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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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MEETING OF THE

RELIABILITY AND PROBABILISTIC RISK ASSESSMENT

AND PLANT OPERATIONS SUBCOMMITTEES

RISK MANAGEMENT TECHNICAL SPECIFICATIONS (RMTS)

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THURSDAY,

MARCH 25, 2004

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., Dr. George E. Apostolakis, Chairman, presiding.

COMMITTEE MEMBERS PRESENT:

GEORGE E. APOSTOLAKIS, Chairman

MARIO V. BONACA, Member

F. PETER FORD, Member

THOMAS S. KRESS, Member

COMMITTEE MEMBERS PRESENT (Continued):

WILLIAM J. SHACK, Member

JOHN D. SIEBER, Member

MAGGALEAN W. WESTON, Staff Engineer

NRC STAFF PRESENT:

WILLIAM BECKNER

TOM BOYCE

MARK CARUSO

JIN CHUNG

NAOTO ICHII

STU MAGRUDER

GARETH PARRY

MARK REINHART

NICK SALTOS

BOB TJADER

MIKE TSCHILTZ

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P R O C E E D I N G S

(8:31 a.m.)

CHAIRMAN APOSTOLAKIS: The meeting will now come to order.

This is a meeting of the ACRS Subcommittees on Reliability and PRAA and Plant Operations.

I am George Apostolakis, Chairman of the Reliability and PRA Subcommittee. Mr. Jack Sieber is the Chairman of the Plant Operations Subcommittee.

Other ACRS members in attendance are Mario Bonaca, Peter Ford, Thomas Kress and Steve Rosen.

The purpose of this meeting is to discuss the risk management technical specifications Initiative 4(b), risk informed completion times.

Maggalean Weston is the -- No? I obviously mispronounced.

It's the same person Maggalean Weston is the cognizant ACRS staff engineer for this meeting, now to us as Mag.

The rules for participation in today's meeting have been announced as part of the notice of this meeting published in the Federal Register on March 8, 2004.

A transcript of the meeting is being kept

and will be made available as stated in the Federal Register notice.

It is requested that speakers use one of the microphones available, identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

We have received no written comments from members of the public regarding today's meeting.

Initiative 4(b) is the most complex of these initiatives primarily because of its reliance upon the licensee's PRAs. The staff is currently evaluating pilot proposals for approving the initiative 4(b) process.

The overall objective of this initiative is to modify the technical specifications to control operation of the plant in a manner more consistent with plant risk in a given configuration.

Current technical specifications address systems independently and do not generally account for the combined impact of multiple equipment on the risk metrics.

The maintenance rule configuration risk assessment requirement in 10 CFR 50.65(a)(4) was added to address this consideration, but does not obviate compliance with current technical specification

requirements.

The current technical specification requirements may present inconsistencies with a configuration risk management approach and may require plant shutdown or other actions that may not be the most risk effective actions given the specific plant configuration.

The staff would like us to comment on Initiative 4(b), particularly the scope and quality of PRA needed to support the licensing process and on the coherence of the various regulatory efforts. That is the maintenance rule, Initiative 4(b), and Regulatory Guide 1.200.

They are scheduled to make a presentation to the full committee in April.

Jack, do you have any comments?

DR. SIEBER: No, sir.

CHAIRMAN APOSTOLAKIS: Mr. Rosen will not participate in today's proceedings due to a conflict of interest, and we will now proceed with the meeting. Mr. Boyce of NRR will begin.

MR. BOYCE: Good morning. I'm Tom Boyce. I'm a section chief for the tech spec section in NRR. We're here to talk about an initiative to risk inform plant technical specifications. This effort is called

risk management tech specs.

With me is the senior staffer for risk management tech specs, Bob Tjader, in the tech spec section; Mark Reinhart, section chief in the PRA Branch of NRR; Michael Tschiltz in the audience, branch chief for PRA Branch, NRR; Bill Beckner, branch chief for the Reactor Operations Branch and my boss in NRR; Nick Saltos, the lead reviewer in the PRA Branch of NRR.

We also have the benefit of a couple of industry speakers. Biff Bradley of NEI and Rick Grantom of South Texas Project will be on the agenda after us.

We last presented to the ACRS in November 2002. This is the next in a series of periodic briefs to the ACRS on risk management tech specs.

The last time we talked to you, we gave you an overview of the eight initiatives that comprise the risk management tech specs. Today we wanted to talk about one of them, Initiative 4(b). As George said in the introduction, we think it is the most ambitious of the eight initiatives because it has got the most heavy reliance on PRA.

Right now we think it requires a full scope and very high quality PRA in order to be

successfully implemented, and what it does is allows for real time setting of allowed outage times for equipment, and this is a significant change from the way industry and NRC has traditionally approached plant technical specifications.

Typically they say up front a piece of equipment is allowed to be out of service for a period of time, say, six hours. At that point, you normally take action, such as shutting down the plant. This would allow a more real time establishment of those allowed outage times based on use of licensee's PRAs.

We are still early in the review process so we won't have all of the answers for you today, but we are developing both issues and answers, we hope, as we go along, and this is part of several risk informed initiatives you are going to be hearing about over the next several months. You are going to be hearing about the staff's plans for responding to the recent SRM on PRA quality this afternoon, and we are going to come back to talk to the ACRS in May, along with, I believe, 5046 in Reg. Guide 1.200 in May.

So at this juncture we are looking for comments and feedback, but not necessarily a letter, unless you are going to write a letter on the larger context of where we're going with risk informed

initiatives.

Any initial questions?

(No response.)

MR. BOYCE: Okay. With that I will turn it over to Bob Tjader.

MR. TJADER: Thank you, Tom.

I will be giving an overview of Initiative 4(b), but prior to getting into that, let me just discuss a little bit what we provided you already.

About a month ago I provided you a three-ring binder which had in it an overview of and status of each of the initiatives and also included in that were the three Initiative 4(b) submittals received to date from industry, that is, the risk management guidance document, the process by which Initiative 4(b) is going to be implemented, and then we received the South Texas full plant pilot, and we received the CE generic single system HPCY pilot.

I'll be providing an overview of -- also you received some slides of our presentation today, including some backup and support slides, and in addition to that some background information. The background information are our initial review comments, initial acceptance review comments of the three submittals and the industry responses. So you

can see from that that we are early in the process and we ourselves have a lot of questions, some of which the responses have already satisfied, but that is what you have received to date.

I will be providing an overview of Initiative 4(b). Biff Bradley of NEI will provide a discussion of the risk management guidance document, the process that Initiative 4(b) will be implemented by, and Rick Grantom will provide a discussion of the South Texas pilot proposal.

We invited Fort Calhoun Station here to discuss the CE proposal, and unfortunately they were not able to attend. If you have any questions on the CE proposal, maybe collectively we can respond to those questions and attempt to do that.

I think in Tom's introduction, I think he covered everything. So I'll go right to the conclusions.

Some of the thoughts that maybe you can help go away from this meeting or this discussion are that the risk management tech spec Initiative 4(b) is linked to the PRA's quality. Initiative 4(b) requires a qualitative risk assessment to determine the appropriate risk informed completion time and requires a high quality PRA.

Communication and training of the headquarters staff and regions are essentially for the successful implementation of Initiative 4(b). That is something that we know we must do and will have to work on in the future.

Initiative 4(b) also happens to be the pilot for the NRC internal risk informed environment initiative related to the communication, education, and acceptance of the staff of risk type initiatives.

And as Tom said, we are early in the Initiative 4(b) process. The pilots are going to be proof of concept of it, and we are going to learn as we go.

Some principles for the risk management tech spec development. In addition to following Commission guidance in the development of the risk management tech spec initiatives, we seek to achieve coherence with other risk informed regulatory developments, such as the maintenance rule, PRA quality Reg. Guide 1.200, Initiative 5069, among others.

We will take four and build upon the existing 5065(a)(4) maintenance rule risk management or risk assessment and risk management programs, and we must insure that licensees risk submittals meet the

standards for quality, such as with Reg. Guide 1.200, the ASME standard and others. That's just to mention two, and others, including some of those that are to be developed.

Plus we must, as already said, communicate. We must involve the NRC staff with a cognizant and various disciplines, such as those listed here, so that we receive a good quality end product and so that we also receive support in the end product.

A general overview of 4(b) and where they are in the initiatives, the status initiatives. There are four general categories of the initiatives. There are the first initiatives that would be approved. They are the ones that rely extensively on the risk management 8.4, risk assessment and risk management programs in place.

There is a second set that require a prior analysis of plan configurations, prior to implementation, before they can then apply a four configuration risk management type programs.

And then there is the third group in which Initiative 4 falls into, which require a quantitative risk assessment and a high quality PRA for implementation.

And then the final category involves rulemaking, which is in the future, down the road, which could potentially relocate non-risk significant systems from tech specs, superseding the four criteria that are currently in 5036.

A little bit of information on Initiative 4, the risk informed completion times. The effect of this is to extend completion times from a nominal or current completion time up to a predetermined backstop, which is a maximum using configuration risk management programs.

The Initiative 4(b) would utilize a process which is currently proposed as the risk management guidance document for determining the risk informed completion time, and it will require real time capability and cumulative and configuration risk matrix.

And the status, the industry has submitted proposals which you have. I have just given you today the feedback that was provided on that and their responses, and as mentioned South Texas and Fort Calhoun were the pilots.

DR. SIEBER: So this extension was done in real time?

MR. TJADER: Relatively speaking, yes,

sir. Right now I think the programs, configuration risk management programs are on computers in the plants. I have seen them work in a matter of minutes, changing configurations and coming up with real time solutions. So I think it can be relative real time. Probably some of the delays might be due to involvement of plant approval by senior staff and things like that if they're not on site, if it's the middle of the night. That's why perhaps what we perceived excessive time for making these determinations.

But these times are to be determined, too. They're going to be worked out in the pilot and other things.

DR. KRESS: How does NRC have assurance that these real time PRAs at the plant meet the quality that they think is needed for this?

MR. TJADER: Well, Initiative 4(b) is a triple pilot. It's a pilot for Reg. Guide 1.200, which should hopefully establish some level of quality. Now, it may not provide a sufficient level of quality for the application that we want, and that may be in Phase 3 of the SRM or something like that. However, we are, for the pilots in particular, are going to do an extensive review if not an audit of the

applicable portions of the PRA, and we are going to through the pilot exercise the configuration risk management program to hopefully insure that there is reliability in the process and repeatability such that similar configurations produce similar results consistently and that sort of thing.

So the pilot will prove hopefully some of that. IF it doesn't, then we'll have to work from there.

MR. BOYCE: I think you have asked the key question for the whole project, you know. How do we have that assurance? And you know, saying the same thing as a combination of up front reviews of licensees, PRAs, licensee commitments to documents, and then follow-on oversight by our inspectors and our headquarters teams as appropriate.

DR. KRESS: That sounds good. Would this be viewed as similar to the way you review some of the computer codes for meeting the design basis accidents, like the thermal hydraulics code?

You know, you will review and approve those and say this now is a blessed code by NRC for use in meeting the Appendix K requirements or something. Would that be the sort of thing that you would do with these PRAs?

MR. REINHART: What we're call this is a proof of concept type approach, and we are going to have to look at the PRA, a review. Some places will have a standard in place or looking at a standard in a reg. guide. Other pieces we don't yet have a standard, but we will have to go in and do a review that is adequate, and we are going to have to as we get into it determine exactly what constitutes an acceptable review.

It is going to be thorough.

DR. KRESS: That is yet to be really.

MR. REINHART: Yes, yes.

CHAIRMAN APOSTOLAKIS: Now, when the reassessment of the completion time takes place, the NRC staff will not be involved, right?

MR. TJADER: No.

CHAIRMAN APOSTOLAKIS: You will review it afterwards?

MR. TJADER: All of these determinations under Initiative 4(b) are to be documented so that we can review them post track.

There is a backstop, a proposed 30-day backstop at this point in time. If a system in the plant configuration allows extension of the completion time up to the 30-day backstop, and if the system or

plant is not restored to operable status, the 30 days either gives the plant enough time to restore it or if it isn't restored, it gives them time to assess the situation and come into the NRC and discuss it and then perhaps propose if the risk assessment warrants it an extension beyond the 30 days.

MR. BOYCE: Just like any other part of the plant operations, licensee has primary responsibility to operate their plant safely. So the answer is, yes, they would be doing this real time. They don't need to consult with NRC as they are doing it. We always have the ability to go in and review what they have done, and we will have increased documentation requirements.

MR. REINHART: the licensee would have an implementation program that would get reviewed and reviewed up front, and so they would have to maintain that program and make their determinations in accordance with that program.

So the resident or whoever was going in to inspect would see that what was done was done in accordance with the program and established criteria that we all agreed on up front.

MS. WESTON: Bob, this 30-day backstop is proposed regardless to what the current completion

time is?

MR. TJADER: That goes right into the example right here.

MR. BOYCE: Yeah, let's segue.

MR. TJADER: That goes right into the example. then perhaps that will answer you question. Otherwise --

CHAIRMAN APOSTOLAKIS: It also applies even if the plant configuration changes.

MR. TJADER: Any time the plant configuration changes in a way that would affect the risk, as in A(4), the risk has to be reassessed.

CHAIRMAN APOSTOLAKIS: Let's say it changes now.

MR. TJADER: If it changes now, you have to reassess.

CHAIRMAN APOSTOLAKIS: So you start the 30-day period?

MR. TJADER: No.

CHAIRMAN APOSTOLAKIS: No?

MR. TJADER: No, no, no. What it is is that there is a front stop, and that is the existing completion time. The plant has to follow the required actions, restore the plant to operability within the existing completion time if within -- sorry. I have

something that I didn't get on PowerPoint here, and --

CHAIRMAN APOSTOLAKIS: So if they do it within the front stop there is nothing else. That's it.

MR. TJADER: No, no.

MR. BOYCE: Maybe we should work through the example and then come back.

MR. TJADER: Yes, I'm getting out another slide. Here it is, here it is. My apologies.

DR. KRESS: We like these multimedia presentations.

MR. TJADER: Okay. Thank you very much.

There's a front stop. That is, as I said already, the existing. Now, this is a proposed revised standard tech spec condition with required action and completion times, and this is an example that is provided in the proposed risk management guidance document, Table 3.1.

DR. KRESS: Before you go on, I wanted to ask about the front stop. It's supposedly what's in the existing tech specs or at least the revised. Will there be a look to see if they actually conform to your risk informed rules of just the front stop part?

You know, I could conceive that some front stops might exceed your risk criteria.

MR. TJADER: Well, the front stops were systems, as they are now, were created using engineering judgment.

DR. KRESS: Yes, I know that.

MR. TJADER: And they were created very conservatively.

DR. KRESS: Oh, you think they're automatically going to meet that risk.

MR. TJADER: Well, they were created very conservatively, and existing tech specs were created with blinders on. They were created assuming only that system is experiencing inoperability. Okay?

And if that is the case and you enter that tech spec, the front stop or existing completion time will be conservative. I don't think there are any that are non-conservative. If there are, then they need to be changed. They should be non-conservative.

Now, the proof is sort of in the pudding once you have multiple interoperabilities and then you find out that through risk assessments, that with multiple interoperabilities you can have --

DR. KRESS: That is almost --

MR. TJADER: That sort of proves it, and so that's sort of a given that these existing ones are very conservative. When they may not be conservative

is when suddenly you have multiple system interoperabilities, and then when you enter the tech spec and you want to go beyond the front stop, you will perform the risk assessment.

DR. KRESS: You see, what is bothering me about this you may be suddenly in multiple things out of the --

MR. TJADER: But you should be --

DR. KRESS: -- and the front stops might not be conservative then.

MR. TJADER: Well, once you're in the first, there should be corrective maintenance going on, and even if there isn't, we're going to stipulate within the program that the risk assessment need to be formed once the second inoperability is entered. That's our intent. That needs to be negotiated.

So anyway, you will be under the risk assessment program in the second inoperability and the risk informed completion time will take effect. Okay? Once you have multiple interoperabilities. Okay?

But anyway, this is an example of -- some of this has to be negotiated, and I'm sure industry in some cases may have different perceptions, but I'm telling you what our perception of the staff is at the moment.

Okay. This is an example that's given in the risk management guidance document. Required action B(1) --

CHAIRMAN APOSTOLAKIS: Wait, wait, wait. Stop with the condition.

MR. TJADER: Okay. The condition is that the subsystems -- forget about what subsystem -- when the subsystem is inoperative. Okay?

CHAIRMAN APOSTOLAKIS: But not the whole HBSI, right?

MR. TJADER: Just one train, just one train.

CHAIRMAN APOSTOLAKIS: One train. Okay.

MR. TJADER: One subsystem, one train is inoperable. Okay? The way it currently is is that B(1) is all that would be generally -- speaking is all that you'd see in the specs, 4(a) subsystem generally speaking, and you have 72 hours to restore it.

The way it is rewritten is by adding B(2.1), B(2.2) and B(2.3). B(2.1) says if they determine they cannot restore the single train to operability within 72 hours, within that 72 hours they must perform a risk assessment, a quantitative risk assessment, to determine the appropriate completion time, and then that must be performed within that

initial completion time.

DR. KRESS: Well, let me ask you about that. The extended time enters into the risk assessment. Does it start after the 72 hours or does it start at the time that you do the risk assessment?

MR. TJADER: The way you use standard tech specs and the way improved standard tech specs, times zero for all actions is when you enter the specs.

DR. KRESS: When you enter the spec is time zero.

MR. TJADER: Right.

DR. KRESS: Okay.

MR. TJADER: So like I said, there are different views on how to accumulate the metrics to determine what the completion time should be. It is presented a little differently, I think, in one or the other of the proposals where they start counting after the 72 hours.

We have raised the question, as you can see by the background information, about that. We perceive that it should be when you enter it. Okay? But that has to be worked out, and regardless of what it is, you need to take into account the time from which it was determined to be inoperable.

B(2.2) says basically what we just said,

is that any time there is a configuration change of significance, you must reestablish that risk informed completion time. It says verify that what you determine, but basically it is reestablish what it is.

DR. KRESS: Do you go back to time zero with that after you've had a configuration change? That doesn't make much sense to me.

MR. REINHART: Time zero started at time zero.

MR. TJADER: Basically, I mean, you are accumulating the risk.

DR. KRESS: It starts at the time you enter the tech spec.

MR. TJADER: Yeah, but you are accumulating the risk from the time it is inoperable, right? The revised circumstance, obviously I think -- I'm sorry. I'm sorry.

DR. KRESS: But I'm going to enter the tech specs. I've got one subsystem inoperable. Now, that gives me a certain level of risk that I can stand for a certain amount of time to meet some acceptance criteria.

And then halfway through there something happens and I get some other systems inoperable. Now I have a new set of risks, but that risk wasn't

accumulated during that first part. It is only started at that point, and I don't know how to do that in terms of when the time for the extension starts.

MR. REINHART: Okay. The time when you enter the LCO, the first LCO is time zero, and if you go in and out of X, Y or Z LCOs until you're back to full compliance, that clock is starting. The risk is accumulating. The 30 days ends from --

DR. KRESS: That would certainly be conservative.

MR. REINHART: -- the original time zero.

CHAIRMAN APOSTOLAKIS: But if you enter state Y on the way, then you recalculate the completion time?

MR. REINHART: Yes.

MR. TJADER: And actually the --

MR. REINHART: From time zero.

MR. TJADER: -- time would be addressed from that point.

DR. KRESS: Well, that would certainly be conservative.

PARTICIPANTS: Right.

MR. TJADER: Actually I think Rick Grantom is going to have some graphs and examples.

MR. REINHART: Now, we are going to have

some examples of this if you want to go through those.

CHAIRMAN APOSTOLAKIS: Okay.

DR. BONACA: But you recalculated the completion time not to exceed 30 days.

MR. TJADER: Yeah, the backstop is from time zero.

CHAIRMAN APOSTOLAKIS: And the criterion is some criterion on ILERP and ICDP. So there is always a criterion there.

MR. REINHART: Yes.

CHAIRMAN APOSTOLAKIS: And you always can meet that.

MR. TJADER: And I think Rick and Biff are going to discuss some of these things.

CHAIRMAN APOSTOLAKIS: Okay, yeah.

MR. TJADER: Sure.

DR. BONACA: Now, is this the same thing that you use for both voluntary and involuntary entry into the tech spec?

MR. TJADER: Yes.

DR. BONACA: Because I think you are making a distinction at that time.

MR. TJADER: Now, there are constraints on voluntary entry that we perceive being put into place.

DR. BONACA: Okay. So this is not

reflected here right now.

MR. TJADER: The constraints on voluntary entry?

DR. BONACA: Yeah.

MR. TJADER: Some of it has to do with loss of function and voluntary entry into that, and again, some of that has to be worked out and negotiated with respect to that. It also has some relation to some of the other initiatives, such as Initiative 6, which is entry into --

DR. BONACA: Yeah, that's an area where I'm sure you'll talk about that, you know, loss of function, I mean, and you know, how far do you go with the tech spec.

MR. TJADER: I think that has to be determined. There's different proposals. I think the staff needs to think about that.

CHAIRMAN APOSTOLAKIS: And the 72 hours, the second 72 hours says that the utility foresees that they cannot complete the repair in 72 hours. So within the same 72 hours, they have to do this calculation to determine the new time.

MR. TJADER: That's right.

CHAIRMAN APOSTOLAKIS: And this always starts from time zero.

MR. REINHART: Correct.

CHAIRMAN APOSTOLAKIS: So if they enter now a new configuration 71 hours from time zero and they need to do a new calculation, they don't do it?

MR. TJADER: they have to, B(2.2), verify completion time. They may do --

CHAIRMAN APOSTOLAKIS: Well, then they may not have time to do it. Then they shut down?

MR. TJADER: I think like a --

CHAIRMAN APOSTOLAKIS: The shut down. Okay. In other words, within 72 hours either you have repaired it or you have done analysis that justifies going beyond. If you haven't had time to do the analysis, tough.

MR. TJADER: Well,m keep in mind that the actions -- basically what you're saying is true, but keep in mind that the actions to shut down take time, and you can enter those shutdown actions and still be performing your risk assessment, and once that risk assessment determines it's okay, you can back out of your shutdown actions. Okay?

CHAIRMAN APOSTOLAKIS: How long does it take to shut down?

MR. TJADER: Oh, six hours to hot standby.

CHAIRMAN APOSTOLAKIS: But when is it

irreversible

MR. TJADER: Well, essentially --

DR. KRESS: In hot standby.

MR. TJADER: Yeah, hot standby.

CHAIRMAN APOSTOLAKIS: You mean within six hours I can stop it?

PARTICIPANTS: Yes.

CHAIRMAN APOSTOLAKIS: So essentially they have 78 hours.

MR. TJADER: Yes, in effect.

MR. HEAD: We envision precalculating many of these other situations we can be in so that the answer is readily available --

CHAIRMAN APOSTOLAKIS: Microphone please.

MS. WESTON: And your name, please.

MR. HEAD: I'm sorry. Yeah, Scott Hayes, South Texas.

We envision precalculating many of these situations that we think we could be in and the answers would be readily available in the control room within a short period of time. If there is some exotic configuration we've never seen before, then we would muster the staff to make that calculation.

Then that would have been precalculated, and we would learn from that and calculate them again.

So that's pretty much --

CHAIRMAN APOSTOLAKIS: Well, that was the question I had. A lot of these have been precalculated, right?

DR. BONACA: Just for the record, it's not 78 hours. It's 72 hours. I mean, my experience was you wrote in an actual statement it was 72 hours, you would certainly make sure that if six hours before the 72 hours is over you had not fixed the plant, you just go down.

CHAIRMAN APOSTOLAKIS: So you start six hours earlier.

DR. BONACA: Yeah, sure enough.

CHAIRMAN APOSTOLAKIS: So it's not 78 hours.

DR. BONACA: You want to be within the tech spec because that's the way we run it.

CHAIRMAN APOSTOLAKIS: Okay.

MR. BECKNER: This is Bill Becker.

The tech spec requirement is to reach hot steam shutdown within six hours in a controlled manner. Many licenses if they believe that they can have a high probability of fixing things and if they can't fix it can shut down in a controlled and safe manner will make use of a portion of that six hours.

Again, the key that the staff looks to is, number one, what the requirement is and can they meet that requirement in a controlled and safe manner?

And, again, I think Scott was back there. I think he would agree with that. In fact, I think I've dealt with South Texas where we've discussed the likelihood that certain equipment would be safely fixed within the AOT plus some portion of that six hours.

CHAIRMAN APOSTOLAKIS: Okay. Have we seen enough of this?

MR. TJADER: I think so. Do you think so?

Now, how do I get this one going again?

MS. WESTON: Fold it on down, Bob.

MR. TJADER: Okay. Just some thoughts on this management Initiative 4(b) and PRA quality. Initiative 4(b) relies on a pool and a process that will provide configuration specific PRA results in a timely manner to determine completion times, and this is a significant change in technical specifications from the inflexible current completion times and tech specs to flexible risk informed completion times.

The PRA model and the configuration risk management process, both must be of high quality, and the risk management tech spec Initiative 4(b) will be

a tech spec significant change, not only two tech specs, but the way we have review and have oversight over technical specifications.

CHAIRMAN APOSTOLAKIS: Is that a definition of a high quality PRA anywhere? The ASME standard talks about three categories. I believe, the NEI review has grades. So what is a high quality PRA

MR. TJADER: Oh, high quality in accordance with the Reg. Guide 1.200 has three elements. There's scope. Let's see. I'll get a slide, slide 8 here. There it is.

And Reg. Guide 1.200, this is the Reg. Guide 1.200 definition of the scope, level of detail, acceptability. The scope doesn't cover --

CHAIRMAN APOSTOLAKIS: Yeah, let me understand that. If I pick any PRA, it certainly has a scope. It certainly goes down to some level of detail.

MR. TJADER: It has to be adequate for the application.

CHAIRMAN APOSTOLAKIS: And who determines that? You do.

MR. TJADER: We do collectively.

CHAIRMAN APOSTOLAKIS: And you have guidance how to do that?

MR. TJADER: Reg. Guide 1.200 would provide guidance.

MR. BOYCE: Well, I think most accurately stated for this application we're developing --

CHAIRMAN APOSTOLAKIS: You're developing it.

MR. BOYCE: Yeah, and Bob hasn't made it to that part of his presentation, but it's essentially the current Reg. Guide 1.200, plus we think in terms of scope it needs to include external events, low power and shutdown and internal events, and transition risk, mode transition risk.

But we haven't reached final agreement on that, and that's our initial thought because of the heavy reliance on the PRA in a real time situation, we think you do need that full scope or you might be missing something until proven otherwise.

And we haven't made it to the point where we have been able to do I'll call it scoping analyses that would prove that we could live without those elements.

MR. TJADER: Yeah, plus Reg. Guide 200 currently addresses full power internal events excluding fire and it will progress and achieve further capabilities as time goes on as you're

probably well aware.

And so with regard to Initiative 4(b) we've got to do a Reg. Guide 1.200 review and plus the other application, and it will be a specific review in addition to the Reg. Guide 1.200

CHAIRMAN APOSTOLAKIS: Now, you will be reviewing the PRA, right? The PRA as it is in several volumes.

MR. TJADER: Yes.

CHAIRMAN APOSTOLAKIS: Does South Texas or the plant, any plant have this moniker?

MR. HEAD: At South Texas, yes, we do.

CHAIRMAN APOSTOLAKIS: Now, my understanding is that in order to put the PRA into a risk monitor, you have to change certain things, like do you go to a huge default tree instead of having the event trees and all of that?

MR. HEAD: We don't do that approach. The approach we have is we have basically a graphical user interface for control room operators in a software program, which is software QA, and behind that --

MR. TJADER: Well, behind that is a database of configurations, and we've precalculated over 14,000 individual configurations of the statio.

So when the operator goes in and uses his mouse to click this is out of service, this is out of service, this is out of service, the program merely goes to the database, finds that configuration and returns him a result, and that's backed up by a fully quantified PRA model, not an aggravated other type of model there. The full PRA level --

CHAIRMAN APOSTOLAKIS: Now, is the staff going to review those predetermined states?

MR. TJADER: Not all of them, but we are definitely going to review some of them, and we have to inform them which ones that we -- that's one of the things that we have to do that you'll see in the responses to the questions that we need to see the PRA basis for many of these.

CHAIRMAN APOSTOLAKIS: Shouldn't you do it randomly?

MR. REINHART: I think a lot of the review has to be determined. Currently we're considering having the licensee submit information, whether it's the whole PRA, or whatever we determine appropriate, to the staff. We would do some at headquarters review, and then we would do some on-site review.

I think one of the questions we would ask Mr. Grantom is if he has these 14,000 presolved pieces

and he updates his PRA, I mean, obviously, I think he's going to come back and tell us he's going to upgrade his 14,000 presolved.

So we have to work some of that out, and I think that there's going to have to be a sampling. I mean, probably it's not going to be a line by line.

CHAIRMAN APOSTOLAKIS: Yeah, but some random sampling of these 14,000 configurations you should review without advanced notice.

MR. BOYCE: Mike Tschiltz.

MR. TSCHILTZ: Yeah, my name is Mike Tschiltz. I'm the PRA branch chief at NRR.

And I think you're honing in on an area where we know we have a lot of work to do and we haven't done a lot yet. I think we need to work closely with the industry, I think, for the industry to develop guidance of how these risk management programs that are used at the different sites, and there are like five different types of programs, accurately reflect the PRA so that we have confidence when they use this tool that they're coming up with the right answer.

CHAIRMAN APOSTOLAKIS: Right.

MR. TSCHILTZ: Now, is that going to involve us going and doing a review of each one of

these? I hope not because that would be an extremely lengthy review and a lot of resources.

I think what we hope to do is to develop some type of guidance that the industry develops and we endorse that would give us confidence that if people follow those guidelines that the PRA is accurately reflective in the model and then we can go and do spot checks of that to verify that it is actually occurring that way.

CHAIRMAN APOSTOLAKIS: Yes. I think a random sample of these 14,000 after you develop this guidance, predetermined states, would be a good idea to gain confidence, raise your confidence and the licensee's confidence. They get an independent review. You never know what you're going to find.

MR. REINHART: I think while South Texas is proposing the presolved, I'm not 100 percent sure that every licensee -- we're only talking about two right now -- is going to propose that approach. So we kind of have to look at these different approaches and say can we go two different ways or do we all have to go a similar way.

And like Mike said, a lot of this is still on the drawing board and we're needing to --

CHAIRMAN APOSTOLAKIS: But my point is if

they propose to have a number of predetermined, precalculated plant configurations, then it would be to everyone's benefit for you guys to independently review some of them.

MR. REINHART: That certainly makes sense to me.

CHAIRMAN APOSTOLAKIS: If they have 14,000, you review 13,000, for example, and you're safe.

DR. KRESS: Yeah, not all plants use that kind of risk monitor, and I'm wondering what they're going to do. Some of them do what you said. That has to be given treatment in some other way.

CHAIRMAN APOSTOLAKIS: Because I do believe that some of the risk monitors rearrange the logic of the plant.

MR. REINHART: And we have to look at that.

CHAIRMAN APOSTOLAKIS: They go to a huge fault (phonetic) essentially. So I don't know what happens there.

MR. REINHART: We will have to understand the process, whether we can approve the process through some sampling and understand what that licensee is doing and then go and verify.

CHAIRMAN APOSTOLAKIS: So this is a good thing to remind the committee that one of these days we should have a subcommittee meeting--

DR. KRESS: On risk monitors, yes, sir.

CHAIRMAN APOSTOLAKIS: -- on risk monitors. We have avoided that.

DR. KRESS: Yeah, we were going to go out to Walnut Creek, I think.

CHAIRMAN APOSTOLAKIS: We never did, but this is very important to understand because the logic is manipulated.

Jack?

DR. SIEBER: Yeah, well, I guess the question that comes to my mind is is a risk monitor ever a Reg. Guide 1.200 PRA.

CHAIRMAN APOSTOLAKIS: That's also true.

DR. SIEBER: They are two different things.

CHAIRMAN APOSTOLAKIS: And that's the issue I'm raising, yes.

DR. SIEBER: Yeah. And so whether you have a good PRA or not, if you're using a risk monitor, that's what has to be audited.

MR. REINHART: Yes.

DR. SIEBER: And they are basically

simplified PRAs.

MR. BOYCE: And just to complicate that a little bit more, the PRA has to be translated into software that can be used for the monitor. So you have got software QA issues in addition to PRA QA issues thrown into that mix, and Bob at least has a bullet on that later. So we do recognize that problem.

DR. BONACA: I have a question regarding quality. When we ask the question about the quality of the PRA, I mean, you to a description of a full power PRA with enhancements, including low power and shutdown maybe and external events, and that's quite a significant level of quality, in my judgment, I mean, insofar as a list is cooked, it should address it.

When we talked about the risk evaluations to support multiple components of a service, not in tech specs necessarily; some of them maybe; one of the positions was of the industry, actually the ASME, was that you could use the lowest level of quality of the three levels. The lowest level would be adequate support, taking components of the service and doing the kind of evaluation.

Are you expecting something different for

the two evaluations?

MR. REINHART: I think that the quality of the PRA we are looking for has to be a high level, not just adequate, and it is going to apply throughout this process.

Once a licensee has the ability to use this system to generate their AOTs, they're looking at the configuration, tech spec, non-tech spec, and I cannot imagine having a certain quality for this piece of equipment versus a certain quality for that piece of equipment.

DR. BONACA: Yeah, but you could still not take advantage of the tech specs, risk informed tech specs, and still do on-line maintenance of certain components as long as they're not in tech specs.

MR. REINHART: Of course.

DR. BONACA: And for that you would expect a lower quality PRA.

MR. REINHART: Of course.

DR. KRESS: Let me ask you.

MR. REINHART: Well, I guess --

DR. BONACA: Let me just --

MR. REINHART: -- if a licensee had a high quality PRA I would be surprised if they had a separate one.

DR. BONACA: Of course. That goes.

MR. TJADER: And what we envision as being ideal for implementation of Initiative 4(b), most of the plant may not be there. In fact, none of them may be because we would like to see shutdown and transition risks included, but if they bound the analysis for that process, then you know, that can be considered.

I'm trying to make a point here and it just left my mind.

DR. KRESS: That happens a lot.

MR. REINHART: I think you were moving to the next slide.

DR. BONACA: When we review that area, we did not make a distinction on whether or not a component was in tech specs or not. We did not make a distinction, and yet the issue was if you take multiple components of the service, since you have now a new configuration, you have a new power plant.

MR. REINHART: You do.

DR. BONACA: You do have to perform an evaluation.

MR. REINHART: They have to re-perform the risk assessment.

DR. BONACA: And the statement was you

don't need to have a high quality for that kind of activity. All you need to have -- what is the category?

DR. KRESS: One.

DR. BONACA: One.

MR. REINHART: I guess I'm not --

DR. BONACA: However, now for this, of course, you're saying I'm interpreting this as a Category 2 or 3.

MR. TJADER: Oh, I know what my point was.

DR. BONACA: -- can't understand.

MR. TJADER: Fort Calhoun Station CE and Fort Calhoun Station R pilot, a single system pilot. Okay?

DR. BONACA: Okay.

MR. TJADER: And I think perhaps a single system pilot will work through some of these capabilities that we may allow for non-whole plant pilots. In other words, you know, applying it just to a select few systems, and perhaps it doesn't need the scope that a full plant one would require.

So the Fort Calhoun Station pilot may address the CE. The single system pilot may address --

DR. BONACA: So you're telling me that the

issue of quality really is still somewhat --

MR. TJADER: A lot of it has to be determined and worked out, but we are going in with a preconceived notion and inclination that that takes a very high quality.

MR. REINHART: I think you are all bringing up questions that have to be looked at and determined, but one of the things at least in my mind is we don't want to go in with the minimum we can do today and hope for better tomorrow if we're going to allow a licensee to go this distance with their plant configuration.

We'd like to see an honest effort for a good quality PRA, and we'll move from there.

CHAIRMAN APOSTOLAKIS: I have a question for South Texas. Why did you choose not to have a monitor and you prefer to have 14,000 pre-calculated states?

MR. HEAD: Well, it's basically for the very reasons you brought up. I didn't want to have to answer questions about what was in and what was not in the model, and I also wanted to have an instantaneous response to the operators. And that was really the primary drivers.

CHAIRMAN APOSTOLAKIS: The monitor is

supposed to do that.

MR. HEAD: Well, there's some calculation time that is involved in there.

The other part of it is though that when we pulled the thread on the configuration of the calculation, I wanted to be able to pull that thread back to a calc., a full Level 1 PRA calculation with external events, and I felt that that was the best way to provide a quality level that would be outside of the operators.

I didn't have to rely on an operator knowing anything about a PRA. All he had to know about is what's in service and what's out of service, what's operable and inoperable, and it kept them in, in a sense, the same world that they're used to being in.

All of the PRA stuff is done separate from them, and we would stand by that separately, and we could stand by that because it's a full level 1 PRA calculation that is archived that that person accessed.

And in a sense, the new plant, the new configuration was analyzed.

CHAIRMAN APOSTOLAKIS: And how much effort did it take to develop those 14,000 calc. states?

MR. HEAD: Well, the big effort primarily for us, and we're the risk man shop and we have the large event tree and I guess now we can say we have the large fault tree and the extremely large event trees, and we have what we call a maintenance pre-tree that we developed, and we basically built a maintenance pre-tree that gave us a system of, for lack of better terms, toggle switches to be able to turn trains of systems on and off and propagate it throughout the entire model.

And we also developed a way to run these things in batches so --

CHAIRMAN APOSTOLAKIS: How extensive was this effort?

MR. HEAD: It was a pretty extensive effort to develop the PME pre-tree. Bill Stillwell here could actually give you all of the painful blood, sweat, and tears associated with that, and there's a microphone there, and you know, Bill is the primary developer of that.

MR. STILLWELL: Bill Stillwell, supervisor of PRA at South Texas Project.

The effort was probably four man-years or four years with three or four people working on it with contract time at times. The model is fairly

detailed.

Those of you --

CHAIRMAN APOSTOLAKIS: Well, this is effort after you had the PRA, right?

MR. STILLWELL: After we had the PRA.

CHAIRMAN APOSTOLAKIS: Okay.

MR. HEAD: This is to build the PME pre-tree to do this application.

MR. HEAD: So we took the PRA, modified it to support on-line applications. Those of you that are familiar with South Texas or with risk man. plants realized we use top of instance split fractions. A split fraction is a system under a boundary condition.

So if you imagine a three train system like a diesel generator, we would have something like 25 different split fractions for that system, combinations of diesels up and down fail because of support system or out of service for maintenance.

Carry that through for all of the systems in the plant, and we have on the order of 2,200 different split fractions that are used in the model.

The model is defined so that any one of those split fractions can be out of service for maintenance. So we basically toggle it off. The model quantifies. Come back and toggle another one

off, and the model requantifies.

DR. BONACA: Well, therefore, this is to re-update all of these configurations once you --

MR. STILLWELL: When we roll out a new model, it is about three weeks worth of continuous batch runs to repopulate the database. At the same time we're doing spot checks to make sure that the changes that we thought we made make sense when get the maintenance configurations requantified.

DR. BONACA: Yeah, the wonderful thing about this is that, you know, this population is verifiable. I mean, you can go in and you can check it. I mean if you do have on-line monitor, and now, I mean, on-line monitors have very large, full PRAs behind it, and they're fast, too, but you don't have pre-calculated results. So you have to verify and validate.

CHAIRMAN APOSTOLAKIS: Thank you, Bill.

I think we are running behind. So you have already shown us your conclusions.

MR. TJADER: I think they've given half of the presentation already.

CHAIRMAN APOSTOLAKIS: What?

MR. HEAD: You've given half of ours.

MR. TJADER: I'm almost done.

DR. KRESS: I have one more question about a scope. I've been envisioning you running along at power and you want to take something out of service for a certain amount of time and you're going to do a PRA calculation, change in risk or the amount of time you can get.

Where does shutdown and low power enter into that picture?

MR. TJADER: It wouldn't for preplanned maintenance. You would assume -- for preplanned maintenance you'd do the risk assessment in advance of taking the equipment out of service to confirm that you have adequate time to perform that maintenance, and it would only be due to an emergent condition that would you be confronted as to whether or not you would come up against a deadline, a completion time that expires and make that determination of whether or not you should shut down.

DR. KRESS: All right. Now, if you have made a determination that you should shut down, where does the shutdown risk enter into the calculation then?

MR. REINHART: Well, it could come in a couple ways, and again, it would depend on the ultimate approach we take, but one approach is to

compare continuing at power versus doing something at shutdown.

DR. KRESS: Or you may end up saying better to continue at power for that given configuration.

MR. REINHART: Exactly. And another piece, thinking a little in the future, if we have to evaluate like our outages, I mean, collectively, to what level do we have to do that and where does this PRA support that?

CHAIRMAN APOSTOLAKIS: Is STP the only pilot?

MR. TJADER: No. Right now we have two. Well, let's talk about the pilots right now.

CHAIRMAN APOSTOLAKIS: Yes.

MR. TJADER: Okay. There are pilots for PRA quality and pilots for Initiative 4(b). Initiative 4(b) and PRA quality are underpinning for Initiative 4(b).

CHAIRMAN APOSTOLAKIS: Right.

MR. TJADER: Reg. Guide 1.200 pilot plants are San Onofre, Columbia Generating Station, South Texas Pilot and Limerick.

Now, South Texas Pilot is the Initiative 4(b) pilot being tested under Reg. Guide 1.200, and

Fort Calhoun Station is another Initiative 4(b) single system pilot for that.

CHAIRMAN APOSTOLAKIS: So Forth Calhoun will be the second one.

MR. REINHART: Correct.

MR. TJADER: For Initiative 4(b).

CHAIRMAN APOSTOLAKIS: For 4(b).

MS. WESTON: Only for a single system though.

MR. TJADER: And then reg. guide --

CHAIRMAN APOSTOLAKIS: But the point is I can't imagine that anyone else is a PRA with the sophistication of South Texas. So maybe you need more than one additional pilot because --

MR. REINHART: We would very much like to have --

CHAIRMAN APOSTOLAKIS: If I drive a Rolls Royce, I can't extrapolate and say that all cars drive like a Rolls Royce.

MR. TJADER: That's the next slide.

CHAIRMAN APOSTOLAKIS: Excuse me for calling you a Rolls Royce.

MR. REINHART: We agree with you, George. We agree with you.

MR. TJADER: We agree, and that's the next

slide. We would like additional pilots. We would like to see a --

CHAIRMAN APOSTOLAKIS: So right now it's Fort Calhoun.

MR. TJADER: Yes. We would like to see a standard tech spec plan pilot. We also have another plant that has volunteered, but we have yet to see a proposal. Whether that would be acceptable or not we don't know, but Hope Creek has potentially volunteered. They've done that in the past. We need to see --

CHAIRMAN APOSTOLAKIS: So anyhow, this will help you.

MR. TJADER: So we would like to see additional pilots.

MR. BOYCE: We might want to get through the slides and then maybe we can get ahead of these guys on some of the questions.

MR. REINHART: Could I just say one thing here? I think if a licensee doesn't have the high quality PRA that we're looking for, they're not going to play in this game.

MR. TJADER: For follow-on plants, it may be a long-term goal.

CHAIRMAN APOSTOLAKIS: I don't know, guys.

I've done this so many times, and then others are allowed to participate, too, because this is risk informed. It doesn't really matter how good your risk information is.

So I'm --

MR. TJADER: I appreciate that. I do, I do.

CHAIRMAN APOSTOLAKIS: You know, we go through an extensive review, and then we say, "Well, what's risk informed, you know?"

They mention CDF someplace. So that's risk information. Well, let's go on.

Okay. Please. Continue and finish it. Finish it and continue.

MR. TJADER: Okay. Actually just a point of interest. Four of the five pilot applications for Reg. Guide 1.200 are tech spec related.

CHAIRMAN APOSTOLAKIS: And that will be reviewed to the same degree as you would review --

MR. TJADER: To the degree of the application. These other pilots, San Onofre, Columbia Generating Station and Limerick are not Initiative 4(b). SONGS, San Onofre is a diesel outage AOT extension for a specific circumstance.

MR. BOYCE: They're Level 1, full power.

CHAIRMAN APOSTOLAKIS: They would not be the 4(b).

MR. BOYCE: Correct. They're just Level 1, full power.

MR. TJADER: -- Calhoun that are Initiative 4(b). South Texas right now is a dual pilot for 1.200.

CHAIRMAN APOSTOLAKIS: Okay.

MR. TJADER: That's what this is attempting to say. Maybe it isn't as clear as it ought to be.

MR. TSCHILTZ: Let me just offer a clarification on that because the Reg. Guide 1.200 pilot may finish before the 4(b) pilot for South Texas and Fort Calhoun. I don't see them being as inextricably linked because what we're trying to get out of the 1.200 pilot is what that compliance with that reg. guide actually means, and is there anything that needs to be changed in it before it's characterized other than trial use, before it's finally issued.

So that's what we're trying to get out of the pilot. We're not looking for an extended pilot. We're trying to do this in a year or maybe a little bit more than a year for some of the initiatives like

the South Texas and the Surry and the others, the fifth pilot with the 5069 for two systems.

But so I just wanted to make the point they're not -- like we may finish the pilot for 1.200 while the other 4(b) pilot continues.

MR. TJADER: Exactly. Actually Reg. Guide 1.200 pilot has to finish before that, and plus we know now that in all probability Reg. Guide 1.200 pilot will not be adequate to firm quality for -- the necessary level of quality.

CHAIRMAN APOSTOLAKIS: When the time comes to approve 4(b), we will have sufficient information to feel confident.

MR. TJADER: Until we get --

CHAIRMAN APOSTOLAKIS: Okay. Let's move on. Let's move on.

MR. TJADER: We talked about the PRA. The one on -- we talked about some of these.

CHAIRMAN APOSTOLAKIS: Exportability.

MR. TJADER: Exportability, that is the ability to apply the pilot, what we just talked about. South Texas to subsequent plants, we need reliability. Is the information acceptable? Is it appropriate? Is it repeatable? Will similar circumstances give you similar results?

A continuation. You know, it needs to have enforceable, and you must have adequate oversight in talking about the PRA quality.

CHAIRMAN APOSTOLAKIS: Very good.

MR. TJADER: Potential implementation structure. On the STAIC (phonetic), our perceived structure of things is that the program requirements of Initiative 4(b) will be stipulated in the administrative control section of the tech specs. It will call out the PRA quality requirements, Reg. Guide 1.200, for instance, and the appropriate guidance document, for instance, Reg. Guide 1.177 and enhanced 1.177 if that's it, and the risk management guidance document.

And also, there will be licensee -- yes?

CHAIRMAN APOSTOLAKIS: Can you tell me in a couple of sentences why Regulatory Guide 1.177 is not sufficient and we have to do this? It's not clear. One, one, seven, seven --

MR. TJADER: One, one, seven, seven, I think, takes a single AOT and a static type of environment.

CHAIRMAN APOSTOLAKIS: Does it say single?

MR. REINHART: If you look at the whole structure, the three tier approach, yes. You're

looking at a single AOT, and like Bob says, to get into a dynamic ongoing situation, we need to put guidance somewhere. One of the options is 177 and appendix. It might be a different reg. guide, but we need to put some sort of regulatory guidance to endorse whatever standards, guidelines and approach that the community collectively develops.

CHAIRMAN APOSTOLAKIS: I didn't realize that 1.177 was for a single thing. That's how you stop here, too.

PARTICIPANT: So what's Fort Calhoun? South Texas was multiple.

MR. TJADER: Well, what he's asking though is 177 as a licensee makes a request to extend an OAT, say, and generally they've done it on one AOT.

CHAIRMAN APOSTOLAKIS: And that's a permanent change.

MR. TJADER: Yes, and it's a front stop.

CHAIRMAN APOSTOLAKIS: Here these are temporary.

MR. HEAD: Well, flexible.

MR. TJADER: Basically 177 changes the current completion time, the front stop completion time, and it says that --

CHAIRMAN APOSTOLAKIS: Oh, so a licensee

then can use 1.177 to change the front stop. That's a permanent change.

MR. TJADER: Right.

CHAIRMAN APOSTOLAKIS: Using this new initiative now they can go beyond, and given a particular configuration that can actually extend even that.

MR. REINHART: Correct.

MR. BOYCE: Yes. In the real time without prior NRC approval.

CHAIRMAN APOSTOLAKIS: With here though the South Texas experience has been that in the cases where you have extended the AOTs, you have never actually reached it. You always complete restoration well before. Is that true?

MR. HEAD: In general, yes, that's true.

CHAIRMAN APOSTOLAKIS: Why do you need the 4(b)?

MR. HEAD: Well, actually, we have had some enforcement discretions that needed to extent the front stop, for example, essential cooling water for a couple of years ago, that if this had been approved at that point in time, our risk analysis would have said we could have taken that additional time without applying for enforcement discretion.

CHAIRMAN APOSTOLAKIS: I see.

MR. HEAD: And there was probably at least two of those situations I can think of off the top of my head.

And so now we have encountered situations like that.

CHAIRMAN APOSTOLAKIS: So the whole idea of 4(b) is to give you extra flexibility

MR. TJADER: Correct.

MR. REINHART: Yes. It may be well to go back and --

MR. HEAD: That's not the whole point.

MR. REINHART: That's not the whole point.

MR. HEAD: Part of it is the improved safety. Part of it is by looking at configurations and looking at the integrated impacts on risk of the establishment.

MR. TJADER: It's the risk intelligent thing to do, and shutting down isn't always the risk intelligent thing to do, and it's to provide you the appropriate complete time to restore systems to operability, you know, taking in mind the overall configuration of the plant, the dynamic manner.

MR. REINHART: It may be well to go back to the question that Tom Kress asked earlier, the

other side of the coin, and I think this is still up in the air as to what to do before you get to the front stop.

And a question comes up. As originally envisioned would be if a licensee had a configuration that didn't allow getting to the front stop, they would take action before they got to the front stop, and there's some discussion that has to go on, whether it's through the maintenance rule evaluation or whether this evaluation, whether it's the same evaluation. At some point there has to be a determination of what happens in front of that front stop.

CHAIRMAN APOSTOLAKIS: Okay.

MR. BECKNER: This is Bill Beckner.

George, you have a good question. It really is. If a licensee were to make full use of 1.177 and risk inform every AOT, you might ask what's the incentive then to develop this extensive program, and we've looked at that dichotomy, and so, yes, that's a valid question.

MS. WESTON: Well, Bill, it allows them to cherry pick if they use 1.177 as opposed to needing a quality PRA for the 4(b) initiative.

MR. BECKNER: That's the difference.

Again, the real difference is 1.177 is a prescriptive requirement where we have preapproved limits versus 4(b) is a risk based requirement where we preapprove and review the criteria that the licensee is going to use for those limits, and that's the major difference, and therefore, 4(b) is much harder. It should be harder.

CHAIRMAN APOSTOLAKIS: Yeah, because in 1.177 I can focus (a) on diesels.

MR. BECKNER: Yes.

CHAIRMAN APOSTOLAKIS: And then I have to make sure that the box of the PRA that involved diesels are of sufficient quality to justify the change.

Now you are asking for a much broader authority. So your whole PRA now comes into scrutiny. So it's only a tradeoff.

Okay. You have shown us your conclusions already.

MR. TJADER: Right.

CHAIRMAN APOSTOLAKIS: Very good. This was very innovative, by the way to start with the closing comments.

DR. BONACA: I have just a question I could ask. Are you looking at some of the let me use

the word "synergies" between this effort and Option 2? Are you looking at all of that?

For example, you may have a train with three systems and you decide that each one of the systems or train is individually not risk significant because you have three of those, but now you may end up with one for a month. Okay? Because tech specs may allow you to do that.

I haven't reflected enough about that, but I'm saying there are two things coming together.

CHAIRMAN APOSTOLAKIS: The risk importance measures maybe different now.

DR. BONACA: Well, no, I'm just wondering.

MR. TJADER: I mean, South Texas can address this. they have the annual risk metrics to evaluate the cumulative risk over a year, and in fact, it was to the extent as I understand it that it affects their bonuses and things like that. So the incentive is to be in the risk intelligent mode and configuration that --

DR. BONACA: Yes. I guess my question is more like, you know, would now the fact that you go to this type of tech spec influence the way that you would look at -- you know, in your evaluation of risk significant system.

MR. REINHART: I think the answer is yes and no, and the no part is 4(b) is really looking at tech specs per se and how you operate the configuration of the plant.

But the yes part is given the configuration based on the high quality integrated PRA, when they come to look at their importance measures, they're going to get the benefit of that PRA to give them the importance measures.

DR. BONACA: No, I understand that. I'm only wondering if when they do, in fact, the Option 2, that would make a difference, would it not?

MR. HEAD: No, because we're still doing the business. Our maintenance programs are still the same. I mean what we're actually able to see now is a reflection in terms of risk of the impact of our maintenance philosophies and approaches here, and so far I haven't seen any type of a change along that line.

It does provide a focus on the risk significant components and combinations of those things that can have synergisms in terms of risk, and we have lessons learned.

DR. BONACA: -- the question is that when you do the evaluation, okay, the likelihood that you

have two trains down on a system or three, and you're left with only one because it happens, okay, because something fails is very low.

So I can understand how you say, okay, each individual train is not risk significant. Okay? But when you intentionally take them out and then for the remaining system you say that you are going to run for a month, I wonder if that made a difference in your mind maybe for perspectives of a deterministic evaluation like defense in depth rather than just risk per se.

DR. KRESS: I'm glad you brought this up because you put your finger on the problem I've had with shutdown risk assessments all along, and that's this. There are two types of shutdown risk. There's this thing when you know what configuration you're in. You want to know what the instantaneous risk is and how long it can stay there and how to manage it during shutdown and during maintenance at power. That's one thing.

Then you want to know what are your risk significant components that you might want to have importance measures for. That requires a PRA that's extrapolated through the whole life of the plant through shutdowns that may exist many times with many

different configurations.

CHAIRMAN APOSTOLAKIS: Fourteen thousand.

DR. KRESS: Many things out of service, and how to make an importance measure calculation with a shutdown risk there, I don't think anybody knows how to do that. It just cannot -- you can bound it possibly by looking at the worst possible conditions, but then you've got a real problem because that bound is too big.

But that's my whole problem with shutdown risk, and somebody needs to work on that, how to do a real shutdown risk that's extrapolated and made throughout the full life of the plant.

CHAIRMAN APOSTOLAKIS: It would be nice to see from South Texas since they have 14,000 different configurations --

DR. KRESS: We might want to look at that.

CHAIRMAN APOSTOLAKIS: -- look at some of the worst of those and calculate the importance measures.

MR. HEAD: Yes, that's been an ongoing and I won't call it a dream, but a project if I can ever get some time to do that, is to go see the configuration specific variation in importance measures for that.

I do have a supporting slide that we can show you where we can show you some stuff along that line, but --

CHAIRMAN APOSTOLAKIS: One last question. We have a utility that takes regulatory Guide 1.177 and applies it to all of its risk significant components. How likely would it be for that utility to invoke 4(b) if it is approved?

They have extended the front stops to a maximum. Will they ever need the Initiative 4(b)?

MR. REINHART: That's a good question. If they went through all of that work, they're going to be looking at them one at a time.

CHAIRMAN APOSTOLAKIS: But they still get approvals.

MR. REINHART: They still do it. Okay. That's their option.

CHAIRMAN APOSTOLAKIS: But do you think they will ever need 4(b)?

MR. TJADER: Well, there are always circumstances where equipment is inoperable and it's difficult to restore to operable status, and it will probably happen invariably, but it will happen that it will come up to that front stop.

Now, the margin, I mean, the risk informed

completion time, configuration based risk informed completion time, wouldn't vary depending upon, you know, if the front stop varies, but I don't think that that determines --

CHAIRMAN APOSTOLAKIS: No, no. If it is difficult to restore something, that will be taken into account in the application for 1.177. So it will already have been extended appropriately.

They are not doing anything new, in other words, with 4(b).

MR. REINHART: Well, the thing they're doing with 4(b) is looking at multiple configurations, and I think if I would coin what Rick said, if he's looking at overall plant safety in an integrated fashion, he wants to know what multiple configurations are.

CHAIRMAN APOSTOLAKIS: Wait a minute, wait a minute.

MR. REINHART: And --

CHAIRMAN APOSTOLAKIS: That's what I'm missing something. If this component is down, you know, I'm following 1.177 now. I'm calculating the incremental conditional --

MR. REINHART: Core damage probability.

CHAIRMAN APOSTOLAKIS: Yeah. That

calculation takes into account all other components and systems.

MR. REINHART: No.

MR. TJADER: It assumes they're all in service.

MR. REINHART: It assumes they're all in service and it's looking at them one AOT at a time, one component at a time. It's not looking at the synergism of multiple components being out.

CHAIRMAN APOSTOLAKIS: Well, it does include an availability due to maintenance.

Wait, wait, wait, wait. One by one. Who wants to come to the microphone?

MR. REINHART: Nick Saltos was going to make a comment.

MR. SALTOS: Yes, this is Nick Saltos.

If I can answer that, what Regulatory Guide 1.177 does, considers is an average risk does not consume the configuration risk.

CHAIRMAN APOSTOLAKIS: At the time.

MR. SALTOS: At any time. We use average risks given a certain component is out to extend the completion time. We don't consider at all the configuration risk. What the use of 4(b) is going to do is going to look at the whole integrating fashion,

the risk of the configuration.

The licensees have the option to decrease the completion time, the outage time for some components and take compensatory measures, do other things so that the risk decreases, and the completion for some components can go beyond what they have calculated using average risk.

CHAIRMAN APOSTOLAKIS: Well, okay. The only thing that is positive for the licensees here is that they may take these extra measures because they are not in the standard PRA. If other components are actually down, the situation becomes worse for them because in the actual PRA, there is a probability they're down.

So if they don't take any compensatory measures implementing 4(b) finds them in a worse situation because now this component is actually down, whereas the baseline PRA says there was operability that would be down.

So the thing that really benefits you is the possible compensatory measures.

MR. HEAD: That's true. The compensatory measures help, but also it's taking into account the actual configuration at the time and using a risk threshold to determine what should be the proper

allowed outage time because in many cases these could be very punitive action statements that will force a plant to shut down now because of these conditions, whereas from a risk perspective we clearly could have compensatory measures or clearly have a lower risk significance of the combination that would allow us to continue to operate.

MR. BRADLEY: I just wanted to mention there is also a difference in the risk guidelines, the criteria for ICDP, because we're basing this off of A(4), the maintenance rule, which already does address controlling the risk of the entire plant configuration, and the risk metrics in there provide a little more room than the ICDP of 1.177, which was based on one system in isolation.

Because you're looking at the whole plant, you have to have a little more room in the ICDP threshold there, and we'll get into this a little more when we talk about our -- yes?

CHAIRMAN APOSTOLAKIS: I think saying that you're looking at the four plant in this new case is really not quite accurate. When you are implementing the regulatory guides, you aren't looking at the whole plant. You might say this component is out, but the calculation is the whole problem.

MR. BRADLEY: Well, A(4) requires, is a regulatory requirement right now for all plants to look at the configuration risk of the entire plant whenever they are taking systems out of service, whether they are in tech specs or not. We already have regulations to do that.

All we're trying to do here is put more rigor into that approach and allow that to give you more flexibility in the tech specs.

CHAIRMAN APOSTOLAKIS: But I think as a general statement, if I apply 1.177 and I extend all of my AOTs to the maximum allowed, the chances that I will ever need to invoke 4(b) go down.

MR. BRADLEY: I think so. I agree, George.

CHAIRMAN APOSTOLAKIS: As a general statement.

MR. BRADLEY: I agree, George.

CHAIRMAN APOSTOLAKIS: Because I can complete my --

MR. BRADLEY: I agree.

MR. REINHART: I think to do that, let's say a licensee is going to systematically do that. What's going to happen is they're going to bring up unique questions to the staff every time they're going

to --

CHAIRMAN APOSTOLAKIS: I appreciate that. I appreciate that.

MR. REINHART: It would be a horrendous effort.

CHAIRMAN APOSTOLAKIS: Yes, but --

MR. HEAD: It's not a licensing strategy we had contemplated doing.

CHAIRMAN APOSTOLAKIS: Okay. It may be infeasible to do it that way or it may be very expensive and so on, but in principle that would be the thing.

MR. SALTOS: Yes, this is Nick Saltos again. Actually, I think if they do that, it seems to me the risk will increase because they will have more space that they are going to use in Area 4 instead of 4(b), and 4(b) is supposed to have better PRA and a better process and documentation.

If you extend the front stop for all, they will use the maintenance rule trying to define the situations where the risk is increased to the point that they will have to shut the plant down or take --

MR. HEAD: Yes, Dr. Apostolakis, Nick makes a good point in that sense. If you were to go and extend all of the AOTs out, and you go and

incorporate that into the frequency or in the duration that you could have, you would ultimately start raising the average --

CHAIRMAN APOSTOLAKIS: The baseline risk.

MR. HEAD: Yes, and you may reach a point very quickly that you can't support anymore.

MR. BRADLEY: A(4) will not let you do that. Right now you cannot. If you went in and did that to all of your AOTs, you would get outside the boundary conditions of the A(4) guidance, which requires you to over time maintain your baseline risk within a window.

So there is a regulation right now. That's why we have A(4), for the very reasons that we're discussing here.

MR. BOYCE: And, George, just to add one more fact to your thought on using Reg. Guide 1.177 and the motivation. Right now we are reviewing risk informed amendments, and so while we are working on Initiative 4(b) and trying to work through one or two plants, the rest of the 103 units are, in fact, coming in and getting individual system-by-system extensions.

So if we take long enough on this, they may well have solved the problem for us, as you point out.

That's just a statement of what I'm currently seeing.

DR. KRESS: Now, let me ask you guys one more question. I'm still hung up on the zero start time. Suppose I enter into the tech spec area my wanting to take something out of service. I go along and a configuration changes for some reason, an unexpected change. I get some other things out of configuration.

Now, I've got a new configuration to calculate the risk, and I've entered the tech specs and been in there for some time. Now, if I go back to zero time and calculate the new risk, I may have already exceeded my risk criteria.

MR. BOYCE: I think South Texas in their presentation is going to address that situation.

DR. KRESS: Okay. If you had that situation, you'd shut down immediately or what would you do?

MR. HEAD: No. We have some examples when we get to our presentation that we can go through.

DR. KRESS: Okay.

CHAIRMAN APOSTOLAKIS: I think it's time to take a break.

DR. BONACA: Oh, finally.

CHAIRMAN APOSTOLAKIS: Mr. Chairman, Mr. Chairman. Until five past ten.

(Whereupon, the foregoing matter went off the record at 9:51 a.m. and went back on the record at 10:10 a.m.)

CHAIRMAN APOSTOLAKIS: We are back in session.

The next presentation is by the industry, starting with Mr. Bradley of NEI. Maybe you want to move a little to -- yes, that's right.

MR. BRADLEY: Thank you.

Good morning. I appreciate the presentation by NRC staff on Tech Spec Initiative 4(b). We now have a couple of presentations to discuss: the industry perspective on this initiative, and I'm going to give just sort of a generic overview from the NEI perspective of 4(b) and why we're doing it and talk a little bit about the risk management guidance document that has been developed by EPRI, which is pretty much the linchpin of 4(b) and which would be used by all plants implementing it, and then Rick will talk in more detail. Rick and his compatriots from STP will talk more about one of the pilot applications we have underway.

When I developed this presentation I

didn't know I'd be giving my conclusions first. So these may seem a little out of sequence, but let we just say how I was going to conclude.

This is a challenging risk application. This isn't a lowest common denominator application.

CHAIRMAN APOSTOLAKIS: Maybe you don't know it, but now we have new rules.

MR. BRADLEY: Yeah, that's what I found out.

CHAIRMAN APOSTOLAKIS: The speaker has five minutes, right? And interrupted?

MS. WESTON: Ten. Ten, George.

CHAIRMAN APOSTOLAKIS: I said five.

MR. BRADLEY: You just broke your own rule.

CHAIRMAN APOSTOLAKIS: We will do a calculation as we go to extend the five to ten.

MR. BRADLEY: Does my clock start now?

CHAIRMAN APOSTOLAKIS: Okay, Mr. Bradley.

MR. BRADLEY: T equals zero.

CHAIRMAN APOSTOLAKIS: T equals zero, now.

(Laughter.)

MR. BRADLEY: This is a challenging risk application. This is an application that demands a high technical capability and scope of a PRA, and it

is probably not an application that that every plant will desire to get.

As I go through my presentation, I'll talk about some of the specific challenges we were facing in developing the guidance document.

It is a work in progress. I'm not going to tell you we have all of the solutions to these things worked out yet. We do believe we have got the guidance document to a point where we need to take it out in the field and let the pilot plants use it and get NRC out there to observe how it would be used and in the process of doing that, start determining the level -- I think the real issue on this is the level of detail.

NRC used the term "exportability" in their slides. Basically this is the vehicle for NRC endorsement, and this is what plants would have to do for risk assessment and management to implement 4(b). So the critical question is getting the appropriate level of detail in that document that will enable it to be exportable.

And that has to be done in concert with the pilots. As we have done in some other applications, such as IS, you really need a live in conjunction with development of the document here. So

that said, let me go on to my slides.

The foundation for 4(b). There was a lot of discussion this morning about needing some assessment of the configuration risk assessment for the whole plant versus the Reg. Guide 1.177 approach. Just to remind you that there is a rule that was promulgated in 1999, that's the new Section A(4) of the maintenance rule that is a regulatory requirement to assess and manage the risk of plant maintenance activities.

And NEI developed a guideline that was ultimately endorsed by NRC that provides metrics for risk assessment, approaches for risk assessment of power operation and shutdown, and also risk management techniques that build off the results of that risk assessment.

And our intent with 4(b) is to take that existing document for A(4) and provide additional detail and rigor as necessary to support this approach.

Because A(4) was implemented several years ago, we basically now have two regulatory requirements on configuration control of the plant. We have tech specs, which is purely based off your deterministic licensing basis, and then you have A(4), which is a

risk basis.

And you can't have conflicts between these, and you will basically have a dual regulation set-up and it can be made more optimal. And that's really what we're trying to do with 4(b).

When A(4) was developed, there was some degree of flexibility provided in the guidance for assessment and management. That was with recognition that you had tech specs as a backstop, as a pretty hard backstop that would preclude you being able to take long equipment outages, et cetera.

At the time, however, NRC recognized we were getting in a double regulation situation and acknowledged that now that A(4) was in place, it could provide the foundation for some additional reform of tech specs, which is what we're trying to do with 4(b).

In recognition that we needed to provide some level of understanding for the NRC staff of how 4(b) works, we did provide a workshop back in February 28th of 2001, where we had a number of plants come in and describe how they do configuration risk assessment and management under A(4). We had over 100 NRC staff attend that. It was held at the auditorium here at Two White Flint.

So our overall objective is to better align deterministic tech specs with a risk management approach required by the maintenance rule. One of our goals is to make changes within the existing tech spec framework and practice.

This is a document the operators use directly. We don't want to make radical, drastic changes to tech specs, you know. There has been discussion in the past of having a one page tech spec, that kind of thing. We're not doing that.

We're maintaining the current format and content of tech specs for the purpose of not providing a culture shock for operators and others in the plants that would have to use Initiative 4(b), maintaining the operator safety focus.

Also, this is an application that provides an incentive for improve PRAs and configuration risk assessment tools. As I said, I don't believe all plants will implement this, but certainly for those plants that want to go on up and have a high quality, full scope PRA, this is an incentive to move in that direction.

I don't see initiative 4(b) as enabling large changes in plant capacity factors or having huge economic incentives for the plants. It does provide

the opportunity to avoid certain forced outages that crop up with the existing tech specs. It provides an opportunity to get out of the NOED type situation where you may need enforcement discretion.

CHAIRMAN APOSTOLAKIS: NOD?

MR. BRADLEY: Notice of enforcement discretion. That's when you get outside your tech specs, but you realize it's a risk insignificant condition and you have to go to the staff and get discretionary enforcement. That's how it's currently handled.

It is basically just providing a better decision making tool and a more refined approach to plant configuration decision making.

The NRC has pretty much discussed the overall framework for 4(b). I just mention a couple of things. It would only apply to equipment, LCOs and tech specs. There are other parts of tech specs, such as safety limits, limiting safety system settings, various parameters. You may have fuel limits, time, temperature limits, things of that nature. Those would not apply to 4(b).

Four (b) would only apply to equipment, LCOs because those other things can't really be modeled in a PRA.

There was some discussion of the front stop. The question sometimes comes up why do we maintain the front stop, the existing AOT. One of the reasons is for operator familiarity. The way the plants are run now, there's tremendous recognition of those existing front stops, and we want to maintain that just to enable the better decision making in terms of do you stay within that or do you go to the extended AOT.

As you approach that front stop for the limiting front stop if you're in multiple conditions, you're going to trigger the more extensive risk evaluation and actions required by 4(b).

Even before the front stop, even now, for all plants, whether you implement 4(b) or not, you're still governed by A(4) in advance of any completion time you have in tech specs right now. It's conceivable right now, today, a plant could get in a situation with multiple completion times where they would have to take actions before they hit the limiting tech spec front stop, and that would not change with 4(b).

There's also a deterministic backstop. That's 30 days. Basically that means even if you have a situation where you could leave the equipment out of

service for a long, long time without accruing any real delta risk, you still have to restore that in 30 days. It's really a deterministic backstop. It's to get you back into your licensed plant condition and for your deterministic accident basis.

DR. KRESS: Where did the 30 days come from? Did somebody just pull that down out of the air?

DR. SIEBER: Yeah.

DR. KRESS: It's a structuralistic -- you're right.

MR. BOYCE: In addition to that, I think historically when the original front stops were established for current plant tech specs, it is based on engineering judgment, but there was also a recognition of the time it would actually take to fix some of this equipment,a nd so for this particular backstop 30 days was intended to capture any foreseeable time it would take to actually fix the equipment.

So it's an operational consideration, in addition to engineering judgment. So it's not completely arbitrary.

MR. STILLWELL: Yeah, the current maximum completion time in tech specs right now is 30.

MR. BOYCE: Thirty days, and what you'll find is some of the PRAs would extend well beyond 30 days, and so we had to pick something, and so we used operational considerations to do that.

MR. STILLWELL: It's also remotely related to 5059 because at some point in time if you left something out long enough you could be viewed as changing the plan.

MR. BRADLEY: That's 90 days. That's sort of the same thing. It was sort of an arbitrary criteria, but we picked 90 days where you would have to do a 5095 evaluation for a temporary alteration to support maintenance.

MR. REINHART: This is Mark Reinhart of the Risk Assessment Branch at NRR.

There was a thought. I think it was said that there is a conceivable ability to calculate an AOT that would go beyond 30 days, and we wanted some way that we thought, as Tom brought out, we could probably get most equipment done, but if there was a reason that we needed to go beyond 30 days, at least the staff would have a touchstone, would have to have some interaction between staff and licensee. Either the 30 days would be a shutdown limit or then they would come in and say, "Okay. Here's the extenuating

circumstances."

CHAIRMAN APOSTOLAKIS: So it is not a rigid backstop.

MR. REINHART: Well, it is a rigid backstop. There would be a shut down, but if there was an engagement, just like today in a NOED, I think it would be extremely rare, but if for some reason there was a need to go beyond like, I think, one of the examples Rick will bring up on South Texas, there would be an interaction with the staff. It wouldn't just be a calculation from a tool.

MR. BRADLEY: The actual final bullet, the actual completion times would be based on the risk assessment and management guidance that I'm going to talk about here. And one thing I want to clear up. This is not a de facto 30 day AOT for everything in tech specs, which somehow some people misconstrue this, but that's a backstop, and the actual AOT you calculate is generally going to be well in advance of that based on the specific configuration.

MS. WESTON: Biff, let me ask you. You said the actual completion times would be based on the risk assessment. Does that mean that the AOTs that are in the tech specs now would possibly change based on risk?

MR. BRADLEY: The way this would work structurally is right now you have like a hard seven-day AOT, for instance. That would be replaced. The seven days would be a front stop. That wouldn't change, but you would have the capability to optionally expand that AOT out to as long as 30 days based on the results of your risk assessment.

MR. GRANTOM: We'll go through that in our presentation. We'll actually show you the mechanism in the tech specs that does that.

DR. BONACA: One other thing that all of us learned, we recall a piece of equipment that wasn't an AOT was urgency. I mean, you just did it. And now that you have an amount of time, is there going to be a concept where you can plan it during the month or is there the same level of urgency covering the equipment?

MR. BRADLEY: That's a good question. I think the level of urgency is really a risk management action, you know. You know, do I need to work around the clock? Do I need to bring on extra crews or whatever to restore this?

And that would be a function of the risk significance of the condition. That's a classic risk management action that in our guidance we'll have to

tie that action to certain risk criteria.

DR. BONACA: But in general the indication is not that you would say, "Okay. I have a month. I can leave it down for ten days."

MR. BRADLEY: Right. That would be --

DR. BONACA: And do something else because I had to --

MR. BRADLEY: Right. No, that would not be our intent.

DR. BONACA: You would still have some degree of commitment to restore it as soon as feasible.

MR. BRADLEY: Right, right.

MR. BOYCE: Just to add to that, I mean, we also share that concern on the staff, and we were looking for ways to incentivize licensees to restore the equipment to operation, and, Rick, I thought you were going to talk about your monitoring of cumulative risk over time as one way to do that.

MR. GRANTOM: Right.

MR. BRADLEY: We're going to get to that.

MR. GRANTOM: We are going to get there.

MR. BOYCE: And that monitoring of cumulative risk may end up being part of our program guidelines that we'd ask licensees to sign up for.

MR. BRADLEY: As a matter of fact, there are a few other incentives. One is the other elements of the maintenance rule that require you to have, you know, track and balance, reliability, and unavailability. There are also elements of the plan oversight process that could come into play if you're getting into, you know, mitigating systems and taking long outages.

You're going to impact the ROP.

CHAIRMAN APOSTOLAKIS: Now, just remind me. The maintenance rule, Paragraph A(4), says assess and manage risk.

MR. BRADLEY: Correct.

CHAIRMAN APOSTOLAKIS: It doesn't give any numerical criteria.

MR. BRADLEY: A(4), the rule itself does not. The implementation guidance we developed, Section 11 of 9301, of NUMARK 9301, does provide metrics. They're guidelines. They're not hard criteria on that.

CHAIRMAN APOSTOLAKIS: CDF.

MR. BRADLEY: Right. I'll talk about that in just a minute.

Actually, as was discussed, we have several pilot plants. South Texas, which is

presenting today.

Also, it may not have wormed its way through the bureaucracy of NRC yet, but Hope Creek has actually formally sent a letter to NRC requesting to be a 4(b) pilot. That's a BWR. That's a whole plant pilot. I think that's good because we need both our B and PWR whole plant pilots.

And also Fort Calhoun. That's actually a lead plant for what was originally a CE owners group joint application report. It's a system specific pilot. It's really just implementing 4(b) on a single system. That's the high pressure safety injection system.

The intent of that was really to take advantage of some work SIOG (phonetic) had done that broke the HPCY system down into its subparts and generated AOTs for various injection valves or pumps out of service that were a subset of the overall HPCY AOT, and this is really a vehicle to try to move that into their tech specs.

It's a little different type of 4(b) approach than the South Texas and Hope Creek plants. Unfortunately they couldn't be here today to talk about that. So most of what I talk about today is going to be more relevant to the South Texas and Hope

Creek pilots.

All three of these plants would incorporate and use the EPRI risk management guidance, which I'm going to talk about in just a minute. This will be incorporated through a reference in their tech specs. That would be a hard regulatory requirement that they have to use the guidance that's in the EPRI document.

So EPRI has taken the initiative for the industry to develop this, and as I mentioned, the starting point was our existing A(4) guidance. We have about 25 pages of guidance already that's already used by all plants to implement A(4).

However, we realize that to implement 4(b) and to remove some of the backstop that tech spec currently provides you have to put more rigor in that process. That would be more rigor in the risk analysis, the expectation for more quantitative methods, as well as risk management actions.

Right now the A(4) guidance pretty much just has a laundry list of risk management actions, and there's discretion on which ones you pick for which situations. We anticipate there would be a little more rigor here in terms of tying specific actions to specific risk levels.

Finally, the existing A(4) guidance doesn't really get into plant shutdown decision making, which is what tech specs are all about, what conditions drive you to shut down. So that will have to be enhanced as well in terms of that shutdown is really like the ultimate risk management action, and so we need a little more rigorous process in terms of what specific conditions, risk metrics, or what have you are going to drive you to a plant shutdown.

CHAIRMAN APOSTOLAKIS: Now, in the package we received, there was an EPRI report published in the first half of 2003. Is that the one you're referring to?

MR. BRADLEY: It is, yes, although that's a draft, and you know, we're still working on it, and as you see on my last bullet here, we received a number of NRC questions, and we're in an iterative process with NRC staff right now of responding to RAIs and improving that document. But that is the draft document.

CHAIRMAN APOSTOLAKIS: Okay.

MR. BRADLEY: Finally, the document would need to provide PRA scope and technical capability requirements. There was some discussion this morning of the A(4) and the fact that you could use what was,

quote, low quality PRA to implement A(4).

A(4) was developed in advance. It was developed in the late '90s. It was developed in advance of any PRA standards even existing, and at the time, it was an additional requirement that was layered on top of the deterministic design on that licensing basis.

So there were not a bunch of rigid PRA requirements put in there for practical reasons, and as a matter of fact, A(4) actually allows you to use qualitative methods as well as quantitative methods.

But 4(b) would move you more in the direction of quantification.

PRA and tool (phonetic) requirements we've proposed, and this is a little bit different from what NRC provided this morning; this is one of the areas we'll still have to close the gap on. We do believe you'd need an internal events and LERF at power, basically meeting capability Level 2 for all of the supporting requirements of the ASME standard as endorsed by Reg. Guide 1.200.

In addition, because what tech specs is really about is knowing what your at power risk is and making a determination of when that at power risk needs to be brought down by shutting down, you need to

have an understanding of your whole at power risk picture.

And because we're dealing with a quantitative determination of AOTs, it's pretty difficult to do this with a qualitative method. So you really need to be able to quantify all of the significant risk contributors in the at power condition. So that would include obviously internal events and fire for all plants.

For many plants that would also include seismic and other external events. So we do recognize that this is moving in the direction of a full scope PRA.

We don't believe you necessarily need to have an LPSD or shutdown PRA to implement 4(b). The reason is that tech specs are always driving you from an at power condition to a shutdown condition.

If you have knowledge of your shutdown risk, that's great, but that's really an offset, and if you don't have that and if you assume shutdown risk is zero, that's conservative from the standpoint of tech specs because that's going to make all of your risk deltas that much larger.

So we believe it's conservative to implement this without a low power shutdown PRA.

However, if you have one, it could be used, and it's going to help offset and demonstrate that the risk of shutting down may be some finite level that you can compare to the at power risk.

DR. SIEBER: In fact, it could be as great as or greater than the risk of continuing operation.

MR. BRADLEY: So you have one that's going to give you more flexibility here.

DR. SIEBER: Yeah.

CHAIRMAN APOSTOLAKIS: Is the internal events PRA at power going to include uncertainty analysis?

MR. BRADLEY: Yes. Because Reg. Guide 1.200 has a fairly substantial treatment of uncertainty, it requires that the base PRA, that the key sources of uncertainty be identified, that they be peer reviewed, and that the key assumptions that flow out of those key sources of uncertainty also have to be peer reviewed and addressed.

So the Reg. Guide 1.200 takes the whole issue of uncertainty in the base model up to a much more rigorous level than what we've had in the past. So the answer would be, yes, it would require that.

CHAIRMAN APOSTOLAKIS: Including model uncertainty?

MR. BRADLEY: Yes. The key sources of model uncertainty have to be determined and peer reviewed and addressed. As a matter of fact, we're working through exactly how that will happen right now in the Reg. Guide 1.200 pilot program as was mentioned earlier, we have four or five of those pilots are tech spec applications.

But, yes, it's a pretty substantial treatment, as well as parameter uncertainty.

CHAIRMAN APOSTOLAKIS: In the context of model uncertainty, there were two papers that we handed out last time when we were discussing NEI-00-04. Maybe you must have them then.

MR. BRADLEY: Yeah.

CHAIRMAN APOSTOLAKIS: One had to do with human reliability, and the other had to do with some risk assessments that the former PRG did showing how different assumptions changed the CDF.

So I think it would be a good idea for you to have a look at this.

MR. BRADLEY: Yes. We have those papers from the previous briefing on 00-04.

One thing I would mention is this is a little different from 00-04 in that in 00-04 we're using sensitivity studies to a great extent to deal

with uncertainties, and 4(b), that's really not as feasible. You can't run a whole series of sensitivity studies when you get in a configuration.

So in terms of being able to use sensitivity studies, we're a little more limited here.

CHAIRMAN APOSTOLAKIS: And, in fact, these two are good examples of what we mean by the statement that the PRA should be appropriate to the issue at hand. In a special treatment requirement when we categorize components, SSEs, it's a fairly conservative categorization. So sensitivity analysis probably are good enough.

Here, judging from what I have read in the draft EPRI report, precision or accuracy requirements are much higher because now you say if I'm between ten to the minus five and ten to the minus six, I do this. So I have to have high confidence that these numbers make sense.

MR. BRADLEY: That's correct.

CHAIRMAN APOSTOLAKIS: So I agree with you, and this is actually a very good example.

MR. BRADLEY: In addition to the base PRA, as I mentioned in my first slide on conclusions, there are some challenges in this. One of the challenges is that there are not yet standards or endorsed standards

by NRC for non-internal events. So the plants that are implementing this, the pilot plants will be in what NRC calls Phase 1 of their PRA implementation plan with respect to their fire and external events models. That will require, for instance, Rick, who has fire and seismic initiators built into his model; that will have to be reviewed by NRC directly because they are currently and at the time we'll be doing this they will not be an endorsed standard yet out for that. So that's one of the challenges.

And also you have the tool itself. There was quite a bit of discussion of that this morning. In addition to the base PRA, you have to have the tool that translates your configuration and determines your configuration risk, and there are a number of ways to do that.

We talked about pre-assessment this morning. There are also other, you know, safety monitor and other ways to do this, and I think it would be safe to say not all plants would intend to do this the way South Texas does by preassessing all of the configurations.

They would also like to explore the capability to use the safety monitor type approach to do this as well, and obviously there will be the need

to address the quality of that tool.

Another important factor is the ability to determine and track aggregate risk. Basically the bottom line on this application is at the end of a cycle or at the end of some finite period of time you're not supposed to increase the baseline risk of the plant.

You can't go into taking large unavailabilities on equipment over time and have your baseline CDF or LERF creeping up over time. So you have to have the ability to track where you've been, determine how much risk you've accrued and at the end of some period, say, a cycle, a fuel cycle, you would assess that and make sure you're still within some window with respect to your base CDF and LERF. That's an important aspect of this.

DR. SIEBER: But the fact is it does creep up regardless of what you do. You're just trying to limit the increments, right?

MR. BRADLEY: Well, I'm not sure it would necessarily creep up because plants are already doing on line maintenance. They already are accounting for those unavailabilities in their existing models, and again, our intent with this initiative isn't to enable, you know, a quantum leap in the amount of on-

line maintenance we're doing. I wouldn't expect that to change.

I mean, we're basically, the way our guidance works, we're basically imposing the Reg. Guide 1.174 permanent change guideline. Say, you know, at the end of the cycle you need to make sure you're within some delta, you know, and we'll have to determine what that is, but I wouldn't expect this to cause long term creep upwards of CDF. That's not our intent, and I don't think the NRC would want that either.

DR. SIEBER: I'll have to think about that for a little bit.

CHAIRMAN APOSTOLAKIS: On the issue of the monitor, I think it's time for the ACRS to really look more carefully into what goes into these monitors. So I'd like to have a subcommittee meeting some time soon, but would NEI pick one or two of the licensees who have good monitors to come and educate us?

MR. BRADLEY: Yes, we would, and also John Gaertner from EPRI is in the audience, and I think EPRI has a large program with regard to various types of configuration risk assessment tools. They have forums and tremendous technical knowledge of those. So I would invite EPRI to also participate in this.

CHAIRMAN APOSTOLAKIS: Now, these tools are different from a monitor?

MR. BRADLEY: There are a number of -- John, if you want to speak to it -- there are several different types of tools.

MR. GAERTNER: I'm John Gaertner from EPRI.

Yes, in addition to some that we've developed, tools such as EOS and ORAM Sentinel at EPRI, there are commercially available tools, such as the safety monitor and some independently developed tools.

We have developed, as Biff said, the configuration risk management forum, which is an EPRI program, but we invite all of our participants, which is every U.S. nuclear plant, to participate in this. We have annual meetings, and we have technical activities throughout the year to investigate, improve these methodologies no matter what tool is used, and we address generic issues that the industry has to make these better, and we give them a forum to communicate.

So we're addressing consistency issues. We're addressing the other improvements that we can make. So we're very proud of that, and we'd be

pleased to participate and provide some input to you.

CHAIRMAN APOSTOLAKIS: I think that would be great, but one issue in particular that I would like us to address is what exactly is it that people do. What changes do they make to the PRA as we understand it in order to convert it to a monitor?

And that can be a fairly technical discussion, but I think it's time that we really understood that issue.

MR. GAERTNER: Yes.

CHAIRMAN APOSTOLAKIS: That's why I am proposing that subcommittee meeting, and there we can also have the more general discussion of configuration management and the various tools you mentioned that EPRI has developed.

MR. GAERTNER: Yes, I understand that.

CHAIRMAN APOSTOLAKIS: Would one day be sufficient for this?

MR. GAERTNER: Yes, I believe it would.

CHAIRMAN APOSTOLAKIS: So maybe we can coordinate it with the ACRS staff.

MR. BRADLEY: Yes. Please, we would be happy to do that and just let us know and we'll set that up.

CHAIRMAN APOSTOLAKIS: Right. Would the

staff have anything to say on the monitors? Have you investigated the monitors and so on? Mark?

MR. BOYCE: We're interested from tech specs' standpoint.

MR. REINHART: This is Mark Reinhart for the PRA branch.

We're definitely interested in the risk monitors. I think we have to understand also how the PRA flows into the monitor and flows into the decision making process and the controls that go on to the monitor and the criteria that gets fed into that.

So I think we would definitely be interested in participating.

CHAIRMAN APOSTOLAKIS: No, I understand that some foreign utilities, especially in Taiwan, have also developed the monitors. Does anyone know whether these are drastically different from what we're doing here? Should we hear from them as well?

MR. CHUNG; Mr. Chairman, this is Jim Chung with the PRA branch at NRR.

We joined EPRI's reliability in the risk work station membership two years ago. So we have access to EOS (phonetic). In fact, EPRI came to the NRR many times to do research, and they gave us seminars. In fact, we had a seminar twice last year.

So I can arrange since I'm the program manager for interfacing with EPRI. What I can do is I can arrange with EPRI and present it to you.

On top of that, we are also members of the Safety Monitor Owners Group. So we have access to the safety monitor, too.

CHAIRMAN APOSTOLAKIS: Like San Onofre is advertised as having a good safety monitor.

MR. CHUNG: Yes, sir.

CHAIRMAN APOSTOLAKIS: I would really like to understand.

MR. CHUNG: We can --

CHAIRMAN APOSTOLAKIS: Now, remember this is going to go down to the dirty details, not just --

MR. CHUNG: Absolutely.

CHAIRMAN APOSTOLAKIS: -- here's a great tool.

MR. CHUNG: We will discuss the master fault tree.

CHAIRMAN APOSTOLAKIS: Yes, exactly.

MR. CHUNG: Exactly, and we can discuss that, how to read Grantom's and faults in South Texas project and things like that.

CHAIRMAN APOSTOLAKIS: Coming back to the question of foreign utilities, are you familiar?

MR. CHUNG: The other member of our work station just like we are. They are using the same tool, slight modifications. For example, in Taiwan, they made their own adjustment or little pedigree has been changed.

CHAIRMAN APOSTOLAKIS: So there is no reason to hear from them.

MR. CHUNG: No. We can listen directly to the horse's mouth, EPRI.

DR. BONACA: One document I would like to say. Maybe, Mr. Reinhart, you're aware of that report that Dr. Shepard of PWG put together. That's quite a remarkable report, very recent, and he really has taken all of the international and then the U.S. experience on this monitor. It's pretty sizable. I don't know.

That would be useful to the membership.

MR. REINHART: Yes. I think that whole effort would be good to bring in. In fact, I would kind of like modify the statement that I think the international experience is good and has some views that maybe we could learn from as well as they could learn from us.

CHAIRMAN APOSTOLAKIS: So what do we do?

MR. REINHART: I think that that would be

good.

CHAIRMAN APOSTOLAKIS: Should we invite somebody?

DR. BONACA: Well, the report, I think, has been issued or is in draft, and I think it would be valuable for the members to receive a copy of it.

CHAIRMAN APOSTOLAKIS: A copy of the report, for sure. The question is --

MR. REINHART: Would somebody from that group be valuable to come present.

DR. BONACA: Shepard is very, very --

CHAIRMAN APOSTOLAKIS: Who is he?

DR. BONACA: He's from U.K., and he's the guy who put together the report, and he is extremely knowledgeable.

CHAIRMAN APOSTOLAKIS: Do we pay them when they come?

MR. REINHART: I think we would invite them to come, but I doubt that NRC would pay for them.

CHAIRMAN APOSTOLAKIS: They will come to educate us but on their own expense?

MR. REINHART: I don't know the answer to that. I think probably we --

CHAIRMAN APOSTOLAKIS: Well, let's explore that.

MR. REINHART: -- need to explore that.

CHAIRMAN APOSTOLAKIS: Let's explore that. Well, some of them, you know, are very proud of what they've done. Maybe they would be happy to come anyway.

MR. REINHART: Yes, I think there's a lot of work that's going on, and what Mario Bonaca was --

CHAIRMAN APOSTOLAKIS: I don't want a presentation that will say, "Gee, these are great tools. Look what they do." I want to understand the technical details behind the monitor. Okay?

MR. REINHART: I understand.

CHAIRMAN APOSTOLAKIS: Yeah, and now, a question to the members. Should this be a subcommittee meeting with the full ACRS?

DR. KRESS: I think so.

MS. WESTON: Yes.

DR. SIEBER: Yes.

DR. KRESS: It's one of those things where we need to educate the full committee.

CHAIRMAN APOSTOLAKIS: The full committee needs to be educated, in my view, because you're going to be hearing about monitors a lot in the future.

DR. SIEBER: That's true.

CHAIRMAN APOSTOLAKIS: So maybe we can

schedule it like a Monday and Tuesday before the full committee meeting, Mr. Chairman.

DR. BONACA: We'll have to look at the PMP and just let's bring it up, Mag. Okay?

CHAIRMAN APOSTOLAKIS: No, but I think that would be the most appropriate time if you want the full membership present.

MS. WESTON: We may tack a day on.

CHAIRMAN APOSTOLAKIS: Yeah, two days.

DR. SIEBER: I would comment that I think that there's a lot for us to learn here and to put it into a four-day ACRS committee meeting will limit the amount of time that --

CHAIRMAN APOSTOLAKIS: No, no, no. The full committee will come to the subcommittee meeting.

DR. BONACA: We will just have the subcommittee the day before.

CHAIRMAN APOSTOLAKIS: It's like we do with security.

DR. SIEBER: It's a whole day's work.

CHAIRMAN APOSTOLAKIS: yeah.

MS. WESTON: It will just be a committee of the whole.

CHAIRMAN APOSTOLAKIS: It's a subcommittee meeting, but all of the members are present; the way

we handled 1.174 and now we are handling security issues.

DR. SIEBER: Right.

MR. REINHART: Mr. Chairman.

CHAIRMAN APOSTOLAKIS: Yes, sir.

MR. REINHART: Another thought that might be well to consider. We're sort of throwing out risk monitoring in a broad sense, and like you say, you want to know the details. As I'm getting more into this, I'm sensing there's a significant difference between the EOS approach --

CHAIRMAN APOSTOLAKIS: Yes.

MR. REINHART: -- and what South Texas is doing, and we probably want to understand both of those.

CHAIRMAN APOSTOLAKIS: Absolutely. I want to understand what does it take to take a PRA and develop a monitor like San Onofre's, this master fault tree and all of that. What happens? Do we lose that information? Do we have that information?

MR. BRADLEY: We can definitely support that. Through EPRI I think we have --

CHAIRMAN APOSTOLAKIS: The models and so on.

MR. BRADLEY: Yeah, we can do that.

CHAIRMAN APOSTOLAKIS: I think that would be extremely valuable to us because we keep talking about the PRA, and maybe we don't realize sometimes that the way it is used is through a different venue, so to speak.

MR. REINHART: I appreciate that.

CHAIRMAN APOSTOLAKIS: Okay. Great. so one day will be sufficient; everybody agrees?

So we will do this in one of the ACRS meetings over the next few months. Thank you very much. Okay. Great.

What else of importance do you have to say?

(Laughter.)

MR. BRADLEY: What kind of a loaded question is that?

I take that as a subtle hint to move quickly. Okay. Let me do that.

The metrics. Basically, again, you have to deal with planned evolutions as well as emergent conditions. This was discussed this morning. Obviously you're going to plan maintenance outages on line or at shutdown, but there is also the thing that can break that you weren't aware of, and that triggers additional issues like how much time do you have to

reassess the configuration. The guidance will address all of that.

There are also three different types of risk metrics that are historically used for this approach. There's the ICDP. That's a temporary risk increase, which has used like a 1.177 type approach.

There's the CDF limit. That's basically what we call the risk speed limit, and then there's also the cumulative risk, the delta CDF that you accrue over time. Obviously LERF would also fall into the same approach. The next three slides, and these are things you're already very familiar with. This just shows how a typical ICDP is calculated. For this particular calculation the ICDP is just the green, the area in green, and here you're using R0, which is the zero maintenance condition. So you're not using the time averaged unavailabilities for the other components that aren't out of service. You're assuming the rest of the plant is in service, which actually gives you a higher ICDP than if you had used what we see here as RIPE, which is basically the baseline risk with a time averaged unavailabilities.

But you're familiar with this, and the EPRI guidance will have criteria on ICDP as a function of what risk management actions or types of risk

management actions would take place at differing levels of ICDP.

One of the challenges that you get into here is this is a simple configuration with one thing out of service, but where you have overlapping configurations or multiple components out of service the issue of how you define a configuration becomes important, and we need to have some rules on what is a configuration where it's more complicated than this, and that's one of the challenges we have.

We'll also, in addition to having ICDP type limits, there is also what we call the risk speed limit, and that's basically just a CDF limit that you shouldn't exceed regardless of the duration of the condition.

DR. SIEBER: Is that plant specific?

MR. BRADLEY: It would have to be plant specific because there is significant variation in plant baseline CDFs. In the A(4) guidance we designated ten to the minus three as the CDF speed limit that shouldn't be exceeded, but that's subject to reconsideration as we move into 4(b).

And, again, you're right. It can be done as a ratio of your baseline CDF or there is a plant specific element to it.

Finally there is the cumulative risk, and the EPRI guidance would require that all plants have to measure and maintain the cumulative risk below some limit, as I talked about earlier on probably a fuel cycle limit.

In addition, a lot of plants, like STP, actually use cumulative risk on a smaller time frame such as a work week as opposed to using a configuration specific definition of an ICDP. They will just define an ICDP limit for a work week and do it that way, which does have some advantages, but this just illustrates how --

DR. BONACA: Just on the speed limit, you know, shouldn't it be a function of how often you get into this?

MR. BRADLEY: Yes. That's why we have to --

DR. BONACA: Because if you set it at ten to the minus three, I mean, hypothetically if you always gain, you know, you could change significantly. I understand you have a cumulative --

MR. BRADLEY: Right.

DR. BONACA: -- and that -- okay, and that may be provided.

MR. BRADLEY: It's a combination. It's

not any of these in isolation. You have to use the combination to do that.

DR. BONACA: And that provides the stuff. Okay.

DR. SIEBER: So that means that if you do some really risky thing that only takes you 15 minutes, if you accumulate risk over a week, you could probably do it?

DR. BONACA: As long as that thing isn't violating this, your speed limit. That's the intent of having the speed limit, is to keep you from doing just that, the very risky, very short duration type thing.

Of course, after you've assessed the risk and have some determination of what it is, you have to take actions based on those results. Those are the risk management actions, and there are a whole number of risk management actions, such as protecting the opposite train, making sure you're not doing any maintenance on other parts of the plant that could cause a large risk spike, given the condition you're in. There are other things, such as working around the clock. There's a whole laundry list of actions that you can take to try to minimize the risk of these configurations you get into.

Those are specific to the configuration you're in and the risk level that you're at. So this guidance has to address those actions and what triggers them. They may be different. The classic tech spec action has shut down the plant. Well, as has been discussed today, there may be other actions that are more risk effective and make more sense than just shutting down the plant when you get into this situation.

And there will be more specificity than what we have in the existing A(4) guidance here.

And that gets me back to my conclusions where I started. So I'm done unless there are any questions.

CHAIRMAN APOSTOLAKIS: Thank you, Biff.

Who's next? Rick?

MR. GRANTOM: I wanted to briefly let you know the participants here: myself, Rick Grantom, for South Texas project; Bill Stillwell, who is the supervisor.

CHAIRMAN APOSTOLAKIS: It is customary when the staff makes presentations like this to put their E-mail and telephone number next to their names. So please next time, can you do that?

MR. GRANTOM: I will do that.

CHAIRMAN APOSTOLAKIS: And there is another question that I'm dying to ask you. What makes you qualified to address this august committee?

I got my answer. Go ahead.

MR. GRANTOM: The manager of risk management at South Texas project, and I've been doing risk management applications since the early '82s and have actually ushered through, with the help of the team at South Texas, several applications before.

CHAIRMAN APOSTOLAKIS: Very good.

MR. GRANTOM: Notably of which is the --

CHAIRMAN APOSTOLAKIS: Sieber wants to say something?

DR. SIEBER: I was just about to observe that that's a risky question to ask.

(Laughter.)

CHAIRMAN APOSTOLAKIS: Okay.

MR. GRANTOM: I feel quite good with the team here and the experience that we have at South Texas project that we are ready to now once again incorporate a new era in risk management.

Following on here with our conclusions, we kept these very simple. We are prepared to support the industry 4(b) pilot. We are serious about this,

and we are doing this. We feel that the application of flexible AOTs is a natural progression in the use of risk insights, and it's an appropriate PRA quality pilot for a Reg. Guide 1.200, simple conclusions.

Now, a lot of the things that I was going to discuss have already been discussed. So I'm probably going to try to move through. This is basically the agenda that we had here, and I'll try to hit through these things. I think we have covered most of this.

This is the 4(b) pilot, Reg. Guide 1.200 for PRA quality. Tech spec structure and format are going to be the same, but we're going to look a little bit different because we're not approved tech spec plant, and so we have a different set of tech specs here. And so our current tech spec AOTs will be a front stop and the back stop that we talked about are also preserved in here.

The EPRI implementation guideline we'll be referencing. One thing that is interesting here, we would apply our approach here for conditions where Tech Spec 303 currently applies, and this is where we have the cross-train failures and this is the very putative (phonetic) shutdown action statement, and so we would subsume that into this.

Of course, this would not be done on a planned basis. This would be an involuntary entry into this.

We have a new tech spec. Our real mechanism here in our tech specs is a new tech spec section called 3.13, and the flexible AOTs are associated with all of the components within the scope of the configuration risk management program. It's only those components.

And here is the scope of those components here. I won't go through all of these, but the intent of this slide is to show you that this is a comprehensive whole plant treatment in the sense that these are the components within the scope of the current configuration risk management program.

CHAIRMAN APOSTOLAKIS: Now, if I could mess up your presentation, --

MR. GRANTOM: I passed my limit.

CHAIRMAN APOSTOLAKIS: Huh?

MR. GRANTOM: I passed my five minute limit.

CHAIRMAN APOSTOLAKIS: There is a Table 3-2 in the EPRI interim report that gives criteria in terms of ICDP and ILERF, which I don't see in your presentation. At which point would it be appropriate

for us to discuss those?

MR. GRANTOM: The implementation slide when get to that point. Plus I have some supporting slides also.

CHAIRMAN APOSTOLAKIS: I'd like to spend five minutes discussing those, but you tell me when it's appropriate.

MR. GRANTOM: Okay. I would be glad to bring that up.

CHAIRMAN APOSTOLAKIS: Okay.

MR. GRANTOM: Here is the --

CHAIRMAN APOSTOLAKIS: By the way, the five minute starts from time zero when Biff started.

(Laughter.)

MR. GRANTOM: Biff took my five minutes.

CHAIRMAN APOSTOLAKIS: Took your five minutes. You are a new configuration.

(Laughter.)

MR. GRANTOM: I understand. Here is actually the tech spec 3.13, the risk management technical specification that was actually proposed, and I might spend just a quick moment here to highlight this.

The intent of this is that the system technical specifications that are currently within our

current tech spec, if they are applicable to configuration risk management would reference this section, this 3.13, and 3.13 then has action statements that says determine that the configuration is acceptable beyond the front stop.

And if you can't meet that, then you determine that the configuration is acceptable beyond the front stop whenever configuration changes occur that may affect plant risk.

And then if you reach ultimately the point that you have to restore the equipment within the 30 days, which is the backstop, and if you can't restore it within the 30 days and you go back to the referencing technical specification and implement the required actions.

So what it actually looks like in a sample system level specification, here's one for essential cooling water. You can see we have highlighted the new parts of this. The seven days is our current front stop that we have. That's the current allowed outage time as it sits right now, but it says that restore to operable within seven days or apply the requirements of Specification 3.13.

So this gives an operator an opportunity. It says he either knows up front that it's going to be

going on past the seven days or he finds out through some other emergent condition that it's going to happen. Now he has the opportunity to go and invoke 3.13 to enter into configuration risk management.

And then he calculates the AOT under a configuration risk management space, accounting for all equipment within the scope of the CRMP being out of service at the same time and calculating the flexible AOTs.

We also had to apply a new tech spec down here for two or more essential cooling water pumps being out of service, and then we can also calculate that with the same type of configuration here with us.

And all of the other systems that are associated with this will have a similar set and so this represents in a sense a very simple change to the tech specs, the same sets of words, the same reference back to 3.13, something very simple to go forward here with this.

MR. STILLWELL: This is something of a dated slide. We would note that the 12 hours or two or more will probably not be the time frame that we would be talking about to make that calculation. It's probably more like one hour or something that's closer to the equivalent of 3.03, and that's why we're

talking about at our statement. We probably have that already precalculated or we would have that already precalculated.

CHAIRMAN APOSTOLAKIS: How many loops does the essential cooling water system have?

MR. GRANTOM: Three trains per unit.

CHAIRMAN APOSTOLAKIS: So when you say with two or more inoperable, that is at least two?

DR. SIEBER: Then you're down to one.

MR. GRANTOM: That means you're down to one or none.

CHAIRMAN APOSTOLAKIS: Why at least two? That's the maximum you can restore.

MR. GRANTOM: Well, we have three trains. so we have -- with two operable, that means one of them is not. With two or more inoperable, that means either one or none is not.

MR. STILLWELL: If you get back to one operable, then you're back in A.

DR. BONACA: Yeah, restore here includes also the one that is still operable.

CHAIRMAN APOSTOLAKIS: So the whole system may be inoperable because with two or more essential. So all three may be inoperable.

DR. SIEBER: Right.

MR. GRANTOM: It's in the realm of possibility.

CHAIRMAN APOSTOLAKIS: In that case, even in that case, you can continue to operate as long as you restore at least two within 12 hours or you go to 3.13.

MR. STILLWELL: That 12 hours is going to disappear.

CHAIRMAN APOSTOLAKIS: Yeah, yeah.

MR. STILLWELL: Three trains of ECW for us is a very short time now.

CHAIRMAN APOSTOLAKIS: So we are not just talking about always having one train of the system operating. You can actually have the whole system disabled.

MR. GRANTOM: Yes, and that would be the situation even in current tech specs now unless it induces a trip. So it's within the same aspects we have of the risk associated, very putative to be able to do those kinds of things, and this would be strictly obviously from an involuntary condition.

MR. STILLWELL: B is the current equivalent of tech spec 3.03.

DR. SIEBER: Well, if you had everything inoperable, that would be an abnormal operating

occurrence, which would put you in the AOT, which gives you maybe a minute or two to do something.

MR. STILLWELL: Depending on the system, yeah.

CHAIRMAN APOSTOLAKIS: Let me understand that. If all three are inoperable, what happens?

MR. GRANTOM: Well, we're in this technical specification 3.0.3.

CHAIRMAN APOSTOLAKIS: Which says?

MR. GRANTOM: Which says you have to be in hot standby.

MR. STILLWELL: Within one hour. Start making preparations and within one hour start shutting the plant down.

CHAIRMAN APOSTOLAKIS: Okay, but during that time you may go to 3.13?

MR. STILLWELL: Yes, sir.

MR. GRANTOM: Yes, we can go to 3.13.

CHAIRMAN APOSTOLAKIS: And argue that even with all three inoperable, I can still operate for more than an hour.

MR. STILLWELL: Yes, sir. Not argue.

MR. GRANTOM: We'd have to have the analysis.

MR. STILLWELL: The analysis would be

available to you. The reason that this is interesting is that there are some systems, like containment spray, where that is a very lengthy period of time. For ECW it is not. It look like 3.03.

DR. SIEBER: Well, you don't need containment spray for normal operation.

MR. GRANTOM: Well, that's true, and so it becomes in a sense --

DR. SIEBER: That's a true risk.

MR. GRANTOM: -- a reflection of its risk significance. ECW here would be highly risk significant, whereas containment spray would not be. So it does look at configuration risk from one, two, and three trains of being inoperable.

CHAIRMAN APOSTOLAKIS: Even though we demanded for AP-600, right?

PARTICIPANT: Correct.

DR. SIEBER: In this scheme, since they have three trains and most everybody else has two, the GDCs require two. This is just recognizing that extra flexibility.

MR. GRANTOM: We do have extra flexibility.

DR. SIEBER: Right.

MR. GRANTOM: For literally almost every

initiating event, one train out of three --

DR. SIEBER: So that is why you have to have two out of service before you get to the LCO.

MR. STILLWELL: Let me just say that that extra flexibility is something that really only manifests itself in the time that we might be allowed to be in that configuration. This still could apply to the two train plan.

DR. SIEBER: Well, it certainly does, but you can have a failure of a single train and not care.

MR. STILLWELL: And our risk numbers reflect that. A two train plant with both containment sprays inoperable would still have probably significant amount, much more time than they have right now with the current 3.03 to bring those back to service.

So some of this is a three train artifact, but a two train plant can apply this also.

DR. SIEBER: Oh, absolutely, and in fact, there it becomes more critical because you have the flexibility to deal with single failures.

MR. GRANTOM: Exactly right.

DR. SIEBER: Without getting into LCOs. So I just wanted to mention that to make sure it's clear to everybody.

MR. STILLWELL: I want to correct that. From a design basis standpoint, we need all three trains. To mitigate the large break LOCA, South Texas needs all three trains.

DR. SIEBER: Oh, yeah?

MR. STILLWELL: Yes, sir. But it's only really for the large break LOCA. For the more risk significant scenarios, one train will typically do it, and that's where we accrue the risk benefits. That's why we're here, is that we have lived this way since we licensed the plant, is that we got this extra train that has risk benefits.

DR. SIEBER: What's short, the high head flow or --

MR. STILLWELL: No, sir. Just real quick, we have -- do you want it deterministically or do you want it --

DR. SIEBER: Give it me deterministically.

MR. HEAD: Design basis space for a large break LOCA, our safety injection systems are not cross-typed. So we have and A train going to A loop, B going to B, C going to C.

DR. SIEBER: I've got it.

MR. HEAD: Single failure, broken loop, one train left.

DR. SIEBER: Right. Got it.

MR. STILLWELL: The critical thing is the broken loop. One train fails and goes out the floor. So deterministically, we need all three.

DR. SIEBER: Yeah. On the other hand, if you had the cross-ties, you wouldn't

MR. GRANTOM: That's right, but that's in a sense why we're in to see -- that's why tech specs look like two train tech specs when we're really three trains. We didn't get credit for that. However, two train tech specs could apply this very well and have some latitudes with this.

DR. SIEBER: Okay. That clarifies it for me. Thank you.

DR. BONACA: The word "operable" you're using here is still the traditional approach?

MR. GRANTOM: Yes, sir, absolutely, still operable.

DR. BONACA: But I understand from option two you are changing some of the definition of operability for the systems, for certain systems. Are you?

MR. STILLWELL: It doesn't change the definition. We don't affect operability.

DR. BONACA: No, no. I'm talking about

you know, operability implies also the degreed and all of the --

MR. GRANTOM: No, sir. The option --

DR. BONACA: Okay? So a system may be functional, but not operable.

MR. GRANTOM: Well, but in option two we would still say whatever that component is that has fallen under the Option 2 our out exemption space is till operable.

DR. BONACA: Okay, but you seem to be changing, however, the pedigree that you're required to have.

MR. GRANTOM: Right. We're allowed to change that pedigree, but in so doing within the requirements we have, that system would be operable.

DR. BONACA: Yeah, okay, all right. Because you changed the definition.

MR. GRANTOM: Right. Because we changed the requirement.

DR. BONACA: Okay.

MR. STILLWELL: I just want to be real clear. We haven't in Option 2, to my knowledge, altered the definition of operable.

DR. BONACA: No, I understand that. You just simply have reduced the requirement.

MR. STILLWELL: Right. Now, the beauty of this is that the degree of operability can be assessed differently depending on why the system is inoperable. If it's because it has pulled the lock or it is torn apart on the floor, the risk impact from that pump is different than if the shift supervisor has told it may not be seismic or qualified.

DR. BONACA: Well, that's why I was trying to pursue that. At times you have a system which is clearly functional, and the NRC will agree with that, would provide still the flow, whatever, but it doesn't meet some specific requirement that is more of a pedigree nature.

So that's still -- and still you have under the Part B. So, therefore, you could have, for example, still this train is functionable, but --

MR. GRANTOM: That's actually part of this whole thing, is what's good about this. If you do end up with some lesser degree of operability -- and this is what really happens to stations --

MR. STILLWELL: That's right.

MR. GRANTOM: -- some lesser degree of operability, all of a sudden you're determined that you have two trains inoperable. Now you're in this 3.03 and both Scott and Bill and I know very painfully

from several times of what we have to do to mobilize to address these needs. This allows that time to be able to go and address that kind of stuff, some things that clearly are not risk significant in that regard.

And I think in a sense this is a safety benefit because it's a true mobilization of the stations when these events occur, and Scott has been through a lot more of it than I have.

The next slide here talks a little bit about the PRA quality item here. We have already kind of talked about it in a sense, but my only point here is that it's Reg. Guide 1.200, but we ar also looking at the PRA quality need for the 4(b) application itself. So there is the PRA quality aspect of the base PRA. There's the quality of what kind of quality do I have to do this type of application here that we're including in both of these.

In the implementation area here, we are applying our configuration risk management program, and it is basically the same program that we use current for A(4) of the maintenance rule. The configuration risk management program is during a proceduralized process. It establishes risk thresholds, non-risk significant threshold of 1E minus six, and a potentially risk significant threshold of

1E minus five.

One E minus six is the threshold basically where we do most of our routine maintenance work activity. We live and breathe underneath that threshold as we go forward, and then the potentially risk significant threshold is the next order of magnitude up where more compensatory measures are taken and the procedure requires that.

CHAIRMAN APOSTOLAKIS: So what is this ten to the minus five?

MR. GRANTOM: What we call the potentially --

CHAIRMAN APOSTOLAKIS: No, but what is it?

MR. GRANTOM: It's ICCDP.

CHAIRMAN APOSTOLAKIS: IC?

PARTICIPANT: Incremental Conditional Core Damage Probability.

CHAIRMAN APOSTOLAKIS: ICCDP.

PARTICIPANT: Per week, right?

MR. GRANTOM: For a week.

Actually it could be cumulative. This is in the configuration. This is the way we do business right now, but with this new tech spec, that would be for that configuration.

MR. HEAD: Yeah, actually it applies right

now. If we have a configuration roll over into the next week, we keep accumulating the risk. So the ICCDP is actually on the maintenance configuration perspective of time.

MR. GRANTOM: And it is important for you to note, too, that we actually do this right now. This is an ongoing process that we do every day, every week at STP now.

CHAIRMAN APOSTOLAKIS: Your PRA includes uncertainty calculations for the parameters.

MR. HEAD: For the parameters, yes.

CHAIRMAN APOSTOLAKIS: So when you say ten to the minus five, this is a mean value?

MR. HEAD: It's a mean value.

CHAIRMAN APOSTOLAKIS: Now, one of the questions that comes to my mind, and I'm often asked that question when I talk to non-PRA audiences and I want to give a talk. They say, "Well, gee, you know, everybody keeps saying that the uncertainties are large, and yet you take action when you see something like ten to the minus five."

How believable is that number? What's the answer to that?

And that was, in fact, the question I had about Table 3-2 of the EPRI report. First of all, I

assume this is not a rigid, you know, limit. I mean, if you are at nine, ten to the minus six, what do you do? Do you say, "I'm below the limit so I don't do anything"?

MR. HEAD: Exactly. That's the limit.

(Laughter.)

MR. HEAD: I was being facetious. In truth, between ten to the minus six and ten to the minus five, we're taking compensatory measures to drive the risk back down. Being in extra crews, starting working overtime, deferring maintenance or completing maintenance that we're already in as soon as possible. So between ten to the minus six and ten to the minus five we're already doing things. At ten to the minus five the compensatory actions increase in severity, if that's the right word, up to and including a forced plant shutdown.

Is ten to the minute five the limit? Yes and no. Above that we shift to a higher gear. Below that eight times ten to the minus six or five times ten to the minus six, we're already making preparations to do what we can to reduce the risk.

MR. GRANTOM: And I guess part of the good part of this application is if, in fact, we know we are accruing risk at this level or a certain level and

we're going to cross that threshold, we're not going to return the equipment back to service; we know that we're not going to be able to do that, then we go ahead and evoke the actions that we need to do at that point in time.

I mean that's generally how we work, but the E minus five threshold is a threshold that we're monitoring to, as is the 1E minus six threshold. So it depends in a sense. If it looks like they're fixing to get it back, well, yeah, we keep marching along to do this, and then as maybe you'll see in some of the supporting slides when we get to that, you'll see that these risk levels are archived and maintained and kept, and you can get this running history of what risk has done over the last cycles or over the last six years.

MR. HEAD: Actually eight years now.

MR. GRANTOM: Eight years. Pardon me.

So the other part of this that I wanted to bring up is --

MR. STILLWELL: Rick, I can't leave that. I think we sort of beat around the bush on that. That's pretty much in my mind the shutdown moment, that if we reach that point and haven't taken some other action and gotten some other relief or did

something else, that that would be the shutdown moment.

CHAIRMAN APOSTOLAKIS: If you take some action, some compensatory measure that is very difficult to quantify, then you will not see an impact on the number.

MR. HEAD: Probably not.

CHAIRMAN APOSTOLAKIS: So how does that affect your decision making process? You're saying, well, the number is nine, ten to the minus six, but look. I have three guys here doing this, which I cannot quantify. So is that a judgment that the number is not really nine, ten to the minus six?

MR. HEAD: As a practical example, some of the things we have done recently, we have been in discussion with the NRC about how good are these compensatory measures. How good is a non-safety related diesel generator set out in the yard, not having a qualified diesel?

CHAIRMAN APOSTOLAKIS: And?

MR. HEAD: And I think what it does is give you a comfort level that we know it's worth something. How much something we don't really need to know.

CHAIRMAN APOSTOLAKIS: Why not?

MR. HEAD: We're comfortable where we are, but where we are right now with the diesel generator, we're not going to exceed ten to the minus five. We're going to get close to ten to the minus five, but we do have non-safety diesel generators that we know drive risk down.

So we approach ten to the minus five. The diesel generators keep us well below ten to the minus five. That's our discussion with the NRC. Are you comfortable with that? Is this good enough or do we say at ten to the minus five we shut down?

So I think where you would be at a limit, you would be talking to the NRC. This is what we have done.

DR. BONACA: I think simply just to define the compensatory action, to alert the operators to protecting the equipment that is needed for compensation is in and of itself a true improvement itself.

CHAIRMAN APOSTOLAKIS: I agree, but the point is are the numbers changed?

DR. BONACA: I don't know.

MR. HEAD: Well, the number that we present would not change.

MR. GRANTOM: The number that we would

present would not change, but there could be cases where we could, in fact, take credit for that. Obviously those are things that we would look to be able to do, but you're right, George. There could be situations where I can't quantify fit. I'm not going to be able to change the number.

MR. STILLWELL: But, George, there have been things in the past where we have unquantified cross-connect capability that's not in the model right now and that, in fact, we could, depending on the time frames, if something was significantly broken and we were going to encounter the ten to the minus five moment, say, two weeks from now, that we could incorporate those into our station procedures and actually in the model and take credit for them, and this would give us time to do that.

MR. GRANTOM: I think that is the important thing. This gives us time to be able to do those kinds of things.

MR. STILLWELL: I envision that to be very rare, but certainly something that we and maybe other stations could do, but it would be something that we would have to pass a certain level of pedigree for us to be able to take credit for it.

If it's just that we say we have it,

that's not going to do it.

DR. SIEBER: No.

MR. GRANTOM: Okay. Well, we've kind of talked about that. I think what Bill was talking to is the recent extended diesel generator allowed outage time that we've had, and Bill and him are monitoring that right now.

Our letter of intent went in with this amendment request in early 2003. We expect our formal amendment request to be submitted in June 2004. So we're actually pursuing this and moving forward, and here's my conclusions again.

But it may be good at this point in time if you'd want to that we can talk about risk profiles and look at the uncertainty and historical aspects of that, and I had some supporting slides for that. I think they're right here.

Biff kind of went over these same slides here. So I don't know that I need to go through this and have the risk assessment, but this is, for example, here an actual risk profile that occurred at STP, and I'd like to use an old one back to 2001 just to give you an idea that we had been doing this quite a while.

You can see the various maintenance states

that are there, A, B, C, and D, and those are distinct, unique sets of equipment that are out of service at a given time, and this is what we planned to do. It says the planned risk profile at the top, and then you look at that same work week for the actual risk profile, and you can see it's slightly different from, you know, what was planned and what we actually did her.

Now, there's also some other supporting information here that defines exactly what, for example, maintenance date G is for this week, and maintenance date G is not the same from one week to the next. It's just how it letters and that type of thing.

But what's important to note here is when you're looking at these incremental or instantaneous changes here, as you get to the cumulative risk, and this is another important point here that I think shows one of the true safety benefits of this methodology as it's imposed into the station.

At the end of this thing you get a planned risk and then you get an actual risk. You've got what you planned to do. Now, what did you really do?

And at the station, these are presented in our teamwork and communication management meetings

every week, what the planned risk profile is for the week, and then on Wednesdays, it's what was the actual risk from the previous week

And when they're off, they have reasons and lessons learned as to why they didn't meet the planned risk profile. They had emergent conditions. Some work ended up earlier than it did before. They had some other problem.

There's lessons learned that go out of this, and this level of dialogue at a managerial level at a station right now, personally I don't know of other stations that do it. They may do this, but to have this highlighted by what they can see here has an extremely powerful effect on the organization as they try to continually improve.

And the name of the game is meet the plan; do your schedule; meet the plan. And when we collect this information week after week after week after week of the actual risks, you start to see a picture. Here's what we have from 1996 through 2000 of a rolling 52-week CDF value. Each data point is the rolling 52-week average going forward, and you can see quite simply that there are synergistic effects that occur.

This area right here is South Texas, are

the two EAD HVAC trains being out of service from an involuntary condition at the same time, and you can see these.

But part of the message also here is when you're looking at uncertainties in a sense, here's empirical data on what those uncertainties really did relative to the variation of plant configurations over time here.

So you can see both units kind of work fairly well together along those lines, but you do see some variation within a window here. So --

DR. SIEBER: Does that include the outages?

MR. GRANTOM: Yes.

MR. HEAD: It does include the outages. In general, the outages will be the lower part of the slide.

MR. GRANTOM: The little valleys down there.

DR. SIEBER: Okay.

MR. GRANTOM: And then you see the impact of what longer allowed outage times do here, and to me when I look at this, I mean, there's a tremendous wealth of information about the operational and maintenance philosophies of the station that one can

see in this, and there's lessons learned to be gained out of these kinds of things.

It gives us very good confidence that, you know, merging into this 4(b) will almost in a sense be just a reaffirmation of what we're already currently doing every week. This would represent in a sense something that would maybe go into an annual report back to the staff of saying here has been our 18 month rolling average for both units. Here's the risk levels.

To me, I mean, this is an extremely important statement of risk management for a station to be able to do this at this one time.

CHAIRMAN APOSTOLAKIS: Can you tell us what economic benefits the utility has from this?

MR. GRANTOM: If you can prevent an inadvertent shutdown from the tech spec --

CHAIRMAN APOSTOLAKIS: Have you?

MR. GRANTOM: In the past from our NOADs, yes, we have.

MR. STILLWELL: We've done a couple from an enforcement discretion space that this would subsume and, therefore, an enforcement discretion would not be needed. I think there has been other cases where we have been in situations where, you

know, the maintenance we needed to do was not allowed because of tech spec restrictions that this would allow us to accommodate.

I just think from a business perspective, you know, I think the risk that we see the most is if we are in some sort of train outage, and we're working on some piece of equipment and the other train component goes out of service. Right now that's basically an instant shutdown that you would be able to manage that risk.

Now, it may still end up because of what it is basically a shutdown, but for some components in tech specs, it would not require an immediate shutdown. So the economic benefits, I think, prove the asset could be substantial.

Now, for us as a three train plant maybe it's a little more than a two train plant, but it's still there by the two train plant, we believe.

MR. GRANTOM: I think it's quite significant, George, when you look at -- you can go back in history and find administrative shutdowns in other areas where people have had things that weren't really risk significant in which they've shut down. Certainly the case in the South Texas project, we would have seen those examples.

And you know, you thought about cost of replacement power, but the other thing, the other intangible here that's not quantifiable is in a sense a quality of life, quality of work issue where you're immobilized in the station here to go and take care of something that everybody knows that this is not a risk significant thing. Staff mobilized. We got ourselves mobilized, and --

DR. SIEBER: And there's a cost to that.

MR. GRANTOM: And there is a human cost to that. There's a human performance cost to that.

DR. SIEBER: Dollar cost, too.

MR. GRANTOM: And there's a real dollar cost there. We're paying people overtime. We're mobilized out there. Of course, we don't get paid overtime, but there are a lot of those issues like that, and to actually shut down, now you're looking at some real money.

DR. SIEBER: Let me ask you to do something for me. If you go back two or three slides to the one that showed the risk --

MR. GRANTOM: This one?

DR. SIEBER: No, the blocks.

MR. GRANTOM: Okay.

DR. SIEBER: And basically what you're

doing is you're accumulating risk over a period of time and comparing it to the plan that you had. You could do the same thing with dollars. You could do the same thing with dose, and I don't know if you've ever done it or not, but I would be curious to know whether you get minimum dollars spent at the same time you get minimum risk, at the same time you get minimum dose, or are they in conflict with one another during --

MR. GRANTOM: A good at power safe running plant is the most economical and safest from the human burden. Almost every faction of the organization benefits from that, and we have looked at the dollars along those lines.

DR. SIEBER: And dose?

MR. GRANTOM: Haven't looked at dose as much, no, but in terms of dollars, you're talking about risk informed asset management now to me --

DR. SIEBER: That's right.

MR. GRANTOM: -- when you're speaking in terms of those kinds of things, and you'll find out that the value of a component in terms of dollars is huge relative to what happens, but there are some components that you can flat make perfect that return nothing in that regard.

DR. SIEBER: So this allows you then to make decisions on how often you will maintain something and how --

MR. GRANTOM: How often you will maintain, how quickly we have to return things to service. It also offers the opportunity in a sense that if you know something is going to be extremely risk significant. Now there's a new argument that could be made in terms of dollars, in terms of these other things that says it's worth more to make this a more robust component. It's worth more to invest money to incorporate predictive tools in there of, you know, vibration monitoring.

It's worth more to develop a more robust maintenance strategy for this component than this other component, and the thing works very well as far as being able to focus management resources and station resources on the things that really matter at that point in time, and it forces itself to do that.

DR. SIEBER: How do you integrate this risk information and cost information into the management decision process? I mean, who's making the decisions and what are they looking at?

MR. GRANTOM: Well, a lot of this is part of our reliability efforts and our reliability

management team that we have at South Texas that looks at a lot of this information. I would say that we're still -- we have, in fact, done this.

For example, South Texas is evaluating the vessel, a head replacement, and we're using these economic risk arguments here to be able to, with uncertainties -- you'd be proud of this, George -- with uncertainties as to what the various options are, what the right fiscal years are to be able to do these kinds of things, and we can roll into those kinds of analyses to inform management to make better decisions.

We are working pretty hard right now at trying to build those same kinds of capabilities in the reliability of a component type of argument. Now, in some cases for modifications, we do a better job at that and more tied into the process. We're working on getting tied in, and Scott is a member of the reliability management team at South Texas, and these are things that we're continuing to work on.

DR. SIEBER: Well, that helps my understanding, and I apologize for taking you off your track.

MR. STILLWELL: One of the reasons we're here is that the integration has taken place. I mean,

this is the way we do business, and it was not that big a jump at all for us to take this, the way we do business, apply it to tech specs, and it's not going to be that big a jump with the stations.

DR. SIEBER: It's like safety culture. If it isn't in your heart, you aren't going to do it.

MR. STILLWELL: Well, it's there. This is the way we do business.

CHAIRMAN APOSTOLAKIS: Okay. Now, are you gentlemen familiar with the Commission's policy statement and phase approach to quality for the PRA?

MR. HEAD: Yes.

CHAIRMAN APOSTOLAKIS: You have read it?

MR. HEAD: We've read it.

CHAIRMAN APOSTOLAKIS: Where would you say you are?

MR. STILLWELL: Let me answer that.

DR. SIEBER: Three.

(Laughter.)

MR. STILLWELL: I have to feel compelled to react to your earlier statement. Using your analogy, we don't view ourselves as a Rolls Royce. I would say personally, we're a seven year old Suburban that we change the tires every now and then and try to take it to places where we've never been before.

DR. SIEBER: Be careful now.

MR. STILLWELL: Excursion, okay?

But what we really have is a really good pit crew. Okay? We have people that use it all the time, and so as I say, I wanted to find a place to react to your Rolls Royce discussion, and I don't think that's --

CHAIRMAN APOSTOLAKIS: But where are you now? Are you in Phase 3?

PARTICIPANTS: No.

MR. GRANTOM: No, we're not.

CHAIRMAN APOSTOLAKIS: Why not?

MR. GRANTOM: Maybe Gareth.

We have no standards on this. We are beyond the standards.

MR. PARRY: Yeah, this is Gareth Parry from the staff.

We're going to be talking about that this afternoon, but they cannot say what -- well, they cannot be in Phase 3. They cannot even be in Phase 2 for many of their applications because we don't have the standards in place for assessing the quality of the PRA, and that's really the definition of the phases, but we're going to talk about that this afternoon.

CHAIRMAN APOSTOLAKIS: That's an administrative thing, I mean.

MR. PARRY: Well, then the SRM is an administrative SRM.

MR. GRANTOM: Well, if I were giving it strictly from the technical perspective, I don't know how to put it in terms of the phases in a sense, but we're clearly beyond what the standard would require because we're incorporating a capability beyond what the standard does for a baseline PRA because we're able to do alignments, configurations, and those types of things.

CHAIRMAN APOSTOLAKIS: Do you feel you have a good baseline PRA that will enable you to address any issue?

MR. GRANTOM: I don't know about that.

CHAIRMAN APOSTOLAKIS: The current state of the art. Huh?

MR. GRANTOM: Yes.

MR. HEAD: So far we have been able to address any issue within the current state of the art.

CHAIRMAN APOSTOLAKIS: Now, is that Phase 3?

MR. HEAD: No, it's not.

CHAIRMAN APOSTOLAKIS: Phase 2?

MR. GRANTOM: No.

MR. HEAD: No, it's Phase 1.

CHAIRMAN APOSTOLAKIS: Regardless of the standards.

PARTICIPANTS: No, you can't separate.

MR. GRANTOM: You guys are going to have fun this afternoon.

(Laughter.)

MR. GRANTOM: George we talked about this yesterday, and it is an issue in a sense because, you know, we build methodologies. We try out the methodologies. We get lessons learned. We get acceptance, and then we build standards.

CHAIRMAN APOSTOLAKIS: You have a seismic PRA?

MR. GRANTOM: Yes.

CHAIRMAN APOSTOLAKIS: You have a fire PRA?

MR. GRANTOM: Yes.

CHAIRMAN APOSTOLAKIS: Do you expect to be very surprised by any standard that will come out in these?

PARTICIPANTS: Yes.

PARTICIPANTS: No.

MR. GRANTOM: Maybe no.

DR. SIEBER: If you are, it will be a surprise.

PARTICIPANTS: It will be a surprise.

CHAIRMAN APOSTOLAKIS: You are surprised it will be a surprise.

MR. GRANTOM: We don't expect to, but I won't discount the possibility that we could be surprised.

CHAIRMAN APOSTOLAKIS: By how wrong the standard will be.

(Laughter.)

CHAIRMAN APOSTOLAKIS: Now let's talk a little bit about this Table 3-2, which unfortunately they took away from me.

MR. GRANTOM: We've got it.

CHAIRMAN APOSTOLAKIS: And making a transparency which I need. It doesn't have to be blown up. Just bring a transparency.

DR. SIEBER: Three, two of?

CHAIRMAN APOSTOLAKIS: Three, dash, two. Ah, we've got it. By George, he's got it. Put it up there. Turn off the high tech stuff.

Okay. So this is the quantitative (phonetic) risk acceptance guidelines. When I look at this, I ask questions to myself similar to the one --

you must have seen this before.

PARTICIPANTS: Yes.

CHAIRMAN APOSTOLAKIS: That I asked you about at ten to the minus five. When there is a calculation of the ICCDP and then based on that calculation I look at this left-hand column, and it tells me if I am below ten to the minus five. Now, if it's above ten to the minus five, that's not entered. Between ten to the minus six and ten to the minus five, I have to do some things.

That implies that I can calculate these numbers with high confidence., and I was glad to hear Mr. Bradley say earlier that, yes, this imposes requirements on the quality of the PRA that we would need to do a good uncertainty analysis and so on, and I agree with that.

Then I happen to look at the slides that Mr. Baranowsky presented at the regulatory information conference this year, and I saw two slides that I found very disturbing.

Can we have slide number three? Would you turn off the overhead projector, please? Number three.

Okay. Now, when these guys were developing the SPAR models, which are the NRC's PRAs

in consultation with the utilities, they don't do it in isolation. What do we see here? The red dots are SPAR CDFs. The blue dots are licensee CDFs, and the trend is obvious. We're talking about an order of magnitude typically, except for a few plants between the licensee CDF and the SPAR, which is the result of negotiation between the NRC and the licensee.

MR. HEAD: I saw the same slide, but there were also two or three other slides associated with this. Is this the one as we were getting the agreement, when we were going out to negotiate with the licensees?

CHAIRMAN APOSTOLAKIS: I believe this is the current CDF and the SPAR. No?

PARTICIPANT: NO.

MR. GRANTOM: I'm not sure.

DR. SIEBER: This is for this afternoon.

CHAIRMAN APOSTOLAKIS: Yeah, but it's also relevant here.

So what is the current one?

MR. HEAD: Well, page 5, I think.

CHAIRMAN APOSTOLAKIS: Let's go to five.

MR. HEAD: Having been an MSPI pilot, the difference is not as large anymore, but that was a lot of work between us, the licensees, and the NRC

contractors to resolve the differences between the spar model and the plant specific PRA.

CHAIRMAN APOSTOLAKIS: But this is only what, two, four, six, maybe ten points.

MR. HEAD: Ten or 12 plants, yes.

CHAIRMAN APOSTOLAKIS: What about the rest?

MR. HEAD: One of the conclusions I came to as a result of this process is the SPARs are intentionally conservative, especially in the area of operator actions, and they should be. We're much more realistic in terms of operator --

CHAIRMAN APOSTOLAKIS: How can we say that we're conservative in the area of human reliability when we don't have good models for human reliability?

MR. HEAD: I would say we have adequate models.

CHAIRMAN APOSTOLAKIS: I don't know about that. Look at one paper.

MR. HEAD: Well, we have been doing operator reliability for 25 years now or 30 years now, and we have benchmarked somewhat against simulator and things that have actually happened. Personal opinion, I would say our operator action models are not necessarily as weak as everyone seems to think.

CHAIRMAN APOSTOLAKIS: Well, the problem there, Bill is that if I pick a model and then pick anther model, I get different results, and I don't know which one to believe.

MR. BOYCE: If I see widely disparate results, I would say that's a big problem. If I see, in fact, there are two results, that's PRA, and that's dead on.

CHAIRMAN APOSTOLAKIS: And I agree, but I don't know what kind of difference I'm going to see. The only evidence I have is from '89 where the differences are big. Nobody has done anything since then.

MR. HEAD: Other than the SPAR model benchmarking.

CHAIRMAN APOSTOLAKIS: Well, the SPAR models? No, the SPAR models also have their own human reliability model. So what is the difference between the SPAR Rev. 3R and the SPAR Rev. 3?

MR. HEAD: I don't know if I can speak to that.

MR. BOYCE: Yeah, I wish Pat Baranowsky was here, and maybe he is best to answer that. I mean, I could guess, but I think Rev. 3 is what is out there right now and we're using for most of like the

STP Phase 3 calculations. I think Rev. 3I is where we've completed the benchmarking efforts where we had contractors, I think, from B&L go out to each of the sites, and then the Rev. 3Is were used for all of the pilot plants, and we did inspections against licensee results and our SPAR 3I results, and we ended up coming up with discrepancies.

After working through the discrepancies, I think we ended up with a Rev. 3R.

CHAIRMAN APOSTOLAKIS: So Rev. 3R is the current situation for these.

MR. BOYCE: For the pilots, and I think that Pat has completed all of the benchmarking of all the utilities, and so I think for the rest of the hundred and -- well, he has only got about 70 SPAR models. So for those 70 SPAR models, I think they are just about all at Rev. 3I right now.

CHAIRMAN APOSTOLAKIS: I?

MR. BOYCE: Right. So I think the current state of affairs is the slide on the upper left.

CHAIRMAN APOSTOLAKIS: Now Mark.

MR. REINHART: This is Mark Reinhart from the Probabilistic Safety System Branch.

I was going to offer on the benchmark trips, the staff did go to every utility and look at

every PRA, but it was more of a here's a scenario. Looking at it from the significance determination process in parallel, they would run a scenario on the PRA from the licensee. They would run a scenario on the SPAR, and if there were differences, like an order of magnitude, we'd try and figure out why there were differences and then go feed that back.

But that was more in the sampling realm rather than a systematic, you know, step by step. Also, I think it was mentioned the SPARs use a lot of standard assumptions across the board, and licensees may or may not use those same standard assumptions. So it will drive some differences.

CHAIRMAN APOSTOLAKIS: Let's go to slide six. So here we have a listing of the major factors that influence the differences, the differences in risk results, and what Mr. Baranowsky has done, he has categorized them into large, medium and small.

So large support system initiator modeling and frequency, the RCPC failure model, which of course is a major model uncertainty, PWR depressurization, and so on.

The question in my mind is: have these PRAs gone through the NEI review process?

MR. PARRY: Our models?

CHAIRMAN APOSTOLAKIS: No. This is the difference between SPAR and the licensee PRAs.

MR. PARRY: The licensee PRAs have, yes.

CHAIRMAN APOSTOLAKIS: And yet the NRC staff still finds these things?

MR. PARRY: This is the difference between the SPAR model.

MR. GRANTOM: And the PRA.

MR. PARRY: Right.

CHAIRMAN APOSTOLAKIS: The SPAR model cannot be different because the agency would be making decisions using SPAR. Baranowsky comes here and says, "We differ with the licensees on how they model support systems," and then we cannot just dismiss that and say, "Oh, but that's SPAR."

I have to understand why, and especially if the licensee's PRA has undergone this review process, which is advertised as very vigorous, and I have no reason to doubt that. Why do I see this? It bothers me.

MR. PARRY: George, can I just make a couple of comments?

MS. WESTON: Your name please, for the record.

MR. PARRY: Oh, sorry. This is Gareth

Parry from the staff.

There are differences because I think the way that the SPAR models have been developed, they only develop them for those initiating events that I think contribute to 90 percent of the core damage frequency. A lot of the things that they don't model very well are the support systems. That's why you see that as a big difference up here.

Other things I can't really speak to, but I know that they're not intended there. They use relatively crude human reliability analysis. They use, I think, to some extent generic data. So there are going to be differences.

And I think what the value of this is is it shows where the big differences are. Now, there may be cases where in the SPAR models they have adopted what a lot of people think are very conservative success criteria, and the one I would think of is the PWR PORV success criteria. For example, for feed and bleed, I think of the SPAR models. They require both PRVs to open in the SPAR models uniformly. I think in the licensee's PRAs they don't necessarily because they've done different success criteria calculations.

CHAIRMAN APOSTOLAKIS: What I'm getting

now is almost a unanimous blasting of the NRC SPAR, including from the NRC staff.

MR. PARRY: No, not necessarily.

CHAIRMAN APOSTOLAKIS: Well, that's what you're telling me, that all of these differences really point to the fact that SPAR is, in fact, wrong.

MR. PARRY: No, these are different assumptions.

CHAIRMAN APOSTOLAKIS: Why should it be conservative? I mean, the SDPs would depend on these things.

DR. KRESS: Because they started out.

CHAIRMAN APOSTOLAKIS: But this is the current state of affairs, is it not?

DR. KRESS: We're trying to work our way down from conservative to be closer --

CHAIRMAN APOSTOLAKIS: Well, first of all, the second one for sure nobody does work. The model hopefully RCPC failure, but I find this very disturbing. You guys may be happy with this.

MR. PARRY: I really think you need to talk to Pat Baranowsky though because he is obviously the guy that can give you the right perspective on that.

CHAIRMAN APOSTOLAKIS: I have, not in

detail, but I have.

MR. REINHART: This is Mark Reinhart froM PRA branch again.

The STP really isn't reliant on the SPAR. What would happen if we got into a Phase 3 STP? We would use SPAR to get some insights. We would also get insights from the licensee, and all of these differences would come out.

Why is there a difference between SPAR and the licensee's results? If it were a comparison there, it might be a different comparison, but if it were, some of these pieces would come to mind. For instance, the second one there, RCP seal failure, that's often a difference between what the staff does and what the licensee does.

I think the licensee staff in developing their PRAs, they have a lot more resources. They have a lot of folks to develop one PRA per licensee, where staff has a few folks with the lab's help to develop SPARs for everybody, and it is really a level of detail of the model.

CHAIRMAN APOSTOLAKIS: Let's go to the next slide. He is not saying we have to improve SPAR. What he is saying is that there is detailed guidance needed for models and parameter estimates for the

factors that result in large and medium variations in risk.

As I read this, it tells me that both the industry and the NRC needs this. He is not saying SPAR models are suffering so that we have to do this. He says implement detailed guidance consistent with high level support of the ASME standard.

I don't see anywhere in here anything that says we have to improve the SPAR models because the industry's models are better. Now, we can have Baranowsky, of course, confirm or refute what I just said, but when I read this, I think the message is we have a problem, and that problem is -- now, that doesn't mean South Texas has a problem. I'm sorry. I don't want to tie this to your presentation.

Probably you are one of the points in the light, but this will come up also in the afternoon perhaps, but I mean, this was presented just -- when was the conference? A month ago?

MR. PARRY: No, last week, the week before.

CHAIRMAN APOSTOLAKIS: So this month.

MR. STILLWELL: I think the regulator, that very first slide that you had that showed all of the red dots on top, the regulator would take solids

that the spar is more conservative for their initial decisions that they have to make when they're assessing something that has happened at a station, and if we get engaged on the issue in detail, we may end up relying on the blue dot for the real answer.

MR. PARRY: Or some place in between

MR. STILLWELL: Or some place in between, but for the --

CHAIRMAN APOSTOLAKIS: So why is he saying then that we need detailed guidance? If that is so simple --

MR. STILLWELL: I said for the first cut, going through --

MR. GRANTOM: I think it depends on what you intend the SPAR models to be able to ultimately do. If they're there to promote communication and dialogue on what the real issue is for an event that has happened at a station, that may be sufficient the way they are. If they're intended to do analysis to confirm an analysis that the station has done, well, now you're talking maybe about a higher level of quality.

And I think that kind of has to depend on what the staff intends the SPAR model to be.

CHAIRMAN APOSTOLAKIS: He acknowledges

like in the penultimate bullet. Define the role of SPAR.

MR. GRANTOM: Yes.

CHAIRMAN APOSTOLAKIS: That's fine. But look at the last bullet. Why is there a need for systematic approaches?

Anyway, I think --

MR. GRANTOM: Well, anyway, in some cases what we're doing, we're looking at deltas, you know, here.

CHAIRMAN APOSTOLAKIS: Well, yeah, the first transparency we had up there. I mean, when I see that in the EPRI report, I feel uncomfortable. Now, what you told me earlier about how you handle the ten to the minus five, that you know, it's not a black and white thing and that you're doing certain things even before you get there. That's probably the best way to handle these things.

These are numbers that give you an indication of where you are and that you have to be alert and start doing thing one, and I hope these numbers will be treated the same here. But when you see things in the table that say that if you're between ten to the minus six and ten to the minus five and for ILERF ten to the minus seven and ten to the

minus six do certain things, then it seems to me the burden on the PRA analyst to come up with a good quality PRA is very high.

MR. GRANTOM: Well, that's true, and if you look at our configuration mismanagement program procedure, you'd see specific, you know, kinds of compensatory measures defined in there as what people do during that particular -- when that occurs.

CHAIRMAN APOSTOLAKIS: Okay. I think we've exhausted this subject.

MR. REINHART: Mr. Chairman.

CHAIRMAN APOSTOLAKIS: Yes.

MR. REINHART: Could i Just offer one other perspective on the SPAR?

From the staff's point of view, if we're going to do a review, the SPAR is an independent check maybe to stimulate our thinking, give us a perspective. If we get down to the details inevitably we're dealing with a licensee on their PRA to really get to the details.

CHAIRMAN APOSTOLAKIS: But my understanding, Mark, is that there is interaction with the licensee, and you have changed the SPAR.

MR. REINHART: Yes.

CHAIRMAN APOSTOLAKIS: If the SPAR model

is conservative in certain aspects, there is an indication that there is some model uncertainty there, and the NRC chose to go to the conservative way as they should.

This is the message I get from all of this. So when, you know, Mr. Bradley comes later and tells me, you know, this is what EPRI developed, that will be an input to my thinking, and I'll try to see how they managed it. Okay?

And the second bullet in the previous slide regarding the RCP seal failure is an example that everybody knows.

MR. REINHART: Right.

CHAIRMAN APOSTOLAKIS: So I think we are going beyond now the standard PRA approach. We're addressing the real issue of uncertainties, and I'm not claim that I know how to handle those, but there's an industry we have to pay attention.

In fact, last time when we were discussing the special treatment requirement rule, Mr. Pietrangelo and Mr. True agreed that they would look into the issue of model uncertainty, but in their case of course the categorization is conservative already. So it is not as urgent as it is here.

Any other comments or questions from the

members? From the presenters?

MR. GRANTOM: Thank you for the time and the opportunity to discuss this.

DR. SIEBER: Thank you.

CHAIRMAN APOSTOLAKIS: Public? I'm sorry. The NRC staff.

MR. BOYCE: Did you see anything that you wanted to explicitly let us know and perhaps a letter? Are you intending to write a letter on risk in general?

CHAIRMAN APOSTOLAKIS: I cannot decide on whether we want to write a letter. We will -- maybe I should do that now. Go around the table and get some preliminary feedback.

We'll talk about it later I am told.

When?

Well, they can give me their impressions. Can you give me your reaction to what you've heard today, please? Who wants to go first? Tom?

DR. KRESS: Well, I certainly think it's a good idea to risk inform the tech specs, and if you're going to do it, I think the approach being taken is a legitimate one. You have to have acceptance criteria, risk metrics, and figure out how to calculate it, how to assure the quality. What

quality of PRA is needed and how to assure that, it seems to me is as yet a to be determined factor, and I'm interested in seeing how that works out.

As far as the details of the risk acceptance matrix and the way you would calculate them and the way you enter into the various parts of it, I think they have thought that out pretty well, and it looks good to me.

The one thing that tends to bother me a little bit is how to choose the zero time when risk configurations change. I think their process of saying you enter the tech specs at zero time and no matter what happens, when it happens that's zero time; I think that's conservative. It maybe too conservative, but maybe that's not NRC's problem. Maybe that's the industry's problem.

So I think that would be a conservative way to deal with it. So on the whole, I'm pretty pleased with what I see. I think it's a good approach. I think it's headed. I think it will make the tech spec more coherent and give some flexibility to industry to use on line risk monitors.

One other issue I have, potential issue I have with it, is -- well, I guess I'll save that one till later.

CHAIRMAN APOSTOLAKIS: Thank you.

Mario.

DR. BONACA: I am encouraged by what has taken place. I like this initiative, and I like what is being done at South Texas. I think the level of flexibility that the plant can have with significant backing of good risk insights.

I'm just thinking that one day when all of this 104 plants will be operating, and they won't be probably under this 4(b), there will be a lot of configurations out there taking place at any given time. So I think it's very important that this risk model be accurate and good.

But I think that for this we see, you know, high quality PRA being used.

CHAIRMAN APOSTOLAKIS: Very good.

DR. BONACA: So I'm very supportive.

Insofar as writing a letter, I think it is probably premature and --

CHAIRMAN APOSTOLAKIS: They're coming back in May.

DR. BONACA: Yeah, it's still a work in progress. My thought would be not to write a letter.

CHAIRMAN APOSTOLAKIS: Peter?

DR. FORD: Yeah, I find that the

development of this tool very, very impressive, indeed. Being a novice in this area, I really am impressed by something I didn't think was possible.

The biggest question I have is the treatment of uncertainties. I hear deterministic numbers, given 72 hours, 24 hours, et cetera, et cetera, in the various presentations that will be made, and I keep asking myself as a deterministic sort of guy, well, what's the uncertainty in that value, and is there any danger of not taking that into account?

But I think I'm expressing more my newness to this particular subject of what is being undertaken.

CHAIRMAN APOSTOLAKIS: Thank you.

Jack?

DR. KRESS: That was my other issue that I didn't bring up.

CHAIRMAN APOSTOLAKIS: The uncertainty aspect.

DR. SIEBER: It seems to me that issues of philosophy and policy here are pretty well thought out both by the staff and licensees in the industry, and so I wonder whether it's worth our while to write an expansive letter that would cover these global kinds

of aspects.

There may be individual things that we want to talk about. I think Tom's question about when is time zero is an important one, particularly in light of the fact, just as an example, if you have a PC of equipment with a seven-day LCO and you go through five days of that and it is probably not risk significant, and then another piece of equipment that goes out, the combination of which is really risk significant, it doesn't give the advantage to the licensee to say time zero starts when the first piece went out.

And so to me I'm struggling with that. If there's a way to do that better and mimic the situation better, then I would encourage people to find that way because to me that's sort of troublesome.

The other troublesome thing is --

DR. KRESS: And you might be able to do that with some sort of cumulative risk concept.

DR. SIEBER: I think you can do it.

MR. STILLWELL: We thought really hard about what you're talking about because we've --

DR. SIEBER: Okay. I think it can be done, and I think it is worth pursuing.

The other thing that I think is significant is that, you know, this is a two phase exercise. One of them is to apply risk information to modify your tech spec so that you have differing outage times, allowed outage times. It all relies on the quality of the PRA. The quality of the PRA relies on Reg. .200, which relies on industry standards, half of which aren't written.

So as we charge forward in the process, we're trying to risk inform the tech specs. I think that there has to be plenty of emphasis on defining what's a suitable PRA, and you know, just getting back a little to the discussion of the SPAR models, I sort of look at the SPAR models as the same kind of assessment tool that the NRC uses in Appendix K.

The licensee comes forward with an Appendix K analysis that meets the rules, and NRC relies on the NRC's analysis to determine whether the final acceptance criteria is met or not.

On the other hand, they assess the quality of the licensee's work by using TRACE or some similar code that's in there, stable of intellectual property, and SPAR models to me are the same kinds of things. If you want to do a general survey, that's fine, but I wouldn't make specific inclusions about specific

plants from the SPAR models because the licensee has spent more time and effort putting in the right numbers and putting in the right logic than was done with SPAR.

I think SPAR has a useful place, but I don't think I can draw any conclusions from that. So I don't know if you can decipher anything out of what I said, but I think that those are my impressions as to where we stand today and what the ACRS ought to do.

And I would like to add I would like to thank the staff for a very good presentation and South Texas and NEI and EPRI and everyone else who has worked so hard on this project.

Thank you.

CHAIRMAN APOSTOLAKIS: I would just make one comment that I don't view the SPAR models that way because they are not developed independently. There is a lot of give and take with the utility, and I don't see why the staff should do something that the utility has done better.

The staff say no, no, no, we'll stick with something that's bad, and therefore, the way I see it is that when there are differences, there are legitimate professional differences regarding a few things, and these differences have to be reflected in

the PRAs. That's where I'm coming from.

Now, if somebody tells me, yeah, we corrected this and now the point is on the line, well, great. Let's all rejoice.

But when I see a list that says, you know, there are differences regarding this and this and that, then I'd like to see some resolution because I don't think that the intent of SPAR is to be capriciously conservative. They will be conservative when there is a reason to be conservative, and that's my starting point, which is related to PRA quality and all of that.

I'd like to thank the presenters, both the staff, NEI, and South Texas. They were excellent presentations in my view. We had good discussion, and we really appreciate your taking the time to come here.

Mr. Grantom must have the last word.

MR. GRANTOM: In responding to the questions about when time zero starts, we didn't actually get to go through some of the examples, but in the supporting slides that we had put together in the presentation, I'd invite you to look at the examples that we provided in there for your own time and your own perusal.

CHAIRMAN APOSTOLAKIS: Okay.

MR. GRANTOM: I just wanted to let you know those were there.

DR. KRESS: George, before you bang the thing, every time we review and look at anything with the words "risk informed" in it, we buck up against the issue of, "Well, what about uncertainties? How are you going to treat those?"

And it boils down to, well, we know how to do parameter uncertainties, but we don't know how to do model uncertainties, and so we will just forget about the model uncertainties and do parameter.

Somewhere along the line, we have got to face up to this issue, and Pat Baranowsky had one of his slides. I think that's what he was talking about. We need to have guidance on how to deal with model and parameter uncertainty in risk informing anything.

And I think the ACRS needs to come up with some sort of position on that.

CHAIRMAN APOSTOLAKIS: And if you recall, last time when Mr. True and Mr. Pietrangelo were here, they agreed to duplicate --

DR. KRESS: They were going to look into that.

CHAIRMAN APOSTOLAKIS: When I suggested

that they look at the three.

MR. GAERTNER: Yes, I'd like to tell you what has happened since then, and we were aware of what Tony and Doug, the interaction they had with you. At EPRI we have initiated a project to address the entire uncertainty issue and develop a guidance document that will include parametric uncertainty as well as modeling uncertainty. We are closely integrated with the NEI effort and with the NRC effort to develop the acceptance criteria that will be used in the NUREG or in the Reg. Guide 1.200, as well as in their action plan.

So that is underway. We're working and we plan to work with NRC Research and with the entire industry on that, and that will be we hope to have a product this year. So we are moving.

DR. KRESS: We'll look forward to looking at that.

CHAIRMAN APOSTOLAKIS: Would you find it useful to have us comment on it?

MR. GAERTNER: Pardon me?

(Laughter.)

CHAIRMAN APOSTOLAKIS: Would you find it useful to come here and present it and have us comment on it?

MR. GAERTNER: Absolutely. That would be wonderful.

DR. SIEBER: What else can he say?

(Laughter.)

MR. GAERTNER: George, you're famous for your opinions on uncertainty. So I would certainly want you --

CHAIRMAN APOSTOLAKIS: So okay. We'll take that into advisement, Mr. Gaertner.

Thank you very much.

I'm very pleased to hear that, by the way. This is really about time. Okay?

DR. BONACA: These are uncertain times.

CHAIRMAN APOSTOLAKIS: These are uncertain times.

Carl, do you want to say anything?

MR. GRANTOM: No, sir.

CHAIRMAN APOSTOLAKIS: Okay. Now I can do it?

MS. WESTON: Yes.

CHAIRMAN APOSTOLAKIS: We'll reconvene at 1:30, I understand, and the subject will be an entirely new subject, PRA quality.

(Whereupon, the subcommittee meeting in the above-entitled matter was adjourned.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Reliability and Probabilistic Risk Assessment & Plant Operations Subcommittees

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.

Rebecca Silberman

Rebecca Silberman
Official Reporter
Neal R. Gross & Co., Inc.

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
RELIABILITY AND PRA AND PLANT OPERATIONS SUBCOMMITTEES
RISK MANAGEMENT TECHNICAL SPECIFICATIONS (RMTS)
ROOM T-2B3, 11545 ROCKVILLE PIKE, ROCKVILLE, MARYLAND

MARCH 25, 2004

- PROPOSED AGENDA -

SUBJECT	PRESENTER	TIME
I. Introductory Remarks Subcommittee Chair	G. Apostolakis, ACRS	8:30-8:35 a.m.
II. RMTS Introduction	Tom Boyce, NRR	8:35-8:40 a.m.
III. Overview of RMTS Initiatives Scope and Status • Initiative 4b, Risk Informed TS Completion Times • Current Issues	Bob Tjader, NRR	8:40-9:10 a.m.
IV. Initiative 4b Pilot Program		
• RM Guidance Document	Biff Bradley, NEI	9:10-9:40 a.m.
• STP* Whole Plant Pilot	Rick Grantom, STP	9:40-10:40 a.m.
V. Summary	Bob Tjader	10:40-10:45 a.m.
VI. General Discussion		10:45-11:30 a.m.

* South Texas Project

Note: Presentation time should not exceed 50% of the total time allocated for a specific item. Number of copies of presentation materials to be provided to the ACRS - 35.

ACRS CONTACT: Maggalean W. Weston, mww@nrc.gov or (301) 415-3151.

Risk Management Technical Specifications

Presentation to the Reliability & PRA, and
Plant Operations Subcommittees of the
Advisory Committee on Reactor Safeguards
March 25, 2004

Principles for RMTS Development

- Achieve coherence with other risk-informed regulation development (MRule, PRA Quality, 50.69)
- Credit for 50.65(a)(4) programs in RMTS Initiatives
- Licensee's risk submittals must meet standards for quality and comprehensiveness
- Involve NRC staff with cognizance for operation, training, inspection, maintenance, regions/STA, and risk assessment

STATUS OF INITIATIVES

- Reliance on existing (a)(4) Program
  - Initiative 2: Missed Surveillances (NRC Approved)
  - Initiative 3: Mode Change Flexibility (NRC Approved)
- Analysis of Specific Plant Configurations
  - Initiative 1: Modified End States (1 yr)
  - Initiative 6: LCO 3.0.3 Action Times (1 yr)
  - Initiative 7: Non-TS Support System Operability (1 yr)
- Quantitative Risk Assessment / Quality PRA
  - Initiative 4: Flexible Completion Times (2 yrs)
  - Initiative 5: Surveillance Frequency Program (2 yrs)
- Rulemaking
  - Initiative 8: Relocate non-risk significant systems from TS (3+yrs)

Initiative 4 – Risk-Informed Completion Times

- Effect: Extend completion time from a nominal value up to a predetermined "backstop" maximum using configuration risk management
- Basis: Under development, to include approved process, requirements for PRA technical adequacy, real-time quantitative capability, configuration and cumulative risk metrics
- Status: Industry submitted draft guidance document & pilot proposals; staff provided feedback. STP & Fort Calhoun are Pilots.

Initiative 4b Example

- See proposed 4b Tech Spec; discuss concepts
- Initiative 4b concepts
  - Front Stop; current CT
  - CRMP-based CT
  - Back Stop
  - Use of Real-Time Risk Assessment Tools and Decision Making Process

TABLE 3-1
GENERIC RISK-INFORMED CTs WITH A BACK-STOP: EXAMPLE FORMAT

Actions Condition	Required Action	Completion Time
B. One [HPSI] subsystem inoperable.	B.1 Restore SI subsystem to OPERABLE status.	72 hours
	OR	
	B.2.1 Determine that the completion time extension beyond 72 hours is acceptable in accordance with established RMTS thresholds.	72 hours
	AND	
	B.2.2 Verify completion time extension beyond 72 hours remains acceptable.	In accordance with the RMTS Program (i.e., within 24 hours of a subsequent configuration change)
	AND	
	B.2.3 Restore subsystems SI to OPERABLE status.	30 days or acceptable completion time , whichever is less.

RMTS INITIATIVE 4b and PRA QUALITY

- Reliance on a tool that will provide configuration specific PRA results in a timely manner to determine Completion Times; this is a significant change to Technical Specifications
- PRA model must be of High Quality (scope, elements, and technical attributes)
- Configuration Risk Management process and tool must be of High Quality
- RMTS 4b will be a significant change to NRC review & oversight of licensee's Technical Specifications

Pilots for PRA Quality and Initiative 4b

- PRA Quality (RG 1.200) is the underpinning of RMTS Initiative 4b
- RG 1.200 Pilot Plants: SONGS, CGS, STP, Limerick
- RMTS Initiative 4b Pilot Plants: STP & FCS
- 4 of 5 Pilot Applications of RG-1.200 involve Technical Specification Amendments
- STP is a Pilot for both RG 1.200 and RMTS Initiative 4b
- Pilots to test:
  - Reg Guide (RG-1.200) ability to prove adequate PRA Quality
  - Necessary scope of PRA
    - Internal Fire + External Events + Shutdown & Transition Risk
  - Software for Configuration Risk Management Tool
  - Configuration Risk Management Process

CURRENT REVIEW ISSUES

- Exportability; Pilot Plant General Acceptance Criteria
  - Reliability
  - Repeatability
  - Enforceable/Oversight
- PRA Quality (proof of concept)
  - Scope
  - Level of Detail
  - Acceptability

POTENTIAL IMPLEMENTATION STRUCTURE

- Program Requirements in Technical Specifications Administrative Controls
  - PRA Quality (RG 1.200)
  - Guidance Documents (RG 1.177+, RMG)
- Licensee Program Guidance
- Oversight

Closing Comments

- RMTS Initiative 4b is linked with PRA Quality
- Communication and Training of HQ Staff & Regions are essential; Initiative 4b is linked with Risk-Informed Environment Initiative
- Early in the Initiative 4b Process; Learn as we go forward

Risk Management Technical Specifications Initiative 4B

Biff Bradley

March 25, 2004

Foundation

- Maintenance rule (a)(4) provision implemented November 1999
  - Resulted in both deterministic (TS) and risk management (MR) regulatory requirements for plant configuration control – sometimes in conflict
  - MR risk assessment and management guidance developed with recognition that TS provided "backstop"
  - NRC recognized that MR could provide foundation for additional TS reform
- Industry (a)(4) programs presented to NRC in February 2001 workshop
  - Over 100 NRC attendees

NEI

Objectives

- Better align deterministic tech specs with risk management approach required by maintenance rule
- Make changes within existing tech spec framework and practice
- Maintain operator safety focus and ease of use
- Provide incentive for improved PRAs and configuration risk assessment tools

NEI

Initiative 4B approach

- Would apply to all equipment LCOs
  - Not applicable to parameters, safety limits
- Maintains existing LCO as "front stop"
  - Operator familiarity
  - Approaching front stop would trigger more extensive risk evaluation and actions
- Deterministic backstop would be established
  - 30 days irrespective of risk impact
- Actual completion times would be based on risk assessment and management using NRC-approved risk management guidance

Pilot Plants

- South Texas Project (whole plant)
- Hope Creek (whole plant)
- Ft. Calhoun (system specific)
- All would incorporate EPRI risk management guidance method through reference in Tech Specs

NEI

Risk management guidance for 4B

- Intent: Achieve NRC approved method for risk assessment and management to implement 4B – reference in TS to adopt initiative
- Developed by EPRI
  - Builds on existing (a)(4) guidance
  - More rigor in risk analysis, risk management actions, plant shutdown decisions
  - PRA scope and capability requirements
- One round of NRC review/feedback complete
  - 75 NRC questions posed and addressed
  - Iterative process to complete development

NEI

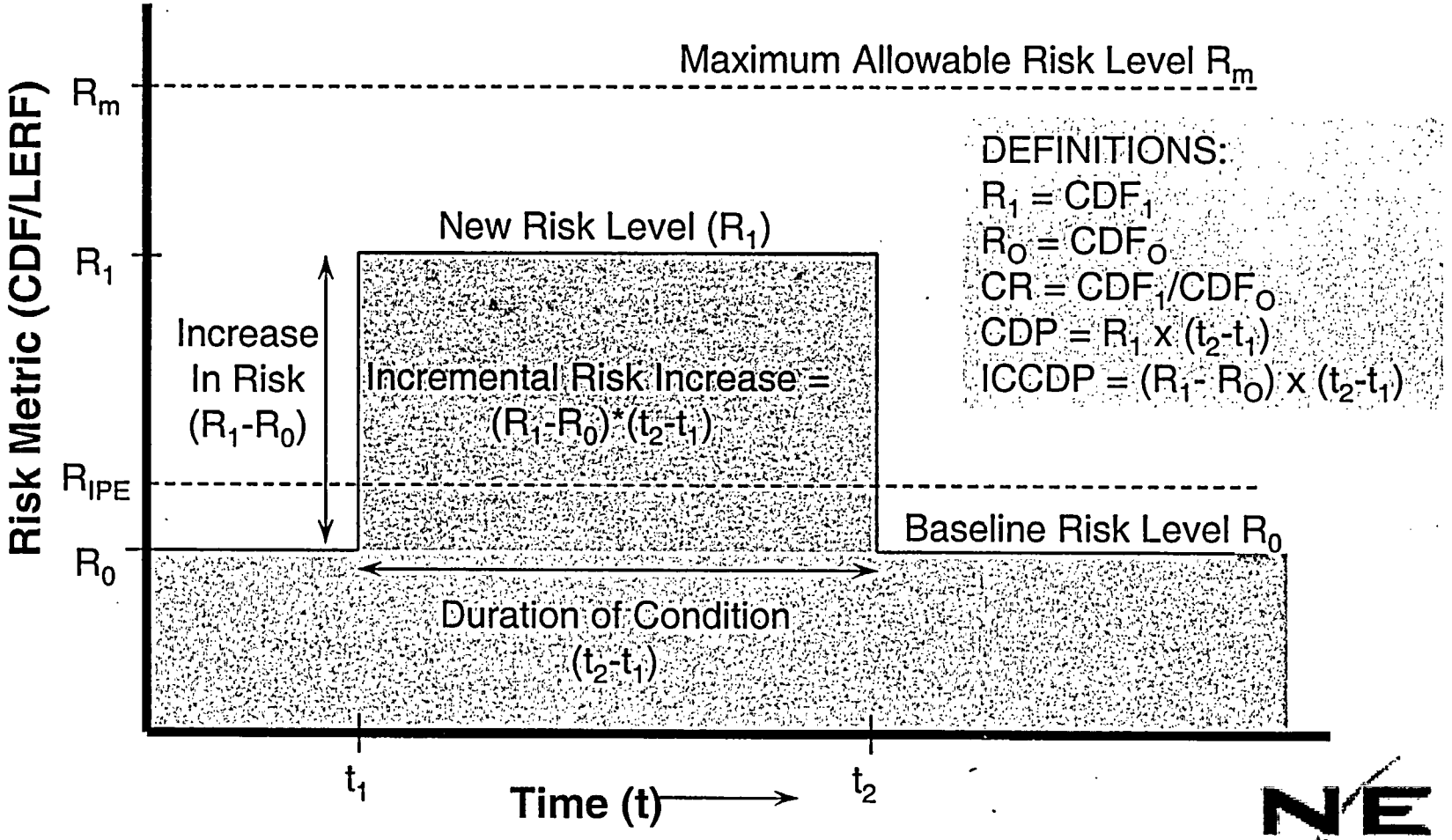
PRA requirements – proposed for 4B

- Minimum PRA and tool requirements
  - Internal events and LERF, NRC Reg Guide 1.200 (ASME standard)
  - External events at power (including seismic, internal fires)
  - Ability to quantify configuration risk
  - Ability to determine and track aggregate risk
  - Updating requirements

Risk assessment metrics

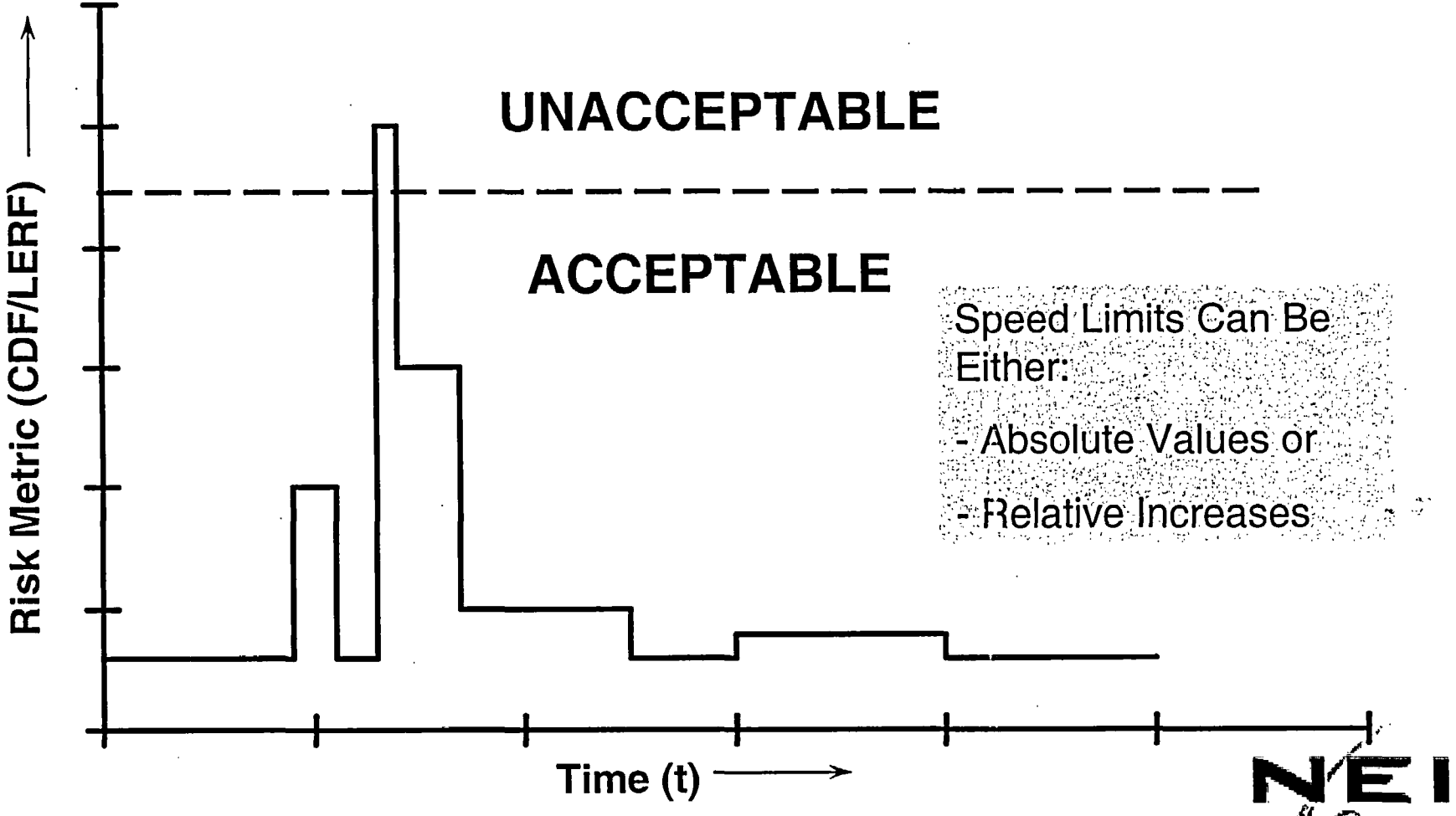
- Planned evolutions
- Emergent conditions
- Guidance will address use of:
  - Temporary risk increase (ICDP)
  - Risk "speed limit" (CDF limit)
  - Cumulative risk (Δ CDF)

RISK MEASUREMENT APPROACH
TEMPORARY RISK INCREASE

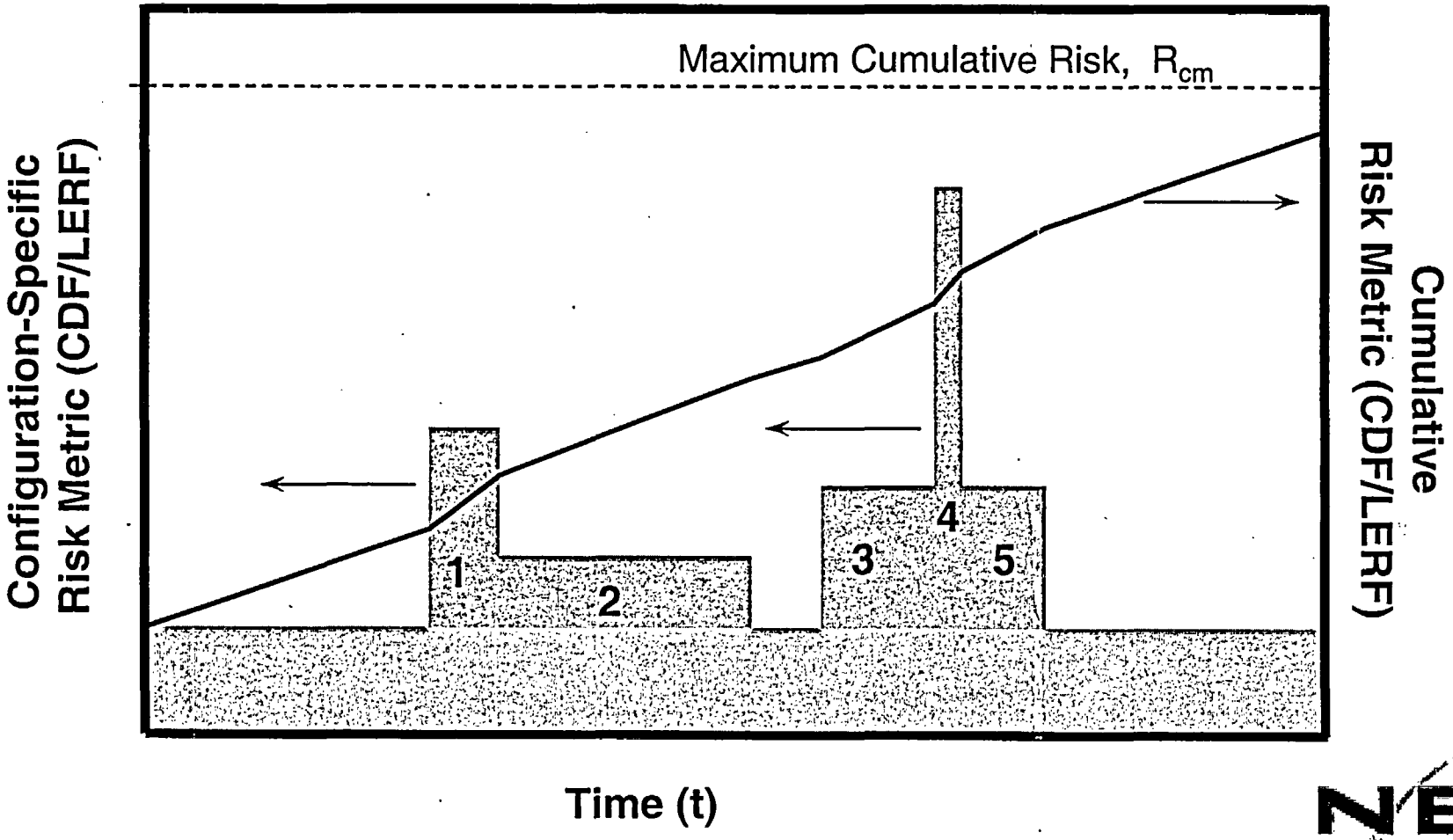


RISK MEASUREMENT APPROACH

RISK "SPEED LIMIT"



RISK MEASUREMENT APPROACH
CUMULATIVE RISK



Risk management

- Actions based on risk metric results
  - Manage risk of configuration
  - Actions may be different from existing Tech Spec LCO requirements
  - Must include plant shutdown decisionmaking approach
- More specificity than existing (a)(4) guidance

Conclusions

- Challenging risk application
- Risk management guidance is work in progress
- Pilot applications will enable further development and detail in guidance
- Goal is NRC endorsement at appropriate level of detail

STP Nuclear Operating Company

STP Risk-Informed Technical Specifications Application

ACRS Subcommittee on
Reliability and PRA

March 25, 2004

Introduction

- STP Participants
  - Rick Grantom — Risk Management Manager
  - Bill Stillwell — Risk Management Supervisor
  - Scott Head — Licensing Manager

Agenda

- Scope and content of the STP whole plant pilot application
- Submittal schedule
- STP PRA Quality (RG 1.200 Pilot)
- Implementation

Scope & Content

- Industry pilot Application for Risk Informed Technical Specifications using Configuration Risk Management (Initiative 4b)
- Comprehensive application of STP's Maintenance Rule (a)(4) approach and STP's Configuration Risk Management Program to produce configuration based allowed outage times (i.e., flexible completion times)
- NRC pilot application for PRA Quality (RG 1.200)

Scope & Content

- Technical Specification structure and format to be retained
- Allows operators to use Risk Management option for determining flexible allowed outage time (AOT) when CTS AOT or "frontstop" has been exceeded
- Imposes a "backstop" for returning equipment to service

Scope & Content

- References the EPRI Implementation Guidelines
- Would apply to conditions where TS 3.0.3 currently applies.
- Establishes a new TS 3.13 to invoke flexible AOT determination
- Flexible AOT based on all CRMP equipment removed from service at a given time

Scope & Content

- Selected instrumentation of TS 3.3
- Code safety valves
- Pressurizer PORVs
- Accumulators
- ECCS
- RHR
- RWST
- RCB Purge
- Containment Isolation Valves
- Containment Spray
- Containment Fan Coolers
- AFW
- MSIVs
- MFIVs
- Atmospheric Steam Relief
- Component Cooling Water
- Essential Cooling Water
- CRE HVAC
- FHB HVAC
- Essential Chilled Water
- SDGs and Off-site circuits
- Batteries
- ESF Buses

Draft TS 3.13

RISK MANAGEMENT

ALLOWED OUTAGE TIME DETERMINATIONS

LIMITING CONDITION FOR OPERATION

3.13.1 When referred to this specification, equipment that has been removed from service or declared inoperable shall be evaluated for its impact on plant risk and allowed outage times determined accordingly.

APPLICABILITY: As required by the referencing specification

ACTION:

Determine that the configuration is acceptable for Completion Time extension beyond the [Front Stop AOT],

AND

Determine that the configuration is acceptable for continued operation beyond the [Front Stop AOT] whenever configuration changes occur that may affect plant risk,

AND

Restore required inoperable [subsystem, component] to OPERABLE status within the Acceptable Allowed Outage Time Extension or 30 days, whichever is shorter.

OR

Take the ACTION required in the referencing specification for required action or completion time not met

SURVEILLANCE REQUIREMENTS

4.13.1: As required by the referencing specification

Sample Specification

PLANT SYSTEMS

3/4.7.4 ESSENTIAL COOLING WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4 At least three independent essential cooling water loops shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With only two essential cooling water loops OPERABLE, **within 7 days** restore at least three loops to OPERABLE status **or apply the requirements of Specification 3.13, OR** be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. **With two or more essential cooling water loops inoperable, within 12 hours restore at least two loops to OPERABLE status or apply the requirements of Specification 3.13, OR be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.**

STP PRA Quality

- PRA quality issues to be addressed as part of the RG 1.200 pilot
- PRA quality scope to include industry peer review, ASME Standard (ASME RA-S-2002), and RG 1.200
- PRA quality needed for the 4B application itself will also be evaluated

Implementation

- Applies the STPNOC Configuration Risk Management Program (CRMP)
  - Same program used for 10CFR50.65(a)(4)
- CRMP establishes risk thresholds for implementation of compensatory measures
  - Non-risk Significant threshold (1E-06)
  - Potentially Risk Significant Threshold (1E-05)

Implementation

- STP has extensive experience in applying the CRMP
  - Routinely used to manage weekly work
  - Effectively applied to manage the recent extended diesel generator outage

Submittal Schedule

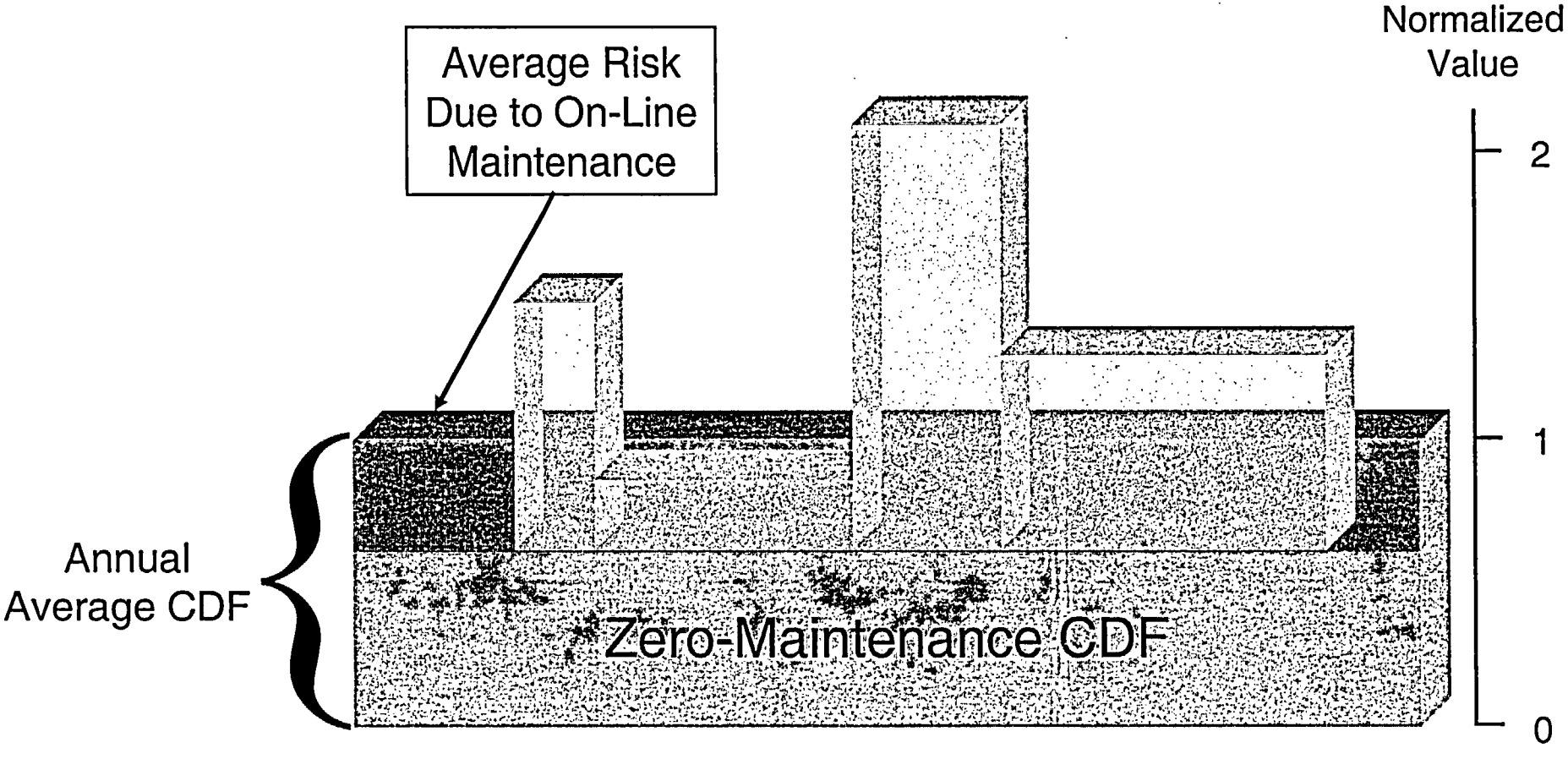
- Submitted "Letter of Intent" with proposed changes in early 2003
- License Amendment Request to be submitted in June 2004

Conclusions

- STP is prepared to support the industry 4b pilot
- The application of flexible AOTs is a natural progression in the use of risk insights
- This is an appropriate PRA quality pilot for RG 1.200

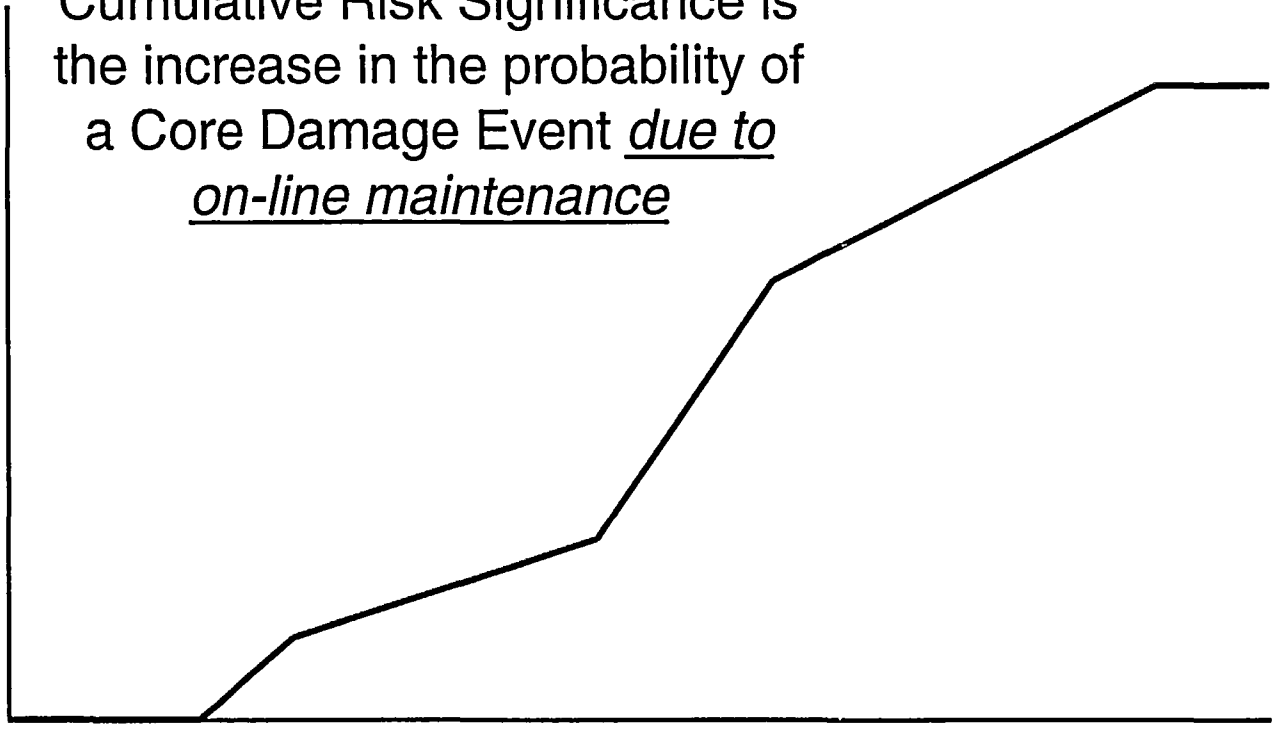
Support Slides

How Risk Values Stack Up

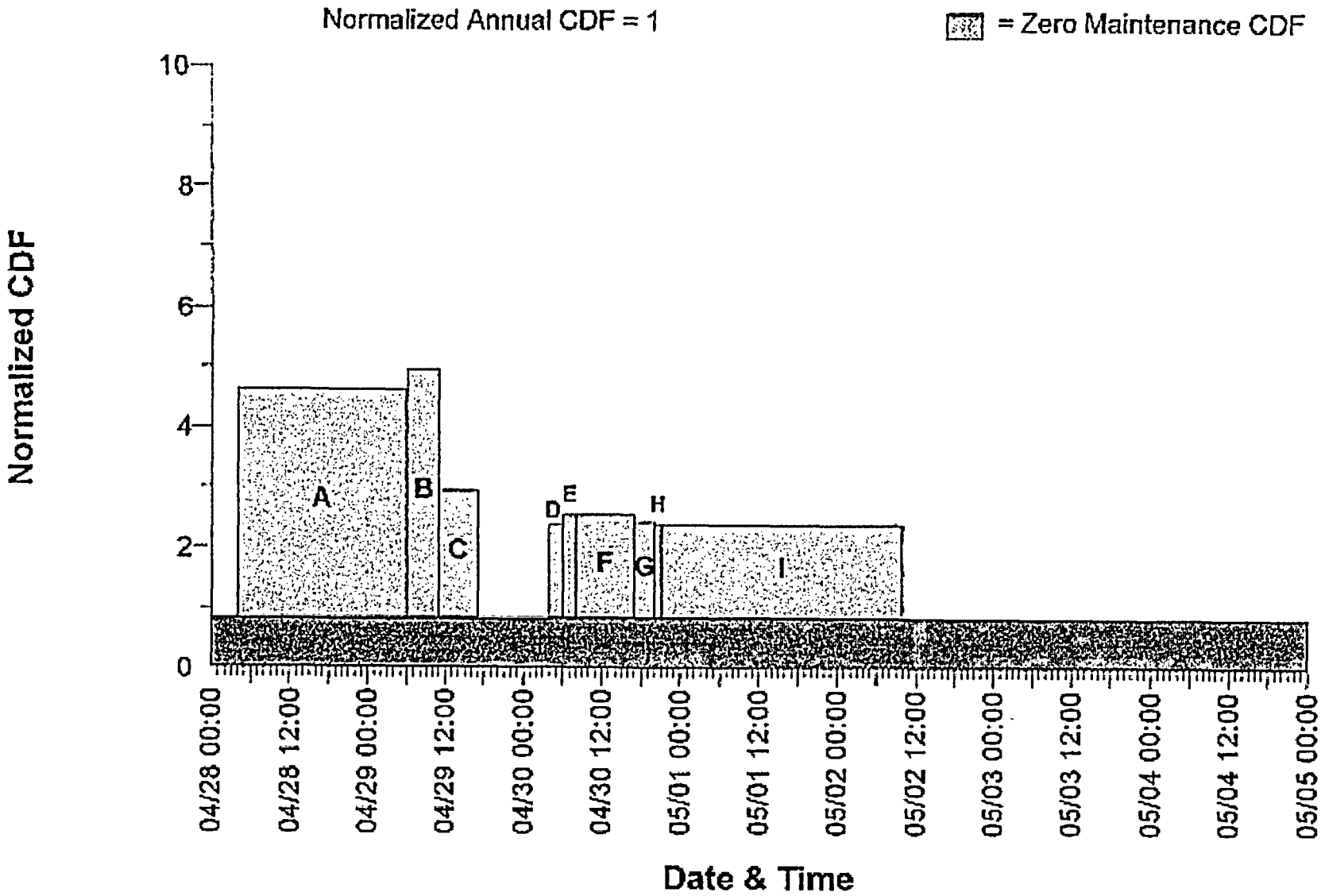


How Risk Values Add Up

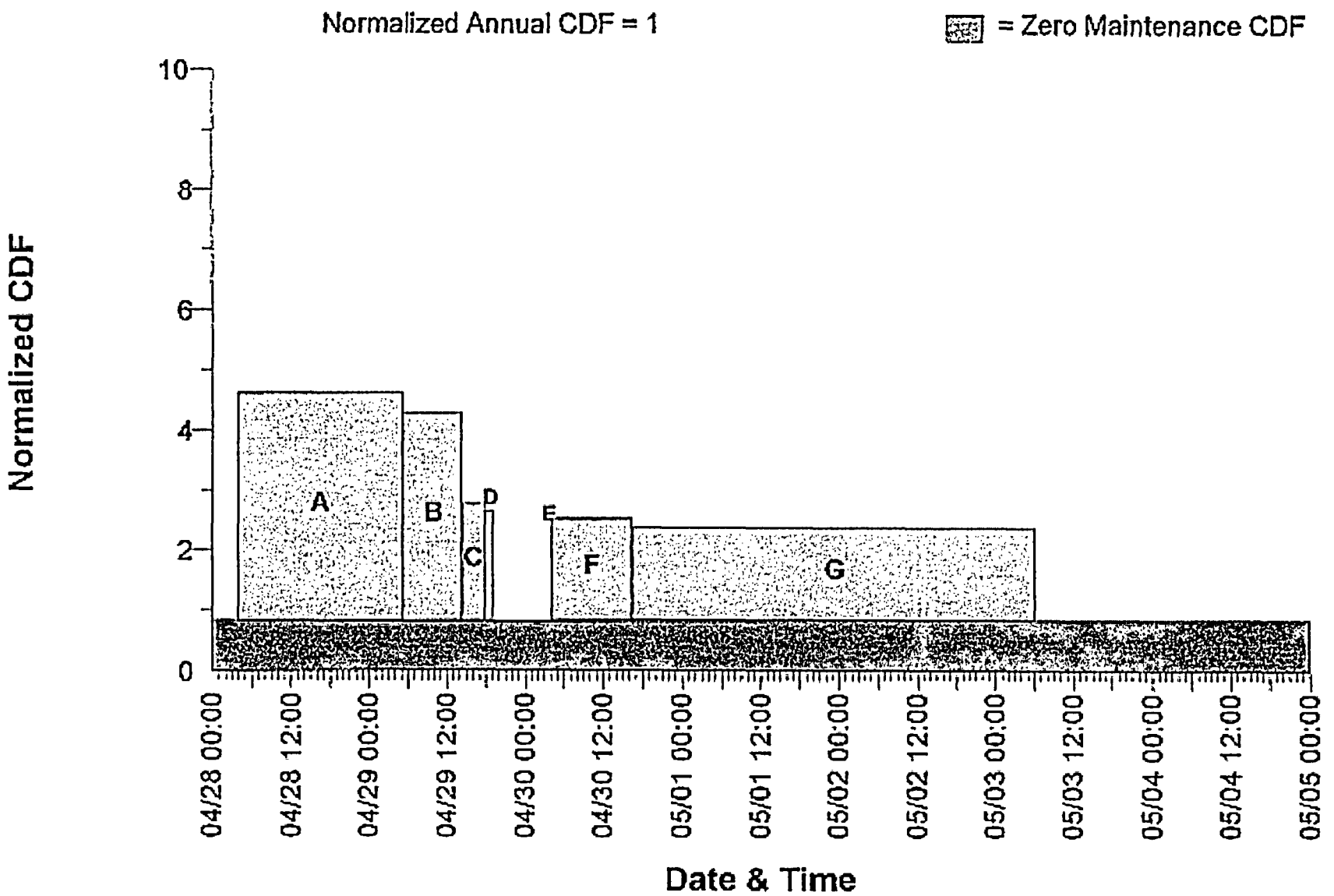
Cumulative Risk Significance is the increase in the probability of a Core Damage Event *due to on-line maintenance*



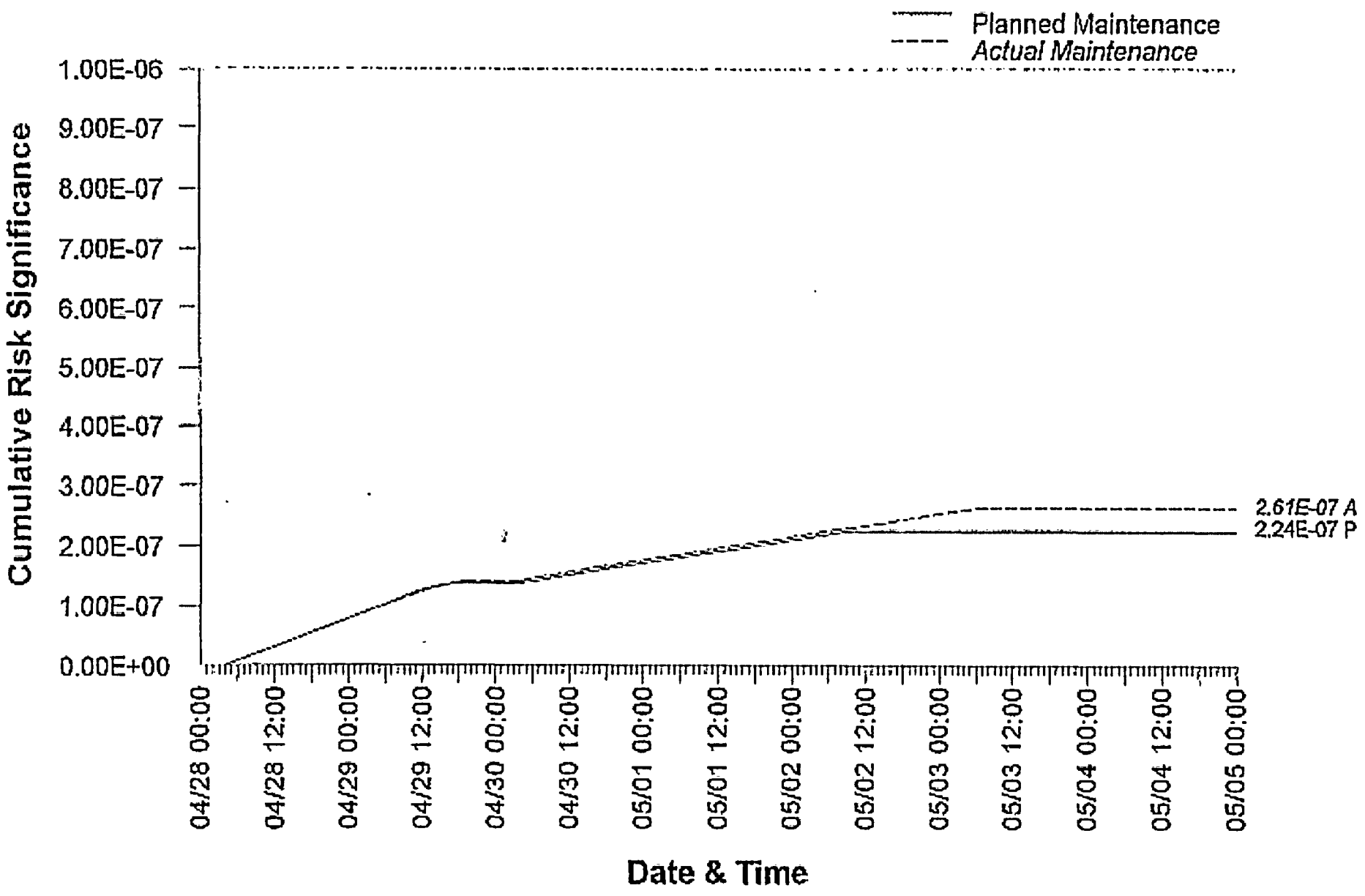
PLANNED RISK PROFILE FOR UNIT 1 WEEKOF 4/27/01

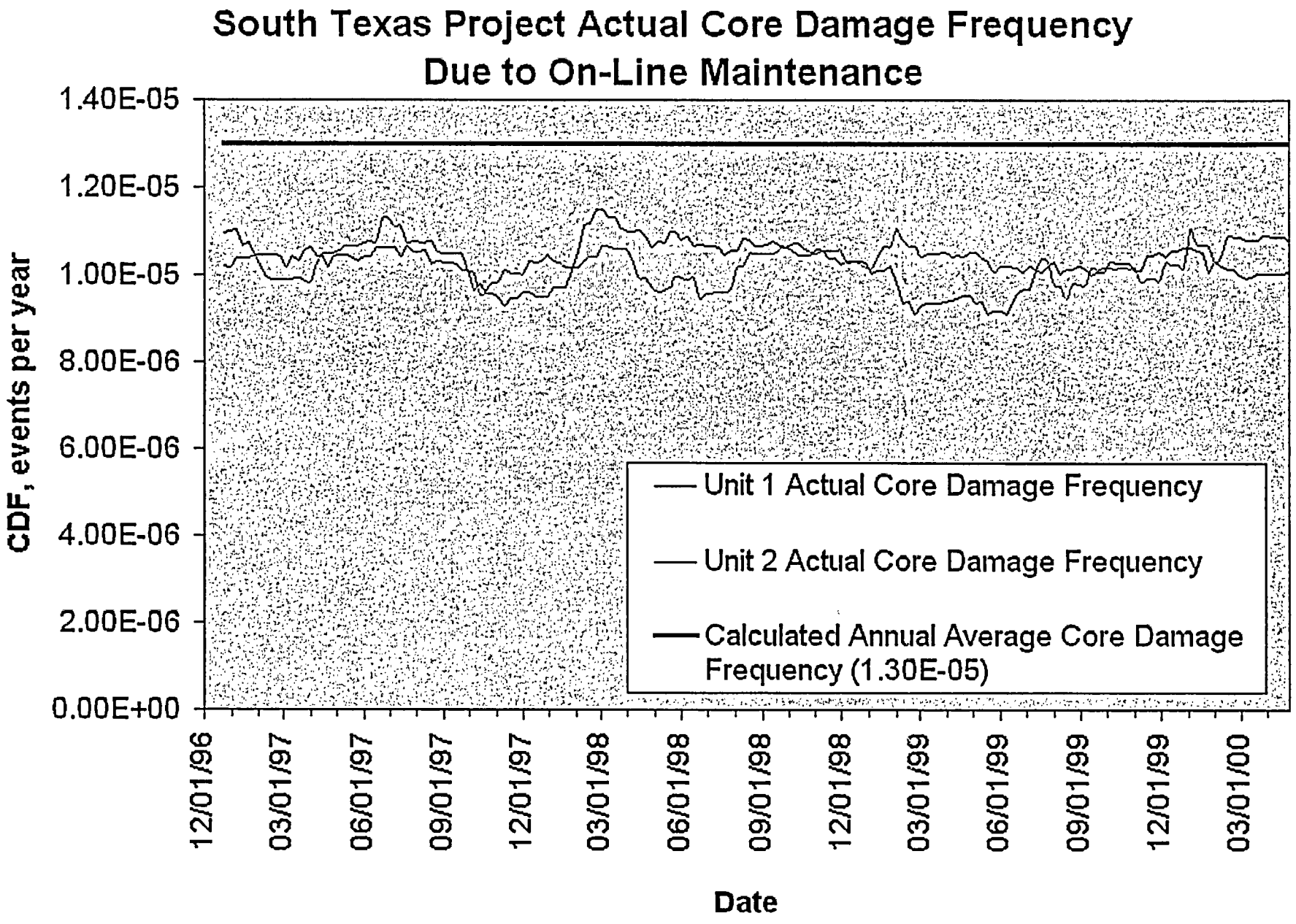


ACTUAL RISK PROFILE FOR UNIT 1 WEEKOF 4/27/01



ACTUAL RISK PROFILES FOR UNIT 1 WEEKOF 4/27/01




South Texas Project Actual Core Damage Frequency
Due to On-Line Maintenance
CDF, events per year
1.40E-05
1.20E-05
1.00E-05
8.00E-06
6.00E-06
4.00E-06
2.00E-06
0.00E+00
12/01/96
03/01/97
06/01/97
09/01/97
12/01/97
03/01/98
06/01/98
09/01/98
12/01/98
03/01/99
06/01/99
09/01/99
12/01/99
03/01/00
Date
Unit 1 Actual Core Damage Frequency
Unit 2 Actual Core Damage Frequency
Calculated Annual Average Core Damage Frequency (1.30E-05)

Application of RITS

Example 1: Routine Train A work week with emergent Train B condition

Time (hh:mm)	Event	Frontstop	Calculated AOT (time to reach 1E-05)	Risk (/hr)	Comment
00:00	Begin Train A work week (SDG, ECW, CCW, HHSI)	HHSI (3.5.2.a): 7 days CCW (3.7..3.a): 7 days ECW (3.7.4.a): 7 days SDG (3.8.1.1.b): 14 days	NA, planned to remain within frontstop allowed outage time.	5.9E-09	Routine planned maintenance
24:00	Train B HHSI found to be inoperable	3.5.2.b: 6 hours to apply TS 3.13	24 days	1.7E-08	Emergent condition where CTS would require TS 3.0.3 entry. RITS permits the station to address the condition with normal work controls.
36:00	Train B HHSI restored	Exit TS 3.5.2.b and TS 3.13 applicability. Back on the work week clock with 36 hours elapsed.	NA	5.9E-09	

Application of RITS

Example 2: Emergent condition while in configuration where TS 3.13 is in use

Time (hh:mm)	Event	Frontstop	Calculated AOT (time to reach 1E-05	Risk (/hr)	Comment
00:00	ECW pump replacement expected to last 10 days.	TS 3.7.4.a: 7 days (Also makes associated SDG inoperable)	1 train of ECW could be allowed OOS up to the 30-day backstop	4.5E-09	TS 3.13 requirements apply after 7 days. The risk is calculated from the time the ECW is taken out of service.
8 days	Turbine-driven AFW found to be inoperable	TS 3.7.1.2.b: 72 hours TS 3.8.1.1.d: 24 hours	27 days	1.5E-08	Regardless of the frontstop time for the TDAFW pump, TS 3.13 applies because the ECW has gone beyond its frontstop. TS 3.13 requires a determination of the acceptability of the configuration with the additional inoperable TDAFW. Application of the CRMP would determine the configuration is acceptable.
9 days	ECW pump is restored	TS 3.7.1.2.b: 72 hours less the 24 hours that have transpired.	> 30 days (backstop would apply)	1.5E-09	The condition that caused TS 3.13 to apply has been exited and there are no TS beyond their frontstop time. The frontstop AOT may be applied to the TDAFW.

Application of RITS

Example 3: Same as Example 2, except that the emergent condition is restored first

Time (hh:mm)	Event	Frontstop	Calculated AOT (time to reach 1E-05)	Risk (/hr)	Comment
00:00	ECW pump replacement expected to last 10 days.	TS 3.7.4.a: 7 days	1 train of ECW could be allowed OOS up to the 30-day backstop	4.5E-09	TS 3.13 requirements apply after 7 days. The risk is calculated from the time the ECW is taken out of service
8 days	Turbine-driven AFW found to be inoperable	TS 3.7.1.2.b: 72 hours TS 3.8.1.1.d: 24 hours	27 days	1.5E-08	Regardless of the frontstop time for the TDAFW pump, TS 3.13 applies because the ECW has gone beyond its frontstop. TS 3.13 requires a determination of the acceptability of the configuration with the additional inoperable TDAFW. Application of the CRMP would determine the configuration is acceptable.
9 days	TD AFW restored	NA	> 30 days	4.5E-09	TS 3.13 still applies. TDAFW no longer contributes to risk calculation. A new completion time may be calculated.

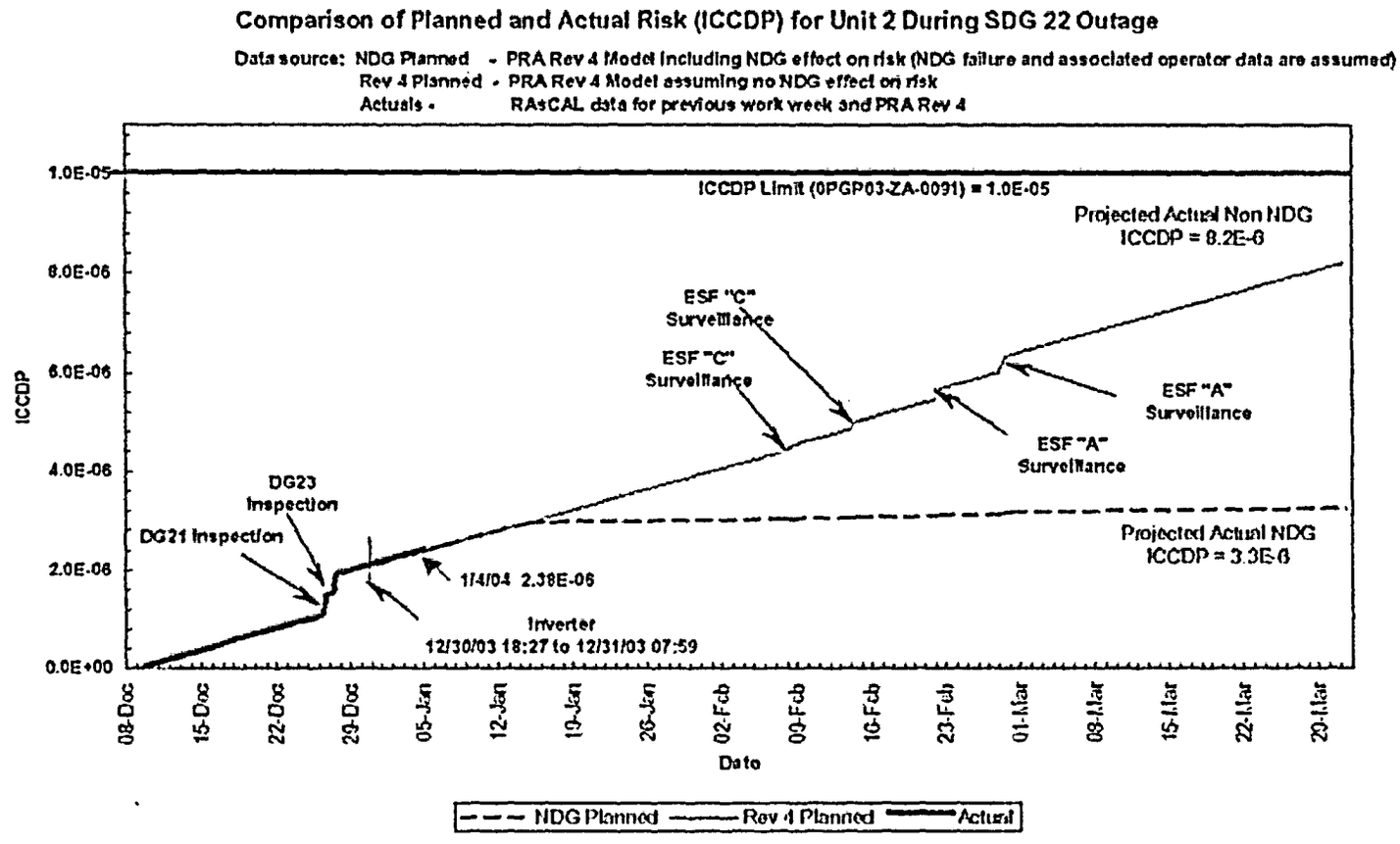
SDG 22 113 Day Extended AOT

- One-time emergency TS Change approved on December 30, 2003
- Configuration risk to be managed by application of the STP Configuration Risk Management Program (CRMP).
- Good example of how the CRMP works
  - Duration and risk bound any that would be encountered using proposed RITS

SDG 22 113 Day Extended AOT

- AOT extension met RG 1.174 and RG 1.182 acceptance criteria
- Installed non-safety DGs (NDG) as compensatory action
  - RG criteria met without credit for NDGs
- STPNOC is closely monitoring the risk profile

SDG 22 113 Day Extended AOT



Backup Slides

Initiative 2 – Missed Surveillance Actions

- Effect: Extension of flexibility granted in Generic Letter 87-09; allow up to one surveillance interval to make up inadvertently missed/incomplete surveillance
- Basis: Infrequent use, likelihood that equipment is operable, entry into corrective action program, assess and manage risk of delay as extension of (a) (4) program (treat as emergent condition)
- Status: Approved, over 90% of plants adopted

Initiative 3 – Mode Flexibility

- Effect: Extension of flexibility granted in Generic Letter 87-09; allow mode transition up in power with inoperable equipment, relying on compliance with TS actions of higher mode
- Basis: Infrequent use, generic risk analysis ruling out some transitions, 50.65(a)(4) assessment and management of configuration risk, oversight of 50.65(a)(4)
- Status: Approved; about 5% of plants adopted

Initiative 1- End States

- Effect: Allow repair in most risk beneficial state (e.g., hot shutdown instead of requiring transition to cold shutdown)
- Basis: CE and BWR generic analysis of preferred mode for repair of inoperable equipment
- Status: Reviewing CE and BWR Tech Spec proposed changes

Initiative 6 – Shutdown Tracks

- Effect: Risk-inform shutdown completion times for not meeting LCO and its actions (LCO 3.0.3 shutdown completion times)
- Basis: CE quantitative bounding risk analysis for specific tech specs
- Status: CE topical under review; SER to be prepared by staff

Initiative 7 – Risk-Informing Support Equipment Impact

- Effect: Allow a TS train to be considered operable up to a prescribed maximum time with degraded non-TS design support features (barriers and snubbers)
- Basis: Generic calculation showing low risk due to low initiator frequency (internal flood, seismic event)
- Status: Staff reviewing proposals

Initiative 5 – Relocation of Surveillance Test Intervals

- Effect: Requirement to perform surveillance remains in TS, frequency adjusted outside TS in TS program using staff-approved methods
- Basis: Review of methods, PRA technical adequacy/quality
- Status: Industry preparing guidance document, methodology, and tech spec changes; Limerick is pilot plant

Initiative 8 – Risk-Informing TS Scope

- Effect: (a) Allow relocation of LCOs not meeting any 50.36 criteria, including criterion on risk significance, (b) Limit scope of TS to risk-significant SSCs
- Basis: Adaptation/adoption of categorization approach from Option 2, generic analysis, PRA technical adequacy
- Status: (a) Industry preparing paper for staff review, (b) 8b requires rulemaking

Feedback from November 2002 ACRS Meeting

- Commission agrees: Graded approach to reliance on PRA capability OK
- Awareness issue: Too much for too little?
- Review/Inspections: Need to guard against abuse – maintain awareness/oversight of patterns
- Integrated effort: Continue to consider how initiatives interact