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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

October 6, 2005

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

526TH MEETING

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THURSDAY,

OCTOBER 6, 2005

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The meeting came to order at 8:30 a.m. in room T2-B3 of Two White Flint North, Rockville, Maryland. William J. Shack, Vice Chairman, presiding.

PRESENT:

WILLIAM J. SHACK, VICE CHAIR

DANA A. POWERS, MEMBER

VICTOR H. RANSOM, MEMBER

MARIO V. BONACA, MEMBER

GEORGE E. APOSTOLAKIS, MEMBER

RICHARD S. DENNING, MEMBER

THOMAS S. KRESS, MEMBER

JOHN D. SIEBER, MEMBER AT LARGE

ALSO PRESENT:

JOHN T. LARKINS, DESIGNATED FEDERAL OFFICIAL

ASHOK C. THADANI, DEPUTY EXECUTIVE DIRECTOR,

SAM DURAISWAMY, STAFF

MICHAEL L. SCOTT, STAFF

JENNY M. GALLO, STAFF

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P R O C E E D I N G S

8:32 A.M.

VICE CHAIRMAN SHACK: The meeting will now come to order. This is the first day of the 526th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the Committee will consider the following: the interim review of the license renewal application for the Browns Ferry Nuclear Plant, Units 1, 2 and 3; proposed recommendations for resolving Generic Safety Issue 80, pipe break effects on control rod drive, hydraulic lines and the dry wells of boiling water reactor Mark 1 and 2 containments; resolution of ACRS comments on the draft final regulatory guide; risk-informed performance-based fire protection for existing lightwater reactor nuclear power plants; Davis-Besse reactor vessel head integrity calculations; quality assessment of selected NRC research programs; and preparation of ACRS reports.

This meeting is being conducted in accordance with provisions of the Federal Advisory Committee Act. Dr. John T. Larkins is the Designated Federal Official for the initial portion of the meeting.

We have received no written comments or

request for time to make oral statements from members of the public regarding today's session. A transcript of portions of the meeting is being kept and it is requested that speakers use one of the microphones, identify themselves and speak with sufficient clarity and volume so they can be readily heard.

As you will note, I'm not Graham Wallis, Chairman of the ACRS, who is still in the south of France somewhere. So --

MEMBER APOSTOLAKIS: Who are you?

(Laughter.)

VICE CHAIRMAN SHACK: Some items of current interest, if you look in your package, you'll see a yellow announcement that will describe some of the reorganization that's occurred in NRR. There's also an article that describes Chairman Diaz' multi-design initiative on international certification of reactors. And again, a number of other speeches and items of interest from the other Commissioners.

I do want to introduce Gabe Taylor. As of October 3rd, Gabe began a six-month rotation with the ACRS. During this rotation, Gabe will assist the Committee with its review of the digital INC research plan and the ESBWR design. Gabe joined the NRC in April of 2005 as a general engineer participating in

the Nuclear Safety Professional Development Program. He graduated from Penn State University with a Bachelor of Science degree in Electrical Engineering with a focus on power and control system design. During his first six months in the Agency, Gabe worked in the Office of Nuclear Reactor Regulation.

One other thing I wanted to mention, as I got an email last night that told me that Spence Bush had passed away on October 2nd. Spence is a former Member of the Committee, Chairman of the Committee and one of the last of the generation of the real nuke founders. Spence told me once he was driving, he drove Oppenheimer to the Trinity site in the Jeep, so he goes back all the way to Day 1 of the nuclear era. He was a remarkable man. He always sort of struck me as the Energizer Bunny. He was about so high and just sort of kept on going, all the time.

Our first item of interest today is Browns Ferry Nuclear Plant license renewal application and Mario will lead us through that.

MEMBER BONACA: Okay, good morning. Yesterday, the Plant License Renewal Subcommittee met to review the interim SCR for the Browns Ferry Nuclear Plant, Units 1, 2 and 3 license renewal. We also met on September 21st and previously in the month of

August at the Browns Ferry to familiarize ourselves with this complex application or a number of applications that the Browns Ferry units are going through right now. You are familiar with the fact that Unit 1 is still at the end of its 22 years almost of layout conditions and will be starting in 2007. That restart will include an EPU of 20 percent and although the EPU is not part of the consideration for license renewal, I raise this issue because of the complexity of the application and the fact that Unit 1 does not have the expected operating experience that the rule intends to have as stated in the Statement of Consideration.

So yesterday, during our meeting we discussed a number of issues which I believe I would like to just briefly summarize that should be of the interest to the Committee today.

The first one is how do you deal with the issue of operating experience of the licensee. The licensee has assumed that the operating experience for Unit 1, 2 and 3 is applicable to Unit 1. We have raised the issue of proficiency. Clearly, it is applicable, like general experience or operating experience, but is it sufficient, particularly for dealing with components which were in lay-up and may

have latent aging effects that will only surface after the plant is in operation.

So we discussed that issue and we felt that there should be in the SER a comprehensive discussion of this issue up front. This is being recognized both by the licensee and the NRC staff and they have agreed to in the final SER to incorporate such a discussion.

The second issue is the fact that the licensee has committed periodic inspection of separate components that were in lay-up and this is really essentially a compensatory action for the lack of operating experience for those components. And I think that we were favorably impressed by that program, although the program is not sufficiently defined. We heard a number of commitments on the part of the licensee and we'd like you to hear today because those commitments are important to determine whether or not, in fact, the operating experience with this compensating factors is adequate for Unit 1.

As a result of the discussion on the periodic inspections, the staff decided to issue a new open item to the licensee dealing with this very issue which means the expectation there will be a program defined by the time the SER, the final SER is issued

that will address this very issue of the periodic inspection program and what it will consist of in detail.

Other comments that we had had to do with the fact that the application in many ways, of the schedules of the plant, from the moment it reached -- the license renewal was submitted in 2003 to today, has changed significantly because the plant is being refurbished before the start. Therefore, the SER seems to not provide an evaluation on a fixed status of the plant, but there are changes in status of the plant that are being addressed within it and the most uncommon that there should be some better understanding of what plant we are talking about in the SER and maybe in the application.

With that I will turn now to Dr. Kuo. I understand there will be first of all a presentation by Browns Ferry and then the staff will address the SER.

Dr. Kuo.

MR. KUO: Thank you and good morning, Dr. Bonaca. I'm the Program Director for License Renewal and Involuntary Impacts Program. To my right are the project managers for this review: Ram Subbaratnam and Yoira Diaz.

Yesterday, as Dr. Bonaca reported, we had a meeting, a supplemental meeting on the review of Browns Ferry license renewal application and I just want to make it clear that we originally had in the SER two open items, but as a result of yesterday's meeting, that number has increased to four. As Dr. Bonaca mentioned one is the result of ACRS' review on the periodic inspection and the other is the result of a regional inspection.

And also, I want to repeat what I said yesterday that this review is rather complicated than usual. The complexity comes from the three concurrent actions like Dr. Bonaca just mentioned. First one is a Unit 1 restart and second one is the license renewal. The third one is EPU. All of these three actions are being carried out concurrently and that adds to some of the complexity to this review, but this was clearly described in our SER. Our focus in this review is to review the license renewal application at the current power level, not at the EPU level. That is the one major thing that we want to make it very clear to this Committee and whatever the impact from EPU review will be, that will be taken care of in the time of EPU.

And also, I just want to mention that I

have Frank Galliespie in the audience who is our Deputy Director for the Division of Program Improvements, but after October 30th, Mr. Galliespie is going to be the Director of the License Renewal Division.

Frank do you want to say something? If Frank doesn't have any opening comments, then we will go ahead with the review, turning this over to the Applicant.

MR. CROUCH: Good morning. My name is Bill Crouch. I'm the site licensing manager at Browns Ferry Nuclear Plant. We appreciate the opportunity to come and talk to you today. Some of you we got to talk to yesterday and others, this may be your first time of hearing some of this story. Others it may be the second because you may have been with us down at Browns Ferry back in August. But we appreciate the opportunity to come and talk to you and tell you that a little bit of the details about our license renewal project.

In addition to myself, we have several members of our Browns Ferry staff here today. I'm not going to introduce all of them to you, but I'll tell you some of the key players. We have Rich DeLong who is our Site Engineering Manager. He has

responsibility for all of the engineering activities on site. He is the overall program owner for license renewal. He owns it. He says, as he said yesterday, it is mine. He's got it. That means that he and his staff own this program and they understand the importance of it.

We also have with us today Ken Brune, who is the Project Manager over the license renewal project. He and his staff are here today so that they can answer any kind of technical questions.

We also have Joe Valente here with us. Joe is the Unit 1 Engineering Manager. He has his staff with him here also. So we can answer questions about Units 1, 2 or 3 or the recovery of Unit 1 or license renewal for any of those. We appreciate the opportunity to answer any questions you have.

As I said, yesterday, we made a presentation to the staff and we're going to use the same package today as what we had yesterday. I'm going to give you a shortened version of it and so I will be telling you, we will now move on to page so and so. We'll be skipping some pages and some bullets and things along the way. We wanted you to have the full information, the full packet in case you wanted to see it. So that's how we're going to proceed from

here.

So we'll be starting on page 2 of the packet that you've got in front of you there. We recognize that there are three big issues before us, the restart of Unit 1, I think being the biggest; and then we've got license renewal and EPU. We realize that there are interrelationships, close interrelationships between license renewal and EPU and we've been considering that all along.

But we also, as we started through this process, we talked to the staff and we recognized that when we submitted the license renewal application that we had to make the license renewal application at current license thermal power since the EPU had not been approved yet. The reason for that was that if we submitted license renewal at EPU conditions, once it was approved by the NRC, that was an implicit approval of EPU, if it was written that way. So instead, the license renewal application is written for current license thermal power.

As we go through this process of reviewing the three big issues, we will always, as part of our design process, construction process, etcetera, we will consider the other aspects of this, but when we talk about the review process, you have to consider

them one at a time and as you move to the next one, you look back at the one that you've already approved and make sure that the effects have been considered. So it's a backward looking type process as we go along, but we've included in our processes, as we've been doing the recovery efforts.

As far as Browns Ferry, Browns Ferry -- there's three units. They're all GEBWR-4 units with Mark 1 containments. They're all in a common building. They were originally designed and constructed by PVA. They were designed and constructed to be essentially identical units. Two of them are opposite hand, but other than that they are operationally identical. When they were built, they had all the same equipment, the same materials of construction, etcetera, etcetera. So they were the same. As it shows up there, the approximate years of operation is in calendar years.

Everybody is probably aware of some of the history of Browns Ferry and that we operated for a while and then we shut down. Units 2 and 3 have been operating as shown up there since 1991 and 1995, respectively. Unit 1 has been in extended lay-up condition since 1985 and we're in the process of recovering that plan right now from May of 2007.

Once we go through and do the restart activities, Unit 1 will be operationally identical to Units 2 and 3.

MEMBER POWERS: Why was Unit 1 laid up?

MR. CROUCH: Why was it laid up or why was it shut down?

MEMBER POWERS: Shut down.

MR. CROUCH: It was shut down in 1985 due to management and safety concerns that we had not come into conformance with various regulations such as Appendix R, EQ, a lot litany of things, and also perceived management weaknesses. We shut all three units of Browns Ferry down as well as units at Sequoia. At that point in time, we negotiated with the NRC a plan for recovery and it was laid out in what's called the Nuclear Performance Plan, three volumes, accepted. It went through and gave us updates for how we needed to revise our management team, what we needed to do for our processes and then specific technical issues that had to be addressed.

MEMBER POWERS: You apparently addressed those for Units 2 and 3, but not for Unit 1?

MR. CROUCH: At that time, we did obviously the management changes applied to the whole utility and they were for the whole site, so yes, they

were done in that respect for Unit 1. The process changes were done for Unit 1 at that time, but we did not do the technical programmatic or technical configuration type changes at that time.

MEMBER POWERS: Why not?

MR. CROUCH: It was a staged recovery, so we did one unit first and then we moved on to the next unit. Once we got Unit 3 recovered, at that point in time we did not need the power, so we did not immediately proceed.

MEMBER POWERS: There must have been some reason to do 2, 3 and then eventually 1.

MR. CROUCH: It was based upon which unit we believed was in the best condition to be recovered the fastest.

MEMBER POWERS: So somehow Unit 1 was in a worse condition than the others?

MR. CROUCH: It had less of the older mods done to it. There would have been more work to get it back running.

MEMBER POWERS: Thank you.

MR. CROUCH: As I said, once we recover Unit 1, Unit 1 will be operationally identical to Units 2 and 3. And I want to make sure everybody understands what we mean by operationally identical.

As we recovered units 2 and 3, we installed hardware that was available at the time. Here we are 10 years or more later and some things you just physically cannot buy any more. Companies have gone out of business or technology has changed. For example, recorders in the control room will not longer be paper recorders like we have on 2 and 3. They're paperless recorders. They're electronic. But as far as the operator is concerned, it's still a recorder. It still supplies the same information to him. You go out to the plant, into the more hardware, the piping systems, you'll find cases where valve manufacturers have gone out of business. It used to be a Brand X gate valve, well, you can't buy a Brand X gate valve any more, so we had bought a Brand Y gate valve. It's still a gate valve. It's still the same size, same material, everything. It's just a different brand.

MEMBER POWERS: All gate valves have exactly the same reliability?F

MR. CROUCH: We have bought currently the best valves. We have bought the valves that have high reliability, whether they have exactly the same I would hope everything we bought by current day standards is as good or better than what was bought back in 1991 and 1995.

So the units will not be, if you walked out there, completely identical from the standpoint of brand names and stuff like that, but from an operational standpoint, they will be the same. We've used the same materials with the same general configuration as far as having a gate valve where a gate valve is supposed to be, etcetera.

We'll now turn to page 3 of the presentation. For license renewal, this was submitted as a three-unit application. As we started the license renewal process, we had not started the Unit 1 recovery at the time, so when we internally started the application, it was to be a two-unit application. As we decide to restart Unit 1, we then backed up and made it a three-unit application. So it does cover all three units.

The application recognizes that Unit 1 is in recovery status and we'll talk about that down through the course of the slides here.

You can see there the current license expiration dates. The license renewal application is based upon current license thermal power. As we talked about we could not reference it to a future power, because that would be an implicit approval of that power level, so for Unit 1 it's based upon the

original license thermal power of 3293. For Unit 2 and 3, it's based upon the current license thermal power which is 105 percent of original or 3458 megawatts thermal.

It was recognized that Unit 1 was in a recovery process and there was lots of modifications to be made to bring it into conformance with Units 2 and 3 from an operational standpoint. As we started the license renewal process, TVA and NRC staff went through and jointly figured out which of these various modifications were pertinent to license renewal and in the course of the application, there is an appendix to the application, Appendix F or Appendix Foxtrot, that lists 13 major programs or modifications that will bring the two units into conformance. These things are such things as replacing the IGSCC with acceptable piping for recirc. RWCU. They're adding things in like hardened wet well vent, the alternate leakage treatment path for MSIV leakage. And there's 13 of them.

So once those 13 items are implemented, then the two units will be back in operational fidelity for the purpose of license renewal.

We'll move on to page 4 now. As we started through the license renewal process, we did

the scoping of the systems that were involved. We used our licensing basis documents. We also used the documents that apply to specific regulated events such as Appendix R, EQ Atlas, etcetera. Based upon that, we came up with 77 mechanical and electrical systems that were within the scope of license renewal projects. Those were laid out. They're marked up on drawings, color coded, so we know exactly what's in scope and we use that as a basis for our license renewal activities.

Moving on to page 5, after we had the scoping done, we went through our various time limited aging analyses. The various ones are shown up there. I won't go through any of them in particular, unless you want some particular details on them.

Moving on to page 7, as a result of our license renewal application, we determined that we needed 39 aging management programs. Of these, 38 of them are common to Units 1, 2 and 3. And there's one that's specific to Unit 1 and that's our Unit 1 periodic inspection program.

The next four pages of your package list those programs and I'm not going to go over each and every one of them, but they're listed there. They're broken up into three categories: those that were just

okay, exactly as is; those that required some enhancement to make them technically sound for license renewal; and those that required some enlargement, basically to include the scope of Unit 1.

There's also six brand new aging management programs that are listed on the fourth page there.

As you will hear through the course today, as we went through this process, the region came in and did an inspection of our programs back in December and we were not ready for that at the time. We had not really started the aging management programs at the time. Since that time, we have gone through and developed all these programs. They are marked up with procedures. They are permanently stored. They will be implemented into the procedures as we get closer to the license renewal process, for those that aren't currently in there already.

It is a track process, controlled under our Corrective Action Program to ensure that the changes get into procedures.

The overall program, as I said earlier, is owned by Rich DeLong and the site engineering contingency there. They are actively involved in the review of these programs. As these programs are being

developed, they did a technical review on all of them to make sure that they were technically sound, that they met the requirements of the engineering aging what we've learned document, and regarding these programs, we'll be implementing them over the course of time.

Move on to page 13. As I talked about, there was one unique program for Unit 1. It was recognized that there's a large amount of equipment out in Unit 1 that is being physically replaced as part of the recovery. This will be brand new equipment, brand new piping, brand new valves, brand new cabling, etcetera. It was also recognized that there was still a substantial portion of Unit 1 that as not being replaced. It will be the original equipment that is still being used.

We were confident that this equipment would be good for the period of current operation, as well as the extended operation, however, we wanted to make sure that the equipment was not experiencing or exhibiting any type of aging mechanism that we were not aware of. So in order to ensure this, we will do additional inspections on the non-replaced equipment out in the plant to ensure that we know what's going on out there.

What we will do is there will be inspections performed prior to restart that will provide us a baseline set of information. We will then do another inspection after several years after restart to see if there's any degradation occurring. And once we enter the period of extended operation, we will do another set of inspections and based upon the results of those three inspections, we will decide if there's anything unusual happening in Unit 1 or if there's any effects coming from the lay-up that we were not aware of.

So this gives us confidence that we will know the condition of Unit 1 as we proceed into the periods of extended operation.

MEMBER POWERS: Perhaps this isn't defined too well yet, but what's going to be different about these periodic inspections that will be different from the other inspections that you're going to do as part of your aging management program?

Is it the timing or is it the actual nature of the inspections?

MR. CROUCH: The type of the inspections will be the same. They'll be visuals or surface exams or ultrasounds, whatever is appropriate for that piece of equipment. The only real difference is that there

will be a slightly larger scope and it will be focused solely on the non-replaced equipment.

MEMBER POWERS: Thank you.

MR. CROUCH: This periodic inspection program, it is one of the open items that we will talk about here in a few minutes and the reason it is an open item is this program has not been fully developed as far as the exact scope and breadth of this program, but the overall concept, everybody agrees on it and we're just in the process of discussing with the staff exactly where we're going to inspect, how often and where.

So moving on to page 14. As we said, Unit 1 was shut down back in 1985 and placed in lay-up status. There were systems that were placed in the dry lay-up and systems that were placed in the wet lay-up. The dry lay-up systems were configured such that the systems were opened up and we blew dehumidified air through the system to make sure that the humidity in the system was low. We monitored the humidity on the downstream end of where we were blowing through. We also went through and monitored the low point drains to ensure that there was no standing water in the systems.

MEMBER POWERS: Your lay-up program

started before the EPRI report was available. Was your program consistent with the EPRI report after it came out?

MR. CROUCH: Bob Moll, did we ever make any changes as a result of the EPRI document coming out?

MR. MOLL: No.

MR. CROUCH: Bob acknowledged that there were no changes required.

We also had systems that were in wet lay-up. These were primarily systems such as reactor vessel where we maintained them full of water. In all of these cases, we maintained the water chemistry in accordance with the plant technical specifications, so that the systems would have been experiencing the same physical condition as if they had been in operation from a chemical standpoint.

Many of the systems that were in wet lay-up such as the recirc. piping, RWCU piping, portions of the RHR and core spray piping that were out to the isolation valves, all this piping has been replaced anyway. The only major system or only major component that was in wet lay-up that will still be present in the plant will be the reactor vessel itself and that component is obviously receiving large amount of

scrutiny through the BWRBIP program. So we're confident we know the conditions down in the vessel.

MEMBER BONACA: One thing that the ACRS makes clear is that the early phase of the shutdown, the lay-up wasn't as controlled as discussed here. There is various inspection reports from 1987 talking about inadequate lay-ups.

Do you have any comment on the impact of those -- on that inadequate lay-up? I mean is it only for components which have been replaced or doesn't sound that way from the SER.

MR. CROUCH: The fact that we had inadequate lay-ups was recognized and corrected by making the lay-up processes in accordance with the EPRI document. The systems that were affecting this, they will be inspected, as we've talked about, so that we can ensure that if there was any adverse effect from the inadequate lay-up, we'll know about it and respond appropriately.

MEMBER BONACA: That's important because I mean that's one of the reasons why we're talking about the periodic problem. I mean simply there was a phase in which it's not understood whether you had some latent effects that could have negative results when you start operation of power.

MR. CROUCH: Now in addition to systems being in dry lay-up and wet lay-up, we had some systems that were simply drained of water and they were left at basic atmospheric conditions. We found some instances where in two cases systems left in that configuration did experience adverse conditions, in particular, the system called the residual heat removal service water system, which is a raw water system that takes water from the river and is the cooling side of the RHR heat exchangers. During Unit 3 recovery, we found that that piping inside the reactor building was extremely degraded due to the fact that it had moisture ladened air inside it in a basically warm environment. That piping required complete replacement in Unit 3.

When we went over to do Unit 1 recovery, we experienced the same mechanism. We knew it was there before we even started Unit 1 recovery and so all the affected piping in Unit 1 like that has also been replaced.

We also found instances where raw cooling water piping that had been drained experienced degradation because some of the isolation valves allowed water to leak back into the system and you got basically the same condition where you had a small

amount of water in basins and airfield system in a warm environment. And it was corroded to the point that it was usable, so we're replacing approximately 3,000 feet of small bore rock cooling water piping despite that.

We found that piping that was in-service full water did not experience this severe degradation because of the chemical treatment in the biocides that were in the piping, so systems such as raw -- the large raw cooling water piping that was still in service, it was fine. It was just the smaller, small portion that was taken out of service going to specific pieces of equipment that were affected.

So we took the lessons learned from when we laid up Unit 3 and applied into the Unit 1 recovery to ensure that we had the full scope. And what that did for us was and we'll talk about this more when we get the operating experience, it ensured that we have the full scope of systems that are required to be maintained and replaced as far as Unit 1 recovery, so the systems will be in good operating condition for when we start the unit back up.

Moving on to page 15, there's some examples there are of various systems that were in the dry and wet lay-up condition, but what I want to draw

your attention to on this slide is the very last bullet down there. As it says "no credit was taken for the lay-up program in determining acceptability structure systems and components for Unit 1 restart."

As we were talking yesterday, a better way of saying this is that the lay-up program is the sole basis for being -- for us saying that a system is good for restart. In addition to having performed the lay-up, we also are doing these inspections that we talked about and we'll also be doing system testing as we start up to ensure that the systems are capable of performing their design functions.

What we mean by this bullet is we have not used the lay-up as the sole basis for making sure a system is good. We will demonstrate that it's good either through visual inspections or system testing.

Moving on to page 17. As we talked about Unit 1, 2 and 3 were shut down back in 1985. Unit 2 was recovered in 1991. Unit 3 was recovered in 1995. And then they have operated since that point in time. So Unit 1 has approximately 23 years of actual operating, calendar years -- we're up to 22 years. Unit 2 has approximately 23 years of actual operating experience. Unit 3 has 18 years of actual operating experience. That's calendar years.

Unit 3 also experienced approximately 10 years of shutdown and lay-up, lay-up in the very same kind of conditions as what we've seen for Unit 1. So having experienced and extended shutdown in Unit 3 for 10 years, we were able to see basically whatever type of lay-up effects that you would see, shutdown effects, would have matured to the point that they would stabilize before we started the unit back up. So we're confident that the information that we gained by recovering Unit 3 is directly applicable to Unit 1.

As Unit 3 started back up, and has now run for 10 more years, after its long period of shutdown, we have seen no unexpected effects of the layout that the units have come up and they've performed very well. We have seen no unusual degradation that we can attribute directly back to the lay-up.

As we talked about the lay-up experience from Unit 3 has been incorporated in Unit 1, talking about the RHR service water and the small bore piping.

When we get ready to restart Unit 1, the licensing basis for Unit 1 will be the same as what we have in Units 2 and 3. As we talked about back on that Appendix Foxtrot where we've got the 13 programs, things that bring Unit 1 back into conformance with Unit 2 and 3. Therefore, the operating experience

that we have on 2 and 3, actual operation as well as the shutdown, lay-up and restart experience, will be directly applicable to Unit 1. So we're confident that even though Unit 1 does not have the legally required 20 years of operating experience, we have operating experience from sister units that will tell us the condition of Unit 1.

Coupling that with the periodic Unit 1 inspections we talked about, we're confident we will know the condition of Unit 1 and be able to detect any unexpected aging effects as we go through there. As we restart Unit 1, its overall design, configuration, operating procedures, text specs, FSAR and everything will be identical to Units 2 and 3.

So once we get done, Unit 1 will be accumulating its own operating experience under the same operational conditions as what Unit 2 will be experiencing.

Moving on to page 19. Through the course of the license renewal process, we made various commitments to approximately 114 commitments made today and these are being tracked in both our on-site commitment tracking system and our Appendix B problem identification, problem evaluation report or corrective action program systems. This will ensure

that the commitments we made for program implementation will get implemented as we permitted it.

Moving on to page 20, as Dr. Kuo talked about, there are four open items currently. One of these has to do with core plate hold-down bolts. These are the bolts that hold the core plate down and keep it from moving in the event of accidents and transients. We're currently in discussions with the staff about the analyses that were done to demonstrate the fact that these bolts will be able to maintain their strength in pre-load, following an extended period of operation.

The second one has to do with the drywell shell corrosion. What this deals with is up at the top of the drywell, there is a set of metal bellows that separates the refueling cavity from the drywell down below. And the bellows keeps the water from the refueling cavity from going down and getting on the outside of the drywell shell.

The staff has requested that we conduct additional inspections of the shell. We have already made inspections in the past and we feel that our IBE metal containment program is sufficient, but we're still in discussions with the staff to resolve this

technical issue.

The third item has to do with the inspection of some piping that's out in the intake structure. The RHR service water piping out in the intake structure is embedded piping and there was some discussions between us and the staff as to how this piping would be contained within an aging management program. We originally made a statement that we would inspect the pipe. We later realized the pipe was embedded and could not be inspected from the exterior and we were planning on doing an exterior inspection. The staff desires that we do an interior inspection.

However, this piping is under our General Letter 89-13 program and that it receives all of the chemical injections for corrosion inhibitors for microbiological inhibitors and the whole program is in conformance with 89-13 which is what is required by the Generic Aging Lessons Learned document. So we're still in discussion with them as to the exact scope of this piping.

MEMBER DENNING: With regard to that piping, how does it relate to the piping that was replaced in the HRR service water?

MR. CROUCH: This piping has been under water the whole time. It is actually made so that the

chemical injections to it happen immediately upstream of that piping. So it has absolutely the highest concentration of corrosion inhibitors and biocides at that point in the whole system.

We also have coupons back in the system that we can pull occasionally to monitor the condition of the piping. We've been pulling those coupons and they're not showing any evidence of corrosion or microfiling either. So we are confident that the piping itself is in good condition. But that's still under discussion with the Region staff.

The fourth open item is this Unit 1 inspection program we've talked about. We're going to consider that an open item to ensure that the program gets fully scoped out and the details are in it so we ensure that the plant is inspected properly.

So overall, we think we've put together a program that is consistent between Units 1, 2 and 3. We are confident that the program is consistent with the Generic Aging Lessons Learned document. The Appendix Foxtrot in the license renewal application will ensure that Unit 1 will be operationally identical to Units 2 and 3 from the standpoint of the operators' concern as well as for license renewal.

We've taken the operating experience from

Units 2 and 3 from both its operation and shutdown and applied it to Unit 1 as part of the recovery as part of the on-going operation to ensure that we know what this plant's condition is going to be in the ensuing years.

So any other questions?

MEMBER RANSOM: I have another question. I just wanted to go through then this issue of the transfer of operating experience and how it is -- what additional actions are being taken to ensure that Unit 1 really has an appropriate either level of operating experience or compensatory measures. The logic of the initial inspection program only relates to nonreplaced equipment, right?

MR. CROUCH: That's correct.

MEMBER RANSOM: And so in a sense, it accounts for the possibility that during the period of lay-up that there could have been things that were -- some mechanisms could have been initiated that perhaps would show up --

MR. CROUCH: Once the system is turned back in operation.

MEMBER RANSOM: Once the system is turned back in operation. Now there's a lot of equipment, however, that has been replaced and so on that

equipment there is no operating experience, but is the logic that much of that equipment has already been replaced on Units 2 and 3 and so that the parallel operation of 2 and 3 is provided, is that the logic?

MR. CROUCH: That is correct. The same equipment that will be installed on Units 2 and 3, using the same materials, so we have introduced no new materials into Unit 1, not already present in Units 2 and 3.

MEMBER RANSOM: But there's no extended period of operation yet of that new equipment?

MR. CROUCH: That is correct.

MEMBER RANSOM: So --

MR. CROUCH: One other program we didn't talk about is there are periodic inspections for Units 1, 2 and 3. It's one of these other aging management programs that will pick up that type of a situation.

If there are no further questions --

MEMBER POWERS: I've got another question about the periodic inspections that you plan for Unit 1. If you do wind up operating the plant, why those are going to be a mixture of current operating bases as well as power uprated conditions.

MR. CROUCH: That is correct.

MEMBER POWERS: Would it be impossible to

separate -- well, count that, I guess as experience, I would think.

MR. CROUCH: Obviously, we will have to look at the results and determine which of these are where due to just operation as well as which of this is aging effects and so that's the reason we've got our various engineers, metallurgists, etcetera that will look at these results to determine what is the mechanism that's occurring here. Where -- like fact, just purely due to the steam or is this some type of a corrosion mechanism due to aging.

If there are no other questions, I would like to thank you for the opportunity to come and talk to you.

MEMBER BONACA: I think now we'll hear from the staff, someone from the SER.

MR. SUBBARATNAM: Good morning. My name is Ram Subbaratnam. And I an a project manager for the Browns Ferry license renewal application. I'm assisted by Yoira Diaz Sanabria and she'll be presenting her portion of the open items. I'm also assisted by Caudle Julian from Region 2, who helped us with the AMR inspection.

Next slide, please.

(Slide change.)

MR. SUBBARATNAM: Bill already explained that we started out with the two open items in the old SER based on the region's inspection in regard to one more item added on, the out-of-service water piping open item and then based on the discussion with the subcommittee, we also added on the unit one periodic inspection requirement as an open item.

As directed by the Committee, this presentation is only related to the safety-related matters of the license renewal application. As previously stated, this license renewal request is of the current uprate power level and does not include external power uprate. This is only the fundamental principles on which we based this evaluation.

The other principle is restoring the current licensing basis of Unit 1 after completion of those 13 Appendix F items. As long as these two items, as I described, we met the fundamental requirement to grant the license at the current power level.

As suggested by the Committee yesterday, we will only talk about the open items which remain on our plate today.

Section 2.4-3, the drywell shell corrosion, one of the items, TVA did a good job of

explaining the mechanism of how the potential of the postulated corrosion could occur. So I'm not going into the details of that. What all we are trying to do is the two staff options of what will be done.

One is to include the refueling cavity seal in the scope of the license renewal so that this will assure that the potential degradation of an accessible side of the drywell is monitored and managed. Alternatively, the staff would also like to retain an option to periodically monitor the degradation, if any, of the inaccessible side of the drywell by using suitable testing matters like ultrasonic testing. We are still in negotiation and discussion with the licensee and we will find a solution to this one.

VICE CHAIRMAN SHACK: I can understand what I get from Option 2 where I monitor the degradation. What do I really get from Option 1?

MR. SUBBARATNAM: Well, Option 1 also is the same thing in a sense. The thing is the refueling cavity seal currently for definition are not within the scope of license renewal. So we are kind of asking the licensee because of the operational issues and problems with the potential degradation, we are kind of going out to ask them to include it into the

scope so it will include -- they will have to look at it during every refueling outage to see how the refueling seals are holding. There are 15 of them which prevent the leakage going down to the sand pocket area.

VICE CHAIRMAN SHACK: But does that mean it will have to have some program that detects leakage through the seals?

MR. SUBBARATNAM: We have to ensure inspection of those things to see that what is the condition of those leaks. If there is any water accumulation in the sand pocket area, based on what you see down the liner and go from there. And if we think that the seal is bad or it's leaking, we probably will ask them to do a corrective action through the plant corrective action procedure to ask them to replace those seals.

MR. KUO: Ram, I think Dave may want to supplement that.

MR. JENG: I am David Jeng. The Option 1, you raised the question if it was to be included in the scope. That would kick in that this would be covered in the current monitoring program, inspection of the seals, so that would take care of that.

MEMBER POWERS: So you understand Option

2, I guess I don't.

MR. JENG: Sir, could you repeat the question?

MEMBER POWERS: I didn't ask it.

(Laughter.)

MEMBER POWERS: I guess the question is what do we mean by periodically monitor the potential degradation of the unit's inaccessible side.

MR. JENG: That's second option.

MEMBER POWERS: Let me be clear. I don't understand what potential means in the sentence and I don't understand inaccessible.

I mean how do you monitor something that's inaccessible.

MR. JENG: Through the volumetric inspection.

MEMBER POWERS: Again, I don't understand -- if it's inaccessible, you cannot monitor it. That would be definition of inaccessible.

MR. JENG: Well, in theory, there will be action from inside the dry well, along with volumetric inspection. It will tell me whether there is a ceiling or not.

MEMBER POWERS: You plan to monitor the actual degradation and not the potential degradation?

MR. CROUCH: Let me see if I can help. This is Bill Crouch, the site licensing manager from Browns Ferry.

MEMBER POWERS: Maybe you can help. I'm not getting help otherwise.

MR. CROUCH: The Browns Ferry containment is a steel structure with concrete liner.

MEMBER POWERS: Son of a gun. Unusual among BWRs, I take it.

MR. CROUCH: And so since it's got concrete on the outside, you can't get to the outside of the steel shell, obviously, but what's proposed to do is to ultrasonically shoot through it to see if there's any thickness degradation of the shell. So if you shoot it from the inside towards the outside.

MEMBER POWERS: I guess I understood that. Now how does that get to the potential degradation.

MR. CROUCH: I think it's the way they're wording it. They would monitor degradation --

MR. SUBBARATNAM: That is probably correct. Actually, they did have some experience of what recommendation there was.

MR. JENG: When we say potential we mean if there were no leaking of those seals, then of course, there will be no degradation. That's why --

MEMBER POWERS: Not monitoring seals here, surely. Actually, we're looking at the thinning of the steel. And it's just wastage that you will detect, right? That raises another question.

Seems that the Taurus, the Fitzpatrick didn't reflect any wastage, did it?

MR. JENG: This is drywell we're talking about.

MEMBER POWERS: I understand that, but steel is kind of steel, right?

MR. JENG: Yes, we have both kinds of steel.

MEMBER POWERS: So is your ultrasound going to work on cracks?

MR. JENG: Well, we are talking about the material basis of the shell thickness.

MEMBER POWERS: So only on wastage matters. It doesn't matter if this thing cracks?

MR. JENG: It's loss of the material concern.

MEMBER POWERS: I mean, I take it your answer means that cracks don't count; the only thing that counts is wastage.

MR. JENG: There should be an environment and conditions which would be conducive to such a

situation.

MEMBER POWERS: You don't know the conditions on that, so -- it's inaccessible. I'm really confused. It's inaccessible, so you don't know the conditions.

MR. JENG: We know the general environment there.

MEMBER POWERS: Oh, can you give me all the data you have on the general environment? Things like pH, water content, chemistry of the water? Include PHI and concentration, conductivity?

MR. JENG: The water aspect is controlled by the water chemistry program, I believe.

MEMBER POWERS: I don't think there's any water chemistry on the backside of that drywell.

MR. JENG: No, this water come from the reactor, you know, during the refueling operations.

MEMBER POWERS: Dr. Shack, I think you understand my confusion on this second option?

VICE CHAIRMAN SHACK: The assumption is that the degradation is wastage rather than fraction. There's no mechanism for fatigue here, really. There is a possibility of stress corrosion cracking, but that does seem unlikely in a carbon steel in this kind of environment so that certainly the most like

mechanism is wastage which is what they're really protecting.

MEMBER POWERS: I'm struggling to understand how they understand the environment, since it's inaccessible.

MR. JENG: Inside air environment, inside containment air environment.

MEMBER POWERS: There are lots of varieties of air in this world.

MR. SUBBARATNAM: We will take this question under advisement. Before we come back we'll have hopefully a better answer for you, sir.

MEMBER POWERS: Thank you.

MR. SUBBARATNAM: The other open item is Section 3.7 on the periodic inspection. Bill Crouch explained in detail how the evaluation came about. He did explain that we met or exceeded the EPRI requirement for that.

I will briefly describe why did staff and the facilitator exceed beyond the EPRI content. They said the staff needed additional information from the applicant to conclude that no new degradation occurred in the external outage. Specifically, the staff requested the following information, that most severe aging did not occur during the extended outage. And

two, additional agings are properly identified, evaluated and managed and proposed the -- proposed management can distinguish the aging during the extended period from the aging during the future operation.

These are the three basic questions with which staff explored the SER and that led to the Unit 1 periodic inspection. We are still in dialogue with the applicant in finalizing a few of details and what staff is briefly looking at only is the scope of the program, the sampling basis, the aging effects and of course, monitoring and trending.

Bill Couch very briefly said that we going to have three occasions when we are going to look at and do a monitoring and trending. We will have finalized details when we come back to the Committee again. And then also, an operating experience commitment.

So these are all the five items we need to finalize before we can finalize the details of this program.

MEMBER BONACA: Can you go to the previous slide? It says, "BFN submitted Unit 1 periodic inspection program."

MR. SUBBARATNAM: They actually were --

that is true, Dr. Bonaca. What you don't see in the safety evaluation, this happened after we wrote that item.

MEMBER BONACA: I understand. We are commenting on the document interaction and there's a statement there that's not identified as a commitment yet, all this stuff has to happen in the SER.

MR. SUBBARATNAM: Right. And when we plan the SER, you will have a new program evaluation which will be the 39th program. We have evaluation for 38 so far.

MEMBER BONACA: We'll look at it then.

MR. SUBBARATNAM: Yes.

MEMBER BONACA: Okay.

MS. DIAZ SANABRIA: Good morning, I'm Yoira Diaz Sanabria. I'll be discussing the open item in stress relaxation core plate hold-down bolts.

The evolution of the issue started when the staff requested additional information of the applicability of BWRVIP-25 loss of preload criteria for the core plate hold-down bolts due to thermal and irradiated effects.

In its response, the applicant has specified that the analysis was evaluated at the assumed expected loss of preload of 20 percent, which

bounced the original BWRVIP-25 value. The applicant indicated that core plate hold-down bolts will maintain sufficient preload to prevent the sliding of the core plate by friction under normal and accident conditions. The bolts also met their ASME, Section 3, Class 1, level D limit at the end of the period of extended operation.

After the staff review, the method of analysis, based on GE's plan specific stress relaxation analysis on irradiated stainless steel materials, requested additional information for the following: horizontal and vertical loads for all operating conditions, prevention of the sliding of core plate due to friction and in our handouts, you have a different second bullet, which we modified yesterday after talking with the staff. It really is the prevention of the sliding of core plate due to friction. And the third one is axial and bending stresses.

The staff have not yet received the information about the mention of Applicant's steel ongoing on its review since this is proprietary information coming from GE's open request. Then this issue is still open and we're waiting for the response from the applicant. This is our understanding.

Any questions about the open item?

MR. SUBBARATNAM: If there are none, we'll turn now to Caudle Julian and he will describe some of his AMR instruction details for us.

MR. JULIAN: Thank you. My name is Caudle Julian from NRC Region 2 and I was the time leader for the Aging Management Program Inspections, License Renewal Inspections at Browns Ferry.

The first inspection we did at Browns Ferry was conducted November 29th through December 17th and the inspection concluded overall that the existing programs which they're going to credit as aging management programs, were indeed functioning well. The inspectors observed that the applicant had not yet begun the implementation process for the new AMPs, aging management programs, in that AMP procedures had yet to be defined and proposed and for the existing programs identification and selection of which particular existing procedures constitute the AMP had yet to be done. Region 2 concluded that the NRC needed to perform another inspection at Browns Ferry.

We did do a good bit of walking down the plant systems during that visit and in walkdowns of the plant systems, we concluded that the plant

equipment is being maintained adequately.

MEMBER KRESS: On your second bullet there, what does "generally" mean. Does that mean there are particular ones that are not functioning well?

MR. JULIAN: Oh, generally functioning well means as we would see in the norm, in the industry, equivalent to other plants. We go in and we inspect

--

MEMBER KRESS: There's no distinction between general and specific then?

MR. JULIAN: No.

MEMBER KRESS: Okay.

MR. JULIAN: If we go in and start looking at ISI programs, fire protection, etcetera, etcetera and sampling things out of there, we're going to detect some little flaws here and there in documentation or performance at any plant. But we thought that Browns Ferry's was on a par with other people that you looked at.

MEMBER KRESS: Okay, thank you.

MR. JULIAN: So we thought the material condition was being maintained at Browns Ferry adequately.

We went back to the second inspection, September 19th to 23rd, let's go to the next slide, please.

(Slide change.)

MR. JULIAN: There you go. We looked at a sample of aging management programs. I counted 40. I was just looking off an old list, I guess. They say there's 39. They had put together implementation packages for each of the aging management programs. The packages, we found, contained some errors and we concluded that they were not meticulously reviewed.

The applicant initiated a PER, that's a corrective action document, a condition report, essentially, other words are used at other plants, to address this under their Corrective Action Program and go back and look at the scope of the problem, since we weren't working on the sampling basis.

Next slide, please.

(Slide change.)

MR. JULIAN: We looked at their plans for tracking future actions using their TROI system. That's the system that TVA has had for years and years and years which is an electronic system for capturing action items that are mainly coming out of licensing activities.

The system and when we got there was not initially linked to the implementation packages, that is, the file record number for the implementation package did not appear in the action items so it would be hard for a person years hence to go back and track exactly what did they want us to do. When we pointed that out, they quickly corrected that within a day.

The inspection sample that we selected --

VICE CHAIRMAN SHACK: Was that unique to this or is that a feature of their tracking system?

MR. JULIAN: I don't think that it was unique to this particularly. It's a free format that they have in their tracking system. It depends on the author to put down what he thinks is necessary to --

VICE CHAIRMAN SHACK: How do you track without making that link?

MR. JULIAN: It looks to us like these items were added probably into TROI as they were going along through the review process and there were no implementation packages and then they really turned to and built these implementation packages, but have not yet got around to going back and putting the references into the system.

We took our sample of inspection commitments and looked through the stack of paper

about that thick of TROI items and we were able to find a tracking method for everything that we sampled, but it was hard. There was much duplication in the system. There was varying formats and loading items in. For example, one place there would be three separate items for Unit 1, Unit 2, Unit 3. Another place, there would be one item for do this on all three units. And it was not very user-friendly in that you're doing random search just through a pile of paper, trying to find the commitment that you're after.

The applicant recognized that and decided to track this, again under their formal corrective action system and then writing a PER on it. And we concluded we'd like to go back, Region 2 would like to conduct another inspection to see the results of that effort, to ensure that they have indeed everything captured as best we can see.

One technical issue that came up during that discussion, we talked about a lot and Bill Crouch talked about earlier is the RHR service water piping. We recognized during the first inspection that there are the water that flows from the river into the chamber which is the suction for the RHR service water, all the safety-related pumps in the plant flows

through three 24-inch diameter cast iron pipes, about 40 feet long, that are cast into the concrete of the intake structure. We raised the question wouldn't it be a prudent thing to do some sort of inspection on those pipes since they apparently have never been looked at and at first, in the first inspection we thought we had agreement that TVA would do a one-time inspection to look at those pipes to see that nothing bad is going on, the pipes are not corroded away, so we're gradually eroding away the concrete. There's not been some sort of build up of material in there that's choking those pipes down or anything else that's not going on, it's an aging effect.

When we came back the second time, TVA had decided that they did not want to do such an inspection. They don't think it's necessary because they don't think that these things can suffer bad aging effects because of their design and it's too hard. That's what it amounts to. We considered the possibilities of divers doing it, but it's probably too dangerous because we're in an environment where they're operating pumps and other pumps that might automatically start in a hurry.

We do not advocate putting people in danger to do such inspections, but we think there are

various ways using TV cameras and other remote mechanisms that such an inspection could be done and so right now TVA has written a PER on this item and is considering how to resolve that issue or writing down a technical discussion of why they think, don't think that such an inspection is necessary.

We'll be working in the future with NRR to help to resolve this issue. So that's something we'd also like to look at when we go back to the next inspection.

Next slide.

(Slide change.)

MR. JULIAN: The conclusion is that NRC will perform another inspection when the applicant has progressed further with AMP development implementation. And in walking down plant systems and examining plant equipment, the inspectors found no significant adverse conditions. It appears that plant equipment was being maintained adequately.

That concludes what I had to say. Are there any questions?

MR. SUBBARATNAM: Dr. Bonaca, that concludes the staff's presentation.

MEMBER BONACA: Any additional questions from members or members of the public? If none, I'll

turn it over to --

MEMBER POWERS: Let me ask just one area that I'm being somewhat curious about. There are bellows on the downcomers from the drywell into the Taurus. Could those be inspected?

MR. SUBBARATNAM: Actually, Dr. Powers, the staff who was dealing with the safety evaluation on this particular aspect is not there today. David was just filling in for him. I will go back to the staff and ask them. He did mention there was an inspection done on the bellows.

MEMBER POWERS: If you can give me the outcome of that inspection, I'd appreciate that.

MR. SUBBARATNAM: We'll do that and take it under advisement and we'll give you a current answer for next time.

MEMBER POWERS: Appreciate it.

VICE CHAIRMAN SHACK: We're ahead of schedule.

MEMBER KRESS: So we're going to write an interim letter here, is that true?

VICE CHAIRMAN SHACK: We do plan to write an interim letter in this case.

MEMBER KRESS: Okay.

VICE CHAIRMAN SHACK: And Mario has a

draft that we'll be discussing later on today.

We're essentially on a break now until 10:15 if there are no further questions or discussion.

(Off the record.)

VICE CHAIRMAN SHACK: We're back into session. We're now going to discuss the proposed recommendations for resolving generic safety issue GSI-80, "Pipe Break Effects on Control Rod Drive, Hydraulic Lines and the Dry Wells of Boiling Water Reactor Mark 1 and 2 Containments" and Jack Sieber will lead us through this discussion.

MEMBER SIEBER: Okay, thank you, Mr. Chairman. this issue has been around since 1978 and was actually instigated by this Committee at that time and it is one of a dwindling number of general issues as the staff has been working them off.

This one is particularly interesting. The concern with the smaller containments is just that. The containments are small, the pressures go higher and the heat absorption and the rejection capability is challenged a little bit more than in the larger containments. The issue here is if there is a LOCA which impacts the hydraulic lines in boiling water reactors, the hydraulic lines which control, provide the motor power to the control rod drive mechanisms,

the question is will the reactor scram or not, because when you have a LOCA you would like the reactor to shut down, particularly if you're going to inject cold water to it, to cool the core. If you have excess reactivity that will give you a cold water accident. The core will overheat and you end up with a major problem. So that's basically the issue.

Now for other control rod drive mechanisms that work is that they have a high pressure heat line and they have a discharge line and the reactor rods will actually be inserted, even if the high pressure line is broken because it can use the pressure inside the reactor vessel to operate the control rod. And if you break the discharge line, that's okay too, because the water will just dump out on the floor and the rod will still insert. The big problem comes is if you somehow block the discharge line so that it can't discharge the water, then the rod won't insert into the core and the resolution of this issue looks at the various ways and the probabilities of either crimping the line shot or otherwise preventing the water from coming out of the discharge line.

So with that introduction, that's basically what the crux of the problem involved in generic safety issue 80 is. I would like to introduce

Jack Rosenthal from the staff to give us further introduction.

MR. ROSENTHAL: Jack Rosenthal, Advance Reactor and Regulatory Effectiveness Branch in the Office of Research.

Given your introduction, I really don't know that I have very much more to say. I just wanted to call your attention to the fact that the decision lingered with us for a while, with the vulnerability identified and just recently Abdul Sheikh did some ANSYS calcs which you'll hear about and that provided a real engineering implement -- increment -- that allows us to resolve the issue. That's a big change that's happened in the last year.

With that, Harold?

MR. VANDERMOLEN: Thank you, Jack. My name is Harold Vandermolen. I work for the Generic Issues Program. On my left is Mr. Abdul Sheikh, who works with the Division of Engineering Technology and yes, we've -- it is indeed a very interesting issue. I'd like to start out by reviewing a little bit with the sequence of events that happens in this --

MEMBER APOSTOLAKIS: Is it clear to everyone why this has been a safety issue for so many years? You said 1977?

MEMBER SIEBER: It was rated as a low priority for many years.

MR. VANDERMOLEN: I'm going to touch on the history in just a moment.

MEMBER APOSTOLAKIS: You will?

MR. VANDERMOLEN: Yes.

MEMBER APOSTOLAKIS: Okay, thank you.

MR. VANDERMOLEN: In the course of the scenario under consideration, we start out with a classic large break LOCA in a boiling water reactor and in this particular scenario, it was noticed that some of these pipes come very near some of the control rod drive hydraulic lines. Now a boiler will have something on the order of 180 control rods, so it's quite a nest of these lines. The hydraulic control units are located outside of primary containment and each one has to be connected to its control rod drive through two lines. So in certain areas around the vessel support skirt you have quite a bunch of these going in.

Now again, it's true, breaking the lines -- it was designed as such that breaking these lines is not going to be a problem. But crimping them shut could give you a problem and what we worry about is the ECCS system that in refilling the reactor with

cold water, and some of the rods being left behind. The way the issue was first posited, we were going to -- we were supposed to worry first about a possible reactivity excursion, which turns out to be not that much of a problem, but also the fact that it's an additional post-LOCAL heat source which is potentially more of a problem. We'll be going into this in considerably more detail in just a moment.

If we can go on to the next slide, I'll just give you a heads up.

(Slide change.)

MR. VANDERMOLEN: After a lot of work, particularly by Mr. Sheikh next to me here, we did discover that the core damage frequency was well below the thresholds and the public risk was also well below the thresholds for us to actually take regulatory action.

I'd like to review the history of this issue a little bit. It was actually raised formally as an inherent issue by the ACRS in 1983 and actually was first discovered earlier than that when an ACRS member on a plant tour noticed that some of the large break -- large pipes were rather close to the next of control rod drive hydraulic lines and started asking well, can you really picture these things remaining

operable if this huge pipe right next to it with 1,000 psi inside of it has burst? Very good question.

We did look at it, beginning of 1983, and we did a -- what we now call a screening analysis. Back then we called it prioritization. It was a calculation that was reminiscent of the sort of thing you should do with nuclear cross section work. As we look at the sort of target area of the nest of control rod drive hydraulic lines and how much -- it's not really a solid angle because you don't go in four or five directions, but how much of an area is subtended from potential sources of -- where the pipe would break and we were worried about things like pieces breaking off, missiles, and things like that.

Purely on these semi-geometrical arrangements, we got a fairly low core damage frequency and we prioritized it as low priority in 1984. Now this is one -- at that time approximately 400 generic issues, so it didn't get to the top of the priority list for many years. What happened then in 1995 it was closed out. That is not because we got tired of it. Nor did we change anything in our analysis. What happened was in 1995, the agency had a policy change where we switched from valuing a person rem at $1,000 to $2,000. And all of these --

there was sort of a blank action. There were many staff projects that were based on risk-informed priority considerations and this then descended into the draft category.

Well, it didn't stay there very long. In 1998, we had a team of people going out, actually working on a different issue, Generic Issue 156-61 and going through some plants looking at piping layouts and they discovered some Mark 1 boilers that not only had the pipe, the large recirc pipe near the control rod drive hydraulic lines, but actually going through the middle of the nest.

And the project manager for that generic issue came to me and said did you know about this? Was this covered in your original analysis? I said well, no. I actually said a few other things, we won't go into that, but it was a bit of a surprise and immediately we said we've got to take a look at this and fortunately we still had that team available and so while they were doing that generic issue, we asked them to start collecting some data for Generic Issue 80 as well.

And they did put together a NUREG in 1999, identifying these breaks and actually reassessing the priority. It's quite a conservative calculation, but

we reopened the issue at that point.

So George, maybe I should stop. Have I answered your question now?

MEMBER APOSTOLAKIS: Yes, that's good. Thank you.

MR. VANDERMOLEN: So it has been a very -- whoops. It has been indeed an interesting process. It was obvious we had to go through a completely different approach. You could not simply write this off based on geometry because it simply was not true. So we went to the Division of Engineering Technology and started asking them well, just what can happen if you have an impact of this nature and at this point I'm going to turn it over to Mr. Sheikh who is going to describe some of these calculations.

MR. SHEIKH: Okay, so I started with this and I looked -- the objective of the assessment was to perform a detailed analysis to see what's the interaction between the big RCS and RH piping with the CRD pipe. And then look whether that after the impact, whether the CRD piping can be crimped, completely shut before it breaks or it will have some space still there before it breaks. So that is the key issue in this analysis.

And based on that, this was a

deterministic approach. But then we went on further and also developed a probabilistic approach to it to determine the CDF, core damage frequencies, for this piping. And then we compared the core damage frequencies with the management directive 6.4 recommendations.

The RHR and RCS piping for Mark I and Mark II -- inside the containment is essentially the same as shown on the next page. There's no basic difference in the routing of the piping inside the containment or the drywell.

The differences are in the layout of the CRD piping. The older plant Mark 1DII has three sets of CRD bundles as shown on page 8 and they come out from one side of the reactor. The other plants, next page -- the other plants have four sets of bundles and they come out diagonally off of it and in this picture on the plant I've shown only two coming out, but they are symmetric, two bundles one the other side.

So the way we did this assessment, we kept the approach which was originally followed in the NUREG 6395 which was issued in 1999 which identified these issues as medium priority and high priority.

For calculating the core damage frequencies, we have done some work which Harold has

done which is based on the most conservative approach which is the NUREG 1150 values, but just to have an idea in the detailed assessment which we passed on, we looked at other frequencies which have been developed since then which are two orders of the magnitude than the NUREG 1150.

The core damage frequencies is dependent on four items which is initiating event and the next item which they called and I followed the same names as in the NUREG CR6395, the next one is PIPETYPE and what they considered the PIPETYPE to be, the number of pipe breaks in that RHR or RCS system as a fraction of total number of five breaks in the high energy lines inside the containment. So that's one factor.

The next factor is the TYPEFRAC and I have -- we have these numbers in the detailed assessment report. Then the next number is the TYPEFRAC which is the fraction of RHR or RCS pipe that can impact on the CRD piping. What we looked at, what represented the plants for different GE models and we looked at the total length of RCS or RHR piping and then looked at where the breaks are predicted in the RCS or RHR piping and looked at how much of that piping can impact the CRD bundles and calculated that fraction.

And then the last item is the RUPTPROB

which is the probability of this RCS piping or RHR piping causing a complete blockage of the CRD piping. That's the issue we have addressed before.

We were not worried that if they bend the pipe or they have a smaller gap. Next page.

(Slide change.)

MR. SHEIKH: So we looked at the different containments. The first one was a GE2 containment, Mark I which is the oldest plant and looking at the layout of these plants, because the CRD piping is located on one side, the RHR piping was not -- couldn't impact the CRD bundles. The RCS piping could impact the CRD bundles and this is shown -- I don't have it, but it's in the assessment, but if you go back to page 8, it's the pipe sits in between the two top bundles. The picture is there in the assessment --

MEMBER SIEBER: Is it shown?

MR. SHEIKH: The pipe sits somewhere. So we looked at the possibility and it's more or less -- the layout is similar to the picture shown on page 14. You can see the CRD bundles. This is the CRD bundles.

MEMBER SIEBER: You will have to talk into the microphone.

MR. SHEIKH: So anyway, the CRD bundles

are there and this is the pipe break. And the break locations, as I said, it's about 18 feet from the CRD bundles and there is a gap at this point of 25 inches.

VICE CHAIRMAN SHACK: When I looked at that, I was trying to figure out why I didn't end up with that final reflected shape. There's a sort of a white cross up there at the top. That's not a stop of any sort. This thing is just straightened out so the jet force is not bending, the moments are balanced and that's the equilibrium configuration of the pipe.

MR. SHEIKH: Yes. I don't know how this white mark is --

VICE CHAIRMAN SHACK: Okay, it's just there.

MR. SHEIKH: Right. This is another GE5 plant, but this is very similar to the GE2 plant. And as you can see, the pipe is not going to hit the CRD bundles, but we went a step further and we assumed it hits the bundle. And we looked at -- we put a small force, a very small force on the RCS pipe.

VICE CHAIRMAN SHACK: The jet force is 600 to a 1000 kip and you put a 1 kip force?

MR. SHEIKH: Right.

VICE CHAIRMAN SHACK: Why?

MR. SHEIKH: Because you can see, once the

-- the pipe is so flexible and any force is going to bend it. As you can see on page 12. And the pipe was, this pipe has deflected almost 90 degrees by a force of a thousand pounds. So if I put more force, it's going to break.

The idea is to show it as it bends, you can still see that there's no complete blockage there and this is also documented in the famous work done at one of the national labs and passed on pictures which shows that they did some actual test on pipe to pipe impact. And they all show that the pipes never crimp completely blocked.

VICE CHAIRMAN SHACK: But then my question there was, okay, you demonstrated that for 3-inch pipe and you recorded the result for a 4-inch pipe, but isn't it easier to crimp a 1-inch pipe?

MR. SHEIKH: No, it's actually the reverse.

VICE CHAIRMAN SHACK: It's harder?

MR. SHEIKH: Right. Because the stiffness of the 1-inch pipe is in bending, is much smaller than in the crushing, you know, as you can imagine, if you have a smaller diameter and you're pushing it with a bigger diameter, it's much harder to crush. Before it crushes, it bends.

VICE CHAIRMAN SHACK: But I envision it bending so much that it's some plastic hinge that forms the kink.

MR. SHEIKH: Yes, but before it forms a hinge, it breaks. And --

VICE CHAIRMAN SHACK: Okay, I guess that's -- is it clear that a 1-inch pipe will break faster than a 4-inch pipe or a 3-inch pipe?

MR. SHEIKH: That is true, because the stiffness -- I mean the ultimate capacity of the pipe is dependent on the stiffness of the pipe and that stiffness is based on the diameter. It's the diameter to the top power of 4 is the stiffness.

VICE CHAIRMAN SHACK: Yes.

MR. SHEIKH: So a 4-inch pipe doesn't break, I mean completely shuts. One-inch pipe cannot. And this report is 5 to 5 impact, 6395. I have shared it with you. They also did this ANSYS's work on it, previously, and they came up with the same conclusion.

But let me find out. We are going defense-in-depth. Number one, we have shown that there is no realistic possibility of the pipe impacting the bundle. Then we are saying if it impacts, it's not going to crimp.

MEMBER DENNING: Can you take us back

again to the Slide 14. There you are saying based upon that, that the pipe isn't going to impact the bundle. What if the pipe break had occurred at the other end, is there a possibility of a break configuration in which you would have forces moving that pipe up?

MR. SHEIKH: Pipe breaks are based on our Reg. Guide and they are for the RCS, the breaks are identified with the stress levels and this is the breaks we are considering is the break at the nozzles.

MEMBER DENNING: So you don't allow the breaks to occur in places other than what you consider to be the high stress levels like in a nozzle?

MR. SHEIKH: And you can't have a break up in the center of the pipe. These have to be -- the breaks have to be at the nozzle.

MEMBER DENNING: It's just not allowed, huh?

(Laughter.)

I mean you physically don't think you can break a pipe there is what you're saying?

MR. SHEIKH: And that is the basis of all the OSEP 3 plants. We don't consider a break in the middle of the pipe. This is not special for these. We do the same thing for the plants which are licensed

after this generic issue.

MEMBER DENNING: For any pipe crimp analysis.

MR. SHEIKH: Right. Anyway, so after we have done this analysis and we concluded that the pipe will bend without significant crushing or crimping before rupture and as was mentioned and passed out these pictures, this behavior is consistent with what we have observed in previous tests.

However, to get to the PR core damage frequently, we came up with the arbitrary number of .1 for this factor RUPTROB to determine what Harold has determined the value is.

MEMBER DENNING: Okay, so this is equivalent to saying that a fracture somewhere in the middle there is 10 percent of the probability that you'll get a fracture at the nozzle, assume it's not impossible to break the straight pipe.

MR. SHEIKH: Right. And these on top of it, Harold's calculations are based on NUREG-1150 and all the draft NUREGs which we are going to be publishing soon. For large damage of pipes, the probability of failure is two orders of magnitude higher. So even if you consider a problem with 1, 2 is still okay.

So let me just carry on with the next one.

(Slide change.)

MR. SHEIKH: This layout, is like we said, is for the other newer plants with a GE3, GE4 and GE5 and essentially the two sets of bundles run parallel on each side of the reactor and there is an RHR pipe up there as shown in Section 8 and it can break. There, again, the way the analysis is done is it's a guillotine break on the RHR on these lines and when you have a guillotine break, the pipe breaks straight in the direction. It's assumed to break straight in line of the pipe.

So as you can see in picture, there is very little series of gaps, 12 to 15 inches here, so if the break occurs here, the pipe is going to go straight and the likelihood of this hitting this bundle which are separated by 15 inches is at least in the deterministic approach, we don't consider it.

MEMBER DENNING: But my impression looking at pipe whips is they go all over the place. Am I wrong?

VICE CHAIRMAN SHACK: Like a firehose.

MEMBER DENNING: Yes, like a firehose. Is that not true?

MR. SHEIKH: These are postulated breaks.

If you have a pipe break, we are assuming that it's a certain guillotine break which means the whole circumference breaks.

MEMBER DENNING: Yes, but don't you have to do it in the most conservative manner in terms of thinking of well, that there could be lateral --

VICE CHAIRMAN SHACK: A zone of influence that looks like a cone?

MR. SHEIKH: If you see the guidelines the way it is done it's straight. That's the force that's taken, going straight in the axis of the pipe.

MEMBER APOSTOLAKIS: Guidelines? Whose guidelines are these?

MR. SHEIKH: The MEB guidelines, the way the plans are designed to always take the full strip out.

MEMBER APOSTOLAKIS: I don't know what that means. The guidelines take precedence.

MEMBER DENNING: The question is do you really believe that -- I mean I realize you may not believe in a guillotine break, but to say that it happens in just the most ideal fashion so that there aren't lateral forces, that certainly doesn't seem like a very good regulatory, conservative regulatory position.

I can certainly see in certain conditions where that's the most conservative thing to do, but here it just happens that everything lined up so that it's going to go and not hit anything whereas something that might be more real, there would be some probability it would.

MEMBER SIEBER: Maybe I can give you a little insight. I've not seen formal experiments in pipe breaks, but I've seen coal-fired power plant boiler tubes burst and what they do and they actually do not whip around. They will deflect into some position where there is some minimization of the forces on it and just stay there. They may be twisted and they change from the original flow vector, 90 degrees or what have you, but they don't flip around and spray like a firehose does. I don't know if that provides any insight or not.

MR. SHEIKH: But going back, this is -- this is like defense-in-depth. Once we have established that the pipe moves sideways for the purpose of Generic Issue 80, even if it hits those bundles, we are saying that it's not going to completely block the pipe and that's the issue. We can defer on whether the pipe will not whip on the side, but as far as the purpose of the Generic Issue

80, even if the pipe hits it, it's not going to crimp it completely shut and that's the issue.

MEMBER DENNING: It's really not taking credit for the possibility that it will whip in the other direction which from that configuration wouldn't matter anyway. It will hit some of the pipes regardless, but if it moves, it hits.

MR. SHEIKH: On the GE-5 plants, there are a total of four plants and these are the later versions of the plants. Most of these plants have installed pipe with restraints and we looked at the piping analysis reports for these plants and we found that * (10:52:25) point 2 is the only one predicting a break as on the intermediate valve as shown on page 16.

This break.

Although the piping system, we looked at the piping system for all the four plants that they all supplied by GE, configuration is the same, everything, and all other three plants don't postulate a break there.

So if bad breaks happen, there is a pipe restraint here and we are saying even if there is a possibility, we don't know, but there is a possibility that this pipe restraint can stop the pipe from

impacting the CRD bundles here because the pipe vertical section of the pipe will move here.

However, once it hits, it's going to hit, part of it is going to hit the concrete and part of it is going to hit the CRD bundles and then going back to my original argument, if it happens, it won't crimp it.

MEMBER DENNING: Before you go on, let's talk about the crimping argument, just to see whether -- there are some figures here that look like they're real pipes, but as far as ANSYS's ability to predict this, how good is it really able to do this? Isn't this a -- I mean, this is a pretty difficult problem as you get into the kinking area and I think that you are making an argument that it failed before crimping shut and do we really believe your failure criterion, or is it possible that in the ANSYS analysis it's believed to be a conservative assumption to say well, it will fail at a certain condition whereas it could be that in reality that it is able to survive to the crimped position? How much confidence should I have in that ANSYS' ability to predict this kind of condition which gets into a kind of an unstable mode when you get to a certain location?

MR. SHEIKH: I don't have the data here,

but for another project we recently ran with another program, Abacus and the results are the same.

MEMBER DENNING: Well, that doesn't necessarily give me a lot of confidence.

Bill, what's your feeling? How much should I believe that analysis?

VICE CHAIRMAN SHACK: You know, that's the thing, these things always predict the deformation. The failure is the tricky part. It would be nice to see the analysis benchmarked against some of these experiments.

MR. SHEIKH: Right, but you know we are talking about is the threshold of failure. It's very difficult to predict, but looking on the other hand, we are talking about a force of a thousand kips hitting these small pipes and we are saying that 6 percent of the force it can destroy 70 of these pipes. So we have to look in the order of the magnitude of the problem.

MEMBER DENNING: And how many -- I was kind of wondering in the analysis, when we assume that some are crimped, how many do we assume are crimped? Does it just take one to get you into problem or do you have to have multiple of the rods not able to enter the core.

MR. SHEIKH: Say that once again?

MEMBER DENNING: Does it only take one rod not entering the core to get you into trouble and do we -- is that what you assume?

MR. VANDERMOLEN: It takes more than one rod, but we don't take credit for that. We assume that -- I'll get into that in a minute.

VICE CHAIRMAN SHACK: But coming back, your argument is again with a very small force you're going to fail the pipe, therefore with the realistic bigger force, your chances of failing the pipe are virtually one and you're going to take it at point 1 anyway and so you're conservative.

MEMBER DENNING: But I do see where you've got these bundled where you're running into and you made -- knocked the heck out of the first couple of them and then as they're kind of losing energy and you have to get one, if that's what it took and that's kind of what I'm wondering, is how many --

MR. SHEIKH: That's what I'm trying to say, that the force, the impact force is dependent on the gap between the RCS pipe and the bundles. And what I calculated assumes that it's only a 6-inch gap and you hit the big pipe on the 70 bundles as 70 pipes

in a bundle and it only takes 6 percent of the force to destroy all those bundles.

MEMBER DENNING: Oh, I see what you're saying. They have -- the factor there isn't very important at all. That's not what's involved with bringing the pipe to rest.

MR. SHEIKH: So you have 25-inch gap, the impact force is significantly more.

MR. VANDERMOLEN: Well, going on to number 17, let me describe a little bit about how we tried to turn this in a probabilistic analysis. As Abdul said a moment ago, we use the four factors that came from an earlier study.

The end state, of course, you must multiply these four probabilities together. It's actually a little bit more complicated than that. Again, as we said earlier for our initiating event frequency, we use sort of a classic value that was used in NUREG 1150. We are aware that there are numerous studies that are coming up with smaller numbers, but we didn't at this point want to take credit for them. But we are aware that they're there.

The next two factors are basically geometrical. We put those in the analysis only unlike the initiating event frequency which is typically a

long normal distribution going up or down a factor of 10, the next two we put together a normal distribution, not long normal, but normal, thinking it was more appropriate for that particular parameter and the way it was based. And we actually have more data there than we do in the LOCA, so we can be fairly certain that we can capture it that way.

The interesting one is the very last one, RUPTPROB which is not a rupture probability, but instead the probability of the pipe whip or jet impingement causing CRD system failure. Now, as we were discussing before in these calculations done on ANSYS really say that it's not going to happen at all and when you put on a distribution there, it's really sort of a degree of belief how confident are you of those answers and have those colleagues told us that we've allowed about a 10 percent likelihood that it could happen, that the calculations might not model everything correctly.

And the way we handle that in this analysis which is has been labeled a bit primitive, but we think is defensible is to take an exponential distribution where it comes down, it has its maximum 0at zero, but we adjusted the exponential parameter to make the mean of that distribution equal to .1. And

we put those in our various codes.

MEMBER DENNING: Before you get to the bottom line, back on the initiating event frequency, how does that get apportioned among the piping. I can't remember exactly how it's really done. I know -- I think in WASH 1400, it was per length of pipe and that wasn't a very good way to do

MR. VANDERMOLEN: WASH 1400 and 1150 it was considered to be 10^{-4} for all the piping put together. But somehow we came up with that and I can't remember whether that was -- and I think there were length of pipe arguments on it as opposed to number of junctions or things like that.

MEMBER DENNING: I've seen it done both ways.

MR. VANDERMOLEN: Yes.

MEMBER DENNING: Then how did you apportion that?

MR. VANDERMOLEN: The apportioning factors are actually PIPETYPE and TYPEFRAC as Abdul just discussed.

MEMBER DENNING: That's a plant-wide frequency and then these others --

MR. VANDERMOLEN: Fortunately, you have two of the systems that could be involved and then to

the vulnerability areas near the SER new lines.

I should turn it over to Abdul for that.

MR. SHEIKH: As I explained, the other two factors of PIPETYPE is the issue of the total number of breaks in all the high energy lines in the containment. I'm sorry, the total of the fraction of the total number of breaks in the RHR lines inside the containment divided by the total number of breaks and the high energy lines with the steam line, the feed water line, all the lines which are inside the containment.

MEMBER DENNING: How do you decide what that fraction ought to be? Is it length of piping or is it --

MR. SHEIKH: No, the number of breaks.

VICE CHAIRMAN SHACK: Which is like high stress junctions.

MEMBER DENNING: The number of junctions.

VICE CHAIRMAN SHACK: Well, high stress locations.

MEMBER DENNING: High stress locations. So it's proportional to the number of high stress locations.

MR. SHEIKH: Right.

VICE CHAIRMAN SHACK: Which probably isn't

too different from other ways you could apportion it out.

MEMBER APOSTOLAKIS: What is a * (11:02:57).

MR. VANDERMOLEN: WASH 1400 goes back a long ways.

MEMBER APOSTOLAKIS: I thought there was more recent work.

MR. VANDERMOLEN: There is more recent work. They all predict lower values. We thought if we used this, no one would argue.

(Laughter.)

MEMBER APOSTOLAKIS: Unless your results were undesirable.

MR. VANDERMOLEN: Well, that's true. Well, absolutely, yes. This happens fairly frequently. Quite often at Engineer * (11:03:28) Space, we are working in areas that are pushing the envelope a little bit on PRA technology. So it's not an unusual situation. We try to bound it where we can. And unlike a classic PRA, we are sometimes using a considerable approach, at least I would not want to -- I'm not sure I would feel comfortable closing this issue out by taking credit for one of these newer distributions until it's been thoroughly approved,

peer-reviewed and certainly with the stamp of this Committee on it.

MEMBER APOSTOLAKIS: So your definition of classic is going back to the reactor safety standard?

MR. VANDERMOLEN: Yes.

MEMBER APOSTOLAKIS: Not to the Romans and the Greeks.

MR. VANDERMOLEN: Not to the Romans, no. It went back to WASH 1400 and the reg. took it from there.

MEMBER APOSTOLAKIS: So are we going to see these distributions now?

MR. VANDERMOLEN: I didn't pick them out. I dread to tell you how it came out, yes.

MEMBER POWERS: It seems to be in your argument that a high energy line break is equally probable at all, high stress location?

MEMBER APOSTOLAKIS: Yes.

MR. VANDERMOLEN: That's correct.

MEMBER POWERS: It seems to me I would have hinted to take it -- saying it's either where it doesn't damage to my CRD piping or not and since I have no idea I would take it 50-50.

MR. SHEIKH: That is countered by the fact that TYPEFRAC which is the ratio of the RHR piping

which can affect the CRD bundles as compared to the total length of RHR piping inside container.

MEMBER POWERS: Well, I will tell you what my inherent fear is is that by breaking it down into these PIPETYPE and TYPEFRAC that you're trying -- you're segmenting down areas that you don't know anything about and you get the classic problem have I segmented it far enough, it doesn't matter what probability I put in there or I will come up with a new consequence or result.

MR. VANDERMOLEN: I like to think that we don't do things like that.

MEMBER POWERS: So would I, but I mean --

MR. VANDERMOLEN: It's the best approach we have. If there were -- I'm not aware of any other bases. If anyone knows of one, we would be more than happy to use it. I'm not aware of any.

MEMBER POWERS: I guess the responsibility is to show sensitive you are the particulars of these distributions.

MR. VANDERMOLEN: Yes. It's actually, for the width of these distributions, it's not very sensitive. Things are pretty well dominated by that initial event frequency uncertainty which is a factor of 10. These are not going to be anywhere near that.

And of course, that last one with the exponential has a long tail on it.

Going on to the next slide, I'll show you what happens when you start cranking it through. It's the usual sort of thing and I have to give the sermon I always have to give whenever I show one of these tables. The fact that we've shown them to two significant figures does not mean that we know these things to that accuracy. The accuracy is shown by looking at the various columns.

VICE CHAIRMAN SHACK: Don't apologize, this is great.

(Laughter.)

MR. VANDERMOLEN: The major reason -- I always have to apologize to someone --

VICE CHAIRMAN SHACK: No, you don't have to. This is great.

MR. VANDERMOLEN: One time I tried doing it at just one significant figure, then the point estimates looked just like the means and somebody asked if I'd actually done the work.

(Laughter.)

MR. SHEIKH: Just a moment if I could interrupt, we always have to make that speech.

(Laughter.)

VICE CHAIRMAN SHACK: These things are critical. These guys did the right thing here.

MR. VANDERMOLEN: I'd like to discuss a little bit what this really means and I think I can --

MEMBER APOSTOLAKIS: Why are your means so close to the * (11:08:01)

MR. VANDERMOLEN: As far as I can tell it's fortuitous. I think it's because the exponential and the -- it's being dominated by the --

MEMBER APOSTOLAKIS: I think it's because you have long tails. It shouldn't happen. So what happened to your tails?

MR. VANDERMOLEN: They're there. It's 10,000 -- it's wiggling every one of those parameters up through its distribution and we did the calculation 10,000 times.

MEMBER APOSTOLAKIS: So the mean is a rigorous Monte Carlo result?

MR. VANDERMOLEN: Yes. Not LHS, it's Monte Carlo.

MEMBER APOSTOLAKIS: Yes.

MEMBER POWERS: It simply refutes the oft-quoted argument that point estimates are close to medians.

MEMBER APOSTOLAKIS: Yes, but I think it

depends a lot on the shape of the distribution.

MR. VANDERMOLEN: It does.

MEMBER APOSTOLAKIS: And also it depends on what you call point estimate. What is your point estimate?

MR. VANDERMOLEN: It's multiplying four means together.

MEMBER APOSTOLAKIS: The means. You see, the biggest question with the PRAs is whether the inputs are actually means.

MR. VANDERMOLEN: Yes.

MEMBER APOSTOLAKIS: It's not so much what happens to the inputs after you calculate. As someone from the staff told us once, they are means because we say they are which I thought was a very good answer.

MEMBER POWERS: When you do an uncertainty analysis you take that number and you put an error factor on it and it will still be the mean.

MR. VANDERMOLEN: It's a wider question than this generic issue, but --

MEMBER APOSTOLAKIS: The driver here, that's important. Do you have a single event or failure that drives these numbers? It doesn't appear that you have that.

MR. VANDERMOLEN: No, not that I know of,

no.

MEMBER APOSTOLAKIS: Yes, you don't. Okay, so you really have defense-in-depth too.

MR. VANDERMOLEN: I guess we do.

MEMBER APOSTOLAKIS: You don't guess, however, you do.

(Laughter.)

MR. VANDERMOLEN: I hadn't thought about it.

MEMBER APOSTOLAKIS: Well, that's why you come before this Committee to get insights.

(Laughter.)

MR. VANDERMOLEN: Well, I have to say appearing here is often very thought-provoking.

MEMBER DENNING: And this is the sequence frequencies. This is not the core damage frequency.

MR. VANDERMOLEN: That is exactly what I'm about to address. It's very tempting to call these core damage frequencies, but it isn't really. Calling these core damage frequencies -- in a very real sense we do, is a very conservative assumption and I think I'm going to try and address -- I can't remember the exact reading of your question earlier, but let me see if I can address it.

What happens in this reactor when this

actually happens, you've broken a pipe. The plant, the reactor depressurizes over a period of time, not instantly, but fairly rapidly. The chain reaction stops very quickly due to the high voiding, but once you've gotten the whole core steam blanket, it starts refilling, some of that I sort of left out.

Now it is true that a voiding water reactor at cold, clean, beginning-of-cycle conditions can achieve criticality on just two rods, if they're adjacent, or diagonally adjacent. Now this is clearly going to be a troublesome situation, but ultimately you want to take this reactor apart after the accident. You've got to have to find some way of getting it subcritical. It's not impossible, but it is going to be troublesome.

But look at what happens right afterwards. As it comes in, you are going to get plenty of voiding. You will refill the core up to the collapse level, up to the two-thirds core height of this accident that matches the jet pump height. And it takes 30 to 40 seconds to refill that core. I will say that because I don't want to beat this to death, but the original question of this Generic Issue was the possibility of reactivity excursion and the reactivity excursion -- the fill time constant of the

fuel is about six seconds, less for some of the modern designs, but on that order.

You are not going to add reactivity so quickly that you don't get moderator feedback. So you're going to lower the rods by the voiding and you're not going to get that excursion.

You do worry a little bit about overheating certain areas of the core and it's part of the reflood, but maybe not as much as you might think because you will turn the chain reaction back on again when you're quenching the core, so you're already turning it over.

But you can get into trouble. This is not a benign event. Ultimately, you're going to reflood that core and it's not going to shut off. Now reflooding the core keeps you from disaster right at the beginning, but ultimately you have to have a heat sink established to the outside. You did that in a boiling water reactor with the RHR heat exchangers. There are four of them and typically they will add up to about two and a half percent of radiothermal power in their heat dissipation capacity.

MEMBER APOSTOLAKIS: Decay heat.

MR. VANDERMOLEN: Right. Now decay heat is going to be fairly high right after the event, but

you have plenty of heat capacity in the pool. But over the long term, after about -- let's see about four hours it got up to 1 percent in your decay heat production, 1 percent of radiothermal power. I'm just using that as a benchmark. And you can dissipate two and a half percent. That's more than enough to bring the plant down.

But if you don't turn the core off, a couple of rods out are probably not going to be a problem. You probably have a fairly, honestly large cluster, but as long as you can stay below a few percent power, you can probably handle it, but if you knock out a quarter of the core, then ultimately you're going to boil the suppression pool. You're going to lose MPSH and your RHR injection and you're going to have a problem in the core.

MEMBER DENNING: Are you assuming there's no ink or is there some reason why it wouldn't inject? Ink?

MR. VANDERMOLEN: Oh, standby liquid.

MEMBER DENNING: Standby liquid, yes.

MR. VANDERMOLEN: We didn't give credit for it and the reason is semi-liquid control is sized, well, it was originally sized to borate reactor with the reactor vessel's normal inventory. Now in this

accident, you are deluding it with the entire suppression pool, pumping it through. Now that adds about 7.5 vessel inventories, at least at Browns Ferry which is the plant I had them check. I think the others are going typically to that. So that's going to lower your ultimate concentration by roughly a factor of eight. It's not going to be enough to bring you some critical -- now that, I don't have any numbers. I understand that some of these plants are now using isotopically enriched boron 10. I don't know what these situations will be there. But that's the reason we're not giving credit for it.

Nor have we given credit for another possibility, every boiler has some way of pumping river water in there. Usually, it's a chain of valve or two between the service water and the RHR injection, but there's always some way where you can ultimately flood the whole thing. It's not normally credited for something like this, but that could be done as well. That would be manual operation of the part of the operators unlocking padlocks and what not on valves or putting in flanges, * (11:15:17) pieces between flanges, something of that nature. You clearly would never want to do that under any normal circumstances, but they do that have. It's called --

what is it called? I'm having a senior moment here.

MEMBER DENNING: The ultimate disaster.

MR. VANDERMOLEN: Well, they have some slang words for it that I don't want to repeat here, but I can't remember the polite word for it.

Standby coolant supply, I believe it is, is what you find in the training manuals. So that is also there.

Well, keeping that all in mind, you see that what we've calculated here are estimated, a probability or a frequency of that state where you have a refilled reactor with some number of rods left behind. That does not necessarily equate to a core damage frequency. However, our thresholds for core damage frequency are even for a plant that's fairly high in its existing core damage frequency are in the order of -- the threshold is 10^{6}. All the plants affected here in their IPEs are reporting an existing core damage frequency lower than that. These are all numbers that in Management Directive 6.4.

Normally, they'd have to have something -- or 10^{-5} in order to be able to take action based on core damage frequency. So this isn't going to make it over the threshold for that. That doesn't mean that we like the situation. It means that we don't have

enough basis to actually take the regulatory action where the burden of proof is on the agency. We did -- we were not satisfied with just this. We thought well, this is not really an early core damage event, but let's at least look at public risk. And we had no easy way of doing that because we have no plant damage state for the Level 2 and Level 3 analyses, but what we did, there was one that had some similarities and that is a plant damage state called PDS7 in the NUREG 50 analysis of the Peach Bottom Plant. This one was initiated by an inadvertently opened relief valve that meets at the suppression pool.

I'm not going to go into the -- all the details of that. You have an expert sitting right over there who knows all about ATWS events, but you wind up in a situation where again, you have a reactor that isn't shutting off and a heated up pool. It is different in that this PDS involves the possibility of high pressure in the vessel, whereas in this generic issue since it's started by a large break LOCA, you know that the vessel will be depressurized.

We have a code that basically uses tabular information to reproduce the NUREG 1150 Level 2 analysis and we ran that out and using the Generic Issue standard site, which is not the same as Peach

Bottom, it's a uniform population density 340 people per square mile which is the U.S. average that we use for these Generic Issues. And we got about .89 person per rem per reactor year out of this. Obviously, I don't believe the .89. This is a different plant damage statement about that being accurate anyway, but somewhere in the order of 1 person rem per reactor year or less which is well below our threshold.

And I didn't put it on the slide, but just for the fun of it, we also ran the calculation since we had the computer set up with a classic LOCA plant damage state, that's PDS-1. It got a risk value in terms of person REM per reactor year that was actually less in the order of .6.

So based on that --

MEMBER DENNING: When you said classic LOCA, did you mean leading to core damage, or did you just mean LOCA? A mitigated LOCA?

MR. VANDERMOLEN: Well, for that plant damage state in the NUREG 1150 that is a LOCA where the ECCS didn't work, so that damage state does assume that you are melting the core, yes.

So ultimately, based on all this, that although we do intend to keep an eye on these configurations in the future, I don't like surprises

like this, but based on these numbers, the core damage frequency and public risk are below our thresholds for taking action, and if you gentlemen agree and will give us a letter to that effect, we intend to close this out with no additional requirements.

I should note in passing that our experience has been that the industry does pay attention to these Generic Issues even when they are closed out and I suspect that there may be more attention placed on the inspection of those vulnerable sections of piping, maybe a little bit extra as a result of this, but I can't really take credit for that.

That concludes our presentation, so gentlemen, I and Mr. Sheikh are more than happy to answer any of your remaining questions.

MEMBER BONACA: I have a question about the four configurations you looked at, different design. How comfortable are you that those are pretty much also the piping configurations and that that will be common to all of them. Are they pretty standard?

MR. SHEIKH: They're pretty standard, but they are supplied by GE plants and the previous walkdowns performed by -- for NUREG previously in in 1998 determined that to be true.

MR. VANDERMOLEN: But an addendum on that, I discussed that rather extensively with Admiral Hare * (11:21:13) because erratically I'm the one that wrote the analysis back in 1983 and felt a little bit stung by this revelation, so I -- based on that, on the walkdowns, I was willing to agree with him, but I wanted to make pretty sure.

MEMBER SIEBER: All right, any additional questions?

If not, I'd like to thank you, Abdul and Harold and Jack for the presentation today and since there are no further questions, Mr. Chairman, I turn it back to you.

VICE CHAIRMAN SHACK: Ahead of schedule again. We will recess for lunch until 12:45.

(Whereupon, at 11:22 a.m., the meeting was recessed, to reconvene at 12:45 p.m.)

VICE CHAIRMAN SHACK: We'll come back into session now.

Our next topic is Resolution of ACRS Comments on the Draft Final Regulatory Guide entitled "Risk-Informed Performance-Based Fire Protection for Existing Lightwater Nuclear Powerplants." And George will lead us through this topic.

MEMBER APOSTOLAKIS: Thank you. Our

Subcommittee on Fire Protection reviewed this matter during its May 17, 2005, meeting, and the full committee reviewed it during its 523rd meeting last June, at which meeting we wrote a letter to the EDO dated June 14, 2005.

And in the letter we had six recommendations, the most important one being the first recommendation that the Regulatory Guide should not be issued in its present form, and there were other comments, conclusions, and recommendations.

We received a response from the EDO in August of this year, in which the staff states that they agree with our -- with five of our six recommendations, and they disagree with the last one, which was that the Regulatory Guide should be revised to provide definitions of the maximum expected fire scenario and limiting fire scenario that are acceptable I guess to us.

So the staff disagreed with that. I think the main reason was that these definitions had already been given in NFPA 805, which is an approved document. And we never got back to approve documents and amend them, do we?

So that's where we are now. I understand today's session will be a relatively short one. And

we were ready to write a letter, but I guess we will not. So I will turn it to Mr. Sunil Weerakkody of the Office of Nuclear Reactor Regulation, who will lead us through this. Am I doing the right thing?

MR. LYONS: Actually --

MEMBER APOSTOLAKIS: I am not doing the right thing. I'm turning it over to Mr. Lyons.

MR. LYONS: Yes. This is Jim Lyons. I'm the Director of the Division of Systems Safety and Analysis, and I just wanted to say you are coming back with the -- with where we are on this Reg Guide. We had hoped to have it all finalized and able to bring back a completely revised version.

We still have a few things that we're working on that we'll go through today, so we can't give you the final. But I think we can give you a good idea of where we're going and what we're doing.

The other thing I wanted to say is, maybe you've seen the NRR is going to be reorganizing. And in the new reorganization I'm going to be the Director of the Division of Risk Assessment, and so we'll have all the -- you know, Mike Tschilz, currently the branch of SPSB, will be in my division.

But included in our division will also be the Fire Protection Branch. So Sunil will be coming

over and will be working with us in the Division of Risk Assessment. So we're going to continue to move forward in risk-informing and using performance-based regulations in the fire area. And so I just kind of wanted to let you all know that as you move forward.

MEMBER APOSTOLAKIS: When do you think you will come back requesting a letter?

MR. LYONS: We are looking at -- well, we'll go to the next last slide first, I guess, which is really December we would have the product ready to come to you. So I think it would be the first of next year that we would be --

MEMBER APOSTOLAKIS: February.

MR. LYONS: -- February that we would be coming back to finalize this.

MEMBER APOSTOLAKIS: I understand we have two persons on the phone. Would you please identify yourselves?

MR. EUTRISS: Tom Eutriss from EPM.

MEMBER APOSTOLAKIS: Just one person, then?

MEMBER KRESS: Must be.

MEMBER APOSTOLAKIS: And what does EPM do related to the subject matter of this meeting?

MR. EUTRISS: We are a fire protection

engineering consultant.

MEMBER APOSTOLAKIS: Thank you.

Okay. Now we'll go to Sunil.

MR. WEERAKKODY: Yes.

MEMBER APOSTOLAKIS: All right.

MR. WEERAKKODY: Again, my name is Sunil Weerakkody. I am the Section Chief of Fire Protection.

Next slide, please.

As Jim mentioned, we came to you about two months ago to ask your endorsement on the Regulatory Guide for 805 in its final form. You had a number of comments. One major comment was to not issue the Reg Guide in the form in which we presented it to you.

Since then, we have spent about two months discussing your comments. We had a public meeting to share your comments with the other stakeholders, all external stakeholders.

MEMBER APOSTOLAKIS: Geez. Do we have that much of an impact?

MR. WEERAKKODY: In this particular case, you did.

MEMBER APOSTOLAKIS: Oh.

MR. WEERAKKODY: Subsequently, we made some changes to the Regulatory Guide. NEI made

several significant changes to NEI 04-02 to address your comments.

Activities on 805 will conclude on other risk-informed regulations such as proposed rule on 10 CFR 50.46(a). As a result, we identified several other issues that we must address, which is why we are -- you are not seeing the final product today.

At the conclusion of today's presentation, if time permits, at -- I plan to provide you at a very high level what those issues are. Today, we are not going to seek your endorsement to issue this Reg Guide. We want to inform you of the changes that we made to the Reg Guide and the NEI-04 to address your six comments.

After we address all issues I mentioned about, we will submit the Reg Guide and NEI report, too, for your review and endorsement around -- in December.

Next slide, please.

Today's presentation will consist of three main items. First, Paul Lain, the Project Manager for 805, will spend a few minutes to inform you about where we are with respect to the implementation of 805. His presentation is relevant, because he -- it will go a long way in addressing a major concern that

you expressed at the last meeting with respect to licensee's plans to develop and use fire PRAs in support of 805.

Then, Bob Randlinski will present to you the list of your comments and how we changed NEI-042 and Reg Guide to address your comments to the best of our understanding of those comments.

Next slide, please.

The next step, we plan to have several meetings internally, and then also with the public, to discuss the -- a couple of the other issues we need to address. Specifically, we want to meet with our pilot also and get their views. Therefore, our planned next step is to provide a final Reg Guide, and NEI will forward it to you in mid-December, and seek your endorsement to release it next year at that time.

And with that, I would like to turn it over to Paul Lain.

Also, I just want to say we have Dr. Ray Gallucci and Dr. Gareth Perry, in case you have any questions that are difficult for us to answer. Okay.

MR. LAIN: Good afternoon. I'd like to just give the committee a short brief on 805, keep you guys abreast on the implementation.

We currently have commitments from Duke

Power and Progress Energy to transition all of their 12 units to 805. We have been informed that Dominion and Constellation are considering transitioning their fleets. And single plants like Beaver Valley and Calloway are seriously considering transitioning.

We expect in December that we'll -- it'll probably be a decision point for a lot of facilities, since there's a deadline enforcement discretion for existing non-compliances that ends in December 31st.

We have chosen Oconee and Dennis Hennike from Duke, and Sharon Harris from Progress to be our pilot plants, and we had a kickoff meeting with them in August to share some schedules. And we're going to meet with both of them in November for our first pilot observation to review their evaluations of fire-induced multiple spurious circuit failures, nuclear safety performance criteria, and the change control process that they're going through.

Our second visit right now is tentatively scheduled in March to review their progress on how they're transitioning over the fundamental elements within -- it's the Chapter 3 of 805. And then, also their fire PRA status, how that's coming.

Next slide, please.

With this slide, we'd like to really

stress that the transitioning plants --

MEMBER APOSTOLAKIS: Excuse me.

MR. LAIN: Yes, sir?

MEMBER APOSTOLAKIS: How long will this transition take?

MR. LAIN: Duke Power has committed to do it in two years, and Progress Energy would like to have three years to do it.

MEMBER APOSTOLAKIS: It takes three years, huh?

MR. LAIN: And it's all in a lot of their tracing cables and developing their fire PRA.

MEMBER APOSTOLAKIS: I see. So they -- well --

MR. LAIN: And what they're doing is they're staggering their plants to do it, so they're -- they're sort of starting a new one every -- every year, and so they're --

MEMBER APOSTOLAKIS: The transition itself does not require a fire PRA, right? It's afterwards that --

MR. LAIN: It's afterwards that helps them. But within their change control process --

MEMBER APOSTOLAKIS: Absolutely.

MR. LAIN: -- a fire PRA really helps

them, if they come upon areas that they do not -- are not in compliance --

MEMBER APOSTOLAKIS: That's right

MR. LAIN: -- it helps them with their transition. So they are working --

MEMBER APOSTOLAKIS: So they have already started this?

MR. LAIN: Yes.

MEMBER APOSTOLAKIS: Very good. Very good.

MR. LAIN: Okay.

MEMBER APOSTOLAKIS: Do we know why? I mean, why did they decide to do it? I mean, the local people are saying that they have invested so much in Appendix R compliance. What is --

MR. LAIN: I think that one of the big motivators is the circuit analysis. Duke Power kind of did a circuit analysis process by a process of elimination, short of -- I don't -- to best describe that is that they sort of -- they figured out what wasn't in a room, and then they -- they figured that their cables were safe.

Now they're actually running through and tracing all their cables and making sure that, you know, they don't end up having a Train A and Train B

affected at the same time. A lot of this came out of the testing that NEI did on spurious actuation of cables when the industry indicated that they didn't think that more than one spurious actuation could happen at a single time. And the testing ended up kind of proving that the multiple spurious could happen.

MEMBER APOSTOLAKIS: I see.

MR. LAIN: And so there has been a lot of activity in the last couple of years to sort of come to light on what the agency expects. And we've had a regulatory information summary -- one or two -- we've revised those -- that have come out. And these two plants are two of the plants that figure they really need to go back and rereview their safe shutdown analysis.

MEMBER APOSTOLAKIS: Okay. Thanks.

MR. LAIN: So they've both committed to spend sort of thousands of hours to sort of -- to transition the tracer cables and enhance their fire PRA. And I think Progress Energy quoted to do their -- all their sites $40- to $60 million. So they've committed to spend quite a bit of money.

Our first -- our current enforcement discretion period is two years. Progress has

requested that we -- we look at -- they'll need three years to develop a quality fire PRA, and so we are currently reviewing with the Office of Enforcement to -- that request.

We stressed to the licensees at last month's NEI information forum that it would be impractical to transition without a quality fire PRA, and we will be scrutinizing the ones without one, you know, through the inspection process.

Our last item we'd like to relay I guess is that we've been revisiting the PRA and the fire modeling guidance, such as Reg Guide 1.174, the draft guide 1.200, RES's fire PRA method -- methodology. And to use for the NRC review -- and we've identified that sort of a fire PRA peer review methodology is needed. So I think we've been in discussions with NEI on development.

MEMBER APOSTOLAKIS: That's interesting.

MR. LAIN: And so as part of our having a quality fire PRA, we're working towards having a peer review methodology.

MEMBER APOSTOLAKIS: Do you think five is going to play a role in all of this?

MR. LAIN: I think five is one of the methods. They have revised five in the -- in the Reg

Guide, and we are looking at that through a fire model effort. But we expect them to not just rely on the old IPEEE items. We expect them to sort of advance and get -- produce better --

MEMBER APOSTOLAKIS: Well, it originally was intended to be a screening approach. So now it's not screening anymore.

MR. WEERAKKODY: To the best of my knowledge -- and Ray might be able to -- I don't believe people could have 805 and have five that they prepared for IPEEEs. And to the best of my knowledge, no one is even planning to do that.

DR. GALLUCCI: This is Ray Gallucci. There is debate right now on the fire PRA Standard Writing Committee as to whether a five even qualifies as a category 1. It's an ASME standard. It would be IPEEE quality. Yes, it's the same type of thing for the ASME standard.

MR. LAIN: So now I would like to turn it over to Bob to discuss more about the specific Reg Guide.

MR. RANDLINSKI: Good afternoon. My name is Bob Randlinski. As Sunil mentioned, my presentation is going to review the comments that we received from the ACRS on the 805 Reg Guide, and on

NEI 04-02, and talk about our response to those comments, and also describe some of the changes that we made to these two documents as a result of those comments.

The first comment, as George mentioned, was that they didn't believe that -- the committee does not believe that the Regulatory Guide is ready to be issued in its present form. We've -- we are accepting the comments that were made, the specific comments that were made, on the Regulatory Guide, and both NEI and the staff have incorporated those comments in a revision to the Reg Guide and to 04-02.

So hopefully, based on our presentation today and our discussion, that the committee will agree that the Reg Guide is ready to be issued.

We then plan to issue the Reg Guide next year, as Sunil mentioned, after submitting a draft final version to the committee in December.

First specific comment was that the initial fire modeling approach should not be used as an alternative to estimates of changes in CDF and LERF. The way we addressed this was to revise Figure 5-1 in NEI 04-02 and --

MEMBER APOSTOLAKIS: Oh, it's here.

MR. RANDLINSKI: It's in your handout. We

can --

MEMBER APOSTOLAKIS: Yes. Oh, that's the old one. Yes. They are burning in that -- ah. You guys are so good. Oh, we have a laser point?

MR. RANDLINSKI: Okay. This was the area of concern last time.

MEMBER APOSTOLAKIS: Wait, wait, wait. The Reporter has a problem.

MR. RANDLINSKI: Okay. The area of concern is -- this is the plant change evaluation of the process in schematic form. And this is from NEI 04-02. It's Figure 5-1. This was the previous revision, Revision 0, which is covered up by that five. The area of concern was this path here, which is the approach -- the fire modeling approach to evaluating a change, and it was shown as a parallel path along -- in parallel with the risk assessment path.

And the concern was, by the committee, that a change could be evaluated using this path only, and you would complete the evaluation without actually evaluating the risk, evaluating CDF and delta LERF.

MEMBER APOSTOLAKIS: That's right.

MR. RANDLINSKI: Okay? There was -- there were words in the document itself that prohibited you

from doing that, but it wasn't clear in the diagram, so we changed the diagram.

So that same area of the schematic is here under risk evaluation, and you see there's no parallel path. Everything comes straight through. Everything goes down through this step. Everything goes down through the step where you have to evaluate delta CDF and delta LERF for every change.

MEMBER APOSTOLAKIS: Good.

MR. RANDLINSKI: Okay?

MEMBER APOSTOLAKIS: Very good.

MR. RANDLINSKI: We've taken all -- we've cleared all statements from 04-02 that indicated that you might not be able -- or that you might be able to use a fire modeling approach by itself, and included some statements that made it clear that you do have to evaluate risk as well as looking at the fire model, if you use that approach.

MEMBER APOSTOLAKIS: Okay.

MR. RANDLINSKI: Are there any questions about the figure? No? Okay.

The next comment was that the staff should not endorse methods for evaluating delta CDF and delta LERF that are not based on fire PRA. 10 CFR 50.48(c), the rule, revised rule, and the NFPA 805 do allow risk

assessments to be performed without a full fire PRA.

So we cannot require the licensees to develop a full fire PRA and use a full fire PRA. However, to the extent possible, we encourage the licensees to do this and --

MEMBER APOSTOLAKIS: Well, I would take a different approach, Bob. I would say, you know, you show me a delta CDF and a delta LERF, I want to be convinced that this is a real delta CDF and a real delta LERF. I don't know how -- I don't care how you do it. Why should I care whether they have a full fire PRA or a 63 percent fire PRA? Maybe, you know, you don't need a full fire PRA in some instances.

MR. RANDLINSKI: Great. Then we're in agreement.

MEMBER APOSTOLAKIS: But the focus is delta CDF and delta LERF. In other words, I don't think anyone should come here -- or to you, actually, not to us -- and say, "We calculated delta CDF, and we didn't have a full fire PRA. And, you know, I think it's okay."

The question is: is your delta CDF realistic? That really should be the focus -- how you did it. I mean, some people are maybe so gifted that they can just do it without any calculations. It's

three 10^{-5}. You know? But if it's real, then it's real.

MR. RANDLINSKI: Good. Then we're in agreement.

MEMBER APOSTOLAKIS: So I would -- we are in agreement, but maybe the tone -- the reason why we're in agreement may be different. I think it would be nice to emphasize that when you evaluate delta CDF and delta LERF, you go back to Regulatory Guide 1.174, and you follow the rule. It says, you know, you should do this.

MR. RANDLINSKI: Right.

MEMBER APOSTOLAKIS: Should represent -- certain decisions, you know, represent, you know, everything you can think of and all that.

MR. RANDLINSKI: Right. And we do reference Reg Guide 1.174 --

MEMBER APOSTOLAKIS: Okay.

MR. RANDLINSKI: -- for that purpose.

MEMBER APOSTOLAKIS: But to go into what 50.48(c) and NFPA allow, yes, I mean, they allow it. But if your delta CDF is not realistic, I'm sorry.

MR. RANDLINSKI: Okay. And as Paul --

MEMBER APOSTOLAKIS: Right.

MR. RANDLINSKI: -- as Paul mentioned, the

first two utilities that are adopting 805 are doing -- are developing full fire PRAs.

MEMBER APOSTOLAKIS: Which is --

MR. RANDLINSKI: And we really anticipate or expect that all of the utilities will do that.

MEMBER APOSTOLAKIS: Of course. I mean, you are switching, and I think Paul mentioned, what, $50-, $60 million that was spent. It's ridiculous to do it half --

MR. LAIN: Duke Power has kind of said that, you know, you -- for the cost of a fire PRA, you know, it's like doing -- doing a partial three times over. You know, you might as well do the full fire PRA to get the economy --

MEMBER APOSTOLAKIS: Exactly.

MR. RANDLINSKI: -- and get the payback --

MEMBER APOSTOLAKIS: Exactly.

MR. RANDLINSKI: -- in the future, and to be able to do the change control process efficiently --

MEMBER APOSTOLAKIS: Absolutely.

MR. RANDLINSKI: -- that you might as well just make it --

MEMBER APOSTOLAKIS: I don't know. Does anybody know? Ray, maybe you know. How much does the

-- a full fire PRA cost?

DR. GALLUCCI: When I was at Ganay, starting with an internal events fire PRA, and already having the cables traced, it cost about $150K.

MEMBER APOSTOLAKIS: That's nothing.

MR. LAIN: The big cost is tracing the cables, which has been said 5- to 7,000 manhours.

MEMBER APOSTOLAKIS: So let me understand this. If they don't do a full fire PRA, they don't have to trace the cables?

MR. LAIN: I mean, I would think they would need to trace the cables for -- you know, in that area that they're doing the change in.

MEMBER APOSTOLAKIS: Right.

MR. LAIN: And that's a big cost.

MEMBER APOSTOLAKIS: That's the point. I mean, it's not just what PRA wants.

MR. LAIN: Right.

MEMBER APOSTOLAKIS: What's the alternative? So one way or another they would have to do it. Maybe not in a complete case -- sorry?

MEMBER POWERS: They would have to do it to make a change. But if they don't do it, there could be some latent defect in there -- in the routing that could cause a problem.

MEMBER APOSTOLAKIS: In general --

MEMBER POWERS: I guess that's what the inspections are designed to find out.

MEMBER APOSTOLAKIS: I think we are past the time when, you know, we could do 30 percent of a PRA and a little bit of the fire PRA. I mean, if you want to have risk-informed decision-making, you'd better have the tools. And I think this is very good. I mean, you know, you have to have the PRA, the fire PRA, because in the past, you know, since '98 when the Regulatory Guide came out, I mean, I think the staff has gone out of its way to accommodate incomplete PRAs.

You know, and if you don't have a Level 2, look, maybe you can do this, you can do that, dance a little bit. I mean, you are okay. If you don't have a shutdown PRA, maybe you can -- well, maybe it's time now to say, "No, you should."

MR. RANDLINSKI: Okay.

MEMBER APOSTOLAKIS: That's why people say that sometimes these committees pontificate.

(Laughter.)

MR. RANDLINSKI: Okay. The next comment was very similar. The comment was that NEI 04-02 contains many statements that are inconsistent with

the Commission's policy of promoting the use of PRA methods. In the Reg Guide, the staff should make it clear that it does not endorse such statements.

As I mentioned, 04-02 was revised, particularly in Appendix J, in Section 5.3, to make it -- to encourage licensees to use a detailed calculation approach to assessing delta CDF and delta LERF. Also, in the Reg Guide we don't specifically endorse non-PRA methods, and we do talk about PRA methods.

Next comment was the staff should ensure that parts of NEI 04-02 that endorses use correct methodology and language. Sunil mentioned earlier we had a -- held a public meeting with -- to share the ACRS comments with NEI and discuss how we should approach those comments, and which of the two documents should be revised to address the comments.

We held several follow-up phone calls with NEI. We've been working pretty closely with them to fine tune their document, as well as make any changes that we needed to the Reg Guide.

And as we got revisions to 04-02, we had full review of those by members of the staff, fire protection, also in the research group, to review the fire modeling and the PRA portions of it. And we

believe that the methodology and language that's now used in 04-02 is correct.

The next part of the presentation is to give you a little more specifics on how we've changed each of the documents. With respect to the Reg Guide -- again, general comment, we agree with your comments, and we incorporated those comments in the final draft.

The Reg Guide states that risk evaluations for non-screened changes should use PRA methods and tools. We added PRA quality references, including Reg Guide 1.174, Reg Guide 1.200, and the ANS fire PRA standard. And we also noted that future additional guidance for fire PRAs will be issued, and it will be -- that future guidance will follow those reference documents.

MEMBER APOSTOLAKIS: So, Ray, you mentioned the ANS fire PRA standard. Can you tell us in 30 seconds what the status of that is?

DR. GALLUCCI: The current status -- we had a Writing and Review Committee meeting at PSA 05 a couple of weeks -- a couple of weeks ago in San Francisco. Comments from -- I think ANS comments had -- preliminary ANS comments had been received. Comments were received from the various reviewers, and

the Writing Committee is preparing what will be a draft for concurrent public comment and ANS's Risk-Informed Subcommittee review probably the end of this month or sometime next month.

By the end of -- certainly by Thanksgiving the final draft should be out for public comment and ANI Risk Committee review. So it's probably within a year of completion at that point.

MEMBER POWERS: Ray, is that standard going to include fire during shutdown conditions?

DR. GALLUCCI: It does not -- it doesn't specifically give any -- it's an at-power type of standard as the other ones. So it won't have anything specific for fire at shutdown.

MEMBER POWERS: Isn't fire -- isn't the probability of a fire more likely under shutdown conditions than operational conditions?

DR. GALLUCCI: There is different types of fires that you would see under shutdown conditions. I think that there's other efforts going on where they're trying to -- between ASME and ANS where they're trying to coordinate all of the standards that are being developed.

And I don't know if the decision has been made yet whether fire during shutdown/flood during

shutdown should be part of the shutdown standard itself, or whether it should be part of the fire or the external event standards.

MEMBER POWERS: It seems to raise the question of suppose someone came, said, "I'm going to design my fire protection system based on NFPA 805," and he hasn't addressed fire protection during shutdown?

DR. GALLUCCI: NFPA 805 does require that fire during shutdown be considered. But the standard is not going to develop any specific technical requirements at this point.

MEMBER POWERS: So how does it work with respect to this?

MEMBER APOSTOLAKIS: So, yes, that's a good point. Bob, when we talked earlier about the full fire PRA, did we include shutdown mode?

MR. RANDLINSKI: Do you mean in the Reg Guide?

MEMBER APOSTOLAKIS: No. No, I mean -- let's go back a couple of slides. I mean, there was some statement there that they have to -- no, back. That they will have to use a full fire PRA. Here. Assessments to be performed without a full fire PRA. Does that include all the operating modes of the

plant?

MR. WEERAKKODY: It does not include --

MEMBER APOSTOLAKIS: Shutdown?

MR. WEERAKKODY: -- shutdown.

MEMBER APOSTOLAKIS: But why not? I mean, I think the issue is very relevant.

MR. WEERAKKODY: The shutdown risk is relevant, George, but -- and I'm glad we have other people here, but in terms of the shutdown risk, both for internal events or fire we are not at the state where we are capable of doing that type of evaluation.

Do you want to add anything, Gareth? I mean --

MEMBER APOSTOLAKIS: So how -- so presumably, then, the shutdown fire issue will be handled in a different way, not probabilistic way? I mean, it has to be handled, because --

MR. WEERAKKODY: There are several ways to handle the shutdown. And if you can think of the shutdown risk management, you know, when you are in a shutdown, each plant, each outage, you may have, you know, different configurations. And you manage the shutdown risk by evaluating the different configurations and make sure that each configuration is safe, rather than sing quantitative PRAs.

So that's -- that's one approach of managing that. But, you know, if you go a step further, if you're looking at any plant, any permanent plant changes, obviously each plant knows if there are any systems that are only important for the shutdown, such as pressurized water reactor or -- which you would just use for less significance during at-power.

So it would be considered, but we are not -- what we are saying is that it would not be numerically evaluated in a -- in a CDF fashion.

DR. GALLUCCI: Let me add that if a plant does have a low power shutdown PRA model, then superimposing a fire model on top of that fire PRA model is somewhat analogous to what you do with the internal events at power model. You would -- you basically would have -- you'd have your plant operating states developed, you'd have different event trees, fault trees, for the shutdown operating mode -- shutdown modes, and you would superimpose fire initiators, etcetera.

There would be -- of course, there's probably more dependence on manual action. So if a plant -- again, the starting point to model fire PRA shutdown is to have a shutdown model in the first place, just like the starting point to have a fire PRA

is an internal events at power model.

MEMBER POWERS: But, Ray, what I'm wrestling with a little bit here is that NFPA 805 requires considering all operational states. So now we're writing a Reg Guide here in which we consider those states where the risk of fire is the least, instead of those where it's the most, it seems to me.

DR. GALLUCCI: I don't know if it's --

MEMBER POWERS: It seems to me that the likelihood of fire is greater during shutdown than it is during normal operations. I may be in error on that. But it seems somehow we're leaving out a part of the equation. Once we're done discussing this, then I'll move and ask about seismically-induced fires.

DR. GALLUCCI: The likelihood may be higher for certain types of fire, but the risk isn't necessarily, because you're, of course, in a shutdown mode. I'm trying to recall --

MEMBER POWERS: Let's see, I'm a shutdown mode, which means my containment most likely is open?

DR. GALLUCCI: Yes.

MEMBER POWERS: So if I do get core damage, my conditional containment failure probability is one?

DR. GALLUCCI: But you're very unlikely to get core damage in such -- in that mode, because you're depowered, you're depressurized.

MEMBER POWERS: Gosh. That sure hasn't been borne up by the shutdown risk assessments that I have seen.

DR. GALLUCCI: Well, Ganay did a full-blown PRA -- fire during shutdown, flood during shutdown -- and shutdown was the minimal of all of the contributors relative to fire, flood --

MEMBER POWERS: But those that I have seen did not show that.

DR. GALLUCCI: Okay.

MR. WEERAKKODY: Can I add something? Dr. Powers, with respect to shutdown, your statement that fires are more likely during shutdown is true. But one of the things you've also got to factor -- there are two things that needs to be factored in.

If you go back to the -- in fact, I had -- there was like 600 actual fire events in a fire database that we looked at when we prepared the IPEEE for our plants, you know, when I was -- I recall, in fact, we put a paper together in terms of the nature of the fires.

What you will find is during outage the

fires you have are, you know -- you know, you do welding, because you've got -- you are working on a component. You know, a piece falls, that kind of non-consequential --

MEMBER POWERS: Maybe I'm looking at a containment penetration seal with a candle. What causes the fire is where -- what it does that becomes important, and you're talking about reasonably rare events. I mean, to argue that all of the shutdown fires are inconsequential --

MR. WEERAKKODY: No, I wouldn't say that. No, I wouldn't say that, Dr. Powers. What I would -- what I would say, though, is that the issue that you mentioned, which was the -- we have somebody who has a candle, the second relevant aspect is when you are in shutdown, you are at very low decay heat level. And this is not just true for fire, but true for every shutdown.

You are at low power levels, and that's why, like Chris said, your conditional --

MEMBER POWERS: It's just not consistent with the shutdown risk assessments that I've seen. We will stipulate, yes, that heat is lower. But, gee, it looks to me like the numbers I've seen for Surry and Grand Gulf were commensurate with normal operations,

even though the time period of shutdown was very small. It was a fraction of the year.

Even after annualizing them, they came in as -- as substantial. So now if my event frequency is higher, and my core damage probability, given a failure, is about the same, it looks to me like my risk is higher. I don't see how it can be otherwise.

MR. WEERAKKODY: Well, if you go to the next level of detail as to what events drive those shutdown risks, you know, I can only -- you know, I'm not focusing on the fire. But going to the internal events for pressurized water reactors, but during -- the fact is that you do go through some relatively at-risk evolutions during mid-loop or when you have things of that nature.

But what is not proved is it's necessarily -- when you go to the shutdown risk, you can pretty much look at -- you can identify and sort of recognize those items that guide risk. So even though you have -- you do have more fires, that does not necessarily relate to higher fire risk due to shutdown.

But I think, you know, we'll go back and take a look at this, but, you know, what I have to do is, you know -- you know, say that we are asking licensees to do low-power and shutdown fire PRAs.

MEMBER APOSTOLAKIS: You are?

MR. WEERAKKODY: We are not.

MEMBER APOSTOLAKIS: Oh, you are not.

MR. WEERAKKODY: We are not. Not at this point.

MR. LAIN: Right now, the guidance is a traditional sort of fire hazards analysis for those areas, and it's kind of recognized at the -- that the fire PRA at shutdown is not -- not available at this time.

MEMBER APOSTOLAKIS: But you are not explicitly stating that you are excluding shutdown fire.

MR. WEERAKKODY: No. What I am saying is that in fire PRAs, the clear message we are telling the licensees is that when you adopt 805, you have to do a full fire PRA on the at-power more.

MEMBER APOSTOLAKIS: So even Progress Energy and Duke, who plan to go through this major conversion, are not planning to have a shutdown fire PRA?

MR. WEERAKKODY: Not at this time. Now, one thing -- you know, Ray mentioned this. Once you know where your cables are, and if you have an internal event shutdown model, to go the next step is

relatively simple.

MR. RANDLINSKI: But don't forget, 805 requires that the licensees meet the nuclear safety criteria for all modes of plant operation. The PRA may not address low-power shutdown operation, but they do have to meet the safety criteria.

MEMBER APOSTOLAKIS: I guess -- are we going to have a meeting here one of these years on the fire PRA during shutdown? Or we will do it in the context of the ANS standard perhaps?

MR. WEERAKKODY: I would think it's --

MEMBER POWERS: They're going to tell you that they didn't do it.

MEMBER APOSTOLAKIS: Huh?

MEMBER POWERS: They're going to tell you they didn't address it.

MEMBER APOSTOLAKIS: But they developed the standard.

MEMBER POWERS: They developed a standard that didn't apply during shutdown.

MEMBER APOSTOLAKIS: Oh, the standard did not apply here.

MEMBER POWERS: They're going to say somebody else will do that.

MR. HYSLOP: My name is J.S. Hyslop.

MEMBER APOSTOLAKIS: Yes, Jay.

MR. HYSLOP: From Research.

MEMBER APOSTOLAKIS: Yes.

MR. HYSLOP: EPRI and Research are talking about doing some work in low-power shutdown and fire to -- starting in '06 to look at frequency specific to low-power shutdown to quantify things and develop tools further for low-power shutdown analyses.

MEMBER APOSTOLAKIS: So when do you think you will be able to come here and tell us a little bit about it?

MR. HYSLOP: Well, we haven't even developed any bullets, any schedule yet. So I don't want to get into that right now, but we're -- we're talking about initiating it in '06. And after we have a better sense of the program and the schedules, I can -- I can tell you.

MEMBER APOSTOLAKIS: Okay.

MR. RANDLINSKI: Yes. The next slide pretty much repeated --

MEMBER APOSTOLAKIS: Okay.

MR. RANDLINSKI: -- it's a repeat of statements I've already made. 04-02 is revised to make it clear that you can't do -- can't just use a fire modeling approach. You have to do a risk

assessment for each and every plant change.

MEMBER APOSTOLAKIS: Who developed NEI 04-02? Is that a legitimate question? Or it's none of my business?

MR. RANDLINSKI: What is that?

MEMBER APOSTOLAKIS: Who wrote NEI 04-02?

MR. RANDLINSKI: NEI and --

MEMBER APOSTOLAKIS: Is it appropriate to ask? If it's not, tell me. I know it's NEI.

(Laughter.)

MR. MARIM: Alex Marim, NEI. We hired a contractor to basically develop the document that was subsequently reviewed by about a handful, maybe eight utility persons who are very knowledgeable in fire protection, which included representatives from Duke and Progress.

MEMBER APOSTOLAKIS: So you can't tell us who that contractor is.

MR. MARIM: Pardon?

MEMBER APOSTOLAKIS: You hired a contractor.

MR. MARIM: Yes.

(Laughter.)

Do you wish to know the name of the contractor?

MEMBER APOSTOLAKIS: Yes, please.

MR. MARIM: Oh, I'm sorry. Kleinsorg and Associates.

MEMBER APOSTOLAKIS: Great. Thank you.

MR. RANDLINSKI: And 04-02 does -- there is a Revision 0 also -- encourage licensees to use a detailed quantitative approach in assessing risk for any plant changes.

And the last slide has to do with discussion near the end of the ACRS letter. It wasn't part of the recommendations, but they are actually comments and questions in this regard. Had to do with fire modeling approach in the LFS versus MEFS. Okay?

MEMBER APOSTOLAKIS: Oh, yes.

MR. RANDLINSKI: And you identified some statements that were -- confused logic, and you were concerned about the margins that were included in the fire model --

MEMBER APOSTOLAKIS: Right, right.

MR. RANDLINSKI: -- to account for uncertainties.

The document was advised to provide some clarification of the safety factors that the guidance recommends are used with the fire modeling approach to account for uncertainties, and they also clarified

that statement that you, George, may have referred to as confused logic, by a simplified approach to calculating --

MEMBER APOSTOLAKIS: Do you use those words in the --

MR. RANDLINSKI: Yes.

MEMBER APOSTOLAKIS: Geez. But the definitions of the maximum expected fire scenario and limited fire scenario will not be changed, right?

MR. RANDLINSKI: They have not changed. There was quite extensive discussion of both in 04-02, but that was in Rev 0. And I assume you saw it.

MEMBER APOSTOLAKIS: Yes, I did.

MR. RANDLINSKI: And, of course, as we mentioned before, the definition is in NFPA 805.

MEMBER APOSTOLAKIS: But don't you guys find it confusing, though, when the limiting fire scenario definition says, "One or more inputs to fire scenario are up to their limit, so that performance criteria is -- are not met." One or more. I mean, it gives you such freedom.

MR. RANDLINSKI: There is guidance --

MEMBER APOSTOLAKIS: It's not one limiting scenario, right? You can have many.

MR. RANDLINSKI: There is guidance in 04-

02. It mentions two, in particular, that are important. And it -- it does provide some specifics.

MR. WEERAKKODY: Dr. Apostolakis, I know that you -- you remember when you had a meeting, subsequently, the full committee meeting. As I recall, your underlying concern was that given that there is some subjective in these definitions and these ratios, the fact that there was this bypass pump in fire model -- and I think what we are saying is that we've taken that bypass valve. Now, that kind of subjective uncertainty which is there can be brought into the risk analysis.

MEMBER APOSTOLAKIS: Is that it, Bob?

MR. RANDLINSKI: That's the end of my presentation.

MEMBER APOSTOLAKIS: All right.

MR. RANDLINSKI: I think Alex wants to -- Sunil, did you want your last --

MR. WEERAKKODY: No, I would rather if Alex goes first.

MR. RANDLINSKI: Okay.

MR. WEERAKKODY: And then takes the rest of the time. You wanted to -- Alex, you wanted to make some remarks, right?

MR. MARIM: Yes, sure.

(Laughter.)

Yes. Alex Marim, NEI. I apologize, I wasn't really prepared to do so, but I can speak to Dr. Powers' question about fire evaluations during shutdown conditions. Those are being conducted today and will continue to be conducted.

It remains to be seen as we start developing a fire PRA, and applying a PRA to deal with fire events, whether we're going to take it to a point of evaluating shutdown risk from the standpoint of a PRA analysis. We're not there yet. We don't really see a need to do it at this particular point in time, but we may evolve to that point as -- as the standards are developed, etcetera.

That's all I have to say. Thank you for the opportunity.

MR. WEERAKKODY: Well, in that case, I will go to my last slide. What I have listed here is the high level some of the other issues that we have and we are addressing. As you all know, 10 CFR 50.69, special treatment, that is a risk-informed rule that was completed. I can't remember which year, but that is already out there.

10 CFR 50.46(a), the proposed risk-informing part of 50.46 ECCS, it's in the proposed

risk stage, and 50.48(c), which is the 805, which was completed last year.

You know, really, we did -- because of the reason I mentioned before, we recognize that as the agency has to maintain compatibility among these rules that have been completed and that are in process while accumulating their differences and purposes. As you know, each one has its own purpose. 50.69 is the final report, to the best of my understanding, is ISIs, ISDs, and the associated risk changes.

50.46(a), something -- it's to do with the break size for -- for pipe break and the associated risk. And 50.48(c) is on fire protection.

So this we worked closely with the PRA Branch to ensure that all the rules and guidance documents benefit from each other's development. For example, we have brought consistency to the terminology. If you can recall, the last time when we were here, one of the things that upset you was that we had terms like inconsequential, non-negligible, negligible. We went back in, and we -- we addressed that.

We are not creating any -- any new words in 805. We are limiting ourselves to the words that are already in 1.174. And to the best of my

understanding, we are using the word "minimal" now, which is equal to 10^{-7} frequency. So we have addressed that issue.

However, I'm not saying everything is final and everything is a done deal. There are still some differences we need to address.

Another issue we -- we identified that needed addressing was the -- with respect to the quality of the PRA. In line with the Commission's expectations on the phased approach to quality, we have done that. If you review our Reg Guide, we have a paragraph about it, and you'll see that when you get the Reg Guide, that specifically refers to the -- you know, Reg Guide 1.200, ANS fire PRA standards, so that we can put ourselves and the licensees to a part of convergence.

The two remaining issues that we are addressing at the present time are things related to self-approval and cumulative risk. I just listed these for your information. I would request that people not go into a whole lot of detail, because we are still having discussions as to what is the best thing to do. But when we come to you in December, we -- these issues would be pre-addressed.

MEMBER APOSTOLAKIS: In December, you will

send us the document. We will have it --

MR. WEERAKKODY: We will work very, very hard to give you the revised documents in December.

MEMBER APOSTOLAKIS: Good. Do you have anything else?

MR. WEERAKKODY: No.

MEMBER APOSTOLAKIS: Member, any more comments?

MEMBER DENNING: Well, I think I should comment that I think that we are -- you know, the things that we're seeing here are just the things we really did want to see. I mean, obviously, the shutdown PRA -- fire shutdown PRA -- it is really awfully early in the game to be providing definitive guidance on what our expectations would be in shutdown fire PRA.

So I -- I do think it's just -- ultimately, I think they are going to want to see that, but I do think it's a little bit premature. But certainly the words that we're hearing here and what you're projecting to the industry is much better, I think, than what we saw before.

MEMBER APOSTOLAKIS: Any other comments?

MEMBER POWERS: Well, we've spoken now about operating events, fires, and a little bit on

shutdown fires. And then there's the other question, which I don't know exactly how to confront, but that's seismically-induced fires. Again, it's painfully obvious what happens in earthquakes. Well, presumably, large concrete robust structures very seldom fail, but very, very often you see fires in those large robust concrete structures.

And so the question comes up: what of those systems/situations? And what I worry about is that, again, we -- we only risk-inform that which is easiest to risk-inform, and we're -- we're failing to address where the important issues are, because of the lack of some computer code.

DR. GALLUCCI: This is Ray Gallucci. Both the fire PSA standard and NUREG/CR-6850 do address seismic fire interactions.

MEMBER POWERS: And have we seen those, Ray?

DR. GALLUCCI: You've seen NUREG/CR-6850. That's the risk requant study. I don't think you've seen the fire PSA standard. But it follows -- it's essentially -- it follows pretty much NUREG/CR-6850 on a higher level. There are -- there is a specific element for seismic fire interactions with the supporting requirements for it. And it says it

parallels what's in NUREG/CR-6850, which you have seen.

MEMBER APOSTOLAKIS: Well, okay. If it -- it's in a NUREG report, what does that mean? The real action is here. Let me ask you this. This fire PRA applies to the power operation, right?

DR. GALLUCCI: Yes.

MEMBER APOSTOLAKIS: So if the earthquake occurs during power operation, should they have included there seismically-induced fire?

MR. WEERAKKODY: Yes. And this is how the connection is made, and then --

MEMBER APOSTOLAKIS: Okay.

MR. WEERAKKODY: -- in our Reg Guide we refer to Reg Guide 1.200. And one of the appendices of Reg Guide 1.200 is going to be the ANS fire PSA standard. And like Ray mentioned, the ANS fire PSA standard contains the necessary-to-take-a-look-at seismic-induced fires.

I do like to make one -- one comment with respect to the shutdown risk and the low-power mode. I think it's not that the staff is not hearing your concern. What our preference is is some of those broader issues be handled under the broader context through the appropriate -- you know, for example, the

low-power and shutdown modes, the fact that we are managing shutdown risk as opposed to low -- you know, developing low-power shutdown, risk assessment is something that is evolving. And on issues like that, we'll develop SPSB and basically follow them.

MEMBER APOSTOLAKIS: Okay. Any other comments from the members? From staff? Public? Members of the public?

Okay. Well, thank you very much, gentlemen. In fact, I'm very pleased by the way this is going. So I'm looking forward to receiving the document in December, and taking it from there. Thank you very much.

Back to you, Mr. Chairman.

VICE CHAIRMAN SHACK: Okay. Again, thank you, gentlemen, for an excellent presentation.

We're a little bit ahead of schedule again, but don't run off yet, because we would like to take this opportunity to at least have a first reading of some of Mario's letter.

We can go off the record for this discussion of the letter.

(Whereupon, the proceedings in the foregoing matter went off the record at 1:44 p.m. and went back on the record at

2:33 p.m.)

VICE CHAIRMAN SHACK: We have a real treat ahead of us now -- Davis-Besse Reactor Pressure Vessel Head Integrity Calculations. And Jack will lead us through this.

MEMBER SIEBER: Okay. Thank you, Mr. Chairman.

I would comment that this issue has been around for a while, and I think most of us were here in 2002 when the cavity in the Davis-Besse reactor vessel head was discovered by the licensee. And a lot of folks like myself speculated, you know, how bad is this really?

And a simple-minded way to approach it, like a plant operator would, is to say, "Well, the failure frequency is 1, and, therefore, CDF is totally a function of the reliability of mitigating systems."

And you can come up with a number that way, but it's not very satisfying, because everyone, including myself, was curious as to if they had a transient at the plant that would raise reactor pressure to the PORV setpoint, or an ATWS, which goes beyond that, would the head have failed?

If nobody did anything and they had enough fuel, how long would they run before it would fail all

by itself? And what is the failure probability, including uncertainties, the year prior to the time of discovery? And these are three basic questions, which the staff and its contractor -- Oak Ridge -- has sought to investigate and answer.

And this afternoon's presentation will address that report, and to help us along and get us started I'd like to introduce Alan Hiser to give the staff's introduction. Alan?

MR. HISER: Good afternoon. I'm Alan Hiser, Chief of the Component Integrity Section, the Office of Nuclear Regulatory Research. As you mentioned, there have been -- there are several aspects of Davis-Besse that we have looked at, and I think you mentioned several of them.

You know, first, looking at the as-found condition and the -- as you know, the margin to failure to that condition. We also looked at analyses to support the ASP analysis, which I -- I think is one of the ways that this presentation came about during the presentation by Gary DeMoss and company in April.

In addition, we supported the SDP process. So three sort of distinct sets of calculations.

We actually completed this work a little over a year ago, so Dr. Mark Kirk, who will be making

the bulk of the presentation, and I have -- have had to go back and try to refresh our memories on some of the details. So if we're a little bit rusty on some of the facts, you know, please excuse us. But I guess what I would like to do is go ahead and introduce Mark, who will make the presentation on this.

MEMBER SIEBER: Well, I can't imagine Mark being rustic.

(Laughter.)

MR. KIRK: Well, you know, in the presence of boric acid, most things just give way.

(Laughter.)

I'd like to think I'm austenitic, but maybe not.

Anyway, I've also got up here, as a list of co-conspirators, the people that really did the work, which are contractors with the HSST program at Oak Ridge. Those include, of course, Richard Bass, who leads the project; Paul Williams and Sean Yin, who did the bulk -- excuse my voice -- the bulk of the finite element calculations; and then Wally McAfee and Richard were responsible for the burst-test calculations.

So the objectives of our analysis, as Alan has already pointed out, were threefold. And I'll go

into each of these in some level of detail.

First, we looked at the as-found condition and tried to figure out how much more pressure it would have taken, given the geometric and material conditions on the day of discovery, to have compromised the primary pressure boundary.

We did that just because it was a question that many people were interested in, but also it was really the only reality benchmark we had. All that we really knew was that that configuration on that day did not fail. And so we felt it was important, indeed critical, to instilling confidence in our analytical procedures that our analysis should also predict that that geometry on that day under those conditions did not fail.

We then did what I've called both a forward-looking and a backward-looking analysis. The forward-looking analysis started with that material condition and geometry and tried to project forward in time based on estimates of corrosion, crack growth rates, in the austenitic stainless steel cladding, and general corrosion rates in the ferritic steel, and tried to project how much longer the cavity might have lasted -- I'm sorry, the cladding might have remained intact under the operating pressure.

And then, we also did what I've called a backward-looking analysis to support Gary DeMoss' ASP calculations, where we tried to postulate what the conditions were a year before February 16, 2002, and that's a requirement of the ASP program, and then calculate forward to get some estimate of the risk of the cladding giving way on the day of discovery.

So, again, I'll go into those in that order, but I would like to start with a description of the as-found state, and then I'll talk about our analysis methodology and results.

So I don't think I'm going to -- well, I'm certainly not going to show you any pictures that aren't available in the public domain, and I think some of these have been more widely seen than others. On the left-hand side of the screen you have several views of the cavity that was carved out of the reactor pressure vessel head by the boric acid.

On the top right, you see a piece labeled "piece M." That's a cross-section through the austenitic stainless steel cladding where the undersurface is the surface that would have been exposed to the pressure of the primary circuit. And the top surface, the undulations in that, are a result of the variable penetration of the weld overlay

process.

And then, the green blob-ish looking thing in the lower right-hand corner is the -- I guess the now famous or infamous dental mold that BWXT took of the inside of the cavity. They did it originally under contract to Framatone and FENOC for purposes of just examination.

In our effort, we actually digitized that and put it into the finite element model. And I'll show you that.

We also contracted separately -- well, through our Oak Ridge contractor -- with FENOC -- James Hyres in particular -- I'm sorry, not with FENOC, with BWXT -- the hot cells down in Lynchburg -- and Jim Hyres in particular, to perform a more detailed characterization of the flaws in the cladding to support our finite element calculations.

And we have reports on that that I believe are available to you. If not, we can certainly make them available. In any event, just a few insights from that analysis.

One is this, on the left-hand side, shows a piece of the cladding, and you can see the full cladding thickness, and then the -- the darkened areas are the areas of in-service cracking. So you're

seeing the surface oxides that developed due to the boric acid corrosion.

And overall from this we found out that the maximum crack depth was about a tenth of an inch, more like 65 mils on average. And while the surface of the exposed cladding was, in fact, a maze of very shallow cracks, there was one area where the cracks were particularly deeper in between two adjacent weld beads that extended over a crack length of about two inches, where the central two-thirds of an inch had significant depth of the kind shown on the left-hand side and appeared to be more open to the surface, as you can see from the photograph.

Also important to our investigation was understanding the crack extension mechanism. The typical microstructure of three -- of -- well, it is a weld metal alloy -- stainless steel is you get a dendritic solidification structure where here the dark areas are the ferrite, the white areas are the austenite.

And I would just point out that the presence of ferrite is intentional in the 308 stainless steel. It's put there to avoid hot cracking during the welding process. So it's not a mistake; it's supposed to be there. Of course, nobody ever --

it's required to be there, or it's not 308 stainless steel.

Of course, it's not designed for exposure to concentrated boric acid, so the concentrated boric acid did to those little islands and pools of ferrite exactly what it did to the rest of the ferritic steel in the RPV head, and it just --

MEMBER POWERS: Let me --

MR. KIRK: -- took it right out.

MEMBER POWERS: Let me understand carefully. You said it's not designed for being in the presence of concentrated boric acid. I mean, it's clearly -- 308 fairly routinely is exposed to boric acid.

MR. KIRK: Yes. But not -- not to that level of concentration.

MEMBER POWERS: What is the threshold between acceptable and --

MR. KIRK: I don't know. And that's certainly beyond my area of expertise. I can get you an answer for that, but --

MEMBER POWERS: I mean, do you have -- do you have a sense of it?

MR. KIRK: No, I don't.

MEMBER POWERS: I mean, ordinary boric

acid is about .1 --

MR. KIRK: Well, the only sense I could give you is probably the same one you already have, that at the level of concentration in the primary pressure circuit everything is just fine.

MEMBER POWERS: And that's like .1 molar?

MR. KIRK: Again, you're outside of my area. I'll defer to anybody who can --

VICE CHAIRMAN SHACK: 2,800 ppm boric -- boron, I would have to compute that into boric acid, into molar quantities.

MEMBER POWERS: .1 mole or something like that?

VICE CHAIRMAN SHACK: Probably.

MEMBER POWERS: And so it has to be more concentrated than that.

MR. KIRK: Yes.

MEMBER POWERS: Is a factor of 10 sufficient?

MR. KIRK: Probably more than that.

MEMBER POWERS: So it's essentially boric acid is what --

MR. KIRK: Yes, it's a saturated boric acid solution that really causes the problem.

MEMBER POWERS: Why would that be?

MEMBER KRESS: Surely it doesn't have to be saturated. It could be some level below that, because there's nothing magic about the saturation level, unless it's a precipitant that does it.

VICE CHAIRMAN SHACK: The other thing that probably is also very helpful is typically to have some oxygen available, which you don't have on the other side of the boundary.

MEMBER SIEBER: Which is essential.

VICE CHAIRMAN SHACK: Well, I don't know that it's essential, but it certainly makes the process a whole lot worse.

MEMBER SIEBER: But, I mean, you always have oxidant around.

VICE CHAIRMAN SHACK: In the coolant system, you know, it's very, very low levels.

MEMBER SIEBER: But it's there.

VICE CHAIRMAN SHACK: Yes. I mean, you know, yes, definitely that.

MEMBER POWERS: Yes.

VICE CHAIRMAN SHACK: If you need PPM and you've got PPB.

MR. KIRK: Okay. Well, again, if that's of interest, certainly my colleague Bull Cullen would be much better suited to answer it than me. I can get

that and get it back to you.

VICE CHAIRMAN SHACK: Appreciate it.

MR. KIRK: Yes. In any event, the bottom figure, which is an optical metallograph, where on the left-hand side is the part of the cladding that was exposed to the boric acid solution in the cavity, and what you see is that the cracks in the stainless steel cladding formed when the concentrated solution preferentially dissolved the ferrite phase. so the cracking is, therefore, in a granular, i.e. between the austenite grains.

Now, this slide I think is a particularly important slide, certainly not from a numerical analysis viewpoint, because all you see is pictures, but even more important is this is the expert, this is the metal, this is what was there on February 16, 2002. And when we look at it in the scanning electron microscope -- I'll lead you through the pictures.

On the upper right-hand side is just a macro photograph where each of those red ticks is -- let me refresh my memory -- I think .025 inches each. So the total crack depth there is about a tenth of an inch, and then we've zoomed in on the -- the light/dark interface where the dark part is the crack that developed in service.

And what we see when we go to the highest magnification of 500x is that on the dark side you get the intergranular cracking that's characteristic of the boric acid attack, but you don't -- and this is the significant part -- in the service darkened area, you don't see any evidence whatsoever of micro-void coalescence that would indicate the ductile overload type of failure that we understand on the basis of our burst test, which I'll explain in a minute, is the way that the cladding would have ruptured had it ruptured.

So the point to be taken away from this slide is that the forensic evidence that's clearly evident in the cracks, in the stainless steel cladding, show that while the cladding did appear to have been deformed by the service loads, there is absolutely no evidence of ductile crack initiation.

So there is no indication from the forensic evidence that this cladding could in any way be characterized as ready to go. And that's, again, an important point to take away from a failure analysis viewpoint.

There's also an important point to take away from the viewpoint of benchmarking our finite element analysis, in that not only should our finite element analysis of this geometry under this material

condition not predict failure, but it should also definitely not predict that the applied J-integral values exceed the J1C, which would mean if that happened that would mean you should be seeing ductile growth in the service darkened regions.

So that's it for our summary in this presentation of the forensic exams. I'll now go on to talking about our methodology for integrity assessment of the vessel head in the as-found state. And this is just a cartoonish-type schematic showing you the various inputs that were needed.

We, of course, characterized the as-found condition, and we talked a little bit about that. We calibrated our failure model using large-scale tests, or I should actually say validated it. That, then, both served as inputs to a finite element model, which, along with material properties, allowed us to assess the structural condition of the cavity.

So for input information to that analysis, and a bit more detail, we needed to know, of course, the geometric configuration of the cavity, and the crack size and distribution. And while I've just gone into some level of detail showing you that on the preceding slides, it should be appreciated that when the initial analyses were being conducted in the

heated days just after the cavity was discovered, most of that information was not available.

In fact, it didn't all become available until sometime in the spring of 2004 after which our analyses were finalized. So that's why if you tuned in to the results of our analysis at various points in time, you'll see somewhat differing results, different conceptions of what the factor of safety against burst was, and how much longer the cavity could have lasted, because we've been continuously refining our models.

So we needed that information to do a credible analysis. We also needed information on the cladding strength and fracture toughness properties, and we needed to perform -- we decided to perform our burst test experiments to confirm our ideas about how the cladding would have failed, had it failed, and to benchmark our predictions.

So in terms of cladding strength, here you've got a bunch of true stress/true strain curves that we collected from the literature, and overlaid in the middle of that you see BWXT specimens, two of them, and those are specimens -- little tiny tinsels that were pulled directly from the Davis-Besse cladding material. So you can see that, from a stress-strain point of view, the material is entirely

typical of 308 stainless steel.

And I'll just point out in passing that we used that information, then, to construct probability distributions, that we then used in our Monte Carlo analysis when we were looking at predicting failure probabilities.

Similarly, we needed to know the ductile fracture toughness of the cladding material at the surface temperature. The results of tests that we performed -- if I can get a pointer here somewhere. Oops, sorry.

The results of tests that we performed on fracture tuft and specimens removed from the Davis-Besse cladding are shown here. And when making all your comparisons at the same test temperature, you see that, again, the Davis-Besse cladding is fairly typical of a 308 stainless steel. Sometimes we can find properties that are not as tough. Sometimes we can find properties that are more tough.

Again, there is nothing particularly atypical about this particular material from a strength and toughness point of view.

As I have mentioned several times, we did a series of burst tests at the Oak Ridge National Laboratory, and here you're looking at sort of the

meat of the burst test where we took a plate of an RPV cylinder that was made for plant service but never installed in plant service. This is what's frequently referred to as the PVRUF material.

There was a six-inch thick reactor pressure vessel steel plate that had been clad using standard industry practice. We then -- our colleagues at Oak Ridge then machined a six-inch diameter hole six inches deep into that plate of steel, leaving only the cladding material.

Some of those -- so we had a six-inch burst disk, which was meant to fairly closely represent the same unbacked area of the cladding that was in Davis-Besse. We also did tests at a number of fall depths, with the intention of both bracketing the fall depths that we observed in Davis-Besse, which was about a tenth of an inch out of a quarter-inch thickness of cladding, and also by performing tests -- parametric and fall depth -- we were able to examine the effect of fall depth on the failure mode.

I would point out something here that, you know, we had some trouble getting away from is to dissuade anybody from the notion that this test is intended in any way to be a one-for-one model or representation of Davis-Besse. It isn't. Clearly, it

isn't. The shape isn't right, and there is no corrosive environment, and it's not done at 600 degrees Fahrenheit.

So there are quite a few things that are different, but what we wanted to do here was to -- to replicate fall depth and unbacked area in an effort to get something close that we could benchmark a model on, and then use the model to capture the much more complex geometric and environmental variables that were difficult to test.

So the objective of performing these tests was to either validate or refute the opinion ourselves, and I think most people that looked at it, that the cladding would tear by -- would fail -- I'm sorry -- by either a ductile tearing or an overload mechanism, and also to assess the accuracy or conservatisms in our predictive fracture mechanics models.

So there is the picture of what the specimen looked like before the test. After the test, if you had a crack of fairly substantial depth -- and by "substantial" I mean two-tenths of the way into the cladding thickness or more, and that's certainly the condition that existed at Davis-Besse on 2/16/02 after the test. And this is now the six-inch test section

that has been cut out of the rest of the reactor vessel steep.

You've just got a nice bulging out. Ultimately, the crack -- and this is the -- this is the pressurized surface, this is the non-pressurized surface. Ultimately, the crack tore through, released the pressure, and the test was over. We got a fundamentally different response from our specimens when there was either a very shallow crack, something like 10 or 15 percent of the way through the thickness, or no crack at all.

In that case, while certainly being less cracked indicates -- and it's, in fact, true, that the test specimen or the structure, if you want to call it that, could withstand a higher load, when the specimen or structure actually failed, the failure was quite catastrophic. And what you're seeing is that the central disk was completely ripped out of the test fixture, and, in fact, cost us several thousand dollars in lost instrumentation until we decided to stop performing tests like that with instrumentation.

So to summarize the results and compare them with our predictions, on this slide the graph -- the blue dots on the graph are the results of the test, and the results are presented as the critical

pressure divided by the cladding thickness plotted versus the crack depth, normalized again by the cladding thickness.

The set of sweeping curves show you the mean prediction and confidence bands on failure when failure is by initiation of stable duct of tearing, whereas the upper lines show you the -- I guess it's better to say the median prediction and the uncertainty bounds when failure occurs by overload of plastic collapse.

And what you see in the test data is a transition between those two failure modes, where if you have either no flaw or fairly shallow flaw the overload plastic collapse type of failure dominates. And while you do get lower failure load -- or, I'm sorry, higher failure loads, failure pressures, you tend to blow out the entire unbacked area, so you get a much larger break in the -- if it were the pressure circuit, in the pressure circuit.

Whereas, when you get the stable tearing type of failure, you fail obviously at much lower pressures, but the size of the opening is expected to be considerably less.

MEMBER POWERS: All gas pressurized systems?

MR. KIRK: Alan, do you remember? I'm -- yes, it's gas.

MEMBER POWERS: If you had done the test with cracks, and hydrostatically loaded it, would it have been -- just left that little fine crack you showed, or would it have ripped open --

MR. KIRK: Obviously, there would be a greater tendency to rip a larger hole.

MEMBER POWERS: So is this --

MR. KIRK: But there --

MEMBER POWERS: -- without a difference here?

MR. KIRK: I think, you know, qualitatively it's going to go that way. Quantitatively, we just -- we haven't covered that in our analysis.

MR. HISER: I'm sorry. What was the context of the question again?

MEMBER POWERS: Well, the distinction has been made here that with a crack you get this -- and it vents the pressure out, because it's gas-loaded. Whereas with no crack, it blows the entire disk out. What I ask is, gee, if you hydrostatically loaded it instead, wouldn't the post-test examination have been about the same?

MR. KIRK: That's a good question. The only thing I could add in is that the -- the calculations that we ran to actually do the integrity assessment effectively did keep the pressure on and calculated the stability of the crack once it tore through. So while that feature, indeed, as you've pointed out correctly, is not well captured in our -- in our test, it is well captured in the analytical model.

MEMBER POWERS: I'm just trying to understand --

MR. KIRK: Yes.

MEMBER POWERS: -- what I'm supposed to do with this information, and it strikes me I'm not going to do anything with it. When it overpressurizes, it busts big time. And there's -- I mean, that's the message I get.

MR. HISER: Well, but I think there's a couple messages. I think the one message is that, you know, it's a race to failure. If you had a -- a static load condition, you know, constant pressure, and the cavity is growing, the cracks are growing deeper, you know, one of them is eventually going to get to a failure condition. And which one gets there faster is the one that would probably determine

whether you blow out the cavity or you end up with a leak.

MEMBER POWERS: No, I'm not sure I'd -- I'm not sure that's the part I bought.

VICE CHAIRMAN SHACK: You know, you get a fishmouth if you -- you know, if you had a load, you get a fishmouth rather than that little tiny crack. I mean, you presumably did predict deformations.

MR. KIRK: Yes. But as you know, trying to go to actually that predictive level, but I would emphasize is that when we did the calculations in the forward- and backward-looking analysis, once the crack tore through we were then able to assess stability of the torn-through crack and determine whether it would continue to rip or rip out.

MR. HISER: And I think in general the calculations -- when you first get the leak, the crack doesn't suddenly go unstable.

MR. KIRK: No, it doesn't.

MR. HISER: And so you would ultimately -- you know, there's going to come a point where you're going to detect leakage through leak detection methods.

MEMBER POWERS: Every place except perhaps at Davis-Besse, I would --

MR. HISER: Well, but I think that -- that really is why this part of the calculation is important, because, you know, whether you blow out an area that's larger and you get the equivalent LOCA from that, or you get a leakage through a slit sort of mechanism that, you know, maybe the crack is growing, but it still maintains stability because the material has fairly high tolerance.

MEMBER POWERS: Do you calculate stream erosion when you calculate these crack stabilities?

MR. KIRK: No.

MEMBER POWERS: Stream erosion, it seems to me, would at some point dominate here.

VICE CHAIRMAN SHACK: Well, you'd certainly be above your tech spec limit.

(Laughter.)

And hopefully be shutting down pretty fast.

MEMBER SIEBER: Hopefully.

MEMBER POWERS: Well, it still would take the load off, Bill.

MR. KIRK: Moving on, further looking at the geometric inputs, the finite element model of the as-found state, we've shown here in detail, more in our reports, how the dental mold was used to get an

accurate representation of both the footprint of the wastage area as well as the three-dimensional geometric shape.

And that, then, on the right-hand side, of course, you see the mold; on the left-hand side, a graphical representation of the mathematical model of the mold that was then used to establish geometry for the finite element model.

We also incorporated into the finite element model the average periodicity of the welding causes the crenulations on the inside surface of the cavity. And the lower figure just illustrates that we located the crack in our cavity model in the same place that it was found in the service condition.

Again, another view of -- showing you the details of the finite element model, to point out that just for purposes of actually getting the calculation done, you know, sometime at least before the end of my career, we have to take a substructure approach where we started off by modeling the whole head without the CRDM penetrations.

We then carved out a little pie-shaped sector, applied the boundary conditions on the pie-shaped sector determined from the bigger model, modeled the effect of the CRDM penetrations, and the

hole and the cladding, and put the crack in that model.

MEMBER SIEBER: I would presume the shape of the wall in the calculation has no effect on -- on burst strength or stress or characteristics.

MR. KIRK: To be honest, probably not. However, having gone through multiple iterations with less elegant models and not being able to predict with any degree of believability the fact that this geometry had not failed, we eventually just pulled out all the stops and said, "Okay. Let's model everything we possibly can." But I would agree. The only --

MEMBER SIEBER: I think the footprint is important.

MR. KIRK: The footprint is certainly important. The only thing --

MEMBER SIEBER: But the wall shape is not.

MR. KIRK: The only thing -- the only feature that I think was probably important to capture, but, again, we didn't do a sensitivity study to show this -- is this -- this nose or little area of overhang here, where you've got material here that's only backed by a very small thickness of the ferritic material.

MEMBER SIEBER: Okay.

MR. KIRK: So I think probably, you know, of all of the complex features of that shape, that's the one that was important. But to get that we modeled the whole thing.

Okay. So going on, so our as-found analysis based on a geometric finite element model to estimate stresses, the actual properties of the Davis-Besse material for the cladding for strength, the actual Davis-Besse properties for the cladding fracture toughness, and because the actual condition was actually a network of interlinking cracks, to make the model tractable we idealized that into three different representations of that network of cracks.

I'm just going to focus on one that we called our bounding model, where we bounded the depth of that network of cracks at a tenth of an inch in the length, at two-tenths of an inch. So the results of the as-found analysis are shown here. I'd like to focus your attention on the graph.

The vertical axis is J applied or the driving - the applied driving force to fracture that occurs as a consequence of the pressure loading. The three different colored curves represent our three different flaw models, and, again, I'll just focus attention on the -- what we've called the conservative

bounding model or flaw number 3 that's shown in blue.

The three horizontal lines represent the range of fracture toughness characteristic of the Davis-Besse material at the 95th median and 5th percentiles. And, to me, the takeaway point from this presentation is that the operating pressure we're nowhere near the 5th percentile J1C. And even at the setpoint pressure we're still below the 5th percentile J1C.

So our prediction would have -- you know, if somebody asked us to predict this, which I guess they did, is that failure didn't occur, and, moreover, hey --

(Laughter.)

-- that was only a few million dollars and several years later. And the ductile crack initiation didn't occur, and, in fact, that's what occurred in service.

The other I think heartening thing to take away from this is that the difference between the operating pressure and the relief valve setpoint pressure was not adequate even getting a bounding flaw characterization, and even given a bounding fracture toughness characterization to compromise the integrity of the cladding.

MEMBER SIEBER: But that's about a 10 percent increase in pressure.

MR. KIRK: That's right.

MEMBER SIEBER: Yes.

MR. KIRK: Yes. So at least to me the takeaway from this is that the -- in reality, obviously, the probability on failure of date of discovery was zero. But based on this analysis, assuming the set valves work -- and I'll leave the probability of that to others that know better -- is exceedingly low.

Okay. So now working on to our forward- and backward-looking analysis, basically the same analysis/methodology. We need a few more inputs, and we also needed to develop from our very detailed three-dimensional finite element model a much more simplified model just to enable the forward- and backward-looking calculations.

And so an in-going assumption to our analysis is that the -- I shouldn't say the complex cavity shape -- the complex footprint shape can be modeled as a circle. And I provided -- and at first blush that looks like an awful gross approximation. I'll give you two scientific reasons and one practical reason why you should maybe let me get away with that.

The scientific reasons is that for failure by plastic collapse the total unbacked cladding area is a much, much more important parameter than the -- than the unbacked area shape. And as evidence of that, I provide you the graph shown here, where the downward-sweeping curve is, in fact, a closed form plasticity solution due to Chakrbady and Alexander, published in 1970, of exactly this geometry.

And then, we performed a number of different finite element analyses, both where we took the sort of boot-shaped footprint and expanded itself similarly, and we looked at different ellipsoidal growth patterns. And for all intents and purposes, given the other approximations in the analysis, all the points were pretty darn close to the theoretical circular growth pattern.

So, again, for the plastic overload type of failure, the shape really just doesn't matter. For failure by ductile tearing, the circular consumption -- I'm sorry, the circular assumption is indeed conservative, because when you put the crack in the middle of the disk, as we did, you know, that the crack, because of the geometry, has to be oriented perpendicular to the principal stresses.

Whereas, we know that the crack in Davis-

Besse formed preferentially due to the -- the metallurgy of the ferrite stainless steel and the boric acid in the cavity, and that turned out not to be oriented perpendicular to the applied principal stresses.

So when we assess the crack in the cavity as a crack in the circle were, in fact, overestimating the driving force to fracture. So those are my -- my scientific reasons why this is a reasonable thing to do. The somewhat non-scientific reason is we just don't know anything better to do.

The corrosion experts were unwilling to be -- and I think justifiably so -- be boxed into a corner to provide any kind of a quantitative model by which either the cavity developed to the shape it was or would have proceeded from there on. So given that lack of modeling information, a circle is about as good as anything else.

MEMBER POWERS: I just can't resist. You would get an A+ in our quality review for justification of assumptions here.

MR. KIRK: Thank you.

MEMBER POWERS: In the first place, circle was -- I mean, a cylinder looked like a pretty good approximation to me to begin with, and you've

convinced me that it's an excellent approximation.

MR. KIRK: Well, remember, I've had three years to think about this.

MEMBER POWERS: And my third thing is I'd be willing to take on trying to calculate based on -- on corrosion, what the shape of the cavity is.

MEMBER SIEBER: Did you say the score would be .8?

(Laughter.)

MR. KIRK: 42. I think the answer is 42.

MEMBER POWERS: I believe you'd get a solid 5 on this one.

MEMBER RANSOM: Well, I know where the as-found model for 2004 and the as-found model for 2002 --

MR. KIRK: Hang on. I'm refreshing. Yes. As I said, our state of knowledge regarding what the footprint of the cavity was and what its shape was evolved significantly over time. The original as-found model, September 2002, was I think based on poroscopic measurements and somebody sticking a ruler down into it, and sketches made by inspectors.

By the time we got to 2004, we had the -- the green pukish-looking dental mold, so we had a much more accurate representation. So that's just

difference in state of knowledge.

Okay. So the input information to these calculations, we needed to have -- since we're doing a probabilistic analysis, our inputs need to be statistically distributed. So we needed to have statistical representations of toughness and strength, which you've already discussed. Some things we had to base on engineering judgments, and I'll talk a little bit about that -- our rules for LOCA binning and our statistical fitting of data.

Other things were based on what I've called expert opinions benchmarked to data, and that had to do with the general corrosion properties of the ferritic RPV steel and the corrosion crack growth properties of the austenitic stainless steel cladding.

It's certainly not to say that data doesn't exist -- in fact, ample data doesn't exit -- for both of those phenomena. You could go into the literature and find lots and lots of it.

The difficulty was, and where we relied on three internal people with expertise in this area to help guide us, is nobody was ever really sure what the thermal and acidic conditions were in the cavity itself. One of my colleagues referred to that as something like sheer conjecture.

So, anyway, we asked three people to make a sheer conjecture on what that was, and that led them to sometimes differing/sometimes similar views as to what the general corrosion and the stress corrosion properties of the ferritic and austenitic materials was respectively.

MEMBER POWERS: If they were looking at general corrosion for the ferritic material, they must have had some estimate of the stability of ferrous and ferrite borates in solution. Yes?

MR. KIRK: Presumably, yes.

MEMBER POWERS: Do you know what they used?

MR. KIRK: I have no idea.

MEMBER POWERS: Because, I mean, I know of exactly one report in the literature on the stability of the borate complexes of iron in solution.

VICE CHAIRMAN SHACK: Well, I mean, I think these were measured from general just corrosion tests of ferritic steel. I mean, they had the corrosion. Given the temperature and a boric acid concentration, as Mark said, we sort of know the corrosion rate. What we don't really know is what the temperature and the concentration is in the cavity.

MEMBER SIEBER: Well, it's always

changing, too.

VICE CHAIRMAN SHACK: Well, yes. That's --

MEMBER SIEBER: And so is the corrosion rate.

VICE CHAIRMAN SHACK: Yes.

MEMBER SIEBER: And that's what makes the problem difficult is that you have a constantly-evolving situation.

MEMBER POWERS: Yes. But it doesn't hold very much.

MR. KIRK: Maybe you need more optimistic experts.

MEMBER POWERS: We're always optimistic.

MR. HISER: If this is even a parameter, we don't even know the end state what it was that they have discovered, because it -- it wasn't sampled. So it's --

MEMBER KRESS: Yes. There is one class of opinions that says that that cavity had gone as far as it's ever going to go.

MEMBER SIEBER: I had heard that. That's conjecture, though.

MR. KIRK: I don't think we had any experts that were that optimistic.

MEMBER KRESS: Well, the reasoning had to do with the size of the -- the opening to the top that would finally relieve the pressure in there, and thereby relieve the concentration and --

MR. KIRK: Right.

MEMBER KRESS: -- boil away the solution that --

MR. KIRK: I was just looking at that. I skipped add and looked at their inputs. Nobody predicted a zero effective cavity wastage rate. So nobody was that optimistic about the situation.

MEMBER KRESS: That's really optimistic.

MR. KIRK: Well, yes.

MEMBER KRESS: You wouldn't have any --

MEMBER POWERS: But there are zeroes and zeroes here, and I can't --

MR. KIRK: The problem is you're working with --

MEMBER POWERS: Yes. Your corrosion rate can always be finite, but it can be so minuscule that it's essentially unmeasurable.

MR. KIRK: Well, I don't think they were actually predicting zero.

MEMBER KRESS: All right.

MEMBER RANSOM: Did the wastage occurred

from the outside and -- in other words, the boric acid concentrate on the outside surface and then go down through the --

MR. KIRK: I believe that's one of the models.

MR. HISER: Yes. I think there's a lot of conjecture on that as well, whether it ate, you know, down at the -- at the -- near the clad, base metal interface, and then that grew up, or, you know, the concentration flowed up to the surface and then it ate down. I mean --

MEMBER SIEBER: Who knows?

MR. HISER: Yes, it's -- all we know is at one point in time everything was intact. February 16th it looked that way, and we don't have any data points in between, unfortunately.

MEMBER RANSOM: It would seem like the evidence would favor from the outside, because otherwise the concentration would be no different than the concentration on the interior of the reactor vessel, as far as the boric acid concentration.

MR. HISER: Well, except you get boron off of the water.

MEMBER RANSOM: There has to be a vent or something, though, doesn't there?

MR. HISER: Well, there's an annulus between the CR --

MEMBER KRESS: There's a place for the steam to go out.

VICE CHAIRMAN SHACK: There's a gap between the -- you know, if you get the crack through the nozzle, then there's a gap for the steam to escape.

MEMBER KRESS: It depends on the size of that gap as to whether it concentrates it or deconcentrates it.

VICE CHAIRMAN SHACK: Yes.

MEMBER SIEBER: And it's not concentric.

VICE CHAIRMAN SHACK: Well, it will get larger.

MEMBER KRESS: It will get larger. And eventually it'll reach a state where it boils this stuff away --

MEMBER SIEBER: Yes.

MEMBER KRESS: -- faster than a crack can put it in.

MEMBER SIEBER: Right. It's just blown.

VICE CHAIRMAN SHACK: But we have plenty of cracks where the wastage did not occur.

MR. KIRK: Sorry?

VICE CHAIRMAN SHACK: We have plenty of cracks where the wastage --

MR. KIRK: Oh, yes. Absolutely.

VICE CHAIRMAN SHACK: So, you know, the exact conditions that produce minimal wastage and the conditions that produce --

MR. HISER: Actually, I would maybe caution a little bit on that. There was another nozzle at Davis-Besse that had some incipient wastage down near the clad base metal interface. I'm not sure how many other plants did sufficient examination to be able to detect anything like this.

MEMBER POWERS: All we're doing is confirming that metallurgy is not yet a precise science.

VICE CHAIRMAN SHACK: No. If you've got essentially your milligram of boric acid on top, it says that not a whole lot came through. I mean, you know, most of those other amounts are associated with like one gallon of total leakage. Well, you know, the amount associated with the leakage here is much larger.

MEMBER SIEBER: I think the statement you made needs some expansion. The examinations may not have been sufficient to determine that a cavity was

forming, but they were sufficient to determine whether there was a crack or not.

MR. HISER: Yes, that's correct. And that's where the examination is focused on.

MEMBER SIEBER: So even though a cavity might have begun to exist, a repair to a place that stopped further progression.

MR. HISER: Right.

MEMBER SIEBER: Okay. You know, just to leave that hanging, one would think, well, it -- there's cavities forming in half the plants, and that's not true.

MR. HISER: No.

MR. KIRK: Okay. And then, the last category of input information was -- I've also said, based on expert opinion -- and I would say somewhat greater level of conjecture than was the previous bullet, and those are the conditions on the -- of the crack depth in the austenitic stainless steel cladding of the cavity size one year before the situation was discovered.

Obviously, the individuals we asked needed the same sort of basic input information, but then they had to, in their minds, back everything up a year.

I should point out -- and I'm perhaps getting a little bit ahead of myself -- that using the information provided by this group of three individuals, and then fitting statistically, we performed our calculations from time of discovery minus a year up to time of discovery. And at least on average they weren't that far off.

The crack depths and the exposed area of cladding that we were predicting at time of discovery did not deviate by that much, again on average, from the conditions that were actually discovered. So what the group did on whole, on average, worked out pretty good.

The engineering judgments that were made, which I guess is somewhat more guidant than assumptions, in my view, had to do with the local binning rules -- the LOCA binning rules, I apologize -- and the statistical fitting of data. LOCAs were categorized as being small if they produced a break in the primary pressure circuit up to three and a half inches in diameter.

And I believe the three and a half inch cutoff was based on what the makeup systems can replace. Medium was 3-1/2 to 4.8, and large is greater than 4.8.

We then had what we called conservative best estimate and less conservative LOCA binning rules, which, again, are detailed in the report. I'd just point out that the conservative model would equate through clad cracking -- in other words, where the crack tip penetrates the cladding layer as complete failure. That was what our conservative models would have given us.

Whereas the best estimate model start -- took that and then calculated the stability of the through clad crack under the pressurized conditions, and saw if it would tear stably or just let go.

MEMBER KRESS: I'm just curious, what's the basis of the 4.8 inch?

MR. KIRK: I apologize, but I -- I don't know the answer to that question. I wasn't involved in that.

Gary, do you -- I'm getting no. I can find that out for you.

MEMBER KRESS: I was just curious.

MR. KIRK: Yes, because it's certainly -- it's certainly -- I apologize. I wasn't involved with the project in the middle. I got it on both ends, and that happened in the middle. But I can find that out for you.

MEMBER KRESS: It probably has something to do with how fast the primary system depressurizes.

MR. KIRK: And then, judgments had to be made regarding how we fit statistical distributions to our judgment information, and that's illustrated on the following slides.

So this table is just the input information that we got from our subject matter experts on our four variables -- those being the cavity radius at time of discovery minus one year, the cavity wastage rate or the general corrosion rate of the ferritic steel, the fall initiation time relative to the time of discovery, how long the falls had been in the cladding, and then also the effective flaw growth rate just put these up for information and to illustrate that the inputs given us by the experts tend to span a fairly wide range, as you might expect, given the uncertainties that they had regarding the environment inside the cavity.

MEMBER POWERS: You mention frequently the experts. Do you ever reveal who the experts are?

MR. KIRK: Alan, should I reveal who candidate 1, 2, and --

MR. HISER: No. These are three staff members that -- that have --

MEMBER POWERS: Three guys you grabbed out of the lunch room and --

MR. KIRK: Who have --

MEMBER POWERS: -- kicking and screaming.

MR. KIRK: -- who have far more expertise in the corrosion area than either Alan or I.

MR. HISER: We don't even say guys, because you make assumptions there.

MEMBER POWERS: Kicking and screaming. I am informed reliably by the current Merriam-Webster dictionary that "guy" is non-sexual. It is uni-sexual now.

MEMBER SIEBER: It is?

MEMBER KRESS: Yes.

MR. KIRK: Now, where I went to school for my bachelor's, which was Virginia Tech, we just say y'all. And when I worked in Pittsburgh, we just said you'ns, and those are also asexual and also not understandable to people that grew up outside of --

MEMBER POWERS: Tom understands it perfectly.

MEMBER KRESS: I understand y'all, and you'ns, too.

MEMBER POWERS: No. You understand y'all. You don't understand you all. You understand y'all.

MEMBER KRESS: But that makes you a Hokie, right?

MR. KIRK: That's right.

MEMBER KRESS: I don't know what that is.

MR. KIRK: And hopefully none of that just got into the minutes, or I'm going to be asked to spell it.

(Laughter.)

Okay. So here we have the probability density functions that we fit to both the cavity growth rate and the crack growth rate. Oh, that's the old one, never mind. One is the probability density; one is the cumulative probability. I apologize for the difference.

But, again, just to point out the cavity growth rate, we were fitting values that ranged from almost nothing per year to up to seven inches per year, and the statistical distributions cover that range. And the crack growth rate in the cladding all the way from almost nothing to a tenth of an inch per month, and then a tenth of an inch per month, given that you've only got quarter-inch cladding, it just doesn't take too long to get through.

With only three data points, it isn't surprising to note that you can fit pretty much

anything through there, and your best-fit statistics don't tell you an awful lot.

So we took some standard density functions and then categorized them as being either best estimate meaning somewhere in the middle, more conservative meaning tending towards higher values, and less conservative meaning tending towards low values, and then we ran a whole bunch of cases for our Monte Carlo analysis to try to get a sense of the effects of model uncertainty on what we will subsequently label our best estimate, or perhaps best guess values. And here you go.

So these are the results of the -- of what I've called the forward-looking analysis where we start with the known as-found state as certain, and then we project forward in time. So on the -- on the left-hand side of your screen you've got the breakdown with LOCA size.

Obviously, you've got no failure probability up to the day of discovery, and then the failure probabilities start to kick up, where the red curve is the total LOCA probability, blue is small break LOCA, brown medium break, and green large break.

And a thing to point out here is that the small break LOCA dominates, and that's a direct

consequence of the fact that we know from our forensic investigations that the cracks were already a tenth of an inch through a quarter of an inch of the stainless steel cladding.

In this case, the deeper cracks actually tend to reduce the consequence of the failure, because even though they claim the failure, had it occurred, would have occurred sooner, there is less energy in the system and, therefore, less likely to blow a big hole in it.

Excuse me. I'm losing my voice.

On the right-hand side, now looking at just total LOCA probabilities, you see the effect of our three different flaw size idealizations. And the results that we've been, you know, talking about are based on our enveloping flaw characterization, which is shown by the -- by the upper curve.

So, again, based on the bounding flaw model, which is flaw 3 -- and I should note that that, while ASME doesn't give practices for enveloping such flaws, they do give interacting flaw practices, and basically we drew a big oval around all of them.

Based on the bounding flaw model, our model predicts that there was between 2 and 22 months of operation beyond February 16, 2002, that could have

taken place before the cladding was compromised where the best estimate value, meaning the median value, is five months.

Obviously, a pretty wide range there reflecting the uncertainties in projecting this forward based on unknown environmental conditions. But then the bottom point I think is a more certain result because of what we do know about the cracks and the cladding, and that is had a failure occurred it's very much more likely to have been a small break LOCA than a larger break.

MEMBER DENNING: Now, that's not necessarily a good thing, right? I mean, as far as conditional core damage and the -- and knowledge about the systems in that plant, it's possible to -- have you looked at -- when you look now and you add on conditional probability core melt, are you better or worse to have a small break LOCA or a large break LOCA?

MR. KIRK: I'm going to have Gary talk to that.

MR. DeMOSS: I'm Gary DeMoss, and I did the accident sequence precursors analysis, which is designed to address just that question. And, actually, our risk was dominated by the large break

LOCA, coupled with the likely sump failure. And that -- admittedly, the probability of that large LOCA, which is driven by the high end of the corrosion rate curve and then the large blowout, has got a tremendous uncertainty on it. But that becomes a high-risk sequence.

And then, medium LOCAs actually was a slightly higher risk sequence, because it also had the CRD and ejection due to that crack growing and getting you. And small LOCA has got a much lower -- better -- two order of magnitude lower conditional core damage probability.

MEMBER DENNING: Even though there is a question about the high pressure injection, or has that just come about in recirculation and too far out?

MR. DeMOSS: Recirculation.

MEMBER BONACA: I thought there was an issue with high pressure injection also, Gary, if I recall correctly. There is definitely in recirculation a question on that, and maybe the pressure doesn't hang up long enough.

MR. DeMOSS: If I could clarify that. The only issue we had is -- is recirculation, because the pump couldn't pump dirty water and would almost fail with certainty in that situation. And that actually

raised the risk of a small LOCA considerably. It doesn't affect a large LOCA at all, because we don't use that pump in a large LOCA.

MR. KIRK: Okay. The next slide, viewgraph 31, compares the forward- and backward-looking analysis in terms of the predicted total LOCA probability on 2-16-02. So, again, the critical difference between the forward- and backward-looking analysis were the backward-looking analysis -- in fact, the inputs that we've provided to Gary for the ASP -- for his ASP work.

In the forward-looking analysis, we start with the known condition on 2-16-02 and proceed from there. With the backward-looking analysis, we're required by the ASP protocols to project backward a year's time and make some judgment about what the conditions of the cavity were.

And for reasons that we have discussed, there is considerable uncertainty in that. So what we get out of our analysis is that the backward-looking analysis predicts an approximately one in five or 20 percent total LOCA probability on 2-16-02 when, in fact, as we know nothing happened.

So why are we predicting 20 percent probability? Well, that's, of course, a direct

consequence of the uncertainty regarding the initial conditions that's inherent to that backward-looking calculation.

MEMBER POWERS: What you're saying there is that if we had 100 Davis-Besse's of this configuration, 20 of them would have failed a --

MR. KIRK: Correct. Yes, that's one possible interpretation.

MEMBER POWERS: Well, if the assumptions that went into that calculation are --

MR. HISER: Yes, assuming those assumptions represent --

MEMBER POWERS: I understand that.

MR. HISER: -- the possible range of 20 Davis-Besse's.

MEMBER POWERS: What you're talking is -- with Davis-Besse, if 20 of them would have actually failed, and presumably failed during the operation, they are not shutdown prior to that, day zero.

MEMBER DENNING: I'm struggling with exactly what -- when you go -- with a backwards analysis, I can certainly see where you can ask a year earlier, what would the probability -- but how does that, then, impact backwards to today -- I mean, if now today is February of 2002, I mean, we know our

state there. How does the backwards analysis impact that? I mean, you went backwards, and then you did an uncertainty analysis from there coming forwards? It's --

MR. KIRK: That's correct.

MEMBER DENNING: There's something a little bit --

MEMBER POWERS: No, it's the other way around. He knows his state. He knows his actual state today, so we're basically doing it as a Bayesian update. There was probability distribution, right?

MR. KIRK: No, I don't think so.

MEMBER POWERS: That's not the way you did it, but that's --

MR. KIRK: No.

MEMBER POWERS: That's what you should have done.

MEMBER KRESS: Wanted to know the failure probability as a function of time. That's what the --

MEMBER SIEBER: Yes, and we integrated the risk.

MEMBER KRESS: I guess the way to get it as a function of time --

MEMBER DENNING: In a forward analysis, I mean, that makes a lot of sense -- the forward

analysis. But somehow the backwards analysis --

MEMBER KRESS: There is no probability fair of actually the time unaccounted. I want to know how much it was at risk during the time they didn't know about it.

MEMBER SIEBER: And the risk keeps changing.

MEMBER DENNING: But we know what the state of it is on February 2002, right?

MEMBER KRESS: Well, you could say it was always that, but it wasn't.

MEMBER DENNING: No, no, I agree. And earlier it was different. But --

MR. KIRK: And I think maybe the -- and I have a lot of sympathy for the question you're asking, because it's difficult for me to think about historical events in a probabilistic sense. To me, history is deterministic. but --

MEMBER POWERS: I think if you look at in the ensemble --

MR. KIRK: Well, it gets to your point. The manifestation that was Davis-Besse did not fail. We know that to be true. But I think perhaps the -- whether it's satisfying or not is a different issue.

Dr. Powers' representation that, you know,

assuming our assumptions of the conditions a year before date of discovery are reasonable or correct, our calculations are showing that, you know, had there been 100 Davis-Besse -- 100 different evolutions of reality --

VICE CHAIRMAN SHACK: Well, I think --

MR. KIRK: -- along those lines, roughly one in five of them would have failed.

VICE CHAIRMAN SHACK: Your uncertainty in crack growth rate is not as though there is a crack growth rate and you just don't know the answer. You know, there is an aleatory uncertainty in the conditions that could have led to crack growth rates anywhere in there, and so it is an ensemble question. And, you know, it's --

MEMBER SIEBER: And to know the probability per reactor year you have to integrate the risk over some period of time to predict it.

MEMBER KRESS: That's the reason they want the time.

MEMBER SIEBER: Right. That's why you go back.

MR. KIRK: Yes. Just, you know, taking those results apart a little bit more into the different LOCA types, I'll just point out that even

though the graphs that I'm showing you, and the graphs that appear in our reports, go both for the backward-looking analysis a year before day of discovery and then out to we're predicting a total LOCA probability of unity.

The ASP analysis only actually used the predicted LOCA probabilities in the year before the day of discovery. So all those other LOCA probabilities are just shown for information purposes only. It's not something that ever actually got used in the analysis.

And, again, you know, focusing attention on the year before day of discovery, as was the case with the forward-looking analysis, a small break LOCA is, again, the most likely outcome, although as Gary has pointed out from an integrated risk perspective, that is not what is dominating the risk.

And just to look at the effects of the different modeling assumptions that we made, which basically includes how we selected statistical distributions to represent the key variables in our analyses, on the day of discovery our backward-looking analysis is predicting a best estimate total LOCA probability of about 20 percent. And that has a range, depending upon how we statistically represented

our modeling assumptions, of between 14 and 24 percent.

If you look at small break LOCA probability, best estimate is 18 percent ranging from 2 to 18; medium break, 1 to 15 percent with the best estimate being 1; and large break anywhere from 0 to 9 percent with the best estimate of about 3.

And, again, I know these are some -- some fairly substantial ranges, but given the uncertainties involved and the limited state of knowledge that's what you wind up with.

So to summarize -- go ahead. I'm sorry.

MEMBER POWERS: You have avoided putting your probability access on a logarithm stage, so we can see at what point you started crossing our level of pain with respect to vessel integrity.

MR. KIRK: Well, I think the -- maybe the answer is -- you're looking for is more fairly dealt with in Gary's analysis, and I would just point out that the curves I'm showing you here are merely -- they're the output of our structural calculation and form inputs to Gary's analysis, where those type of issues are taken up in a much more sound, scientific way.

MR. HISER: Yes. I think maybe one

message from this is the numbers are huge. You know, they're orders of magnitude higher than what's acceptable. So you need to do proper maintenance and not allow these kinds of conditions to occur. I mean, a lot gets --

MEMBER POWERS: Is it a good idea to have a hole in the head like that?

MEMBER DENNING: Well, the thing that strikes me is the forward analysis -- to me, the forward analysis says that if we had buttoned it up and operated for the next cycle that it probably would have had a break.

MR. HISER: Probably. Yes, probably. They were on a two-year cycle and, what, the 95 percentile was 22 months. So that's pretty close to one.

MR. KIRK: Unless you take Member Kress' very optimistic view that the corrosion has stopped.

MEMBER DENNING: But he didn't make that view. He just said that -- he just said that it necessarily --

MEMBER POWERS: I thought you believed it passionately.

MEMBER KRESS: Well, I do hold the view.

VICE CHAIRMAN SHACK: Yes. But what's

your probability of belief in that number?

MEMBER KRESS: .8.

VICE CHAIRMAN SHACK: Oooh. He's convinced.

MR. KIRK: Okay. So just to -- to summarize for our analysis of the as-found condition, our forensic examinations, and those performed by others, most notably BWXT found no ductile tearing initiated from the corrosion-assisted flaws, and that suggests that cladding rupture was in no way imminent on the day of discovery.

Our analysis predicted that there was no crack initiation on the day of discovery, and our analysis also quantified that pressure in excess of the relief value setpoint would have been needed to rupture the cladding on 2-16-02.

Our forward-looking analysis where we treat that as-found condition is known, and try to maintain some insight into events in the future -- said that we had between 2 and 22 months more of operation that would have been needed at the operating pressure to rupture the cladding. And the best estimate, meaning the median value, is somewhere around five months.

And the most likely consequence of

cladding rupture would have been a small break LOCA. Using the backward-looking analysis that was input into the ASP calculation, and taking a single point away from that, we're predicting approximately a one in five chance of some sort of LOCA on the day of discovery, and in all likelihood that would have been a small break.

MEMBER KRESS: Your conclusion that the most likely consequence is a small break LOCA implies to me that the failure was crack growth.

MR. KIRK: Yes. What was? I'm sorry.

MEMBER KRESS: That the failure mechanism was actually crack growth.

MR. KIRK: Yes, yes.

MEMBER KRESS: So that my -- my position that the cavity didn't change in size much doesn't really affect that the vessel probably would have failed anyway, because of crack growth and --

MR. KIRK: Yes. It's --

MEMBER KRESS: -- it probably wouldn't have been much different in timing.

MR. KIRK: Well, obviously, it's a race. As the cavity size gets bigger, you get a bigger unbacked area, so you get more bending stress.

MEMBER KRESS: So the crack grows faster

is the --

MR. KIRK: So there is more -- yes, there is more applied stress, but there is already an unbacked area, so there is already bending.

MEMBER KRESS: Yes.

MR. KIRK: So the cracks are, I think safe to say, already growing.

MEMBER KRESS: Yes.

MR. KIRK: So, yes, you're right. Even if the cavity had stopped growing entirely, that doesn't mean that it wouldn't have failed, at least in my view.

VICE CHAIRMAN SHACK: No. I mean, you could actually do that calculation, presumably.

MR. KIRK: Yes. Well, presumably, it's one of the many thousands of manifestations that we did.

MEMBER KRESS: Yes, it would have --

MR. KIRK: But, I mean, you'd shift the probabilities if you turned it off.

MEMBER KRESS: But I'll bet the time doesn't change that much.

MR. KIRK: Probably not.

MEMBER KRESS: For failure.

MR. KIRK: That's it.

MEMBER SIEBER: Do any of the members have additional questions or comments?

MEMBER KRESS: Comment. That was a terrific presentation. I appreciate it.

MEMBER POWERS: I reiterate that had you been -- had this work been submitted for the quality review, I think it would have scored extraordinarily highly.

MEMBER SIEBER: Yes.

MEMBER KRESS: So we appreciate that. Thank you.

MR. SCOTT: Jack?

MEMBER SIEBER: Yes.

MR. SCOTT: I'd like to ask a question if I could. Can you speak a little bit to the probability of a rod ejection having occurred in conjunction with this? Could you all address that?

MR. KIRK: No, I personally can't. Can anybody else? Sorry, just not my area.

MR. SCOTT: Okay.

MR. DeMOSS: Yes. Gary DeMoss, the ASP panelist again. The rod ejection probability was considered in the ASP analysis -- separate materials -- an analysis which I'm not equipped to speak in detail on. I'm a PRA guy.

But it was actually the most likely cause of a medium LOCA, more likely than the ejection of the cladding that they -- analogous to what they showed from the laboratory.

MR. SCOTT: Gary, do you know what the probability they came up with was on a rod ejection occurring?

MR. DeMOSS: I could dig it out here I think fairly quickly. But it was -- it was higher than the 1 percent medium LOCA that was generated for the unbacked cladding.

MR. SCOTT: So the medium break LOCA that's in the presentation here does not include the rod ejection situation.

MR. DeMOSS: No. No, that's just cladding -- cladding failure.

MR. SCOTT: Okay.

MR. DeMOSS: Two percent was the estimate of the -- with an analogous -- analogously constructed analysis that -- you have a 2 percent change of rod ejection in that -- during that year leading up to the discovery of the problem.

MR. SCOTT: Okay. thank you.

VICE CHAIRMAN SHACK: Wouldn't the rod ejection require the whole failure of the nozzle?

MEMBER SIEBER: Yes.

VICE CHAIRMAN SHACK: I mean, that would seem a whole lot less likely.

MEMBER SIEBER: I would think so. Certainly not the --

MR. HISER: Given that it wasn't a large circ crack.

MEMBER SIEBER: Yes.

VICE CHAIRMAN SHACK: I guess until you know how they got to that number, I guess, you know, I mean, if you had postulated the possibility of a circ crack forming --

MEMBER SIEBER: That's another analysis, however, which I don't think has been done. Right?

MR. KIRK: No. I don't believe so.

MEMBER RANSOM: What does the ASP stand for?

MR. KIRK: Accident sequence precursor.

MEMBER RANSOM: What is it?

MR. KIRK: Accident sequence precursor.

MEMBER RANSOM: Oh, okay.

MR. DeMOSS: Let me make a correction. I've reread my analysis. One percent, not 2 percent, is the chance of a rod ejection. Just still higher than maybe you accept, but it's based on the work done

for the SDP.

VICE CHAIRMAN SHACK: But do you know if that is based on some sort of an estimate of a circular crack?

MR. DeMOSS: Yes, that's based on Steve Long's work to estimate the circular crack.

VICE CHAIRMAN SHACK: And I know what he's relying on.

(Laughter.)

We know how shaky that analysis is.

MEMBER SIEBER: Well, which way is it shaking?

MR. DeMOSS: Shaking would not be a good thing.

MEMBER SIEBER: Are there any additional questions? If not, I would like -- I thought it was a good presentation and a good analysis by the heavy section steel folks at Oak Ridge. And thanks, Mark and Alan, for putting this together for us.

I understand you're not expecting a written response from us, unless we feel it necessary for -- to do so.

MR. HISER: In all honesty, we're hoping this is the last time we have to talk about Davis-Besse, cladding, and calculations.

MEMBER SIEBER: I probably hope that more than you do.

MR. HISER: Oh no. Not a chance.

(Laughter.)

Not a chance.

MEMBER SIEBER: Well, I'm hoping that there are no problems like that to analyze in the future. Okay?

So thank you very much. And, Mr. Chairman, I turn it back to you.

VICE CHAIRMAN SHACK: Okay. We're on time again. And, actually, we can come back early since we're on our own at this point. So --

MEMBER DENNING: George would like to say he'd like a full 15 minutes.

(Laughter.)

MEMBER APOSTOLAKIS: Yes, I would like a full 15 minutes.

VICE CHAIRMAN SHACK: Then we'll go to 4:15. We'll live it up. Well, be back at 4:10.

(Whereupon, at 3:51 p.m., the proceedings in the foregoing matter went off the record.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding:	Advisory Committee on Reactor Safeguards 526TH Meeting
Docket Number:	n/a
Location:	Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Eric Hendrixson

Eric Hendrixson
Official Reporter
Neal R. Gross & Co., Inc.

An Assessment of the Structural Integrity Challenge Posed by Boric Acid Wastage in the Davis Besse RPV Head

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UT-BATTELLE
ornl

B. Richard Bass, Paul Williams, Wally McAfee, and Sean Yin
Oak Ridge National Laboratory

ACRS Briefing
USNRC Headquarters • Rockville, MD • 6th October 2005

VG 1

Objectives of Our Analyses

- **As Found (only possible reality benchmark)**
  - **Assess the structural integrity of the primary reactor coolant pressure boundary for the conditions that existed at Davis Besse on February 16, 2002**
- **Looking forward (SDP support)**
  - **Assess the structural integrity of the primary reactor coolant pressure boundary for conditions postulated to exist at Davis Besse had it not been taken off-line for a scheduled maintenance outage on February 16, 2002**
- **Looking backward (ASP support)**
  - **Assess the structural integrity of the primary reactor coolant pressure boundary for conditions postulated to exist at Davis Besse for February 16, 2002 minus one year (ASP analysis)**

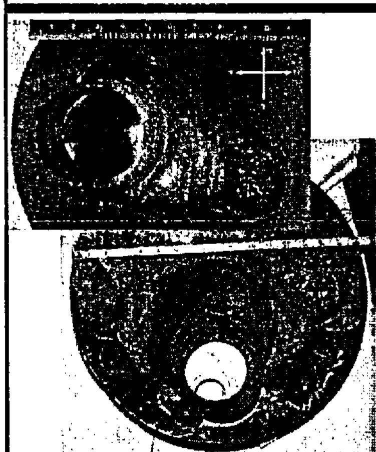
VG 2

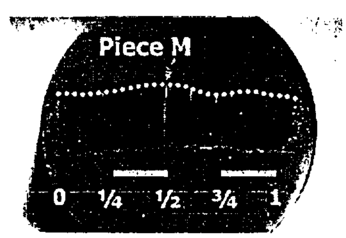
Presentation Outline

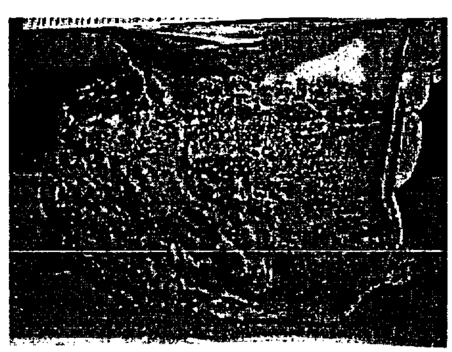
- Description of the as found state
- As Found analysis
  - Methodology
  - Results
- Forward & backward looking analyses
  - Methodology
  - Results

VG 3

16th Feb 02 Conditions at Davis Besse
("as found")



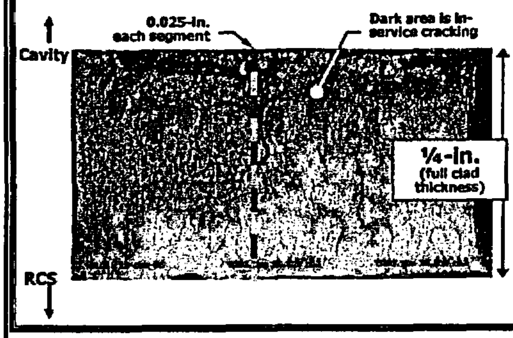




VG 4

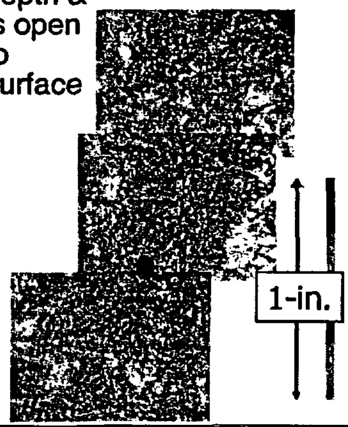
Davis Besse Crack Characterization

Crack Depth
- 0.1-in max (over 20% of length)
- 0.065-in. average

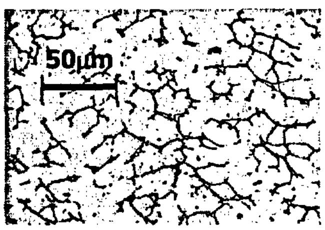


VG 5 [All metallography by J. Hyres, BWXT]

Crack Length
- 2-in max
- Central 0.66-in. has significant depth & is open to surface

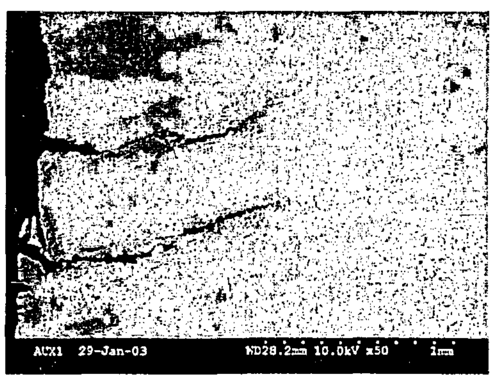


Crack Extension Mechanism



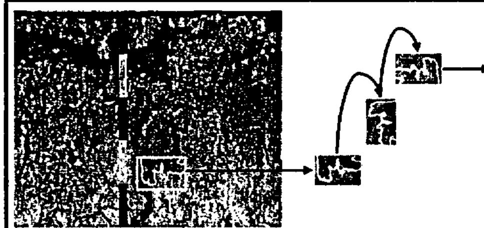
<u>Dendritic solidification structure in 308SS</u>
- Dark = ferrite
- Light = austenite

Cracks in the 308 stainless steel cladding formed when the concentrated boric acid solution in the cavity preferentially dissolved the ferrite phase. Thus, the cracking is intergranular (i.e., between the austenite grains).

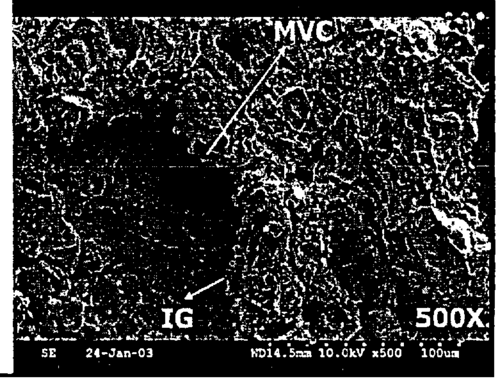


VG 6

Crack Morphology



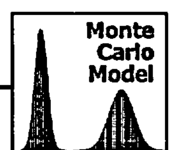
- In-service cracks are inter-granular & result from preferential attack of ferrite phase by boric acid.
- Lack of ductile tearing on service darkened side of fracture suggests that operating pressure did not load cladding above the ductile crack initiation threshold (i.e., cladding rupture was not imminent on 16 Feb 02).



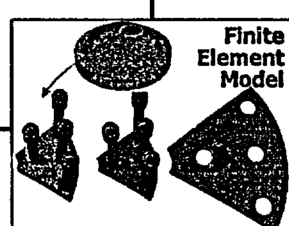
VG 7

Methodology for Integrity Assessment of the "As Found" State

Probabilistic Structural Integrity Assessment

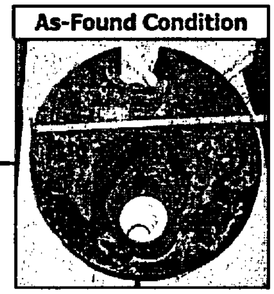


Deterministic Structural Integrity Assessment

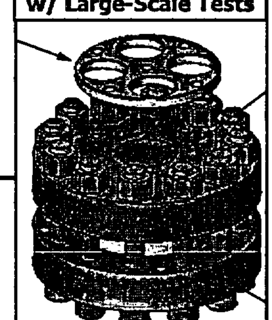


Material Properties

As-Found Condition



Failure Calibration w/ Large-Scale Tests



VG 8

Input Information

- **As-found configuration**
  - **Cavity geometry**
  - **Crack size and morphology**

  While described on the preceding slides, the totality of this information was not available at the outset

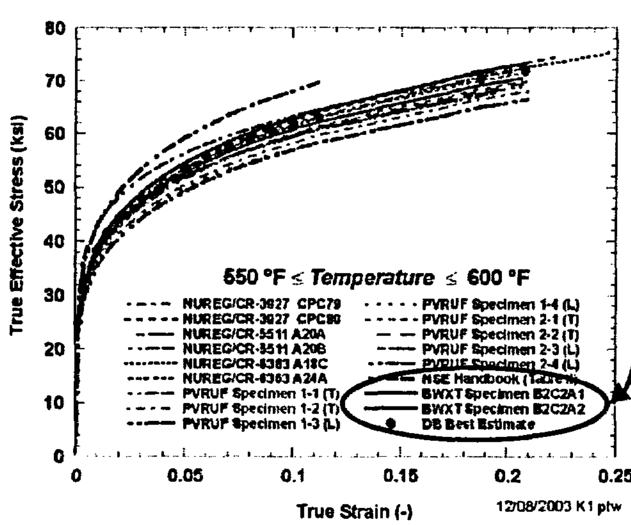
  - ✓ **June 2003: BWXT failure analysis report (for Framatome ANP)**
  - ✓ **April 2004: BWXT report on detailed crack examination (for ORNL)**

- **Cladding strength & fracture toughness properties**

- **Cladding failure mode & predictive benchmark**
  - **Discerned based on burst testing**

VG 9

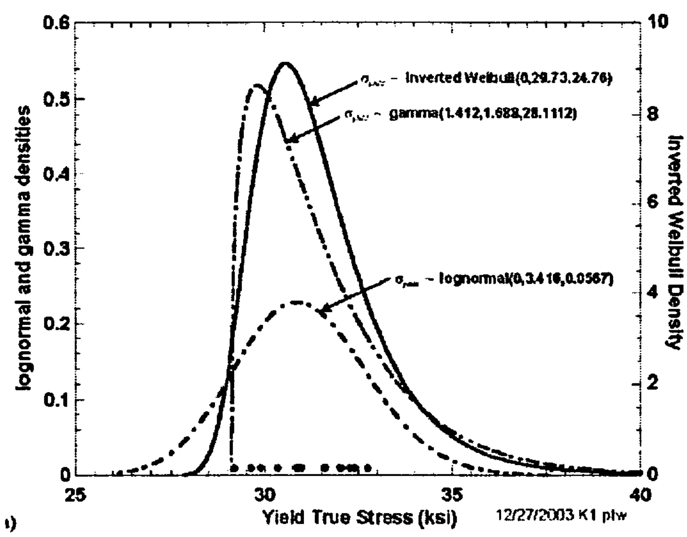
Cladding Strength



Tests on DB cladding agree well with literature data

VG 10

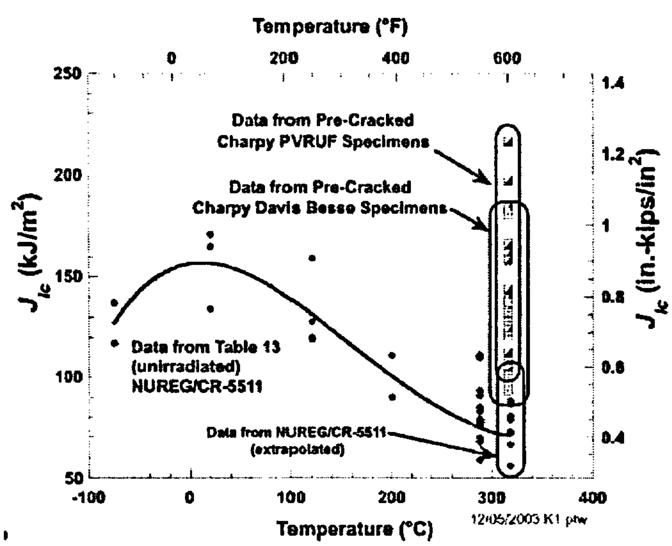
Cladding Strength



These data provide the basis for a statistical description used in our Monte Carlo analysis.

VG 11

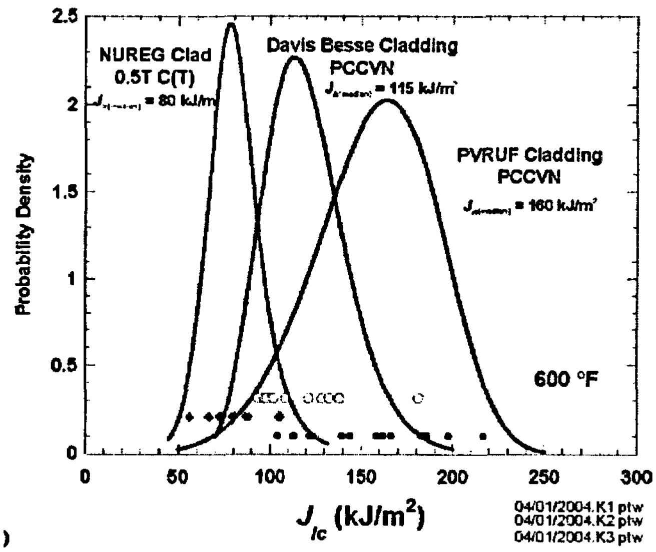
Cladding Fracture Toughness



Tests on DB cladding agree with literature data

VG 12

Cladding Fracture Toughness



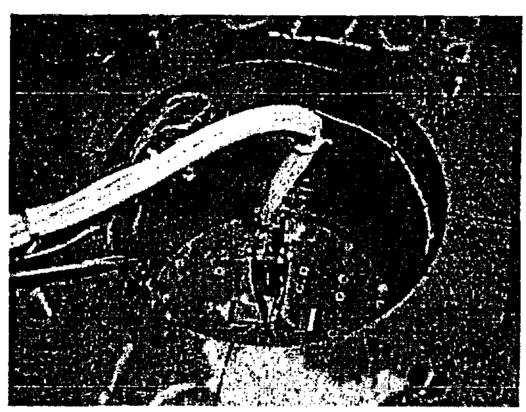
These data provide the basis for a statistical description used in our Monte Carlo analysis.

VG 13

Burst Testing

- Captures the essential structural characteristics of state of DB on 2-16-02
  - Un-backed cladding area
  - Flaw depth
- Not intended as a 1:1 model or representation of DB
- Objectives of tests
  - Validate opinion that cladding will fail by ductile tearing
  - Asses accuracy / conservatism in model predictions of failure loads

Pre-Test



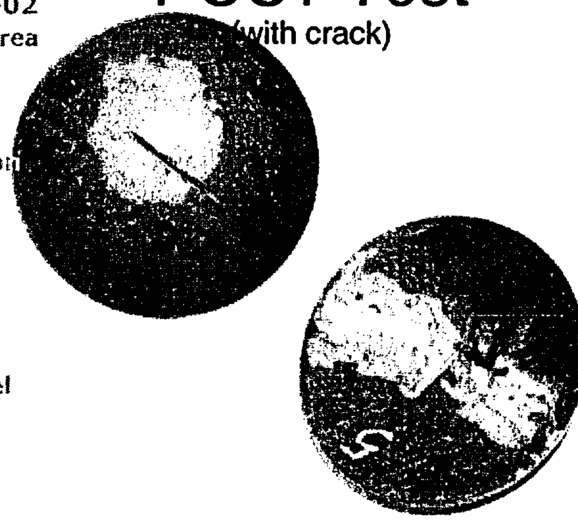
VG 14

Burst Testing

- Captures the essential structural characteristics of state of DB on 2-16-02
  - Un-backed cladding area
  - Flaw depth
- Not intended as a 1:1 model or representation of DB
- Objectives of tests
  - Validate opinion that cladding will fail by ductile tearing
  - Asses accuracy / conservatism in model predictions of failure loads

POST Test

(with crack)



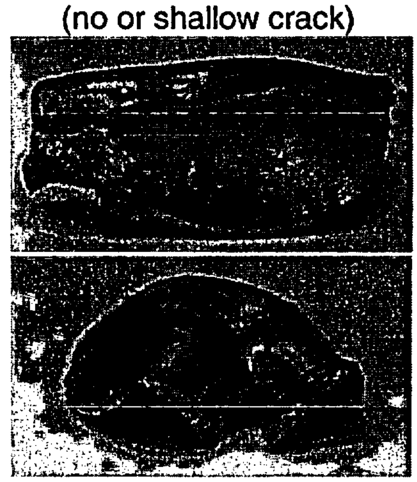
VG 15

Burst Testing

- Captures the essential structural characteristics of state of DB on 2-16-02
  - Un-backed cladding area
  - Flaw depth
- Not intended as a 1:1 model or representation of DB
- Objectives of tests
  - Validate opinion that cladding will fail by ductile tearing
  - Asses accuracy / conservatism in model predictions of failure loads

POST Test

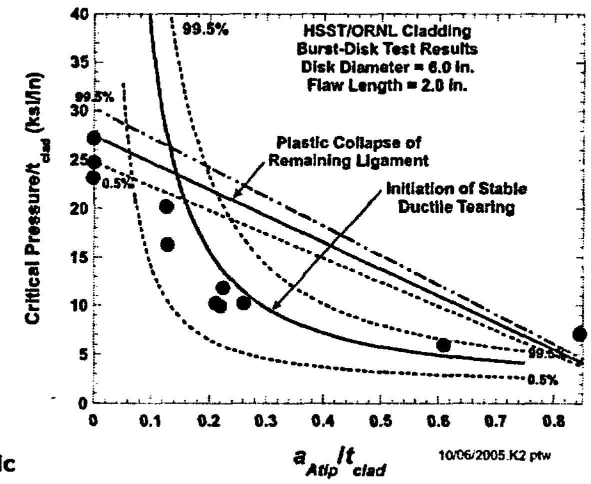
(no or shallow crack)



VG 16

Comparison of Burst Test Data with Model Predictions

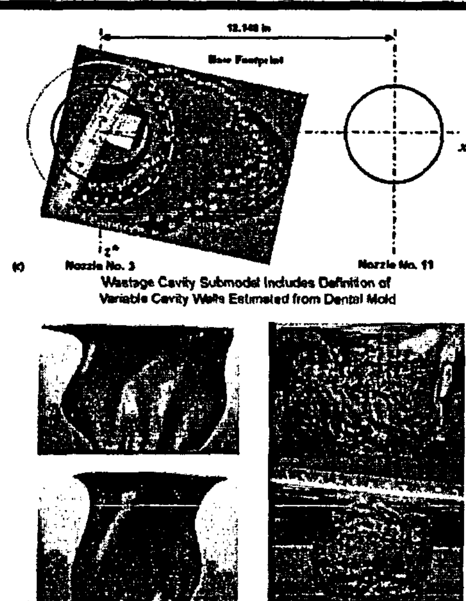
- **Good test-to-test repeatability**
- **For deeper cracks (> ≈15% of the cladding thickness**
  - **Stable failures (leaks)**
  - **Predicted well by ductile cracking model**
- **For shallower cracks or no cracks**
  - **Catastrophic failures (blowout of un-backed area)**
  - **Predicted well by plastic collapse model**



✓ Failure mode characterized
✓ Model validated

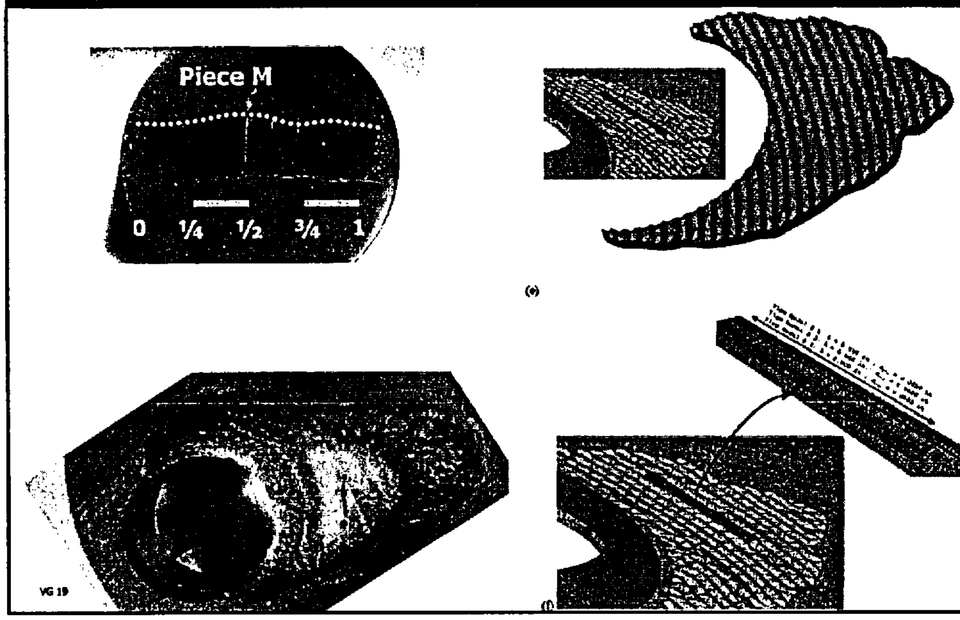
VG 17

Geometric Inputs to Finite Element Model of As-Found State

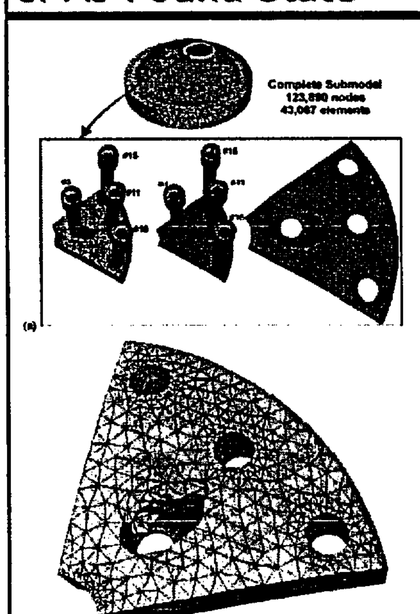


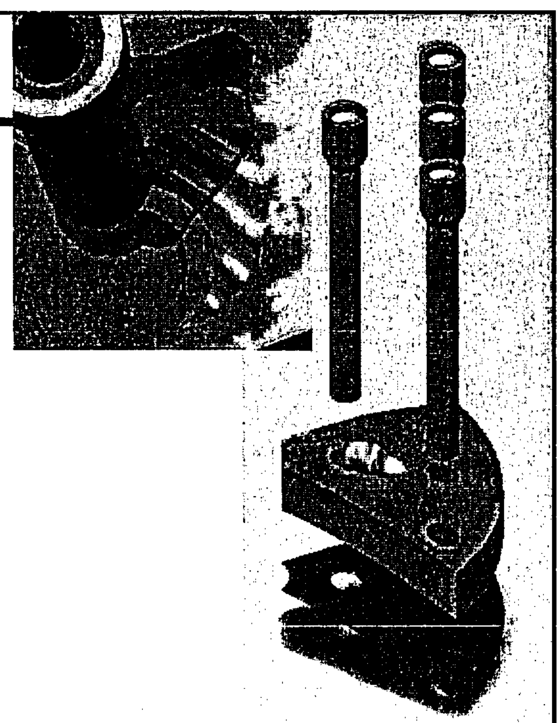
VG 18

Geometric Inputs to Finite Element Model of the As-Found State



Finite Element Model of As-Found State





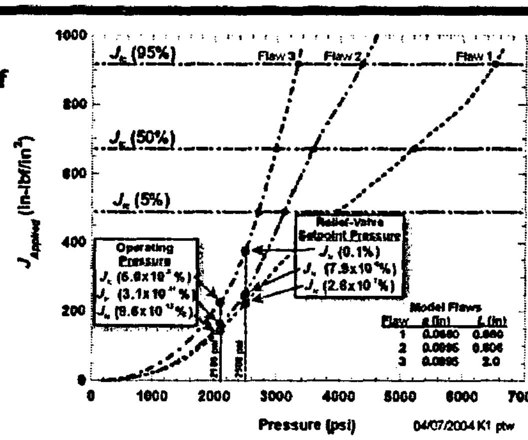
As-Found Analysis

- is based on the following
  - Geometrically accurate finite element model to estimate stresses
  - Actual DB properties for cladding and ferritic steel strength
  - Actual DB properties for cladding toughness
  - 3 Different idealizations of as-found crack network
    - ✓ Flaw 1: Best-estimate depth (0.065-in.) & length (0.66-in.)
    - ✓ Flaw 2: Bounding depth (0.1-in.) & best estimate length (0.66-in.)
    - ✓ Flaw 3: Bounding depth (0.1-in.) & length (2-in.)

VG 21

As-Found Analysis Results

- Prediction
  - Pressure in excess of relief valve setpoint pressure needed to rupture cladding
  - Factor of at least 1¼ safety margin exists against ductile crack initiation occurring at the operating pressure even assuming
    - ✓ A bounding flaw characterization
    - ✓ A lower bound fracture toughness characterization

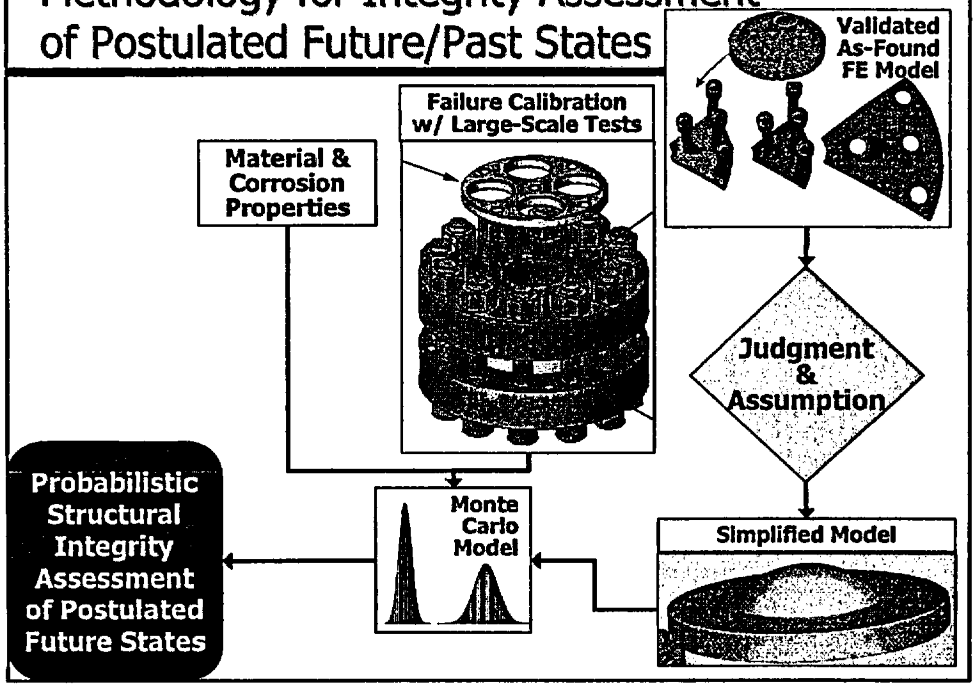


- Our prediction is that
  - Failure did not occur
  - Ductile crack initiation from crack network did not occur

- What actually happened was
  - Failure did not occur
  - Ductile crack initiation from crack network did not occur

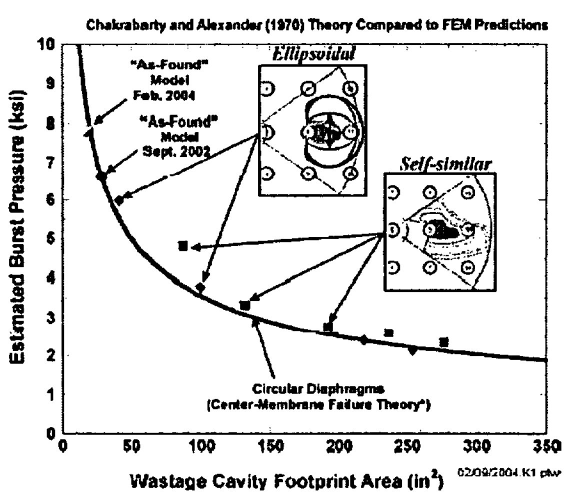
VG 22

Methodology for Integrity Assessment of Postulated Future/Past States



Assumption

- *The complex cavity shape can be modeled as a circle*
  - For failure by plastic collapse, un-backed cladding area is much more important than cavity shape
  - For failure by ductile tearing, circular assumption is conservative
  - State of knowledge was (and is) not adequate to defend a more complex representation of how the cavity shape evolved (or would have evolved) with time



VG 24

Input Information

- Based on statistical representations of data
  - Toughness properties
  - Strength properties

Discussed already

- Based on engineering judgments
  - LOCA binning rules
  - Statistical fitting of data
- Based on expert opinions benchmarked to data
  - General corrosion properties of the ferritic RPV steel (controls cavity growth rate)
  - Corrosion crack growth properties of the austenitic cladding (controls crack depth growth in cladding)
- Based on expert opinion (for ASP analysis only)
  - Crack depth on 2-16-02 *minus one year*
  - Cavity size on 2-16-02 *minus one year*

VG 25

Engineering Judgments

- LOCA binning rules
  - Small up to 3.5" diameter
  - Medium from 3.5" – 4.8" diameter
  - Large > 4.8" diameter
  - "Conservative" model equates thru-clad cracking with failure of cladding
  - "Best estimate" model assesses stability of thru-clad crack based on standard *J-R* curve analysis techniques
- Statistical fitting of data
  - Illustrated on the following slides

VG 26

Expert Elicitation Information

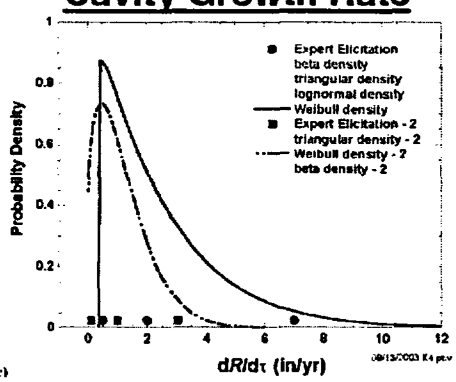
Judgments Obtained from Informal Expert Elicitation

Parameter Description	Parameter Units	Subject Matter Expert ID No.#	Lower Bound	Median (BE) Value	Upper Bound
			Associated Percentiles		
			5%	50%	95%/99.9%
Effective Cavity		#1	0	1.25	2
Radius at TOD-1	(in.)	#2	0	1.125	2.5
R_0		#3	0	1.5	2.25
Effecive Cavity		#1	1	2	7
Wastage Rate	(in./year)	#2	0.5	2	6
$dR/d\tau$		#3	0.75	1.5	(-)
Flaw Initiation		#1	12	36	48
Time w.r.t. TOD	(months)	#2	1	6	60
$\Delta\tau_{flaw\text{-}ini}$		#3	(-)	(-)	(-)
Effective Flaw		#1	0.001	0.01	0.1
Growth Rate	(in./month)	#2	0.001	0.01	0.1
$da/d\tau$		#3	0.004	0.01	0.04

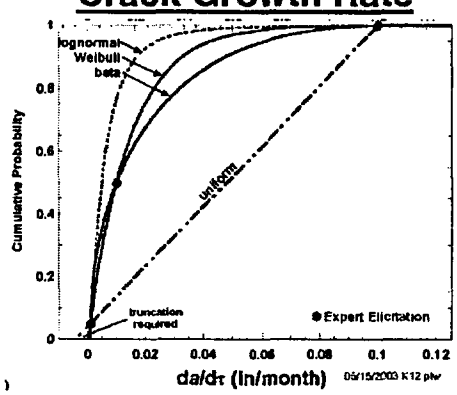
VG 27

Statistical Representation of Expert Elicitation Information (Examples)

Cavity Growth Rate



Crack Growth Rate

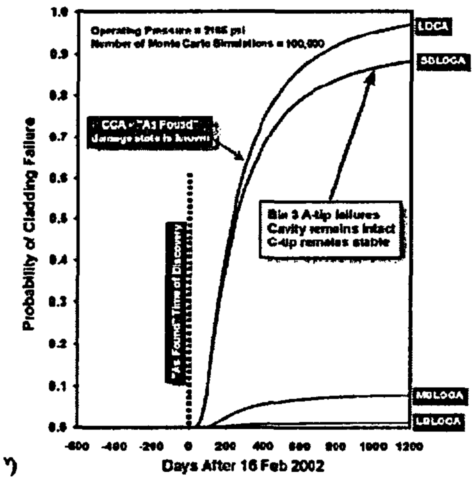


Sampling Distributions Categories	dR/dτ (in/yr)	da/dτ (in/month)	R_0 (in)	$\Delta\tau_{flaw\text{-}ini}$ (months)
BE	beta-1	Weibull	beta	Weibull
MC	triangluar	lognormal	triangular	lognormal
LC	Weibull	uniform	normal	triangular

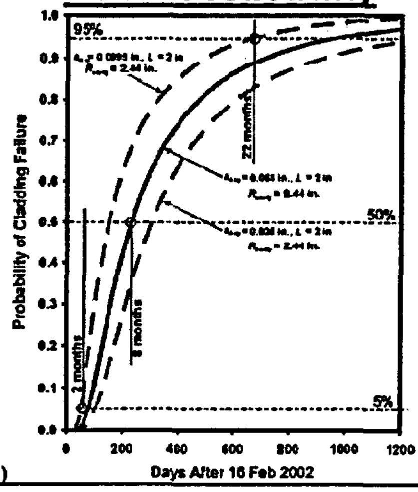
VG 28

Results of "Forward Looking" Analysis
(as-found state known)

LOCA Size Breakdown



Effect of Assumed Crack Size on Total LOCA Probability



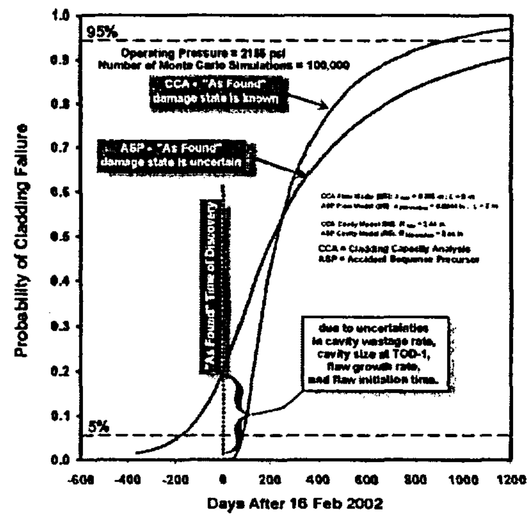
Results of "Forward Looking" Analysis
(as-found state known)

- **Based on bounding flaw model (Flaw 3: consistent with ASME practice) between 2 & 22 months of operation beyond 2-16-02 could have taken place before the cladding was compromised**
  - **Best estimate is 5 months**
- **Had the primary pressure boundary been compromised the most likely consequence was a small break LOCA**
  - **Known deep initial flaw depth favors SB-LOCA**

VG 30

Comparison of Forward and Backward Looking Analysis on the Predicted Total LOCA Probability on 2-16-02

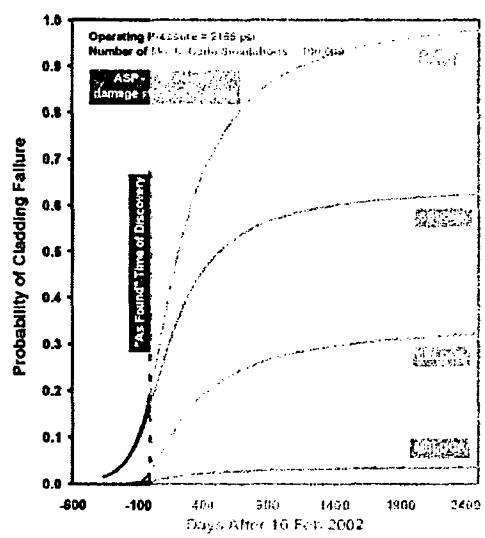
- **Backward looking analysis predicts an ≈20% LOCA probability on 2-16-02 (when, in fact, no LOCA occurred)**
- **This occurs as a direct consequence of uncertainty regarding the initial conditions assumed in the backward looking analysis, i.e.**
  - **Cavity size on 2-16-01**
  - **Depth of flaws in cladding on 2-16-01**



VG 31

Summary of Best-Estimate "Backward Looking" (ASP) Analysis

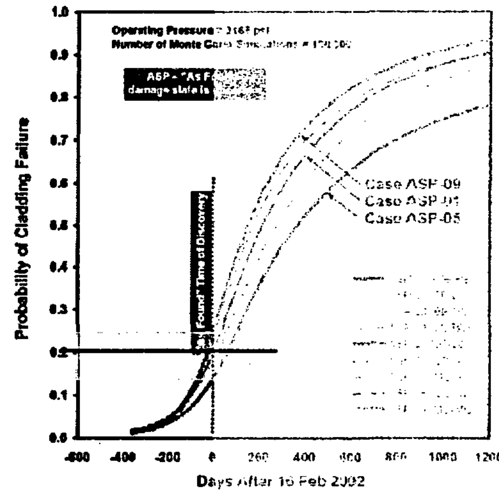
- **ASP analysis only uses predicted LOCA probabilities between 2-16-01 and 2-16-02**
- **LOCA probabilities for dates beyond 2-16-02 shown *for information only***
- **As was the case with the forward looking analysis, SB-LOCA is the most likely outcome had the pressure boundary been compromised**



VG 32

Effect of Uncertainties / Judgments on Total LOCA Probabilities

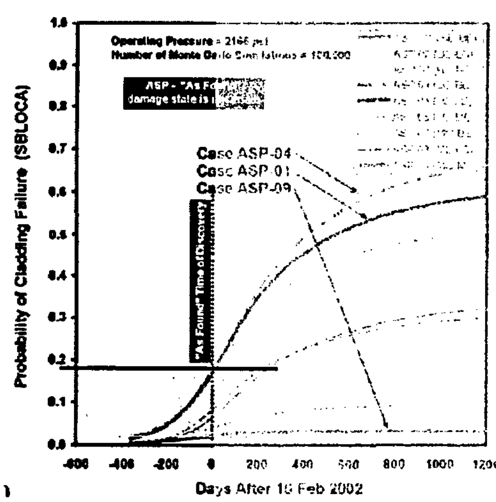
- **Total LOCA probability on 2-16-02**
  - **Min ≈ 14%**
  - **Max ≈ 24%**
  - ***Best estimate ≈ 20%***



VG 33

Effect of Uncertainties / Judgments on SB-LOCA Probabilities

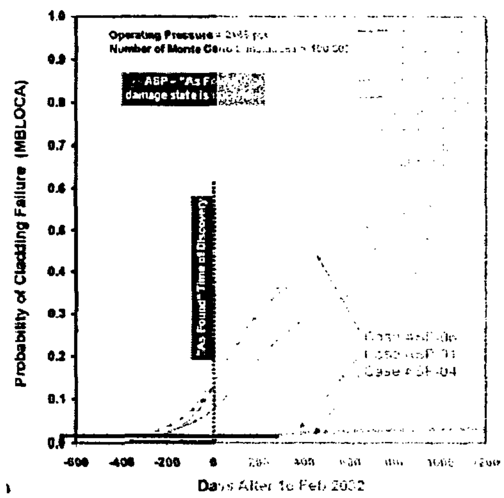
- **SB-LOCA probability on 2-16-02**
  - **Min ≈ 2%**
  - **Max ≈ 18%**
  - ***Best estimate ≈ 18%***



VG 34

Effect of Uncertainties / Judgments on MB-LOCA Probabilities

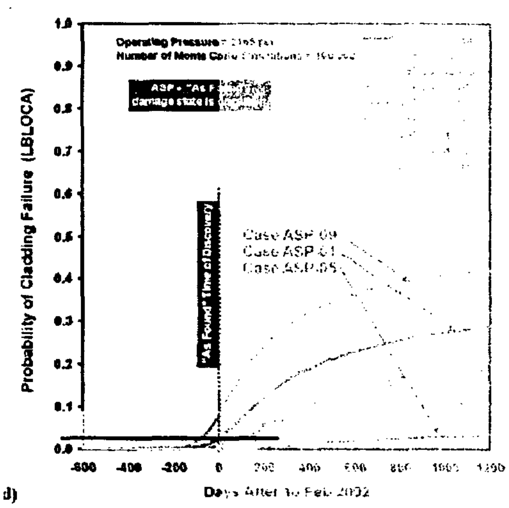
- MB-LOCA probability on 2-16-02
  - Min < 1%
  - Max ≈ 15%
  - *Best estimate <1%*



VG 35

Effect of Uncertainties / Judgments on LB-LOCA Probabilities

- LB-LOCA probability on 2-16-02
  - Min = 0%
  - Max ≈ 9%
  - *Best estimate ≈ 3%*



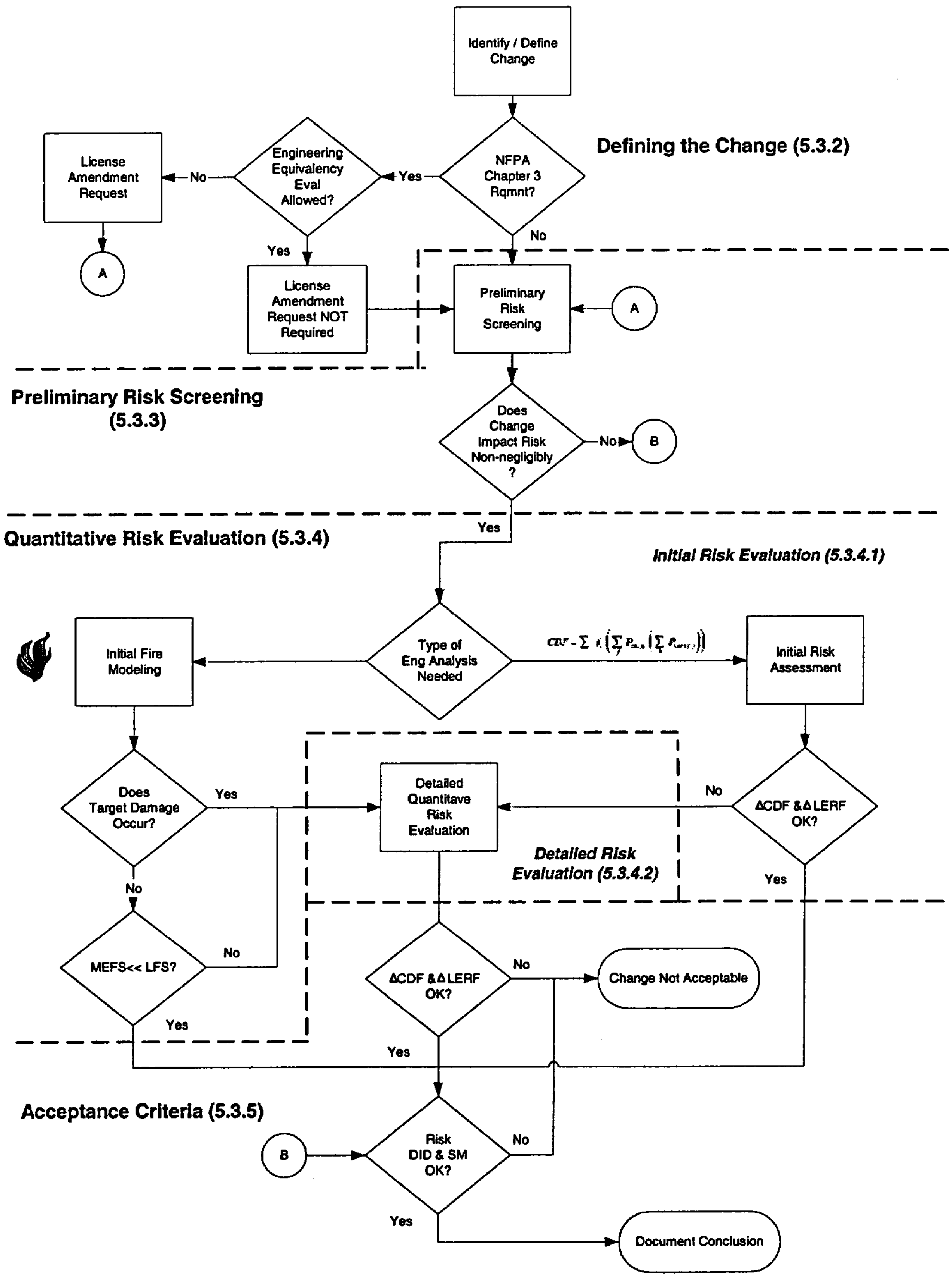
d)

VG 36

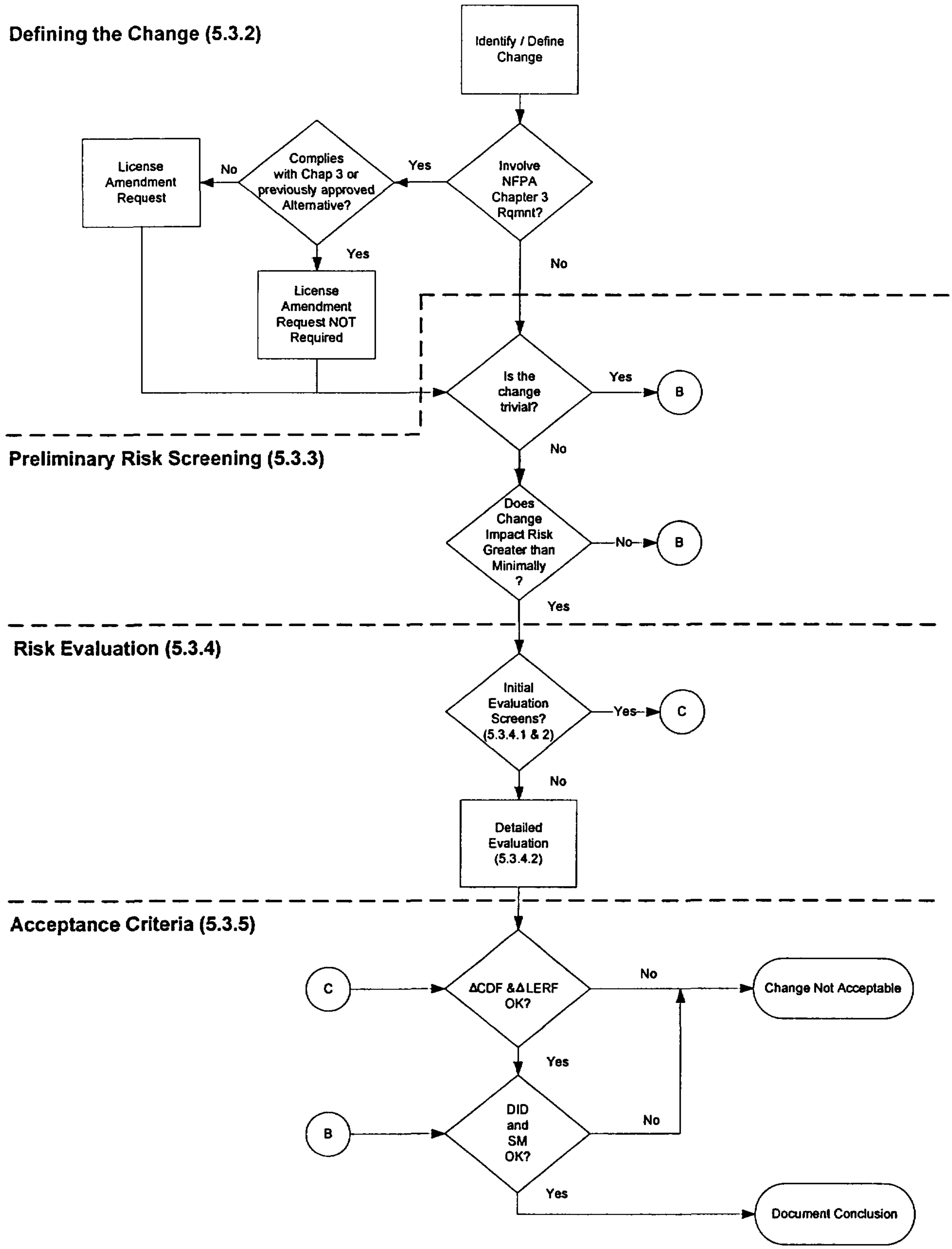
Summary

- **As-found analysis**
  - Forensic exams found no ductile tearing initiated from corrosion assisted flaws – suggests cladding rupture was not imminent
  - No crack initiation predicted on day of discovery
  - Pressure in excess of relief valve setpoint pressure would have been needed to rupture the cladding
- **Forward looking analysis (as found condition known)**
  - 2-22 months more operation needed to rupture the cladding ... best estimate is ~5 months.
  - Most likely consequence of cladding rupture is SB-LOCA
- **Backward looking analysis ... ASP (as found condition uncertain)**
  - ~20% (+/-5%) total LOCA probability on day of discovery
  - Most likely consequence of cladding rupture is SB-LOCA

VG 37



NEI 04-02 Figure 5-1 Revision 0



NEI 04-02 Figure 5-1 Revision 1

REGULATORY GUIDE FOR NFPA 805 RULE
ADVISORY COMMITTEE FOR REACTOR SAFEGUARDS
October 6, 2005

Sunil Weerakkody, Chief
Fire Protection Section
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
October 6, 2005

OBJECTIVE

- Inform ACRS about how the NRC Staff and NEI addressed ACRS Comments
- Inform ACRS about other issues remaining to be addressed
- Seek ACRS agreement with respect to changes made to the Regulatory Guide and NEI-04-02 to address ACRS comments.

STAFF INTRODUCTION

- Outline:

  - Status of NFPA 805 Implementation – Paul Lain
  - Changes to the Regulatory Guide and NEI-04-02 – Robert Radlinski
  - Additional changes to the Regulatory Guide – Sunil Weerakkody

NEXT STEP

- Will provide the finalized Regulatory Guide and NEI-04-02 to ACRS, and seek endorsement to issue the Regulatory Guide after all changes are made

REGULATORY GUIDE FOR NFPA 805 RULE
ADVISORY COMMITTEE FOR REACTOR SAFEGUARDS
October 6, 2005

Paul Lain. Project Manager for NFPA 805 Implementation
Fire Protection Section
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Status of NFPA 805 Implementation

- Duke Power Sends Letter of Intent – 2/28/05
  (3 sites, 7 plants)

- Progress Energy Sends Energy Letter of Intent – 6/10/05
  (4 sites, 5 plants)

- NRC/RGN II/Progress Energy/Duke Power Kicks Off of Pilot Implementation – 8/11/05

- First Observation Visit Scheduled for November 2005

High Level Issues on Transition Plans - Use of Fire PRAs

- Each plant that transitions to NFPA 805 plans to trace cables and develop or enhance Fire PRAs.
- Progress Energy requested an extension to the discretion period to develop Fire PRAs.
- DSSA and Office of Enforcement are considering changes to accommodate additional changes necessary to enforcement discretion policy to enable the development of fire PRAs
- Staff has informed licensees that transition to NFPA 805 without a fire PRA is impractical
- Staff plans to use completed and emerging regulatory guides, RES products, and industry standards to ensure that the pilots rely on acceptable methods for PRA and fire Modeling

REGULATORY GUIDE FOR NFPA 805 RULE
ADVISORY COMMITTEE FOR REACTOR SAFEGUARDS
October 6, 2005

Bob Radlinski
Fire Protection Engineer
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

OBJECTIVE

- Review ACRS comments and Staff responses

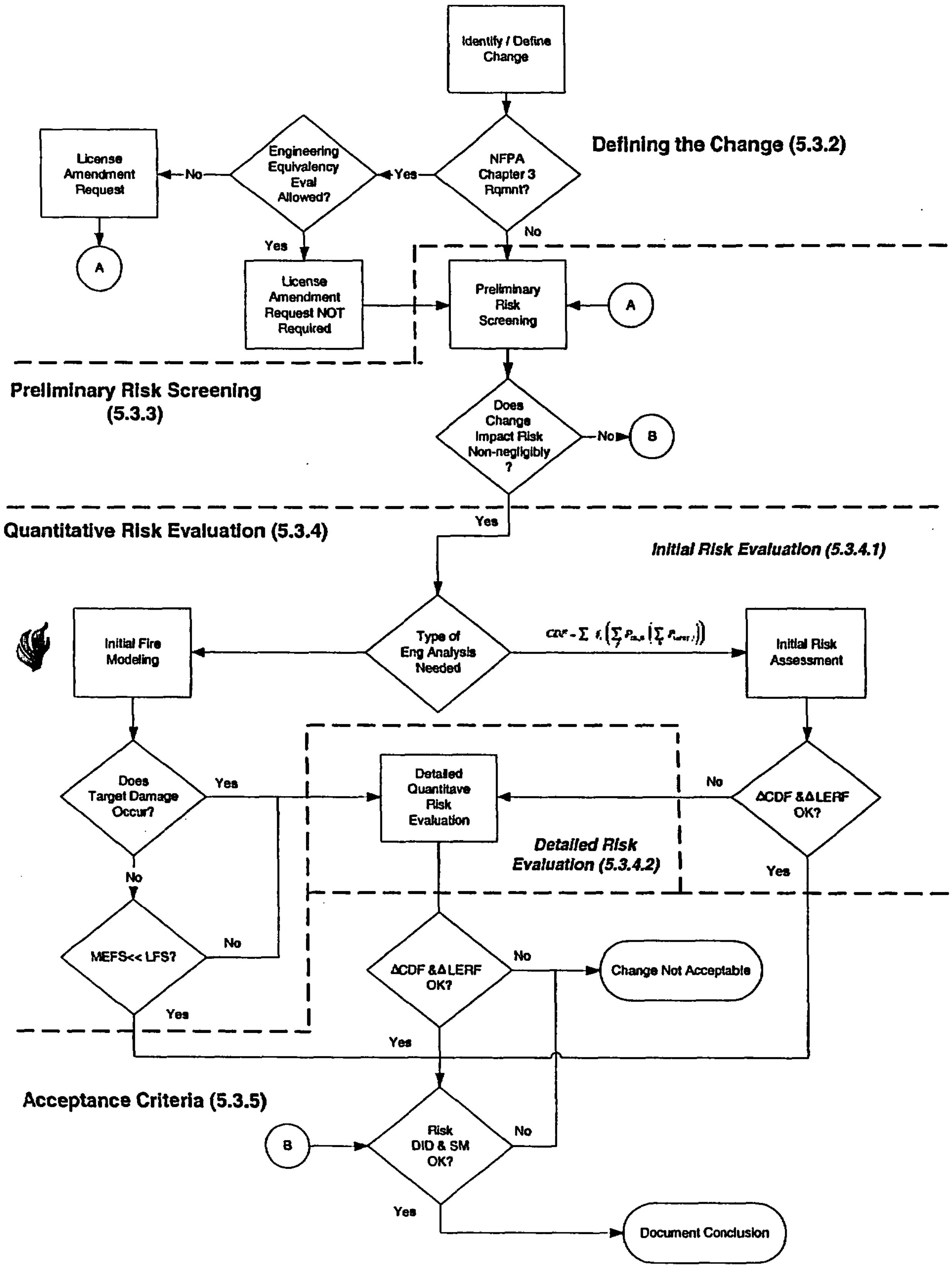
- Describe changes made to the NFPA 805 Regulatory Guide and NEI 04-02 to address ACRS comments

ACRS Comments

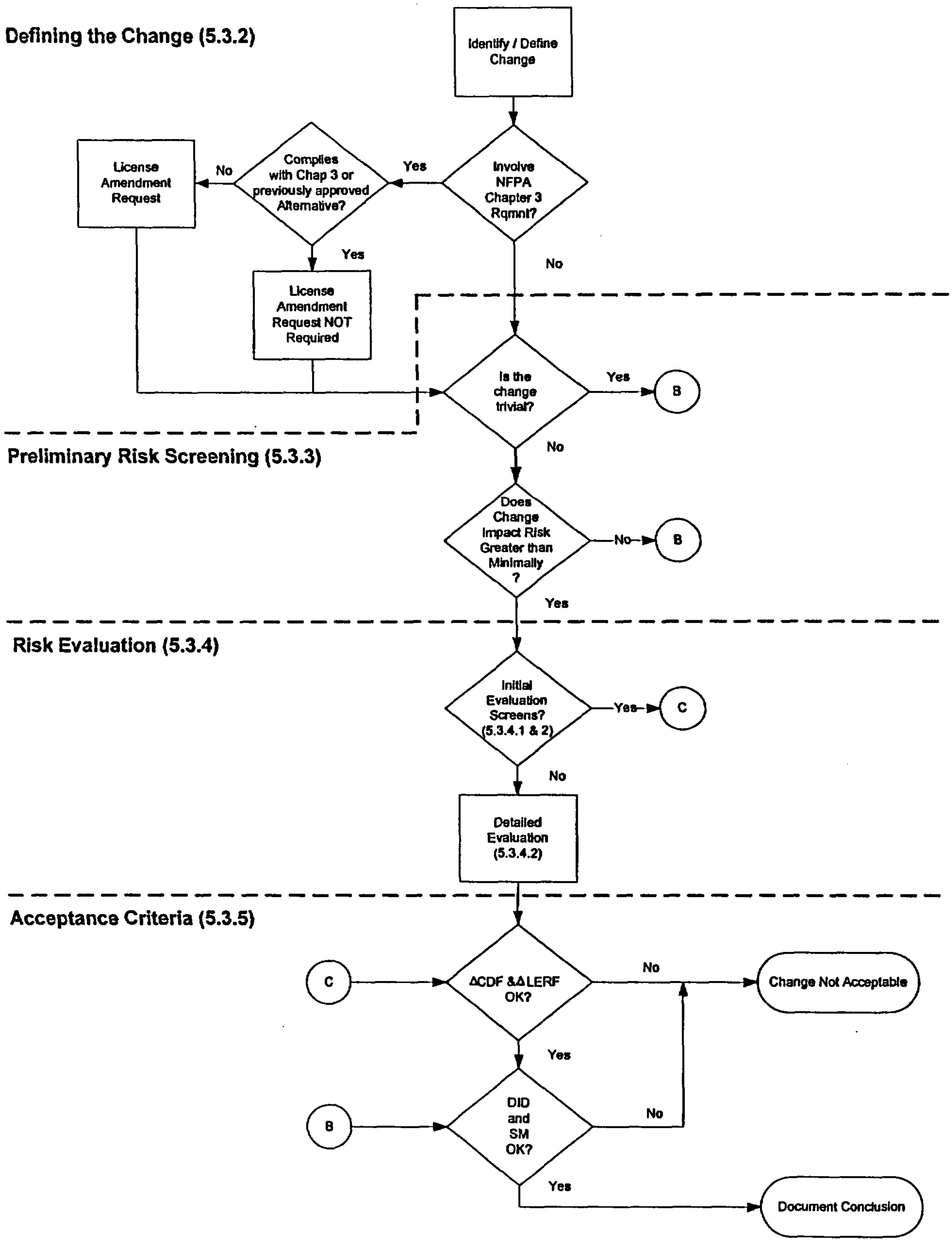
- ACRS Comment: The Regulatory Guide should not be issued in its present form.
- How Addressed: The Regulatory Guide has been revised to incorporate the ACRS comments. We plan to issue the Reg Guide next year after submitting draft final versions of the Reg Guide and NEI 04-02 to the ACRS in December 2005

ACRS Comments (cont)

- ACRS Comment: The “initial fire modeling” approach should not be used as an alternative to estimates of changes in CDF and LERF.
- How addressed: NEI 04-02 has been revised to eliminate this approach (See revised Figure 5-1)



NEI 04-02 Figure 5-1 Revision 0



NEI 04-02 Figure 5-1 Revision 1

ACRS Comments (cont)

- ACRS Comment: The staff should not endorse methods for evaluating ΔCDF and ΔLERF that are not based on a fire PRA

- How Addressed: 10 CFR 50.48(c) and NFPA 805 allow risk assessments to be performed without a full fire PRA. However, to the extent possible, licensees are encouraged to develop a full fire PRA and the Regulatory Guide does not specifically endorse non-PRA methods.

ACRS Comments (cont)

- ACRS Comment: NEI 04 -02 contains many statements that are inconsistent with the Commission's policy of promoting the use of PRA methods. In the Regulatory Guide, the staff should make it clear that it does not endorse such statements.

- How Addressed: Statements in Appendix J, "Plant Change Evaluations", and Section 5.3, "Plant Change Process", were revised to be consistent with revised Figure 5 -1.

ACRS Comments (cont)

- ACRS Comment: The staff should ensure that the parts of NEI 04-02 that it endorses use correct methodology and language.
- How Addressed:
  - Held public meeting to share ACRS comments with NEI and discuss resolution
  - Held several follow-up phone calls with NEI
  - NRR and RES staff members reviewed all draft revisions to NEI 04-02
- Based on our reviews and discussions with NEI, we believe that the methodology and language used in the final version are correct.

NFPA 805 Regulatory Guide Changes

- Agreed with ACRS Comments and incorporated in final documents
- State that risk evaluations (for non-screened changes) should use PRA methods and tools
- Added PRA quality references including RG 1.174, RG 1.200 and the ANS fire PRA standard
- Noted that future additional guidance for fire PRAs will follow these referenced documents

NEI 04-02 Changes

- Agreed with ACRS comments and incorporated in final documents
- Eliminated all statements indicating that a change could be evaluated using the fire modeling approach without a risk assessment
- Encourages licensees to use a detailed, quantitative approach to plant change risk assessments

NEI 04-02 Changes (cont)

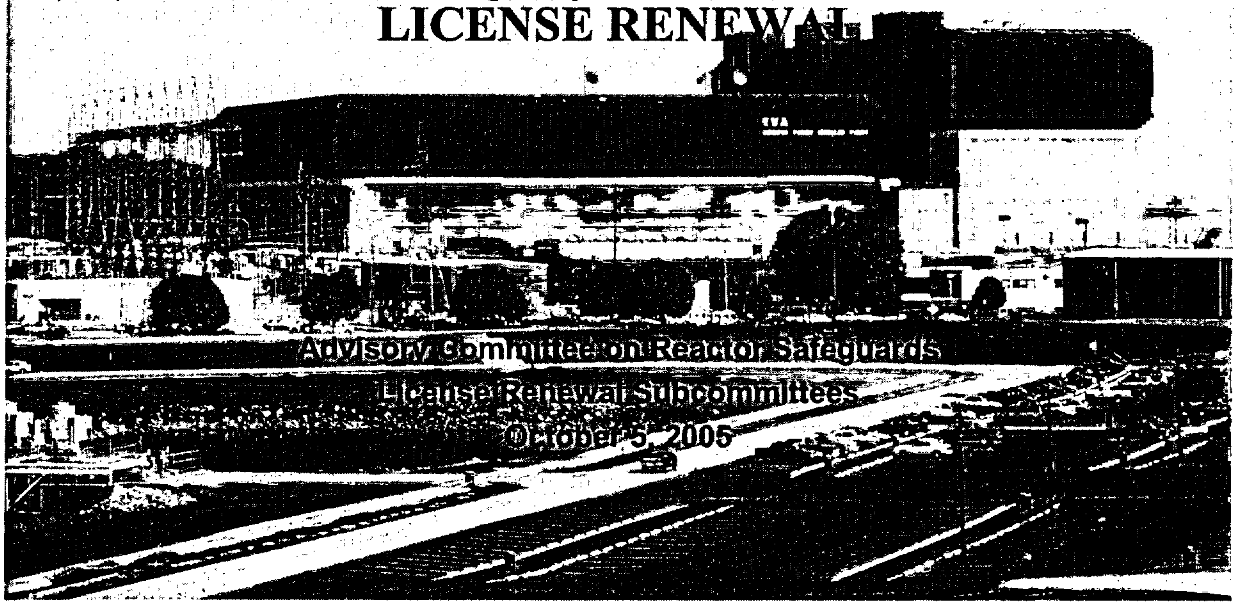
- Clarifies safety factors used to address uncertainties associated with fire models (the Reg Guide includes statement that margin must be large enough to bound uncertainties)
- Clarifies simplified assessment of ΔLERF

OTHER ISSUES

- 10 CFR 50.69, 10 CFR 50.46(a) & 10 CFR 50.48(c)
- "Self-Approval"
  - Prior approval of methods
  - Threshold values
- Cumulative Risk
  - Baseline CDF
  - Tracking

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT

LICENSE RENEWAL



Advisory Committee on Reactor Safeguards
License Renewal Subcommittees
October 5, 2005

Agenda

- Description of Browns Ferry
- BFN License Renewal Application
  - Scoping
  - Time-Limited Aging Analysis
  - Aging Management Programs
- Unit 1 Layup
- Unit 1 Operating Experience
- License Renewal Commitments
- Open Items

Description of Browns Ferry

- All Three BFN Units are General Electric BWR 4 Reactors with Mark I Containments
- Approximate Years of Operation
  - Unit 1 – 10
  - Unit 2 – 23
  - Unit 3 – 18
- BFN Units 2 and 3 in Operation Since Recovery in 1991 and 1995, Respectively
- Unit 1 in Recovery Outage with Restart Scheduled for May 2007
  - Unit 1 will be operationally identical to Units 2 and 3
- NRC Performance Indicators Green

BFN License Renewal Application

- Three-Unit Application Submitted December 31, 2003
- Original License Expiration
  - Unit 1 – December 20, 2013
  - Unit 2 – June 28, 2014
  - Unit 3 – July 2, 2016
- License Renewal Application at Current Licensed Thermal Power for each Unit (Unit 1 – 3293 MWt, Units 2 and 3 – 3458 MWt)
- Appendix F Describes the Differences Between Unit 1 and Units 2 and 3
  - These differences will be eliminated prior to Unit 1 restart (May 2007)
- Requests for Additional Information ~230 (13 are Environmental, Remainder are Safety Evaluation)

Scoping

- Scoping Basis
  - Updated Final Safety Analysis Report
  - Safe Shutdown Analysis calculation
  - Maintenance Rule documentation
  - Controlled Plant Component Database
  - Licensing Basis and Design Basis documents
- Specific Scoping for Regulated Events
  - Fire Protection
  - Environmental Qualification
  - Anticipated Transients Without Scram
  - Station Blackout
- 77 Mechanical / Electrical Systems in Scope

Time-Limited Aging Analysis

- Neutron Embrittlement of the Reactor Vessel and Internals
- Metal Fatigue
- Environmental Qualification of Electrical Equipment
- Primary Containment Fatigue
- Plant Specific Time-Limited Aging Analyses
  - Reactor Building Crane Load Cycles
  - Radiation Degradation of Drywell Expansion Gap Foam
  - Irradiation Assisted Stress Corrosion Cracking (IASCC) of Reactor Vessel Internals
  - Stress Relaxation of the Core Plate Hold-Down Bolts
  - Emergency Equipment Cooling Water Weld Flaw Evaluation

Reactor Vessel Time-Limited Aging Analysis

- Neutron Embrittlement of the Reactor Vessel and Internals
  - Unit 1: Conservatively evaluated using 54 Effective Full Power Years at Extended Power Uprate conditions
    - Peak fluence of limiting weld 1.95×10^{18} n/cm^2
  - Units 2 and 3: Conservatively evaluated using 52 Effective Full Power Years at Extended Power Uprate conditions
    - Peak fluence of limiting weld 2.3×10^{18} n/cm^2

License Renewal Aging Management Programs

- 39 Aging Management Programs Total
  - 38 are common to Units 1, 2, and 3
  - 1 is for only Unit 1 (i.e., Unit 1 Periodic Inspection Program)
- 11 Existing Aging Management Programs Requiring No Enhancement
- 11 Existing Aging Management Programs Revised Only to Include Unit 1
- 11 Existing Aging Management Programs Require Enhancement for all Units
- 6 New Aging Management Programs

License Renewal Aging Management Programs

- Existing Aging Management Programs Requiring No Enhancement
  - 10 CFR 50 Appendix J Program
  - Above ground Carbon Steel Tanks Program
  - ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD Program
  - ASME Section XI Subsection IWE Program
  - Bolting Integrity Program
  - BWR Control Rod Drive Return Line Nozzle Program
  - Diesel Starting Air Program
  - Fuel Oil Chemistry Program
  - Inspection of Overhead Heavy Load and Light Load Handling Systems Program
  - Reactor Head Closure Studs Program
  - Systems Monitoring Program

License Renewal Aging Management Programs

- Existing Aging Management Programs Requiring Revision Only to Incorporate Unit 1
  - BWR Feedwater Nozzle Program
  - BWR Penetrations Program
  - BWR Reactor Water Cleanup System Program
  - BWR Stress Corrosion Cracking Program
  - BWR Vessel Inside Diameter Attachment Welds Program
  - Chemistry Control Program
  - Closed-Cycle Cooling Water System Program
  - Environmental Qualification Program
  - Fire Protection Program
  - Flow-Accelerated Corrosion Program
  - Open-Cycle Cooling Water System Program

License Renewal
Aging Management Programs

- Existing Aging Management Programs Requiring Enhancement (All Units)
  - ASME Section XI Subsection IWF Program
  - Buried Piping and Tanks Inspection Program
  - BWR Vessel Internals Program (includes steam dryers)
  - Compressed Air Monitoring Program
  - Electrical cables not subject to 10 CFR 50.49 Environmental Qualification requirements used in Instrumentation Circuits Program
  - Fatigue Monitoring Program
  - Fire Water System Program
  - Inspection of Water-Control Structures Program
  - Masonry Wall Program
  - Reactor Vessel Surveillance Program
  - Structures Monitoring Program

License Renewal
Aging Management Programs

- New Aging Management Programs (for all Three Units)
  - Accessible Non-Environmental Qualification Cables and Connections Inspection Program
  - Bus Inspection Program
  - Inaccessible medium voltage cables not subject to 10 CFR 50.49 Environmental Qualification Requirements Program
  - One-Time Inspection Program
  - Selective Leaching of Materials Program
- New Aging Management Program (Unit 1 Only)
  - Unit 1 Periodic Inspection Program

One-Time Inspection Program

- Applies to Units 1, 2, and 3
- Verifies the Effectiveness of Aging Management Programs by Confirming that Unacceptable Degradation is not Occurring
- Where No Aging Management Program is Identified, the Inspections Confirm either:
  - Aging Effects are not Occurring, or
  - Aging Effects are Occurring at a Rate that does not Affect the Intended Function
- To be Completed Prior to the Period of Extended Operation
- Examples of inspection items:
  - Reactor coolant pressure boundary piping, valves, fittings less than four inches
  - Bottom thickness of above ground tanks
  - Submerged concrete and component supports
  - Ventilation ducts

Unit 1 Periodic Inspection Program

- Periodic Inspections will be Performed after Unit 1 is Returned to Operation to Verify No Additional Aging Effects are Occurring

- The Periodic Inspection Sample Locations will be a Subset of Non-Replaced Piping Locations (takes credit for restart inspections)

- First Round of Periodic Inspections will be Completed Prior to Period of Extended Operation and after Several Years of Unit 1 Operation

- An Inspection will be Performed during the Period of Extended Operation

- Subsequent Inspection Frequency will be Determined Based on Inspection Results

Unit 1 Layup Program

- Criteria
  - EPRI NP-5106, "Sourcebook for Plant Layup and Equipment Preservation", Revisions 0 (1987) and 1 (1992)
- Types of Layup
  - Dry
  - Wet
- Lessons Learned from Unit 3 Layup and Subsequent Restart Applied to Unit 1

Unit 1 Layup Program

- Examples of Systems in Layup
  - Dry

Core Spray	Condensate
Reactor Core Isolation Cooling	Feedwater
High Pressure Coolant Injection	Off Gas
Residual Heat Removal	Main Steam

  - Wet

Reactor Vessel	Control Rod Drive
Recirculation	

- Results Met or Exceeded EPRI Guidelines
- Performed Visual, Surface, Ultrasonic, and Remote Inspections to Assess Unit 1 Condition
- No credit was taken for the lay-up program in determining the acceptability of structures, systems, or components for Unit 1 restart

Unit 1 Operating Experience

- 10 CFR 54.17(c):

  An application for a renewed license may not be submitted to the Commission earlier than 20 years before the expiration of the operating license currently in effect.

- Unit 1 Met this Requirement

- Unit 2 and Unit 3 Operating Experience is Applicable to Unit 1

Unit 1 Operating Experience

- Unit 1 has 10 Years of Operation
- Unit 3 Shutdown for 10 Years
  - Extensive layup experience with Unit 3 directly applicable to Unit 1
  - No layup induced aging effects during 10 years of ensuing operation
- Layup Experience from Unit 3 Incorporated into Unit 1 Recovery
  - RHR service water piping
  - Small bore piping
- Unit 1's Licensing Basis will be the same as that of Unit 2 and Unit 3 at Restart (Appendix F)
- Unit 1's Design, Configuration, Operating Procedures, Technical Specifications, and Updated Final Safety Analysis Report Identical to Unit 2 and Unit 3
- Internal and External Plant Operating Experience Incorporated into BFN Corrective Action Program

License Renewal Commitments

- Commitments made Through Application and Requests for Additional Information
- Tracked with Onsite Commitment Tracking System and Corrective Action Program
- ~ 114 Commitments made to Date

Open Items

- Core Plate Hold-Down Bolts
- Drywell Shell Corrosion
- Inspection of RHRSW Piping

Summary

- Three Unit Application at Current Licensed Thermal Power
- Prepared using Generic Aging Lessons Learned Report (Rev. 0, 2001)
- Appendix F ensures Unit 1 Differences are resolved prior to Restart of the Unit
- Unit 2 and Unit 3 Operating Experience is Applicable to Unit 1

United States
Nuclear Regulatory Commission

GENERIC ISSUE 80
PIPE BREAK EFFECTS ON CRD HYDRAULIC LINES IN BWRs

Presented by
Abdul Sheikh
Harold VanderMolen
Office of Nuclear Regulatory Research

October 6, 2005

Safety Significance

- Initiating event is a large break LOCA
- If pipe break is near CRD hydraulic lines, whipping pipe may crimp or kink some withdraw lines, preventing a cluster of rods from scramming
- ECCS refills reactor vessel with cold water
- Possible reactivity excursion
- Additional post-LOCA heat source

Findings

- Core damage frequency well below thresholds
- Public risk well below thresholds

History of GI-80

- Raised by ACRS in 1983
- Prioritized as low priority in 1984, based on pipe layout geometry
- Closed out in 1995
- Reopened in 1998, based on discovery of new piping configurations
- NUREG/CR-6395 in 1999 identified breaks in RCS and RHR piping that may damage CRD piping in BWR plants

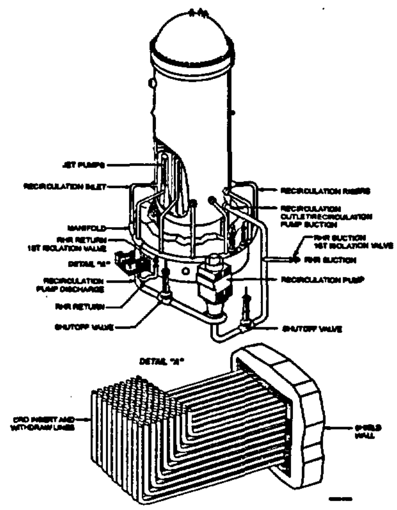
Technical Assessment Objective

- Perform detailed analysis of RHR and RCS break interactions with CRD piping
- Determine if complete closure of CRD piping on impact with RHR and RCS piping is possible
- Determine revised CDF based on a conservative estimate of the probability of crimping of CRD piping
- Use revised CDF to determine appropriate rating for GI-80 in accordance with MD 6.4

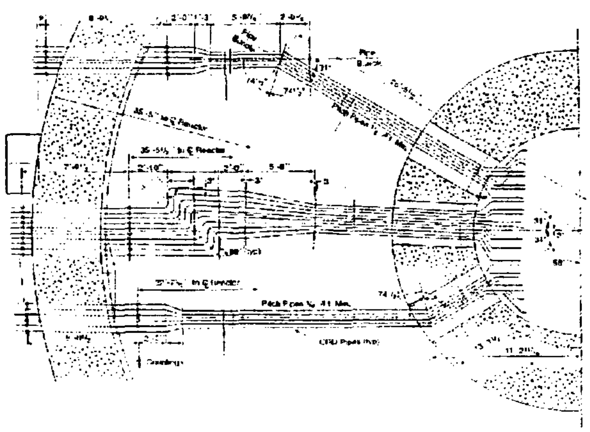
BWR Mark I and Mark II RCS Piping and CRD Arrangements

- The RHR and RCS piping layout and configuration for GE Mark I and Mark II is essentially the same
- The CRD piping layout for Mark I GE2 is different from Mark I/II GE3/GE4/GE5
- Mark I GE 2 has three sets of CRD bundles
- Mark I/II GE3/GE4/GE5 has four sets of CRD bundles

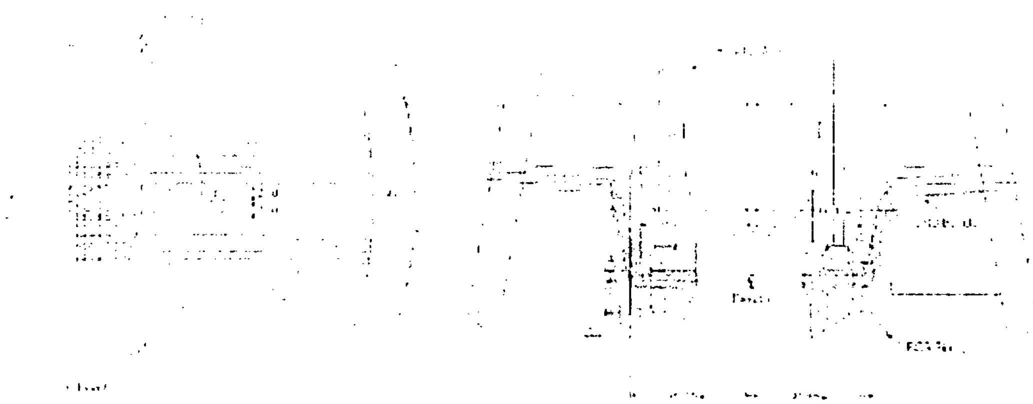
GE Mark I and II RCS Piping Layout



Mark I GE2 CRD Piping Layout



Mark I/II GE3/GE4/GE5 CRD Piping Layout



PLAN VIEW

ELEVATION VIEW

9

Event Quantification Process

CDF for RHR/RCS piping impact on CRD piping is a function of the following factors

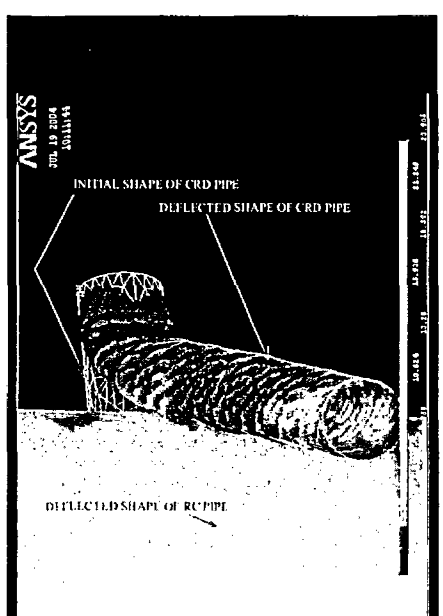
- Pipe rupture initiating event (IE)
- Fraction of piping considered in IE that is from RHR or RCS system (PIPETYPE)
- Fraction of RHR or RCS system piping that can impact CRD piping (TYPEFRAC)
- Probability of pipe whip or jet impingement that can cause CRD system failure (RUPTPROB)

10

Probability of CRD System Failure (RUPTPROB) for Mark I–GE2 Containment

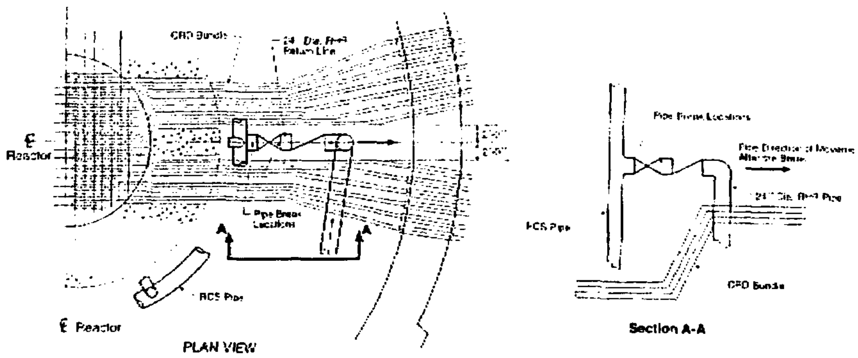
- RHR piping cannot impact CRD piping
- CRD piping bundle located 18 feet above the postulated break location of RCS piping
- 25 inch clearance between RCS and CRD piping
- RCS piping will fail (plastic hinge will form) before it can impact the CRD bundle
- Finite element analysis performed for a hypothetical impact to CRD piping
- CRD piping flexible and will bend without significant crushing or crimping before rupture
- Analysis results consistent with the behavior in the test results documented in NUREG/CR-3231
- RUPTPROB can be conservatively taken as 0.1 for CDF calculations

Deflected Shape of CRD Pipe



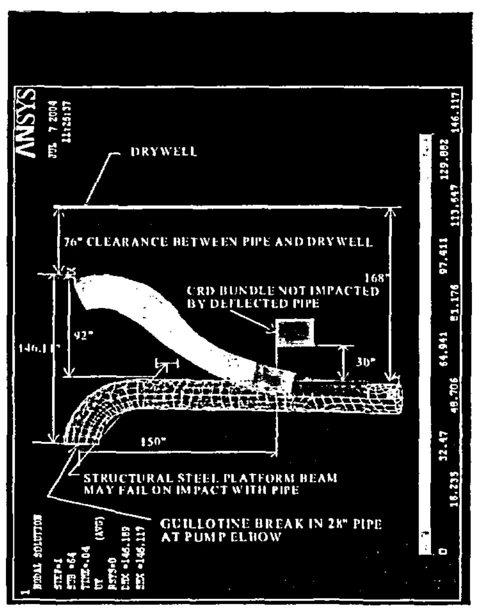
RUPTPROB for Mark I and II–GE3/GE4 Containment

Impact of RHR pipe on the CRD piping is improbable
RUPTPROB can be conservatively taken as 0.1 for CDF calculations



RUPTPROB for Mark I–GE3/GE4 Containment (Contd)

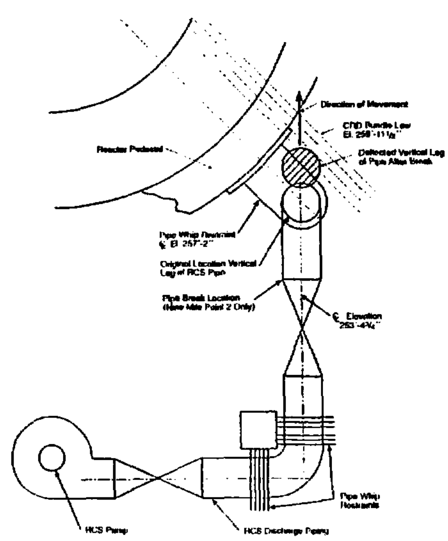
- Deflected Shape of the RCS Pipe Relative to CRD Piping
- Impact of RCS pipe on the CRD piping is improbable
- RUPTPROB can be conservatively taken as 0.1 for CDF calculations



RUPTPROB for Mark II–GE5 Containment

- Layout of RHR and CRD piping similar to Mark II GE3/GE4 plants
- Pipe whip restraint will prevent RHR pipe to impact CRD piping
- There is a 18 inch gap between RHR and CRD piping
- RCS pump discharge pipe break downstream of isolation wall postulated only for the Nine Mile Point 2
- There is a possibility of RCS piping impacting the CRD bundle if the pipe whip restraint fails
- After impact with RCS piping, the CRD piping will bend without significant crushing or crimping before rupture
- Pipe whip restraints on the vertical leg of RCS piping and on circular header will prevent RCS pump vertical discharge pipe break impact on the CRD piping
- RUPTPROB can be conservatively taken as 0.1 for all CDF calculations

RCS Pump Discharge Pipe Break Downstream of Isolation Valve in Mark II-GE5 Containment



Probabilistic Analysis Approach

- Initiating event frequency – used "classic" large LOCA frequency, lognormal distribution
- PIPETYPE – Normal distribution, based on four existing licensee submittals
- TYPEFRAC – Normal distribution, based on review of plant drawings
- RUPTPROB – Exponential distribution, based on ANSYS calculations

Probabilistic Analysis Results - Sequence frequency

Product Line	Sequence	Point Estimate	Mean	Median	5th Percentile	95th Percentile
GE2 Mark I	RCS	2.7E-7	2.8E-7	5.9E-8	1.8E-9	1.1E-6
GE3&4 Mark I	RCS	3.9E-7	4.0E-7	8.6E-8	2.6E-9	1.6E-6
	RHR	1.3E-7	1.3E-7	2.3E-8	8.6E-10	5.4E-7
	total	5.2E-7	5.3E-7	1.2E-7	4.0E-9	2.1E-6
GE4 Mark II	RCS	3.0E-8	5.1E-8	8.3E-9	1.7E-10	2.0E-7
	RHR	2.7E-7	2.8E-7	5.9E-8	1.8E-9	1.1E-6
	total	3.0E-7	3.3E-7	7.2E-8	2.3E-9	1.3E-6
GE5 Mark II	RCS	2.7E-7	2.8E-7	5.9E-8	1.1E-9	1.1E-6
	RHR	3.0E-7	3.1E-7	6.6E-8	2.1E-9	1.3E-6
	total	5.8E-7	5.9E-7	1.3E-7	4.6E-9	2.4E-6

Public Risk

- Estimated for GE4 in Mark I containment (most common)
- Based on NUREG-1150 plant damage state for ATWS initiated by stuck-open safety/relief valve
- Result was less than one person-rem per reactor-year

Conclusions

- Core damage frequency and public risk are well below thresholds
- Generic Issue GI-80 will be closed out with no additional requirements

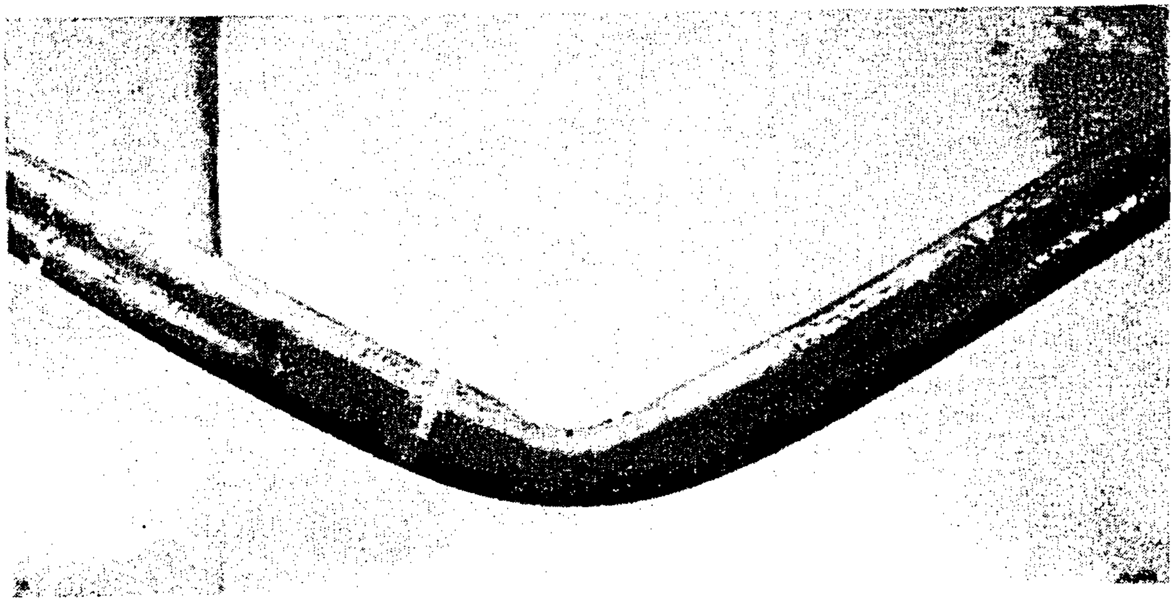


FIGURE 2.20. Impacted 3" SCH 160 Pipe

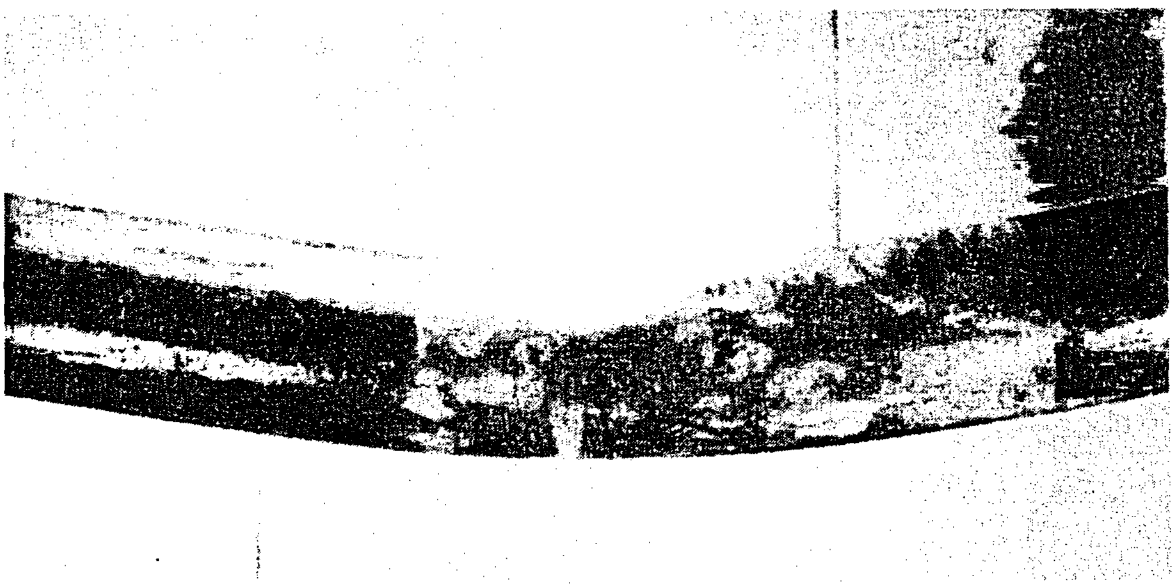


FIGURE 2.21. Impacted 6" SCH 40 Pipe

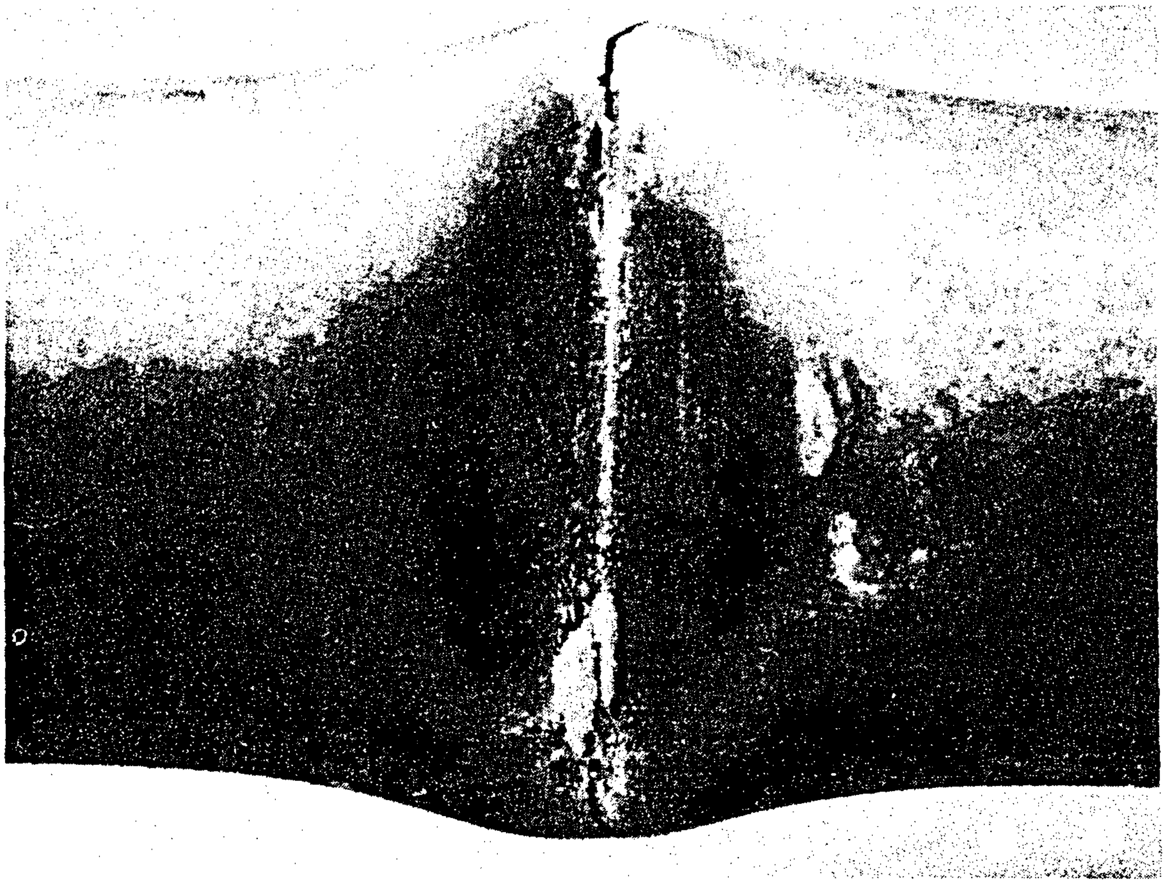


FIGURE 2.24. Failed 6" SCH 40 Pipe - Top View

FIGURE 2.25. Failed 6" SCH 40 Pipe - Side View

FIGURE 2.26. Failed 3" SCH 160 Pipe

Browns Ferry Nuclear Plant
Units 1, 2, and 3
License Renewal
Safety Evaluation Report

Staff Presentation to the ACRS Full Committee

Ram Subbaratnam, and
Yoira Diaz Sanabria, Project Managers
Office of Nuclear Reactor Regulation

October 6, 2005

Review Highlights

- **License extension request – December 31, 2003**
  - Unit 1: December 20, 2013
  - Unit 2: June 28, 2014
  - Unit 3: July 2, 2016

- **SER with Open and Confirmatory Items issued on August 9, 2005**

- **Four (4) Open Items**
  - 1 Scoping and Screening: OI 2.4-3
  - 1 Unit 1 Periodic Inspection: OI 3.0-3 LP
  - 1 Time-limited aging analysis: OI 4.7.7
  - 1 RHRSW Piping: Inspection Finding

- **Two (2) Confirmatory Items**

- **Four (4) License Conditions; Three Standard and one specific to BFN**

- **Fourth Condition requires completion of Unit 1 CLB differences (13 Items) described in LRA Appendix F**

Section 2.4: Scoping and Screening of Containments, Structures and Supports

Open Item 2.4-3 Drywell Shell Corrosion

- Potential Corrosion of the inaccessible portion of the Drywell affected by the leakage from the refueling cavity seal

- The staff proposed two options:

  (1) Bring the refueling cavity seal in the scope of LR or
  (2) Periodically monitor the potential degradation of the inaccessible side of the dry well

Section 3.7: AMR of Unit 1 Systems in Lay Up

Open Item 3.0-3 LP

- Unit 1 Periodic Inspection Program
  - BFN submitted Unit 1 Periodic Inspection Program
  - Staff in reviewing the Program element needed additional confirmation.
  - Section 3.0 of the final SER will include the staff evaluation of this program

Section 4.7.7: Stress Relaxation Core Plate Hold-Down Bolts

- TLAA evaluated for loss of pre-load in accordance with 10 CFR 54.21 (c)(1)(ii)

- Expected loss of preload of 20% which bounds the original BWRVIP-25 value

- In a plant specific analysis
  - Core plate hold-down bolts will maintain sufficient preload to prevent sliding of core plate
  - Hold-down bolts meet ASME Section III, Class 1, Level D service limits at the end of PEO

Section 4.7.7: Stress Relaxation Core Plate Hold-Down Bolts

- **Open Item 4.7.7**
  - The staff reviewed the method of analysis based on GE's generic stress relaxation data on irradiated stainless steel materials
  - The staff requested additional information to address
    - Horizontal and vertical loads for all operating conditions during PEO
    - Sliding of core plate from core plate rim during the PEO
    - Axial and bending stresses of bolts

Browns Ferry Nuclear Plant Units 1, 2, and 3 License Renewal Safety Evaluation Report

Caudle Julian, Senior Project Manger
DRP, Region II

Browns Ferry License Renewal Inspection

- AMP inspection conducted November 29 - December 17, 2004

- Inspection concluded that existing programs to be credited as aging management programs for license renewal are generally functioning well.

- Inspectors observed that the applicant had not yet begun the implementation process for new and enhanced AMPs

- AMP procedures have yet to be defined and composed

Browns Ferry License Renewal Inspection

- For existing programs, the identification and selection of which particular existing procedures constitute the AMP had yet to be done
- Region II concluded that NRC will perform another inspection when the applicant has progressed further with AMP implementation.
- In walking down plant systems and examining plant equipment the inspectors found no significant adverse conditions and it appears plant equipment was being maintained adequately.

Browns Ferry License Renewal Inspection

Second (optional) AMP Inspection

- Conducted September 19 - 23, 2005
- Reviewed sample of 40 AMP Implementation Packages containing proposed procedures
  - Packages contained some errors and were not meticulously reviewed
  - Applicant initiated PER for corrective action

Browns Ferry License Renewal Inspection

Second (optional) AMP Inspection (cont.)

- Reviewed plans for tracking future actions using TROI system

  - Not initially linked to Implementation Packages but quickly corrected
  - Inspection sample commitments were included
  - Much duplication and varying format resulting in confusing document

- Applicant decided to track future actions using PER process

- Region II will follow up on these issues during a future inspection

Conclusion

- Region II concluded that NRC will perform another inspection when the applicant has progressed further with AMP implementation.

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Browns Ferry Nuclear Plant
Units 1, 2, and 3
License Renewal
Safety Evaluation Report

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5

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Browns Ferry Nuclear Plant
Units 1, 2, and 3
License Renewal
Safety Evaluation Report

Caudle Julian, Senior Project Manger
DRP, Region II

7

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- AMP procedures have yet to be defined and composed

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Browns Ferry License Renewal Inspection

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Browns Ferry License Renewal Inspection

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Browns Ferry License Renewal Inspection

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Conclusion

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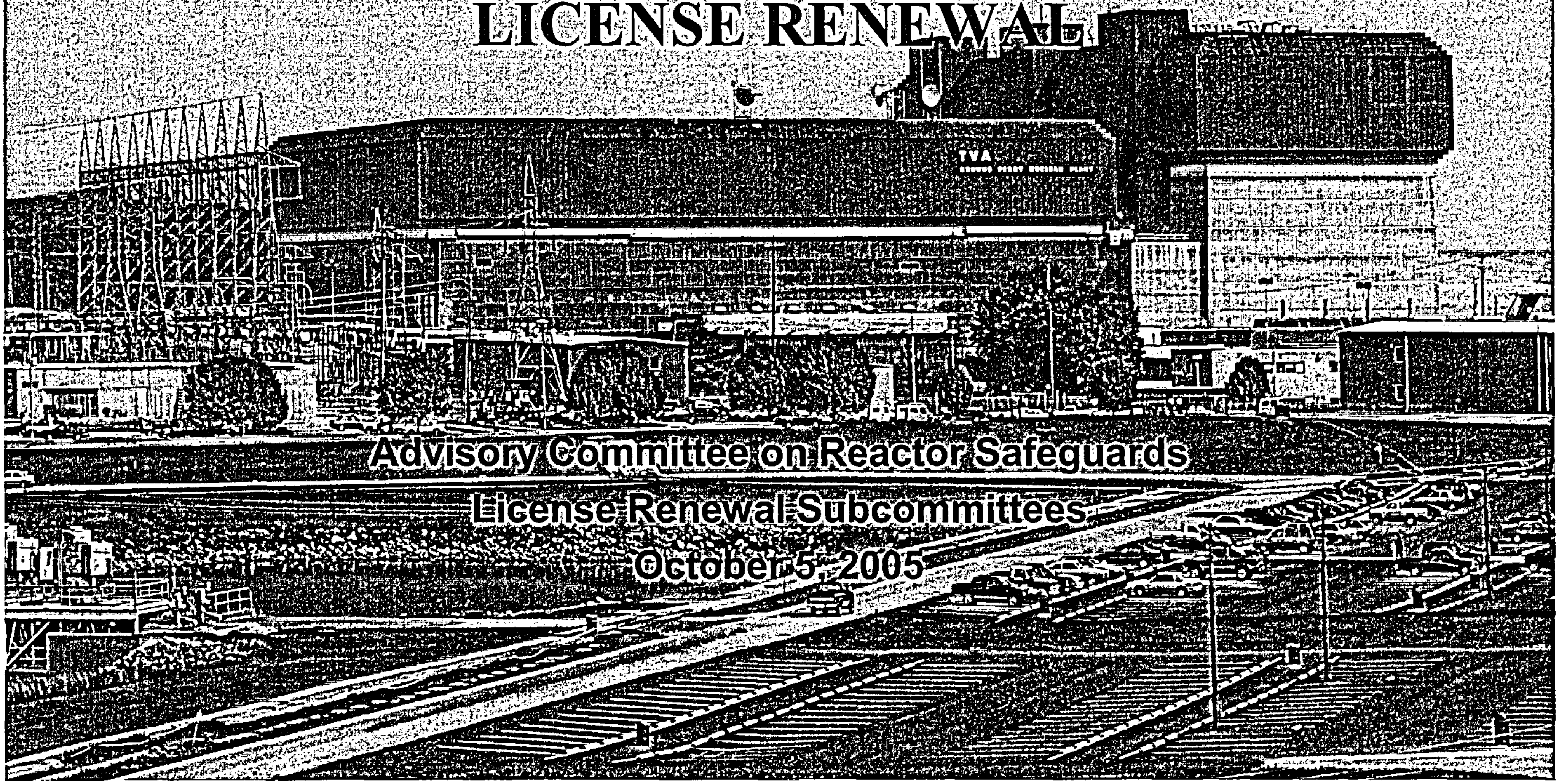
12

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT

TVA

LICENSE RENEWAL



Advisory Committee on Reactor Safeguards

License Renewal Subcommittees

October 5, 2005

Agenda

- Description of Browns Ferry
- BFN License Renewal Application
  - Scoping
  - Time-Limited Aging Analysis
  - Aging Management Programs
- Unit 1 Layup
- Unit 1 Operating Experience
- License Renewal Commitments
- Open Items

Description of Browns Ferry

- All Three BFN Units are General Electric BWR 4 Reactors with Mark I Containments
- Approximate Years of Operation
  - Unit 1 – 10
  - Unit 2 – 23
  - Unit 3 – 18
- BFN Units 2 and 3 in Operation Since Recovery in 1991 and 1995, Respectively
- Unit 1 in Recovery Outage with Restart Scheduled for May 2007
  - Unit 1 will be operationally identical to Units 2 and 3
- NRC Performance Indicators Green

BFN License Renewal Application

- Three-Unit Application Submitted December 31, 2003
- Original License Expiration
  - Unit 1 – December 20, 2013
  - Unit 2 – June 28, 2014
  - Unit 3 – July 2, 2016
- License Renewal Application at Current Licensed Thermal Power for each Unit (Unit 1 – 3293 MWt, Units 2 and 3 – 3458 MWt)
- Appendix F Describes the Differences Between Unit 1 and Units 2 and 3
  - These differences will be eliminated prior to Unit 1 restart (May 2007)
- Requests for Additional Information ~230 (13 are Environmental, Remainder are Safety Evaluation)

Scoping

- Scoping Basis
  - Updated Final Safety Analysis Report
  - Safe Shutdown Analysis calculation
  - Maintenance Rule documentation
  - Controlled Plant Component Database
  - Licensing Basis and Design Basis documents
- Specific Scoping for Regulated Events
  - Fire Protection
  - Environmental Qualification
  - Anticipated Transients Without Scram
  - Station Blackout
- 77 Mechanical / Electrical Systems in Scope

Time-Limited Aging Analysis

- Neutron Embrittlement of the Reactor Vessel and Internals
- Metal Fatigue
- Environmental Qualification of Electrical Equipment
- Primary Containment Fatigue
- Plant Specific Time-Limited Aging Analyses
  - Reactor Building Crane Load Cycles
  - Radiation Degradation of Drywell Expansion Gap Foam
  - Irradiation Assisted Stress Corrosion Cracking (IASCC) of Reactor Vessel Internals
  - Stress Relaxation of the Core Plate Hold-Down Bolts
  - Emergency Equipment Cooling Water Weld Flaw Evaluation

Reactor Vessel
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    - Peak fluence of limiting weld 2.3×10^{18} n/cm^2

License Renewal
Aging Management Programs

- 39 Aging Management Programs Total
  - 38 are common to Units 1, 2, and 3
  - 1 is for only Unit 1 (i.e., Unit 1 Periodic Inspection Program)
- 11 Existing Aging Management Programs Requiring No Enhancement
- 11 Existing Aging Management Programs Revised Only to Include Unit 1
- 11 Existing Aging Management Programs Require Enhancement for all Units
- 6 New Aging Management Programs

License Renewal
Aging Management Programs

- Existing Aging Management Programs Requiring No Enhancement
  - 10 CFR 50 Appendix J Program
  - Above ground Carbon Steel Tanks Program
  - ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD Program
  - ASME Section XI Subsection IWE Program
  - Bolting Integrity Program
  - BWR Control Rod Drive Return Line Nozzle Program
  - Diesel Starting Air Program
  - Fuel Oil Chemistry Program
  - Inspection of Overhead Heavy Load and Light Load Handling Systems Program
  - Reactor Head Closure Studs Program
  - Systems Monitoring Program

License Renewal
Aging Management Programs

- Existing Aging Management Programs Requiring Revision Only to Incorporate Unit 1
  - BWR Feedwater Nozzle Program
  - BWR Penetrations Program
  - BWR Reactor Water Cleanup System Program
  - BWR Stress Corrosion Cracking Program
  - BWR Vessel Inside Diameter Attachment Welds Program
  - Chemistry Control Program
  - Closed-Cycle Cooling Water System Program
  - Environmental Qualification Program
  - Fire Protection Program
  - Flow-Accelerated Corrosion Program
  - Open-Cycle Cooling Water System Program

License Renewal
Aging Management Programs

- Existing Aging Management Programs Requiring Enhancement (All Units)
  - ASME Section XI Subsection IWF Program
  - Buried Piping and Tanks Inspection Program
  - BWR Vessel Internals Program (includes steam dryers)
  - Compressed Air Monitoring Program
  - Electrical cables not subject to 10 CFR 50.49 Environmental Qualification requirements used in Instrumentation Circuits Program
  - Fatigue Monitoring Program
  - Fire Water System Program
  - Inspection of Water-Control Structures Program
  - Masonry Wall Program
  - Reactor Vessel Surveillance Program
  - Structures Monitoring Program

License Renewal
Aging Management Programs

- New Aging Management Programs (for all Three Units)
  - Accessible Non-Environmental Qualification Cables and Connections Inspection Program
  - Bus Inspection Program
  - Inaccessible medium voltage cables not subject to 10 CFR 50.49 Environmental Qualification Requirements Program
  - One-Time Inspection Program
  - Selective Leaching of Materials Program
- New Aging Management Program (Unit 1 Only)
  - Unit 1 Periodic Inspection Program

One-Time Inspection Program

- Applies to Units 1, 2, and 3
- Verifies the Effectiveness of Aging Management Programs by Confirming that Unacceptable Degradation is not Occurring
- Where No Aging Management Program is Identified, the Inspections Confirm either:
  - Aging Effects are not Occurring, or
  - Aging Effects are Occurring at a Rate that does not Affect the Intended Function
- To be Completed Prior to the Period of Extended Operation
- Examples of inspection items:
  - Reactor coolant pressure boundary piping, valves, fittings less than four inches
  - Bottom thickness of above ground tanks
  - Submerged concrete and component supports
  - Ventilation ducts

Unit 1 Periodic Inspection Program

- Periodic Inspections will be Performed after Unit 1 is Returned to Operation to Verify No Additional Aging Effects are Occurring
- The Periodic Inspection Sample Locations will be a Subset of Non-Replaced Piping Locations (takes credit for restart inspections)
- First Round of Periodic Inspections will be Completed Prior to Period of Extended Operation and after Several Years of Unit 1 Operation
- An Inspection will be Performed during the Period of Extended Operation
- Subsequent Inspection Frequency will be Determined Based on Inspection Results

Unit 1 Layup Program

- Criteria
  - EPRI NP-5106, "Sourcebook for Plant Layup and Equipment Preservation", Revisions 0 (1987) and 1 (1992)
- Types of Layup
  - Dry
  - Wet
- Lessons Learned from Unit 3 Layup and Subsequent Restart Applied to Unit 1

Unit 1 Layup Program

- Examples of Systems in Layup
  - Dry

Core Spray	Condensate
Reactor Core Isolation Cooling	Feedwater
High Pressure Coolant Injection	Off Gas
Residual Heat Removal	Main Steam

  - Wet

Reactor Vessel	Control Rod Drive
Recirculation	

- Results Met or Exceeded EPRI Guidelines
- Performed Visual, Surface, Ultrasonic, and Remote Inspections to Assess Unit 1 Condition
- No credit was taken for the lay-up program in determining the acceptability of structures, systems, or components for Unit 1 restart

Unit 1 Operating Experience

- 10 CFR 54.17(c):

  An application for a renewed license may not be submitted to the Commission earlier than 20 years before the expiration of the operating license currently in effect.

- Unit 1 Met this Requirement

- Unit 2 and Unit 3 Operating Experience is Applicable to Unit 1

Unit 1 Operating Experience

- Unit 1 has 10 Years of Operation
- Unit 3 Shutdown for 10 Years
  - Extensive layup experience with Unit 3 directly applicable to Unit 1
  - No layup induced aging effects during 10 years of ensuing operation
- Layup Experience from Unit 3 Incorporated into Unit 1 Recovery
  - RHR service water piping
  - Small bore piping
- Unit 1's Licensing Basis will be the same as that of Unit 2 and Unit 3 at Restart (Appendix F)
- Unit 1's Design, Configuration, Operating Procedures, Technical Specifications, and Updated Final Safety Analysis Report Identical to Unit 2 and Unit 3
- Internal and External Plant Operating Experience Incorporated into BFN Corrective Action Program

License Renewal Commitments

- Commitments made Through Application and Requests for Additional Information
- Tracked with Onsite Commitment Tracking System and Corrective Action Program
- ~ 114 Commitments made to Date

Open Items

- Core Plate Hold-Down Bolts
- Drywell Shell Corrosion
- Inspection of RHRSW Piping

Summary

- Three Unit Application at Current Licensed Thermal Power
- Prepared using Generic Aging Lessons Learned Report (Rev. 0, 2001)
- Appendix F ensures Unit 1 Differences are resolved prior to Restart of the Unit
- Unit 2 and Unit 3 Operating Experience is Applicable to Unit 1