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PUBLIC NOTICE
BY THE
UNITED STATES NUCLEAR REGULATORY COMMISSION'S
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

JULY 18, 1997

The contents of this transcript of the proceedings of the United States Nuclear Regulatory Commission's Advisory Committee on Reactor Safeguards on JULY 18, 1997, as reported herein, is a record of the discussions recorded at the meeting held on the above date.

This transcript has not been reviewed, corrected and edited and it may contain inaccuracies.

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

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PLANT OPERATIONS/FIRE PROTECTION SUBCOMMITTEES

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FRIDAY,

JULY 18, 1997

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ARLINGTON, TEXAS

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The Subcommittees met at the Nuclear Regulatory Commission, Region IV Headquarters, Suite 400, 611 Ryan Plaza Drive, Arlington, Texas, at 8:00 a.m., John H. Barton, Chairman of the Subcommittee for Plant Operations, presiding.

SUBCOMMITTEE MEMBERS:

JOHN H. BARTON, Subcommittee Chairman

DANA A. POWERS, Subcommittee Chairman

MARIO H. FONTANA

THOMAS S. KRESS

DON W. MILLER

ROBERT L. SEALE

WILLIAM J. SHACK

ACRS STAFF PRESENT:

JOHN T. LARKINS, Executive Director

AMARJIT SINGH

ALSO PRESENT:

ELLIS W. MERSCHOFF, Regional Administrator

JIM DYER, Deputy Regional Administrator

DWIGHT CHAMBERLAIN

VINCENT EVERETT

T. PAT GWYNN

KATHLEEN HAMMILL

ARTHUR T. HOWELL

BILL JONES

JOCELYN MITCHELL

KEN PERKINS

DALE POWERS

JEFF SHACKELFORD

BLAIR SPITZBERG

A-G-E-N-D-A

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

(8:00 a.m.)

CHAIRMAN BARTON: Good morning. The meeting will now come to order. This is a meeting of the ACRS Joint Subcommittees on Plant Operations and Fire Protection.

I am John Barton, Chairman of the Subcommittee for Plant Operations. Dr. Dana Powers is the Chairman of the Subcommittee for Fire Protection.

ACRS members in attendance today are Mario Fontana, Thomas Kress, Don Miller, Robert Seale, and William Shack.

The purpose of this meeting is to discuss Region IV activities and other items of mutual interest, including significant operating events and fire protection issues. The subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and activities as appropriate for deliberation by the full ACRS committee. Amarjit Singh is the cognizant ACRS staff engineer for this meeting.

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register on June 17, 1997. A transcript of the meeting is being kept and will be made available as stated in the Federal Register notice.

It is requested that the speakers first identify themselves and speak with sufficient clarity and volume so that they can be readily heard. We have received no written comments or requests for time to make oral statements from members of the public.

On behalf of the Committee, we are pleased to have this opportunity to meet with members of the Region IV staff. Some of the activities of the Plant Operations Subcommittee of the ACRS include visits to the various sites and monitoring of regional activities. Yesterday, the committee had an opportunity to visit Comanche Peak.

At this time, I'd like to ask Dana Powers if he has any opening remarks.

MEMBER POWERS: I'll make the opening remarks about what the plans are for the Fire Protection Subcommittee. The Commission does anticipate formulating some sort of a performance-based alternative fire protection regulations and review plans.

The Fire Protection Subcommittee and the POA Subcommittee both have been following the development of performance-based fire regulations throughout the world over the last few years, and in particular concerned how they might be applied to particular objectives of the NRC.

We are anticipating some heightened activity as the staff develops its plans in connection with a performance-based alternative to the current fire protection regulations, and so the Fire Protection Committee is in the business of gathering information in anticipation of forming an ACRS position on these regulations.

This is the first of our expeditions that we anticipate making to the various regions to better understand what the situation with respect to fire protection.

CHAIRMAN BARTON: Thank you, Dana.

The chairman of the ACRS Committee, Dr. Seale, is here also, and, Bob, would you like to say something?

MEMBER SEALE: Well, since we're starting a little late, I'll hold my remarks to a minimum. I would like to say we're very pleased to be here. We had an excellent visit out at Comanche Peak yesterday, and we look forward to talking to everyone here.

I'll give you a heads-up on one thing that you might be -- you might want to know about. One of the things we are also interested -- we are interested in is the inspection program and how it's going to reflect some of the performance-based regulation implementation issues. It's a different process or at least we think it should be, and we would like to know how the regions are -- after all, they're the ones that -- where the rubber meets the road -- are tooling up to meet that somewhat modified challenge.

I think that's all I want to say, except I'm glad to be here, and I really am looking forward to the meeting.

CHAIRMAN BARTON: Also in attendance is John Larkins, who's the executive director of the ACRS/ACNW and Jocelyn Mitchell, representing the EDO's office.

At this time, I'd like to turn the meeting over to Ellis Merschoff.

MR. MERSCHOFF: Thank you. Welcome to Region IV. We really are delighted to have you here, providing an opportunity for the staff to tell you just what it is we do and answer any questions you may have.

Unfortunately, we have some competing demands for our time today. As you're probably aware, Hurricane Danny spun up in the Gulf yesterday and came ashore at 3:00 a.m. near the Waterford site. We activated our emergency response center to monitor the storm. We have dispatched inspectors to the site and have been following that throughout the evening. I'll need to spend some amount of time today following that effort as well.

Right now, the storm remains a hurricane. It's sitting over the Delta, and the Waterford plant is in mode 4, cooling down, but the conditions at the plant have not been particularly severe.

In terms of important things, lunch: You should have all received a blue envelope and the menu. As early as possible this morning, if you could circle your choices, include any special instructions, information, with or without mayo, include 8 percent tax --

CHAIRMAN BARTON: Welcome to the great State of Texas.

MR. MERSCHOFF: That's right. And restrooms: Restrooms are adjacent to the elevators.

Moving right along, we've prepared a wide-ranging discussion today in terms of Region IV issues, covering the organization, our responsibilities, uniformity among the regions, how it's maintained, some particularly interesting events: the frazil ice instance at Wolf Creek, the steam extraction line rupture recently at Fort Calhoun, and various fire protection issues, events, that the Region has responded to.

We have a discussion from our senior reactor analysts in terms of PRA and how we're working that into the regional inspection program, the SALP program, the master inspection plan, the PIM, the sorts of things that are discussed and an important part of our program and in our assessment program are included in our discussion today.

It's fairly voluminous; it's fairly extensive. And we're extremely responsive to your interests. If you want us to speed up, slow down, or change course, you've got the right people here to do that.

The speakers -- and I'll go through their background here shortly -- are the right ones to address your questions relative to the inspection program. They have each been inspectors and involved in managing the inspection program through the year and currently have that responsibility within the region.

Before I turn the meeting over to Jim, I'd like to go through briefly the key speakers that are listed on your agenda, so you get some sense of the diversity of the leadership and management here in Region IV and the experience that we bring to bear.

Jim Dyer is the Deputy Regional Administrator, 14 years' experience with the NRC. Jim's been an inspector in the office of INE; section chief for the special inspection branch in NRR; regional coordinator and chief for the EDO staff; a project director in NRR for bench reactors and for Region III and V reactors. He has been the director of reactor projects in Region IV, now the Deputy Regional Administrator and operating experience in the Navy.

Pat Gwynn is a presenter. Pat, who is probably up babysitting Hurricane Danny at the moment, is the Director of the Division of Reactor Projects here in the Region. He has been with the NRC for 17 years. He has worked at the Bettis Atomic Research Laboratory, been a senior resident inspector at the Zimmer and Clinton sites, a technical assistant to Chairman Zech, director of the Division of Reactor Safety here in Region IV, and has operating experience from the Navy.

Art Howell, I believe, is with us. Art's currently the director of the Division of Reactor Safety in Region IV, 12 years' experience with the NRC. He's been an inspector in the office of INE, member of the diagnostic evaluation and incident response branch in AEOD, participated in numerous diagnostic evaluations. He's been the deputy director of DRP and has operating experience from the Navy.

Dr. Blair Spitzberg, who'll speak this morning, is not with us yet. As I said, there's a lot going on, so we'll have folks coming in and out. Dr. Spitzberg's currently the chief of the nuclear materials, inspection fuel cycle and decommissioning branch. Dr. Spitzberg has worked as a materials inspector, as a fuel cycle inspector, and emergency preparedness inspector, and the chief of the nuclear materials and licensing branch.

And Dr. Spitzberg will be speaking today on decommissioning and dry cask storage.

Additionally, our two senior reactor analysts, Jeff Shackelford and Bill Jones, will be talking some about that program and the use of PRA. Jeff who is here has worked with Pickard, Lowe & Garrett in the development of PRAs. He's been an inspector in the Region II-Atlanta office. He's worked in NRR, in the PRA branch; currently in Region IV as our SRA, and has operating experience with the Navy.

And, finally, Bill Jones -- Bill is currently in the emergency response center and has been monitoring Hurricane Danny through the evening, as has Pat Gwynn, so your presentations from Mr. Gwynn and Mr. Jones should be particularly interesting, considering they're done on a minimum amount of sleep.

Bill has been the senior resident inspector at both BWR and PWR plants and extensive inspection experience here in Region IV.

Region IV has recently undergone a significant change in terms of the managers. In fact, if you'll look at the ten senior executive-level managers in the Region, only three of them were in the same position that they currently hold that they had been a year ago. So in the course of the discussions in these areas, a question asked may well be answered by someone else, because that person is the incumbent with the knowledge.

The corporate knowledge is here, and mixed around, it makes for a stronger organization in the long term. But we are an organization undergoing change and working in the sleep-deprivation mode for at least a couple of the presenters.

That ends my opening remarks, and unless there are any specific questions, I'd like to turn it over to Jim, Deputy Regional Administrator, and step out and see how my incident response is going.

CHAIRMAN BARTON: With a strong staff like that, it sounds like your job is pretty easy.

MR. MERSCHOFF: It is.

MEMBER SEALE: We were arguing as to whether it was Hurricane Danny or Hurricane Dana.

MR. MERSCHOFF: It's a minimal strength hurricane, so it must be Danny.

MR. DYER: Thank you. My name's Jim Dyer. I'm the Deputy Regional Administrator for Region IV. And just a point of clarification: Ellis presented a regional organization that's a lot more stable than that. He said a year. Actually the reorganization took place in February to March, and so all of us have been in our job about three months.

I guess just a bit of a geographic -- and I guess before we start off, I'd like to -- since we're trying to catch up a little bit, if there's parts that you want me to waive off, just give me a high sign, and we can skip to the -- you know, the chase in that.

But overall Region IV, the major regulated facilities within the Region, we have 14 power reactor sites, 21 operating reactors at those sites, and two power reactors that are in construction that were -- have been subsequently mothballed and they're applying for decommission up at the WNP facilities.

We have 20 test and research reactors that were within the last two weeks have just been transitioned to headquarters for complete regulatory oversight. We were the first region to transition all our non-power reactor regulation activities back to headquarters, and we just boxed up everything and finally got it shipped out about two weeks ago.

We have two uranium fuel fabrication facilities, the General Atomics facility in San Diego and the Siemens Fuel up in Washington, and 1,241 byproduct materials licensees.

The history of Region IV is somewhat -- in April of '94, we transitioned where the consolidation of Regions IV and V took place, and it created our Walnut

Creek field office; additionally followed up from that in October of 1995, we took one site from both Regions III and II. The Grand Gulf site transitioned from Region II to Region IV, and the Callaway site transitioned from Region III to Region IV.

The Callaway SALP just ended up -- the first SALP in Region IV just ended up in -- last month, and that was really the final part of the transition plan where we fully transitioned total ownership for Region -- I mean, for Callaway into the Region IV facilities.

The one unique aspect about those two transitions were the States of Mississippi and Missouri, as far as our state programs liaison goes -- Regions II and III still have ownership for those states, as far as the material licensees and that our state interactions are limited to just for the reactor and emergency planning focuses in that. So in this case, the way we regulate is those two states have to deal with two different regions within the NRC.

MEMBER POWERS: How do they feel about that?

MR. DYER: They're getting used to it, but it's not been -- that was probably the stickiest part of the transition. When we did it in such a hurry, we made the decision, and we did it -- getting state interaction was probably our biggest lesson learned for that.

I think we did a much better job when we transitioned the non-power reactors recently, because we went out -- once we had made the decision and came up with a schedule, we interfaced with all the states that were going to be affected. I think Dwight Chamberlain was the principal -- and Charles Hackney were the principal go-betweens in those efforts and that.

But we alleviated -- answered a lot of the questions, made them feel a little more like they were -- they had the right to refuse and that. I think, if I'm not wrong, I think we only had one state really -- the State of Kansas had some concerns, and they may write a letter. But it was just because we increased their -- they had to get acquainted with new faces in dealing with the NRC, and that was just the normal change process.

Overall, the Region's organized with four divisions, three line divisions that -- as the other regions are -- three line divisions that support the materials and the reactor facilities, and then our division of resource management and administration, who Kathleen Hammill is the division director. She's sitting in the corner, and I invited her here in case there was any questions about the DRMA support area and that.

Additionally, we also have the Walnut Creek field office, which has constituents or components from each of the four divisions. They report to Ken Perkins in the field office. He was the former DRP director and regional administrator in Region V when we consolidated the office and that.

You know, the regional responsibilities, in an -- probably an over-simplified, we have four principal responsibilities: that of being inspection, enforcement, licensing activities, and, of course, incident response, which we're playing a role in significantly today.

MR. LARKINS: How large is the Walnut Creek office?

MR. DYER: I think it's right around 30, 30 people.

MEMBER SEALE: What subset of the Region IV reactors are -- work through the Walnut Creek office?

MR. DYER: We have -- well, you'll see it when we get to the DRP organization. Nominally, we have the four former Region V sites managed from the Walnut Creek field office; the DRP contingent was there.

MEMBER SEALE: Yes.

MR. DYER: Because of the problems at Waterford 3 site, we have dedicated a branch here in Arlington to support Waterford, and because of the distribution of resources between Arlington and Walnut Creek, we were able to -- we created a new branch in DRP, a temporary branch in DRP, for River Bend and Grand Gulf that is currently managed from the Walnut Creek field office.

It's a temporary branch until we get through the increased enforcement and inspection activities at the Waterford 3 site. We just over-stressed our DRP organization here, and one of the things we learned --

The staffing levels of Walnut Creek, you know, back in '94 when we collapsed the former Region V, if anything, given the current budget cutbacks and that and staff levels that the Region has gone through, as well as all the other regional offices -- and the turnover has been lower in Walnut Creek, so they're not stretched as thin as we are here in Arlington, and so we stretched them a little bit by transferring oversight for those facilities.

Walnut Creek has no incident response activities. Their incident response center was taken down, and we manage all the incident response out of here in Arlington. But the overall inspection work, sign-out, enforcement preparations and that, we do from Walnut Creek.

The office of the regional administrator, again, it has Ellis and myself. We also have a number of staff functions which support the various activities.

Again, some of those staff functions also have a contingent office out in the Walnut Creek field office, namely the public affairs and the state liaison activities.

I think in recent times, given the added emphasis on public affairs, interaction with the states in enforcement and allegation activities, this role of staff functions' importance has grown significantly, I would say, in the past six months to a year. And so this is an area that we're continually looking for new ways to improve the way we manage those functions in particular.

And the regional counsel's involvement with the increased workload we have on allegations of willful cause, intimidation and harassment -- that's an area that we're really not familiar as engineers and operating backgrounds in our dealings with, and we've been putting the stress on Bill Brown, in particular, to help the staff in his participation in our weekly allegation review meetings and our -- all our enforcement activities and our review of a lot of our OI activities and that has been significant.

The current DRP organization, which I hope you can find in your handout, because I don't think you'll be able to read it from the -- on the slide, but our current DRP organization is one, as I said -- if I had to correct this slide, it would be that the Walnut Creek field office staff, which is in your left-hand, is really -- it's actually a component of the office of the division director, as much as -- if you had to move that box, it should have probably been right underneath or as part of the office of the division director of DRP.

Ken Perkins, because of the supervisory responsibilities, has a lot of the DRMA functions and that are all assigned to this because of we have to have direct oversight of employees and that for appraisals and supervision and time and attendance reporting and that, so for --

They take administrative supervisory oversight from Ken Perkins in the field office, but they take program direction from Kathleen in -- here in Arlington, Texas.

Additionally, as it's called out here, reactor projects branch G is the temporary branch I spoke of. It's in the lower right-hand corner, right next to technical support staff. This branch we created towards the end of February; actually, I guess, towards the end of April time frame. And it was largely because of we have a special branch.

We unloaded Branch D, which previously had the three Entergy -- three of the four Entergy sites, and we've had a significant amount of enforcement and safety issue activity at the Waterford 3 plant recently, and as a result of that, we had to unload the DRP branch. We just -- we weren't providing adequate attention to either Grand Gulf or River Bend in that, because Waterford 3 was simply dominating.

Overall, I guess, my over-simplification of the role of DRP, you have some specific items in there, but DRP is, in my mind, analogous to a general practitioner in the medical profession. You know, as far as maintaining cognizance of the health of the licensee, they're the generalists.

They're responsible for all four SAL functional areas. They monitor the implementation, whether it's, you know, rad waste transportation, engineering modifications, operations, any examinations and that. They have to be the eyes and ears for the Region, and their sensitivity as a generalists role is to -- if they have a problem is to raise it through their morning meetings and contact with their DRP branch chief, and then we get the proper support, either from our other divisions and DRS and DNMS or from the program office and headquarters.

But the demands on the resident inspectors and the DRP branch chiefs are to be our first line of defense, our screening filter, and to provide the first cut as to what we need to pursue and that. So -- and that's largely their role.

Additionally, they have the incident response responsibilities and site coverage activities that go on, that require around-the-clock coverage or back-up site coverage.

DRS, on the other hand, is our -- is organized on the -- based on the four SAL functional areas. We have the engineering branch, maintenance, operations, and the plant support branches. Art Howell, who is sitting in the back, is the director of the division of reactor projects, and Dwight Chamberlain, who's handling the slides, is the deputy director of the division of reactor projects.

The -- back -- hearkening to my medical profession analogy and that, this is our specialist. They pretty much conduct -- there's -- in the core and in the regional initiation inspection activities, as far as plant inspection goes, they do the planned programmatic reviews in the various SAL functional areas, in accordance with the inspection modules that have been issued from the program office.

Additionally, they do a lot of reactive inspection activities that are in follow-up to either events, allegations, or just something that the resident inspectors stumble upon that either goes above their abilities or the resources to get the work done, so we -- they tend to get redirected and aligned as far as scheduling and that goes. They have to -- they get their schedules changed on a routine basis.

MR. LARKINS: Jim, I've been away from this for a while. Let me ask a quick question. On the project side, it looks like you guys have gotten away from the N-plus-one, and I guess it's sort of just placing residents and others where -- as needed.

MR. DYER: No. We are at N-plus-one at -- I think all our sites officially -- we just lost -- at Comanche Peak, you know, we just issued -- our only four SALP 1 performer is now Comanche Peak. Callaway was a four SALP 1 performer, but it was a single-unit site, so we had two residents there for coverage.

Comanche Peak is a dual-unit site with four SALP-1s. We are now requesting permission to go to N residents at Comanche Peak, but that's our only all SALP-1 performer.

MR. LARKINS: It looked Diablo Canyon and Palo Verde were.

MR. DYER: Diablo Canyon a four SALP-1 performer, and we withdrew it after their last SALP and went to N-plus-one, and as soon as we did that, the other resident inspector who was already there got selected for senior resident at WNP-2, and so we currently have an opening in that -- at that site.

And Palo Verde, we've had a tremendous turnover in all our resident staff at Palo Verde. I think we've lost them all within six months.

MR. LARKINS: Nobody likes Arizona.

MR. DYER: Actually, it was the alternatives beyond Arizona that -- if we would have -- they would have stayed there if we would have left them in Arizona. The big question with the resident program is, of course, moving.

MR. LARKINS: I guess basically you're saying you're still basically implementing N-plus-one.

MR. DYER: We are implementing N-plus-one.

MEMBER SEALE: You mean they stayed in Arizona, but they quit the Commission.

MR. DYER: Actually I think some of them -- they wanted to go farther west, but they weren't about to come east. We aren't really posting and filling any additional jobs in the Walnut Creek field office, and so they have a choice. They can either go to another site, or they could move east, and both alternatives were not acceptable. And so some of them have left to go to DOE; some of them left to go take other jobs in the industry and go back to school and that.

Again, one of the things that is, as I said, going through the major functional responsibilities within DRS -- we use them in the four SAL functional areas, and they are very focused, programmatic. They give us a different cut set, too. Where -- I call it a silo effect, with the DRP, where what we have is a generalists understanding of all four SAL functional areas at that site and can integrate across those areas for common weaknesses.

DRS gives us a different type of cut set. Because of the branch organizations, we can get a cut set of -- across the operations area, for instance, what is the sense in operator licensing across all 14 of our sites? And John Pellet, the operations branch chief, we expect him to be able to give that different perspective from what DRP has. DRP does not have that perspective, except maybe at the division director level. And by then, you're on data overload, and you just don't have enough of a focused look.

So I think the valuable insights come from the DRS branch chiefs in looking at each of the four SAL functional areas and comparing and contrasting strengths across all 14 sites.

One of the things that we focus on here in

Region IV in accomplishing the inspection program is we try to do as many team inspections as we can. We've found that we get sort of a synergistic effect if you can combine, say, engineering, the individual engineering modules, and go out and take a look, you know, in total in seeing -- you know, getting the feedback across the lines in multi-disciplined areas and as opposed to individual, discrete inspection activities done in the various areas, so we try to do all our engineering activities or our plant-support activities as much as we can in groups.

Some regions will do them individually and discrete, and then integrate them back in the regional office. We try as much as we can to do it in a team environment.

Overall, division of nuclear material safety, who's Ross Perrano and Linda Howell, and both are out of the office today -- as far as -- we have a nuclear materials inspection branch, a licensing branch in the materials area, and then we also have a contingent in the Walnut Creek field office which sort of has all aspects of it.

I think as far as in the reactor interface and that, we handle our decommissioning inspections activities from the NMSS or DNMS branch, branches. Additionally, we do our dry cask storage inspection, which I believe is

Blair's subject this afternoon, from the division of nuclear material safety.

Our division of resource management and administration is, of course, the support groups that keep us out of trouble, keep us in, you know, airplane tickets and that, and keep the lights on, and all the activities.

I think as far as the inspection area where we're changing the most and that is probably in the computer support areas and being able to effectively communicate between the sites and here, and to transfer data bases between the regional office and headquarters is part of a -- you know, the next panel discussions we're talking about some of the activities that we do of communicating our findings and maintaining uniformity among the regions.

Probably key of that is the concept that's relatively new called the plant issues matrices which has been basically a reader's digest of the significant findings within the Region at various sites and that by functional areas.

And to get that data not only from the regional branch chief to the division directors to the regional administrators to the various projects and headquarters management offices in headquarters is -- the communication of that data in a discrete, accurate format that is -- that's really key to getting a proper assessment and a focus that allows accountability, better oversight and that.

And right now, getting the information and transferring it effectively from the site to regional office and from regional office to headquarters is one of our major challenges that we're undertaking and facing in that.

MEMBER POWERS: I just wondered if the PIM has been set up so that everybody had access to it, or is it still one of those things that's in the offing?

MR. DYER: Right now, we have it on our -- what we call our R-drive, I think is the -- and that's our read-only drive. And it's a manual operation that each of the divisions has it on another subdirectory drive where they maintain it, and then they QA it, and then periodically, which has been the discussion of how periodically, it gets updated on the formal R-drive to where it's cast in concrete.

But then the problem we've had is the data base, when you put 18 months' worth of data in there, is getting so large, it gets rather cumbersome and transferring it and shipping it to headquarters. As far as I can tell -- Kathleen, correct me if I'm wrong -- I believe the headquarters does not have access to our read-only drive. That's one of the data base issues and computer support issues that we're still working on.

But that R-drive also has the electronic copy of all our issued inspection reports and formal inspection report responses and everything else, and typically, when we get ready to do a periodic review, we're manually transferring the data to headquarters. And if we transfer all 14 sites, 18 months' worth of data, it's a load.

MEMBER POWERS: But I can -- right now I can go through and scan Comanche Peak or something like that.

MR. DYER: You could if you were in this --

MEMBER POWERS: In this building.

MR. DYER: -- building.

Okay. I think that completes my presentation on the regional organization and how we're set up. I'd be happy to entertain any questions you may have.

MEMBER KRESS: How many people do you have in the whole region and how many are here?

MR. DYER: There's 203, I think, in the total region. Kathleen, how many are here?

MS. HAMMILL: Well, there's 35 sites plus -- about 130 are here.

MR. DYER: About 130 people are stationed in the Arlington office. We're on three floors, 3, 4, and 5, here.

(8:30 a.m.)

Any other questions?

(No response.)

MR. DYER: Okay. That concludes my presentation, and right now -- I made up the time. Do you wish to continue, or do you want to take a break?

CHAIRMAN BARTON: We'll keep on going.

MR. DYER: Okay. I guess the next part of our presentation is a panel discussion. I don't know if Pat Gwynn -- the last -- we had a Commission briefing scheduled originally for 8:30 on Hurricane Danny, and then Pat came in and said it looked like it got delayed till nine o'clock, so it may be that Pat's in --

CHAIRMAN BARTON: Why don't we take a break then, and we'll see where Pat is.

(Whereupon, a short recess was taken.)

MR. DYER: I'm Jim Dyer, Deputy Regional Administrator, and now we're doing the panel discussions. I think by the way we were going to do the -- we set up to do the panels, we assigned leads to the various topics and that. As Ellis said in his introductions, because of our recent job transitions and that, if you ask a question that normally would be answered by the DRS director, it might get answered by the DRP director and that.

Pat Gwynn is -- as I said, he's up doing a

Commissioner's tech assistance briefing on Hurricane Danny, so he'll join us in progress. I also have Dwight Chamberlain, the deputy director of the division of reactor projects, representing DRS, and he has specific inspectors who will -- and branch chiefs to discuss the various topics that you asked about.

I think overall, first of all, I was going to discuss the activities for maintaining uniformity among the regions and our training program, training and development program, so I'll begin our formal presentation. Again, we're very flexible. If you want to cut to the -- you know, ask questions, however you want to work it, we can --

MEMBER POWERS: One of our members who was not able to attend would interrogate you closely on your training in the PRA area, so to assure his queries get answered, even though he's not here, you might touch on the training in the PRA area.

MR. DYER: Okay. Where's Jeff Shackelford? Join us. Jeff is one of our recent senior reactor analysts, graduate and that, and can probably address the level of detail to the inspectors and that.

MEMBER POWERS: I'm sure that we'd want to explore the issues of not only what the training is but how they understand the uncertainties of PRA, the incompleteness issues, the limitations.

MR. SHACKELFORD: Just to give you a brief overview of that, myself and my counterpart, Bill Jones, who'll be giving you a presentation this afternoon, are the senior reactor analysts in the Region, and I'm not sure how familiar you are with that program.

Basically every region now has two senior reactor analysts and there are two at headquarters, and we are the PRA designees, if you will, for the Region, and we had an extensive training in PRA from the Agency.

My own -- in my own background, I worked for Pickard, Lowe & Garrett for a number of years, and I have a specific industry experience, and the other SRAs throughout the country have various backgrounds and so forth, so we would represent, I guess, the highest level PRA expertise that the regions have, and our job is to coordinate risk-informed activities throughout the Region and sort of support the rest of the Region.

MEMBER POWERS: I guess the question comes down to, what is the expectations for that expertise. Is it a case of being knowledgeable about the current standards of application of PRA, or is it to be knowledgeable about the forefront?

MR. CHAMBERLAIN: You might want -- I don't want to cut this off, but you might want to hold that question for the presentation this afternoon.

MEMBER POWERS: And if I ask questions that are appropriate to wait, I'm a patient --

MR. CHAMBERLAIN: Well, we're going to go into what our expectations are and what we're trying to use those people for.

MEMBER POWERS: Just to telegraph the kind of questions that would be asked --

MR. SHACKELFORD: Bill has an entire presentation tailored towards that very issue.

MEMBER POWERS: Very good.

MEMBER FONTANA: At some point, though, would you discuss at all the implications of performance-based regulation on the Region?

MR. SHACKELFORD: It has a -- I don't know that we have a specific session related to that, but I'm going to be discussing the Fort Calhoun steam rupture here shortly which has some maintenance rule implications which are performance-based. That'd be a specific application of that type of approach.

MEMBER FONTANA: Because I think it would be of real interest of, you know, how do regions feel this thing would be really -- the impact it would have on real implementation.

MR. DYER: Yes. I guess I question -- as far as being a performance-based inspection, we did that to some extent; I mean, not as informed, but that is an aspect that particular this region, in my mind, has always been focused on is a performance-based orientation as opposed to a programmatic review, paper review, to focus on implementation, to focus on the consequences.

It was that very aspect that drove us, as I said earlier, to the team inspection where we can -- you know, if we find something, we can get an integrated look at it. What's this tell us about everything that's going on at the plant? And we had that to some extent.

I think the SRAs have provided a new dimension that a lot of us dinosaur inspectors had never ever thought of.

MEMBER FONTANA: Well, it would be interesting to get their perceptions, because I -- the impression that I've got is it means different things to different people.

MR. DYER: Do you have a specific example you're thinking of?

MEMBER FONTANA: No. But we keep talking about it, and I'd like to say, Well, gee, you know, I'd like to see one.

MR. DYER: You know, our perspective on, you know, the performance-based inspection is that, yes, you focus on the implementation, on the consequences and the results as opposed to focusing on whether or not all the process was followed and the procedures were adequate.

MEMBER POWERS: I guess that one of the things that -- we would kind of like to use the maintenance rules as starting force for a lot of performance-based regulation that people are talking about nowadays. But the question that comes to my mind is when I see drafts of these new performance either rules or reg guides or standard review plans, is that there's a wide disparity in the interpretation of what performance means.

And in particular, there's a wide disparity in the amount of detail that you find in these. And so what I would like to hear from you fellows is: What would you like to get? Do you want detail, like, Here's a performance-based plan and it should have all of these elements, in great detail? Or do you want something that's much more flexible than that?

That kind of information and feedback, what you're looking for when somebody says, All right; we're coming up with performance-based rules, reg guides or standard review plans, and -- or anything else, but those are the big three.

MR. SHACKELFORD: There's one example that I think you may be aware. There's a move to change the maintenance rules, the A-3 portion of the maintenance rule which now says that you should perform assessments and --

MEMBER POWERS: Right.

MR. SHACKELFORD: -- and the issues --

MEMBER POWERS: Says you shall or will or --

MR. SHACKELFORD: You will, you shall. And the issue is: Should there be reg guides and so forth to tell you -- just making it a "shall" doesn't really make anything happen, and you need to know what we expect.

And we to some extent, the SRAs, are involved in that. We maintain a counterpart relationship with the people who are working on these things, and so we -- you know, the Region doesn't make policy; we implement it. So we are cognizant of those activities, and that is something that's currently underway.

Dale Powers will be talking to you this afternoon about the risks of on-line maintenance, and I helped him a little bit with his presentation, and what he's going to tell you is some of the results of some of the maintenance real base-line inspections, with particular emphasis on what people are doing in the A-3 portion of the maintenance rules.

And you'll see there's a wide range of approaches there, from very qualitative sort of seat-of-the-pants type assessments, all the way up to real-time calculations. And I think that's kind of what you're driving at.

MEMBER POWERS: Yes.

MR. SHACKELFORD: There's a performance-based aspect to --

MEMBER FONTANA: Yes. How do you guys feel about it, and what do you think about what the implications of trying to actually implement it are. Like you say, you're already doing considerable amount of it, but it seems to me that everyone -- it's in the eye of the beholder. It seems to mean different things to different people.

MR. SHACKELFORD: That is a very difficult area, because I was on a lot of those early maintenance rule inspections. I just came to the Region from headquarters, as Ellis told you before, and I was heavily involved in developing the guidance that they use now to assess that.

And given the fact that it says, should perform the assessment, it makes it very difficult for an inspector to enforce that aspect of the rule, if nothing else. We can certainly go in there and make statements about who's better than others. We can say -- you can find weaknesses and give various approaches, but --

MR. CHAMBERLAIN: I think there's been, you know, complaints by the industry too that maintenance rule is supposed to be a performance-based rule, but we're -- really our inspections are more programmatic, and that's probably a valid issue. In the earlier inspections at least, we're looking at program, make sure they got the programs in place.

For this new rule, hopefully -- we do discuss performance-based issues. Every day when an issue comes up, is that a performance-based issue and related to the maintenance rule, whether we need to look at it in terms of how the maintenance rule dealt with that issue, so we do that all the time.

But our maintenance rule baseline inspections really are programmatic inspections.

MEMBER POWERS: This is inescapable. Every performance-based rule that I have seen put forward begins by saying, Okay, you set up this program. Sooner or later, somebody has to come along and say, Did you set up the program and does it meet the requirements of the -- does it have all the elements of the program that it has to have?

I mean, that seems to me that that's an inescapable thing that once that's in place, maybe the inspection's a good deal different after that, but at the front end, you got to find out whether there's a program or not.

MR. SHACKELFORD: Well, the alternative to not looking at that would be to wait until something breaks. And we've said that we're not satisfied with that approach, so --

MEMBER SEALE: But even if you have a "shall" rather than a "should" or a "will" rather than a "should," there's still the question of what the implementation of that imperative is. Somebody -- everybody may implement something, but it may not be the same thing.

MR. SHACKELFORD: That was brought up at the Commission meeting on the maintenance rule where that was a big issue, and my comment was that the industry has always assessed the risk of maintenance activities. That's what their SROs' job is, so there's no one out there's going to tell you, We don't do an assessment.

The issue is: What is our expectation of that assessment? And that's what I was saying, you know, that the reg guides and the guidance that we need to develop to, you know, sort of have a minimum threshold of what the Agency expects --

MEMBER SEALE: So in response to Dr. Powers' question about how specific should the guidance be, you would say you would like to have reg guides and things like that which would give you a template, if you will, for what these various implementation programs should be, and then you can first verify that and then inspect against it.

MR. DYER: Well, I think it should establish a floor. I mean, I don't want to inhibit the industry from being smarter than the NRC and coming up with a better way of accomplishing --

MEMBER POWERS: I have seen drafts that go all the way from, oh, for instance, in connection with steam-generator performance-based rule, they specify chapter and verse on what the program should be. They let you fill in -- the licensee got to define the program, but it had to have all these elements, and it was fairly detailed.

We recently got one in fire protection area that says, You establish program, period. I mean, it gave no specific guidance at all. And we already run into the problem that what those programs will be will differ from site to site to site by radical amounts or at potentially could.

To give no guidance at all seems to me to be just asking for an unenforceable, uninspectable, uninterpretable --

MR. DYER: It doesn't help with consistency.

MEMBER POWERS: It doesn't help with consistency. Yes.

MR. DYER: Okay. I think overall the first topic I'd like to cover is the activities that we have for maintaining the uniformity among the regions in particular, and I'd broken up into two aspects. The first slide is talking about some of the agency-wide initiatives that are directed from headquarters that all the regions implement, and then I specifically -- the second slide talks about what we do in Region IV.

I think, thinking about this, the main thing is that we have enough -- we also have a battle on, you know, on the smaller level: How do we maintain consistency among sites? And it's much the same way than to make sure that once we get consistency among the sites, then making sure that we're consistent among the regions.

And so I guess taking the top down look, some things that -- the guidance that we've gotten from headquarters, NRR in particular -- and I will say just -- Pat and Dwight can echo it, but I would say that it has improved significantly in the last few years, and it's starting to be considered a lot more than it previously was.

I think getting the feedback from the inspectors in the regions on a lot of the -- before the program direction comes out has been most beneficial in asking the implementation-type questions and doing some of the other activities about validating the inspection procedures before they're issued has been a big help in that.

And I think -- I'm recently assigned as the regional representative on CRGR, and I know now that I see my principal role there is to raising that flag. Hey, what's the inspection activities going to be when we get a new rule or a new reg guide and that? So --

MEMBER POWERS: I mean, you're raising interesting questions. We get a lot of -- when we get these rules, reg guides, or standard review plans, then we get a lot of testimonials from people that have looked at them. But I don't know that we've routinely asked for inspectability-type questions.

You know, I wonder if that's something that we shouldn't be --

MR. DYER: Well, the regulatory analysis -- I don't know if you get that as we get it as part of CRGR --

MEMBER POWERS: Yes, we do.

MR. DYER: It discusses what the impact, what the assessment of the costs on the Region are going to be; you know, for training inspectors, what the expected extent of the inspection procedure, how many sites, how you're going to accomplish the program, so it requires to get through CRGR, at least a conceptual.

That is often not captured, and I think one of the lessons learned that we've taken away from CRGR is that we've got to start demanding from the staff that they be bringing this up in parallel and that. I know that NRR is starting to work on it. It's a new concept, and when the rule or the reg guide or the standard review plan chapter is, you know, still in a state of transition and review, it's somewhat difficult to figure out.

My bid position, at least from the CRGR perspective, is, you know: Is this going to be a 100 percent maintenance rule type, visit every site, or is this going to be a resident inspector go kick the tires on this rule and regulation, once we get it implemented and that, at least get the staff thinking in that general direction as to what the extent of the inspection would be?

I think overall the agency training programs have significantly improved for inspectors. There is a r cent manual Chapter 12.45 update to tighten up and extend and identify the specific areas of inspection who had done -- of course, the risk-assessment training for inspectors and supervisors is coming down the pipe, and as again, we've got --

You know, we just recently, within probably the last six or eight months, got our senior reactor analysts back on the staff, and they're starting to convert some of us who didn't have an idea, you know. We're more the seat-of-the-pants type risk-assessment types as opposed to the quantitative analysis and that, and their involvement in our day-to-day activities has helped out, but it's also identified, you know, from the need that we need to get the entry-level inspectors of the future are going to have to have this as a critical tool.

MEMBER MILLER: What portion of your staff have gone through any of the PRA training programs?

MR. DYER: I'd have to ask the divisions. I can't remember.

MR. GWYNN: PRA basics for inspectors, every one of the inspectors has had that course. But it's a very rudimentary class. It needs to be improved. It is being improved, and that's the baseline, I believe, that all of the inspectors have had.

The amount of specific training that they've had beyond that depends upon the individual.

MR. DYER: We've done some IPEEE training, for example.

MEMBER MILLER: How about, say, senior managers? There's a course for management level.

MR. GWYNN: I attended the pilot for the senior managers class that was held last year.

MR. SHACKELFORD: One of the headquarters SRAs is currently developing a new course that's supposed to take the place of what Pat just discussed. It's supposed to be a two- or three-week more intensive course.

MEMBER MILLER: Related to managers?

MR. SHACKELFORD: For managers and for inspectors, too, particularly residents who are on the site.

MEMBER MILLER: So the regional administrator here is willing to spend three --

MR. SHACKELFORD: I don't think that --

MR. DYER: No. Actually it came out -- you know, we just held the senior management meeting, where he came back, but that was one of the things that was evidently discussed at the senior management meeting, because when he debriefed Pat and Art and I on the results of the senior management meeting, it's -- you know, the expectation was made to put it in your training plan.

You're going to -- you know, you're not too old. You are going to learn about risk assessments and the tools and that that -- we are willing to dedicate the time and the resources to get that done.

MEMBER MILLER: I went to the three-day program here a few weeks ago, which is quite good, but certainly could spend more days.

MR. DYER: Yes. I actually went through the

PRA basics for inspectors in about 1984 when the Agency -- when it was back in I&E, and they did the initial -- and I have flashbacks occasionally, but that's about it.

MEMBER MILLER: This would all bring it back.

MR. DYER: Yes.

MEMBER MILLER: I had a question on a different topic just for a moment. A training program for your -- I'm chair of the I&C subcommittee -- training for programs I&C, has anybody here gone through those? There's been a couple of programs at headquarters -- one at the training center in Chattanooga and one at headquarters. Have your regional inspectors been through any of those?

MR. CHAMBERLAIN: I think we sent a couple of inspectors to digital instrumentation.

MEMBER MILLER: Yes. Digital I&C.

MR. CHAMBERLAIN: Yes. We did that about three weeks ago, a couple of our regional --

MEMBER MILLER: They do have a set program --

MR. GWYNN: That's a continuing process.

MEMBER MILLER: Right.

MR. GWYNN: They've been attending those classes as they were made available over a period of time, two people in the Region that are dedicated to that effort.

MEMBER MILLER: So you have two on your staff pretty much that are going to be or are the experts in digital I&C.

MR. GWYNN: That's correct.

MEMBER MILLER: Okay. Thank you.

MR. DYER: Okay. I think overall program office guidance, as I said, the inspection program guidance has -- in my mind, has significantly improved recently, and I would note that, believe it or not, the inspection manual chapter 06.10 on inspection reports, the expectations for inspection reports, was a critical component of that.

A lot of times we think of inspection program guidance, we think of the TIs, the technical instructions, that come out, and we think about the inspection procedures.

But I think the manual chapter 06.10 that outlined what the expectations were in the various sections of the report went a long way to focusing our inspectors as to, you know, directing their inspection and the expectations for how much detail, the expectation for implementation considerations, and that performance-based aspect that Mr. Fontana was bring up and that, that it served a good purpose in the Region.

MEMBER FONTANA: To back up just a little bit on the prior subject, do you intend to have people that can actually do hands-on PRA analysis that you would develop in-house? I know you hired one over here, but --

MR. DYER: Well, Bill Jones is an in-house --

MR. SHACKELFORD: Yes. We actually -- one of the things Bill's going to tell you is for every escalated enforcement case, we do some sort of formal analysis. It may or may not be quantitative, depending on the tools we have available, but -- and for major events, we try and come up with the risk significance estimate.

We have contacts at the licensees, and we obviously don't have the tools and models that they do here, and we recognize that. But we do communicate with them, to try and better understand the risk of inspection findings or violations. So we actually do our own self-contained --

MEMBER FONTANA: Okay. I was just wondering at what level you'd gotten to. Thanks.

MR. DYER: I think additionally the use of what I call task-interface agreements -- these are TIAs as we refer to them here in the Region, which is where we ask the program office for direction. We've become much more disciplined in doing that.

In the past, we were good at picking up the phone and calling somebody you knew in the branch, at headquarters, if you had a question. It was all done informally. Now it's done formally. We request -- you know, we get an answer back, and if Region IV asks for an interpretation of a regulation or, you know, a TI or technical instruction and that, or how we should do an inspection, that goes to all the divisions and all the regions. And so it gets a wider distribution of the activities.

The plant performance reviews, this PPR process and that, you know, I wasn't a believer at the beginning, but I can tell you that that has significantly helped in the assessment and in the direction activities of maintaining uniformity among the regions and among the -- within the Region. That's a very valuable document, because it's clear, and it allows an accountability for the branch chiefs, for the divisions, and among the regions during the senior management meeting process.

Also as I'm sure you're aware, the recent improvements to the senior management meeting process, the Arthur Andersen, the performance indicators, it's -- you know, I'm not sure they're the right performance indicators or not, but just that concept of having a view from 20,000 feet above, you know, the day-to-day grind that gives an overall data review, just asks the question and be able to answer it, is another --

CHAIRMAN BARTON: The committee has been following that. In fact, we're going to get a briefing, I think, on the status of that in September, end of August or September.

MEMBER SEALE: Have you come up with any predictive performance indicators that you'd like to throw at the kitty?

MR. CHAMBERLAIN: If I did, I'd be making a lot of money working somewhere else.

MEMBER SEALE: Ah, a realist.

MR. DYER: When I was a DRP director, mine was how many two o'clock in the morning calls did I get, you know, for plant events.

MEMBER SEALE: Those are easy to count. That's one thing about them.

MR. DYER: Sometimes they're not; that's the problem.

Overall, again, program office coordination and oversight -- we've seen the participation from NRR has significantly increased, not only in audits and oversights, but also in the decision-making and the activities and that.

We've seen an increase for the project managers and their willingness to get the tech staff to support, you know, enforcement panels and our, you know, follow-up from the morning meetings and that we hold here in the Region and that, that that has been an increased emphasis and a focus, you can tell, from headquarters.

The periodic counterpart meetings, a lot of times those have -- and I'll let Pat or Dwight talk about the most current ones of that. But those have become a vehicle for the program office to sort of calibrate the regions all in one sitting, and we've gotten -- we get high-level.

If you get the DRP directors for all four regions in a headquarters office in one room at the same time, you can pretty much get any individual who'll -- you know, in headquarters from the director of NRR to the EDO, to the deputy EDOs to most division managers, and they will emphasize their focus on what they want -- how they want their program, and I think it's a very valuable tool.

It also allows informally a lot of the interface with the various counterparts, and I know Ellis and I, when I was a DRP director here in Region IV and he was in Region II, we used to talk a lot about, you know, how you manage the PIM, how you respond to events, how you do that, and so it's a good lessons-learned vehicle that I found very valuable.

The SALP observation program and feedback, I think that's also -- you know, that's driven -- there's a mandatory for anybody chairing a SALP board is every 18 months you have to view, observe another SALP, the SALP process in another region, and that gave us particular insights in that -- on how data's presented, how the assessment's made, and the feedback given to follow up various strengths and weaknesses in licensee performance.

MR. LARKINS: Jim, not to put you on the spot, but I'm just curious.

MR. DYER: Sure.

MR. LARKINS: How do you see the coordination between the EDO's office and the regions in terms of when you need special inspections or things like that, when there is an event that comes up where headquarters wants to -- you have a team --

Do you see that process having improved in terms of coordination?

MR. DYER: Actually, especially since February, Region IV has a very good communication with the EDO's office, sometimes more than Ellis and I would appreciate.

No. By that, I guess I'm -- EDO office pretty much doesn't involve itself, you know, with the exception of the major DETs and the approval for teams and that, and even before Joe left the Region, you know, Region IV was a net donor to the Millstone, Dresden, Maine Yankee activities.

Outside that, I think the senior management meeting process, where they get all this -- it's -- essentially there's a certain counterpart meeting flavor to that, and having participated in one as an acting regional administrator, there's a lot of activity that goes on about getting the best and brightest to focus -- from all the regions, to focus on our problems and that. And I think we're all willing to do it.

MR. LARKINS: I know you brought the perspective, having been in EDO's office and having been in projects and headquarters and also here at Region, so I was just wondering about your perspective on the coordination.

MR. DYER: And the EDO coordinators and that, they're better now than when I was there as far as staying plugged in to the morning, the daily meetings that we have, the calls and that, and -- but they're pretty much on top.

I think one of the areas that certainly occupies a great portion of our time and that is in uniformity, and it's probably the area that creates the greatest amount of feedback from the industry is in the area of enforcement.

There is -- I think we're making progress in that area. Overall, you know, the development of the enforcement manual, the expansion of the regional administrator's enforcement staff where we went from one enforcement coordinator to two recently, in the past year and a half, and have our staff from the RA's office involved with the various divisions that are, you know, largely issuing the non-escalated enforcement, and then the coordination for the escalated enforcement, up through the regional administrator's office and that, and coordinating with Jim Lieberman's office in Office of Enforcement in headquarters and that, that has facilitated a consistency.

I think it's trickling down right now. I think the escalated enforcement process, we have a weekly meeting with Jim Lieberman and the regional administrator every Thursday at 12:30, and we go through any cases that we think could be potentially escalated, and we get a headquarters read, and it's usually you'll have representative --

We'll have our regional counsel; we'll have the Office of Enforcement; and we'll have NRR on that call, discussing whether or not this reaches the threshold for escalated enforcement. And it's a very consensus-building question-answer process and that.

That does not take place anywhere near the extent for non-escalated enforcement, and so right now, I think that's the area that we probably struggle the most for, and utilities are very conscious now of severity level 4 and 5 violations, 4 -- I mean, and minor violations. e eliminated the --

CHAIRMAN BARTON: The enforcement language, you said, is relatively new? What's in the enforcement language? What are you trying to do with it?

MR. DYER: What's in --

CHAIRMAN BARTON: What's it's purpose?

MR. DYER: The enforcement manual is to just issue a standard, you know, guidance for how to implement the enforcement policy within all the regions and headquarters.

MR. GWYNN: It's very detailed in terms of fire protection; there's a special section that relates to fire protection. And there's a special section that relates specifically to security and health physics.

And so it provides a baseline from which any inspector can go to that manual, if they have identified a violation in a specialized area, look at the criteria that are laid out there for what constitutes a level 4, what constitutes a level 3, and so that really provides a basis for consistency that we didn't have in the past.

And Office of Enforcement is continuing to refine that manual, and as they refine it, then we get better at being uniform.

CHAIRMAN BARTON: Good.

MR. DYER: And, of course, this additional staff is taking a look at -- we're auditing, doing internal audits, and challenging the various divisions to make sure -- and various inspectors, to make sure everybody is handling it in a similar vein.

MEMBER SEALE: Your increased attention to non-escalating cases brings up a very interesting issue. I've heard the idea expressed that managers in some licensees want to know about threshold-level, if you will, violations, things that are below the level for enforcement, and they want to be very -- be perceived as very active in encouraging the reporting of those kinds of things within the organization, as a symptom of concerns that need to be addressed by the local management.

That is, this is, if you will, an activity or an active indication that there's a problem that they need to solve if something like that comes up.

The other side of that coin, though, is that if you get in -- if it gets blown out of proportion and all, you then go into the penalty phases and all of those kinds of things, and then there is obviously within some people within the organization a reluctance to lay your linen out there, for everybody to look at.

Certainly you have as much right as anybody else to look at sub-escalated level enforceable type problems; that is, the things that happen but at below the level of some kind of action.

On the other hand, there is the difficulty of potentially sensitizing everyone to your interest and turning off the desire or the willingness to bring these into high profile within the licensee's organization, so that they can be addressed in a constructive manner. That's a tightrope; you're kind of walking on the ledge there.

And I think you understand as well as anybody that the licensee ultimately has to solve the problem, and anything you can do to encourage them to solve it at the low level phase should be in the cards.

MR. DYER: And I think the recent change -- and I don't remember the date, but the recent change where we got rid of the severity level 5 violations and we went to the minor violations, anything less than a severity level 4, you know, conceptually a severity level 4 violation is significant enough that if left uncorrected, it could result in potentially far -- or escalated significant issue.

MEMBER SEALE: Sure.

MR. DYER: And so the threshold below that, you know, getting it at that level, allowing us to get rid of, you know, inadequate procedures that didn't result in any problems type thing or wouldn't result in any problems, to get rid of -- remove that burden from us was a big help to us, because we were spending entirely too much capturing the enforcement administration in that.

It also served as an incentive to licensees to address it, and it allowed us not to have to address the true nits, not important safety issues, that are out there that we want licensees to be addressing at that level before they get to that.

Additionally, the ability to issue a non-cited violation as a 4, severity level 4, and typically the way -- when we would do that is when the licensee has identified -- self-identified something that avoided a problem downstream, and then often it's written up in the inspection report as being a -- you know, an attaboy, if you would, to the licensee and treating it as a non-cited violation.

MEMBER SEALE: So really to present this perhaps is as a very real form of regulatory relief.

MR. DYER: It is, but some of the outside entities that read inspection reports don't feel that way, and, you know, they count the number of NCVs and ask the question why you didn't find it before you created it, you know. And our sensitivity is we feel very good when they find it before it finds them.

MR. CHAMBERLAIN: Even in the escalated area, too, we try to use -- you know, give them credit if they identify it and they do the right things, you know. It goes down the path, you know, non-civil penalty, but we do have to address those; every escalated case has to be addressed.

MR. GWYNN: Even for some escalated cases, where the licensee has really gone beyond minimum expectations and been very proactive finding --

MEMBER SEALE: Truly intervened.

MR. GWYNN: Exactly. In those cases, we can exercise discretion and not cite a significant safety problem. We have done that on occasion.

MR. DYER: I think the next thing I'd like to talk about is our Region IV specific activities, and these are things that we in our conduct of day-to-day activities.

Probably the first thing that may be unique to Region IV, certainly the level of participation, is we have a daily morning meeting, and that's a regional daily morning meeting, and it's at 10:00 a.m., because we have to wait for the West Coast to wake up and get started and that. If we held it any earlier, I think the people at Palo Verde would revolt, because I think they're heading in to the site at about 4:00 a.m. now to get plant status for our morning meeting.

But that's a very detail meeting where we go over plant status at all 14 sites, and by that, it would be any significant LCOs or maintenance activities or any significant findings the licensee has identified that they're initiating corrective action on.

We get briefings on hurricanes; you know, anything -- and it's typically a region-wide meeting that the regional administrator will attend or the deputy in his stead.

DRP sort of is the chairman of that meeting and goes through site by site, and DRS is in attendance and updates on any inspections they have going on, activities, and, you know, it's a forcing function. The branch chiefs lead the discussions. We don't connect the sites unless there's a special briefing we want, but the branch chiefs lead -- DRP branch chiefs lead those discussions, and it usually means that they're conducting their briefing, site briefings, as early as 7:30 in the morning and that to get prepared for it.

MEMBER FONTANA: I'm just curious. Is that video-conferencing or --

MR. DYER: We video-conference with Walnut Creek field office, but we don't -- we have NRR on the bridge. We hook up a bridge, and NRR participates in that, and so does the EDO's office. They'll usually attend. Jocelyn used to go down and attend the -- you know, there's a headquarters connection that usually occurs down in NRR projects.

MEMBER FONTANA: So they have to put their ties on and everything.

MR. GWYNN: We find a lot of value from the video-conferencing, and we're working hard to make that happen with headquarters as well. We have had some video-conferenced Thursday calls with the Office of Enforcement, and so we're initiating that process to try to expand the video-conferencing further.

MR. DYER: I think we're -- we're even looking at conducting our first individual enforcement conference via video-conferencing, rather than, you know, having individuals fly in and that or us fly out. It's this week. I don't know if it's today or -- this afternoon?

CHAIRMAN BARTON: You're going to have the public on the video-conferencing?

MR. DYER: No. Individual conferences are closed.

MR. GWYNN: It turns out that NRR and we have used our equipment.

MR. DYER: I think also on -- if I get the dates right, let's see. I think it's Tuesday, Wednesday, Thursday, depending on the -- we have what we call inspection report debriefs, where, depending on the timing, it's usually sometimes before the exit, after the exit, but certainly before the inspection report is ever signed out, and we finalize it, it's a debrief of the findings, of the significant findings, to the regional administrator or myself, and all the division directors, to put it in perspective and to, you know, make sure that our enforcement perspective is provided.

Typically the comments will be that, you know, Wait a minute; you know, that's a violation, or, No, that's not a violation. Or, you know, You're making a big deal out of nothing, or, you know, in the case of performance-based, the inspectors have pretty much figured out that if they come in and say that we found -- we're going to issue a violation on a procedure for an inadequate procedure, we'll say, What's the consequences, and if it's --

The message getting back to the inspectors is, Don't bring an in-office review to the regional administrator or the division directors, you know, as being your only issue. What's the consequences of that inadequate procedure? It can't be a hypothetical discussion. We want to see, you know, Did you go out and verify when it was used, you know. Was the pump put together right? Was the test conducted properly, you know, things like that, in pursuing those lines of questions, just --

And additionally at those morning meetings, I would say that we -- by going through which equipment's going out of service, which LCOs that are entered, it's been remarkable how many times you'll find, you know, a diesel -- the licensee will have a diesel and a schedule for outage, and at the same time, they've got a turbine-driven aux feedwater pump or a transformer problem, or we've heard there's thunderstorms in the area, you know, and things like that.

You know, that's typically -- we'll assign -- management will assign follow-up either of the -- mostly of the SRAs to say, Okay, has the licensee done a risk perspective on this; have they followed. And many times we'll find that it's a lack of coordination. The left hand didn't know what the right hand was doing.

CHAIRMAN BARTON: Even though they did an on-line maintenance risk assessment?

MR. DYER: Yes. It's -- you know, they did this review, and they looked at all their tech specs and their safety-related equipment, but they didn't factor in the fact that they've got a thunderstorm coming over or the fact that their gas-turbine generators, which are controlled by the distribution crowd -- or work in the switch yard is scheduled at the same time.

You know, it's the command control aspects that we sometimes pick up and ask questions on.

MR. LARKINS: It seems like there's an increasing trend towards doing more on-line maintenance instead of waiting until the outage and --

MR. DYER: Absolutely.

MR. LARKINS: We heard yesterday that folks were -- although they're not pushing in that direction, they're doing more of that and taking a look at the risk impacts of doing that, and it appeared that the risks in some cases was lower for doing on-line than doing during outage, and I was just interested to hear you say that you guys do take a look at that.

MR. DYER: Oh, yes.

MEMBER SEALE: Have your senior reactor analysis people in the PRA mode taken a look at that as a kind of a generic issue, to identify up front, so to speak, those kinds of things that you would consider to be appropriate as a class; let's say, sort of have a first reaction, if you will, whether or not a particular activity is appropriate for on-line or should be off-line or vice versa?

MR. SHACKELFORD: I don't think that we have what you'd call a checklist or anything for that. The maintenance rule, A-3 type of look, is designed to give us a perspective on how does the licensee perform their assessment for on-line, as well as shutdown maintenance. A-3, you know, runs together with mode, so we --

MEMBER SEALE: Well, I'll ask you a related question then. You've obviously had -- you've familiarized yourself with the IPEs or the PRAs as the case may be --

MR. SHACKELFORD: Right.

MEMBER SEALE: -- for your plants, plants in your region. Do you have an already identified synopsis, I guess I'd call it, of the areas of concern that are addressed in the IPE and the areas that are not addressed in the IPE? For example, do you know that the Callaway IPE will be helpful in addressing on-line maintenance issues?

MR. SHACKELFORD: We don't have anything that you would call formally set up like a matrix for that. One of the things, again, that Bill hopefully will discuss with you is what we are doing in that area. We're building a PRA library here that has that kind of stuff.

MEMBER SEALE: Okay. But it would be kind of a useful thing to have, to help you cut to the chase, if you will --

MR. SHACKELFORD: Right. One of the things that we want to do, Bill and I, is to visit each site. We have the IPEs here which are essentially a summary document --

MEMBER SEALE: Yes. We're --

MR. SHACKELFORD: -- very little detail.

MEMBER SEALE: We're painfully aware of that.

MR. SHACKELFORD: And what Bill and I were going to try and do is establish a better line of communication where we can get more detailed, updated information or access to it. When these issues come up, typically the IPE won't address the nuances of a configuration.

MEMBER SEALE: That's right.

MR. SHACKELFORD: And we have to discuss this with the licensee, so we don't have in-house the information always that's necessary. We do know the questions that need to be asked, and we're comfortable doing that, and then that's what Jim has been talking about.

When these things come up in the mornings and we get assigned to look at it, we know who to go call to discuss what assumptions were made. But we don't really have all the tools that would be required.

MR. DYER: I think the last unique thing with Region IV is, of course, our involvement with the inspection exits. Additionally, we try to get our regional branch chiefs out to a lot of the exits, and if there are significant findings, either from headquarters or region-based inspections, you know, we'll escalate to a division director level to get our point across to the licensees or whenever there's a significant program review, such as some of the AE inspections that we did at WNP 2 in Arkansas.

And to put it in perspective and that, the -- also the overall inspection report preparation process and that is again -- I echo that we, you know, conduct an inspection report debrief at the division level mandatory, you know, and usually at the regional administrator. The regional administrator's office will carve time out of our schedule to make sure we're at the debriefs.

If we're not and the division directors hear the debrief, one of the screening factors from the DRP director is, This is one you need to go talk to the RA about. And that has happened, and the value of that is that in the RA's office, we get a lot of the stray calls from the site VPs who call in to just, you know, tell us how good they're doing and provide, you know, Is there anything on our radar screen.

And it's these inspection report debriefs that will something on our radar screen and file it away that the next time the site VP from Cooper calls in, we're going to talk about their performance on that notice of enforcement discretion, or we're going to talk about their performance in this last start-up and that, things that we observed in that, and provide a critical feedback.

And it's a good sense, from our perspective, as to whether or not our issues are percolating up through their organization, because if the first time they hear about an issue is from me or Ellis, then that's usually an embarrassing point for them. And so --

CHAIRMAN BARTON: Is this process you're describing unique to Region IV?

MR. DYER: I think it is. It's a carryover from when this was an eight-site region. You know, they had the luxury of doing that back when it was the Arlington eight sites, and it's one of the things that we're carrying over, now that we're a big region, to a 14-site region, that in particular.

You know, when it was the Arlington eight sites, we actually had the luxury where the division directors signed out all the inspection reports. Right now, when there are 14 sites, that's a significant stress on the division director, and we're in the process of delegating it down with adequate controls to the branch chiefs.

These debriefs are a critical component of that delegation, if you would, and the quality controls we can maintain through the PIM, plant issues matrix reviews, are that. So we're in the process of downgrading that, but --

MR. GWYNN: Just for information, I know that Region I has a process. It's not face to face with the inspector. It's an e-mail process, where the inspector, when he returns to the office, prepares a bulletized summary of the findings and provides it to the managers in the office.

And then if it's an exception process, if there are some findings that management has a strong interest in, then they ask for a specific face-to-face debrief. It's an exception process. So they're similar functions, but just slightly different.

MR. DYER: It also allows the staff to -- it eliminates any filters between the staff and regional administrator, to know what's the regional administrator's safety philosophy and what things will wind him up in a hurry.

You know, I think everybody's pretty well sensitized that if a turbine-driven aux feedwater pump goes down -- we don't need to know the risk numbers on that. That's one that we want to have discussed and what was the cause.

I guess the next thing -- and this may be -- we'll get Jeff in -- is our staff training and development. The overall staff training and development was the last topic that I wanted to talk about, and we've got -- is this slide out of sequence? I think it may have gotten put in at the end later on. They snuck up and they gave me this topic.

Of course, the overall inspection and qualification guidance provided by the headquarters guidance -- I spoke earlier of the manual chapter 12.45 which recently expanded and tightened up and become much more specific in the direction given from the program office with respect to qualifications.

The HOLB direction, operator licensing branch direction for examiners. has always been fairly -- the technical qualifications guidance and that has been very thorough historically, and then recently the development of the resident inspector development program, the senior resident inspector development programs and the senior reactor analyst programs --

I think our overall view here from Region IV is that the senior resident development program was not as successful as the resident inspector development program. I think the resident inspector development program, bringing outside people in and getting a crash course on how to become a resident inspector is -- we just didn't -- we can't get enough.

And making the leap from senior -- from resident inspector to senior resident inspector can largely be done on on-the-job training, as acting for the senior resident when the senior resident's not there or assigned to a team inspection is probably as good if not better training than a lot of the coursework and the activities that were put into the senior resident development program.

The senior reactor analyst program and that, I think we're going to talk about later this afternoon, but the overall -- I think we're just starting now to see the benefit. It was a net export of talent certainly from the Region for a long period of time, and now that we've got Jeff and Bill Jones back, it's starting to pay off for us in the Region.

One of the things that we found out in this region is that wher you screen for the senior reactor analysts and you take your best and brightest and put them in the pipeline, it's a two-year pipeline. Before they get out, they're liable to be promoted or transferred somewhere else. You know, they are enviable resources that -- and so we took Jeff from headquarters, because he was almost qualified, you know, but --

MR. SHACKELFORD: I'm glad they're transcribing this.

(General laughter.)

MR. DYER: That's right, under your appraisal.

MR. LARKINS: Jim, on the resident program, are you looking more for people with some experience, or are you willing to take the right-out-of-college engineer?

MR. DYER: No. We will not -- I mean, we can't take an intern-level. We need to have -- I would say right now, this region has really hemorrhaged in the resident inspector ranks. I forget. Pat could tell how many openings we currently have, but we have had a tremendous turnover in the past six to eight months, and it's -- you know, it has a trickle-down effect.

If you lose section chiefs, you know, or you lose a senior resident, then the residents move up, and a lot of our residents have moved to headquarters and taken promotions and that, so we're running lean right now on site coverage.

As I said, you know, the four residents at Palo Verde have had a complete turnover, I'd say, within the last eight months. The same thing is going to happen at Diablo Canyon, and WNP 2 is the same way, and River Bend will be the same.

So, I mean, we're talking total turnover.

MEMBER POWERS: I mean, this is panic time. For the eyes and ears, this is a non-trivial loss that you're talking about.

MR. DYER: Yes. And I guess the good news part of it is we've been able to rob from other regions and headquarters as much as they rob from us --

MEMBER POWERS: Yes. It doesn't serve the problem integrally.

MR. DYER: It's just -- it's a four-month transition period, while everybody starts moving, you know, moving your household effects and everything that's creating the anxiety attack.

MEMBER POWERS: Some of these guys may want to move west too.

MR. GWYNN: Actually it's interesting. The saying that misery loves company, well, I have three other division directors of projects who have the same problem that I have, so this is not unique to Region IV.

MR. DYER: Here also in Region IV, we have --

we use a training committee. I'm the training committee chairman. It's comprised of the other division directors and selected members of the staff for the support functions, largely from the DRMA organization.

We issued -- we have a regional policy guide that outlines our inspection, how we're going to implement the inspector and examiner training and qualification within the Region. It also provides our priorities for training, how we're going to implement it.

We came up with a five-priority-level training scheme, of training based on mandatory -- you know, priority 1 is mandatory training to support qualifications; then priority 2 is -- or I guess we used A, B, C, D, and E.

But priority B is mandatory training, supplemental. It would be training supplemented by -- directed by the program office, such as continuing education training for the supervisors, managers, or requal training and that.

Priority C is developmental training for your own current job. Priority D is developmental training within the Region IV scope of work, so it may be an HP would want to cross-train as a reactor inspector and vice versa.

And priority E is developmental, but within the scope of the NRC. And where this really comes into play -- I mean, we use it for judging, you know, which training we support based on maintaining a minimum critical staffing. We also do it --

The critical area that's really come into with the budget cuts has been in our 368 money, which is our discretionary outside training, tuition, reimbursement, and our cash and that. That is -- we are being held to much tighter standards, and so that's where we really have to make the hard decisions.

And those are done at the committee level, and the divisions do the first cut, and they bring them to the committee and the other divisions can challenge them on whether or not they properly classified the kinds of training they want to do and that.

MR. LARKINS: And I think we see training money being cut back agency-wide.

MR. DYER: Oh, yes. Yes.

MR. GWYNN: But this is very important. The availability of 368 funds to supplement the technical training division capabilities is important when you have new technology that's being developed to support safety at the plants, like these high technology probes that are being used in steam generators.

The TTD doesn't train on that, but our

inspectors need to understand how that equipment works and what its flaws are, and they can only get that by attending training that's given by others that costs money, dollars. And without the 368 money, we're in trouble.

MEMBER POWERS: That seems like that's a particularly severe area in your work, Don, on digital I&C.

MEMBER MILLER: Well, I'd say add PRA without a doubt.

MEMBER POWERS: Well, PRA, I think, can be effectively done in-house, because NRC has been so forward in its contributions to the development of that technology, and they've got the expertise. They're net exporters of that technology.

But digital I&C, we're net users, and what we don't want to be is abusers of that technology. And that's a place where you just don't have any trainers that know -- I mean, what they know is stuff that's out of date. They're behind the curve all the time on that.

It's not a failure on their part. They're doomed to be behind the curve on that point.

MEMBER MILLER: The only good news in that is the number of -- net number of people in the entire Commission that need digital I&C is not very large. As pointed out, there are two here, and that's certainly quite adequate.

MR. DYER: Sometimes I wonder.

MEMBER MILLER: Well, I would hope maybe -- hopefully down the pike, we'll have more digital I&C upgrades, so maybe two will not --

MEMBER POWERS: It seems to me the reg guide that I read required more than two just to through it.

MR. DYER: We've had a number of -- I mean, I can think of Comanche Peak and their conversion to the digital feedwater system; Arkansas, you know. Digital feedwater at Arkansas in a B&W plant is critical, and we had -- we're still trying to sort our way out of a major -- we consider it a major event.

We did a reactive inspection at WNP 2 where they had -- they converted a digital feedwater system -- they went to digital feedwater and the adjustable speed drive recirc pumps all in the same outage, and the system interactions that that created and especially when they -- we finally convinced them towards the end of their outage -- I mean, at the end of their operating cycle to do a -- you know, to do the task that -- where they trip a main feed pump from 100 percent power and ensure that the plant won't trip and stabilizing that, you know.

When they did it, it took them right to the forbidden zone of their power-to-flow curve, and they had to trip the reactor. And when we -- Bill Jones led the team inspection that went out there, and we had all of our I&C expertise, I think -- if they weren't on the team, they were helping from the office here or wherever sites they were during that activity, but just trying to sort that out was a real challenge.

MEMBER MILLER: Now, headquarters used that particular example or used that as an example in one of our meetings. Now, headquarters is telling us that they're heavily involved in all the digital I&C upgrades.

MR. DYER: They were on the team.

MEMBER MILLER: Yes. They probably -- I knew they were on the team. I suppose the question is: Headquarters is telling us at our level that they'll take all the tough problems, and the regions don't need to have quite the in-depth expertise. Maybe we need to ask the questions of the regions. Is that -- turn off the transcriber. Is that indeed the situation? Or do we really need to build more depth within the regions too?

MR. DYER: Well, I think -- and I'll let Pat, because I'm -- if somebody can't translate it into simple terms and convince me or Ellis what happened and do we really understand the way this plant operates, there's usually a lot of fur flying in the Region.

I mean, it's --

MR. GWYNN: Really, in my view, it depends upon whether you want to be reactive or proactive. If you want to be reactive, well, then headquarters-based approach will work. If you want to be proactive, you need to know what's going on in the plants and where there are problems with what's going on in the plants.

And so having our inspectors in the plants knowing what's going on and being able to understand it so that they can translate that information and inform headquarters -- that's what happened in this case.

We did a proactive inspection at WNP 2 where we sent our digital I&C trained people out to take a look at these two modifications before they restarted from the outage, and we saw problems.

And so with those problems, then we watched the licensees restart from that outage. We watched how the plant performed. We kept the pressure on the licensee to demonstrate that the system would, in fact, operate properly, and there was some questions over time as to whether or not they were going to perform this feed pump trip test.

It was a part of the original preoperational tests for the plant, and so, you know, without the proactive approach, well, then the Agency never would have known until, you know, until it happened at the wrong time, you know, and so then you're in a reactive mode. We were proactive in this case.

MEMBER MILLER: Didn't that delay their restart?

MR. GWYNN: From this most recent outage, their corrective actions significantly delayed their restart on this most recent outage. Yes.

MEMBER MILLER: One of the concerns I've had is the -- at the resident level, the amount of training you're getting. I think all they're doing is that manual training workshop is all the residents, I believe, are --

MR. DYER: We had a speaker come out, and we had -- I can't remember who it was; I think the program office came out during the resident meeting at one point.

MEMBER SEALE: Could I ask: Have you -- well, I guess not "have." But will you suggest that they keep track of the performance that the parts of those two systems that were involved in this modification that gave you the trouble, to see whether or not there's undue maintenance required? Because that kind of thing is exactly the sort of thing that makes equipment wear out early.

MR. GWYNN: A performance-based rule will give us all of that information that we need. They're monitoring that on a continuing basis, and when you have maintenance-preventable functional fires or even a functional fire, they have to review to determine if it's maintenance-preventable, and they have to track that information. So this is risk-significant equipment, and they have that, thanks to the rule.

MEMBER MILLER: I guess the message I'm hearing as the one who worries about training that we maybe should review a little bit in more depth what we're doing at the regional level with I&C. I guess the view we were getting was headquarters would take care of the difficult problems. But you've got a good point on it.

Headquarters doesn't know about it until it happens; you'd rather know about it before it happens.

MEMBER POWERS: As more and more plants make these transitions, I think we'll need more and more --

MEMBER MILLER: As Dana just pointed out, we have, as we're speaking, hopefully the standard review plan for I&C is being issued. Unfortunately it's a little thicker than we'd like to see it, and it's going to require a little more effort to everybody to dig through it.

MR. GWYNN: I guess there's another significant event that's occurred recently where I think without our inspectors being involved, that the digital

I&C problem would not have come clearly to light for the Agency, and that wαs the steam generator dry-out event where we had an augmented inspection team at Arkansas Unit 1.

There they had main steam relief valve, a safety valve on the main steam system, that failed to open, because it wasn't properly assembled, and so that was the focus of a tension in terms of what occurred at the plant.

But the reason that the dryout occurred was because of a problem with the software in a digital feedwater control system.

MEMBER MILLER: The Arkansas ones are B&W. Right?

MR. GWYNN: That's correct. And so we put a lot of attention on that, and we got headquarters involved, but we were again in a position where we had the right people at the site to ask the right questions, and then to get the right people from headquarters involved in that activity.

MEMBER MILLER: When did Arkansas do the digital feedwater upgrade?

MR. DYER: I think it was this spring outage, and they had their --

MR. GWYNN: I think it was a couple of years ago.

MEMBER MILLER: Yes. I thought it was -- because I think EPRI was heavily involved in that one.

MR. GWYNN: It's a couple of years ago.

MEMBER MILLER: So that one, I'll try and make certain those kind of issues -- there's a digital I&C workshop that EPRI is sponsoring that might bring some of these kinds of generic -- you've added to my list of notes here.

MR. GWYNN: It was an analog digital interface that caused noise in the system, and then the software couldn't interpret the noise, so it locked up the control system.

MEMBER MILLER: B&W plants, as you know, have extra problems in that area. Of course, all the B&W plants were going to upgrade all their systems to a digital, but -- maybe you're not aware -- it being too expensive, they've never done that. Or at least some have done it and some not.

MR. DYER: Well, you know, my knowledge was when I saw the digital feedwater cabinet located between two feedwater heaters on the turbine deck with no air conditioning, it was --

MEMBER MILLER: That's not a digital I&C problem; that's just a sensibility problem.

MR. DYER: Yes. I mean, it's a harsh environment, that that is something that -- I mean, the sensitivity --

MEMBER MILLER: SALP 1 engineering. Earlier or yesterday, there was an issue brought up about lightning, and we have a lightning guideline coming along. But it seemed like in this region, you may have more problems with lightning than, say, other regions.

MR. DYER: Comanche Peak and Grand Gulf certainly.

MR. GWYNN: Grand Gulf has solved its problem, and Comanche Peak has made a lot of progress towards solving its problem, although I'm not confident. It really hasn't been heavily tested yet.

MEMBER SEALE: Actually Palo Verde may have more of a problem in that regard, because ground is harder to find in the desert. Like it doesn't exist.

MR. DYER: We haven't experienced a whole lot of events that I know of, but --

MEMBER SEALE: They're far enough away, I guess, from the mountains, so they don't get quite as much lightning as you get in the mountainous parts of the state.

MR. DYER: I can tell you for a fact Comanche Peak is right in the thunderstorm pathway. It comes up.

MEMBER POWERS: When you mentioned activities during periods where there's thunderstorm in the area, do you rely on digital indications of thunderstorms, or do you use ground potential measurements?

MR. DYER: Actually I think we use the Weather Channel. I think the individual -- the sites are very sensitive to it now, and --

MEMBER SEALE: They're not monitoring ground protections routinely?

MR. DYER: I -- quite frankly, I don't know.

MR. GWYNN: I can't answer that question. I don't know.

MEMBER SEALE: It would be interesting to know if they try to monitor current off those little whiskers they have.

MEMBER POWERS: Measuring the ground potential is such an easy thing to do, and it's -- I mean, in explosives business, you do it routinely, because your eyeball and the Weather Channel, good as it might be, is usually not a good indicator how much lightning you're going to have, and --

MEMBER MILLER: It may be too late.

MEMBER POWERS: Well, the problem is you get lightning when there's not obviously a storm present. You might not call it a storm, but the sky thinks it's a storm.

MEMBER MILLER: As I've mentioned, there's guidelines coming down the pike which we'll seen in November.

MEMBER POWERS: We've seen a draft of it already.

MEMBER MILLER: We have?

MEMBER POWERS: Yes. I have a draft of it.

MEMBER MILLER: Oh, I haven't seen one. That is the one, of course, we emulated last fall.

MEMBER POWERS: I definitely have drafts of it already.

MEMBER MILLER: Any mention of monitoring the ground potential in there?

MEMBER POWERS: They do not.

MEMBER MILLER: We'll have to bring that up.

MEMBER POWERS: That's why we want to review it.

CHAIRMAN BARTON: Before lightning strikes, we're going to move on.

MEMBER SEALE: Could I ask one question? Dr. Powers wrote me a little here, and I think it's worth passing -- you're talking about your problems with your inspectors, just keeping them. Are there any special incentives for inspectors?

MR. DYER: Yes. You know, particularly for the resident inspectors, there is the bonus. There is a bonus for the -- going into or coming off of a site.

MEMBER SEALE: But not while you're there.

MR. GWYNN: That's what we're trying to address, because in the past -- and I was a resident inspector; Dwight was a resident inspector. When we were in the program, the resident inspectors were and continue to be on a special pay scale, and that special pay scale, if they were working in the regional office, they'd be getting paid one level; if they're working at a site, they get paid that much plus three steps in the pay scale. So it's a three-step increase, and that gave them an incentive; gave me an incentive to want to be in the program and to stay in it.

But today, the Government-wide has gone to locality pay, and the regional offices and headquarters are usually in locality pay areas; the sites aren't. And so there's been a significant erosion of that three steps, such that today there's very little difference between the salaries in the two locations. And with the relocation bonus, it gives people an incentive to move out to a site, but it also gives them an incentive to move back.

So if they don't have an incentive to stay, the three-step increase which has been eroded, then there's a disincentive for them to stay at the site.

MEMBER SEALE: I guess my reaction is --

MR. GWYNN: We're working to fix that.

MEMBER SEALE: -- who was dumb enough to think that you wouldn't have this problem when you went to that approach?

MR. GWYNN: Well, the locality pay was not an agency decision.

MEMBER SEALE: I appreciate it, but, by golly, that's something you didn't have to stand there and wait for the railroad to run over you to know you were in the track.

MR. CHAMBERLAIN: They did add the moving bonus to try to compensate, because they didn't have a moving bonus before that.

MEMBER POWERS: But it's like he said. It's now an incentive to go and then find another job.

MR. DYER: I think, you know, we'd like that, you know. I mean, that was the thrust. We wanted to have mobile resident inspectors, maybe not as mobile as -- we over-achieved. And I think that's what we're finding out now, plus the fact that I think the -- given the experience drains with the early-out program and that, there's been particularly from headquarters a lot of movement out, and resident inspector experience is a highly desirable attribute to have in headquarters as well as in the region.

MEMBER POWERS: I think it is difficult to train inspectors. It's an experience-based education that's 95, 90 percent, something like that -- the education is just a frosting on that cake.

MR. DYER: I can say, you know, the bonus comes -- carries with it a two-year commitment at the resident -- at the site, and in the last six months, I've signed two waivers for people to keep their bonus and leave early, because they got promotions. And typically it's a year to year and a half to qualify.

So, I mean, as far as getting full-time resident inspector support, you know, we've probably got six months out of them. One of them we moved from one site to another in a promotion.

Our overall qualification process: We have mandatory training. You know, if you follow the program office guidance on individual development plans, those are optional. One of the things that we mandate within the Region is a training plan, which takes a look at the next one year's worth of training, and it's negotiated and developed between the employee and his or her supervisor, and it'll identify, you know, what the expectations are for the next upcoming year.

That's our basis for budgeting and bringing to the training committee what the anticipated needs are for the Region. That's what we use for scheduling purposes and that, to identify what we need. And so we've implemented here in the Region a training plan that -- between the employee and his or her supervisor.

We also have -- as part of that training plan, we have a qualification, the qualification process for individual inspectors and examiners, consisting of the direction -- I mean, the requirements that are in the HOLB guidance and the manual chapter 12.45. In addition, in Region IV, we've identified some additional requirements that we want to have on a regional basis.

Largely those are involvement with incident response, where the -- one of the things that we think is that -- where the inspector qualifications deal largely with what does it take to be an inspector, we also have the need for incident response, and that as part of your inspector qualifications, because our inspectors are providing site coverage during counterpart meetings.

Of course, our residents are first responders normally, is that any inspector at any site could be called upon to be the first responder to a plant event that we insist that they have experience, understanding, participation in drills, a check-out from the emergency response coordinator, and a walk-through from our incident response center, and what the expectations are for, you know, a trip with complications, and they respond to the site, who they call, when they call, and what kind of information we're going to be wanting and insisting upon here from the Region.

So that's where we -- we also have additional requirements to make sure they understand the SALP process and a lot of the activities that are going on in the Region, and recently we enhanced the inspector qualification requirements in the area of allegations, to make sure.

We found that most of our allegations come from interactions with inspectors on the sites, and if the inspectors don't properly handle that initial encounter with an alleger, we pay for it later, either by being inefficient or having -- you know, not taking the proper actions on an allegation, and that's the kind of rework we just can't afford in our current climate of reduced resources.

Additionally, one of the things that we've done here in the DRS organization is all our examiners are cross-qualified among different -- all the different vendor-types and we've qualified the examiners as inspectors. And we've found that, in particular, from our operating licensing branch, a particular weakness with our resident inspector program has been the sensitivity to proper reactor operations in the control room, what the expectations are.

Our residents are in the control room daily, and for them not to have a -- you know, they may overlook things that a trained eye from the examiner and operator licensing viewpoint would pick up as far as how the shift turnover's conducted, how the operators walk down panels, review of procedures, plant conditions, and things like that.

And we've found that in the course of our examiners going out on inspections or in the conduct of exams themselves, that if we add a couple days on and have them cross-train some of our inspectors, particularly the residents at the sites, we gain some benefits.

And we've got positive feedback from the inspectors that said, you know, that after the examiner walked them through a shift turnover, they had about five or things that they, you know, were totally insensitive to. And it's just that different perspective that really has paid off, and so we're continuing with that activity here in this region.

MEMBER POWERS: I don't know what the experience is within NRC, but I know the experience within

Department of Energy that shift turnovers can be the biggest source of subsequent events of anything I can think of. I mean, it's more than maintenance.

It's just amazing that amazingly complicated events will be going on, and the guy just doesn't mention it to his replacement. Oh, by the way, this thing's about to die.

MR. DYER: I think the other thing that I wanted to talk about, too, is that, you know, in the program guidance for qualification, it talks about interim and final certifications. We -- you know, going through the board process and then the final interview with the regional administrator, and in this region, we -- it's a combined interview with the regional administrator and division directors on the initial qual, and any subsequent qualifications, it's an interview with the regional administrator.

Or if we hire in an inspector who's already qualified from another region, and they go through their site-specific quals or job-specific qualifications, then before they recertify, they have a final meeting with the regional administrator and maybe the deputy regional administrator, but just to go hrough what -- just for us to make sure we have a confidence from a management standpoint with the people we're qualifying inspectors.

One of the things that we recently changed here is we found that we were getting sloppy as we did an internal audit. The process in headquarters and used to be in this region was to allow an interim certification. In other words, you can get productive work out of a trainee if you go out and qualify them on specific inspection modules, particularly at the sites.

You know, certain modules, inspectors would qualify on, and we would be allowed to capture their inspection activities under -- as if they were a fully qualified inspector, and then what happens is you find out by the time they qualify on all modules, sometimes they lost the emphasis or the branch chief did to complete the qualification process and that, or particularly if you had one senior resident --

I think the most embarrassing point when I was a DRP director was that we had a senior resident who was on his third site, and we had a branch chief turnover, and when the new branch chief went in to review the training records, he realized that the existing senior resident at a particular site had never finished his qualification.

Everybody -- I mean, we all knew him. He'd been a senior in the region before, and he had just never had the final check-out from the regional administrator or the new division director and that. And so as it turned out, I think we issued his four-year letter, which told him he had one year left at the site, at the same time we issued his final certification as a qualified senior resident inspector at that site.

And so as a result of that, interim certifications are only good for six months, and they have to be renewed by the -- with the regional administrator now, and the division director gets to renew that, and it's just a good tickler for us to put the heat from the regional administrator's office on the divisions and the divisions to the branch chiefs, that once you start getting productive work out of the individual, you don't forget about the qualification process.

And so that's it. Again, the other thing is the fundamentals of inspection refresher course. One aspect that we have here in this region with that is that we accomplished that training via our counterpart meetings and our training weeks. You know, the requirements are basically every three years, that inspectors outside of their technical requirements receive ongoing inspector training, four hours from a regional management perspective and four hours from a program office perspective.

And the way we accomplish again is that during our counterpart meetings, we specifically track that for the individual inspectors and the attendance at the -- when we have an agenda for the counterpart meetings, there are specific topics that are identified as part of the fundamentals of inspection refresher course.

That completes my part of the panel. I've taken most of the time. If there's any other questions on those --

(No response.)

MR. DYER: Okay. Did you want to take a break now, or did you want to continue?

CHAIRMAN BARTON: How about a five-minute break.

(Whereupon, a short recess was taken.)

CHAIRMAN BARTON: For sake of time, do you want to start at the -- I think most of us know about frazil ice at Wolf Creek; if we've got time, we'll go back to it -- start with the Fort Calhoun steam extraction event?

MR. CHAMBERLAIN: Jeff Shackelford's going to give that discussion. He's the one that led the team inspection there. You've already met him. He's an SRA. So I'll turn it over to him for that discussion.

MR. SHACKELFORD: Okay. Before we start, I just wanted to point out that I put this display board up in the corner over here. I don't know if you had a chance to look at it. It has some additional photos and information about the event. If you get time between the sessions, you might want to take a look at it.

We gave this presentation to the senior resident and resident inspectors during the last counterpart meeting, so it was an information-sharing type event, so that they could take any lessons learned that we found at Fort Calhoun for their sites, and, you know, one of our methods of communicating this to the NRC and the industry, and I have a slide on that later on, to show you how we tried to -- our ongoing effort to communicate what went on there.

On April 21 of this year, there was a rupture in the extraction steam line at Fort Calhoun. Basically, the fundamental cause of this was full accelerated corrosion in one of pipe elbows there.

In terms of safety significance, this event led to what we considered to be an unnecessary plant, transient, and personnel hazard. Fortunately, there were no people in the vicinity of the rupture when it occurred. And I put a picture of the pipe rupture. I think you may have seen a copy of it, and there's one up here. And I'm real sensitive to -- when I've given this briefing several times, I don't like it when people call it a steam leak, so --

This was not a steam leak. This was a steam rupture. And Fort Calhoun recognizes that, and they are thankful that no one got hurt.

MEMBER POWERS: To be quite honest with you, the pipe picture is not as effective as the surrounding equipment pictures. It makes it perfectly obvious.

MR. SHACKELFORD: Right. If we had more time, the presentation we gave with the residents -- I actually have a video of walking through the plant. The plant was essentially inaccessible for about four or five days following the event, due to asbestos contamination in the plant.

So there were a lot of side issues, you might call it, other than what would have been the root cause here of the pipe being ruptured.

MR. PERKINS: Maybe if we don't get a chance to see that, we could get a copy, and I could show it during --

MR. SHACKELFORD: Sure. It's about a ten- or fifteen-minute just --

MEMBER POWERS: That would be very helpful. Yes.

MEMBER KRESS: Is this safety significance, which says it led to unnecessary plant, transient, and personnel hazard, is that a standard category of safety significance?

MR. SHACKELFORD: I don't know about standard category. I guess what we mean there is we felt that this pipe rupture was preventable, and we'll even discuss that later on. But it caused the operators to trip the plant.

There were some other interactions later on. The fire protection, for example, was actuated due to some steam heating of the fusible links. There was some intermittent grounding on some switch gears. All of that together, I guess, we considered to be an unnecessary challenge to the plant and the operators caused by --

MEMBER KRESS: You don't have categories of safety significance to check off and say, This is category 1 safety significance --

MR. SHACKELFORD: Not in those terms. I mean, the enforcement policy itself kind of tries to do that.

MR. GWYNN: In terms of the international standard that's used, we don't -- we have not classified this event.

MR. SHACKELFORD: Okay. The next few bullets just kind of go along, describing the event. As I said, on April 21, 1997, it was probably about 8:30 in the evening; that's part of the reason that -- they weren't at a shift turnover time, and most of the day people were gone. That's one of the reasons no one was in the vicinity.

This is a very high-traffic area where this pipe is located, and if you've ever been to Fort Calhoun or if you ever go there, you're almost certain to walk right by this particular pipe.

But the operators heard a loud noise in the turbine building and then a continuous, I guess, roar, you might call it. They can look out -- they can open the door from the control room and look out onto the turbine deck, and when they did, they saw steam and the noise, so they immediately tripped the reactor, and I think the estimates were that it took them about 19 seconds to -- between the time they heard the rupture and the time they actually tripped the unit.

They really didn't receive any primary site indications in the control room. This is -- I don't know how familiar you are with the secondary plant there, but this is an extraction steam line that comes off the high pressure turbine. Once they tripped the reactor and that, in effect, tripped the turbine, and that had the effect of isolating the steam rupture.

However, they didn't know at the time where the rupture was, but they did have a fair indication they might have steam rupture, so they went into their emergency procedures and initiated emergency boration as a precautionary measure, just to ensure that they would have adequate shutdown margins.

MEMBER POWERS: Where does that extraction steam go?

MR. SHACKELFORD: It goes to the feedwater heaters. It's part of the --

MEMBER FONTANA: It preheats the feedwater?

MR. SHACKELFORD: -- efficiency of the secondary plant.

MEMBER FONTANA: Regenerative feedwater heater. Right?

MR. SHACKELFORD: I guess you would call it that. It's steam right off the main steam that's feeding the -- heating the feedwater going back to the steam generators, a secondary site efficiency consideration.

MEMBER SEALE: What pressure is that system at?

MR. SHACKELFORD: 250 pounds, 400 degrees Fahrenheit was what they estimated the operating conditions. The design conditions are a little bit higher than that. I believe it's 325, 425.

MEMBER POWERS: I take it you're fairly supportive of the operators going to the emergency procedures at this point.

MR. SHACKELFORD: Right. Later on in the

discussion -- we ended up determining -- and I don't know if you had a chance to read our inspection report. But we gave the operators, I guess, a thumbs-up, if you will. We thought that they -- they probably, even though we don't go on to speculate this in the report, but they may have saved the plant additional damage and complication by acting so quickly.

The plant did not trip automatically on this event, and it's not clear that it maybe ever would have, or it might have been some time before it did, so by isolating the steam leak or rupture, I guess -- I guess I'm the only one who can call it a leak. By isolating the rupture early, I guess it would be safe to say that they probably did avoid --

MEMBER POWERS: What you know for sure is by isolating early, you prevented any ancillary damage to equipment --

MR. SHACKELFORD: Right.

MEMBER POWERS: -- from the steam flow.

MR. SHACKELFORD: Right. And --

MEMBER POWERS: And I think you emphasized that in the report.

MR. SHACKELFORD: Right. There were interactions with the primary site, I guess you can call it. There are some switches and pressure transmitters in the blow-down path there that will feed the system, the emergency switch gear room that's just several away from the site of the rupture

Part of our inspection and part of our initial response was to determine what kind of primary site indications or interactions may have occurred in terms of the risk significance of this event. Could this event have gone on to disable equipment necessary to mitigate it, and that was our concern initially, because there were grounds on some safety-related equipment.

And part of our follow-up was to look at how that came about.

MEMBER POWERS: One of the areas that persistently comes up in connection with fire events is if you had a small event that gets put out, nobody thinks about it. Smoke goes up, goes into the electronic packages and things like that. Six months later you've got a problem, because of corrosion of contacts and things like that.

MR. SHACKELFORD: That's one of the sensitivities of our regional administrator. He was on board in Region II when Sequoyah had their steam rupture, and one of the complications was, after all was said and done, the moistures left in certain contacts and transmitters that sets up corrosion circuit, if you will, and then later on, it comes back to trip the plant.

And we made that very clear to Fort Calhoun, that we wanted to know what they were going to do to address that issue, and they were sensitive to that as well, and part of their corrective action and commitment going forward was --

They obviously inspected all of the applicable equipment in the blow-down path, but they've also instituted a program to periodically go back and check various transmitters that even didn't have moisture in them, just to make sure, because the moisture can be very hard to detect. You just really can't see it unless it's really bad, so they are looking periodically at equipment out there to address that issue.

I guess that's -- we felt like that's really all they could do, because they did do a comprehensive walk-down of the damage, and they're continuing to look at it.

As it says here, during the event, the fire suppression systems actuated, and those -- basically the fusible links on some of the heads were fused due to the temperature of the steam and then sprayed down some equipment, and the deluge system over the lube oil reservoir, which is actuated by a rate of temperature rise, gave way, and it actuated.

The complication here was that they realized fairly soon there was no fire. They didn't need this actuation, so they were attempting to isolate the affected portions, and there was some confusion about the procedures that should be used and how to do that. And they ended up taking the entire fire protection system to full lock to stop the unnecessary spray-down of the equipment.

And that was a subject of another fire protection issue that was just at issue with the plant. We didn't fault the operators for that particular issue, because they did have a procedure in hand that allowed them to do that. But we questioned whether or not that procedure was appropriate.

Moving on, the rupture was in a 12-inch four-stage extraction steam line, and there you see the -- basically the steam conditions inside the line. It's a fairly spectacular rupture. This is what they call a large radius of sweep elbow, and it was probably about a six-square-foot hole opened up in the side of the pipe.

This particular location was in the licensee's erosion/corrosion monitoring program. However, it had never been actually inspected by NDE techniques during the life of the plant. They were using what many of you are probably familiar with as the Checworks computer code to predict wear rates in various parts of various systems, and then using that as a guide as to which locations to inspect and not.

And at the time, they believed that this was a relatively low wear rate location and that other locations in this same system should be wearing at higher rates, and they were inspecting those particular locations. As it turned out, those locations they were inspecting did not exhibit significant wear, so their belief was that if the worst case is okay, then you don't need to worry forward.

MEMBER POWERS: The reason they don't get wear at those locations is because they were getting the wear upstream of it.

MR. SHACKELFORD: There's still, I guess -- there's even new information that's come to our attention as late as this week about problems with Checworks and their implementation of it. One of the problems at least was one of these otherwise high-wear rate locations, they have now determined was an elbow that they had replaced in 1985 and had not factored into their model.

So, in other words, their modeling program thinks this is a 20-year-old elbow that hasn't worn out very much; therefore, the other 20-year-old elbows are in the same condition, when, in fact, this is not a 20-year-old elbow, and so --

CHAIRMAN BARTON: Isn't this like a lot of other events? When you dig into it, you find out that they had found some fitting in some other areas by the erosion/corrosion program and just didn't go far enough in inspecting --

MR. SHACKELFORD: Right.

CHAIRMAN BARTON: -- and if they had gone to this elbow, they would have seen thinning at that point when they replaced some other pipe and elbows a few years ago?

MR. SHACKELFORD: Right. That's in their -- I think you probably saw that in the inspection report. We determined that the next upstream elbow had been replaced in 1985 due to excessive corrosion.

CHAIRMAN BARTON: Accelerated corrosion.

MR. SHACKELFORD: Right. When they went forward with their program -- I believe it was in -- I forget the dates now, but when they instituted their erosion/corrosion program in '88, they failed to really go back and look at past history as well as they should have, so their belief and Checworks was telling them that this large radius elbow won't -- is not going to be a big problem for you.

They didn't remember, I guess you could say, that they had a problem with a large radius elbow, which would have -- no matter what Checworks tells you, if you've got plant-specific information, it's going to be more valuable to you. So that was just another deficiency that we noted there.

And that's why I say this was a preventable event. I mean, we're looking in hindsight, and we're very good at that. But these are not subtle issues. These are right there, so -- and they acknowledge that. They're not trying to, I don't think, take the high road on that.

But unfortunately the missed it, and the only good thing about it, as I said, was no one in the vicinity of the rupture when it happened.

MEMBER SHACK: Now, flow-assisted corrosion is, you know, an area that the NRC decided to leave to industry really to develop a program to react to. When they developed their program, you presume will be inspected in some way, that the program was satisfactory. What did you use to judge the acceptability of the program when they set it up?

MR. SHACKELFORD: Okay. I did a lot of -- I became very fluent in erosion/corrosion during this time, so I became knowledgeable about the history of this.

I was looking for regulatory requirements, and prior to the maintenance rule, there were just -- to be honest with you, I mean, there's a generic letter and there's a bulletin, and there are responses to the same, but none of those constitute a regulatory requirement.

MEMBER KRESS: That's because this is a secondary system?

MR. SHACKELFORD: Right. This is completely a nonsafety-related secondary side system.

MR. CHAMBERLAIN: I think, Pat, you might have some insight what kind of inspections we did, but I think it was more performance-based. If there was problems, we went out and looked. Why didn't the program detect it, but we did do those kind of reactive things.

MR. SHACKELFORD: There was an inspection, and we looked at the results of that, and then the inspection --

MEMBER SHACK: Because it was looking at good elbows, said everything was terrific.

MR. SHACKELFORD: Right.

MEMBER KRESS: Does this use --

MR. SHACKELFORD: Primarily UT.

MEMBER FONTANA: You can actually inspect this stuff. This has the type of insulation --

MR. SHACKELFORD: Right. It has reflective insulation.

MEMBER FONTANA: Do you have to remove that?

MR. SHACKELFORD: Yes. You have to remove the insulation and grid the elbow. It's a labor-intensive process to inspect each pipe. It is. But you can see what happens if you don't, so --

But this particular elbow is estimated that it, you know -- we're concluding after-the-fact readings here, which could be somewhat distorted by the event itself, but .05 inches for about two feet, so you've got a two or three-inch wide, two-foot long strip that's about half the thickness of a penny, whereas the nominal wall thickness of that pipe is almost half an inch. So this is a significant amount of degradation in that pipe.

In the follow-up, they inspected many other elbows. Okay? You can imagine the type of follow-up they've done. I should have brought in their corrective action documents. It's a volume this thick, the things they did and people they talked to.

They had Jim Taylor, the former EDO, there as part of their advisory committee, so they really did an extensive follow-up. But they found another elbow downstream of this -- the one that broke that was thinner. It just didn't happen to rupture.

MEMBER KRESS: If you go back and plug in the wet steam conditions and the flow conditions in the Checworks, will it after the fact tell you that you should have expected this kind of erosion?

MR. SHACKELFORD: At the time, they did had EPRI on site and many other experts, trying to determine why Checworks had failed to predict this, and they couldn't come up with any satisfactory answers.

The one thing that I did, you know, after the fact, that -- and there again, it's hindsight, but I think it's something that would have been obvious to someone doing it.

You could have plotted the predicted values versus the actual values on a graph, and Checworks tells you to do that. And if you had done that, you would have seen this large, diffuse cloud of points which, if nothing else, would tell you you have no predictive capability in this area.

Now, that -- you know, so that's not really a black mark against Checworks at that point. It's telling you, I don't know how to predict this line. If it's a tight pattern of points, then you have some reasonable prediction. They weren't doing that. So regardless of how good or bad Checworks may have been predicting this wear rate, they did have an ability to have detected that that they had missed.

And, here again, they acknowledge that, and it's a part of being able to use Checworks effectively. I mean, I read the Checworks manual and talked to the people there, and it's in there, but this would be a more sophisticated use of the code, I think. I think it's sort of a --

When we talk about generic implications, that may be one of them is if you're going to use one of these methodologies, you really need to know how to do it.

MEMBER KRESS: Is Checworks relied on for the same information in other parts of the plant that may be more risk or safety-significant?

MR. SHACKELFORD: I wouldn't say so. You know, obviously the primary side is under the ISI program, and they do some modeling there, too, but they rely on a lot more --

MEMBER KRESS: Even there, they don't inspect the full system.

MR. SHACKELFORD: No. Checworks is used all over the world and all over the plant.

MEMBER KRESS: But we wouldn't expect this kind of erosion from the primary system.

MR. SHACKELFORD: Right. I mean, this is a -- you know, it's like a two-phase phenomenon.

MEMBER KRESS: It's a steam problem.

MR. SHACKELFORD: Right.

MEMBER SHACK: Well, no. You can have a single-phase feedwater. I mean, Surry's got a great big rupture.

MR. SHACKELFORD: Right. If you look at the industry guidance on this, NSAC 202 and some other guidance documents tell you, what are your most susceptible systems, and extraction steam is notorious. You know, we'll get to that in a second when you look back here. It is a bad actor in the world of flow-accelerated corrosion.

Feedwater is really not. I mean, some of the more spectacular events have occurred, and people got killed at Surry and so forth and Sequoyah.

MEMBER SHACK: You're right. Hundreds of them happen in extraction steam lines. I mean --

MEMBER SEALE: Let me ask you. Does anyone use Checworks in fossil plants?

MR. SHACKELFORD: I believe they do.

MEMBER SEALE: I would be amazed if they didn't.

MR. SHACKELFORD: See, Checworks is really a suite of codes, and when I say Checworks here, I really mean the flow-accelerated corrosion module of the Checworks. They have modules for other applications, and for instance, service -- you know, it's a large market, and what --

MEMBER SEALE: Especially if they use it in fossil plants. Yes.

MR. SHACKELFORD: They publish a textbook on this, and there's a lot of fossil-related events and fossil-related applications. I obviously didn't really get into that during this inspection, but I had the impression that they had a pretty wide market.

If you wanted to go out and buy yourself a copy of Checworks and model your home, let's say, you'd have to pay about $150,000 for it. The EPRI members get it free, but they have to pay $50,000 a year to be a member of the users group and get the updates.

MEMBER FONTANA: That's one thing I thought was kind of amusing when I read the report. You know, it kind of cast aspersions on Checworks, and I get to the end and want to find out more about Checworks, and it says, Oh, it's proprietary.

MR. SHACKELFORD: Yes. It's all proprietary. And I have some slides. I didn't realize this was going to be a public meeting and transcribed, which I had some slides that went into a little bit more detail about the approach and algorithm that Checworks uses, but I had to take them out. But I guess if you're interested in follow-up discussions or something, I might could probably do that.

MEMBER KRESS: I think we planned on looking into Checworks in one of our subcommittees.

MEMBER SEALE: But this may indicate we'll have to close part of that meeting, so we can really dig into the details.

MR. SHACKELFORD: I think some of this recent information that I was talking about -- I mean, in the beginning, I had a very negative impression of Checworks, because I couldn't find out anything the licensee had done wrong, and yet in terms of the modeling and the predictions were still bad.

I still felt like they could have identified that the predictions were bad if they had evaluated the data properly, but, you know, they can only go so far. So -- but this new information does indicate that their application of Checworks was less than stellar, so Checworks itself may not be --

CHAIRMAN BARTON: Don't condemn the program; condemn the implementation of the program.

MR. SHACKELFORD: Checworks is probably a good tool in the sense that they can't inspect every inch of --

MEMBER SEALE: Well, how old is the data presentation package part of it?

MR. SHACKELFORD: Excuse me?

MEMBER SEALE: The data -- you know, now you've done the calculation. If it's a fairly modern code, it's likely that everything is plotted against everything in all kinds of glory, and you can probably do the kind of interpretive analysis you're talking about on line.

MR. SHACKELFORD: Well, see, one of my -- this is something that obviously I wouldn't have put in the report, but it was my impression of Checworks that Checworks is a beautiful interface. I mean, you know, it gives you color-coded graphs of the pipe and, you know, very nice graphics and models, and --

MEMBER SHACK: You almost believe it.

MR. SHACKELFORD: You want to believe that, and if you're not really a skeptical, sophisticated user, then, you know, it's a computerized presentation of this, and you need to really look at what it's telling you. I think that was one of the lessons that Fort Calhoun may have learned from this is that it's a very nice package, and it is a valuable tool for them. Don't get me wrong.

But it requires the correct level of interpretation of the results to make sure that you understand what it's telling you. Just because it's a color-coded rendition of the pipe doesn't mean that's the actual condition that's there.

MEMBER SEALE: By the time they get through, you think you're on Mars.

MR. SHACKELFORD: I wouldn't go that far.

MR. MERSCHOFF: If I could interrupt you for a minute, you made an excellent point in terms of this is an application issue. Many plants have had good success with Checworks. It's intended as an iterative process that converges on the model. There was a problem with the application of the iterative approach here.

Now, this is a subject of potential escalating enforcement that we'll be meeting with the licensee on, in fact, just Monday, so there's some aspects here that we really can't get into, and the question's still open in terms of the enforcement on just how good or how bad this particular application was.

MEMBER SHACK: But that is a problem in the sense of the way this was handled from day one, with sort of a generic letter that said there was a problem here and the industry was going to develop a program, and you sort of -- then it kind of just sort of left floating in the air until we're down to this very performance-based kind of thing, you know, that when the pipe ruptures, there's a real problem.

MR. SHACKELFORD: Right. And if you look at the enforcement history of pipe ruptures -- and I did prior -- to this event, it's typically -- you're not able to cite the problem which occurred. You're not able to go in and say, You had bad erosion/corrosion control, because that's not a regulation. You would have to find some obscure operating procedure or maintenance procedure that they may or may not have done well, and then cite against that, and you kind of lose the message somewhere along the way, you know.

MR. MERSCHOFF: But there is a change. The maintenance rule has brought this category of equipment within the regulatory arena. This is equipment that can cause a transient to trip, and so now it's within the performance-based arena in a regulatory sense, and is, in fact, this particular issue that will be discussed at the enforcement conference on Monday, the nexus between poor performance, a rupture, and the maintenance rule requirements to monitor the condition of a system to prevent -- to assure that it can perform its function.

MR. SHACKELFORD: As I said, we felt the overall operator response was superior. You know, the operators acted in a very timely decisive manner and tripped the plant and worked towards stabilizing the unit there.

There was extensive damage in the vicinity of the rupture. I don't know if -- if you have the opportunity to look, one of the motor control centers was significantly deformed by the blast of the steam, and there was a lot of insulation blown about the building. The report contains a brief kind of rundown of the damage which occurred.

MEMBER POWERS: One of the issues that continues to arise in connection with BWRs especially, but even in connection with PWRs, is contamination of sumps by blow-down from pipe ruptures. It looks like we've got an additional data base on the amount of material and how far it flies out of this experience.

Is anybody trying to collect that data base?

MR. SHACKELFORD: I don't know that they -- the licensee -- we didn't really look at that in our report, I mean, the quantity, let's say, of asbestos that may have gotten distributed throughout the turbine building, but they brought in special skids of filtration equipment, and I couldn't even begin to tell you how much they probably had spent to clean up that building.

MEMBER POWERS: I'm sure the clean-up was painful.

MR. SHACKELFORD: Right.

MEMBER SHACK: But it would be nice to know if the code that predicts just how far this stuff will blow was reasonably close to accurate.

MEMBER SEALE: And particularly for the BWR people, where you have, you know, all those sumps to worry about.

MEMBER POWERS: You know, it has gone beyond just the BWR. We have the problem with PWRs, because once they go into recert, that's where this -- draw from the sumps, and they plug up just as bad --

MR. SHACKELFORD: Well, I mean, this just strips the pipes clean. I mean, this type of rupture just --

MEMBER POWERS: That's what we expected it to do.

MR. SHACKELFORD: And if it's there, it's going to -- if it's in the path --

MEMBER POWERS: How far down that pipe did it --

MEMBER SEALE: And how far did the flying insulation go?

MR. SHACKELFORD: And there was, you know, quite -- as you might expect, this physical deformation of tubing and some cable trays and things -- I guess overall there wasn't a lot of significant equipment -- I mean, there was more physical damage than operational damage of equipment.

They did extensive testing of the cables and things in the area. As a matter of interest, those cables, even though -- they are the same cables that are in the containment essentially, qualified in just kind of a locus or a steam-leak in containment. So they did that in this case. I guess that's another data point that might be of interest.

MEMBER SHACK: You don't happen to know if anybody went back with the ASME code case that is, you know, used to evaluate whether you can survive this thinning and found out whether it would have, in fact, predicted failure of this elbow and said you were okay on the one that measured O_2.

MR. SHACKELFORD: You know, I think as part of the licensee's follow-up -- because I've been following -- I became very close to this event during this whole thing, and they're continuing to look and find things. And one of the issues that came up at their plant was -- and you can correct me here if I'm wrong, because this wasn't something we inspected at the time, but it seemed an interesting point was that there's this issue of a critical flaw in a component.

In other words, for a given pipe and set of conditions, you don't have to postulate a rupture in this particular pipe, because you don't think it can happen. You have -- the largest failure that you are required to postulate is something far less than what happened here, and that's based on some ASME-type guidance.

Here, you --

MEMBER SHACK: Well, that's -- you know, those things are usually assumed based on fatigue cracks, you know. Erosion/corrosion was something they really didn't envision in the code when it was originally done, but there is a code case now that does allow you to evaluate thinned pipe rather than, you know, the nominal quarter t flaw, 2 t long that's --

MR. SHACKELFORD: I'm not --

MEMBER SHACK: You don't know whether that's -- but even there, I mean, there's really relatively little information to validate that. You know, that's really an analyst's prediction of what would happen, and --

MR. SHACKELFORD: Well, Fort Calhoun has been very active in the aftermath of this, trying to communicate their findings to the industry. They've gone to some EPRI meetings and conferences and -- they call it CHUG, which is Checworks Users Group -- meetings. They're trying to do their part to communicate anything they've found, so they might be a good resource for that.

MR. CHAMBERLAIN: I think what Jeff's talking about, it was like the Hire-Linebrink [phonetic] analysis. You know, they didn't assume breaks in these kind of lines, so that was beyond that kind of analysis.

MEMBER KRESS: But structural mechanic types, like you said, this would probably be duck soup to predict. Flaws don't enter into this. This was just a structural failure.

MEMBER SHACK: I can predict anything. The question is whether it will -- Checworks predicts stuff, too. Predictions are cheap.

MEMBER KRESS: If you input the pressures and the temperatures and the wall thickness distribution and did a finite calculation, that's all you need. You hit in on the button.

MR. SHACKELFORD: Well, Fort Calhoun brought their own panel of experts in there. You may be familiar with Dr. Chung Chu, failure prevention, and there were some incredible theories espoused early on, and, you know, coining new phrases and everything. And none of them, I think, in the end were proven. I mean, this -- and the bottom line was this was a 20-year-old pipe that had never been inspected. You know, that's getting down to what happened. That's where we at least --

CHAIRMAN BARTON: So much for Chung Chu's QV&P program.

MR. SHACKELFORD: He coined the phrase, the amplified V vortex.

CHAIRMAN BARTON: He always comes up with new phrases.

MEMBER SHACK: Well, I mean, there are two problems here. One we're sort of predicting why it occurred; the other one is -- if I knew it was .05 and 2 feet long and 3 inches wide, I could do it.

But the ASME code gives you simplified ways to do that, and the question is, how well the simplified -- you know, especially with -- I assume the reason the .02 didn't go is it's a rather different geometry and presumably is somewhat more localized.

It would just be interesting to know whether the code case sorted them out right.

MR. SHACKELFORD: Well, one thing of interest -- and I don't know if it's very clear in the report; I hope it was. But the second stage extraction line runs parallel to the fourth stage. The geometries are almost identical, the run of the pipe and where they go. The second stage showed no significant degradation, and, you know, obviously there's some geometry differences, but the piping material and the ventage are all the same.

But what is significantly different is the conditions inside the pipe. The second stage is a much higher quality, higher temperature steam than the fourth stage.

So for what it's worth, you know, that was also a finding.

MEMBER SEALE: What's the over -- is there a significance in the overall mass flow rate, not just for water content, but the overall mass flow rate?

MR. SHACKELFORD: I don't think it was a significant difference. Checworks, as you say, should take that into account, and part of the -- getting back to what happened here, there was some modeling deficiencies, I believe, that contributed to the Checworks -- you know, the failure to identify it.

Even the modeling deficiencies notwithstanding, the evaluation of the day-to-day -- even if you were modeling it poorly, once you start evaluating your data, you ought to be -- that ought to generate questions for you. You know, you'd say, Well, it's not predicting well, so I shouldn't trust it. I don't know why I shouldn't, but I shouldn't. And those kind of issues are what we brought out in the report.

CHAIRMAN BARTON: I think we need to move on. I think we've solved Checworks --

MR. SHACKELFORD: Okay. The next page really just kind of -- we'll skip over that one for now, and we'll skip the next two pages then, because we talked about root causes and contributing causes.

The event follow-up activities: This is what the NRC has done, and this is what the licensee has done. And I have this meeting listed as one of the things we have done. I mean, we've attempted to communicate what happened at Fort Calhoun in order to let other people know and to take what lessons they can learn from it. And I think that that's -- this might be a good example of hopefully closure of an issue.

I mean, something happened that was unfortunate, but we inspected it, issued our report. We had a public meeting where Ellis came down and presented his views on the event to the licensee in no uncertain terms. This event has been briefed on the events briefings that NRR conducts.

We've had several other meetings, a maintenance rule workshop meeting, our own resident inspector meeting, and I've been in contact with some of your staff throughout this as well.

We're working on an information notice that we hope will help to bring more of these issues to light, and then obviously we'll be conducting inspections, follow-up activities, to look at the long-term corrective actions.

The licensee has also done a lot. As I said, they convinced me that they didn't want this to happen and they feel lucky that no one was hurt. They've done quite a bit of self-assessment and communication to the industry.

In the last slide, I really won't talk about it much --

MR. MERSCHOFF: Jeff, there's one error on that slide. The public enforcement conference is really 7/21, not 6/21.

MR. SHACKELFORD: Okay. Yes. I'm sorry about that. We have a public enforcement conference this coming Monday.

MEMBER KRESS: What is a public enforcement conference?

MR. SHACKELFORD: I guess the correct term is predecisional enforcement conference. They come in, and we'll discuss the issue and what we -- go ahead.

MR. DYER: This gives them the opportunity to present their side of the story. We've gone out, conducted our inspection. We held our internal panel and in our view, between us and the Office of Enforcement and NRR, concluded that this has the potential to be -- reach escalated enforcement.

As a result of that, then we -- I can't remember if we issued them a choice letter or what. We decided to call them in for an enforcement conference, a predecisional enforcement conference, before we make up our decision, before we make our decision on the enforcement, and they can present their -- they can either, you know, deny the violation, show what they've done to mitigate it, or present their side of the story.

MEMBER SHACK: Part of due process.

MEMBER KRESS: Have you had these before?

MR. DYER: Yes. Essentially all our predecisional enforcement conferences --

MEMBER KRESS: Do you expect -- who shows up to these?

MR. DYER: A lot of times it's co-owners of the facilities. Sometimes the states may. It really depends on the nature of the issue.

MR. DYER: Intervenors show up?

MR. DYER: I don't believe we've ever had any intervenors. Never in this Region.

MR. MERSCHOFF: In Region II occasionally intervenors would show up. This was a new initiative that the Agency took a couple of years ago, maybe three years ago, to open the predecisional enforcement conference to public observation, not participation, in order to be more visible.

After a trial period that ended recently, the Agency elected to continue this indefinitely, with the exception of certain issues that involve individuals where privacy might be involved or safeguard of information, but the vast majority, absent a good reason why not, of those enforcement meetings would be open to public observation.

CHAIRMAN BARTON: There goes that DSI again about getting the public more involved in a process that we took exception to, said, no, no. You get, Yes, yes.

MR. SHACKELFORD: That's all I really had on the event. The last slide is just sort of a reference of different erosion/corrosion events that have occurred and the documentation of them.

CHAIRMAN BARTON: Are we ready to move on to the next topic?

MR. GWYNN: I was asked to talk about the Region IV interface with INPO. I wanted to just acknowledge up front that our -- the Agency's interface with INPO is dictated by a publicly available memorandum of understanding. The principal point of contact under that memorandum of understanding is through the EDO's office, and so the first point that I have is that there is no direct interaction between Region IV and the Institute for Nuclear Power Operations.

However, there are a number of indirect interactions, and they typically occur through the headquarters office. For example, we receive copies of INPO's schedule, the schedule that they have for plant evaluations and for those other activities, outage assist visits, maintenance assist visits, training accreditation visits. We get their schedule.

And so with their schedule, we're able to use that when we schedule our inspections, and under the agreement, we avoid scheduling our activities at the site at the same time that INPO's at the site. If, in fact, there are conflicts -- for instance, we may have an inspection that's been scheduled for some time, and INPO overlays one of its activities on top of our inspection -- then when those conflicts come up, we interact with the office of the executive director for operations, and that conflict is resolved at that level.

Another way that we have an indirect interaction with the Institute is through our resident inspector monitoring of third-party assessment results at the plants. Now, under the agreement, INPO is required to bring significant safety findings to the attention of the Agency, and that's done at a high level.

If, in fact, in our routine inspections at the plant our inspectors are required to review third-party assessment results and to evaluate those results to make sure that we have an understanding of them and that our assessment of the results is consistent with INPO's, that there are no significant safety findings there; to the extent that there are significant findings in our view, then those are communicated to the regional office, and if there are questions about those findings, well, those would be coordinated through the headquarters office again.

The final point that I wanted to make here is that from time to time, regional managers are requested to observe the meetings of the National Academy for Nuclear Training Accreditation Board. That's a part of the Agency's interaction with the National Academy for overview of training activities at the site.

INPO is a presenter to those National Academy board meetings where the board makes its decision about accreditation and re-accreditation of licensee training programs, and we provide feedback to the program office through the headquarters operator licensing branch, in order to make sure that the Agency maintains a view as to the validity and value of the accrediting board activities.

And so those are the specific items that I wanted to bring to your attention today, and I'd be pleased to answer any questions.

MEMBER SEALE: Well, I think one of the reasons this issue came up is that there are certain things that INPO does and certain things that the

Commission does, particularly, for example, in event analysis, where the perspective is such slightly different; the objective is quite consistent, commonly shared, commonly held.

And I think there's been an increased interaction between INPO and AEOD in those kinds of results. And the question really arose was: Are there INPO activities that you would like or you could use more access to? Are there things you do that might be -- well, there are certain things that you observed no doubt which may not be directly in your turf, but INPO sticks its nose in places where no one else does. And it might be sometimes a cue would be a useful thing to sensitize those people to an issue really.

So really the question is: Is there a profitable, enhanced interactions that are possible?

MR. GWYNN: Well, I know that through the memorandum of understanding and our interactions with the Institute from time to time -- for example, the chairman or other commissioners talk directly with --

MEMBER SEALE: It's generally at that level.

MR. GWYNN: Yes. And so those types of activities do go on. I know that there are interactions between the headquarters office and INPO concerning generic communications to avoid duplication of effort.

But from time to time, because of the circumstances that you described about differences of perspective on issues, we go ahead with generic communications that may duplicate some aspect of theirs.

So that's about all that I can say on that subject.

MR. CHAMBERLAIN: I want to introduce Chris VanDenburgh. He's our engineering branch chief, and he's going to be talking about fire protection, but specifically the ANO fire and our follow-up to that. That was a joint effort between DRP and DRS, and the follow-up -- the residents were kind of the first responders to that, and then one of Chris's inspectors later on was involved, so I think Chris kind of oversaw the whole effort.

So, Chris.

MR. VanDENBURGH: Thank you. Good morning.

This inspection occurred in October and November of '96. Phillip Qualls -- you probably remember Phil. He was my fire protection engineer. Unfortunately he's transferred to NRR. And Jim Melfi was the resident inspector at ANO. He first came across this problem.

This was an interesting aspect to us, because it was the first case we've seen recently involving wicking effect of lube oil leakage on fibrous insulation, and it caught the licensee by surprise, as you'll see as I go through some of the sequence of events.

And it has highlighted to this region a generic issue with lube oil systems and a lack of understanding of many licensees concerning the collection requirements of Appendix R. And since that time, we've had issues at Fort Calhoun, at Diablo Canyon, at Songs, and to a certain extent at Palo Verde.

In almost each case, the systems to collect this lube oil leakage have not been maintained or installed appropriately, and in some cases, specifically the NO, modifications have been made to the reactor coolant pumps, such that the collection system was not considered and didn't collect -- adequately collect the lube oil leakage.

We issued the inspection report in February '97, and we were concerned about the implementation of their fire program. More specifically, the event showed us a problem with the modification performed on Unit 1, which replaced pump B and failed to install the adequate collection system. Specifically they had not reviewed the design change.

MR. SINGH: Do we have slides for this?

MR. VanDENBURGH: I'm sorry. No.

MR. SINGH: That's okay. Fine.

MR. VanDENBURGH: Actually all we have is the inspection report. There are no figures or anything of interest that I could readily --

MR. SINGH: What's the number?

MR. VanDENBURGH: The inspection report dated February 3, '97, was 96-27. On the docket on the NO, it's 53-13-368. There's also associated an enforcement action number wi:h that.

As I was saying, they had modified the system and didn't perform an adequate fire protection review, in part because the design engineer who summarized the modification did not adequately and fully describe the modification. So when fire protection looked at this short description in the mod, they saw no need to perform any further detailed fire protection review, which would have -- and the error, in our view -- identified the lack of collection systems for this external lift oil pump that was added.

MR. GWYNN: The modification was the replacement of the reactor coolant pump motor with a motor of different design.

MR. VanDENBURGH: Correct. The old motor had a shroud that encompassed all the high-pressure piping. The new pump did not, this level of detail was inadequate for fire protection to identify the fact that some high-pressure piping was exterior to the shroud.

MR. GWYNN: Now, I think it's important to note that this high-pressure lift oil pump only operates at two key points in the operation of the reactor coolant pump. One is when you start it, and the other is when you shut it down. And the lift oil pump is supposed to prevent excessive wear on the thrust bearing as the motor starts and stops.

MR. VanDENBURGH: Right. Basically a quick synopsis of the events of October 17: In the afternoon, they were heating up the hot stand-by after an outage, and they noticed the fire on the steam generator B and the reactor coolant pump B that's in the reactor coolant pump enclosure.

They sent two fire brigade operators out at the time to respond to the fire and declared it an unusual event, because it was lasting longer than ten minutes. And our inspectors observed some of the actions during this unusual event.

After they got rid of all the smoke out of the reactor building and cooled down, we walked down various areas and inspected the reactor coolant pumps. We noticed an oil film on the side of the steam generator B and on the side of the reactor coolant pump.

They later determined that the fire was

caused, as I mentioned, by oil in the insulation, had accumulated in the insulation due to previous leak in this piping, basically during a preventive maintenance pump run of the high-pressure lube oil pump. They had noted a cracked weld on the discharge line, the maintenance technician did, so therefore he initiated a maintenance work order to repair that cracked line, but failed to recognize that there was oil soaked lagging in insulation.

It wasn't immediately obvious that the oil had penetrated into the insulation. He had noticed the oil leakage, because it actually sprayed upon him. He had a little bit on his coveralls, so he cleaned that up, cleaned up the general area, and issued the work request. They rewelded the cracked weld.

They later determined that the crack had actually occurred prior to his maintenance run and his activity, such that during the previous shutdown from the outage, when the lift oil pump had been run. As the pump was being secured is when they postulate that we lost the lube oil, and it sprayed upon -- in the general area and soaked into the lagging. And it wasn't immediately obvious.

They had actually operated that pump for an extended period of time when the reactor coolant system was relatively cool, as they shut down, around 250 degrees. That's why it didn't flash to fire due to the wicking effect at that point in time.

And as Pat said, they normally only run these high-pressure lube oil pumps during start-up or shutdown. They figured that a total of only seven gallons sprayed out of the lube oil pump during that period of operation. It wasn't very -- a large quantity, and they have determined this from a difference in oil both prior to the trip and afterwards. This was a forced outage due a reactor trip.

And as I mentioned, they had not identified any excessive oil visually obvious on the lagging. The reactor coolant pump lube oil has a flash point of approximately 400 degrees and an auto ignition point of approximately 700 degrees. So although the normal metal temperature on the B generator at the time of the fire was approximately 430, they concluded that it had to be due to this wicking effect of the insulation.

As you're probably well aware of, it increased the surface area; the oil allowed for a decrease in the flash point.

Their response, the actual response to the unusual event, the fire, was quite good. We had a couple of concerns concerning some personnel safety aspects which is probably really unrelated to this discussion. It had to do with climbing up a ladder with a fire extinguisher and the danger that that poses in terms of dropping it on people below or just dropping it and knocking the nozzle off. They hadn't considered the fact that they would have to fight a fire in that area.

One of the major concerns that drew us to an enforcement conference and it resulted in an escalated action here, unlike some of the other lube oil collection problems we've seen, is the repeated opportunities for this licensee to have identified this problem and fixed it earlier.

For example, a condition report, quality assurance document, had not been initiated at the time they found the lube oil leak during maintenance. We believe if they had done that in conjunction with some other hindsight, they might have been able to recognize or at least postulate when the leak had occurred or have questioned themselves, was the leak present when the pump had been operated earlier.

But because of their quality program, as it related to fire protection and it wasn't a fire protection deficiency, they didn't see the need to write a CR. On hindsight, they recognized that as a program weakness.

So, therefore, the maintenance technician at the time he identified the leak didn't write a CR, so really nobody got an overview of the problem and could link it with other issues, other issues being radiation techs -- health physics techs, that is, in the general area had noticed oil drip and accumulation on the floor underneath the reactor coolant pump on numerous occasions and had actually cleaned it up two or three times, but didn't bother to tell anybody, because they didn't see it as anything more than a housekeeping issue.

In addition, a senior supervisor, an electrical technician, in containment at the time of heat-up -- this was after the pump had been fixed -- noted in their opinion excessive haze and smoke in containment, and in fact, the electrical technician concluded that there was oil-soaked lagging that was causing this problem in this general area.

They did the appropriate thing in one aspect. They informed the outage control desk where they were controlling these -- the activities of the forced outage. They did not, unfortunately, write a condition report which if reviewed in a timely manner could have been tied to the other condition reports which, of course, had not been reviewed or had not been initiated.

The outage desk talked to the fire protection people, but only asked what the auto ignition temperature was of oil. Finding a temperature 700 degrees, much above

RCS -- anticipated RCS temperature, they didn't see the need to be concerned about a fire.

And, of course, they were unaware of a wicking effect and didn't indicate to anybody that there was oil-soaked lagging, and it only affects oil-soaked fibrous insulation.

So these combination of events, we believe, if a good quality program had been implemented and if they had -- would have increased at least the opportunity for them to recognize this problem.

Therefore, we considered this to be a more significant regulatory issue, and we brought those folks in for a conference and took action. But the issue itself centers upon the unrecognized phenomena by the operators and the people at the outage control desk of the wicking effect, lowering the auto ignition temperature of the lube oil.

And it is difficult to note oil-soaked lagging, especially when they're encapsulated with the various reflective metal sheeting.

MR. GWYNN: There was an historical aspect that was also important to me on this event where the start-up of Unit 1 from its previous refueling outage, they had had turbine lube oil spilled on lagging on the Unit 1 high-pressure turbine, and as the plant came up to rated power, temperatures on that turbine increased, and they had a fire on the turbine.

And so they realized after that that they needed better controls on the clean-up of oil spills that occurred during refueling outages, and so this was a precursor that they had had that they really didn't pay attention to, because the problem had been inside containment on a turbine.

MR. VanDENBURGH: In fact, they had considered it, but they had isolated the concern to paper-backed insulation, as opposed to fibrous insulation. There's really no effective difference when you're talking about this phenomenon, but their training from the root cause of the turbine was to worry about paper-backed. And when they asked, there was no paper-backed in this area, so it was not a problem.

CHAIRMAN BARTON: Also let me ask you: What's the threshold of reporting deficiencies on a deficiency report so you can be evaluated by appropriate people?

MR. VanDENBURGH: Well, that was one of the main topics of this enforcement conference, and our opinion was that this hazard was a commission adverse to quality, in that not necessarily from the perspective of the fire program, but its effect on other operable equipment.

And once put in that light, they recognized that they had a hole in their quality program that didn't ask for initiation of CRs. They actually had --

CHAIRMAN BARTON: What's their CR?

MR. VanDENBURGH: Condition report.

CHAIRMAN BARTON: It's like a deficiency report?

MR. VanDENBURGH: A deficiency report. It's the first level quality assurance document for documentation. They had a rather elaborate system of designating services, Q being safety-related, F being fire protection-related to halon suppression, fire dampers, fire suppression, fire detection.

And since this lube oil leakage didn't affect those fire systems and it wasn't safety-related, they didn't have to initiate a CR.

CHAIRMAN BARTON: Something wrong with the program. It's a basic deficiency that's -- you know, should -- well --

MEMBER KRESS: How did they know what was burning? When they looked at the smoke?

MR. VanDENBURGH: Well, they actually saw flames when the fire broke out.

MEMBER KRESS: Okay. But there was no instrumentation that detected a fire. Is that what I just heard?

MR. VanDENBURGH: I don't recall a fire alarm being received.

MEMBER KRESS: That s interesting.

MR. VanDENBURGH: There are fire detections --

MR. DYER: I think there are fire detection capabilities -- I don't know what type -- in that enclosure, but it would take a much larger fire to actuate that --

MEMBER KRESS: You said it burned more than ten minutes?

MR. VanDENBURGH: That's why they declared an unusual event. It was about 12 minutes. It was only about six inches tall and burned around the ring -- the feedwater ring on the steam generator. There's really no safety-related equipment, and there was no collateral damage other than some --

MEMBER SEALE: Must have made a lot of smoke.

MR. VanDENBURGH: A lot of smoke. Prior to the fire, actual flames, there was a lot of smoke. That's what alerted the electrical supervisor. His experience was there should not be this much smoke. That's why he reported out, which is what you would expect him to do.

That's a brief summary. I tried to keep us on time.

MEMBER SEALE: The comment about damage from -- subsequent damage from the smoke is -- that was made earlier is also relevant here and something you might want to be looking for.

MR. CHAMBERLAIN: On the long-term damage to equipment that may have experienced the smoke. We talked about that.

CHAIRMAN BARTON: Staff training and development? Did we already cover that? It looks like lunch break.

(Whereupon, at 11:45 a.m., the meeting was adjourned, to reconvene at 12:30 p.m. this same day, Friday, July 18, 1997.)

A-F-T-E-R-N-O-O-N S-E-S-S-I-O-N

(12:30 p.m.)

CHAIRMAN BARTON: We're back in session. I'll turn the meeting over to Dwight to introduce the next presenter.

MR. CHAMBERLAIN: Okay. I want to introduce Bill Jones. He's our other senior reactor analyst, along with Jeff Shackelford, and he's going to be talking about how we're envisioning using the SRA program here in the Region. We have a policy guide still in draft, that's being issued, so he's going to go through that with you, and hopefully answer any questions you have in this area.

Thank you. Go ahead, Bill.

MR. JONES: Thank you.

My name is Bill Jones. As Mr. Chamberlain indicated, I'm one of the two senior reactor analysts. The other one provided a presentation this morning, Mr. Jeff Shackelford.

There are two senior reactor analysts assigned to Region IV. We are in the division of reactor safety and report directly to the director and deputy director for division of reactor safety.

Mr. Shackelford and myself have both completed the training program and rotational assignments for SRA certification, and that process should be completed before too much longer.

The SRAs have been involved in the dissemination and development of PRA resources in the region. One element that is in process is a training program under development by NRR to be provided to our resident inspectors and some of the regional-based people, about a two- to three-week training program to provide for more in-depth PRA understanding.

In addition to that, the SRAs, we've been involved in the development and review of new Reg 1560 and presentation of that material, particularly while we were involved in the office of research.

We're also involved in providing overviews of several licensee IPEs to the resident and regional inspectors. That is an area that we are continuing with. However, we are looking at licensee PRAs now because of the status of many of the IPEs not currently reflecting the facilities as they exist today.

In that regard, we are implementing a PRA library. This is a significant effort, because it is designed to bring the regional capabilities up to the understanding of what the licensees, PRAs, and PSAs really tell us.

We are currently looking at obtaining system notebooks for the PRAs and PSAs. As I indicated, we do have the IPEs, the IPEEEs, the technical and staff evaluation reports. Those reflect, in many cases, two, three years ago and not necessarily the current plan or current risk.

We're also involved in the risk-informed pilot programs. In particular, we will be involved when they are approved and all licensees begin to implement those for many risk-based issues associated with those, graded QA, IST, ISI that we'll be involved with.

And those are the areas that we're gathering information in our library and other risk background information, human reliability analysis, and so forth.

We're involved in many performance-based risk assessments. This is an area that our management emphasized when we first arrived back in the regions. It was going to be our responsibility; that was clear to us. These involve areas such as the notice of enforcement discretion, enforcement severity evaluation, inspection finding evaluations, event evaluations.

I'll go through each of those briefly. In the area of notice of enforcement discretion, an SRA will be made available for assessing licensee risk arguments and coming forth with notification of enforcement discretions, NOEDs. That has been mandated from the regional administrator himself, and we understand --

MEMBER SEALE: Is this unique to Region IV?

MR. JONES: Region II does that also, that I know of.

MEMBER SEALE: Thank you.

MR. JONES: Uh-huh. Enforcement severity evaluations: LOE recently issued an EGM 97-11 which mandates the SRA involvement in review and severity levels. That was actually in place in this region prior to this EGM being put in place.

The SRAs review each potentially escalated action. Some of them do not lend themselves well to risk assessment, but those that do, we're involved in the Region IV panels, either directly or through a memo describing our risk insights into that, or directly with predecisional conferences, and in review of licensee responses to these violations.

In each of those cases, we have performed these activities. Like I say, we're new to this, but we have in each of those three that are -- or those two areas I described, we have been involved there to date.

Other areas, inspection finding significant evaluations: This is one where we have an ongoing effort to get our -- for the resident inspectors and the regional inspectors to understand what our capabilities are as SRAs. And we are starting to see input come back to us as far as questioning, What is the risk of an event or an inspection finding.

These are -- we're starting to see more of these, and we also receive input during our daily events briefing or pipe meetings, pipe status meetings, as to events that we will be involved in reviewing. We are -- have the capability of providing short-term turnaround on the risk insights or areas where we may need to provide additional inspection effort.

MEMBER KRESS: When you're talking about a risk, are you talking about core damage, for instance?

MR. JONES: In the big picture, yes. But what we look at is qualitative type insights that we may get. We have the capability in our training program and the software and hardware to perform qualitative type risk assessments. We have limited models at this time. We use the ASP models, so we have the capability to actually go in and develop fault trees or whatever, to actually come up with a quantitative type insight.

The way we -- on a short-term turnaround type items, we really provide the qualitative type review --

MEMBER KRESS: Because you don't have time.

MR. JONES: Right. That's really the purpose of the SRA. The long-term accident or event importance review, those are done by headquarters and by the national labs involved in more extensive models than we have time to look at. But we have the capability to provide within a day or two, short-term turnaround, risk insights into those type of issues, anything from equipment, human actions that may be important, any way they may need to go with that, and whether or not an event is really important or not.

And like I say, those are mostly qualitative type reviews. Matter of fact, those -- Jeff and I are somewhat reluctant to provide quantitative reviews, particularly with the uncertainties involved in the models that we have.

MEMBER KRESS: That was going to be my next question.

MR. JONES: That's why I stress qualitative type review. We're looking for orders of magnitude changes and things of that nature.

CHAIRMAN BARTON: Your reputation precedes you, Tom.

MR. JONES: I've also attended several ACRS meetings when I was on rotation.

In addition to inspecting findings which we're now getting input back, the events evaluations which we find out about during our daily briefings on plant status, we also sit in on the events briefings provided by generic communication branch, and these are for insights that we can -- or provide for our own plants.

For example, a lot of the level instrumentation problems we've seen lately, Region IV has had some facilities with level instrumentation problems involving reactor water storage pool and things of that nature, and we've seen similar problems with line control tank instrumentation --

These are the kind of things that we're looking for, risk insights to provide to our Region IV plants up front. In addition, we -- I didn't mention this, but biweekly we have a conference call with all the SRAs. It's coordinated by headquarters, and this is to review the type of issues that we see coming up, and it's just to keep that open link with the SRAs and headquarters and ourselves.

The next item was the maintenance rule equipment configuration evaluations. Mr. Powers is going to talk about the maintenance rule next, but we have the capability to do and we have participated in as the PRA, so-called experts, the maintenance rule inspections in several cases.

Development of equipment reliability and availability for system and component performance, and what we're looking for is differences between what was assessed in the PSA or PRA and understand why those differences occur, and then to extrapolate that out through possible performance issues, as to whether or not the licensee's maintenance program or whatever is causing a difference between what we're seeing in availability or reliability come out.

An area that we are tasked with by my management is the outage risk reviews. This is one where we've only done one of so far, but it's to review the licensee outage controls, when they go into potentially significant risk configurations during shutdown. This is an area where qualitative is about the best that we can do.

MEMBER POWERS: You don't have in your arsenal much to supplement a general intuition in this area.

MR. JONES: On shutdown risk?

MEMBER POWERS: That's right.

MR. JONES: That is correct.

MEMBER POWERS: Can you give me a feeling of what handicap you feel, not having that, or what -- maybe the other side of the coin, how much better off you would feel if you had more of the support that you have for operational risks available to look at the shutdown configurations.

I mean, in the operational area, you have a wealth of information, a wealth of examples, done by the NRC. I mean, the first line complete evaluations and understanding of where the uncertainties are, an understanding of where the incompleteness is, and we have some opportunity to calibrate the results of those analytic exercises against real experience. In the shutdown, you just don't have that.

How much of a handicap that is, because -- especially things like just risk achievement worth and things like that, that even if you don't believe the exact numbers, at least you've got a number to calibrate your experience with.

MR. JONES: Yes. We do have to rely extensively on what the licensee provides us. It would be beneficial for us to be able to at least identify which components are significant, particularly the ones that aren't obvious. Fire protection is one of them.

MEMBER POWERS: That's right.

MR. JONES: That would particularly be important during the shutdown risk, and that based on our experience tells us that that's something that we want to consider. But a shutdown risk model would identify that or at least should identify that.

And that is a -- not a deficiency, but an area that we do have to look at is to think through on an operational side what type of equipment is important, why is it important, and to get into the low-pressure modes of what type of equipment is brought out as a result of that. That would be an example.

We do have some -- we have to rely on the licensee's analysis and try to understand and see that they considered those type of areas.

MEMBER POWERS: Licensees, a lot of them now, are using the Oram [phonetic] models. It suffers from being a proprietary capability, I call it, quasi-analytic capability, does not have the kind of peer review and critique that you have. How do you go about looking at Oram analysis?

MR. JONES: The only one I've looked at so far was Arkansas, so I haven't had an opportunity to get into that area. So I really can't provide an assessment of what kind of problems we'll see when we get into that.

What I did for the Arkansas shutdown risk was to essentially apply the operational type risk insights and to carry them over into low pressure, what it takes to maintain level and what kind of back-up you --

MEMBER POWERS: You kind of go to first principles --

MR. JONES: So to answer your question directly, I don't know what it's -- what problems it's going to cause.

CHAIRMAN BARTON: Does Arkansas use Oram?

MR. GWYNN: Yes, they do.

CHAIRMAN BARTON: They do?

MR. GWYNN: Yes, they do.

MEMBER KRESS: Would you focus on what it takes to keep the core covered?

MR. JONES: It really doesn't speak to as much the -- and, of course, you look at the ability to restore containment integrity. That's an important one that came out after Vogtle was those type of insights, that you see that are incorporated into licensee shutdowns.

MEMBER SEALE: And, of course, the consequences of the containment being open in terms of the availability of certain systems.

MR. JONES: When you open it up, you, of course, lost any level 2 considerations, as far as assessment are concerned, so you are relying on the level 1, the type of systems that would mitigate core melt and the ability to establish the containment integrity within a period before you would end up with -- it would depend on the ke and so forth, what evolution you're involved with.

MEMBER KRESS: I think that's a good perspective.

MR. JONES: That -- like I say, this is thinking ahead, not having been involved extensively in this.

In the overview that I did perform was an in-office; it was not a site. We try -- we will be getting on-site tasks to perform these reviews. Mr. Shackelford and myself have divided the facilities up in Region IV, and we're going to develop specific cognizance of what their risk profiles are and why things are risk important.

And that's something which they're working to. I think I've been in place about four months, and I think Jeff's been in place about two months, maybe two and a half. These are all areas also that we have identified in our policy guides, and this policy guide was based on our management's expectations and what we will be doing.

MEMBER KRESS: Do you think a shutdown rule would help you right now?

MR. JONES: I know there's a Commission meeting coming up on us shortly. I plan on listening to that, so maybe I'll find out then.

CHAIRMAN BARTON: Okay. Any questions? That trip is on our September meeting. Right?

MR. JONES: The next slide is inspection planning and implementation. This is also a performance-based area. For example, we will be involved with helping to select systems for AE, the upcoming AE inspection. That is a large NRC resource, specific to looking at systems and their design capabilities. And PSA, PRA provides unique insights to which systems we may want to look at.

As I mentioned earlier, we get to the point where we're looking at the inspection programs for graded QAs, our in-service inspection and in-service testing. This region has several licensees that are involved in these pilot programs: South Texas, Palo Verde, Comanche Peak, ANO, and so we'll have up-front and probably lead the way in looking at risk associated with these type of activities and helping to develop the inspection process from that.

The last one is operator licensing, and this gets to the type of operator actions that are important and understanding why they're important. And this goes back to our library also, of understanding why certain operator actions are included.

What we've seen in many of the PRA and PSA updates from the IPEs is that actions that were important no longer are, or systems or components, their walls have dropped off considerably. A lot of cases, that is due to operator actions. This is an area that can be fed back into the operator licensing process for their consideration.

That's what I had for what we're doing in the Region. As I mentioned, many of these areas, outage risk review and so forth, we have a long way to go on them. We received the management support we need to go down those avenues, and the expectation is there for us to look at those.

Like I say, the Arkansas outage risk review was more of an in-office review. Those areas will expand out to get to the sites and really provide some meaningful insights into these type of activities. We have a lot of different activities on our plate right now, and we're working through them.

MR. CHAMBERLAIN: I hope you get the view that I have. I think we've got a lot of capability in our two SRAs. If we can just keep that moving, keep that emphasis going, I think we can really do a lot with it.

I guess Dr. Powers needs no introduction. Dr. Dale's our maintenance branch chief, and he's been responsible for all of our maintenance for baseline protections, and I think that's his topic area, or at least the risk of on-line maintenance portion of the maintenance review.

DR. POWERS: I guess in this region, we've found that our licensees have typical reasons for doing on-line maintenance that we've seen elsewhere. But since the development of the maintenance rule, we've seen more focus come on balancing availability and reliability, clearly a benefit of the maintenance rule.

Our licensees are certainly interested in extending structures and systems and component life by balancing preventive maintenance against corrective maintenance. In some situations, we've seen arguments where the risk associated with removing an SSC from service during power operation may actually be less than during an outage.

MEMBER KRESS: How do you judge those arguments as to whether they have any validity to them?

DR. POWERS: The validity to those?

MEMBER KRESS: Yes. How do you judge that?

DR. POWERS: I don't believe the Agency has done a formal review on any one of those. We came close to it with the Fort Calhoun application. They were going to take down a diesel during winter months, to do a full 18-month tear-down, and we came close to reviewing that, but it never happened. The utility at the last decided not to.

We've seen amongst our Entergy facilities, with declining resources, more of an interest in balancing -- not balancing, but in being efficient in utilizing their own staff resources, resource-sharing amongst the plants, an effort to try to cut the workforce, so that they're not going into outages with just hundreds and hundreds of staff to watch over, and along with that comes less reliance on contractors. And, of course, everybody shares economic benefits from shortened outages.

In regard to risk assessment tools, we need these tools, because many of the regulations were developed at times when the industry's philosophy was to do major maintenance during long outages, and now that that's evolved, we have plant -- I would call it plant baseline risk envelopes that are times of no major maintenance that now have spikes associated with SSCs being taken out for service.

And so we need to monitor those spikes to ensure that the risks remain acceptable. Our utilities are using basically four different tools to assess risk.

MR. LARKINS: May I ask you a question?

DR. POWERS: Yes, sir.

MR. LARKINS: What's your criteria to say this? Do you have a criteria to say whether those are acceptable? You were talking about spikes in the risk. Above what level would you say this is --

DR. POWERS: I think that's always a judgment call. We don't have requirement --

MR. LARKINS: You don't have a requirement of the curve requirement.

DR. POWERS: No. There's no requirement for that. I think our expectation is 10^{-4}, but, you know, I think we would argue on some cases if we thought risk was too high for the benefits to be achieved that we don't have a --

MEMBER KRESS: You mean the amplitude of the spike would be 10^{-4}?

DR. POWERS: Uh-huh.

MEMBER POWERS: Do you have an allowed outage time that -- the new reg guide's got one that has a probable listing basis to it or more fairly, it can be converted into a risk capping. Do you think that has more generality to it?

DR. POWERS: I do, sir. Yes.

MEMBER POWERS: It just strikes that it is a rule that comes straight out of the existing rules. I mean, it has its genesis back in the deterministic era, but it has a -- you can have a probablistic interpretation on it; it gives you a cap for the amount of risk you'll tolerate during an equipment outage.

DR. POWERS: We have not, I believe, in this region in the last decade or so had any particular issues where we found risk to be unacceptable on any particular maintenance activity. I think our utilities are getting much more smarter, and they recognize the benefits of keeping risk to a minimum.

If there's any message I would leave you with today, it's the maintenance rule has been very beneficial to safety. It has improved the control of risk in power plants.

MR. CHAMBERLAIN: And the allowed outage time on any one piece of equipment may be okay, but we want them to look and they are looking at the combined effect, you know, what we talked about the storm and only one piece of equipment, and is that acceptable.

MEMBER POWERS: Sure. That would be -- I mean, what you -- you can -- is the allowed outage time to give you a risk cap, and then you have to look at everything else to see what the risk actually became.

MR. LARKINS: We heard yesterday that at least Comanche Peak will also consider defense and depth considerations in addition to the risk envelope, so either procedurally or other ways, supplementing what they were doing.

MR. CHAMBERLAIN: Licensees are getting pretty sophisticated. Jim talked about we did see some examples where we didn't think they did the right things, but I think those are getting less and less. We just need --

DR. POWERS: The trend is definitely positive from a safety point of view.

We've got four tools that are used in this region. The first one there is qualitative judgment is the old way, widely used prior to the publication of the maintenance rule, and it's commonly used today for non-risk-significant BOP, balance of plant, SSCs.

Most of our licensees are using a matrix of SSC combinations. It's simple, convenient, but it's two-dimensional, so it has a limited applicability to only dual combinations of SSCs, and typically we see only the high-risk significant SSCs that are addressed by the tech specs in this matrix.

I mentioned Fort Calhoun. They, for instance, used a specific configuration calculation at one time. Other licensees do too. It's slow, costly, and it's not user friendly, and it takes trained PRE people to implement.

What seems to be, in my view, the future in this -- these tools is the latter, the computer-based tool. In particular, all of our Entergy plants are using a model. They call it EOOS, equipment out of service, model, and it's basically a real-time model. It's in the control rooms even.

And this model compares the proposed plant configuration and the associated risks against an average plant configuration previously quantified by the PSA model.

When I think of good attributes of on-line maintenance risk assessments, I -- when I mentioned there is no requirement for on-line risk assessments, we think some of the good attributes that should be included therein is -- they should address all maintenance activities that affect reliability and availability, not just corrective maintenance, but also preventive maintenance, predictive maintenance, surveillance, and post-maintenance testing.

They should account for the total SSCs that are out of service, not just the risk-significant SSCs. There are interdependencies of SSCs, and they should be performed for all on-line maintenance, regardless of modes of operation, and they certainly should be available for use for emergent work. Everybody deals with frozen schedules that at the last minute become undoable.

Our Agency's expectation for safety assessments is basically given in the maintenance rule, paragraph (a)(3). It says -- and I quote -- "In performing monitoring and preventive maintenance activities, an assessment of the total plant equipment that is out of service should be taken into account to determine the overall effect on performance of safety functions."

There is an April staff requirements memorandum that instructs the staff to look at the changing of the rule from "should" to "shall." My personal view is we should, and I think it shall happen.

In terms of guidance for assessing on-line maintenance risk, I think of two documents. In 1995, INPO sent to its members a letter on managing maintenance during power operations. That's a letter that embraces the concept of on-line maintenance. It gives some concepts for employing, but it's very short on details.

More recently, NUMARC has provided more detailed guidance in NUMARC 93-01, and we have endorsed the NUMARC guidance in our reg guide 1.160 as being an acceptable way to implement the maintenance rule. It goes far beyond risk; it considers all aspects of the maintenance rule.

Over the last decade in Region IV, we've had two opportunities to do programmatic inspections of on-line maintenance. Our first -- I believe first in Region IV was the TI 126 on evaluation of on-line maintenance in 1994. We had the resident inspectors do the follow-up to this TI, and they spent about a week each on looking at all aspects of on-line maintenance. They weren't PRA experts, and so you don't have a lot of PRA expert insights in those inspection findings.

More recently, we're in the process of using the inspection procedure 62.706 to perform our maintenance rule baseline inspections. These inspections are being performed by teams out of the Region, and they include PRA experts from Brookhaven, INEO, and in some cases, our senior reactor analysts as well.

I was going to tell the committee about our TI findings, but when I went back and looked, I found that they really aren't germane anymore. The industry has come so far that those findings in '94 are basically worthless today, and I can tell you about our baseline inspections, though.

This region has 14 sites --

MR. LARKINS: Can I ask you a question?

DR. POWERS: Yes, sir.

MR. LARKINS: Would you say that's across the board in the Region or are there outliers?

DR. POWERS: There's utilities that aren't where they ought to be today. I'm convinced of that, and I'll be explaining one real soon here. But I think that's across the board, that everybody's improved greatly.

We've done six baseline inspections, and I tried to characterize these into three categories:

licensees with no programmatic weaknesses, licensees with programmatic weaknesses, and what's probably more useful to the NRR staff in r sponding to the staff requirements memorandum is licensees with failures to perform risk assessments.

I've not listed under these all of the risk insights that are neutral: adequate, sufficient, acceptable; but I tried to list the findings that are weaknesses, violations, or strengths.

Cooper is the first utility here. They're using as a risk tool a matrix. When we looked at their program, we found that the operator knowledge was lacking on their own requirement for evaluating the impact of plant status upon risk. We found the use of an inappropriate standard performance criteria for reliability, and that had an adverse effect on the risk ranking for SSC safety significance.

What I'm talking about there is MPFFs, maintenance preventable functional failures. They were only considering failures which does not consider demands on a system, time in service, so they only had part of the story there.

We found that they were not -- we found one example where they had entered into a predetermined risk-significant window without first performing a prerequisite checklist. We found in regards to unavailability that they were not monitoring some risk-significant systems. This included ADS, HPSI, emergency diesel generator and RHR, and we found several -- probably about 20 -- examples of failures to perform risk-significant risk assessments on safety-related emergent work.

There were no high-risk significant examples, and you might ask: How did we have enforcement in that area, since risk assessments are not required? They are actually required by the utilities program at Cooper. They were in a quality procedure, and it was a management expectation that it happen, and it had not been happening.

Overall, the risk assessment process at Cooper at significant procedural weaknesses. We were quite critical, some dozen or so examples of violations in that inspection. We found the process did not address actions when SSC failure occurred while in a risk-significant window, did not address assessing risk when removing SSCs of low risk significance, and it was unclear on the responsibility of performing risk assessment for emergent work.

The second licensee that we have here, we were on site last week, completing this inspection, Diablo Canyon. They too are using a matrix. These decisions are preliminary at this time, but the matrix we found did not account for all risk-significant SSCs such as an aux building and switch gear ventilation, and we had one failure to perform a risk assessment prior to removing from service a high risk-significant SSC, and that was the aux saltwater, very important system at Diablo Canyon.

Overall, their risk assessment process was considered adequate by the team.

Third licensee in this category is Grand Gulf. Grand Gulf is using the Entergy EOOS model, a very sophisticated model compared to the other utilities. However, we found some weaknesses here. Operators lacked the sensitivity to the need for monitoring and tracking SSC unavailabilities and changing risk configurations.

This is important, because if your operators aren't logging and noting for reliability and system engineers what's happening to the equipment, then they don't know.

We found availability was not being monitored for some risk-significant SSCs. Included was the instrument air, nuclear boiler instrumentation, and control rod drive.

We found that SSC performance criteria were not established commensurate with the risk assessment. What had happened was they did a sensitivity studies, and they found that if the plant was really operated at the level of unreliability that was assumed by some of the performance criteria, that core damage frequency would double. So they went back and changed those criteria obviously.

We found the SSC risk-ranking methodology was lacking in that it did not assess unavailability and reliability assumptions. Here the risk-ranking methodology is used to determine what should be in scope and then to determine what importance should be given to that in your risk tool.

There was one failure to perform a risk assessment prior to removing a diesel from service there. But we thought that overall the risk assessment process was a good process. It's in the early stages of implementation.

The second category I have here is licensees with programmatic weaknesses, which include Palo Verde. Their tool was a matrix. We found that the evaluation of cumulative risk impact on multiple SSC outages lacked an analytical basis and in some cases yielded nonconservative estimates.

Overall, the risk assessment process had procedural weaknesses. Its guidance for assessing configurations not addressed by the matrix was weak. And the matrix did not address some BOP SSCs that were not modeled in the PRA.

Another licensee with programmatic weaknesses was WNP-2. Their risk tool was something between qualitative judgment and a matrix. It's just a procedural listing of certain SSCs of high safety significance, and that's for the operator and the engineer's consideration.

A positive note was that a risk assessment was required to evaluate safety prior to voluntary entry into tech spec action statements for corrective maintenance.

We found that unavailability was not monitored for certain risk-significant SSCs that included the nuclear condensate, reactor heat water, and uninterruptable AC power supply. Here again, they also had an inappropriate use of a criterion of MPFFs for reliability.

Another positive aspect was that a risk assessment on a frozen maintenance schedule was provided for changes involving high risk-significant configurations.

Overall, the risk assessment process had procedural weaknesses. It did not include all SSCs of high safety-significance; it did not address the necessity of performing a risk assessment for emergent work nor for unanalyzed configurations. And it did not address the impact on safety when low safety-significant SSCs were removed from service.

The last category -- and I have only one licensee in that area -- is programs with no programmatic weaknesses: Waterford 3. Their tool is EOOS. We found a positive aspect that they have an operations guide that provides guidance for consideration of seasonal weather conditions and quantitative assessments of switchout activities. I expect that guide is pretty well thumbed through by today with the hurricane nearby.

Their SSC risk-ranking methodology was lacking in that it did not address unavailability assumptions. We also found the method for establishing unavailability performance criteria was lacking in that it did not fully evaluate the cumulative risk impact of all system interdependencies.

They too were not monitoring unavailability for certain risk-significant SSCs that included engineering safety features, actuation, plant protection, core protection, calculators, broad-range gas monitors, and containment polar crane.

Overall their assessment process, though, was considered to be as superior.

And I guess that concludes all I had planned to say, but I wanted to leave you with the fact that we see real benefits to the maintenance rule. We see licensees monitoring NRC's inspection findings. They're on the Internet. And it's been our custom to get questions about findings at other plants from other utilities that we have to deal with.

CHAIRMAN BARTON: Dale, you said you see improvements for the maintenance rule. What do you think utilities' perspective is on the maintenance rule?

DR. POWERS: Mixed bag, sir. I've had utility managers say it has been good for us; it helped us focus. And I've also had some that indicated that it really wasn't -- hasn't been that useful to them.

MEMBER POWERS: I guess we got mixed perspective yesterday, which a little bit surprised me anyway, that -- my feeling was that -- had always been that it was a focusing tool and that it allowed insights that you wouldn't ordinarily get about your maintenance programs, and that it was a pretty good example, a stockinghorse, as I call it, for other performance-based regulations coming down the pike.

Now maybe I'm not so convinced of that. So I'm interested in any insight you might have on what a performance-based rule really ought to look like, to make your life easier, other people's life easier, my life easier.

DR. POWERS: Well, I guess -- that's a pretty big question. We probably should not use "should" in regulations, for one thing.

MEMBER POWERS: I think we can take that as a lesson learned.

DR. POWERS: This rule, I believe, allowed flexibility for utilities to do what they needed to do to comply with it, to draw upon existing programs. And it was, I believe, very well communicated to the industry, and it was pretty well endorsed by the industry. There were a lot of workshops. A lot of people have benefitted from it. A lot of operators know more about risk today than ever.

And if those operators don't know what's important, their logs aren't going to reflect that for the maintenance rule coordinators who come along and try to determine, what's our risk like. But I'm not sure I want to tackle your question.

MR. CHAMBERLAIN: I expect there's a lot -- you'll probably hear the licensees don't like the fact that this opens up another window for us to take enforcement, you know, and that's the negative.

MEMBER POWERS: That's the major objection that you hear? Yes.

MR. CHAMBERLAIN: That's the negative side, I'm sure.

MEMBER SEALE: Well, I think there's another aspect to this, though. The jury is still out on what the full impact of the maintenance rule. I mean, it's clear that we don't really understand it all. And a lot of the utilities have a show-me attitude right now, because they want to see more. And maybe if they keep asking for more, maybe they'll get more.

DR. POWERS: We noticed that Southern California Edison is basically in a state of dejection over the maintenance rule. Their views were -- in particular, Harold Ray, the CEO out there, had the view that the maintenance rule was going to provide them relief from regulatory requirements, and it has not.

And I personally don't see where he reads that into the statements of consideration or the rule.

MEMBER POWERS: I think there's a lot of, This is supposed to give -- a lot of things. This is supposed to give us relief. I don't see that in the objectives or statements of consideration or anything. It's supposed to give us focus, pay attention to what really is important to safety, and if that saves resources for the Agency and the licensee, so much the better, but that's not the objective. It's supposed to give us focus.

MR. LARKINS: Do you have a feel for the relative level of resources that licensees are putting into some of these efforts, that there's any correlation with your observations?

DR. POWERS: Difference licensees are doing it in different means. The depth that they have involved in these programs differ greatly. For instance, I see Grand Gulf having expended minimal effort to develop a good product, but they're relying on just a very few key people, whereas if you go to other places, like Waterford, they trained and developed a lot of staff, and maybe they get more benefits out of that staff knowledge now.

They have depth in their program, where you don't in others, so that would make a big difference. But I don't have a good feel for the resources.

MR. LARKINS: What about Cooper?

DR. POWERS: Cooper? Cooper was our concern for five years. We were encouraging that utility to get ready, to get ready. We couldn't force the hand. And basically in the last year before the rule took effect, they scrambled and assembled contractors and developed a rule that when -- we went there, because that was -- in August of 1996, that was our second licensee to pick in the Agency.

And the reason we went there was because the program office, as well as the Region, was concerned about the delayed implementation of the rule. We would have gone there first, but Palo Verde offered to host a team, and that team was a big team. There were 18 people that went, 6 inspectors and 12 people that oversaw to ensure consistency. Cooper's our first example, I think.

MR. CHAMBERLAIN: We haven't done the baseline at Comanche Peak yet.

CHAIRMAN BARTON: They told us that they were waiting for you guys to come.

MR. CHAMBERLAIN: They've done a self-assessment, and they've looked at all the other findings, so --

CHAIRMAN BARTON: Got you lined up.

MR. CHAMBERLAIN: They're ready, I think.

CHAIRMAN BARTON: Well, thank you. I think we're on cur schedule for break, so -- until 1:35.

(Whereupon, a short recess was taken.)

CHAIRMAN BARTON: We need to stay on schedule. We're doing pretty good so far.

MR. GWYNN: My name is Pat Gwynn. I'm the director of the division of reactor projects here in Region IV, and I've been asked to talk with you about the Region IV inspection program.

It's a pretty wide-ranging discussion here. As you can see from the slide, I want to start out talking about the status of our plants, then go into the inspection program in a broad sense, and talk a little bit about the resident inspection program.

And if you're interested, I am prepared to talk a little bit about the details of what a resident inspector does, talk a little bit about the region-based inspection that we perform, talk about the plant issues matrix, which is an enhancement to the inspection program that's been implemented recently, the way that that plant issues matrix is used in plant performance reviews, and then the SALP program, and at your request, I have a matrix of recent SALP scores here in the Region.

So with that, I'll go directly into slide number 2, which had just Region IV plant status report. That -- if you'll put the next one up, I have yesterday's plant status report. This is difficult to see. I hope you have a copy.

This status report is provided to us by the NRC operations center every day. They get this information by testing the emergency notification system telephones with the control rooms and determine plant status information.

I wanted to highlight a couple of items on this status report. Callaway is operating at 95 percent because of an axial-offset anomaly in their core. That axial-offset anomaly is getting some interest on the part of the Commission, and there's a meeting scheduled on the 31st of July with Westinghouse Electric to better understand the nature and the potential safety consequences associated with this anomaly.

MEMBER POWERS: Does the Region do core analyses, or is that all done out of --

MR. GWYNN: Principally that work is done by headquarters, the reactor systems branch. From time to time, we work with them. We've done a recent inspection at WNP-2 on core reload analysis. We've done a pilot inspection at Palo Verde a couple of years ago, looking at core reload analyses that were being done by that facility.

We have an individual on staff. I think he just presented to you, Dr. Powers, who is our fuels expert in the Region, and he helps us quite a bit in that area.

MEMBER POWERS: Did quite a little bit of research in that area in the past. I know that.

MR. GWYNN: Yes, he has. So we try to keep involved in understanding what's going on, but we rely heavily on headquarters' expertise in this area.

The other plants, most of them are operating at full power. San Onofre Unit 2 and 3 are coming back up to power. Unit 3's been down in a refueling outage for some time. During that refueling outage, they found a problem with some check valves in their plant that had potential implications for Unit 2. Unit 2 performed a test, found that they had the same problem, and shut down for a maintenance outage to resolve the check valve problem.

CHAIRMAN BARTON: Were these the check valves that were in the check valve program or other check valves?

MR. GWYNN: These are check valves that are in the check valve program. Yes, sir. It's a problem that you would not normally expect to find. These valves had been provided by Carrotest [phonetic]. They had originally been provided with a spring that's a part of the actuating mechanism.

They need to have balanced flows through two check valves and some replacement valves that have been provided by the manufacturer had a different spring, without any information from the manufacturer that indicated that the spring was difference. Because of that, they were unable to balance flows through two different charging lines in the plant, and unbalanced flows were a concern for one specific design basis accident, and so that caused them to take action to promptly correct that problem.

South Texas, both units at full power. WNP-2 is coming up out of its annual refueling outage. They're the only plant in the Region that's still on a 12-month refueling cycle. And Waterford 3 has been shut down for quite some time in a refueling outage. They are -- were about to restart. They've made a mode change and were starting to restore the plant to an operating status when they were challenged by Hurricane Danny, and I believe the regional administrator talked with you about that this morning.

So that's my quick overview. One point that I would make that is something that's come to our attention recently: This report is now put on the Worldwide Website for the Agency on a daily basis, and it gets quite a bit of interest, especially from the financial community, and that's something that we get feedback on from time to time from the plant owners.

Going on, the overview --

MEMBER POWERS: The plant owners like that or don't like that?

MR. GWYNN: No. They don't like it, because there's information here about projected restart dates, and when the control room provides that information, it sometimes can affect the spot price of gas, that type of thing, so there's a lot of sensitivity and licensees are much less likely to give us speculative information. You can see that it says "unknown" when Waterford will restart. In the past, they might have provided us a best-estimate date.

MEMBER POWERS: They run into a fiduciary issues on that, giving out false or misleading information.

MR. GWYNN: Exactly. Okay.

The overview of the power reactor inspection program: The objectives or the program are laid out in manual Chapter 25-15, and I brought a copy of it, just to hold up. This is our Bible for the reactor inspection program for the operations phase of power reactor operations.

Basically, we're charged to ensure that licensees operate safely, that they identify safety problems, and that they identify trends in performance, and that's our charge. We do that through a combination of core, regional initiatives, safety issue, and reactive inspections.

And I'd like to try to make clear what the difference is. Core inspection, we have a number of core inspection procedures that these are the procedures that are performed at every plant, every cycle; every SALP cycle, we perform each of these procedures typically.

And so a core inspection is the minimum

inspection program that we've committed to the Commission and the Commission has committed to the Congress that this Agency will perform at every operating facility in the country.

Regional initiative inspections are inspections that go beyond the core program and typically focus in areas where we've seen problems in the past.

Safety issues inspections are specialized inspections. Usually there are temporary inspection instructions that are put out by the program office, NRR, that tell us what to do in that area, in response to bulletins, generic letters. We have temporary inspection instructions. Recent examples are the vehicle barrier system inspections at plants, access authorization programs at plants.

Of course, I'm sure you're all familiar with the TI 25-15.109 motor operated valve inspections that have been going on for quite some time. Those are safety issues inspections.

And then whenever there's an event at a facility, we go into a reactive mode, and reactive inspections are in addition to the planned inspections that we have. So core, regional initiative, and safety issue inspections are planned activities for the facility. We schedule those in advance. We work very hard to keep coordinated with the licensee, so we minimize regulatory impact on the licensee's organization while we're performing our inspections. These reactive inspections, they're not scheduled; they're not planned, and we perform them as needed, based on facility performance.

Our inspection approach is to do a selective examination or sampling of licensee activities. And those sampling inspections are typically performance-based inspections. We talked a little bit about performance-based this morning.

My best example of the difference between performance-based and programmatic inspections were the maintenance inspections, maintenance team inspections that the Agency performed a number of years ago. We went to -- and I don't like to use specific examples, but I think that this one is well known -- went to the South Texas Project and performed a maintenance team inspection at that facility.

The team came back with a colored chart that showed licensee performance in each of the important areas related to maintenance, and it was almost all green. It was almost a perfect program. But when you looked at the plant and the material conditions of the facility, it was bad. The plant was shut down, both units, for over a year, principally because of material condition problems at the plant.

And so a performance-based inspection would identify that there was a problem with maintenance at the facility, that our maintenance team inspections -- that we thought that they had the best program around. So that's how I try to define the difference between a performance-based and a programmatic-based inspection.

We also try, to the extent that we can, to use risk information in planning our inspections at the facilities. We use it in selecting the sample. If there are risk information available that would indicate that we ought to look one system or one component over another, we'll use that information in selecting our samples for these inspections.

Also, we emphasize the importance of licensee self-assessment processes during our inspections, and we give licensees credit for self-identification and correction of problems at their sites.

When we find problems, our principal actions in response to the finding of regulatory problems or violations at the facility, we might issue a notice of violation. If it's a particularly significant problem, we'll have an enforcement -- a predecisional enforcement conference, and make a determination whether a civil penalty ought to be assessed.

In that case, when there are situations that involve inoperable safety equipment or unsafe operation of the facility, then we can get into other things like orders to modify, suspend, or revoke the license, things that are immediate safety problems at the facility.

We don't consider those to be enforcement issues. They may turn out to be enforcement issues later, but we treat those as safety problems, and we work on safety problems first and worry about enforcement later. And that's our basic approach to inspection.

We have a couple of other tools. In the event that there's an agreement between us and the licensee that there's a problem and that there are specific actions that they need to take to fix that problem, then we can use a thing called a confirmation of action letter, where we document an agreement between us and them on the actions that they will take to correct the problem, specific time frames associated with those commitments that they've made to correct that problem, and we follow up on the confirmatory action letters, principally through inspection; may or may not involve enforcement.

We also have what used to be an order to show cause. It's now called a demand for information under 10 CFR 50.54(f). That demand for information was used last fall to require licensees to submit information to the

Agency about the design basis for their facilities.

So that's a quick overview of the program in general. I'd like to ask if there are any questions at this point, before I go into the resident inspector program in particular.

CHAIRMAN BARTON: Is it just perception, or is there an awful lot of CALs being issued lately?

MR. GWYNN: Well, the Agency has changed its posture somewhat related to the implementation of 10 CFR 50.59. That's the rule that allows licensees to make changes to their facility, as long as they don't involve change to the technical specifications or an unreviewed safety question.

And today if a plant is shut down and the licensee identifies or we identify that there is an unreviewed safety question in their plant, well, then our posture is that we will not allow that plant to operate until they've corrected that unreviewed safety question or the problem it's causing, the unreviewed safety question.

And that has resulted in a number of confirmation of action letters where licensees and the Agency have agreed on the action that's needed to correct the conditions that are involved.

Agency policy is still evolving in this area, and I'm not in a position to give you a lot of information on that at this time.

CHAIRMAN BARTON: We've been following where 50.59 is going.

MR. GWYNN: I believe that the Agency is working hard to draw a bright line between what's a modification to the facility on the one hand and what's a deficiency in the plant. And if we can get that bright line drawn clearly and understand that with the industry, then I think we'll be in a better position to handle these types of situations.

Going to -- unless there are other questions?

MEMBER SEALE: In that regard, have you had any -- do you have utilities that use the EPRI -- what is it? -- 215 -- 125 -- NSAC 125 approach to evaluating 50.59?

MR. GWYNN: I would say that most licensees --

MR. CHAMBERLAIN: They were using that, and we were actually using some to --

MR. GWYNN: -- have adopted that in the past, and we did not object to their adopting --

MEMBER POWERS: Have you seen cases where people have used it -- I won't necessarily ask you to say properly, but conscientiously, and failed to come up -- or came up with what you considered to be an improper determination?

MR. GWYNN: Well, we've had some controversy at one particular facility in the Region about margin to safety and the threshold that might be applied, and that has caused some difficulties in our inspection at that facility.

But we've dealt relatively well with those, using assistance from the Office of Nuclear Reactor Regulations.

MR. CHAMBERLAIN: You know there's a new reg, too, out for comment right now, draft new reg 1600, that's really kind of replacing that NSAC document.

MEMBER POWERS: Yes. We've written a letter on that.

MR. GWYNN: But we're not implementing that. It's out for comment, and we have very clear instructions to our inspectors that although they may be aware of that, we are not implementing that. We're implementing the manual chapter 9900 guidance that we've provided to our inspectors and the generic letter 91.18 guidance that's been promulgated in the past.

CHAIRMAN BARTON: That's the operability --

MR. GWYNN: Operability be graded in nonconforming conditions. Yes. So those are the things that we're using right now. We're watching as the policy evolves. I know that the Agency is about to issue a revision to generic letter 91-18, to help to define that bright line that I spoke about a few moments ago.

Other questions?

(No response.)

MR. GWYNN: Okay. Resident inspector program: This program really began in the late '70s. The concept was put in place in about 1977, before the Three Mile Island accident, and that -- the purpose of having a resident inspector program was to provide a continual NRC on-site presence at each power reactor in the country, to provide for a rapid NRC response to plant events, to increase inspection time and direct observation of licensee activities at the plant --

During those days, the focus was almost all on records review, and so this was a desire to increase direct observation of licensee activity.

To provide us with enhanced knowledge of the conditions at licensed facilities and a better basis for some regulatory decisions. If you're basing your decisions on the paper that exists rather than on the -- what actually exists at the plant, that can be misleading at times, and so it was important for us to have an agency expert on that plant. And this provided us that opportunity.

It allowed us to provide less reliance on records accuracy and more independent verification of licensee activities, which in rare circumstances has been important to the Agency.

It's also provided us additional assurance that management control systems are effective and that licensee performance is, in fact, acceptable.

Some of the key activities that resident inspectors undertake include the detailed knowledge of the facility and the regulatory requirements that apply to that facility, license conditions and the technical specifications in particular.

They conduct general and detailed inspections of plant systems, operations, activities, and events at the facility. They review licensee reports to assess safety impact and accuracy, and these reports include things like the condition reports that we talked about this morning or other deficiency-reporting documents.

And so on a daily basis, it's not unusual to find our inspectors reviewing the deficiencies that were identified in the plant the day before, just to make sure that we understand the current safety situation at the plant and where there are questions about that situation, well, then they pursue those questions to make sure that we fully understand what the implications are for the deficiencies on ongoing plant operations.

That -- the resident inspectors, he or she, they're required to maintain a knowledge of all significant NRC inspector findings at their site, so they are the owners of the NRC's issues at that facility.

Whether they're identified by the resident inspector or by others, we expect them to know and understand what those issues are, what the schedule is to deal with those issues, who's responsible for those, both in the licensee's organization and in ours, and then, of course, they prepare inspection reports that communicate their findings to the licensee, to the NRC, and to the public.

They also interact with regional staff, headquarters from time to time, daily, in order to make sure that they're clearly communicating their findings and the results at the plant.

As Mr. Dyer indicated this morning, each branch chief in the region has a morning call with the resident inspector. That morning call in this region also includes in the NRR project manager for the facility. It typically occurs at 7:30 a.m. That's whether it's Central time or Pacific time. It occurs at 7:30 a.m., and that's what drives our morning meeting to be ten o'clock.

So that close coordination between the site, the NRR program office, and our people here helps us to maintain a good understanding of what the safety situation is at the plant and what the Agency needs to do from time to time to ensure that we're acting promptly on problems at the facilities.

I have a slide that talks about documentation and inspection findings, but I'll go past that since Mr. Dyer talked this morning about manual chapter 06.10 and its benefit that we've seen for our inspection program.

The resident inspection is the next slide, and what I wanted to do was to just spend a few minutes to talk to you about what a resident inspector does, day to day, at the plant. And his Bible, beyond manual chapter 25.15, is inspection procedure 71.707. That is plant operations inspection, and that's where he spends most of his or her time.

The resident inspector requirements are broken down into daily inspections, biweekly inspections, monthly, tri-monthly, semi-annual, and outage inspections. And so these inspections and frequencies dictate what they do day to day in their plants.

On the daily inspections, we expect them to perform control room observations on a daily basis, and during those control room observations, they'll be looking for such things as proper control room staffing as specified by the license and that the access to the control room's been properly maintained, that the operators are attentive to the controls, that there's formality and communications in the control room, that they're adhering to approved procedures and to the technical specifications for the facility, and that they know the status of lighted enunciators in their plant.

That means that they know what degraded equipment that they may have. They -- our inspectors review such control processes in the control room as their shift supervisor and tag-out logs, operating orders, plant trouble reports, and the control room log, to make sure that they're aware of, again, what's happening in the plant.

Jumper and bypass logs, determinations of reactor coolant system inventory leak rate -- those are important, and we sometimes verify that those are being properly performed.

We also observe containment integrity and the actions that the licensee is taking to ensure that containment integrity is maintained.

CHAIRMAN BARTON: Are they required to observe shift turnovers?

MR. GWYNN: Shift turnover is on my list. Yes, sir. I should have had it at the top, because that's typically the first thing that they do in the morning is go to the control room, observe the shift turnover and get the plant status for their 7:30 meeting.

They also look at equipment out of service. They verify the operability of the reactor protection system and other safety systems on a daily basis, and they observe surveillance activities that are in progress in the control room.

We also expect them to tour the plant on a daily basis; in other words, to get out into the plant and to know what's going on; inspect major components, looking for general conditions that might degrade system operation, looking for control of fire hazards in the plant, that there aren't accumulations of debris and other materials that might exceed fire loadings that are allowed; to independently assess the condition of safety equipment and the availability of plant equipment; observe general plant cleanliness.

And oftentimes, they'll attend the licensee's plant of the day meeting, and that helps them to schedule their inspection activities and to keep us aware of the important things that are happening at the plant that day.

On a biweekly basis, they perform a more detailed evaluation of the operability of a selected engineered safety feature train. Typically they use PRA information in the selection of those systems, and some of the things that they look at when they perform these biweekly inspections are correct valve positions, alignment of power supplies and breakers, verification that power's been removed from some equipment if it's required by the plant configuration.

For instance, if the plant's in reduced temperature operations, LTOP, low temperature over protection, may be important. Certain pumps are required to be tagged out, so that they don't over-pressurize the plant components. And so they would verify that.

Verify or inspect major components for leakage, proper lubrication, cooling water supply, and general condition, and verify that instrumentation and support systems are available and operational.

Those are some of the things that they look at during those ESF system walk-downs.

On a monthly basis, they independently verify safety-related tag-outs. They look at the problem identification system in more detail to confirm that it's being properly implemented. They will verify a selected portion of the containment isolation line-up, and they keep informed of third-party audits. I talked about that this morning.

This isn't just the activities of the Institute for Nuclear Power Operations, but other third-party audits that may be performed at the facility, looking at activities of off-site review committees and the site safety review committee.

On a tri-monthly inspection, they verify overtime for licensed operators, and they verify notices to workers are continuing to be properly posted.

On a semi-annual basis, they look at the seismic monitors for the facility, to confirm that they remain operable. And they do a detailed ESF system walk-down, which typically will mean that they'll break out PNIDs, that they'll walk the system hand over hand with valve lists, with breaker configurations. This is a much more detailed walk-down than the biweekly inspection that I spoke about earlier.

MEMBER POWERS: Which one of these inspections do they look at the security and safeguards?

MR. GWYNN: That's typically done on a daily basis, as they're making their plant tour. They're required during their plant tour to look at such things as health physics being properly implemented in the plant, that the security system -- you know, every time that they come into the facility, they interact with the security system; they observe security activities in the access areas for the plant; and so --

MEMBER POWERS: Do they walk the perimeter?

MR. GWYNN: They do on occasion. We don't ask them to do that frequently, but they do walk the perimeter on occasion.

During outages, they'll take a focused look at things that typically aren't happening day to day during plant operations, and in particular we pay close attention to reduced inventory operations and to other activities at the plant that may impact shutdown risk.

And so if there's a diesel out of service, well, then they'd look at switchyard access control, as an example. All of the time, they're looking at the implementation of work controls in the plant. That's a part of their routine daily monitoring, but during outages, typically there's a lot of modification activities that are going on, and so they'd focus on the modifications and the post-modification testing that's being performed.

Containment close-out is an important activity that's done during outages. Fuel handling is another one that they'll observe during outage activities, and verification of safety features that typically may not be accessible.

And as an example, during the recent refueling outage at the Cooper Nuclear Station prior to close-out of the dry well, our inspector was underneath the reactor pressure vessel, looking at the control rod drive housing support configuration to verify that that important passive safety feature was properly installed, and he found some things that needed to be corrected. So that was a valuable activity.

We also look at the effectiveness of licensee controls, their corrective action systems, the goodness of root cause analyses that are performed, and scheduled audits and surveillances of control room activities and other activities at the plant, to confirm that their independent oversight is operating properly and effectively.

MEMBER POWERS: When one inspectors or looks at a root cause analysis to judge the goodness of it -- I'm not sure what goodness means in that case.

MR. GWYNN: That can be somewhat subjective, and we sometimes have to get into discussions as to how much in depth a root cause analysis is needed. It depends upon the significance of the problem that's involved.

But if they're required to perform a root cause analysis -- and they are for significant conditions adverse to quality -- then we expect our inspectors to look at those root cause analyses on a sampling basis, of course, and when they look at them, see if the licensee has utilized objective measures, perhaps an outside laboratory, to take a look at fracture surfaces that may be involved.

You know, it depends upon the specific situation, but to verify that the licensee has used the tools that are available and that the conclusions that they've drawn based on the objective information that's available is consistent with good engineering analysis.

CHAIRMAN BARTON: I'm familiar with -- every time I had an event at my station and we did -- put together a group to go and do root cause analysis, we always had one of the residents participate in that -- not participate, observe, was an observer, and he usually sat through most of the meetings that the root cause group conducted. So they were really intimately familiar with the process and what was going on.

MR. GWYNN: Not only do you learn a lot about the goodness of that specific root cause analysis, but licensee's self-assessment capability comes forward very clearly in those activities, and that's why it's important for us to observe those.

MEMBER POWERS: You opened your remarks by indicating that you'd used risk information where you can. And I'm thinking in particular of a couple of scoping studies that the NRC has sponsored about shutdown risks. Do those provide you any particularly useful information?

MR. GWYNN: Well, we were going to talk with you this morning about the Wolf Creek draindown event. That -- in that case --

MEMBER POWERS: That's not fair, because they didn't cover that particular mode of operation, and it would stun me if they'd gone to that detail.

MR. GWYNN: Most licensees do not have true shutdown PRAs. But oftentimes they do have ORAM tip or other similar tools that are available to them. We'll look at the results of their analysis. Depending upon the level of sophistication of the PRA program at the plant, it varies considerably from plant to plant. We'll take a look at those analyses; we'll look then based on what they've done, at the controls that they've put in place for high-risk activities, and sometimes we'll do independent verification under certain circumstances.

MEMBER POWERS: I think what you're telling me is that generic studies or representative studies that headquarters may have done would be of limited applicability to a particular plant.

MR. GWYNN: Even plant-specific studies, if they're too general in nature, are not useful in conducting on-site inspection activities.

MR. CHAMBERLAIN: You know, I think the work that was done for preparing shutdown rules and the industry work and the NUMARC guidance that was put out, all that work was looked at, and we use that to some degree to go, when a licensee's going into an outage. You know, are they doing the right things; are they keeping back-up power?

We're looking at that and seeing what the licensee's doing really, and similar to what the shutdown rules might require.

MEMBER POWERS: But the specific -- looking at Surry, the trouble is they're too Surry. They're just -- I understand.

MR. GWYNN: That is a quick summary of our resident inspection program. Of course, we have resident inspectors at every plant in the Region. We're typically staffed at N-plus-one for plants that are all SALP category 1 performers. The Agency adjusts resources of the plant appropriately. We're in the process of making a recommendation regarding staffing at Comanche Peak.

CHAIRMAN BARTON: Now, who has to approve that?

MR. GWYNN: That's approved by the director of the Office of Nuclear Reactor Regulations, recommended by the regional administrator.

MR. LARKINS: I'd be interested in knowing how much time is spent on 71.07 activities versus regional initiatives and follow-ups, something like that.

MR. GWYNN: That varies from site to site. The core program provides estimates as to the amount of time that's necessary to perform each inspection procedure. But those estimates are based upon the skills of an average inspector, and so if you have a high-performing inspector who really knows the plant well, who is very familiar with the inspection procedures, they may be more efficient in the conduct of the inspection than another inspector who's just learning the plant, who -- even though he's been previously qualified at another facility, isn't sufficiently familiar to be as efficient as somebody who's been at that plant for a longer period of time.

So it's difficult to give you specific breakdown. But, in general, I would estimate that a typical resident inspector would spend about 50 to 70 percent of his direct inspection effort doing the core program. They are, to a large degree, the Agency's core inspector for the facility.

There are some other core inspection modules, inspection procedures, that are performed in EPHP securities. We have an additional core module for licensee self-assessment programs that's performed out of the regional office.

We have a core module for ISI programs that are performed out of the regional office, but to the large extent, the resident inspectors perform the core inspection program for the Agency at each of the power reactor sites.

Now, if a site only has a core program and does not have, you know, a regional initiative inspection effort as scheduled and planned, then we from time to time find ourselves with more inspection capability at a site than what is needed to accomplish that core program. And then that results in a management challenge for us to provide opportunities for those inspectors to inspect at facilities that have more than a core program.

And we've been more effective over the last four to five years in accomplishing that part of the inspection mission than what we had been in the 1980s and early 1990s. Today I can't stand here and tell you that that's a perfect program. We still have some facilities where we do more inspection than what we had planned, and we're continuing to look for ways to better manage that inspection resource.

MR. CHAMBERLAIN: One you didn't mention was we've got a fairly large engineering core inspection, which you may talk about later in the region-based.

MR. GWYNN: Yes.

MR. LARKINS: At one point it might be interesting for the committee as to how long it takes to train -- get a resident inspector certified through the board and everything.

MR. GWYNN: Typically from the time that an individual is hired as an inspector, whether he's a resident inspector or regional-based inspector, our expectation is that they would complete that training and certification process in no more than two years, but it's our desire for them to finish that more quickly. Eighteen months is a nominal time. Some inspectors, depending upon their level of expertise coming into the job, can complete their certification in a year.

But anything under a year is rare and unusual. There's so much training that's required and formal training activities, and then the on-the-job training is the most critical part of training an inspector, on-the-job not only at the site but in inspection techniques and skills that they need to perform inspections.

In this region, we've considered that that aspect of the job, the actual on-the-job practice of inspection techniques is so important that we significantly increase the number of inspections under instruction that are required for certification.

Manual chapter 12.45 specifies four; we

specify ten additional inspections under accompaniment before an inspector can be certified, just because we think that that's such an important part of the program.

MEMBER POWERS: Have you identified skill base or background that leads to particularly good inspectors?

MR. CHAMBERLAIN: We talked about that. We're trying to develop a profile of what would be a good inspector, and we know what they look like when we see them, but --

MEMBER POWERS: A mean SOB, prerequisite number one.

MR. GWYNN: Actually I've seen a wide range of different personality types that use different inspection techniques very effectively. We have one individual in the Region who has a very dry British sense of humor who very effectively utilizes that sense of humor in the inspection process, and he can learn things that some other inspectors could never drag out of somebody, just by utilizing his dry humor, and a very, very sharp intellect with a depth of technical knowledge in his area of expertise that goes beyond most licensees.

CHAIRMAN BARTON: Has the licensee smiling as he's writing the violations. Very effective.

MR. CHAMBERLAIN: It's interesting, too -- in some parts of the country, a person may be effective, you know, in inspecting, a certain type of inspector. A New Yorker in the Northeast may do fine up there, but if he comes to the South and uses the same style, he can offend someone, and that's --

MR. GWYNN: And then there are a lot of inspectors that can't use the technique that I discussed earlier effectively. It just won't work for them, so it's -- in a large extent, it's personality-driven.

MEMBER POWERS: One of the areas that I persist in being concerned about is if we try to quantify human performance and the lack of performance and human error is the -- if you do studies of human performance in Sweden, does it do any good in the United States at all?

It's a very different culture, you know. What affects the performance in Sweden, it's not obvious to me, has any bearing on what affects performance in the United States and probably nothing at all like Japan.

I just don't know how translatable human performance is over fairly short geographical distances.

MR. GWYNN: I've had the opportunity to meet and talk with some Swedish inspectors in the past, and I can tell you that those individuals -- I don't know if they're typical, but the ones that I met were very large men, and --

CHAIRMAN BARTON: Intimidation works well for --

MR. GWYNN: It works well for them, so just for what it's worth.

Going to the region-based inspection program, the regional-based inspection program is carried out by inspectors that typically have a higher level of specialized expertise than what our generalists resident inspectors have.

They are based here in the regional office, and they inspect all of our plants, and that's an aspect of regional-based inspection that's important, that we need to retain. Our resident inspectors have a very, very sharp understanding of their plant, and in this region, we require them to have a lesser knowledge of a back-up plant for emergency response responsibilities, and so typically they'll know two plants reasonably well, one very well.

But these regional-based inspectors inspect all of the plants in the Region, and so they have a broad-based understanding of licensee safety performance in their area of expertise at every plant in the Region, and they can bring value to the plants that our resident inspectors can't bring.

And that's one of the major values of having a regional-based inspection program. Also if there are events at a facility, to be able to bring that specialized expertise to bear, I think is important. In addition, we talked this morning about the value of being able to identify problems before they become events, and sometimes you need specialized expertise in order to do that.

I think we've seen some fire protection issues that came forward as a result of having Phil Qualls, our fire protection inspector, who we've now lost to headquarters, and that's just an example of their specialized expertise so valuable to the Region.

Also these region-based inspectors provide an important independent check on our resident inspection program. They may go to the facility and find that conditions are different from what the resident inspectors had portrayed, and we utilize that separate view.

We encourage that separate view, and when we go through our plant performance review process, which I'll discuss a little bit later, having that separate view available during the plant performance reviews is important to ensure that our inspection program for the facility is being maintained viable and healthy.

MEMBER POWERS: Have you attempted to ascertain in even qualitative terms the value you bring to the plant by having inspectors with a cross-sectional view of a lot of different plants, that come into a particular plant? It seems to me they would inadvertently impart information. Well, so and so is doing this a better way up at this other plant, and you might want to think about it.

Do you think you get any of that kind of advantage?

MR. GWYNN: That was a major advantage in the past. That happened a lot. We encouraged the inspectors not to talk about specific plants, but to identify that there are other practices that they've seen, and today, that -- although from time to time, we still get value and in particular under specific circumstances, we've seen value from having that, but because the licensees have so much involved themselves in cross-fertilization activities, plant visits, looking at benchmarking other facilities, that -- the value of that has become less over time.

But there are still some plants where it's extremely valuable. There are some plants that don't do as much benchmarking and visiting other facilities, don't get the value effect of cross-pollenization that the might otherwise, and so there are some plants where that's still of great value.

MEMBER SEALE: The INPO people use peer evaluators from other plants much more extensively now than they used to, and so there's just almost a continuous feedback among them.

MR. GWYNN: We have a few plants in the Region that actually have a travel budget for their operating staff, because they want their operators to get out and see how others are doing the same job and bring back their learning experience, and while they're there, they impart experience from their own plants. So that brings a lot of value.

Dwight, would you like to add anything about the region-based inspection program before I go on, because, you know, I'm the projects director and the resident inspectors report to me through the branch chiefs and projects. Dwight is the DRS deputy director, and the division of reactor safety is where all of our regional-based inspection is located.

MR. CHAMBERLAIN: I think our past management and our current management really want to have a strong region-based program. They see a lot of value in it, and Joe Callan really stressed that and wanted an independent DRS, not somebody that just serviced DRP. He wanted DRS to be independent, issue their own reports, have their own views, so you could kind of balance DRP, so that everything's not driven by DRP.

And the way we've rotated our managers, I was an acting deputy in DRP. I was a branch chief in DRP.

I've worked in DRS; I've worked in DNMS. So we all understand each other's role, and I think that made us stronger too.

MR GWYNN: I'll to plant issues matrix --

MEMBER POWERS: There seems to be a percolation or iteration of the management structure within this regional office; I mean, a lot of changing of jobs and things like that, to give --

MR. GWYNN: I was the deputy director in projects. I went to be the director in reactor safety. I was there for three years. I've been director in projects now since March of this year. And I'm hoping that my next job in the Region will be the division of nuclear materials safety.

MEMBER POWERS: Pretty thorough cross-section by the time you're done.

MR. GWYNN: Well, I have some role models that have --

MEMBER POWERS: You know what a successful career type is here.

MR. GWYNN: The plant issues matrix is a relatively recent addition to our tools that we have in managing the inspection program for the facilities. It really is only a chronological listing of plant issues. It comes from inspection reports, from licensee event reports, from event notifications that have been made by licensees to the headquarters operations office.

So it's a chronological listing of all of the key issues for each of the plants in the Region. We have an inspection manual chapter 3.04 that provides guidance on PIM format, the information that's to be provided for each entry, and gives us some sense for the threshold that we're supposed to use in determining what belongs in the plant issues matrix and what does not belong in the plant issues matrix.

We are working hard today to try to become more uniform in these plant issues matrices, because there's still a lot of variability amongst the branches.

MEMBER POWERS: I'll have to admit I've heard about this PIMs about a year ago, I think, and then I got another introduction to it at the regulatory information meeting. I'd love to see one one day.

MR. GWYNN: I had a back-up slide. I was going to put one up in front of you, and I lost it, so it was an inadvertent, not an advertent, loss of the back-up slide, so I apologize for that.

MEMBER POWERS: I'm beginning to suspect this thing doesn't really exist.

MR. GWYNN: This has developed into a very valuable tool for us, and it's used as part of both the time performance review and the senior management meeting itself processes. This -- it identifies each of the items by whether it's a strength of the licensee's program or whether it's a violation.

MEMBER POWERS: See, this is an aspect that I hadn't heard about.

MR. GWYNN: It classifies each of the items to help to make clear what we ought to take from the information. It shows the source of whether it's an LER, whether it's an inspection report, or whether it's a EN or an event notification. It shows the source document. It has a brief description of what the issue is, and we're trying to improve those brief descriptions so that they're meaningful by themselves. Sometimes you have to go to the source document to get the full meaning. So --

And then right now we include a cause. If we have information that relates to the cause of a problem that's identified in the PIM, well, we'll try to bring that forward there.

This -- typically if you'll look at an inspection report today that's been prepared under manual chapter 6.10, you'll see that it includes an executive summary, and the executive summary -- many of the executive summary statements become PIM entries; not all of them, but the key findings for the facility, both the strengths and the problems, are brought into the plant issues matrix.

The PIM -- some of the problems, some of the improvements that we need to make relate to the consistency between technical divisions, the consistency between the regions. There's still a lot of work to be done in that area. The threshold for PIM entries, I mentioned; the level of detail in these PIMs -- those things are still evolving over time.

Another important aspect of the plant issues matrix is whether or not it should be released to the public. That's a question that's been asked by the Commission. It's currently not publicly available. It is a Commission decision as to whether or not that document will be released to the public.

Right now, having it in a condition where it's not publicly releasable, believe it or not, causes us some problems, because we would like to be able to hand a copy of it to the licensee when we go to their plant and talk with them about the results of our PPRs, our plant performance reviews, but we can't do that right now, because it's not a publicly available document.

So that's the down side. Now, the other side of the equation is that there's some trepidation that there might be information in there that people haven't seen before, that -- you know, there are a number of different concerns about the potential release of the PIM.

I think that those will be addressed as a part of process changes that we're making right now, and whether or not the PIM is released to the public, as I said before, is a Commission decision. The --

MEMBER POWERS: Have no fear. I can't get one. It's really secure.

MR. GWYNN: Typically it does go back 18 months or 24 months, whatever the typical SALP cycle for a facility is, and it's an important compilation of information that's already on the docket. There really should be nothing in the PIM that's not already on the docket and available publicly, so that's the format that we're working towards.

The plant performance reviews under manual chapter 03.04, these are also an improvement in our process. The process improvement started in 1988, but we really made major improvements to the plant performance reviews in 1995 and 1996. These plant performance reviews are done -- they're required to be done on a semi-annual basis.

And this is a time when we, as the Region, come together at a table where the division of reactor projects, the division of reactor safety; we have the seen before, that -- you know, there are a number of different concerns about the potential release of the PIM.

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Office of Nuclear Reactor Regulation on the telephone. We talk about performance insights that have been gained at each of the facilities over the last six months. We talk about those performance insights by SALP functional area.

And so it gives us a very quick -- and this is not a SALP; this is not an in-depth assessment. This is a quick look-back, to look for trends in safety performance and to see if we need to make adjustments to our inspection program as a result of recent trends in safety performance at the plant.

That plant performance review then will result in adjustments to our master inspection plan which we maintain for each of the plants in a region where it's appropriate to make adjustments, and these adjustments can be to either increase or decrease inspection, depending upon the trends that are seen at the time.

That inspection plan then, once the adjustments have been made, we take the inspections off of the plan that are scheduled over the next eight months. We put those into a letter, and we send those to the licensee. So we give the licensee on the docket an eight-month look-ahead on the inspections that we have planned for their facility, and where we've made adjustments to the plan.

If those inspections are inspections that they've previously been informed of and they're continuing to be on the schedule, well, we just include those, but where we've made adjustments to the plan and we've added inspections, then we would tell the licensee the basis for the adjustments that we've made.

MEMBER POWERS: Recently the NRC commissioned an outside consulting agency to look at performance indicators and trending that were done out of the senior management meeting; came back fairly harshly critical. If NRC were to commission this same group to come in and look at your trending and indicators that you do for your performance plan, would they be as equally critical?

MR. CHAMBERLAIN: In terms of our supporting our PPR process?

MEMBER POWERS: Well, their essential criticism was that the decisions to move plants onto a watch list were made late, that the trending information was there, but the decision to actually act on that trending information came in long after it should have by any other -- by any objective examination of the trends.

MR. GWYNN: I really hesitate to speculate as to what the results might be. I'm certain that there would be some criticism of our process in terms of its transparency, you know, and in particular an outsider looking in might find it difficult, because we don't maintain real careful records as to the discussions that occurred.

We have some records. We certainly have discussion papers that are used, but where we get into a level of detail that goes beyond those discussion papers, we don't maintain transcribed minutes or anything along those lines concerning the information that supports decisions that were made.

So I'm sure that there would be some criticism of the process. On the other hand, this is looking back six months, and in this region, we actually do it more frequently than is required. At this time, we're doing quarterly plant performance reviews, and we do that for a specific reason.

We found that both the plant performance review process and the SALP process were dominated in the past by the division of reactor projects and the resident inspectors, and that was a criticism that the industry laid on the Agency, and in response to that, some time ago, quite some time ago in this region, we made changes to our process, so that the division of reactor safety was much more involved in both SALP and the PPRs that we perform here.

But we -- during the initial process of getting our reactor safety division more involved in plant performance reviews, we found a lack of ownership on the part of the regional-based inspectors, and so we went to quarterly plant performance review to gain more ownership, and so the division of reactor safety is responsible for the Q PPRs; the division of reactor projects is responsible for the other plant performance reviews that we perform, and that's --

There's another aspect that we implemented at the same time that I thought brought a lot more value to the plant performance review. At the semi-annual plant performance reviews that are on a schedule that's consistent with the senior management meeting cycle, we vertically look at each plant by plant, so there is a discussion by plant -- each SALP functional area is discussed, and the division of reactor projects leads that.

In the Q PPR, we don't look by plant. We look horizontally across functional area, and so the DRS branch chief -- we have an operations branch, a maintenance branch, an engineering branch, and a plant support branch, and so each of those branch chiefs look across all of the plants in the Region and talks about performance of the plants in each functional area, one functional area at a time.

And so that provides feedback to the projects division as to where we really ought to be concerned, and it helps to levelize the playing field, and it helps us in our allocation of resources process, to make sure that we really are putting our resources at the plants where the problems are most. And this PPR approach has brought value to this region in terms of making sure that our resource allocations are appropriate for the plants.

MEMBER POWERS: Okay. Now, just a comment that, of course, one of the criticisms of the senior management meeting was that it was dominated by the regional administrators. It sounds like maybe you've taken care of one of the potential criticisms --

MR. GWYNN: Well, there's no question. The senior resident inspector at one time certainly did dominate SALP. I remember when I did my first SALP as a senior resident inspector, I prepared all of the briefing materials. I prepared the draft report. I was the one that made the presentation at the public meeting to the licensee. And so the senior resident inspector dominated that process.

MR. CHAMBERLAIN: That's not fair. When I was a senior, I wrote the report too. Now my deputy director and I have to write it.

(General laughter.)

MEMBER POWERS: Who said it was supposed to be fair?

MR. GWYNN: This is an evolving process, and I anticipate that we will continue to get better, and in particular, we need to get more efficient in our plant performance review process.

CHAIRMAN BARTON: Are you going to tell us any secrets on SALP or everything we already know?

MR. GWYNN: Everything that you already know. I think that what I would do is put up the very last slide, which is our SALP matrix for Region IV. And this is just a quick overview of what the SALP ratings have been for each of the plants in the Region.

The most recent SALPs that we've done have been at Comanche Peak and Wolf Creek and Callaway. Those are the three most recent. We just recently finished the San Onofre SALP, but those results haven't been published yet, and so they're not -- what you have is results from 18 months ago for San Onofre.

If there are any questions, I'd be pleased to address those, and I apologize --

CHAIRMAN BARTON: Very informative.

MEMBER POWERS: Let me ask you one question. I look at this matrix of the plants, and I said, They hold engineering to a tighter standard than they're holding everything else. Why shouldn't I draw that conclusion?

MR. GWYNN: No. That's -- I think that what you're seeing there is in the past the Agency has put a lot of time and attention in the operations area. We have a lot of time and attention in plant support, a lesser extent in the maintenance area. But engineering, we didn't spend a lot of time, and we really didn't have all of the expertise that we needed to assess engineering programs.

A couple of years ago, we changed our approach to engineering inspections. The Agency increased the amount of time that was allocated to engineering inspections, and when they did that, we changed our approach. We went to a team inspection of engineering in this region, and as a result of using team inspections, using outside contractors as members of our team, using vertical slice approaches to the first week of the inspection with a horizontal look across the engineering organization based on the results of the first week during the second week of the inspection, we became better equipped to assess engineering performance at the plants.

And as a result of that, we've had some problem areas identified, and we're focusing on those.

MEMBER POWERS: I think Millstone and Maine Yankee helped to --

MR. GWYNN: Actually, to be quite honest with you, these SALP category 3s, except for the Wolf Creek category 3, were in existence prior to Millstone. Yes, sir.

MEMBER POWERS: Were prior to the Millstone and Maine Yankee?

MR. GWYNN: And WNP-2, prior to their most recent SALP, also had a category 3 in engineering.

CHAIRMAN BARTON: Dwight?

MR. CHAMBERLAIN: Our next presenter is Blair Spitzberg, division of nuclear material safety. He's going to be talking decommissioning and dry cask storage activities.

CHAIRMAN BARTON: Is there some way you can get through these slides in about 15 minutes?

DR. SPITZBERG: I'm glad to have the opportunity to be here. I think it's appropriate that I go near the end, because I'm going to be talking about the latter stages of the nuclear fuel cycle here.

After all of my predecessors' hard work is over with and the plant is shut down, then they're confronted with the problem of having to decommission the plant.

By the way, my name is Blair Spitzberg. I'm the chief of nuclear materials inspection and decommissioning branch. I'm in the division of nuclear materials safety and safeguards.

Just to give you an overview, we have in this region probably a higher number of decommissioning reactors, I think, than the other regions. These are the particular sites, and a handout that you don't have in your handout is a map showing the location of our decommissioning projects.

And what I'll do since we're on an abbreviated schedule here is I'll try and walk through some of these sites and only focus on those where I think there's the major activities ongoing at the present time or some areas that I think might be of interest to you.

The Trojan plant is in Oregon. It's a four-loop PWR plant that's in active decommissioning now as we speak. It has had the large component removal is completed, so that the pressurizer and the steam generators, reactor coolant pumps have been removed. The reactor vessel and internals remain on site.

As I mentioned, it's actively undergoing dismantlement and decontamination, and they expect to complete that by the year 2002. They're not going to be taking down the structure by that time. It's not going to be a green field, I think, until about 18 years later under the current plans.

They have proposed that the reactor pressure vessel be buried as a single shipment at Hanford as opposed to cutting up the reactor vessel into pieces and shipping them separately, and I'm going to come back to that.

They have started the construction of a dry fuel storage pad on site. I'm going to be up at Trojan just next week, because they're going to be pouring the concrete pad, and we're going to be looking at that.

MEMBER POWERS: I just can't resist asking why in the world anybody would want to bury the Russell and Hanford -- why in the world, more precisely, why in the world Hanford would want anybody to bury their vessel at Hanford.

DR. SPITZBERG: Well, that's a good question, although I think it's not too dissimilar from the submarine reactor compartments that they're burying routinely up there.

By the way, let me -- before I forget, let me introduce Vince Everett over here, who's among my group, and he's the lead decommissioning inspector and spent-fuel storage project inspector for me. And I brought him along not only because he helped prepare most of these slides, but also because hopefully he'll be able to answer questions that I can't.

As I mentioned, currently under review is an application submitted by Trojan to transport the reactor vessel filled with low density concrete to the Hanford site for burial as a single shipment, as opposed to the alternative which is to cut the reactor into 54 segments and ship via highway.

The licensee has noted in their application several savings in addition to just the monetary saving is that it is a considerable exposure savings to not only the plant personnel but also to the transportation personnel as well as members of the public. It's a little bit -- not quite as significant.

But just, for example, the savings in dose to the plant workers is expected to be -- well, if they ship intact, it's expected to be about 67 person rem versus 154 person rem if they have to cut it up.

In addition to that, the State of Washington and the State of Oregon have gotten behind this request, and at this point, have shown pretty strong support for it.

Part of the problem with this request, as I understand it is that in order for it to be shipped as a type B package, there will have to be granted an exemption to certain requirements of the type B certification process, and so I think this is the major technical hang-up with the NRC. I don't know how that would be resolved.

Before I leave Trojan, let me also mention one other thing that we're going to be looking at next week and that is that they have a project that they're going to be initiating in the next few weeks where they're going to be burning some of the organic filters that have been used to clean up some of the fuel debris in their systems.

And they have a process reformer project that has been proposed where they're going to be actually burning the organic material from these filters, so that the residual activity can be placed into dry storage on site, and they have to eliminate the organic materials so that they won't have a source term for gas generation in the ISFSI.

Okay. Rancho Seco, I'm not going to spend much time on this. This is a PWR, a Babcock & Wilcox plant that operated from 1975 to 1989. It's currently in a safe storage status.

MEMBER KRESS: I'm just curious. What kind of organic filters?

DR. SPITZBERG: These are rubber filters that were part of the -- as I understand it there was some fuel degradation that occurred in the past operations of Trojan, and they did get some fuel debris and particles into their systems, and in order to clean up this, they passed the debris through filters which had some gaskets, rubber organic gaskets, as part of the filters.

And before they can put these filters with the debris into dry storage, they have to eliminate the gas-generation potential of the organics.

Rancho Seco is currently in SAFSTOR status, although they have got some limited dismantlement activities underway in the turbine building; very low potential for having to deal with contamination problems at this point.

They expect to make a decision within a year or so as to what the future pace of their decommissioning is. They have completed construction of an ISFSI on site. They've completed the concrete storage module, but they have not yet fabricated the storage baskets that will be used to house the fuel. The fuel is still in the spent-fuel pool.

One of the reasons for this is because, as you're probably well aware, there's been some concerns with both the major spent-fuel storage vendors. Their vendor happens to be the Vector NUHOMS system, and there's some quality assurance concerns that are being addressed now that has delayed the construction of their storage basket.

Moving on to Humboldt Bay is an early design of a BWR. It's located in Eureka, California, which is in a seismically active area. It operated from 1963 until 1976. This reactor is located in a subsurface caisson, right on the coast, and it is in a SAFSTOR status with no decommissioning or decon work going on except for some work that is associated with some investigation and repair work on the caisson.

This is a depiction of the reactor caisson here. One of the issues we've been dealing with over the past several months is that there has been an increase in the rate of groundwater in-leakage into the reactor caisson.

As noted on the next slide, the in-leakage in 1992 was between about 100 to 150 gallons per day. It went as high as about 10,000 gallons per day within the last year, and it's currently running about 7,800 gallons per day.

If you put back the diagram, where they think this in-leakage is coming in is if you look at the joint in the base mat of the caisson and the suppression chamber, they believe it's coming in in that general area. The leakage is accumulating in a sump area of the caisson and is being continuously pumped out.

Early on, they were detecting some low levels of contamination in this water. They investigated and determined that the contamination was coming from plant systems such as the sump and the sump grates that were contaminated, so they -- about a year ago, they initiated a project to clean that up, and currently the water that's being pumped out of the caisson is below any tech spec limits for release, and they're able to discharge it directly into the canal.

They do have a process monitor on it, so they are continuously monitoring it.

San Onofre, it is a PWR that operated until -- from 1968 until 1992. It's in a SAFSTOR status. There's very little activity ongoing there from a decommissioning standpoint. We were out there a couple of weeks ago. Things are pretty quiet.

Last summer we did have to deal with some concerns expressed by members of the public over a spent fuel pool leak that was discovered in 1986 and was subsequently repaired, but nevertheless the spent fuel pool now is showing very low leak rate, about 3 gallons per week.

Fort St. Vrain, located in Colorado, this plant is under the project management of NMSS as opposed to the other plants that are under NRR project management. It's a high-temperature gas-cooled reactor. The fuel is in dry storage currently.

There is a license termination letter is currently with the Commissioners, and we expect that if they concur in this letter, that this license will be -- the 50 docket license will be terminated in the near term, probably over the next month or two.

The other interesting aspect of Fort St. Vrain is that the spent-fuel storage installation there is being -- in the process of being transferred to the Department of Energy under prior contractual arrangements with Public Service of Colorado, and there is a pending license application under review now with the NRC for that transfer. And so we have been engaged in some prelicensing inspections of the DOE to evaluate their readiness to accept the transfer of this facility.

MR. LARKINS: Are they going to leave that fuel there for a while? Is that the current plan?

DR. SPITZBERG: That's the plan. Originally the fuel was going to go back to INEL, but I understand that that's not being considered at this time.

The last plant I'll just mention briefly is Vallecitos. It's early G.E. test reactor in California, and it's in long-term SAFSTOR, very little activity going on site, and they have no immediate plans to go into active decommissioning.

Let me just kind of go through a list of problem areas that we've been dealing with in the reactor decommissioning arena, and if you like, I can go into more detail about them, but unless you have any specific questions, I'll just go through them quickly.

We've been seeing problems at most of our sites at one point or another with free-release surveys, and part of the problem with free-release surveys stems from the human factors part of doing repetitive surveys of material that you receive and expect to be free of contamination.

We've also had some issues at plants involving paperwork discrepancies, doctoring of paperwork, instrument sensitivity issues, and while free-release surveys, a problem in that area does not necessarily represent a significant risk to the public, it can be a very flammable issue when it comes to public perception of what the decommissioning process entails.

MR. CHAMBERLAIN: Let me ask for a second. Were you going to talk about dry cask storage?

DR. SPITZBERG: Yes.

MR. CHAMBERLAIN: Are you interested more in that? Do you want to get a few minutes on that? I don't know how tight your schedule is.

CHAIRMAN BARTON: Pretty tight.

MR. CHAMBERLAIN: Let me skip this and maybe just quickly, two or three minutes, talk about dry cask storage. Will that work?

DR. SPITZBERG: That's fine.

MR. CHAMBERLAIN: Let's do that.

CHAIRMAN BARTON: It's not a lack of interest in this. It's --

DR. SPITZBERG: I understand. Let's go to the dry cask storage. We currently have two facilities where we have -- oh, this is a graph that is not in your handout that I want to put up to illustrate the nature of the problem that's going to be confronting us on dry storage of spent fuel is that if you look at this graph, we're just at the low end of what looks to be an exponential power curve on the need for spent-fuel storage capacity above and beyond the spent-fuel pools at this country's operating nuclear power plants.

You see it starts to go into an exponential power curve about the year 2000 and shoots straight up from there, and we're in 1997, so I just wanted to put this up to illustrate the nature of the problem we're faced with.

I think I mentioned the two -- that we have two ISFSIs that currently have casks that are loaded. This is a diagram that shows where our current or future ISFSIs that we know about are going to be located, and obviously I think there will be more beyond this.

Currently we have Arkansas Nuclear One as an ISFSI in operation as does Fort St. Vrain as I mentioned. I won't go over the plants that are proposing ISFSIs in the near term.

Let me move on to ANO. You may be familiar with some of the problems that have been surfacing with dry fuel storage in the recent months. ANO has been in the center of some of this, not from any problems that are unique to that utility, but more with problems that are related to the dry fuel storage systems themselves.

ANO is currently under a confirmation of action letter that causes them to investigate the nature of some weld cracking phenomenon that has been observed at ANO and other plants.

What happens is that the -- if we have -- do we have a diagram of the ANO cask? This shows the cask system in the concrete cask, but the problem that has been occurring at ANO and Palisades involves cracks on the shield lid which is the lower of the upper lids there on the multi-assembly sealed basket.

And there have been cracks that have formed after welding of this shield lid on two casks at ANO and one at Palisades, and currently there is an intensive effort ongoing with the vendor, the users, and the NRC to determine what the cause and corrective actions necessary for this weld cracking phenomenon are.

I don't know how much detail you want me to go into on that. I'm more than willing to elaborate.

MEMBER SHACK: What's the material that the weld --

DR. SPITZBERG: This is carbon steel.

MEMBER SHACK: What's the general nature of the -- it's hot-cracking during the weld?

DR. SPITZBERG: Well, the cracking has occurred at ANO during the repass and during the final pass on the shield lid weld. At Palisades, was it the repass? And one of the concerns that we have is that our expert has said that there is some evidence that it could be caused by hydrogen cracking.

And hydrogen cracking has a phenomenon associated with it which is unsavory for long-term storage of fuel in that the cracks can occur in a delayed fashion, up to a year after the weld, so theoretically if it is hydrogen cracking, you could complete the weld, test the weld, and have it pass the tests, only to have the crack form at some later date.

So that's one of the concerns that is being investigated, to see whether or not it is hydrogen cracking or delayed cracking as a potential.

Let me move on to just the TMI fuel, because I wanted to -- if you could move over to the DOE TMI-2 fuel, we have a license application that's under review right now from the Department of Energy for a dry-fuel storage installation at Idaho National Engineering Laboratory, to house the TMI-2 fuel debris.

This fuel debris is in various forms, anywhere from intact fuel assemblies to fuel elements to fuel debris and dust, and so there's three different types of canisters. I've given you the diagram for the three types of canisters that are proposed for use.

One of the unique features of the TMI dry-fuel storage, however, is that it will use commercial design by NUHOMS, but it will be a ventilated cask to allow for the escape of radiolysis gases from the fuel debris, which is in contrast to the loss of sleep that we've had over the weld cracks at ANO.

If we go to the last slide, I'll just close up with some of the problem areas that we've been seeing in the dry-fuel storage area, the welding of the lid, hydrogen generation from the coatings. You're probably aware of the issue involving chemical reactions between the boron and the spent-fuel cooled water and the coatings of the casks that lead to hydrogen generation and, in fact, led to hydrogen emission event at Point Beach; documentation of safety reviews, experience in loading and moving casks, and the upgrading of the crane capacities at many of these facilities.

So that's the speed record for going through all these slides.

CHAIRMAN BARTON: Forty slides in 12 minutes; that's pretty darn good. Sorry we had to rush you through this part of the presentation.

DR. SPITZBERG: These will come in handy another time, I'm sure.

MR. CHAMBERLAIN: I believe that wraps us up. I did want to thank Laura Hurley for doing our slides today. She wasn't expecting to have that job today, but she --

CHAIRMAN BARTON: She did very well.

MEMBER POWERS: This issue of sealing up fuel into a cask and what goes on inside that cask, hydriding, clad, forming hydrogen, producing gas, pressurization and things like that -- it just seems to be a conundrum to me. I just don't see how we can seal things up.

DR. SPITZBERG: Well, there's also a problem, I think. Obviously there's -- we understand the problems that DOE's been having in trying to get a permanent repository, but we're going to find ourselves before long with 100 high-level spent-fuel storage facilities in this country. Most of them are going to be sitting out next to our interstate highways for everybody to see.

MEMBER POWERS: You might understand those problems. I don't understand their problems.

MEMBER KRESS: But I agree with Dana. We really ought to leave them vented, I think.

MEMBER POWERS: Well, I just don't -- we stored some fuel at Hanford, and lo and behold, now you don't know what -- they have to get it out. I don't want to open those casks for love nor money, because I know that clad is very well hydrided, and it bursts into flame as soon as I bring it out. It's just awful stuff to work with.

DR. SPITZBERG: That's the same type of cladding that commercial --

MEMBER POWERS: It's a uranium zirconium excreted fuel, quite unlike commercial fuel, and it hydrides very well, aggressively, and a little bit of moisture goes a long ways, and here we've sealed it up. It's nicely hydrided. You open that up; you get a fire. I mean, there's no two ways about it.

Your problems in sealing up may not be nearly as bad with commercial fuel, but you've still got -- I mean, you're radializing water to create these aggressive oxidants and reductants. They're going to do their thing. And that thing's usually bad.

And so I just don't understand how you can seal things up. I mean -- burn it in the reactor. That's the only answer to the problem. Keep the plants running. Recycle that sucker.

CHAIRMAN BARTON: Ellis, in closing, I want to thank you on behalf of the committee, thank you and your staff for putting on a very informative day. I think we learned an awful lot, have some appreciation for Region IV and why Region IV is as well respected as it is.

I think you've got a lot of good people and some good programs going here that we don't see. It seems to be a forward-looking, aggressive region.

MR. MERSCHOFF: Well, thank you. The staff really worked hard on this, and I hope that it's provided you the information you needed. We were a little disjointed with people coming in and out, but it was just due to the --

CHAIRMAN BARTON: It worked out fine; it really did.

MEMBER SEALE: I was very pleased to hear some of your reactor safety engineers mention that they had managed to stick their heads in to some of our meetings sometimes when they were back in Washington on rotation, and certainly anytime anyone from Region IV is there while we're meeting and they have an opportunity to come in, we'd be very pleased to have them look over our shoulders and so on, and say hello to us.

MR. MERSCHOFF: I'll pass that on to the staff. It's useful to see how committees like this work and the kinds of questions they ask, because you don't want to learn that the first time when you're up there trying to --

MEMBER SEALE: Well, and we appreciate the fact that it helps humanize the interactions between the groups, and that's important, too.

MEMBER POWERS: Well, I think they probably did themselves no good service by the show that they put on for us, because now we'll want to come back and see how some of these programs develop and what not, so they have to put up with us again.

MR. MERSCHOFF: You're more than welcome here in Region IV. We actually execute the programs that we talk about. It's gone on for a long time. I've just inherited --

CHAIRMAN BARTON: We want to think Linda Osling and the administrative staff, because we know without her work, none of this would have went as well as it did go. Thank you.

(Whereupon, at 3:05 p.m., the meeting in the above-entitled matter was concluded.)

C E R T I F I C A T E

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: ACRS SUBCOMMITTEE ON PLANT OPERATIONS/ FIRE PROTECTION

Docket Number: N/A

Place of Proceeding: ARLINGTON, TEXAS

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Barbara J. Wall

BARBARA J. WALL
Official Reporter
Neal R. Gross and Co., Inc.

INTRODUCTORY STATEMENT BY THE CHAIRMAN OF THE
PLANT OPERATIONS AND FIRE PROTECTION JOINT SUBCOMMITTEE
NRC REGION IV OFFICE
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TX
JULY 18, 1997

The meeting will now come to order. This is a meeting of the ACRS Joint Subcommittees on Plant Operations and Fire Protection.

I am John Barton, Chairman of the Subcommittee for Plant Operations, Dr. Dana Powers is the Chairman of the Subcommittee for Fire Protection.

The ACRS Members in attendance are:

~~George Apostolakis~~, Mario Fontana, Thomas Kress, Don Miller, Robert Seale, and William Shack.

The purpose of this meeting is to discuss Region IV activities and other items of mutual interest, including significant operating events and fire protection issues. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions as appropriate, for deliberation by the full Committee.

Amarjit Singh is the Cognizant ACRS Staff Engineer for this meeting.

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register on June 17, 1997.

A transcript of the meeting is being kept and will be made available as stated in the Federal Register Notice. It is requested that the speakers first identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

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

(Chairman's Comments-if any)

We will proceed with the meeting and I call upon Mr. Ellis Merschoff, Region IV Administrator, to begin.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-8064

June 26, 1997

RN 0119 - REGION IV MEETING WITH ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS) SUBCOMMITTEE ON PLANT OPERATIONS AND FIRE PROTECTION

EFFECTIVE: Upon Issuance
CONTACT: L. A. Yandell
DATE CANCELLED: July 21, 1997
DISTRIBUTION: Standard plus cc
SUPERSEDES - N/A

/s/ Ellis W. Merschoff
APPROVAL: ______________________________
Ellis W. Merschoff, Regional Administrator

A. Purpose/Discussion

This Notice promulgates the agenda and assigns responsibility for the public ACRS subcommittee meeting in Region IV on Friday, July 18, 1997, in the Training Conference Room on the 4th floor.

B. Action

Personnel assigned responsibility in the attached agenda are requested to complete their assigned tasks. The subcommittee will be visiting Comanche Peak on Thursday, July 17, 1997.

Attachment:
As stated

cc:
A. Singh, ACRS
RIV Coordinator, OEDO

DOCUMENT NAME: R:_RON\RN0119.DRP

To receive copy of document, indicate in box: "C" = Copy without enclosures "E" = Copy with enclosures "N" = No copy

RIV:C:DRP/TSS	PAO	D:DRP	D:DRS	D:DNMS
LAYandell;df	BWHenderson	TPGwynn	ATHowell	RAScarano
6/ /97	6/ /97	6/ /97	6/ /97	6/ /97
DRA	RA			
JEDyer	EWMerschoff			
6/ /97	6/ /97			

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MEETING AGENDA

ACRS VISIT TO REGION IV

JULY 18, 1997

8:00 a.m.	Opening Remarks	John J. Barton Subcommittee Chairman
8:10 a.m.	Introduction	Ellis W. Merschoff Regional Administrator
8:20 a.m.	Region IV Organization Organization & Responsibilities Unique Aspects of Region IV	Jim Dyer Deputy Regional Administrator
9:20 a.m.	BREAK	
9:35 a.m.	Panel Discussion: Activities for Maintaining Uniformity Among the Regions (JD) Current and Past Issues (AH) Wolf Creek Frazil Ice Event Ft. Calhoun Extraction Steam Line Break Event Fire Protection Issues Staff Training and Development (JD) Interface with INPO (PG)	Jim Dyer Deputy Regional Administrator T. Pat Gwynn, Director Division of Reactor Projects Arthur T. Howell, Director Director of Reactor Safety
11:45 a.m.	LUNCH	
12:30 p.m.	Senior Reactor Analyst Program Risks of Online Maintenance	Arthur T. Howell, Director Division of Reactor Safety
1:20 p.m.	BREAK	
1:35 p.m.	Status of Plant Operations SALP Program & Region IV Ratings Resident Inspector Program Master Inspection Plan Plant Issues Matrix (PIM)	T. Pat Gwynn, Director Division of Reactor Projects

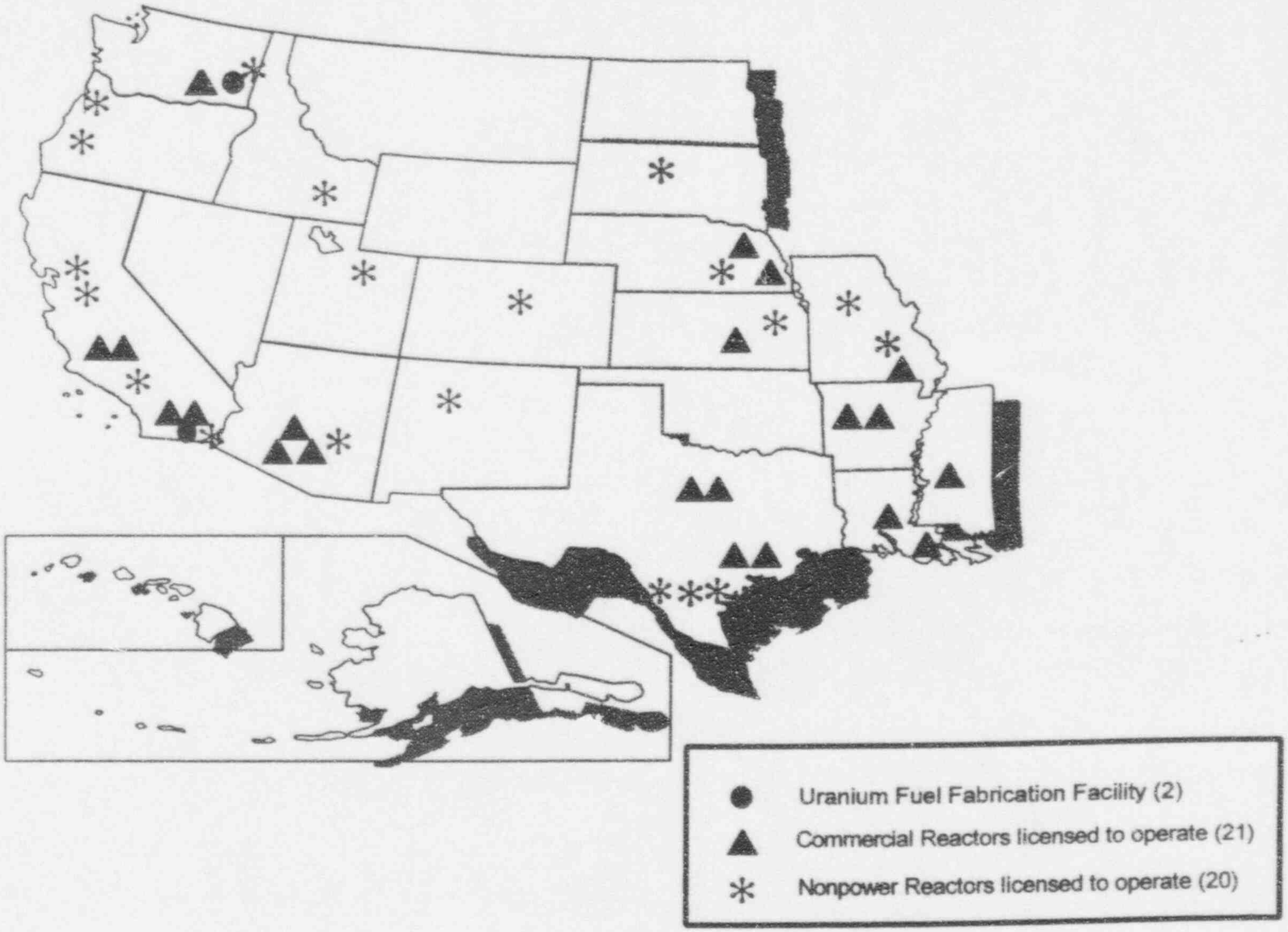
2:20 p.m.	Decommissioning Dry Cask Storage	D. Blair Spitzberg, Chief Materials Inspection Branch
2:50 p.m.	Closing Remarks	John J. Barton Subcommittee Chairman
3:00 p.m.	ADJOURN	

NRC REGION IV

Arlington, Texas

VISIT OF THE
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
JULY 18, 1997

REGION IV
MAJOR REGULATED FACILITIES



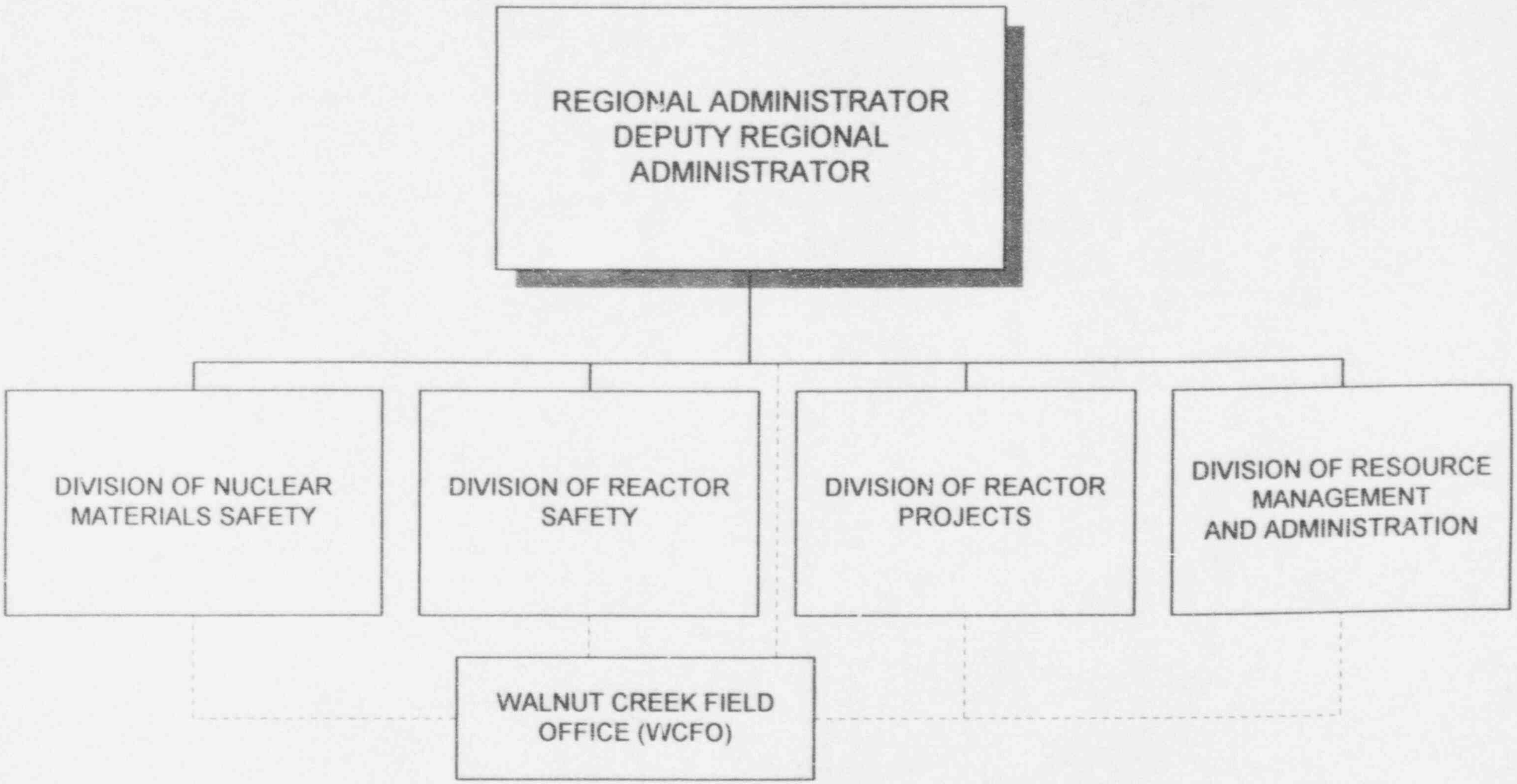
Region IV Data

Number and Types of Licenses

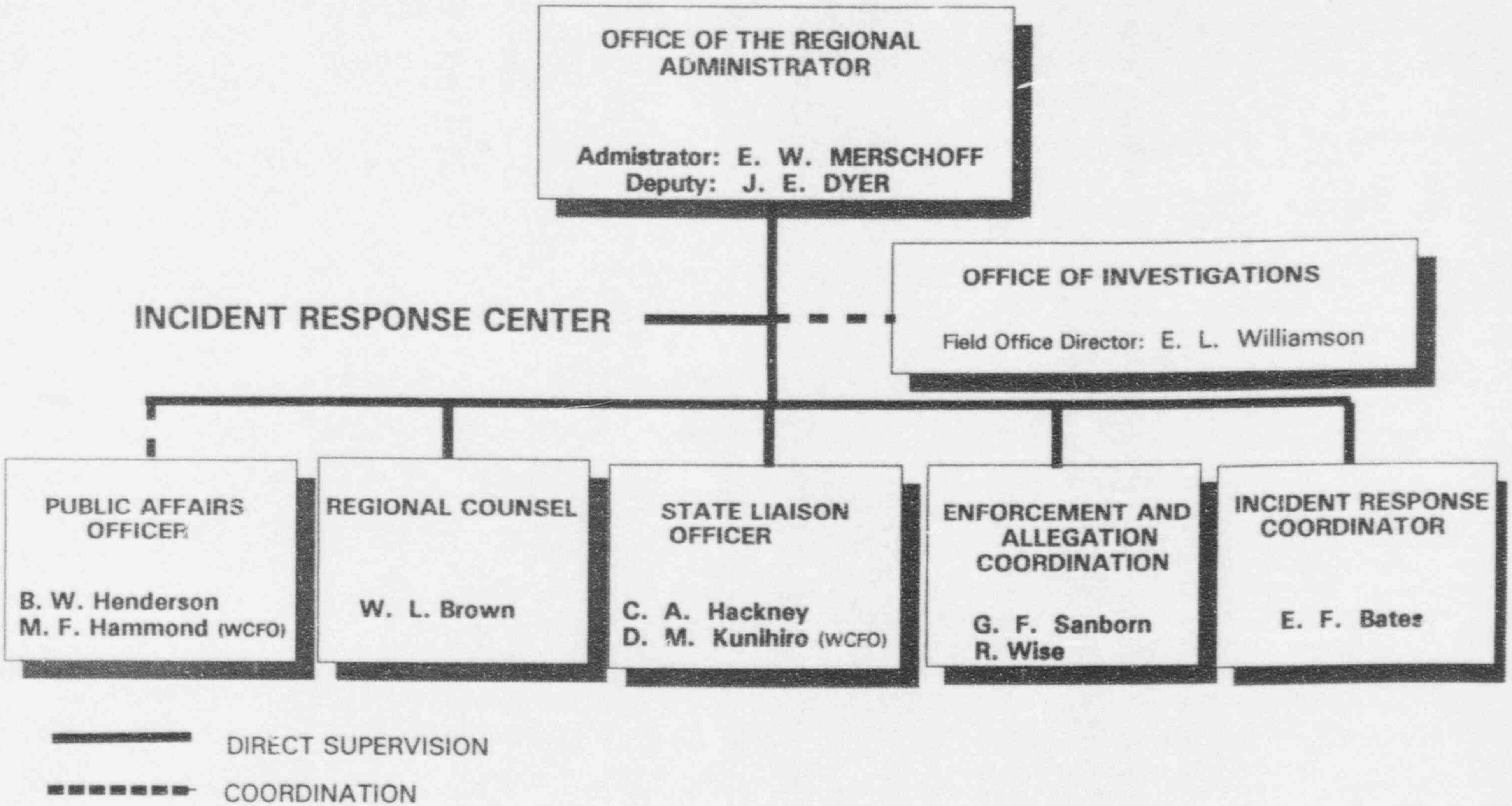
- 14 Power Reactor Sites
  21 Operating Power Reactors
  2 Power Reactors in Construction (mothballed)
- 20 Research and Test Reactors
- 2 Uranium Fuel Fabrication Facilities
- 1,241 Byproduct Material Licenses

REGION IV

July 17, 1997



OFFICE OF THE REGIONAL ADMINISTRATOR



DIVISION OF REACTOR PROJECTS

T. P. Gwynn, Director
Kenneth E. Brockman, Deputy Director

Lucy Thomas, Div. Sec'y
Denise Freeman, Sec'y (PB-B, C, TS)
Colleen Murnahan, Sec'y (PB-A, D)

REACTOR PROJECTS BRANCH A

J. Tapia, Chief
Ron Kopriva, SPE
John Edgerly, PE

CPSES
Greg Werner
Harry Freeman
Vonna Ordaz
Rebecca Nease
Caroie Austin, SOA

STP
David Loveless
Jack Keeton
Wayne Sifre
Lenora Reyna, SOA

REACTOR PROJECTS BRANCH B

B. Johnson, Chief
David Graves, SPE
Ray Azua, PE

FCS
Wayne Walker
Vincent Gaddy
Nancy Curley, SOA

WC
Fred Ringwald
Brad Smallridge (10/97)
Shirley Allen, SOA

CAL
Dave Passehl
Frank Brush
Dawn Yancey, SOA

REACTOR PROJECTS BRANCH C

E. Collins, Chief
Charles Marschall, SPE
Brad Smallridge, PE

CNS
Mary Miller
Chris Skinner
Shirley Neddenriep, SOA

ANO
Kriss Kennedy
Steve Burton
Jim Melfi
Vicki High, SOA

REACTOR PROJECTS BRANCH D

P. Harrell, Chief
Greg Pick, PE
Greg Werner, PE

WAT-3
Lee Keller
David Proulx
Pat Smith, SOA

WALNUT CREEK FIELD OFFICE (WCFO)

K. Perkins, Director

Maurine Smith, Sec'y
Karen Hunko, OSA
JoAnn Hooker, OSA
Jo Bianchi, Sec'y

REACTOR PROJECTS BRANCH E (WCFO)*

H. Wong, Chief
Gary Johnston, PE
Brad Olson, PE

WNP-2
Scott Boynton
George Replogle
Helen Brownell, SOA

DC
Mike Tschiltz (Vac 7/97)
Don Allen
Vacant
Jean Gallis, SOA

REACTOR PROJECTS BRANCH F (WCFO)*

D. Kirsch, Chief
Dyle Acker, SPE

SONGS
Jim Sloan
John Russell
John Kramer
Stefani Neidholdt, SOA

PV
Frank Brush (Act)
Dan Carter
Vacant
Nancy Salgado
Tammy Buchan, SAO

REACTOR PROJECTS BRANCH G (WCFO) (NTE: 2/28/98)

R. Huey, Chief
Dave Corporandy, Temp PE (NTE: 2/28/98)

RB
Ward Smith
David Proulx
Pat Smith, SOA

GG
J. Dixon-Herrity
Kathy Weaver
Mary Jane Spivey, SOA

TECHNICAL SUPPORT STAFF

L. Yandell, Chief
Ray Azua, PE
Loretta Williams

06/20/97

MAJOR FUNCTIONAL RESPONSIBILITIES OF DRP:

- COORDINATION OF THE OVERALL NUCLEAR POWER PLANT INSPECTION PROGRAM AT NUCLEAR POWER SITES
- MANAGEMENT AND IMPLEMENTATION OF THE RESIDENT INSPECTION PROGRAM
- COORDINATION OF THE SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE (SALP) PROGRAM

DIVISION OF REACTOR SAFETY

A. T. Howell, III, Director
D. Chamberlain, Deputy Director
I. Barnes - Technical Assistant
J. Shackelford, SRA
W. Jones, SRA

Cheryl Goines, Sec'y
Lynn Berger, Sec'y
Vacant, Sec'y

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Bill Ang (WCFO)
Paula Goldberg
Dave Periera (WCFO)
Mike Runyan
Linda Smith
Tom Stetka
Bill Wagner

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Cliff Clark (WCFO)
Lee Ellershaw
Paul Gage
Claude Johnson
Bill McNeill
Chuck Paulk
John Whittemore

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J. Pellet, Chief
Laura Hurley
Howard Bundy
Ryan Lantz
Steve McCrory
Tom McKernon
Tom Meadows
Mike Murphy

PLANT SUPPORT BRANCH
(5th FLoor)

B. Murray, Chief
Tom Andrews
Tom Dexter
Bruce Earnest
Gail Good
Gilbert Gurerra
Michael Hay
Blair Nicholas
Larry Ricketson
Dennis Schaefer
Michael Shannon

06/20/97

MAJOR FUNCTIONAL

RESPONSIBILITIES OF DRS:

- CONDUCTING ENGINEERING/SAFETY INSPECTIONS AT OPERATING NUCLEAR POWER PLANTS
- IMPLEMENTATION OF SPECIAL SAFETY INSPECTIONS IN RESPONSE TO OPERATIONAL EVENTS
- ADMINISTRATION OF REACTOR OPERATOR LICENSE EXAMINATIONS
- CONDUCTING HEALTH PHYSICS, RADIOLOGICAL EFFLUENT AND CHEMISTRY CONTROL INSPECTIONS
- CONDUCTING PHYSICAL SECURITY AND EMERGENCY PLANNING LICENSING & INSPECTIONS

SPECIAL TEAM INSPECTIONS

- SAFETY SYSTEM FUNCTIONAL INSPECTION
- OPERATIONAL SAFETY TEAM INSPECTION
- MAINTENANCE TEAM INSPECTION
- REGULATORY EFFECTIVENESS REVIEW
- QUALITY VERIFICATION FUNCTIONAL INSPECTION
- SAFETY SYSTEM OUTAGE MODIFICATION INSPECTION
- EQUIPMENT QUALIFICATION
- FIRE PROTECTION
- PROBABILISTIC RISK ASSESSMENT
- EMERGENCY OPERATING PROCEDURES
- AUGMENTED INSPECTION TEAM
- ELECTRICAL DISTRIBUTION SYSTEMS FUNCTIONAL INSPECTION

DIVISION OF NUCLEAR MATERIALS SAFETY

R. Scarano, Director
L. Howell, Acting Deputy Director
Vacant, Technical Assistant
J. Hornor, SAO(WCFO)

Vacant, Div. Sec'y
Nancy Hodges, Branch Sec'y
Wanda Warren, Branch Sec'y

NUCLEAR MATERIALS LICENSING BRANCH

C. Cain, Acting Chief
Vivian Campbell
Jack Whitten
Jackie Cook
Lou Carson
Vince Everett
Tony Gaines
Christie Hernandez
Billie Gruszynski

NUCLEAR MATERIALS INSPECTION AND FUEL CYCLE/DECOMMISSIONING BRANCH

D. B. Spitzberg, Acting Chief
Bob Brown
Mark Shaffer
Jeffrey Cruz
Bob Evans
Richard Leonardi
Bill Radcliffe
Linda McLean

MATERIALS BRANCH (WCFO)*

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Dave Skov
Beth Prange
Jim Montgomery
Joan Garcia
Emilio Garcia
Kent Prendergast
Chuck Hooker
Dean Chaney

Judy Gartner, Sec'y

06/20/87

MAJOR FUNCTIONAL

RESPONSIBILITIES OF DNMS:

- MATERIAL LICENSEES
  - INSPECTIONS
  - LICENSING

- FUEL FACILITIES
  OVERSEE INSPECTIONS IN ALL AREAS
  - OPERATIONS/CRITICALITY CONTROL
  - SECURITY
  - EMERGENCY PREPAREDNESS
  - RADIATION PROTECTION

- URANIUM RECOVERY FACILITIES INSPECTION

- DECOMMISSIONING OF ALL FACILITIES
  INCLUDING POWER REACTORS

- AGREEMENT STATE PROGRAM

DIVISION OF RESOURCE MANAGEMENT
AND ADMINISTRATION

K. Hamill, Director

Carol Hill, Sec'y

PERSONNEL STAFF

K. League, RPO
Joseph L. Lopez
Connie A.Lano

RESOURCE MANAGEMENT
BRANCH

P. Krayer, Chief
Yvonne S. Elko
Wanda L. Forns
Nancy Holbrook
Dean Papa
Michael Phillips
Susan Pierard
Sandy Lindsay
Stacey Rosenberg
Jody Talbot
Arnold Wieder

<u>Contractors</u>
Jamye Prince
Lanell Allen
James Buchanan

ADMINISTRATIVE
MANAGEMENT BRANCH

L. Ousley, Chief
Debby Bacon
Caro Bartley
Robert Carpenter
Glenn A.Ewald
Kathy Gardin
Judy Kilcrease
Phil Longdo

06/20/97

MAJOR FUNCTIONAL RESPONSIBILITIES OF DRMA:

- **MANAGING THE REGION'S RESOURCES:**
  - DEVELOPING AND EXECUTING THE BUDGET
  - COORDINATING LICENSE FEE INFORMATION
  - MANAGING REGIONAL TRAVEL
  - MANAGING ACCOUNTABLE PROPERTY
  - MANAGING PROCUREMENT AND CONTRACTING
  - MANAGING FINANCIAL ACCOUNTING
- **HUMAN RESOURCE MANAGEMENT**
  - RECRUITMENT AND STAFFING
  - EMPLOYEE BENEFITS AND DEVELOPMENT
  - LABOR RELATIONS
- **MANAGING INFORMATION TECHNOLOGY**
  - NETWORK ADMINISTRATION AND SECURITY
  - USER ASSISTANCE, "HELP DESK"
  - UPGRADES AND EQUIPMENT REFRESH
  - COORDINATING COMMUNICATIONS INCLUDING VOICE, DATA AND VIDEO CONFERENCING
  - MANAGING THE MAIL, FILE AND LIBRARY SERVICES

ACTIVITIES FOR MAINTAINING UNIFORMITY AMONG THE REGIONS
AGENCY WIDE-ACTIVITIES

IMPROVED AGENCY TRAINING PROGRAMS

- FUNDAMENTALS OF INSPECTION AND CONTINUING REFRESHER
- RISK ASSESSMENT TRAINING FOR INSPECTORS AND SUPERVISORS

PROGRAM OFFICE GUIDANCE

- INSPECTION PROGRAM GUIDANCE
- INSPECTION PROCEDURES & TEMPORARY INSTRUCTIONS
- TASK INTERFACE AGREEMENTS
- PLANT PERFORMANCE REVIEWS
- RECENT IMPROVEMENTS TO THE SMM PROCESS

PROGRAM OFFICE COORDINATION & OVERSIGHT

- SPECIFIC INSPECTION PROGRAM MANAGERS
- AUDITS/ASSESSMENTS OF REGIONAL OPERATIONS
- PERIODIC COUNTERPART MEETINGS
- SALP OBSERVATION PROGRAM / FEEDBACK

ENFORCEMENT COORDINATION AND OVERSIGHT

- ENFORCEMENT MANUAL
- REGIONAL ENFORCEMENT STAFF
- ENFORCEMENT PANELS FOR SIGNIFICANT FINDINGS
- OE AUDITS OF NON-ESCALATED ENFORCEMENT
- INCREASED OE OVERSIGHT AND INVOLVEMENT IN NON-ESCALATED CASES

ACTIVITIES FOR MAINTAINING UNIFORMITY AMONG REGIONS

REGION IV SPECIFIC ACTIVITIES

ROUTINE ACTIVITIES

- DAILY MORNING MEETING
- BRANCH CHIEF MONITORING OF ACTIVITIES IN PROGRESS
- INSPECTOR DEBRIEFS WITH REGIONAL MANAGEMENT
- REGIONAL ENFORCEMENT STAFF INTERACTIONS

MANAGEMENT INVOLVEMENT IN INSPECTION EXITS

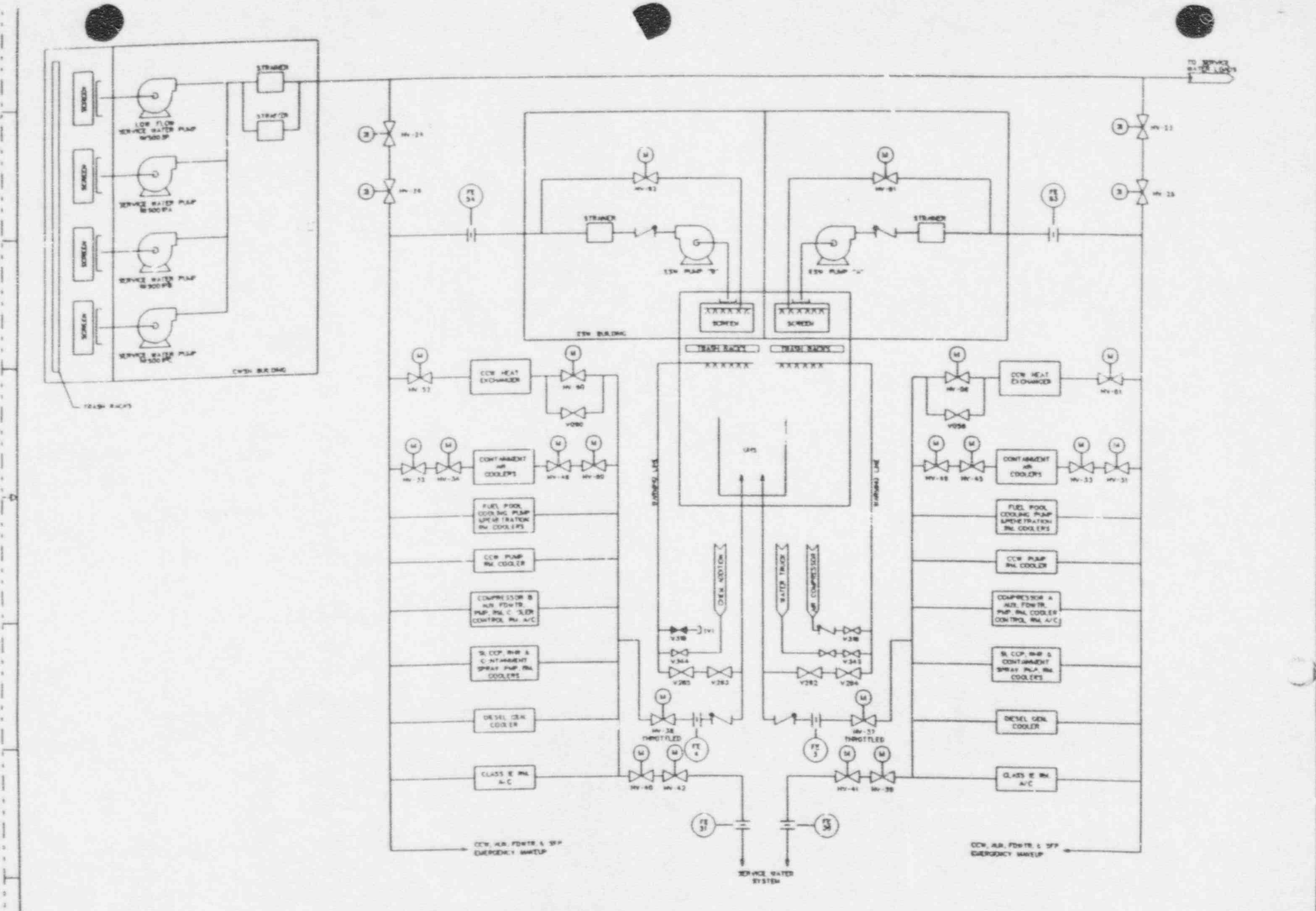
- BRANCH CHIEF OVERSIGHT OF RESIDENT INSPECTOR EXIT MEETINGS
- DRS MANAGEMENT INVOLVEMENT IN REGION AND HEADQUARTERS-BASED INSPECTION
- EXITS INVOLVING SIGNIFICANT ISSUES/EVENTS

MANAGEMENT INVOLVEMENT IN INSPECTION REPORT PREPARATION

- PERIODIC AUDITS BY REGIONAL ENFORCEMENT STAFF
- PERIODIC COUNTERPART MEETINGS / TRAINING FOR STAFF
- PERIODIC FEEDBACK FROM INDUSTRY
- REGULATORY USER GROUPS

ATTACHMENT 4

SIMPLIFIED FLOW DIAGRAM OF THE ESSENTIAL SERVICE WATER SYSTEM



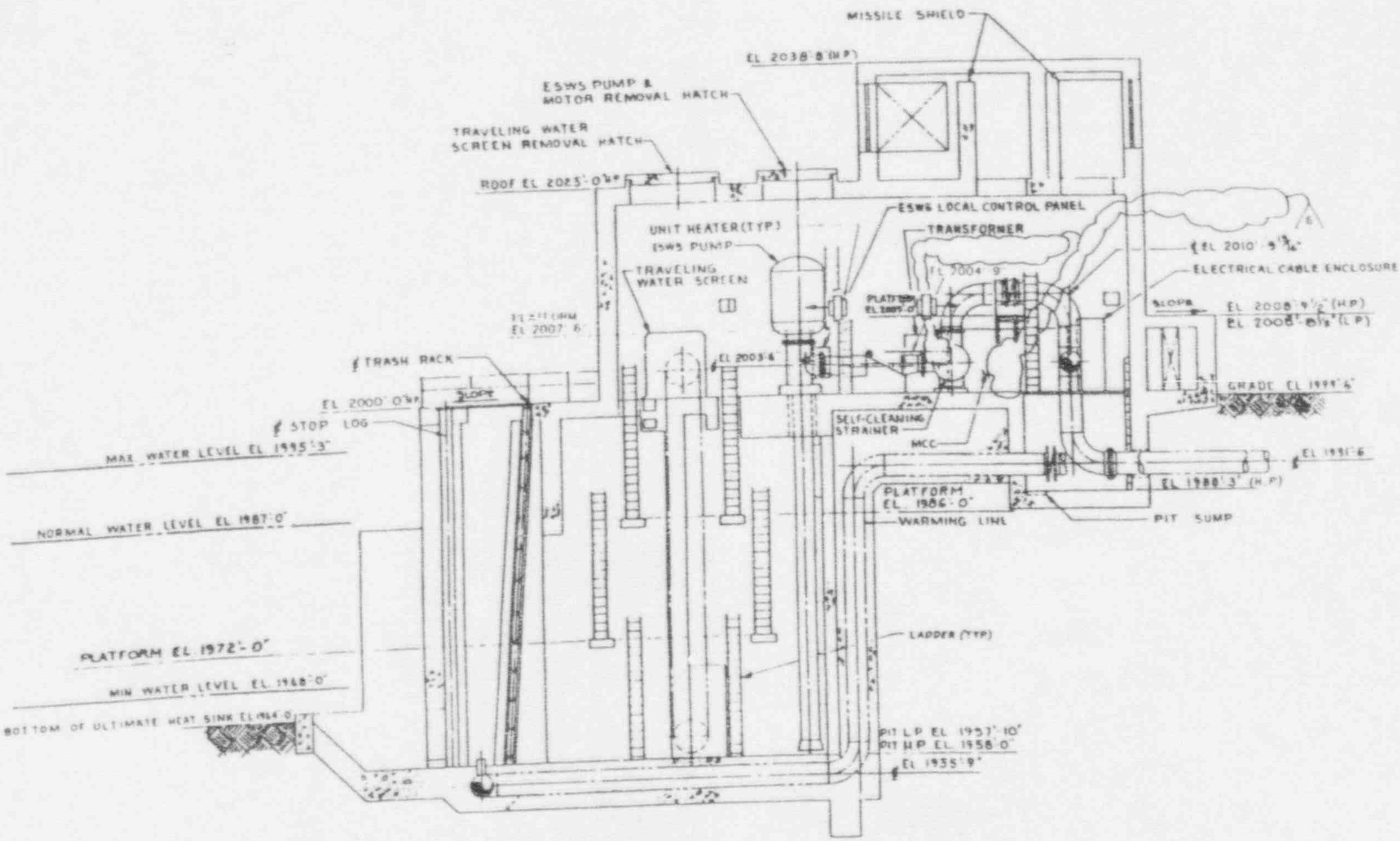
ESSENTIAL SERVICE WATER & SERVICE WATER SYSTEM INTERFACE

WOLF CREEK

REV. 1

ATTACHMENT 5

DIAGRAM OF THE ESSENTIAL SERVICE WATER PUMPHOUSE

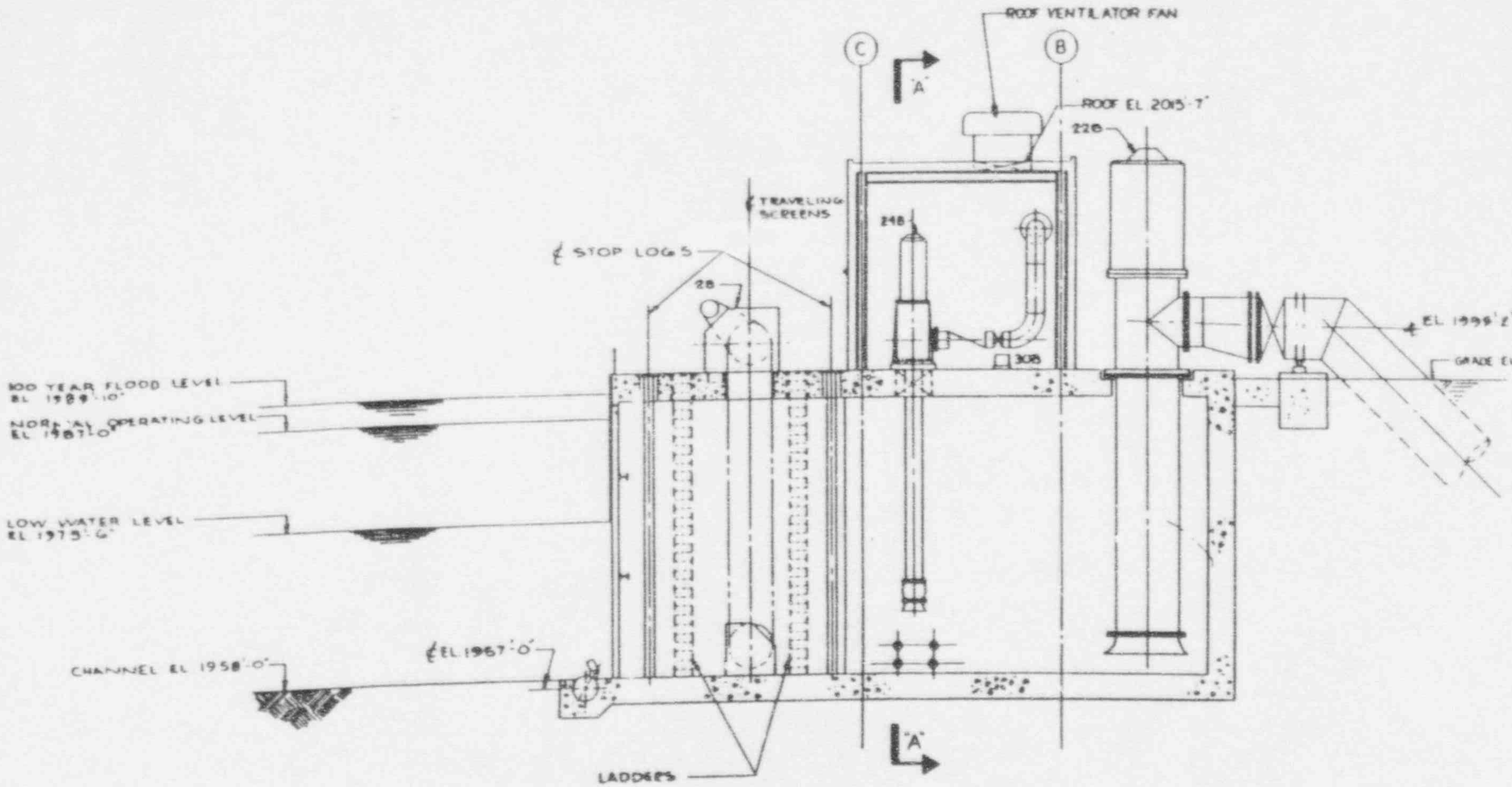


SECTION A (M-K6081)

SEE DWG. M-K6080

ATTACHMENT 6

DIAGRAM OF THE CIRCULATING AND SERVICE WATER PUMPHOUSE


ROOF VENTILATOR FAN
C
B
A
ROOF EL 2015'-7"
228
℄ TRAVELING SCREENS
248
℄ STOP LOGS
28
308
℄ EL 1999'-2"
100 YEAR FLOOD LEVEL
NORMAL OPERATING LEVEL
LOW WATER LEVEL
CHANNEL EL 1958'-0"
℄ EL 1967'-0"
LADDERS

SECTION "B-B"

Appendix D

IIT 96-002

Photographs and Thermography Results

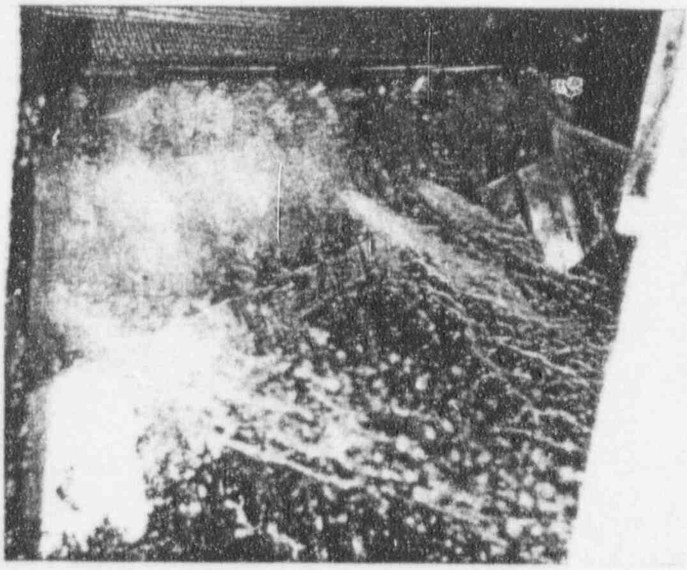


Photo of Screen Wash at the Circulating Water Screens during the icing event.

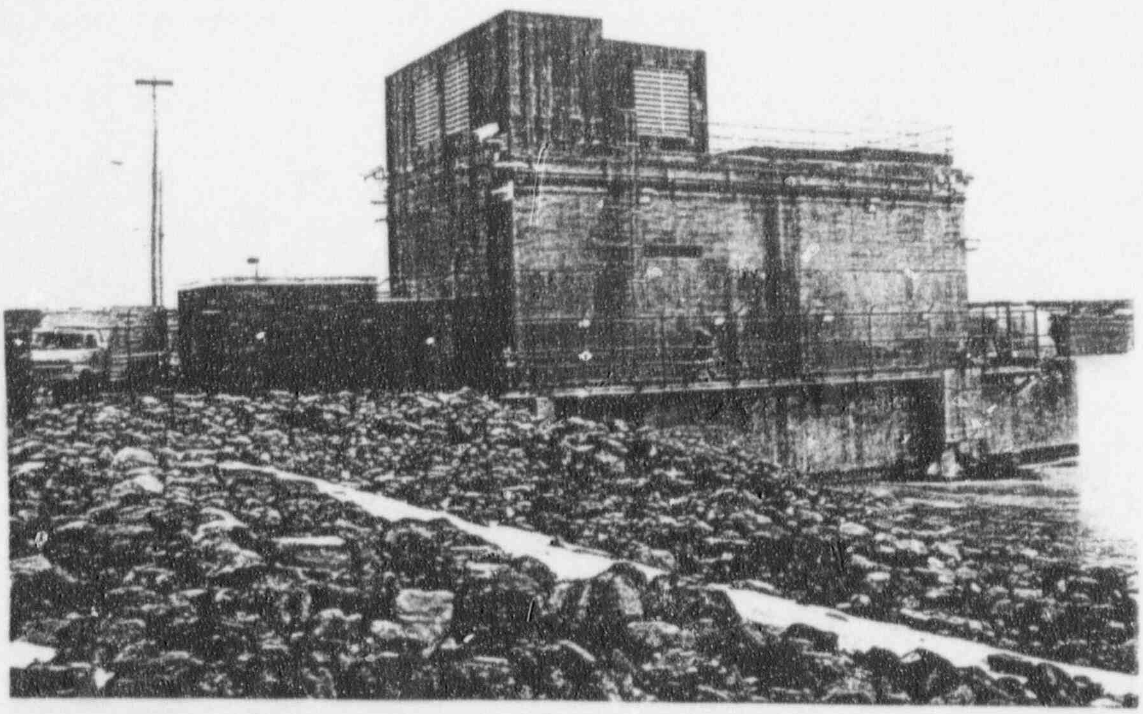
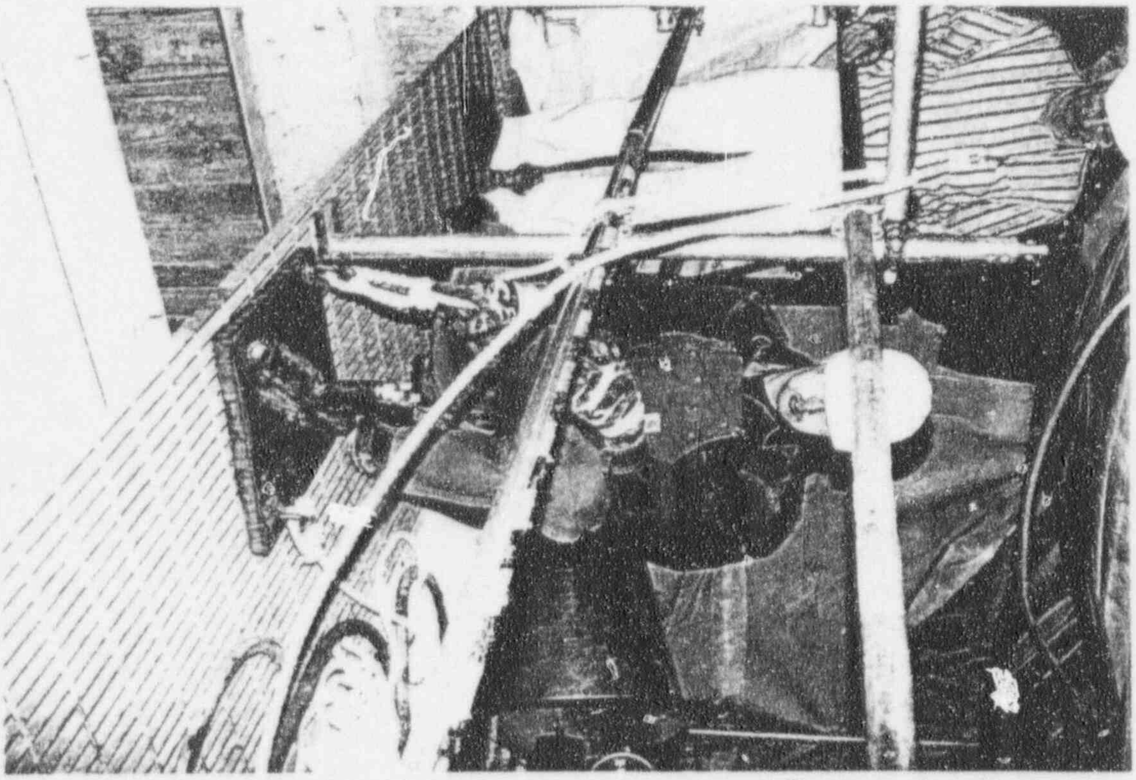
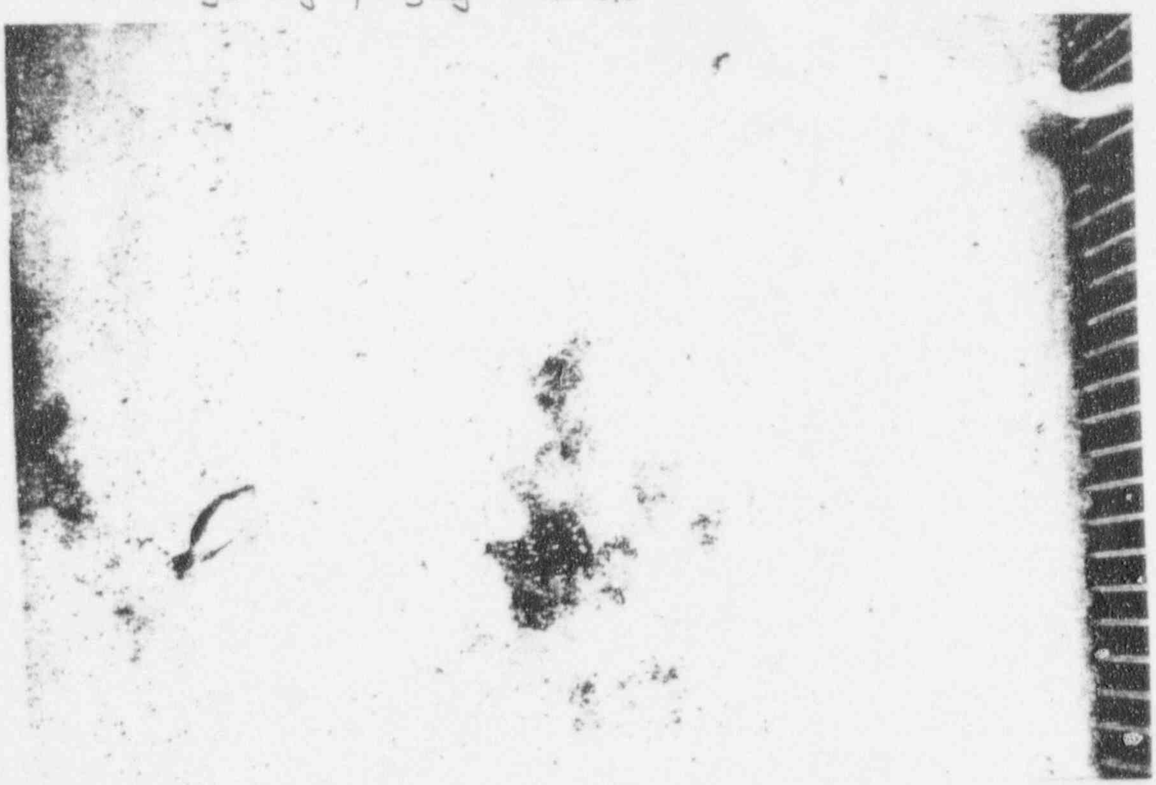


Photo of the Essential Service Water Building

Appendix D
IIT 96-002
Photographs and Thermography Results

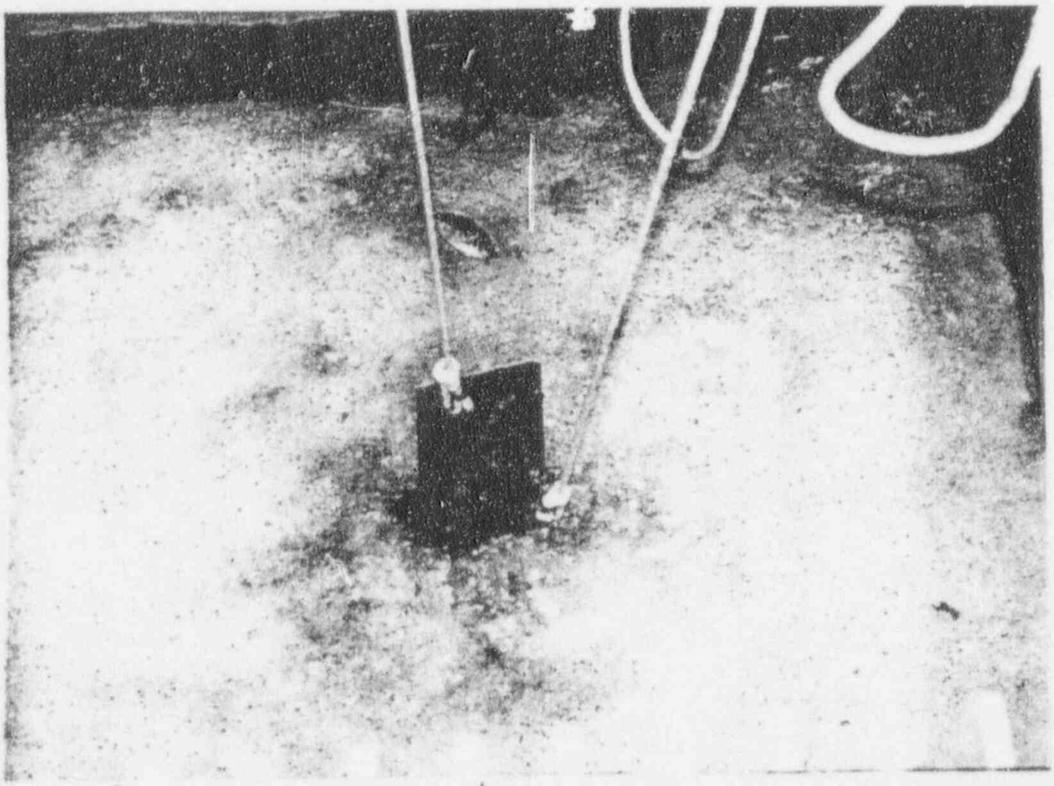


Inside the tent, over the B ESW Bay prior to ~~lowstagering~~ lowering sparging manifold

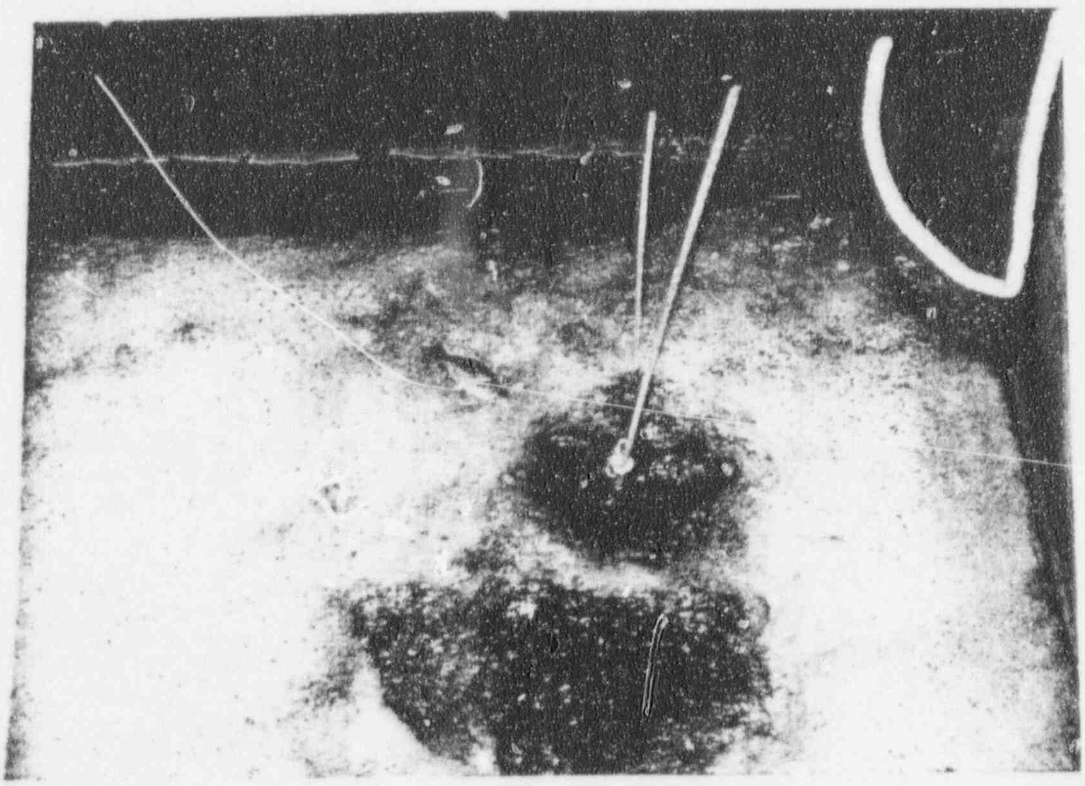


Surface of B ESW Bay outside of trash racks

Appendix D
IIT 96-002
Photographs and Thermography Results

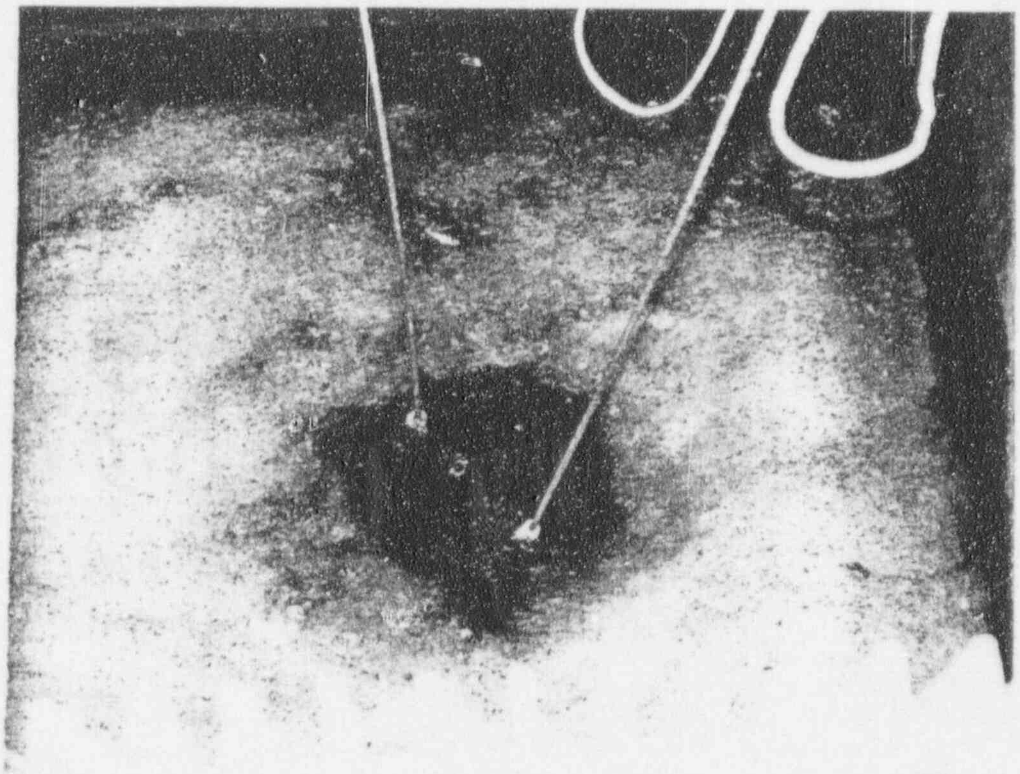


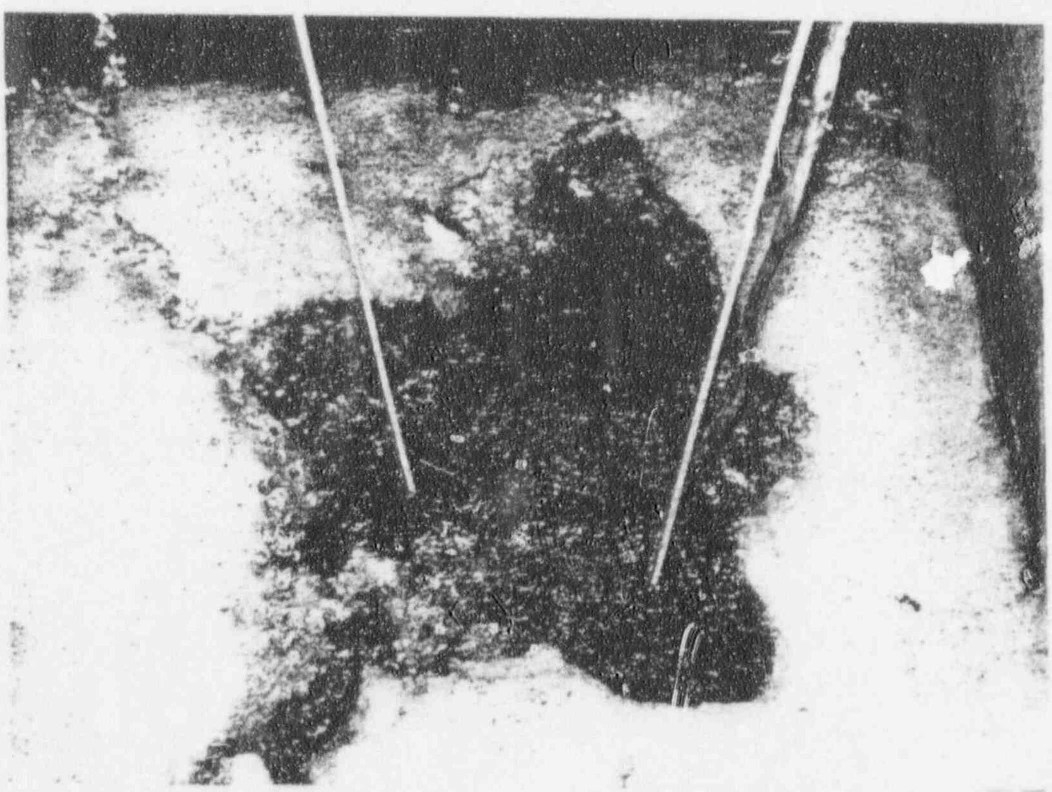
Using sparging manifold to push through surface ice in B ESW Bay



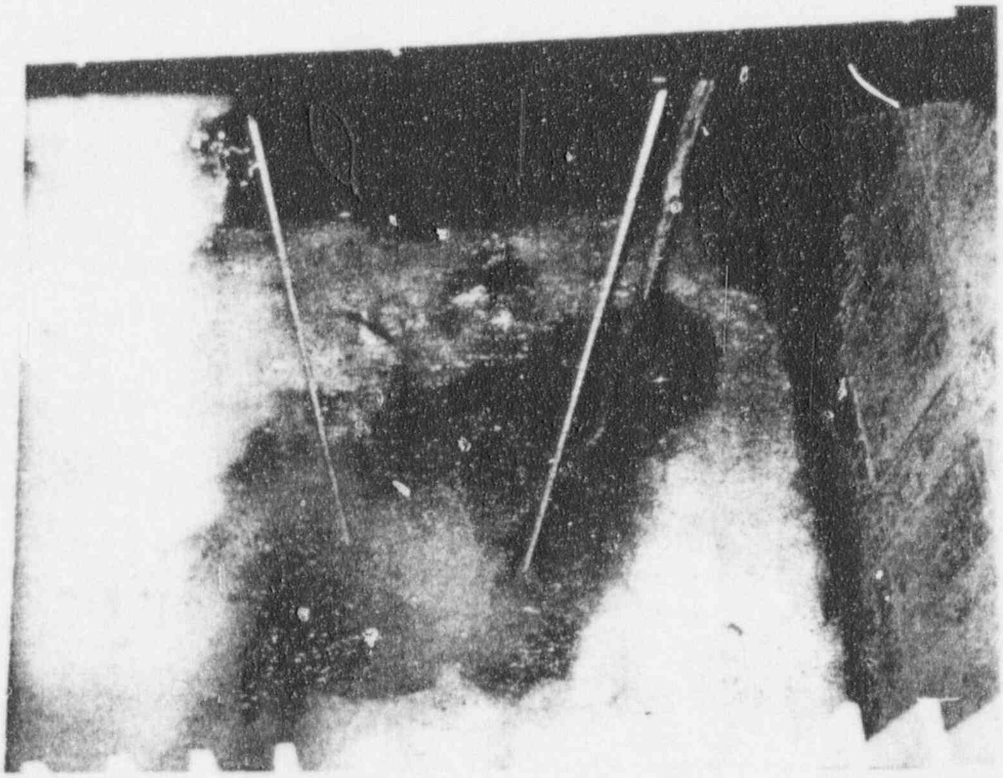
More of the Same

Appendix D
IIT 96-002
Photographs and Thermography Results

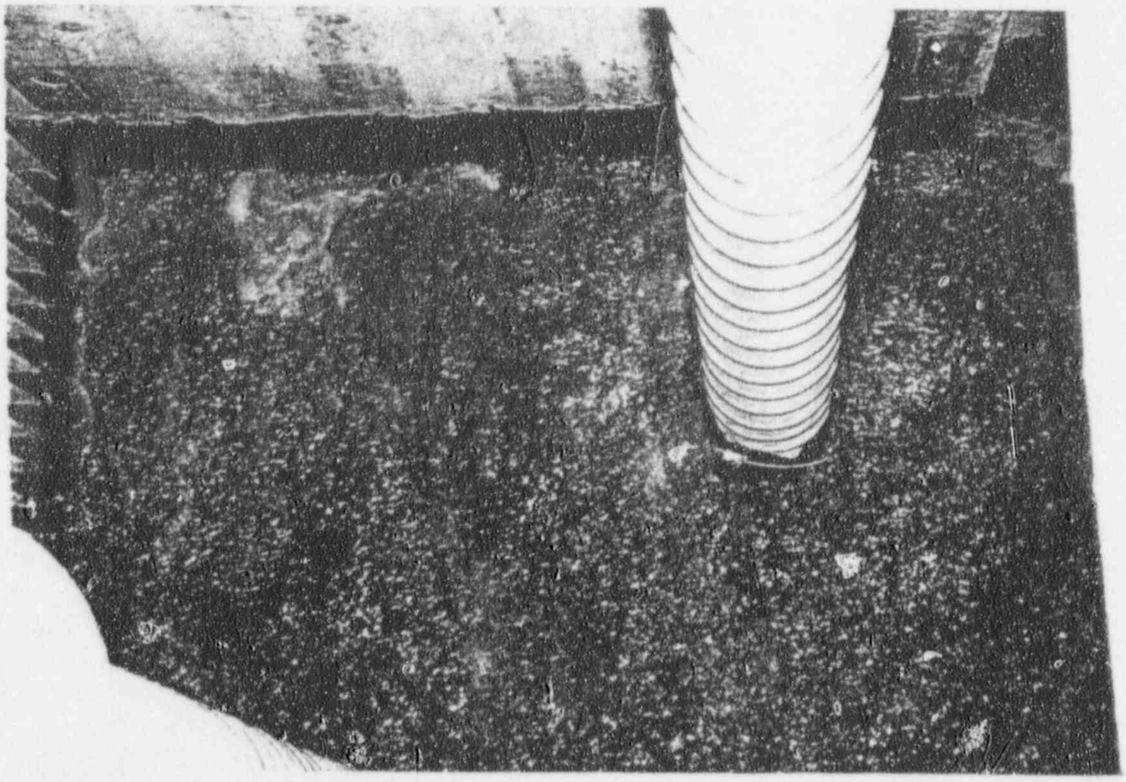




Initiation of Sparging in B Bay



Initiation of adding hot water to surface of B Bay.



A ESW Bay after it was cleared

Appendix E
Root Causal Factor Charts and Supporting Information

Barrier Analysis of Inappropriate Actions

Inappropriate Action	Barriers	Effectiveness
Bechtel letter instructed individual performing evaluation to assume that the service water will enter the ESW screenhouse through the warming line at 35F (1976).	Bechtel controls for verification of design assumptions.	Not effective. Assumption not verified and proved to be incorrect. Heat loads where inadequate to raise ESW "A" warming line temperature to 35F during normal plant operation. Actual warming line temperature was estimated to be 33F.
Maintenance removed packing gland follower on TDAFP. When reinstalled it was not in contact with packing ring.	This event being evaluated by PIR 96-0269)	
Bechtel calculation determines actual flow through ESW warming line will be 4413 gpm with valves EFHV-39, 40, 41, 42 closed and EFHV-38, 38 open. Calculation assumed line would be full.	Bechtel controls for verification of design assumptions. Also design models for determining flow rates.	Not effective. Assumption not verified and proved to be incorrect (line only runs approximately half full).
Procedure revision to STN GP-001 to keep traveling screens in manual sloww in cold weather to prevent surface ice from damaging screens.	Consideration of the impact a procedure revision will have on the plant design.	Not effective due to the lack of administrative controls to provide for an engineering review of operational changes that could impact design.

Appendix E
Root Causal Factor Charts and Supporting Information

Inappropriate Action	Barriers	Effectiveness
Operators opened ESW return to SW iso valves EFHV-39, -40, -41, -42. Operators closed (throttled) ESW to UHS iso valves EFHV-37, -38.	SYS EF-200 instructs operator as to correct line-up.	Not effective due to procedure not being used. Procedure not used due to imminent loss of service water.
ESW system operating procedure not verified in a timely manner.	Expectations that procedures be verified in a timely manner.	Expectations barrier not adequate. A more formal administrative barrier may be appropriate.
In transition from E-0 to ES-2, copy of ES-2 was not in the control room.	This event is being evaluated by PIR 96-0278.	
GEN 00-005 Att. A continues to be worked before beginning GEN 00-006.	No administrative barriers identified.	
ERO response recording said there was no emergency when call was made.	Causes and corrective actions for this issue are being evaluated by PIR 96-0260.	
Security did not make building announcement until 30 - 40 minutes after pagers activated.	Causes and corrective actions for this issue are being evaluated by PIR 96-0261.	

FORT CALHOUN STATION

EXTRACTION STEAM LINE RUPTURE EVENT

(April 21, 1997)

NRC SPECIAL INSPECTION REPORT NO. 50-285/97-09
NRC INFORMATION NOTICE NO 97-XX

FORT CALHOUN
RUPTURE IN EXTRACTION STEAM LINE
APRIL 21, 1997

PROBLEM

RUPTURE IN EXTRACTION STEAM LINE.

CAUSE

EXCESSIVE PIPE WALL THINNING ATTRIBUTED TO FLOW-ACCELERATED CORROSION (EROSION/CORROSION).

SAFETY SIGNIFICANCE

RUPTURE OF PIPING LED TO UNNECESSARY PLANT TRANSIENT AND PERSONNEL HAZARD. POSSIBLE GENERIC IMPLICATIONS ASSOCIATED WITH PREDICTIVE METHODOLOGY (CHECWORKS).

DESCRIPTION OF EVENT

- ON APRIL 21, 1997, WHILE OPERATING AT 100 PERCENT POWER, CONTROL ROOM OPERATORS HEARD A LOUD NOISE IN THE TURBINE BUILDING, FOLLOWED BY A VERY LOUD CONTINUOUS NOISE.

- THE OPERATORS CHECKED THE REACTOR INSTRUMENTATION AND NOTED NO ABNORMALITIES; THERE WERE NO CHANGES IN REACTOR COLD-LEG TEMPERATURE, STEAM GENERATOR PRESSURE, OR REACTOR POWER.

- THE SHIFT SUPERVISOR OPENED THE CONTROL ROOM DOOR TO INVESTIGATE AND NOTED A LARGE AMOUNT OF STEAM FLOWING FROM THE GRATING IN THE TURBINE BUILDING. THE REACTOR WAS MANUALLY TRIPPED WITHIN 19 SECONDS OF THE EVENT.

- THE OPERATOR REALIZING THAT THE PLANT MAY HAVE BEEN EXPERIENCING AN UNCONTROLLED HEAT EXTRACTION EVENT ENTERED THE PLANT EMERGENCY OPERATING PROCEDURES AND INITIATED EMERGENCY BORATION AS A PRECAUTIONARY MEASURE.

- DURING THE EVENT, THE FIRE SUPPRESSION SYSTEMS ACTUATED AND THERE WERE INTERMITTENT ELECTRICAL SYSTEM GROUNDS.

- APPROXIMATELY 40 MINUTES INTO THE EVENT, THE OPERATORS ISOLATED THE FIRE PROTECTION SYSTEM.

- APPROXIMATELY 52 MINUTES INTO THE EVENT, SHUTDOWN MARGIN WAS VERIFIED AND EMERGENCY BORATION WAS SECURED. NO SAFETY SYSTEMS WERE AUTOMATICALLY ACTUATED.

<u>DISCUSSION</u>

- FT. CALHOUN EXPERIENCED A RUPTURE IN THE 12-INCH LINE THAT CONNECTS THE FOURTH STAGE OF THE HIGH PRESSURE TURBINE TO THE FEEDWATER HEATERS. THE LINE IS FILLED WITH 92 PERCENT QUALITY STEAM AT 250 PSI AND 400 DEGREES FAHRENHEIT. THE "FISH-MOUTH" RUPTURE OCCURRED AT THE OUTER EDGE OF A 5 FOOT RADIUS BEND AND WAS APPROXIMATELY 54 INCHES LONG AND 18 INCHES WIDE.

- THE RUPTURE LOCATION WAS NOT INCLUDED IN SITES INSPECTED BY THE LICENSEE'S EROSION/CORROSION MONITORING PROGRAM. THE LICENSEE USES THE "CHECWORKS" COMPUTER CODE AS A TOOL TO AID IN THE IDENTIFICATION OF SITES TO BE INSPECTED. THE CHECWORKS METHODOLOGY DID NOT PREDICT THE WEAR RATES WHICH WERE EXPERIENCED IN THE SYSTEM. INDUSTRY-WIDE AND PLANT-SPECIFIC OPERATING EXPERIENCE WAS NOT INCORPORATED INTO THE EROSION/CORROSION PROGRAM (6 PIPE LOCATIONS IN 3 SYSTEMS WERE BELOW MINIMUM ALLOWABLE WALL THICKNESS)

- THE OVERALL OPERATOR RESPONSE TO THE EVENT WAS SUPERIOR. THE OPERATORS ACTED IN A TIMELY, DECISIVE AND CONSERVATIVE MANNER.

- THERE WAS EXTENSIVE DAMAGE IN THE VICINITY OF THE RUPTURE. THE BACK PANEL OF ONE NON-SAFETY MOTOR CONTROL CENTER (MCC) WAS DAMAGED DUE TO STEAM IMPINGEMENT. INSULATION, CONTAINING ASBESTOS, WAS BLOWN THROUGHOUT THE TURBINE BUILDING. NO PERSONNEL WERE IN THE VICINITY AT THE TIME OF THE RUPTURE.

- INTERMITTENT ELECTRICAL GROUNDS WERE OBSERVED ON TWO SAFETY-RELATED BUSES. THESE GROUNDS WERE ATTRIBUTED TO GROUNDS ON TURBINE BUILDING MCCs WHICH ARE SUPPLIED BY THESE BUSES. THESE BUSES ARE CONNECTED VIA CRITICAL QUALITY EQUIPMENT BREAKERS DESIGNED TO ISOLATE THE SAFETY BUSES IN THE EVENT OF GROUND FAULTS. (FT. CALHOUN OPERATES AN UNGROUNDED ELECTRICAL SYSTEM).

FOLLOWUP

- THE NRC DISPATCHED A SPECIAL INSPECTION TEAM ON APRIL 23, 1997, TO INVESTIGATE THE CAUSES AND CIRCUMSTANCES SURROUNDING THE EVENT. A SPECIAL PUBLIC MEETING WAS CONDUCTED ON MAY 2, 1997, PRIOR TO RESTART.

- THE LICENSEE CONDUCTED EXTENSIVE WALKDOWN INSPECTIONS TO IDENTIFY AND ASSESS POTENTIAL DAMAGE TO PLANT EQUIPMENT.

- THE LICENSEE IMPLEMENTED MEASURES TO INCORPORATE INDUSTRY-WIDE OPERATING EXPERIENCE INTO THE EROSION/CORROSION PROGRAM.

- THE LICENSEE CONDUCTED EXTENSIVE FOLLOWUP ULTRASONIC TESTING OF OTHER LARGE RADIUS ELBOWS.

- THE NRC IS CONSIDERING THE NEED FOR AN INFORMATION NOTICE DISCUSSING THE ISSUES ASSOCIATED WITH CHECWORKS MODELLING PREDICTIONS.

ROOT AND CONTRIBUTING CAUSES

Preliminary Results - Failure Mechanism

- Flow Accelerated Corrosion (FAC)

Root Cause for the Failure to Identify Significant Degradation

- Over-reliance on elbow radius as a predictor of relative wear rate, with insufficient consideration of plant history and industry operating experience.

Contributing Causes

- Failure to include the "sweep" elbows in the inspection program
- Lack of a proceduralized methodology for selecting inspection sites
- Incomplete usage of plant history data
- Incomplete usage of industry operating experience and resources
- Lack of specific guidance on analytical model usage and maintenance
- Lack of adequate management/supervisory oversight

EVENT FOLLOWUP ACTIVITIES

NRC ACTIVITIES

Special Inspection (4/23/97-6/10/97)
Inspection Report (6/17/97)
Public Meeting (5/6/97)
Public Enforcement Conference (6/21/97)
Events Briefing (5/27/97)
Maintenance Rule Workshop Briefing (6/3/97)
Resident Inspector Counterpart Briefing (6/18/97)
ACRS Briefing (7/18/97)
Information Notice (Proposed)
Inspection Followup Activities (TBD)

LICENSEE ACTIVITIES

Self Assessment Team
Industry Notification
Users Group Presentations
Followup Activities

EROSION/CORROSION CONTROL PROGRAMS

Regulatory "Requirements"

Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning"

Information Bulletin 87-17, "Thinning of Pipe Walls in Nuclear Power Plants"

10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants"

Industry Operating Experience and References

INFORMATION NOTICES:

82-22,	"FAILURES IN TURBINE EXHAUST LINES"
86-106,	"FEEDWATER LINE BREAK"
87-36,	"SIGNIFICANT UNEXPECTED EROSION OF FEEDWATER LINES"
88-17,	"SUMMARY OF RESPONSES TO NRC BULLETIN 87-01"
89-53,	"RUPTURE OF EXTRACTION STEAM LINE ON HIGH PRESSURE TURBINE"
91-18,	"HIGH ENERGY PIPE FAILURES CAUSED BY WALL THINNING"
97-XX,	"RUPTURE OF EXTRACTION STEAM LINE PIPING"

INPO NOTIFICATIONS:

SOER 82-11,	"Erosion of Steam Piping and Resulting Failure"
SOER 87-3,	"Pipe Failures in High Energy Systems Due to Erosion/Corrosion
SER 6-95,	"Condensate Pipe Break Due to Flow-Accelerated Corrosion"
SER 1-87,	"Erosion/Corrosion Induced Failure of Feedwater Piping"
SER 88-84,	"Extraction Steam Line Break"

NRC Inspection Reports:

50-280/86-42
50-281/86-42
50-285/97-09

Industry Standards

NSAC-202/L, "Recommendations for an Effective Flow-Accelerated Corrosion Program", (Proprietary)

CHECWORKS (Proprietary)

STAFF TRAINING and DEVELOPMENT

NRC REACTOR TRAINING AND QUALIFICATION GUIDANCE

- NRC INSPECTION MANUAL 1245 (INSPECTOR)
- HOLB - MC-0170 (LICENSING EXAMINER)
- RESIDENT AND SENIOR REACTOR ANALYST PROGRAMS

TRAINING COMMITTEE OVERSIGHT

- DIVISION DIRECTOR LEVEL PARTICIPATION
- TRAINING PRIORITIES ESTABLISHED

TRAINING PLANS MANDATED FOR ALL EMPLOYEES

- QUALIFICATION , DEVELOPMENTAL AND REFRESHER TRAINING
- REVIEWED WITH EMPLOYEE APPRAISALS
- SUPERVISORY AND MANAGEMENT TRAINING

INSPECTOR/EXAMINER QUALIFICATION PROCESS

- SUPPLEMENTAL REQUIREMENTS BY REGION IV
- QUALIFICATION BOARD
- INTERIM / FINAL CERTIFICATION
- EXAMINER CROSS QUALIFICATION

FUNDAMENTALS OF INSPECTION REFRESHER TRAINING DURING COUNTER PARTS MEETING AND TRAINING WEEKS

REGION IV INTERFACE WITH INPO

- NRC/INPO MEMORANDUM OF UNDERSTANDING

- NO DIRECT REGION IV INTERACTIONS

- INDIRECT REGION IV INTERACTIONS

- OBSERVATION OF NATIONAL ACADEMY FOR NUCLEAR TRAINING - ACCREDITATION BOARD MEETINGS

REGION IV MEETING WITH ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS) SUBCOMMITTEE ON PLANT OPERATIONS AND FIRE PROTECTION

BRIEFING ON

REGION IV SENIOR REACTOR ANALYST PROGRAM

William B. Jones, Senior Reactor Analyst
Division Reactor Safety
NRC Region IV

JULY 18, 1997

DEVELOPMENT OF PRA RESOURCES

- SENIOR REACTOR ANALYST (SRA)
  - 2 SRAs established in Division Reactor Safety
  - Training program and rotational assignments completed
- IPE AND PRA INSIGHTS PROVIDED TO REGION IV STAFF
  - Overview of NUREG 1560 (IPE Program: Perspectives on Reactor Safety and Plant Performance)
  - Specific overviews of several licensee IPEs provided to resident and regional inspectors.
- IMPLEMENTING PRA LIBRARY
  - Developing comprehensive library of licensee PRAs (system notebooks), IPEs and IPEEEs, technical and staff evaluation reports, risk informed pilot programs, and risk background information.

REGULATORY CONSIDERATIONS UTILIZING RISK INFORMATION

- NOTICE OF ENFORCEMENT DISCRETION (NOED)
  - SRAs are responsible for assessing licensee risk informed bases for NOED requests.
- ENFORCEMENT SEVERITY EVALUATIONS
  - Enforcement Guidance Memorandum 97-011 establishes the guidelines for providing risk informed insights into the enforcement process.
  - The SRAs are responsible for reviewing each potentially escalated enforcement action for risk insights and providing a perspective to the regional and Office of Enforcement (OE) enforcement panels.
  - The SRAs are responsible for reviewing risk arguments presented by licensees during pre-decisional enforcement conferences or in their response to apparent violations.

INSPECTION FINDINGS AND EVENT EVALUATIONS

- INSPECTION FINDING SIGNIFICANCE EVALUATIONS

  - The SRAs review, with the regional staff, inspection findings of potential risk significance. Findings which warrant a more detailed analysis are reviewed with Region IV management on a case by case basis.

  - The SRAs have the capability to perform independent risk assessments as needed using the NRC risk assessment tool IRRAS. The accident sequence precursor models used can be modified to provide additional areas for review and discussion with a licensee.

- EVENT EVALUATIONS

  - Attend weekly event assessment meeting chaired by the Events Assessment and Generic Communication Branch of NRR for potentially risk significant issues which may apply to Region IV plants.

  - The SRAs provide short term review of potentially significant events. These findings are provided to NRC management for consideration in any follow up activities.

- MAINTENANCE RULE EQUIPMENT CONFIGURATION EVALUATIONS

  - Equipment reliability and availability can be assessed for system and component performance which are not consistent with the licensee's PSA assumptions. This information would be considered in planning inspection activities.

- OUTAGE RISK REVIEW

  - Licensee outage controls will be reviewed for potentially risk important configurations and controls established (operator actions and/or supplemental equipment) to prevent or mitigate potentially significant events.

INSPECTION PLANNING AND IMPLEMENTATION

- INSPECTION PLANNING AND PRIORITIZATION
  - Provide risk informed assessments of plant performance reviews (PPRs), plant information matrixes (PIMs) and inspection findings for inspection planning and prioritization.
  - Implement inspection program based on licensee risk informed Graded QA (STP), inservice inspection (PV) and inservice testing (CPSES and ANO).
- OPERATOR LICENSING
  - The SRAs will provide the operator licensing examiners with risk important operator actions which would be significant in mitigating an accident or in minimizing the failure of components and systems.

RISKS OF ON-LINE MAINTENANCE

IN REGION IV NUCLEAR POWER PLANTS

DR. DALE A. POWERS

MAINTENANCE BRANCH CHIEF

DIVISION OF REACTOR SAFETY

NRC REGION IV

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS MEETING

ARLINGTON, TEXAS

JULY 18, 1997

REASONS FOR CONDUCTING ON-LINE MAINTENANCE

- APPROPRIATELY BALANCE SSC AVAILABILITY AND RELIABILITY
- OPTIMIZE SSC LIFE BY BALANCING PREVENTIVE VERSUS CORRECTIVE MAINTENANCE
- IN SOME SITUATIONS, THE RISK ASSOCIATED WITH REMOVING AN SSC FROM SERVICE DURING POWER OPERATION MAY BE LOWER THAN DURING AN OUTAGE
- MORE EFFICIENT UTILIZATION OF ON-STAFF RESOURCES, WORK FORCE LEVELING, AND LESS RELIANCE ON CONTRACTORS
- ECONOMIC BENEFITS OF SHORTENED REFUELING AND MAINTENANCE OUTAGES

RISK ASSESSMENT TOOLS FOR ON-LINE MAINTENANCE

Many regulations were developed during times when industry's maintenance philosophy was to conduct long outages involving significant maintenance activities. Now that this philosophy has evolved, plant baseline risk envelopes (without major maintenance) exhibit spikes when SSCs are out of service.

- QUALITATIVE JUDGEMENT

  Widely used prior to the publication of the Maintenance Rule

  Commonly used today on non-risk significant BOP SSCs

- MATRIX OF SSC CONFIGURATIONS

  Convenient, simple reference

  Limited applicability to only dual combinations of SSCs, which are typically only the high-risk significant SSCs addressed by the Technical Specifications

- SPECIFIC CONFIGURATION CALCULATION

  Slow, costly

- COMPUTER-BASED MODEL

  Compares proposed plant configuration and associated risk against average plant configuration previously quantified by the probabilistic safety assessment model

GOOD ATTRIBUTES OF ON-LINE MAINTENANCE RISK ASSESSMENTS

- SHOULD BE PERFORMED FOR ALL MAINTENANCE ACTIVITIES THAT IMPACT SSC RELIABILITY AND AVAILABILITY

  Post-Maintenance Testing

  Surveillance

  Predictive, Corrective, and Preventive Maintenance

- SHOULD ACCOUNT FOR THE TOTAL SSCs OUT OF SERVICE, NOT JUST THE RISK SIGNIFICANT SSCs

- SHOULD BE PERFORMED FOR ALL ON-LINE MAINTENANCE REGARDLESS OF THE MODES OF OPERATION

- SHOULD BE PERFORMED FOR EMERGENT WORK THAT WILL RESULT IN CONFIGURATION CHANGES

NRC EXPECTATION FOR THE PERFORMANCE OF ON-LINE MAINTENANCE

SAFETY ASSESSMENTS

10 CFR 50.65

MAINTENANCE RULE

PARAGRAPH A(3)

"IN PERFORMING MONITORING AND PREVENTIVE MAINTENANCE ACTIVITIES, AN ASSESSMENT OF THE TOTAL PLANT EQUIPMENT THAT IS OUT OF SERVICE SHOULD BE TAKEN INTO ACCOUNT TO DETERMINE THE OVERALL EFFECT ON PERFORMANCE OF SAFETY FUNCTIONS."

A change from "should" to "shall" is under consideration in response to the April 11, 1997, Staff Requirements Memorandum

GUIDANCE FOR ASSESSING ON-LINE MAINTENANCE RISK

- "MANAGING MAINTENANCE DURING POWER OPERATIONS," INPO, FEBRUARY 17, 1995

- "INDUSTRY GUIDELINES FOR MONITORING THE EFFECTIVENESS OF MAINTENANCE AT NUCLEAR POWER PLANTS," REV. 2, NUMARC 93-01, APRIL 1996

  Endorsed by Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Rev. 2

PROGRAMMATIC INSPECTIONS OF ON-LINE MAINTENANCE

- TEMPORARY INSTRUCTION 2515/126, "EVALUATION OF ON-LINE MAINTENANCE," OCTOBER 27, 1994

  Performed by resident inspectors

- INSPECTION PROCEDURE 62706, "MAINTENANCE RULE," AUGUST 31, 1995

  Being performed by region-based teams that include PRA experts

BASELINE INSPECTION EXPERIENCE WITH ON-LINE MAINTENANCE RISKS

LICENSEE PROGRAMS WITH FAILURES TO PERFORM RISK ASSESSMENTS

COOPER NUCLEAR STATION

- RISK TOOL - MATRIX
- OPERATOR KNOWLEDGE OF REQUIREMENT FOR EVALUATING THE IMPACT OF CHANGES IN PLANT STATUS UPON RISK WAS POOR
- AN INAPPROPRIATE USE OF A STANDARD PERFORMANCE CRITERION FOR RELIABILITY HAD AN ADVERSE EFFECT ON THE RISK RANKING FOR SSC SAFETY SIGNIFICANCE [Violation of a(2)]
- ONE EXAMPLE OF ENTRY INTO A PREDETERMINED RISK-SIGNIFICANT WINDOW WITHOUT FIRST PERFORMING A PREREQUISITE CHECKLIST [Violation of Criterion V]
- UNAVAILABILITY WAS NOT MONITORED FOR RISK SIGNIFICANT SSCs (AUTOMATIC DEPRESSURIZATION, EMERGENCY DIESEL GENERATOR, HIGH PRESSURE INJECTION, AND RESIDUAL HEAT REMOVAL) [Violation a(2)]
- SEVERAL FAILURES TO PERFORM RISK ASSESSMENTS FOR SAFETY-RELATED EMERGENT WORK (NO HIGH-RISK SIGNIFICANT EXAMPLES) [Violation of Criterion V]
- RISK ASSESSMENT PROCESS HAD SIGNIFICANT PROCEDURAL WEAKNESSES: IT DID NOT ADDRESS ACTIONS WHEN SSC FAILURE OCCURRED WHILE IN A RISK-SIGNIFICANT WINDOW, IT DID NOT ADDRESS ASSESSING RISK WHEN REMOVING SSCs OF LOW-RISK SIGNIFICANCE, AND IT WAS UNCLEAR ON RESPONSIBILITY FOR PERFORMING RISK ASSESSMENT FOR EMERGENT WORK

LICENSEE PROGRAMS WITH FAILURES TO PERFORM RISK ASSESSMENTS

DIABLO CANYON (DRAFT)

- RISK TOOL - MATRIX
- MATRIX DID NOT ACCOUNT FOR RISK-SIGNIFICANT SSCs (AUXILIARY BUILDING AND SWITCHGEAR VENTILATION)
- ONE FAILURE TO PERFORM A RISK ASSESSMENT PRIOR TO REMOVING FROM SERVICE A HIGH-RISK SIGNIFICANT SSC (AUXILIARY SALT WATER) [Violation Criterion V]
- THE RISK ASSESSMENT PROCESS WAS ADEQUATE.

LICENSEE PROGRAMS WITH FAILURES TO PERFORM RISK ASSESSMENTS

GRAND GULF

- RISK TOOL - EOOS SOFTWARE FOR QUANTITATIVE EVALUATIONS
- OPERATORS LACKED SENSITIVITY TO THE NEED FOR MONITORING AND TRACKING SSC UNAVAILABILITIES AND CHANGING RISK CONFIGURATIONS
- AVAILABILITY WAS NOT MONITORED FOR RISK SIGNIFICANT SSCs (INSTRUMENT AIR [Violation a(1)], NUCLEAR BOILER INSTRUMENTATION AND CONTROL ROD DRIVE [NCVs])
- SSC PERFORMANCE CRITERIA WERE NOT ESTABLISHED COMMENSURATE WITH THE RISK ASSESSMENT [NCVs]
- THE SSC RISK RANKING METHODOLOGY WAS LACKING IN THAT IT DID NOT ASSESS UNAVAILABILITY AND RELIABILITY ASSUMPTIONS
- ONE FAILURE TO PERFORM A RISK ASSESSMENT PRIOR TO REMOVING AN EMERGENCY DIESEL GENERATOR FROM SERVICE FOR PREVENTIVE MAINTENANCE
- THE RISK ASSESSMENT PROCESS WAS GOOD

LICENSEE PROGRAMS WITH WEAKNESSES

PALO VERDE NUCLEAR GENERATING STATION

- RISK TOOL - MATRIX
- THE EVALUATION OF THE CUMULATIVE RISK IMPACT OF MULTIPLE SSC OUTAGES LACKED AN ANALYTICAL BASIS AND, IN SOME CASES, YIELDED NON-CONSERVATIVE ESTIMATES
- THE RISK ASSESSMENT PROCESS HAD PROCEDURAL WEAKNESSES: THE GUIDANCE FOR ASSESSING CONFIGURATIONS NOT ADDRESSED BY THE MATRIX WAS WEAK, AND THE MATRIX DID NOT ADDRESS SOME BOP SSCs THAT WERE NOT MODELED IN THE PRA MODEL

LICENSEE PROGRAMS WITH WEAKNESSES

WASHINGTON NUCLEAR PROJECT - 2

- RISK TOOL - A PROCEDURE LISTED CERTAIN SSCs OF HIGH-SAFETY SIGNIFICANCE FOR CONSIDERATION

- A RISK ASSESSMENT WAS REQUIRED TO EVALUATE SAFETY PRIOR TO VOLUNTARY ENTRY INTO TECHNICAL SPECIFICATION ACTION STATEMENTS FOR CORRECTIVE MAINTENANCE

- UNAVAILABILITY WAS NOT MONITORED FOR RISK SIGNIFICANT SSCs (NUCLEAR CONDENSATE, REACTOR FEEDWATER, AND UNINTERRUPTIBLE AC POWER SUPPLY) [Violation a(1)]

- AN INAPPROPRIATE USE OF A STANDARD PERFORMANCE CRITERION FOR RELIABILITY HAD AN ADVERSE EFFECT ON THE RISK RANKING FOR SSC SAFETY SIGNIFICANCE [Violation of a(2)]

- A RISK ASSESSMENT ON A FROZEN MAINTENANCE SCHEDULE WAS PROVIDED FOR CHANGES INVOLVING HIGH-RISK SIGNIFICANT CONFIGURATIONS

- THE RISK ASSESSMENT PROCESS HAD PROCEDURAL WEAKNESSES: IT DID NOT INCLUDE ALL SSCs OF HIGH-SAFETY SIGNIFICANCE, IT DID NOT ADDRESS THE NECESSITY OF PERFORMING A RISK ASSESSMENT FOR EMERGENT WORK NOR FOR UNANALYZED CONFIGURATIONS, AND IT DID NOT ADDRESS THE IMPACT ON SAFETY WHEN LOW-SAFETY SIGNIFICANT SSCs WERE REMOVED FROM SERVICE

LICENSEE PROGRAMS WITH NO NOTED WEAKNESSES

WATERFORD-3

- RISK TOOL - EOOS SOFTWARE FOR QUANTITATIVE EVALUATIONS

- AN OPERATION'S GUIDE PROVIDED GUIDANCE FOR THE CONSIDERATION OF SEASONAL WEATHER CONDITIONS AND QUANTITATIVE ASSESSMENTS OF SWITCHYARD ACTIVITIES

- THE SSC RISK RANKING METHODOLOGY WAS LACKING IN THAT IT DID NOT ASSESS UNAVAILABILITY ASSUMPTIONS

- THE METHOD FOR ESTABLISHING UNAVAILABILITY PERFORMANCE CRITERIA WAS LACKING IN THAT IT DID NOT FULLY EVALUATE THE CUMULATIVE RISK IMPACT OF ALL SYSTEM INTERDEPENDENCIES

- UNAVAILABILITY WAS NOT MONITORED FOR RISK SIGNIFICANT SSCs (ENGINEERED SAFETY FEATURES ACTUATION, PLANT PROTECTION, CORE PROTECTION CALCULATORS, BROAD RANGE GAS MONITORS, AND CONTAINMENT POLAR CRANE) [Violation a(1)]

- THE RISK ASSESSMENT PROCESS FOR WAS SUPERIOR

REGION IV INSPECTION PROGRAM

STATUS OF PLANTS

INSPECTION PROGRAM

RESIDENT INSPECTION

REGION-BASED INSPECTION

PLANT ISSUES MATRIX

PLANT PERFORMANCE REVIEWS

SALP

SALP RATINGS

REGION IV PLANT STATUS REPORT

FOR 07/17/97

NRC OPERATIONS CENTER
PLANT STATUS REPORT FOR 07/17/97
UNEVALUATED INFORMATION PROVIDED BY THE FACILITY

REG	PLANT NAME	PHONE	%PWR	DOWN	RESTART	REASON OR COMMENT	*	#
4	ARKANSAS NUCLEAR 1	4563	100					
4	ARKANSAS NUCLEAR 2	4563	100					
4	CALLAWAY 1	4564	095			ADMINISTRATIVE POWER REDUCTION DUE TO AXIAL OFFSET ANOMALY		
4	COMANCHE PEAK 1	4565	100					
4	COMANCHE PEAK 2	4565	100					
4	COOPER 1	4566	100					
4	DIABLO CANYON 1	4567	100					
4	DIABLO CANYON 2	4567	100					
4	FT CALHOUN 1	4568	100					
4	GRAND GULF 1	4569	100					
4	PALO VERDE 1	4570	100					
4	PALO VERDE 2	4570	100					
	PALO VERDE 3	4570	100					
4	RIVER BEND 1	4571	100					
4	SAN ONOFRE 2	4572	070			HOLDING POWER WHILE WORKING ON A MAIN FEEDPUMP	*	
4	SAN ONOFRE 3	4572	001			MODE 2 - STARTUP CRITICAL BELOW THE POINT OF ADDING HEAT	*	
4	SOUTH TEXAS 1	4573	100					
4	SOUTH TEXAS 2	4573	100					
4	WASHINGTON NUCLEAR 2	4574	087			INCREASING POWER	*	
4	WATERFORD 3	4575	000	04/11	UNK	MODE 4 - HOT SHUTDOWN REFUELING OUTAGE		
4	WOLF CREEK 1	4576	100					

NRC POWER REACTOR INSPECTION PROGRAM

OBJECTIVES - MC 2515

MASTER INSPECTION PLAN

CORE
REGIONAL INITIATIVE
SAFETY ISSUE

REACTIVE INSPECTIONS

NRC POWER REACTOR INSPECTION PROGRAM

INSPECTION APPROACH

ACTIONS IN RESPONSE TO VIOLATIONS

RESIDENT INSPECTOR PROGRAM

CONTINUAL NRC ONSITE PRESENCE

INCREASED INSPECTION TIME

DIRECT OBSERVATION OF ACTIVITIES

ENHANCED NRC KNOWLEDGE OF CONDITIONS

BETTER BASE FOR REGULATORY DECISIONS

RESIDENT INSPECTOR PROGRAM

<u>LESS RELIANCE ON RECORDS</u>

<u>GREATER NRC INDEPENDENT VERIFICATION</u>

<u>RAPID NRC RESPONSE TO PLANT EVENTS</u>

<u>KEY RESIDENT INSPECTOR ACTIVITIES</u>

RESIDENT INSPECTION

INSPECTION REQUIREMENTS

DAILY INSPECTIONS

CONTROL ROOM OBSERVATIONS
PLANT TOUR

BIWEEKLY INSPECTIONS

MONTHLY INSPECTIONS

RESIDENT INSPECTION

TRI-MONTHLY INSPECTIONS

SEMIANNUAL INSPECTIONS

OUTAGE INSPECTIONS

EFFECTIVENESS OF LICENSEE CONTROLS

RESIDENT INSPECTION

DOCUMENTATION OF INSPECTION FINDINGS

FORMAL INSPECTION REPORT

REGION-BASED INSPECTION

INSPECTORS WITH SPECIALIZED EXPERTISE

BASED IN REGIONAL OFFICES

INSPECT ALL PLANTS

BROAD-BASED PERSPECTIVE

NARROW TECHNICAL FOCUS

INDEPENDENT CHECK ON RESIDENT

PLANT ISSUES MATRIX (PIM)

CURRENT PIM

PIM IMPROVEMENTS

RELEASE OF PIM

PLANT PERFORMANCE REVIEWS (IMC 0304)

<u>OBJECTIVES</u>

<u>PROCESS</u>

<u>OUTPUTS</u>

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE

<u>OBJECTIVES</u>

<u>PROCESS</u>

<u>OUTPUTS</u>

SALP OBJECTIVES

INTEGRATED ASSESSMENT OF PERFORMANCE

ALLOCATE NRC INSPECTION RESOURCES

COMMUNICATE RESULTS

SALP PROCESS

PREPARATION

BOARD MEETING

SALP OUTPUTS

SALP RATINGS

SALP REPORT

MASTER INSPECTION PLAN

SALP CATEGORY RATING DEFINITIONS

CATEGORY 1

CATEGORY 2

CATEGORY 3

CURRENT SALP FUNCTIONAL AREAS

<u>OPERATIONS</u>

<u>MAINTENANCE</u>

<u>ENGINEERING</u>

<u>PLANT SUPPORT</u>

<u>SAFETY ASSESSMENT/QUALITY VERIFICATION</u>

CURRENT SALP SCORES FOR REGION IV FACILITIES

SITE	OPERATIONS	MAINTENANCE	ENGINEERING	PLANT SUPPORT
ANO	1	2	1	1
CALL	2	1	1	1
CPSES	1	1	1	1
CNS	2	2	3	2
DC	2	2	2	1
FCS	2	2	1	1
GG	1	2	1	1
PVNGS	1	1	1	2
RBS	2	2	2	1
SONGS	2	2	1	1
STP	2	1	2	1
WAT	2	2	3	2
WNP-2	2	2	2	2
WC	2	2	3	2

REACTOR DECOMMISSIONING IN REGION IV

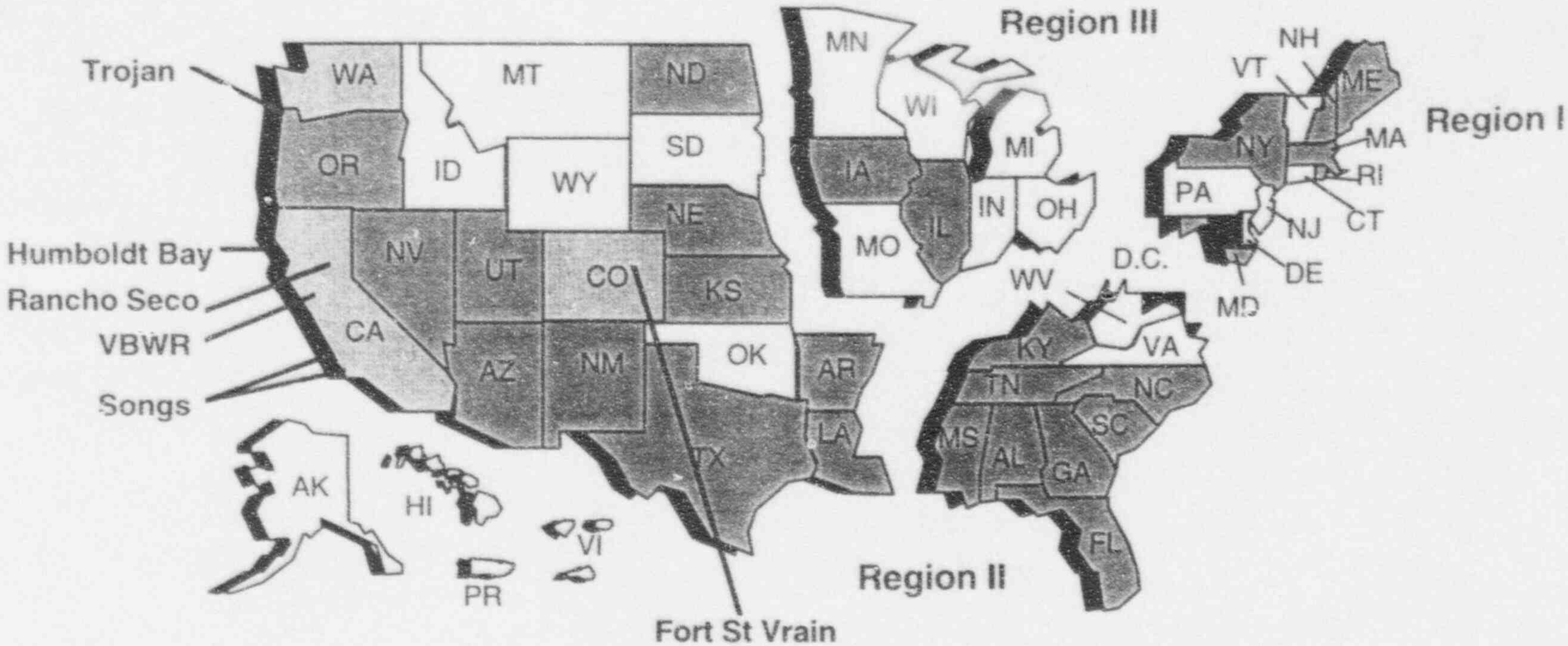
Dr. D. Blair Spitzberg, Chief
Nuclear Materials Inspection and Decommissioning Branch

July 18, 1997

REACTORS IN DECOMMISSIONING

- Trojan
- Rancho Seco
- Humboldt Bay
- San Onofre Unit 1
- Fort St. Vrain
- Vallecitos

Region IV REACTOR DECOMMISSIONING SITES



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TROJAN

- Rainer, Oregon
- Westinghouse 4 loop PWR
- 1153 Mwe
- OL issued - November 1975
- Commercial Operations - May 1976
- Shutdown - November 1992

TROJAN STATUS

- Actively undergoing dismantlement and decon - completion by 2002
- Steam generators, pressurizer, and coolant pumps buried at Hanford
- Reactor pressure vessel burial as one unit has been proposed
- ISFSI construction started
- current staffing is 274

TROJAN REACTOR VESSEL PROJECT

- Application submitted to bury vessel at Hanford
- 2 million curies activated metal, 155 curies inner surface contamination
- Shipped as type B, exclusive use via barge up Columbia River
- Total weight of 1,013 tons

RANCHO SECO

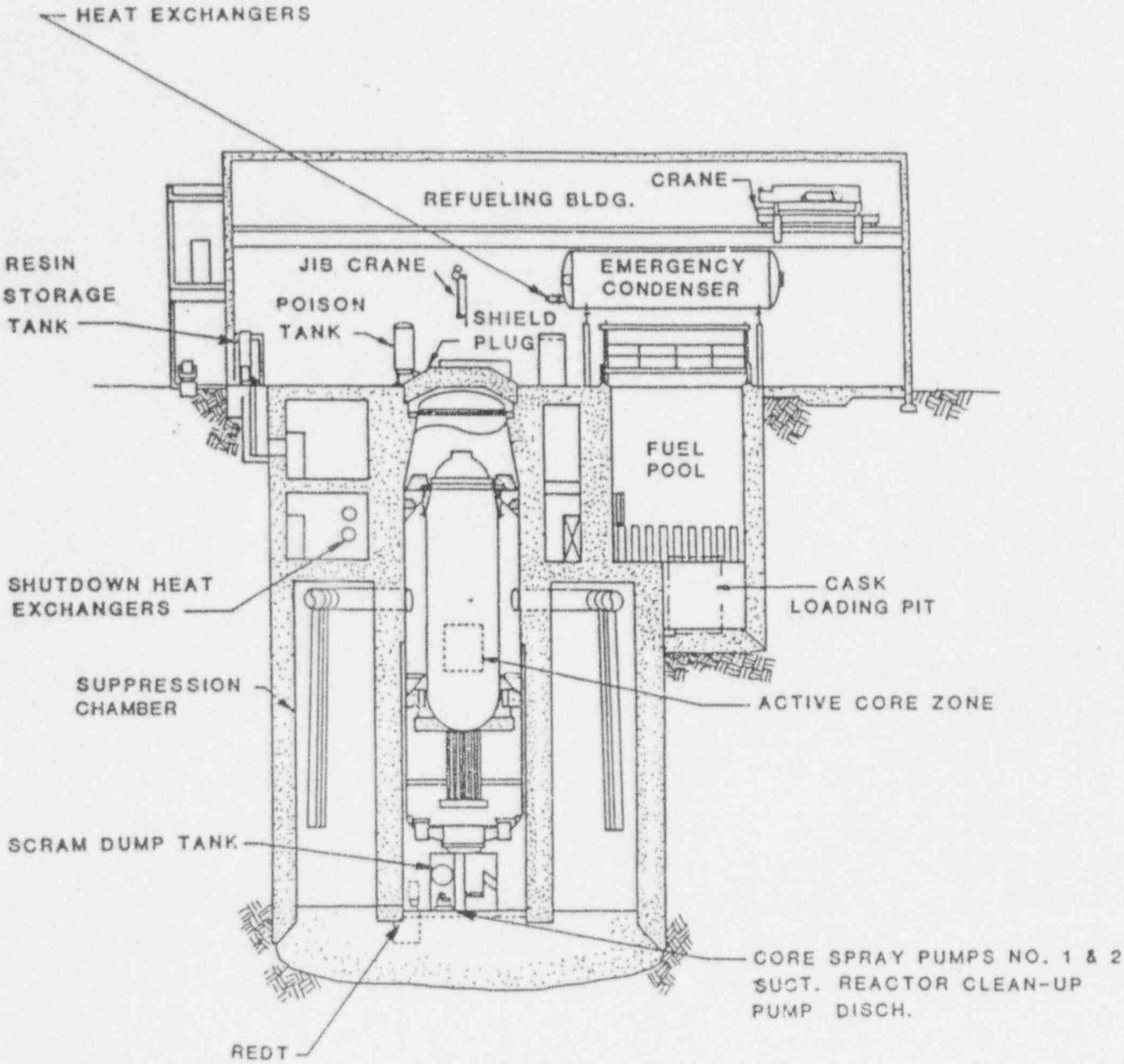
- Sacramento, California
- B&W Reactor
- 918 Mwe
- OL issued August 1974
- Commercial Operations - April 1975
- Shutdown - June 1989

RANCHO SECO STATUS

- SAFSTOR with limited dismantlement underway in turbine building
- Decision within a year to pursue dismantlement
- Site issues involve deterioration of facility
- ISFSI near completion

HUMBOLDT BAY

- Eureka, California
- Early GE BWR design
- 65 Mwe
- OL issued - August 1962
- Commercial Operations - August 1963
- Shutdown - July 1976



SECTION E-E

FIGURE 3-11 EQUIPMENT LOCATION

HUMBOLDT BAY STATUS

- SAFSTOR with repair work underway for in-leakage problem
- Stack near containment has cracks
- ISFSI desired but limited by tsunami potential
- Current staffing is 39 (plus 56 contractors on in-leakage work)

HUMBOLDT BAY LEAK PROBLEM

- In-leakage into caisson sump is currently 7800 gpd
- Levels as high as 10,000 gpd occurred last summer
- Pump capacity is 43,200 gpd
- Cs-137 below release limits
- Contingency plans established

SAN ONOFRE

- San Clemente, CA
- Westinghouse PWR
- 436 Mwe
- OL issued - March 1967
- Commercial Operations - January 1968
- Shutdown - November 1992

SAN ONOFRE STATUS

- In SAFSTOR
- First leaks in spent fuel pool liner started in 1986
- April 1995 leak of spent fuel pool liner of 2000 gallons
- Current leak rate 3 gpw

FORT ST. VRAIN

- Platteville, CO
- GA HTGR
- 330 Mwe
- OL issued - December 1973
- Commercial Operations - January 1979
- Shutdown - August 1989

FORT ST. VRAIN STATUS

- Decommissioning complete
- License termination letter with Commissioners
- ISFSI being transferred to DOE
- Current staffing is 25 (15 are security)

VALLECITOS

- Pleasanton, CA
- GE test reactor (AEC License #1)
- OL issued - October 1957
- Shutdown - December 1963

VALLECITOS STATUS

- Long term SAFSTOR
- Some in-leakage had occurred in the past

PROBLEM AREAS

- Free Release Surveys
- Allegations
- Spent fuel pool leaks
- Licensee "going to sleep"
- Compliance with 49 CFR
- Maintenance rule applicability
- Deterioration of facility and equipment

ISSUES

- Finalization of various regulatory guidance documents
- Role of NRR versus NMSS during decommissioning
- Inspections emphasis change (health physics, employee concerns, free release surveys, OSHA, heavy loads, spent fuel pool)

STAFFING AND INSPECTIONS

- Currently one inspector and two openings
- Typically conduct semiannual inspections at SAFSTOR facilities and bi-monthly inspections at DECON facilities

FUTURE SHUTDOWNS

- Deregulation or plant performance issues could drive any of the region IV plants into decommissioning
- Currently, no additional plants are discussing decommissioning with Region IV.

LICENSE EXPIRATIONS

21 operating plants

- 2008 Diablo Canyon Unit 1
- 2010 Diablo Canyon Unit 2
- 2013 Ft. Calhoun
- 2013 San Onofre Unit 2
- 2013 San Onofre Unit 3
- 2014 Arkansas Nuclear One Unit 1
- 2018 Arkansas Nuclear One Unit 2
- 2022 Grand Gulf

LICENSE EXPIRATIONS

continued

- 2022 Grand Gulf
- 2023 Washington Nuclear Project Unit 2
- 2024 Callaway
- 2024 Palo Verde Unit 1
- 2024 Waterford
- 2025 Palo Verde Unit 2
- 2025 River Bend
- 2025 Wolf Creek

LICENSE EXPIRATIONS

continued

- 2027 Palo Verde Unit 3
- 2027 South Texas Project Unit 1
- 2028 South Texas Project Unit 2
- 2030 Comanche Peak Unit 1
- 2033 Comanche Peak Unit 2

DRY CASK STORAGE IN REGION IV

Dr. D. Blair Spitzberg, Chief
Nuclear Materials Inspection and
Decommissioning Branch

July 17, 1997

INDEPENDENT SPENT FUEL STORAGE INSTALLATIONS

Facilities with Fuel Loaded

- Arkansas Nuclear One
- Fort St. Vrain

INDEPENDENT SPENT FUEL STORAGE INSTALLATIONS

Facilities Under Construction

- Trojan
- Rancho Seco
- DOE Idaho TMI-2 Fuel

INDEPENDENT SPENT FUEL STORAGE INSTALLATIONS

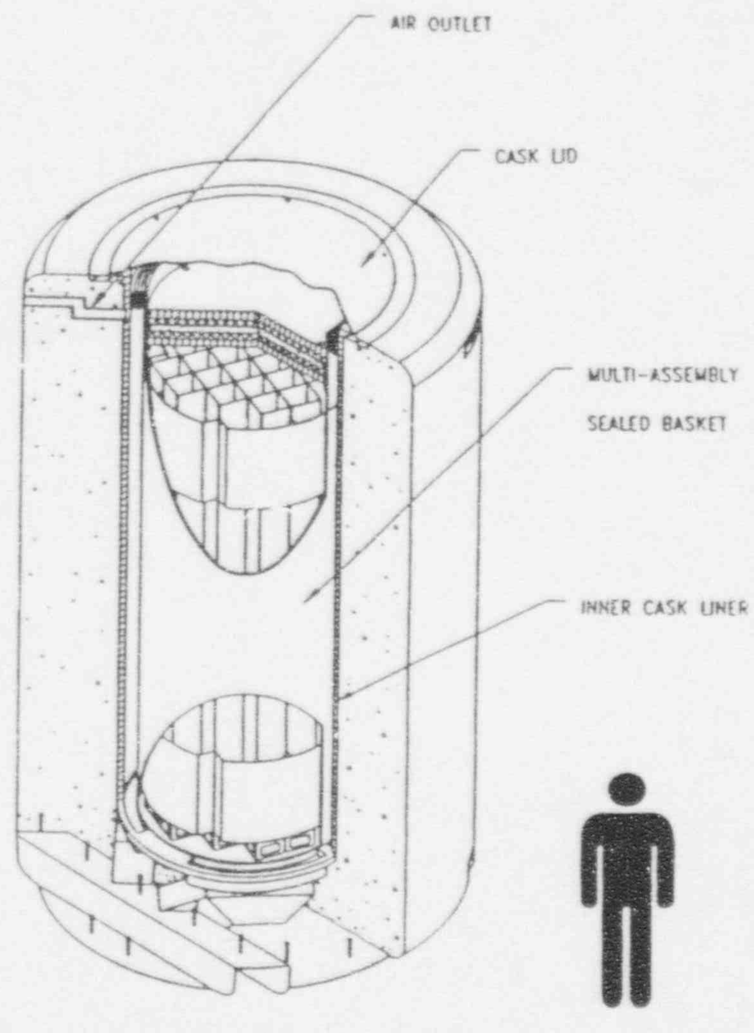
Probable Near-Term Facilities

- WNP-2
- Humboldt Bay
- Diablo Canyon
- Palo Verde

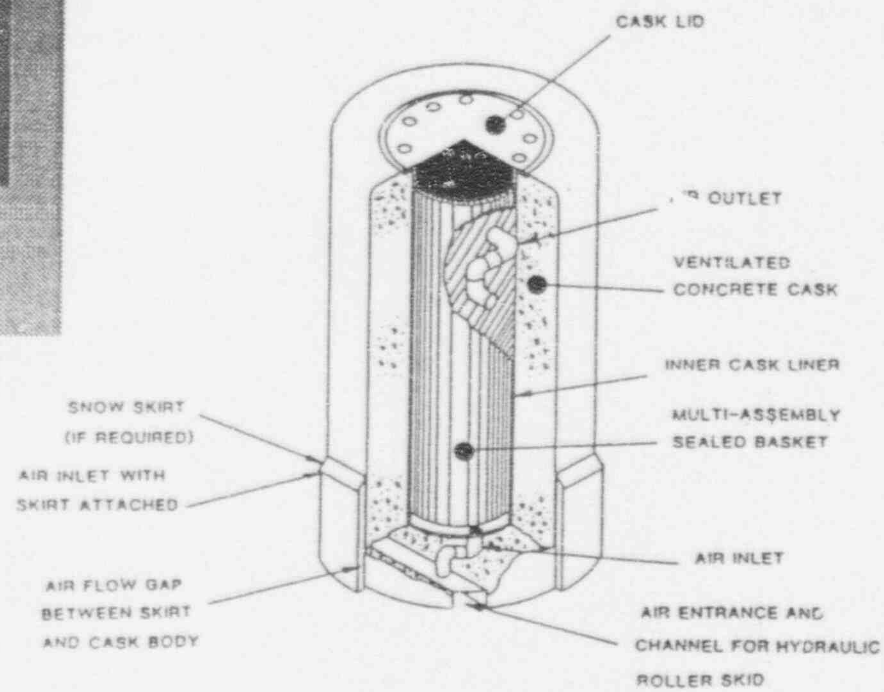
ARKANSAS NUCLEAR ONE

- Sierra Nuclear VSC-24 design
- First cask loaded December 1996
- Four casks loaded
- Ten additional casks constructed

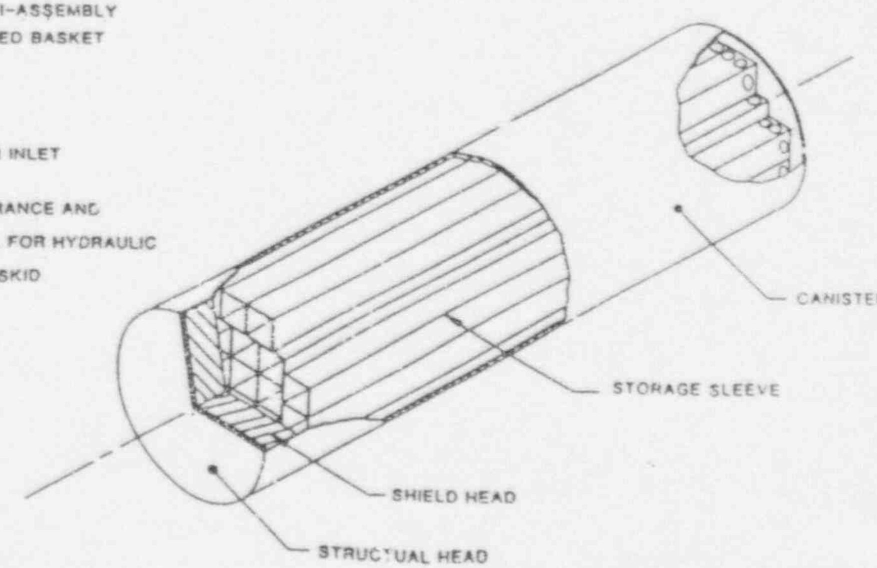
VENTILATED CONCRETE CASK



MULTI-ASSEMBLY SEALED BASKET



THE VENTILATED STORAGE CASK



ARKANSAS NUCLEAR ONE CASK CRACKS

- CAL in place requiring resolution of cracking phenomena prior to additional loading
- Cask #1 - crack in shield lid final weld
- Cask #3 - crack in shield lid root weld

FORT ST. VRAIN

- Foster Wheeler design
- 1464 spent fuel elements in storage
- highly enriched fuel in graphite
- Feb. 1996 contract between DOE and PSCo
- DOE Application submitted Dec 96

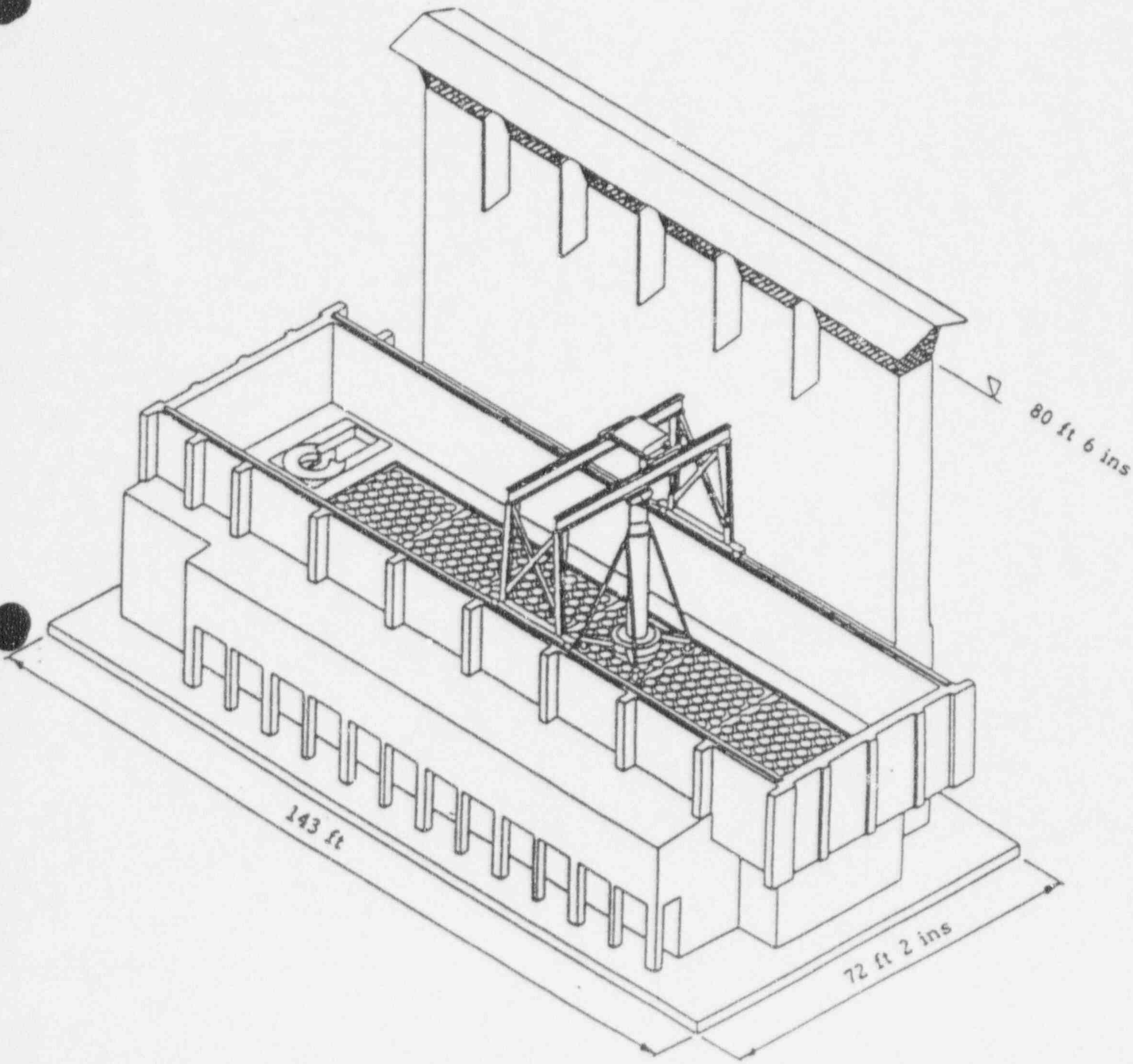


Figure 1.2-1 MVDS Fort St. Vrain (without roof structure)

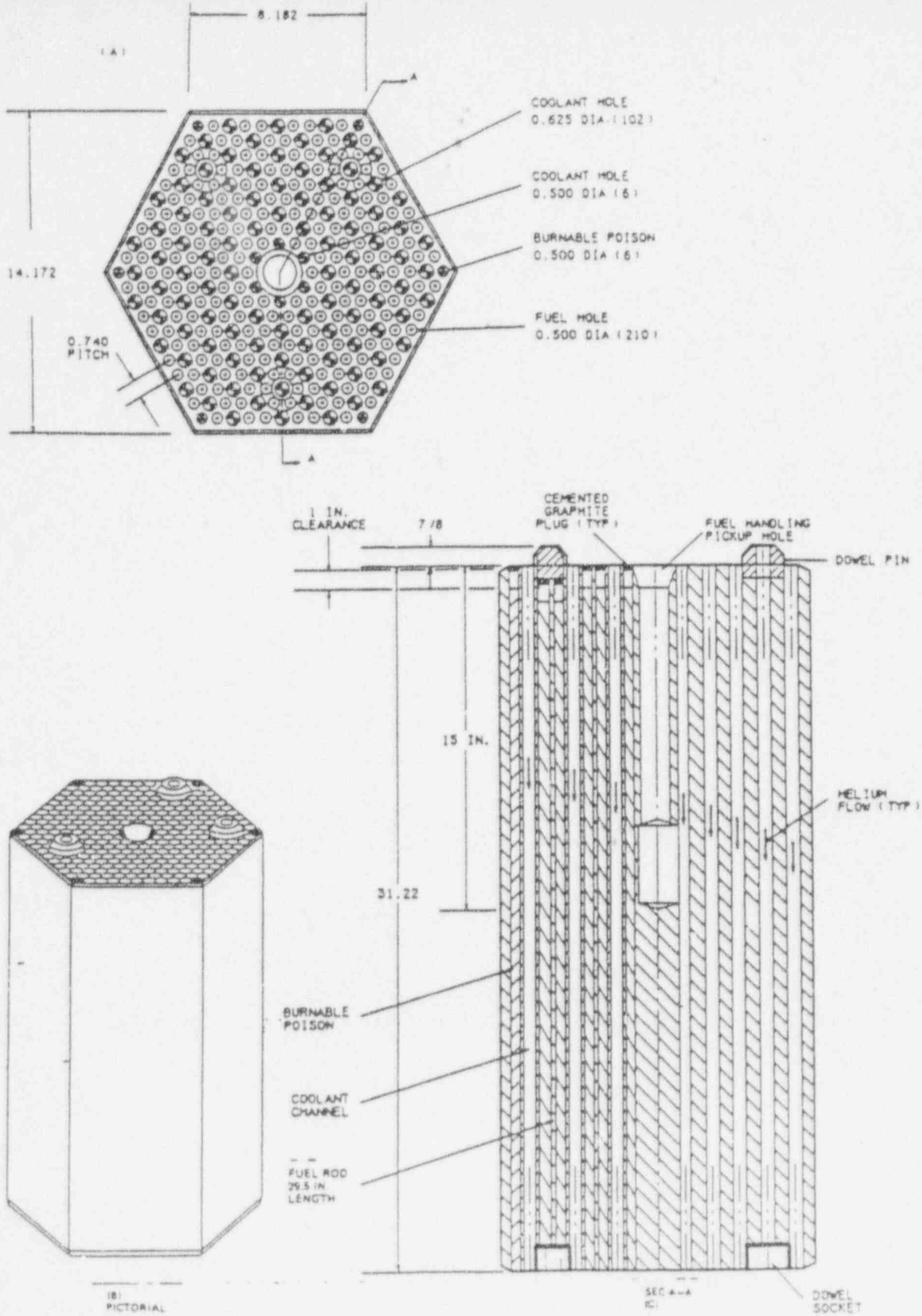


Figure 1.1-4 Standard Fuel Element

TROJAN

- Sierra Nuclear Transtor Design
- 36 casks are planned
- Concrete pad under construction
- Cask on hold because of cracking issue
- 1998 loading planned

RANCHO SECO

- Vectra NUHOMS design
- 22 casks (modules) are planned
- ISFSI is complete
- Casks on hold due to Vectra QA problems
- 1998 loading planned

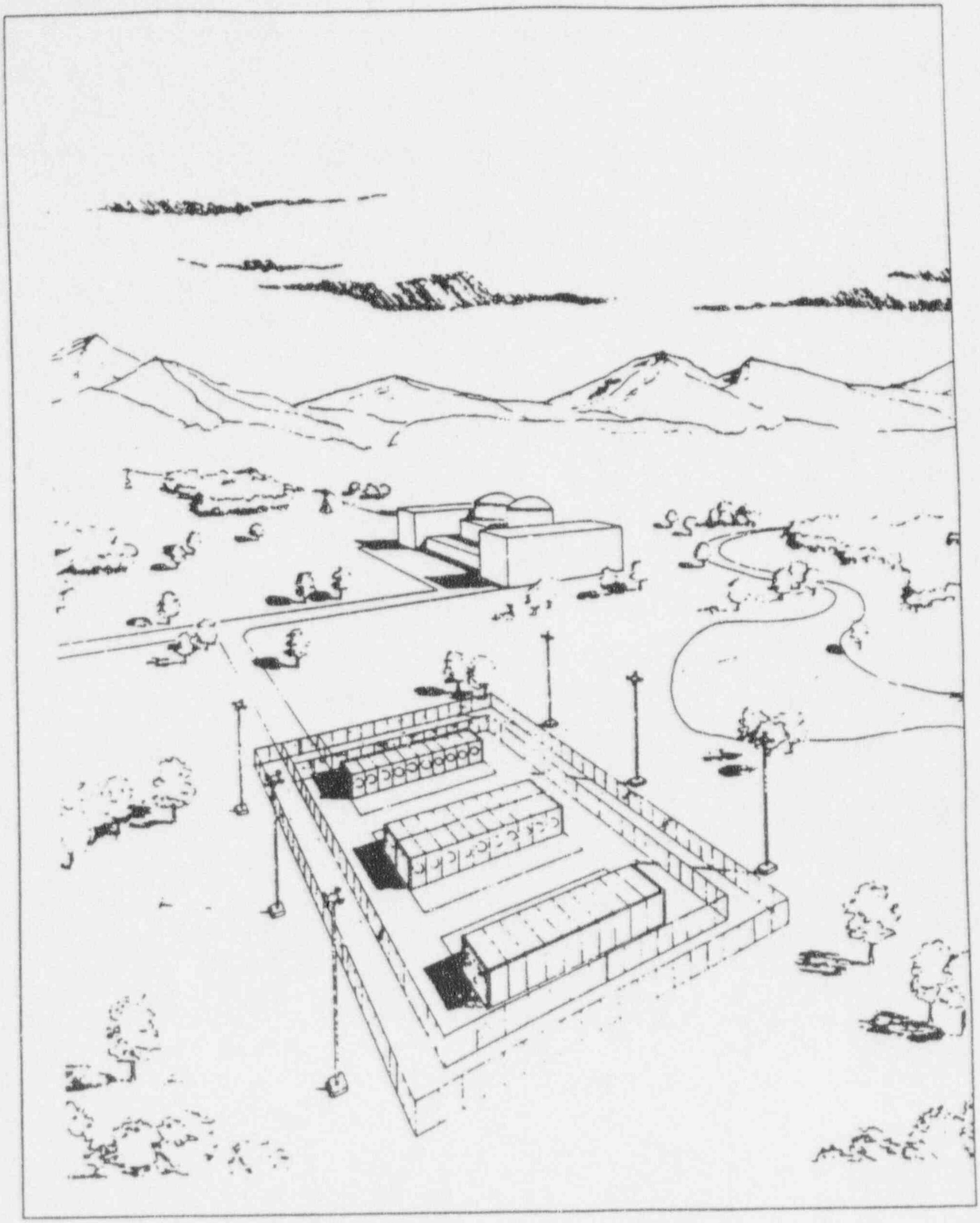


Figure 1.1-1
Illustration of Typical Life-of-Plant NUHOMS® ISFSI
(for information only)

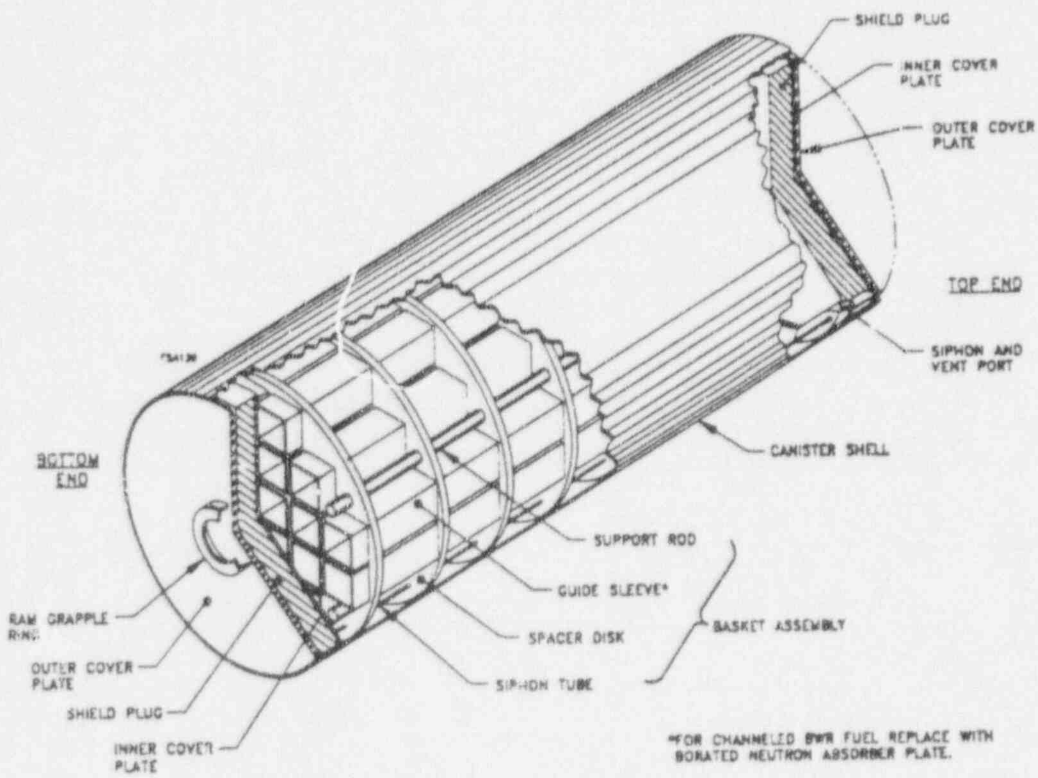
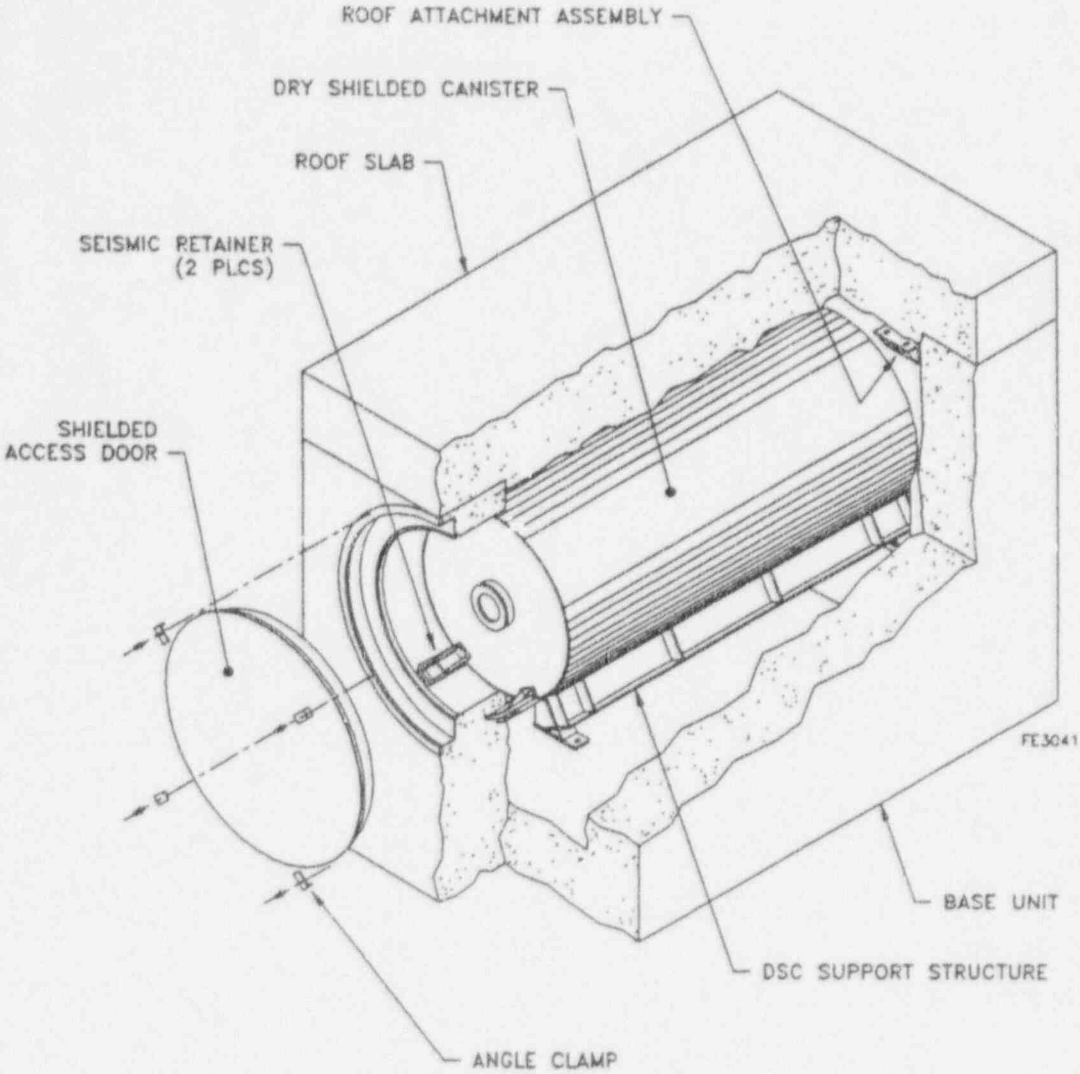


Figure 1.3-1

NUHOMS® Dry Shielded Canister Assembly Components



NOTE: Nominal Dimensions are shown in Table 1.2-1

Figure 1.2-2
Prefabricated NUHOMS®-12T Horizontal Storage Module
Front View
(Sheet 1 of 2)

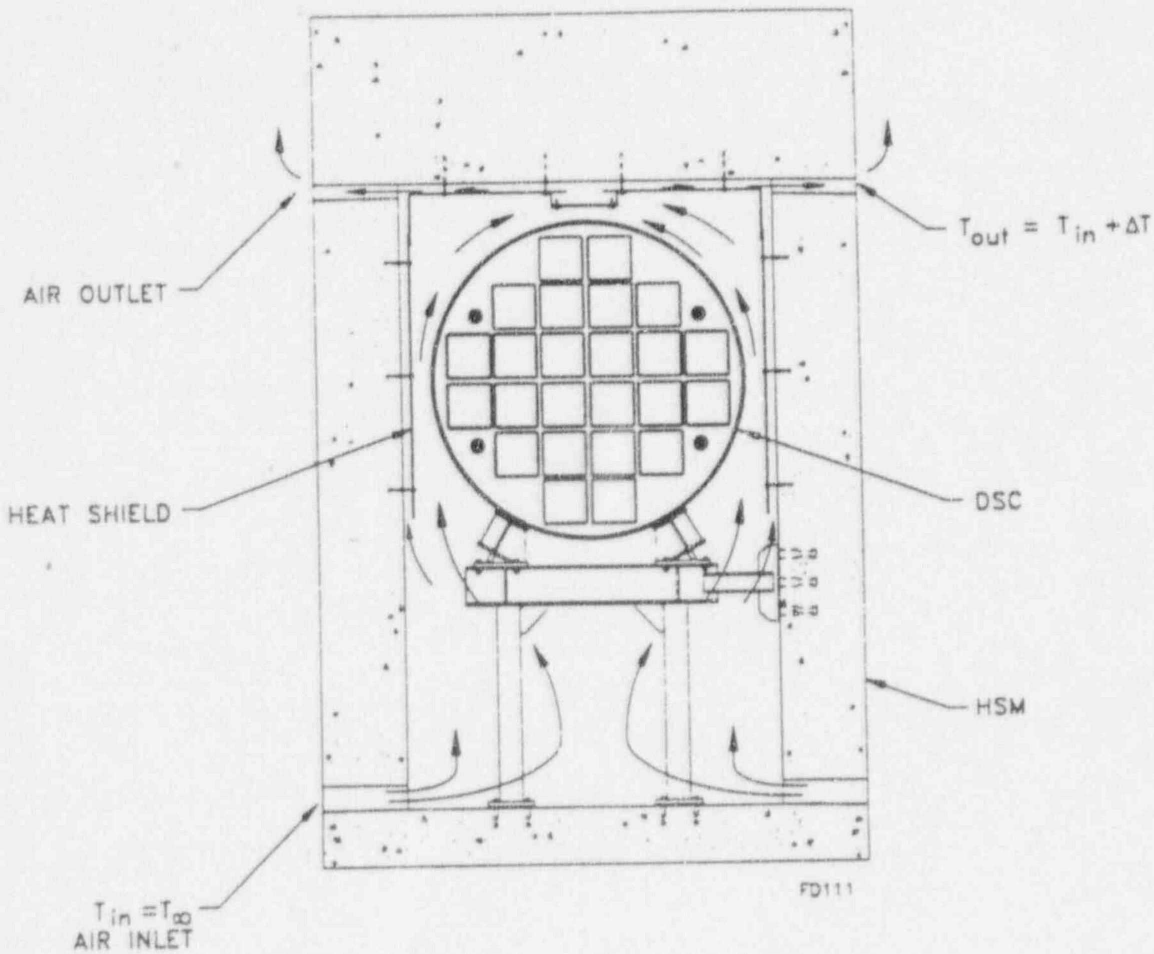


Figure 1.3-5
<u>HSM Ventilation Air Flow Diagram</u>

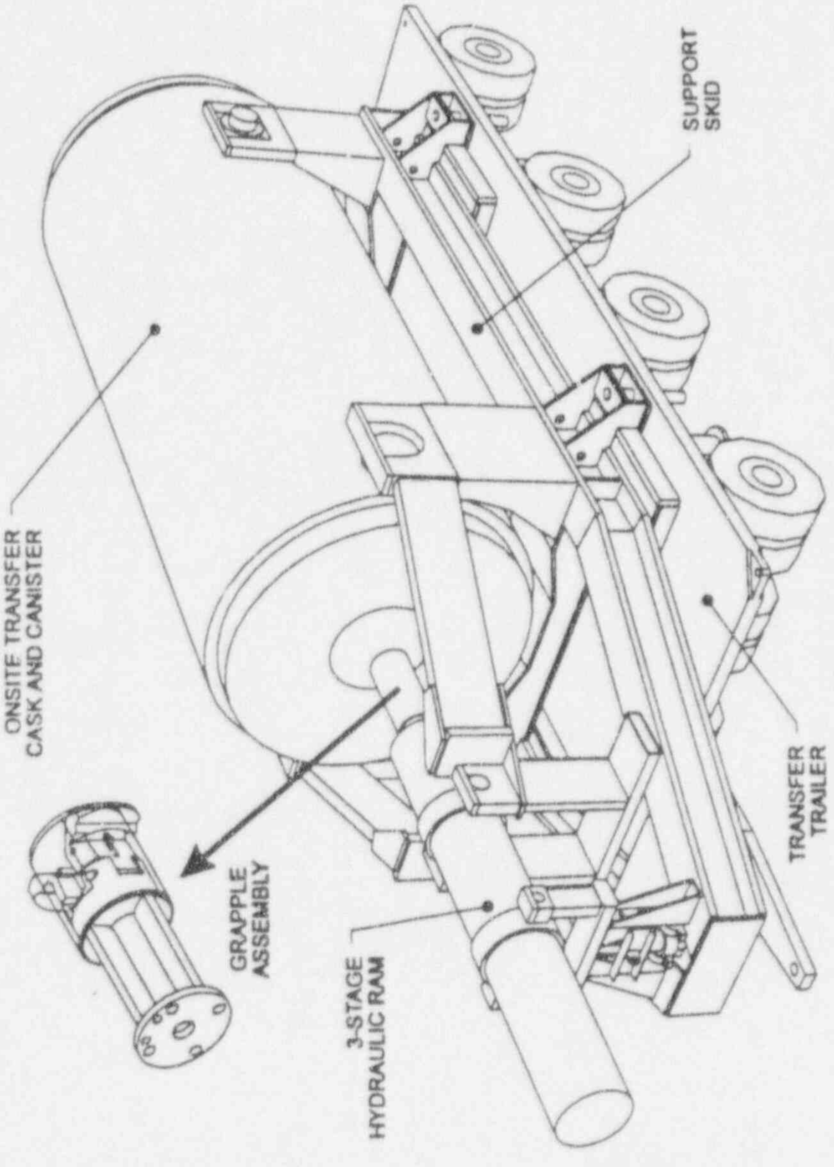


Figure 1.3-9
Hydraulic Ram System for NUHOMS®

DOE TMI-2 FUEL

- Located at INEEL - Idaho
- Vectra NUHOMS special design
- fuel debris in a vented cask
- 30 casks (modules) are planned
- 1999 loading planned

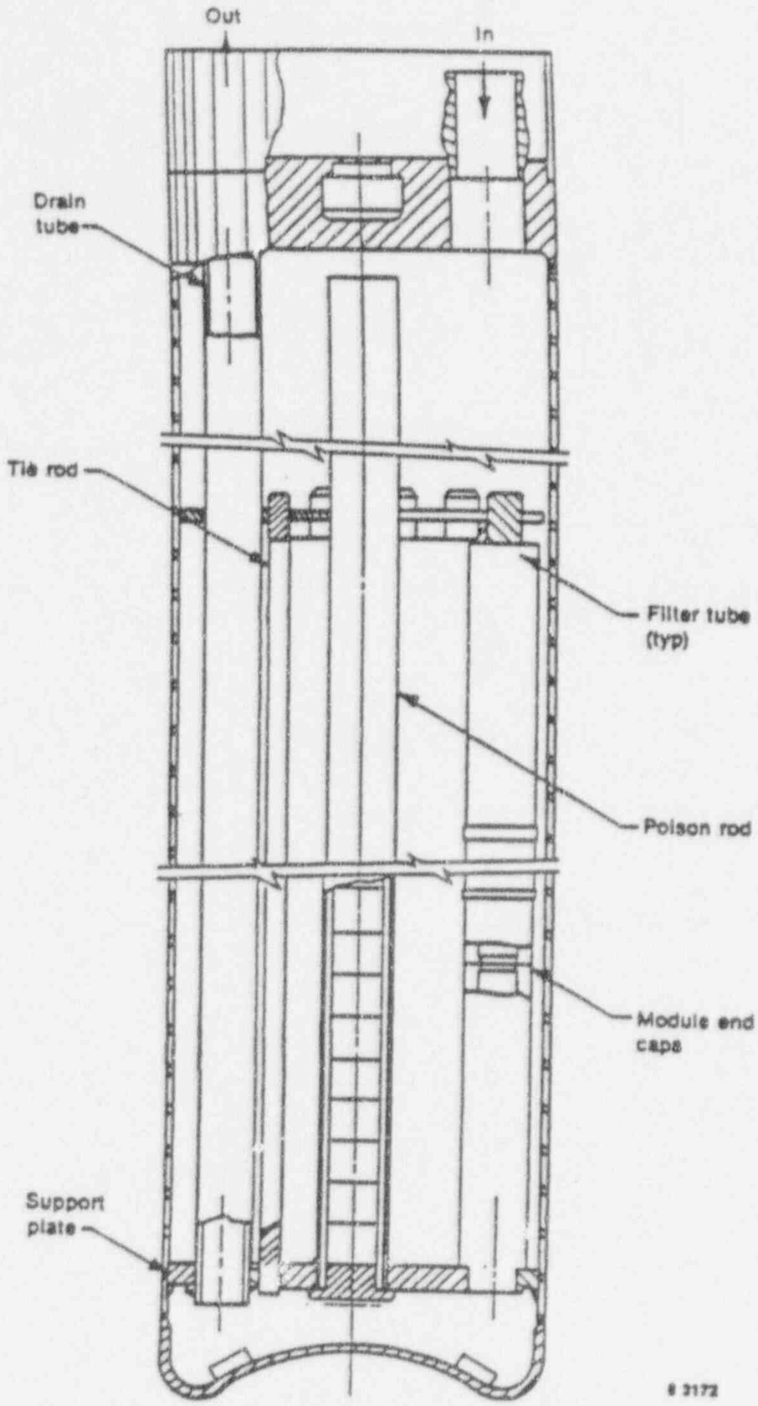


Figure 3.1-3
TMI-2 *Filter* Canister
[Reference 3. 1]

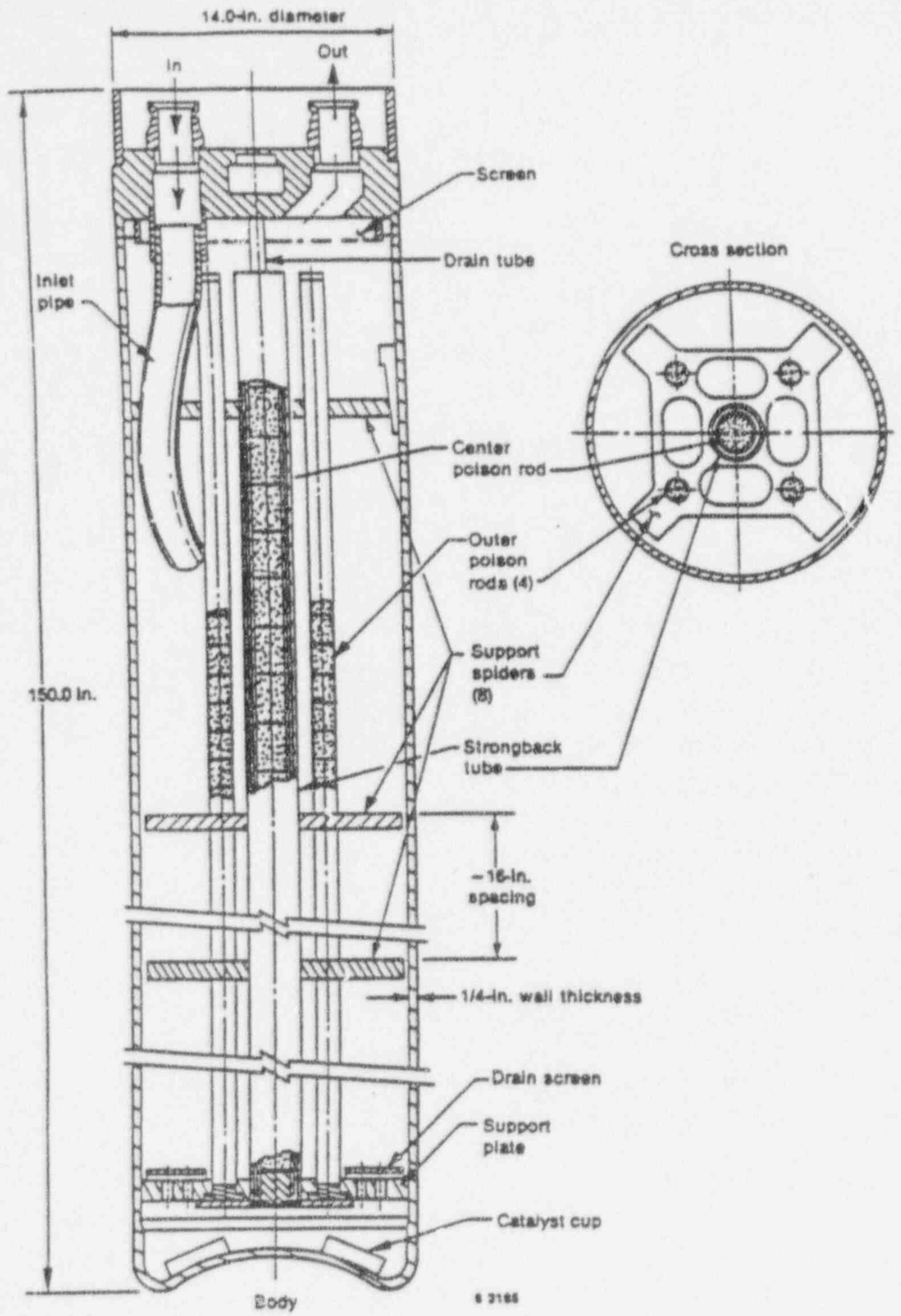


Figure 3.1-2
TMI-2 *Knockout* Canister
[Reference 3. 1]

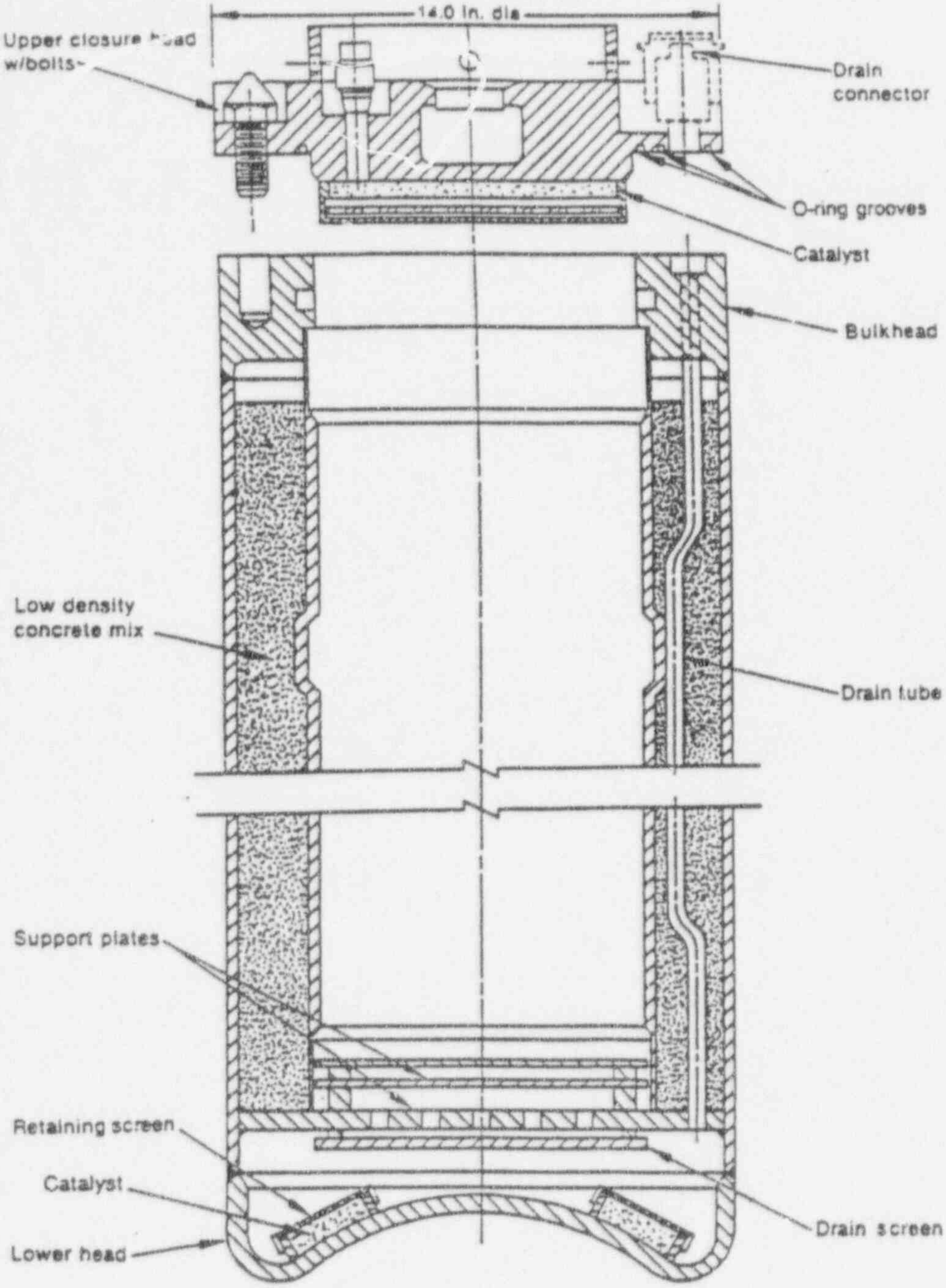


Figure 3.1-1
<u>TMI-2 *Fuel* Canister</u>
[Reference 3.1]

WNP-2

- Initial bids requested in late 1996
- All bids were evaluated as inadequate
- New bidding planned for this year
- Loading planned before 2000

HUMBOLDT BAY/DIABLO CANYON

- Joint effort under discussion
- Very early stages
- Loading date not determined
- Humboldt will have hard time placing pad onsite due to tsunami potential

SAN ONOFRE

- Discussions underway within company
- Don't expect significant activity until a cask is available for both shipping and storage

PROBLEM AREAS

- welding of lid
- hydrogen generation from coatings
- documentation of safety reviews
- experience in loading/moving casks
- crane capacity