance that an operator might have
17 to take that action?

18 MR. PIERINGER: Yes, sir.

19 MEMBER RAY: Okay.

20 MR. PIERINGER: In fact, a key
21 consideration in some recent proposals that had
22 operator reaction within two minutes of an event
23 initiation, and it was presuming they were responding
24 to a prompting alarm.

25 And my experience is that operators want

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1 to validate an alarm. They don't want to just react
2 to the alarm coming in. And that reluctance to
3 initiate the action was a key part of the logic in
4 asking the applicant to redesign that particular part
5 of the task.

6 MEMBER RAY: Yes, because, you know, the
7 blowdown stresses in some of the core support
8 structures, for example, says if I push this button
9 I'm going to replace the core support structures, and
10 that's a big event, bigger even than blowing off the
11 steam generators. Okay.

12 MR. EAGLE: I think one of the key things
13 about this is it's a warning. I think if you, any of
14 you think of it, we talked about actions taking place
15 and just in your imagination you imagine that, you
16 know, if some action takes place and you have a
17 difference of about 30 minutes here, that's a lot of
18 time for maybe making decisions.

19 And part of this, by the way, in terming
20 out the time required by the operator, includes in
21 case he has to analyze it, he also, if he makes a
22 mistake it has to recover from it.

23 So this is to give you a warning. As that
24 narrows down, I think we're all concerned about, you
25 know, what could be done and to the operator's

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1 actions, so the main thing this was put in for is to
2 give a warning.

3 Whereas before, we did have a hard limit
4 now we have a, basically this is just a warning. And
5 also it gives an area that'll be more review if this
6 difference is less than 30 minutes.

7 MEMBER BROWN: This was a fallout of a
8 previous ACRS letter that we wrote back in September
9 of 2007, and then was amplified in the ISG-5 review.

10 And so that the things that were changed,
11 at John's request, was to make sure we reflected the
12 uncertainty in the time available as opposed to appear
13 to be just time required in the way they had initially
14 written the thing.

15 CHAIR ABDEL-KHALIK: In the past, the 30
16 minutes pertained to the total time available.

17 MR. STATTEL: That's correct.

18 CHAIR ABDEL-KHALIK: And now this is put
19 in as --

20 (Crosstalk)

21 MEMBER STETKAR: This is margin and
22 uncertainty. I mean -

23 (Crosstalk)

24 MR. STATTEL: There's really not a direct
25 correlation between the past rule and the, well, I

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1 shouldn't say rule, but the past requirement and this
2 30 minute mentioned.

3 I also want to put this into context.
4 This is a direct quote out of the BTP, however, it is
5 contained in a separate note under a subsection. And
6 the subsection actually provides the guidance which is
7 not shown on this slide here.

8 It is really just a note and it's only
9 intended to be an example.

10 MEMBER BROWN: Well, it's there to kind of
11 reflect what we had in ISG-5. I mean fundamentally,
12 I mean it's to get that concept in.

13 MEMBER RAY: Well, Charlie, I just think
14 that, I do, I'm, you know, a skeptic that somebody
15 isn't going to want to pause and think a good long
16 time before they take some of these -

17 MEMBER BROWN: I agree with you. I was
18 hard over on even doing this, okay. I was beat to
19 death. I come from the rule the 30 minutes was the
20 minimum you had and you ought to make sure that larger
21 times weren't required before you allowed this kind of
22 stuff to go on.

23 MEMBER RAY: Between all the agonizing and
24 -

25 MEMBER BROWN: Absolutely.

1 MEMBER RAY: -- is this really, really,
2 really what I want to do.

3 MEMBER BROWN: That the committee made the
4 statement, you know, four years ago that we really
5 need to be more practical and that there are some
6 operator actions that you can do in 30 seconds.

7 And as long as they're simple and
8 straightforward we ought to allow those, okay, as
9 opposed to limiting it to 30 minutes and whatever else
10 you had to do. So I'll stop right there.

11 John, did you have anything else? Mike?
12 Bill?

13 MEMBER REMPE: No.

14 MEMBER BROWN: I'd like to take a couple
15 of minutes. Is Richard Wood still here? He's from
16 O&R, excuse me, Oak Ridge National Labs. I apologize.

17 He's been the NUREG, originally 6306
18 involvement, 6303, I'm sorry, on diversity analyses
19 and I guess there was a follow on NUREG 70, 70?

20 MR. WOOD: 7007.

21 MEMBER BROWN: 7007. And he wanted to
22 make a couple of comments on the new NUREG. It's not
23 out yet, I think.

24 MR. WOOD: No, it's my understanding it
25 has been -

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1 MEMBER BROWN: Oh, it has been issued?

2 MR. STATTEL: Yes, it is issued.

3 MEMBER BROWN: Okay.

4 MR. STATTEL: Okay, correct.

5 MR. WOOD: I'm Richard Wood from the Oak
6 Ridge National Laboratory. And I had some brief
7 observations and that I think lead to some questions
8 that I trust that the Committee will consider as they
9 finalize their evaluation of this document.

10 One of the key objectives of the Working
11 Group 2 was to resolve the issue of what constitutes
12 adequate diversity with the implied context that the
13 need for diversity has been established through the
14 Diversity and Defense-in-depth analysis.

15 And so that was discussed at length in the
16 activities of the working group. And also
17 concurrently, there was a research program that the
18 Office of Nuclear Regulatory Research engaged in which
19 led to NUREG-7007, which was released after the
20 issuance of ISG-02.

21 So I understand that the purpose of
22 Revision 6 of BTP 7-19 is to incorporate the positions
23 embodied in ISG-02 and that appears to have been
24 accomplished.

25 But I will note that subsequent to the

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1 development of that document, there were these
2 technical bases that were developed through the
3 research program that are not addressed in the
4 revision, specifically the diversity strategies that
5 are embodied in Section 6 of NUREG/CR-7007, which
6 identified means of resolving the vulnerabilities,
7 postulated vulnerabilities of common cause failure.

8 And so the question that I think comes up
9 is, is there a plan for Rev 7 of BTP 7-19 that will
10 address the issue of what constitutes adequate
11 diversity, and if the strategies that are identified
12 in NUREG/CR-7007 are not quite adequate in the minds
13 of the staff, are there activities planned to take
14 those forward or a different approach so that the
15 objective of TWG-2 can be completely resolved and
16 those positions can be put in the branch technical
17 position to address the issue of what constitutes
18 adequate diversity?

19 And so that's all I had to say.

20 MR. JUNG: This is Ian Jung, and an issue
21 came up during last year to development as well as the
22 Subcommittee briefly, to establish that I think
23 there's some value.

24 Anybody can use that. I mean the industry
25 is given a document that can supplement the ISG-2 and

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1 BTP Revision 6 that's coming out.

2 But NRR and licensing staff looked at
3 that, and even the assumptions made and the data set
4 that was used, essentially one of the key is to come
5 up with a numerical value that says, oh, this is, one
6 may, you know, degree of, you know, diversity is if
7 you have certain numerical value based on a sample set
8 of applications that's been used in nuclear power
9 plants and the whole work in other industry.

10 I think there's value to it, yet the staff
11 did not feel fully comfortable putting that out as one
12 of the acceptable guidelines until we validate the
13 methodology for one or two actual applications and see
14 how it works out.

15 So we, right now the staff has decided to
16 defer the endorsement of 7007 NUREG until we validate
17 that through one of the applications or two
18 applications.

19 If in the future as the applicant actually
20 chooses to use that because it's going to be
21 additional burden in addition to BTP 7 Version 19. So
22 that's where we are and we'll evaluate that in the
23 future to see whether that's a acceptable methodology
24 to demonstrate adequate diversity.

25 In terms of adequate diversity, the way

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1 that it was handled is all that the remaining
2 guidelines in 14 in terms of just manual methods, the
3 quality requirements, expectations in the Generic
4 Letter 85-06, their quality provisions and degree of
5 diversity in NUREG-6303, as a total staff felt that we
6 have a viable method right now.

7 It's not easy, but viable method that's
8 been done. So I think adequate diversity, we are
9 using those guidance and use some engineering
10 judgments to reach a safety findings right now. So I
11 think more to come on that subject.

12 MR. WOOD: If I may, I just wanted to
13 clarify that NUREG/CR-6707, the primary information in
14 that deals with diversity strategies. And there's
15 frequently a misconception that the tool which Ian
16 refers to is the product.

17 The tool is a comparative analysis tool
18 that's in an appendix, is the strategies that are
19 identified in Chapter 6 that define a conservative
20 basis for establishing adequate diversity.

21 And I would recommend that there be a new
22 look at 7007 to look at the strategies rather than
23 looking at the tool. And I do agree, the tool needs
24 considerable more work to assess some of the
25 subtleties that might not be accounted in the tool,

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1 but the strategies themselves are based on a very
2 detailed analysis of the cause of common cause, the
3 nature of common cause failure.

4 They deal with the purpose of an I&C
5 system, the process for developing an I&C system, the
6 product, which is the I&C system itself, and the
7 performance of the I&C system.

8 So with the first two, the purpose and the
9 product, you deal with the sources of common cause
10 failure. With the product itself, you deal with the
11 location of that vulnerability within the architecture
12 of the system.

13 And with the third, the performance, you
14 deal with the influences that trigger common cause
15 failure from those vulnerabilities. So you're dealing
16 with environmental influences, human interaction,
17 internal states and the trajectory of signals that are
18 introduced from the plant.

19 So it was a very thorough assessment and
20 it was supplemented by a review of the techniques that
21 are applied in other industries for addressing the
22 issue of common cause failure, along with recent
23 examples in the nuclear industry and international
24 plants.

25 So there's a very solid technical basis

1 for those strategies. And I'm afraid we got so
2 wrapped up in the tool that we lost sight of the
3 strategies that are there that provide a very good
4 basis for determining, is there adequate diversity in
5 this proposal or not?

6 And so I am recommending that the
7 Committee consider asking for a fresh look at those,
8 and if they prove to be insufficient there should be
9 additional work conducted to take them to the level
10 that this goal can be achieved of defining what
11 constitutes adequate diversity when diversity is
12 required based on the Diversity and Defense-in-depth
13 analysis.

14 So I agree with what Ian said, I just
15 don't want us to lose, to throw the baby out with the
16 bath. We don't need to wait until the tool, which is
17 a comparative tool, is rigorously validated when we've
18 got a very solid technical basis that's embodied in
19 that document itself, in the main part of the
20 document.

21 MEMBER BROWN: Okay.

22 MR. WOOD: Thank you.

23 MR. STATTEL: I would like to mention that
24 the team that worked on this revision was very
25 cognizant of the 7007 development and the guidance it

1 provides.

2 We did consider it and we had considerable
3 discussion on whether to incorporate that within this
4 guide. As Ian stated, the staff decision was not to
5 incorporate that here or to endorse it.

6 However, I'd also like to mention that
7 we're not just keeping it on the shelf. In several of
8 our reviews we have used the guidance from 7007, and
9 made the determinations of how diverse the systems
10 were.

11 We've used this for the Wolf Creek
12 application, we've applied the methods for Oconee
13 application, so we are gaining experience as we go
14 forward with our reviews.

15 And I would hope that in a future revision
16 of BTP 19 we would, in fact, endorse that NUREG.

17 MEMBER BROWN: Okay, if there's no more
18 comments I want to thank you all for a lively
19 Subcommittee meeting we had as well as a lively full
20 Committee meeting, and thought you were presented a
21 good case and thoughtful comments.

22 Thank you very much.

23 MR. STATTEL: Thank you.

24 MEMBER BROWN: I'm complete, pass it back
25 to you, Mr. Chairman.

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1 CHAIR ABDEL-KHALIK: Thank you. We are
2 off the record at this time.

3 (Whereupon, the foregoing matter was
4 concluded at 12:19 p.m.)

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**Presentation to ACRS
Standard Review Plan
Branch Technical Position 7-19 Revision 6**

November 3, 2011

Richard Stattel, NRR/DE/EICB

Gene Eagle, NRO/DE/ICE2

Ian Jung, NRO/DE/ICE2

Russell Sydnor, RES/DE/DICB

Paul Pieringer, NRO/DCIP/COLP

**BRANCH TECHNICAL POSITION (BTP) 7-19 Revision 6,
“GUIDANCE FOR EVALUATION OF DIVERSITY AND
DEFENSE-IN-DEPTH IN DIGITAL COMPUTER-BASED
INSTRUMENTATION AND CONTROL SYSTEMS”**

PURPOSE OF THIS BRIEFING:

Highlight and identify the key elements from incorporating DI&C-ISG-02 Revision 2 into BTP 7-19 Revision 5 to form Revision 6, and the action items from the ACRS I&C subcommittee presentation

Current Status of BTP 7-19, Revision 6:

- Received OMB approval as “non-major rule” ,
(Congressional Review Act)
- Presented to ACRS I&C Subcommittee Sept. 07, 2011
- Expected to be issued by November 30, 2011

Agenda

1. Purpose and General Basis of BTP 7-19 Revision 6
2. Background
3. NRC Four-Point Policy on Defense-in-Depth and Diversity (D3)
4. Comments on NRC Four-Point Policy on D3
5. Independence of the Diverse Means
6. Automated verses Manual Diverse Means
7. Component verses System Level Actuation
8. Spurious Actuation
9. Combining Two Manual Initiation Systems
10. Public Comments and Staff Response
11. Notable Clarifications in BTP 7-19 Revision 6
12. Summary and Questions

Purpose and General Basis for BTP 7-19

- Purpose: Assure adequate D3 and provide guidance for evaluating applicant's D3 assessment and D3 design
- Software-based digital systems are considered susceptible to the same software error appearing in identical copies of the software-based logic or architecture that are present in redundant divisions of safety-related systems
- Therefore, software-based or software-logic-based digital system development errors are a credible source for a potential common-cause failure (CCF)
 - ****
- ***In summary, while the NRC staff considers (software) CCF in digital systems to be beyond design basis, nuclear power plants should be protected against the effects of anticipated operational occurrences (AOOs) and postulated accidents with a concurrent CCF in the digital protection system***

Background

- DI&C-ISG-02 Revision 2 (currently effective) was issued in June 2009 considering ACRS comments as:
 - ISG will help licensing review
 - The staff should determine the conditions under which operator manual actions can be credited as a diverse protective function
 - The issue of spurious actuation needed to be examined further
- Decision made to merge DI&C-ISG-02 Revision 2 into NUREG - 0800 (the Standard Review Plan) by incorporating DI&C-ISG-02 Revision 2 into BTP 7-19 Revision 5 to create **BTP 7-19 Revision 6** (main reason for Revision 6)
- 70 public comments received and addressed
- Presentation to ACRS Digital I&C Systems Subcommittee Sept. 07, 2011
 - Minor revision to “Note” using Mr. Stetkar’s (ACRS) suggestion

NRC Four-Point Policy on D3

[from SRM on SECY-93-087 in Item 18, II.Q]

1. “The applicant shall assess the defense-in-depth and diversity of the proposed instrumentation and control system to demonstrate that vulnerabilities to common-mode failures have adequately been addressed.”
2. “In performing the assessment, the vendor or applicant shall analyze each postulated common-mode failure for each event that is evaluated in the accident analysis section of the safety analysis report (SAR) using best-estimate methods. The vendor or applicant shall demonstrate adequate diversity within the design for each of these events.”

NRC Four-Point Policy on D3 (cont)

[from SRM on SECY-93-087 in Item 18, II.Q]

3. “If a postulated common-mode failure could disable a safety function, then a diverse means, with a documented basis that the diverse means is unlikely to be subject to the same common-mode failure, shall be required to perform either the same function or a different function. The diverse or different function may be performed by a non-safety system if the system is of sufficient quality to perform the necessary function under the associated event conditions”
4. “A set of displays and controls located in the main control room shall be provided for manual, system-level actuation of critical safety functions and monitoring of parameters that support the safety functions. The displays and controls shall be independent and diverse from the safety computer system identified in items 1 and 3 above.”

Comments on NRC Four-Point Policy on D3

Concerning Point 2

- The term “best-estimate methods” is more accurately referred to as “realistic assumptions” – defined as normal plant conditions corresponding to the event:
 - Power levels, temperatures, pressures, flows, and equipment alignment
 - This revision only clarified intended existing scope
 - It was not intended to expand or re-define scope
- The “corresponding to the event” phrase was added to emphasize that some analyzed events at worst conditions may occur at power levels other than the power range (i.e. zero power; see BTP 7-19 Revision 6, Section B.1.4)
- Events from Safety Analysis Report (Chapter 15) as specified by **Point 2** must be addressed

Comments on NRC Four-Point Policy on D3

Concerning Point 3:

- If D3 analysis indicates potential for CCF, Point 3 directs applicant to identify or add a diverse means to perform either the same function or a different function
- The phrase “Safety Computer System identified in items 1 and 3 above” from Point 4 clearly indicates primary application is to the automated safety–related reactor trip system (RTS) and the engineered safety features actuation system (ESFAS)
- Point 3 also applies to manual initiation methods for the reactor protection system (RPS) if subject to the CCF
[Note: RPS includes RTS and ESFAS]
- Diverse means may be accomplished by automated, manual, or a combination of these for initiating mitigating function

Comments on NRC Four-Point Policy on D3

Concerning Point 4

- Directs providing a set of displays and controls (safety or non-safety) in main control room (MCR) independent and diverse from any CCF vulnerability in RTS or ESFAS and at division/system level
- For control and management of “(plant) critical safety functions” [From NUREG-0737, Supplement 1] Reactivity Control, Reactor core cooling and heat removal from primary system, Reactor coolant system integrity, Radioactivity control, Containment conditions
- If not subject to CCF, some of these displays and manual controls may be credited as all or part of diverse means directed by Point 3
- For digital modifications in operating plants, retention of existing controls in MCR may help satisfy Point 4
- Once manual actuation from MCR using Point 4 controls is completed, controls outside MCR may be used for long-term (and/or perhaps short-term situations) management when supported by suitable HFE analysis and procedures

Independence of the Diverse Means

- Independence requirements of diverse means from safety protection system (i.e., physical and electrical) are defined in IEEE Std. 603 and communication separation in DI&C-ISG-04
- Diverse means could be safety-related and part of a safety division, and would be subject to meeting divisional independence requirements
- Diverse means could be non-safety-related; then the IEEE Std. 603 requirement to separate safety from non-safety equipment would still apply and would require independence of the two systems
- In either case, the diverse means should be independent of the safety system such that a CCF of the safety system would not affect the diverse system

Automated vs. Manual Diverse Means

Clarification when operator action is acceptable as a diverse means to address a potential CCF

- Perform a D3 analysis of RPS using realistic assumptions
- If subject to potential CCF, need a *diverse* means to perform the safety function subject to the CCF
- Diverse means may be *automated or manual*
- Automated diverse means is preferred
- If manual means is selected as diverse means, acceptability is based on HFE analysis

Special Note on Manual Action in Diverse Means

“As the difference between Time Available and Time Required for operator action decreases, uncertainty in the estimate of both of these times must be evaluated carefully. These uncertainties could invalidate or reduce the level of assurance of a conclusion that operators can perform the action reliably within the time available. For actions with a limited margin of time to act, such as less than 30 minutes between the Time Available and the Time Required, additional staff review will be performed.”

Component vs. System Level Actuation

- Diverse means performed on a system-level basis for each division in accordance with the policy in SECY 93-087 SRM
- Does not prohibit use of manual controls to operate individual safety system components after the safety system function actuates
 - Depends on type of function and specific design objective
 - Some actuations go to completion (e.g. reactor trip or containment isolation)
 - Some actuations start safety function and may then need manual action to complete (e.g. controlling vessel levels)
- Potential for CCF in digital safety systems should be considered in new plants and in upgrades to existing plants (backfit of current NPP equipment is not intended)

Spurious Actuation

- Two types of CCF associated spurious activation
 - I. Caused by CCF in automated RPS
 - II. Caused by the Diverse Means

Spurious Actuation

- (I) Spurious actuation caused by CCF in automated RPS
 - Spurious RPS actuation is a lesser safety concern than failure to actuate because challenges presented by spurious actuations are not considered to be as significant as failures to respond to AOOs and DBEs
 - Further, spurious actuations are annunciated and thereby immediately detected
 - Assuming a postulated CCF in automated RPS and related displays, operators still have the (diverse and independent) Point 4 displays and controls and/or Point 3 diverse means that can be expected to detect the spurious actuation
 - Spurious actuations that could challenge barriers to release of radioactivity typically are addressed in the plant licensing basis (e.g., over-pressurization of PWR primary coolant system caused by spurious actuation of high pressure safety injection system)
 - Therefore, spurious actuations of safety-related digital protection system resulting from CCF do not need to be addressed beyond what is already set forth in plant design basis evaluations

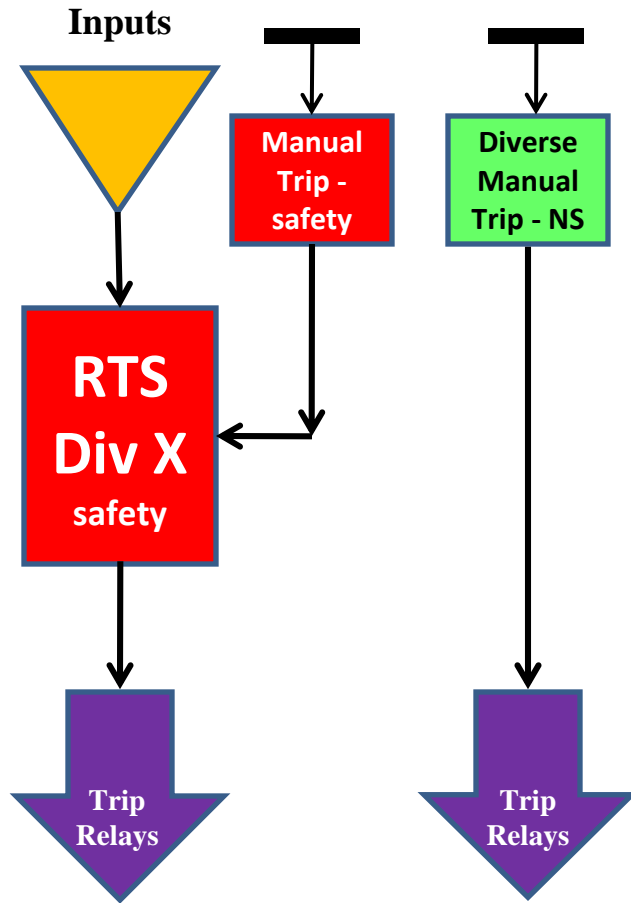
Spurious Actuation

- (II) Spurious actuation caused by the Diverse Means
 - Design of diverse automated or diverse manual means should address how to minimize the potential for spurious actuation of the RPS caused by the diverse means

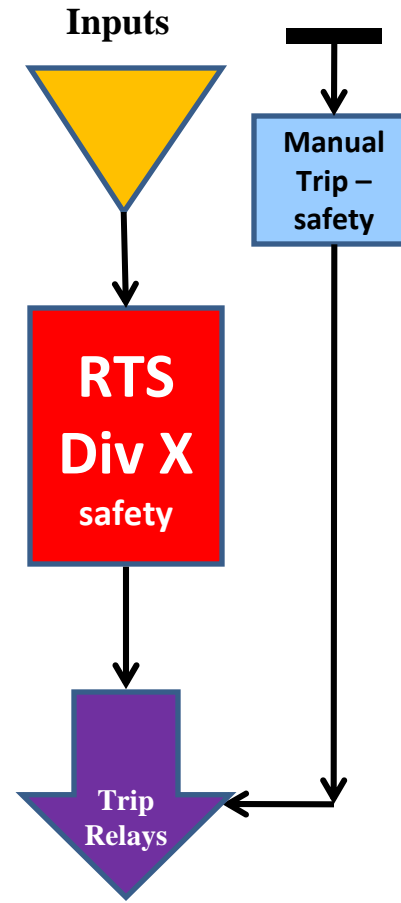
Combining two Manual Initiations

- Two manual initiation systems may be needed
 - One ***required*** by IEEE Std. 603-1991 (safety-related)
 - One independent and diverse (safety or non-safety) needed per BTP 7-19, ***IE*** RPS manual initiation safety system subject to the postulated CCF
- Two manual actuation systems may be combined if:
 - RPS manual initiation of the automated RPS is independent and diverse from automated RPS
 - Safety-related
 - Not subject to same potential CCF as automated RPS

Two Manual Initiations Means Needed



Only One Manual Initiation Means Needed



Notable Public Comments and Staff Response

- In some instances comments led to additional clarification for clearer understanding and improved explanation
- Staff agreed with some comments in principle , but not with the specific rewording recommendations. Staff addressed these comments based on principle or accepted portion
- Staff agreed that not all RPS safety functions may be disabled by a CCF, but pointed out that assuming all RPS functions are disabled is considered a worst case bounding condition
- Staff accepted a comment expressing concern that after actuation of ESF functions from the MCR, the need may exist for some use of local controls later (e.g., re-align equipment , manual override failures, 72+ hours after event)

Notable Clarifications in BTP 7-19 Rev 6

- Based on ACRS letter on RG 1.62, *Manual Initiation of Protective Actions*, “system level” was changed to “system or division level (depending on the design)”
- Since single failures concurrent with a CCF are not required to be postulated and normal equipment alignment is assumed, diverse actuation of one division is sufficient provided that division will be in service, i.e. diverse design may need more than one division
- The use of the term “diverse backup method” was replaced with “diverse means” to match with the Four-Point D3 Policy and because some current NPP RPS portions termed “primary” and “backup”
- A CCF that affects normal displays or controls should not prevent an operator from manually initiating safety functions

BTP 7-19 Revision 6

Summary

- Again, the current interim staff guidance in DI&C-ISG-02, Revision 2 was merged into the Standard Review Plan by incorporating DI&C-ISG-02, Revision 2, guidance into BTP 7-19 Revision 5 as Revision 6
- Revision 6 of BTP 7-19 is an extensive revision providing significant specific guidance for a number of stakeholder concerns
- Revision 6 of BTP 7-19 is expected to be issued by **November 30, 2011**
- ACRS review and advice of this revision are appreciated

Questions?



U.S.NRC

UNITED STATES NUCLEAR REGULATORY COMMISSION

Protecting People and the Environment

ACRS Full Committee Power Uprates

**NRC Staff Review
Nine Mile Point, Unit 2
Extended Power Uprate**

November 3, 2011



Introduction

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Division of Operating Reactor Licensing

Office of Nuclear Reactor Regulation

Introduction

- Objective
- Background
 - NMPNS EPU Application – May 27, 2009
 - 3467 to 3988 MWt, 15 % increase (521 MWt)
 - 20 % increase above original licensed thermal power
- NRC staff effort
 - Pre-application review and public meetings
 - Acceptance Review
 - Requests for additional information
- EPU Implementation

Topics for Full Committee

- NMPNS EPU Overview
- Anticipated Transient without Scram and Stability
- Fuel Methods - IMLTR
- Materials and Mechanical & Civil Engineering
- Steam Dryer Analysis
- Review of open items / Conclusions