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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
PLANT OPERATIONS AND FIRE PROTECTION SUBCOMMITTEES
REGION II VISIT

WEDNESDAY, JUNE 19, 2002
8:30 a.m.
24th Floor
SAM NUNN FEDERAL CENTER
61 FORSYTH STREET SW
ATLANTA, GEORGIA

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P R O C E E D I N G S

MR. ROSEN: Good morning.

This is the Advisory Committee on Reactor Safeguards, joint Subcommittees on Plant Operations and Fire Protection.

I am Steve Rosen, Chairman of the Fire Protection Subcommittee, and also substituting for Jack Sieber who is Plant Operations Subcommittee chairman who is unable to be with us today.

On my right is John Larkins who's the technical director of ACRS, Mario Bonaco who is the vice chairman of ACRS, also Graham Leitch a member from the ACRS, Dr Vic Ransom a member of ACRS, Dr. Dana Powers from the ACRS and Dr. Bill Shack a member of the ACRS.

We also have a member of the ACRS staff with us, Ms. Weston who's a project engineer with the ACRS, Kendra Bilk and Martha Whitaker.

We are all very glad to be here. We had an interesting and exciting day yesterday at Watts Bar, and we look forward to having a fruitful discussion here today.

MR. REYES: And we want to welcome you to Region II. I know you had a good tour of the Watts Bar facility yesterday. We would like to make today better yet.

We have an agenda on the right-hand side of your folder that we believe is responsive to your request, but as the day goes along if you find a need for information

1 different, we will do that.

2 The agenda that we have prepared has a lot of actual
3 presentation by members of the staff, from management, from
4 inspectors, resident inspectors. I think you're going to find
5 it very engaging and direct feedback from the people who are
6 implementing the programs.

7 We would like to just briefly give you a refresher on
8 Region II just for a few minutes -- we're not going to dwell on
9 it a lot -- before we get into the subject matter.

10 Just as a reminder, Region II covers the Southeast of
11 the United States, it's ten states on the Mainland. We also
12 cover the Caribbean; the U.S. Virgin Islands is also under our
13 jurisdiction, and we do have licensees there. No reactors, but
14 we do have industrial radiography, medical irradiators, et
15 cetera, et cetera, so we have a lot of licensees in the U.S.
16 Virgin Islands.

17 The region organization is typical with other
18 regions. We have four divisions, three technical in nature who
19 specifically you're going to hear from today. The Division of
20 Reactor Projects and the Division of Reactor Safety are going
21 to have members of their management and inspection staff
22 present to you today on the different topics, because that's
23 what's more relevant to this subcommittee.

24 A brief background, we have a large population of
25 licensees. Of the 103 reactors in the United States we have

1 33, so we do have about a third of the operating nuclear
2 reactors in the country, and most of them are pressurized water
3 reactors, but we do have a little bit of a mix in terms of
4 vendors.

5 In terms of fuel facilities there's nine fuel
6 facilities in the country; we regulate five of them, so we have
7 half of the fuel facilities we regulate here. We have a
8 relatively modest materials licensee population on the order of
9 800 give or take a few every day.

10 But most of our efforts are in the reactor side of
11 the house, so I think that would be relevant to the committee.
12 And we have a large population of them, about a third of the
13 units, so the staff that's going to be talking to you have
14 broad experience in that in that kind of day-to-day activity in
15 this.

16 I would like Bruce Mallett, my deputy, to briefly
17 talk to you about some of the challenges we're working on in
18 the region from an organizational point of view, and after that
19 we will move right into the technical subjects on the agenda.

20 MR. MALLETT: Thanks, Luis.

21 I would add that the last time you were in Region II
22 I know Dr. Powers was here, I don't know if Graham was here or
23 not. I think he might be the sole person that was here the
24 last time.

25 We have made some changes since you were here. One

1 of the concepts we have put into the region is the team leader
2 concept, and with the new reactor oversight program which we
3 have people who are going to talk about later on today one of
4 the keys to that are teams, and we have installed a team leader
5 in each branch to not only lead those teams, but also help the
6 branch in managing the branch.

7 We also think since you were last here have license
8 renewal, and several of our plants have achieved license
9 renewal, and we have special teams to inspect those license
10 renewal functions, and you may hear some of that later on from
11 some of the speakers during the day.

12 Also on the agenda I want to highlight one thing.
13 You had asked for input on what we feel are the challenges,
14 where we feel we are in the reactor oversight process.

15 You heard some of this from the Watts Bar licensee, I
16 know they're not bashful in giving you some of that
17 information.

18 So what we thought might be a good way to do that is
19 to have a spectrum of individuals from the inspectors all the
20 way up to the managers to provide you their thoughts on that
21 this afternoon, and then allow you to ask them questions, and
22 I'm sure you're not bashful in asking those questions either.

23 Luis and I thought it might give you an idea of the
24 regional operations if we tell you what we think our challenges
25 are, and these are right out of our operating plan, and we'll

1 try to point out some things that we've done to address those.

2 They also are connected if you look down the list
3 with the ten challenges that the chairman gave the agency not
4 only last year in the agency action review meeting, but also
5 this year at the review meeting.

6 One of the challenges he gave us was in human
7 capital, and we have changed that a little bit in area to call
8 focus workforce planning on retention and development of skill
9 needs.

10 We established a strategic workforce plan here, and
11 that has helped us bring together in one area a focused plan on
12 how we're going to recruit and maintain the skills in the
13 region that we need not only for new business, but also to
14 conduct the inspection program and operate in licensing and
15 reactor areas.

16 So several years ago a part of that was to develop a
17 matrix of skills of the people that we need, not necessarily
18 that we have on board, and so we established that list of
19 skills and there were some holes in it, and that's what we
20 used then to target recruiting of individuals.

21 Some of the individuals you see over here in the
22 audience have been here several years, Billy Crowley, and some
23 of the people have been here just a few weeks, so we have a
24 whole gamut of individuals, and part of that is due to this
25 recruiting effort to obtain those skills.

1 Our next step in that strategic workforce plan is
2 obviously to develop people, and also to develop them before
3 the person with that skill leaves.

4 For example, if we have an expert -- and, Billy, if
5 you don't mind I'll use your name -- like Billy Crowley in the
6 materials area, then we want to develop someone before Billy
7 decides to retire and leave the agency for at least a year and
8 maybe two years before he leaves, rather than wait until he
9 leaves and then we've lost that transition. So we believe in
10 this, we think the strategic workforce plan has helped us in
11 that.

12 Luis, is there anything you wanted to add?

13 MR. REYES: No.

14 MR. LEITCH: Could you give me an idea of how many
15 people are in Region II?

16 MR. MALLETT: We have around 200 I think is a good
17 number to use.

18 MR. LEITCH: That includes the sites?

19 MR. LEITCH: There's about fifty-some resident
20 inspectors, and there are some site secretaries, but they're
21 only working maybe ten hours a week, so they aren't a full --

22 MR. LEITCH: So it's about 200?

23 MR. REYES: If you include part-time employees it's
24 222.

25 MR. LEITCH: Thank you.

1 MR. MALLETT: We at most of our sites are now down to
2 the number N of residents; we only have N plus 1 at two sites
3 -- or are we down to one now -- one site.

4 The second bullet we have -- Does that answer your
5 question?

6 MR. LEITCH: Yes, it does. Thank you.

7 MR. ROSEN: That N you mean, that's the number of
8 units at the site?

9 MR. MALLETT: That's correct. We only have one
10 three-unit site that's operational right now, and that's
11 Oconee. The other ones are all two or one.

12 MR. REYES: The policy is we have a minimum of two
13 residents, and for those units who have three reactors we will
14 have three meeting the number of units, but if there's only one
15 reactor we still have two residents there, a minimum of two.

16 MR. LEITCH: We have Loren Plisco, our division
17 director of projects, on the agenda later on. He can give you
18 some more information.

19 And one of the challenges is obviously to when those
20 people are up for their rotation to get them to a new site, or
21 get somebody there to fill in the void when they have left that
22 site.

23 MR. LEITCH: As you have identified here the skill
24 set needs for different individuals, can you compare that
25 throughout the regions so maybe there's some cooperative

1 efforts to identify particular skills that are needed, and if
2 one region doesn't develop it maybe another region will develop
3 it?

4 MR. REYES: We're doing a little bit of that. The
5 agency is putting together a strategic workforce plan, and in
6 fact they're using outs as an input to that.

7 One of the discussions is for efficiency and
8 effectiveness should we go in the future to a center of
9 excellence.

10 Let's take fire protection for example. Should we
11 have a fire protection engineer or two in each region, or
12 should we create a center, meaning one of the regions will hold
13 all the skills in fire protection as a mechanism to keep a
14 large group with that skill, and of course you can travel in
15 any direction. So we haven't finalized that.

16 What we do at the present time is we share resources.
17 At the present time we have inspectors helping Region IV do an
18 inspection at the Coopers Station. You may have heard of some
19 of the agency activities there.

20 We helped Region I on Indian Point. We do examining
21 of operators in another region, they help us with some exams.
22 So we share resources, but it's not part of the integrated
23 workforce plan.

24 At the present time each region has, is designed to
25 have resources to do all the inspections, so we would expect,

1 Bruce and I are expected to have fire protection engineers do
2 the fire protection inspection, and metallurgical engineers.
3 That's because the design on the region when I talked to you
4 about the organization is identical, and we all do the same
5 kind of implementation. But we do share resources, and the
6 question into the future is that the best way to do that.

7 I can tell you specifically on the fuel facilities
8 which is a smaller number, and we have five, that means some
9 regions have one or none, and at the present time there's a
10 proposal in front of the commission to make a change in that
11 arrangement, so maybe the most efficient and effective way is
12 to regulate all the fuel facilities from one location, and then
13 you can keep criticality expertise, chemical and nuclear safety
14 expertise, and it will be a better approach.

15 And I think on the reactor side we're probably going
16 in that direction for certain specialties where they're hard to
17 get, hard to keep, and you don't need them every day.

18 MR. MALLETT: One area in particular we have shared
19 outside the routine reactor oversight program is in the license
20 renewal. We have several people that I would consider experts
21 in that area now in reviewing licensees' programs for aging,
22 and we've sent them to other regions.

23 We have probably done the most license renewals,
24 inspections in Region II of any region.

25 MR. REYES: When a region only has one of those we

1 share with them our expertise and resources. There's a lot of
2 sharing going on, but not as a design of the organization.
3 That's what we're questioning now is should we design the
4 organization differently.

5 MR. MALLETT: The next challenge area that we have
6 that we're quite excited about some of the things we have been
7 doing is the use of information technology. We changed this
8 one a little bit. In our view it ought to be to reduce
9 operational burden and gain efficiencies, not just to use the
10 latest bells and whistles that come along.

11 And we've done some things that we like in that area.
12 For example, in our operator licensing where we go out and
13 review individual an individual candidate's job performance
14 we're working on, in Chris Christianson's division we're
15 working on using a -- what do you call it, a tablet? -- a
16 notebook computer instead of taking all these pages that you
17 record candidates' results on you have it on electronically on
18 a little tablet no bigger than about his size [indicating], and
19 you carry that around with you. It's going to prove much more
20 efficient than in the past.

21 We are piloting some use of personal data assistants,
22 PDAs, for inspectors to use on inspection. For routine simple
23 things you can use a checkoff type thing. We're doing that
24 both in the reactor area and in the materials area.

25 And something we just started is use of digital

1 cameras -- and Luis may want to say something more about that
2 -- for the residents.

3 MR. REYES: One of the issues you'll see later on is
4 improve communications, and as a mechanism to improve internal
5 telecommunications the technology today offers you a situation
6 where you're going to go with a digital camera and take a
7 picture of the component, the equipment, or the situation, put
8 it in our system and not only we have it, but we can put in the
9 inspection report, and a picture is worth a thousand words, and
10 a way to communicate better with the public. So we are now in
11 the field testing several brand names.

12 DR. POWERS: We got a demonstration of that during
13 our visit to Watts Bar. It was I thought a terrific
14 communication device just within the confines of the site
15 itself.

16 MR. REYES: It's been very effective. As you know,
17 we have instructed licensees to do reactor vessel head
18 inspections, and now it's easy when the inspection is going on
19 the inspector can go in and photograph, take pictures, and
20 immediately we have access to a visual description of the
21 inspection and we can share that internally. And we're looking
22 forward to getting the whole fleet of inspectors with that
23 equipment.

24 MR. MALLET: In fact, some of our residents are
25 getting innovative. Loren Plisco shared an anecdotal story,

1 some of the residents are taking a picture of a material
2 condition that's not what you would want it to be in the plant,
3 and they're going up to the plant manager and showing him right
4 on camera "Is this what you would want in your plant?"

5 MR. REYES: It's faster than paper.

6 DR. POWERS: The one that was described to me was of
7 some leakage, and they could take it in the motion picture mode
8 and they could come up and say "Did you understand that the
9 leakage is this bad?", and they could see it.

10 MR. REYES: It is a very effective tool. We're just
11 doing field testing with several models and brand names before
12 we do the big investment, but we made the decision to go
13 forward. We just want to make sure it's a smart decision.

14 MR. MALLETT: The other thing we're doing in this
15 area that's proved very effective for us is we have what we
16 call docking stations now. Instead of permanent computers on
17 the desktop we have a station you can dock it or plug in
18 essentially your laptop, and you can take that with you in the
19 field. It's saving inspectors having to take volumes and
20 volumes of things on paper; now you just have one little CD,
21 even the regulations, and just plug it in if you need it, and
22 that's worked out very well for us.

23 The next one I would combine with the last one on
24 communication. You know, one of the agency's challenges was to
25 work on the communication, and we've done several things there.

1 One is internally we have our own communications plan to help
2 us improve how we communicate not only up and down the chain,
3 but also across organizations between the division of reactor
4 safety that Chris Christianson is the division director of, and
5 the division of reactor projects that Loren Plisco who is going
6 to speak to you later is the division director of, and we've
7 found that plan is a good tool to guide us through some planned
8 activities to try and improve in that area.

9 One of the things Chris's division has done a lot of
10 is meet with their staff in small focus groups for a what-
11 would-you-like-to-have changed, and kind of a -- what do you
12 call it, Mark Lesser, a three-sixty review I guess of where
13 we're going and what we ought to do, and that's proved fruitful
14 for us.

15 Externally we tried something that we're working on
16 is instead of the meetings we have had just with licensees at
17 the end of the cycle, we have targeted some meetings with local
18 officials, and even a town meeting with Commission Diaz, so
19 what we hope to gain out of that is interface with the public
20 to answer questions not in response to a particular event or
21 issue, but at a time when you're not in that scenario we find
22 we get a lot more candid discussion, and I think it proves to
23 improve the public's confidence in us.

24 When you're responding to an event in a meeting
25 you're always coming from the negative side of trying to say

1 what we did and respond.

2 The last bullet there is to improve the use of the
3 significance determination process for after-inspection
4 findings. I won't go into any great detail on that because we
5 have Loren Plisco who is going to talk to you about that in his
6 presentation, and Charlie Payne in the fire protection is going
7 to talk about that.

8 Probably the overall challenge in Region II is we're
9 working on an up-front plan to determine how much time we
10 should spend on the Phase III portion of the significance
11 determination process rather than run the model to the same
12 time frame so that we don't have cases that are three years old
13 we can try to have some scope up front of how much time do we
14 want to spend determining is this a white-white or a full white
15 finding for example.

16 That's the end of our introductory remarks. If you
17 have any other questions, we'll be glad to answer them.

18 DR. POWERS: Some questions about the prioritization,
19 your district thinking about prioritization.

20 You get a bunch of findings in that you say, well,
21 I've got a stack of findings here, I think they're probably
22 green, you know, just looking at them, but I've got this other
23 one that's more complicated, and do you set those kind of green
24 ones aside and work this complicated one, or is there a queuing
25 process, or how do you think you would work this thing?

1 MR. REYES: Well, what we have tried to do, and I
2 think somewhat successfully, most inspectors screen quickly out
3 in the screening process the ones that are not significant, and
4 I think this afternoon when you talk to them I think you'll get
5 that feeling.

6 The ones that now have some significance and then
7 you're trying to determine Phase II or Phase III and all that,
8 we engage our senior reactor analyst, and basically use all the
9 resources to help him do that.

10 The problem is that they're very resource-intensive,
11 and specifically in some areas. In mitigating systems it's not
12 that difficult.

13 We have been at it -- the technology has been at it
14 as you know for a long time. Fire protection is very
15 frustrating. We have the previous problem with security, and
16 we end up changing our whole security significant determination
17 process, so the areas we're using the risk is fairly new,
18 they're really resource-intensive and --

19 DR. POWERS: Well, that's basically what I'm asking.
20 Say you ask your senior reactor analyst who's the one to attack
21 this, I mean that would go and process one at a time. He's got
22 to figure out which one he picks up.

23 MR. REYES: Yes.

24 MR. MALLETT: Exactly right.

25 MR. REYES: We're trying to follow the ones we had to

1 him, if you follow what I'm talking about.

2 DR. POWERS: I'm still talking when it gets to him
3 he's got five of them, how is he picking them up?
4 chronologically?

5 MR. REYES: We have, organizational-wise we have two
6 senior reactor analysts, and they have particular plants
7 assigned, so first we divide the workload.

8 And the second one is basically when they arrive. We
9 try to do them by when they arrive, but what happens -- I'll
10 give you an example -- you've got a fire protection on one
11 that's taking all of your time and we're trying to interface
12 with headquarters on it.

13 The second one comes in which is straightforward
14 mitigating systems. That one gets work and probably would get
15 resolved much faster than the other one. We've got another one
16 with shutdowns, in the shut-down mode, and it will take us a
17 year to get through -- and that's a give and take as we go and
18 have headquarters' help.

19 But they come in sequentially, and one of the senior
20 reactor analysts is going to talk to you this afternoon, and I
21 would encourage you to explore this further with him. But we
22 have to work by plant between two of them, and then they
23 process them as they arrive.

24 Remember, we're dealing with the site to correct the
25 safety issue, so the fact that colorizing, risk assigning an

1 event may take a year or two has nothing to do with the field.
2 The field has been corrected or compensated somehow. We do
3 that right away.

4 MR. MALLET: The other thing we did which I think
5 helps that process is we had the senior reactor analysts
6 reporting to the division director. We changed this year to
7 have them report to branch chiefs in Chris' division of reactor
8 safety. We think that gets them closer to where the decisions
9 are made as to which one you work on first.

10 MR. REYES: Right.

11 MR. MALLET: And Mark Lesser is going to talk to you
12 about Alloy 600, but he's also branch chief in that division
13 and may want to share some things.

14 DR. POWERS: I understand. I have no idea what the
15 right way to do it is. Actually I'm curious how you're
16 thinking about it.

17 MR. MALLET: We're working on that. We don't have
18 it solved totally yet.

19 MR. REYES: It's by plants, and then how they come in
20 into the pipeline and they get processed, but some of them get
21 backlogged.

22 DR. POWERS: If Steve would just run his fire
23 protection subcommittee correctly, we'd have all this fire
24 protection done real fast; right?

25 [Laughter.]

1 MR. CHRISTIANSON: Additionally on the SDPs which are
2 greater than green, we have established a tracking system for
3 them, and every Wednesday we have that DRP division and the DRS
4 division in a morning meeting get together and go over the
5 status of that to make sure that everything is tracking okay
6 and that we understand where it is in the process.

7 And that's to try to -- we have an internal goal of
8 90 days. We don't make it all the time on some of the
9 complicated ones, but that's what we're trying to do on the SDP
10 process.

11 MR. MALLETT: One of the reasons we did that was we
12 got some cases that were out there a long time, and we said why
13 did this take us this long, and in looking back we felt that we
14 should have done a better job up front in deciding how much
15 effort are we going to spend. But we haven't solved this
16 thing.

17 DR. POWERS: When you have a chance if you can go
18 back and look at things and say, now, what tools should we have
19 had to accelerate this process. You know, that's feedback
20 that's really useful to us.

21 MR. MALLETT: You're going to get that this
22 afternoon.

23 MR. REYES: You're going to get a lot of it.

24 MR. ROSEN: Are you keeping up with the flow of
25 findings that you have to do these analyses on, or are you

1 falling behind?

2 MR. REYES: We were not, and then we established
3 several things such as the tracking mechanism, we talked to the
4 program office. One of the problems is that we're not going to
5 invest any. For example we had one that still is not finished
6 and they're in shut-down, and those resources are down limited
7 to one or two individuals in headquarters, and so the reason
8 the reason why the agency has some particular topics are
9 limited, so we have met with Sam Collins, the director of the
10 office of NR, and he understands the situation and there's
11 changes being made.

12 Today we're much better off. I think we're getting
13 closer to the goals that we want to accomplish.

14 Now, one thing I should have said before was while we
15 were talking about structure, we're trying to increase the
16 knowledge of all the inspectors on risk, because what we would
17 like to do is exactly what you talk about, quickly process
18 those that have no significance so we can leave the limited
19 resources we have such as senior reactor analysts and all that
20 to only have a handful, so we only have a handful getting to
21 those that are the real significance, and they don't have to
22 deal with the other ones that can be disposed of rather
23 quickly.

24 So we're sending a good number of our inspectors and
25 managers to the whole series of courses that the SRAs went to

1 just as a mechanism to keep those limited resources dealing
2 with the important cases, and be able to use the larger
3 population to process the ones that don't have real
4 significance.

5 DR. POWERS: You will be gratified to know that this
6 has worked, by the way.

7 MR. REYES: Is that right.

8 DR. POWERS: I was walking through with your resident
9 looking at trains and whatnot, and he was explaining to me how
10 it was counterintuitive what the risk significance of the
11 various trains were, and why, and he's very knowledgeable in
12 risk technologies.

13 MR. REYES: And I don't know if you remember, we have
14 an amendment to the commission that as of December of 2001 we
15 would have every resident go through the early-on training, and
16 we did that.

17 And what we're trying to do now is we're trying to
18 nudge that up, because we think if the inspectors and their
19 first-line managers can deal with most of the flow, the ones
20 that are no significance, then we can be more effective with
21 the ones that are because the senior reactor analyst has a less
22 number of issues to deal with, and they don't get distracted
23 with the ones that could have been handled by the staff.

24 DR. POWERS: This was a very difficult risk analysis
25 to do mentally.

1 MR. REYES: Oh, yes.

2 DR. POWERS: And he lined it up for me very clearly,
3 and so, yeah, I would say your residents based on that
4 interaction are getting very knowledgeable and very
5 sophisticated.

6 MR. REYES: It's a very hard goal, I have to tell
7 you, because we have competing interests as you know. But we
8 are determined to do it, and I think it's paying off.

9 MR. ROSEN: I think you've got a very large problem
10 here, Luis, in that order to maintain both the external and
11 internal confidence in this whole process you need to not have
12 important events that are risk-significant linger very long.

13 MR. REYES: We agree.

14 MR. ROSEN: And in that because the input of the
15 equation is not under your control. The class are going to
16 have findings, and you can't control how many that is going to
17 be, so at any given moment, any given morning you could come in
18 and find your nice work plan disrupted by two or three major
19 findings of the 33 sites in your region.

20 MR. REYES: Yeah.

21 MR. ROSEN: So given that, if I were in your shoes
22 what I would want to do is make sure I keep that backlog
23 squeezed down real tight so that I don't have the vulnerability
24 of having a number of findings coming in on any given day that
25 overwhelms the rapid remedial capability.

1 MR. REYES: We are relatively lucky compared to the
2 other regions. Our two senior reactor analysts are graduates
3 from class number one, and we have had no turnover, we have had
4 no turnover in the senior reactor analysts, so what that has
5 done for us to help us -- and I agree with you -- and that is
6 that they're very familiar with the facilities, and since we
7 have them assigned split, and they're familiar with previously-
8 done risk analysis at those assigned facilities and have helped
9 them.

10 But I can tell you my colleagues in the other regions
11 have a little more difficulty, they have had turnover of the
12 senior reactor analysts, and being new to the plant, and being
13 new to the business is just -- it just aggravates the problem
14 you're talking about.

15 MR. ROSEN: And I would think, though, that the one
16 possible way to improve your effectiveness a great deal would
17 be to lean on the licensees quite heavily in the sense that
18 most licensees have the scope PRAs for at least three internal
19 events, and maybe for external events as well, and that your
20 first reaction to a serious finding seems to me ought to be a
21 meeting of your resident, and maybe even the SRA with the
22 licensee and ask them for their take, and then you can compare
23 that with yours before you light off independently and try to
24 create a new wheel.

25 MR. REYES: We're doing some of that. Because we

1 have the SRAs here for a long period of time and they have
2 assigned facilities we have a couple of matrixes that we use to
3 help us in this.

4 One is the name and the interface for each facility
5 in terms of risk, so we know who to call and who to talk to.
6 The SRAs can show you that.

7 The other thing we have done since implementation of
8 the program is that we have taken each facility in Region II
9 and developed a predetermined set of events and calculated the
10 risk for it. In other words, at midnight I pull out this sheet
11 and Summer had singular tube rupture I already have the number,
12 and the licensee has agreed with that number we have
13 calculated, and we have had a dial-up. So I can tell my boss,
14 by the way, we're in this, we're in this bracket. It's not
15 perfect, but we're in this bracket.

16 MR. ROSEN: You may not have had that exact event,
17 but knowing what one of the things is you can say that the
18 difference between that event and his event is probably to make
19 this less significant or more significant.

20 MR. REYES: Correct. And we can tell them, by the
21 way, there were many malfunctions in addition to the main event
22 so that as a minimum the risk is this, and probably worse, or
23 higher risk.

24 MR. ROSEN: That fact he's very familiar with in the
25 human performance area with the anchor action technique that's

1 in some of the successes where you set up operator actions and
2 you decide what the risk of a given operator recovery action,
3 is it likely that an operator will recover under certain
4 circumstances, you get a panel of experts together and do that,
5 and then when you get another event you say how complicated was
6 that compared to the one you just analyzed, so you're actually
7 using the same sort of technique as used in the success
8 likelihood index method, and I think that's a good thing to do.

9
10 MR. REYES: In fact this matrix is kind of intuitive.
11 We look at a set of examples like a steam generator tube
12 rupture, and the numbers vary from plant to plant in some cases
13 significant, and then when we say why and then it gives
14 insights about the plant. Some of them have added additional
15 makeup pumps for operational and safety reasons so they have
16 extra, they have additional resources that make the changes
17 significantly. And we have now those insights in a very handy
18 area available, we'll be glad to share that with you if you're
19 interested.

20 It helps us a lot, because we agree with you it is
21 very important that we handle events and findings in a rather
22 expeditious way for public confidence, and we would like to get
23 the results.

24 DR. SHACK: Who generated the matrix for you?

25 MR. CHRISTIANSON: The senior reactor analysts.

1 MR. REYES: We took the SRAs, senior reactor analysts
2 who are assigned to the plants, and we say, okay, let's come up
3 with a matrix. Say at midnight on Sunday -- I'm not a
4 practitioner, so I told them at midnight on Sunday -- I said
5 when you guys are here and it happens during the day it's easy
6 for me, I knock on the wall and say come over here and we get
7 it done.

8 But the for the worst-case scenario Sunday at
9 midnight I said I have to have a mechanism to talk to the
10 senior managers in the agency, and I would like to have an idea
11 of the zone we're in, how bad it is. So we created this matrix
12 and then filled the numbers, and they calculated them, and we
13 actually exchange out with the utility, and they know we have
14 this matrix, and they know we agree in general terms with the
15 number.

16 And what I wanted to do too was that I found out that
17 the utility management had this problem too. We had an event
18 where -- and what I forced them to do is if plant managers know
19 I carry that in my briefcase so now they force their analysts
20 to give them the list of key events and what the risks are, and
21 so I wanted to force a change in the utility to this risk
22 mentality, and we're being somewhat successful with that in
23 putting this matrix together.

24 MR. ROSEN: They followed all this through when the
25 reactor oversight process was set up, but the fact that you're

1 doing these things, and the fact that the licensees for their
2 own health and safety are picking up on it is a very good thing
3 that the agency and the licensees are working together to
4 understand risk management, which is what we're really doing.

5 MR. REYES: Yeah.

6 MR. MALLETT: The other thing we're doing which we
7 have also preached this, we have an advantage here we're close
8 to INPO, so we go to all their new INPO managers seminars, and
9 Luis has been on the agenda, I've been on, Loren has been on
10 there, and we go and we preach this to them that here are some
11 lessons learned that you ought to have when you respond to an
12 event, and here are some issues.

13 That's been quite effective interchange, and so
14 eventually you get to every manager in their organization with
15 that concept. So now we have managers, senior managers decide
16 to call us very early as you suggested during an event to just
17 say, hey, this is where we think we are, where do you think you
18 are.

19 MR. REYES: It's very important I agree to have that
20 dialogue.

21 Okay. That's all we wanted to talk about in terms of
22 the general discussions. We have a detailed agenda and we're
23 almost on schedule.

24 Do you want to continue with the agenda the way it
25 is, and then you let us know when you want to pause.

1 MR. ROSEN: Let's move on. We'll try to get most of
2 the agenda behind us by four if we can.

3 MR. MALLETT: I see people looking at coffee. We did
4 have a break built in after Mark Lesser's time.

5 MR. ROSEN: Let's keep rolling.

6 MR. LESSER: Good morning. My name is Mark Lesser,
7 I'm Chief Engineering Branch 2 here in Region II, and I would
8 like to talk about some follow-up of some of the Alloy 600
9 issues in Region II, and specifically we'll talk about the
10 latest on V.C. Summer pipe crack that occurred in 2000, and
11 what your status is on follow-up on Bulletin 2001-01 control
12 rod drive mechanism vessel head penetration cracking, and the
13 temporary instruction that our inspectors are doing.

14 Okay. The V.C. Summer crack follow-up activities, a
15 brief refresher, in the fall of 2000 the licensee during their
16 outage identified a 2 1/2-inch long axial thru-wall crack in a
17 'A' hot leg weld, and they cut out that section, a 12-inch
18 spool piece, they cut that out and rewelded it.

19 Basically they did a root cause evaluation, we did a
20 special inspection. The cause was attributed to primary water
21 stress that caused the cracking, and complicated by, or
22 contributed by high residual stresses from multiple weld
23 repairs during the field installation, the field construction
24 of that weld.

25 DR. BONACA: Did the root cause ever question why

1 they didn't know of the cracks previously in other inspections?

2 MR. LESSER: The root cause looked into that, and
3 they had done their ten-year ISI a few years before that, and
4 with ultrasonic testing, and --

5 DR. BONACA: They didn't see it? '

6 MR. LESSER: They didn't see it, and they didn't see
7 this crack if it existed, and there's the possibility the crack
8 did exist at that time, and that basically the equipment
9 there's a possibility that a lost -- well, actually a lost
10 coupling, with the ultrasonic it did not have a good coupling
11 at this particular point on the pipe, and so that was basically
12 -- you know, we didn't see that. So they felt that that was a
13 generic problem.

14 DR. BONACA: There wasn't only that crack, there were
15 other cracks in other nozzles, and they could identify --

16 MR. LESSER: Yes.

17 DR. BONACA: -- in the previous inspection the year
18 before the primal crack, so that crack must have been there.

19 MR. LESSER: It was there.

20 DR. BONACA: The reason I'm asking that question is
21 trying to build some more confidence in inspections.

22 MR. LESSER: And there are briefings that are
23 ongoing. For instance, improved sled design for transducers
24 that are running along side the pipe wall to reduce the
25 possibility of a loss of coupling.

1 MR. REYES: One of the contributing causes is -- and,
2 Billy, you just jump in if we do it wrong -- the sled, the
3 machine that runs over the pipe with the sensors, the older
4 designs didn't have what you would call a shock absorber,
5 didn't have robotic articulated for the sensors, and it turns
6 out that this weld in particular which was a weld made by hand
7 it was rough, it was rough by today's standards, the sled
8 actually lifted the sensors over that area, and it's hard to
9 prove, it's hard to prove it but with today's technology their
10 articulated sled is much more likely to keep the sensor in
11 touch with the pipe and the weld in question.

12 Billy, anything else to add to that? So technology,
13 I think the new technology is going to assist in trying to
14 eliminate some of the contributing causes.

15 MR. CROWLEY: All of them were similar, they were all
16 manually welded, and the inside surface which the UT transducer
17 was traveling on was rough, which didn't provide an optimum
18 surface for examination.

19 MR. CHRISTIANSON: Bill Crowley was the team leader
20 for the special inspection for the pipe crack issue at V.C.
21 Summer.

22 MR. ROSEN: You just said something that interests
23 me. You said the UT inspection was from the inside surface?

24 MR. CROWLEY: Correct.

25 MR. ROSEN: How big a pipe was this?

1 MR. LESSER: 29-inch inside diameter, 2 1/2-inch wall
2 thickness.

3 MR. REYES: The biggest pipe you have on site, all of
4 their main steam.

5 MR. LESSER: Right next to the outlet from the
6 reactor vessel, so it's fairly close.

7 DR. BONACA: That to me though would be an essential
8 part of the root cause if I understand it, and also
9 communication with other licensees if it is an issue of
10 contact.

11 MR. REYES: And in fact every licensee who did the
12 inspection subsequent to that, that articulated sled was in
13 high demand because nobody wanted to use the old technology,
14 worry about the sensor not coupling well based on an
15 imperfection of the pipe, and all the licensees are aware of,
16 one demanded the contractor use the new technology to make sure
17 the coupling was there.

18 DR. BONACA: One last question I have, clearly that
19 experience shows that the use of eddy current combined with
20 metric [?] is ineffective to identify to a T the existence of a
21 crack.

22 Is this being expanded in use, or is it too
23 burdensome?

24 MR. LESSER: I can tell you I sat in some meetings
25 where the rule of the industry is taking the lead in working

1 with NRR staff in the materials reliability project referred to
2 as the MRP. They're doing a lot of work in where all the Alloy
3 600 is in the plant first of all, identifying all the
4 dissimilar metal welds, and trying to identify the best
5 technology to find these, to gather data.

6 In fact, one of the pieces of data is the follow-up
7 inspection at V.C. Summer which they did this last spring, so
8 there's a lot of work going on there between the industry and
9 the agency to find what needs to be done.

10 MR. REYES: The problem too in testing is that
11 there's no baseline. The plants have been operating now for 25
12 years, 20 years, and this was not done during construction, so
13 you are going to have a lot of indications, we saw that at
14 Summer, and it could be as simple as a scratch on the pipe from
15 construction, or it could be incipient developing of a flaw,
16 and then you would have to dispose of all that large volume of
17 information, so there's some hesitation from the industry from
18 a practical point of view on if we this then what are we going
19 to do, is the regular going to impose us to stay shut down
20 until we analyze every one, so that's part of the exchange with
21 the industry.

22 DR. BONACA: The reason why I was pursuing it, we are
23 reviewing license renewals, and they depend so significantly on
24 the quality of the inspections, so I was pursuing that to see
25 if you have confidence that they have tried hard to do it

1 right, or if it was simply an inspection that was maybe split
2 up somewhat.

3 MR. REYES: Let me ask Billy to add to that, because
4 he's been in the team inspections for all the license renewal
5 inspections in Region II, and we've done the most, so Billy, do
6 you want to add to that a little bit.

7 MR. CROWLEY: I didn't quite understand what the
8 question was.

9 DR. BONACA: We ask you know are doing the regular
10 license renewals, and we depend on these programs that include
11 particularly these kinds of inspections for the license
12 renewals. As the plants are getting older these kinds of
13 things will be getting more common, you may get more cracks
14 that may expand to open a crack, so the point I was trying to
15 understand is do we understand the cause of this completely,
16 and can we be confident that when the next license renewal
17 application comes in and they say yes, we have performed in-
18 service inspections that we can be confident of that.

19 MR. CROWLEY: I think a lot depends upon what comes
20 out and what's going on in the industry. We're trying to
21 understand what needs to be done to get the best inspection, do
22 we need to add eddy current. You know, if so, a lot of work
23 has to determine what the acceptance criteria are.

24 So I feel like with the NRC and the industry together
25 looking at this issue and determining the best inspection

1 methods, you know, we can be confident we're doing everything
2 we can to preclude passing something like this up.

3 MR. REYES: The utilities are very sensitive to this
4 for a lot of reasons in terms of having to put the unit out of
5 service for long periods of time. We've seen a lot of work in
6 trying to identify it early, and I'm looking at Billy here, but
7 we feel comfortable with the extent of what they have done, but
8 this Eddiker & Tussen [?] is still an issue on the table.

9 The biggest issue from where I sit is coming up with
10 an acceptance criteria that the industry and the regulator can
11 agree on, because it becomes a practical matter once you get
12 all the information, what do I do with all this information.

13 DR. BONACA: I just have this last comment to make,
14 but I just thought of a question. You mentioned the root cause
15 was TWSC, and it was allowed to propagate right through the
16 whole nozzle. That's a long process, and it just goes to the
17 heart of the issues of license renewal because there's a crack
18 that's going to elongate through a long time, and we depend on
19 those programs for saying yes with confidence, we have
20 confidence that we can go 20 more years with that plant. And
21 we are likely to see some of these issues crop up more
22 frequently now as the plants are getting older.

23 MR. ROSEN: What was the agency's response to all
24 this? If we're getting this kind of finding in more than a few
25 questions it could put into question the whole process.

1 MR. LESSER: At this point the agency has not put out
2 any new regulations or requirements for that, and there was
3 some uniqueness in V.C. Summer. This was field welding versus
4 shop welding.

5 But as I said, we're in the process of looking at the
6 generic --

7 MR. ROSEN: Excuse me. Are you saying that this was
8 the only field welded pipe in the region?

9 MR. LESSER: I didn't say that.

10 MR. REYES: On the location of the large line, the
11 hot legs and cold legs, this was the only one that was started
12 and finished by hand -- is that right? -- and all the errors
13 were grinded out. From there on they started the automatic
14 welding process on the other legs at the station.

15 MR. ROSEN: At V.C. Summer.

16 MR. REYES: At this station.

17 MR. ROSEN: You have 33 plants out there.

18 MR. REYES: Yeah.

19 MR. ROSEN: How widespread was that kind of manual
20 operation? is the next question.

21 MR. REYES: In the early days it was common.

22 MR. ROSEN: Common.

23 MR. REYES: In the early days.

24 MR. LESSER: This was field welded with -- the other
25 thing was multiple welder errors.

1 MR. ROSEN: That was the situation that was at the
2 root cause of this, not PWSCC, which is field-welded, multi-
3 repaired nozzles is common, so --

4 MR. REYES: Well, the licensees, because we need to
5 follow on your question --

6 MR. CROWLEY: Not all of them were field welded, not
7 all the dry metallic welds were field welded.

8 MR. ROSEN: Common doesn't mean all; common means
9 half, or every plant might have one or two, so that should be
10 the focus of what you're thinking about.

11 MR. REYES: Knowing that, the utilities took that
12 information, and they can tell from their records which one was
13 what we call a problematic during construction, meaning it had
14 to be repaired many times, and grinding, and all that, and they
15 went in and specifically looked at those, and the results we
16 have back we haven't seen this again, it doesn't mean that we
17 won't, but they realized that if you have all these conditions
18 you are more likely to have a problem, and they have been
19 looking at that.

20 The industry was really taken aback by this his event
21 because of its implication, and we have a lot of PWRs in Region
22 II, so we have followed this closely.

23 I guess time will tell, but so far we haven't seen
24 something similar.

25 MR. ROSEN: But I wouldn't take a lot of comfort from

1 that, because this was just the fall of 2000, and so it's the
2 summer of 2002 and not much time has elapsed. When you think
3 about crack propagation rates and the kinds of --

4 MR. REYES: And I was thinking of the older units
5 that are more likely to experience this, and we have a few of
6 those here. So far -- they actually looked, they went and
7 looked at this situation, and it hasn't shown up. Doesn't mean
8 we're not going to see it.

9 MR. LESSER: Getting back to the other cracks that
10 were found, the second bullet, when they did remove this spool
11 piece and examined it they used eddy current, and they found
12 other cracks in the unit with eddy current shallow cracks, and
13 as part of their extent of condition looked at the other loops
14 with eddy current, and they found cracks there, generally
15 shallow cracks of the size-length of about a quarter inch to
16 about six tenths of an inch was about the size.

17 The licensee back in 2000 did a structural integrity
18 analysis that was submitted tot NRR staff who reviewed that and
19 accepted those flaws as is for one cycle of operation with the
20 understanding that they would go back at the next outage and
21 inspect.

22 And so V.C. Summer's next outage was just this last
23 spring. They did two things. They not only went back and
24 inspected, relooked at the 'B' and 'C' hot legs, but they also
25 did mechanical stress improvement process.

1 This is actually a clamp that's put on the weld, and
2 they actually compress that, squeeze the pipe to try to
3 eliminate the tensile stresses on the inside diameter of the
4 pipe.

5 MR. REYES: What it does, it changes the surface on
6 the inside of the pipe and the weld there, the starting
7 location of the PWSCC.

8 MR. LESSER: And actually they're using about 20,000
9 pounds of pressure to actually plastically deform the weld, the
10 pipe about 1 percent and actually get a 1-inch reduction in
11 circumference of the pipe.

12 They did this on the 'B' and 'C' hot legs. We had an
13 inspector observe some of those activities, and NRC research
14 also had their contractor who was on the original special
15 inspection team come back to V.C. Summer and look at the new,
16 the later nondestructive examination activities that they were
17 doing. They inspected 'B' and 'C' hot legs before mechanical
18 stress improvement and after mechanical stress improvement.

19 DR. SHACK: Do other licensees, your BWI licensees in
20 Region II use MSIP?

21 MR. LESSER: It has been used in -- yes, it has been
22 used in the past on BWRs, yes.

23 MR. REYES: This is the first PWR that we know of.
24 This is the first BWR that we know of that it's been used on.

25 MR. LESSER: The eddy current inspections this year

1 showed good correlation with the results of 2000. There were
2 no new indications in 'B' and 'C,' and basically any changes in
3 length that they observed they attribute that to measurement
4 uncertainties and different technologies. And the licensee
5 concluded, and the NRC concluded there was no growth in the
6 crack length for any of those. There's four indications that
7 follow, a total of four indications in the 'B' and 'C' hot
8 legs.

9 And the NRC staff approved V.C. Summer for start-up
10 for another, one more cycle of operation, again with the
11 understanding they will do another inspection at the next
12 outage.

13 MR. REYES: This is the best data we're going to have
14 on eddy current testing on this application, so everybody is
15 looking at it very closely.

16 DR. BONACA: The other plants out there that find
17 cracks, they're not doing this stress relief operation, they're
18 not being committed to inspect every cycle and so on, so we
19 will see. But you're telling me that the inspection techniques
20 are being improved.

21 MR. REYES: Yeah, specifically for the known causes
22 or contributing causes at Summer like the articulated sled and
23 the position of the sensor, being sensitive about field welds
24 that had a lot of grinding, a lot of rework, and things like
25 that.

1 That intelligence, I think Summer brought that to the
2 light, and we've seen that on the field work.

3 MR. LEITCH: Would you think that the mechanical
4 stress improvement would destroy some evidence of the crack
5 growth rate? Would they still be able to look at these cracks
6 and get meaningful crack growth data with the mechanical stress
7 improvement?

8 MR. REYES: I'll ask Billy. Billy, do you have a --
9 Do you understand the question?

10 MR. CROWLEY: We should arrest any crack growth, but
11 I guess as we continue to inspect these welds in the future we
12 will find out. If the mechanical stress improvement does what
13 you expect, you should stop the growth.

14 DR. SHACK: In fact, in theory you should be able to
15 see it easier because it should blunt the crack which means
16 your chances of getting a crack tip reflection are actually
17 improved. That's the theory at any rate.

18 MR. LESSER: Let me move on to Bulletin 2001-01,
19 control rod drive mechanism vessel penetration, cracking and
20 temporary instruction status.

21 We have been doing the temporary instruction which is
22 gathering data and inspecting licensee activities as they
23 implement this bulletin, the bulletin inspections.

24 It is being performed by the resident inspectors
25 and/or regional experts in nondestructive examinations. That

1 means basically the licensee is going to do a visual, pretty
2 much we'll have resident inspectors do the temporary
3 instruction. If they're going to be using volumetric
4 techniques we will have one of our DRS inspectors do the
5 temporary instruction.

6 The current status, the Bin 1 plants, these were
7 defined by the temporary instruction. Bin 1 were those plants
8 that at the time of the bulletin had already had active
9 cracking. Our only plant in Unit 2 was Oconee. All three
10 Oconee units have shown thru-wall cracks, have penetrations.
11 We have done the temporary instruction on Units 1 and 3, and
12 Unit 2 we will do it this fall.

13 Bin 2, those were plants that were within five
14 effective full power years of the reference plant, Oconee 3,
15 and we have done the temporary instruction on both the North
16 Anna and Surrey units.

17 North Anna 2 and Surrey 1 both had cracks that were
18 repaired. Robinson, we will do the TI this fall.

19 MR. LEITCH: You said North Anna and Surrey both had
20 cracks that were repaired?

21 MR. LESSER: Yes, North Anna 2 and Surrey 1.

22 MR. LEITCH: And the other units have been looked at,
23 and no cracks found?

24 MR. LESSER: That's correct.

25 MR. LEITCH: And how many cracks were in the units

1 that were repaired?

2 MR. REYES: While he's looking for that --

3 MR. LESSER: I've forgot the number.

4 MR. ROSEN: We have a special interest in that,
5 because North Anna and Surrey are currently up for license
6 renewal.

7 MR. REYES: Correct. But they have purchased reactor
8 vessel heads, and they will be replaced in 2004. We have eight
9 -- what I was going to tell you while Mark is looking for the
10 numbers -- we have eight units that have announced head vessel
11 replacements, the three Oconee, Crystal River, and the four --
12 the two Surrey and the two North Anna.

13 In fact, going back to our strategic work force
14 planning, starting in 2003 other than Davis Bessie will be the
15 first region that's going to go into a very heavy schedule of
16 spring-fall, spring-fall, spring-fall replacement of vessel
17 heads.

18 Some of those include cuts into containment,
19 containment will be cut. In fact, the top of the containment
20 will be cut in some cases to get them in. So our engineering
21 resources starting in '03 are going to be very taxed.

22 MR. ROSEN: It seems to me this is not a regional
23 problem.

24 MR. REYES: No, no.

25 MR. ROSEN: I mean that's a whole new ball game,

1 cutting into containments and things like that, so it's not
2 just head replacement, and you need to get some input from
3 headquarters.

4 MR. REYES: We've done it before. The steam
5 generator replacement at Surrey, Turkey Point, and Robinson
6 required containment cuts.

7 MR. ROSEN: I don't mean to interrupt. I don't think
8 one containment cut is not equal to another containment cut.
9 Containment cuts, some cuts are a specialty art.

10 MR. REYES: Yeah, and we went through Surrey one
11 before when they replaced the two generators, and so we'll have
12 to go through all that again.

13 MR. ROSEN: To me it's more like original
14 construction, and your expertise have to be -- how should I say
15 -- not as vigorous as they once were.

16 MR. REYES: Correct. We are very fortunate that we
17 have people like Billy Crowley and others who were in those
18 days. And our intention, just so you now part of the
19 strategic work force plan is every one of these activities will
20 have an experienced inspector who's done it before, and they
21 are going to be accompanied by a designated person who will
22 have had upon designated to have been through concrete school
23 and all those things, and will be the designated person to take
24 this --

25 MR. ROSEN: Rebar.

1 MR. REYES: Yeah, rebar. So we have a very heavy
2 period of work coming on because of all the announced reactor
3 vessel heads replacements.

4 MR. LESSER: I think to answer your question, North
5 Anna 2 had three thru-wall leaks, and Surrey 1 had two thru-
6 wall leaks.

7 DR. SHACK: Is Oconee the only one with leaks that's
8 been reinspected?

9 MR. LESSER: Yes.

10 DR. SHACK: When's the next reinspection coming up
11 for some of these that had leaks?

12 MR. REYES: North Anna 1 is coming into a full outage
13 on September, and --

14 DR. SHACK: Because it was rather surprising you
15 didn't have more leaks.

16 MR. REYES: In Region II we don't have anybody in
17 that situation, but there may be some in other regions.

18 There was not leaks every place. In these eight I
19 talked to you about they basically decided, it's a business
20 model decision, the time out of service for the station and the
21 cost of doing the NDE and the repairs both from money and
22 exposure. In a business model the decision is quick, you spend
23 \$10 million to buy a new one and get it over with, and that's
24 why I think you're going to see more and more.

25 DR. BONACA: Most of the cracks were axial; right?

1 The ones you discussed.

2 MR. REYES: You mean the ones that we found leaking?

3 DR. BONACA: Yeah.

4 MR. LESSER: Some of them have been circumference,
5 and some of them have been axial. Most of them are axial.

6 MR. REYES: One or two of them.

7 MR. ROSEN: Tell me a little bit about what you saw.

8 Was this popcorn boric acid deposits?

9 MR. LESSER: Yes.

10 MR. ROSEN: In every case, or thru-wall cracks? Was
11 it identified from the boric acid deposits, and later confirmed
12 by volumetric inspection?

13 MR. REYES: I'm looking at Billy. The ones that I'm
14 aware of, the pictures that I've seen, you have a little bit of
15 boric acid deposit, you can describe it as popcorn, and we can
16 get you some of the pictures.

17 And then the question is where did that come from,
18 and then you go and do the NDE from inside the vessel head and
19 confirm either axial or circumferential, depending.

20 I think we only had one circumferential, and North
21 Anna had two. I think that's correct.

22 MR. LESSER: You know, when they visually look at the
23 head with either remote optics or something you can see boric
24 acid crystal around the nozzle, around the four-inch nozzle, if
25 that has been squeezed up from the annulus from the bottom of

1 the vessel.

2 Now, part of the bulletin is they have to be able to
3 show that in fact there's enough room in this interference bit
4 that will move up and make itself known there. All the plants
5 may not necessarily be able to show that, and if they can't
6 show that then they can't call themselves -- they can't call
7 that a qualified visual inspection. They have to -- if they're
8 in a higher susceptibility category they would have go to in
9 and do volumetric inspections.

10 MR. REYES: But the pictures are very telling. I
11 mean you look at it and right away you know it's boric acid,
12 popcorn kind of shape, and you right away know you have to go
13 underneath.

14 MR. ROSEN: I believe -- and I'll ask the other side
15 of the question -- if it doesn't show that do you know
16 anything?

17 MR. REYES: No.

18 MR. ROSEN: It could still be going on?

19 MR. REYES: Yes, that's correct.

20 MR. ROSEN: It could be still cracked, certainly it
21 could be -- not thru-wall, but the next question is could you
22 have a thru-wall crack and it doesn't show at the surface?

23 I have examined that question several different ways
24 in several different forums, and the answer I typically get is
25 if you have a thru-wall crack it will show on the surface, and

1 I was wondering what you think.

2 MR. LESSER: Well, no, I don't believe that's the
3 staff's position. I believe that you have to be able to also
4 show analytically and with as-built dimensions that the
5 interference, the nozzle though the head will in fact expand
6 when you're heated up and there will be an annulus to allow
7 that to travel.

8 There is some thought that, you know, that if it's
9 too tight you may not see it bubble up there.

10 MR. REYES: I don't know what the answer is to the
11 question, but I can tell you what the answer is to the problem:
12 replace the head with different material, and that's what I am
13 -- you know, as far as I can tell that's why you have eight
14 vessel heads in Region II already lined up for replacement.
15 I'm just giving you --

16 MR. ROSEN: If I'm wearing your moccasins, Luis, I
17 would be a little bit uncomfortable about a clean inspection
18 because it it's clear to me that that crack would not be
19 damaging the head without showing boric acid deposits on the
20 surface.

21 MR. REYES: Correct.

22 MR. ROSEN: I have never been fully apprised of that.

23 MR. REYES: You have to use several things that get
24 you to the comfort factor. One is the equation that gets you
25 to is it a likely situation to be occurring or not, and we

1 learned -- and I'm no expert on this -- we learned from the
2 French that we may have to modify our equations a little bit,
3 but I agree with you. But I think if you do a visual and you
4 don't have any more gaps in it, then by analytical you don't
5 think it's likely either I think you have reason to believe
6 it's okay.

7 Now, we have a lot of plants that are not in that
8 category, and that's why I think you'll see the replacement of
9 the vessel heads, and as far as I'm concerned that's the only
10 answer.

11 I think you're going to see a lot of replacement
12 vessel heads coming up. Once the first ten or twelve get it
13 pretty much done and all the lessons learned are there, I think
14 you're going to see more utilities going in that direction.

15 I have several executives who have told me that
16 they're going in that direction, they're just trying to figure
17 the timing.

18 DR. BONACA: Those are only the ones in the highest
19 susceptibility category, so the intermediate they would not
20 jump to that conclusion yet. I think with the questions that
21 Steve is pursuing I think that's very significant. One could
22 say why not have an automatic inspection of all those
23 intermediate class to get a sense of where you are unless the
24 decision is made to replace the head, which I don't think is
25 going to be made for most of us.

1 MR. LESSER: I think you're right, because the Bin 4
2 plants for example, some of the projections show -- corrosion
3 is a function of time and temperature, and if they have a lower
4 head temperature the likelihood of corrosion and the corrosion
5 rate is going to be much smaller, and some of the models are
6 showing it may be many, many, many years past their license
7 where they would start to see this, so it will be the ones that
8 are susceptible first.

9 MR. REYES: The ones in the top tier are going to go
10 to the bottom because they're going to put new vessel heads
11 with new material, and then what used to be in the middle is
12 now your top concern as a regulator.

13 DR. BONACA: I mean it seems to me is the opposite
14 situation. The burden is to demonstrate that there is a
15 concern with the boiler head.

16 MR. ROSEN: I asked of the MRP, Don Refus, and he
17 showed me a chart applying the temperature, compliance, and
18 various things, and he told us how all these points seemed to
19 be consistent with the model, the time and temperature model,
20 and I asked him what would not be consistent with time and
21 temperature, and he pointed to a plant, a low-temperature
22 plant, or a low-temperature region on the graph and said if we
23 get a crack in one of those we'll go back to square one in
24 designing the system. So I think that's what we will be
25 looking for.

1 And you're right, the picture will change as people
2 change heads, but it may come out that those hot level, most
3 susceptible plants will be rather not susceptible. Even though
4 they are the most susceptible in their remaining BWI they will
5 be rather unsusceptible because of their temperatures.

6 So then you can go a little bit relaxed except if you
7 get aa leak in one of those. That's a telltale that says
8 something is wrong with the simple model, and there are more
9 factors involved here.

10 MR. LEITCH: Was there any commonality in heat
11 numbers of the nozzles having cracks in North Anna and Surrey?

12 MR. LESSER: I don't have that information. I think
13 there's some site --

14 MR. REYES: I know a little bit about it, the B&W
15 units. I was told, and I cannot confirm this, that they were
16 looking at the tube itself, the material for Crystal River,
17 Oconee, and Davis Bessie to see if there was a heat of material
18 was involved in it, and I haven't heard the answer whether
19 there was.

20 MR. LEITCH: And I think we heard, if I recall
21 correctly, that the ones that were cracked at Davis Bessie were
22 from the same piece that was common strata, but I don't have
23 that data.

24 MR. LESSER: Some of the open issues still with the
25 bulletin, again we have a few plants that we're going to

1 complete the temporary instruction on this fall, and we'll be
2 all done with that, there are some plants that have not
3 received a closure letter from the NRR, NRR is continuing to
4 review that.

5 And also how we disposition and document the
6 enforcement of thru-wall cracks, still we're working through
7 that to be consistent throughout the region.

8 And also from a significance determination the first
9 of set of cracks that occurred at Oconee, we considered that we
10 used enforcement discretion, the second set of cracks we would
11 consider those, but that's still predecision.

12 And I think we talked, we were talking about vessel
13 head replacements. Oconee is starting with the spring of 2003
14 they're going to replace Unit 3; Crystal River in the fall of
15 '03. I didn't put North Anna up there, but North Anna and
16 Surrey we've got some indications that they're planning to
17 replace their heads.

18 We are planning to go -- the Oconee heads are
19 currently, they were fabricated in Japan, they're currently at
20 the B&W facility in Canada. A couple of my staff is planning
21 on a visit of that facility in July along with NRR to observe
22 basically some of the fabrication of the heads.

23 With that that concludes my presentation. Are there
24 any other questions or discussion?

25 MR. ROSEN: Is the head fabrication in your

1 understanding going to be very much like what we've got now? I
2 mean is it a straight fit on those nozzles?

3 MR. LESSER: I believe so. They would be using Alloy
4 690.

5 MR. ROSEN: Are the fabrication techniques still the
6 same?

7 MR. LESSER: I don't know a lot about it, to tell you
8 the truth. I'm making the assumption it is.

9 MR. ROSEN: Clearly if that's what we're doing we
10 want to know a lot more about the dimensional fit.

11 DR. SHACK: Of course they will do a baseline
12 inspection this time.

13 MR. LESSER: Oh, yeah.

14 DR. SHACK: We will get a pre-service inspection.

15 MR. LESSER: Okay. Well, thank you very much. Yes.

16 MR. ROSEN: To come back for a different thing, on
17 the boric acid inspection programs, how sensitive do you think
18 your licensees are about removing -- you know, did they leave
19 boric acid on susceptible materials? Is that -- You know,
20 they did that at Oconee, I mean at Davis Bessie. Do you know
21 that that's going on in your plants that somewhere they're
22 leaving boric acid on materials because they feel it's harmless
23 and they don't want to spend the command RIMS to get it off?

24 MR. LESSER: You know, that's a good question. I
25 don't think we've looked before Davis Bessie obviously. I

1 think there's a big difference before and after Davis Bessie
2 would be my feeling talking to people, but I don't think it's
3 something that people -- we don't know if they looked that hard
4 at it, and we were relying on their 2002-01 bulletin responses
5 and then what we do with that.

6 DR. SHACK: Do you have any feeling for how they
7 react to tech spec leakage?

8 MR. LESSER: Yes.

9 DR. SHACK: Everybody has a one-GPM limit, but what
10 do they really do, you know, when do they really start to worry
11 about the leakage?

12 MR. LESSER: That's a good question. >From my
13 experience, and I think I would probably say generally most of
14 the plants monitor it and have a baseline unidentified leakage
15 that they have seen for a long time, and when it goes up
16 there's a bit of a spike well below one GPM, even well below a
17 half to a quarter GPM at some point they say, hey, something
18 has changed in here, let's go in and look. They may send
19 people to go in and look-see if they can find something.

20 I think -- you know, my feeling is that most of them
21 are pretty sensitive towards that because they know it's only
22 going to get worse once it starts coming up.

23 MR. ROSEN: Mark, isn't it your experience or the
24 experience of your inspectors that that's not the first
25 indication they have of a leak, that the first indication is

1 typical radiation monitoring alarms from particulate or other
2 sensors in the containment?

3 MR. LESSER: No, I don't know that they're that
4 sensitive, the rad monitors are that sensitive to pick up leaks
5 at low levels about a tenth, or a change in a tenth of a GPM.

6 My experience is that they pick it up, they see
7 something when they do their three-day unidentified leakage
8 calculation is their first sign that something has changed.

9 DR. SHACK: When French went through, they wanted to
10 do leakage monitoring on the heads they built a can over it so
11 they could contain it and then sniff it, so obviously you're
12 sort of pushing the limits at the kind of leakage levels you're
13 interested in.

14 MR. ROSEN: Especially plants that don't have fuel
15 leakage problems.

16 MR. LESSER: That's right. That's a big input into
17 whether the rad monitors will pick it up, absolutely.

18 Okay. Thank you very much.

19 MR. ROSEN: I think that's when our break was
20 scheduled. What do you think?

21 MR. CHRISTIANSON: We were regularly scheduled for a
22 break from 10:00 to 10:15. If you would like to have a 15-
23 minute break we can reconvene at 25 after.

24 MR. ROSEN: Yeah, I think that's a good idea. So
25 we're on break until 25 after ten.

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[A brief recess.]

MR. CHRISTIANSON: The next presentation is Plant Operating Experience, Loren Plisco, Director, Division of Reactor Projects.

MR. PLISCO: Good morning.

What I would like to do is I was going to give an overview of plant operating experience in Region II really from an ROP perspective.

I'll give an overview of plant performance showing the action matrix, and a summery of which cross-performance indicator thresholds we think here in Region II, and a summary of our nongreen findings that we've had through the first two inspection cycles.

And then I'm going to ask individual branch chiefs, they're going to come up and talk about some specific -- and I wasn't going to cover them all, but I picked out some specific findings and PI issues that have come up that we have run through the process, and they'll talk a little bit about what the technical issue was and how we handled it within the process.

What I was trying to do is give you an idea of the kinds of things that have bubbled up out of the program that we've had to deal with in the process, the kind of technical issues and the kind of performance indicators.

MS. WESTON: Loren, if I may, do you have in your

1 packages the printouts for those issues?

2 MR. ROSEN: Also, Loren, would you also indicate how
3 the regions are doing in terms of not generating false
4 positives in terms of scores on, you know, getting a red when
5 it really looked to be a yellow. Have there been any Region II
6 cases where you said it was yellow and after the regulatory
7 conference it came out lesser than that, or greater than that?

8 MR. PLISCO: We have had some. They either stayed
9 the same or they were lesser. None of them went up.

10 MR. ROSEN: I'm interested in those not because it
11 changed so much, but because clearly there was some lack of
12 understanding of the actual circumstance that got rectified in
13 the process, and that's inefficient, and it's something we need
14 to work -- I don't think you'll ever get a hundred percent on
15 it, but you need to work to minimize that.

16 MR. PLISCO: Well, two of them specifically we're
17 going to talk about. I think Kerry is going to talk about both
18 of them. We had one in security which is another issue.

19 MR. ROSEN: Well, those are flags for us about some
20 process issues that -- you know, nothing against the people,
21 but it's the process issues I'm after.

22 MR. PLISCO: And they weren't issues of new
23 information, they were really issues of assumptions, or models
24 that were used, and then in the discussion with the licensee
25 there was agreement to either use a different model, or

1 approach in the modeling.

2 MR. ROSEN: And the lessons-learned process was then
3 generated which puts that in the front end so the next time
4 that kind of thing comes up you don't end up in that same
5 place.

6 MR. REYES: We'll show you one example particularly.

7 MR. PLISCO: And Kerry actually has two he's going to
8 talk about. One is a Surrey diesel issue which the SDP
9 analysis came out higher, and after the reg conference it ended
10 up a little way. And then the Summer-Watts Bar issues, the
11 same thing is true. And there's a different story on each one
12 of those and why that ended up --

13 MR. ROSEN: I'm interested in learning provision for
14 the staff.

15 MR. PLISCO: The other point I wanted to make is that
16 when I show these summaries the good news and bad news about
17 the rank oversight process is it's more real time than the
18 When you look on the Web site, and you look at summaries of
19 where the plants are that's as of a certain time frame, and if
20 you look a month later, you know, on a day-to-day basis it
21 changes, which is good because then we have some current
22 information rather than SOP you look back 18 months when you
23 look at the most recent SOP it was really whole information,
24 real time.

25 MR. ROSEN: You're giving a plant that's really

1 solved a lot of problems a very bad report.

2 MR. REYES: Two years later you'll see it's --

3 MR. ROSEN: Two years later, right.

4 MR. PLISCO: But it has caused a few communication
5 difficulties, since it is a moving target and there's a lot of
6 information out there, and what's on the Web site is typically
7 updated quarterly where the plants are action measures, where
8 it really can change daily if a new finding comes up, or a new
9 finding it changes their status, which has been a new
10 communication issue we've had to deal with.

11 And I'll show you an example on the first slide.
12 This is a summary of where we are nationwide. This was as of
13 March 31st, the first quarter, and that's what's currently on
14 the NRC's Web site.

15 In Region II you can see we don't have any plants
16 that are in the degraded cornerstone or above.

17 MR. ROSEN: This says you need to be in an even-
18 numbered region.

19 MR. PLISCO: And I was going to walk through that
20 this is a snapshot. We have actually had two plants that have
21 been in the degraded cornerstone; they're out of it now, and
22 you're going to hear some of the discussion when the branch
23 chiefs talk about that.

24 Oconee 1 has been degraded cornerstone and they are
25 currently out; Farley 2 was degraded cornerstone and they're

1 currently out. So as I said, it's a moving target. If you look
2 back historically we have had plants in these categories.

3 And the same for regulatory response. Right now we
4 have three plants, that's Oconee 1 and Surrey 1 and 2, and the
5 branch chiefs are going to talk about the specifics of the
6 reasons why they're in there.

7 But we have had about eleven plants that have been in
8 and out of that category through the first two inspection
9 cycles.

10 DR. POWERS: You have no idea how much more
11 enthusiastic I am about your headings, your columns than
12 colors.

13 MR. PLISCO: And these are what we try to use in the
14 public meetings when we're trying to communicate to get away
15 from the colors.

16 DR. POWERS: Because those communicate, whereas your
17 colors don't. This tells you what you're doing, and the colors
18 just don't.

19 MR. PLISCO: Any questions on this overview of where
20 we are and where the rest of the regions are?

21 MR. LEITCH: This is as of the end of March?

22 MR. PLISCO: March 31st, that quarter. And it's
23 updated -- we update the matrix that's on the Web site at the
24 end of the quarter.

25 MR. LEITCH: The fact that Davis Bessie is not in the

1 unacceptable performance column --

2 MR. PLISCO: All that means is it hasn't been
3 resolved yet.

4 MR. LEITCH: That's still in the pipeline.

5 MR. PLISCO: The final finding hasn't been issued yet
6 as of March 31st is what it means.

7 MR. LEITCH: I think that's one of the issues,
8 though, that we were talking about that were related to public
9 comments. If you showed the public that slide and said this is
10 as of March 31st I think they would expect to see one in the
11 unacceptable performance column, or maybe that's not where it's
12 going to wind up, but it's unacceptable to me, though.

13 MR. RISEN: I think they're through with drawing
14 conclusions on --

15 MR. LEITCH: They're not, that's the point. What I'm
16 saying is if you showed this in a public forum it doesn't
17 exactly instill public confidence when you see there's no
18 unacceptable performance.

19 MR. PLISCO: And that was the point I was trying to
20 make, it's a snapshot at the end of the quarter, and you really
21 have to look at other information to find out where you really
22 are. And we have an example we're going to cover today in
23 Region II. We actually have plant in the degraded cornerstone
24 as of last week. Harris went into degraded cornerstone. We
25 issued a white finding last Thursday that gave them two

1 mitigating system cornerstones which puts them in the degraded
2 cornerstone, and George is going to talk about the technical
3 issues that put them there, but in fact this just happened last
4 Thursday. So it says zero, but we have one now.

5 MR. REYES: In two weeks, June 30th when the next
6 quarter rolls over it will show that.

7 MR. PLISCO: It will show that, yeah, sure.

8 This is a summary for the Region II plans where
9 licensees have crossed the PI thresholds during the first two
10 assessment cycles.

11 MR. ROSEN: That's impenetrable for me.

12 MR. PLISCO: I was going to explain that.

13 The column on the left are the cornerstones. It's
14 initiating events, mitigating systems, barriers, emergency
15 preparedness, radiological protection, occupational
16 radiological protection, public, and physical protection, the
17 seven cornerstones. I was trying to get it all on one slide.
18 I'm guilty.

19 MR. ROSEN: It's just a little to short for me.

20 MR. PLISCO: I'm guilty.

21 And as you can see, most of our activity has been in
22 mitigating systems. That's where a lot of our inspection
23 effort is focused.

24 In the PIs there were a lot issues especially early
25 on with interpreting how to do that performance indicator, how

1 they collect the data, what counted and what didn't count, and
2 there's actually ongoing work that the program office has in
3 place to try to address some of the problems that were in that
4 performance indicator.

5 But as you can see in the first cycle we had five
6 crossed thresholds in that performance indicator. We're going
7 to talk about some of those when the branch chiefs talk about
8 the specific issues, they will give you some examples of the
9 kinds of things that cross thresholds and why they cross the
10 thresholds.

11 One I wasn't going to speak too much about when the
12 branch chiefs talk is in the barrier. We did have three cases,
13 you can see two in the first cycle and one in the second.
14 Those were RCS leakage issues, and that's been interesting from
15 a public confidence-public communication issue. That PI
16 threshold, the white/green threshold is only 50 percent of the
17 tech spec limit, so you can have a plan as a white issue that
18 they can continue to run, but the problems are still there.
19 That's been a little bit of a communications issue.

20 We respond, we do extra inspections, and they still
21 haven't even reached the tech spec. But that was one of the
22 PIs that had a lot of debate early on, should we have a
23 performance indicator. That was a discussion of making sure we
24 had something that showed the public where our plants were as
25 far as what their system leakage was, and that was the

1 threshold that was picked.

2 And that green-white threshold was really intended to
3 be I think a 95 percent outlier threshold, and that's why they
4 picked the 50 percent. But we do have problems in risk
5 communication with the public on why the agency is responding
6 when they haven't even reached the tech spec.

7 MR. ROSEN: Remind me, is that a 50 percent of
8 unidentified or identified?

9 MR. PLISCO: It's identified, 50 percent of
10 identified leakage.

11 In a couple cases there was valve leakage, a packing
12 leak, or a pressure seal type leak that exceeded the 50 percent
13 of the tech spec, and that drove that into the white threshold.

14 I also want to mention since January 1st we haven't
15 had any new, this is all we've had since March, two inspection
16 cycles and the current one that we started January 1st.

17 The next, this is inspection findings, the nine green
18 findings that have been issued during the first two assessment
19 cycles, and again you can see most of our activity is in
20 mitigating systems.

21 We're going to talk about all the specific issues
22 that are listed here, the six mitigating systems issues, and
23 the one physical protection issue. That was a Farley issue
24 that Steve is going to talk about.

25 And as I mentioned, we've had a one new finding, that

1 was the issue at Harris, and we'll talk about the technical
2 issues related to that. It was a foreign material issue at
3 Harris, and that was a white finding in mitigating systems. It
4 was just last week we issued that.

5 MS. WESTON: Let me ask you a question. The first
6 quarter 2002 had a yellow; there were none in this region, but
7 you're showing the end of the year, not first quarter 2002.
8 Any particular reason?

9 MR. PLISCO: Well, what we're trying to depict on
10 here is completed cycles. The January one just started. I
11 mean it will go through December. And I mentioned what has
12 changed the first couple months in the first quarter, but I
13 didn't show it on here because it really had only been three
14 weeks.

15 MR. REYES: If you see the dates at the top, we
16 decided, the agency decided to change what we call the cycle of
17 assessment to end-of-year, end of calendar year, so the
18 headings are different because we as an agency shifted to the
19 year calendar.

20 MR. PLISCO: This year is going to be a full calendar
21 year inspection cycle. We did that to sort of balance the
22 workload in regions of the assessment cycle, to get out of the
23 fiscal year because our workload in the regions when we did the
24 assessments at the end of the year was laying on top of the end
25 of the budget year, and appraisals, and everything else, and we

1 shifted to a calendar year cycle for the inspection program.

2 MR. ROSEN: Now I understand what you're doing here.

3 My comment is really about tell me about the ones
4 that shifted from yellow to white, really about the inspection
5 part.

6 MR. REYES: Those are the examples we have.

7 MR. PLISCO: We'll talk about some of those.

8 Any questions from an overview standpoint? The
9 branch chiefs will talk about some of the specific finding
10 issues.

11 MR. ROSEN: You know, I do have an overview comment.
12 Let's just go back one slide. I'm a little bit slower than you
13 are.

14 Just looking at the pattern of findings of mitigating
15 systems, not in the other place --

16 MR. REYES: You mean why? Is that the question?
17 Why?

18 MR. ROSEN: No. I don't even know how to formulate
19 the question. It just seems so narrow.

20 MR. REYES: We have taken a hard look at that. If
21 you get another region you'll see a different spread. For
22 example, in Region IV they've been having a lot of emergency
23 preparedness kind of findings, and if you do that table for
24 Region IV you'll see yellows and whatnot in NEP.

25 We have taken a look at our program, and the program

1 office comes and takes a look when there's a difference in
2 terms of the population or findings from the regions to try to
3 see is there something that's being told here, and we haven't
4 been able to correlate it either, so if you have an answer
5 we'll work on it because we think it's hard to make some
6 correlations in some of the other areas, but we don't have an
7 answer why one region will have a different spread than another
8 region.

9 MR. PLISCO: And we have findings of other regions,
10 but none that have crossed the threshold.

11 MR. ROSEN: Well, clearly mitigating symptoms, that's
12 the readiness of the plant to deal with transient actions.
13 That's really important.

14 DR. POWERS: It's also the area that you would hope
15 that the NRC inspectors are focusing most of their attention
16 on.

17 MR. ROSEN: True. And why is his region so good and
18 all the other places have only one finding.

19 DR. POWERS: Well, again, you don't want to get too
20 excited about a small sample.

21 MR. ROSEN: True. All I'm expressing is my --

22 MR. REYES: We have looked at --

23 DR. POWERS: It seems to me much more impressive to
24 me actually as being the fact that we actually get findings in
25 the colors other than green out of the system at about the rate

1 that we kind of anticipated we would get them the system was
2 set up. I think that's the real take-home lesson at this stage
3 in the experience with it, because experience is just too short
4 to start drawing patterns and conclusions.

5 MR. REYES: To give you one thing that my bosses have
6 done, and they have met with INPO, the senior managers meeting
7 between NRC and INPO, and they have asked INPO to take their
8 plants, group them geographically like the regions, and look at
9 the rankings that they give them, INPO 1s, 2s, 3s, and 4s.

10 There is a correlation, there is a general
11 correlation. We at the agency are trying to make sure that in
12 fact we're implementing all the programs the right way, and we
13 have exchanged with the other regions to do inspections to try
14 to if we're doing things differently and all that, and --

15 MR. ROSEN: I think it's the right thing to do, and
16 I'm trying to sit here and say now suppose that you came back
17 with no correlation how would you react to it, and are we being
18 overly confident when we see there's a correlation.

19 MR. REYES: Right. And it just --

20 MR. ROSEN: And it's a small sample.

21 MR. REYES: But I'm just trying to note we have asked
22 the same question in trying to find out other ways to make sure
23 that we are --

24 MR. ROSEN: I mean I think you have to do that, I
25 think it's unavoidable, but I don't think I would expect

1 anything to come out of it until you have like five or six
2 years of experience, and especially at first when you get a big
3 perturbation you learning, licensees learning, everybody
4 learning, definitions kind of floating a little bit, things
5 like that.

6 MR. REYES: I'll give you an example. There's a
7 randomness on the barrier, those three -- on the barriers is
8 the PI what I'm thinking about -- it basically was equipment
9 that started leaking, and for a while we had three units, three
10 different components and they just started leaking, and the
11 plant eventually shut down and replaced the whole -- there
12 doesn't seem to be a relationship there. We probably don't see
13 any for a while, and then we have three.

14 MR. ROSEN: I mean that's exactly what we're trying
15 to do is get some indication. The telling thing is if you
16 could in doing the root cause analysis you found that there was
17 something deficient in their corrective action program that was
18 leading to this. If you don't, then you say, well, fair
19 enough, and then it eventually works its way out of the rolling
20 average and whatnot.

21 MR. PLISCO: And we did find that in one case. It
22 was a -- one of the rack system PI hits was North Anna, they
23 had a rack and system and system bypass valve packing leak.

24 I think when our inspectors went back and looked at
25 it they didn't have a program to replace the packing.

1 MR. REYES: That was a real problem.

2 MR. PLISCO: It had been in there fifteen years or
3 something. That's what the problem was.

4 DR. POWERS: Yeah, that's what you wanted to do. I
5 mean it works, score one for the -- take a structuralist view,
6 Steve. Quit taking the rationalist view. This is a
7 structuralist program.

8 MR. ROSEN: I am a rationalist with structural
9 tendencies; you are a structuralist with rational tendencies.

10 [Laughter.]

11 MR. REYES: I just wanted you to know that we raised
12 the same question, the agency senior management raises the same
13 questions all the time making sure that we're not missing
14 something.

15 MR. ROSEN: Yeah, I think you need to pass swinderize
16 [?] and look at the patterns, but not draw too much from it
17 right about now.

18 MR. PLISCO: Some people would also say, especially
19 for the inspector findings, if you laid on top of that how many
20 hours were spent in each of those categories the bulk is in
21 mitigating systems, so some people would say that's where you
22 spend your hours, that's where you're going to define the
23 issues.

24 DR. POWERS: And where thou looks thou will find.

25 DR. LARKINS: The more you compare DIE for mitigating

1 systems, how does that rack up?

2 MR. PLISCO: I don't know the percentage, but we have
3 some inspectors here and I think they can tell you most of the
4 areas that they look at is in mitigating systems, when we look
5 at maintenance and operation --

6 MR. REYES: The real significance is there, so it
7 takes you there.

8 MR. PLISCO: Steve.

9 MR. CAHILL: My name is Steve Cahill, I'm a branch
10 chief over the Southern Company plants. I took over that
11 branch right before even the ROP, so I have been with them all
12 through this cycle.

13 It started out well when we entered the ROP Farley
14 had all green performance indicators and we were in the
15 licensee response band, but very quickly just a couple weeks
16 into it we had an issue come up, and that was their first
17 status for the PIs, it was the first quarter of the calendar
18 year with data they submitted at the end of April.

19 They wound up having a white performance indicator
20 that affected both units. It was on emergency AC power on
21 availability, and it crossed the white threshold.

22 DR. LARKINS: Excuse me. Both units where?

23 MR. CAHILL: Everything I'm talking about it just
24 Farley.

25 That's in the mitigating systems cornerstone, and as

1 the slide says the cause of it going across the line was fault
2 exposure hours. They were doing some 18-month surveillance as
3 it failed, and it was a long-duration surveillance, and so the
4 fault exposure hours at that time were T over 2, and nine
5 months at a time those added up very quickly.

6 We wind up for our process we told them we were
7 coming in and do a supplemental, and we had our resident
8 inspectors do our supplemental inspection 95001 which basically
9 is just verifying their root cause, and they come up with the
10 appropriate corrective actions.

11 We looked into that and concluded they adequately
12 addressed that. And we also had a regulatory performance
13 meeting with them for the first white in the regulatory
14 performance column. It was just a meeting with myself and the
15 plant manager.

16 The PI returned to green about a year later, so that
17 in and of itself was not that significant, but when we go on to
18 the next one very shortly after that -- and this was actually
19 something Luis took a lot of pride in -- in the next period,
20 the first period, basically the second quarter of calendar year
21 2000 Farley recognized that they had a lot of issues going on
22 with all the speed work, and in this case the PIs called heat
23 removal, and they had had some surveillance failures, they were
24 having some fault exposure hours they already knew were adding
25 into their PI calculation, and they had a performance problem

1 that lingered for a while.

2 Basically they knew beforehand that their data
3 submittal was going to cross that white threshold. And this is
4 data they were not supposed to submit until July, so we engaged
5 early on this. They basically admitted that it had crossed the
6 threshold, and we initiated our process.

7 This also -- this only affected Unit 2, but it also
8 is a mitigating systems cornerstone, so knowing that the white
9 PI would be in that mitigating systems cornerstone two white
10 PIs constitutes a degraded cornerstone.

11 The root causes of this were also pretty much
12 similar. We went and -- we started out doing -- there's a lot
13 of comment themes, preventive maintenance and maintenance rule
14 limitations, so we started out doing our supplemental
15 inspection 95002 on this. Again, we were letting the residents
16 do it.

17 And the difference between the first supplemental,
18 the 01 we did versus the 02 was it looks at their root cause
19 and their corrective actions, but it takes a broader scope of
20 it and also looks at an extending condition, how broad is this
21 problem.

22 And when the residents finished that phase of the
23 inspection they came up with a couple of common themes in the
24 maintenance rule limitation.

25 And so we wound up doing this inspection in two

1 parts, the proposed and actually implemented a second part of
2 the inspection with a DRS, division of reactor safety
3 specialist going in and looking at their maintenance rule
4 implementation. So we actually show two separate inspection
5 reports for this one inspection.

6 Again we concluded that Farley's performance in
7 addressed the root causes and developing corrective action was
8 acceptable.

9 Also in the course of this after the residents had
10 concluded their portion of the inspection, but before the
11 specialists came in we held for our action matrix a regulatory
12 performance meeting, and Loren actually chaired that. It was a
13 higher level when the action matrix was the integrated
14 cornerstone.

15 This was a public meeting where we basically
16 initiated dialogue with Farley's plant management on what the
17 issues were.

18 And after we completed those supplemental inspections
19 and did our performance meeting that completed our actions for
20 the integrated cornerstone and the action matrix, and that PI
21 also returned to green in the first quarter of calendar year
22 2001.

23 In the fall of 2000 we had another PI that crossed
24 the threshold. This was the initiating events cornerstone that
25 was the Unit 1 on the plant power changes PI, so the fact that

1 it was in a different cornerstone I think interacts with the
2 other one, so it was basically a single white PI in isolation,
3 so we went in and did the same IP that we did the first time
4 around which is our IP 95001.

5 The cause of this PI crossing the threshold -- and
6 this is another one that they knew they were heading this
7 direction and initiated dialogue with us, they were being very
8 open and up front -- they had a lot of cooling tower problems.
9 Those aren't something that we would normally focus much
10 inspection resources on, and Farley had not focused a lot of
11 their resources in maintaining them, so they actually had
12 portions of their cooling tower collapse, and they wound up
13 taking six unplanned power changes in this year period the PI
14 calculates, and four of those were directly due to the cooling
15 towers.

16 And their obvious corrective action plan out of that
17 was they're doing a wholesale cooling tower replacement. They
18 have not implemented that. They did short-term repairs, but
19 they will be replacing their cooling towers next year.

20 MR. PLISCO: They're just the old wooden style, just
21 collapsing.

22 MR. ROSEN: How old are they now?

23 MR. CAHILL: They're original.

24 MR. REYES: Yeah, 30-some-odd years. These are low
25 profile mechanical drive cooling towers, and their sides are

1 made out of wood, and wood and water for 25 years gets you into
2 trouble.

3 MR. CAHILL: This was a fairly easily-understood
4 issue, so we elected to have the resident do the supplemental
5 inspection.

6 MR. REYES: They knew they needed to do the work, but
7 they delayed it, and they made some assumptions, and it didn't
8 turn out that way.

9 MR. PLISCO: But again I think this is a success of
10 the ROP. This is an area where we may have handled it
11 differently in the old program. You know, cooling towers, BOP,
12 we really wouldn't have said much. But now with the impact of
13 looking more at risk, and the power changes, and transients
14 they had to do something to fix it.

15 MR. LEITCH: Interesting you bring it up. We heard
16 yesterday that Watts Bar took a scram several months ago due to
17 a cooling tower fill problem. It's kind of the same type
18 situation.

19 MR. CAHILL: One issue that came up a little with
20 this point, Farley was very sensitive that they had crossed the
21 threshold, and obviously wanted to get back to green, so they
22 were preplanning several down powers in the future for any
23 future cooling tower problems, and they were trying to make it
24 so that they wouldn't have to take future PI hits.

25 Basically once they crossed the white threshold they

1 started looking very closely at the criteria and making sure
2 they understood them, and could do everything possible to make
3 sure they didn't have to take future hits. So there was a lot
4 of dialogue between us on letting things just fall where they
5 may versus the fresh views of managing the PIs.

6 MR. ROSEN: When the licensees now really start
7 thinking about these PIs and start managing their way around
8 the PIs to me what I see is not -- this is not managing the
9 indicators; this is really managing the risk because they end
10 up doing things that result in no unplanned power changes, or
11 fewer of them, and that is not just managing indicators.
12 That's managing the real stuff. That's what I like to call
13 chicken, not feathers. It matters.

14 I think the behaviors you see out of this system are
15 the ones we intended to promote.

16 MR. REYES: I think that the examples we're showing
17 you, and we share the view, is that the ROP has really
18 highlighted issues that perhaps may not have been highlighted
19 before, but more than that, it has changed their behaviors, or
20 reinforced certain behaviors, and you see the plants coming out
21 of the white PIs and white findings and go to the green, after
22 doing a review and changing the way they do business. So it's
23 been successful.

24 DR. POWERS: Surely you're not suggesting, Steve,
25 that we're managing the culture of the plant.

1 MR. REYES: Because they actually sit down on the
2 meetings and decide where the discussions are going on, and you
3 know right away.

4 MR. ROSEN: And it gets painfully obvious to the
5 licensee that that's not what you intended, that's not the
6 behaviors you were intending to promote, so they don't want to
7 be in that circumstance.

8 MR. REYES: No, they don't.

9 MR. CAHILL: This PI quickly returned to green in the
10 third quarter of 2000 as some of those first down powers fell
11 off the rolling one-year window that they look at.

12 So at the end of the calendar year, or actually the
13 first quarter of 2001 none of these PIs were in the white band,
14 they were all in the green which -- the reason I'm mentioning
15 that is because the next issue we had was a white finding in
16 the physical protection cornerstone.

17 This was actually started in July of 2000, we did an
18 OSRE about it, and preliminarily we said three out of four the
19 drills that they had failed, but at that point we had a lot of
20 issues with the protection SDP, and basically that SDP was, or
21 the significance determination process was in limbo, and we
22 were really hamstrung in moving forward, so these were put in
23 abeyance for a while while the SDP got finalized, and it wasn't
24 until the spring of 2001 that we really had the SDP finalized
25 so we could move forward on this.

1 MR. MALLET: Steve, you might clarify, move forward
2 on what we did with the finding. They proceeded to fix the
3 issue.

4 MR. CAHILL: The performance issues that came up,
5 they took immediate corrective actions on those.

6 The findings were apparent violations, they were just
7 basically held open until the spring of 2001.

8 Our first look at that was in June we sent them a
9 choice letter saying that this looked like a potential yellow
10 finding.

11 MR. ROSEN: You called that a what?

12 MR. CAHILL: A potential yellow finding.

13 MR. ROSEN: You said a choice letter?

14 MR. CAHILL: We sent a choice letter. It's basically
15 a --

16 MR. ROSEN: I know. I just hadn't heard that term.
17 You can choose to have a regulatory conference, or you can
18 choose not to have one.

19 MR. REYES: You're right. That's what we call it,
20 it's a choice.

21 MR. CAHILL: They obviously elected to come in in
22 July of 2000 when we had an enforcement conference.

23 MR. ROSEN: Enforcement conference, or was it a
24 regulatory conference?

25 MR. CAHILL: It was both.

1 MR. ROSEN: Isn't there a difference between a
2 regulatory conference and an enforcement conference?

3 MR. REYES: This is in the transition, so we had to
4 have two kinds of meetings. But today we would have a
5 regulatory conference.

6 MR. ROSEN: Okay.

7 MR. REYES: In those days we were mopping up old
8 issues and new issues, so we had both.

9 MR. CAHILL: Basically at the time of the choice
10 letter Farley realized that this yellow would overlap, would
11 backdate to July 2000 when the OSRE was because that was on a
12 timely finding, and that's why it would show up in our action
13 issues, and that would overlap with our degraded cornerstone
14 that I talked about earlier, performance indicators. So even
15 though it was a year later we were processing this the
16 backdating of that thing to the time of the finding would
17 overlap, and that could constitute multiple degraded
18 cornerstones.

19 Farley's efforts to work on this physical protection
20 finding obviously escalated accordingly, but there were
21 multiple degraded cornerstones that would have been the same
22 type of inspection that Cooper is getting now and that Indian
23 Point has gotten.

24 So anyway, we had this enforcement conference in
25 July, and a lot of issues came up, but the drills -- basically

1 two of drills were invalidated from us processing the SDP. One
2 for some artificialities, and one was basically we did not
3 comply with the design basis threat on the way the drill was
4 conducted, so it wasn't valid for the OSRE conduct guidelines
5 we have now.

6 You asked before about ones that came out high. Our
7 final decision which we issued in August was this was a white
8 finding. A lot of that, the SDP for physical security is
9 fairly subjective, you have to make programmatic assumptions to
10 be able to take it from white to yellow, and without having
11 that large a number of drill failures we couldn't use the
12 language that was in the yellow finding SDP, so it was issued
13 as a white.

14 Therefore, that unit of the cornerstone really did
15 not interact with the degraded cornerstone we had before, it
16 constituted a degraded cornerstone all of itself. Actually it
17 was a white -- excuse me, a white finding on the physical
18 protection cornerstone, so we did a supplemental inspection in
19 November of 2001, and we had a regulatory performance meeting
20 which again was a meeting between myself and the plant
21 management in December of 2001. And that has closed our book.

22 So right now Farley is back in the licensee response
23 column, and all their performance indicators are green.

24 MR. REYES: I think you're going to find out on the
25 other examples that colors were changed as a result of the

1 regulatory conference. A lot of the changes had to do more in
2 the subjective areas of how the colors are defined, so we
3 talked to the yellow security, and when we talk about another
4 one I think you'll see that there are certain processes -- if
5 it's a mitigating system it's straightforward, and then there's
6 others that are not as precise, and I think you will see more
7 color changes.

8 If you do your work up front well, you only should
9 see changes on those that are more subjective.

10 MR. ROSEN: And as you get more experienced with
11 this, and the licensees become more experienced in interaction
12 with the resident I think before the finding is even written
13 you can get the facts in line that have bearing on how you
14 judge the matter at hand so that you can probably say, okay,
15 now, these are the facts, this is what really happened, and
16 you're both shaking your head yeah, that's what really
17 happened. Now, given that, that fits over here, right? and you
18 can say yeah, I think it does, and you can jointly agree having
19 agreed on the facts that this is where it fits and it's a
20 yellow, or it's a white, or it's a green.

21 So I think it's all a matter of learning how to use
22 the system, and I'm very encouraged by what I see.

23 In fact, I think there's another use for it all that
24 seems apparent to me and that you've thought of already is this
25 concept of coming in and out of findings, in and out of white.

1 At the moment you're doing that, you see a finding of white,
2 and you look up and down the column and across the matrix and
3 see if there's anything else so you can put it in the right
4 place on the action matrix.

5 But in retrospect as you build more and more of this
6 record you can look back and see for a given plant it's been in
7 and out of white a lot of times, you can do a calculation of
8 what percentage of the time it's had the white, or two whites,
9 or whatever, you can look back at the track record that even a
10 plant that's doing a lot of that should be of some more concern
11 than one that maybe had an isolated case, or one that's always
12 coming in and out of white in the various areas you've got to
13 start drawing some conclusions there.

14 MR. REYES: We do that.

15 MR. CAHILL: I forgot to mention when it was up there
16 before, we had planned do to a follow-up OSRE after we issued
17 the white finding in August 2001, we had an OSRE scheduled for
18 September 2001. That got canceled for obvious reasons, it was
19 scheduled the week of September 11th. We were going to do our
20 supplemental, and the scope of that was going to be determined
21 on the results of that OSRE, and since we didn't do the OSRE we
22 went in and did a broad-scope supplemental inspection just to
23 verify how they had addressed the performance issues associated
24 with the white finding.

25 MR. LANDIS: My name is Kerry Landis, I'm the branch

1 chief for Branch 5 which is the Virginia power plants and V.C.
2 Summer Plant.

3 I'm going to shift my comments a little bit to
4 address the focus that you identified of why the changing
5 color, and also the lessons learned from that.

6 We had at V.C. Summer a fairly straightforward event
7 where operators failed to follow surveillance, failed to open a
8 discharge valve to the emergency feed water system, the
9 turbine-driven emergency feedwater box feed water, and locked
10 it in the closed position thinking that it was open, and the
11 independent verifier came through and did not verify that the
12 valve was open. Did verify that it was locked, of course.

13 So that condition existed for 48 days, and the NRC
14 did a Phase 3 SDP calculation using the ask-human-error work
15 sheet which is pretty much the static human error conditioners,
16 and came up with a yellow, and we issued the letter, choice
17 letter for that.

18 The licensee came in, and right before they came in
19 we understood that they were going to use a more dynamic human
20 error rate predictor model THERP, and we didn't have really the
21 expertise to be able to go through that in detail prior to the
22 regulatory conference.

23 We did listen to it, and subsequent to the conference
24 we did take their full calculation, THERP calculation, had an
25 independent review of that, and agreed with them that it did

1 more accurately reflect the dynamic ability of operators to be
2 able to recognize the condition and to recover emergency feed
3 water.

4 That ended up lowering the probability almost in
5 half, which dropped it right down into the white zone.

6 MR. REYES: And that's the point I was trying to
7 make. If you calculated just for the out-of-service time for
8 the turbine-driven auxiliary water pump you would have come
9 into yellow, and all that made it change back to white was how
10 do you model the recovery, how early it was corrected and have
11 recovery, and I personally walked down this system and this
12 valve.

13 We probably have half and half of the staff agreeing
14 that we should give them as much credit as we did or not, but
15 the point being is that you are going to get to a regulatory
16 conference with a color on these subjective areas and these
17 areas where you have to make an estimate, your best estimate of
18 how quickly can they identify the parameter, how quickly they
19 actually reach the component, find it, which is labeled good
20 lighting, inaccessible and recoverable.

21 MR. ROSEN: Good lighting in the station blackout
22 condition for this pump; right? Was this pump turbine driven
23 off feed, it's intended for cases where you have no off-site
24 power and no on-site power.

25 MR. REYES: This valve is --

1 MR. ROSEN: Because the lights are going to be out in
2 this case, so you could have --

3 MR. REYES: I walked, I climbed, and I touched this
4 valve, and it's not as easy, and I did it personally I know
5 what you're talking about, I took my time and went down there.

6 But my only point is, and I'm not arguing if the
7 model is right on recovery or not, is that you are going to get
8 the situations where you get yellow, and when you model the
9 recovery you may come down to white, gives them more credit
10 than you originally did. So I'm not sure we'll ever get out of
11 the situation where we go to a reg conference and we don't
12 change the color.

13 MR. ROSEN: No, I don't think you will, but I think
14 in this case the lesson learned might be that in a case like
15 this you really ought to use THERP right out of the box, not
16 use simplified model if you suspect that the operator's dynamic
17 responses will change the result dramatically.

18 MR. REYES: I think we both learned, the licensee and
19 us we both learned.

20 MR. LANDIS: What do we now, Walt? He did the
21 analysis.

22 MR. ROGERS: Well, we don't just use the THERP right
23 out of the box. We use whatever given the model that we're
24 using to develop the risk impact problem, we will use that
25 methodology.

1 The V.C. Summer case was an excellent case because it
2 essentially established how we do business. We went in using
3 the ASP. However, coming out there we said if we used the
4 licensee's full-stroke model then we'll use the same
5 methodology that they used that worked on modeling other
6 operator actions, recovery actions which in their case is
7 THERP. So we'll draw the THERP, we'll do that. We use the
8 SPAR model as the model that we're using, then we would use the
9 SPAR and the work sheets to develop, so now we have a level of
10 consistency.

11 That's what V.C. Summer produced is our methodology
12 that we would use to go into the regulatory conference.

13 MR. ROSEN: I'm not sure we're communicating just
14 yet, and I think it's important that we do.

15 What I'm saying is that you have a circumstance like
16 this where it's the outcome -- an important document like the
17 color on it is going to depend on how well you model something
18 like a human recovery action.

19 Then you ought to know that pretty early on, and you
20 ought to say we can fill out the ASP work sheets, but it's not
21 the right answer for this. We really ought to be -- And we'll
22 do that, but we're not going to base -- we shouldn't base our
23 determination on that, we should say after the determination to
24 use ASP, but if you use a more accurate model or a model that
25 takes into account both factors you get this answer, and then

1 let you make the decision which one do you want to use.

2 I don't think you should be blind to that, you
3 shouldn't be in any kind of rote mode. You should be using the
4 best tools available is what I'm suggesting.

5 Do we not agree or --? I mean it's okay not to
6 agree.

7 MR. ROGERS: I think you've got to look at what all
8 you're using to draw your insight and apply the appropriate
9 knowledge.

10 If you look at the two HEP work sheets it pretty much
11 uses the same factors.

12 MR. ROSEN: The same performance shape.

13 MR. ROGERS: They have them, they may have them on a
14 different set of weightings and how they're done, and when you
15 -- I mean we knew going in that this would be the -- and this
16 was our test case on the protocol that we would use from here
17 on, and if we were to go to V.C. Summer and have another
18 performance deficiency that we have to analyze and we're going
19 to analyze the human recovery action we'll know where to start.

20 MR. REYES: And I think -- I understand your point,
21 and what we have seen is we have seen more and more responses
22 to the choice letter saying no, we agree with you, Regulator,
23 it's white or whatever, and we don't think it will be fruitful
24 to have the meeting because we share with them here's your
25 calculation or assumptions on how we got to it, and we see more

1 and more of that, and it's the up-front work -- I agree, is
2 this the right thing to do.

3 MR. ROSEN: It seems to me it's the right thing to do
4 is to do more work up front to get it right, and that's models
5 that you can agree on, and rather than it's a false positive or
6 a false negative.

7 MR. MALLETT: But regardless of what color you come
8 out with, it's also important what we said earlier today is
9 that we deal with the issue and get it fixed.

10 MR. ROSEN: Oh, yes.

11 MR. MALLETT: I don't want to give you the impression
12 that we were waiting on that.

13 MR. ROSEN: No.

14 MR. CHRISTIANSON: Walt Rogers is one of our region's
15 senior rep analysts.

16 MR. LANDIS: You really hit the lesson learned and
17 captured both of these that I'll go into for the next event
18 here also, but the lesson learned is any time you have
19 variations in the application of the risk modeling we need to
20 understand that it will either have the same risk model THERP
21 or we're going to get into a varying condition on core damage
22 probability calculation here at Surrey we need to do the same
23 thing as the licensee, or at least understand the difference
24 and what impact it has.

25 DR. SHACK: I certainly don't agree that you have to

1 do the same thing as the licensee. I mean I think you have to
2 understand what the licensee did and how the modeling
3 assumptions affect the outcome, and then you make a decision.

4 I mean I would hate to see a procedure that said,
5 okay, the licensee did it this way so we've got to do it this
6 way.

7 MR. REYES: No, we don't, but we try to make sure
8 that they understand how we did it, and we ask them how do you
9 do it and what assumptions you use. It's important that we
10 come up with an answer which is the right answer, and the
11 dialogue is always helpful. I think you'll find out we do a
12 lot of that up front.

13 I think somebody did a review of the different
14 regions and the final determinations versus the preliminary,
15 and we were closer than most.

16 DR. SHACK: Especially in something that's affected
17 by human error modeling there is no right answer.

18 MR. REYES: That was my point.

19 MR. ROSEN: But in some models don't they take into
20 account the safety factors quite as well as others, and things
21 like operator stress and --

22 DR. SHACK: I think it's very important to understand
23 that the outcome is very conditional on your understanding of
24 human error probability without declaring that this model is --
25 you know, because we'll bring George here and we can -- How

1 many days do you want to debate the issue?

2 MR. ROSEN: I want to find out what his problem is.

3 MR. PLISCO: Walt is very good at briefing us on -- I
4 mean I think this case came, it was right on the line, it was
5 right ont yellow/white line, and he told us ahead of time is is
6 what's going to make the difference in the call on this.

7 And there's other cases where it doesn't matter, it's
8 in the middle, and even if you argue about it it doesn't
9 matter.

10 MR. REYES: This is a good point. Coming to this
11 meeting, going through the meeting we knew exactly what the
12 discussion was going to center on, and what the decision was
13 based on, and so it was not -- we knew it could go either way.

14 MR. ROSEN: That's why you get the big bucks to make
15 that decision.

16 MR. REYES: They do the heavy lifting, I get the
17 credit for it, but Walt and the technical staff and managers
18 did a very good job.

19 I knew before we entered the meeting exactly, Boss,
20 this is why and this is the zone where we're going to have to
21 make the agreement on. They called me in the meeting tried to
22 get that.

23 DR. POWERS: They're doing a good job of making you
24 look good is what you're saying.

25 MR. REYES: Yeah. And we want to keep it that way.

1 [Laughter.]

2 DR. POWERS: Let me ask you a question a little bit
3 philosophically. Just the point you made, you know, you have
4 these findings come out of Phase 2 and they go into Phase 3 and
5 maybe we'll get a change in color. Are you very concerned
6 about that? I mean it doesn't -- somehow it just doesn't
7 bother me very much, because I kind of expect things to change
8 colors, especially on the front end of things, but maybe you
9 have more experience on that.

10 MR. REYES: My experience is not like the other
11 regions', so I'll speak from my experience.

12 We have a small number of situations where the color
13 changed, and they all have been in the yellow and white zone.
14 So the outside, the concerns with the public perception that
15 you go to red, and then you go to white, and those kinds of
16 things, we haven't experienced that.

17 In the cases that we have gone to a regulatory
18 conference to try to discuss one of those, we ahead of time
19 know that the answer is going to be based on which assumptions
20 and which areas are being debated, and I personally don't have
21 a concern in having a small number of the situations have to be
22 changed because of final --

23 DR. POWERS: If you feel like you're coming into
24 these conferences with a good understanding of how it's going,
25 it could go either way especially when you're close, I mean I

1 think it can change color all it wants to. That's what I
2 wanted to hear.

3 MR. REYES: And we see more and more lately, and I
4 think we're just better at it, both the licensee and us, more
5 and more agreement up front and deciding we won't go to the
6 meeting, there's nothing else to do, we agree on the color of
7 the risk significance, and so we see more and more of that.
8 I think it's going to get better.

9 MR. PLISCO: We have an example coming when George
10 talks on Harris. We just had a reg conference a couple weeks
11 ago. They agreed with the violation, they agreed with where we
12 were, and that wasn't even a point of discussion. They just
13 wanted to tell us what they did for corrective action.

14 DR. POWERS: Yeah, and as the process matures swings
15 are not going to be so wide.

16 MR. REYES: Other regions don't have the same
17 experience, they have had relatively significant variations on
18 all that.

19 MR. ROSEN: I think Region III has had some. I think
20 we were told that yesterday at Watts Bar, they did a study.

21 MR. REYES: Yeah.

22 MR. MALLETT: But part of that is what we talked
23 about earlier, this change we're trying to incorporate is how
24 much time do you spend, how much effort do you use. You have
25 to be careful that you don't trim it too short that all your

1 answers are going to change.

2 DR. POWERS: I mean I really like where you're coming
3 from. You're saying if I understand specific colors really
4 don't matter, and as long as I understand where I am I think
5 that's far more important.

6 MR. LANDIS: The next was a white finding at Surrey,
7 and in April of 2000 the Number 3 EDG lubricating oil silver
8 concentration began to increase indicating that the piston pin
9 bearing surface had excessive wear -- well, that it was having
10 wear. They didn't know that it was excessive until later.

11 After successfully completing monthly two-hour full-
12 load surveillance runs in April of 2001 the Number 3 EDG was
13 inspected, and the piston pin bearing surfaces were found
14 severely degraded in seven of the twenty pistons.

15 Now, in March of 2000 just prior to April here they
16 had switched in all three EDGs, and for a two-unit facility
17 they've got three EDGs, Number 3 is the swing EDG, and they had
18 switched the engine oil from an Amoco oil product to a Chevron
19 oil product, and when they did that they didn't know, and the
20 industry was not informed that there was modification in the
21 chemistry to remove a chlorinated compound that would allow it
22 to be more cohesive to the metal, to stay on there longer.

23 The reason it was removed was more for hazardous
24 waste reasons. So they didn't understand that impact, and so
25 right after that silver concentration began to increase, and

1 there is a normal increase in silver concentration as normal
2 wear occurs.

3 The vendor had indicated that they could go up to 1
4 ppm of silver concentrate --

5 MR. ROSEN: Which vendor was that, by the way?

6 MR. LANDIS: This was --

7 MR. ROSEN: This was which diesel manufacturer? I
8 assume that's what you meant by that.

9 MR. LANDIS: Yes. It's the diesel, and Fairbanks.

10 MR. MALLETT: General Motors, wasn't it.

11 MR. LANDIS: No, no. EMB. We were comparing two
12 different -- Fairbanks Morris is at North Anna, and EMD is at
13 Surrey, and we were trying to compare the two all along, so
14 it's EMD these were.

15 MR. REYES: Correct.

16 MR. LANDIS: Now, the vendor recommended that they
17 only had to watch it above 1 ppm, so above 2 ppm silver they
18 needed to take some action, but it wasn't imperative, it wasn't
19 an urgent thing you had to shut down the diesel.

20 Well, they did, they reached above 2 ppm late in
21 2000, and in the next few oil samples in early 2001 it
22 confirmed that it was above 2 ppm.

23 So they took it down, and took a look at it, and it
24 was pretty devastating damage to the piston wrist pins area.

25 It had --

1 DR. BONACA: What about the other diesels?

2 MR. LANDIS: The other diesels, they then went in and
3 checked those, and there was some minor damage on one of them,
4 a little wear on the other, so it was a common mode issue and
5 that factored into the PRA calculations.

6 They ended up replacing all 20 power packs in all
7 three diesels, and changed out the oil to a different oil.

8 As it turns out, that oil, the new oil doesn't have
9 the chlorinated compound either, but they think that it will
10 have better cohesion characteristics.

11 DR. BONACA: So the change risk was very small, but
12 what if they had run those three diesels for an extended period
13 of time?

14 MR. LANDIS: That's where -- you're getting to the
15 very point that was the difference in the calculation. We
16 issued a yellow finding, a preliminary yellow finding, and that
17 was based upon the fact that the diesel factored in, Number 3
18 was considered not to be able to carry out its intended safety
19 function for the full 24-hour mission time. And there was
20 really no disagreement with the licensee on how that
21 calculation was arrived at.

22 Then very late in the game just prior to the
23 regulatory conference they proposed taking advantage of --
24 total probability is the sum of the probability of initiating
25 event of loss of off-site power for less than two hours plus

1 the probability of core damage for initiating events where the
2 loss of off-site power lasts for longer than two hours.

3 Now, the reason for the two hours was every month
4 they had been testing these diesels and, frankly, we were
5 absolutely amazed that the amount of damage that was on Number
6 3 EDG it had just passed a surveillance and ran full load for
7 two hours. So when they --

8 MR. REYES: The length of the mission was the only
9 question, could you survive --

10 MR. LANDIS: They separated the 24 hours into two
11 hours, and then the remaining 22, and so they took advantage of
12 the fact that there are much lower number of loss of off-site
13 power events where you cannot recover in a two-hour time frame.
14 And that ended up lowering it down to a white finding, and we
15 concurred in that.

16 MR. ROSEN: This process is so much more robust than
17 what we used to do, and we actually get down to talking about
18 the real type of issues, in that sense it's much more robust.

19 MR. REYES: Instead of the amount of money of a
20 penalty in the meeting you talk about --

21 MR. ROSEN: You talk about this. This is the way it
22 should be done.

23 MR. LANDIS: And we clearly agreed with them that
24 this calculation more accurately reflected the real core damage
25 problem.

1 MR. MALLETT: And because they didn't want to get
2 into this it also forced them to look at how do they change
3 their detection methods, change the threshold look so they
4 don't get into this risk issue in the future, which is the
5 right thing to do.

6 MR. ROSEN: Your point about the consequences of
7 managing risk rather than managing indicators, it may look like
8 they're managing indicators, but if you pick the indicators
9 they right they're managing risk.

10 MR. REYES: Now the old analysis and the fresh ones
11 are different.

12 MR. ROSEN: Right.

13 DR. RANSOM: A curious point on that, though. You
14 would think that there are applications where these diesels
15 were running constantly and there would be experience with
16 oils, and so why did they change an oil like that without
17 verification that an oil change for that kind of oil would be
18 satisfactory?

19 MR. LANDIS: All of them it turned out were
20 independent, all of these oils, all three, and they changed to
21 a Mobil oil after this. All three of them were recommended by
22 all the vendors, and were determined that they were okay. It
23 just turns out that the EMD because it doesn't have forced-flow
24 oil at the start is a little more critical to oil cohering to
25 the bearing surfaces.