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UNITED STATES
NUCLEAR REGULATORY COMMISSION

In the Matter of:)
)
POWER ASCENSION TEST PROGRAM)
FINAL PHASE II)
SELF-ASSESSMENT REPORT)

Pages: 1 through 100

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Tuesday,
September 18, 1990

Building 475,
475 Allendale Road
King of Prussia, Pennsylvania

The Commission met, pursuant to notice, at 1:00 p.m., in the main conference room,

PRESENT:

Neal A. Pillsbury, Director of Quality Programs.

Joe M. Vargas, Manager of Engineering.

D.E. Moody, Station Manager.

G.J. Kline, Technical Support Manager.

Ted C. Feigenbaum, Senior Vice President, NHY.

Bruce L. Drawbridge, Executive Director of Nuclear Production, NHY.

Edward Desmarais, Independent Review Team Manager.

James M. Peschel, Regulatory Compliance Manager.

Terry Harpster, Director, Licensing Services.

W. Hehl, Director, Regional Projects, Region I.
Ronald L. Nimitz, Senior Radiation Specialist.

Victor Nerses, Acting Director, Project Director of 1-3, NRR.

Noel Dudley, Senior Resident Inspector.

Present: (Continued)

Ebe McCabe, DRP Projects Section Chief.

Jon Johnson, DRP Projects Branch Chief.

Tim Martin, Regional Administrator.

Jim Wiggins, Deputy Director, DRP.

Michael Case, Operations Engineer.

Karla Smith, Regional Counsel.

William Oliveira, Reactor Engineer, Operations Section, DRS.

P.K. Eapen, Chief, Special Test Program Section.

David Bessette, Chief, Operational Programs Section.

Peter Drysdale, Senior Reactor Engineer.

Lee Bettenhausen, Chief, Operations Branch.

P R O C E E D I N G S

MR. JOHNSON: Good afternoon. This is a meeting between Public Service Company oi New Hampshire and the NRC. It is an open public meeting. It is being transcribed mainly for efficiency for us, for us to be able to document the summary of the meeting.

The purpose of the meeting is to discuss the New Hampshire Yankee assessment of the Power Ascension Test Program. What we will do is go around the table and introduce each other, and then what I will do is turn the meeting over to New Hampshire Yankee. I expect it to take probably no more than two hours. And I would hope that anybody that has any questions during the presentation, make sure we give you feedback and answer the questions.

MR. WIGGINS: Jim Wiggins, I am Deputy Director, Division Director of Projects here in Region One.

MR. JOHNSON: Regional Administrator Mr. Tim Martin is here. He stepped out for a moment; he will be back shortly.

I am Jon Johnson, DRP Projects Branch Chief.

MR. MCCABE: Ebe McCabe, DRP Projects Section Chief.

MR. DUDLEY: I am Noel Dudley, Senior Resident Inspector.

MR. NERSES: Vic Nerses, Acting Director of

Project Director of 1-3, NRR.

MR. NIMITZ: Ron Nimitz, Senior Radiation Specialist, Region One.

MR. HEHL: I am Bill Hehl, I am the Director for the Regional Projects, Region One.

MR. HARPSTER: Terry Harpster, Director of Licensing Services, New Hampshire Yankee.

MR. PILLSBURY: Neal Pillsbury, Director of Quality Programs, New Hampshire Yankee.

MR. VARGAS: Joe Vargas, Manager of Engineering, New Hampshire Yankee.

MR. MOODY: Don Moody, Station Manager, Seabrook, New Hampshire Yankee.

MR. KLINE: Gary Kline, Technical Support Manager, New Hampshire Yankee.

MR. FEIGENBAUM: Ted Feigenbaum, Senior Vice President and Chief Operating Officer, New Hampshire Yankee.

MR. DRAWBRIDGE: Bruce Drawbridge, Executive Director of Nuclear Production, New Hampshire Yankee.

MR. DESMARAIS: Ed Desmarais, Independent Review Team Manager, New Hampshire Yankee.

MR. PESCHEL: Jim Peschel, Regulatory Compliance Manager, New Hampshire Yankee.

MR. EAPEN: P.K. Eapen, Chief, Special Test Program Section.

MR. OLIVEIRA: Bill Oliveira, Operations Section, DRS.

MS. SMITH: Karla Smith, Regional Counsel.

MR. CASE: Mike Case, NRR.

MR. MARTIN: Tim Martin, Regional Administrator.

MR. FEIGENBAUM: Okay, good afternoon. My name is Ted Feigenbaum, and as I said, I am the Senior Vice President and Chief Operating Office of New Hampshire Yankee.

As most of you may already know, I will be assuming the position of President and Chief Executive Officer upon Ed Brown's retirement on October 1st.

On behalf of New Hampshire Yankee and our joint owners, we are pleased to provide you with this briefing today. As you may know, Seabrook completed its test program on the 17th of August, and the plant is currently operating at 100 percent power.

We have some presentations that should take, I guess, formally about 45 minutes. And please, if you have any questions, just stop us and we will try to address them.

First of all, Gary Kline is going to report to you on the results of the Power Ascension Test Program since we last briefed you at the 50 percent power plateau back on June 19th. He is also going to discuss some of the lessons we have learned during the Power Ascension Program, and that we plan to carry forward into normal plant operations.

Bruce Drawbridge will discuss the areas where we believe we can improve through increased management attention. And he will brief you on some of the short- and long-term initiatives we are taking to strengthen ourselves as an operating company.

Ed Desmarais is going to talk about the self-assessment program, emphasizing the maintenance evaluation which we conducted as part of the overall self-assessment team evaluation.

So that we can maximize the effectiveness of the information exchange today, I have asked our speakers to concentrate on the things that we are doing to improve our organization, and not to dwell on the portions of the test program that we feel went smoothly and really do not require any further discussion.

From the beginning of the test program, we stated that we would manage it in a conservative manner, and not be driven by schedule. And that is exactly how we carried the program out. The Power Ascension Test Program lasted about 155 days, a little bit longer than we expected. And that was essentially due -- the biggest delay was about a month to detune the turbine generator equipment, which we discussed at length when we met last in June. So we will not take the time to go into that this afternoon.

We also had two unplanned reactor trips, which Gary Kline will brief you on, apart from the turbine work. Other than that, the tests went pretty much according to schedule, and the results were as we expected. We believe the test program demonstrated the readiness for full power operations, not only of the equipment and the systems in the plant, but also the operators and the entire support organization.

I think the good results we had were a direct result of our careful and deliberate preparation for the test program. We reviewed and revised every test procedure to incorporate lessons learned. The lessons learned from our low power test program, from industry experience. From the lessons learned from NUREG 1275, which was the NRC's Operating Experience Feedback Report for New Plants, which was very valuable to us.

We made sure that the operation and test crews were thoroughly trained and briefed, and we had ample time on the simulator to practice complex procedures, which was very helpful as well.

We made sure the entire New Hampshire Yankee organization was properly focused on supporting the test program. But as a new plant entering commercial operation, I know from my own experience at other units, and my personal conversations with other senior managers in the industry, and through meetings with them at NUMARK and INPO, that there are certain pitfalls following commercial operation that we need to be on the lookout for.

One is complacency, and the other is a loss of trained personnel.

As senior management, we are keenly aware of these potential concerns, and we will be closely watching for any signs of them. I do not, however, anticipate a problem in these areas.

We have a great many programs underway and initiatives in the planning stages or in progress at New Hampshire Yankee, and there would be no opportunity for our organization to let down. These initiatives include improvements we are going to be making to our maintenance program, that Bruce and Ed will be discussing; the completion of our INPO accreditation for our technical training programs.

We are also in the middle of preparations for the upcoming emergency planning biennial graded exercise, which will be held in December. And we are also deeply involved in preparations for our first refueling outage that will contain a fair amount of work and a whole lot of planning. Be ready for them.

As far as turnover of our staff, New Hampshire Yankee has generally had a low turnover rate, even during the darkest days of the Seabrook Project. We provided opportunities for our licensed operators to advance their careers by transferring outside of the Operations Department. And we have really only lost from the company five licensed operators since 1984, despite the frustrations and the delays in getting the unit licensed and on-line.

Now, this may have something to do with the quality of life in New England, but I know there has been a strong sense of purpose among the people who work at Seabrook, a determination to license the plant and to show the public and our regulators that we can make it one of the safest and most efficient sources of energy in the country.

Also, our emphasis on open communications between our employees and the management of the company, and the importance we place on each individual employee, has also had an important factor in recruiting and retaining talented people.

Now, to get to the heart of the briefing today, I would like to turn the presentation, at this point, over to Gary Kline, who will brief you on the results of the second half of the Power Ascension Test Program. And after Gary, Bruce and Ed will speak. And then I will return for a few closing remarks.

Gary?

MR. KLINE: Thank you, Ted. Again, I am Gary

Kline. I am the Technical Support Manager. And during Power Ascension testing, I functioned as the Power Ascension Test Program Manager.

At our meeting on June 19th, we discussed the development of the program, including preparation, procedure development, and training, and testing activities up to that time. Today, I would like to concentrate on the testing that we completed since our 50 percent power meeting.

Since that time, we have conducted all or portions of 29 power ascension tests. And there are four in particular that I would like to discuss in greater detail today, and those are on the bottom of the second slide.

The first one that I will be discussing will be the large load reduction, ST-35. That is third from the bottom. That test was performed twice, once at 75 percent power, and once at 100 percent power. And that was run by initiating a set-back condition in the turbine, which decreases the plant power at about two percent per minute, down 50 percent.

During the test, the primary and secondary plant performed essentially in accordance with our projected response. After the second load reduction at 100 percent power, we delayed power ascension about 24 hours, in accordance with tech specs, for axial flux difference, to get our penalty minutes back in spec.

The second test that was on the slide, the inner trip from 100 percent power, ST-38, was performed by the plant transient response to a trip from 100 percent power, met our standard design requirements. Additionally, this test verified that the actual HUT leg RTD temperature response time is conservative, with respect to the values used in accident analysis.

ST-38 was initiated by tripping the generator, which in turn tripped the turbine, tripped the reactor. Once the trip took place, the shift operating personnel utilized their appropriate normal and emergency operating procedures to recover the plant to a stable HUT stand-by condition.

Selected plant parameters were monitored throughout the test, and the subsequent analysis of the data showed that the plant responded as expected.

Approximately one hour after the reactor trip, we entered natural circulation, ST-22. And that involved simultaneously tripping all four reactor coolant pumps. The purpose of this test is to verify that the plant can enter natural circulation conditions and adequately remove decay heat.

In fact, it took about 11 minutes to actively establish natural circulation conditions.

The last major test was the loss of off-site power, ST-39. This test was initiated by simulating a loss of off-site power with the opening of the off-site power feeds to the plant, and tripping the turbine. The reactor was at approximately 20 percent power, and we were above our P-9 subpoint.

The test verified that the emergency diesel generators would start and reach their rated speed and voltage within 10 seconds, and also verify that the power sequencer would perform its designed function of sequencing our required loads on.

This test has also demonstrated that the plant can be maintained at a stable condition, which we verified for a 30-minute time span after loading the diesels.

Our Power Ascension Test Program was essentially completed following the completion of ST-40, which was more commonly known as the warranty run. That was completed on Friday, August 17th.

I would like to discuss our review and analysis of the Power Ascension Test Program results. All of our tests that we performed have been reviewed by our Sort Committee and Management Oversight Committee. All test results and test exceptions have been reviewed and approved.

Our initial start-up report had been submitted on June 13th, and the first supplement was submitted last week on September 13th. Some of the results are included in these reports, and the final report, the final start-up test report, will be published prior to September 30th.

With regard to test exceptions, during the program we had a total of 62. The majority of them were very minor in nature, and would include administrative details like receiving the final report from GE on our turbine torsional test results.

The three listed on the slide are three more significant ones. The first one had to do with power distribution measurements, ST-29, which was conducted at each plateau. Our planer peaking factor affects was slightly more than our limit at a given plateau, and per technical specifications we have performed our analysis and accepted the results.

During our LOP test, we concurrently ran ST-43, which is our computer test procedure. During the initiation of the test, the primary host on our computer -- we have two hosts -- was slowed down. The back-up host noted that the computer slowed down, and we had a fail-over during the test, and we lost about two to five minutes' worth of data during that test. That one is still under review.

ST-46, that basically is our ventilation system testing. During the test -- we did that in the middle of the summer -- we did have some high temperatures in the east and west pipe chases, and we had some temporary cooling in there to maintain our technical specification limits. Therefore, we had an exception against the procedure at that point.

Overall, there are still, to date, there are only 11 test exceptions left open. We all have them in our tracking system, and are working towards a final plant close-out.

The last time we were here, I showed a different version, an earlier version, of this slide that showed our unplanned trip results, up to 50 percent power. This slide has been updated to show completion through 100 percent testing. Our goal was zero plant trips. We did not meet that goal. However, I am very pleased with the results we did receive.

The first reactor trip that we did have, of the two, occurred on June 20th, while the reactor was at approximately 30 percent power and increasing. The trip was caused by an unexpected actuation of a relay in our generator protective circuitry. The relay is designed to protect the last 5 percent of generator windings from ground fault. This protective function, which is not required by the generator manufacturer, it is customer trip, initiated a turbine generator trip, when the production circuitry was activated at about 30 percent level.

The turbine generator trip, in turn, initiated the reactor trip, because the protective circuitry actuation is related to set point adjustments that are based on assumed third harmonic voltages supplied by our vendor.

In actual operation, our third harmonic voltage, which is a noise over 60 hertz frequency, turned out to be lower than anticipated. Therefore, the set point was overly conservative.

Since this protection is not required, we have reviewed the functioning of the relay with the relay supplier and the vendor in detail, and we have initiated a modification to convert it to monitoring circuitry, and it is an alarm function only at this point.

The second reactor trip occurred on July 5th, while the reactor was at 75 percent power. This trip was caused by main steam low EHC oil pressure signal, and it was due to vibration. The switches were monitored on our main steam stop valves. There was excessive vibration at a particular point at 75 percent for those switches to be monitored in that location, causing contact closure.

At that point, we relocated the switches to an environment that did not exhibit vibrations, and the problem went away.

In the determination of this root cause, we did talk to other plants to determine if they had experienced th~ same problem, and we also worked closely with the vendor.

In summary, the Power Ascension Test Program, I feel, was very successful. Despite the problems with the turbine, the actual performance of our tests were essentially in accordance with our test schedule and the results were very much as expected.

We, as a company, learned a great deal from power ascension testing. Two major areas that I feel we excelled at were in preparation and teamwork. The Power Ascension Test Program was a complete New Hampshire Yankee team. It was not just an operations and test personnel effort. Training, Engineering and Maintenance Departments, to name just three, worked very effectively with the operations and test crews to solve problems and make this an effective test program. And I think I am confident that you will see this same teamwork in the future.

With regard to preparation, there are three significant areas that we will be carrying over into permanent plant operation. I think that the procedures we developed for the test program were unique in nature, and very good. They have some features in it that we are already utilizing, and additional procedures, as we go through operation. Basically, background and briefing documents for complex evolutions are a key ingredient to have, I think. Training, the use of testing the procedures on the simulator for complex evolution I think was key to debugging the procedures, and making sure that training for the test crews and the operations group was of high quality, and provided thorough knowledge of the evolution to people that are going to be doing these complex evolutions.

And finally, and even prior to entering the test program, we conducted pre-test briefings, pre-evolution briefings, right outside the control room. And we found that those briefings can be extremely helpful, and we are continuing to use that technique.

We have also identified some areas where we can improve. And at this time, I would like to turn the presentation over to Bruce Drawbridge, who will address these areas and other issues.

MR. DRAWBRIDGE: Thank you, Gary. My name is Bruce Drawbridge, and I am the Executive Director of Nuclear Production at New Hampshire Yankee.

I will discuss some of the events that occurred during the test program, and I will also discuss the use of the Power Ascension Test Program self-assessment results, and in particular, some areas where we are devoting additional attention.

I agree with Gary that the Power Ascension Test Program was very successful. Now, my conclusion is not based solely on my own observations, or the technical results. It is also based on the observations and reports from various oversight functions, and from observations of other senior managerent.

The results of the power ascension self-assessment were submitted to you on Tuesday of last week. And before I discuss how management will use the report and recommendations, I would like to have Ed Desmarais, our Self-Assessment Team Manager, provide an overview of the assessment, and discuss the assessment of the maintenance program.

So I will turn it over to you, Ed.

MR. DESMARAIS: Thank you, Bruce. I am Ed Desmarais, the Independent Review Team Manager. And I will discuss the self-assessment team efforts.

Before I do this, I would like to highlight the role of self-assessment at New Hampshire Yankee.

First and foremost, self-assessments are a management tool, which they use to identify areas for improvement. In a general sense, these self-assessments can range from weekly reports or compliance inspections, to experience-based management evaluations.

New Hampshire Yankee has a number of diverse but well-coordinated groups which do these self-assessments on different aspects of the company's business. For the Power Ascension Test Program, New Hampshire Yankee set up a special group called the Self-Assessment Team. This team was chartered with evaluating the conduct of the test program, as well as the functions that would ensure its success.

On June 19th, I described the scope of the self-assessment and the composition of the team, so I will not repeat that today. Instead, I will briefly discuss examples of the types of evaluations we have done, and how they resulted in recommendations and conclusions. After that, I will talk about the team's efforts on the maintenance evaluation.

Evaluating the conduct of the test program and plant operations was a primary focus of the team and the Management Oversight Committee. Throughout the entire test program, the team did this by attending the same initial and requalification training as the test group and the operators, by attending pre-shift briefings, by reading and reviewing all test procedures and their revisions, observing every test, independently reviewing all test results, observing the test result review and approval process, and by presenting the results of these efforts to the Management Oversight Committee.

Through these and other efforts, the team was able to conclude that the test program was conducted in a cautious and conservative manner, and the plant operates per the design basis.

The team also evaluated activities that supported the test program and plant operation. As would be expected during a test program, a number of design and maintenance challenges occurred. As an example, we closely followed the engineering and technical support efforts to analyze and design fine-tuning adjustments to the feed water pump, the feed water regulator valves, the heater drain pump discharge valves, and the moisture separator reheater.

The team reviewed each design package and modification, and discussed the results with the Management Oversight Committee. The SAT, or the Self-Assessment Team, has recommended that technical support and engineering document and analyze the chronological history of the design revisions to the feed water and heater drain string for lessons learned.

The team also reviewed events surrounding the turbine setback on July 2nd. The setback occurred during the performance of a repetitive task involving the generator step-up transformer cooling fans. The potential for this event had been identified about a month earlier, and a revision to the repetitive task sheet was initiated. This event occurred before the revised repetitive task sheet had been issued.

The team recommended that station management further review this event for generic implications on revising issued work packages.

The last example for the power ascension self-assessment involves performance indicators. During the first few months of the self-assessment, the team recommended to the Management Oversight Committee that New Hampshire Yankee adopt and develop INPO-style performance indicators in anticipation of plant operation. These indicators were initially issued in March of 1990, and have evolved over the past few months.

Our assessment indicates that management did use the work request, request for engineering services, surface contamination, and receipt inspection performance indicators to track and, where necessary, make mid-course corrections. Our evaluation also resulted in a recommendation to complete the outstanding performance goal and analysis information for some of the indicators.

These few examples typify the activities and observations that provide the basis for the recommendations and conclusions in the June and September reports.

Many of the areas for improvement that Bruce will discuss today began with recommendations that the team identified and reviewed with the Management Oversight Committee.

The team has looked at many different activities during the past 10 months. Our maintenance evaluation is one example of the key area of focus. The first part of the evaluation looked at the ability of maintenance to support the test program and full power operation. The June and September self-assessment reports summarized the team's activities that led us to conclude that maintenance can support safe and reliable plant operation.

As we mentioned in our presentation on June 19th, the Self-Assessment Team was also doing a special evaluation using the proposed regulatory guidlines in DG-1001. This second part of the maintenance evaluation indicated that overall, New Hampshire Yankee has developed, or is currently addressing, the programmatic aspects contained in those maintenance elements.

Using the rating scheme from the draft guidance, we determined that most of the elements are satisfactory. Some of the elements were evaluated to be good, while others need additional attention.

These ratings reflect criteria which is aimed at fostering excellence in maintenance programs and practices.

The team's general conclusion is that, overall, our maintenance program and practices are satisfactory.

We were able to determine these ratings and conclusions through a series of different types of evaluations. The first involved a comparison of our existing New Hampshire Yankee maintenance program with the proposed regulatory guidance.

To ensure an objective and independent review, we asked an experienced maintenance individual from another utility to make this comparison. His report, which is appended to our maintenance report, concludes that in general, the program documents have considered all the elements stated in the NRC inspection guidance in some form or location. The major weakness is in how the various documents relate and they demonstrate a smooth flaw.

The second type of evaluation involved comparisons of our maintenance program with maintenance programs at other nuclear power plants. At various stages in the evaluation, we either visited or contacted other nuclear plants. The team also contacted INPO to obtain a list of utilities noted for exceptional or superior performance in selected areas of maintenance. We have provided this information to our Maintenance Department.

The third part of the evaluation was based on direct observation of maintenance work. The team observed each part of the work process, beginning with the identification of a work activity, through retrieving archive work packages from the records center.

The first example of direct observation involves the installation of a design package on the heater drain pump. This modification replaced the existing gland packing with a mechanical seal.

We attended the pre-work briefing, reviewed the work for proper authorization and work documents. At the work location, we verified tagging, foreign material exclusion, and the assignment of qualified workers.

During the actual performance of work, the team noted that some administrative aspects of the work could be improved. We also observed that maintenance inspectors inspected the work in progress several times, and that individual departments work well together.

The post-modification test was performed as specified. The data collected, reviewed, and approved.

Another observation example invol es the feed water and steam flow calibration. We began by observing the pre-work briefing in the INC shop. The supervisor reviewed the work package, and the steps to be taken by the two teams involved in the calibration.

This work activity needed good coordination to ensure consistent communications and expectations between the two teams involved in the calibration. The work activity needed good coordination to ensure consistent communications and expectations between the team in the RCA and the team and the control room.

As part of observing this work activity, we reviewed the work package for authorizations, the radiation work permit, tagging, documentation, and general adequacy. Throughout the calibration, procedures were explicitly followed, and the communications crisp and professional. This was particularly significant in light of rotating technicians into and out of the RCA.

The work package was properly completed, reviewed, and closed.

The third example of direct observation involves the diesel generator 18-month surveillance that occurred over several shifts. As in the previous examples, the team reviewed the contents of the work package and the availability of spare parts.

In the field, we also verified that assigned workers were qualified, a detailed log was maintained as work progressed, tagging was per the tagging order, and procedures were followed. The surveillance test was performed, and the test results reviewed and approved.

The team also took different slices of the maintenance process as a cross-check on our direct observation of work. One of these slices included a review of the procurement process for its impact on maintenance.

In the beginning of the test program parts availability was impacting the performance of work in the field. Management established the Materials Task Force to analyze and correct this problem. Through the efforts of this task force, and a planning and scheduling group, parts ordering and expediting has been improved. Work requests are not released until all identified parts are cleared through receipt inspection, and parts availability for work scope changes is now at approximately 98 percent.

The team also reviewed a good-sized sample of the maintenance procedures for content, ease of use by the workers, inclusion in the work packages, the preparation and revision process, and the biannual procedure review. Our evaluation indicated that procedures are issued and controlled as specified by the programs.

We did find, in certain instances, that the content of procedures could be improved to clarify vague statements, such as "as required," or to provide more specific direction.

The last example of direct observation involved the maintenance training and qualification program. Our evaluation began with the Training Advisory Committee that establishes the content and scope of the training program. The evaluation continued by attending different training sessions, reviewing the training schedule and attendance, reviewing the initial qualification of workers, and verifying that qualified workers were assigned to work activities.

The team found that the Training and Qualification Program is working as designed.

In the fourth type of evaluation, we reviewed new, pro-active initiatives intended to improve maintenance. These activities are in the initial stages of development or scheduled for future action.

Our reliability-centered maintenance program is one of these efforts. Engineering has developed the first package using the diesel generator as a prototype. And this package is currently being reviewed by our technical support and maintenance groups.

Beginning in 1991, Engineering is scheduled to develop several reliability-centered maintenance packages each year until they are complete.

The team also reviewed the implementation status of the work-controlled data processing system. The current information systems for maintenance are essentially stand-alone systems that require multiple data entry and access. New Hampshire Yankee is currently at the two-year point in a five-year schedule aimed at implementing a single system for maintenance information.

Parts of this new system are now being used and approved on. When completed, the system will provide information on planning and scheduling, procurement, personnel, trending, documentation, measuring and test equipment, and configuration control.

The final example I will discuss involves the performance monitoring program for plant systems. This program was initially reviewed by the Self-Assessment Team during the low power self-assessment program. At that time, the team reviewed the program outline and performance reports on the few systems it had operating history.

Since that first review, the only additional operating history has been due to the Power Ascension Test Program. The monitoring program, when fully implemented, will provide an analytical tool to improve maintenance by pro-actively finding and correcting equipment systems and problems.

From these four types of evaluations, the team identified areas of strength. These include the planning, scheduling of work, work package preparation, the actual performance of maintenance work, and the pro-active efforts which I just mentioned.

We also identified areas for improvement, which are cited as specific recommendations. Some of these recommendations include: better coordination and integration of maintenance support functions, establishing a dedicated procedure-writers' group, improving work history descriptions, and developing maintenance-specific performance indicators.

These, and a number of other specific recommendations for improvement, were discussed, accepted, and endorsed by the Management Oversight Committee.

We have documented this maintenance evaluation in a separate internal report, which we have made available on-site to the senior resident inspector and other NRC inspectors to review.

I will conclude by reiterating that this maintenance evaluation is an example of our self-assessment efforts. We believe that the endorsement of our recommendations by the company's top management team indicates that the assessments have proven to be a valuable tool for the company.

I will now turn the presentation back over to Bruce, so he can discuss how New Hampshire Yankee is addressing these recommendations.

MR. DRAWBRIDGE: Thanks, Ed. I think that reports such as the maintenance evaluation are very valuable management tools. We will be utilizing results of this and other internal evaluations, along with a total power ascension self-assessment report, as we implement initiatives for the enhancement of our operating organization.

We recognize that we must continually work to improve all aspects of our operation. That includes maintenance, operations, engineering, or training.

We also recognize that it requires active management involvement. I want to assure you that senior management is involved as we implement our initiatives.

Some of the initiatives that we are currently pursuing include enhancement and streamlining of our programs and procedures, improvements in our facilities, and maintenance actions to improve reliability and maintainability.

We not only tested the plant, but have also tested our personnel, in our administrative control programs, with a great deal of emphasis on our work control and maintenance programs. We have determined that the programs are satisfactory; but, they could be streamlined and enhanced to better support plant operations.

One of our initiatives is to consolidate and streamline our work control program, and our maintenance programs, as well. I am working with key station managers to implement recommendations from the self-assessment maintenance evaluation, internal programmatic reviews, as well as comments received from NRC inspectors during the Power Ascension Program.

Now, Ed Desmarais has already mentioned the ongoing work to develop the reliability-centered maintenance, that is RCM program. And we will be including

RCM considerations in this implementation.

I am looking at the recommendations, and I am going to establish a master schedule for their implementation.

I have recently made some changes within the maintenance organization to facilitate the control of work. I made these changes to remove potential distractions so that maintenance personnel can concentrate on the day-to-day maintenance of the plant.

Changes that I made, to date, include the reorganization of the Maintenance Department to create two separate sub-organizations, Mechanical Maintenance and Electrical Maintenance. We feel this should facilitate the control of work. We have also reassigned a manager to a staff position, where he has responsibility for planning and coordinating long-term projects, also facility additions, as well as major turbine overhauls.

And finally, the responsibility for maintenance of our off-site siren system, we transferred from the maintenance organization to our site services organization.

Root cause determination is on ongoing initiative, and we will continue to work on it to improve our overall performance. At our last meeting, I mentioned an enhancement that we are developing to our root cause analysis process. Our new root cause determination procedure was issued the end of July, July 30th.

Now, we have not had enough experience to date with a new procedure to really produce any evaluation of trends. However, this program will be continuing.

I would like to discuss another ongoing initiative that we introduced at the June 19th meeting. And this is our trip avoidance program.

As Gary mentioned, our trip avoidance program was very successful during the Power Ascension Test Program. We experienced only two unplanned reactor trips.

We did, however, experience an unplanned reactor trip on August 22nd. This was after the conclusion of the Power Ascension Test Program. This trip occurred with the unit at 100 percent power, while conducting some minor maintenance on the generator EHC circuitry.

We were aware that the industry had long experienced problems with unexpected EHC sy response during maintenance. We reviewed this work a ity in detail prior to the implementation, and took all the precautions that we deemed to be prudent. Unfortunately, we still experienced the trip. And we have not determined the exact cause.

Now, our discussions with our vendor, GE, has indicated that other plants have experienced similar trips with unknown causes involving EHC circuitry.

In the future, we will continue to carefully evaluate EHC maintenance activities, performed at power to minimize challenges to plant systems.

We are currently evaluating our check valves as part of an EPRI project. The research portion of the project will determine the operating characteristics of each one of our check valves. Now, this data will subsequently be incorporated into surveillance procedures for these check valves to allow us to more accurately test the valves. Now, we anticipate that the program will be developed by the end of this year, and implementation will commence with our first refueling outage.

As you may be aware, we also have an extensive program to ensure the operability of motor operated valves, both during normal operation and also during transient situations. This program utilizes a unique technology, developed by NHY. And it involves the use of strain gauges, as well as personal computers to diagnose and assess the performance of each motor operated valve.

Now, the previous method, using Movat's equipment, required actuator disassembling, in some cases. That was during the performance of calibration. That was primarily for butterfly-style valves.

Our MOV strain gauge program will include all motor operated butterfly valves and rising stem valves, whenever possible. The program has two objectives. One is to accurately measure the forces applied to the valve shafts by the valve operator. And second, to utilize strain gauge measurements to verify that the valve actuator switch settings insure valve operability under the design basis conditions, for the life of the plant.

We feel this is a creative approach to an NRC concern.

An additional area where we are devoting attention is the fine tuning of our secondary plant. In particular, the feed water and connosay system. We have experienced some secondary plant oscillations at power during the Power Ascension Test Program.

We have established a team of individuals to review the operational characteristics of the secondary plant, and develop additional design or procedural enhancements to ensure the reliability and the ease of operation of the secondary site.

I would like to very briefly discuss two plant facility enhancements. As you may know, we have a five-year major plan, an overall plant facilities plan. Plant facilities are included within this plan, so it goes over a five-year period.

The first project we are implementing is a direct result of our Power Ascension Test Program experience.

In order to enhance our chemistry capabilities, we are installing a half-million-gallon demineralized water storage tank. Work on the installation of the tank is in progress now, we just started. And we project that the tank will be in service by March of next year, the end of March of next year.

We are also completing design work on a building that will house our new decontamination facility, and a hot INC shop. And we expect that this work will be done by the last half of 1991.

I would like to address events that occurred during the test program. We had a series of LERs that occurred during the Power Ascension Test Program. As you can see, we have classified the LERs according to their root cause. There was one LER attributed to a weakness in our configuration control program; three due to equipment failures; and five classified as caused by personal error.

Now, the three equipment problems were the type that would be expected during start-up of a new plant. However, the remaining LERs were not expected, and our review of these LERs has provided additional input to our overall management assessment of operations to date.

At the June 19th meeting, I described an ongoing evaluation of configuration control aspects of our work control program. We have completed evaluation, and have reached the following conclusions.

Existing station programs and procedures are satisfactory to maintain configuration control of installed plant systems and components. However, the administrative controls for a configuration control are fragmented throughout our station manuals and procedures.

The task team that performed the configuration review recommended that the existing configuration control documents and procedures be consolidated and simplified to provide a consistent, uniform configuration control program for all departments.

This recommendation is being implemented as part of the integrated program consolidation that I discussed earlier.

In regard to the personal error LERs, as far as I am concerned, one personal error is one too many. Last year, we implemented a human performance evaluation system, HPES. As part of the implementation of this program, we review events caused by personal errors to determine if there is a fundamental underlying cause. We have not identified a unique cause for these events, but we have identified several factors contributing to personal errors.

Attention to detail is always a concern with personal errors. We have identified two areas we will be addressing in order to increase attention to detail.

These are self-verification, or self-checking if you will, and increased management supervisory presence and involvement in the field.

It should be noted that there is a lot of activities being performed during power ascension. And whenever there is a lot of activities, there is always the potential for personal errors. That notwithstanding, we are concerned about personal errors, and we will continue to work on eliminating them.

The two LERs involving unlocked high rad areas were unique in their ultimate cause, but could have been prevented by self-verification. These two LERs in particular I found very disappointing. In both cases, the doors appeared to be locked, but physical manipulation of the door would have revealed the problem.

Meetings have been held with the technicians involved to review the physical configuration of locks and doors, and to reinforce the need to physically check doors to verify their security.

I made it clear to station managers and supervisors that I would not tolerate these types of errors. It should be noted, I said it in a few decibels higher than I am talking to you today.

Finally, I would like to assure you that we will not forget the lessons learned during the low power and

Power Ascension Testing Programs. We are using the experience gained to enhance the operation of both the station and the company.

Now I would like to turn the presentation back over to Ted. Ted?

MR. FEIGENBAUM: Thanks, Bruce. Well, the presentations today have emphasized some of the ways that we are striving to establish and maintain a pro-active philosophy at New Hampshire Yankee. A key element of that philosophy is finding weaknesses before they manifest into operational problems.

Although the power ascension self-assessment has formally concluded the process of internal self-evaluation and critique remains very active at the company. Through a combination of line management self-evaluations, comprehensive root cause and event evaluations, formal quality program performance-based reviews, and most of all close tracking and follow-up of the corrective actions that come out of all these self-assessments and reviews, we believe that New Hampshire Yankee will remain ahead of the curve in identifying and addressing weaknesses in our programs and procedures and people.

I think Seabrook is off to a good start. Our testing program demonstrated the readiness of the staff of the plant systems and equipment for plant operations.

And as we enter the early years of commercial operation, I can assure you that safety will be utmost in our minds of management during all our decision-making processes. And we will continue to work towards ways to improve.

Now, interestingly, industry experience has also shown that the plants with good safety records, the ones with a few unplanned trips, few violations or challenges to safety systems, and with good maintenance practices, are also the reliable and the highly productive plants, as well.

And it is our corporate mission, and the mission of all of us here at the table, to achieve all of these goals and join the ranks of some of the more successful power plants in this nation.

That, essentially, Jon and Tim, concludes our formal remarks here this afternoon. If you have any questions that you would like to discuss on the self-assessment or the Power Ascension Test Program, we would like to respond.

MR. JOHNSON: Sure. I think we have quite a few questions. I will start off by asking, first of all, I guess, in the maintenance area and the technical support areas, you talked about annual reviews of maintenance requests, or backlog of maintenance requests, and an annual review of RESs, engineering service requests.

How do you envision that annual review to take place? And what do you expect to get out of it? On the surface, it looked to me like it was not frequent enough to get some benefit out of it. But maybe I misinterpreted the purpose of it.

MR. KLINE: Well, actually, we have monthly reviews.

MR. DRAWBRIDGE: Why do I not jump in here? We review within my organization, within production, we review. We have a weekly report that comes out as to where we stand on backlogs, et cetera, as far as work requests are concerned. That has a wide distribution. I look at it on a weekly basis. Most of the other management within the company look at it on a weekly basis, too, as well.

It is also updated for particular items on a daily basis, on our plan of the day. And there is a plan of the day report that also comes out, along with hot sheets, et cetera, for work requests.

We also have a committee called the Smerk Committee that looks a little longer term as to items that we want to have Engineering look at, such as RESs, reprioritize those on an ongoing basis. In fact, we have a member of our engineering staff that sits in on Don Moody's morning meetings every morning. Every morning we have a meeting in Don Moody's office at 8 o'clock, where many of the plant managers and supervisors sit in on.

We have a member from Engineering who sits in on that meeting, too, as well. And if problems come up that were noted the previous day, or that evening, that we want Engineering to look at, we tell that Engineering representative. At that point, he goes back, and that becomes the top RES, if you will, right for that day. So there is a continual feedback for ongoing-type things.

And then on a periodic basis, we also look as to where we stand with the RESs.

The annual review, that is more of a sanity check, if you will, as to where we stand, where we want to go, et cetera.

MR. KLINE: That is really to adjust our goals, most of it.

MR. DRAWBRIDGE: Right, right.

MR. KLINE: To see whether you set the right goals for backlogs.

MR. DRAWBRIDGE: How we have done it in previous years, how we are looking this year or this past year, where we want to go, you know, in future years.

MR. JOHNSON: Have you had one of those yet?

MR. DRAWBRIDGE: For this year?

MR. JOHNSON: For any year. Have you had this annual review meeting or goal meeting?

MR. KLINE: Yes.

MR. DESMARAIS: It basically came off as part of start-up reviewing, everything we had out there, to make sure that nothing had fallen through the cracks.

MR. JOHNSON: What do you see as the big picture? Do you see yourselves able to manage the backlog?

MR. DRAWBRIDGE: Oh, yes, we have been managing the backlog right along. You mean as far as RESs and --

MR. JOHNSON: Let's just take engineering requests.

MR. DRAWBRIDGE: Oh, yes. Oh, yes. They have come down substantially. I do not have the numbers in front of me, but from previous years, they have gone down quite a bit. I do not know, can you --

MR. VARGAS: The program started in 1986. Basically, the RES program is a vehicle for all the departments to communicate with Engineering, not just the station. Since 1986, we have received about 4,000 RESs. To date, there are about 750 that are open.

Now, the annual review that you were alluding to is the annual review of the five-year plan. We take every RES that is scheduled, and put it into a five-year plan. We started this about a year-and-a-half, two years ago. And every year we update the five-year plan, such that the initiator of the RES now knows whether we are going to respond to his concern.

Now, there are a lot of forums, as Bruce has indicated, whereby the priority of a particular RES can be raised. Specifically, that is the daily Don Moody meeting, or the daily DOE meeting, or the weekly Smerk meeting, Smerk meaning, as Bruce indicated, is a Seabrook Modification Resource Committee, of which engineering participates, the station participates, Operations and Maintenance participates.

So there are at least three forums, in addition to the annual review of the five-year plan, whereby priorities of the RESs can be raised.

To date, we have no priority one RESs open. Priority one RESs are very high priority items, which we respond to within two or three days. Those are priorities. Most of the RESs that we have are priority three and fours, which are long-term enhancements. Those are factored into the five-year plan. And every year at this time, we get together and revise the five-year plan.

MR. JOHNSON: Okay.

MR. FEIGENBAUM: A lot of the priority three and four RESs have to do with efficiency enhancements, ways to make a job easier for the plant and more efficient, less time, less personnel. And we schedule those as we can get to them, and evaluate them on a routine basis.

The ones needed to support the plant, again through the daily involvement of Engineering, at the station managers' meeting and a constant Smerk re-review of the priorities, the station is supported. So we will always have some backlog of good ideas that people have that we will be evaluating at one time, and putting into the schedule as we can handle them.

MR. JOHNSON: Okay.

MR. DRAWBRIDGE: And those RESs, I think as was noted earlier, are not only just station requests, they support the entire site, as well.

MR. WIGGINS: In your assessment report, the maintenance area, a couple of items of places where I guess you referred to as needing improvement, kind of intrigued me. Maybe you can give me a little bit more background as to what they are, and what their significance is.

I guess it looks like you think you need to do more work in rework, and root cause analysis, and maintenance history collection analysis and application. Tell me a bit about what you meant by that, or how bad the problem is.

MR. DRAWBRIDGE: Well, in the area of rework, right now, we are looking at a definitive way of defining what rework constitutes. Right now, we do not have an indicator where we can follow the amount of rework that occurs.

Right now, I have a maintenance manager looking at the INPO definition of rework. We are going to come up with a definition, and use that for the last quarter of this year. And what we want to do is, beginning of next year, we want to set a goal for -- a limit as to how much rework we want to shoot for. We want to first define, you know, what rework is, so we can put it into our data base so that when we have a work request that has rework associated with it, we can capture that information.

MR. WIGGINS: Is it your sense that there is a rework problem now? That you do not have the answer now, or just you want to make sure that --

MR. DRAWBRIDGE: My gut feel is we do not have a problem. But if you do not really look at it carefully, and really define what rework is, how can you -- I mean, it is just a gut feel. You have to really define what you consider rework, and then see what you have. And then go from there.

There is nothing that jumps out at me as having a problem, no. But I want to be able to define it, and be able to see where we really stand. Then we can start comparing ourselves with other plants that use the same definition. Hopefully other plants will be using the same INPO definition. And really see where we stand, and where we want to be. That is the important thing; where we want to be.

MR. WIGGINS: How about for the root cause assessment in the maintenance area?

MR. DRAWBRIDGE: Yes, I mentioned it very briefly. We developed a procedure that just got out on the street the end of July. To define root cause, and how to use root cause methodology. This is more for things that are of a more minor nature, where you would not do a formal full-blown root cause, but you still want to capture that information so that you could put it back into your data base, along with the rest of your maintenance activities.

So if you have a problem with a piece of equipment, you can really define what that root cause is, and make sure you are really, really correcting it. That is why we wrapped it in with the rework, because if you do not define the rework and if you do not really find the root cause, obviously you could, in the future, cause more rework.

MR. WIGGINS: The improvements in maintenance history, data collection that you are shooting for, does that portend a problem with your documentation that exists so far?

MR. DRAWBRIDGE: That alludes to the data base, I believe. The unified data base.

MR. DESMARAIS: There are really two aspects to that.

MR. DRAWBRIDGE: Yes, sure, go ahead. Go ahead.

MR. DESMARAIS: When we reviewed a good-sized sample of the work requests, we identified the fact that some of the documentation of the work history at the conclusion of the work efforts was lacking. It was there, but it was not sufficiently definitive to provide for later application and analysis and application of the history, so that you would be able to use it in a predictive sense.

So that area that we are identifying is to improve the existing practices for documenting work history, so that they can actually be applied in a more predictive manner.

MR. WIGGINS: So basically you have records that an activity took place, you are trying to improve the description of what the activity was. Your trying to guess what information you would need to have in there, say, if you are looking at it five years from now.

MR. DESMARAIS: That is right, that is right.

MR. WIGGINS: Okay. I had a couple of other questions that go outside of maintenance.

In your report you talk about your verification team looking at EOPs, and you identify a series of EOP discrepancies. Give me a feeling for the severity of those discrepancies?

MR. DRAWBRIDGE: Do you want me to hit that, or do you want me to do it?

MR. DESMARAIS: Why do you not do it?

MR. DRAWBRIDGE: The EOP-type things were relatively minor type of problems that occurred. We did a complete re-review of our EOPs in preparation for actually a review that is occurring.

Whenever I am in this building, I am always worried about the roof coming off.

(Laughter.)

MR. DRAWBRIDGE: I am sorry, I lost my train of thought.

(Laughter.)

MR. DRAWBRIDGE: I can address that a little bit in technical support. As part of the independent process, we loan some of our more senior people to Operations for their effort for validation verification. And the majority of the effort has been to make sure there has been consistency throughout the procedures, to make sure the procedures are consistent in approach, in going from one generation to another or in referral back and forth between procedures. And it has been pretty much minor clean-up.

EOPs have been used on the simulator now for a number of years. And they have been in pretty good shape, overall.

MR. PILLSBURY: In the SAT report, it talks about one technical discrepancy. And then a number of additional discrepancies, but those were administrative discrepancies of a minor nature, as opposed -- I believe that it is in the operations section of your report.

MR. WIGGINS: Okay, so basically your sense is these are minor discrepancies.

MR. PILLSBURY: Yes.

MR. WIGGINS: You indicated in the discussion on, I guess one of your events or trips, that the problem was a repetitive task procedure, was marked for change, but the change had not been made before that repetitive task was --

MR. DRAWBRIDGE: Yes. In that case --

MR. WIGGINS: I guess in reading the report, I got a different view. I guess maybe I am just captured by the words that indicated a note was made on the one, and then a month later, the procedure go issued in a note that followed along. And as a result, it repeats the same thing. That was the generator fan.

MR. DRAWBRIDGE: Okay, I was going to take it. That involved the package already being ready to go.

MR. WIGGINS: I guess the question I really had, and I guess you addressed it, I wanted to know what the outcome is. When you used your SAT, in my understanding of what you said, asked, is there a more generic problem in terms of how procedures are changed, revised? And I guess that is what I was wondering, what you find when you looked at that.

MR. DRAWBRIDGE: In this case, they reviewed the repetitive task sheet, found the problem, corrected the problem. However, we did not take it one more step.

The repetitive task sheet, a lot of times we will pre-stage certain packages, ready to go into the field for use. We did not take that extra effort to verify the RTS when it was updated, that there was not already a package already formulated ready to go out in the field. In that case, that is what happened; there was a package ready to go.

So since we did not take that extra effort to make sure that there was not an old RTS ready to initiate, that package did go into the field, and we had a problem.

MR. WIGGINS: And what have you taken to address that problem?

MR. DRAWBRIDGE: Now what we will do, as a further step, when an RTS is updated, we will check to see if there is any packages there that are already pre-staged, ready to go out in the field.

MR. WIGGINS: Okay. It seems you would be susceptible to having that, if you pre-stage maintenance work, and have procedures in there --

MR. DRAWBRIDGE: That is right, that is right.

Same is true of RTSs or procedures, as well.

MR. WIGGINS: You could get a vendor document that comes in, that says, "Now, do not do it this way, you have got a pre-staged work package that references the old vendor's way of doing it."

MR. DRAWBRIDGE: Exactly.

MR. WIGGINS: That could trap you.

MR. DRAWBRIDGE: So what we do now is, if we are changing a procedure, or if we are changing an RTS, we would check and verify.

MR. FEIGENBAUM: Prepared work packages.

MR. DRAWBRIDGE: For a prepared work package, to make sure if there is a prepared work package out there, that we would pull that package, make a change to the RTS or the procedure.

MR. WIGGINS: That is more effective than the other way around? Verifying any procedure in the package as the up-to-date revision?

MR. DRAWBRIDGE: No, no, no, no. They are up to date. They are up to date at the time the package is developed. You have to understand that we will -- in the case, we used what we call a system week concept, where in a given time, you already have scheduled out certain systems that we are going to do preventative maintenance on. And that is scheduled out well, well, well in advance.

About six weeks before that system week comes up, we will prepare the packages for that system week. And what I mean prepare the packages, it is not only putting in the procedures, et cetera, et cetera, it is also verifying that we have spare parts available, depending upon what the RTS or the procedure says. So that the package is whole. We know when the individual takes that package and goes out on the street, he will have the spare parts, he will have the equipment, and he will have the procedure. He will have everything needed in order to do that process.

Unfortunately, you have this gap where you will have a package ready to go, but it might be a month or a month-and-a-half before the package is actually implemented. So it is for that time frame where a new procedure or a new RTS revision comes through that we have to guard to make sure that, when we make that change, we go back and pull the package.

MR. WIGGINS: The problem you are attacking, that you just discussed, would it be different then from let's say a surveillance test that is pulled out and is found to have a problem in it? And then a change request is made to the surveillance? And the methods that you have at Seabrook to make sure that next time you go through the surveillance, you will at least note that there is a change outstanding to it?

Most people that I have seen do it the other way around. Whenever they get their hands on a procedure, one of the things that the procedure user has to do is make sure he has in his hand the up-to-date revision, whatever kind of change paper is out against it.

MR. DRAWBRIDGE: We had this squared away for procedures. We have always had for procedures that you go back and check the package. We did not have it for RTSs. And that is where we fell down.

MR. WIGGINS: So this was the outlier.

MR. DRAWBRIDGE: This was the outlier, yes.

MR. WIGGINS: And then my last one.

MR. MOODY: I just want to echo, procedure-wise, that cannot happen, as far as a delay in the RTS. You first mentioned procedures issued for a period of hours. Anything that is out there is retrievable through the system, where that procedure exists in a pre-stated document. And it is changed at the time the procedure comes out.

So procedure-wise, it is, as I just mentioned before, when a procedure comes out with new change, all work associated with that change or planned to be associated with that change is changed at that time. The repetitive task sheet is a data sheet, if you will, and that is the open mark that Bruce mentioned.

MR. WIGGINS: And the last item is jumping to a new area. I guess this is kind of an observation. I was reading through your performance indicators, and I was intrigued or taken aback at the licensee event reviewers. Mainly, I have no problem with a goal of reducing those LERs caused by personal error. But I was kind of intrigued by how you got to it. The statement says, "To maintain the total number of LERs as low as possible, the corporate goal is LERs caused by personal error to be less than or equal to five."

Now, it is the first part of the sentence that intrigues me, because if not properly communicated to your staff, they could get the view that you are trying to suppress LERs, or you are trying to hold down the number of them, which I do not think is what you really want to do.

MR. DRAWBRIDGE: No.

MR. WIGGINS: I think you really want to report everything that needs to be reported, and you would like to solve the underlying causes that precipitate the events that are being reported, so you lower them that way. I guess, I assume that is your view.

MR. DRAWBRIDGE: That is right, that is correct.

MR. WIGGINS: And your people understand that?

MR. DRAWBRIDGE: Oh, yes, yes. They understand that.

MR. MOODY: That has been discussed with all of the organization, from the new mechanic or operator coming in to the top levels of management.

MR. JOHNSON: One of the events you had was a problem with valve line-up by instrument rack, a pressure transmitter. We found some extra valves that were not on, I guess, any kind of control system.

Your assessment of that problem describes going out and looking at the valves in the plant to see if you have any more problems like that. And it goes in and it talks about updating some instrument loop diagrams.

Could you give me a little bit more detail as to how confident you feel in your P and IDs, and your valve line-ups? But not just your valve line-ups. How about circuit-breakers and fuses? I mean, if this was a valve, but you know, how confident you are about the systems your operators and technicians have to operate the plant by.

MR. VARGAS: The PIDs have undergone various stages of revision. All the P and IDs have been redrawn from the old CP and IDs to the -- P and IDs. They have all been field verified, field walked out. And we feel very confident that they reflect the actual condition of the plant.

The condition of the valve through the PT-506, that would appear on the CWD ILD portion of the electrical schematics that we are generating right now.

The engineering documents that depict that valve right now are on the old UEC drawings. Since that issue has surfaced, we have now undertaken the CWD ILD version of engineering schematics. It is, in essence, a three- or four-year plan to show all instrumentation valves on engineering schematics. We decided this on a system basis. We decided this on the CBS system. As we finish the system by system, we are going to walk these systems down such that, by the time we are through, by the time we are finished, all of the instrument valves will show on the electrical drawings.

MR. FEIGENBAUM: And in the interim period, Joe, until that effort is --

MR. JOHNSON: Yes, how do you control it now?

MR. VARGAS: The way we control it right now, the valves are shown on engineering documents, okay? The problem that we have had was that they were not consolidated on drawings right now. They show on two fragmented drawings.

In this particular case, in looking at the procedure, the procedure did reference the correct engineering documents. The drawings that the procedure had referenced were correct, and they were shown on those engineering documents.

MR. FEIGENBAUM: Gary or Don, maybe you could talk about the walk-down that was done.

MR. MOODY: We looked at the walk-down, these type of instrument racks that had a bulkhead valve, identified any other existing ones, had those bulkhead valves and identified them in procedures as such.

There is two mechanisms that control those instrument panels. One is what we call 4.5. They go up, and the valve out there in the instrument system that is not in the proceedures that make up the 4.5. Which shows that they are operating that valve, and it also shows that they restored the valve to the original condition, following the evolution that it is going to go through.

And the 4.5 form is used for those valves that are not specifically identified in -- the 4.5 is normally a valve with a policy change position, be it a lifted -- 4.5 may -- and in fact, the need has been terminated.

MR. JOHNSON: How do they know whether they can open this valve if it is not in the procedure?

MR. MOODY: Because it is an instrument valve, it is identified as an instrument valve, then the instrument people can open it. If it is an operation valve, you follow the operational --

MR. DRAWBRIDGE: Those valves, however, they were going to be -- the rack-mounted valves were going to be, or have been captured, as I recall, in the RTSs. And we are going to lock-wire them either open or closed, depending upon what the situation was. Because it was not only what we call bulkhead valves, but it was also when we went through our walk-through, it was also drain valves. We wanted to make sure that were in the proper configuration.

MR. WIGGINS: On the racks?

MR. DRAWBRIDGE: On the racks. And we also did a walk-down of non-rack-mounted.

MR. WIGGINS: What is your boundary for responsibility, say on an instrument line? You got the process, then you got a root valve. And then all of a sudden, it gets in the instrument line, and you wind up with a bunch of instrument valves in the --

MR. MOODY: The operation is a general statement. Operation is taken to the root valve. IC has a valve downstream of that, manifold drain valves --

MR. DRAWBRIDGE: In this case, that particular valve was in the rack. It was in a different area; it was up higher than the rest of the, the manifold valves, if you will. But it was clear it was an INC valve.

MR. WIGGINS: Okay, so it was not a jurisdictional problem.

MR. DRAWBRIDGE: No.

MR. WIGGINS: It was just a valve on the rack that maybe had been missed.

MR. DRAWBRIDGE: Right.

MR. FEIGENBAUM: And now it is in the RTS.

MR. WIGGINS: Now it is in there, all right. That has happened before.

MR. DRAWBRIDGE: Oh, yes, yes. There was, in this case there was a root valve further up right near the turbine. In this case, it was clear that it was an IHC valve.

MR. JOHNSON: Okay, I guess I am a little confused. I thought this was a new set of valves that was not on, and valve line-up sheets, it was not on procedures, and it was --

MR. VARGAS: As I said before --

MR. JOHNSON: In other words, a missing set of valves.

MR. VARGAS: The engineering documents are correct. They have been correct.

MR. JOHNSON: Okay. Okay, now, I guess the question is, in this assessment report, what do you feel about your system for taking the engineering documents, and implementing them as an operational tool?

MR. VARGAS: The engineering documents that are existing today are accurate, and they reflect the condition of the plants. The ILD and CWD effort that we are undertaking is to enhance the maintenance capabilities of the system. It is purely a maintenance tool for them to interpret our documents, but the documents that we have on the street today are correct.

MR. JOHNSON: Well, let's say you start up from your next refueling outage. What will you use to line up your systems?

MR. DRAWBRIDGE: We will use the revised RTSs for that particular equipment that -- let's say the INC person would be involved with. The RTS would include all the associated valves when he goes to align that particular circuit.

MR. JOHNSON: And does this RTS, if it has all the valves in it so it does not need to refer to these engineering documents.

MR. DRAWBRIDGE: That is right, that is right. Obviously, the individual can look at the particular drawing, too, as well, if he so desired. But the RTS would capture those valves.

MR. MOODY: Calibration procedures -- whether that is true -- verifications of the --

MR. WIGGINS: That is an intriguing question. As I said, I do not think this is the first plant that has had this problem. That there have been particularly instrumentation valves that exist, and they were not really captured on either operators or the INC text procedures or line-ups. At least it seems to me I have heard of that before.

If that is true, if I am right that I have heard of that before, does something in your processes fail you that you were not keyed to go look out at Seabrook to see if you had exposure to that kind of a problem? Was industry experience telling you that? Or did you ask yourself that?

MR. FEIGENBAUM: Well, Jim, the way I understand your question is that a valve that is not shown anywhere. These were shown.

MR. WIGGINS: No, no, no. See, well, maybe I am wrong. What I think the man said is --

MR. DRAWBRIDGE: They just were not on the RTS.

MR. WIGGINS: These are not spurious valves. They are on engineering drawings. The plant is constructed the way the drawings say the plant should be constructed.

MR. DRAWBRIDGE: That is correct.

MR. WIGGINS: Well, that is fine. But usually people out that are task operating facility, INC operators, whatever, they do not carry a whole spectrum of engineering drawings with them. They have some drawings that they find particularly useful, and are controlled that way. And they have procedures. And they go out with one of the two to do what they do what they want to do.

And it has been, I think I heard before, where you have, if you put the operating procedures about a line up here, and you put the instrumentation and control tech procedure here; you put the two together, and sometimes valves like these fall through the cracks. They are not on either. Okay, I have heard of that before; I have seen it at other facilities. Have you? And if not, why didn't your office assessment organization not alert you to that type of thing, before you got to this point?

Granted, it was an easy lesson to learn here. It was not exactly the most earth-shattering thing of importance. It is the best way to learn these kind of a low-impact thing. But was there something that you missed? Or you have not look at yet, maybe? That you might be able to get something out of assessing?

MR. DRAWBRIDGE: No, we certainly looked at it now, because we did the walk-downs of all those rack-mounted instrumentations. Basically, the RTS primarily looked at the configuration of the actual manifold itself. It did not include, not only these valves up here, what I call bulkhead isolation valve, it also did not include the drain valves, too, as well.

MR. WIGGINS: That was not the scope.

MR. KLINE: Jurisdiction was addressed on that, whether or not operations or INC had primary responsibility for position.

MR. WIGGINS: What I am getting to is, if you have an office assessment and you have people plugged into the industry, you know, should they have told you or warned you that there might be a problem? So you should have found this? You know, as you were getting operating proceedures.

MR. DRAWBRIDGE: I see. I misinterpreted your --

MR. WIGGINS: Yes, I do not have a problem with what you did after you found it. That sounds fine, you know. Did something fail you? The elements of your organization that are trying to keep wired into what the other utilities developed, did that fail you?

MR. DESMARAIS: Jim, when we did the assessment, we did not uncover anything that would have led, through the office experience review program, would have led us to look at that problem.

MR. JOHNSON: I guess my final question, what about breakers, fuses? Have you taken this experience, and gone to the --

MR. MOODY: Hand slide lengths.

MR. JOHNSON: Slide lengths. You have got things that electricians operate, and things that INC technicians operate. And what about the things that are in the middle, that nobody is -- that somebody is missing right now?

MR. DRAWBRIDGE: I think we are in pretty good shape. I think I alluded to it when I spoke on the configuration management control, that we think we have captured everything. The problem from my perspective is, the problem is that some of the departments are using a slightly different method from department to department. And we want to make sure we use the same standardized method, and that the configuration control for Seabrook station is streamlined, everybody understands what everybody else is doing. That way, there is no question in the future, if a new system goes in, for example -- skid-mounted system, or something like that.

If you have skid-mounted system with vendor supplied valves, for example, it will be clear whose jurisdiction those valves come under, and which procedures that they follow up on.

So what we want to do is, we think our configuration control program is decent. We want to improve upon it. We want to standardize it, and we want to make sure everybody understands what is what, across the organization. We do not feel we have a problem department to department; we want to make sure that everybody, the right and the left hand are talking to each other.

Did I answer your question?

MR. JOHNSON: I think so. I heard that you have looked at that. I just wanted to see if you took this problem with valve line-ups and went outside of that and looked at the circuit breakers.

MR. MOODY: What about the other thing of -- we also set up a task force to work within, that involves other departments, be it INC, be it electrical, be it maintenance, be it operations, be it physical chemistry. On what they had in place, as far as configuration control, and how that narrows the base betwe\n the other organizations in the station.

We had each department identify how they interfaced back and forth across that line. In fact, there is some consistency -- the same way.

MR. DRAWBRIDGE: See, Jon, it is not only breakers, fuses, slide lengths, et cetera. It is also what the configuration of a particular piece of equipment is at any given time.

For example, you are probably well aware, at one point in time when we were at the beginning of power ascension, we were going to do some trouble-shooting in the turbine. And we had an open work request in order to do trouble-shooting on the turbine, as we were spinning the turbine. And we ran into a problem with the slide length not being in the proper configuration. That was because the work package itself was open.

We went back and looked at our configuration control process to assure that the work in progress for outstanding work requests, where you might be doing trouble-shooting, that that package is properly reviewed to assure ourselves that we do not have something in a different configuration than what we want.

So it is not only just focusing on a particular piece of equipment. It is focusing on the timing on when that piece of equipment is being used, what you might be working on, and what that final condition of the equipment is.

Because the point I am trying to make is, we should not only just focus on what type of equipment, but in what situations you might be trouble-shooting or using that equipment. So it is a many-faceted issue.

MR. JOHNSON: I understand that. I was just concerned with the basic procedure, valve line-ups, and P and IDs, and circuit breaker line-ups. Whether you had all the equipment captured in a system to be used. I was not going to take it the next step in terms of during maintenance. I just want to make sure there is a system there, whether it be a line-up procedure or a P and ID, that is accurate and covers all the equipment.

Because for this cabinet or instrument rack, I thought there were some procedures or drawings being used that did not show them.

MR. DRAWBRIDGE: Which cabinet was that?

MR. JOHNSON: That is the turbine impulse pressure.

MR. DRAWBRIDGE: Oh, I see, yes.

MR. JOHNSON: The tools the people were using did not show, the RTS did --

MR. FEIGENBAUM: The RTS did not show that. That is correct. That is correct.

MR. DUDLEY: Also, the loop diagrams.

MR. DRAWBRIDGE: I have to go back and look, now; it has been a while, now. I am not sure. I do not think the loop diagrams showed it. However, the original document did show it.

MR. DUDLEY: You had to go all the way back to the engineering drawings.

MR. DRAWBRIDGE: Right. But correct me if I am wrong now, Noel, was there not a valve number that was A or B?

MR. DUDLEY: Yes. B-4.

MR. DRAWBRIDGE: Yes, there was like an A/B, yes.

MR. DUDLEY: It was a generic drawing for all racks.

MR. DRAWBRIDGE: Right, right.

MR. MOODY: A typical.

MR. DRAWBRIDGE: A typical of the --

MR. DUDLEY: A typical mercury rack valve arrangement.

MR. DRAWBRIDGE: Right.

MR. JOHNSON: Thank you.

MR. MCCABE: On the repetitive task sheet issue and the problem with the shifting of the fans on the step-up transformer. I see that the first time that type of problem came up was when you could not increase power above a certain level because the interlock had not been cleared from a previous fan shifting.

Then the problem occurred, and then a very similar problem occurred because the isophase duct cooling fan shifting brought about the same problem.

Are you satisfied that, one, the initial indicator was properly listened to? And that the corrective actions are going to cover not only the fans, but the isophase duct cooling? And have you reviewed other places in the plant where this problem may occur?

MR. DRAWBRIDGE: Yes, we have. You want to hit it, or else you can get the isophase question?

MR. KLINE: I will take it. At that first one, where we had difficulty increasing, it was, in fact, a place where we identified that there was a problem with our setback circuitry. That is where we identified that we did need to revise the RTS.

Unfortunately, in that RTS revision process is where we did not retrieve the field package. Therefore, we ended up with a setback.

We did, in fact, review in detail all of our setback and runback circuitry, however. And the isophase duct cooling was the result of an individual reading of procedure, with a change already in it, and misreading the change.

There is a delay circuitry in that fan such that dampers open before the fan starts. So when he started that fan and shut off the other one, there was a 30-second time delay in that damper opening before the fan actually started, the other fan, the second fan, now being off. But there was a dead band, and that came down.

So in fact, the review was complete. The readability, I guess, of the change in the isophase duct cooling fan situation was in question. But, in fact, the change was made. And we do have, in fact, some temporary modifications going in -- some permanent modifications going in, I should say -- to eliminate that as a problem altogether with the time delays in the circuitry.

MR. MCCABE: You are modifying it on both sets of fans?

MR. KLINE: Yes. Time delay is going in in isophase, and static cooling?

MR. VARGAS: Yes, static cooling.

MR. KLINE: Static cooling. So all of it was reviewed. Unfortunately, an individual doing maintenance on the last event read the note incorrectly.

MR. MCCABE: On your maintenance personnel training, when do you envision completion of the training modifications coordination that you have identified in this report? And full accreditation of your maintenance training program.

MR. DRAWBRIDGE: Full accreditation, right now we plan to go for accreditation, I believe it is November of this year. We go before a boaid, the Accreditation Board. We have already had the internal -- they do not call it an audit, but I call it an audit -- where members of the academy, INPO, come in and assess not only maintenance, but it is also tech staff training, chemistry HP. There is a whole bunch of them. We hope to get accreditation by the end of the year.

But that is not the end of the process. That is just part of the process. Accreditation is an ongoing process, where you continually improve, and use feedback from what is actually being done in the field to improve your training programs. And then we have the accreditation that occurs every two years thereafter.

So we do plan to get accredited by the end of this year. But from then on, we will be constantly doing an interim process in our training programs, not only for maintenance but all of those.

MR. VARGAS: We have gone through the maintenance qualification, to check off or not check off, whichever would be the case, which individuals qualify for what tasks, in conjunction with preparation for going through the accreditation.

MR. DRAWBRIDGE: We also use training coordinators. For example, in the case of maintenance and some other departments. We find that to be very useful. They act as a liaison. They are in the department, and they act as a liaison between the department and the training department. That way when they see problems, or a department head sees an area where they feel there is a weakness that can be addressed by training, that is sent back to the training department.

MR. MCCABE: About the area of radiation protection, when you are shifting from no source term to a bigger source term whose operation is continuous, what are your plans in regard to radiation protection, staffing, and in regard to the rad waste disposal issue? What are your plans for going ahead with those areas?

MR. FEIGENBAUM: Don, you want to take that?

MR. MOODY: At the present time, where the rad waste storage area, store rad waste, we have got them at the station. We are sorting, segregating, compacting rad waste we generated to date. And we are getting on the order of 94 to one reduction.

But, as you mentioned, we have only had a source term for a short term. We have probably got, to date, accumulated around 100 cubic feet of low-level waste, which we keep on site. We have got enough storage area on site at least for the first cycle, and probably up to at least two cycles to store it in the buildings we have got there on site. Then we will either have to use another building on site, or build a facility to store low-level waste.

That is the status we have got right now.

MR. FEIGENBAUM: Do you want to discuss the staffing, Don?

MR. DRAWBRIDGE: Do you want to hit that, or do you want me to hit that?

MR. MOODY: Go ahead.

MR. DRAWBRIDGE: Okay. Well, the reason why I thought I would discuss it is I had a talk with Ron Nimitz last week on this very issue.

Staffing in the HP area we are going to watch carefully. Right now, we think we are adequately staffed. We are certainly not overstaffed in the area. There are a couple of areas that we are keeping close watch on. Records-keeping area is one. And also the amount of overtime that we use.

We are going through the budget process right now. Next year we are also looking very carefully as to what kind of augmentation we are going to need for our first refueling outage. This is an area we are going to watch very closely. We are just beginning to see a source term, of course, and as I alluded to earlier, in the HP area, we are being challenged for the first time. And I think we have to keep a real close watch as to where we are, and where we are going.

This is something that Don and myself, and other senior management is going to keep a real close eye on.

MR. FEIGENBAUM: We feel comfortable right now with the staffing, the way we are.

MR. JOHNSON: Is the control of overtime adequate?

MR. DRAWBRIDGE: Control of overtime? I get overtime reports for all areas, not just HP, but for all areas. And we watch them. And we do have some overtime that occurs in the HP area right now, doing surveillances, et cetera. And we have to watch that. We have to make sure that it does not get excessive in any way, shape, or form.

But right now we want to take a look at that area, along with other areas, too, and see where we check out.

MR. DUDLEY: Yes, one area I wanted to touch on was your quality assurance program. I know that you have outstanding some recommendations in the quality assurance area, where you decide responsibility and due dates for those recommendations.

That information does not appear in the self-assessment team report. Could you go into some background on where you feel your quality assurance program is? And where you would like to see it move in the future.

MR. FEIGENBAUM: Neal, do you want to talk about the open items? We did a study -- before you go into this, we did, as you know, a self-evaluation similar to what we did for the maintenance evaluation, for the quality programs area some time ago. And there were a number of short-term and long-term recommendations.

We have accomplished the short-term recommendations, the things that we absolutely felt we needed to do to get our programs up to snuff. There were a number of long-term enhancements, good things to do, and there are still a few outstanding items left over from that, including job rotation and a few others.

But I will let Neal Pillsbury, who has recently had a reassessment done on our performance-based quality program, and where we are moving in that direction. I will let him summarize where we stand on that.

MR. PILLSBURY: Yes, Neal Pillsbury, Director of Quality Programs. As Ted has said, when we did the assessment in April of 1989, we identified a number of areas that we felt we needed to take immediate action on. And in essence, those immediate action areas and the identified initiatives that were already underway are essentially complete, or fully implemented, and continuing in ongoing programs.

The other good idea suggestions continue to be evaluated. Those are tracked on a matrix. We assess that at least on a quarterly basis, and they are periodically assessed in nuclear quality group or in production interface meetings, which we tend to have them on -- or try to have them on a monthly basis. I think we had about 10 meetings in 1990. So we keep track of it.

I think all of those, everything that has come out of that self-assessment evaluation in the quality programs area has been very beneficial to the organization. We are proud of the advancements and success that we have accomplished over the time between April of 1989 and today. I think that the relationships between the quality organization and production organization, and engineering organizations, are significantly better. The communications are better. And things such as the finding review board are working well; the nuclear quality group production periodic meetings are working well.

My relationships with the Station Manager, and with Bruce, and our ability to resolve things without having to go to Ted -- and there has only been one that I can think of, ever since Bruce has been on board, that we have discussed it with Ted. But all of that relationship is much better.

We would like to be more pro-active. We certainly have additional enhancements. And everybody here recognizes that we have had a difficult time with allegations this year, which have consumed much of the energies within the quality organization that we would have more liked to have put on pro-active and enhancement-type initiatives within the organization.

But those initiatives are there. We know exactly what we want to do. And hopefully, we will make better progress. It has been a challenge this year simply to carry out the promised initiatives associated with the Power Ascension Test Program. Not at all to dilute any of our routine activities, and not let up at all on what we wanted to accomplish, in terms of Power Ascension Test Program self-assessment and nuclear quality group inspections and surveillances and audits directly associated with the Power Ascension Test Program. We did not let any of that slip. But we did have to put overtime in just to handle the allegations load.

MR. WIGGINS: How many recommendations are we talking about that are still open? Approximately?

MR. PILLSBURY: It is down to a dozen or 15, I think, on that order.

MR. WIGGINS: Out of how many? How many long-term were there?

MR. PILLSBURY: There were -- I do not.

MR. FEIGENBAUM: Fifty or 60?

MR. PILLSBURY: Yes, on the order of 60. There were about 44 that were good ideas; 11 that were identified initiatives that we asked the organization to support, and all those have been; and six immediate term.

So the six immediate, six or seven immediate, and the 11 ongoing initiatives, are essentially done and being continued in ongoing programs today. And then another 44 that have all been worked on, with the exception of a dozen or 15.

MR. FEIGENBAUM: A couple other things, just to give you an idea. As I mentioned, job rotation out of the quality program into other areas was one of the recommendations that was made. But with everything going on, with power ascension and allegations from Congressional staffers, it just was not possible to handle that well. We could have moved people around, but it would not have been the kinds of assignments that we really wanted them to experience.

The other thing is facilities, it was a good idea to look into putting all the quality people in one physical location. And we were not able to accomplish that this year. And it is something that we are continually re-evaluating, as to whether that is the way we want to go. Is it better -- there is two trains of thought here. One train is, put everybody that is quality together, so you get a critical mass, if you will, of thinking. And the other train of thought is, keep the people in quality together with the groups that they are observing and overseeing.

So we are still discussing that. And we will be looking at it again in the future. And we keep quarterly, as Neal said, re-looking at a few of these open items that are left.

They were items to look at. They were not all committed as absolutely we were going to do every one of these things. And we look at them, and we evaluate them. If we think there is good ideas, we follow through on it.

MR. WIGGINS: For those that you agree are good ideas, have they been scheduled out? Resource loaded? Or any idea of how much it would take the organization to implement?

MR. FEIGENBAUM: That is the majority of them. The ones that are left are the ones that were really lower priority, and still some difference of opinion as to whether we want to go and do that. So we are still evaluating many of those.

MR. MARTIN: Ted, what did you mean by keeping the quality assurance people with the people they are observing? What did you mean by that?

MR. FEIGENBAUM: Well, for instance, right now we have quality control people located inside the protected area with the plant personnel, in close proximity to the work that is going on, as opposed to the quality, procurement quality people that are located in a different area, that go out to vendors and do audits.

Quality assurance people, right now, are located with the engineering groups, in the tech support group, in our operational support building. If we were going to take the quality control people, and the quality assurance, and the procurement quality people, and put them in one facility, they would not be with any one particular, or close to, physically, any one particular group of people that they work with day to day, closely. They would not be with the purchasing people, they would not be with the engineers, and they would not necessarily be with the maintenance plant personnel.

So I am from the school of thought, I actually like the way it is, even though they are split up and it is a little tough for the quality management people to keep their fingers on various groups in different locations. I like having the quality control people inside the plant, inside the protected area, near the work. I like having the QA folks near the engineers. And that is what we are kicking around right now, really, whether that is a good recommendation or not.

MR. MARTIN: Okay, but there is an Achilles' heel with that, and I would kind of like to hear how you are dealing with it, objectivity and independence. How do you maintain that objectivity and independence if you keep them close?

MR. FEIGENBAUM: Well, when I said "close," I mean they are in the same general area. They are not side-by-side. They are close to the people that they have to communicate with. They are independent in terms of their reporting lines. Neal Pillsbury has all the quality programs people reporting through a quality assurance manager to him. The independent review team reports to him our employee concerns and allegations.

He reports directly to me. Those people that work for him do not work for Don Moody, and they do not work for Bruce Drawbridge. There is a lot of interface there, at all levels, not only the working level, but at Bruce's level and the middle management level. But there is that independence; but yet, I think physically it is good for them to have their handJ on the pulse of what is going on in the plant, the activities that they are responsible for checking and verifying.

If they were physically in a facility outside the plant, I think that the value of the quality control group would diminish.

MR. MARTIN: We rotate our inspectors. Do you rotate your quality assurance people?

MR. FEIGENBAUM: Yes, we do rotate them. We rotate them between groups. The recommendation was made to take the quality assurance people and put them in engineering, take the quality assurance people and put them in maintenance. Actually, many of them came from maintenance; they do not really want to go back.

And we are looking at that, and I think that is a good idea. You have to guard against the independence problem when you do that. But it just was not in the cards for this year, with all the responses to the independent regulatory review team that we were working on, and the Power Ascension Program, and round-the-clock coverage. We just could not coordinate a good job rotation program at this point. But we will look at it again.

MR. PILLSBURY: Tim, we do do some extensive rotation within the quality programs area, which achieves some of the subjectivity, or objectivity, I think, that you are looking for. I can do that. That is within my organization.

We have not been able to formalize and set up the rotation program between production and the nuclear quality group. But that is one of those good ideas that we are working on, and attempting to figure out a way to do it.

But within quality programs, for instance, we are taking people from the nuclear quality group and applying them to the IRT self-assessment team assessment effort, and vice-versa. From the ISEG group back and forth within the groups. And that helps to build the objectivity, and the cross-discipline involvement. and so forth.

I had one additional thought, Noel, in answer to your question about other pro-active things that we are doing. We tend to measure ourselves a couple of different ways. We use as barometers an individual from the Bartech Organization that I think you people are familiar with, to come in and look at our programs, in-depth, in detail, several times a year. As a matter of fact, he was back here just recently. He helped us with our initial formulation of thought and philosophy and concept on performance-based assessment, and did some of our initial training. And then has come back and looked at that, as well as all of the other facets of our operational quality assurance program in a disciplined, formal way.

We also look at self reports from all over the nation, to soak up the good ideas, and evaluate ourselves against those, as well as from our Joint Utility Management Audit Association. We are a participant in the Juma organization. We send various numbers of people from our organization to other organizations to do their annual management audits. And in turn, enjoy their participation at Seabrook, and their ideas, and so forth.

In fact, we have just had a Juma audit here within the last month.

MR. DRAWBRIDGE: I would like to just say a couple words, that Neal alluded to. And I would also like to mention, from my perspective, the interface meetings that we have with the quality organization I found to be very beneficial. It is usually a free exchange of ideas, to say the least. Some of the meetings are tough. QA, QC, they call a spade a spade. We call a spade a spade on occasion, too, as well. But I think the meetings are always refreshing. Because at the end of the meetings, we understand where people are coming from. And there is a mutual respect that is developed as a result of these meetings.

There is also a mutual respect that is developed when you have a QC organization in the plant, stationed in the plant on a regular basis. It was not mentioned, but

Neal could have mentioned that we have a QC supervisor that sits in on Don Moody's morning meetings. And he hears the same thing that we do; he sees some of the decisions that may be decided at those meetings, and the thought processes as well. So there is a mutual respect, a team effort that occurs here, that does not compromise their independence, but it is a, I think it is a very healthy interface between the two organizations that occurs on a daily basis. And then when we have our monthly meetings, I think that is going through the organization, and I think that they are very beneficial, very beneficial in the long term.

I, myself, do not always like to be criticized sometimes. But when I hear someone that I respect saying something that makes sense to me, then I take heed of it. I think that is true of anyone in an operations organization.

Any other questions? Ron?

MR. NIMITZ: I just had a quick question on this rad waste issue. Discussions with your staff up there, they were not able to give me any clear information relative to storage locations, capacities, and that sort of thing. Where it is going to go, what your interim storage locations were going to be. Storage of rad waste around the facility can cause fire protection problems, seismic loading, radiation exposure problems. And there does not seem to be any long-term plan as to what you are going to do with this, relative to your capabilities to shift off stuff off-site.

You are backed up seven or eight weeks there with material stored in your waste processing building, that you are backed up trying to process. And I guess that we do not see a long-term plan as to, we could come in and see something that says where is this going to be, is this adequate or not adequate. It appears to be in the formulation stage now.

MR. DRAWBRIDGE: That is correct. We have, under Dennis McClain, who also reports to me -- he does not report to Don Moody. He has an individual who is tasked with looking at that this fall, as to what we plan to do in the interim short term; that is, the next four or five years. And then also, you know, long-term interim, the next year or so. And then longer term, the next four or five years and beyond.

There is a couple of different options we are looking at. But he is still in that process. And they have not yet sat down with me and given myself and Don a full briefing on it yet, because they are still looking at the different options.

MR. NIMITZ: Currently, it is a good waste reduction initiative using the ventilizer systems. They have no ALARA design. And as the source term increases, you are going to cause exposure control problems, RES --

But overall, we do not see -- how can I say -- a complete rad waste program, in terms of what you are going to do with that stuff.

MR. DRAWBRIDGE: That is right, Ron, and that is because it is being developed. They are looking at it now. And it is not internal, the station that is being done by my production group, production support group.

MR. NIMITZ: Do you have some sort of goal as to when this plan will be developed?

MR. DRAWBRIDGE: Yes, it should be developed by the end of this year.

MR. JOHNSON: Okay, well, that certainly will be an area we will be inspecting and then monitoring. We understand why you did not have a plan, I guess, initial operation. But I think, just by the questions, we are interested in it, and interested in where you are going. But also we will be conducting routine inspections of that area.

Anybody have any other questions?

MR. MARTIN: I have a couple here. My understanding is that you now need to operate with three condensate pumps continuously.

MR. DRAWBRIDGE: That is correct.

MR. MARTIN: What is the ramifications of that, and are there any plans to resolve that issue?

MR. DRAWBRIDGE: I alluded to it briefly in my presentation. On occasion, during power ascension, and on occasion afterwards, we have seen some perturbations on the secondary side. And because of that, the suction of our feed water pumps will tend to oscillate. And if it diverges enough, you could get a trip on low suction on the feed water pump.

Because of that, we have the third condensate pump on. We have been able to get up to, I think 98 percent?

MR. MOODY: Ninety-nine plus.

MR. DRAWBRIDGE: Ninety-nine, well, okay, I will call it 98 percent power on the two condensate pumps. However, when an oscillation occurs, the operators justifiably do not like to see those swings. And so they want to keep that third pump on.

We have a task team that is assembled that is looking at the entire feed water string. There is one thing that came out of it already, and that is a configuration of a pipe on some MSR drains. We think if we reconfigure, it will help on the situation, because that, in turn, feeds down to our heater drain tank, and causes some perturbations in a level, and initiates some of these oscillations that occur.

So what we have the task team doing is looking at that. They are also looking at feed water levels to make sure that those are exactly where they should be. And looking through the whole string, to make sure that we can nail down these oscillations.

And once we can get the oscillation problem corrected, and we think we should be able to take off that third condensate pump. But a concern is for your feed water pump suction during the oscillation.

MR. MOODY: We have not counted all the way down. We get an automatic start on the condensate pump of 330 pounds of pressure, suction pressure. Feed pump people, that trip could be as low as 190. We have not challenged that. We have left that, and not looked -- we have not challenged that set point.

MR. MARTIN: Is it a trip of the feed pump? Or is it a start of additional condensate pump?

MR. MOODY: We have an automatic condensate pumps status of 335, 330 pound suction on the feed pump. The feed pump trip is set right now at about 220 pounds.

MR. DRAWBRIDGE: And that is not instantaneous trip, though, Don. There is a time delay.

MR. MOODY: No, there is a time delay of about 20 seconds on that trip.

MR. KLINE: That will set you back to 55 percent power.

MR. MOODY: And that will run you back. We did, as I say, got up to -- well, you said 98 -- 99 plus before we got that automatic stop on that third pump. After we come up the last time.

MR. MARTIN: You know that we are going to be doing a maintenance team inspection in November. We have a number of initiatives and we are engaged in to enhance the maintenance program. Are they going to be in effect, what we are going to look at in November? Or will it be a completed program? Or will there be a lot of things that are still in transition?

MR. DRAWBRIDGE: We will, in the November time frame, we will still have things in transition. I believe, unless I am mistaken, I thought the maintenance audit was going to be changed to the -- I think it was a March time frame. Is that true?

MR. DUDLEY: I have not been able to track it, track the source of that in the region.

MR. DRAWBRIDGE: Oh.

MR. DUDLEY: There is no knowledge of that in the region.

MR. JOHNSON: Bill, anybody know?

MR. MARTIN: We will have to get back to you on that.

MR. FEIGENBAUM: It is my understanding that it is

November.

MR. DRAWBRIDGE: Okay, that is what we originally heard. And then it was our understanding that there was a potential that that was going to be shifted out to the March, I think it was the March time frame of next year. But to answer your question --

MR. FEIGENBAUM: It will be in the middle of --

MR. DRAWBRIDGE: -- in the November time frame, we would be going through this transitional process.

MR. MARTIN: Okay. You pa[illegible]d your power ascension program. What kind of assessment program do you have now of operations? And does it involve back shift activities?

MR. DRAWBRIDGE: You mean independent assessment? Or ongoing assessments?

MR. MARTIN: Independent assessment of what is going on in the plant.

MR. DRAWBRIDGE: Neal, you want to get that?

MR. PILLSBURY: Sure. We have routinely utilized nuclear quality group back shift assessments. We have also routinely used the independent safety engineering group on-site evaluation activities on back shifts. I cannot quote percentages to you, but that is a routine part of both the operational quality assurance program and the independent safety engineering group responsibilities.

MR. MARTIN: How frequently was that done?

MR. PILLSBURY: I cannot quote hours. Hours or frequency. I would have to go back and look that up. I would assume on the order of two or three surveillances on a quarterly basis. So somewhere around a dozen times a year.

MR. MARTIN: What about senior managers? Operations managers, in particular. They come in on their own back shifts, and observe operations?

MR. MOODY: They all come in, including myself. But over the test period, there was a lot of activities going on. So I am not sure you would see a representative of what the day-to-day operation would be, because it was not on the additional people from operations on, test personnel, maintenance -- supplemental forces. So I am not sure you would see in that environment what you might be looking for in an operating plant, on a day-to-day basis, on a back shift.

We do plan to have people come in on the back shifts, back shift meaning both the swing and the morning shift. We have that now, that some people come in. It has just not been part of a plan, orientated, closely structured, that so many times you will come in, or so many times you will come in, and so forth. We have done that on a scheduled basis.

MR. MARTIN: So it is not an articulated, then, goal of management that senior managers, with certain frequency, will get in the plant on back shift to observe the operators, particularly in the control room?

MR. MOODY: No. That is not stated in the policy, as such.

MR. MARTIN: I bring it up, because we just recently experienced a licensee which has a fairly good record. A resident inspector walked in and found both the RO and SRO inattentive at the controls. And no licensee can tolerate that. And one of the things that we will be following up on is how this condition developed. It appears, at least on the back shifts, in discussion with the operators, they believe a different standard exists than the day shift.

MR. FEIGENBAUM: We will take that back and look at it.

MR. MARTIN: How long does it take you to get a new rad con staff member up and running, so that he can be an effective part of your staff?

MR. MOODY: A technician?

MR. MARTIN: Rad con.

MR. MOODY: Again, it is going to depend on the level of experience of the individual. We can hire in at the senior level. But if we have some contractors, let's say building up for the refueling or coming out of the refueling, we feel that we do need to supplement our staff, we can roll a contractor into any wide position, in a very short period of time. And bring that individual up to speed.

Ed, we can hire a senior technician, assuming they are familiar with our own internal programs.

MR. MARTIN: My understanding right now, you have got a rad con staff on the order of 20 permanent people. Is that a fair number?

MR. MOODY: Fair number.

MR. MARTIN: And that you are running right now, the source term you got overtime rate of about 15 to 20 percent for those people. As the source term continues to grow, are you going to have enough lead time to maintain that number of openings?

MR. MOODY: If you look at the 15 to 20 percent, that includes a number of hours rolled in there for the surveys that were made coming up to the various power levels. I believe that is rolled in there.

MR. MARTIN: They were one-of-a-kind type, that is what you are --

MR. MOODY: Yes. I do not expect that number to be anywhere near that --

MR. NIMITZ: Well, this is based on information I gathere relative to the month that you were at 100 percent power. So that would be essentially --

MR. MOODY: August?

MR. NIMITZ: I am sorry, that would be reflective of routine conditions. So it raises some questions in terms of personnel coming in on weekends to perform routine surveillances, and small, minor source that you have now, the activities that staff could perform very easily, triple or quadruple based on the source term.

MR. MOODY: That was also the time frame, we made a number of, I believe, containment entities for various surveys, or work --

MR. NIMITZ: Well, I am just talking routine work, not non-routine.

MR. MOODY: I do not expect it to be anywhere near that level that you quoted.

MR. NERSES: When you say that, when would I expect to see it? The month of September? November? When would I expect to see it?

MR. MOODY: I guess the best estimate to take a look at what it looks like, I would take the last part of -- assuming that we have got no major evolutions planned, no outages and so forth planned. I think if we take a look at the last quarter of 1990, we get a pretty good feel of what the routine would be.

MR. MARTIN: Well, we will do that.

MR. JOHNSON: Well, I guess that is something good to take a look at your data, too. But I guess there is lots of other probably similar plants that have gone through this exercise, that are fairly new, in the same condition, and have gone through this. Maybe even a little bit older, so you can see what their experiences were. It is probably worthwhile to take a look at that, too.

MR. MOODY: Oh, I believe that we do all that.

MR. JOHNSON: Okay. Anybody else have any questions?

MR. DRYSDALE: Could I get back to your issue of -- prior to the achievement of commercial operation, you had a goal of having your -- referred to as the plant labelling program, I think is what you referred to, completed by the time you achieved commercial operation.

I understand what you are saying about this configuration control program, it still being in development. Have you, in fact, completed formally this plant labelling program? Or has it kind of been absorbed into the new configuration control program?

As you know, I think these instrument regs, we have discovered some labelling problems several months ago. And I am just interested, to what extent have you actually completed that program?

MR. MOODY: We have not completed the program as such. We have taken a look to a task force, how the configuration control was laced through all of the -- and so forth. As part of that, labelling, a useful label amounts to a much larger program. We do not use non-vent names on labelling required. We are looking at going back, reassessing that. Looking at bigger tags.

So the labelling program, as a result of our own internal task force, has expanded a good deal beyond what the initial concept was.

MR. DRYSDALE: Well, I know you have done a number of log -- configuration controls verifications. What is your feeling now about problems that might be out there still with respect to components that are not labelled?

MR. MOODY: Well, as I mentioned, I do not feel there is a lingering problem out there. Because if we find something that is not labelled, if you will, be it an instrument valve or something like that. If the valve was going to be moved, then we were contract -- it would be contract control and so forth, identified on a 4.1, what we call a 4.1 form, which is the same form we used for, as I say, slide lengths --

Operate that valve, and put it back in its original position. And then take a look to see if that valve was, in fact, should be or should not be identified on some document or procedures they were using. That is the vehicle that would be used today. If you found that situation.

MR. OLIVEIRA: Back in November, November last year, our examiners found the problem of EOPs not specifically addressing malfunction. In other words, you go through an action item and something else comes up. And during the power ascension, when there is a lot of things like having to bring in condensate pumps, having to do something else, and other things.

And I was just wondering, how is, dealing with these problems when the issue right here, the initial issue is that the EOP itself is not addressing the malfunction. In doing these tests there were malfunctions, and they had say let's go to something else, let's do something else. But I have a difficult time trying to fully understand if you do have a problem, how will you handle the EOPs? When the EOPs themselves are not dealing with these problems.

MR. MOODY: Let me try to understand the question.

MR. DRAWBRIDGE: I did not hear the entire question.

MR. OLIVEIRA: I said back in November of last year, one of our examiners said that the EOP being implemented in this event did not specifically address the actions that were taken to correct a malfunction. What happened here, a valve did not reseat during a test. And I was likening it to observing some of the ascension testing, if things did not function -- we have to get the consig pump on-line, number three consig pump back on-line, because we were having -- from the flow.

The heater drain is not opening and oscillating properly. And I was wondering, in view of this, I was wondering how does that relate with the EOPs of people involved --

MR. MOODY: EOPs basically take you through a series of progressive steps to get to either, in a functional recovery procedure, out of the emergency operating procedures. Normally in the EOP, it works you back into a normal operating procedure.

For instance, you have low suction on your feed pump. And an operating procedure would get you back into starting an additional condensate pump by dropping off one or the other. But we have looked at the EOP, -- looked at the EOP and the procedures that they relate to are mentioned in the text of those to correlate those together, to make sure that they, in fact, flow.

But the EOP will drive you either into a condition to stay within that condition in the normal operating shutdown procedures, just using the word EOP itself. We have looked at all those connections.

MR. JOHNSON: Thank you.

MR. MARTIN: If I might add something. One of the primary intentions we had during the power ascension program is to verify that the EOPs worked appropriately. And when we performed a test like loss of power test of the unit, check of 100 percent power test, we intentionally use the EOPs as much as practical to make sure that they were usable. And in all of those instances where we did refer out to an EOP, we had perfect success in using those procedures.

I am not sure exactly the situations you are referring to on the condensate pumps. There is no relationship that we experienced during a power ascension that relates the oscillations back to an EOP. But we did validate the EOPs during power ascension, and found no problems.

MR. DRAWBRIDGE: There is also an EOP audit going on this week. I do not know if you are aware of that.

MR. JOHNSON: Right, that is right.

MR. DRAWBRIDGE: In fact, today they were going to be in the simulator. We are going to walk --

MR. JOHNSON: Yes, I think we have an ongoing team inspection at the site now that will be looking into that again. So we will get another fresh look at that within the next week or two.

MR. OLIVEIRA: I just remember reading this --

heater drain system to make sure -- very unique situation. Try to correlate that to an EOP. I did not see and I wasn't going to say stop --

MR. MARTIN: There is no relationship there.

MR. JOHNSON: Okay. Any other questions? Okay, well, I appreciate you spending the time to come in here. And I thank everybody for their questions.

What we intend to do is document the transcript of this meeting, and provide that transcript to you and to the public. And we intend to give you feedback on your self-assessment report in a routine inspection report, similar to the way we dealt with the 50 percent meaning.

Again, thank you very much. We appreciate your time. And the meeting is concluded.

(Whereupon, at 3:16 p.m., the meeting was concluded.)

REPORTER'S CERTIFICATE

DOCKET NO.:

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LOCATION: King of Prussia, Pennsylvania

I hereby certify that the proceedings and evidence are contained fully and accurately on the tapes and notes reported by me at the hearing in the above case before the United States Nuclear Regulatory Commission

Date:

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