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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

517th MEETING

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THURSDAY,

NOVEMBER 4, 2004

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ROCKVILLE, MARYLAND

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The Committee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., Dr. Mario V. Bonaca, Chairman, presiding.

COMMITTEE MEMBERS PRESENT:

MARIO V. BONACA, Chairman
GEORGE E. APOSTOLAKIS, Member
RICHARD S. DENNING, Member
F. PETER FORD, Member
THOMAS S. KRESS, Member
VICTOR H RANSOM, Member

COMMITTEE MEMBERS PRESENT (Continued):

STEPHEN L. ROSEN, Member

WILLIAM J. SHACK, Member

JOHN D. SIEBER, Member

GRAHAM B. WALLIS, Member

ACRS STAFF PRESENT:

JOHN T. LARKINS, Director

SAM DURAISWAMY

JOHN FLACK

MICHAEL R. SNODDERLY

MARVIN D. SYKES

MAGGALEAN WESTON

NRC STAFF PRESENT:

DAVID DIEC, NRR

RICHARD DUDLEY, NRR

GLENN KELLY, NRR

THOMAS KOSHY, NRR

JOHN G. LAMB, NRR

RALPH LANDRY, NRR

EILEEN McKENNA, NRR

JOSEPH MUSCARA, RES

DALE M. RASMUSON, RES

RICHARD RASMUSSEN, NSIR

NRC STAFF PRESENT (Continued):

WILLIAM RAUGHLEY, RES

BRIAN SHERON, NRR

SUNIL WEERAKKODY, NRR

ALSO PRESENT:

FRED EMERSON, NEI

ROBIN DYLE, Southern Nuclear

ROBIN JONES, EPRI

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P R O C E E D I N G S

(8:31 a.m.)

CHAIRPERSON BONACA: Good morning. The meeting will now come to order.

This is the first day of the 517th meeting of the Advisory Committee on Reactor Safeguards.

During today's meeting, the committee will consider the following:

One, proposed rule language for risk informing 10 CFR 50.46;

Proactive materials degradation assessment program;

Proposed rule on post fire operator manual actions;

Grid reliability issues and related significant operating events; and

Preparation of ACRS reports.

A portion of the meeting will be closed to discuss safeguards and security matters.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Dr. John Larkins is the designated federal official for the initial portions of the meeting.

We have received no written comments from members of the public regarding today's sessions. We have received request from NEI for time to make oral statements regarding proposed language for risk informing 10 CFR 50.46, and the proposed rule on the post fire operator manual actions.

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 will begin with some items of current interest. You have in front of you a package, in fact, and you'll see inside there are a couple of interesting remarks, speeches from Commissioners.

Also in the later part of the package you Inside NRC articles. There's one that refers to ACRS criticizing industry PWR sump methodology. You may be interested in that one.

With that I think we will turn to the first item on the agenda. Be aware again that in a couple of these meetings we have also time for the industry to make their own remarks. So we should accommodate them in the schedule.

With that, I will turn to Dr. Shack, who is going to lead us through the presentations on proposed rule for risk informing 10 CFR 50.46.

DR. SHACK: Okay. Most of us were at our subcommittee meeting last week where we reviewed the proposed rule language that the staff has developed for a risk informed 50.46, and I think we'll just get essentially a condensation of that presentation today for those members who haven't been there.

And I won't take up any more of Brian Sheron's time because he has got a lot to cover.

MR. SHERON: Good morning. My name is Brian Sheron. I'm the Associate Director for Project Licensing and Technical Assessment in NRR, and I was going to give you sort of a quick overview of where we are with the 50.46 rule revision.

Obviously, our objective is we would like to get a positive letter from the ACRS to move forward and issue the rule for public comment. Our plan right now is to get the proposed rule to the Commission by next month, the end of December.

The plan would be that if the Commission was favorably inclined to release it, it would go out for public comment. In parallel, we would be developing a regulatory guide to accompany the rule, which we would be down obviously in reviewing with the ACRS during the course of next year, but I think overall we would like to see the rule hopefully be issued final by the end of 2005.

Just for some background, back in July we received an SRM from the Commission directing the staff to risk inform the large break LOCA requirements. They asked that the proposed rule be completed in approximately six months.

We briefed the committee in July on our conceptual approach. We then held a public meeting in August. Actually what we did is we issued the proposed rule language and a proposed statement of considerations, which represented sort of like a work in progress at that time, in early August. And then we had a follow-up public meeting, the purpose of which was not to receive or debate the rule from the standpoint of the structure or anything, but rather, to get inputs from stakeholders for our cost-benefit analysis, which is required as part of the regulatory analysis of the rule.

DR. SHACK: Why weren't you looking for comments on the structure and content?

MR. SHERON: That's not the purpose. We do that through the regular draft rulemaking process, you know, where we issue it for draft and for public comment. This was not to, for example, debate what's the right break size or anything, but rather for the public to say, "Okay. If this rule were to be promulgated, what do we believe would be the benefits or the costs associated with implementing it?"

And that would help us in determining the cost-benefit analysis.

DR. WALLIS: Are you going to present anything about the cost-benefit analysis today?

MR. SHERON: I don't believe so, no. I'm looking over to Eileen, and she's saying, no, we don't have anything at this moment on it.

This is a voluntary rule. Okay? So from the standpoint, it's not a backfit. So it's not going through the normal 51.09 process of cost beneficial demonstration.

The CRGR review has been deferred to the final rule stage. I'm on the CRGR, and basically our job is to look to make sure that there's no unintended backfits.

DR. WALLIS: I'm sorry. I'm sorry. So your argument for doing this is going to be based on benefits? It has got to be based on something.

MR. SHERON: Yes. There will be a cost-benefit analysis to demonstrate that there are obviously safety benefits as well as perhaps economic benefits associated with implementing the rule.

DR. WALLIS: So this will come out next year some time when we'll know more about that?

MR. SHERON: Eileen, do you want to?

MS. McKENNA: This is Eileen McKenna. I'm in the NRR, in the policy and rulemaking program.

In parallel with developing the proposed rule, we are also developing a regulatory analysis, and as Brian indicated, one of the main reasons for having the meeting was to get a little more information from the industry about potential benefits and associated costs with this rule, and that will be part of our package that goes to the Commission in December. We're kind of working it in parallel.

The committee may also be aware that we did receive some written responses from a couple of the owner's groups at NEI about potential benefits that they saw with the rule, and we are factoring those into our regulatory analysis.

DR. WALLIS: So you're going to give it to the Commission next month, but we never get to see it?

MS. McKENNA: It's the difficulty with the schedule that we had. We weren't able to have it available for the committee in advance of this meeting.

MR. SHERON: Is there a possibility we could have something by the end of November that the committee could consider briefly at the December meeting?

MS. McKENNA: I think we have a draft of the reg. analysis, something we can talk about if the committee has an interest in doing that.

DR. WALLIS: I was just interested. I mean, this is one of the arguments for doing it, and if it looks really impressive and compelling, maybe you could tell us what it is.

MS. McKENNA: Well, as I say, I think part of it, and maybe you know, the NEI may speak to this as well, is that, you know, there is a lot of potential benefits, but they are kind of plant specific and utility interest, you know, in terms of whether they want to make the investment in what's necessary in terms of doing new analyses to obtain some particular benefit, and you know, we can only make some estimates of what those things are based on what we think the rule would provide, but ultimately it is going to be an element of is it attractive to a particular licensee.

MR. SHERON: For example, a power up rate, if someone proposed a power up rate, they would have to go and do a complete assessment of the ability of their plant to be able to accommodate it from the standpoint of do I need to upgrade the secondary side; how much equipment do I need to change out in terms of pumps, heaters, turbine, et cetera.

And that becomes a very plant specific type of analysis that we really don't have the capability to estimate on a generic basis, but I think we would be willing to come down at the December meeting if the committee wants and provide information on where we are with our cost benefit analysis because I think we'll be fairly far along at that time, and we can get something done in advance, and then if you want to put something on the agenda for that meeting, that would be fine.

DR. RANSOM: I think it would be particularly interesting to know if there are any safety benefits. I think --

MR. SHERON: I'm going to get to that.

DR. RANSOM: -- you alluded to that, and that would, I think, be of more interest to the public and to the people here I would think.

DR. APOSTOLAKIS: Brian, last time at the subcommittee meeting some members of the public suggested that we don't need this rule; that all of the changes that are being proposed under the rule can, in fact, be realized with the existing regulations. Is that true?

MR. SHERON: I think what they were referring to is the approach that we currently have for a best estimate LOCA. Okay? Not the old evaluation model, but the approach that was taken was one that you have a best estimate model, and then what you do is you assess the uncertainty on it, and you establish and you do your calculations at the uncertainty level. I think they used 95-95 as the number.

The logic is, and when we formulated the rule back in the late 1980s, okay, the whole logic was that if a utility wants to reduce that uncertainty that they impose on top of the best estimate to account for margin and the like, if they, for example, want to spend more money, get more data, develop more detailed models, more complex models to reduce that uncertainty, then they get a benefit because what happens is that the uncertainty, if you think of it as a Bell shaped curve around a best estimate number, you shrink that in so that the 95th percentile moves in. Okay?

If 2,200 is still your limit, that whole curve can move up, which means your best estimate can move up, which could mean that the power can be increased. So that's what they were driving at, was that there's a built-in incentive, you might say, in the current rule that if you develop more accurate models, better models for predicting, you can, in fact, achieve some benefit, but it doesn't give you all the benefit that I think we're -- and I'm saying the word "benefit." I'm saying safety benefit as well as economic, and you know, we'll get into some of the areas in a second in terms of the safety benefit.

But going to a best estimate model, you know, in the beyond transition break size region, one of the whole benefits basically was to try and take an area that is of much lower risk significance and de-emphasize so that we're not spending as much time focusing in that area. Okay?

All right, and it's a matter of resources to some extent. You know, why do we want people sitting there and calculating out to four decimal places something that's a very, very low probability event?

DR. WALLIS: This is a real test case for risk informing the regulations. I think if number two happens, then one can say we've done something good risk informing the regulations.

If the only thing that happens is the third bullet, then we'll say that's all the public might think the only purpose of risk informing is to let up on the regulations.

MR. SHERON: Right.

DR. WALLIS: If you really think it's up to the industry to show that number two is real.

MR. SHERON: Exactly, and that's what we've been stressing, is that we expect to see when licensees come in to use this, we expect to see overall risk numbers decrease and go down.

DR. KRESS: Let me ask you a question about bullet three. I'm not quite sure yet. One, point, one, seven, four talks about delta CDF limit and one times ten to the minus five, and I wasn't sure whether you intended that to be for each change or the sum of all the changes.

Could you tell me which it was?

MR. SHERON: Well, I think what you heard was that the intent was to bundle. Okay?

DR. KRESS: To bundle and make it the sum of all the changes.

MR. SHERON: Right. But I think we've had some internal discussions after the last subcommittee meeting, and I think we need to rethink that a little bit because I think I may have discussed with you or with Mario a scenario that I raised, which, you know, kind of said that there could be negative effects to that kind of an approach. Okay?

So we're still working on that one a little bit, and the intent is not to -- we don't want to penalize safety for the sake of, you know, taking a very rigid --

DR. WALLIS: But bundling does provide the incentive to fulfill the second bullet

MR. SHERON: Yes.

DR. WALLIS: Because you can trade it off against the third bullet.

MR. SHERON: Yes.

DR. WALLIS: So I think you need to retain some of that aspect.

MR. SHERON: There will be some. Okay? But I don't think you want to sacrifice, for example, a licensee proposing a combination of things that would result in an overall reduction in risk, you know, where some may go up; others go down.

DR. WALLIS: That is bundling, isn't it? You can trade off one against the other.

DR. KRESS: But I think without having the limit of the sum equal to one times ten to the minus five, you have the built in incentive anyway. It's there. You're just putting one limit on it. I'd put another limit on it. My limit I think would allow one times ten to the minus five for each change. I thought that was the intent of 1.17 --

DR. WALLIS: Can you just accumulate until you get to the end of --

DR. KRESS: No, no. There's a built in limit in 1.174. So they would say, "Oh, oh, I'm getting closer to the limit. I'd better do something to reduce risk."

DR. WALLIS: There's no incentive to do number two until you get to the limit it seems to me.

DR. KRESS: Well, there is because the intent is that the closer you get to the limit, the more regulatory scrutiny you get. Now, I don't know what that gradation is, but that certainly would provide some incentive.

DR. WALLIS: I guess this will be worked out.

CHAIRPERSON BONACA: At the subcommittee, by the way, I stated my total disagreement with that way of thinking, and I want it to be on record for this meeting here.

DR. KRESS: Yeah, I wanted to be sure there's two voices.

CHAIRPERSON BONACA: Risk informing regulations should be an opportunity for us to increase the risk of these plants, period. I think there may be opportunities, and I think that the objective for me should be the one of the control in each one of the changes in a way that there will be minimal risk increase in the aggregate, not an effort to reach ten to the minus four as if it was a goal for these plans to be at. I don't think that's is a goal.

DR. KRESS: We also heard from the industry that if you want to make the cumulative risk increase one times ten to the minus five you'll greatly constrain and limit what they're able to do with this rule. Now, I don't know if that's a proper interpretation of what is said or not, but that's the way I interpret it.

CHAIRPERSON BONACA: You know, as we are betting expectations for newer plants to be well below in risk and we are allowing for license renewals and power up rates without really broad considerations of risk increases, et cetera. It seems to me that we are treating the two groups of plants in a very different way, and I think that --

DR. KRESS: It could be, but my point is that there is a limited number of changes you can make. So this business of you guys saying you're going to creep all the way up is really not true. You're going to creep up some by the number of changes that are left, but there's just not that many changes you're going to make.

DR. SHACK: So we'll risk inform the next regulation.

MR. ROSEN: Well, besides the point that Tom made that 1.174 is the ultimate stop. I think we heard from the staff with the subcommittee meeting that what we're talking about was one times ten to the minus five for each set of applications. In other words you can get one times ten to the minus five for risk informed ISI, another one times ten to the minus five for risk informed ISI, another one, point --

DR. SHACK: Right.

MR. ROSEN: -- ten to the minus five for graded QA, and another one in here in 50.46.

DR. KRESS: It's not a matter of teeth in --

MR. ROSEN: No, I was going to draw the opposite conclusion. I was going to say, well, those are reasonable chunks. It's sort of an allocation formula for the different applications, and anybody who wants to think that risk can be reduced in their plant and they can get some beneficial change in that area should go for it, recognizing, of course, that overall they've got to meet 1.174. So they have to make an overall global allocation. They can't spend all of their budget, the 1.174 budget on risk informed IST, for example. They've have nothing left for anything else.

CHAIRPERSON BONACA: Well, again, what I meant to say, I meant to say that those figures for me mean something completely different. Okay? The range between ten to the minus five, ten to the minus four does not represent an allocating budget of increases for each one of these until you get to ten to the minus four, and then you stop. You can't think about it that way because that means that we're promoting a risk informed approach to regulation, which goal is the one of bringing these plants all the way to the member or the risk allows for that to happen. I mean that's really -- if we read it that way.

DR. APOSTOLAKIS: I don't think the intent was to bring all of the plants to the goal of ten to the minus four.

CHAIRPERSON BONACA: But ultimately if you allow -- I mean, if there are benefits --

DR. APOSTOLAKIS: But it's not the discretion. I mean they don't have to approve everything as you approach the goal.

CHAIRPERSON BONACA: But the issue should not be for the staff to have to fight every single little bottle on every one to ten to the minus five.

DR. APOSTOLAKIS: But the ten to the minus five was never intended to be for all the changes.

CHAIRPERSON BONACA: I understand that.

DR. APOSTOLAKIS: Are you saying that every change we make --

CHAIRPERSON BONACA: No, no.

DR. APOSTOLAKIS: -- the assumption of ten to the minus five? That doesn't make sense.

CHAIRPERSON BONACA: I'm only saying that ten to the minus four, okay, to me seems like a stop that said you're on the cliff. You can't do anything more with that. Okay? I mean, you know, you've got to stay there or increase risk. It wasn't intended that way, for plants that may be closed to ten to the minus four right now. It wasn't a limit for the plant that is down to ten to the minus five now. It can have a lot of initiatives and creep up and creep up because it has a lot to give. I don't think that a plant with ten to the minus five has --

DR. KRESS: What if it is ten to the minus six? Are you going to stop it at ten to the minus six?

CHAIRPERSON BONACA: Well, I said to more accepting of initiatives, not of the concerted plan to either way at the margin provide ten to the minus six. Otherwise, for example, the objective for new reactors to be down in the ten to the minus six order maybe --

DR. KRESS: You know, if I took that approach, I would take a ten to the minus six plant and say I don't want you to go up very much and increase. I'm not going to let you do a one times ten to the minus five delta CDF because now I've changed a ten to the minus six plant to a ten to the minus five plant, and you know, that's a really significant change.

And if my objective is to keep each plant at its current level or close to it, which is what I think your approach would do --

CHAIRPERSON BONACA: Yes.

DR. KRESS: -- I think you're treating plants a lot differently, because you're changing a ten to the minus six plant to a ten to the minus five.

CHAIRPERSON BONACA: No, I'm saying the

code of regulation approved these plants which was a deterministic approach that is in the license right now. Okay? Now, they intend to risk inform the regulation. I never understood it as a means of now relaxing a lot of the regulatory requirements from in the license in order to get benefits that will increase this risk to a certain level. I viewed each initiative as one that should have a very minimal increase in risk at most or fully a decrease in risk, and treat it individually that way.

And now the way of apportioning the risk in that range to each one of the changes you may make because that's a different way of looking at it. Okay? I made the example of a plant that could make a strategic plan to have all of these initiatives and increasing only by one, ten to the minus four, each one of them, and getting a lot of benefits in operations, et cetera, and bring it to ten to the minus four and just making an extreme example of how you could interpret that view.

MR. ROSEN: I think you're right. It's an extreme example, but it's possible. I don't think in reality it's going to go that far.

DR. WALLIS: Why would one not do that?

DR. APOSTOLAKIS: It's not possible.

DR. WALLIS: Why would one not do that?

DR. APOSTOLAKIS: I think you forget the context of 1.174. There are two important inputs to the decision making process: defense in depth and safety margins. The staff can always invoke defense in depth and in combination --

(Laughter.)

DR. APOSTOLAKIS: Well, I'm sorry, but that's the way it is. In other words, the whole discussion this morning has been under the assumption that all we care about is the delta CDF and delta LERF, and that's not true. The staff looks at the whole thing, and I doubt very much that they would allow any plant to keep adding ten to the minus fives and go to the goal. They would never do that.

DR. SHACK: I think this topic deserves a separate discussion, but we really need to move on.

DR. APOSTOLAKIS: But there's one last problem. It is not just a delta CDF. Remember we made a big deal out of it. At that time we said this is the quantified part of risk. There are also benefits that are not quantifiable. Okay?

In other words, even when there is a delta CDF of ten to the minus five increase, the expectation was that if you put everything together, you really don't increase it.

CHAIRPERSON BONACA: Let me just say that while the resistance of the industry to use the formulation in the past was that we have a license. The plant has been decided to be safe. We don't want to be ratcheted by risk informed regulation, by risk information in doing more and more safe. This plant is safe enough.

I think that that's a reasonable statement. The complementary statement is also true, should be. Okay? Risk informed relationship should not be a means of ratcheting up risk.

DR. APOSTOLAKIS: Absolutely.

MR. ROSEN: I think the complementary statement is that either the plants are at one times ten to the minus five should be given the opportunity to use small but insignificant portions of risk to bring them up a little bit. I think it's a totally one sided argument in which the side of the plants that are lower in risk is not being heard.

DR. APOSTOLAKIS: I think the guide is deliberately vague on the issue of bundling and how you add up all of these things. We had a long discussion at that time about that, and finally it was left to the staff to make these decisions.

There are no rules one way or the other.

CHAIRPERSON BONACA: Dr. Denning had a comment and he didn't get a chance.

DR. DENNING: Let me be really quick. I realize it's time.

You keep talking about -- Tom, in particular, was talking about -- a one times ten to the minus six plant as if there really is such a thing as one times ten to the minus six plant, and one times ten to the minus five as if we really can believe that because the CDF that's predicted for that is one times ten to the minus five.

It could easily be well above one times ten to the minus four. I think that there's tremendous room here to really improve risk and that the tradeoffs here are really a matter of taking away the effort to things that aren't risk important and put into the things that are risk important and improving risk by doing that.

DR. KRESS: We have long advocated that the uncertainty of these numbers need to be quantified to some extent and factored into the decision process, and I think that's what you're saying.

DR. APOSTOLAKIS: I think for the record though maybe Dr. Denning can tell us whether he actually means that the ten to the minus six plant can easily be ten to the minus four.

I don't believe that.

DR. DENNING: Well, first of all, there is no one times ten to the minus six plant out there. That's an anomaly of PRA. As far as the ten to the minus five plant, it could easily be greater than ten to the minus four because there are all sorts of things in PRA that we haven't been able -- you just can't get down to the depths, and I Could point out Surry and things that we didn't know about Surry when we did WASH-1400 that would have made the risk of that plant dramatically bigger than what we calculated.

(Laughter; Chairman pounds gavel.)

MR. SHERON: Okay.

DR. SHACK: Don't make too many changes in that before you come back to talk to us about it.

MR. SHERON: Yeah. Well, what I was going to say is I think at the subcommittee we did make a promise that we would have a separate meeting on 1.174 and our experience, and so forth, and I think that would be a good forum to continue this discussion. It's a good topic. There's nothing wrong with it.

I do want to emphasize that our expectation is that licensees will demonstrate that plant risk is reduced through optimization. If you looked at the comment letters that we received from the owners groups, as well as NEI, they all focused on what they believe were safety benefits.

You know, I mean, we all understand that they probably see economic benefits as well, but our focus is on the safety benefits. I'll talk a little bit about what they might do.

Some of the areas we think that would improve safety, reduce risk. One is adjust containment spray timing and flow. Several benefits. One is it conserves the refueling water storage tank inventory.

With regard to sumps and potential for blockage, it reduces debris wash-down and no threat to the sump NPSH.

It also extends the time for manual switch-over to recirculation and for some breaks may, in fact, eliminate the need to do the switch-over. If I remember, if you look at risk analyses, you'll find out that the operator performing the switch-over is one of the things which drives core melt.

I remember on Davis-Besse when we were looking at their PRA, that was one of the key drivers on the risk from a LOCA. It was the operator failing to perform the switch-over.

Improved emergency diesel generator reliability. We think that if they use the best estimate analysis so that they don't have to start the diesels as quick, the cold start, in order to demonstrate they can get the ECC systems on and functioning as quick as they have to. That will improve the diesel reliability. We're all familiar with the concerns about the cold, fast starts.

Less demanding load sequencing n the diesels. We also think that the accumulator set points could be readjusted for more optimum inventory control. Dr. Hochreiter was here at the subcommittee meeting, and I always remind him that way back in the 1970s when he was at Westinghouse and I was working on ECCS he came in and told me. He said if we were to design the best estimate ECCS system, he said we'd never pick 600 pounds for the accumulators. We'd do something else.

So my guess is that there will be some other set points that could be identified that would produce a more optimum ECCS flow in a best estimate.

We think they might be able to adjust the low pressure safety injection set points to minimize the time that they're in mini flow operation. This is basically where the pumps have started, but they can't inject against the head. So they have a mini flow line to prevent them from dead heading.

That's there to protect them, but, again, it's not the optimum way to run the pumps. Adjust system resistances to improve operation for the more likely breaks, and this could just be, you know, any flow restrictors or anything else that's in the primary system, and modify core design to reduce vessel fluence.

Obviously if you can get a higher peaking factor, you can peak the power more towards the center of the core. You can probably then optimize fuel design and the loadings such that you have higher power in the center, lower power at the periphery. That's lower fluence. That reduced the fluence on the vessel, reduces potential for pressurized thermal shock.

DR. WALLIS: Brian, is this emphasized now more in the rules which is going out for public comment because the earlier draft talked more about relaxing regulation, didn't talk about the benefits so much. Is this now more in the rule than it was before?

MR. SHERON: Well, it won't be in the rule as much as probably in the --

DR. WALLIS: In the preamble.

MR. SHERON: Or the statement of considerations.

DR. WALLIS: Right. Have you emphasized it more now?

MR. SHERON: I haven't seen the latest version. I don't know if Dick or --

DR. WALLIS: Okay. It will be more in there because the person that I remember didn't have enough of this sort of thing in it from my point of view..

CHAIRPERSON BONACA: As part of the emergency diesel generator reliability, you know, one of the elements is the assumption of loss of off-site power not being taken for breaks beyond the transition point. Today we're going to review the issue of great reliability, and in it, you know, there is a clear description that over the past ten year there has been significant degradation and great reliability, and there are statements that say that oftentimes the greater operations and under voltage conditions that may cause loss of offset power coincident to this cram of the reactor, the statement right there.

Are you looking at this issue? I mean,

when you're going to look at the loss of set power issue, are you going to revisit current data rather than looking just at the historical data?

Because many of the decisions of statements made bout loss of set power have been really derived from experience that dates back to the '80s when the regulation wasn't there yet.

MR. SHERON: Right, but we are looking at that, but we are doing that, as I think I said, through a BWR owner's group topical report, okay, that they have submitted. We intend to start to review in January, and that's a legitimate issue that we said we would look at, and that is that the assumption right now which is that you assume a loss of off-site power occurs simultaneously with the loss of coolant accident, they would like to eliminate that. Okay?

But the question is you're right, and that is if I have a degraded grid or if I have a less reliable grid, okay, would the LOCA which ultimately trips the plant off line, would that in turn cause a loss of off-site power, okay, which would be a LOCA with a delayed loop.

PARTICIPANT: That's right.

MR. SHERON: And that raises questions about double sequencing of the safety systems and stuff, and that's something we're going to examine as part of that whole review of the BWR owner's group.

MR. ROSEN: And I think that question based on the data from the past was always that that LOCA would not likely cause a LOOP. It was highly unlikely, and the question that's being asked -- Mario is asking it, and I agree -- is is that assumption still correct. Has enough changed in the grid due to deregulation to bring into question that?

MR. SHERON: Well, I think that's something we're still looking at right now. I don't feel comfortable. My staff hasn't come to me and said there's a problem here, but we are looking at it. Okay? We're reexamining whether or not, for example, we have to revisit the station blackout rule with regard to coping times and stuff.

Hopefully you'll hear some of that this afternoon.

DR. SHACK: But, I mean, in this rule beyond the transition break size you've built in the idea that you don't have to consider the loss of off-site --

MR. SHERON: Correct, yes. From a probability standpoint, given that plus the probability of getting a break of that size. We believe it's still acceptably low.

CHAIRPERSON BONACA: It's important to review that assumption in light of some of the statements being made in the stuff presented to us from the staff itself.

MR. SHERON: Right.

CHAIRPERSON BONACA: Okay.

MR. SHERON: Today's presentations that you'll hear, you'll get an overview. Dick Dudley will give you an overview of the proposed rule and the conforming changes. There's other regulations that are affected. Just so you're aware, when we sat down to formulate what this revised rule would look like, one of the biggest issues we faced and agonized over is what we call tentacles, and what you find out is 50.46 and the analysis that's done basically touches almost every aspect of the plant design. Okay?

And one of the things we had to make very, very sure when we formulated this regulation was that we were not adversely affecting some other aspect of the design or inadvertently doing something that we didn't realize when we made these changes.

So you'll hear about some of the conforming changes. There's other regulations that are affected. We'll talk to you about the ECCS analysis requirements that would go along with this revised rule, and then your favorite subject, which is the process for approving plant changes based upon a new DBA LOCA. Okay? How we would go about reviewing that.

As I said, our schedule is to complete the statement of considerations in November. Hopefully what we might be able to do is get that down to the committee as well so that you can see that, and then again we can come down in December and discuss any further information that you need from that.

We would like to receive an endorsement letter in the November time frame hopefully We would get a proposed rule package to the EDO in December. Again, I just want to re-emphasize this is not a -- this is strictly a rule that goes out for public comment.

DR. WALLIS: So we can send an endorsement out of this meeting, but we won't have seen the statement of considerations and we won't have seen the risk-benefit analysis. So we're just going on faith that you're going to do a good job on those two things.

MR. SHERON: Well, we always do a good job. You know that

DR. WALLIS: I'm sure you will.

(Laughter.)

DR. WALLIS: And I'm sure it's improving, too, as a result of our comments.

MR. SHERON: Yes. I see my staff over there all nodding.

And presumably if the EDO is satisfied with the package, the EDO would forward it to the Commission by the end of December. We would look hopefully for the Commission to give us the blessing to go out and issue it for public comment, which would get it out probably in the January-February time frame.

We are starting right now on the development of a regulatory guide. We'd like to have a first cut at that in the summer, in June of this coming year. This will be guidance on acceptable ways the staff would find for implementing this rule and hopefully address a lot of the questions that have come up here, as well as with the industry and so forth in terms of what do we mean by that, and so forth.

DR. APOSTOLAKIS: So when will you come back here with a final version of the rule?

MR. SHERON: A final version?

DR. APOSTOLAKIS: Well, I mean, there has to be something.

MR. SHERON: Eileen, do we have a -- I'm guessing in the fall of next year maybe.

MS. McKENNA: It really depends on a couple of factors. One is how long the Commission deliberates and whether they accept it in the form that we send it to them. Again, as I say, it's a 75-day nominally comment period, then a matter of how many comments we have and what does it take for us to evaluate them and determine the responses to them.

So it's probably sooner than what Brian said, and it depends on those kinds of factors.

MR. SHERON: I would guess in the fall next year we'd have a final package to --

DR. WALLIS: I'd ask for our approval of a final rule until we have seen an acceptable reg. guide.

MR. SHERON: Yes.

DR. WALLIS: Because they seem to be tied together.

MR. SHERON: Well, they'll go hand in hand. So we --

DR. WALLIS: Don't delay our review of the reg. guide to the point where we can't finish that job before you come up with a final.

DR. APOSTOLAKIS: Nos, in June of '05, you will come to us asking for a letter saying that it's okay to issue the guide for public comment?

MR. SHERON: That's a rough date, but I think what we would do is we would present the guide that we have. If it's ready to go out for public comment at that point, then, yes, we might.

You know, the other thing we might want to do is come down and maybe in April or something, depending upon how far along we are and provide you with interim reports.

DR. SHACK: I mean, I assume there would be subcommittee work on the reg. guide.

MR. SHERON: That's what I mean. There would be subcommittee going on probably as we go through the development.

We haven't even started this yet. One of the things --

DR. WALLIS: I think that would be good if you could plan this out so that the subcommittee has got to look at it, but it may be April, May.

MR. SHERON: Sure. We have a meeting set up. I think it's November 18th with the industry because one of the things we're looking at is do they want to take on as initiative a developing guidance document, which we could endorse ultimately at some point down the road through a reg. guide.

Our intent would be not to rely solely on the industry to develop something, but we would do just like we did on 191, where the industry developed a guide, but the staff developed one in parallel. Okay? We had a fallback. So we needed to have something.

So if the industry doesn't need --

DR. SHACK: That was such a success.

(Laughter.)

MR. SHERON: But that's what the plan is, and the ultimate plan is that when a final rule goes out, there will be a reg, guide that goes along with it. So it will be a package.

And that's the end of my presentation. I kept us right on schedule.

DR. WALLIS: You're ahead. It says 9:24 a.m. on the slides.

MR. SHERON: Well, there's only four more hours of presentations then.

DR. WALLIS: No, no. That's the date at which it was written. I'm sorry.

MR. DUDLEY: Okay. I'm Dick Dudley. I'm

the Rulemaking Project Manager for the 50.46 rule.

I'm going to talk to you briefly about the regulatory structure of the proposed rule.

We're going to essentially leave exhibit 50.46 unchanged. We will just add to it a provision that allows you to meet 50.46 or to take the voluntary alternative option and comply with the new rule that we're adding, Section 50.46(a).

In addition to adding 50.46(a), we're going to make minor conforming changes to 50.34, basically explaining which facilities this rule is applicable to, and minor changes to the backfit rule to allow certain exceptions that I'll talk about later.

And also we have to make certain other conforming changes to some of the general design criteria so that there aren't conflicts between 50.46(a) and the GDC under certain LOCA requirements and conditions.

MR. SIEBER: What happens to Appendix K?

MR. DUDLEY: No change, right? Except for documentation requirements, but there's no substantive change in Appendix K.

MR. SIEBER: Well, if you move to a best estimate code, Baker-Just probably gets replaced, right? And also the ANS standard for decay heat probably gets updated.

MR. DUDLEY: I'm sorry. I can't --

MR. SHERON: What we're doing is we're adding let me call it a third alternative to 50.46. Licensees have three options now. They can do it according to the old evaluation model approach, which has all of the very specific requirements of Baker-Just, ANS 1971, et cetera, et cetera, 20 percent, and they can do a standard classical evaluation model calculation.

The second option, which is the one we revised the rule back in I think around 1988, allows for a best estimate alternative where you use the best estimate code combined with an uncertainty analysis of the 95?95 basically. I don't think that's specified in the rule.

And then you can do your ECCS analysis using that best estimate method, but it still has certain requirements that are associated with it.

What this does is this is yet a third option where a licensee can divide up their plan into two break spectrum sizes based on a transition break size, and for the breaks that are beyond the transition break size, they can use a best estimate code. It doesn't have to be at let me call it the 95?95 uncertainty level that the option end of current 50.46 has. They don't have to take into account the single failure and a number of other assumptions. So it's even a more relaxed analysis approach than what's in the current 5046.

MR. SIEBER: Okay. So Appendix K becomes even more of a Bronze Age artifact than it is today, right?

DR. SHACK: No. He could choose to use it for below the TBS breaks since he doesn't have a qualified best estimate small break LOCA. He's still going to be using it for all those.

MR. SHERON: There are plants that are not necessarily LOCA limited, and there are plants that may not be able -- they may in their own analysis not see a lot of benefit to going with this 50.46(a), in which case there may be no financial incentive or any incentive for them to change to another code, other than it's a lot of money and a lot of time and they don't get a benefit.

MR. SIEBER: Okay. Thank you.

MR. DUDLEY: The structure of the draft rule is shown on this slide. Basically what we're doing is we take the entire LOCA break spectrum. We divide it into two regions by defining a transition break size. We're going to call that TBS as an acronym.

The selection of the TBS was based upon break frequency and other considerations. For the breaks in the smaller break region, they'll continue to be design basis accidents, and they have to continue to meet all of the existing requirements in 50.46 and other places for design basis accidents.

But under this alternative, breaks larger than the TBS would become beyond design basis accidents, with the exception that we would still require that mitigation capability be maintained for these breaks up to the full double-ended guillotine break. But we would allow the mitigation to be done using less stringent analysis assumptions and acceptance criteria, as you've already heard. We're not going to require a single failure assumption in this mitigation analysis.

But we are going to require that the capability to mitigate be demonstrated for all at power operating configurations. What we mean by this, if a facility is licensed to and plans to operate without a component or a system in service, they have to show that they can mitigate this full double ended break with the remaining equipment that's available.

In addition, since the TBS now becomes the largest design basis LOCA, the TBS break conditions are going to apply in other areas where regulatory requirements are based upon LOCA attributes. For example, this would be an equipment qualification, perhaps in containment sprays or with valve priming issues.

So after a plant selects this alternative and completes their ECCS analysis, some plants will find that their designs are no longer limited by the double ended break of the largest pipe. Those licensees will be allowed to propose changes to plant operations or design by two methods.

They can either propose and have them approved by the NRC by the license amendment process or they'll be able to use an inconsequential risk criterion that would allow them to make these specific changes without NRC looking at the individual changes.

And I'll give you more explanation on how that works later.

Those that submit license amendments, the license amendments must be risk informed. They must meet the criteria that are essentially the same as those in Reg. Guide 1.174 for defense in depth.

Safety margins must have a monitoring program. Changes in risk must either reduce risk or increase it a very small amount that's determined to be acceptable.

And the PRAs that they use to demonstrate the changes in risk must meet the PRA quality and scope requirements that we have included in 50.46(a).

DR. WALLIS: Now, do those PRA quality requirements say something about acceptable uncertainty in the calculation of risk? Because if you're going to say you've got an acceptable risk, you can't really evaluate that without knowing how good an estimate of that risk the PRA is giving you.

MR. DUDLEY: That's a specific detail that I really can't answer.

DR. WALLIS: It seems to me very important.

MR. DUDLEY: We'll be able to do that in an upcoming presentation, right? If you can wait a moment.

DR. APOSTOLAKIS: This is intended to be a mean value, which is effective in the uncertainties, but also you know, remember the famous words "increased management attention" when it comes to this.

I was wondering though. All of the safety benefits that Brian listed, is there impact on delta CDF quantifiable?

MR. DUDLEY: I imagine some are and some aren't.

DR. APOSTOLAKIS: Yeah, but that's really an important consideration. I don't think they are. Some of them are not.

MR. SHERON: Some of them may not. For example, I think I was thinking about that when I was up there because, you know, if a plant had success criteria that says, you know, if you can mitigate a LOCA with two out of three accumulators and you put it in the PRA that way, in other words --

DR. APOSTOLAKIS: Yeah, that's probably --

MR. SHERON: You know, and then if they conclude that based on a best estimate analysis or something they can now mitigate it with something less, you're right. It probably wouldn't appear in a PRA.

DR. APOSTOLAKIS: Or conserving the RWST inventory. I don't know how you quantify that. Can you quantify that?

DR. DENNING: Yeah, I think you can quantify that particular one, George, and I think it's probably one of the most important ones, particularly delaying, having to switch over to recirc. I think you could do a quantify --

DR. APOSTOLAKIS: Oh, that one, yeah.

DR. DENNING: Well, and that's tied into preserving --

DR. APOSTOLAKIS: Well, that ought to fix it that way. Okay.

MR. DUDLEY: And this slide discusses changes that we're going to make to the GDC. Again, we have to make some conforming changes to the GDC so that GDC requirements don't conflict with requirements allowed for LOCA analyses in 50.46(a).

In particular, we're going to remove the single failure requirement for these five GDCs, for electric power systems, emergency core cooling, containment heat removal, containment atmosphere clean-up and cooling water.

And in addition, on GDC 4, on environmental and dynamic effects, we looked at that for a good deal of time, and we decided we would not make changes to GDC 4. The same dynamic effects for pipe breaks will still need to be considered, and the other capability under GDC 4 to use leak before break analyses will stay. So we're not going to change GDC

4.

GDC 50 on containment design basis. Our current position with that is that we're not going to need to change it. GDC 50 generally speaks to the margin between your calculated pressure and your design pressure of a containment. Our most recent reading of that looks like there's enough that you can interpret the existing GDC to allow one level of margin for your design basis accidents and a different level of margin per your beyond design basis accidents, which would be the mitigation analyses that are done for the accidents, breaks larger than the TBS.

So right now we don't think we need to change GDC 50, but our steering committee hasn't yet met to approve that decision.

DR. KRESS: Will GDC 38, removing the single failure criteria there, allow them to make major changes in their spray system in containment?

MR. DUDLEY: I'm really not sure about that.

DR. KRESS: When they do the calculation for the LOCAs.

MR. SHERON: The intent is that if there's a safety benefit to not having the sprays come on automatically, but allowing manual operator action to start the spray; so, for example, if they get a break and let's say it's a very small break, all right, you don't need the sprays to come on automatically, and so you don't want to, again, have this big inventory of water coming in, potentially clogging the sump.

So you would allow the operator to make that decision whether they need to manually start the sprays or not.

DR. KRESS: But the equipment and the capacity of the sprays would still be the same? I assume they won't change that.

MR. SHERON: What?

DR. KRESS: The capacity of the sprays.

MR. SHERON: Well, this gets into the question -- and Dick alluded, you know, that we're going to discuss this a little more -- and that is that if the capacity of, for example, the sprays and so forth is relied upon for other accidents, as well as for severe accidents, if you take credit for it in a risk assessment, okay, again, we talked about that we're going to put a criteria in for changes to late containment failure. Okay?

We have to go through and the licensee will have to go through that entire analysis. Similar to that, one of the concerns was that, for example, if a licensee goes in and cuts a hole in a containment to remove and replace steam generators and they say, "Gee, I can save a lot of time and money if I don't have to do a repair that restores the containment to its original structural strength. I can put in something that's thinner, if you want to call it that." And the question is would we allow that.

The answer is probably not. Okay? But the question we ask is, well, if a licensee does propose the repair that may not restore something to its original condition, but if they can come in and demonstrate that the change in risk all the way out, you know, through severe accidents and so forth is inconsequential, would we allow it?

In other words, you know, maybe they just want to use a little bit less rebar or something, and our steering committee is going to discuss that next week to decide because that gets into the question of do you allow zero changes or are there some minor changes that you can allow and what are the criteria?

But the intent of this whole rule is that we don't want to degrade the capability of the plant to accommodate accidents beyond design basis out through severe accidents. So that's why we have to go out to Level 2.

DR. WALLIS: You're going to have to bring in difference in depth, I think, too, because there are some reactors that we've looked at where you could approve from risk considerations you didn't need a containment at all, and yet you still have one.

MR. SHERON: Yeah. Don't worry. Nobody is going to take any containments off.

DR. WALLIS: No, but if you start making it weaker, how weak does it get before it isn't containment?

MR. SHERON: Right, and the intent right now is that we don't want to see containments weakened.

MR. DUDLEY: One thing I'd like to clarify. I might have said remove the single failure requirement from these GDC. What we're going to do is really allow an exception to the single failure requirement in these GDCs for the 50.46(a) analyses portion that's done for breaks larger than the TBS.

For breaks smaller than the TBS, they still will meet the regular GDCs and the full requirements.

DR. APOSTOLAKIS: What this does is really sets the assumptions under which the analysis will be done; is that --

MR. DUDLEY: That's correct.

DR. APOSTOLAKIS: That's really what it does.

MR. DUDLEY: That's correct, right.

DR. SHACK: So even if you did it with Appendix K you'd actually get margin.

MR. DUDLEY: Yes.

I'd like to talk a little bit about the process for making inconsequential risk changes. Licensees, again, will be allowed to make these changes without specific NRC review, but first they would submit their PRA to the NRC, and they would also submit their process, review process, for these changes.

The PRA would have to meet the acceptance criteria in 50.46(a), and the licensee review process, we would have to look at that and make sure that we feel it would insure defense in depth and adequate safety margins.

DR. APOSTOLAKIS: Now, that bothers me a little bit. The acceptance criteria will be according to the phased approach that the Commission is promulgating?

MR. DUDLEY: Yes, we discussed that, I

believe, in the subcommittee meeting.

DR. APOSTOLAKIS: But this really says that there should be standards or industry consensus documents, and if you look at those, they really tell you what you should have in the PRA, but they really don't go very much into the detail of how you do these things. And for something as important as this one, I'm wondering whether that would be sufficient.

I mean, they tell you they have to have common cause failures. Well, that's very good, but then how do you do that? I mean, that's a very important consideration.

So for something like this, which presumably will have great benefits to the licensee, it seems to me it would be worthwhile to spend some extra time reviewing the quality of the PRA beyond the standards.

MR. DUDLEY: Would it be possible to hold that question until we talk about it? There's a PRA section coming up shortly.

DR. APOSTOLAKIS: Well, it's definitely possible.

MR. DUDLEY: If you could, please. Thanks very much.

DR. APOSTOLAKIS: All right.

MR. DUDLEY: So once a licensee submits their program to the NRC, the NRC would then, if we believe it's acceptable, we would approve it as a license amendment. We'd modify this licensee's license probably at a license condition. It would authorize a licensee in the future to make changes without NRC specifically looking at them that had risk changes that were below the inconsequential risk threshold.

DR. WALLIS: And is it something like ten to the minus six?

MR. DUDLEY: Yeah, I believe that's right, and again, Mark Rubin or others will talk about that later on, yes.

MR. ROSEN: Do you remember in the subcommittee meeting we discussed this point? And in your first bullet that the licensees could make changes without specific NRC review might be better stated as they could make changes without specific prior NRC review, and we used the example of 50.59 process where licensees report these inconsequential changes on, say, an annual basis or something like that, and then the staff has a chance after the fact, granted, but a chance to at least say, "Yeah, we kind of agree these are all inconsequential, except for this one we'd like more details on," and that would be a way of making me more comfortable.

MR. DUDLEY: Exactly, and you know, we appreciate that recommendation by the subcommittee. We're going to look at that, and more than likely that's the process that we're going to implement. Thank you.

DR. KRESS: Once again, we have the same problem here with ten inconsequential changes at one times ten to the minus six. It adds up to one, ten times ten to the minus five.

MR. DUDLEY: Well, the inconsequential threshold will be summed over all the changes. The bundling issue --

DR. KRESS: So the one times ten to the minus six will be all inconsequential?

MR. DUDLEY: Every change that's made under this criterion.

DR. KRESS: And that will be tracked some way by the plant or by the --

DR. APOSTOLAKIS: I still think this is an issue that we're rushing into. It was deliberately stated in a vague manner in 1.174 because you cannot predict in advance what you want to bundle and what you don't want to bundle. We have to trust the staff's judgment every now and then, and I think you will not find anything definitive in the Regulatory Guide 1.174 that says you have to bundle or you do this. It was very vague.

It was recognized that there was an issue, that you can't just keep approving things and so on, but you have to trust that the staff will take action, and it seems to me that here if you start writing down specific rules how to do it, eventually you will run into the same problem like 1.174.

DR. SHACK: Well, I think most of these inconsequential changes will be unquantifiable.

DR. APOSTOLAKIS: It will be unquantifiable, exactly.

DR. SHACK: They will be less than ten to the minus six, but they're really ten to the minus --

DR. WALLIS: Twenty-one, or something.

DR. APOSTOLAKIS: Or they will be completely unquantifiable. It will be a matter of judgment.

MR. ROSEN: They will be unquantifiable because they're not models.

CHAIRPERSON BONACA: Yeah, they're not modeled, most of them.

DR. APOSTOLAKIS: Yeah, yeah.

MR. ROSEN: And this requirement, if you want to make an inconsequential change that you have to know what the value is, it will require a bunch of modeling of stuff that doesn't matter. It just doesn't make any sense.

DR. KRESS: Maybe that could be the definition of inconsequential. It is not modeled in the PRA.

DR. APOSTOLAKIS: Oh, then they will submit incomplete PRAs.

(Laughter.)

MR. ROSEN: The things that aren't modeled by the practitioners are things that they know don't show up in any sequences. So you know, this is completely sensible.

DR. APOSTOLAKIS: No, but it may even be modeled --

MR. ROSEN: It's not a plot against the United States of America.

DR. APOSTOLAKIS: The model may not be sensitive to small changes, like earlier Rich pointed out that if you preserve the inventory of RWSD, you have a longer period for the operator for manual action.

Now, again, if you're increasing that by several minutes, I don't know what the order of magnitude is. I just don't know which model can make the distinction and tell you it was ten to the minus four and now it's 1.2, ten to the minus four.

The models are not so sensitive to such changes, but everybody will agree that if you increase it by a few minutes, yeah, it's okay.

MR. ROSEN: I think you end up knowing the sign of the number, but not the number. You know, it's either better or worse.

DR. APOSTOLAKIS: Yeah, but I do agree with the recommendation that these should be submitted to staff for review.

DR. SHACK: Mark, do you want to make a comment?

MR. RUBIN: I'll just observe that the committee comments pretty much illuminated the issue that we were trying to come to grips with here. In most cases, if not all cases, these will not be quantified in the PRA because they are truly inconsequential, you know, E to the minus very large number.

The case that we would expect the licensees to make in most cases is that these are non-issues, and we didn't want to put an overly burdensome reporting and review requirement on them for things that were truly done in the epsilon range.

If they got things that were starting to be questionable, inconsequential, well, that's why we want them to submit their process to us in the beginning, to make sure it's a robust one, and there's a high confidence that they can cull out and identify these essentially non-issues and to let them act on them without staff review.

But give us confidence that the ones that don't meet that trip point we will be seeing and we'll have an opportunity to evaluate.

DR. KRESS: This is one of those places I think, George, we just have to trust the staff.

DR. APOSTOLAKIS: Yeah. You can't legislate every detail, and so far, I mean, I haven't seen a case where the staff has made risk informed decisions where they didn't exercise due caution. So you know, there's a good record behind it.

MR. DUDLEY: This just talks a little bit about the licensing process for the design changes that are other than inconsequential. Again, they come in as risk informed license amendments. It would just be NRC review and approval of those amendments to insure that they comply with the acceptance criteria.

And during the license amendment review, the NRC will also evaluate any possible security impacts that might arise due to these changes proposed under this process.

DR. APOSTOLAKIS: So this is something that will be entirely up to the staff, right? The industry will have no guidance on this, on the last bullet?

MR. DUDLEY: The security review?

DR. APOSTOLAKIS: Yeah.

MR. DUDLEY: I understand that NSIR is working on this process to try to quantify it and develop a better process, but --

DR. APOSTOLAKIS: And that will be communicated to the licensees?

MR. DUDLEY: Suzie, can you respond to that?

MS. BLACK: I can try, yes. Suzie Black, Division Director, DSSA.

And there is a group that has been put together to provide guidance on how to evaluate changes to the plant and their impact on security and vice versa, and you'll hear more about that during the fire protection session this afternoon. Somebody from NSIR is coming to discuss what our plans are.

DR. APOSTOLAKIS: I guess my question was when the staff evaluates possible security impacts, they're not going to surprise the licensees. The licensees will have some idea in advance as to what the staff is looking for.

MS. BLACK: Actually, the SRM that came down from the Commission this summer said don't take away the ability of the plant, the inherent ability of the plant to deal with security incidents through this rule.

In the Commission paper that we sent back up to them, we discussed how we intend to do that and whether additional rulemaking was needed for licensees to do this interface. But, yes, before this is issued, there will be some guidance to the licensees of what we mean by that in the rule.

MR. SHERON: George, let me. This is not unique to 50.46. Okay? The question has been raised at every change that a licensee makes to their plant, whether it's under 50.46 or some other regulation or just a regular, you know, "I want to change something in my plant. Here's a license amendment."

We have to go through and determine if there's any security impact. So what we decided, as Suzie said, is we put in a Commission paper that, when we sent this up just recently for the status, that we were going to look and see if there is another regulation, be it 50.55 or whatever. I'm sorry. Fifty, fifty-nine or 50.73, for example, where we would put a more global requirement that licensees need to evaluate the impact of design changes on security and vice versa. Okay?

In the same sense, we've set up a Safety-Security -- what is it called?

MS. BLACK: Interface Advisor.

MR. SHERON: Interface Advisory Panel, and what that panel does is for every license amendment that's supposed to come in, that comes in, the intent would be that, first, the project manager would do a screening to see whether it tripped certain criteria which we're going to develop and the like.

If it doesn't, fine. It goes in and staff does its technical review and the like.

If it does trip the criteria, then it would go to the Safety-Security Interface Panel, and they would look at it, and they would make a determination whether or not NSIR needs to review it from a security standpoint in more detail. Okay? And so that's the process we're going to follow.

DR. APOSTOLAKIS: Thank you.

MR. DUDLEY: And last, the NRC is going to periodically evaluate LOCA frequency information. If, in the future, information comes to light, perhaps a new degradation mechanism or something of that nature that might cause us to believe that the LOCA frequency numbers that we have today are significantly increased, the NRC will change the transition break size. We'll do this by a rulemaking or order, depending upon the significance of the change.

Plant design changes that have already been made under 50.46(a) will continue to be required to meet the same acceptance criteria. That means in some cases it is possible that a licensee might have to restore its design or part of its design back to what it was originally, or might make other compensatory changes so that the facility would continue to meet the acceptance criteria.

And this is why we had to make the change to 50.109, where we added a couple of exceptions, that the backfit rule did not apply to when the NRC changed the transition break size, and until the instances where the licensees might have to reverse or change some of their design changes that otherwise would be protected by the backfit rule.

DR. APOSTOLAKIS: Of course, you have a

lot of cushion here because you have fairly conservative --

MR. DUDLEY: Right. When we selected the transition break size, we did so so that it's very -- it's not very likely that we'll have to change it.

DR. APOSTOLAKIS: And the reevaluation will be done by expert, right?

MR. DUDLEY: Yes, yes. That's correct.

Okay. Next. Jennifer Uhle will talk about -- Ralph Landry will talk about our emergency core cooling system requirements.

DR. WALLIS: Ralph, are you going to take the questions as well as talk?

MR. LANDRY: I'm sorry?

DR. WALLIS: Are you going to take the questions as well?

MR. LANDRY: The questions? It depends on what questions are asked. That remains to be seen.

My name is Ralph Landry. I'm from the Reactor Systems Branch in NRR, and this morning I'm going to talk a little bit about the ECCS analysis requirements that we're putting into the new Rule 50.46(a).

So far you've heard Brian and Dick talk a little bit about the overview of the rule and some of the content of the rule, and what I would like to talk about is some of the numeric specifics or analysis specifics that are required and the acceptance criteria that we've placed into the new rule.

Not to belabor this point, but there is a difference between PWRs and BWRs when you analyze a LOCA in that PWRs for a large break and small break tend to be governed by different phenomena. The transition break size that has been brought out in the 50.46(a) is a size that's going to put you between the large break and the small break phenomenologically and shift it over towards the large break size.

For BWRs, we don't see as much effect for break size because BWRs have automatic depressurization systems so that small breaks are turned into large breaks so that you don't see the phenomenological demarcation for a BWR that you normally would see for a PWR.

So a lot of the remarks are really more specific to a PWR with this new rule.

In the below TBS range, basically everything is the same as it is today with 50.46. You have to use an approved methodology, and as was discussed a little bit earlier, that methodology can be an Appendix K compliant methodology. It can be a realistic or best estimate methodology for which you have assessed and determined the uncertainty.

You have to meet the worst single failure criteria. You have to meet the requirement for loss of off-site power. You have to use only safety systems, and so forth.

In the above TBS range though, we're changing what is an acceptable methodology. We still want to review and approve the methodology. However, at this point, it's up to the licensee what they want to use. They could still use an Appendix K compliant methodology if they want to. They could use a realistic methodology that has already been reviewed and approved.

But when they do the analysis now, we are looking at reducing the required uncertainty in the calculation. Where today we want a 95 percent probability on the final result, we may reduce that probability level, that uncertainty level when we do a realistic analysis in the beyond TBS range, or the licensee may submit a new methodology which we have not reviewed and approved to date.

And when we do the review and approval on that methodology, our goal now is to only look at the important phenomena, only those phenomena that are important to the transient so that we are not reviewing all of the medium and low level phenomena that we would currently review when we review a realistic analysis methodology.

So this would significantly reduce the review time and review effort for a new methodology.

In the beyond TBS range there would be no single failure criteria prescribed. However, when a plant is placed into a condition, it has to be in a condition that has been analyzed. In other words, if the plant has up rated their power and they want to take a train of ECCS out of service, they would have to have performed an analysis for that condition or else do something.

We don't want to prescribe exactly what they'd have to do. They could reduce the power. They could do a new analysis. They could take some action so that they have not placed their plant into an unanalyzed condition.

DR. KRESS: Ralph, the concept of having the different confidence level in these two different regimes of break sizes intrigues me because I have never seen a technical criteria for how one chooses other than picking something out of the air, a particular confidence level for something like that.

Do you have in mind a process or a set of criteria on how one really decides what is an acceptable confidence level for something like that?

MR. LANDRY: We'll discuss that more, Tom, when we get into the regulatory guide. At this point, we're thinking about a reduced not confidence level, reduced probability level. We're looking at different numbers, but we haven't decided on one at this point, and we have to go through much more discussion before we make that decision.

Now, when we talk about reducing the probability level on the uncertainty or the uncertainty level, you have to keep in mind we're talking about a lower probability event.

DR. KRESS: Certainly. It has to be part of your reasoning.

MR. LANDRY: So our feeling is we would not require the same level of uncertainty analysis for that event as we would a more probable --

DR. KRESS: Certainly in principle it makes sense. The question I have is how do you really decide what's --

MR. LANDRY: We haven't formulated the exact number, but we're going to work on that, and we're going to put something into the regulatory guide to describe it.

DR. WALLIS: Don;'t you put the confidence somehow into the PRA as a measure of the likelihood that you'll meet the success criteria? You could.

MR. SIEBER: Yeah, but they don't do that.

MR. LANDRY: We don't want to specify confidence because specifying probability and confidence is dependent upon the statistical methodology that is used. Some statistical methodologies will not return a probability and a confidence level.

Jennifer, you would like to make a comment.

DR. UHLE: This is Jennifer Uhle from the staff.

This is regarding the question you had about what exactly we would prescribe as being acceptable for this reduced percentile. Right now the 95 is typically acceptable, and that's sort of difficult, obviously.

Yuri Orechwa from the staff -- and he has presented in front of the ACRS before -- he's our statistical I would say genius and he's working on that to some degree, and it will be -- that effort will take on a lot more I would say focus as we get closer to looking at the reg guide. It is something we're thinking about, and we would prefer it not to be arbitrary, and we're trying to do our best to come up with something that's technically defensible.

DR. KRESS: Do you know whether or not he's thinking in terms of the loss function or the utility function for this?

DR. UHLE: You're going to have to ask me that again. The what function?

DR. KRESS: Well, it's called by some people a loss function, and other people call it a utility function.

DR. UHLE: I'll let Yuri come up where and talk about that, again, based on his genius level, and I'm pretty much a novice.

DR. APOSTOLAKIS: You graduated before I came to MIT, I think, didn't you?

DR. UHLE: No, I just avoided your classes.

(Laughter.)

MR. ORECHWA: I didn't want to be in this position. This is Yuri Orechwa.

Specifically to your question of loss function, this would have to do with whether you're using Bayesian statistics or something like that.

DR. APOSTOLAKIS: Certainly.

MR. ORECHWA: There are different ways of approaching this problem. Actually it has been touched on before, and it has been under the support of the NRC. I just found that out a week ago or so. We will look at it and try to present to you at least a consistent picture, maybe not an answer, and I think we need to know first what the problem is and what we are looking at.

But definitely you have to way somehow the amount or the information that is going to be brought to the table, loss function or whatever. You have to unify it with some kind of picture, and there we're going to have to use some rules. There are many available, but the main thing here is how far do you want to go into theoretical statistics and get lost, and how far do we have to stay practically in order to deal with it with licensees.

DR. KRESS: This issue shows up practically every time you make a decision.

MR. ORECHWA: That's right. If you all want to come and get --

DR. KRESS: It's well worthwhile.

MR. ORECHWA: If you want to come, I'm giving a talk at the ANS meeting just on that subject.

DR. SHACK: Except the uncertainty here is really ruled by the uncertainty in the LOCA frequencies, which are enormous. I mean, this is rocket science.

DR. KRESS: I understand. I understand.

DR. APOSTOLAKIS: But let me ask.

DR. KRESS: But I would like to see a consistent --

DR. APOSTOLAKIS: The safety benefits that Brian listed earlier will not be realized for breaks below TBS, correct?

MR. ORECHWA: That's not my --

DR. APOSTOLAKIS: That's not yours. Is that true, Ralph or Brian?

DR. UHLE: This is Jennifer Uhle again. Sorry, Ralph. Were you going to?

MR. LANDRY: Yeah, go ahead.

DR. UHLE: I think that what this will allow is more fine tuning of the accumulator injection points, things like that. So we could be or perhaps the licensee could show, you know, lower small break LOCA temperatures based on the fact that they won't be fine tuning their ECCS system to the double ended guillotine or large break.

But I think whether or not it is going to be showing up in your CDF, that may be doubtful.

DR. APOSTOLAKIS: No, but I thought the argument was that the reason why we have this transition or break size is that -- and we are relaxing some of the things we're doing for breaks above it -- is that there will be some benefits. We're not doing it just -- safety benefits -- we're not doing it just for economic reasons.

And I'm wondering how many of these benefits will not be realized for breaks below the TBS and whether the confidence you are getting by imposing these requirements is worth the price.

DR. KRESS: That's akin to the same question.

DR. APOSTOLAKIS: It's similar.

DR. KRESS: Yeah.

DR. APOSTOLAKIS: I mean, you're giving up something of the expense of gaining more confidence that you have analyzed it in a very conservative way.

DR. SHACK: No, no. I mean, what you're doing is you're essentially optimizing your system response to the accidents that will happen instead of optimizing the system response to the accident that won't happen.

MR. ROSEN: I would say the accidents that are more likely to happen.

DR. APOSTOLAKIS: How do you know that? I mean, how do you know that the operators will use only safety systems? Is that correct? I mean, won't they try their best to save the plant?

MR. RUBIN: They certainly will, and that's why we have the OPs and the SAMGs.

If I could make a quick comment.

DR. APOSTOLAKIS: Yeah, but you're giving credit only to safety systems.

MR. RUBIN: Well, you asked a question about the benefit down in the TBS and below space. Remember the benefits or the safety increases, safety reductions from this rule will be based on the actual plant modifications, the changes you make based on the difference in the analysis methods and assumptions that will be allowed by the new rule.

In some cases, those changes may offer a benefit in the below TBS range. For example, a delay in the spray actuation for small breaks, well below the TBS, you're not going to be blowing as much debris down in the sump if you control the sprays early. Long term recirculation reliability will, therefore, be increased.

The same on the diesels. Changes that we may allow, it will be beyond this role when we do the LOCA LOOP, but it certainly is very related, as the committee mentioned before. These changes in the diesel loading and time sequencing hopefully will result in increased diesel reliability, which will help for SBO sequences.

So not just beyond the TBS.

DR. APOSTOLAKIS: So we are realizing most of these benefits throughout the range.

MR. RUBIN: In whole severe accident assessment process, in all of the initiators, certainly. That's why we have to look at them.

DR. SHACK: What you're saying, George, is you could have a new rule that would allow you -- you would go strictly on a risk basis. You'd get rid of all the artificial constraints here, and you'd just design the system to minimize --

DR. APOSTOLAKIS: No, I didn't say that.

DR. SHACK: -- the risk --

DR. APOSTOLAKIS: No, I didn't say that.

DR. SHACK: -- as an alternative, but you know, you are still in design basis space. So, you know, the below TBS accidents --

DR. APOSTOLAKIS: Yeah, I know, yeah. But the whole idea of being in design basis space is to have a higher degree of confidence that you are prepared to face, you know, unfortunate circumstances. And my question was, you know, what price do you pay for that higher confidence.

And apparently the safety benefits are everywhere by relaxing the requirements above TBS.

MR. ROSEN: Because small breaks are much more likely than large breaks, and that's where you accrue the benefits. You're not going to have those accidents, but you are going to be -- it is more likely that you will.

DR. WALLIS: This is all qualitative. Do you want a quantitative measure, George?

DR. APOSTOLAKIS: Well, it would have been nice, but I'm not asking for it because I know it's pie in the sky.

DR. WALLIS: I don't think you'll get it from talking about 95 percent?75 percent because it doesn't figure in the PRA anyway.

DR. APOSTOLAKIS: It doesn't appear in the PRA. We're breaking up into pieces, I think.

MR. LANDRY: Okay. To continue, one other benefit that we're looking at in the TBS and above range was to be able to use non-safety equipment where today the licensee cannot take credit for non-safety equipment.

And we're proposing that not only can full credit be taken for all of the ECCS and all of the safety grade, but even non-safety grade equipment can be utilized.

DR. APOSTOLAKIS: Wouldn't it be possible, Ralph -- and you don't have to do it now -- but coming back to the question that Dr. Kress started, how do you decide what are the conditions you're going to impose on the analysis for breaks below TBS? Couldn't these conditions be selected in a conservative way from the PRA?

Instead of saying it's design basis, and the moment you say "design basis" we all say, "Ah."

MR. ROSEN: It has actually been suggested for the --

DR. APOSTOLAKIS: I am not claiming originality.

MR. ROSEN: -- for the future plant designs where we don't have design basis --

DR. APOSTOLAKIS: I know, but I'm asking the question whether there's any insight we can apply to those.

MR. LANDRY: Last week when we met with the subcommittee, Brian Sheron went through a lot more information than he did this morning on the background and basis for the rule, and one of the things that was pointed out at that time was that when we set out to develop this new rule, we had the constraint of a particular length of time which we had to develop this rule. so to do so, we could not be overly creative.

We wanted to look at the rule and say what can we retain, what can we change to give benefit and accomplish the task within the constraints of the time available.

DR. APOSTOLAKIS: But it could be done, I hope. Anyway, let's go on.

MR. SHERON: George, if I could just --

DR. APOSTOLAKIS: I accepted the answer.

MR. SHERON: Okay. Well, I just wanted to point out that it's not so much also timing, but the small break doesn't have nearly as much conservatism that's imposed in it than the large break did, I mean, if you think about it. Okay? It's basically a best estimate model with single failure and, you know, maximum peaking factor in decay heat, but there's a lot of those other conservatisms that were imbedded into the large break models that are not in the small break.

So there's a question of how much margin is really there and do we understand it. Okay? But I could certainly see that if a licensee, for example, were to optimize the accumulator set point, if you ever look at a small break analysis, what you'll find out is that the limiting small break implants is set by the accumulator set point pressure. Okay?

For the break size in a CE plant with a 200 pound accumulator is set by the break. The limiting break size is the one which asymptotically brings the pressure down to the set point so that it takes the longest period of time before the accumulator kicks in because once the accumulator kicks in, you put a lot of cold water into the system; it condenses all of the steam; it drops the pressure, and then the low pressure kicks on and it floods the plant.

For a Westinghouse plant, the limiting break is the one that asymptotically brings the pressure down to 600 pounds and takes the longest period before that accumulator kicks in. Okay?

So I could see that if they don't need the accumulators basically for the large break the way they did, they could stagger those set points so that perhaps you wouldn't have small breaks as limiting. In other words, if you had accumulators kicking in at different points, at different pressures, then you wouldn't have this limiting small break concept for a small break.

DR. SHACK: We're going to have to move on if we're going to get the PRA in here and you all want a shot at Mr. Kelly.

MR. LANDRY: Okay. Continuing to the acceptance criteria, in the TBS and below break size range, we have retained all of the acceptance criteria that are currently in 50.46, a PCT limit of 2,200 degrees, maximum local oxidation of 17 percent, hydrogen generation equivalent to core-wide oxidation of one percent, coolable geometry, and long-term cooling.

For the above TBS range, we are proposing only two acceptance criteria: that you retain a coolable geometry and that you maintain long-term cooling.

Today with what we know, we are going to say in the statement of consideration and discuss even further in the regulatory guide that by coolable geometry, we understand that to be 2,200 degrees Fahrenheit and 17 percent maximum local oxidation.

But we don't want to put that in the rule because if a licensee can come in with data to justify a different temperature and different oxidation level, we would be willing to review that and hear their argument.

So we want to keep the acceptance criteria simple for the above TBS range, with a particular understanding of what it means today and keep that door open for the future.

The documentation that we would require in the below TBS range would be essentially the same documentation as currently required by 10 CFR 50, Appendix K, Section 2. Section 2 of Appendix K describes the documentation required whether you're talking about a realistic LOCA model or an Appendix K compliant model.

Both models are described for their documentation in Part 2. In the above TBS range, however, we would relax that documentation requirement to be that material sufficient to demonstrate that the performance criteria will not be exceeded.

DR. WALLIS: It seems to me those words are not relaxing it. If you say demonstrate that they won't be exceeded, to me that means with 100 percent probability.

MR. LANDRY: If you're doing a realistic calculation or an uncertainty analysis on it --

DR. WALLIS: Just demonstrate it won't be exceeded is an absolute deterministic statement, and you're actually toughening up the requirements.

MR. LANDRY: Actually we're trying to relax the requirements.

DR. WALLIS: I know that's what you're doing, but unless you say there's low probability or something, you haven't relaxed it. You just don't want to say that.

MR. LANDRY: At a lesser probability.

DR. WALLIS: At a lesser probability. That's okay.

MR. LANDRY: Okay. The current 50.46 requirement is that you have to report to the NRC if you have a change in calculated PCT greater than 50 degrees Fahrenheit or the sum of the absolute values of the changes in PCT exceeds 50 degrees within 30 days to plan on what you're going to do, a re-analysis or whatever the licensee is going to do to correct the situation.

We wanted to add to that now because at the smaller breaks you'll be saying at a moderately high temperature for an extended period of time. Local oxidation becomes more important. So we want to add the requirement that if you exceed a change in maximum local oxidation of .4 percent, you have to report to the NRC the same as you would if you exceed the temperature change of 50 degrees Fahrenheit.

This is --

DR. KRESS: Numbers like that always intrigue me. Why isn't that .5 or .3 or .7?

MR. LANDRY: We debated whether it would be .5, and we got into this a little bit last week, but we said .4 is to 17 as 50 is to 2,200, not looking at that temperature as actually a delta temperature.

DR. KRESS: That sort of implies that oxidation and temperature have the same effect on coolability, but anyway, that's one way to do it.

MR. LANDRY: Well, oxidation and temperature do have an effect on ductility.

DR. KRESS: Yeah, but not the same effect.

MR. LANDRY: Very similar because if you have two --

DR. KRESS: This implies they have the same effect.

MR. LANDRY: If you have two rods and you have a rod at 2,200 degrees and 17 percent and a rod at 1,800 degrees and 17 percent and you quench both --

DR. KRESS: This implies a linear relationship between the two, but --

MR. LANDRY: We were just trying to indicate that at the smaller break --

DR. KRESS: It suits me.

DR. WALLIS: You mean the no percent oxidation is equivalent to the core being at zero degrees Fahrenheit?

MR. LANDRY: We didn't know how to quantify pre-oxidation that might exist, whether it starts from zero or whether you're starting with a ten percent preoxidized condition. So we had to make a decision, and we felt that point --

DR. SHACK: This isn't part of the rule, and so this can be changed.

MR. LANDRY: We felt that .4 percent is reasonable.

DR. SHACK: But, I mean, the idea is you really do need a limit on the oxidation --

MR. LANDRY: Correct.

DR. SHACK: -- whether it's .4 or .5 or .2.

MR. LANDRY: Right, .2, .4, .5. We feel that it is important to have a limit upon which you must report that you made a significant change.

DR. KRESS: I think this is one area that needs some work. There is a need for a definite correlation between temperature and oxidation degree and ductility, and I think such a correlation probably exists for this. You know, it would be clad type specific.

And then one could take that correlation and then one needs something that says this is an acceptable ductility for coolable geometry. I don't know where one gets that, but that's also an empirical number.

And then all of these numbers might make some sense, and the question I have is does that correlation exist, and where will I find it?

MR. LANDRY: If you stay tuned, Tom, a year from now. The Office of Research has an ongoing program for the fuel ductility, oxidation work.

DR. KRESS: Wonderful.

MR. LANDRY: That information is supposed to be brought together September of next year, September of '05, and some time after that point, they will have a report together on their findings dealing with oxidation questions.

DR. KRESS: Well, thank you.

MR. LANDRY: So if you stay tuned, there hopefully will be an answer.

DR. KRESS: So this could be viewed as a

confirmatory thing. This is your judgment now, and you might could have a confirmatory --

MR. LANDRY: This is our judgment today based on what we know today.

DR. DENNING: Now, this is just a 30-day reporting requirement. It's not necessarily acceptable.

MR. LANDRY: That's correct. That's correct.

DR. DENNING: So it's just that we're going to live for 30 days with this slight thing and realize it doesn't significantly increase our risk.

MR. LANDRY: That's right. That's all we're saying, is if you change your oxidation by this much, you have to tell us in 30 days and tell us what you want to do. That doesn't say shut the plant down. It simply says you tell us and we'll decide where we're going from that point.

In the above TBS range, we want to recognize that this is a much less probable range, and we want to reduce the burden. So instead of reporting when you have a delta PCT of 50 degrees, we want to now say when you have a delta T of 300 degrees in a calculation you need to report.

Now, of course, that doesn't mean if

you're at 2,100 degrees and you have a delta T of 300 it's okay because you exceed 2,200 at that point, but it simply says that we want to recognize that this is much more probability so that the reporting requirement is less stringent. We give a little more leeway in that.

DR. WALLIS: Well, Ralph, do you have any idea about the kind of plant changes that might give rise to a delta PCT of 300?

MR. LANDRY: We haven't seen any. Nothing has been proposed.

DR. WALLIS: You've got to tie this number to something sensible, and it may be that in order to get this 300 you've got to make a revolutionary change in the ECCS system. I just have no idea. So I'd like to know how this ties in with the kind of extent of changes that would create a number like that.

I think you need to do some homework before you come back and justify these numbers next time.

DR. DENNING: Are these things the result of design changes or are they the result of "I discovered an error in my calculation"?

MR. LANDRY: It can be both. It can be. The changes in calculated temperature are changes due to correction of errors in the code. They can be plus and minus. Changes in hardware, Harper's state, operational changes, and so on.

Jennifer wanted to make a comment.

DR. UHLE: Yeah, and I also want to point out that this is a cumulative change, and so it's not just any change in and of itself that's a 300 degree change. It's if you make 20 changes, you find a few errors. You de-rate a pump, you, you know, do a variety of things or you change your peaking factor, any kind of change that's going to affect the PCT, including errors to the code.

That is accumulated; this 300 degrees is accumulated over a period of time, and so as soon as you hit the 300, that's when you come in and report and schedule a reanalysis or take other action to come into compliance.

And, again, at all times you have to insure that you're meeting all of the success criteria, all five of them in the less than TBS range, but you know, the two of them in the greater than TBS range.

MR. LANDRY: And, again, as Jennifer said, this is an accumulated. It's the sum of the absolute values. So it's not a plus 300 degree change.

A final comment on the regulatory review. When we review the models as we've been talking about reviewing the possible models that would be resubmitted or new submittals, we would be focusing on the adequacy of the evaluation model to represent the important parameters.

We would not be looking at medium ranked, low ranked parameters. We're going to focus in on those parameters that are highly ranked and that are highly important.

A lot of the discussion of what we're going to be looking at in a model, what we're going to expect in a model is going to be described in the upcoming regulatory guide.

DR. SHACK: You know, we had this emphasis. I just can't see the incentive for a guy to go out and get a new large break LOCA code at this point. I mean, I can see them putting money in a relaxed fuel acceptance criteria, but why would he bother to come up with a new code?

MR. LANDRY: They may not. As I said earlier, even in the above TBS range, a licensee could come in with an Appendix K model if they want. They could come in with an already approved evaluation model that's for a realistic LOCA or they could dome in with a new methodology which we haven't reviewed so far.

We're not trying to shut the door and say you will do this, but leave that up to the licensee of how they see the way that they want to achieve benefit in this range.

DR. WALLIS: @Well, you could come up with a new correlation for disbursed flow heat transfer, which only covers the data with a 75 percent confidence rather than 95 percent confidence, stick it into your code, and predict a different number.

MR. LANDRY: Right.

DR. WALLIS: That would be not a very difficult change to make in the LOCA code.

MR. LANDRY: It may have a great benefit.

DR. WALLIS: It might be acceptable to you to use a cruder correlation for some physical phenomenon.

MR. LANDRY: That's right. There are all kinds of ways a licensee can apply that.

DR. WALLIS: Have a lot of judgment in assessing what is acceptable and what is not.

MR. LANDRY: Right. I believe that concludes what I had, and Glenn Kelly is next to talk about the favorite topic, PRA.

MR. KELLY: Good morning. I'm Glenn Kelly, formerly of the Probabilistic Safety Assessment Branch, now of the Reactor Security Special Projects under Bill Kane and Jack Grove, and I've been lent back to give this presentation today.

As we talked at the subcommittee meeting, there's basically four steps that we expect licensees to go through in order to demonstrate that they have acceptable changes that they're proposing. The first thing we wanted to do is to define the proposed change that they'd like to handle. Now, we think that that's pretty self-evident that that's something that you want to do, and so we'd like them to basically explain how that proposed change is going to affect the plant and what they're planning on changing, whether it's SSCs, procedures, et cetera.

What we're proposing follows very closely with the Reg. Guide 1.174 guidance for combined change requests. We want to look at all of these contributors and determine their overall effect on risk, and we bundle these together to make sure that they're having a reasonable impact on safety.

We're doing this because we really believe that there's going to be potential there for licensees making very significant changes to the plant under this regulation, and we want to make sure that we're really tracking and understanding what's going on with those changes.

DR. KRESS: Does that mean they have to define all of the changes they're going to make under this rule at one time?

MR. KELLY: No, it doesn't. It means that each time they're intending on applying the rule that they should be, whether it's using a normal regulatory process or coming in and getting staff review and approval or if they're doing it under an inconsequential change, that they've carefully determined what it is that they're proposing to change, understanding the implications of those changes and then comparing those implications to the acceptance criteria that we have laid out in the draft rule.

DR. KRESS: Which implies to me that here's my plan. I have sort of a baseline risk status right now, and so I'm going to take all of these changes and keep track of how they affect my plant with respect to that particular baseline.

CHAIRPERSON BONACA: That's right. The original baseline, yeah.

MR. KELLY: It's baseline in the sense of how the plant was before the changes and how the plant was after the changes. We may be updating the PRA over time, but it's still going to be based on the plant the way it was before and then how the plant is now.

DR. KRESS: Now, suppose make some changes to the plant that aren't related to this rule. No change of baseline. You're still --

MR. KELLY: Where we picked it up -- and we're going to be talking about that a little later -- is in the reporting requirements where we're expecting that because we have other risk informed and non-risk informed processes that allow you to change things here in the plant, and we want to make sure over time that these other changes don't somehow undermine the bases on which we've made the changes under 50.46(a).

So we ask them every time they come in within, say, every two refueling cycles, come in and do a PRA update, that they're going back and looking; that with all the changes that have happened in the plant and all of the changes that have happened in the PRAs, they're improving their models, that they continue to meet the criteria set forth under 50.46(a).

Now, we spent some time at the

subcommittee meeting talking about tradeoffs between increases and decreases, and so we expanded a little bit more to talk about that because we do believe that it's important to provide incentives to licensees, to particularly go in and take advantage of the safety benefits that they can get out of the rule.

So as I say, with this type of bundling that we're proposing, that we did propose originally was one that we felt did have benefits, but after discussion with the subcommittee, we're giving some additional consideration to it because we don't want to throw any disincentives in there that would cause the licensee to think that they shouldn't be making these safety beneficial changes.

So we're going to give some more thought to that and probably expand on this in our reg. guide as we go forth with that.

Now, there's two basic ways that we would expect a licensee to make changes to its plant under 50.46(a). The first is using your license action request, which would be kind of your normal way of doing it where you'd send in a submittal. NRC would review it. Eventually we'd probably approve it, and then the licensee could go ahead and make its submittal or -- excuse me -- make its changes.

The second way would be the licensee would determine that it wanted to have the authority to be able to make inconsequential changes that would allow it to make these changes without prior NRC review and approval.

Now, in order for us to give them that authority, what we want them to do is to come in with a description of the processes that they have for making these determinations. We want them to come in and talk to us about their PRA.

Now, here there's going to be a difference in what they're telling us about their PRA versus a plant specific submittal. On a plant specific submittal when I've got certain changes that they want to make, we're particularly going to be interested in those aspects of the PRA that are dealing directly with those changes.

Under the inconsequential change when they initially come in, what we have to really make sure is that they have sufficient breadth in their PRA where they have processes for dealing with areas where they lack that breadth in the PRA so that we feel that they're going to make good decisions when it comes to determining whether or not a proposed change is inconsequential or not, and these are the things.

And that's why we've indicated in the statement of considerations that we expect that we will probably put more resources into the initial inconsequential change submittal than we would normally put in for a specific plant review submittal.

Licensees also will have the opportunity to say, you know, I know that, for example, I don't have a fire PRA. I don't have a good way of dealing with that, and therefore, I'm not going to make any changes under inconsequential changes that would affect my fire area or we may look at it and say we're not satisfied with your process under fire, and therefore, we do not give you authority to make changes that would affect the fire areas.

We've added a criterion in the rule dealing with coolable geometry, and we have slides here talking about that and why we felt that that's important.

Currently plants operating under 50.46 are in a situation where they normally can handle a concurrent loss of off-site power with a LOCA, large or small, and the most limiting single failure, and that gives them a lot of margin, and it adds to their defense in depth capabilities.

What we were proposing to allow them on

their 50.46(a) for the beyond TBS region is that a licensee would be able to operate its plant in a situation where they no longer would have to meet the single failure criteria, and they no longer have to when they perform their analysis assume that they would lose off-site power concurrent with the LOCA.

But we also know that a fairly large percentage of the time, in the five to ten percent of the time that they're operating, they may have important equipment out of service for maintenance or test or whatever, and absent some kind of requirement that they not operate in those situations where they're in an unanalyzed condition, the potential would be that if they should have a large LOCA during those periods, that they could go to core melt and early containment failure.

We don't want to allow that to happen, and therefore, we put in a requirement that says you should only be operating your plant in a configuration where you have analyzed it under our 50.46(a) rules, and that you're okay under those circumstances.

This may place some limits on what they can do. Ralph talked a little bit about it before, that they may choose perhaps to -- or was it Dick? I forget -- but they may choose to lower their power when they're operating or make some other changes to the plant so that they're within a configuration that has been analyzed, but we do feel that that's a very prudent way for them to operate the plant, given that we've given them this additional flexibility.

Similarly, under Reg. Guide 1.174, Reg. Guide 1.174 says that if you're going to make changes to the licensing basis, you're going to have to meet all of the criteria that are in the regulations, and we are assuming that you're not changing anything that's going to be affecting your late containment releases.

And when something like that did come up, we were handling it by dealing with those issues under the defense in depth proposition.

Now, we've done that and we've been successful in doing that, but that requires a lot of staff resources, and it's kind of an ad hoc argument because although we have specific criteria for what constitutes a waiver, helping to make sure that you have adequate defense in depth, they're not easily measurably, and it requires, again, a lot of effort on the staff to deal with that.

And because of that and because under this proposed rule licensees would have the ability to modify how they operate their containment systems, perhaps the sprays or the containment coolers, we felt that it's prudent to add a late containment failure metric to help assure that int he event that they are modifying equipment that would be affecting lake containment failure, that we're aware of it, and that they're not increasing risk in that area too much.

We don't have a specific number yet for what that criteria is going to be. We're going to give some more thought to it, and again, that will show up in the regulatory guide.

DR. WALLIS: So late release frequency is the same thing as the frequency of late containment failure?

MR. KELLY: Effectively, yes.

DR. WALLIS: Can you make it so that it's pronounceable and sounds different from LERF?

MR. KELLY: Given the short period we have, we just tried to find something that was good, but we can find a good acronym for it, I'm sure.

DR. APOSTOLAKIS: Six month again.

MR. KELLY: The numerical risk criteria that we're using basically come out of Reg. Guide 1.174. The rule is going to require that any increases that do show up in our analyses and risk assessments from the proposed changes would be estimated in some way, and estimated is really as I mentioned before in quotes, but be sufficiently small. And I say estimated because if you're using a methodology that is a non-PRA methodology, we still expect you to be able to come in and justify that the changes are adequate or adequately -- have an adequately small effect on risk.

There are a number of things on which this rule is based. This rule continues to require the deterministic engineering calculations be performed, but it also requires that risk assessments be performed, and one of the things that we wanted to do under the rule is to assure that we have adequate technical competence in the PRA. We believe that the results, to the extent that we think that the insights are reasonable and that the PRA appears to be capable of to the state of the art being able to estimate core damage frequency, LERF, and late release frequency.

Where a utility is able to take advantage of standards that exist, and if it meets those standards so much the better. This will reduce NRC's resources that it requires for performing the review, and as it says in the phased approach, you know, where we have the standards we'd like to rely on them.

Where we don't we're going to go ahead and do the reviews that we need to in order to assure ourselves.

DR. APOSTOLAKIS: But again, the standards only are necessary conditions, not sufficient. So it seems to me some PRA review would have to take place.

MR. KELLY: That was my expectation. It's not sufficient to say that I comply with the standard.

DR. APOSTOLAKIS: Yeah.

MR. KELLY: I can comply with the standard, but still the devil is in the details. I mean, you still need to have a reasonably good confidence that the PRA is appropriate and adequate. In my opinion, what the standards do is it provides you with a very strong starting point or maybe even mid-point to say that I've got a good structure. If I follow the standards, I've got the structure. I'm looking at the right things.

Another question is whether they did a good job of looking at the right things. That's a little bit different question.

DR. APOSTOLAKIS: Now, the NEI review process goes into more detail, as I understand it. So that may be one way of structuring the peer review process.

MR. KELLY: And we have the peer reviews

that are performed, and those we also intend on taking advantage of.

DR. APOSTOLAKIS: Good, good.

MR. RUBIN: If I could just supplement, I'm Mark Rubin from the staff again, to supplement Mr. Kelly.

Yes, he's right on point. We look at the entire quality program of the licensees that support the PRAs, which means their internal quality processes, the industry peer reviews. We're relying on the standard ourselves. We certainly hope that the licensees reassess against the standards and then as we get individual applications, we do look at details as necessary to get confidence in the analysis methods.

Our starting point is often the peer review comments, the significant comments, and then we go from there as necessary to look at the details.

DR. WALLIS: When you look at the details, do you actually have the PRA run using different assumptions? Are there some really questionable assumptions that it would be good to vary them and see how sensitive the answer is to those assumptions?

The same thing you do with the thermal hydraulic code. If you have something which you think you're not too sure about, you vary it, and you see how much influence it has on the answer.

Can you do that sort of thing?

MR. RUBIN: Yes, Dr. Wallis. We will pursue issues where we think there are questions, questionable assumptions, questionable modeling details. We don't rerun the PRA ourselves. We'll either ask the licensee to recalculate based --

DR. WALLIS: You ask them to do it?

MR. RUBIN: We'll ask them to do it or sometimes we may do a bounding calculation ourselves. In some cases a hand calculation is sufficient. We do have the SPAR models available to ourselves as well, but we do have them recalculate when we have questions on their approach.

MR. KELLY: So what we want to assure is that the PRAs meets a minimum criteria, and we talked about that again in the rule that's laid out. We need to be sure that what we've assumed in the analyses in our PRA reasonably models the reality to plant over time, and so the rule, proposed rule would require that licensees update their PRAs on a periodic basis, that when they do that, we want to make sure that they're retaining sufficient technical quality in their PRA, that it continues to match what's going on in the plant, and as was mentioned before, there's a potential concern that other changes that have happened in the plant that are not part of the 50.46(a) process may affect the implications of the changes that have been made under 50.46(a).

Also, licensees have the right and take advantage of the opportunity to often improve their PRA models. Many times PRAs for various reasons, including cost, may kind of "black box" certain areas or take conservative assumptions, and the licensee may choose to take advantage of improving that model to show that its risk profile is actually much better than it looked or maybe it wants to do some things and it realizes by modeling more accurately in a PRA they're able to more clearly estimate what the effects are from changes to the plant.

So what we, in essence, have done in the rule, as we said, NRC wants to be notified in some manner if, just as Ralph was talking about, the 50 degrees and 300 degrees and the four percent with the change in oxidation. We're saying that when your baseline PRA changes, baseline risk changes by a certain amount, the change in risk due to 50.46(a) changes changes by a certain amount, we'd like to be informed, not that we're going to do anything about it necessarily, but we'll probably want to look into it, understand a little bit more about why these changes are occurring, and if there's something unusual, then we might pursue that a little bit further, but it just --

DR. WALLIS: That makes more sense, but the sentence makes no sense. There's no way that the licensee reporting these changes gives you confidence in technical adequacy.

MR. KELLY: Well, what it does is it helps us to be aware of perhaps some change --

DR. WALLIS: -- but you've got to check the technical adequacy.

MR. RUBIN: This is Mark Rubin again.

That's absolutely correct. We want to have some trip points where there are some I hate to call them significant changes in the risk when those are relatively small values, but it would give us notification that there are variations in risk.

The baseline, there may be some trends up, and this will give us the ability --

DR. WALLIS: I understand that. I understand that.

DR. KRESS: Are you not interested in the updating PRA if it gives the significant decrease in

CDF and LERF? Wouldn't you want to know about that, too, and know the reasons why?

MR. RUBIN: Well, I think as safety regulators our concern is that safety is maintained. What we've seen over time with the risk informed initiatives is often risk decreased from some of the initiatives, but some risk increases from others, and when we get a risk informed application, we always get the new baseline PRA numbers. So we're making the decision based on the most current.

But for the reporting requirement, our concern is that there are enough significant trends up. Safety decreases, and those are what we want to use for the trip points. We're certainly very pleased when, you know, risk is decreased over time and we do see that when new initiatives come in, but that's not what we want to use for the trip point.

DR. DENNING: Doesn't it make more sense to relate these to an absolute value? Let's look at core damage frequency. Does it make more sense to have it tripped based upon an absolute change in core damage frequency?

Suppose you have a one times ten to the minus five plant and then increases by 20 percent versus a ten to the minus four plant decreases by 20 percent. Isn't it really the absolute value of the core damage frequency that's important rather than the relative?

MR. RUBIN: Well, we looked at both values. So what you see there is a hybrid. You see absolute for deltas, and you see a relative for the overall trend, and we thought that was a reasonable compromise. We do trip on absolute for the 50.46(a) related changes, and so plants that are -- have the lower risk profiles will really only be reporting when they really to them comparably significant changes because their risk area is so low to start with.

They will trip though on the overall trending risk values on a relative, the 20 percent range, and that will give us some knowledge that even the plants that have very low risk profiles to start with, if they're starting to trend up continuously will be aware of that.

These are not safety criteria. These are not criteria of unacceptability for changes in plant profile, but just to give us a sense of what the trends are.

DR. DENNING: I missed when you apply these. You talked about the first two after an update, and I though that was some change in the PRA, not implying a change in the plant, and I thought the last two were changes in the plant associated with a 54.68 implementation.

MR. KELLY: PRA updates typically will include not only changes to the PRA model itself based on just improvements to the model, but they will also include over some periods since the last PRA update had occurred. There have been changes to the plant and you're also going to put those in there. So you have a combination of the two normally.

DR. APOSTOLAKIS: So what the third sub-bullet there says to me is you have petitioned to make some changes based on 50.46(a), and you have calculated the delta CDF that's acceptable. Three years down the line for whatever reason, your PRA changes, due to modeling or some other, and it does not change the CDF more than 20 percent.

But if you recalculate the delta CDF that was originally submitted on 50.46(a) and you find that the change is more than ten to the minus six, then you have to report it.

MR. RUBIN: That's exactly the way we envisioned it.

DR. APOSTOLAKIS: It's the delta CDF change that you have to report if it is more than ten to the minus six, which sounds awfully low.

MR. RUBIN: We only related to the 50.46(a) changes. Yes, it is ten percent of the allowed --

DR. APOSTOLAKIS: In other words, your change that was approved two years ago has to be monitored as the PRA changes.

MR. KELLY: But remember that the overall PRA change was supposed to be less than ten to the minus five. So the expectation here is that we're saying we're just looking to see that, and if the committee likes another number, they're certainly --

MR. RUBIN: Well, this is an area that we expect comment from the industry.

DR. APOSTOLAKIS: One of the problems that bothers me, Mark, here is do we really have such accuracy in PRA numbers.

MR. RUBIN: No, absolutely not.

DR. APOSTOLAKIS: And you have some licensee submitting point estimates. Then you have other guys doing uncertainty analysis. I mean, ten to the minus six easily by changing the high tail of the distribution, you can get that.

So I don't know. I mean, we keep talking about the large uncertainty in the PRA, and then we say if it's more than ten to the minus six, we want to know about it. You have to be very careful how you state all of this.

I mean, I think that the subject is okay, that you would like to know what happened to the approved delta CDF, but I mean, this is --

MR. RUBIN: We understand, and we completely agree with your observations on the uncertainty.

DR. APOSTOLAKIS: You have to do something.

MR. RUBIN: I wouldn't argue that these changes are statistically significant as far as showing a real change in plant risk, but the deltas will show some impact of trending, and if the bottle changes in the unrelated plant modifications, when you back calculate, show a change, we're using this for our trip point.

I think the recognition is that most of the changes that impact plant risk, if not many of them, will not be related to 50.46(a). We may not even see them because they may not be areas that are controlled by our regulatory oversight, changes to, you know, plant systems that aren't safety related, that they can do on their own on on 50.59

DR. APOSTOLAKIS: Why does this have to be in the rule if we're not so sure --

DR. SHACK: It's not in the rule.

DR. APOSTOLAKIS: It's not in the rule?

MR. RUBIN: Yes, it is. Yes, it is.

DR. APOSTOLAKIS: We're only discussing the rule today, right?

MR. RUBIN: Right.

DR. APOSTOLAKIS: Why can't it be in the regulatory guide?

MR. RUBIN: Well, this is to be consistent with the thermal hydraulic reporting requirement that Ralph talked about.

DR. APOSTOLAKIS: But you can say in the rule, you know, if the baseline CDF increases by X, what X is to be determined to be.

MR. RUBIN: Yes, we could.

DR. APOSTOLAKIS: You don't want to put these things in the rules. Put it in the regulatory guide. The numerical values can be in the regulatory guide, and in the rule you just say that there will be provisions for which the agency will be informed if there are changes in CDF, and let's think about it later.

MR. RUBIN: We thought of that alternative when we were developing the rule, and then we'll give it some additional consideration now.

DR. APOSTOLAKIS: Okay.

MR. RUBIN: Thank you.

MR. KELLY: So unless there are any other questions on PRA, that finishes my presentation.

DR. SHACK: Brian, when do you think you can provide us with the total rule package so we can decide whether we're going to have time to do it in December or not?

DR. APOSTOLAKIS: Why would we review it in December if we're writing the letter now?

CHAIRPERSON BONACA: Well, that's an issue, in fact.

DR. APOSTOLAKIS: Oh, we may not write the letter now then?

DR. SHACK: Well, we can write the letter on the rule language.

CHAIRPERSON BONACA: We got the request on the first slide that says received letter, endorsed the originally proposed rule for public comment. We have not seen the rule.

DR. SHACK: And that's another question for Brian.

CHAIRPERSON BONACA: And we haven't seen

the statement of considerations.

DR. SHACK: -- is it will be acceptable to wait until December or you'd like to have our comments on the rule language, and then if some reason we change on the rule, that the rest of the package -- the language to me seems to be the most important part here.

MR. SHERON: Yeah, it's the rule language, and the question is: is it acceptable to go out for public comment at this time?

I mean, obviously if the committee is not comfortable with writing a letter at this time until you see the final package, as well as the statement of considerations and so forth, you know, I presume that wouldn't impact our schedule tremendously that I'm aware of.

You know, because the plant was not to get the package to the Commission probably until the latter part of December, which means we were probably going to get it up to the EDO by mid-December or so I would think. So if the committee, you know, if we met the first week in December with you and if we could get a letter the week after, I think that would probably be acceptable.

MR. KELLY: But we just wouldn't be able

to include much feedback from your -- you know.

DR. WALLIS: Pardon me?

MR. KELLY: We wouldn't be able to include feedback, I don't think.

DR. WALLIS: Well, you've got some feedback today, but I prefer --

MR. KELLY: Yeah, from the December meeting is what I'm saying.

DR. WALLIS: Endorses something that we know exactly what we're endorsing.

DR. APOSTOLAKIS: Yeah, I think you got most of the comments during the subcommittee meeting and today's meeting.

DR. SHACK: But hose are all in the rule language. That's the tricky part of this, you know, that we've seen the rule language. What we haven't seen is the statement of considerations or at least we only have the draft version from July on that.

CHAIRPERSON BONACA: So we'll have to discuss that.

DR. SHACK: But, again, when would we have the total package? We will have it two weeks before the December meeting, you know, in that first week? No.

We would have it on the day of the

meeting?

MR. SHERON: If it was a week, it would be optimistic, but I think you will have seen, you know, basically the rule language and so forth. The additional part I think you're really looking for is the statement of considerations.

I think you've all seen there was a first cut at SSC.

DR. SHACK: That's the July version.

MR. SHERON: Right, and obviously we're trying to work on that to improve it and stuff. You know, to the extent --

DR. SHACK: But it has changed.

MR. SHERON: Yeah.

DR. WALLIS: It must be changing if you can't give it to us within two weeks. It must still be changing.

MR. SHERON: Well, it needs to go through a concurrence process as well. That's the problem, is that obviously if we send something to you and then we get some comments from another office or something, we don't want to -- you know, I don't want to give you something and then come down here in December and say it has changed again.

MR. SHERON: Well, we'll have to decide

that.

CHAIRPERSON BONACA: Do we have another presentation?

DR. SHACK: No.

CHAIRPERSON BONACA: Oh, I thought it was the industry.

DR. APOSTOLAKIS: Oh, there's more?

PARTICIPANTS: No.

CHAIRPERSON BONACA: All right.

DR. DENNING: We have an expert elicitation meeting on the 16th on this. Is that true?

CHAIRPERSON BONACA: Yes.

DR. APOSTOLAKIS: We do?

DR. WALLIS: Can we expand that to look at the rules?

I'm just kidding you, Mike.

CHAIRPERSON BONACA: We'll take a break now. It says for the break and then come back at five after 11.

(Whereupon, the foregoing matter went off the record at 10:47 a.m. and went off the record at 11:05 a.m.)

CHAIRPERSON BONACA: Let's get back into session.

The next item on our agenda is a presentation of the proactive materials degradation assessment program, and since Dr. Ford jumped on the other side, then we have Mr. Sieber chairing this part of the meeting.

We are running about 20 minutes late. So if we can stay within the time that was originally allotted, which is about one hour and a half, that would be great, one hour and 15 minutes, something like that.

MR. SIEBER: Okay. We will try to do our best to make up a little bit of time hopefully, especially since this topic is so well under control.

By way of introduction, I'm sure everybody remembers the Davis-Besse event and following materials problems on the Davis-Besse head. A lot of people whispered under their breath, "I don't want to be surprised again," and the outcome of that was an initiative of proactive materials management, and the staff has undertaken to develop that, and of course, industry has spent many millions of dollars developing materials management protocols and techniques, again, to try to eliminate surprises to be able to predict failures in the future, and therefore, make for safer plants.

So today we are going to hear a status report, really an update. We heard one in June. We heard one in October of last year, and so this process will bring us up to date as to where things stand right now.

We have Dr. Ford as a brief speaker first; Joe Muscara from Research secondly; Robin Dyle from Southern Nuclear representing licensees in the industry; and Robin Jones from EPRI, and so we'll begin with Dr. Ford.

DR. FORD: First of all, as an ACRS member I have to claim a conflict of interest. I have worked briefly with the two Robins on their program, and I am now working a lot with Joe Muscara on his program. So I'm really talking as Joe's employee, I guess.

My objective for opening this is that I requested these presentations, and the prime reason was that I want to make sure that you, the committee members, knew about the progress that has been made in these two projects which have got very similar objectives.

Joe's is probably a little bit premature, but it is important that you hear what has been done early in the game, and my contribution is to calibrate you on some of the technical challenges that both of these projects face.

You see on the screen there a damage versus time schematic curve, and the important parameter here is now on the time axis, and these two cases here refer to reactive space, the way we manage these problems right now.

Case one would be epitomized by, for instance, three or four stainless steel cracking piping in BWRs, well recognized, very well understood. I transmitted to you all some papers recently which goes into the academic and scientific understanding of this particular problem. They're well under control, got appropriate control and inspection criteria spaced out for it.

Case two is epitomized by, for instance, the boric acid corrosion in PWR vessel head penetrations. For that specific component we do not understand, in my view, the details of the kinetics of that process. We cannot put in good space that locus or that damage versus time project.

As a result, this has to undergo fairly draconian monitoring techniques. Now, those two cases spans the spectrum of reactive space. It's the land of GALL and AMPs, if you like.

The third case is what these two programs are relating to. They relate to a situation where we have not seen cracking or damage of any other sort in the reactors, and the question is: is it latently possible that you could have damage in the future where you have yet to see it, the NDE resolution of it, and go on up to higher degrees of damage?

And can we, if we had that predictive capability to develop mitigation actions, life management actions, well before it creates a safety or operational problem?

The challenges to developing such a proactive scheme are several, but they come under three main categories. The first is we're not just talking about cracking. We're talking about a whole multitude of various degradation modes all of which have got different rate limiting steps to their mechanisms and, therefore, to the derivation of the damage time plots.

The other problem that we have is that all of these degradation modes are multi-system problems. Many of them depend on specific material environment conjoint requirements, cracking ones that go further under stress. We have to understand all of those parameters in order to define the kinetics of damage development, and on top of that, you have the various stents to design PWRs versus BWRs, the Westinghouse four-LOOP plants versus other LOOP plants.

We've also got a question of the subcomponent, how it is designed, manufactured, and in some cases repaired, and there's also the operating mode aspect. So it's a multi-dimensional problem.

The third technical challenge is if we're to understand the kinetics within those conjoint materials, environment, and sometimes stress space, then we are calling on a multitude of arts. It is not just mechanics. It is not just metallurgy. It's not just electrochemistry. It is all of the above.

And it is only in the last 15, 20 years that we have developed as an industry the capability to come up with predictive techniques which can address these time dependent degradation modes.

The bottom line there as I say at the bottom, the project is not an easy one, but it is my personal opinion it is a doable problem to be solved.

After that very brief introduction, I'd like to pass it on to Joe. He's going to go and cover the NRC program.

DR. MUSCARA: Thank you, Peter.

It's a pleasure to address the committee on this issue. We've been here once before. We make a little bit more progress, not a great deal of progress yet, but we felt this was a good time to let you know where we are.

And before I begin, I would like to thank and acknowledge Mike Switzer for his help that he's provided me over the past year in this project.

Well, again, I don't need to spend a lot of time on the background. I think you know it. You've heard it before, but in effect, materials degradation has been experienced in nuclear power plants almost since inception of operations.

For example, in the early '70s we experienced steam generator tube degradation, and that, of course, continues through today. BWR pipe cracking was a big issue in the late '70s and '80s. More recently we've had the VC Summer hot leg cracking, the Oconee vessel head penetration cracking, and the Davis-Besse vessel head degradation.

NRC and industry have responded to these occurrences reactively, that is, as they have occurred, and we've taken actions to maintain safety and reliability, but some of these actions that we've taken in some cases may have provided some new problems, mostly because of the reactive nature of the response.

In particular, this is true in the area of steam generator tube degradation. So these are approaches that have been inefficient. They have resulted in increased financial and manpower burden, compromised regulatory effectiveness and efficiency, and importantly these approaches have had the potential to erode public confidence.

So we have decided to take a more proactive approach to materials degradation assessment, and we want to develop a foundation for appropriate actions to keep materials degradation from adversely impacting safety.

But in addition, as we've indicated earlier, we want to avoid surprises, and to avoid surprises, we really need to think in broader terms than just the risk and the safety.

In trying to develop a scope for this program, we needed to address several questions. One of them, the most important, I think, is what is proactive with respect to materials degradation. I should say I consulted a dictionary and that doesn't give me much information. It's not even in the dictionary, the unabridged version.

But in my view, if we really want to be proactive, we need to predict potential degradation in components for in the future, and then we need to take steps to avoid that degradation, and as a minimum, we still need to predict locations where degradation is possible.

We then need to monitor those locations, and then take actions in repair and replacement in a timely way so that it would not affect the component reliability and safety.

So the prediction is really a critical aspect of proactive materials degradation assessment and management, and this is an area that we were concentrating at the beginning of this activity.

So we also want to maintain component reliability, public confidence, and avoid surprises. So by this we mean that we want to avoid the release of radioactivity anywhere in the plant. That is, we want to avoid radioactive water winding up on the floor.

And in addition to that, of course, we do want to avoid failure of safety significant components. But if we keep these two things in mind, then one realizes that we have to evaluate hundreds and actually thousands of components for a particular plant type.

We do consider risk in our work, and in

fact, we have some activities ongoing that are beginning to address some of the risk significance, and we will use this information to help us prioritize research efforts later on and also to prioritize development of additional regulatory guidance.

So as far as our approach for the program, you know, it's essentially a two-step program. The first step is to identify materials and locations where degradation can reasonably be expected in the future.

And the next step then is to develop and implement a research program for the components and degradation of interest. So that is we need to have a technology base to allow us to be predictive, to allow us to develop fixes, and to allow us to monitor and control the degree of degradation.

Now, these technology areas include areas of in-service inspection and continuous monitoring techniques for the detection, characterization, and evaluation of degradation. Maybe in this bullet I should stress the idea of continuous monitoring. You know, that's an area where there's the technology available, but it has been used very little.

And in effect, in some cases periodic in-service inspection may not be effective for two reasons. One, the reliability of the techniques, the probability of detection may not be adequate for mechanisms that proceed fairly rapidly. So if we can't detect the degradation early enough in its life, then the periodic inspection may not do us much good.

In addition to the reliability inspection, we are limited on how often we can inspect. I mean, certainly we cannot inspect any more frequently than once every fuel cycle. So for some degradation mechanism, we're going to need to start thinking, you know, more proactively, think ahead, and start thinking about using continuous monitoring versus just periodic in-service inspection.

CHAIRPERSON BONACA: You know, in some of the examples that you provided in the first slides actually, I mean, VC Summer had a defect in a weld that was known to the operators, and there were stresses there due to the repair, and to some degree -- I guess where I'm going is that you can look at old issues and focus your inspection on everything, but it seems to me that in many cases we go back and look and say, you know, we knew there were stresses there built that may have resulted in something downstream, Oconee vessel head penetrations.

I mean, clearly now we believe that some of the cracking is tied to stresses in the head and where the nozzle comes. So Davis-Besse.

I wonder, you know, if you're also looking at there are opportunities for individual plants to look back at construction periods where they have records where there are specific locations where it's not unlikely to see some defect to grow through the years.

And then in that case you won't need a blanket medicine for everybody. I mean, you maybe just focus on those. I don't know if you can make a comment on that.

DR. MUSCARA: Well, clearly, many of us were not surprised by some of these degradations. We've seen it before, similar locations, similar plants.

With respect to going back and looking, again, that's another major advantage of a continuous monitoring technique. With that kind of technique, you really don't need to know where the degradation might appear, and you really don't need to know what the mechanism is. It will detect degradation as initiation grows, and that's something, again, in my mind that I think we should start paying more attention to those kinds of techniques both for current plants, but in particular -- and this is not the subject of today's discussion -- for new plants, you know, when you have the opportunity to instrument the plants during the construction stage.

CHAIRPERSON BONACA: I guess I'm commenting on the issue of VC Summer. I mean, VC Summer now, we're all questioning in-service inspections. Are they effective and so on and so forth?

But then the major question is, you know, will anybody else get a VC Summer crack? And the issue seems to be so tied to a specific defect that was originally built in. They had to repair it. They repaired the most defective. It was effective enough for 20 years, and then the crack came through.

So I'm just trying to understand, you know, to what a degree are we going to indict still today the techniques that were used to inspect when in reality it was a unique problem with the nozzle at VC Summer.

DR. MUSCARA: Well, I'm not sure that it is unique, a unique problem. We've seen that kind of cracking before certainly in BWRs, and your point about time is a good point. I mean, in a slightly different environment, it may take longer to occur, and that's one of the things we're challenging our experts to think about and discuss, is that even though we haven't seen degradation yet, are there conditions that will evolve that we will see in the future?

CHAIRPERSON BONACA: I guess what I'm commenting on is oftentimes we have these events happening. Then we sit back and we say, well, they looked back and they found that, you know, in fact there was a problem in this component, and so on. Well, if this was known information maybe that is something that at least the operator should be sensitized to, to look back in the records maybe and to know what to look for specifically.

DR. FORD: IF I can make a comment, your remark primarily relates to where are you going to do the continuous monitoring, and certainly when VC Summer occurred, there had been other failures in other plants, in Sweden, for instance, and there was a correlation we believed that correlated with repair welds, but that is not a unique criterion.

So certainly finite internal analysis of residual stresses would indicate you could get cracking more where you're had a weld repair, and that's where you'd monitor. But it is not a sole criterion. It is not a sufficient criterion.

DR. MUSCARA: Well, I don't want to belabor the point, but when you start looking at records, you will find that many, many components have experienced repairs. So that brings back the same problem. Do I look at everything?

Well, one of the advantages of continuous monitoring, it's a global technique. So you really don't have to know exactly where to monitor. We monitor the whole system.

MR. ROSEN: But isn't it also true that continuous monitoring will detect cracks that will not go through wall during the life of the plant even in an extended life?

DR. MUSCARA: Right.

MR. ROSEN: So how do you distinguish between cracks that occur, but are not consequential and cracks that occur and are?

DR. MUSCARA: I think we're getting off the subject quite a bit, but there has been at least ten to 12 years of research in developing the technology, and one of the developments was a correlation between the acoustic emission parameters re true crack growth rate, two fraction mechanics parameter, Ks and delta Ks.

So the advantage is that you can detect initiation and then you can monitor the crack and know exactly or know closely what size cracking you're getting so that you know that you do not need to take immediate action for a long time. But at least it gives you the information. It says it's cracking. It's proceeding a certain rate.

I can then plan our additional inspection and repairs if necessary. So that there's a correlation there that relays the AE to the cracks severity.

MR. ROSEN: Okay.

DR. MUSCARA: So to move on then, we also need to look at in the research program, you know, techniques for ameliorating distress source for mitigation or prevention we expect of degradation, and by stress source, I mean not just the stress, but the stress and the environment, the embrittlement, et cetera.

There would be need for research on materials for repair and replacement. There would be need for improving techniques for repair and replacement. That is, we do not want to repair a component and leave it more susceptible to degradation than it was before. So we want to make sure that the techniques that are used can improve the residual stress situation. They can also improve the microstructures.

And then, of course, there's need for post repair of fabrication or the inspection techniques. Now, in developing such a research program, you would consider ongoing international research, and we also need to address gaining a better understanding of current and potentially new degradation mechanism and dependencies.

And again, I would like to stress that this is an important part of what needs to be done. That is, if we are to develop mitigating techniques, we really need to understand the mechanisms, not only understand the mechanisms, but we need to understand the dependencies, the parametric dependencies on the degradation mechanism.

So then one can develop fixes from one point of view and from another point of view as a regulator we can evaluate the efficacy of these fixes. So we need to have better mechanistic understanding, you know, better understanding of the dependencies that affect degradation.

So to talk about the first part, which is the identification of the components of interest, we have ongoing two activities to accomplish this step. In the near term activity, we'll we looking at existing information to identify components that have experienced degradation that can give us some quick results, and in fact, we're getting close to finishing up the portion of the research.

And then in the next step we want to use the phenomenon identification and ranking table process to identify plant components susceptible to future degradation, and that's somewhat a little bit longer duration for this portion of the work.

So you already identified components that have experienced degradation. We have under contract the Pacific Northwest National Laboratory, working together with Argonne National Laboratory and some NRC staff. We have pulled together a task group to review information that's available on components that experience degradation.

Most of this information comes from the GALL report, but we also have looked at the LERs and the INPO database, EPIX.

And the objective of looking at this work is to identify those components that have experienced degradation and then to review and evaluate the current in-service inspection and leak monitoring techniques, and to make recommendations with respect to improvement as necessary.

And, again, it's premature to talk about results, but I believe already we know some recommendations will be coming forward in the areas of performance demonstration, on probability of detection, on inspection methods that are periodic versus continuous monitoring, and we'll some observations with respect to implementation of risk informed inspection.

Just to go back and spend a very small amount of time on performance demonstration, you know, you brought up the idea that we've missed the crack in VC Summer. What I'd like to point out is that although we have requirements in the ASME code for performance demonstration, these requirements apply to components where there's a supplement in the ASME code that provides more information on how to develop a performance demonstration program.

When we started working in this area, the idea was that any component that was inspected, that was required to be inspected by the code, needed to be inspected according to a qualified procedure.

Well, the words got changed a little bit as the documents went up the line with review and endorsement, and right now it is limited to those components where there is an additional supplement.

But the generic information on how to develop in the performance of a demonstration program is there. So one of the recommendations clearly is that any component that we inspect, if it's important to inspect it, it should be done appropriately, and we should be using a qualified procedure.

Now, the inspection that was used and that they're using for those components, there's no supplement currently in the code. So any weld that is a similar metal weld is inspected, but not inspected according to qualified procedure, and so that's one area that we need to make an improvement.

These components need to be inspected according to a qualified procedure.

CHAIRPERSON BONACA: But I have a question now. Isn't it true for VC Summer that VC Summer now has certain commitments now --

DR. MUSCARA: Yes.

CHAIRPERSON BONACA: -- to reinspect the repair, right?

DR. MUSCARA: Yes. But this is the difference between the reactive approach and the proactive approach.

CHAIRPERSON BONACA: Yeah, and I'm saying before I was going after the issue that so much of what is being done, you know, insofar as the inspection, the frequency, we're looking at license renewal, for example. It's tied to operating experience.

Anything that happens in operating experience, we track it. We know that it was a defect in a certain location. We fix it; we reinspect it frequently before we drop it.

All I was commenting on is that during construction, construction is not just simply like popping out the plant. I mean, during construction there were defects identified, repaired, et cetera. Yet I'm saying all of the memory is not considered in the inspection programs, and yet when you go back and you find defects, for example, we found voids in the containment walls. And we go back and they say, yeah, they looked back and they found that they had some voids here and there and then they find additional voids now.

So the problem was already identified, but the moment which the plant started, none of that information was carried into the programs to support the plants in the future.

I find it a little bit peculiar, but I guess that's the current licensing approach.

DR. MUSCARA: In a general sense, you know, the inspections are conducted, for example, for piping, are supposed to be conducted in areas of interest, and distress is one area. Areas of high stress should be included in the sampling plan. But, of course --

CHAIRPERSON BONACA: I don't want to debate, but I just wanted to explain why I was thinking that way. You know, operating experience is so important for them to move forward. Construction experience doesn't seem to reflect any of these problems.

MR. SIEBER: I would point out that there are some plants that have augmented inspection requirements and tech specs, and in some cases those inspection requirements either refer to a construction area repair or to a combination of materials that folks thought would give rise to cracking, deterioration, what have you.

So we can't say that everything has been overlooked and that the regulatory and operating memory is lost because some plants have it. The problem is it's not across the board. And I think one could perhaps back in true construction records, and it's not clear to me that that's the most cost effective way to accomplish implementing materials degradation regulation.

And so that's why I would favor this program as opposed to a big record search and establishing more augmented programs because I don't think you would get everything, and secondly, I think it would be a tremendous burden with not too much benefit.

CHAIRPERSON BONACA: No, I haven't proposed that, Jack. I just was looking for some insights from the representatives. I mean, they're proactive. So --

MR. SIEBER: That's true.

DR. MUSCARA: I probably shouldn't keep beating on this one, but I'm sure you'll get a better sense from the industry. They're trying to take advantage of the experience that they have from plant to plant, from program to program, which may not necessarily have been done so in the past.

But if we're going back to the VC Summer, that kind of weld and component has degraded and has cracked in BWRs. Now, we're not paying much attention to this because this was a PWR, but in fact all of the parameters that are necessary for degradation are there. It's a matter of timing, and because the PWR may have a little bit better chemistry, it may mean that we delay the problem. It doesn't mean that we necessarily eliminate it.

And part of the challenge that we have is to try and consider these time dependent phenomena and determine whether even though we haven't seen it in the past, is there a good chance that we'll see it in the future?

So another activity we have ongoing is to determine the condition of core damage frequency for components where special requirements may need to be improved. Now, this is a little bit old bullet. In fact, what we'll be looking at is the condition of core damage frequency for those components where we've experienced degradation in the past.

What I'm finding is that there are just too many components with various degradation. So regardless of how good the inspection program is, we don't include those components into this program. So very soon we'll be providing data to our PRA folks on the components that experience degradation, and they will doa condition core damage frequency analysis for those components.

We will also be collecting information probabilities of failure for different components to be used in future detailed risk assessments. This year, fiscal '05, we'll be collecting information where it is already existing. For example, there may be information available in risk informed ISI programs, in probability affair (phonetic) components, and there's also information from the recent LOCA frequency studies.

And next year we'll be performing specific component analysis to augment the information you already have, and the specific analysis will be based on probabilistic fracture mechanics and on piping failure and population databases.

So we will do some analyses on components where there's not information available for trying to predicting the probability of failure of those components for different plausible degradation mechanisms.

So for the longer term activity, we are looking at an expert elicitation. Well, we felt that expert elicitation was really the only feasible approach for identifying components that are susceptible to future degradation, and this is because trying to do this exercise analytically for every component would require a great deal of time, funding, and in effect, it would require data that we don't have, not only data, but also better understanding of mechanisms.

So to try and predict analytically today the potential for degradation, all of these thousands of components really wasn't feasible. So we decided that the best way to go at this right now would be through an expert elicitation process, and we find that the PIRT process or PIRT-like process was acceptable for this kind of exercise.

In particular, I like the structured process that PIRT provides for the expert elicitation. It provides for the phenomena identification in a quantitative scoring or ranking of the different phenomena, and the way the PIRT exercise has been conducted, it provides an easy, continuous way for documenting results and providing final reports.

So I thought that it would be a good context for our work to use a PIRT-like process, and we have begun this process. We have an eight member international expert panel. These are experts in materials and corrosion science. The panel is augmented by experts in presentations to the panel in the areas of systems and operational experience.

We have planned eight one-week long meetings over a one-year period. We provide background information to the panel on materials, stressors, function of components and operating experience, and then the panel, with the help of the panel, we develop lists for PWR and BWR components that may be associated with future degradation phenomena.

And our results, when we are done with the reports would be reviewed by a large group of international experts.

I don't spend a great deal of time, but I indicated earlier that we'd be looking at systems and components that relate to safety, but also where we might have a release of radioactive water, and so this is a list of both PWR and BWR systems that we'll be addressing.

Some of the systems we'll address in their entirety, for example, the primary cooling system and the ECCS system, but other systems we'll be looking at only portions, the safety related portions or those portions that may be carrying pressurized water, radioactive water.

We have contracted with the Brookhaven

National Laboratory to develop and provide the background information and to manage the PIRT meetings.

Now, the components that we will be evaluating derive from the systems of entrance, and for us a component is that continuous portion of the system that is of the same material and has the same product form, and in addition, experiences similar stressors, for example, the temperature, pressure, residual stress levels, fatigue cycles, irradiation, water chemistry, and so on.

Now, multiple components of the same material that experienced similar stressors are agglomerated. For example, as we develop the components from a plant drawings of a given system, say we're forming a particular pipe in a pipeline. A component could really be section of pipe that's 20 feet long.

But when we get to the weld, now suddenly the material changes. So at the weld we have a separate component that's made up of the weld itself and the heat affected zones on either side of the weld.

But then if we continue on and this is a butt weld, there's another section of pipe which is the same as the first section we looked at. So in order to minimize the amount of work that the experts have to do, essentially a component is the same material, the same stressors. That's lumped together with the first component.

So the component list is developed from the piping population database, partially is PIPExp database that we have licensed from Bengt Lydell, where he has gone through a similar exercise. He was looking for discontinuities in a system. So effectively he had to look at piping, welds, bends, valves, and so on. So we're making use of the data.

In addition, we're making use of the plant drawings, and I should mention that we've had a tremendous amount of help and support from Exelon staff providing us data, plant data, operational data, but in addition, the plant drawings from which we develop the components.

We then develop operational experience, and this is included with each component, wherever it's appropriate, and the sources for this experience again have been the GALL reports, LERs and the EPIX (phonetic) database.

And in addition to this, we provide the panel with presentations and information from our staff at the NRC Technical Training Center related to the system functions and to operational experience.

So then all of this information is provided to the experts for their evaluation of potential degradation mechanisms.

That's just a schematic that shows from the RCS, a subgroup, the cold leg piping that the experts do receive so that they can put the components in context. So this shows them where the different components are located within the subsystem.

This is an example of the data that goes to the experts. That essentially describes the component, the material, its size. If it's a weld, it describes the weld material and the material on either side of the weld, and also things like operating temperatures and pressures and flow, information on residual stresses where we have it, information on the operating stresses, and then other comments that are useful for evaluating degradation for specific components.

Just to bring you up to date on where we are with the PIRT, we already have held two of our expert panel meetings, and we already have considered for a PWR, a four-LOOP PWR plant the reactor coolant system and most of the emergency core cooling system.

In addition to the agglomeration that we perform in pulling together similar materials, the panel experts agglomerated the components one additional step, and they've done this according to the degradation that's expected.

For example, if the experts felt that it would make the same call on 304 and 316 because it experienced similar stressors and there was no basis for having a different degradation mechanism, those components were also lumped together.

So when we started out for the RCS system, we had over 500 components. Without agglomeration of similar pieces of material and similar stressors, we came down to 315 components, and then these 315 components are agglomerated by the technical experts and to 88 subgroups.

So then they rated the potential for degradation for these subgroups, and we still maintained the identification of the components that are in the subgroups.

So the experts then assigned numerical values to three parameters in the evaluation for the potential degradation that we expect for a given component, and in addition, it provided the basis for their decisions.

Now, these three parameters are: number one is the susceptibility factor, and here we ask the question of can significant material degradation develop given plausible conditions. That is, we are stressing here the plausible conditions.

For example, we know that stainless steel is susceptible to stress corrosion cracking. So one could call stress corrosion cracking for every piece of stainless steel that's in the plant. What I wanted to get to was a bit more closely related to for the specific component in the stressors that it observes.

So in a given location in the plant, all of the conditions necessary for cracking may not come together. So that material, yes, is susceptible to stress corrosion cracking, but in a given location the conditions are not right for cracking to occur, and so we wanted to put some stress on the idea that we want to evaluate the component, the material degradation mechanism, but also its specific environment.

And so with respect to ranking then the susceptibility factor, we have a one, means that there's a conceptual basis for a concern from data or potential problems under unusual operating conditions. A two means that there's a strong basis for concern for known but limited plant problems, and three designates it has been a demonstrated, compelling problem or multiple plant observations.

We then rank the confidence level in these calls, and this is really the personal confidence in the judgment of the experts in calling that particular degradation for the particular component. And one is low confidence. Two is moderate confidence, and three is high confidence in that call.

And then we also evaluate knowledge level for the material and the integration mechanisms that has been called out for the specific component, and here we're looking at the extent to which the relevant dependency has been quantified.

That is, you know, if we understand the problem well enough to develop a fix or evaluate a fix, then that will be a three.

So one, again, is poor understanding. Two, there's some reasonable basis to know the dependencies. And, three, there's extensive data and experience so that you provide a clear insight into mitigation or management of the problem.

Now, one additional item that I'd like to mention is that although we have eight panel members, we're not looking for consensus. It is my feeling that even if only one expert had a concern about a component that we really want to know about that; we want to review, evaluate, and study further.

So in our reports, we will have the report from all the eight members. We're not really looking at consensus per se.

And this just provides an example of the scoring sheets that the experts used to provide their analysis of which component or group and subgroup.

So I think based on the first two meetings I already see some interesting insights evolving with respect to potential future degradation mechanisms. And we really have developing inside. So I think mainly based on the fact that we truly have the world's top experts in this work, we're making use and taking advantage of experience that has been developed not only in the States, but in other countries.

Our expert panel members are members from the U.S., from Canada, from Japan, from France, and from Sweden. So we have quite a broad range of experts and expertise.

DR. WALLIS: Did these insights tell you anything you didn't know before?

DR. MUSCARA: Did they so far?

DR. WALLIS: Have you personally? Were there some surprises?

DR. MUSCARA: Well, that's why I had that one bullet, that you would already have some increasing insight, interesting insights, yes. One area in particular, and it's based on experience, and again, it's not that we didn't know about the phenomenon. It's just that it wasn't very high up on the radar screen, and this is an example where we had experienced some stress corrosion cracking at plants on stainless steel at seaside, where what we found is that there are salt deposits on the stainless steel components.

And that has been found a number of places, maybe not reported because it doesn't meet the requirement for reporting, but it has been found, and it has been an area that clearly the panel is concerned about.

I guess I also must say that one of the challenges I'm giving the panel is to make use of information we've provided them, make use of past experience. But we're also making use of information that we know on time dependent dependencies. So we're challenging the panel to think forward and think about these components and the environment, and estimate whether degradation should be experienced even though we haven't experienced it yet, possibly because incubation periods are somewhat longer and somewhat different conditions.

But there's challenge to think forward and to look at the possibility for degradation in the future, not just based on past experience.

DR. WALLIS: Are there any new degradation mechanisms which appear?

DR. MUSCARA: I'm sorry?

DR. WALLIS: Any new mechanisms, degradation mechanisms which appeared as a result of these?

DR. MUSCARA: Not really. We started out by providing the panel, you know, different degradation mechanisms we were aware of, and we discussed if there are any others that we should be considering. I think most of us were pretty familiar with what the potential degradation mechanisms are.

DR. FORD: You have to make a differentiation between mechanism and mode. There are no new mechanisms of cracking that we're finding, but there are new applications.

DR. WALLIS: -- over the years, every ten years or so somebody discovers --

DR. FORD: I think we've got all of the possible ways that atoms can go into solution. We've got every conceivable way. It's a question of whether you see something that you would not have predicted.

For instance, we're interested in the pump blockage thing. We talk about Reg. Guide 1.32. This mode of cracking or transferring the cracking under insulation plays exactly into this question of pump blockage.

DR. MUSCARA: So we have left six more expert panel meetings that will cover the rest of the PWR and the BWR components. The next meeting is actually the week of November 15th, so week after next.

We expect to have a PWR report at least in a final draft prepared by June 2005, and a similar report for BWRs in December 2005.

Now, to move on to Step 2, and that is the need for the technical base to allow us to be truly proactive with respect to managing degradation, we want to accomplish the second step by pulling together an international group. This will be a group that's made up of technical experts, and of course also the sponsoring organizations. And together we would develop a broad based research program plan that would address materials and degradation mechanisms, mitigation, repair and replacement, and nondestructive examination.

We then would evaluate what research is already going on that different organizations are willing to share and identify areas where there may be some gaps.

And then based on this, we would pull together the program that's needed, and through the cooperative agreement, we would sponsor, implement, and share the research results.

In order to do this, we clearly need to have some planning meetings. My thinking is that we could have about three meetings this calendar year, '05, to plan the program, put together an agreement, and then hopefully start the cooperation and exchange of information in 2006.

DR. WALLIS: You're going to publish several NUREGs as a result of this?

DR. MUSCARA: Clearly, as a result of the identification step.

DR. WALLIS: Several NUREGs?

DR. MUSCARA: There would be at least two NUREGs. Well, we may decide to combine the two, but there will be drafts available.

DR. WALLIS: There will be some sort of permanent reference which is there?

DR. MUSCARA: Oh, yes, yes, yes.

I think this is the last viewgraph that discussed briefly utilization of results.

So the results would be lists of plant components that may be susceptible to future degradation, and the reasoning behind these calls, and the knowledge base on these mechanisms.

DR. WALLIS: Now, these are all for existing reactors?

DR. MUSCARA: Yes.

DR. WALLIS: Are you doing anything about future reactors?

DR. MUSCARA: Not in this exercise, but you know, there will be information here that will be quite useful for future reactors, in particular, the ones that are light water based.

DR. WALLIS: So you're looking at something like AP1000?

DR. MUSCARA: Well, because we're talking about materials and environments that are similar, then most of the conclusions that we find here would apply to those reactors also. If we're talking about high temperature gas cooled reactors, you know, fewer insights may apply there.

DR. WALLIS: But you're looking at

individual components here in great detail.

DR. MUSCARA: Right.

DR. WALLIS: And some of these other reactors have different components.

DR. MUSCARA: That's right, but what's important is the components are of the same material unless it's in the same environment, and when you look at that, you'll see the same materials and the same environments in a lot of different plants, including the advanced reactor concepts.

MR. SIEBER: I have a question. On your slide on page 14 and 15, it has a table that describes components, and it's very detailed. It goes down to the boss (phonetic) on the thermal weld.

I pictured your final output as being perhaps several CDs with literally thousands and thousands of components and subcomponents, and so ranked in some way or another. So I wonder how a licensee is going to be able to deal with this listing of thousands of components in any kind of realistic way.

DR. MUSCARA: Well, there are a number of steps, of course. The first step was that we didn't want to miss anything because we were trying to hold --

MR. SIEBER: I don't think you will.

DR. MUSCARA: I don't know.

MR. ROSEN: Well, I have a concern about that. I'll get to it in a minute.

DR. MUSCARA: But the next step, as I indicated, we're also doing some risk work. So that's one basis for ranking, but I'm sure the industry is also looking at what are the consequences of failures in different components. So they will have a ranking based on other parameters.

But to me with this first step I did not want -- in my mind regardless how expert the experts are and how careful you look at this, I think there will always be surprises, and I thought I wanted to -- you know, if I started out by ranking at the beginning and eliminating components, you know, I open myself up for missing things.

So at the first step I want to be as comprehensive as we could within the context of safety systems and those systems where you might release radioactive water. So we already eliminated a number of systems, but we still were winding up with thousands of components that we're evaluating.

Well, not all of these thousands of components will be susceptible to degradation mechanisms that all have threes in our scoring. Some of these will have one. So that's another basis for ranking.

So we do need to agglomerate and summarize the results, but clearly we will have all of the results available for all of the components and all of the costs.

DR. WALLIS: All of these components that have reactor coolant inside and air on the outside have no insulation on them?

DR. MUSCARA: I'm sorry?

DR. WALLIS: They're all uninsulated pipes or something that you're list?

MR. SIEBER: No.

DR. MUSCARA: No, no. Many are insulated.

MR. SIEBER: They're all insulated.

DR. WALLIS: No insulation listed as being a part of the outside environment..

DR. JONES: It's kind of taken into account in the notes here.

DR. WALLIS: Whatever is in the insulation can chemically affect the outside.

DR. MUSCARA: Sure,a nd that's addressed.

DR. FORD: That's quite a doubt.

DR. MUSCARA: And I'm not showing you the entire table. I was trying to summarize and give you some of the key items, but there are places for comments, and again, each expert is required to give us a basis for their call, and already in some of the work that we've done the insulation plays a role, and it's listed in the comments.

DR. RANSOM: Has there been any effort to examine the decommissioned plants to look for what kind of state they're in?

MR. SIEBER: Yes.

DR. RANSOM: There has?

DR. MUSCARA: We've had several projects. We've looked at different components.

MR. SIEBER: Reactor vessels frequently.

DR. MUSCARA: Vessels, the stainless casting of steels when we were trying to evaluate embrittlement, thermal embrittlement that occurs in these materials.

MR. ROSEN: I'm about to ask a question about the analogue to the completeness argument in PRA, which is, you know, you talked about how expert the experts are. You've assembled a group of experts, and one of them even is from this august body.

And yet we know that we all worry about missing things. Is there anything more fundamental that one could do other than just getting a roomful of the very best experts you can find and talking to them in some structured way like this? Is there anything more fundamental? Is there a meter one can put on the pipe and say, "I don't know what it's going to tell me, but it will tell me something"?

DR. MUSCARA: Again, I brought this up before, and we literally spent ten to 15 years developing a technique that could continuously monitor the integrity of components. There they can tell us if cracking is initiated and if cracking is progressing, and if it's progressing, how big it is getting.

MR. ROSEN: Yes.

DR. MUSCARA: So in my mind if you're looking for the best meter we could put on today -- and you can do this globally or you can do this for components of interest -- but it's acoustic emission monitoring.

MR. ROSEN: All right.

DR. MUSCARA: It has the capability for detection of --

MR. ROSEN: So you don't need experts except after the meter goes off. Then you bring your experts in.

DR. MUSCARA: Well, then you want to do some evaluations about the potential growth and so on.

MR. ROSEN: So at some point you can recommend that all plants instrument --

DR. MUSCARA: Well, I think it's a recommendation that makes sense, where we can and where there's a particular interest.

MR. ROSEN: Should I think about this effort as being an effort that goes to the place where ultimately you're able to tell the plants what meters to put on and where?

DR. MUSCARA: In fact, as I said, we've done quite a bit of work. Not only have we done the work; we've conducted work on operating plants to prove that the technique works. The ASME code was convinced that the technique works, and it's in the ASME code. So there is a procedure and a process in the code if one wants to use this technique on how to instrument the plant and how to analyze the data.

MR. ROSEN: And that's the protection against missing things because if you can get a signal that's not on any of these tables and none of the experts --

DR. MUSCARA: Sure. Clearly, to try and instrument an operating plant, there's lots of work, lots of radiation exposure. So it may not be feasible to fully instrument an operating plant, but for new plants, a lot more feasible, a lot more doable.

But for a plant that's in service, if you have a specific problem, let's say we're really interested in the head. Well, one could instrument just the head and get information from that.

CHAIRPERSON BONACA: I think we need to move on. We have still two presentations to go, right?

MR. SIEBER: Right, we have two to go.

DR. MUSCARA: Yes. Well, I think I was finished. Thank you.

MR. SIEBER: You're done.

CHAIRPERSON BONACA: All right.

DR. DYLE: It's amazing that I was actually able to get the computer to work. This is not one of my strengths.

(Laughter.)

MD. DYLE: And it's not my computer. I have mine dummied up.

My name is Robin Dyle. I'm from Southern Nuclear, and some of you all have seen me. I've been involved in the BWRVIP effort since 1994. I've been here before talking about BWR cracking in many different ways.

I'm also a member of the Materials Technical Advisory Group. So I'm representing the industry effort on materials issues, and I want to do a real quick step through the logic of how we got to where we are and try to make up some time here and then save time for Dr. Jones to talk more about some of the technical details, and then if we have time demonstrate to you our degradation matrix to some degree so that you can get an appreciation for it.

I will mention we had a meeting Tuesday with NRC senior management and walked through this matrix that is going to be presented, and that it has been forwarded to NRC by letter in CD form. So it's NRC's hands and available to be shared, and I believe Ted Sullivan is the point of contact in NRR for that.

As you're probably aware, and it has been presented before, there was a materials initiative that was voted on that said we're going to address materials issues, and just a couple of significant items about it.

From the initiative process, when the chief nuclear officers vote for an approve an initiative, it becomes binding on all of the owners. They did that. It was a unanimous vote, and they said, "We're going to deal with this. We're going to get surprises behind us, and we're going to be proactive."

And I bolded two items there. We're going to prioritize materials issues, and then we're going to take a proactive, integrated, and coordinated approach to deal with it, and that's what we want to talk about.

Here's the policy statement from the initiative, and I'm not going to read that to you, but again, the highlighted items are going to be forward looking. We want to respond to emerging issues, and we want the safety and operational risk significance to be fully established prior to disposition.

No pencil whipping, no saying it's not a problem. If you have something that's identified, deal with it the right way. Figure out the right technical solution, and then go forward.

There's two groups that are responsible for this, just so you understand. You've probably heard MEOG and MTAG or MATAG talked about. The MEOG is a group of chief nuclear officers or the executive chairmen of the different issue program groups, like the BWRVIP, the MRP, Westinghouse Owners Group Materials Committee. There's a whole series of groups that are involved.

So we have executives there involved to make the policy decisions, and also to make sure money is in the right places.

A Materials Technical Advisory Group, which I am part of and Dr. Jones is, is those of us who either lead these issue program groups or solicited experts to help us make the technical judgments and do a crosscutting look at what's going on; that the BWRs and PWRs are not working in isolation.

Here's a list of the groups that are involved in this program that are covered by the initiative. Dr. Muscara mentioned NDE issues. We have the NDE Center and the PDI, Performance Demonstration Initiative, here, the Chemistry and Research Programs through EPRI, three NSSS owners groups that work on materials issues, and then the EPRI programs.

Just to give you an idea about how significant our spending is here's the budgets for the current fiscal year and next year that these programs have allocated.

So it's in the neighborhood of 46, $47 million a year just on materials activities.

Again, we said we wanted to be forward looking, coordinating and trying to deal with this. So how are we going to do it? This is --

DR. WALLIS: How does -- I'm sorry -- how does something like thermal hydraulics come into this? Pipes can break because of thermal stresses or thermal shock or waterhammer or thermal striking or thermal fatigue or all kinds of things. Are these all materials people doing all of this work?

DR. DYLE: No.

MR. SIEBER: No.

DR. DYLE: It is not all materials people.

DR. WALLIS: I just haven't noticed anything other than materials talked about so far.

DR. DYLE: It's not all materials people, and when I get to later on in the process, I explain how we integrate other people in there, but that's a valid question.

One of the expectations, again, the last item there, is that every utility is going to participate. What we have said is we're going to require executives participate from all utilities, technical people, and that all of these products that are developed to be proactive will be implemented.

So we wanted to provide a comprehensive

view of all the materials issues. We're trying to identify the challenges. We're working with the IPs. This is here for you to read, and you can see what we've got in our strategic plan.

The main thing is that we understood we needed a strategic plan. We couldn't continue to have eight or nine groups independently. We needed to coordinate this effort and have some focus to make sure we're looking at the right things in the right sequence.

MR. ROSEN: What does IP stand for?

DR. DYLE: Issue program.

MR. ROSEN: Oh, issue program.

DR. DYLE: I'm sorry. And that could be an owners group or an EPRI committee.

We wanted to provide a systematic approach, similar to what Dr. Muscara talked about. We want to identify vulnerabilities, assess conditions, what we can do to inspect and evaluate. How can we mitigate things? What repair and replacement techniques are available?

And we came up with an approach that we would develop a degradation matrix and then what we call issue management tables.

Now, Dr. Jones is going to talk in detail about the degradation matrix. I'm not going to spend a lot of time on that. I'll talk more about the issue management table, which is where we end up with. It helps us manage this.

DR. WALLIS: The problem with managing this is that you don't have measures of success. It's not as if you have a column and you know when it has been solved because you can compare your specs with what you actually achieved. Here your measure of success is kind of there is not some unexpected materials problem that appears magically in the next ten years.

It's very difficult to get hold of that measure of success.

DR. DYLE: That is one of the issues. Another measure of success is can we do for the rest of the industry like we've done for BWR piping. We had significant cracking, but over time, with research and inspection, we found a way to mitigate those issues, either through stress improvement work --

DR. WALLIS: Those successes are no egg on your face.

DR. DYLE: That's right.

DR. WALLIS: That's rather hard to achieve.

DR. DYLE: You have this existing plant that's operating. So how do you continue to operate it safely and minimize the degradation? That's where you end up.

Again, I will skip through this because Dr. Jones will talk about the degradation matrix so that there will be more detail than what I'm going to go into.

We have a strategy. We have a degradation matrix, and then you say, well, what do you do with it? And this is the process that we're going to use to try to get to aging management.

And I would characterize what NRC is doing. They started a component to try to work their way up. We really tried to start as a phenomenological level and work our way down.

So from the DM you would identify the component-component function, the materials of construction, the mechanisms that might be in play and the likelihood of them. You look at combinations of things, like you could have IGSCC and fatigue in the same location. So which one is the predominant mechanism you need to manage to deal with initiation or what would you be dealing with that would result in final failure?

So we tried to identify that, and we identify the locations that can fail. Now, I'll tell you what we did for the BWRs on the internals. We started with all locations can fail, and we're going to inspect or do something until we better understand that.

And I think in some locations or some plants that's what you end up with. Then we go through and we look at the consequences of failure, and that includes system responses, operator actions, leak detection, all of those things that exist that might be a tool that helps us understand the failure and what the operators would do.

For example, when we dealt with shroud cracking, one of the things we said was, well, if I had a 360 degree through-wall flaw, is there something that the operators would detect, and we said yes, and we describe that, and we make sure the operators are trained to deal with that.

DR. WALLIS: A 60 degree through-wall flaw is presumably a broken pipe?

DR. DYLE: Well, in the case of the shroud, it would be a very large broken pipe, but you know, we tried to account for that core spray piping. What if the core spray pipe failed? Could I have some advanced notice of that if I had IGSCC that I had missed, and the answer was yes. Because of the instrumentation that was available, you would get a change in delta P.

Similarly, with the slick system in the BWR. So there's things that we would try to counter there.

The other thing you walk through is sometimes the owner, the designer of the plant might say, "Well, this is how the system operates." Well, that's the way it was designed 30 years ago, but we've changed procedures. We operate the plant different, and we want the operator to say no. Here's what happens. If this occurs, then here's the response, and here's the next response, and these are the systems we bring into play.

So we understand the operator actions that would be involved. Look at the inspection capabilities and history. If we want to inspect the location, what have we done? What have we found? What can we do?

VC Summer, they were doing inspections, but the transducers weren't the right type to really punch through the 182. So we need better transducers. We need to be doing things of that nature. All of those work together.

Evaluation capabilities. What can we do from understanding crack growth rate or what are our fracture mechanics tools? And part of what we found as we went through this, for example, in the BWR realm again with the top guy, you have a grid structure. That's not like doing a pipe flaw evaluation. So how would you evaluate a crack there?

And by going through the analytical process of developing an evaluation tool, you better understand how the mechanism nay behave. Looking at mitigation technologies, noble metal for BWR has been successful in turning off initiation and slowing down crack growth.

Stress improvement was used for the BWRs, is being considered for PWR plants, preemptive overlays or even replacement. We developed options for the BWRs and some of the PWRs you're looking at, and we said it's going to cost a lot of money to inspect this, and if I find something that's going to cost a lot of money to deal with it, I'll just replace it.

Ultimately that's where the PWR fleet came with the heads. It's better to get rid of the problem than inspect it. So all of this rolls into the decision making, and then based on all of this information, you would identify the gaps and needs as you currently exist, and then what the strategic plan is supposed to do is work from the highest to the lowest to eliminate those gaps, and that's the program we're trying to put together.

DR. WALLIS: Hopefully the people who are finding the gaps aren't the same people who want to get the work to eliminate the gaps.

DR. DYLE: Correct, and I will mention before Dr. Jones gets started, one of the things we did with the degradation matrix was we drew experts together, but we minimized the amount of utility participation because we didn't want people sitting in the room saying, "Oh, no, that won't happen," and to screen things out. So we didn't want to allow that to happen.

This is difficult to see, but this is an example of a table where you would summarize the results of that process that I just went through in those two slides, and what I've done is this is kind of a simplified version of where we are with the BWR fleet today, and just as Dr. Muscara talked about going through multiple components, we have done the same. You have seen the presentations of the internals where we looked at multiple locations on the shroud, multiple subcomponents over a jet pump, and all of those things.

But we rolled this up, here the BWR returns. Well, there's all the materials you used. Things that we have identified either from field experience or from laboratory data or in some cases experts. This has occurred in the petrochemical industry or some other location. There's no reason why we don't believe it would occur here.

We've looked at consequences of failure. This has really simplified the core configuration. There's other things that you have, and there's additional issues, whether you had a main steam line break or a recirc line break or an earthquake, depending on what happened.

Mitigation, yes, there's some we can do, but there's some work needed because there's areas that we can't properly mitigate that are high fluence.

So you see how this would be filled out and then you have gaps. So I don't have anything there, and you say, well, VIPs have been working ten years. Do you have gaps? Absolutely. And we can show those to you when we get to the degradation matrix, provided we have the time to do that.

But, for example, we've already understood that we have some problems. When we took the first cut at the strategic plan, and this is in the strategic plan for 2004, these are the high priority items that we said the industry needs to go work on, and to that degree, we have additional funding that was made available. We collected $6 million this year. We'll collect an additional $6 million next year above and beyond that slide I showed you for the 46 million to attack these problems sooner rather than later.

When we went through this process, we said here's the things we need to do. Here's the things we need to be working on. Since we collected that money, we've already authorized spending nine million of the 12 million to get at some of these issues, some of the fundamental understanding of stress corrosion cracking in the PWR environment.

The high fluence issues for Bs and Ps, we're doing fracture toughness work and crack growth work for highly irradiated stainless steels, and we're looking at even the ability to do welding on the highly irradiated stainless.

So we've already started working on the solutions that came out of this first review. And with that I'll go ahead and go to the next presentation unless you have some questions there.

(No response.)

DR. JONES: Good afternoon. I guess it is just about afternoon now.

I'm Robin Jones from EPRI. Right now I'm the Technical Executive that all of the materials programs that Robin listed report to. So I have the sort of overall responsibility for making sure that integration takes place within EPRI programs. I'm between EPRI programs and with the outside world, as well.

As Robin as been saying, we've been busy trying to define vulnerabilities using a pretty process that's somewhat similar to the one that was described by Joe. The bottom line status right now is that we have used the expert elicitation process to get input on degradation vulnerabilities, and we have information on all of the materials used in the reactor coolant system, PWRs and BWRs.

We combined the input here into a tool which allows fairly easy interrogation of the experts' input, and that's really intended to be a tool for people like Robin, et al., and the people in the industry to use to either look in at an observation that they've got and find out is this consistent with what we expect, or to look in and say what should we be thinking about for this particular material and this kind of application in a BWR.

So there is a tool, and we'll demonstrate it to you if there's enough time, and right now the first version of the degradation matrix has already been shared with NRC a couple of days ago, although they actually saw it a couple of times during development as well.

As Robin pointed out, there is a materials issues strategic plan that lays out a systematic approach to developing management programs for all actual and reasonably to be expected degradation issues, and the first step in that plan is to identify vulnerabilities, and that's what I'm going to talk about, that first step.

And the effort in this area, we designated or gave the name "degradation matrix" because that was the intent, was to produce a tool that is essentially a summary of vulnerabilities.

DR. WALLIS: Are you doing very much the same thing that NRC is doing?

DR. JONES: Yeah. We're doing it in a completely different way. I think as you heard from

Joe, he starts at the component level and works up. Okay? We're starting at the global level and working down because we thought that that would probably be easier and quicker and cheaper to do, and we're going to actually meet at the level of about the GALL report because that's really where we want to get the input.

DR. WALLIS: You're using different experts?

DR. JONES: We're using some of the same experts, but --

DR. WALLIS: Same experts?

DR. JONES: Some of the same experts.

DR. DYLE: Sorry for interrupting. I would like to mention that Dr. Robin is on our expert panel also.

(Laughter.)

DR. JONES: Including myself and Dr. Ford.

But, yeah, it's a somewhat different approach that we thought would last to get into this more quickly.

DR. WALLIS: Dr. Ford is on both of these groups?

DR. JONES: Yes.

MR. ROSEN: And the ACRS.

DR. JONES: And the ACRS, right.

So our first step was to identify the materials used for major passive components and systems within the materials initiative scope. So we get lots of materials, say, associated with the reactor pressure vessel or with the internals, as Robin showed us before, and for each of those materials, we attempted to figure out what possible vulnerabilities are there based on field experience, laboratory data, speculation.

Then we got a team of people together. There were 29 people in all. Fourteen of them were experts. We also had people from EPRI, some of whom I think would be considered experts as well, and we went through an elicitation process that we prepared a format for and basically got people to fill it out. It was more of a consensus process than the one that you heard from NRC. We argued back and forth about is this really likely.

The list of people involved is the last page of the handout, if you want to figure out who they were.

Then the outcome is to identify and characterize the issues that pose potential threats, and we used the color coding scheme to identify what were the more important threats, if you like, and I'll show you an example of that in just a minute.

All right. So we started out here by defining essentially the scope of the effort. You see this is Level 1 of the degradation matrix. In the tool itself there's discussion of that, the materials and vulnerabilities at a very high level, at this level.

So we have --

DR. WALLIS: It's only steels? It's not seals and things like that?

DR. JONES: That's correct. Right now it's major passive components. We did actually collect some information about other materials in the process of this, and we expect that we'll expand the scope to cover that in the future, but right now it's all metals.

DR. DYLE: Well, with the addition of fuel related issues.

DR. JONES: Oh, yeah.

DR. DYLE: Again, it is metal, but we are looking at, for example, interaction with cladding and things of that nature from the water chemistry perspective.

DR. WALLIS: This looked like steel or something.

DR. JONES: Well, there's nickel based alloys in there as well, as you know, and, yes, we did do a first cut at a similar kind of table as I'm going to show you here for fuel and other core components. So fuel and the control aspects of the core.

All right. So what we're trying to do is create a table now. We do one of these for each of the major components shown in the top, Level 1, and for example, the PWR pressurizer, it's defined here on the left-hand side, and the materials that are used are defined down the left-hand side, and along the top are the various degradation modes. The big picture ones are SCC, corrosion wear, fatigue, and reduction in toughness, and then the subsets within each of those.

I actually did find out about a phenomenon that I didn't know much about when we started this activity, and it's the one called LTCP. That's low temperature crack propagation, which is a form of low temperature hydrogen embrittlement which we'll see in a minute is one of the things where we have a question mark. Does it actually apply? Do the conditions that are required for it exist within the plant?

Some of them do and others we're trying to figure out yes or no.

MR. SIEBER: Is the work you're describing here duplicative in any way with the PIRT effort that the NRC research is doing?

DR. JONES: Yes, but because it comes from a different direction, the degree of duplication is really quite slight.

MR. SIEBER: They look similar to me.

DR. JONES: Yes, yes, but as I said, this is top down, and Joe is bottom up, and it will be interesting. We can cover the variations plant to plant much more easily than Joe can, but he can get the specifics of the stressors for at least some groups of components more explicitly than we can.

And if we arrive at the same conclusions about the vulnerabilities, I think it will be valuable confirmation.

MR. SIEBER: Yeah, I asked the question because I thought maybe there would be some common basis where you could get the best out of both kinds of systems and perhaps consolidate some of the effort that's going into all of this.

DR. DYLE: And that was discussed Tuesday with Dr. Paperiello and Joe and others, that the reason we've provided the DM to the staff is now for them to review it and provide comments back to us so that we can understand that.

We're trying not to do this in a vacuum, but do it in an open fashion so that we can share that kind of information and learn the lessons that way.

MR. SIEBER: Well, I think for this to be effective, you're going to have to do that, and so I encourage both the staff and the industry to make that happen.

Thank you.

DR. JONES: In fact, Joe's team of experts have all seen the current version of this, and they'll also hear from us when we update it in any way.

All right. So now we've got the makings of a table here. Each of these cells that are in the table refers to a combination of a material, an application, the pressurizer in this case, and degradation modes.

And so we then used the expert elicitation process starting with the EPRI team to get the strawman, and then with the outside experts to look at that strawman about what are the vulnerabilities.

Yes means that we are pretty certain that that combination of degradation mechanism of material is likely to occur. It either has occurred or we've got compelling laboratory evidence that it could occur.

No, N, means we don't have any reason to believe that that would work.

NIA means it's not applicable. You see most of the radiation stuff here, of course, isn't applicable to the pressurizer because the exposure is very small.

The question marks are the interesting ones. Those are where there's a phenomenon. We don't really know whether it applies or not. We don't have any field experience, and we don't know whether the conditions exist.

So, for example, you see some question marks in the low temperature plant propagation column here, and we see one yes there where we've actually at least confirmed the observations by having a second investigator do some --

DR. WALLIS: That way it might be really useful because you might be discovering things.

DR. JONES: Yes.

DR. WALLIS: Unlocking the question, doing some investigation, finding something out.

DR. JONES: Yes, yes. So one of the first things we're trying to do, of course, is to convert these question marks into yeses or noes, and there's a series of small projects in place to do that.

DR. WALLIS: What are these E things?

DR. JONES: Oh, yes. I'm sorry.

DR. WALLIS: Are those links to somewhere else?

DR. JONES: The E things are the link between this table and this Level 3, which are notes.

DR. WALLIS: They're computer links.

DR. JONES: So there are computer links that link various levels together. Anything that is in blue here is also linked to a more detailed information base. So there's additional information about all of the materials and degradation mechanisms in narrative reports that are hyperlinked into the table.

So this is --

DR. DYLE: Robin, if I could, the real value of this is that for a utility person that's trying to use this tool, they may not understand this where some of the industry experts did. So if they want to go to the N note, that's where the E came from. They can understand why that was put in the table and start trying to evaluate the significance of it.

DR. MUSCARA: Not to delay you too much,

you know, you're talking about that working together and cross-pollination, but in fact, we're using the same idea. In our plan, we have comments from the experts, but then those are linked to discussions. They are similar to what we see here that give more information about why you made the particular call.

DR. JONES: The only difference is that Joe's process maintains those comments which were developed independently, if you like, and here she had a consensus process that led to a comment.

Okay. The other thing we did was to look at all of the yeses and decide how much do we really know about this particular phenomenon for this particular material, and what are we doing about improving our knowledge?

The greens, we've got one of those on here. Here it's not really green, but it's greener in that. It means that we actually have a mandatory program in place that's addressing that particular degradation issue, and as far as we know, there's not any reason to do additional work. As far as we can see, the issue is being adequately addressed.

Yellow means that there's work ongoing that will get us to that point in a reasonable period of time, and the orange ones, which were red but obliterated the content in here --

MR. SIEBER: A very good color to choose.

DR. JONES: Right. Those are the areas where we clearly don't have enough information to manage this issue effectively, and we don't have enough activities going on to give us confidence that we will have in a reasonable time the elements of a management program.

The sort of thing that drives you to that is an issue where we don't have adequate or at least proven inspection capability or we don't understand the mechanism well enough to figure out what kind of mitigation actions might occur, and we're not working on that with a sufficient urgency to get us there soon.

So this is a way of figuring out in this part of the activity what are the highest priority elements.

MR. ROSEN: What about likelihood, Robin? At that point when you see those reds turn up, do you say, yeah, but it isn't likely because or it is likely?

DR. JONES: That's part of the evaluation that's done in the IMT, the issue management table that Robin showed you. So all I'm doing here is in isolation of the consequences or the likelihood, here is the state of knowledge.

MR. ROSEN: Because I could imagine someone say, yes, it's highly likely but there's so little of it in the system. There's only this one piece, one application. It's very limited.

We'll live with that.

MR. SIEBER: Here's another thing that maybe is missing, maybe is not, but it seems to me that you ought to have risk information in these tables because if something breaks that it really doesn't threaten the plant in any way, maybe you don't need to aggressively inspect, prepare, and so forth, and you could knock a couple hundred pages out of your table.

MR. ROSEN: Well, it would be better, I think --

DR. JONES: You have to be a bit cautious here. Okay? At the moment we're talking about vulnerabilities. The assessment of vulnerabilities, the significance of them is part of the ultimate prioritization, but from the susceptibility point of view and the knowledge about that susceptibility, we have to maintain this until we've proved to ourselves that it's not a significant issue.

And that's a part of a separate activity. This is just one column in the issue management table, and there's lots of others that are used to determine how important is it to understand the mechanism, for example.

MR. ROSEN: If you get a free airline ticket as a utility person to Rockville to explain a leak in your reactor coolant pressure boundary, it would help a whole lot if you had these tables behind you and were able to point to here we knew about it, here were the consequences, and we had concluded that it would be limited or it would have limited risk significance.

And, yeah, we don't like the idea we had one, but it's probably the only one we're going to get because it's in the place we said it would be if there was one. We didn't detect it, but we can fix it.

I mean all of that is a very good background story.

DR. DYLE: And I think what you just described is where the BWR fleet is in regard to IGSCC and piping. As Dr. Ford mentioned early on, we kind of understand that. We understand how that's characterized and the programs are in place. So when we have something, we have the possibility of framing that.

When we've had some first occurrences on some internals, for example, when a jet pump beam failed, we were able to talk to the staff and say, "Remember we told you this is what would happen. Here's what the operators would do. Here's how the plant would behave."

And they were able to look at that and say, "Sure enough, that's exactly what happened. You had that well characterized, and we understood it."

MR. ROSEN: And the consequence was limited ahead of time and we knew it.

DR. DYLE: That's right, and we had those described.

And I went through the issue of management process quickly, but if you go back and look at those steps, that's where we're trying to get the rest of the fleet, with this knowledge once you take all of these mechanisms and understand where they are, characterize the relative significance of them, where they occur in the plant, what the safety implications are, how the operators would behave, and all of that into an integrated fashion that then says here's the way we're going to attack --

MR. ROSEN: And all of this is an argument for completeness and the documentation in the database, which goes against the idea that you know, you ought to throw out stuff early. I mean, you really ought to have it all there and then make the conclusions when you're done. I think that's where you're headed.

DR. DYLE: Right.

DR. JONES: Okay. So the degradation matrix actually consists of three levels of information. The Level 1 is the summary information that really defines the scope and explains how the other levels are structured.

The second level is the tables and the third level is the M notes for the tables.

We also added information in narrative form that basically sums up the results in narrative as opposed to tabular form both from the viewpoint of materials and from the viewpoint of phenomena. That adds up to about 100 pages of material in hard copy, and so that's why we finished up linking this, so that it was a convenient way of moving around the table.

If you want to find out everything about something specific, you can usually find out that by reading no more than a couple of pages, and the way that the hyper links work, you can get to those couple of pages very easily and by several ways.

Okay. The future. We're going to update and revise this thing. We will probably have another expert elicitation because we want to add in stuff about fuel materials. We haven't done an expert elicitation yet. That was just EPRI's style.

DR. WALLIS: Does this also contain state of the art acknowledge? Is it all words or does it actually have equations and graphs and data in it?

DR. JONES: It has some of those, and it has some more references to places where it goes out.

DR. WALLIS: You could find it.

DR. JONES: Yeah.

And we'll almost certainly have to switch to a Web enabled approach here because we'd like to be able to link into a lot of those references so that people can actually get more information than we can possibly provide in our summary narratives.

DR. WALLIS: If you really want to know, you often need to go to the real evidence --

DR. JONES: Yes. Oh, yes.

DR. WALLIS: -- of what the expert thinks.

DR. JONES: Yes. Right now that's covered with references, and I think it's going to be covered with links in the next generation of this tool.

MR. ROSEN: The people at the point of the spear will really have to do that. If they really have a crack at the plant, those people will have to do what you suggest.

DR. JONES: Yes.

MR. ROSEN: There are other people who are on the peripheries of the problem and won't need that kind of detail, and so this would enable both kinds of user.

I have what I consider to be a dirty question, and that is because you probably don't have enough to do. My question is: what about materials degradation and risk significant systems outside the reactor coolant pressure problems.

DR. JONES: Okay. That's a very good question. You know, that's one of the things that we'll look at next after we prove to ourselves that this approach really does give people what they want.

MR. ROSEN: Ask Jeff Gorman about essential cooling water aluminum bronze degradation. For example --

DR. JONES: We have a lot of background information on the systems, and it's in the materials handbook, and we will eventually broaden the scope to include other systems that have some safety significance.

DR. DENNING: I have a question about something that struck me with the experts, and that was I didn't see any university experts. I'm kind of wondering is that because it's such an applied problem. I could be wrong. Maybe they're out there and they weren't visible there. But is it just an applied problem?

Is it a result of where our universities are right now and that they're not addressing the kinds of problems that are in the nuclear field?

DR. MUSCARA: In our group we have three university experts.

DR. DENNING: And they're from where?

DR. MUSCARA: From Japan and from the U.S.

DR. JONES: And what we found is exactly what you were speculating.

MR. SIEBER: You will have to speak into the microphone.

DR. JONES: Oh, I'm sorry.

What we found in attempting to get university people involved is, yes, there are half a dozen people who are really working in this area, but the vast majority of their work is on future reactors, and so they're not entirely up to speed on the problems that we see in the current reactors.

One of the things that we will do with the results here --

DR. SHACK: The reactor doctor?

MR. SIEBER: Right.

DR. JONES: One of the things that we will do, by the way, to answer a question that came earlier, is we will update the advanced reactor requirements document, which is where this kind of information is captured. Material selection criteria, et cetera, et cetera, are captured in the ALWR, and that will answer the question about what do you do about AP1000, and so on.

DR. DYLE: For the sake of time I guess we'll stop. I also have the degradation matrix linked up here if after the break you want to look at it and see what's involved, but again, we've made it available to the staff, but if you'd like to see it, then we can show that to you after the break.

MR. SIEBER: Is that it?

DR. DYLE: That's our presentation.

MR. SIEBER: Okay. Well, I certainly want to thank you for the presentation. It's a good status report. I think you folks are doing very good work, and hopefully it will improve our ability to not be surprised in the future.

I understand from our meeting summary that you are not expecting a letter or a report from us.

DR. MUSCARA: No, I wasn't, but if you'd like to send a nice letter, we'll always accept it.

(Laughter.)

MR. SIEBER: I may send a card. How's that?

(Laughter.)

MR. SIEBER: But in any event, I hadn't planned on writing one. I think you can tell from our questions those areas where we have some interest. On the other hand, speaking for myself, I think that you're on the right direction. I think you're making progress, and I think it's an important task to do.

So with that, Mr. Chairman, I turn it back to you.

CHAIRPERSON BONACA: Okay. Thank you.

And thank you for your presentations. It was a pleasure to see you again, and to be associated with the Power Council another time.

DR. JONES: Could I offer just one closing thing?

CHAIRPERSON BONACA: Yes.

DR. JONES: If anybody would like the

electronic version of the degradation matrix, just tell one of the Robins and we'll get it to you.

MR. SIEBER: I would.

DR. DYLE: And I would also offer that if you look at it and you would like additional information , we'll be glad to come back and either talk to the full committee or the materials subcommittee. We're trying to do this out in the open to make it available.

MS. WESTON: The reports will be sent to all of the members, as is our practice electronically.

MR. RILEY: This is Jim Riley, NEI. I'm project manager for materials issues. I can just add a little something to what we've been doing here. I'm also a member of the NTEC.

But I want to reemphasize the fact that this degradation matrix and issues management table are living documents. They are a work in process, and we are definitely looking for input from the experts who know what's going on in these areas so that we can make this thing as smart as possible and so that we can avoid duplication of effort because all of us recognize we've got a limited number of resources and we've got a big job ahead of us.

So this information is public. We've sent it to the NRC, and we'll share it with folks who would like to take a look at it and have some input to give to us.

Just keep in mind as you get it we don't have all of the answers yet. We're trying to work there, and it is definitely a work in process that will continue to be worked on into the future and perhaps in the future pick up additional systems, et cetera, and different materials like we've been talking about.

But for that we need to concentrate on the most important stuff, and that's what we're doing.

CHAIRPERSON BONACA: Thank you.

I think with that we will take a break for lunch. Do you want to have a full hour or do you want to try to recover?

Shall be get together at 1:30? One, thirty. All right. So we'll recess for lunch until 1:30.

(Whereupon, at 12:40 p.m., the meeting was recessed for lunch, to reconvene at 1:30 p.m., the same day.)

AFTERNOON SESSION

(1:31 p.m.)

CHAIRPERSON BONACA: Okay. Back into session.

The next item on the agenda is proposed rule on post fire operator manual actions, and Mr. Rosen will take us through the presentation.

MR. ROSEN: Thank you, Mr. Chairman.

The purpose of this meeting is to discuss the current rulemaking activities which would allow for the use of certain manual operator actions to satisfy existing requirements of 10 CFR 50, Appendix R. The staff is currently seeking approval from the Commission to release a draft proposed rule for public review and comment.

We had an excellent, invigorating meeting of the Fire Protection Subcommittee on October 27th going over some of this ground, and I think you will all find this interesting.

I'll turn the meeting over now to Suzie Black.

MS. BLACK: Thank you.

I'm Suzie Black, Director, Division of Safety Analysis at NRR, and I want to thank you for holding this ACRS meeting. It's important to hear the views of all stakeholders on this particular rulemaking.

The rule language has not been easy to develop, and it may not be able to cover all situations in this rule that we thought we would be able to accomplish when we started writing the rule originally, but these situations which we aren't going to be able to cover with this rule are nonetheless safe, but they may not meet the rule criteria and, therefore, may still need exemptions.

The rule language must be specific enough to preclude potentially unacceptable manual actions, ones that are not feasible or reliable, and fire protection depends on defense in depth, and we are insuring that if this rule is issued that we don't undermine that principle.

The rule has been put on the Web, and I wanted to note it is not risk informed. We have a risk informed fire protection rule that was recently issued that licenses can use. It's 50.48(c), also known as NFP 805, and through that rule licensees could adopt that part of the regulation and approve these manual actions through that process as well.

We felt that risk informing this one piece of Appendix R would be much more difficult. So we're supporting the approach of a more holistic risk informed fire protection program.

But let me reiterate that it is not our intention to permit unsafe, unfeasible, nonreliable manual actions in lieu of fire protection features through this rulemaking. There have been assertions that the NRC is fixing the rules to reward bad behavior and that what we intend to codify is uncontrolled, unsafe, ad hoc, or last ditch efforts to shut the plant down, and I assure you that is not what this rulemaking is about.

Yes, this rule is supposed to approve what was previously unapproved, but also what was considered to be safe and what would have been approved through the exemption process had we not gone through this rulemaking.

We're continuing to inspect and identify unacceptable manual actions if they're out there, and their feasibility when we identify manual actions that haven't been approved are assessed, and if they're judged to have safety significance, corrective actions and comp measures are required.

It is only those that we believe that are acceptable that will be approved for this rulemaking.

Thank you.

MR. DIEC: Good afternoon. My name is David Diec, and I'm a project manager for this rulemaking effort. With me today are Richard Rasmussen from the Nuclear Security and Incident Response Office, as well as Sunil Weerakkody from Nuclear Reactor Regulation.

The agenda for the briefing today, I will go through the background of the rulemaking effort. Key topics today will be discussed by Richard and Sunil and the security interface compliance with informing the proposed rule, acceptance criteria, detection and suppression, and time margin concept. I will come back and briefly go through the current proposed rule status at this time.

The next slide, we're going to talk about the background during development of the rule. As you recall, back in June of 2003 we forwarded a proposed rulemaking to the Commission for consideration. In the rulemaking blend, we indicated that many licensee implemented operator manual actions to meet the requirements set forth in Section 3(g)(2).

We concluded that current requirements as written in Section 3(g)(2) cannot be reasonably interpreted to allow the use of such operator manual action other than physical barriers, distance separation, detection of suppression to bring the plant down to a safe hot shutdown condition.

We also acknowledged that while those operator manual actions are just to be incompliance with the current rule, the use of such operator manual actions to achieve safe shutdown and alternative approach is acceptable through normal NRC exemption process, 50.12.

Our finding, inspections finding today indicate that many of such operator manual actions would be found acceptable and safe when they are reviewed by and approved by the staff.

To resolve the apparent misinterpretation, we propose to revise the 10 CFR Part 50, Appendix R, Section 3(g)(2) and also codify the operator manual actions as an option in Section 3(g)(2).

We also in the plan indicated that there needs to consider enforcement discretion or other alternatives to provide regulatory stability during the rulemaking activity.

CHAIRPERSON BONACA: Excuse me. I don't understand. The second bullet says "codify operator manual actions option in Section . . . (redundant trains located in the same fire area)."

MR. DIEC: Section 3(g)(2) talks about the redundant trains that are used to achieve and maintain hot shutdown that are located in the same fire area.

CHAIRPERSON BONACA: Yeah, and I'm familiar with that. Now, I'm trying to understand operator action in this context.

MR. WEERAKKODY: The 3(g)(2) area would have cables of -- redundant trays of cables running through it, and the context of the operator manual actions is if you had a fire in that particular area, the licensee would rely on operators to bring the plant to hot shutdown.

MR. ROSEN: And by taking actions outside that area.

MR. WEERAKKODY: Taking actions outside of that area, yes sir.

CHAIRPERSON BONACA: So the assumption here is that the fire will, in fact, disable both trains.

MR. WEERAKKODY: Yes, sir.

CHAIRPERSON BONACA: Unless you have some action, and the operator action is outside the area and is credited for in this case.

MR. WEERAKKODY: I think the most accurate way to put it is to bring the plant to hot shutdown, we are relying on the manual action that is implemented outside the area.

MR. ROSEN: Right, and this rule will establish a tie through a reg. guide which establishes the way to do an analysis to show that those actions are reliable and feasible or feasible and can be taken.

DR. WALLIS: I don't understand. I thought he said that the action was to somehow get these trains to now function. I assume you've lost those trains.

MR. WEERAKKODY: We assume that those grains are lost.

DR. WALLIS: You've lost redundant trains. You've lost, say, two out of four maybe or something?

MR. WEERAKKODY: No, it's two out of two.

DR. WALLIS: You've lost two out of two?

MR. FRUMKIN: Right. Let me give a quick explanation. This is Dan Frumkin of the staff.

What this typically is or an example of this could be you have both trains in the same room, but you only have control cables for one train in the room such that an operator can go down to the equipment. It is powered. It's just not available from the control room to be controlled. So you send an operator down to the piece of equipment, to the pump, to the pump control station, and then you start the pump.

Then you can throttle the pump from a valve somewhere or something like that. So you do lose both trains' control from the control room, but you don't lose full functionality of the trains.

MR. ROSEN: Thank you, Dan.

DR. APOSTOLAKIS: So you could lose power to both trains?

MR. WEERAKKODY: In some instances that may be the situation, yes.

DR. APOSTOLAKIS: So they go outside and find another power source?

MR. WEERAKKODY: If that capability was there.

MR. ROSEN: Well, they'd have to do the time line analysis and show it could be done reliably, feasibly and reliably.

CHAIRPERSON BONACA: By codify you mean the JSFW (phonetic) requirements, for example, again, accessibility to the location, the protection that you would have for a successful --

MR. WEERAKKODY: Yes, exactly. What we would mean by that is we are coming up with a set of objective criteria that we could hand over to a licensee and say, "If you meet the following ten criteria, then you can take credit of this other new option."

DR. WALLIS: All of these actions are planned ahead of time.

MR. WEERAKKODY: Yes, sir.

MR. ROSEN: Yes, and any procedures and the operators are trained on.

DR. WALLIS: The operator needs to know where the fire is and what damage it has done.

MR. ROSEN: No. Only where it is.

DR. WALLIS: Where it is and some assumption about what it --

MR. ROSEN: The fire pre-plans usually tell him what indications to look for, and then what actions to take depending on what he finds.

MR. WEERAKKODY: Having procedures training on some of the fundamental basic requirements that we have said one has to have.

MR. ROSEN: Okay. Go ahead.

DR. APOSTOLAKIS: Well, you will go into more detail, I hope.

MR. WEERAKKODY: Yes, yes.

MR. DIEC: Okay. In September of 2003, the Commission approved the staff rulemaking plan to go forward with the rulemaking activity for the operator manual action application.

The objectives of the rulemaking are twofold. It satisfied the effectiveness goal and insured safety goal. It seeks to clarify the use of operator manual action as a regulatory option, and this reduces the need to have the staff and resource to review individual, plant specific operator manual action.

And the rulemaking that we are utilizing provides the framework for us to establish the visible, reliable operator manual action with the use of detection and suppression as a new requirement.

We met with stakeholders as well with subcommittee on fire protection issues in a number of times. In September of 2003, we met subcommittee to discuss the rulemaking plan, and there are a number of issues that were raised regarding reliability of such use of operator manual action, and we also held a number of meetings with the public to discuss about the interim acceptance criteria that we published in the Federal Register notice and solicit formal comments from public for those applications.

We came back in April of this year, 2004, to address the reliability issue using operator manual action to the subcommittee, and we also introduced the concept of time margin, as well as addressed other concerns that were raised by the public regarding about the applicability of operator manual action throughout the Section 3(g), namely, 3(g)(1) and (3).

We also published the rule text, rule requirement text recently to engage with the public and to provide the openness and access to the rulemaking activities that we were performing.

MR. ROSEN: And had a subcommittee meeting, another subcommittee meeting with us on the 27th of October.

MR. WEERAKKODY: Yes.

MR. ROSEN: It's not on that slide, but that's --

MR. DIEC: Thank you.

At this point I'm going to turn it over to Richard to discuss about security in relationship to the rule that we're working on.

DR. WALLIS: Can you tell me more about the time line? You put this rule text out a week ago?

MR. DIEC: Yes.

DR. WALLIS: And you're waiting for public comments?

MR. DIEC: No, for information only.

MR. WEERAKKODY: The proposed rule would be formally published for public comment after the EDO's Office and the Commission sees it; is that right, Dave? And that's going to happen in a couple of months.

MR. ROSEN: What the staff is here now, Graham, to ask us for is a letter that says we think it's ready to go out for public comment.

DR. WALLIS: That's why I'm puzzled. It seems to have already gone out.

MR. ROSEN: No, no. As he said, it was just released for information at that stage.

DR. APOSTOLAKIS: Is that common?

MR. DIEC: Yes. The Commission in the past has said it is a good thing for us to share information regarding about the activities that we're working on so that we can take the input from stakeholders into the consideration.

MR. ROSEN: Well, very helpful.

DR. APOSTOLAKIS: But you're not asking them to comment.

MR. DIEC: No. The formal solicitation --

DR. WALLIS: You're giving them more time, aren't you?

MR. DIEC: Yes. The formal solicitation

process will take place once the Commission endorses for us, the staff, to publish the proposal package in the Federal Register notice. At that time --

MR. ROSEN: There will be a 75-day comment period after that?

MR. DIEC: Typically, yes.

MR. ROSEN: So this on the 25th was just to get it out kind of ahead of time. It's a good thing.

DR. APOSTOLAKIS: And essentially they will have what, two months plus 75 days?

MR. DIEC: Yes.

MR. ROSEN: And helped us in the subcommittee meeting, for example. The stakeholders had the hard copy text of what the staff was thinking about.

DR. APOSTOLAKIS: It sounds like we are circumventing the public comment period idea.

MR. ROSEN: Circumventing what?

DR. APOSTOLAKIS: The whole idea of soliciting public comments. I mean, you already have some comments.

MR. ROSEN: Well, this issue has many stakeholders and many people wanted to see the draft before they came to the subcommittee.

MS. McKENNA: This is Eileen McKenna from Policy and Rulemaking.

I want to clarify a couple of things. One is on the previous slide there was a bullet we didn't spend a lot of time on, but I just want to note that we did put out a draft version of the criteria last fall in the Federal Register and solicited comments at that point from the public. It was not in the form of a rule at that point. It was interim criteria, but it did help us develop the criteria that will be discussed further.

The publishing of the language on the Web most recently was exactly to support the subcommittee meeting so that we were able to have the other stakeholder comments be enlightened by where the staff was with the rule.

And we'll be doing the formal publishing for comment for the 75-day period once the Commission approves publication.

DR. APOSTOLAKIS: Is there any rulemaking that you are not involved in, Eileen?

MS. McKENNA: Well, I'm now a section chief over in the Policy and Rulemaking Program. So I'm involved in a lot of them, not all of them, but many. So you'll probably be seeing me often.

MR. DIEC: Okay. With that I'm going to turn over to Richard.

MR. RASMUSSEN: Hi there. Richard Rasmussen with NSIR, Division of Nuclear Security.

And I'm going to discuss the security aspects of this rulemaking and the considerations that we've put into that.

Security is not currently addressed in 10 CFR 50, Appendix R, and as we were working through this rule, we came to the conclusion that the security concerns were more appropriate if we considered them on a broader context than just fire. This rule is changing Section 3(g)(2) of the rule, which is just one small section, and the approach that we would feel more comfortable with is addressing the security issue much more globally.

We're currently evaluating the safety and security interface issue for future rulemaking, and also we're in the process of developing industry communication to get this message out in the interim period.

MR. ROSEN: Let me ask you a question, Richard. Richard is it?

MR. RASMUSSEN: Yes.

MR. ROSEN: Section 3(p)(2) of the rule

says -- no, excuse me -- yeah, Section 3(p)(2) of the rule says this analysis required, and it says a postulated fire time line showing that there's sufficient time to travel to action locations and perform actions required to achieve and maintain the plant hot shutdown conditions under the environmental conditions expected to be encountered, including security events, without jeopardizing the health and safety of the operator, et cetera.

So the question at the subcommittee is how was one to do that. There's no guidance in the regulatory guide. So what's going to be one with that wording in 3(p)(2)?

MR. RASMUSSEN: At the time when we were considering that, that was put in there was a place holder while we considered the various approaches that we had available, and that wording has been removed.

MR. ROSEN: Ah, okay. But now fine. That's one very important, big answer.

the second question is now that that's removed, if you codify this rule and everybody is happy with it, how does one go ahead? Is there going to be a parallel rule that comes together at the same time or does everything on fire stop and wait for the security rule?

MR. RASMUSSEN: We think that this can go forward. The issue really is one of clarifying the need for the licensees to consider the impact on the security force when they do anything. If maintenance goes out and erects some kind of structure that interferes with the security plan, clearly that's an issue that we wouldn't expect to happen in the site. It's degrading the security plans. It's not in accordance with the security plans, and so that's really no different than the concept that we were trying to convey with this.

The solution to that problem is one of communicating that particular vulnerability and expectation and then proceeding with a better way of promulgating it, like rulemaking to be specified.

MR. ROSEN: Well, as a good security man, I'm sure you came at this like here's an operator manual action that's going to interfere with security. I'm rather worried about the opposite.

DR. APOSTOLAKIS: I get the impression it's not that. This is a general statement that they will worry about security in future rulemaking. What you said is you're not particularly concerned about this rule; is that correct?

MR. RASMUSSEN: I think the concern in

terms of this rule originally was the situation where the fire is as a result of a security event. Operators have to get to various places in the plant to react, and they'll no longer be able to or they'll expect security escorts, coordination with security, and it was our intent to build in a process for that to get thought of ahead of time.

MR. ROSEN: Okay. That's a good clarification.

This is fires as a result of a security event, and that's one very important and my principal focus and concern. There's also a fire which interferes with security, has nothing to do with the security of it; wasn't started by some sort of malevolent act. It just was a normal plant fire, but the security force that rushes in comes in, interferes with the fighting of the fire.

And if you think this is a hypothetical, let me hasten to tell you it is not because at the Vermont Yankee plant they very recently had just exactly that event where they had a start-up transformer fire, and the Vermont State Police interfered with the activities once the fire started.

It was resolved peacefully, but it was fair contentious at the time. So this is just an operating experience example of where the security force, in this case an external security force --

DR. APOSTOLAKIS: I'm confused now.

MR. ROSEN: -- interfered with fire fighting activity.

DR. APOSTOLAKIS: I thought Mr. Rasmussen said that they will not do anything special to this, that this is a general evaluation of future rulemaking activities.

MR. RASMUSSEN: That's right.

DR. APOSTOLAKIS: So all of the stuff that Mr. Rosen just told us, where does it go? Who evaluates that?

MR. RASMUSSEN: Well, it's true. It exists. It obviously existed at Vermont Yankee. Hopefully the industry has promulgated that as lessons learned. I don't think that's a new concern. Being a senior resident, we encountered that thought quite a while ago.

I can't say that everybody has implemented corrective actions, but the point getting back to this was any fix that we do specific to Paragraph 3(g)(2) will be minuscule compared to the overarching concept that we feel is better evaluated with a more global approach.

MR. MORRIS: If I may address the committee, my name is Scott Morris. I'm the chief of the Reactor Security Section in NSIR, and Rick works for me.

As you know, there's a variety of rules that are, you know, in the works now, 50.46, this one, 50.48, and 50.69, some others, and in each and every case appropriately, our office, NSIR, and specifically my division, my section, gets an opportunity to comment on these rules.

And when we got those rules in our hands and looked at them, you know, we always look at them through a different prism, and we look at it through a security prism, obviously, and had suggested to NRR and others, you know, that we need to start thinking through the safety-security interface not just in the context of these rules on a piecemeal basis, but rather in a more global context.

And so what we wound up with ultimately was in the 50.46 proposal that went to the Commission within the last month or so -- I can't even remember now -- a couple of weeks ago, what we told the Commission was that we were going to examine the merits of a more global approach to establishing regulatory requirements for safety-security interface, you know, and potentially amend some other section of the regs., maybe 50.59, 50.54, or maybe in Part 73 or create some new rule that gets at the more basic issue of safety-security interface.

And I think what you're seeing here -- and there is general agreement, obviously, between NRR and NSIR as indicated by this memo that went up on 50.46, that this is the approach that staff thinks is the right one to take.

And so based on that, the initial language that we had proposed for this manual actions rule was withdrawn in lieu of doing a more permanent thing.

Now, that is a long-term effort, obviously, and so in the interim there is a safety-security working group that the staff, you know, has put together and is starting to discuss these things.

One of the early products, if you will, will be, as Rick alluded to, is the generation of some generic communication to the industry to sort of put them on notice if they're not already that this is an issue and more to come and you need to consider these things.

CHAIRPERSON BONACA: And we were briefed yesterday from NSIR, in fact, and I cannot talk about it, but we heard about the fact that this issue is being addressed, needed a context.

MR. ROSEN: Right, and my question now is -- thank you very much. That's helpful.

MR. MORRIS: Sure.

MR. ROSEN: My question resolves itself to how does one proceed forward with the manual actions rule with this effort going on, which I applaud, when the very next step after the rule is codified is you can expect the licensee or the licensees to show up on your doorstep and say, "Here's a time line and here's some manual actions we want credit for."

But those won't have any security thought process imbedded in it because you took those words out of the rule, which I think you ought to do.

I think these things need to come together at some point so that actions on the operator manual action thing can go forward. Otherwise they're going to be stopped.

CHAIRPERSON BONACA: Well, I thought that one difference between what I envision here and what I envision there was the dimension of the fact.

MR. ROSEN: Dimension?

CHAIRPERSON BONACA: Dimension of the --

MR. ROSEN: And the condition?

CHAIRPERSON BONACA: And the conditions of the plant.

MR. ROSEN: I don't know. I think we need a regulatory solution rather than an event driven solution.

MR. SIEBER: I would guess that there will be a companion reg. guide that tells you how to do the analysis and construct the time line.

MR. ROSEN: Yeah, that reg. guide is already written, Jack, but it doesn't take into account security. There's nothing in it about security now.

MS. BLACK: That's correct, Steve.

This is Suzie Black.

And it's thought that the security considerations should be put in another guidance document that would be more broad. There are already other manual actions that are being taken in the plant's fire production and other manual actions that aren't related to fires.

And we believe that this interface is already happening or this communication will remind the industry that they should be mindful of these interactions between plant operators out in the field doing work which may or may not relate to a fire and the interface that they have with security and also the security guards doing things that may interfere with safety of the operation of the plant.

But we think it's appropriate to have that guidance somewhere else, and so I think that this guidance document that goes out with this rule will not even touch this subject. This subject will be discussed through this other communication.

MR. ROSEN: Right. I understand that, and I think that's appropriate, but how do you get these two rules to come together is the question.

MS. BLACK: You don't need to have these two rules come together because right now this type of evaluation of the adequacy of manual actions is already ongoing in other areas, and this is just codifying one addition place where they can do manual actions.

They already do them under 3(g)(3) or 3(b(1)(A) or like swap over to the sump for recirculation for a LOCA.

MR. ROSEN: So you think adequate guidance exists now or --

MS. BLACK: No, I think that's exactly why NSIR is developing this additional guidance, but to the extent that the guidance is out there currently that we don't think anything special or different should be done for this 3(g)(2)(A) small piece; that the status quo that is currently underway when licensees evaluate any change to their plant is applicable to this as well.

CHAIRPERSON BONACA: I just need to understand that. The current Appendix R regulation does not address security concerns, right?

MS. BLACK: Correct.

CHAIRPERSON BONACA: So this seems to me as a clarification regarding the ability of licensees to leverage operator action if they follow certain specific rules of operator action. You know, I don't see why we should introduce now a security issue into this modification. It seems to be a limited scope modification.

I agree with you your concerns. I mean, at some point it has to be addressed, and we heard yesterday one way in which it can be addressed, but in the context of this regulation, I think I actually am pleased to see that it is taken out of the table because that would have confused the issue. There would have been not only allowing manual action, but also introducing now this FT security link that isn't in the regulation.

MR. ROSEN: Right. The fact that they

took it out of this rulemaking is a good thing. I'm still concerned though that should things go swimmingly and you get done, 75 days from now you have limited public comments, and you go to rulemaking and you make the rule, and then you have licensees free to come in and ask to take credit for these actions, ought to take credit for them depending on how you exactly do that.

But you won't have guidance in place for them to do it in a security context.

MR. HANNON: Steve, this is John Hannon. I'd like to address that.

I think it's a fair expectation that by the time the rule is issued that we can expect to have some guidance out on the street that would be coming from the security interface. So you wouldn't be faced with a situation where you'd have a rule that had gotten implemented without the security-safety interface guidance being published.

MR. ROSEN: Okay. I hope that's true. I mean, I think this rule is needed. It helps the agency, and it helps the stakeholders. So I would not be -- I would be unhappy to find out that once the rule was promulgated the staff is saying, well, we can't accept requests to deal with it in this way, even though we have a codified rule because we haven't fully addressed the security interface.

MS. BLACK: But, Steve, I think that there's 805 out there right now that licensees can adopt that has exactly the same issue because licensees could say, "I want to substitute the manual action for a fire barrier," and do the evaluation themselves right now.

So I don't think it's unique to this rule. I think it is, indeed, something that we need to focus on, but I don't think it should stand in the way of any small regulatory improvement.

MR. ROSEN: Okay. I understand. Thank you.

MR. RASMUSSEN: Okay. Then I'll turn it over to Sunil.

MR. WEERAKKODY: My name is Sunil Weerakkody. I'm the chief fire protection in NRR.

We briefed the subcommittee, you know, last week about this rule, and we had a detailed presentation.

My presentation today is going to focus on a couple of the criteria that we had introduced that was of significant public interest. We could not fully answer. I know Dr. Apostolakis indicated he wants to see the criteria. I can answer those questions. There's a number of people in my staff here who remember what those criteria are, and I think they can give more information.

One of the first and foremost things that I wanted to apprise this committee of is one of the significant concerns, issues that has raised some important stakeholder concerns is in the area of compliance, and I want to make a statement here that this rule in no way condones any kind of wilful noncompliance with our regulation.

And let me explain why I say that by, you know, quickly going through the events on this side of the box.

In early 1980s, after we published the Appendix I -- I can't remember the exact date -- the staff conducted Appendix R fire protection inspections, and during this period, for your benefit let me just tell you another piece of information. When the Appendix R rule was published, there was a lawsuit against NRC, and when the court of appeals concluded that the rule can go forward, there were a couple of important issues that they brought forward.

They said to this agency you have to keep the exemption process available with respect to this rule, using like the 50.12. It's important because we were imposing this rule on a number of plants that could begin operating.

And the second thing, I think this goes to, Dr. Apostolakis, your comment. One of the weaknesses that the court of appeals pointed out was that we did not give the stakeholders enough opportunities or chances to come in and comment.

So that's why I think when you go forward with this rule, we want to make sure that these old stakeholders have enough opportunities to comment.

Having said that, I think the next important thing is while we conducted these inspections, there were cases where we found that some licensees were using manual actions in the 3D2 areas, and we pointed out that to do that they need the NRC approval. And they came in with license amendment requests of 50.12 exemptions, and we reviewed them; we approved them.

So the important thing here is that having license amendments or having manual actions in 3D2 areas is not a new thing. What is new here is codifying that.

And let me go to the next bullet here. In 1990s, we go to the 1990s. We continued our manual action or we continued our inspections, the fire protection inspections, and this is the period where the thermal lag issues came up, and that led to a higher increased use of manual actions in 3D2 areas.

And what happened was, you know, some of the licensees misinterpreted the rule, and they thought they could use manual actions without NRC approval.

In the early 2000 --

DR. APOSTOLAKIS: When you say "used," you mean take credit for.

MR. WEERAKKODY: They credited manual actions, but they failed to recognize that if they are fully committed to 3D2, they need to come to us for approval.

So when we did the inspections in early 2000, you know, as part of our triennial ROP inspections, we found a number of situations like that, and then there were meetings with all stake holders, and we I would say reached a fork in the road, which is we had a choice. We had a choice, and the choice would be to tell all the licensees who were unapproved manual actions, you'd better come in with amendments, or the other choice would have been to publish through a rule our acceptance criteria and share it within industry so that they could themselves decide whether those are acceptable or not.

And that is where we are today. I just wanted to clarify that because that's been a big issue of contention with some stakeholders.

One other thing. What we did was we realized when we had this issue in front of us that it is important for us to get out there and put more specific criteria as soon as possible for the licenses and for our inspectors. So in March of 2003, we listed the set of criteria in our inspection procedure and said, you know, these are the criteria among other things that the inspectors should use to find out whether the manual actions are feasible or not because we wanted to maintain regulatory stability while the rule is in the making.

MR. DIEC: Just a point I wanted to mention is when we say "feasible," we mean both feasible and reliable.

MR. WEERAKKODY: Let me go to the next slide.

And then David had this slide. I just wanted it for the benefit of this committee to make a couple of points here.

You know, we have in the public side as

3(g)(1), 3(g)(2) and 3(g)(3). In 3(g)(1) area, we say a particular area is a 3(g)(1) area. You expect a complete, separated trains and different like here is Train A in this area, Train B in that kind of area, and you find a lot of areas like that in the more recently built plants.

The 3(g)(2) areas have the redundant trains in the cables, and then the 3D3 areas are areas like the control room where you cannot -- you know, you have to have everything in place and really rely on alternate shutdown panels or dedicated shutdown capability for those areas.

Now, let me go to the next one here.

This is an important issue that I want to spend a couple of minutes on. You know, speaking for the fire protection program, we are very open minded and committed to risk informing anything. I mean, that is the agency's direction, and that is where we are heading.

When we looked at the manual action rulemaking, and we did consider can we risk inform this, and one of the things that I want this committee to recognize is when I say I want to risk inform a particular area, it entails a particular risk calculation. In other words, I can go to one area of a power plant, and depending on the amount of combustible, depending on how far or, you know, where the plans are, how far they are, it's a very situation specific.

The only way I can make a risk informed rule is laying out some high level goal, such as if your core damage frequency is less than this and you made defense in depth and safety margin, the principles you see in 1.174, that's how we could risk inform.

And one of the things I think most of this committee, if not all, would know is we have done that. Fifty, forty-eight (c), which was finalized just a couple of months ago, it's titled "Risk Informed Performance Based Rule," and if you know the betas (phonetic) of this rule, you know, today a licensee can adopt 805 and if they feel that our compliance with this criteria cannot be met, they can do a risk calculation, and they can show that the CDF is less than ten to the minus six. They can show to us they need defense in depth, and they can do that train analysis. In fact, they don't even have to come to us for approval. They just have to document the analysis. That's 54 --

DR. APOSTOLAKIS: It seems to me this is

the issue that was discussed in the early days when 1.174 was debated, picking and choosing, and if you are in a deterministic rule, you'll have to be deterministic. You can't take a little piece of it and risk inform that. That's what you're saying.

If you want to be risk informed, go to 50.48(c) and do the whole thing in a risk based way.

MR. WEERAKKODY: And that's exactly, Dr. Apostolakis, and that's the basis for saying that. When a licensee commits to 805, they go through a transition, and when they go through this transition, they make sure and we make sure they have the right program, right elements to be in that plan.

And once they're in that plan we back off and we let them manage their plant by core damage frequency and defense in depth. And we have very limited capability to do pick a deterministic rule and plug in the Ps and say you can do this.

However, we recognize that, you know, there would be a large number of plants out there who don't want to change the program. For them the 50.12, 1.174 for exemption process is available.

My staff, even though we are fire protection, we have started receiving and reviewing 1.174 applications. We can do that. The process is out there and already a couple of licensees are taking advantage.

So the path is available. So we are committed to risk informing, but we are trying to put a --

DR. APOSTOLAKIS: But if they use 1.174, they would have to consider the whole fire issue, right, not just this particular piece?

MR. WEERAKKODY: Under 1.174 the licensees have the capability and the right, I would say -- it's a process that is available. The only difference, Dr. Apostolakis, is if they use 1.174, they need to come to us, get it reviewed and approved. If they adopt 805, they don't even have to come to us. They have adopted it, and then --

DR. APOSTOLAKIS: But can they do a 1.174 or can they apply using that and look only at the operator action with the probability? I mean, it seems to me they would have to clarify a risk assessment, wouldn't they?

MR. ROSEN: They would.

DR. APOSTOLAKIS: In which case they're coming close to 50.48(c).

MR. ROSEN: Right. All the way over on the right-hand side of the spectrum is 50.48(c).

Where the staff has been in Appendix R space is all the way on the other side of the spectrum, in full compliance.

What this rule is an attempt to do is to move a little bit off the full compliance role in setting up a time line approach. It's not quantitative, and it's not a PRA, but it does consider the elements of the sequence.

So to that extent it has some of the elements of risk analysis in it. My trouble with this is that even though the staff has put in that risk element in the time line, which is good, they've stuck to this requirement for requiring fire detection and suppression in the area of the fire in order to take credit for manual actions in areas remote from the fire.

And that to me is so deterministic that it pegs the meter on the left-hand side.

CHAIRPERSON BONACA: Detection is because, I mean, you have to know that you have a fire or to --

MR. ROSEN: Yeah, one could -- yeah, the detection part make a whole lot more sense than the suppression part, but if you had detection and suppression in a fire area, the likelihood is you will not need manual actions because the fire will be put out. It seems to me much more reasonable to level the playing field and simply say you can ask for credit for a manual action, even for a fire in an area that doesn't have detection and suppression, but you have to take that account into account in the time it requires you to detect the fire in an area that doesn't have detection, and the fact that the fire will burn unsuppressed shortens the amount of time you're going to have to take actions.

You can deal with that in the time line, and to my -- you know, we had this discussion at length in the subcommittee, and we didn't reach a resolution, and I think the issue is still on the table.

I'll give you another opportunity to--

MR. WEERAKKODY: Yeah, I will be coming to that in mine two slides from now, yes.

DR. APOSTOLAKIS: I'm a little bit puzzled by the whole slide here. Why are you showing us this?

MR. WEERAKKODY: Well, the purpose of showing it is this is one of the issues that when we had the ACRS subcommittee meeting --

DR. APOSTOLAKIS: Oh, the subcommittee raised it.

MR. WEERAKKODY: -- at the subcommittee

meeting, this is the issue. I think it is a very valid question to pose to the staff. Given that the 1995 PRA told us to risk inform, why aren't you risk informing this rule?

And I am I think explaining. We tried.

DR. APOSTOLAKIS: The subcommittee asked for it. You're doing the right thing.

MR. WEERAKKODY: Yes.

MR. ROSEN: That's right, and I just stated as best I could my position. I'm not sure the other members of the subcommittee were exactly on board with what I said or where they stood with respect to the staff's position. So we'll have a chance to discuss that.

And the answer to your question is the reason the slide is up there is to put that issue on the table for the full committee so that we could have a chance to talk about it.

MR. WEERAKKODY: I mean, a summary answer is --

DR. APOSTOLAKIS: It sounds like you're protesting too much.

MR. WEERAKKODY: In summary, we have had these discussions. My point is to risk inform, the only way to do that is to set high level criteria, the core damage frequency level. We have done that. In fact, internally we brag in our section that there is no other rule that you can point to that I know of in 10 CFR that uses core damage frequency as acceptance criteria, except 50.48(c).

So it's there. It's an FPA --

MR. ROSEN: Yes, but how many people have taken advantage of 50.48?

MR. WEERAKKODY: No one yet.

MR. ROSEN: No one.

MR. WEERAKKODY: Yes.

MR. ROSEN: How many people do you think will take credit for operating manual actions presumably?

MR. WEERAKKODY: I would say maybe 50, 50 plants at least because there are some plants who are not bound by 3D2, and that could be half of the population. They are not legally bound by the exact language.

CHAIRPERSON BONACA: Let me ask you a question because I only got half of the answer. Detection and suppression now, detection makes sense. Okay? I want to know that you can detect it so that the guy can come in and say, "Oh, there is a fire."

Why do you have to have also automatic

suppression to take credit for operator action?

MR. WEERAKKODY: I can --

DR. APOSTOLAKIS: Are you coming to this later?

MR. WEERAKKODY: There's a slide on the section on suppression.

CHAIRPERSON BONACA: Oh, all right. I was just trying to understand the logic. I mean, here we are challenging the logic of what you have. So I'm trying to understand the logic.

MR. ROSEN: I'm waiting for the answer.

DR. APOSTOLAKIS: Give the guy a chance.

CHAIRPERSON BONACA: Yes.

DR. APOSTOLAKIS: Give us all the answers right now.

(Laughter.)

MR. ROSEN: We only have -- yeah, go ahead. You've got 45 more minutes.

MR. WEERAKKODY: I have?

DR. APOSTOLAKIS: Less.

MR. WEERAKKODY: I don't need that much..

MR. ROSEN: Oh, we have an industry presentation.

DR. APOSTOLAKIS: If I interrupt --

MR. ROSEN: Thirty-five.

MR. WEERAKKODY: Let's go to the next slide, acceptance criteria. These are not the acceptance criteria in word by word as they appear in the rule, but this --

DR. APOSTOLAKIS: Now, why did you need that parentheses there? "Ensures low probability of failure." This is a deterministic group.

MR. WEERAKKODY: But as Chairman Rosen pointed out, what we did was one of the things we received from all our stakeholders has been simple feasibility is not sufficient. Our acceptance criteria has to make sure that there is reliability.

DR. APOSTOLAKIS: So how do you decide that?

MR. WEERAKKODY: Okay. One way, one solution was this quantification, and we knew going in that first off to get consensus model to do HRA quantifications, that's going to be a challenge.

The second challenge would be even if it was successful, the questions on the uncertainties in terms of implementation, that could be a challenge.

But what we did was -- and the Office of Research helped us out -- they formed an expert panel and went through the type of issues that are looked at under HRA and looked at those qualitatively and tired to factor those things with a time margin.

In other words, rather than saying if you need ten minutes or 20 minutes, having exactly 20 minutes to perform the action is not sufficient. You need to have some margin, and when that margin is decided, that was done by looking at the --

DR. WALLIS: Is it just time?

DR. APOSTOLAKIS: Yeah, it's not just time.

DR. WALLIS: The subcommittee you were talking about an operator having to find a ladder and to put it up against something and climb up and turn something. Presumably he could fall off the ladder or the ladder could be misplaced. All kinds of things could go wrong.

DR. APOSTOLAKIS: There could be a lot of smoke around.

DR. WALLIS: Not just time.

DR. APOSTOLAKIS: Smoke.

MR. WEERAKKODY: It's the uncertainties.

MR. DIEC: It has the elements you mentioned.

CHAIRPERSON BONACA: I'm anxious to get to the point. Could you proceed with the presentation?

MR. WEERAKKODY: Yes.

MR. ROSEN: The answer is it's not just time. All those other things are considered.

MR. WEERAKKODY: And the second bullet is permit both licensees and NRC to establish consistency as to what operator manual actions will be allowed.

One of the problems we have encountered consistently in fire protection and that has led to a lot of questions is the lack of clarity in our regulations. And I think the acceptance, when we deal with acceptance criteria, we tried very hard to come up with a set of objective criteria so when an inspector interferes us with the licensee, there is a clear expectation of what is needed. And that was something that we looked for when we deal with acceptance criteria.

DR. WALLIS: And you're going to explain acceptance criteria to us then?

DR. APOSTOLAKIS: He just said it's expert opinion.

MR. WEERAKKODY: That is the --

MR. ROSEN: That's the next slide, right?

DR. APOSTOLAKIS: is it?

MR. ROSEN: Slide 11. I don't know what you're on. I have 11.

DR. WALLIS: I think the only acceptance

criterion seems to be time.

MR. WEERAKKODY: I think, Dr. Wallis, I think what is missing so far, and it seems like both you and Dr. Apostolakis are asking, you know, and we had a slide in our previous presentation where we had listed the eight to nine -- actually do you have a copy?

There was one slide where we summarized. What I think we could do is not the rule language. There was like one slide.

DR. WALLIS: The reason for asking these questions is the column with the present situation is there is vagueness. We're not quite sure. The operator isn't quite sure. The licensee isn't quite sure if his operations are going to be acceptable. It seems to me uncertainty.

And the whole idea of the rule is to clarify this and have some fair criteria so that the licensee understands when he's in compliance. Isn't that the whole idea of the rule?

And all of this other stuff about risk informing is irrelevant.

MR. WEERAKKODY: Right, yes. I think what I am saying, Dr. Wallis, is I can go over the eight items that are in our acceptance criteria.

DR. APOSTOLAKIS: Give us a few.

MR. WEERAKKODY: Okay. One of the things we look for is the environmental conditions. Let me just quickly go through the bullets. We looked at the functionality of an accessibility to the two frontal cables.

We look at the availability of the indications for diagnoses.

We look at and insure whether the communication, the radios, crates, et cetera, are available.

We look at whether the portable support equipment are there.

For that particular fire scenario if life support systems, equipment are needed, we make sure that those things are ready to go, like a SCBAs and protective gear.

And then we look at a fire time line.

So the seven items I listed here, what you would find in the rule language, these explanations, not just one word as to what, exactly what it means.

Now, if I take an example of something from --

MR. KLEIN: Sunil, excuse me. This is Alex Klein. I'm a fire protection engineer. I work for Sunil.

There are a couple of more criteria that I'd like to mention just to clarify that there is more to the criteria.

We have criteria in the rule for procedures and for training. We have a criterion on implementation. In other words, the staffing, is the staffing available?

DR. APOSTOLAKIS: How does one train for a fire when there may be smoke in the real thing? How do you do that?

MR. KLEIN: That's a very good question, and that's through the criterion labeled demonstration, and what we do is we've provided some guidance where we ask the licensee to -- there are, of course, certain limitations with respect to simulation, smoke and so forth, and the environment, and that's where the time margin is also taken into account.

And I believe that when the expert elicitation panel got together, they took into account things like the fact when a licensee demonstrates an operator manual action, that he can't introduce smoke into the environment. You can't introduce the fact that there might be active fire fighting suppression activities going on. So I believe that when the expert elicitation panel sat down, they took into account the fact that licensees would be limited to how much they could actually simulate when they performed the demonstration.

DR. APOSTOLAKIS: Do you remember any names of these experts?

PARTICIPANT: Gareth Parry.

MR. GALLUCCI: This is Ray Gallucci. I wasn't on the panel, but I worked with the panel.

Gareth Parry was on it. Rebecca Nease, Senior Regional Inspector; Marty Kazarians consulting to Sandia on fire protection; Jim Bongarra, a senior engineer here at NRC; Michael Jung, who is in the PRA Branch; and Peter Coltay (phonetic).

DR. APOSTOLAKIS: So there was nobody --

MR. GALLUCCI: No, no, but several people had -- Michael Jung had been an SRO. Alan Kolaczkowski and John Forrester were the coordinators.

CHAIRPERSON BONACA: Please let me just interfere if I could for a second because, Jack, we have spent almost an hour dancing around the issue of what are you proposing. You know, you're telling we don't want to go risk informing because, et cetera. These are all of the discussions you had on the subcommittee, but we were not a subcommittee.

I need to understand. Now, the only page where I find some criteria is page 12. Maybe we should go to that page. Is it what you're proposing there? Could you explain to us what is this change? I mean, I don't know how many other members are at the subcommittee meeting, but for those who weren't we need to understand this.

CHAIRPERSON BONACA: What page is it?

MR. WEERAKKODY: No, it's not on page 2. I guess what we will do, Dr. Bonaca, I am going to ask Rick to -- can we make ten copies of the rule itself and bring it over?

What we will do is give me a few more minutes to go over the other slides, and what they will do is bring --

MR. ROSEN: Bring what?

MR. WEERAKKODY: -- bring the rule criteria to share with you because I think what Dr. Bonaca is saying is that, you know, he hasn't seen the rule criterion.

MS. BLACK: Well, I think the package we sent to you in advance, that included the proposed rule statement of considerations. At the end of that package is the actual rule language, which does list these acceptance --

MR. ROSEN: Of course, and we all have -- we have that. We have the rule language. We have the regulatory guide. We have the regulatory analysis and one more thing. I forget what. We had four things.

DR. APOSTOLAKIS: Yeah, but it is customary during the presentation to summarize those things. You don't just once in here and say we had them. Yeah, you had them and you must have read them.

MR. WEERAKKODY: We could do that. What I'm hearing on the -- the more contentious fact here, but I will go with the other ones.

DR. SHACK: Somewhere before we finish, the issue I would like to get to is why you think you need the automatic suppression.

CHAIRPERSON BONACA: I've been asking several times.

DR. APOSTOLAKIS: We all want to see that.

DR. SHACK: If we could just aim at that particular topic.

MR. WEERAKKODY: Okay. So let's do that now.

CHAIRPERSON BONACA: Because that's the only thing that we really -- that we had ever prepared before, had read before, were those two issues. Okay?

And the issues were contentious in the sense that why do you need that, and it seems to me in the presentation of the industry the same point is made.

So return to the extended basis for saying if you want to have manual option allowed, you have to have all sorts of multi-file process suppression (phonetic), and I'm trying to understand the connection there.

DR. SHACK: The connection. The nexus as we say.

MR. WEERAKKODY: Let me do that, that and that.

DR. APOSTOLAKIS: Okay. Go ahead.

MR. WEERAKKODY: What you see pictorially here is in 3(g)(2) we had three ways to meet the 3(g)(2). One was to have a three out of five barrier. The other was to have a 20 foot separation without intervening combustibles and with suppression and detectors, one our fire barrier with fire detection and suppression, and the one that we are adding is overt actions with --

DR. APOSTOLAKIS: So this is "or."

MR. WEERAKKODY: This is "or," after the --

DR. APOSTOLAKIS: This is "or," "or."

MR. WEERAKKODY: Yes.

DR. APOSTOLAKIS: Okay.

MR. WEERAKKODY: Now, when we were working on the proposed rules, we did ask ourselves should the operator manual actions have the acceptance criteria, and we looked at a number of things.

And, again, one of the things that we recognized was we are looking at 3(g)(2), which means if you assume that a fire happens here and we just let it burn without any kind of suppression or detection, what that means is we are letting the two trains that we rely on --

DR. WALLIS: Well, now I'm really puzzled. You just have a fire and you let it burn?

MR. WEERAKKODY: If we --

DR. APOSTOLAKIS: He says if we let it.

MR. WEERAKKODY: If we do not have --

DR. WALLIS: But do you ever do that?

MR. WEERAKKODY: We don't -- we are not proposing we do that.

DR. APOSTOLAKIS: It's a hypothetical.

MR. WEERAKKODY: It's a hypothetical. If we do not have a fire detection and an automatic fire suppression or a fixed fire suppression system to mitigate that fire, we will be relying solely and only on a manual action to bring this plant to a hot standby.

One of the things that me and all the staff who worked on this issue realized was a manual action's reliability, typically they are not very high. They could be a .2, .1, and if they're highly reliable, maybe a .01, and from a difference in depth aspect -- in other words, you have a fire, and there's one other action that you rely on to prevent or to do shutdown, which is in this case the manual action, we did not want to have a situation where we are relying on a manual action whose failure probability may be a .2.

And it's hard to quantify or upper bound failure probability for the manual actions for all of the situations out there.

DR. APOSTOLAKIS: So what you're saying is that the suppression system, in fact, may save one of the trains?

MR. WEERAKKODY: Yes.

DR. SHACK: Without a barrier of any sort.

MR. WEERAKKODY: Even without a barrier. And we have discussed this a lot within the staff. Three D2 area has to be done in cable. So the choice that the staff has made --

MR. ROSEN: Into the microphone, please.

MR. WEERAKKODY: The choice that we had to make was are we as regulators going to say I'm going to rely on the manual action and, therefore, I have one success part whose failure probability I do not know, but which we know can be sometimes high and say not have that requirement or are we going to put that as a requirement?

Now, we chose in our proposed rule, and we are keeping a very open mind on this during the public comment period. We chose for the proposed rule as regulators we need to put that as a requirement because, you know, knowing full well that in some situations maybe that could introduce unnecessary --

DR. APOSTOLAKIS: What is a suppressant?

MR. WEERAKKODY: The suppression system could be a fixed water system that -- go ahead. Alex of my staff is an operative.

MR. KLEIN: Yes. A fire suppression system can consist of a water based system, for example, a sprinkler system, much like --

DR. APOSTOLAKIS: Wouldn't that accelerate a failure?

MR. ROSEN: No, it puts fires out

DR. APOSTOLAKIS: The electric shorts are not --

MR. ROSEN: But by far the most important thing is to put the fire out.

DR. SHACK: But what are the chances that you can actually send a signal through after the suppression system comes on and dowses everything?

MR. KLEIN: It was one of the lessons learned with the Brown's Ferry fire. One of the lessons learned was to apply water.

DR. APOSTOLAKIS: I k now, I know. When in doubt either complete the square or put water on it, and water is reasonable. But if you have partial damage. Water may actually do damage, but anyway, I understand the argument now.

MR. SIEBER: But there are other fire suppressants.

MR. KLEIN: Yes, that's correct. There are gaseous fire suppression systems also.

MR. ROSEN: The principle of fire protection, the overarching principle is to put the fire out. Put the fire out. It's not so hard to understand.

DR. APOSTOLAKIS: This argument is different.

MR. ROSEN: The other things are potential consequences of putting the fire out.

DR. SHACK: But we also want to shut the reactor down, and he's arguing that it should take some credit for that if you had the fire suppression system.

DR. KRESS: Well, what I gather from what he has said, George, is you have two trains to shut this thing down. If you have a 20 foot separation between them, the fire in one area is probably not going to affect the one in the other. If you have a one hour fire barrier, you can say the same thing.

If you have neither of those you'd better have a fire suppression system on them because the fire in one place is going to affect the train in the other. That's what I gather.

MR. ROSEN: Well, that's true, but why should then one say you can't take credit for an operator manual action in an area completely remote from the fire?

DR. KRESS: I'm saying you have to have it. If the train is fairly close together.

MR. ROSEN: Well, yeah, but he's not talking --

DR. SHACK: And he's only talking two ways to get the system shut down, and that seems to me reasonable enough.

DR. APOSTOLAKIS: He wants to have defense in depth.

MR. ROSEN: But that has nothing to od with giving credit for operator manual action.

MR. SIEBER: Well, wait a minute. This rule is the 3(g)(2) rule.

MR. ROSEN: I'm the chairman of the committee. I think I ought to be given a chance to try to explain this because the staff has not.

(Laughter.)

MR. ROSEN: This chart you see in front of you, think of it as columns, four columns. The staff is saying the first three columns are roughly equivalent. In other words, you can take credit for a three-hour fire barrier in an area or, or you can take credit if you have 20 feet of separation with no intervening combustibles, or you could take credit for a one-hour fire barrier if you have fire detectors and automatic suppression.

Do you see those things above in the columns? That's what the current rule says. For a 20 foot separation in one hour, you have to have fire detectors and automatic fire suppression. You don't need that for a three-hour fire.

Now, they're adding to that operator manual actions, and they're saying for cases we have operator manual actions, they want parallelism with the 3(g)(2)(b) and 3(g)(2)(c).

CHAIRPERSON BONACA: That means in this case you have one-hour fire barrier. You have no 20 foot separation. There is no three-hour --

MR. ROSEN: That's the staff's argument.

CHAIRPERSON BONACA: -- and therefore you want to have automatic fire suppression and fire detectors above.

MR. ROSEN: That's the staff's argument. Now, the argument that I offer and maybe some of the other members will offer at the subcommittee -- I don't know -- is if you're going to analyze operator manual actions in accordance with the reg. guide that has all of that PRA-like stuff, you know, if you consider the time line and you add a margin, a factor of two on the time line and you have all of the considerations of communications, life support equipment, can you really do it feasibly and reliably?

Why prejudice, why bias the result by saying you've got to have fire detection and automatic suppression, too, just because of the parallelism argument with what you now have in 3(g)(2)?

Now, I grant part of that argument which is if you don't know about the fire, fire detectors, well, then maybe the thing burned uncontrollably for a long time. Having been in plants for my entire career, I know that's not true. I mean fires tend to get noticed fairly soon.

But I could understand the arguments of detection, but I really do not understand the argument for suppression, except in this construct that you put up up here. The parallelism construct, we have to maintain that. That's a deterministic, compliance based construct.

CHAIRPERSON BONACA: I think one thing I could postulate, however, Steve, I mean, would be, for example, given that I have this room with equipment and trains that are less than 20 feet apart, I don't have any fire barrier in between. Okay. The likelihood of operators manual action success is not that great.

MR. ROSEN: Why? They're not even in that room. They're in a separate room doing actions that are intended to combat the fact that both trains in that room burned down.

They could be completely in another building.

DR. APOSTOLAKIS: The question is how reliable do you think that action is? And the staff's argument as I understand it is a classic defense in depth argument. We have large uncertainty. We want an excellent defense in depth.

MR. ROSEN: Well, but the staff's argument is only true if the actions are complicated. In other words, if they're very simple actions, if the fire starts out in our conference room on the other side and all I have to do in the control room is go outside the control room door and turn a switch, it is obvious to me that I can do that and with a very high reliability. So the argument isn't perfect.

For very simple operator manual actions, one can do it without suppression and detection in that area.

DR. APOSTOLAKIS: You have to appreciate though they are not really dealing with one specific situation and another specific situation. They are trying to have a rule.

MR. ROSEN: Of course, of course.

DR. APOSTOLAKIS: And there may be situations where it's not so obvious and simple.

MR. ROSEN: That's right. That's why you do the time line. The time line shows whether the actions are complicated or not, whether they're feasible and reliable.. For a very simple action I maintain the time line will show you can do that without suppression or detection probably.

I'm willing to give in on detection.

DR. WALLIS: Will you explain to me why you don't want to suppress the fire? I don't understand that.

MR. ROSEN: If you say it that way it characterizes pejorative. I didn't say anything about not wanting to suppress the fire.

DR. APOSTOLAKIS: Well, why do you want to do away with this.

MR. ROSEN: I do not want it to go away. I want simply to be able to analyze it realistically.

DR. APOSTOLAKIS: No, you said you wanted to replace this automatic fire suppression. You want to get the operator manual action to go up another step, don't you?

DR. APOSTOLAKIS: Yeah, to be a separate colony for --

MR. ROSEN: I don't want to require automatic suppression across the board because there are actions that are simply not needed, and if we allow that and if that's what we recommend to the

Commission, that they put this in place, we will not meet the objectives of this rule.

DR. SHACK: But that's the same with 20 foot separation. I don't need fire suppression a lot of the time either. You know, it's a small fire. They're far away, but when you're writing the rule, you write the rule with the fire suppression and the 25th separation.

MR. ROSEN: But then nobody will come in for approval under the operator manual action criteria. It's basically going to end up being essentially an empty set. This whole discussion will have been valueless.

I will not if I'm a licensee come in for approval of an operator manual action if I have to first go in and put in automatic suppression and detection. I don't need to. Once I put in automatic suppression, it detects it. I don't need credit for an operator manual action.

CHAIRPERSON BONACA: The question is important here. Are you telling me that, no, I would expect the plants surrounding today so that they either have three hour fire barrier or they have 20 feet separation, automatic fire suppression, and fire -- is it in existence now?

DR. APOSTOLAKIS: Yeah, that was my question, too.

CHAIRPERSON BONACA: And so, therefore, I'm saying you're looking at other action that the licensee may come with, are not going to tie my substitute for areas where there is no automatic fire suppression or fire detector right now, is it?

DR. KRESS: Our understanding was that some of them are. We're operating with the operator action --

MR. ROSEN: They're taking credit for that action, and now the question is: will they get cited for noncompliance? Will they come in for an exemption or will this rule cover them?

What I hear all being argued by some of the members of this committee is they'd rather have the licensees come in for exemptions on the 50.12, and I think that would exactly be the reverse of what this was intended to achieve.

DR. SHACK: When you've given credit for manual actions, have you always required fire suppression?

MR. WEERAKKODY: When a license amendment comes to us, there have been cases where we have approved those amendments without suppression, but let me explain why. Then at that point we have the opportunity to find out how much combustibles are there. Like, for example, I know my staff who is not here today, he said, you know, he had received an approved amendment where the licensee would say in this area you have no combustibles, no ignition sources. It's classified as G(2), but then the staff is satisfied that it's safe.

And one of the other things I wanted to make a remark is I know most of these members, you know, you like numeric, but let me just be the numerator. I know Dr. Wallis is saying that.

We all know that if you look at the fire frequencies in areas, they may be in the order of maybe one in 1,000 or let's say one in 10,000. As the NRC people responsible for the safety of those out plants, I want to make sure that when I make the rule I'm not letting greater than ten to the minus five kind of actions out there without our approval or some examination.

So if I'm saying my fire frequency is one in 10,000 and if I say my failure probability of the manual action is a .1, okay, a number of us have done HRA calculations, and those numbers come out not .01 and not .03. In most cases they come out at .2, .1, sometimes .3. In some cases they come out at .01.

Sitting here in the head of this, I don't know what that number is. So given that, when we make the rule, we want to be able to say we have maintained adequate protection out there.

What I am saying is unless I see a risk calculation or unless I see a license amendment, like you said, that tells me here's how much combustibles, we cannot say all situations out there provide adequate protection without --

MR. ROSEN: But you have that covered, Sunil, with the requirement for the time line and the action in the reg. guide.

DR. APOSTOLAKIS: Can you tell us what the time line is?

MR. ROSEN: It's in the --

MR. WEERAKKODY: The next page.

DR. WALLIS: That has nothing to do with the requirement for fire suppression. The only time you wouldn't have fire suppression would be if you had a room with no combustibles in it.

MR. WEERAKKODY: That is the one I clearly know. There may be other cases where we might approve it for some other reason, but this is the one that stuck in my mind because I asked my staff, "When did you guys approve some of this?"

DR. WALLIS: Are there other really instances out there in the plant where they don't have automatic fire suppression and they have combustibles around?

MR. WEERAKKODY: Well, there could be another case, Dr. Wallis. Let's say, for example --

DR. WALLIS: Does that exist out there?

MR. ROSEN: I should think so.

MR. WEERAKKODY: I believe so. Do you have an answer to that?

DR. APOSTOLAKIS: Why is the time line so important?

MR. WEERAKKODY: Can you give a better answer to Dr. Wallis' question?

MR. KLEIN: With respect to any specific license amendments?

DR. WALLIS: I'm sort of in favor of having automatic fire suppression. I just want to know a situation where it might be absurd to require it so that my own preference could be demolished. I think that normally you would expect to have fire suppression installed.

MR. KLEIN: It could be a situation, Dr. Wallis, where you might have a very large fire area, large volume, where you might have combustibles, for example. You might have Train A on the left side of this large volume and Train B on the right side of this volume.

DR. WALLIS: Twenty foot in between?

MR. KLEIN: You've got more than 20 feet. You've got some large distance in between.

MR. WEERAKKODY: No, I think --

DR. WALLIS: Then you're covered.

MR. WEERAKKODY: Then you're covered in here. I'll give you a better situation. You may have -- and I broke down some plants where there's this big area. It gets labeled as 3D2 because in the big area you have Train A and B cables running through.

However, when you walk in the area, you find these two cable trays crossing, and they may be even horizontally apart, 13 feet apart, okay, and you look around. It's all empty. There's no pumps, no combustibles there.

Clearly, we would approve something like that, but then we also looked at, and I have walked through some other plants, where you have the Train A and B cables with the HPCI Pump A, HPCI Pump B, LPSI Pump A, LPSI pump -- all in this one area, and I would say that's a situation where --

MR. ROSEN: Where fixed suppression makes sense.

MR. WEERAKKODY: -- you need, you definitely need detection and suppression.

So I think the point I am making here is that when we make the rule, I do not know unless it is a fully risk informed rule like 50.48(c), to say, okay, for these cases you don't need detection suppression, but we would recognize and we have always recognized and in all public meetings that this requirement is going to create some unnecessary conservatisms, and that could be solved with amendments, license amendments.

But we don't look at those amendments as unnecessary amendments. We look at those as necessary amendments that has a role to play.

Do you want to go to the next one on the time?

MR. ROSEN: We'd better get on with it.

DR. SHACK: Mr. Rosen thinks this provides sufficient margin when you look at the time line, and I guess that's really the question.

MR. ROSEN: That's right.

DR. SHACK: Either it does or it doesn't.

MR. SIEBER: You have to look at why the

20 foot separation.

MR. ROSEN: Jack, I'm going to have to ask you to -- we've only got 15 minutes left. We've got a ten minute presentation. Can we let him get through?

MR. SIEBER: I'll just say that I agree with the staff rather than the other.

MR. WEERAKKODY: Let me go to the time margin. Let me not spend a --

DR. APOSTOLAKIS: I think we're going to discuss this much more.

MR. SIEBER: I agree with you.

DR. APOSTOLAKIS: Go ahead.

MR. WEERAKKODY: Okay. Thank you, sir.

On the time margin, rather than going into a lot of detail, let me just say that we spent a lot of time, thanks to Office of Research support, dissecting the different time components and trying to come up with some kind of margin that insures reliability of the manual action.

Now, as Chairman Rosen says, it is possible that in some situations that this time margin would give you such good reliability that if you do a calculation you can show the core damage frequency is less than ten to the minus six.

DR. APOSTOLAKIS: I thought the whole idea of developing new models for HRA was to get away from this.

MR. ROSEN: We're not doing HRA here. We're just doing a sequence analysis.

DR. APOSTOLAKIS: It doesn't matter what you're doing. In the early days we said time is the most critical dimension here for performance of the operators, and develop models and all of that, and then the whole world collapsed and they said, "No, that's not it. There are other things, too."

So I'm not doing HRA here, but it seems to me that this goes back in time, doesn't it?

MS. LOIS: Can I answer this question?

DR. APOSTOLAKIS: Yeah.

MS. LOIS: This is Erasmia Lois, the Office of Research.

I totally agree with you that HRA takes into consideration many other human performance aspects, but what happens is with this specifically, apparently the acceptance criteria, the qualitative acceptance criteria, were not discussed here in any kind of detail.

But when we got together and we tried to address the accommodation of the ACRS to consider HRA risk insights as part of this rule, we recognized that many of the human performance issues, performance shaping factors, for example, that are considered as part of HRA are taken into consideration through the acceptance criteria: staffing procedures, availability of equipment, CBAs. All of that is part of the rule.

And in addition to the reg. guide requires the licensees to have demonstrated the feasibility of their actions, and, therefore, a lot of the uncertainty has been removed.

Now, the remaining uncertainty, which is what about if the guy falls off the ladder or what about if the guy, you know -- it's smoke in the room and, therefore, he has to put on the CBA, et cetera. That part of the uncertainty, we thought that it can be addressed through the time margin. Otherwise we would have to develop HRA methodology and data that would have, you know, variance issue approved and the licenses should also agree with and it would have been a much more detailed analysis needed, that we thought that probably not needed for this specific issues.

DR. APOSTOLAKIS: To me the issue of smoke is a key issue here. If they don't see where they're going, you know, they have to wear heavy equipment and so on, time may be affected significantly.

MR. ROSEN: That's why you do the time analysis. If they have to go into an area in which there is smoke, you have to show that there's adequate time to do that.

DR. APOSTOLAKIS: So there's guidance how to calculate, estimate those times, diagnosis and implementation time?

MR. GALLUCCI: This is Ray Gallucci, who also worked on the reg. guide.

Yes. In order to establish a time margin, you must first do a demonstration which assumes that all of the previous criteria, environmental conditions, et cetera, are met.

But just a summary point on some other items here. What Dr. Rosen was saying about being able to incorporate detection and suppression in the analysis, and what you, Dr. Apostolakis, are saying about why not just do basic HRA, the answer to that is that's what 50.48(c), NFPA, 805 provides. This is the deterministic rule where you're forced to back off from some of the ideal analytical conditions.

MR. ROSEN: All right. We need to go on because I want to talk about demonstration or else you'll have no chance to respond.

MR. WEERAKKODY: I think one of the things I wanted to comment --

MR. SIEBER: Demonstration?

MR. ROSEN: It's on your next slide. Just go ahead.

MR. WEERAKKODY: No, the next slide is the time margin.

MR. ROSEN: Well, it talks about demonstrated time.

CHAIRPERSON BONACA: Let's complete the presentation and then --

MR. ROSEN: I'm trying.

MR. WEERAKKODY: In the proposed rule we have said let's have double the time that is demonstrated, but one of the things I want to right after that say is we have in the proposal asked the question from the licensee or any other stakeholder and said to them if you could suggest better methods that we could use and in substance then we would consider them.

MR. ROSEN: Right now the rules require a demonstration of each manual action every 12 months, correct?

MR. WEERAKKODY: I believe the words are --

MR. GALLUCCI: Yes, that's correct, or classes of manual actions, not specifically every one.

MR. ROSEN: That's not what it says, but it says manual actions.

MR. GALLUCCI: Well, the reg. guide would give you that relaxation and clarify that.

MR. ROSEN: That's not what it says in the reg. guide right now. So I just wanted to know if you have anything more to say about demonstration before we adjourn on this subject.

Right now the language in the reg. guide and the rule says you have to demonstrate each action every year. It seems to me unreasonable, but go ahead.

It seems disruptive and chaotic actually.

MR. WEERAKKODY: You mentioned that in the last time, and we're going to take that as a take-back and reevaluate.

MR. GALLUCCI: That would be a rewording, specify classes of manual actions.

DR. APOSTOLAKIS: Why don't you give them more flexibility then and say, "Okay. We are convinced that the operator action is uncertain and we want an extra defense in depth measure," and right now you are saying that's a fire suppression system.

How about if somebody says, "I'll install a one hour fire barrier"?

DR. SHACK: He's already done it. He moves to the other column.

DR. APOSTOLAKIS: Then he moves to the other and you still need the suppression.

MR. WEERAKKODY: They have installed three hour.

CHAIRPERSON BONACA: I think manual action is always an alternate for the one hour barrier.

DR. APOSTOLAKIS: Yeah.

MR. WEERAKKODY: Or the 20 foot.

DR. KRESS: What fixes T3?

DR. SHACK: That's the time you need to do the action.

DR. KRESS: I know, but I could pick one out of the air?

DR. SHACK: No, it's a thermal hydraulic.

DR. WALLIS: It's about 100 percent in time.

DR. SHACK: It's whatever action you're proposing to do to shut it down.

DR. WALLIS: A core disaster.

MR. ROSEN: It's the time available.

DR. KRESS: I know what the action is. I

want to know what fixes it. What determines it?

MR. SIEBER: T3 is twice T1 plus --

MS. LOIS: Are you able to preserve enough equipment from fire damage so that you can go to hot shutdown? I mean, if you can take the --

DR. KRESS: I understand the reason for it. I understand what you're doing. I just want to know what determines T3. I'll need to calculate a number. How do I calculate that number?

MR. GALLUCCI: T3 is the time from when the fire starts to when you can achieve and maintain hot shutdown conditions based on the plant's thermal hydraulic analysis, any other considerations they may have. It's something that is determined by the licensee or the inspector if the licensee hasn't determined that.

DR. KRESS: It is characteristic of the shutdown system of you reactor?

MR. GALLUCCI: Hot shutdown.

DR. KRESS: Hot shutdown. That's all I wanted to know. What was T3?

MR. ROSEN: Okay. I think we've got enough of that. Unless you've got something else to say, let's move.

MR. WEERAKKODY: No, I think unless you

have any questions, I'm more than happy to --

DR. WALLIS: This thing we've been all arguing about, is that already presently apart from the operator actions? Is that presently the rule?

MR. DIEC: It is presently in the proposed rule.

DR. WALLIS: The present rule is not ready. All you've done is stuck in --

MR. WEERAKKODY: Yes, that's correct, yes.

DR. KRESS: Yeah, but not all the plants have this fire suppression

CHAIRPERSON BONACA: This is for the Chairman of the ACRS.

MR. ROSEN: All right. I think we're ready to hear from the industry. They have requested ten minutes.

MR. EMERSON: This will be brief. This is just an update of the information we presented at the subcommittee meeting last week.

We were asked at that subcommittee meeting whether we recommended that the rulemaking proceed or not, and so this presentation is structured around the specific recommendations we have with respect to that rulemaking.

The recommendations are summarized on

Slide 2. They address the areas of automatic suppression, time margin factor, security events, which has already been covered and I won't deal with it all in this presentation, and the structure of the rule itself as to whether it should be a detailed rule or a simple rule with detail in the regulatory guide, and a request that we improve the degree of stakeholder participation in the development of these acceptance criteria.

DR. WALLIS: Is that stopping going out how? It will still go out now for comment and you'd have these commends on it.

MR. EMERSON: Yes.

DR. WALLIS: So there's no reason we should stop it from going out now for comment unless it's totally flawed.

MR. EMERSON: I don't recommend that we stop the rulemaking. I would --

DR. WALLIS: So you're recommending that it not go out for public comment.

MR. EMERSON: I am recommending that some changes be made before it does out for public comment.

The first change I would suggest is a simple rule with the text changed to (c)(1), as you see on the slide. With the acceptance criteria that are currently in the proposed Section 3(p) be in place in a regulatory guide.

The reason for that is if you put this level of detail in the acceptance criteria in the rule itself, it's a very cumbersome process to get it changes if you decide a year down the road that your criteria are wrong.

Secondly, you're going to have a great many exemption requests which kind of defeats the purpose of this rulemaking in the first place.

Security events I'll skip through since that's been covered adequately.

The only thing I would add to the discussion of automatic suppression is a reminder that automatic suppression is already provided for in fire areas according to the regulations, has been there for many years, has already been deemed adequate to address the fire hazards in any particular fire area, and it's just very difficult to see how additional suppression in those areas is going to change the operator's ability to carry out a manual action in an area complete remote from the fire area where the suppression is.

This provision will, again, defeat the purpose of the rulemaking by resulting in a lot of requests for exemptions because this will be a very expensive thing for a plant to implement, either modifications to put in suppression or to go through a number of exemptions in a large number of fire areas with little or no safety gain. That's really our basic objection to it.

In the area of time margin, again, we believe that if this provision stays in there, it isn't treating operator actions consistently for manual actions, consistently with the way they're treated for other areas of plant operations and event response, such as EOPs, severe accident management guidance, all of which use operator actions extensively for situations that are beyond the normal licensing basis.

DR. WALLIS: What are these manual actions replacing in the present rule? Maybe they're replacing the fire suppression system rather than the fire barrier.

What are they equivalent to? I have trouble telling where to put them in this matrix.

CHAIRPERSON BONACA: What, the family?

DR. WALLIS: No, the staff proposes that they're equivalent to a one hour barrier. Are you proposing that they're equivalent to a fire suppression system, the manual action?

MR. EMERSON: Well, manual actions are a different area of defense in depth. Suppression is one area of defense in depth. Prevention is another.

DR. WALLIS: Maybe there's another level and they don't replace any of these things?

MR. EMERSON: Well, manual actions I don't think directly falls into the area. It falls into the area of how are you going to deal with a fire after it has caused damage, and mixing it up with suppression we don't think is a --

DR. WALLIS: I think that's the whole problem with this diagram because I don't see how operator manual actions replace these physical things. Can you elucidate that for me somehow?

MR. EMERSON: No, because I agree with you.

DR. WALLIS: Well, how do we take account of them then?

MR. EMERSON: I think you take account of them by asking yourself whether it represents a viable way for a plant to address an accident, a fire induced damage after it has occurred, which is, again, the third element of defense in depth.

So I can't answer your question because I don't see the parallelism either.

DR. APOSTOLAKIS: Well, I mean, we keep talking about defense in depth. There is a fundamental question here. One is the one Sunil raised, but the other is the uncertainty in the operator actions.

The other is this is not the only place where we're applying defense in depth in the fire area. I mean defense in depth is all over the place, in prevention and all that stuff. So the question is do you want to apply this structuralist approach, which is really rationalist here, in every single piece of the fire protection construct or at a much higher level?

CHAIRPERSON BONACA: Yeah. No, I understand that. But there are many ways to look at a fire as a different animal. For example, the first bullet there says operator actions are not analyzed in other scenarios, et cetera.

But you know, most of the scenarios when you look at operator action in the control room, you're looking at different kinds of issues. I mean, the ability of responding to different situations, here you have smoke, for example, and smoke is a unique characteristic of fire. Heat, difficulty of locating where it is, I mean, the list when I think about it makes somewhat different this issue insofar as the time requirement. I mean there is much more uncertainty, it seems to me.

MR. EMERSON: That may or may not be true. You're not necessarily carrying out a manual action where there's any environmental problem. It may be in an area that has no smoke, has no particular heat level, has no particular environmental issue at all.

CHAIRPERSON BONACA: But it may be in some areas that problem.

MR. EMERSON: And I guess what I'm proposing is there are different ways to deal with those uncertainties than to just establish an arbitrary 100 percent time factor as a penalty. I think it just unnecessarily degrades demonstrated performance. If all of the operators demonstrate the ability to carry out a manual action in 20 minutes and you have 30 minutes to do it, and you add this 100 percent time margin factor, you automatically are going to fail in your ability to carry out the action, and that seems to be an unnecessary penalty that doesn't really help you a whole lot, given the fact that a lot of your thermal hydraulic analyses leading to this are already conservative, and this is just in our view piling a conservatism on top of conservatism with no particular gain.

You know, I would be the first one to agree that they need to be feasible and reliable, but this I don't think is going to get us there.

The net result of our recommendations is we think the rule should be simpler and flexible, and we think our recommendations would do that.

We think it maintains a safety focus with acceptance criteria in the right place where they can be changed if new technology suggests itself.

We think manual actions ought to be greater with operator actions used in other parts of the plant and event response.

DR. APOSTOLAKIS: Let me understand that. Which parts do you have in mind in the third bullet?

MR. EMERSON: Which parts?

DR. APOSTOLAKIS: Yeah, you're saying operator actions used in plant operations and event response.

MR. EMERSON: EOPs and severe accident management guidance.

MR. ROSEN: We don't double. We don't, for example, double an EOP action in time. I mean, we don't say because you have to take this action in an

EOP that you need twice as much time to take it as you really have demonstrated.

DR. APOSTOLAKIS: I'm really confused now. Is there a rule about the EOPs? Are they part of a design basis?

MR. ROSEN: No. It's just like he's making an analogy about what we do in operator actions.

DR. APOSTOLAKIS: And I'm trying to understand the analogy. Is Appendix R part of the design basis? Are the EOPs severe accident space?

CHAIRPERSON BONACA: No, EOPs are not severe accident space.

MR. EMERSON: Severe accident space is an extension of the EOPs beyond the core damage point.

DR. APOSTOLAKIS: SAMGs are there. So EOPs are still in design basis?

MR. ROSEN: Yeah, EOPs include zero, which is what you do right after you get reactor SCRAM.

DR. APOSTOLAKIS: Okay. Now I Understand.

CHAIRPERSON BONACA: I mean, I can agree in part because as I hear all of this that in the context of looking for -- creating for manual action in some scenarios where this is not a very flexible rule that he proposes. It's a pretty stiff rule. I mean, it says you should do this, this, and this.

DR. APOSTOLAKIS: As opposed to Appendix R which was --

CHAIRPERSON BONACA: No, as opposed to there would be instances where you walk down and you agree with the licensee that in this particular condition if he keep all flammable away from this area, it can be successful without having that barrier maybe between. I can see how these are a little bit stiff.

MR. EMERSON: We think you can establish performance goals for reliability instead of just legislating one particular way to do it, and a very conservative way at that.

We think there ought to be a little bit more opportunity for stakeholder input and one of those areas might have been this expert elicitation that led to this time margin factor in the first place.

And we want to reduce or eliminate the need for extensive changes to existing thermal hydraulic analyses or modifications or exemptions if they have little or no safety benefit.

That concludes my presentation.

DR. WALLIS: I'm really perplexed because it seems to me there were two things. One is what do you do physically about fires like barriers, suppression, protection, and so on. That's one level of action which should be appropriate to whatever combustibles there are and how much you want to save this area, and so on.

But then there's operator actions, and these things are two separate things it seems to me, and each should be appropriate, and they should back each other up with appropriate defense in depth. I can't see substituting one for the other. I don't understand that.

CHAIRPERSON BONACA: But you see if you look at the table here, you know, that's clear what's happening right now. There are plants out there in some location where there need operator action, but there is no sprinkler system. There is no automatic fire suppression system, and the plant believes that they are capable of doing that.

Now, in some cases they get inspection.

DR. APOSTOLAKIS: They can always go to 805, can't they?

MR. EMERSON: Yes, they can.

Any other question?

MR. ROSEN: No.

MR. EMERSON: Okay. Thank you for the opportunity to talk to you again.

MR. ROSEN: Thanks.

I have nothing further.

CHAIRPERSON BONACA: Okay. Any additional comments?

DR. APOSTOLAKIS: We will discuss it again.

CHAIRPERSON BONACA: We will have to discuss it again.

All right. With that if there are no further comments right now, thank you for the presentation, and we will take a break now for 15 minutes, until 3:25, 3:25.

(Whereupon, the foregoing matter went off the record at 3:09 a.m. and went back on the record at 3:26 p.m.)

CHAIRPERSON BONACA: Okay. Let's get back into session.

The next item on the agenda is the grid reliability issues and related significant operating events, and Jack Sieber will take us through the presentation, and we have allotted one and a half hours for that.

MR. SIEBER: Okay. Thank you, Mr.

Chairman. I will be very brief.

I think each of you got a copy of a report that is a draft report on grid stability, and hopefully you have had an opportunity to read it. I've read it. It's a good report. It's a work in progress. This is Part 1 of maybe three parts that will ultimately come out, and I think it has important information that we ought to fully consider.

And to start this session I'd like to introduce to you Jose Calvo. When we were talking about the ultrasonic flow measurement project, which is now resting, Jose was a part of that and responsible for the staff's operation there.

So Jose, why don't you introduce your team and get us started?

MR. CALVO: Yes. Jose Calvo. I'm the Branch Chief of the Electrical Instrumentation and Control Branch, and we have a super presentation for you here today.

We're going to tell you there are two offices involved, the Office of NRR, the Office of Research. He's going to say the same thing. So I'm going to quickly summarize it. We'll make you a presentation about the status, what we have been doing up to now, what we're going to do next. And then we are going to see where all of the research is going to be planned with this.

And I know you were interested in solved events, and they're happening sine August 14, 2003. WE will also tell you about that.

John is the lead project manager in this d, and he has been trying to more this grid reliability issue forward.

MR. LAMB: Good afternoon. My name is John Lamb. I'm a lead project manager regarding electrical grid reliability for the Division of Engineering in the Office of Nuclear Reactor Regulation, NRR.

I would like to thank the ACRS for inviting the staff to today's meeting.

The staff has been working to resolve electrical grid reliability issues. The purpose of this presentation is to provide information only to the ACRS about the staff's actions and status regarding electrical grid reliability.

The staff is not expecting a letter from the ACRS.

The staff will make four presentations: first, by NRR regarding the overview of the grid reliability activities; second, by NRR regarding the loss of off-site power LOOP event; third, by the Office of Nuclear Regulatory Research regarding the overview of the loss of off-site power frequency and duration analyses; and the last presentation by Research regarding the status of investigation of grid operating data for signs of change and potential vulnerabilities.

The overview presentation will be divided into summary, background, staff actions, key information, status, and milestones.

Because of inconsistency in how industry is addressing the need to insure the availability of off-site power following a unit trip, a generic communication may be needed in order to insure future licensing readiness to cope with an event similar to the August 14th, 2003 power outage and to insure that regulatory requirements will continue to be met.

The staff is currently working on a regulatory basis for a generic communication.

On August 14th, 2003, the largest power outage in the history of the United States occurred in the northeastern United States and parts of Canada. Nine U.S. nuclear power plants tripped. Eight of these, along with one nuclear power plant that was already shut down, lost off-site power. Although the on-site emergency diesel generators, EDGs, functioned to maintain safe shutdown conditions, this event was significant in the terms of the number of plants affected and the duration of the power outage.

In December 2003, the NRC Chairman directed the NRC Executive Director of Operations to conduct a review of the issues raised in a report entitled "State of U.S. Power Grid from Nuclear Power Plant Perspective."

Following the --

DR. WALLIS: This blackout was not caused by something which happened at a nuclear power plant.

MR. LAMB: That's correct.

Following a deterministic risk evaluation, it was concluded that there were certain urgency to address before the summery of 2004 those significant issues manifested by the August 14th, 2003 event.

The NRC has identified 48 concerns with the reliability of off-site power to nuclear power plants that need to be resolved. The staff used deterministic and risk assessment to characterize the safety significance and priority of the 48 issues. These concerns have been divided into three groups to be resolved.

Group one contains ten concerns that the staff has determined need to be addressed in the short term.

Group two has 21 concerns which are beyond the statutory authority of the NRC and fall within the Federal Energy Regulatory Commission's, FERC's, and North American Electric Reliability Council's, NERC's, purview.

Group three has 17 remaining concerns not addressed by the other two approaches.

The group one. The goal of the ten group one concerns was to insure that nuclear power plants were ready for an off-site power event in the short term. Short term was defined as the next potentially stressful grid period, which was the summer of 2004.

To resolve the group one concerns, the staff developed a three prong approach. First, the staff raised awareness of the concerns by developing and issuing a regulatory issue summary, a RIS, 2004-05, "Grid Reliability and the Impact on Plant Risk" and the "Operability of Off-sit Power," highlighting the significance of the grid reliability with respect to the operability of the off-sit power system for nuclear power plants.

Second, the staff assessed the licensee's readiness to manage any degraded or losses of off-site power through inspections and interviews using temporary instruction, TI, 2515/156, off-site power system operational readiness.

Lastly, the staff monitored and reviewed the conditions and events through the summer of 2004. You'll hear more detail of the LOOP events in the next presentation.

In a non-public memorandum from Luis Reyes, the Executive Director of Operations, to the Commission, dated August 6th, 2004, the staff determined that the operational readiness of off-site power systems for nuclear power plants would be assured during the summer of 2004.

On August 13th, 2004, the NRC issued a public press release titled "NRC Confirms Nuclear Power Plants' Operational Preparedness with Respect to Electrical Grid Reliability," which summarized the results of the August 6th, 2004 memorandum.

As I said, group two has 21 concerns which are beyond the statutory authority of the NRC, and we've been following those activities.

Group three has 17 remaining concerns not addressed by the other two approaches. The staff has consolidated these long-term concerns into four topical areas: off-site power system availability, station blackout review, risk insights, and interactions with external stakeholders.

The off-site power system availability, the issues in this topical area concern off-site power stability and reliability, communication protocols between the nuclear power plant operator and its transmission system operator; also, the engineering assessment of loss-site power assumptions in accident analyses and updating the licensing basis for off-site power systems.

Station blackout review. The concerns are the underlying assumptions for assessing nuclear power plants' coping duration and recovery of off-site power, unavailability of EDGs, and the calculation of station blackout risk with updated standard guise plant analysis risk, SPAR, models.

Risk insights. The issues in this area primarily relate to group probability, the allowed outage time extension for on-line EDG maintenance, risk assessment of off-site power assumptions and accident analyses, maintenance risk assessment before and during switchyard work, and assessment of cumulative risk impacts of combined LOOP events at multiple units and sites.

In addition, this topical area encompasses the effort to predict the likelihood of future blackout events using grid operational data obtained from NERC.

The issues and the interactions with external stakeholders area concern interactions with external stakeholders to address grid concerns, such as containment of cascading power blackout, collection of grid operational data, and cybersecurity.

DR. WALLIS: Can I ask you about grid reliability?

MR. LAMB: Sure.

DR. WALLIS: Is grid reliability something sort of random that happens out there and then the plant responds to it or does characteristics of the plant itself affect the grid reliability?

MR. SIEBER: Both.

MR. LAMB: Both.

DR. WALLIS: Both. So we have to be concerned about things that happen at the plant, the way it's connected to the grid, the way it responds to transients which could itself trigger unreliable response from the grid.

CHAIRPERSON BONACA: But typically it seems to me --

DR. WALLIS: It works both ways.

CHAIRPERSON BONACA: Yeah, but I thought that if you have a stable grid with no under voltage experience, for example, it's more than likely that you will have a loss of, say, power in the plant even if the plant has a SCRAM.

I mean, I think there is a connection insofar as the likelihood of having a loss of, say, power between an action from the plant like a SCRAM and the fact that the plant is connected to the grid voltage, isn't it?

MR. CALVO: Yes, but the stability of the grid insures the availability of site power to the nuclear power plant.

CHAIRPERSON BONACA: That's right.

MR. CALVO: Right? Now, the other most important part that we support the contention is how do you manage the grid and how do you know, how do you project a management with that grid that if something happened in the area with the nuclear power plant, you still insure the availability of off-site power, but tell me before it happens. All right?

So actually what we're trying to do we call it a contingency analysis because you look into the future and you say if you manage the grid in this manner and we lose the nuclear power plant or we lose a critical transmission line, that the availability of site power still will insure to power the emergency buses.

So you can say today the grid is managed stable. It looks fine, but it may be fine because that nuclear power plant is providing the kind of supports that are needed to be fine. Okay?

And what we'd like to know: what else is going to happen in the location in there that it will cause a problem so you lose the power plant? For instance, they've got a power plant somewhere in the northeast, okay, that there is limited the kind of makeup hours that you can provide to the grid, makeup hours to insure that you've got the reactivity that you needed.

And the question is that even though it's capable of providing you a little more nakeup hours that you need, you cannot provide all of those makeup hours because if you happen to lose the particular plant and you lose that big hunk of makeup hours and then you ask yourself the question if the grid can support it.

If the grid is not supported, then you're saying, "Ah-ha, you are not meeting the first contingency. Therefore, something needs to be done."

CHAIRPERSON BONACA: Probably I was simplistic in my statements, but my understanding was really this connection. I mean, if you have a degraded voltage in an area that is connected to the plant and that's what the plant is experiencing, then a SCRAM of that plant may cause a further decrease of your voltage of the line and cause, in fact, a loss of that power of the plant. I mean, there is an interaction there.

MR. CALVO: That's correct.

CHAIRPERSON BONACA: And my understanding that at least for the report you wrote, that in fact in recent time because of the grid degradation or overload, the situation of under frequencies is experienced more and more frequently.

MR. CALVO: That's correct, and what we plan to do, we had some issues to assess that. See, we in the 20th Century, we look at the nuclear power plants in a silo. We say, "Okay. I don't care. Give me power. If you don't give me power, I'm going to have diesels (phonetic)," up to a point, and the reasonable assurance is between the combination of the off-site power system and the on-site power system.

But things can change in the 21st century.

We are transmitting power, big hunks of power off and on. Now, in some kind of way can they police some of those mega bars? Can they police some of that?

So now we're looking into the nuclear power plant. It must contribute to the well-being of the grid. It's one of the contributors, one of the fossil fuel plans. The combination of all that contributions in there. Okay? That's the one who will insure you the availability of off-site power to a nuclear power plant, and that's why we are approaching this concern, and we look into the risks, and we look in all of the situations to find out whether we have what we need on site and what else needs to be done if the off-site is not what it's supposed to be.

MR. LAMB: Okay. Based on NRC inspections to insure compliance with NRC regulations, assessment of licensee responses and assessments completed in the summer of 2004 are the results of the audits conducted by NERC. NRC believes that effective actions are being taken to enhance the availability of off-site power for safe nuclear power plant operations.

Also, we found out that nuclear power plant operators need to be aware of the off-site power needs and found considerable variability and uncertainty among licensees regarding the responses to the three key questions of the TI.

DR. APOSTOLAKIS: What are these questions?

MR. CALVO: If I may, there's three key questions that we felt. First of all, the relation of the electrical utility industry, mostly in the northeast, mostly everyone; before that it was the protocol integrated. So we want to find out how do you communicate with your transmission operator. What kind of the communication protocol do you have? That is the first question.

If the answer is yes or no, is that contractual? Is that some financial responsibility? If you don't tell me that I'm in trouble with the grid so I can do whatever that needs to be done, like staff maintenance, worry about the availability of off-site power.

The other question, the communication protocol was the nuclear power plant identified those voltage limits of the critical transmission lines that it must be maintained at all the times, even as a result of tripping the unit because this is minimal voltage that we need for the off-site power to provide and supply the emergency buses. So that was into the calculation.

And the third one is how do you do all of this. So we asked them then what kind of a contingency analysis did you do. Are those contingency analyses on line? How often a frequency do you do and how do you convey that information to the transmission operator, which in turn provides that information to the nuclear plant operator?

And the critical part in there is that if the grid gets degraded, as a nuclear power plant owner I'd like to know not because I'm going to declare into the tech specs and declare the off-site power system inoperable. I have 24 hours to fix it or I have 72 hours to fix it. What is important is that you made the nuclear power plant operator aware that, look, you now must depend on the on-site system capability. So whatever you do, don't do anything that it will cut down the capability.

So if I've got a debated bill (phonetic) and I'm doing a maintenance for the diesel, we're going to tell, "Put it back the way it was or finish quickly because now you're into a situation that you should not be into."

And normally if they had done it this summer, when the summer comes along irrespective of whether you've got it, they have been very cautious not to do those kinds of things in the summertime because as you will hear later on, when you've got the heightened ability of losing off-site power during the summer.

So that's the three questions. We not only ask --

DR. WALLIS: You said that you pull off the grid if the grid voltage drops too much. If the grid voltage drops too much you pull off it and shut down.

MR. CALVO: No, no. I'm saying that we convey to the submission operator --

DR. WALLIS: -- too much to support the emergency buses.

MR. CALVO: We want to be sure that at all the time you've got the right kind of the voltage at the switchyard. So after you take all of the voltage drops down to the emergency bus and you get sufficient buses to operate those --

DR. WALLIS: So if the voltage drops to much on the line, you pull off it.

MR. CALVO: No, if the voltage drops up to the line -- I want to elaborate a little bit on this. What you do, the question is: is that a continuous comedown? We've got what we call an under voltage protection, degradable protection, and what this will do, if you stay there for a long period of time, what you want to do, you want to prevent that because of that low voltage, okay, you may be damaging some of the equipment already running, like the service water pump for the diesels.

If that thing is damaged because you blow fuses to the control circuits or the model status, then who cares about the diesel? Because they can come along any time you want it, but they want people to pick up any loss because they're not there. The electrical system has been degraded to the point that it had blown some fuses.

DR. WALLIS: Do you pull off the line or do you still keep operating or what?

MR. ROSEN: Yes. If they are fast acting, under voltage relays, if you get to that point where you have a degraded -- if you have a degraded bus that's been degraded for a while, these relays will go and the plant will trip to protect its own safety.

DR. WALLIS: So your tripping then lowers the voltage even more, which then gets the next guy to trip and this goes down the line.

MR. ROSEN: Well, there may not be a next guy in a local area.

MR. CALVO: If that continues to be, yes, you will eventually low voltage conditions we may end up tripping off the line.

DR. WALLIS: Like 12 men pulling on a rope. When one gets weak and he pulls off, the other guys get weak and they pull off. Pretty soon the rope is gone.

MR. CALVO: Well, look at it this way. It can happen that way. The other way it can happen and depending whether you are at power, you can disconnect from the line, but you still don't trip the unit, and you can provide power from the unit itself to the emergency buses, and you can control the voltage you want.

DR. WALLIS: To do that, but then you're producing far less power than you were before.

MR. CALVO: Yeah, that's right. Less power --

DR. WALLIS: -- the stability problem of the lines.

MR. CALVO: How do you balance maintaining the well-being of the grid with the nuclear power plant or maintaining safety? Okay. You've got some care. You've got to call. You've got to play the biblical role.

What we tend to do today, we precipitate to shut the plant down, which sometimes is the worst thing that you can do when the grid is oscillating. Okay? So you've got to balance this out.

We've got those big flywheels in the reactor coolant pumps. Under this condition you've got a tripper. You don't want to get there. The question is: do we do that conservative or not?

So those things have got to be balanced.

DR. APOSTOLAKIS: But these cannot be new questions, are they?

MR. SIEBER: No, they aren't.

DR. APOSTOLAKIS: People hadn't thought of all these things before?

MR. SIEBER: The questions have always been there. On the other hand, the grid right now, since there has basically been no investment for 15 years, and new load comes on every year just because of the growth of the economy, the stability of the grid is more in question now than it was before.

MR. ROSEN: And also because large loads are being transferred from Point A to Point B on the grid that were not being transferred before, and those loads are being transferred because of deregulation.

A contract with a power plant over here in my coffee cup with a load way over on the other side of the grid can be written because this guy gets a good price.

So now loads transfer all the way across here rather than coming from the local plant, and that creates much more flow through intervening switchyards and whatnot.

CHAIRPERSON BONACA: The system hasn't necessarily to be a grid.

MR. CALVO: And people don't add more transmission lines unless it's economically beneficial to them. They don't build no more local plants, whether they're fossil or gas turbines, because it's not economical.

So all you do, you're trying to optimize how do you manage the grid. Do you manage to switch a monitor where you take care of all of these concerns in there.

DR. APOSTOLAKIS: Now, these issues sound like they refer to an individual plant. Now, the fact that you had nine plants trip during the August '03 event, does that create any issues that you have, you know, a large number of plants tripping?

MR. CALVO: That will be part of the presentation. One of the issues that we have come up with, so you trip nine plants. If you look at your one individually, your risk is not important individually, but when you look at it for the simple condition of core damage probability, you're getting close in the middle of the ten to the minus four. A diesel will not have started. Then you get into ten to the minus three. I think the research will tell you about those things.

And the other issue that we had, which I think is a policy issue, so nine plants will trip. What is the cumulative risk for all of those plants? And normally we don't look at the cumulative risk. We look at only one plant.

If all the plants in the United States will trip, if you only look at one plant, what is the cumulative risk? Is that important or that's not important?

Okay. The question is there are a lot of plants that are very close to each other, and the question is should that be considered as a potential risk to those plants with a certain area.

DR. SHACK: When you were saying nine plants, there were nine units or nine sites?

MR. CALVO: I think it was nine units.

PARTICIPANTS: Nine units.

MR. ROSEN: But that wasn't the only plants that tripped. There were a lot of fossil plants that went off, too.

MR. CALVO: Oh, yeah. It was a tremendous amount of fossil plants.

MR. SIEBER: Forty.

MR. ROSEN: It was nine nuclear plants, but a lot of fossil plants.

CHAIRPERSON BONACA: One reason why I'm interested right now in this presentation, I mean, you have different scenarios. One is just simply loss of off-site power and the ability of the plant to support itself. Okay? No accident.

There is the other concern that, you know, we right now are looking at a LOCA with coincident loss of off-site power. The reason why this was construed, in the early times the thought was you have a SCRAM. The SCRAM may cause an upset of the grid, and so you lose off-site power. Now, the SCRAM might be caused by LOCA. So you have a LOCA with the SCRAM. The SCRAM causes loss of off-site power, and now you have to depend on your diesel. So you have this fast start and so on.

Now, you know that we are looking at the change in the 50.46 in which loss of off-site power may not be considered any more coincident with the breaks of over a certain size. So I'm concerned about that kind of scenario, too, where you have an event of the plant, whatever event, and you have a SCRAM. A statement is made in this document that because of the frequency, still the grid might be degraded. The SCRAM of itself may cause loss of off-site power.

MR. CALVO: It could, but if the grid has been managed the way at least we expect it to be managed, then you have not lost the off-site power because then you are prepared to meet the first contingency, and the first contingency in this case will be loss of the plant.

CHAIRPERSON BONACA: We'll talk about that.

MR. CALVO: Agreed.

CHAIRPERSON BONACA: You will talk about that?

MR. CALVO: Yeah, we can if you want to, but I think maybe you can get a better flavor when you see how the risk component enters into this.

And, yeah, those are the things that you're asking is fine. And what we're trying to, those three key questions that we asked this summer, one of them is to tell me whether you look into the future and you tell me if I lose that unit, will I lose the off-site power, and the answer that we get back, it was some good answers, but we need to verify, and we are working into that now, and the component of risk will enter into the picture, too.

MR. LAMB: Okay. In summary for the overview, in the four topical areas, in the off-site power system availability in a station blackout review topical areas, the staff is considering a generic communication.

The staff will determine if regulatory action is warranted based on the research risk analysis and the risk insights topical areas, and you'll hear two presentations from Research in a little while.

And the staff will set up a process for NRC to receive NERC operational data and to interact with NERC during grid emergencies.

MR. CALVO: If I may, NERC is a very extensive program that is rotational every three years, and he goes through all of these control areas which is composed of the independent system operators or transmission operators, and there are some questions which will help us to see the handshake has been taken between the nuclear power plant or in the teal (phonetic).

So we're keeping a close eye on what NERC is doing to find out that truly there's that kind of a handshake between the transmission operator and to the nuclear power plant line. They can talk to each other these days. You know, if you're in the residual market, you don't talk to each other, but at least this particular one, I think they do talk to each other insofar as telling them that the grid can be degraded.

MR. LAMB: Next you're going to hear from Tom Koshy about the LOOP events.

MR. KOSHY: Thank you.

Essentially it's the planned events that I'm going to discuss with you today based on your staff request, and we have added a couple.

Essentially to give you a rough overview, what we have observed is this loss of off-site power events have occurred primarily due to three reasons, and I'll go through these reasons as I go through these individual plant events.

First is the design deficiency in the sense as it relates to the protection system in the switchyard area.

And the second one is the lack of adequate maintenance. I'm referring to how well the breaker is operating for isolating a fault or condition.

And the third one is an operational oversight in the sense I'm talking about the management of the switchyard and also on the grid site collectively.

And some of those conclusions are based on certain planned events which are sensitive, but I will discuss the public part of what is available in the docket at the --

CHAIRPERSON BONACA: So some of this is under the control of the plant, but some of it is not.

MR. KOSHY: It's not, yes, correct.

CHAIRPERSON BONACA: Well, as you go through the presentation, please specify because I want to understand what the plant can do.

MR. KOSHY: Yes. This is the Vermont Yankee main plant from our file that happened on June 18, 2004. It began as a ground fault from the dislodged piece of the isophase bus. That is the piece that is connecting from the main generator terminals to the main transformer, the step-up transformer that goes to the transmission line.

They had an expansion piece in the isophase bus which is kind of built with leaves, and one of those leaves broke loss.

There are some indirect connections with increasing the flow of air in that compartment, which is anticipated for the power up rate, but I would say that this event -- see, this modification has contributed to the acceleration in the sense it happened sooner. That would be the only connection with the power up rate planning, but other than that it essentially happened because that piece came off, and it created a fault.

DR. WALLIS: It created a spark.

MR. KOSHY: This is 33 kV, the main generator. So that created a major fault.

DR. WALLIS: There was a spark that ignited the oil presumably.

MR. KOSHY: Yes. The first part of the event shook up the plant so much the reserve compartment oil at the top. It started leaking down. So the fault fire propagated into that oil and caught fire.

So I can go back to the previous --

MR. SIEBER: Usually when you get a fault like that it's so violent that it will expand the tank, spill oil out the top, blow the bushings.

MR. KOSHY: In this case the fault began

in the isophase bus, not directly in the transformer. If it is a small connector into the transformer, that would have indicated.

MR. SIEBER: That would hit the generator then.

MR. KOSHY: Right. This explosion happened in the isophase bus, and that propagated; that shock essentially created oil leaks on the top of the reserve wire and then the oil caught fire.

Onward to Limerick. On June 22nd, a 500 kV breaker was taken out of service for maintenance. When this breaker was opened, they had an internal fault, which created a problem.

And along with that there was a concurrent failure on another breaker that had a different problem, collectively in the sense led to both main output breakers tripping.

Unit 2 safety vessels also transferred to the alternate off-site power. In this case the main 400 kV transformers are operated by somebody else. Usually, generally speaking the main output breakers are in control of the plant, and in many cases the maintenance services come from outside. The plant does not maintain it though they have responsibility for controlling that breaker.

In this case, the emergency diesel generators were not needed because the other off-site power was available and transferred successfully.

The next is River Bend. This again happened remotely far away. A guy wire failure required an automatic trip off breakers at the River Bend switchyard, but since that breaker was slow in clearing that fault, the back-up protection system which is sometimes also referred to as the step breaker protection system, if one breaker did not do its primary job, the back-up protection system trips breakers that are around it so that the fault can be contained.

So in this case when the back-up system of breakers started tripping, it took away one of the off-site power sources, and in the second set, the delay further caused the fire current to remain locked in. So that took away the division safety vessel also.

The root cause, slow operation of the breaker and in this case maintained outside of the nuclear power station, but that area has not gone through deregulation. So there is kind of a better relationship with the people who are operating the transmission line and also who are maintaining the switchyard breakers.

The next one is Palo Verde.

DR. APOSTOLAKIS: Let me understand. What are you looking for when you do all of these? Are you trying to learn anything?

MR. KOSHY: What we are finding is -- in fact, let me jump to the last slide which I used as a back-up slide since you asked the question.

She's going slowly.

DR. WALLIS: A big bird was that?

MR. KOSHY: Yes. I'll come to that, too.

MR. ROSEN: A n on-safety related bird.

MR. KOSHY: What we are hoping is in this nuclear stations, they need to build up some contractual and firm arrangements with the transmission operators and the reliability coordinators so that there will be reasonable control in the maintenance activities, corrective maintenance or preventive maintenance, so that they have some commitments on firm power with reliable systems available to nuclear stations.

So this dotted line is the indirect relationship that we hope to see among electric utilities. These boxes may be a little different. You know, I put it in division. There are ten reliability councils below which there are reliability coordinators, and then there is transmission owners and operators, and nuclear stations come far below here.

All of these people should have a respect for what is needed for nuclear stations to make sure that these maintenance type of activities and what they do will guarantee reliable power for the off-site power.

MR. CALVO: And that is what we have done all summer 2004. We actually inspected 100 and two, oh, one, and three (phonetic) nuclear power plants, and this is one of the three questions that we asked: how do you communicate these concerns back to the nuclear power plant and how the nuclear power plant reacted to it?

So it's very important. Because otherwise it will be actually blind, okay, and that's very important. I wish we can get a contractual protocol so whoever doesn't do it, it will be some financial responsibility in there, but we're not there yet.

DR. WALLIS: Why are the green arrows different from the blue arrows? They do the same thing.

MR. KOSHY: Well, in this case they have

a direct relationship in selling power, a direct relationship in selling power, and this one I was trying to represent. See, this is NERC organization, reliability council.

DR. WALLIS: So they need a direct link to them, not going through the other ones. Is that the idea?

MR. KOSHY: Yes. Here you can have a direct link. This will be direct because reliability coordinator is an independent organization. They don't own anything. They are just operators. They have computers and essentially assessments can condense the analysis. That's all they have.

These other people who own the hardware and these other people have, let's say, organizations like PJM, MISO, and New York ISO. These people make command decisions for preserving the grade, and they also operate the market.

MR. CALVO: And normally, the New York ISO, for instance, will not talk to the nuclear power plant operator. They will not.

MR. KOSHY: By law.

MR. CALVO: He will go to the original transmission operator, and he expects him to talk to the nuclear plant operator. They want to be independent this way.

But one thing they do that is very interesting, they have got automatic load dispatching and not for the nuclear power plant; for the fossil fuel plants. They control the governor. So they can go up in power or come down in power as needed.

In the future, when the nuclear power plant will not be base loaded anymore, there may be interest and reveal more, whatever is happening in the future; then with all of this patching, the automatic control is there.

So some of this has automatic control. That's where it's important from the cybersecurity, is these CADA systems because you cannot be affecting, you cannot shut down the whole grid if a bug gets into the computer who is controlling these things. So that's important.

MR. KOSHY: Shall I go to Palo Verde?

MR. CALVO: They want to hear about the bird.

MR. KOSHY: Okay. This began because of bird excrement on the 230 kV line, and let me go to the next picture so that I can explain how it really happened. The bird is on the top of the insulators, and the insulators' wires, the connectors go this way.

So the bird droppings get this way, and therefore, the face had a ground fault against the tower. And that took away several pieces of the insulators, and now you have a phase to ground fault.

MR. ROSEN: And surprise to the bird.

MR. KOSHY: What we hear, the bird escaped.

(Laughter.)

MR. KOSHY: Could be at large.

MR. SIEBER: You do your "duty" and fly away.

DR. APOSTOLAKIS: It's beyond the statutory authority.

MR. KOSHY: Right, clearly. And then you have a phase to ground, and the ground wire takes an undue amount of current, and that in turn breaks up.

In the meantime, these insulators broke and fell down. So it has a phase-to-phase fault, phase-to-ground fault, and the wire that is on the top broke and was tripping into all of these phases and has created a variety of faults.

MR. ROSEN: So that was the overhead ground wire, not the main power wire.

MR. KOSHY: Yeah, the ground wire, yes.

DR. APOSTOLAKIS: Why did that break?

MR. KOSHY: Because once you have a phase-to-ground fault, the ground wire takes the high current.

MR. SIEBER: The load, yeah.

MR. KOSHY: And the fault did not clear for 39 seconds. So it overheated. It is much beyond the rating of that wire. It just broke.

DR. WALLIS: Also your wire broke because the insulator broke.

MR. KOSHY: That just dropped down. In fact, the next picture will show you.

DR. WALLIS: It dropped down on the next.

MR. KOSHY: Yeah. This is the broken insulator. It is somewhere on the top here. It dropped to the next space and this is the broken insulator. See these belts are missing?

MR. ROSEN: What is that stuff behind there on the ground?

MR. KOSHY: Oh, there a nursery there with all plants, and in fact, that is why somebody saw the bird take off and go and this audiovisual effects forward.

I know this is not very clear, but let me try to explain what has happened. Liberty line is where the problem occurred, and the breaker that did not open is the 1022 that you see here. And what we find is since this breaker did not clear the fault, the fault remained on this bus, and that in turn transformed this 230 kV power to 500 kV, and there is no such protection for a ground fault in this segment.

Therefore, the fault essentially propagated to the Palo Verde switchyard, and the switchyard essentially went dead. So that's how much the fault propagated.

MR. CALVO: And you asked the question what did we learn from this. Put the bird aside for a while. What we learned from this one is that there is a fault that propagated from a 230 kV to a 500 kV switchyard, and it knocked down three nuclear power plants, which at one time was visualized by the staff as being incredible.

Not only the three nuclear power plants came down. Also a lot of fossil fuel plants came down. The total was about 5,000 megawatts.

So the question is they look at it and say what are the generic implications, and you've got some generic implications, and we got a group of the West Coast reliability council, and the council is going to come out with a report at the end of this month, which is going to help.

Now, they have fixed the problem. Otherwise we would not have been able to start up the plant. They put in some protective relays and that kind of stuff, but it was done kind of in a hurry. So this group is going to study the situation and see what implications are.

And you've got to look at the combination, the whole nation. What kind of situation was this? And that may help solve all of these problems.

MR. ROSEN: Was this Liberty line very remote from Palo Verde?

MR. KOSHY: Yeah, about 40 to 60 miles.

MR. ROSEN: So something 40 to 60 miles away happened that affected Palo Verde.

MR. CALVO: The three plants, and the question is it's a fault that propagated, and it should have been arrested, but it was not arrested. It continue, continue, continue, and it knocked three units down because it was not enough protections in there.

MR. ROSEN: My point is if you just look at the switchyards locally around the power plants even five miles, ten miles away, you might not get the right picture because here is an example where the effect started 40 miles away.

MR. CALVO: And the contingency analysis, if they cannot factor into the fact that a fault can be propagated, it won't show up. The analysis should include the possibility of a fault, what the fault can do to you in support of meeting the first contingency.

And when we review Palo Verde, we review on the basis that you can't afford to lose two units at the same time because you've got problems with the grid.

But anyway, that's what you learn from it. So it's not mainly Palo Verde. It's the situation like this. So this group is going to be looking at it and see what are the generic implications that we have.

MR. KOSHY: Looking at why it was propagated so much, there was one ancillary relay that was taking the perfection signal for that Liberty line that did not work properly, and that one ancillary relay was forwarding the signal to the trip coils. They had two redundant trip coils, but both of them are coming off the same relay.

So essentially because that relay failed, the breaker did not open. And, again, this 230 kV switchyard was the largest that was connected to the 500 kV because of its respective ratings. So it is able to transmit a very high level of fault current to the 500 kV station.

By way of corrective actions, they have now installed double relays so that the strip coils will have separate signals coming in. On breakers, some of the breakers were very old and that had only single trip coils. They are considering to install another set of trip coils there.

And the removed the second layer of protection. That was, let's say, an older design which didn't look very appropriate, and they have removed that.

And the third part, which was actually seen as a weakness was APS agreed to add another set of Zone 2 ground fault relays so that the fault current will not propagate from 230 kV to 500 kV.

And from the grid control part an automated response to three unit trip is being developed at the control center.

Now, we are expecting a study from the Palo Verde station soon after the Western Area Council finishes their study this month to look at the reliability of that area, and we are currently working on a non-public generic communication to share these grid problems with the industry. That's currently on progress.

Any questions?

MR. ROSEN: I want to come back to Mario's original question. How many of these will you think are attributable to overloading of the grid?

MR. KOSHY: It's not really overloading of the grid. We found maintenance practices at Vermont Yankee could have helped.

MR. ROSEN: Right.

MR. KOSHY: In Palo Verde's case, it was outside of the nuclear stations.

MR. ROSEN: Right.

MR. KOSHY: But that design deficiency did affect.

MR. ROSEN: It's a design deficiency having nothing to do with deregulation.

MR. CALVO: No, no. Palo Verde, by the way, is a vertically integrated utility. It has not quite yet got into the regulatory integration market. We found some things as a result of this that have impacted California.

MR. ROSEN: Well, let me try and state it the other way. I don't see any impact on any of these events from the deregulation. I mean it's not clear to me that deregulation was in any way implicated in these events, except if you say maybe the maintenance was less than what would have been done in a vertically integrated company.

But that's a reach, and I'm not sure.

MR. CALVO: Again, that's true, but you've got to wait for the summer, you know. When the markets are cut down and where the overloading enters into the picture --

MR. ROSEN: Oh, I understand that.

MR. CALVO: But you're right. You can't blame that to the over power, turning in too much bulk power from one to the other. It was not, but Palo Verde is a very good one. It's the very best sample because it's still vertically integrated and they don't have the power flows.

MR. ROSEN: I guess the answer to his question, which I don't want to prejudge the answer when the question is asked. The question was basically to what extent is the deregulation implicated in these events, as I understood his question, and the answer I think is not really.

CHAIRPERSON BONACA: Well, I was referring to this report.

MR. ROSEN: Yeah, yeah.

CHAIRPERSON BONACA: The report states

otherwise. I mean, the examples here don't support this.

MR. CALVO: I think you will get at least a better perspective to answer your question when the risk group gets in here.

MR. ROSEN: Okay.

MR. KOSHY: One point I might make is the maintenance activity when managed from a nuclear station, they kind of put a different level of quality on those things that provide off-site power.

MR. ROSEN: But they don't manage something 40 miles away when a bird jumps on it no matter what happens.

MR. KOSHY: Those breakers that did not operate in the switchyard was a clear case where they did not respond to vendors' recommendation on what the maintenance should have been.

MR. ROSEN: Well, that's possible.

MR. KOSHY: So that is the case in two events that I shared with you, and when you don't do that type of maintenance, one breaker not clearing the fault in the first three to five cycles results in the whole switchyard going out.

So, in other words, there is an influence area of, say, second level of protection. So if the first level of protection they are not doing the right thing, then the plant is going to trip or lose off-site power.

MR. CALVO: The regulation is not only bringing power force increased tremendously. Also it has broken down transmission owners from generation owners. You also have built new entities, and different coordinators for these things up.

So new entities in there, and they are not as good as coordinated than it was before.

CHAIRPERSON BONACA: I would like to quote, however, because I mean this is a report that you have sent to us for review, and this is the first elaboration, is "transmission system congestion overloading is increasing. Experience shows that transmission line congestion near an NPP degrades the plant's operating voltages and may result in a LOOP in the event of a reactor trip."

MR. CALVO: I don't know what report you're reading from.

MR. LAMB: You'll be hearing more about that from Bill Raughley.

CHAIRPERSON BONACA: It's abbreviated version of the draft status report concerning the assessment agreed for collecting data for signs of change and potential vulnerabilities.

MR. CALVO: You're going to hear the author of that comment later.

CHAIRPERSON BONACA: Is that right?

MR. CALVO: That's right.

CHAIRPERSON BONACA: Okay. So what's the next presentation?

MR. RASMUSON: I'm Dale Rasmuson, and I'm from the Office of Research, and I'm here to tell you about some of the activities that we're doing in the area of looking at risk here.

First we'll start off with a couple of definitions that we work with. Loss of off-site power is defined as loss of the off-site power to all safety buses.

And station blackout is the loss of all off-site and on-site AC power to the safety buses.

NRR tasked Research with three tasks. One is to provide a preliminary accident sequence precursor analysis for each of the eight affected plants to provide insights for near term agency actions. These were completed and sent out about March 1st of this year.

MR. ROSEN: Excuse me. Which eight affected plants?

MR. RASMUSON: Those that experienced loss of off-site power.

MR. ROSEN: On August 14th?

MR. RASMUSON: On August 14th.

MR. ROSEN: Okay.

MR. RASMUSON: Yeah, sorry about that.

Then we were tasked with two other tasks that are directed at reevaluating the station blackout rule. The first task was using updated data or using recent data, to update the frequency and the nonrecovery probabilities. Then using that information, assess the core damage frequency of LOOP and station blackout risk for the industry, and we will talk about what our plans are in that in a few minutes.

Previous LOOP studies include NUREG 1032, which covered a period from 1968 through 1985. I worked on sort of the periphery of that doing some of the statistical work. John Flack here did a lot of the calculations on that.

In 1987, AEOD did an update of the frequency and nonrecovery probabilities using data from 1980 through 1996. That is documented in NUREG CR-5496.

NUREG CR-5750 is the initiating event

frequency study that Idaho did, and there they have LOOP events in there. They did not classify them in any way, but just calculated a frequency, and it covered 1987 through 1995.

Research did a study on grid events documented in NUREG 1784, and they considered information from 1985 through 2001.

Our current study is considering events from 1986 through 2003. We're picking up where NUREG 1032 left off.

The events have been classified in 1032 as plant centered, grid related events and weather related events. Weather was split into severe weather and extreme weather events.

NUREG CR-5496 followed that same classification, although there were not very many weather events at all, and so we just had one category of severe weather events.

NUREG 1784 classified events a little differently. Part of the plant centered events in 1032, part of the definition was to include the switchyard, but there in 1784 they were interested in looking at the grid itself and considered the switchyard as part of the grid, and so they put events as plant centered and grid events and weather events.

In the current study, we have broken the switchyard out as a separate category so that we can group them however people would like to to look at their contributions, and so we have introduced that.

We also have the two weather event categories, the extreme weather and the severe weather events.

LOOP and severe or station blackout core damage frequency, really there's four factors that are considered there: the frequency of LOOP events, the duration of the events, the reliability of the on-site emergency power, the EDGs, and then the plant specific coping capabilities.

And all of those are important for the estimation of the risk. Frequencies and durations you can look at sort of together. You can combine those and look at sort of composite curves to get an idea of that.

But to really understand it and to see what the overall implications are, you need to consider all of these things.

We are going to be using the SPAR models. We actually thought we were going to just be able to use just a subset of them, but it turns out that we are going to be able to use all of them.

We have updated the SPAR models with new loop event tree, which incorporates the new Westinghouse and CE pump seal models in it. We are also updating the basic event parameter estimates based on EPIX information.

So the initial version of the basic parameter estimates was from basically the NUREG 1150 era, and that has been one of the criticisms that licensees have said, well, you know, your basis event parameters are really quite conservative and are not up to date, and so we are going to be using this latest information that we have.

We are also as part of the study doing an in depth review of EDG performance using the best available information we have, not only information from EPIX, but looking at LERs and that and comparing information from both of those sources there.

PRAs use a recovery time which is the time that the operator could have recovered power to an emergency bus, and as we got reviewing this and interacting with other people, with EPRI and so forth, EPRI had some events where they classified events. Well, you know, this plant really didn't lose power. It was always available at the switchyard and things like that.

And so we thought it might be useful to really collect data in three areas. The first one is time that the power was restored to the switchyard. The second time is here on your left, is T3, is the time that it was actually restored to the bus, and sometimes those times are quite long in that because the plants are operating on the EDGs, and they're there and the EDGs are more reliable than they used to be, and so plants are comfortable to stay there and run them.

MR. ROSEN: Especially if the grid had evidence of problems before that tripped.

MR. RASMUSON: Exactly.

MR. ROSEN: And now they say the grid is back, but it's still showing the same evidence of frequency of variations. Plants may elect to stay on diesels because they feel, as you suggest, that the diesels at that time are more reliable than the grid.

MR. SIEBER: Well, that's the typical operator response. Since we understand why the trip occurred, he won't go back.

MR. ROSEN: Even though the grid is up.

MR. RASMUSON: Right, and the time that we really want is the potential restoration time, and this is what was collected for NUREG 1032 and what was also done in 5496.

As part of what we've done, we have had interactions with NRR, with the engineers and risk analysts over there, both in Research and that, and we found that concepts were not well defined, and so to aid in the communication of this potential restoration time, I sat down with my branch chief, Pat Baranowsky, and this is sort of the ideas that he had when they were doing the 1032.

One, when no other power sources are available, you're really in a station blackout condition.

Two, power is to be restored through the switchyard.

Urgency to restore power exists because of the potential accident conditions.

MR. ROSEN: You skipped the other one, the third one, which is the most --

MR. RASMUSON: Oh, power restored to the switchyard is of usable quality. Right.

MR. ROSEN: That's the question of voltage and frequency variation that's still occurring.

MR. RASMUSON: Exactly, and no extensive diagnostics or repair are required. Faults have been cleared. Operator actions needed involve alignment with relatively routine verification in switching.

Recovery time is based on a best estimate of the time operators would need to execute the necessary power recovery tasks in a pending accident situation.

And, three, the reasonableness of the estimated recovery time would be based on consideration of HRA factors, such as stress, available time, difficulty in the recovery task, and adequacy in training of procedures.

Another area that we have been looking at is the use of plant specific LOOP frequencies in our analyses, and there are different ways that we could do this. One is to use just the plant specific information itself, and you know, there are some plants that have experienced quite a few events. There are others that have never experienced any.

And so you may have frequencies that may go from .2 to .3 on down to, you know, much lower than that, approaching close to zero if we were going to just use a single plant unit's information.

We could use industry values. We could use regional estimates. We have actually analyzed our data by the NERC areas in that and have results that way, or we could use some type of Beyesian estimates of using industry distributions and updating those with plant specific information.

And that is the approach that we have sort of suggested that would be the best that we use for right now.

The status of where we're at, the ASB --

DR. SHACK: Why don't you do the Bayesian update on the regional estimate? Wouldn't that be a little more specific?

MR. RASMUSON: We could do that. We just felt that you are using the -- when you start parsing the data too much and you start using it again, you know, are we getting into too much of a double counting or not?

MR. ROSEN: Wouldn't it be better to use a Bayesian estimate like you suggested with plant specific updates, but with a floor so that it can't go lower than this number? Because if you don't have all of the experience you've got in the world, tomorrow is still coming. So you're not going to give them zero just because that's what the plant has had.

MR. RASMUSON: No, we're not. I mean, if you use the industry values --

MR. ROSEN: That becomes the floor.

MR. RASMUSON: -- that's sort of the

floor, right. I mean, it's a little bit less than that, but it does.

MR. ROSEN: It effectively becomes the floor, the industry value, even though a local plant might be better than that.

MR. RASMUSON: If I take my industry value or my industry distribution and I have zero failures and some operating time, then I'm going to get a value a little bit less than the industry value.

MR. ROSEN: Okay. I see.

MR. RASMUSON: Okay. As I said, the preliminary analyses have been done on the ASP analyses. We've received comments back from the utilities, and we are in the process of finalizing those analyses, and they should be issued in the near future.

Frequency and duration analyses have been completed. A draft report has been written, and we're in the process of transmitting that now to the NRC and to external stakeholders.

The CDF evaluations, we're getting ready to start that. Like I said, we are going to be using all of the 72 plant models, which we think is really a milestone.

The draft report will be issued for

stakeholder review in early 2005. Because the report has not been issued, I really am not at liberty to share information about things right yet in a meeting like this.

But some general insights that I can share with you. LOOP frequency is decreased. It was basically constant over 1997 to 2002. I think as we were discussing some of the industry trends program and the integrated indicator that we briefed you on, we've shown you some trends there where you've seen that.

LOOP durations have slowly increased from 1986 through 1996. If you take the average for each year, they have sort of increased. That's an interesting thing in that from '97 through 2003, they have remained basically constant. I don't know what the reason for that is, but we do know that for the early time period, if we take the mean of that and the mean of the later period, they are quite a bit different.

Since 1997, LOOP events have occurred more during the summer, and these are sort of the same insights that were obtained in NUREG 1784, and when you look at those, we're looking at power events here, and I think that during this last period, you know, I think most of them, the majority of them, I mean, over 90 percent of them have occurred during the summer period, May through October.

And the probability of a LOOP event due to a reactor trip is increased during the summer months.

So basically that's a quick overview of what we have done and what we are planning to do, and if you have any questions, we will be sending the report to you. Probably you'll be receiving it next week, you know, within the NRC here for your comments, to review and to comment on.

MR. ROSEN: Let me see if I get it from all of this. What you say now is LOOP frequencies are likely to be lower, but if you have one it's likely to last longer, and if you do have one, it's likely to be in the summer.

MR. RASMUSON: Yes.

MR. ROSEN: Longer in the summer, but more unlikely.

MR. RASMUSON: That's right.

DR. DENNING: could you give us a feel as to what kind of plants LOOP is now dominant accident sequence in? Does it tend to be a dominant accident contributor to certain types of plants?

MR. RASMUSON: Steve, have you done enough to answer that? No.

We haven't really gotten into our --

DR. DENNING: I didn't mean necessarily with the new model, but just historically looking at older data in the SPAR models.

MR. RASMUSON: I'm not familiar with the SPAR models. I have not really run those in that aspect, but I do know that some of the information there, that they can be very dominant contributors to maybe 70 percent of the core damage frequency to where they're much smaller than that, maybe 30 percent or so, in that aspect of things.

MR. FLACK: This is John Flack.

I worked on the early models and worked on the 1032 as Dale had mentioned.

I guess you'll find on the East Coast that the frequencies are higher because of, one, for exposure to hurricanes, and the other is the northeast grid tends to have more events and of longer duration.

I think Bill Raughley might want to talk about that when he gets up, but then you have the Florida peninsula which used to be notorious, which they have improved the grid over the years. So it hasn't been classified so differently than the rest of the country, although hurricanes, again, is a problem on the East Coast.

So the challenges are different. I think if you look at the domains that you find the plants in, but the station blackout rule, of course, required plants to put in so many diesels and cope with such a long period of time. So as a plant vulnerability, the rules still work there in removing any susceptibility.

MR. RASMUSON: If you take the data and you plot it on a U.S. map, I don't have good slides of this, but it's very striking to me to see how from the 1032 data, you know, you get a big cluster down here in the Florida and so forth and then you take the newer data, you know. The South is much different than that. I mean, there's not a lot of events down in the South like there used to be.

In 5496, one of the outliers was Pilgrim. Now, Pilgrim has done a lot to fix itself, and they're back in the pack now. They're part of the population. They're not an outlier plant anymore in that regard.

So there's been a lot of things that have been done, but there's still the cluster of events up in the Northeast. You had that before, but you have a lot of plants up there, but you'd see that from looking at the data in that regard.

So any other questions?

DR. WALLIS: Well, I remember Graham Leitch before he left presented some data which seemed to indicate LOOP frequency was increasing in the last year or two. Is there any indication of that?

You stop at 2002 in yours?

MR. RASMUSON: Yeah. Well, that was on the frequency there. No, it basically has been fairly --

DR. WALLIS: Up until today.

MR. RASMUSON: Yeah, it has been fairly from about '97. You know, you have sort of an increasing trend up to '96 that was statistically significant, and then it would fluctuate around, but there was not a statistically significant trend in that over that period. It was flat.

DR. APOSTOLAKIS: I think what Graham said was that there was an increase in switchyard incidents, not necessarily loss of off-site power.

CHAIRPERSON BONACA: Okay.

MR. RASMUSON: Okay. Thank you.

CHAIRPERSON BONACA: We've got one more.

MR. RAUGHLEY: I'm Bill Raughley from the Office of Research, here to talk to you today about a report. It's the first draft of a report that we're working on.

Right now we've divided the task up into three steps. The first was to obtain some great data, and we did that from NERC, analyzed that data. We dabbled in some different areas and presented to Electrical and asked them where do they want us to drill down and what would they like us to do next.

DR. APOSTOLAKIS: When will this report be ready?

MR. RAUGHLEY: We have a stakeholder review in June.

DR. APOSTOLAKIS: And that includes us or are we going to have it earlier?

DR. SHACK: We have it.

MR. RAUGHLEY: You have my first draft.

DR. APOSTOLAKIS: I didn't see it. I'm sorry.

DR. SHACK: E-mail.

DR. APOSTOLAKIS: Oh, it was E-mailed?

DR. WALLIS: It was one I couldn't read probably.

MS. WESTON: I gave you a hard copy, Graham.

DR. APOSTOLAKIS: Well, you should have done that to me, too.

MR. RAUGHLEY: This is an overview of the report. The purpose, how we got into this was off the NUREG 1784. Jose asked us to look at grid data and come at the problem from the grid side rather than keep looking at it from the nuclear side. He said, "Look at it from the grid side and come down to the plant."

And what we're doing is we're looking for signs of change, emerging trends or potential vulnerabilities that may be masked by just investigating the nuclear plant data alone.

And the issue here is has the grid changed or are there trends or vulnerabilities such that we should start looking at the regs. different or are we okay or should we revisit the assumptions about our grid risk analysis.

So that's the potential use of this. You know, we don't know yet if we're drilling a dry hole or a wet hole. We're just starting to look, but I think we're in a wet hole.

DR. APOSTOLAKIS: I don't understand this. You want to know what the potential vulnerabilities of the grid are?

MR. RAUGHLEY: Yeah, that section --

DR. APOSTOLAKIS: But you can't do anything about these, can you? I mean if there is a vulnerability somewhere it's --

MR. ROSEN: I wouldn't be so sure the NRC can't do something about it. The NRC has licensees, and if you put pressure on the licensees, they can put pressure on the people above them.

DR. APOSTOLAKIS: Didn't somebody use the words "beyond the statutory authority of the NRC"? Now you are changing that?

MR. ROSEN: No, no, wait a minute. Listen. I said the NRC has licensees, right? Those licensees can put pressure on the people who they have contractual relationships with if they get --

MR. CALVO: After October 14th, I was plagued with people asking me, "Don't worry about it. The likelihood of this happening again, it's never going to happen again."

We said we don't know what that is, and what I thought was important to know is how the grid connects to the nuclear power plant. So we're always looking for the nuclear power plant to the grid. So let's go outside.

Now, keep in mind now that the nuclear power plant has no transmission. As transmission operators, we don't regulate them anymore. So I think what's very interesting to find out is what is the contribution of the grid, the way you manage the grid, the availability of those fossil fuel plants.

Look. It's 20 percent of power the nuclear properties contribute to it. They need the other 80 percent of power to assure the availability of power. If we don't know what the other 80 percent is, how do we know if the off-site power availability is going to be insured.

MR. ROSEN: I'm not arguing with you.

MR. CALVO: All right.

MR. ROSEN: I think you're exactly right. I'm just arguing with George that there's nothing he can do about it.

MR. CALVO: Nothing we can do about it, but we can sure state these contingency analysis that you each year they tell you exactly what is the vulnerability of that nuclear power plant in that particular area.

So we go to the grid and play it back. We're looking for the power plant, and we put it the other way.

DR. APOSTOLAKIS: Well, I'm sure there's a reason. We'll come to this. I just was wondering.

MR. CALVO: It's very hard to sell these things now because I'm getting outside the box. So

I've got to have --

MR. ROSEN: I know how that feels.

MR. CALVO: -- got to have the people who support it. So I became passionate about this. Right now we're telling you about it. We're going to come tomorrow asking you for an endorsement. Okay? And we want to be sure that you understand where we're coming from.

MR. ROSEN: Great.

CHAIRPERSON BONACA: Let's move on with the presentation.

DR. APOSTOLAKIS: I enjoy passionate people.

(Laughter.)

MR. CALVO: Well, sometimes it gets you into trouble.

MR. RAUGHLEY: Some of the things we're trying to do is identify and assess grid reliability. People tend to talk about that as an indefinite term and not get down to some numbers.

The percent of the time the grid is degraded and you're a nuclear power plant.

Some insights that we can obtain from looking at the off-site power supplier. The grid is a complex system.

And some vulnerabilities that are potentially risk significant issues.

DR. APOSTOLAKIS: What's the definition of a complex system?

MR. RAUGHLEY: I'll get into that on the last slide if you could wait until then.

DR. WALLIS: Other analytical models for grid behavior, are they reliable, predictive?

MR. RAUGHLEY: Yes.

DR. APOSTOLAKIS: They must be.

MR. RAUGHLEY: Yes.

MR. ROSEN: Right.

MR. RAUGHLEY: Plenty.

As a summary, an overall summary, we're developing indices and insights to gauge the impact of changes in transmission system loading and grid reliability based on obtaining -- we have 600 events, actually 700. I've used 600 events from NERC, and 7,000 transmission line records.

DR. APOSTOLAKIS: Nationwide?

MR. RAUGHLEY: No, the transmission line records are in the Eastern interconnection. I'll tell you about that. It's next.

DR. RANSOM: Historically they've used excess generating capacity as a measure of reliability.

DR. APOSTOLAKIS: Oh, you're pointing. I'm sorry.

DR. RANSOM: Has that changed a lot in recent years?

MR. RAUGHLEY: I'm missing this.

CHAIRPERSON BONACA: Could we please? I mean we're having separate conversations. Vic Ransom was asking a question here.

MR. RAUGHLEY: The eastern interconnection is from the east of the Rockies and Texas. This behaves as one synchronous circuit. This behaves as another synchronous circuit, and Texas behaves as the third synchronous circuit.

CHAIRPERSON BONACA: Vic, why don't you shoot your question?

DR. RANSOM: Well, historically they've used excess generating capacity as an overall measure of reliability, and it used to be about 20 percent. Has that declined in recent years?

MR. RAUGHLEY: Yes. It's on an individual basis, but if you look at some of the individual ISO has put out reports on that. For example, the New York ISO shows that through 2006 or they're projecting that in 2006 or seven that they'll have insufficient generation.

MR. ROSEN: Insufficient, which means zero percent?

MR. RAUGHLEY: Zero reserve, and then they have the actions. You know, that justifies the actions they have -- how much generation they have to bring on line. So it's if they don't bring this generation on by this time, this time, and this time. Then they'll exhaust their reserve.

MR. ROSEN: What time did you say the zero percent was? Two thousand and?

MR. RAUGHLEY: It's 2006-2007. I forget the --

MR. CALVO: But they've still got to meet the criteria. They've got to meet the first contingency. As soon as you've got to meet the first contingency, you've got to have enough power.

In the Northeast, the worst contingency that you had is losing the line from Hydro Quebec, which is limited to only about 1,200 megawatts. The reason you've got 200 megawatts at the headwater is because you cannot cope with the rest of the line without disturbing the whole grid.

So you've got still a margin, but you've got to be prepared to compensate for downline. You may have to borrow from PM. Otherwise you're not meeting the first contingency, and then every nuclear power plant in the Northeast and there, they will be in violation of their won tech specs and violation of anything they're doing.

You've got to see the margin, but because of that, they've got to have it. They made it the first contingency.

MR. RAUGHLEY: The power market is taking care of any shortages. So as soon as a shortage pops up that identifies an area that the people need to build in and that the power market responds to that fairly rapidly.

The things that I'm going to tell you about in the remaining few minutes here are that the transmission system congestions increased. Grid reliabilities changed, not changing. It has changed. The number of larger and longer blackouts have increased, and the data since '99 shows the true performance of the grid, and that both the grid and the off-site power supply tend to behave as a complex system, and that's been of interest to us because that technology used different methods than we're currently using.

As background, I used the definitions of

NERC reliability, and they talk about reliability in terms of the adequacy of the generation supply and the operating reliability of the power system to withstand the disturbance.

On the adequacy of the generation supply, it's the adequacy to meet the demand to its customers all the time, taking into account unexpected, unscheduled, reasonably unexpected, unscheduled outages.

The events are reported, grid events, above a certain threshold, are reported to DOE. It's sort of like an LER. Now it goes to an NRC LER, except there are defined thresholds.

For example, in my report I'm focusing on blackouts and the blackouts that we're talking about are more than 50,000 customers lost for an hour, more than 300 megawatts shut for more than 15 minutes.

On adequacy events, they're required to report a wide area of voltage reductions, wide area of public appeals or load sheds more than 100 megawatts, and that's the size of the events that we're talking about.

In the scheme of things, in the scheme of the grid, they are relatively small events. Losing 300 megawatts or 50,000 customers is nothing. So the grid should be able to take these without much problem.

NERC bends these events into their three categories, and I ended up with 193 adequacy events, approximately 450 operating reliability events, and 68 unusual events.

And when you're looking at the grid data, there's some similarities and differences in the vocabulary that you have to watch out for. First off the off-site nuclear plant, off-site power system, and the grid are the same system of generators, transmission lines, transmission facilities and loads. It's all the same thing we're talking about.

Recognize that the nuclear power plants is both the generator and the load on that system, and the nuclear power plant is subject to the same conditions as the grid.

And the other thing is the NERC blackout is not a station blackout. so there's two different things there to keep clear.

The next area, I'll give you some background on the increased transmission line loading, and I think between most of these bullets were covered at the end of the last presentation by a couple of gentlemen here.

Open access of the generators to the transmission system from deregulation does result in new power flows in the grid, and what happens is this is FERC Order 888, required that anybody can put a generator on the grid, and you have to give them access.

What that does is causes an incremental increase in the loading and you don't always know where that load is going to go. So if you were to park a generator on the grid, the power flows according to the laws of electricity, not the power market, and you've just got to be prepared for where that's going to go.

Typically what happens is somebody will sell power. You know, somebody in Virginia may sell power to somebody in New Jersey, and they have to arrange for those power flows to make all of the contractual arrangements all the way up, and that's done through analytical techniques.

DR. WALLIS: Do they keep track of the electrons to make sure?

MR. RAUGHLEY: Yeah, they do some code flows for circuit stability analysis just to make sure everything is going to work.

And the thing you have to recognize about the open access transmission, even if your state hasn't deregulated, that's going to affect you. You know, there's the traditional deregulation where you've removed the generators from the rate base, and then there's this other part where everybody has open access to the grid, and that affects everyone.

MR. ROSEN: And grids are interstate.

MR. RAUGHLEY: Yes. Like I said, you've got three grids, the Eastern, Texas, and the three circuits.

MR. ROSEN: Most of the grids are interstate. Texas is something isolated.

MR. RAUGHLEY: Yes. If you look close on here, Texas has some AC to DC to AC connections that effectively isolate them from the rest of the group.

MR. ROSEN: So as not to be contaminated by the rest of the country.

MR. RAUGHLEY: And vice versa.

(Laughter.)

MR. RAUGHLEY: The other thing that's going on in the blackout task force report, if you look at Chapter 7, I believe, they go back and discuss past operating events, but they start out by noting that in the -- that there's been an absence of major transmission projects over the last ten to 15 years.

So utilities have increased the utilization of the existing transmission systems to meet demand.

And then NERC has anticipated that there was going to be congestion as a result of the FERC Order 888. So they created what they called the transmission load relief request, the TLR, and that's the records we've accessed to do some of the analysis, and that's just on an Eastern connection.

What this is for is it's a way for the ISOs and the operating entities to manage the congestion and respect the limits on the transmission lines.

And it is a graded system from one to six. A number one is a "no, never mind." A two announces there's a problem and they're going to take action in 30 minutes in terms of canceling some transactions. Fours reconfigure the grid. Five is an announcement that they're going to take action, larger relief, larger cancellation of transactions.

So there's this step-wise system demand units. The other thing about transmission line congestion is we had an event; the Callaway event demonstrates that a transmission congestion can degrade nuclear plant voltages.

The other thing, there was a couple of us, Tom, myself, three or four other people from the NRC were on the blackout task force. In Chapter 7, they presented the grid statistics as a complex system, and to the grid people -- and it drew our attention because it's completely different than what we're doing at the NRC, but to the electric folks or transmission folks, it's, yeah, it's a complex system and it brings with it a different set of statistics and methods and way of doing things.

So we're just getting introduced to that. So we'll just talk briefly about that.

DR. APOSTOLAKIS: Yeah, but if you don't have to tie to chaos theory, complex systems are complex systems, and usually a power plant is a complex system, and you use PRA to analyze it. So it depends on the complex system you're talking about.

These are networks really, aren't they? I mean the grid is a network, which is a complex system because it's a complex network. But to say that experts in chaos theory view it, I mean, --

MR. RAUGHLEY: I don't know what that means. That's their claim to fame.

DR. APOSTOLAKIS: God, I hope they have other claims, too.

CHAIRPERSON BONACA: All right. Let's

move along.

MR. RAUGHLEY: The next slide, this is a plot of the number of transmission line relief requests, and here you're starting in 1997 when deregulation started. Then you're going to 1998, 1999, 2000, 2001, 2002, 2003. I think things are getting worse each year.

And this ended in August of 2004 and September. The point lies right there, and the October point lies right there. So it's right on top of it. I think the cold summer probably helped.

What you notice here, you know, each year is getting worse than the next. There's always a peak in August. And we talked about the LOOP events were more May to October. You can see here in May is when you start to ramp up, and you ramp down by the end of September, October.

DR. WALLIS: What exactly is transmission load relief?

MR. RAUGHLEY: These are the transmission line LERs, which are records of the number of times the transmission lines overloaded and they've taken action to relieve.

DR. WALLIS: Too much power going along a wire.

MR. RAUGHLEY: Yes.

DR. WALLIS: So they have to do something.

MR. RAUGHLEY: Yes. The objective is to take action before it does all of that, and this is what it's attempting to do. But it's showing you working the system harder and things are getting worse.

What I'm going to do next is I've put some charts in the report. If you do some time series plots on the grid, you can see that at certain phase of the year there's a lot of overload. I think I can get it down to the times and places that the overloads are occurring the most. It's indicating bottlenecks.

And our interest would be if they are at spots next to nuclear power plants, which would cause the voltage drop when you tripped the reactor.

DR. RANSOM: Are these components of the grid privately owned transmission lines?

MR. RAUGHLEY: Yes.

DR. RANSOM: So those people get paid for the power that is transferred over their system.

MR. RAUGHLEY: Yes, correct.

DR. RANSOM: You wonder with this excess why aren't more lines being built, I guess.

MR. RAUGHLEY: Well, that's part of the

problem, is there aren't any line being built.

DR. RANSOM: Is that because they're not profitable or because regulation?

DR. APOSTOLAKIS: This is beyond the statutory authority of the agency.

CHAIRPERSON BONACA: Because reliability is not necessarily an objective for each one of them individually.

MR. RAUGHLEY: When you're shifting power from A to B, I think there's a lot of arguments on why should you build a line in New Jersey to ship power from Virginia to Massachusetts. It's that sort of argument.

CHAIRPERSON BONACA: End up line Amtrak.

DR. WALLIS: I wonder what do we learn from all of this though. Do we learn that this is exciting or that everything is fine?

CHAIRPERSON BONACA: Well, let's see the next observation here.

MR. RAUGHLEY: I haven't drilled it down to the nuclear plant yet. It's just starting. What we're hoping to learn is whether or not this condition is potentially hurting the nuclear power plant voltage.

MR. SIEBER: Your next slide may tell us, give us a little insight as to where you're headed.

MR. RAUGHLEY: Yes. There's 25 slides of things I've done with the NERC data, and this is the adequacy, and what these events are, these are wide area voltage reductions, public appeals, and load shedding more than 100 megawatts.

You can see there was improvement in this 15-year period, and then that has been offset by the increase in this period. The same on the grid operating reliability. These are blackouts, and these were the --it's either 50,000 customers out for more than an hour, 300 megawatts lost in 15 minutes. There are some larger type events.

And I've divided into weather and non-weather events. You can see you're relatively flat through this time period, and then both the weather and the non-weather events pretty much doubled in this period.

CHAIRPERSON BONACA: Those are blackout events, right? Number of blackouts?

MR. RAUGHLEY: Yes.

And then here we're looking at events more than 800 megawatts. We picked 800 because that was the average load loss on the grid event.

And here the larger events are getting

larger is what's going on here, and this I picked four hours because this is the typical -- in the station blackout, you're really only interested in the long events. The shorter events are just noise.

But just to get an idea the longer events are getting longer, and as I think you summarized it, at the end of the last slide from what Dale said, pretty close to what you observed in the nuclear plant, David.

DR. SHACK: But his LOOP frequency is decreased and it's basically constant over '97-'99. So somehow you guys are bidding data differently.

MR. RAUGHLEY: This is grid events, and he's talking nuclear plant events.

DR. SHACK: Wouldn't the LOOP frequency be a lot --

MR. RAUGHLEY: In the last report, NUREG 1784, I looked at the grid differently than he did, and we have slightly different areas. What we did is there will be a table in his report comparing ours. We sat down in two columns so that it's clear what the differences are.

And then this is this complex system theory, and as described by the power laws and according to these people, you take a log-log plot of the number events and the size of the event and plot it, and it has what they call a power tail straight line here. Then it ends to be a complex system, and this is the nuclear plant LOOP data, and it shows the same type of characteristic.

DR. APOSTOLAKIS: So basically you --

MR. RAUGHLEY: What these people are proud of, the August 14th blackout was predictable following their theory. It's a point on the curve.

And, again, what we had hoped to gain from this is additional insights from those that Dale is doing.

DR. APOSTOLAKIS: Two comments. One is this has nothing to do with chaos theory. This is complex system theory.

But the second, it was predictable that something would happen. Now what? See, that's the problem with that stuff. Basically they are fitting curves.

MR. RAUGHLEY: Yeah, there are.

DR. APOSTOLAKIS: Okay. Something would happen. Yeah, thank you very much.

MR. RAUGHLEY: There's two groups. One is from Cal Tech and they said what you said.

DR. APOSTOLAKIS: Oh, if it's Cal Tech,

it's different.

(Laughter.)

MR. RAUGHLEY: And their view is this is how it's going to be and you have to be prepared for it and --

DR. APOSTOLAKIS: Oh, yeah, I know.

MR. RAUGHLEY: -- the other group is being funded by DOE. It's a collection of universities and Oak Ridge, and they're looking more at the mechanism of what's going on there.

DR. APOSTOLAKIS: You cite two or three papers here. One is accepted for publication. Do you have copies of these? Can we get copies of these papers?

MR. RAUGHLEY: Yes, I'll Xerox them and leave them in your box.

DR. APOSTOLAKIS: I'd appreciate that. Give it to Ms. Weston because I don't have a box.

DR. DENNING: Can we go back to the previous slide? I'd like to follow up on what Bill was saying. If we look at that trend that we see down there and ask the question should we be concerned about that I think was where Bill was going, and we saw a difference --

MR. RAUGHLEY: And where I think you

should be concerned here is if you want to -- I think you should base the risk on what's going on and not what has happened. This might be a better predictor, might give you a better indication of the risk, this data.

If you mix it with this data, you're going to water down what has happened.

DR. DENNING: That's right. Well, I was looking historically at what the risk of loss of off-site power has been, and now looking at that component of it, that's pretty much today outside of our control, and I think that what we're seeing is the part that's outside of our control or largely outside of our control is really increasing substantially, and I would expect the loss of off-site power to be somewhat proportional to that, although there are other factors that may be happening that are why Dale's answers are different.

But I think that it is indicating we have to really start worrying about what's happening in the grid and the communication.

MR. RAUGHLEY: I think that's Jose's whole angle on this.

DR. APOSTOLAKIS: Very good.

MR. ROSEN: Another way of saying it is to say that that last bar on the chart is more like the future. That reflects what the future will be like more than the other three smaller ones.

MR. RAUGHLEY: Yes, yes.

CHAIRPERSON BONACA: Good.

MR. SIEBER: Do you want to summarize?

MR. LAMB: I'd like to thank the ACRS for having the staff come and give this informational brief, and we do not expect a letter from the ACRS on this topic.

And in summary, I just wanted to summarize the four topical areas that we're working on. The staff is considering a generic communication in the off-site power system availability of station blackout review topical areas and based on the risk results that we're going to get from the research studies that you've heard about, the staff will determine if regulatory action is warranted.

And then the staff is setting up a process to receive information, operational data from NERC, and interact with NERC during great emergencies, and that will take care of the interaction to the external stakeholder's topical area.

Thank you very much.

MR. SIEBER: It would be good if we could get a copy of your final report and whatever your generic communication to the industry is, and that way we can make our independent judgment as to whether that's appropriate or not.

So I would add that. I think your presentation is fine. I think we have to keep in mind that you've only done part of the work so far. There's more that has to be done before anybody can draw a final conclusion about anything, but the important thing is do the assumptions which underlie the industry risk numbers with regard to LOOP events, do they continue to be valid as the system reliability changes?

And so that's the big question to be asked.

If no one else has any questions, Mr. Chairman, I turn it back to you.

CHAIRPERSON BONACA: Thank you, and we appreciate the presentation.

We'll take a break until 5:20, 5:25.

(Whereupon, at 5:07 p.m., the meeting was adjourned.)