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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

530th MEETING

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FRIDAY, MARCH 10, 2006

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The meeting came to order at 8:30 in room T2B3 of 2 White Flint North, Rockville, MD, Graham Wallis, Chairman, presiding.

PRESENT:

GRAHAM WALLIS	CHAIRMAN
GEORGE E. APOSTOLAKIS	MEMBER
J.SAM ARMIJO	MEMBER
MARIO V. BONACA	MEMBER
RICHARD DENNING	MEMBER
DANA A. POWERS	MEMBER
OTTTO C. MAYNARD	MEMBER
WILLIAM J. SHACK	MEMBER
JOHN D. SIEBER	MEMBER AT LARGE
THOMAS S. KRESS	MEMBER
JOHN LARKINS	DESIGNATED FEDERAL OFFICIAL
DAVID FISCHER	STAFF ENGINEER

C O N T E N T S

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

8:30 a.m.

CHAIRMAN WALLIS: The meeting will now come to order. This is the second day of the 530th meeting of the Advisory Committee on Reactor Safeguards.

During today's meeting the Committee will consider the following.

Draft final revision for DG 1128 to Regulatory Guide 1.97; criteria for accident monitoring instrumentation for nuclear power plants; evaluation of precursor data to identify significant operating events; future ACRS activities; report of the planning of procedures subcommittee; reconciliation of ACRS comments and recommendations; draft final ACRS report on the NRC Safety Research Program; and the preparation of ACRS reports.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Mr. Sam Duraswellme is the designated federal official for the initial portion of the meeting.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's sessions.

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

I now turn to my colleague, Jack Sieber, to introduce us to the first item of the agenda. Jack.

MEMBER SIEBER: Thank you, Mr. Chairman. John Lamb prepared for each of you a binder which has the pertinent documents for this morning's session.

Enclosed within it and key to that is IEEE Standard 497-2002. And the Regulatory Guide 1.97 would endorse this particular IEEE standard with some exceptions. And the staff will explain those exceptions to us.

Now as a matter of background, this standard, its predecessor standards, was - came in the aftermath of TMI for accident monitoring instrumentation. The first standard and its two revisions were really proscriptive in nature in that there were tables and lists of instruments that had to exist in various types of plants and what their qualifications should be.

This latest IEEE standard is far more

flexible and more performance based. And instead of the list of instruments, you now review the emergency response guidelines. If, in Westinghouse plants that's what they call them. And your emergency operating procedures, abnormal operating procedures and so forth.

And identify every place where an operator does something based on an instrument that he reads. And that becomes an instrument that is action and monitoring instruments.

And because of that flexibility, there is some care has to be taken and in the implementation of the standard.

So without giving away the whole story here, what I'd like to do is make a general comment that I think the staff did a good job on, on this particular one, and I'd like to introduce Bill Kemper, who'll tell us what the staff intends to present. Bill?

MR. KEMPER: Thank you, Jack.

Yes my name is Bill Kemper. I'm the branch chief for the Instrumentation and Electrical Engineering Branch in the Office of Research. As Jack said, we are here today to present the final draft version of Reg Guide 1.97 for the Committee's review and concurrence.

Some of the ACRS committees have seen the majority of this information already during the June 14th, 2005 ACRS INC subcommittee meeting. However, the document has been sent out for public comments, review and comments, and we did receive a fair amount of comments which we're going to cover those with you today. And therefore the document has been revised.

So George Tartal, who's an INC engineer in our branch is the author of this document, and he will be providing the presentation today. Barry Markus is up there with him, who is also an INC engineer in NRR. And Barry is here primarily to provide information the Committee may desire on this matter with regard to regulatory issues or regulatory perspective, if you will.

So Barry's also the technical lead with NRR for the Reg Guide 1.97 program, and he's the principal reviewer for all licensing applications associated with that subject matter.

So unless there's any questions at this time, we'll go ahead and get started with the presentation. George?

MR. TARTAL: Good morning. My name is George Tartal and I work in the Instrumentation

Electrical Engineering Branch of the Office of Nuclear Regulatory Research.

At the June 2005 ACRS digital INC subcommittee meeting, I presented draft guide DG-1128. DG-1128 was the draft version of Rev 4 of Reg Guide 1.97.

DG-1128 was released for public comment in August of 2005. The staff has since received public comments, provided responses to the comments, and made the appropriate revisions to the Guide.

Today I present to the Committee the final Rev 4 of Reg Guide 1.97, criteria for accident monitoring instrumentation for nuclear power plants.

First I'll provide a brief background on the history of accident monitoring, then I'll discuss the current revision, Rev 3 of Reg Guide 1.97. Then I'll provide a brief overview of the endorsed IEEE Standard 497-2002, which is a revised standard for accident monitoring criteria.

Then I'll describe the guide presented for discussion today, Rev 4 of Reg Guide 1.97, focusing on the regulatory positions contained within.

Next is a discussion of public comments received and the associated staff responses, followed by a conclusion.

Instrumentation are required to monitor variables and systems under accident conditions by 10 CFR, Part 50, Appendix A, Criteria 13, 19, and 64.

Rev 1 of Reg Guide 1.97 was issued as an effective guide in August of 1977. Then the accident TMI happened in 1979 and the lessons learned from TMI and post-TMI action plan NUREG-0737 which was later codified in 10 CFR 5034(F), resulted in Rev 2 to Reg Guide 1.97 in December of 1980.

Rev 2 endorsed consensus standard ANSI/ANS 4.5-1980, and was to be implemented via NUREG 0737, Supplement 1.

Rev 3, the current revision, was issued in May of 1983. It continued to endorse ANSI/ANS 4.5-1980, which has since been withdrawn and is now an inactive standard.

In Rev 3, each -

MEMBER APOSTOLAKIS: So I'm sorry, what's the difference between Rev 3 and Rev 2 then?

MR. TARTAL: Rev 2 provided a table of design and qualification criteria - I'm sorry in Rev 3. Rev 2 had the design qualification criteria all throughout the text of the document, so it was more of an organization.

MEMBER APOSTOLAKIS: I see.

MR. TARTAL: In Rev 3, each accident monitoring variables assigned a variable type and a category. The variable type is selected based on its accident monitoring function, and the category is selected based on the required quality level.

So let me briefly review for you the variable types and categories used in Rev 3 since we're going to talk about them later in this presentation.

The proscriptive tables of accident monitoring variables are organized by variable type. Type A are for planned manual actions with no automatic control.

Type B are for assessing plant-critical safety functions.

Type C are for indicating a potential or actual breach of fission product barriers.

Type D are for indicating safety system performance and status.

And Type E are for monitoring radiation levels, releases, and environs.

So these are the five types of variables that are defined in Rev 3.

The design and qualification criteria applicable to each variable are determined by one of three assigned categories.

Category 1 is for indicating the accomplishment of a safety function, and analogous to safety-related instruments.

Category 2 is for indicating safety system status, and analogous to augmented quality-related instruments.

Category 3 is for backup and diagnostic variables, and analogous to non safety-related instruments.

So let me give you a few examples. Primary containment pressure is required for monitoring containment integrity. And that's a Type B, Category 1 variable.

Containment atmosphere temperature is required for monitoring containment cooling system status. That's a Type D, Category 2.

Everybody with me? Good.

IEEE Standard 497-2002 was created to consolidate the criteria from inactive standards ANSI/ANS 4.5-1980 and IEEE Standard 497-1981, as well as from Reg Guide 1.97, Rev 3.

It provides a technology-neutral approach intended for advanced design plants. It takes a performance based and non-proscriptive approach to the selection of accident monitoring variables.

The proscriptive tables of BWR and PWR variables from Rev 3 have been replaced by variable selection criteria based on the design basis accident mitigation functions. This is the most significant change from Rev 3.

Another significant change from Rev 3 is that the selected variable type determines which performance design qualification, display and quality assurance criteria are applicable as categories are no longer used.

MEMBER SIEBER: I'd like to point out that when you talk about this being applicable to the advanced design plants, I think that there are some plants where this would not be particularly suitable.

Some concepts, for example gas reactors, molten salt, and that kind. I see this as totally applicable, however, to evolutionary plants, which will probably be the next generation that comes along.

But this, this will be revised again if we get into more exotic reactor types, I'm sure.

MR. TARTAL: Thank you.

So this slide gives a brief overview of the criteria and the standard. The definitions for variable types A, B, C, D and E are similar to the definitions that were in Rev 3. Some typical source documents are referenced for each variable type, like EOPs, EPGs, and AOPs.

The performance criteria include range, accuracy, response time, duration, and reliability. Design criteria include single and common cause failure, independence, separation, isolation, power supply, calibration, and portable instruments.

Qualification criteria include environmental and seismic qualification. Display criteria include display characteristics, identification, display types, and recording. And finally, quality assurance criteria are given.

So that brings us to the final guide as it exists today. Rev 4 of Reg Guide 1.97 was prepared as a response to a user need request from NRR. It endorses IEEE Standard 497-2002, with exceptions and clarifications.

It's intended for new nuclear power plants, while conversion to the new criteria by current operating plants is recommended on a comprehensive and strictly voluntary basis. And we'll talk more about that in a moment.

It was issued for public comment as draft guide DG-1128 in August of 2005. The staff has since resolved the public comments and produced the final guide.

The final guide takes eight regulatory positions against the IEEE Standard.

The first regulatory position addresses the question, how might current operating plants using Rev 2 or 3 of Reg Guide 1.97 convert to the criteria in IEEE 497?

The standard states it's intended for new plants, but "the guidance provided in this standard may prove useful for operating nuclear power stations desiring to perform design modifications or design basis modifications."

Now the staff has been contacted by the industry concerning Rev 4 and informed that there is interest in applying it to current plants. The problem is that the standard doesn't tell you how current plants should apply it.

So what if current plants want to use all the guides and convert to the new method? Now by the term convert, we mean revising all of their accident monitoring licensing commitments to Rev 4.

Now the standard, since it's intended for new plants, does not provide any guidance in translating from specifying variable types and categories to only specifying variable types.

Categories do not directly correlate to variable types. Although generally, Types A, B, and C correlate to Category 1, Type D correlates to Category 2, and Type E correlates to Category 3, with some exceptions.

The individual criteria for a particular variable type may be more or less stringent than what is currently met. And the converted variable should meet all of the new criteria for that variable type.

Although Rev 4 is intended for licensees of new nuclear power plants, current operating plants may convert to the new criteria on a voluntary basis.

Partial conversions by variable or system or other grouping could result in an incomplete analysis where there is the potential for some, some variable or system interactions to be left unanalyzed and unmonitored.

The staff does not endorse partial conversion.

MEMBER KRESS: Could you expand on that a little bit? I'm not really sure what you mean by an incomplete analysis.

MR. TARTAL: By incomplete analysis, what we're talking about here is if, if a plant wanted to do a partial conversion, in other words on say one variable or one system, there may be some other interactions with that system or with that variable that could be left unmonitored as a result of only converting this one variable.

We don't want them to say, take a tunnel vision approach to this.

MEMBER APOSTOLAKIS: So it's all or nothing?

MR. TARTAL: That's what we're recommending. All or nothing. This is our guidance

MEMBER APOSTOLAKIS: Isn't that the same as the requirement for fires and FBA 805 you either convert to it or you don't?

MEMBER KRESS: Yes.

MEMBER APOSTOLAKIS: You can't just pick and choose.

MEMBER SIEBER: I think one of the difficulties is that Type A instruments in the new standard, to me at least, seems to encompass more instruments than in the old standard because you're talking about contingency actions.

MR. TARTAL: Yes.

MEMBER SIEBER: Which is the subject of your regulatory position four. And so the numbers of instruments that are in Type A will be greater under the new standard, and because Type A is the most stringent qualification requirement, you may have to backfit the plant to establish the appropriate qualification under the new standard.

In other words, do a physical change to the plant if you're required to implement the entire standard for every accident monitoring variable.

On the other hand, if I look at the standard, there's some things in the new standard that aren't in the old standard. For example, discussion of digital instrumentation and defense and death and diversity and how these things should be incorporated into your system. I think these concepts are pretty important, and I agree with the standard writers that they did a pretty good job in doing that.

And I would hate to forego the opportunity to apply these very good concepts that are in the standard to an instrument system that I'm going to modify and so I ignore or forget about this standard, this latest standard, because I don't want to have to go through the plant and requalify a bunch of other instruments that aren't related to it.

MEMBER APOSTOLAKIS: But, Jack, when you say an instrument system, what do you mean? A set of

-

MEMBER SIEBER: A set, a train, for example, to me is an instrument system that goes from the primary sensing element all the way to some kind of display. That would be the smallest thing.

MEMBER APOSTOLAKIS: If you have -

MEMBER SIEBER: Okay and instruments - go ahead.

MEMBER APOSTOLAKIS: If you have a safety function, okay, and you're monitoring parameters using a number of systems, then you're saying that I should be able to modify one of them using these new ideas and leave the others with the old standard?

MEMBER SIEBER: Yes. Well that would be, to me that would be, that's what the staff calls picking and choosing. And they don't like that concept.

To me I think that if you do the right analysis to make sure that you continue to cover all the variables, that's what I think about when I think in terms of analysis that needs to be done.

I don't think I would want to be in a position of them backfitting the plant.

MEMBER KRESS: It seems to me like, if I were going to convert wholly over, I would go through the analysis and find out which instruments go in which category that I have. I don't know how, how to have them all categorized and limited, but now I'm going to start changing whatever it is you have to change in order to make them into the new thing.

I see no reason why they all ought to be changed at one time. Because I've already got the analysis made, and there's not an incomplete analysis there, so I may want to change half of them one shutdown and half of them another.

So the question I have is what, what is meant by complete changeover? I mean, does that have to be done all at one time, or can I do it in increments?

MR. TARTAL: The intention is all at one time.

MEMBER MAYNARD: I guess I'm not convinced that they're all or none. I do agree with just picking. I don't think you want to allow hey this instrument and over here and do that, but if a plant is modifying a system, putting in a new design, later technology, I don't believe it would be that difficult to envelope that new system to be able to define that without losing the rest of it there.

And I think you might be discouraging

some, well, incentive to go to some of the newer technology, and also it may make it more difficult to have the staff to have criteria to review.

I'm not sure you want to take away the option to do it, but again I also I don't believe that plant should be able to come in and just, I want to change this instrument to this new standard and just kind of a hodgepodge of it.

But if you're putting in a new design, if you're modifying a system, I think you need to be taking a look at what is the best standard to address that new design system. And I think you should be able to encompass that.

MEMBER KRESS: I think they ought to allow incremental changes.

MEMBER APOSTOLAKIS: No, but, would it be more acceptable to convert to the new system if you're dealing with a safety function rather than a particular system?

Would that be more acceptable?

MEMBER SIEBER: Well, that might not be accident monitoring if it actually performs an action. These are things that - accident monitoring isn't Type A. Or operator manual actions that the operator takes by reading his procedure and seeing some indication on some instrument as opposed to having it on automatic trip or something like that.

I think the perfect example, at least in Westinghouse plants, is the old analog were out of position in the cable system. Which was known to be inaccurate and subject to changes in reactor outlook temperature because of changes in the reluctance of the control rod guide tubes. And a lot of, not a lot but some, licensees converted to a digital-type system which is designed to overcome some of these physical difficulties that the system had.

You could apply this new standard very easily to a new digital rod position indicating system, but you would probably not do it if you had to convert everything in the plant to the new standard because it would now bring into the fold as Type A variables, a lot of variables that you formerly didn't consider Type A variables.

It may change your qualification requirements on some instruments. You might have to redo the seismic analysis or the EQ envelope or something like that. Or separation criteria.

And so there's some difficulties in regulatory position one.

MEMBER BONACA: I wonder if they have an

example that substantiates your concern. I mean - do you have an example?

MR. KEMPER: Yes. This is Bill Kemper. If I could just try. Let's say for example at a BWR, Reg Guide 1.97 would require that they have position monitoring available for their code safeties on a primary system.

The intent is to monitor primary system leakage, right, a leakage path. Another way of doing that could be using the AOPs, just look at reactor coolant system pressure. Look at reactor building sump level. Look at quench tank pressure. There's many different ways in monitoring a reactor coolant system leakage.

So a licensee could come in and make an argument to say that we don't need these position indicators, which are probably problematic to maintain on the code safeties because we have other alternative means to monitor that.

But some of those alternative indications may or may not be in Reg Guide 1.97. So they would effectively - our concern is they could effectively gerrymander or just cherry pick, if you will, to eliminate this one problematic indicator without including the other balance of indications that they're going to take credit for and that they would use pursuant to their EOPs.

That's one concern. The second concern is that from an inspection standpoint, it will be very difficult, I think, for the resident and the regional inspectors to come in and inspect a licensee for compliance of Reg Guide 1.97 if he has a potpourri of commitments, if you will, you know between Rev 2, Rev 3 and Rev 4.

So that's the other part of it. We were concerned that it may be very difficult, if manageable at all, by the resident inspectors and regional inspectors to inspect for compliance of this particular document.

MR. TARTAL: Or the licensees for that matter.

MEMBER SIEBER: But the licensee is required to maintain his current licensing basis which to me means there ought to be documents that show which instruments belong to which version of the standard.

MEMBER SIEBER: I think I agree that one of the problems here is the fact that a licensee could do just exactly what you said and decide all I have to do is change my EOPs and eliminate reference to this instrument and figure out another way to do it, and then since it isn't in the EOPs anymore, it's not subject to the standard anymore so I can take it out, or retire it in place or do whatever I want.

I think that we have to guard against that. On the other hand, there is a price to pay for such a guarded approach.

MEMBER MAYNARD: Well, I think you bring up some valid concerns. I'm still not sure that you want to just totally close the door on it. I think NRR, NRC still has control over whether you authorize a change to a licensing, just somebody comes in. And I think it would put the burden on the utility to demonstrate that it doesn't lose some of the things or create a problem.

They would have to show, I think, how is it clear to the inspector what to be inspected to, and how are they going to maintain it. I think the NRC still has control of whether or not they approve that. I'm just not sure you want to close the door in a hard and fast rule and say no.

MEMBER SIEBER: I think though that the - you know it almost sets the staff out like they're potentates some place. They actually have to follow the rules, too. And so their hands are somewhat tied to whatever they approve at this time as far as the standard's concerned. They can't make the licensee do something that isn't in the rules.

MEMBER APOSTOLAKIS: Yes, but I thought, coming to your argument, or Bill's argument is that the staff will have difficulty evaluating such situations. They would probably need further guidance of some sort.

MEMBER BONACA: And so the licensee would-

MEMBER APOSTOLAKIS: The NRC does have control, but can they actually do something meaningful? I think that's the argument from the staff.

MEMBER SIEBER: I think you can make the same argument in the fire protection area. For example, there are so many different ways depending on how old your plant is and how it was licensed and NFP 805 introduces just another one of these variations.

Where a licensee, you know, has to keep track via some kind of a documented road map is just where they are in licensing space and what their design basis really is.

And if you can do it in fire protection, I would think that you could do it in instrumentation. I give the staff and its inspectors credit for being able to wander through applications of more than one standard.

MR. TARTAL: Again, we're not putting forth a requirement here. This is only our recommendation.

MEMBER SIEBER: Right.

MR. TARTAL: Hence it being a Reg Guide.

MEMBER APOSTOLAKIS: What does that mean?

MEMBER SIEBER: Yes, which means a licensee could go and get an exemption should the staff see fit to approve it.

MR. TARTAL: That would be a deviation in this case, but yes.

MEMBER SHACK: You didn't have to ask for an exemption here.

MEMBER POWERS: No.

MEMBER SHACK: Meaning just come in and say I did it differently, please approve it.

MR. TARTAL: Exemptions are for rules.

MEMBER POWERS: I will comment, Jack, that with respect to your fire versus instrumentation analogy, that you drew there. Recall that when we were going through the triennial fire inspections, we found most licensees had not done a good job of preserving the licensing basis for fire protection.

MEMBER SIEBER: I know that. I had listened to various staff people complain about that. Okay, why don't we continue on.

MR. TARTAL: Very good.

The second regulatory position addresses calibration during an accident. The standard requires maintaining instrument calibration by means of recalibration, proper calibration interval specification, selecting equipment that does not require calibration, or by cross-calibration with other channels having no relationship to that variable.

Recalibration is the only one of these means, though, that can satisfy the requirement to maintain calibration. The staff position is that validating instrument calibration is more appropriate than maintaining instrument calibration during an accident.

The third regulatory position addresses severe accidents. The IEEE standard does not directly address severe accident monitoring, although it is mentioned as future work for the standard.

The standard does, however, include the requirement for Type C variables to have extended ranges, which was a post-TMI action item now incorporated in 10 CFR 5034(F).

This regulatory position incorporates the language from NUREG-660, the post-TMI action plan, into the criteria to clarify the need for extended ranges for Type C variables. Again this is not a new requirement, but only a clarification.

MEMBER SIEBER: On the other hand, you when you're doing your classification, your analysis, you can screen out instruments that would be used beyond the design basis of a plant, right?

MR. TARTAL: Yes, and you'll see that a little later in the presentation, yes.

The fourth regulatory position addresses contingency actions. Contingency actions are defined by the IEEE Standard as alternative actions taken to address unexpected responses of the plant or conditions beyond its licensing basis.

The standard excludes all contingency actions from the scope of potential Type A variables. The term contingency action is applied as if they are to mitigate accident conditions that are beyond licensing basis of the plant.

However, the definition of the term provided by IEEE may not exclude some licensing basis conditions related to unexpected responses of the plant.

Therefore, the staff position is that this restriction toward contingency actions should not be endorsed. Instead, the licensee should consider all operator actions within the licensing basis during the variable selection process.

MEMBER SIEBER: I guess when I read this one and thought about this combined with the first regulatory position, that was, to me, the killer. Because this is where the extra work comes from is the contingency action.

Had you not had this then it would be neater to accept a wholesale conversion to the new standard when you decide to make the change to the plant.

But this combination to me makes it more difficult.

MR. TARTAL: Again, the consideration of contingency actions does not necessarily increase the number of Type A variables that will be monitored.

It's up to the licensee to evaluate their contingency actions and how they use them and determine whether it really is a Type A variable or not.

MEMBER SIEBER: Yes, but to actually have to do the work in order to find out whether you're right or not.

MR. TARTAL: That's correct.

MEMBER SIEBER: And I don't think you have - or I know I haven't.

MR. TARTAL: The fifth regulatory position addresses the number of points of measurement for a variable. It's not addressed in the IEEE Standard, but was addressed as a regulatory position in Rev 3.

The regulatory position recommends the number of points of measurement for each variable should be sufficient to adequately indicate the variable value.

The sixth regulatory position addresses the codes and standards referenced within the IEEE Standard. This is a boilerplate regulatory position for Reg Guides that endorse industry standards.

It provides guidance on how a licensee should use those reference codes and standards depending on whether they're codified in regulations, endorsed in Reg Guides, or neither codified nor endorsed.

The seventh regulatory position addresses Type C variable operating time. The standard requires at least 100 days of operating time for Type C variables.

The staff position is that licensees may optionally use an operating time that is specified in their licensing basis documentation, which is consistent with the criteria for the other four types of variables.

The eighth regulatory position replaces the term "post event operating time" with "operating time" in the IEEE Standard. This language is consistent with the title change of the standard from "post accident monitoring" to "accident monitoring". The staff position is that the operating time should encompass the full accident duration.

Now to discuss the public comments received on the draft guide and the related staff responses to the public comments. Seven sets of comments were received by a diverse selection of industry groups. NEI, NUGEQ, IEEE, BWR Owners Group, Westinghouse, TVA, and Exelon.

Each of the public comments was addressed, and the responses made publically available in ADAMS, and the accession number's given here. For this presentation, I'll highlight the significant comments and describe the effect on the final guide.

Public comments associated with regulatory position one, voluntary conversion to Rev 4 for current plants. One comment recommends that the Reg Guide should recognize the acceptability of a plant's current licensing basis.

Another comment is there is an unnecessarily restrictive requirement to convert the entire plant's accident monitoring system to Rev 4.

Another comment addresses the draft guide language that the Reg Guide being not intended for current operating reactor licensees is confusing. Another comment requests the Reg Guide to provide guidance for performing digital upgrades.

And the final regulatory position now states that it is intended for new nuclear power plants. Public comments associated with regulatory position number two, calibration during an accident.

One comment stated it was not clear that the requirements are relaxed based on the standards listed in the standard for maintaining calibration. Another comment stated that calibration was only required during post-event operating time and not necessarily during the full accident duration. The third comment requested additional relaxation by changing maximum extent to extent practical. The final regulatory position revised the term "maintain calibration" to "validate calibration."

Public comments associated with Regulatory Position No. 3, Type C Variable Extended Range Requirements. One comment recommends that extended range requirements be addressed in Section 5.1 of the IEEE Standard instead of Section 4.3. Another comment requested the addition of current alternative source terms into the Reg Guide. The regulatory position was revised to reference 5.1 of the Standard.

Public comments associated with Regulatory Position No. 4, Contingency Actions. One comment stated that BWR Contingency Actions extend beyond the design basis. Another comment stated there are no limitations to the contingency actions considered. Another comment stated that contingency actions are by definition beyond design basis. Another comment was to exclude design basis actions from contingency action criteria. The regulatory position was revised to recommend consideration of contingency actions within the plant's licensing basis.

MR. KEMPER: This is Bill Kemper. If I could just add this and again the operative phrase there is "within the plant's licensing basis." So what we were faced with here is certain licensees were saying contingency actions should be off limits because they're not. But what we found was that's not a unilateral interpretation within the industry. To some, it's an NSSS type of term that's treated differently within the NSSS community.

So our position again just to try to be as clear as we can is we said we don't care what you call the actions. You can call them contingencies, operator actions. It doesn't matter. As long as they're needed to combat an accident in a manner that's within your plant's licensing basis, then they should be included in Reg Guide 197 program.

MEMBER SIEBER: One of the difficulties here is that depending on who the vendor was Westinghouse, Combustion Engineering, General Electric or what have you, BMW, the ERGs were written differently. Some were accident-based, some were symptom-based and because of that, at least one of the owners groups went to what they called criteria safety function procedures which to me sounds an awful lot like all these contingency actions because you're trying to solve the problem with the accident you think you have.

On the other hand, somebody else, usually the shift technical advisor, is looking at this different set of instruments to make sure or to detect whether you're going outside the procedural boundaries and into unanalyzed space. Those are the contingency actions that I think you have to find. It would be good to have instruments that actually work when you're trying to maintain or restore safety functions. So I really didn't have too much of a problem with the staff's concept here.

MR. TARTAL: There were no public comments against Regulatory Position No. 5, Number of Points of Measurement. Public comments associated with Regulatory Position No. 6, Reference, Codes and Standards. The comment requested the Reg Guide to allow the use of those codes and standards within a current plant's licensing basis. The staff position here is that a current plant voluntarily converts to REV 4 should meet all of the applicable criteria for that variable type and any necessary deviations documented by the licensee will be reviewed the staff and approved on a case-by-case basis. And that's consistent with the current process of licensees requesting deviations from REV 2 or REV 3. So there were no changes to the regulatory position.

Position No. 7, Type C Variable Instrument Duration. The comment requests the option for using the licensing basis documentation as a source for Type

C variable instrument duration. The staff incorporated this option by adding the regulatory position.

Public comments associated with Regulatory Position No. 8, Clarification of Operating Time. You will recall an earlier public comment regarding post-event operating time versus full accident duration. The staff position again is that operating time should encompass the full accident duration. So the final regulatory position modifies the term "post-event operating time" to "operating time" and this regulatory position was added as a result of the comment.

In conclusion --

MEMBER MAYNARD: I'm sorry. Could I have just a minute for Position 4 just for my own understanding? I'm not challenging your position on that, but licensing basis isn't always that clearly defined. I want to have a little bit of discussion to make sure we don't create an unintended consequence here. I believe contingency actions are good and I want to make sure this doesn't provide a disincentive for plants to have contingency actions just so they don't have to add programs and stuff. Can I get your thoughts on that?

MR. KEMPER: Let's see. Bill Kemper. Let me give this a try. Contingency actions have a wide variety of use. For example, one contingency action could be that if both charging pumps don't start automatically, then you start the third pump.

Another contingency action could be that if you're in a beyond-design basis scenario and you have significant core melt, then you need to run cables from one MCC to another MCC because that's the problem. You've lost power to half of your ECCS cooling train. That's clearly, that last example is clearly beyond design basis. That's severe accident mitigation guidelines is what the CE community calls it anyway. But the first is you're still trying to stay within your design basis to mitigate a LOCA and stay within your accident analysis. So that's the problem that we're struggling with.

If we just carte blanche say all contingency actions are out of balance as far as Reg Guide 197 is concerned, then we may unintentionally eliminate some indications that are needed for the operators to perform those types of access.

MEMBER MAYNARD: And I understand and like I said, I'm not challenging your position. I just think we need to keep in mind going forward that we make sure we don't create a disincentive for having contingency plans in place. We can always have them in the back pocket.

MR. KEMPER: Absolutely. You are absolutely correct. They are absolutely needed.

MR. TARTAL: In conclusion, Reg. Guide 197, REV 4 endorses the current industry standard, IEEE Standard 497-2002, with exceptions and clarifications. Public comments have been received and staff responses are publicly available in ADAMS. This revision is intended for new nuclear plants and any current operating plant wishing to convert to this criteria may do on a comprehensive and voluntary basis. There are no back fit issues associated with the revision. Now any final comments or questions?

MEMBER SIEBER: I guess I could make a statement. I really studied this job thoroughly and I did not detect any place where there was a technical error either in the standard or in the staff's way of handling it which eliminates one of the barriers toward implementing a NUREG guide. So if there are issues, in my own mind they are issues in how to implement as opposed to whether it's technically correct or not correct.

I thought the documentation, particularly the public comments, were thoughtful and I found the staff's documentation of how their whole process of going through this including resolution of public comments is very well done. For me, it was easy to read, understand what your thought process was and why you made the decisions that you did. So overall I can say that I think the staff did a pretty good job here even though I may disagree with one or two minor things, but overall very good. Well done.

MR. TARTAL: Thank you, Dr. Sieber.

MEMBER SIEBER: Any questions from anybody?

MEMBER MAYNARD: I would second your comments there. Again in reviewing this, it looks like overall a very good job, a thorough job. May still have some doubts as to the all or none but I certainly understand pros and cons of that. I certainly understand that that's something that requires some more thought, but I do not disagree with some of your concerns relative to that at all.

MEMBER SIEBER: Any other questions or comments? If not, Mr. Chairman, I think we have finished.

CHAIRMAN WALLIS: Finished.

MEMBER SIEBER: Wow. Thank you very much.

CHAIRMAN WALLIS: We seem to be gaining some time. I wonder if we could use the time to discuss your reaction to this in the form of your letter since it's on your minds.

MEMBER SIEBER: Okay.

CHAIRMAN WALLIS: As I understand it, we are in general. Can we come off the record in that case? Let's go off the record.

(Whereupon, the foregoing matter went off the record at 9:17 a.m. and went back on the record at 10:18 a.m.)

CHAIRMAN WALLIS: Back on the record. The next item on the agenda also concerns Jack Sieber who will lead us through this matter, Evaluation of Precursor Data to Identify Significant Operating Events. Jack.

MEMBER SIEBER: Okay. Thank you, Mr. Chairman. For those of you who have read the research report which by now should be everyone at least in draft form, you will note that in the operating experience section I call Accident Scenario Precursor in the Analysis of Operating Experience the keystone of the Agency and the Agency couldn't function and do its statutory obligations and enforce its rules without insights that this program provides.

So we're going to hear from the staff today about their most recent analysis and compilation of insights that they gained from examining operating experience and this will be an information briefing. Unless something startling and unbeknown to me occurs, we do not plan to write a letter on this. On the other hand, I'm hoping that all of us appreciate the importance of this subject to the functioning of the Agency.

MEMBER POWERS: I think we should look at this carefully to see how we want to dampen those words of high praise that you include in the research approach.

MEMBER SIEBER: Well, I may be alone in my opinion, but I will not change my mind.

MEMBER POWERS: I wanted to see you explain to Mr. Diaz how we have asked and then we have the Commission.

MEMBER SIEBER: That's right. You explain that. What I would like to do now is introduce Pat Baranowsky who is the Deputy Director for Operating Experience and Risk Analysis to provide a few words of introductions.

MR. BARANOWSKY: Thanks. Of course as you know, the Office of Research just reorganized and I became the Deputy Director for that position and one of our branches in there is the Operating Experience branch which primarily has the role of analyzing data for accident sequence precursors. The Acting Branch Chief Doug Weaver is out because his wife just had a baby. Normally the Branch Chief is Mike Cheok who I think you all know and he'll be continuing to have a significant role in the accident sequence precursor analyses. I wanted to let you know that.

As you mentioned, the purpose is to come and brief the Committee on what we've been doing over the past year and we're pleased to be able to do that. We'll talk about the status of the program, then the trends and insights and a summary. That will all be provided by Gary DeMoss who has been taking a significant role in leadership in the analysis of the accident sequence precursors.

Sorry. I mentioned that and are we about ready to get to you, Gary?

MR. DEMOSS: Do you want me to do this one?

MR. BARANOWSKY: I can't tell. What's the next one? Just for historical purposes, we like to put things like this into the record so folks can remember what the Accident Sequence Precursor Program is. It's been around a long time. It was implemented right around the time with Three Mile Island and it has the primary objective to systematically evaluate the operating experience, to identify and document instances that have potential to lead to severe core damage and have a high enough probability to be of interest to us.

So it's a tool that rakes through the operating experience information and points out the most significant ones that we should focus on. It's become a significant input to the Annual Performance and Accountability Report in Industry Trends Program. In fact, it was discussed by Jim Dyer at the Regulatory Information Conference in his discussion on Tuesday. The Program is also used to identify issues that can have potential for generic communications or study or generic safety issues.

And one other thing that is the last on the list over here but I don't want to understate it is the use of this program as a partial check on our PRA models and feeding back into the SPAR models in particular. But we've also had discussions with folks from industry on various modeling issues that don't seem to agree with results of accident sequences showing significant sequences and the nature of scenarios. And I think this is the point where I turn it over to Gary. So if it's not, I'm turning it over.

MR. DEMOSS: Okay. Some of the highlights I think we're going to show in the presentation today. Again for the record, I'm Gary DeMoss. We're going to announce that the Fiscal Year 2003-2004 events are substantially complete and the results were reported in the SECY paper referenced throughout this presentation. There were no significant precursors in Fiscal Year 2003-2004 and we're far enough in Fiscal Year 2005 to announce that there were no significant precursors in that year.

The trend analysis, the major point we want you to take out of the trend analysis, we'll break this down quite a bit as we go through is that there was no trend in the rates of occurrence of precursors in the last ten years. You'll see some mixed results and some interesting results in our trending I hope, but there is certainly no increasing trend in our higher risk precursors which I think we have to consider good news.

First I'm going to --

MEMBER APOSTOLAKIS: Let me ask a question here.

MR. DEMOSS: Sure.

MEMBER APOSTOLAKIS: Your highlights are based on the condition of core damage probability of these precursors. It would be also of interest to see not only from these three years but also from the past whether there have been any precursors that if I look at the PRA, the scenario that happened was not there, in other words, the issue of the structure of the PRA not just the probabilities. Are you guys monitoring that? Are all these sequences of the precursors included one way or another in the PRA and is it just a matter of the probability or there may be some insights regarding the actual logical models that the PRAs are employing right now?

MR. DEMOSS: I don't think we've found insights in the logical models. We've found and we tabulate those, although I don't have a slide on it today. We tabulate events that are not directly covered in the PRA. But I think the structure of the model, the mitigating systems, has been robust even in just the SPAR models in certainly in a more detailed PRA.

MEMBER APOSTOLAKIS: I mean this issue came up also in the old days when TMI happened. The question was did the reactor safety study have that sequence. And of course at some level, the PRA always has it because if you go high enough to the system level or even the functional level then of course it's there. These are very broad events.

But I guess the actual way through which something happens often times is not in the PRA and the question is of course whether this is an omission or you have to cut off the analysis at some point. I mean, for example, the TMI accident was a small LOCA. So in that sense, it was in the reactor safety study. But the actual way it happened was not in the reactor safety study and the question is whether that can be declared as incompleteness of the analysis or something that we know. The details of an actual occurrence are not expected to be in the PRA. Right? When you say the failure rate of a component, that represents a class of possible ways that a component can fail.

MR. DEMOSS: Right. It represents an integral of all possible ways it can fail/

MEMBER APOSTOLAKIS: Exactly.

MR. DEMOSS: I guess one that comes to mind now and it's not a real current one is a condensate storage tank where we take into account that it could fail to provide water. But we don't take into account that it could fail to provide water due to junk floating in there. The PRAs are just not that specific.

MEMBER APOSTOLAKIS: So we're in agreement with that, but the question is whether at some higher level we found something that should have been in the PRA. I'm not talking about the detail of failure modes. So you're saying no.

MR. DEMOSS: The ASP is not at a higher level found that.

MEMBER APOSTOLAKIS: ASP what?

MR. DEMOSS: The ASP program has not found anything at a high level that should be in a PRA, for example, an operator action that was taken that probably successfully solved the problem. I don't think we've found anything that --

MR. BARANOWSKY: Gary, I think you're actually -- If you go down a little bit, he's saying the very top structure just as you said with the Watch 1400 Report has the sequences in there.

MR. DEMOSS: Yes.

MR. BARANOWSKY: But I think one, if I recall, remember there was like an Event B type sequence at, which plant was it, Waterford or Wolf Creek or something. There was a drain.

PARTICIPANT: Wolf Creek.

MR. BARANOWSKY: And you won't find that sequence in any PRA that I know of. But it was one of our significant findings and in fact it led to generic communications and so forth and that's why I remember it. So from that point of view, I think we've found several where there are unique characteristics to the sequence of events which we have either noted or tried to accommodate into our models.

I don't know that every time they get into a model, but they might just get into a generic issue program because like with the Wolf Creek Event B, it's pretty hard to come up with the scenarios for every plant model without doing a very detailed analysis of their maintenance and procedures which actually was the cause of this situation. So I hope that -- Anyhow, we're trying to fold those back in either to the models or make note of them and get them into generic communications so they are covered in the regulatory program.

MEMBER DENNING: Could I quickly check a couple of things? As far as what you've identified as a significant precursor, that is core damage probability greater than 1 X 10^{-3} that's a cutoff that you use to say it's significant or not significant.

MR. DEMOSS: Yes.

MEMBER DENNING: That seems to me to be -- I would have gone lower to call significant recognizing we have a number of precursors that happen every year and certainly if we had the belief there were things out there at 1 X 10^{-4} per year, for example, and recognizing the uncertainties associated with core damage probability, I would have put it significant at a lower level. How much does that impact?

MR. DEMOSS: We do track important precursors. Also I think the definitions by nature are arbitrary, but we certainly track it at each order of magnitude level and important precursors are rare and receive a tremendous amount of attention. Significant precursor has Congressional reporting requirements and what not attached to it.

MEMBER DENNING: Okay. So it's not that you're not. It's just in a different category.

MR. DEMOSS: That's right.

MEMBER DENNING: And when you say the higher risk precursors, that 1 X 10^{-5}, is that actually the core damage frequency associated with those?

MR. DEMOSS: Core damage probability. Conditional core damage probability.

MEMBER DENNING: It is conditional. Now let me see if I understand what you're saying there then. We have a significant precursor at 1×10^{-3}. You have higher risk precursors. That includes other categories that are -- Higher risk is not more.

MR. DEMOSS: That's a loose term I put in this overview slide. You'll see that we tabulate our precursors in four different orders of magnitudes and the top couple of order of magnitudes are greater than 10^{-5} and we don't get too many in there and we're not getting more is all I'm saying here. The higher risk is in small letters. It's not a well defined --

CHAIRMAN WALLIS: This is just arbitrary names for categories.

MEMBER DENNING: This is just arbitrary. Yes, but I thought higher risk was more scary than significant, but maybe it was just the words are confusing.

CHAIRMAN WALLIS: You're arguing about the word.

MEMBER APOSTOLAKIS: Significant is the scariest.

MEMBER DENNING: That's the scariest. Significant is scarier than higher risk.

MEMBER APOSTOLAKIS: In fact you report

this to the public. Right?

MEMBER DENNING: That's okay.

MR. DEMOSS: Yes. To Congress and the public.

MEMBER DENNING: Okay. That clarified it. Thanks.

CHAIRMAN WALLIS: Higher risk is greater than high risk. It does sound a little bit as a wrong word to use.

MR. BARANOWSKY: Gary, maybe I can help out here. I think the term "significant" should actually have quotes around it and what he means "higher risk precursors" he means higher than the ones that are lower.

CHAIRMAN WALLIS: Yes.

MR. BARANOWSKY: As opposed to being a category. It's a little bit of a semantics theme.

MR. DEMOSS: I think that will be little clearer as we go through some of the tabulations and graphics later.

MEMBER APOSTOLAKIS: Maybe you can call it intermediate instead of higher.

MEMBER DENNING: That's okay.

MR. DEMOSS: Another new term but yes, that would work. All right. Before we go into the trending and the levels of risk in detail, I'm going to mention some of the recent ASP program accomplishments and give a report on the status of the program.

Some of the major things we've done recently are we finished the Davis-Besse, the final Davis-Besse, ASP analysis in March of last year and we've completed essentially all of 2004 precursors with a couple of issues that aren't entirely dismissed. We're well along in the preliminary assessments of all of the FY `05 events. I think we've identified all of them and are in the process of generating packages for that.

We completed the SECY last year which was a greatly expanded study of trends and insights compared to previous annual SECY reports and hopefully we'll find this useful. I think we'll take it one step further here in the near future and maybe clarify a few things and I think it's a useful exercise.

We've completed a trial application of an expert elicitation methodology and issued the Palo Verde.

MEMBER APOSTOLAKIS: Expert opinion. You're not eliciting the experts. You are eliciting their opinion. This is a word that is needed there.

MR. DEMOSS: Okay. And we'll talk about that in a little more detail in a future slide. And we've tried to reduce some of the burden of NRR and region and licensing reviews of lower risk events by streamlining our review process in a risk-informed manner and that was approved by management in December 2005.

MEMBER APOSTOLAKIS: Now do we have the ASP analysis for Davis-Besse? Have we seen this?

MEMBER DENNING: Yes, I think we did.

MR. DEMOSS: It's been presented to subcommittee in detail and certainly publicly available and that sort of thing.

MEMBER APOSTOLAKIS: What is it, a NUREG?

MR. DEMOSS: No, it's simply an ASP analysis. It was announced on the website much more aggressively than normal.

MEMBER DENNING: I didn't know we definitely had a presentation on it.

MR. DEMOSS: You had a series of presentations of the ASP analysis and that led a request of the presentation for the metallurgical analysis which is really ground-breaking work and that was given you the last, the ASP analysis was given last spring and the metallurgical work was given by

Mark Kirk in the fall I believe, November.

MR. THORNSBURY: Yes. It was late summer. Last year at this time, we had Gary and his group do this same presentation and that included a portion of it, specifically on Davis-Besse which led us to ask for the follow-up.

MEMBER APOSTOLAKIS: Can you get me a copy of the analysis?

MR. THORNSBURY: Yes. That's easy.

MEMBER APOSTOLAKIS: But how does one account for cultural issues? You accounted for those. You don't have to tell me the details.

MR. DEMOSS: Cultural issues?

MEMBER APOSTOLAKIS: I mean yes. Davis-Besse was a major failure of safety culture.

MR. DEMOSS: I mean we have procedures to the fact of that in specific human actions. We measure what we observe to happen. We don't predict whether it will happen again or not. I think a safety culture study would go a long way toward procedure.

MEMBER APOSTOLAKIS: So you use SPAR-H.

MR. DEMOSS: You can factor a culture in some ways into the SPAR-H.

MEMBER DENNING: But the thing is all of those cultural things led to not identifying. Where they started was you had such and such a condition, a physical condition, and from that point on --

MEMBER APOSTOLAKIS: Right. It's conditional on what happened.

MEMBER DENNING: Yes.

MR. DEMOSS: Okay. The current status of the ASP analysis is tabulated here. I think interestingly you can see we had around 20 of actual precursors identified each of the last few years and you can see the status of actually completing an issue in these precursors tabulated here. The notes will explain that some analysis of CRDM events are still lagging behind because we don't have a real good method to quantify them. In previous years, the ASP team would have categorized these as impractical to analyze and not attempted them. We're still working and making some progress and hope to finish those this spring.

Just as a note to tell you, in addition to the precursors identified, the ASP program actually does a full risk analysis of 20 to 50 events and finds that they are less than 1 X 10^{-6} in conditional probability and we use the term "rejects these analysis" from the actual publication on the counts of these ASP analyses.

All right. 2004. I picked what I think are the more interesting analysis and actually a significant percentage of our analysis count is going to be covered on this page and if you bear with me a minute, I would like to talk a little bit about each event. The first one we have here is a grid LOOP of Palo Verde. In fact, it was a good deal of the southwest portion of the United States.

MEMBER SIEBER: That's the one with the bird.

MR. DEMOSS: That's the one with the bird.

MEMBER SIEBER: Okay. I won't describe that in any more detail.

MR. DEMOSS: No, I don't have a slide on the bird itself. We focused on phalange and what we had was a grid LOOP complicated by a couple of breaker failures in the switch yard at Palo Verde and diesel failure on Unit 2. The dominant sequences we got on Unit 2 were the seal LOCA following a station blackout leading to core damage.

MEMBER POWERS: Just is it an unavailable diesel generator or a failure?

MR. HUNTER: It started with -- failed to load.

MEMBER POWERS: So it wasn't --

MR. DEMOSS: Which in risk term, again I apologize for the jargon.

MEMBER APOSTOLAKIS: It failed. I'm sorry. Let me follow that. When did it failed?

MR. DEMOSS: It failed shortly after the start, after it started.

MEMBER DENNING: It didn't synchronize or something.

MR. DEMOSS: It wouldn't synchronize but it didn't work.

MEMBER DENNING: It didn't work.

CHAIRMAN WALLIS: It does stop though.

MEMBER SIEBER: No –- away.

CHAIRMAN WALLIS: It couldn't connect in some way.

MR. DEMOSS: Yes. I don't have a great deal of details on the diesel failure. Chris is the analyst.

MR. HUNTER: I have the analysis in front of me. Chris Hunter. Essentially it failed to load after receiving the starter signal and they couldn't maintain the voltage and operators actually tripped the diesel. It turned out to be a failed diode.

CHAIRMAN WALLIS: So it was an electrical problem. It wasn't a diesel problem.

MR. HUNTER: Yes.

MEMBER KRESS: What are the three numbers in parentheses?

MR. DEMOSS: The three numbers in parentheses, I was heading to, are the actual conditional core damage probabilities for the three units.

MEMBER KRESS: Three different units.

MR. DEMOSS: Right. There are three units at Palo Verde. Units 1 and 3 had a 90^{6} because their diesels were successful and Unit 2 with the one failed diesel had a 4 X 10^{-5} and I was saying the 4 X 10^{-5} was actually dominated by the possibility of going to station blackout, in other words, having the other diesel fail and a seal LOCA would probabilistically lead to a likelihood of core damage. The dominant sequences on the two plants without a failed diesel were actually the LOOP followed by an early failure of the auxiliary feed water system which is again fairly common for a LOOP analysis that both of these are.

Another relatively high risk and interesting analysis was some voids in the suction piping also at Palo Verde unit and this is the ECCS suction that they would use to go into piggyback recirculation. A significant amount of air was found in the suction piping and of course reported to the NRC. The licensee did a great deal of analysis and determined that for the relatively low flow rate through the system following a small LOCA that the piggyback recirculation definitely would not work.

The licensee after analysis using scale models and laboratory work and then extrapolating said that the system would most likely work for a medium LOCA because the flow rates were high enough. The NRC Thermal, Hydraulic and Fluids guys took a look at this and said maybe, maybe not but unfortunately your modeling is not adequate to prove it would work. So no credit was given for that working and the SDP actually did their analysis assuming that failure of recirculation in a medium LOCA. The SDP came out with a mid 10^{-5} conditional core damage probability.

The ASP analysis decided to take, since we were already working on an expert elicitation of opinion process, we decided to try this process on the pump experts. Excuse me. I should said the fluid flow experts I guess on either side of this issue and this is not a full blown expert elicitation panel. We don't have the resources to do that on ASP analysis. This only takes the system experts a couple of hours to go through this process and a few more hours for the person putting it on.

MEMBER APOSTOLAKIS: That's okay. The NUREG that was issued several years ago has different categories of expert opinion elicitation processes and clearly says for many problems you don't have to go to the full blown approach. That's fine and what you're doing is fine.

MR. DEMOSS: Right.

MEMBER APOSTOLAKIS: This is not an issue of national importance in which case you would need to assemble experts from all over the world and so on.

MR. DEMOSS: Exactly. We tried to come up with a focused and defensible analysis useful for an ASP analysis. I want to make that clear for people not familiar with it that it was not --

MEMBER MAYNARD: Was one of the things that drove this number up the length of time that the condition had existed?

MR. DEMOSS: Yes.

MEMBER MAYNARD: Because it had existed for --

MR. DEMOSS: It did. By structural rule, an ASP only looks at a year duration for a problem like this, but it indeed had existed not for the life of the plant but way back toward the beginning of it.

MEMBER MAYNARD: Pretty close to it, yeah.

MR. DEMOSS: So this expert elicitation of opinions is a systematic process to create a probability distribution for this, in this case, failure of the function necessary for recirculation and we did this and came out about a factor of three lower than what the SDP had done who conservatively and necessarily with their time frames that they had assumed that the high pressure recirculation function would not work in medium LOCA.

MEMBER APOSTOLAKIS: Do you mean they had the probability of one and you had something like 0.3? Is that what you're saying?

MR. DEMOSS: That's correct.

MEMBER DENNING: Yes. I have some concern about the use of expert elicitation panels in lieu of conservative analysis in this type of situation. I think that there are times when we have, and it could be for practical purposes in some cases, where you might have to fall back to expert elicitation panels. But I think that it is fraught with issues in that one only falls back on it when you really have to. That's my personal opinion.

I think that it's so easy to elicit and I know that there are ways that one sets it up, stuff like that. But I think we could really fool ourselves if we fall into in my perception a trap of going the easy route of expert elicitation panels in that for things like ASP I think that it doesn't hurt to be a little conservative and really challenge whether we want to push further on something. So I just hate it when we have to fall back on expert elicitation panels myself.

MEMBER SIEBER: Actually that points out a problem that I see with PRAs where the state of the art could be improved and it's something that the staff might want to think about. Anytime that you have a failure of a piece of equipment and a PRA is either operable or it's failed and it doesn't take into account the concepts like margin where something may not meet all of the criteria but somehow or other it does or it can operate and this would be a long term kind of a thing because it would be very difficult to try to model in to a PRA the concept of margin.

But I think that sort of addresses what we're talking about here as far as the Palo Verde incident. There probably was some margin there. There is a couple of ways to deal with it. One of them is to be conservative and say it failed and you get a number. And another one is to ask your friends which would be the expert panel and what number do you want and put that number in there or to try to do some kind of analysis that says I have this much margin and therefore even if I don't meet all of the conditions, it's likely to be successful.

MEMBER BONACA: But if you have, in PRA, you have evidence that you have margin you assume in fact that it will operate. I think here it's a unique regulatory application of PRA that has to contain some conservative. So probably that's what skews some of the assumptions here, but typically if you have the basis for concluding that the equipment will operate even if it is not operable by definition, regulatory definition, you will assume that.

MEMBER SIEBER: It's sort of like the concept of containment overpressure. Some plants, it's allowed and other plants, it's not allowed.

MEMBER APOSTOLAKIS: The major as we all know, the way the regulatory system treats uncertainties is two-fold. One is the extensive use of redundancy. That structure is different.

MEMBER SIEBER: Right.

MEMBER APOSTOLAKIS: And other is large safety margins. The PRA really deals only with redundancy issues. There is an major impediment in trying to do what you suggest which I think is reasonable and that is you have to have a good evaluation of the uncertainties in the thermal hydraulic calculations. So what they're resorting to now is the vendor gives us the results.

If this temperature is below this, it's okay and they do the redundancy of the calculations and they say it's okay or it's not okay. But in an ideal world if you had a distribution of that temperature and you would calculate your own temperature, then it's an easy thing to find the probability that the stress is greater than the strength. But this is the major impediment. We tried to do something like that a few years ago and immediately you hit a wall.

MEMBER SIEBER: It's a very difficult problem.

MEMBER APOSTOLAKIS: You hit a wall because you don't even -- This Agency probably has the tools, but smaller organizations no.

MEMBER SIEBER: Well, I would be -- For example, if you take a power up-rate before the uprate, everything is supposed to work and you have these failure probabilities. Now you do an uprate, use some of the margin that you have, but the failure probabilities don't change. So you do a pre-uprate PRA and a post uprate PRA. Nothing changes except the operators have to move it a little faster and that to me is not the right application.

MEMBER APOSTOLAKIS: This Committee is on record urging the staff or recommending not urging that some quantification of the margins would be useful.

MEMBER SIEBER: I think so.

MEMBER APOSTOLAKIS: But I'm not sure that there is a major effort to do that.

MEMBER SIEBER: Yeah. Well --

MEMBER APOSTOLAKIS: This goes way beyond what these guys are doing. We're talking about something --

MEMBER SIEBER: We talked about a couple of things in PRA space. One of them is dealing with margin and how we model failure, component failure, is the other one. It has to do with the previous question which was do we model all the phenomenon and no matter if you had an infinite amount of time and infinite amount of analysts, there would always be one out there that thinks you did a model. On the other hand, these are areas of improvement of the process I think.

MEMBER APOSTOLAKIS: In some areas actually it is being done, for example, the evaluation of the probability of failure of the containment under certain accident conditions. People do resolve to this method that I mentioned. You know they have a distribution for the strength of the containment. They calculate the uncertainties and the severe accident results. But this is an exception. It's not the rule, especially one PRA. It's exactly what you are complaining about. It's always yes/no.

MEMBER SIEBER: Yes. I suspect we've spent enough time on that and I've gotten my feelings out.

MEMBER APOSTOLAKIS: That's a good suspicion.

MEMBER SIEBER: But maybe we can just continue on.

MR. TARTAL: Okay. I appreciate that. Another interesting event that occurred in `04 was the LOOP at St. Lucie following Hurricane or during Hurricane Jeanne. They attributed the cause of the LOOP to salt spray on the switch yard. Of course, no one was out there to verify it because indeed they couldn't go out there for many hours and that had a big effect on our analysis because we don't know at what point, if their diesels had failed, their diesels did not fail, at what point they would have gone out there and verified the switch yard was safe and we also don't know exactly when that switch yard became operable. So we did our best from licensee reports.

Another interesting thing that comes out of this analysis which incidently was dominated like Palo Verde with the short term failure of auxiliary feed more so than the longer term station blackout sequences, but I think one thing that's important in this analysis is the way we gave the licensee credit for their pre hurricane shutdown procedures. We used the operating model, at-power PRA model for this analysis, but actually the licensee was shut down and cooled down to 350 degrees or so.

In doing that, they make things a lot simpler and some of the things we assumed is that they've removed the possibility of an early relief valve lifting, they're down below the transition temperature for an RCP seal LOCA and by removing these possibilities from the operating model, I think we give them a fair shake and a fair credit for their pre shutdown procedures which looking at it roughly reduces the risk by an order of magnitude.

MEMBER APOSTOLAKIS: So you did this because St. Lucie doesn't have a PRA for shutdown?

MR. TARTAL: The shutdown PRA is actually not as good a tool for a recently shutdown plant as the operating model because you do have steam. You do have steam for your auxiliary feed. You do possibly if you heat up you can maybe even bypass your MSIVs and steam to the secondary plant. So the plant really is going to behave more like modeled in the operating model than in the low power shutdown model some several hours after shutdown.

MEMBER APOSTOLAKIS: That's very interesting. So maybe we should stop asking for shutdown PRA.

MR. TARTAL: I beg to differ because the work gets rather exciting and we can't handle that with an operating model.

MEMBER SIEBER: Or come up with a new class "recently shut down."

MEMBER APOSTOLAKIS: Recently shut down.

MR. TARTAL: Another interesting analysis we had in `04 was the Calvert Cliffs trip and a potential for an over-cooling transient. The reactor tripped on a relatively common loss of main feed situation but a relay failure caused them to lose control of their atmospheric dump in turbine bypass valves.

MEMBER SIEBER: They stayed open.

MR. TARTAL: And therefore they did have excessive cool down and a safety ejection. They shut their MSIVs and successfully recovered the plant, but if an MSIV had failed, they would have had some significant core damage sequences to deal with. This is interesting for a couple reasons. One, our SPAR models and many licensee PRAs have stopped modeling over-cooling sequences because in the base case of the PRA, you don't get a risk that shows up. But we actually got a bit of a risk and had to dust off and remodel those scenarios to address this ASP event.

MEMBER BONACA: How did the cool-down happen? I know the loss of main feedwater.

MR. TARTAL: The loss of main feedwater lower generator level as you'd expect and aux feed came on and that sort of thing, but the K-7 relay I believe it was caused both the atmospheric dump and the turbine bypass valves to stay open and to not run back to a more closed position as it should have.

MEMBER BONACA: So you kept feeding.

MR. TARTAL: So we kept feeding and cooling down and again, the operators that did see what was happening took control of that. And we're not looking at anything in the upper range of precursors. We're looking at a mid 10^{-5} event here.

MEMBER APOSTOLAKIS: Good.

MR. TARTAL: Moving on and we'll have to go through this a little more quickly because we really can't talk about work in progress too much but I thought I'd highlight some of the things we're working on fiscal year 2005 and we'll be able to speak about in more detail at a future date, we have a flooding vulnerability out there that's received considerable analysis. We had single failure vulnerabilities announced, identified, early in FY `05 due to meters that actually tap into both safety buses at a number of plants and these are some obscure failure modes that theoretically can de-energize both safety buses at a power plant and it's a difficult quantification exercise.

We've had a number of initiating events throughout the year. We've had trips complicated by problems with low voltage power, problems with RCIC, leakage in the primary plant and some safety valve issues. Additionally, we've had LOOPs complicated by hurricane and relatively minor equipment failures.

MEMBER APOSTOLAKIS: So this is now again coming to my favorite theme of structural changes. In PRAs in general, we do not consider the concurrent existence of two initiated events. Isn't that right, Pat?

MR. BARANOWSKY: Two?

MEMBER APOSTOLAKIS: Of two initiated events?

MR. BARANOWSKY: Not unless they are correlated somehow.

MEMBER APOSTOLAKIS: But the LOOP was an example of the hurricane.

MR. BARANOWSKY: Yes, it should have been as a result of the hurricane.

MEMBER APOSTOLAKIS: If it's the result, you're right.

MR. BARANOWSKY: Yes. But sometimes --

MEMBER APOSTOLAKIS: I thought that there was already a loss of power and then the hurricane hit.

MR. BARANOWSKY: But a LOOP could result in a safety relief value opening and staying stuck. So you would have loss of oxide power plus loss of coolant, but they are correlated through the model.

MEMBER APOSTOLAKIS: Do we account for these?

MR. BARANOWSKY: We account for that.

MEMBER APOSTOLAKIS: We is not us. We is the PRA community.

MR. BARANOWSKY: The PRA community accounts for it as a result of things that were done many years ago.

MEMBER APOSTOLAKIS: Yes.

MR. DEMOSS: Additionally, we're exercising really for the first time our shutdown models on several events right now. The models haven't been widely used and so we got in opportunity to use it on events that occurred on a solid plant and mid LOCA event.

CHAIRMAN WALLIS: What's a solid plant?

MR. DEMOSS: No bubble in the pressurizer to PWR.

CHAIRMAN WALLIS: That's right.

MEMBER SIEBER: Charge it a little bit and the pressure goes.

MR. DEMOSS: Yes. Now we're going to step away from the events and talk about the trends covered in the SECY paper for the next several slides.

MEMBER APOSTOLAKIS: So Davis-Besse was a precursor in FY 2002.

MR. DEMOSS: That's correct.

MEMBER APOSTOLAKIS: And we have the perennial problem now. You said earlier that it was completed when?

MR. DEMOSS: With the final, it was the preliminary analysis was developed to the public and the licensee in 2004 and the final analysis in 2005, March 2005.

MEMBER APOSTOLAKIS: Why does it take so long?

MR. DEMOSS: Well, that question varies for the specific case of Davis-Besse we needed a significant amount of laboratory work and modeling to come up with the probability of the head failing. It didn't fail. It did not cause a LOCA and the Metallurgic worked quite hard and spent quite a bit of money.

MR. BARANOWSKY: That's a good example of what happens when you do these detailed analyses to support. We did some early analyses and got in the ballpark, let's say, without having done that, but it was a very important event for the Agency. So we spent the time and effort on it and it takes that much time to do these models.

MEMBER APOSTOLAKIS: And the detailed analysis was significantly different from your early back-on-the-envelope calculation?

MR. BARANOWSKY: The probabilistic results were not a lot different but I think the understanding was much better than one could get.

MEMBER APOSTOLAKIS: Absolutely. The earlier statement of expert opinions are not always pretty good.

MR. THADANI: No, I think, George, there were some significant issues that came out. The staff had to do some experimental work as a matter of fact to really understand what implications there were in terms of both pressure loading and the timing. But the effects if the plant had stayed operational for eight more months, what would have happened? And these issues were pretty important to understand.

MEMBER APOSTOLAKIS: I don't doubt that.

MR. THADANI: So a lot of it was because a fair amount of experimental work had to be done before one could really analyze.

MEMBER APOSTOLAKIS: And this, I guess, was another example of maybe a new complete nuclear threat. I mean this was medium-sized LOCA in a location that had not been analyzed before.

MR. BARANOWSKY: It's one of these cases where you have a medium-sized LOCA in the PRA, but there are some unique characteristics to it.

MEMBER APOSTOLAKIS: Not in that location.

MR. BARANOWSKY: Right. And by the way, we had known this was going to be a significant precursor for a long time. So it was always carried on the books as that, but we wanted to wait until the detailed analysis ASP said because we knew there were some implications to the more detailed analysis results of the metallurgy.

MEMBER APOSTOLAKIS: But this is a kind of unique event and we all know that.

MR. DEMOSS: Yes.

MEMBER APOSTOLAKIS: But as you know, there has been criticism in the past that you guys are slow in producing the results. Is that still correct?

MR. THADANI. Yes.

MR. BARANOWSKY: We're proceeding down in a catch-up plan –- Thank you, boss.

MR. THADANI: No, you had a correction plan to deal with that issue, Pat.

MR. BARANOWSKY: And every time we want to speed it up, we're told speed it up, do it quickly but also put in horrendous amounts of details in the nonprobabilistic risk models such as thermal hydraulics or mechanical aspects.

MEMBER APOSTOLAKIS: Okay. So those are the things that hold us up.

MR. BARANOWSKY: So those are the things that hold us up.

MEMBER APOSTOLAKIS: The moment you said -- I know it's slow.

MEMBER SIEBER: The quick way is just do a sine of failure probability of one and look at the mitigating system response and you come up with a pretty good approximate answer. You can do that during lunch.

MR. BARANOWSKY: We do that to screen events. We do that to screen the event and then we'll also take a look at what we think are the realistic ranges and if the ranges are such that you're going to draw some different conclusions, we have to do the more detailed analysis.

MEMBER SHACK: But the difficulty here really wasn't getting the probability of the LOCA itself. I mean once you had the LOCA, it was just another medium-break LOCA, wasn't it? The real difficulty was in deciding what the probability of the LOCA was.

MR. DEMOSS: Actually the medium LOCA was pretty much just another medium-break LOCA because it's not a bad place to have one. But we were complicated by the sump and the HPI pump problems that co-existed at Davis-Besse.

MEMBER SIEBER: On the other hand since you're looking at failures probability per year and you calculate that it take three months for the thing to fail, you get the same answer either way. Right?

MR. DEMOSS: Pretty much.

MEMBER ARMUO: In your analysis, did you ever come up with an estimate of when this thing would actually fail?

MR. DEMOSS: The metallurgist did and actually presented that and if I recall, it was a median of five months and then a bounds of two to 12. Is that correct? Again, I'm not the metallurgist.

MR. THADANI: Yes, that's correct. It was I believe two months to 12 months with a median of five or six months, something like that.

CHAIRMAN WALLIS: So this was at Davis-Besse?

MR. DEMOSS: Yes, Davis-Besse.

CHAIRMAN WALLIS: So a metallurgist was predicting how fast the hole was growing?

MR. DEMOSS: Yes.

CHAIRMAN WALLIS: I thought that was a

thermal/hydraulic/chemical phenomenon.

MR. DEMOSS: He was supported by it.

CHAIRMAN WALLIS: He was supported. Okay.

MR. DEMOSS: But there was a quite few people. There was a team of people working on it.

MEMBER SIEBER: But there were still some simplifications in the calculations. Go ahead.

MR. DEMOSS: Okay. Other things. The importance of SECY 05-R192 was that we had four precursors that we call important precursors greater than 1 X 10^{-4} and that includes Davis-Besse and then a potential common mode failure of the aux feed system at Point Beach. This is I believe a Mode 2 or 3 event and then another potential common mode failure of AFW Point Beach after they fixed the initial one and didn't do that correctly. Again, those analyses have been submitted and reviewed and those are the major ones in the last few.

As I stated early on, there has been no trend in the rates of occurrence of all precursors.

MEMBER APOSTOLAKIS: Excuse me, Gary. Can you define trend here? How do you use the word "trend"?

MR. DEMOSS: We measure it statistically with a P value. I'll have a slide on that I believe the next slide.

MEMBER APOSTOLAKIS: Don't give me your statistics. Tell me what it means. Is that from Dave Raspinson? The P value?

MR. DEMOSS: Yes. It means we're not finding more precursors than we were in the 1990s on a 1993 ro 2004 trend. There is a lot more information in this precursor count and count by risk that we're going to talk about, but the top level measure is no significant trend.

MEMBER APOSTOLAKIS: So they're occurring randomly. That's what you're saying.

MR. DEMOSS: I think we break it down and show that they're really not quite occurring randomly. We just don't have a significant trend in the count of precursors.

MR. BARANOWSKY: Gary, why don't you just in the interest of time just move right along to that because I think you're just saying what you're going to say.

MR. DEMOSS: Okay.

CHAIRMAN WALLIS: By trend, you look at it as is it increasing or decreasing. You don't look for some kind of a frequency or anything.

MR. DEMOSS: The final bullet on this

slide really describes some pictures down the road. So we'll talk about that when we get to some figures.

MEMBER APOSTOLAKIS: You have some figures. Yes.

MR. DEMOSS: Some figures on that.

MEMBER APOSTOLAKIS: Yes.

MR. DEMOSS: First, we do mention the trending approach that we use consistently and we do measure a P value which quite simply is a standard statistical measure to look at the probability of random data looking at the trends. So low P value means that it's not likely to be random data. And we start our trending around 1993 because that's when we started using our own SPAR models for ASP.

Just to support that trending in `93, first I want to show you a long term history from 1984 to current of the number of precursors per year and `92 and before we had quite a few more. I don't know what we exactly attribute it to. I think it's far enough in the past that I don't think it's important that we trend there. So the dataset that we're actually going to do our --

MEMBER APOSTOLAKIS: Is it you may fit --

MR. DEMOSS: Yes sir. We might.

MEMBER BONACA: But I think especially in recent time with the SPAR model pretty accurate as you have, your ability of evaluating precursors has improved tremendously. I mean in the `80s it was a much rougher models that you used. Right?

MR. DEMOSS: Yes sir. Much rougher.

MEMBER BONACA: So that really is a contributor to that.

MEMBER APOSTOLAKIS: So what you're saying, Mario, is that there is combination of reasons here. First, we may indeed further decrease getting better or whatever, but also our analytical abilities have improved.

MEMBER BONACA: Absolutely. Yes.

MEMBER APOSTOLAKIS: Although this `03 areas are sore to the eye.

MR. DEMOSS: We'll look at `03. This is just a blow-up of the right side of the previous chart. We're going to trend these events from 1993 to 2004 and again as I stated previously, if you take this picture as a whole and try to calculate a trend, your statistics tell you that it's not a trend.

MEMBER APOSTOLAKIS: Let me understand this. Does the P value reflect only the existence of a trend that is monothermic?

MR. BARANOWSKY: Yes. This is pure

straight line trending. If someone tried to do a best bit, I think you would see a trend that looked like a smile on that curve.

MEMBER APOSTOLAKIS: So if it goes up and down and up down, then the P value would not be represented here.

MR. BARANOWSKY: He's saying a straight line trend.

MEMBER APOSTOLAKIS: It will not be.

MR. BARANOWSKY: It will not be, yes.

MR. DEMOSS: This is a slope of zero.

MR. BARANOWSKY: It depends on the model and are you going to tell them about some of the investigation that we did to see what's going on in 2000?

MR. DEMOSS: Right. I want to focus on that. The fact is it's a linear trend. We don't have an increase or a decrease going on here and I think that's what I want you to take out of it.

MEMBER APOSTOLAKIS: Maybe you should make that explicit because no trend identified is kind of too general for the ability of this method to identify behavior.

MEMBER POWERS: It is very frequently observed in econometric data that there is serial correlation in the results. That is the discrepancy between the linear correlation. One year is positive. The next year will also be positive to a high degree of probability. Do you look for serial correlations here and if you do look for serial correlations, do you attempt to revise your linear model to accommodate that serial correlation?

MR. DEMOSS: The answer is we don't look at that deep. We start looking for logical or an engineering reason for what we're seeing rather than try to take our statistics to that advanced level.

MEMBER POWERS: The econometricians find value in trying to, because they so frequently find as you might imagine and they tend to do quarterly data, sometimes even monthly but definitely quarterly data, that one quarter is bad, the next quarter is better and things like that and they find value in doing an analysis of the serial correlation. I wonder if there might be some value here because, yes, they do a mechanical manipulation of the statistics and what not but then they try to interpret what is that telling them.

MR. DEMOSS: I see what you're looking for and maybe would identify some activity at the NRC that was having an effect on the correlations or something like that. But we haven't tried to go that deeply and I'm not sure the amount and type of data would really support that.

MEMBER POWERS: It may not. Your data is clearly not as dense as their data.

MR. DEMOSS: Right. We're talking about 20 events a year.

MEMBER POWERS: That's not beyond the pail. Often times, they do it. But I will admit. Your data is not as dense as the econometricians get to work with.

MEMBER KRESS: If you did what you were saying you would perhaps attach more significance to that 1996 on the previous curve

MEMBER POWERS: You might or actually I would expect it to be that you would not attach such great significance to 1997.

MEMBER KRESS: Yeah.

MEMBER POWERS: Okay. I'm guessing but my guess would be that they would go that way.

MR. DEMOSS: Okay. This is a set of figures that we present annually. I think they are useful figures that gives a top level look at what we're seeing in the ASP program. First, we look at the top left, the precursors in the 10^{-3} bin, the significant precursors and we don't see a measurable trend in that. We only see three over the 12 or so years that we're looking at.

For the 10^{-4} bin, we see on the average of about one per year in precursors in this case in the 10^{-4} bin and you see a decreasing trend here. They tend to bunch up in years because you often have like our Point Beach example the same issue at multiple plants and that does count as two precursors because there is risk.

CHAIRMAN WALLIS: There's really not a decrease. Take away the first point. If you take away the first point, there isn't a trend. So it's not really that significant.

MR. DEMOSS: Possibly so. For consistency, we stuck with 1993. I don't think we see an increase which is actually the important result though.

MEMBER KRESS: What are the vertical lines on the curve?

MR. DEMOSS: The vertical, that's the uncertainty of the curve. The next bin is again not showing an increase or a decrease and that's precursors in the 10^{-5} bin and as you can see, we get five or so a year of those. So they are not particularly rare and when you put them in bins like this, we do see an increase in the number of precursors in the 10^{-6} bin which is the lower of the bin, the much more commonly occurring bin. That's something we'll look at down.

MEMBER APOSTOLAKIS: Now the 10^{-6} rise there, I suspect that has to do more with the analytical capabilities than actual time. I mean the analyses keep becoming more detailed and better with the years. Right?

MR. DEMOSS: I'd like to think so. Yes.

MEMBER APOSTOLAKIS: Yes, so maybe --

MEMBER DENNING: Do you think it's driving them down?

MEMBER APOSTOLAKIS: Driving them up.

MEMBER DENNING: Well, I don't know.

MEMBER APOSTOLAKIS: Ten to the minus six.

MEMBER DENNING: Or maybe it's taking events that would have been --

MR. DEMOSS: I'm going to show you on the next couple slides what I think is driving that and that's not what we concluded. But we can talk about it. Let's do that in a slide or two.

MEMBER SHACK: How could the analysis have anything to do with events?

MEMBER APOSTOLAKIS: This is just occurrence or this is their ASP.

CHAIRMAN WALLIS: It depends on how you calculate the numbers.

MEMBER APOSTOLAKIS: How you calculate the numbers.

MEMBER POWERS: You take a conservative analysis at the 10^{-4} event and you take a realistic analysis at the 10^{-6} event. It's the same event.

MEMBER APOSTOLAKIS: It should be going the other way.

MEMBER DENNING: No, I agree with Bill's assessment.

MEMBER SIEBER: Or you just rethink your failure probability data.

MR. DEMOSS: All those things are going on certainly and that affects the trend and it makes it difficult to measure. We did trending in a couple of periods. We looked at `93 and 2004 period and then we looked closer at the 2001 to 2004 period which makes us suffer from sparse data since it's only four years. But I think it's an important four years.

The reason that's an important four years is kind of two-fold and I think we try to pick them up in the bullets. There is an evolution of the methods and our capabilities to use the SPAR models on complex conditions. In past years, ASP just wouldn't take on some of these more difficult, unusual events that weren't fairly straightforward and applicable to the tools and that's going to include shutdown events as we start doing more of those.

And the other and probably larger effect is that the ASP has always screened LERs, will always continue to screen LERs. We have never been a primary screener of inspection reports. The SDP has picked up a fair number of events that don't have LERs and put any time the SDP comes up with a greater than green finding ASP for a mitigating system cornerstone event, ASP automatically picks that up.

So what I'm doing with this slide is I wanted to find a rebaselining we did to normalize that criteria to look at just the events that ASP would have picked up if we didn't have an SDP and we'll use that for some of our graphics and data analyses in the next couple of slides.

At the 10^{-4} and above level, that would have been the top two bins of that four graph page, none of this is doing anything and I think the reason is we weren't and we never have been missing events in the 10^{-4} range and they've always gotten serious ASP analysis. If you look at the FY 1997 to 2004, you see the ASP program scope is increasing and you measure an increasing trend in the number of events. But if you remove a couple of chunks of events from this rebaseline data and those two chunks are the CRDM events which is about ten events that occurred and were discovered in 2002-2003 time frame with all the head cracking and the eight LOOPs that occurred on one day in August 2003, the trend significantly flattens out.

I guess the other thing we're going to show here in the next couple graphs is that of course we don't have to rebaseline the 2001-2004 events. We just don't show any trends yet partially because it's scarce data, partially because I don't think there are any trends in the recent data.

We did a variety of other looks at our precursor data that we have, described them in great detail in the SECY and I'm just running through the high points right now. We looked at the frequency of initiating events occurring versus the frequency of ASP analyzing degraded conditions. We're getting more and more degraded conditions we're finding and that's consistent with the theory that SDP aggressive analysis of events is identifying more events for the

ASP program.

MEMBER SIEBER: How do you know it's not a reflection of the so-called bathtub theory in aging plants, the older the plant gets the more events you're going to have?

MR. DEMOSS: That's something we would like to address in the future. We have not found a way or dreamed up a way to mine that out of this data but it's something that is a good question.

MEMBER SIEBER: I think it's key to what are the things we're doing these days.

MEMBER APOSTOLAKIS: About how many –– I mean surely you see whether some of these failures are due to aging effects, don't you?

MR. DEMOSS: That information is available to us. ASP's primary goal is to measure the risk of the event as it occurred and we're not the cause and correction engineers. So it's there but we're not ––

MEMBER SHACK: But in just your one, the CRDM events are clearly aging events. The LOOP events are not.

MR. DEMOSS: I wouldn't say 100 percent without looking, but I think you're right.

MEMBER APOSTOLAKIS: Or it's the aging of something else that we don't regulate.

MR. DEMOSS: Right. Ceramic insulator aging is another issue. I'm not prepared to speak on that or investigate that right now.

MEMBER SIEBER: The growth in the system load is an aging issue. If the system capacity stays the same and the load increases, the margin disappears and you add more LOOPs.

MR. DEMOSS: If we were to analyze aging with ASP, we would need a concise definition and I'm not sure which side of that definition your phenomenon should be on.

MR. BARANOWSKY: Gary, the scope of the work normally is to determine if there is an increasing trend and then there is an Agency program to go and look at the why part. That's the Agency Trending Program that's run by NRR and although we might contribute to that discussion, they're really the ones who figure out if it's aging or whatever.

MEMBER SIEBER: Okay. Thank you.

MR. DEMOSS: Okay. Again you've had a presentation on LOOP initiating events from Dr. Raspinson of our branch and our statistics do like his show a significant increasing trend on LOOP-ASP events which is not identical to the number of LOOPs during this `93 to 2004 time frame and it would not be statistically significant over that long time frame if it were not for the August 14, 2003 grid issue.

Another trend we've noticed is that BWR precursors are showing an increasing trend while PWR precursors do not show an increasing trend and we basically were unable to come up with a why on that.

MR. HUNTER: The BWR trend is strongly influenced by the LOOPs. If you take out the LOOP events, there is no trend for the BWRs.

MR. DEMOSS: Okay.

MEMBER APOSTOLAKIS: Can you explain that a little more?

MR. HUNTER: Sure. We actually had very few LOOP events especially during the 1997 through 2001 period for BWRs. We don't know exactly why but as you see in the overall total precursor trend, the BWR trend is strongly influenced by the Northeast blackout where five BWR events. That's five precursors right there. You also had Peach Bottom. You had a few other. Dresden, no not Dresden, but you had a couple other LOOP events in there. So you're not talking about a lot of data and you're talking it's back-loaded on 2003 and 2004 with LOOP events and that's what's causing the increase in trend in the BWRs.

CHAIRMAN WALLIS: Presumably steam dryer events never become safety significant enough to show up on this.

MR. BARANOWSKY: That's a good assumption. I don't recall a steam dryer event in ASP, but I've only been in it since `03.

CHAIRMAN WALLIS: Is that so? Do the steam dryer events not show up on this?

MR. BARANOWSKY: I can just tell you that they're not in there. I don't know if it's a good assumption. I'm a new kid on the block, but there would be --

CHAIRMAN WALLIS: I look to you as knowing everything.

MR. BARANOWSKY: I've been trained on thermal hydraulics for the last 18 months. So now I can go back and look at that.

MR. DEMOSS: Okay. The final part of our analysis of events is a look at some indices that we calculate to give us a comparison to the risk majored in PRAs in general and we have two ASP indices. We have an annual ASP index which assigns all the risk of an ASP event to the year it occurred and normalizes it to the reactor operating time and to take a look at some ASP events that actually were designed deficiencies that existed since either beginning in the plant life or early in the plant life. We've come up with a new index to show that.

This is an index we've been reporting for a long time that is the total risk calculated ASP analyses divided by the reactor years of operation that year and it shows that ASP core damage frequencies is generally calculated to below $1E^{-5}$ which is in the same general ballpark as where the risk models are. It also shows that significant precursors put a big bump on this when one does occur and you can see the Davis-Besse being the most prominent feature of this graphic.

MEMBER APOSTOLAKIS: What is a ΔCDP?

MR. DEMOSS: ΔCDP is the change in core damage probability over the time in which an anomalous condition exists at a plant.

MEMBER APOSTOLAKIS: Change. Is it on the figure somewhere?

MR. DEMOSS: Right. They are added in with the actual conditional core damage probability following initiators.

MEMBER APOSTOLAKIS: So show us on the figure. Where could I look at that?

MR. DEMOSS: They are both added in

together and normalized by dividing the reactor years for each year. But they could be separated but they're not.

MEMBER APOSTOLAKIS: I don't understand that.

CHAIRMAN WALLIS: They're added together.

MEMBER APOSTOLAKIS: You have the total CCDP --

MEMBER SHACK: The number you get is that total divided by the number of reactor years. That's what he's applying.

CHAIRMAN WALLIS: But there are no separate --

MEMBER APOSTOLAKIS: So CCDP is the condition of the probability of core damage given the condition. Right?

MR. DEMOSS: No, conditional core damage probability is the probability of a plant given the initiator.

MEMBER APOSTOLAKIS: That's what I said. Given the condition. Given the --

MR. DEMOSS: Okay. We use the word "condition" as "initiator condition."

MEMBER APOSTOLAKIS: Okay. Condition.

MR. DEMOSS: We use the word "condition"

to --

MEMBER APOSTOLAKIS: So you find that to be 10^{-4}. Then for the same event, what is the △CDP?

MR. DEMOSS: There isn't one. We don't do a △CDP for the same event. We would do a △CDP for we inspected Plant X and found that the RCIC pump was unable to respond for the last several months. It was therefore nonfunctioning.

CHAIRMAN WALLIS: There is no initiator.

MR. DEMOSS: So it's a conditional core damage probability that if an initiator, what the increase in core damage probability if an initiator had occurred during the time that pump was unavailable.

MEMBER APOSTOLAKIS: So why is it not a CCDP? It is a CCDP.

MR. DEMOSS: It is another conditional core damage probability calculated differently. Correct.

MEMBER APOSTOLAKIS: It's just that it includes the occurrence, the probability of the occurrence, of the initiator over that period.

MR. DEMOSS: Right.

MEMBER APOSTOLAKIS: But it is a CCDP.

MR. DEMOSS: And with the time to

multiply.

MEMBER APOSTOLAKIS: I don't think you should call it a △CDP. It's CCDP under different conditions.

MEMBER KRESS: You have to add it up for all precursors.

MEMBER APOSTOLAKIS: Sure.

MEMBER KRESS: So it's not conditional given precursor. It's this total △CDP.

MEMBER APOSTOLAKIS: But it's all CCDP. It's not delta. That's what confusing me.

MEMBER KRESS: It's not conditional though.

MEMBER APOSTOLAKIS: It's conditional on the events that have been observed.

MR. DEMOSS: It is conditional on the events. The △CDP we actually subtract out, during the period of time, we subtract out the core damage probability that existed, the baseline if you will, that existed if that RCIC pump would have been operable at its nominal failure probability during that period of time.

MEMBER KRESS: Those type of things you can't really add together, George.

MEMBER APOSTOLAKIS: Because the

conditions are different.

MEMBER KRESS: Yes.

MR. DEMOSS: The answer is –– Dale, do you want to take that one on, whether you can have CCDPs and CDPs?

MR. RASMUSON: Sure. For those events that involve a reactor trip where you have an initiator, the base case would be zero in that case. So the difference would be the CCDP that you calculate. Whereas when you have a condition or an unavailability event, we calculate the base case and then you analyze the model for the event itself and we subtract the difference between them. So in reality, the calculations are the same for both of these things.

MEMBER APOSTOLAKIS: But you have to address the distinction between the two, but I think the issue now is let's say you only have CCDPs for simplicity.

MR. RASMUSON: Okay.

MEMBER APOSTOLAKIS: And you have five of them. These are all conditional on different conditions.

MR. RASMUSON: Right.

MEMBER APOSTOLAKIS: So what is the

meaning of the sum when you really add them up?

CHAIRMAN WALLIS: It's a measured total change in risk.

MEMBER APOSTOLAKIS: But it's different conditions.

MEMBER KRESS: It's not total. You have to somehow weight it by the frequency --

MEMBER APOSTOLAKIS: Yes. You have to weight it by the probability of the frequency of the condition that would materialize.

MR. BARANOWSKY: No.

MEMBER APOSTOLAKIS: Why not?

MR. BARANOWSKY: No. What you're doing is you're saying in essence let me assume that all the core damage risk was due to the plant being in the state associated with the precursor and nothing else. And then add all those up because risk doesn't come in some uniform manner. For instance, diesel generators work quite well over some period of time and then they fail. So that's when you're at your highest risk. In theory if you add these up over a long enough period of time in case, each one being like a little experiment, you're getting a total that would over time equal approximately the total core damage probability.

MEMBER APOSTOLAKIS: Let me give you an example. Suppose that you have a coin that has failed and you calculated the probability of seven heads out of ten tries. Then you have another coin that has heads on both sides and you calculate the probability of seven heads in ten tries. Now if you add those two, what on earth are you getting? Nothing.

MR. BARANOWSKY: I don't think that's the same thing.

MEMBER APOSTOLAKIS: It is the same thing. You're adding conditional probabilities that have different conditions. One is a double-sided coin. The other is --

CHAIRMAN WALLIS: But you're measuring a risk to the public, aren't you, in both cases and you're adding them up?

MEMBER APOSTOLAKIS: But as Tom says, these are conditions on different things. You have to weight them.

MR. BARANOWSKY: Why would you be able to add up all the core damage probabilities and divide by the number of reactors to get an average core damage probability?

MEMBER APOSTOLAKIS: Because they aren't condition.

MR. BARANOWSKY: Okay. Let's just do this thought experiment and forget the coins and go to nuclear power plants and let say that that issue now is a diesel generator was taken out of service at Plant A and a pump was taken out of service at Plant B and thrown in the garbage. Redo the PRA and they did it for one year. Redo the PRA and tell me can you add those two together to get the average for those two plants.

The answer is yes. That's all you're doing. You just have a new in essence model over a one year period of time that has a different availability of key systems and the reason it's called conditional is because the condition is those systems were in some state that didn't allow them to contribute in some manner to the reduction in risk.

MR. RASMUSON: This is Dale Rasmuson. But you have the conditional probability. If you take the weight that you're going to be and if you set it equal to one, then the sum becomes an upper bound on the true probability that you're going to get.

MEMBER KRESS: That's a better answer. I like that.

MR. BARANOWSKY: Okay. That's a statistician.

MEMBER KRESS: I'll buy that.

MR. BARANOWSKY: That's why we work together.

MR. RASMUSON: But the idea of index, George, as you know, started from a paper that you and Ollie put together on a use for this.

MEMBER APOSTOLAKIS: Then it's okay.

MEMBER SIEBER: Moving on.

MEMBER APOSTOLAKIS: I see. Yes.

CHAIRMAN WALLIS: Do you remember that paper, George?

MEMBER APOSTOLAKIS: It's all right now.

MR. DEMOSS: I think this slide sums up what we've discussed on this particular index and I guess the limitations, the first bullet, the limitations talks about the relationships and the SPAR statistics and the fact that we do screen out events less than 10^{-6} and we don't know theoretically whether there's a million of them or five of them. And additionally, the SPAR models only cover internal events. So all these are only internal event risk.

The second index that we've begun preparing this past SECY paper has the same issues with conditional core damage probabilities and in fact when we were totally it, I didn't differentiate between the two conditional core damage probabilities. That's fine. We've had that discussion. But we did take the risk that existed for a long period of time and applied it to previous years. So this is not a trend decrease that you're looking at on the graph at all. It's just the fact that you don't have any post 2004 years to add risk to 2003 and 2004. So please don't look at this as a trendable index at all, but it does show the importance of long term risks and the importance of detecting them and correcting them.

MEMBER BONACA: So, for example, 1993, we envision this long term because of conditions. That's because they didn't know at that time, but you still counted them.

MR. DEMOSS: Right. We still calculated that.

MEMBER BONACA: But there may be some other conditions we haven't discovered yet.

MR. DEMOSS: That's right and that's why you're seeing low -- We hope not, but you're right. There might be and that's why we'll always expect to see low bars in 2003 and 2004, the most recent years, because by 2003 we have all the Point Beach and D.C. Cook conditions that we know about corrected.

MEMBER BONACA: Yes. All I'm saying okay, but in the future, we may find that there were other plants having other conditions and they would adapt here in this case.

MR. DEMOSS: Yes sir.

MEMBER BONACA: And they'll bring up a -- however.

MR. DEMOSS: Absolutely.

CHAIRMAN WALLIS: This is a significant message, isn't it? That there will be no trend in most of the other figures, but this shows a significant message that those things that are going on for a long time and undetected have a significant impact.

MR. DEMOSS: That's what I believe it shows. Yes.

MEMBER SIEBER: From an industry standpoint.

MR. DEMOSS: Right.

MEMBER SIEBER: What's the difference between an ANSPAR and a regular SPAR?

MEMBER APOSTOLAKIS: I'm sorry. What?

MR. DEMOSS: In 2003, we did what I'll call a significant enhancement in the 2002-2003 time frame. We did some significant enhancements to the SPAR models. Our data analysis reports that we used to quantify the SPAR models had lagged for a while. So we redid those and updated all the component data. We had Dr. Raspinson's Station Blackout study, so we could requantify our LOOP and diesels from that detailed study.

MEMBER APOSTOLAKIS: Who reviewed that?

MR. DEMOSS: And you reviewed that and we also finished making, we also at the same time, concurrently expanded the scope of the SPAR models to really cover essentially all the initiators that the licensee does.

MEMBER SIEBER: That change in level there has nothing to do with the enhancement I presume. You know the last two years are enhanced.

MR. DEMOSS: I think it does because when we enhanced them we ended up with some lower risks especially in the Station Blackout area.

MEMBER SIEBER: You should enhance it some more. You should redrive the risk –

MR. DEMOSS: We're going for best estimate.

MEMBER SIEBER: Just keep on enhancing.

MEMBER KRESS: I'm not sure I understand. If you had something that existed for a long time which increased the risk, why do you divide by the number of years? Why don't you multiple by number of years?

MEMBER SIEBER: It's different every year.

CHAIRMAN WALLIS: No, he puts it in each year.

MR. DEMOSS: In each year, we divide by the number of reactor operating hours for that year total for the nation.

MEMBER SIEBER: And that's why they're different every year.

MR. DEMOSS: Although that's almost been constant since 1993 and --

CHAIRMAN WALLIS: That's why the gray bars are almost constant. It's the same thing being added in each year, isn't it?

MR. DEMOSS: Right and in fact, a way to look at that is the fact that the gray bar stays the same height. That means that --

CHAIRMAN WALLIS: Right. Until you fix it and then it goes down.

MR. DEMOSS: Right.

CHAIRMAN WALLIS: And as soon as you discover something, they may all go up.

MR. DEMOSS: Correct.

MEMBER KRESS: I see.

CHAIRMAN WALLIS: So the something may be below the ground there waiting to emerge.

MEMBER KRESS: Oh yes.

MR. DEMOSS: Yeah. This doesn't show that. It just shows the importance of finding these long-term existing problems and correcting them.

MEMBER SIEBER: So it's either you find them or they find you.

MEMBER KRESS: Thank you.

MR. DEMOSS: Okay. And I think again the worst attributable, that chart, were covered. The major feature is that it includes the risk of a precursor for the entire duration of the condition. As I explained, the initiating events only show up in the year they occurred. I guess one thing I want to say is Davis-Besse we only added risk to 2002 because, yes, there was probably some risk before that but it was a relatively rapidly aging thing and we weren't going to spend more of the Agency's money to quantify that.

CHAIRMAN WALLIS: How does this work with something like some blockage thing? Suppose all these screens are being fixed now.

MR. DEMOSS: Right.

CHAIRMAN WALLIS: Does this imply that

some of those plants would have had blocked screens had they had a LOCA in which case isn't that some preexisting condition that should somehow figure into this program?

MR. DEMOSS: Right now, that's out of the scope of the ASP because it's not reported as a deficiency.

CHAIRMAN WALLIS: It isn't but it's a reality that might well exist and could exist.

MR. DEMOSS: I'm sure. We could apply this sort of an index calculation to some screens.

CHAIRMAN WALLIS: But people haven't actually evaluated that yet. But the fact that they're replacing them with much bigger screens indicates that there might well have been some condition existing which needed to be corrected.

MR. DEMOSS: Yes. I'd hate to try to look at that off the top of head.

MR. BARANOWSKY: Let me take a crack at this a little bit. That's a generic issue and normally what we should be doing is analyzing the risk implications to do backfit for that and I don't know if we plan to. But I know when we did Station Blackout, for instance, we took a look completely across industry and said "How much risk reduction do we expect at virtually each plant by going to that rule" and we should if we do things the way we did things in the old days do the same for sump. I'm not saying we will, but if we have resources, that's the way to do it.

CHAIRMAN WALLIS: So it's something you're thinking about or at least you're aware you might be doing.

MR. BARANOWSKY: Well, as it turns out, now I have Generic Issues in my organization on top of ASP. So yes, looking at it.

MEMBER MAYNARD: I think you would be required to if the solution to the sumps required a backfit. If the modifications are made without a backfit, then I don't think the process automatically requires you to do it.

MEMBER SIEBER: Well, the sump issue is really a compliance issue. Is it not?

MEMBER KRESS: It's not a backfit.

MEMBER SIEBER: It's not a backfit, but you're always supposed to have an operable sump. And if you don't, you have to fix it and that's not a bad thing.

CHAIRMAN WALLIS: Backfit or not, there obviously would be appear to be some change in the risk in the plant by changing --

MEMBER KRESS: It would be of interest to know –

CHAIRMAN WALLIS: It would be interesting to know what it was.

MEMBER SHACK: -- did analyses of those things.

CHAIRMAN WALLIS: And then it was changed because there were all sorts of --

MEMBER SHACK: Yes, but then they introduced the mitigating.

CHAIRMAN WALLIS: That's right. Mitigating things, but the number they came up with originally was too high. Okay.

MEMBER SIEBER: Last slide.

MR. DEMOSS: Yes. Finishing up this slide, the important thing to take away from this is as we've said the four long-term precursors really contribute a lot of the total integrated average CDF and any way you total it, those couple of long-term precursors --

CHAIRMAN WALLIS: I guess that's why I'm sort of thinking aloud here. If there are design defects somewhere in the plant that have been going on for a long time, there ought to be some way to catch those in this program too and not just the fact that some left air in the pipes so the pump wouldn't work. We know that's an operational error. But if someone had designed the pipe line so that it wouldn't work, and then it had to be fixed, that is an existing design defect. Do you catch things like that?

MR. DEMOSS: Somebody else catches them and we do the risk analysis is the answer.

CHAIRMAN WALLIS: Yes, but it has to somehow get into your system.

MR. DEMOSS: That's right.

MEMBER SIEBER: A lot of these come in through LERs.

MR. DEMOSS: Correct.

MEMBER KRESS: And normally, those kind of things don't end up being events.

MEMBER SIEBER: Right.

CHAIRMAN WALLIS: But they are or they do contribute to risk.

MEMBER KRESS: Oh, yes.

MEMBER SIEBER: Yes. Somebody's walking through your plant and sees something and they said, "I wonder why this is like this." And all of a sudden, that comes in as an issue.

MR. DEMOSS: All right. And as a wrap-up

slide, I'm just going to quickly go through what I want you to take away from this. The first part was ASP program status. We continue to evaluate the safety significance of operational events. On the issue of timeliness, we are in better shape than we have been in previous years. We're preparing our 2005 events to support the Agency Action Review Meeting in April.

MEMBER KRESS: Is that a new meeting? I haven't heard about that. Have they had these before?

MR. DEMOSS: I'm not prepared to talk about the history of that right now.

MR. BARANOWSKY: That's not a new meeting. That's the one where the senior managers get together and determine which plants are problems.

MEMBER KRESS: Oh, they just renamed it.

MEMBER SIEBER: Yes.

MR. BARANOWSKY: Yes. That's been at least for a year or more like that.

MEMBER KRESS: Yes. Okay.

MR. DEMOSS: And here's the term you don't like. The occurrence rate for higher risk precursors which means the top couple bins is constant or decreasing. The overall risk from ASP events is relatively constant depending on how you look at it and trend it and the number of precursors we're analyzing is higher now because of recent increases in LOOPs which may or may not continue and the number of events being identified by the SDP which I would expect to continue.

That's the end of my prepared presentation. I will turn it back to Dr. Sieber unless there are more questions.

MEMBER SIEBER: Your timing is excellent. I appreciate the presentation and I'm sure my colleagues do also and I will reiterate that I think this is an important work and vital to the Agency. And with that, Mr. Chairman.

CHAIRMAN WALLIS: Thank you. Thank you for getting through and just on time. Excellent. We are going to take a break. We don't need the transcript anymore. Thank you and we're going to take a break until 1:00 p.m. Off the record.

(Whereupon, at 11:49 a.m., the above-entitled matter was concluded.)