ENCLOSURE 1

SALP BOARD REPORT

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE
INSPECTION REPORT NUMBER

50-338/88-04 AND 50-339/88-04

VIRGINIA ELECTRIC AND POWER COMPANY

NORTH ANNA PLANT UNITS 1 AND 2

SEPTEMBER 1, 1986 - APRIL 30, 1988

I. INTRODUCTION

The Systematic Assessment of Licensee Performance (SALP) program is an integrated NRC staff effort to collect available observations and data on a periodic basis and to evaluate licensee performance based on this information. The SALP program is supplemental to normal regulatory processes used to determine compliance with NRC rules and regulations. The SALP program is intended to be sufficiently diagnostic to provide a rational basis for allocating NRC resources and to provide meaningful guidance to licensee management in order to promote quality and safety of plant construction and operation.

An NRC SALP Board, composed of the staff members listed below, met on June 21, 1988, to review the collection of performance observations and data to assess licensee performance in accordance with guidance in NRC Manual Chapter 0516, "Systematic Assessment of Licensee Performance". A summary of the guidance and evaluation criteria is provided in Section II of this report.

This report is the SALP Board's assessment of the licensee's safety and management performance at North Anna for the period September 1, 1986, through April 30, 1988.

SALP Board for North Anna Units 1 and 2:

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F. Cantrell, Chief, Reactor Projects Section 2A, DRP, RII
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II. CRITERIA

Licensee performance is assessed in selected functional areas depending on whether the facility has been in the construction, preoperational, or operating phase during the SALP review period. Each functional area normally represents an area which is significant to nuclear safety and the environment, and which is a normal programmatic area. Some functional areas may not be assessed because of little or no licensee activity, or

because of a lack of meaningful NRC observations. Special areas may be added to highlight significant observations.

One or more of the following evaluation criteria was used to assess each functional area; however, the SALP Board is not limited to these criteria and others may have been used where appropriate.

A. Management involvement in assuring quality
B. Approach to the resolution of technical issues from a safety standpoint
C. Responsiveness to NRC initiatives
D. Enforcement history
E. Operational and construction events (including response to, analysis of, and corrective actions for)
F. Staffing (including management)
G. Training and qualification effectiveness

Based upon the SALP Board assessment, each functional area evaluated is classified into one of three performance categories. The definitions of these performance categories are:

Category 1: Reduced NRC attention may be appropriate. Licensee management attention and involvement are aggressive and oriented toward nuclear safety; licensee resources are ample and effectively used such that a high level of performance with respect to operational safety or construction quality is being achieved.

Category 2: NRC attention should be maintained at normal levels. Licensee management attention and involvement are evident and are concerned with nuclear safety; licensee resources are adequate and are reasonably effective such that satisfactory performance with respect to operational safety or construction quality is being achieved.

Category 3: Both NRC and licensee attention should be increased. Licensee management attention or involvement is acceptable and considers nuclear safety, but weaknesses are evident; licensee resources appear to be strained or not effectively used such that minimally satisfactory performance with respect to operational safety or construction quality is being achieved.

The functional area being evaluated may have some attributes that would place the evaluation in Category 1, and others that would place it in either Category 2 or 3. The final rating for each functional area is a composite of the attributes tempered with the judgment of NRC management as to the significance of individual items.

The SALP Board may also include an appraisal of the performance trend of a functional area. This performance trend will only be used when both a definite trend of performance within the evaluation period is discernable and the Board believes that continuation of the trend may result in a change of performance level. The trend, if used, is defined as:

Improving: Licensee performance was determined to be improving near the close of the assessment period.

Declining: Licensee performance was determined to be declining near the close of the assessment period.

III. SUMMARY OF RESULTS

A. Overall Facility Performance

The North Anna Power Station is staffed and operated by knowledgeable and well qualified personnel. The senior station management positions including the superintendent levels are occupied with personnel who are now or have been licensed Senior Reactor Operators. Late in the SALP period changes were made in station management due to the normal company rotation policies. The station manager was transferred to the corporate office, the assistant station manager for operations and maintenance, was promoted to station manager, the operations superintendent was promoted to assistant station manager for operations and maintenance, and the technical services superintendent was transferred to the operations superintendent. These changes have not had an adverse impact on station operations.

Corporate management involvement in plant performance continues to be evident based on the continued monitoring of the performance indicator program, the support of the Quality Maintenance Team concept, and the initiation of the significant event review meetings held between corporate management and station personnel. An example of direct corporate involvement in station performance was the excellent handling of the technical issues and determination of root cause and corrective action associated with the July 1987 Unit 1 steam generator tube rupture.

A change in corporate management also occurred late in the SALP period due to reorganization of the company. A new vice president for nuclear operations was installed when the former vice president was promoted to senior vice president in charge of all power operation. The reorganization was performed to realign the company and its resources to more directly support power operations, especially nuclear power operations.

With the exception of extensive refueling outages on both units and a 90 day steam generator outage on Unit 1 the facility had high availability as demonstrated by the parallel 170 day and 217 day continuous on line operation of Unit 1 and Unit 2, respectively. The availability factor was aided by the licensee's reduction in at power reactor trips and technical specification required shutdowns due to excessive leaks rates. This reduction demonstrates the licensee's efforts with the Westinghouse Owners Group for reactor trip reduction by determination of root cause and adequate corrective action in the area of excessive reactor coolant system leakage.

Overall performance of operation, maintenance and surveillance was good. However, a weakness was identified in the area of attention to detail and failure to follow procedures associated with these functional areas. The weakness was mainly demonstrated during outage related situations.

Regarding occupational radiation exposure, data available for calendar year 1986 indicate that a total exposure of 722 person-rems was received by personnel at the North Anna station. The 1987 collective radiation dose was 1520 person-rems which is twice the national average. The 197 outage days in 1987 was the major contribution to the increased dose.

The licensee is continuing with programs to implement new and innovative techniques to improve performance and quality in the various disciplines involved in nuclear power plant operation. These include an expansion of programs in which personnel down to the craft level in the maintenance areas are being sent to observe techniques employed by the French and Japanese at their nuclear stations in order to improve performance at the licensee's stations. Also, during this period, the licensee received full accreditation from INPO for all of their training programs.

As can be seen in subparagraph B below, several functional areas have changed SALP performance category. Training has improved one level while outages had fallen off one level. As indicated in Section IV.K, the eleven basic training programs have been accredited by INPO and operator test performance is well above the industry average. Training in other functional areas showed management involvement. As indicated in Section IV.H of this report, off-normal or outage related activity indicated problems and weaknesses; restarts from outages and outage induced work appeared to have numerous personnel error problems.

B. The performance categories for the current and previous SALP period in each functional area are as follows:

Functional Area	Previous SALP Dates	Current SALP Dates
	March 1, 1985 August 31, 1986	September 1, 1986 April 30, 1988
Plant Operations	2	2
Radiological Controls	2	2
Maintenance	2	2
Surveillance	2	2
Fire Protection	1	1
Emergency Preparedness	2	2
Security	2	2
Refueling/Outages	2	3

Quality Programs & Administrative Controls Affecting Quality	2	2
Licensing Activities	1	1
Training	2	1

IV. PERFORMANCE ANALYSIS

A. Plant Operations

1. Analysis

During the assessment period, inspections of plant operations were performed by the resident inspector and regional inspection staffs. Because of the number of operational problems observed, a special Operational Performance Team Inspection was conducted in April 1988 to assess overall facility performance prior to the end of the SALP period.

Unit 1 began the SALP period undergoing low pressure turbine repairs while Unit 2 began the period at 100 percent power. The capacity/availability factors were 55.2/60.6 and 81.9/86.0 (Unit 1 and Unit 2, respectively) for the duration of the SALP period. Unit 1 entered a refueling/maintenance outage on April 19, 1987, and on August 24, 1987, Unit 2 entered a refueling/maintenance outage.

The only major interruption to power operation occurred on July 15, 1987, when Unit 1 experienced a steam generator tube rupture (SGTR) and it was shutdown until 50 percent power operation was authorized on October 9, 1987. On November 5, 1987, the NRC lifted the 50 percent power restriction and Unit 1 achieved 100 percent power.

A review of plant operations from September 1986 to April 1988, demonstrates the licensee's ability to safely operate both units during steady state power operations. However, a number of problems were observed during unit shutdowns, startups and outage situations. The ability to operate the units at power without major problems was demonstrated by the 170 day continuous run of Unit 1 prior to the refueling outage in April of 1987, and a parallel, 217 day continuous run of Unit 2 until a reactor coolant pump seal failed in May 1987. During that same period, Unit 2 also operated for 415 days without an automatic reactor trip until the shutdown for the refueling outage in August 1987.

Unit 1 experienced nine reactor trips; of these nine only three occurred during 100 percent power operation. Two of these three trips were manual trips that were initiated by observant, responsive operators and all three were the result of equipment malfunctions. The remaining six Unit 1 reactor trips occurred during transient or outage situations. Of these six reactor trips, three occurred while starting up from an outage at power

levels less than 20 percent power; one occurred during the coastdown to the refueling outage and two occurred with the unit in cold shutdown. Also, of these six reactor trips, three were due to personnel errors and three were due to equipment failures.

Unit 2 experienced only two reactor trips during the SALP period, each of which was automatic and occurred with the unit subcritical. One occurred during the shutdown for the refueling outage and was due to an equipment failure and the second occurred during the refueling outage with the unit in cold shutdown as a result of a personnel error.

The number of trips for Unit 1 is approximately the same as for the last SALP period but the at power trips have been reduced. The Unit 2 trip rate is much less than for the last SALP period and neither of the reactor trips was at power. During the SALP period, Unit 1 had a total of five at power automatic reactor trips and Unit 2 had zero at power automatic reactor trips. The total automatic at power trips of 3 and zero for Units 1 and 2, respectively, remains below the 1987 industry average of 3.64 automatic reactor trips per year. The licensee's goal of two reactor trips per year per unit was not achieved on Unit 1 but was more than met on Unit 2 with just two trips in a 20 month period. The overall reduction in power operation trips and the reduction in the total number of trips (see Section V.J) from 16 for both units during the last SALP period to the present 11 reactor trips demonstrates the success of the licensee's efforts in their trip reduction program. However, a weakness, demonstrated by the number of reactor trips, 8 of the 11 which occurred during reactor startups, shutdowns, or outage situations, was observed in the area of non-steady state operation trip reduction, especially in the area of personnel errors.

The number of unplanned manual shutdowns also improved from the last SALP period. During the last SALP period, there were a total of 16 Technical Specification required shutdowns, predominantly in the area of excessive reactor coolant system (RCS) leak rates. During this SALP period, of the eight unplanned manual shutdowns, only one was associated with an excessive RCS leak rate. Unit 1 had to commence a shutdown on March 23, 1988, due to a greater than 10 gpm RCS leak rate, but the leakage was reduced to less than 10 gpm before the unit had completed the shutdown. Of the remaining seven unplanned manual shutdowns, two were related to RCP seal failures, two were voluntary due to NRC concerns relating to ASME Code Section XI testing of containment isolation valves, one was due to a steam generator resin intrusion and the final two were due to personnel errors which resulted in failed equipment.

The operations staff's response to the reactor trips and other operational events, especially the SGTR event in July 1987, has generally been very good. However, both operations and other

station personnel's performance during outage related situations has not been as good. Violations (a), (c), (d), and (f) are examples of lack of attention to detail and inadequate/failure to follow procedures which occurred during outage situations. These violations as well as other events which occurred during outage situations are discussed in more detail in section IV.H. Operational problems relating to inadequate procedures and failure to follow procedures were also identified during evaluations in areas other than outages such as routine power operations. Violation (b), example 1 of violations (f) and (g) are examples of failure to follow procedure problems while Violation (i) is an example of an inadequate procedure.

An operational performance assessment was performed late in the SALP period (end of March and early April). The inspection team found corrective actions for violations (such as (c), (d), and (f), which occurred mid-SALP period) in place or being initiated by the licensee. The corrective actions were extensive and appeared to be focused on the problems identified earlier in the SALP period.

The North Anna station is staffed with knowledgeable and professional management and operations personnel. Station management involvement in plant activities is evident by their presence in the plant during regular and non-regular hours and their continued support of licensee initiated programs. Some of these programs are as follows: the check operator program; the program of using licensed SROs as coordinators in other departments such as maintenance; the Human Performance Evaluation System (HPES); the program for training the Shift Technical Advisors (STA) to become licensed SROs (seven STA, degreed engineers, hold active SRO licenses); and daily plant meetings, daily telephone calls with the corporate office and the Surry Station to discuss current events. A number of station management personnel hold SRO licenses or have been licensed and have extensive operating experience at North Anna.

Corporate management involvement is evident in the continued communication and agreements established with foreign nuclear organizations. The licensee has sent several station personnel to other countries such as Japan, Switzerland, and Spain to observe firsthand how other nuclear organizations conduct business. Several countries have sent representatives to the North Anna facility to tour their facility and to observe their operation. Corporate management stays involved with current events by conducting significant event review meetings with station personnel. These meetings are conducted between the Vice President of Nuclear Operations and the personnel at the station involved in a particular event. This allowed station personnel to appreciate firsthand the significance that licensee management was placing on each of the station events. The licensee has continued to issue and review their "Nuclear Performance Monitoring Management Information Report," which

provides monthly trending information to corporate management consisting of 34 different areas to help management review performance.

Control room decorum continues to be very professional and well maintained. Access to the control room is strictly controlled, especially during shift turnovers. The majority of administrative business is conducted in the Technical Support Center (TSC) where the Shift Supervisor (SS) maintains an office. This minimizes the congestion and noise levels in the control room. Operators are attentive to plant operations and alarm status. The control room is clean, uncluttered, and well organized. The attitude of personnel is consistently professional. Operator turnovers are conducted with detailed check sheets and the recent development of a computer assisted information package maintained by the operations department provides a detailed running status of various operationally important components in the plant, both safety and non-safety related.

The Operations Superintendent frequently visits the control room to observe shift operations and communicate with the plant staff. Additionally, the Operations Superintendent generally meets weekly with the operations crew during requalification training.

Station housekeeping is very good. The painting and upgrade program conducted in the turbine building has had excellent results. That and the uniform dress policy for all station personnel seems to have raised the level of pride and professionalism on the part of station personnel and helps maintain the station in good material condition. The auxiliary building is maintained in a clean condition. The painting and upgrade program, recently completed in the turbine building, is just beginning in the auxiliary building. The painting program augments the licensee's already established program for labeling, painting and identification of pipe runs and safety related equipment.

The control boards had very few outstanding work orders. Work orders located in the control room are only written for defective switches or meters and not associated components. It was identified that not all control room instrumentation used for long term cooling evaluations are in the calibration program. As a result, the licensee is reviewing the calibration program to ensure that all required instrumentation is being properly calibrated. The licensee is continuing efforts to bring the annunciator panels to a "black board" condition. This is further described in section IV.C of this report.

The licensee has an excellent problem identification program which consists of Deviation Reports (DRs) and Work Requests (WRs) for non-conforming conditions. The threshold for these

reports is very low as evidenced by the large number generated. However, the licensee has not yet developed a manageable system for trending these reports. The licensee is in the process of developing a computer based program for trending and grouping DR's to provide management with a tool for determining root cause and correcting minor errors before they lead to a major problem. The licensee has developed a HPES which has been used extensively to review various operational events. This system has provided the licensee some valuable root cause information and in some cases generic information to help prevent other types of events.

During this evaluation period, an inspection was conducted by the regional staff to assess compliance with Generic Letter 81-21, Natural Circulation Cooldown. This Generic Letter required the licensee to establish and implement Emergency Operating Procedures (EOPs), and conduct training relating to the possible loss of the reactor coolant pumps during power operations. Weaknesses were identified in the documentation of deviations from the Westinghouse Owners Group (WOG) Emergency Response Guidelines (ERGs) for the Natural Circulation Cooldown EOPs. Violation (h) was issued for inadequate EOPs when it was determined that the quantitative cooldown curves used in the natural circulation cooldown EOPs exceeded those specified in the Technical Specifications. No problems were identified concerning the licensee's training in this specific area. However, this inspection only reviewed three of the Licensee's 42 EOPs and did not do a programmatic assessment of the Licensee's Procedures Generation Package (PGP).

VEPCO submitted 57 Licensee Event Reports (LERs) for the North Anna plants covering the period from September 1, 1986 to April 30, 1988. This number of LERs is below average; however, three of them have been ranked as significant by the AEOD screening process. The LERs appear to be reasonably complete and were submitted in a timely manner.

Two of the significant LERs were caused by personnel errors that reflect weaknesses in plant operations while the third event showed good operator response to a tube rupture event. The most serious personnel error occurred during a maintenance evolution while the plant was shutdown. A 20 percent loss of primary system inventory went undetected over a three day period, because of a lack of attention to detail. A major concern was the fixation on only the pressurizer level as the basis for reactor inventory when a known leak was present. For more details see the Outage section.

A review of all the LERs in this time period indicates that in about one-half of the events, personnel errors (failure to follow procedures, inadequate procedures, etc.) was determined to be the cause of the event.

Nine violations were identified during the assessment period. These violations and related violations in other sections also indicate a lack of attention to detail, especially in outage related situations. The failure to follow procedures was also identified during the last SALP period. The violations are listed as follows:

a. Severity Level III - Violation for failing to declare "A" Steam Generator Steam Flow Channel III and "B" Steam Generator Steam Flow Channel IV inoperable (87-38), Unit 2 only.

b. Severity Level IV - Violation of containment integrity when conducting a surveillance for the hydrogen recombiners (87-15).

c. Severity Level IV - Violation of TS with four examples for inadequate procedures or lack of procedures (87-21), Unit 1 only.

   1) Inadequate procedure for establishing plant conditions for the RCP maintenance
   2) Lack of procedure to lower pressurizer level which resulted in a reduction in vessel level without the operators knowledge
   3) Lack of procedure to draw a vacuum in the pressurizer to reduce RCS leakage
   4) Inadequate maintenance procedure for performance of the RCP maintenance

d. Severity Level IV - Failure to perform a 10 CFR 50.59 safety evaluation prior to conducting a test on the RCS which was not described in the FSAR (87-21), Unit 1 only.

e. Severity Level IV - Failure to notify HP when a radiation alarm was received on the main steamline monitor (87-24), Unit 1 only.

f. Severity Level IV - Violation of TS for failure to follow procedures and inadequate procedures with five examples (87-36).

   1) Failure to follow procedure which resulted in the partial draining of the RWST below the TS limits
   2) Failure to follow procedure which resulted in the lifting of a pressurizer PORV at its low pressure setpoint
   3) Inadequate procedure which resulted in an unexpected reactor trip signal
   4) Violation of TS for failure to place an inoperable power range nuclear instrument in trip within one hour

5) Failure to follow procedure resulting in an inadvertent cooldown of the RCS below the TS limit

g. Severity Level IV Violation for failure to follow procedures, three examples (88-06): failure to follow procedures for audits of operator aids, configuration control of casing cooling system, and revision of surveillance instruction and abnormal procedure.

h. Severity Level IV violation for inadequate emergency operating procedures for natural circulation cooldown: cooldown curves exceed those in the Technical Specifications (87-39).

i. Severity Level V - Inadequate procedure resulting in failure of a charging pump (86-28).

One deviation was identified as follows:

- Deviation for failure to follow procedure generation package commitments in generating emergency operating procedures for natural circulation cooldown (87-39).

2. Conclusion

Category 2

Trend: Declining

3. Board Recommendation

Despite several indicators of good performance (e.g., reduction in trips, response to SGTR and knowledgable operations personnel), the Board is concerned with the number and severity of incidents that have occurred during non-routine operations. Management attention should be directed toward improved procedures, adherence to procedures and attention to detail. No change in the level of NRC staff resources applied to the routine inspection program is recommended.

B. Radiological Controls

1. Analysis

During this assessment period, inspections were performed by the resident and regional inspection staffs. There were five radiation protection inspections, including one special appraisal of the licensee's program for maintaining exposures as low as reasonably achievable (ALARA), one radiological effluent and confirmatory measurement inspection, one environmental monitoring inspection and one chemistry inspection. There was one inspection to review the events associated with an apparent skin overexposure.

The licensee's health physics, radwaste, and chemistry staffing levels were appropriate and compared well to other utilities having a facility of similar size. At the end of the SALP period, all supervisory positions were filled, and the licensee was in the process of actively recruiting to fill other vacancies in the organization. An adequate number of ANSI qualified licensee and contract health physics technicians were available to support routine and outage operations. The licensee utilizes some contract health physics support in non-outage periods. During outages, the licensee supplements the health physics staff with additional ANSI qualified health physics technicians and decontamination support personnel. The contract technicians who work at the plant during non-outage situations become coordinators of the supplemental contractor technicians, resulting in improved interfaces between the contract technicians and the permanent plant staff.

Key positions in the radwaste management program and environmental surveillance programs were also filled with qualified staff. During the assessment period, the licensee's radiation protection organizational structure remained unchanged.

The knowledge and experience level of the site health physics staff was good. Staff members are enthusiastic about their programs and show a dedication to doing the job well. The staff had a very low turnover rate and an effective training program. The health physics operations staff works a six shift rotation that allows one sixth of the staff the opportunity to attend proficiency training classes each week. The licensee has constructed a mockup of the entrance and exit to the radiologically controlled area (including change rooms, monitoring stations and RWP postings) for training of plant staff in radiological controls. In addition, the licensee has installed a working containment hatch in the training facility for training staff on containment entry and exit procedures.

Management support and involvement in matters related to radiation protection and radioactive waste control were good as evidenced by management's participation on ALARA committees, both station and corporate. The plant's radiation protection manager received the support of other management in implementing the radiation protection program.

During the assessment period, there was an event that resulted in a worker skin overexposure from a microscopic 1.6 microcurie cobalt-60 particle. Based on the particle activity and residence time of the particle on the skin, a dose to the skin of the whole body was determined by calculation to be 23.6 rems. The total quarterly dose to the skin of the whole body exceeded the NRC limit by a factor of three. The exposed individual was a health physics technician who failed to wear the required protective clothing and to promptly perform personal

contamination surveys. Although a violation for exceeding the NRC dose limit would normally be classified as a Severity Level III, in this case, the violation was classified as a Severity Level IV since the health implications of this exposure were small due to the small area of skin exposed. In response to this event, the licensee established special precautions in areas where there might be high specific activity particles.

The licensee has improved personnel monitoring capability by installing "state-of-the-art" whole body friskers. The licensee's personnel dosimetry program was recertified by the National Voluntary Laboratory Accreditation Program in September 1986.

The licensee began development of a plan to upgrade the radiation protection program in 1983. In 1985, the licensee formally issued the Radiation Protection Plan (RPP) which established policies and responsibilities for upgrading the radiation protection program. The licensee also issued an implemention plan which established the schedule for upgrades in specified program areas such as external dosimetry, respiratory protection, and ALARA. The implementation plan called for the preparation of more than 200 procedures. Although the development and implementation of the RPP has been in progress for nearly five years, at the end of the assessment period, less than 50 percent of the RPP procedure upgrades were in place. The delays in implementing the RPP are due, in part, to a lack of strong direction and leadership from the corporate health physics staff. The licensee's goal is to have the RPP fully implemented by 1989.

The licensee's radiation work permit and respiratory protection programs were found to be satisfactory.

In December 1986, the area of the plant controlled as contaminated was approximately 13,500 square feet (ft^2) or about 12.8 percent. Prior to December 1986, the licensee made considerable progress in reducing the total area of the plant maintained as contaminated. Between December 1986 and the end of the assessment period, the licensee did not significantly reduce the area contaminated. The total area contaminated remains above that of a good performer in Region II.

During 1987, there was a 25 percent increase in the number of clothing and skin contamination events compared to 1986. The increase was influenced by a 75 percent increase in outage days for 1987 including a steam generator tube rupture outage. The licensee's corporate health physics staff evaluated the personnel contamination events and has made recommendations to reduce the number of events and to improve personnel contamination monitoring and control programs.

The 1986 collective radiation dose was 361 person-rem per unit. This compares favorably with the national average of

397 person-rem per PWR unit. The 1987 collective radiation dose was 760 person-rem per unit, which is twice the national average for 1987 (368 person-rem). The 1986 and 1987 collective dose both exceeded the goals established by the licensee. The licensee experienced 193 outage days in 1987, which was a major contributor to the increased dose.

Near the end of the assessment period, the NRC performed a special evaluation of the licensee's program for maintaining radiation dose as low as reasonably achievable (ALARA). Although the necessary elements of an effective ALARA program were in place, the overall effectiveness of the program in reducing the station's collective radiation dose is yet to be demonstrated. Licensee plant and corporate management are routinely involved in setting program goals. The Vice President Nuclear personally monitors collective dose trends and reviews instances where dose goals are exceeded. Management has dedicated significant attention and resources to collective dose control and reduction.

The licensee has taken a number of actions to reduce doses, including additional training to improve the staff's awareness of ALARA concepts; procurement of video equipment to provide remote monitoring of equipment, areas and jobs; procurement of a computerized Visual Information Management System which will display approximately 90 percent of the plant for project planning; removal of snubbers from high dose rate areas; and installation of permanent reactor head shielding. However, a number of the initiatives (e.g., source term reductions) in the licensee ALARA Action Plan have not been completed and do not have completion dates assigned.

Gaseous effluents included 1,050 curies of mixed fission and activation products in 1987 and 5,706 curies in 1986. These releases were comparable to the average of 21 PWRs in Region II for CY 86.

Liquid effluent releases included 1.32 curies of mixed fission and activation products in 1987 and 0.94 curies in 1986. These releases were comparable to the average of 21 PWRs in Region II for 1986. Maximum calculated doses resulting from 1987 releases were 0.44 mrem (thyroid) for gases and 3.81 mrem (liver) for liquids. Liquid releases on mixed fission and activation products in 1986 and 1987 reflected a downward trend from the average of about 5 curies per year for the period 1983-85.

Annual effluent release summaries for 1985 - 1987 can be found in Section V.K of this report.

Liquid and gaseous radwaste treatment facilities appeared to operating satisfactorily, as evidenced by the magnitude of the reported releases for 1986 and 1987, which are consistent with releases from other facilities in Region II. During the

assessment period, the licensee approved the construction of a new radioactive waste treatment facility which will provide state-of-the-art liquid and solid radwaste processing.

The licensee's high range gaseous effluent monitors (NUREG-0737, Item II.F.1, Attachments 1 and 2) were modified by providing air-conditioned cabinets to protect sensitive electronic components from overheating. That action had substantially improved the operational reliability of these monitors.

Environmental monitoring programs were conducted in an adequate manner. Environmental samples were analyzed by a contract laboratory and no analysis results exceeded the Action specified in the Technical Specifications.

During 1986, the licensee shipped for burial 18,668 cubic feet (ft^3) of solid radioactive waste containing 797 curies. In 1987, the licensee shipped 17,272 ft^3 containing 1,640 curies. In 1988, the licensee had shipped 3,288 ft^3 of solid radioactive waste having 4.7 curies for burial as of April 30, 1988. During the assessment period the licensee began shipping dry active waste to a vendor for volume reduction. Actions taken by the licensee should result in a reduction in solid radioactive waste shipped to low-level waste burial facilities for disposal.

An inspection in the area of plant chemistry was performed one month before a steam generator tube in Unit 1 failed. The poor condition of the Unit 1 steam generators (5 to 8 percent of tubes plugged, indications of tube defects at several elevations of the tubes, denting, removal of 3500 pounds of sludge during the 1987 refueling outage) resulted from poor chemistry control during the initial years of plant operations. During the last two years, chemistry control had been improving, due in part to the following: significantly less water inleakage through the condensers, increased attention and resources given to the control of microbiological induced corrosion; installation of a reverse-osmosis plant for producing makeup water; expansion of the inservice inspection program to monitor the conditions of condenser tubes and to detect incipient pipe thinning; and increased chemistry manpower and training resources. However, optimum protection against pipe corrosion and prevention of further degradation of steam generator tubes has been hindered by release of ion exchange resin into the steam generators from the condensate polishers; presence of copper alloy feedwater heater tubes; and restraints on pH control due to the addition of boric acid to minimize denting and to the increased loss of metal from copper alloy tubes at higher pH ranges. The licensee is in the process of installing and testing a comprehensive plant chemistry monitoring system that will allow a more accurate, online, state-of-the-art monitoring of plant chemistry in all important plant systems.

Seven violations were identified during the assessment period:

a. Severity Level IV - Failure to document Rubidium 88 contamination (86-28).

b. Severity Level IV - Failure to maintain radiation exposure records in accordance with instructions contained on Form NRC-5 (87-14).

c. Severity Level IV - Failure to maintain occupational exposures to the skin of the whole body below regulatory limits (87-30), Unit 1 only.

d. Severity Level IV - Failure to perform adequate radiological survey (87-30).

e. Severity Level IV - Failure to adhere to Radiation Work Permit (87-30).

f. Severity Level IV - Failure to follow the requirements of RWP 87-3156 (87-38), Unit 1 only.

g. Severity Level V - Failure to establish, implement, and maintain procedures for calibration of an alpha survey instrument (86-27).

2. Conclusion

Category 2

3. Board Recommendations

None

C. Maintenance

1. Analysis

During the evaluation period, maintenance inspections were performed by the resident inspectors and six inspections were performed by the regional inspection staff. An Operational Performance Assessment Team also reviewed the licensee's Operations - Maintenance interface.

Two concerns were identified during the previous SALP period. These concerns involved a large undefined maintenance work order (WO) backlog and numerous TS required shutdowns due to excessive RCS leak rates. To address these concerns, the licensee developed new procedures, programs, and policies to identify, categorize, and reduce the significant backlog items and to minimize RCS leakage.

The maintenance WO backlog is now trended monthly and categorized into the following areas: safety related and non-safety related corrective maintenance items, programmatic

items which include preventive maintenance, and completed but not closed WOs. The safety related and non-safety related corrective maintenance items are also broken down into the unit mode required for the work to be performed (e.g., with the unit operating or shut down), as well as identifying the number of safety related items which are greater than three months old. The corrective maintenance backlog is tracked daily during the morning meetings with station management. Consequently, station management has real time data on a day-to-day basis of the status of the overall maintenance condition of the unit.

The licensee has devoted the resources necessary to reduce the number of corrective maintenance backlog items for both safety and non-safety related items by approximately 50% from the number maintained during the last SALP period. This was accomplished even though the number of new items identified each month is still significant. The large number of new WOs identified each month, especially during the periods approaching the refueling outages indicates the licensee still has a good problem identification program and the attempt to reduce the number of backlog items has not influenced the threshold for identifying new problems.

Along with trending and reducing the number of safety related backlogged WOs, the licensee developed an administrative procedure to ensure that all safety related WOs required for plant operation are completed prior to the unit startup. This procedure requires that the licensee develop a complete list of outstanding safety related backlog items with a written evaluation describing the effect of each item on the associated safety related equipment. This list is then reviewed by the Station Nuclear Safety and Operating Committee (SNSOC) prior to the unit startup to verify that Technical Specifications are being complied with, that there is no degradation of safety related equipment, and that all equipment is in compliance with the North Anna design basis. The combination of this review and the effort to complete the work associated with the safety related WOs serve to reduce the concern relating to the maintenance backlog.

One weakness noted in the licensee's program for reducing the number of backlogged WOs has been in the area of completed but not closed WOs. The number of these items is greater than 8,000. The licensee has informed the inspectors that these WOs have been reviewed for completeness, but have just not been entered into the computer system for final closeout. The licensee has devoted most of its effort and qualified personnel to the task of completing work associated with the WOs, in order to address the concern relative to station material condition. Minimal effort has been placed in the area of properly inputting the completed maintenance data into maintenance history. This reduces the licensee's ability to rely on historical data for such

things as root cause determination which was identified as a weakness during the last SALP period.

The number of Preventative Maintenance (PM) backlog items is increasing due to the increased numbers of new PMs being identified. The licensee still needs improvement in the area of Preventative Maintenance identification as evidenced by RCS valve packing leaks, check valve problems and gas leaks in the auxiliary building. The licensee has not developed a check valve PM program in spite of the identification of industry check valve problems and the need for an adequate PM program. However, since recent discoveries of check valve failures in the main feed lines, auxiliary feed steam supply lines and the charging pump discharge lines, the licensee has committed to and is in the process of developing a comprehensive check valve PM program.

To address the concern of excessive RCS leakage, the licensee has become more systematic in the approach to the identification and repair of potential leakage paths. The licensee established a policy to perform permanent repairs on equipment which had been temporarily repaired by the use of leak isolating materials (e.g., Furmanite). Permanent repairs are to be scheduled during the next available outage following the use of leak isolating materials. This policy still needs some fine tuning as evidenced by RCS leakage due to a body to bonnet leak on 2-RC-90, a valve in the resistance temperature detector bypass line of the RCS. This valve had previously been "Furmanited", but permanent repairs had not been performed during the following refueling outage.

One of the results of the reduction in the maintenance WO backlog is that previously identified leaking equipment is being repaired on a more timely basis. Also, the Licensee's Chesterton valve repacking program has received increased emphasis. This program which is basically a preventative measure, involves replacement of packing in several thousand valves in the plant with new packing even though the valves have not been identified as having leakage problems. As discussed in the outage section, the licensee has had some planning problems relating to the completion of the program, but the effort is continuing. One enhancement needed in the valve repack program involves the determination of the priority of the valves receiving the periodic packing replacement. This could help further reduce RCS leakage in the high radiation areas (e.g., containment) when the unit is at power, and help eliminate the gas leaks in the auxiliary building. The licensee's leakage reduction efforts appear to be effective in that the units have only experienced two power reductions due to excessive RCS leakage during the last 20 months of the SALP period.

The licensee has devoted considerable resources to the Limitorque motor operated valve (MOV) program. The program for

MOVATS testing of the station Limitorque MOVs meets the NRC requirements of IE Bulletin 85-03 and has been determined to be well managed. The licensee is committed to performing signature testing of all safety related Limitorque MOVs.

Management involvement in the maintenance program is evident by: the continued support of the Quality Maintenance Team (QMT) program; the MOVATS program, which is to be extended to cover all safety related valves; the permanent repair versus continued use of "Furmanite" policy; and the Chesterton valve repacking program discussed above. The QMT concept is continuing at North Anna and the progress is continually reviewed by the station and corporate management. The results of the program appear to be excellent, but to ensure that the program is effective, the licensee has assigned the Quality Assurance (QA) organization to perform a comprehensive review of the QMT process.

The overall material condition of the secondary plant has been greatly enhanced due to improvements in the reduction of steam leaks as follows: by replacing old packing with a new style of graphite packing (Chesterton) and by use of live loading of packing on selected valves such as the MSIVs; reduction of body to bonnet leaks by insuring use of proper gaskets, using more graphoil type gaskets, and insuring proper torquing of bonnets; and improved communication between North Anna and Surry maintenance departments during monthly conferences held with corporate support.

The licensee's approach to technical issues is generally very good. An example of this is the excellent response to the problem associated with the steam generator tube rupture in July of 1987. The licensee devoted a great deal of management and technical effort and resources to determine the root cause and the necessary corrective action needed to prevent recurrence. This information was promptly relayed to the NRC and the industry.

Most maintenance activities were observed to be organized and well planned by the planning department especially in the area of maintenance on TS equipment during unit operation. The use of licensed ROs and SROs as coordinators has greatly helped the planning and maintenance organization accomplish their work. This was especially evident during the service water outage which was coordinated by a licensed RO. The work was well organized and proceeded smoothly because the RO understood the necessary operational requirements associated with the service water system. However, one weakness was noted in the area of mechanical maintenance planning. The amount of work required to be accomplished by the mechanical maintenance planners appears to exceed the resources dedicated to the job and much of the work is given to the maintenance foreman to perform the planning.

Another example of a program which uses a licensed SRO as a coordinator is the control room alarmed annunciator reduction program (black board concept). This program has been very successful. During normal operation, each unit only has a few alarmed annunicators which for the most part represent short duration abnormal conditions. The control room boards are now set up to allow the operator to focus on real operational events.

Problems have resulted from inadequate or failure to follow maintenance procedures. A large number of the maintenance procedures are general in nature and require the maintenance foreman to write in the steps necessary to perform the work. This practice can lead to inadequate and improperly reviewed instructions. Violations (a), (b), (c), (h), and (i) are examples of failure to follow procedures. Violation (i) resulted from maintenance personnel working on the wrong RCS flange in containment causing a 1000 gallon leak to the containment sump. This was due, in part, to a failure to follow procedure and failure to conduct a proper pre-job briefing. Another example of a failure to follow a maintenance procedure was the cutting of the wrong incore flux thimble tube by a contractor technician. This did not affect the operability of the tube and therefore was not cited as a violation. Violations (c), example 4, and violation (f), example 4, of the Operations section are examples of inadequate maintenance procedures which resulted in two events. An additional example of an inadequate maintenance procedure occurred during the Unit 1 refueling outage which resulted in the improper installation of a Moisture Separator Reheat (MSR) stop valve. Following the unit restart the licensee discovered the valve was inoperable which placed them in non-compliance with TS; this resulted in the unit operating at reduced power levels for a period of time and eventually resulted in a unit shutdown to repair the valve. In response to these and other procedural problems, the licensee has established a new procedure writing group under one supervisor. This group will review, change, and upgrade procedures as necessary.

Problems have also been identified in the area of post maintenance testing. The problems and associated violations are discussed in the Surveillance section. A review of the area determined that the shift supervisor is responsible for verifying that post maintenance testing is completed prior to returning equipment to service; however, since testing is completed in various procedures associated with the work package, it appeared difficult to verify that all post maintenance testing is completed. A form identified as the "Post Maintenance Follower" has been added to maintenance procedures to assist the shift supervisor in the review for completeness.

During the evaluation period, a team inspection on Environmental Qualification (EQ) of electrical equipment was performed. The EQ inspection identified four violations. The violations indicate that improved performance should have occurred in: receipt inspection; installation of equipment; and maintenance. Staffing was considered adequate. Personnel in the EQ area appeared to be very knowledgeable of the EQ issues. Top management was supportive of their subordinates. Key positions were identified, and authority and responsibilities were defined. Even though the four violations (d, e, f, and g of Section IV.C, Maintenance) were identified in the EQ area, it is considered that North Anna is one of the better plants with regard to EQ aspects. This is attributed to their active participation in EQ issues, assignment of key positions and a management group that places EQ on a high priority.

Inspections have also been performed in the areas of feedwater pipe replacement due to service induced erosion; recirculation spray heat exchanger diaphragm plate installation; pressurizer safety and relief valve discharge pipe support modification; incore flux detector thimble tube leakage; eddy current examination following steam generator tube rupture in Unit 1; installation of downcomer flow resistance plates in the steam generators; installation of reactor vessel head shielding; installation of pressurizer safety valve loop seal insulation ovens. Within these areas, the inspectors determined that the licensee expended sufficient resources for these design changes. The activities inspected were adequately planned, performed, supervised by qualified personnel in a safe and controlled manner. Documentation was concise and retrievable. Quality control involvement in these areas was considered adequate.

Predictive maintenance is being performed including oil analysis, vibration measurements, and MOVATS motor operated valve testing. PM frequency changes are then made, based on predictive maintenance, corrective maintenance, and operators recommendations. However, as discussed earlier, repetitive failures of machinery have not been well trended in the past, and have not been a substantial factor in adjusting PM frequencies. In one case, the hydrogen and oxygen analyzers for the waste gas decay tank were known to drift when subjected to summer temperatures. However, no licensee action was taken to increase the PM frequency on these safety instruments. Other examples of repetitive equipment problems are: repetitive out of service condition of radiation monitors, repetitive 10 CFR 50 Appendix J valve type C leak test failures, and the continual out of service condition of TS required waste discharge sample pump. Trending of repetitive failures could be done with deficiency reports (DR) and WRs, but was not effectively performed during this period. The licensee had not routinely trended DRs, but as discussed in the Operations section, has committed to begin trending them so that repetitive failures would be noted and would receive management attention. It was

also noted that trending of work orders for repetitive machinery failures was not effective.

Due to recent improvements in the maintenance department such as the procedure rewrite program, QMT, and the planned addition of eleven new system engineers, there is indication of an effort to improve the performance of corrective maintenance. Nonetheless, planning, work history, repetitive failure analysis, and root cause analysis are being affected by the large backlog of complete but not closed work requests.

Nine violations were identified during the assessment period.

a. Severity Level IV - Failure to maintain control of safety related materials (87-12), Unit 1 only.

b. Severity Level IV - Failure to perform adequate operability channel checks on radiation monitors (87-24), Unit 1 only.

c. Severity Level IV - Failure to generate a non-conformance report for non-conforming equipment (87-26), Unit 1 only.

d. Severity Level IV - EQ maintenance requirements in qualification document review, files not adequately addressed in the station maintenance program procedures (87-32).

e. Severity Level IV - Unqualified limitorque operators. (87-32).

f. Severity Level IV - Performance characteristics not adequately addressed in the QDR file (87-32).

g. Severity Level IV - Raychem splice sleeves in unqualified configuration (87-32).

h. Severity Level V - Failure to perform a documented design analysis with supporting calculations and to document a design change (88-02).

i. Severity Level V - Failure to follow procedure and failure to have an adequate procedure resulting in a 1000 gallon leak from the RCS (88-01), Unit 1 only.

2. Conclusion

Category 2

3. Board Recommendations

Management needs to be more responsive to providing improvements in the maintenance area. This was demonstrated by their initial hesitancy in developing a check valve PM program, and the failure to provide adequate staffing to mechanical maintenance

planning to reducing the backlog of completed but not closed work orders. Additionally, improved procedure development and adherence should be addressed. No change in the level of NRC staff resources applied to the routine inspection program is recommended.

D. Surveillance

1. Analysis

During the evaluation period, inspections were performed by the resident and regional inspection staffs. Inspections were conducted in the areas of: inservice inspection, local leak rate testing, set point testing of mainsteam and pressurizer safety valves, core physics post-refueling tests and RCS leakage measurements.

The Technical Specification (TS) required surveillance program was routinely reviewed by the inspectors. The program was generally conducted in a timely manner. Exceptions were documented in Licensee Event Reports (LERs) for missed surveillances. The missed surveillances tended to be the non-routine types, especially in the area of ASME Code, Section XI required testing of pumps and valves.

The licensee has demonstrated a problem in the area ASME Code, Section XI containment isolation trip valve testing especially in the implementation of their program. Improper reviews, inadequate understanding of the Code requirements and overall management of the program in certain areas resulted in Violations (e) and (f). These violations demonstrate the failure of the licensee's Section XI group to get directly involved with the routine testing of containment isolation valves. The operations staff verified that the containment isolation valves are in compliance with TS, but they were not fully versed on the Section XI requirements for valve testing. The inspectors determined that valves which either failed or increased in stroke time sufficiently to be placed in alert condition, were being mechanically agitated and restroked to obtain compliance with TS. This was being performed without the knowledge of Section XI group; however, all of the operator actions were being documented on station deviation reports (DRs). The lack of direct involvement and review of related DR's by both the Section XI staff and the Quality Assurance group allowed this condition to continue until identified by the NRC.

On the other hand, the Section XI group was very involved with the work and testing of Limitorque Motor Operated Valves (MOVs) operators. This was partly due to the work required by Inspection and Enforcement Bulletin (IEB) 85-03 during the last refueling outage. The licensee's program for Limitorque MOVs is developed and meets the requirements of IEB 85-03. This program

is an example of a good practice in the area of Section XI testing.

Numerous problems were identified in the area of post maintenance testing. Violations (b), (f) and (g) resulted from the failure to perform post maintenance testing. Violation (g) directly contributed to violation (a) in the Operations section which resulted in a civil penalty of $100,000 because the post maintenance test, if performed properly, would have identified one of the inoperable steam flow instruments prior to the unit startup. The failure of the licensee's group responsible for the post maintenance testing and the safety committee to properly review the completed paperwork associated with the steam flow instrumentation, also contributed to the lack of post maintenance testing.

Violation (b) was due to the failure to properly conduct post maintenance testing of the condenser air ejector. This resulted in the loss of an important piece of information available to the operator during the steam generator tube rupture event. The inoperable condenser air ejector radiation monitor also would have prevented the automatic diversion of the air ejector discharge to the containment if the actual release from the tube rupture was excessive.

Violation (f) resulted from the failure of the licensee to recognize that the modification being conducted on the solenoid valves associated with containment isolation valves could affect their performance (e.g., stroke time). As a result of not performing post maintenance testing, potential problems associated with Section XI testing requirements were not identified.

The responsibility for the post-modification testing associated with Violations (f) and (g) has been assigned to the Superintendent of Technical Services. This change should help bring modification post-maintenance testing under the same scrutiny as the TS required surveillance testing. A weakness was noted in developing required post-maintenance tests, reviewing these tests and verifying that the tests are conducted properly.

The licensee's local leak rate program was reviewed during September - October 1987. Generally adequate management involvement, staffing, and training were indicated by the controls, procedures, and prior planning contained in program procedures. One weakness was identified in the direction of testing isolation valves. Appendix J allows testing of isolation valves in the wrong (non-accident) direction if shown to be conservative. Where both isolation valves were outside containment, the local leak rate test is performed by pressurizing between the valves. The licensee's evaluation of conservatism had not adequately considered the location of valve

packing. Walkdowns to evaluate this condition performed subsequent to the inspection revealed five instances where the local leak rate test did not include the packing on each unit. The inspector concluded, however, that the licensees performance and control of local leak rate testing is much improved since the previous inspection in 1984.

Setpoint drift associated with code safety relief valves has been a reoccurring problem and the root cause has not been determined. Management has authorized sending the relief valves to WYLE Laboratories to accurately test the valves. LERs identifying setpoint drift are accurate; however, no reason for drift is given except for "cause unknown." Although this drift problem is generally identified in IE Notice 86-56 (July), the licensee has not performed a diagnostic study to determine the cause of setpoint drift.

The completed post-refueling, startup tests for each unit were reviewed in April 1988. The tests performed and the procedures used to perform the tests were acceptable.

Problems were identified in the area of EDG testing. Violation (c) resulted in the 2J EDG being electrically overloaded due to an inadequate surveillance test. This overloading of the 2J EDG was also done using the same procedure, but for slightly different reasons during the last SALP period. Violation (d) resulted from the operators improperly changing a procedure designed for unit operation at pressure, to allow the procedure to be performed with the unit depressurized. This inappropriate procedure change resulted in the discharge of an accumulator into the depressurized RCS. Examples 2 and 3 of Violation (f) in the Operations section resulted in events during the refueling outage due to using inadequate surveillance procedures or failure to follow a surveillance procedure. Example 2 resulted in a challenge of the Low Temperature-Overprotection System, and example 3 resulted in an unexpected generation of a reactor trip signal. Example 4 of Violation (f) in the Operations section was caused, in part, by an inadequate physics test procedure which did not place the affected power range instrument in trip. The rest of the outage related startup and physics tests were conducted as required.

The licensee's approach to the resolution of technical issues from a safety standpoint was demonstrated in their Limitorque MOV program and the primary to secondary leakage monitoring program developed following the SGTR event. This leakage surveillance program is much more conservative than TS and probably the most intensive and detailed program in the industry. The licensee installed state-of-the-art leakage detection monitors (Nitrogen-16 (N-16) detectors) on the main steam lines that can detect changes in the primary to secondary steam generator leak rates by counting the N-16 population in the main steam lines.

Six violations were identified during the assessment period. As discussed in the operations section, the violations in the surveillance section indicate a weakness of inattention to detail and failure to follow procedures. The violations are listed below:

a. Severity Level IV - Failure to provide adequate post-maintenance testing before restoring 1-RM-SV-121 air ejector radiation monitor to service (87-24), Unit 1 only.

b. Severity Level IV - Overloading of the 2J emergency diesel generator - similar violation to 86-04-01 (87-36), Unit 2 only.

c. Severity Level IV - Violation for changing the intent of a surveillance procedure without prior safety committee approval (87-36), Unit 2 only.

d. Severity Level IV - Failure to adequately implement the inservice testing program (88-02).

e. Severity Level IV - Failure to conduct stroke time testing of a containment isolation valves following maintenance (88-05), Unit 1 only.

f. Severity Level IV - Failure to perform adequate post maintenance testing on Unit 2 "A" steam generator flow channel III (87-38), Unit 2 only.

Two potential violations on control room habitability which were discussed in Inspection Report 87-19 were not resolved in this SALP period.

2. Conclusion

Category 2

3. Board Recommendations

None

E. Fire Protection

1. Analysis

During the assessment period, inspections were conducted by the regional and resident inspection staffs of the licensee's fire protection and fire prevention program including followup review on previously identified 10 CFR 50, Appendix R safe shutdown and related fire protection items.

The licensee's procedures for the administrative control of fire hazards within the plant, and organization and training of the

plant fire brigade were found to meet the minimum NRC requirements and guidelines.

Surveillance procedures for inspection, testing and maintenance of the fire protection systems and features were satisfactory except procedures were not developed and implemented for inspection of fire barrier wrap enclosures, fire stops, and radiant energy shields installed to satisfy the separation requirements of 10 CFR 50, Appendix R as identified in a violation (a).

The licensee's implementation of the fire prevention administrative controls, general housekeeping, and the control of combustible and flammable materials in safety-related areas of the plant were found to be satisfactory. The fire protection extinguishing systems and fire detection systems for plant areas were found to be functional, or appropriate compensatory measures were employed.

The organization and staffing of the plant fire brigade meet the requirements of Technical Specifications and NRC guidelines. Fire protection staff positions were identified, and authorities and responsibilities were clearly defined. Personnel were well qualified for their assigned duties. The training and drill records for the individual fire brigade members and on duty operating shifts satisfied the requirements of plant procedures and NRC guidelines. However, it was identified that, in 1986 and 1987, seven fire brigade shifts had not participated in required quarterly fire brigade drill because of scheduling difficulties encountered during outage and periods of shift overtime (Violation b).

The triennial fire prevention/protection QA audit was conducted within the specified frequency and appeared to cover all of the essential elements of the fire protection program. Except for the violation item discussed above (Violation b), the licensee had implemented corrective actions associated with the audit findings, or was reviewing the findings to determine the appropriate corrective actions.

With the exception of the violation identified, the management involvement and control in assuring quality in the fire protection program is evident due to the involvement in the site fire protection program, and the implementation of fire protection procedures which meet NRC guidelines. The licensee's approach to the resolution of technical fire protection issues indicates an apparent understanding of issues.

Two violations were identified during the assessment period:

a. Severity Level IV - Failure to develop and implement surveillance procedures for Appendix R Barrier Wrap Enclosures (87-37).

b. Severity Level IV - Failure to implement fire brigade training and timely corrective action for fire protection QA audits (87-37).

One deviation was identified during the assessment period:

a. Installed fire detection system in the Unit 2 quench spray pump house is not in conformance with commitments for full area coverage (87-37), Unit 2 only.

2. Conclusions

Category 1

3. Board Recommendations

None

F. Emergency Preparedness

1. Analysis

During the assessment period, inspections were performed by resident and regional inspection staffs. Two routine emergency preparedness inspections were conducted. The Annual Emergency Preparedness exercise, scheduled for August 4, 1987, was not conducted because the licensee implemented the Emergency Plan during the SGTR event of July 15, 1987.

The routine inspections conducted during the assessment period disclosed that the licensee had an adequate emergency preparedness program. This finding was consistent with those of the previous annual exercise which demonstrated a satisfactory overall licensee performance. The inspections indicated that the following emergency planning elements were adequate: Emergency detection and classification; protective action decision-making; notification and communications; shift staffing and augmentation training; dose calculation and assessment; public information; audits; and changes to the emergency preparedness plan. The inspections disclosed that management support for the emergency preparedness program was reflected by providing training beyond minimal regulatory requirements regarding training of damage control teams (in response to a previous finding).

In the licensee's response to the SGTR event, which was terminated at the Alert emergency classification, the following key elements of the North Anna Emergency Plan were adequately implemented: (1) classification in accordance with the emergency plan implementing procedures; (2) notification of state, local and federal response organizations; (3) activation, and staffing of the ERFs including the control room, TSC, OSC, LEOF, CERC, and emergency news centers; (4) communications

between ERFs and principal response organizations; (5) accident assessment and mitigation; (6) offsite impact assessment; and (7) recovery planning. Since the SGTR event was terminated at the Alert classification, several key elements were not demonstrated, namely: evacuation of non-essential plant personnel; protective action decision-making and formulation of protective action recommendations that would be necessry if there had been a significant offsite release of radioactive material, and deployment of and use of offsite radiological monitoring teams.

The licensee supplied detailed information documenting their response to the event including implementation of the plan, critique of their performance, and planned corrective actions.

The licensee requested an exemption from the annual exercise of its emergency plan as required by 10 CFR 50.47 and Appendix E to 10 CFR 50, based upon activation of their Emergency Plan in response to the SGTR event. The exemption request was granted by the NRC based upon the finding that the underlying purpose of the cited regulatory requirements was met during the licensee's response to the SGTR event.

No violations or deviations were identified in the emergency preparedness area during the assessment period.

2. Conclusion

Category 2

3. Board Recommendations

None

G. Safeguards (Security/Material Control and Accountability)

1. Analysis

During this evaluation period, six routine inspections were performed by the resident and regional inspection staffs.

Security

The security organization continues to benefit from site and corporate management support. The licensee has initiated a program to replace aging security hardware and associated equipment. The continued rejuvenation of the security program is possible only with management support and aggressive security organization leadership.

The two violations identified during this evaluation period are considered isolated and not reflective of a regulatory

breakdown. The first violation, failure to properly display an access badge, is attributed to a single occasion of personnel error. The second violation (c), failure to install one alarm zone correctly, is also considered isolated in its nature.

The licensee continues to exhibit good security shift supervision, procedure revision, access controls and alarm station discipline.

The security program conformed with commitments contained in approved physical security, contingency and training and qualification plans with the exception of the areas noted.

Inspector observations and findings indicated that the licensee's approach to technical issues related to physical security program commitments were sound, conservative and thorough in most cases.

The licensee has a well-established and aggressive hands-on performance training program. In an effort to add more realism to guard force response tactical experiences, the licensee as the first in Region II, has purchased fiber optic laser and MILES (laser engagement) systems. The violations noted below were not indicative of the total effectiveness and proficiency of the security program at North Anna.

Materials Control and Accountability (MC&A)

During the assessment period September 1, 1986 through April 30, 1988, one regional based inspection was conducted in the area of MC&A at the North Anna site. The inspector determined that the licensee had established, maintained and followed written MC&A procedures for controlling and accounting for new and spent fuel receiving, storing, shipment, inventory burn-up calculations, records, and reports. The licensee, however, was not aware of the requirement to account for all non-fuel (incore detectors) Special Nuclear Material (SNM) as required by the regulations. A new procedure was written to ensure that all SNM (fuel and non-fuel) undergo a semi-annual physical inventory. The implementation of the new inventory procedure has not yet been examined by an on-site inspection.

Violation (b) was issued for failure to establish and maintain an adequate MC&A procedure which resulted in a failure to conduct a physical inventory of all non-fuel on inventory.

The violations identified in the Safeguards Program were as follows:

a. Severity Level IV for failure to properly display an access badge (86-29).

b. Severity Level IV for use of an inadequate material control procedure (87-09).

c. Severity Level IV for failure to correctly install an alarm zone (88-07).

2. Conclusion

Category 2

3. Board Recommendations

The Board recognizes the improvements in the licensee's Safeguards Program which are largely due to an extensive training effort. Consequently, the Board recommends that the NRC staff apply resources to the routine inspection program at a continued reduced level.

H. Outages

1. Analysis

During the evaluation period inspections were performed by the resident and regional inspection staffs. Refueling operations were observed for Unit 1 during April, May and June 1987 and for Unit 2 during August, September and October 1987. The inspectors observed reload from the control room, refueling floor, and the spent fuel pool area. The inspectors also observed a 90-day unplanned outage on Unit 1 during the months of July through October 1987. This outage was a result of the steam generator tube rupture event.

The refueling outages demonstrated adequate planning and scheduling. Meetings were conducted daily with station management and schedules were adjusted as necessary. Several planning and scheduling weaknesses were observed. During Unit 1 refueling outage, approximately 1530 valves were scheduled to be repacked, but because of planning problems, only 300 were completed. During the Unit 2 outage, the valve repack program was better planned and approximately 600 valves had their packing replaced. These valves did not require the packing to be replaced because of leakage, but were being repacked as a preventative measure. This program was established to place all station valves in the Chesterton valve packing program and to reduce RCS valve packing leaks during power operations. Both units were plagued with TS related shutdowns due to excessive RCS leakage during the last SALP period. Unit 1 also demonstrated a weakness in the planning of the A Reactor Coolant Pump (RCP) outage which extended the refueling outage by approximately 12 days. The five year RCP inspection had just been completed by Westinghouse on the A RCP, and during the first operation of the A RCP, the motor developed a ground. The unit was in a heat up following the refueling outage and in an attempt to minimize the inpact on the refueling outage, the licensee

inadequately planned the A RCP outage. Instead of draining down the RCS to repair the RCP, the licensee chose to maintain a level in the pressurizer to prevent a need to fill and vent following the maintenance. This contributed to the pressurizer becoming subatmospheric and the resultant reduction in the reactor vessel level without the operator's knowledge as documented by violation (c) of the Operations section.

A scheduling weakness was observed during the Unit 2 refueling outage which involved planning and scheduling of the tests required by Operations to return equipment to an operational status. The maintenance, repair and modification of equipment appears to have been adequately scheduled, but the schedule did not adequately consider the time and resources necessary to properly test the equipment. Maintenance testing for the most part occurred near the end of the outage, and as demonstrated by Violation (f) (second example) of the Operations section, and (c) of the Surveillance section, testing was conducted in conditions contrary to the normal procedures which resulted in events such as lifting a pressurizer PORV and injecting an accumulator.

The refueling operations for the most part were conducted properly. There were several exceptions. During the Unit 1 refueling outage, a contractor refueling bridge operator attempted to move a spent fuel assembly in the spent fuel pool with the assembly still partially inserted in the fuel racks. This resulted from an improper turnover, failure to follow refueling procedures, and an inattention to detail. The fuel assembly was inspected and found not to be damaged. This event resulted in the violation identified at the end of this section. Also, during the Unit 1 outage, the containment crane operator allowed the upper internals to come in contact with the upper internal stand, bending one of the fuel alignment pins. The pin had to be cut and machined off of the internals. During the Unit 2 refueling outage, a fuel assembly was damaged after being removed from the core and attempting to be placed in the upender. This evolution was being conducted by contractor operators and even though the exact cause of the event could not be determined, the licensee chose to replace the contractor refueling operators with station personnel. The remaining refueling operations were conducted without any problems.

Following the Unit 1 refueling outage, the unit experienced a steam generator tube rupture event. This event resulted in a 90 day unscheduled outage. The licensee demonstrated the ability to plan and execute a major outage on very short notice. The tube rupture outage was extremely well managed and the necessary resources and attention were placed on the problems associated with root cause determination and adequate corrective action to prevent recurrence. The Unit 2 refueling outage, which began before the Unit 1 outage was completed, was not only impacted by the resources devoted to Unit 1, but by the corrective actions

associated with modification and testing performed on Unit 1 and were added to the Unit 2 refueling outage. The licensee performed extensive eddy current testing of the steam generators for both units, repaired the Unit 1 ruptured tube, performed preventative plugging on questionable tubes (beyond the Technical Specification requirements) for both units, installed downcomer flow resistance plates in the steam generator for both units, and developed a surveillance procedure which included Nitrogen-16 monitors to ensure detection of steam generators tube leaks prior to the rupture.

One problem associated with the Unit 1 steam generator repairs involved the method for maintaining accountability of materials which entered and exited the steam generators. The review of the accountability log following the steam generator close out identified numerous discrepancies (material not accounted for). Upon questioning by the inspector, the licensee's quality assurance section reviewed the discrepancies. The foreign materials, even though believed not to be in the steam generators, were evaluated for their potential damage as if they were in the steam generators. The licensee conducted safety evaluations and concluded that the material would not result in damage to the steam generators. The accountability log for the Unit 2 steam generator repairs was changed to be resolved every shift; consequently, the log did not contain any discrepancies following the steam generator close outs.

As discussed above, the licensee performed two major outages in parallel. This demonstrated the licensee's ability to provide the resources, both management and technical, to adequately plan, schedule, and conduct major maintenance evolutions on the North Anna units. These outages, even though extensive, were conducted in a timely manner considering the large amount of work accomplished.

Immediately following the tube rupture event, the licensee conducted meetings with the NRC, the press, other interested nuclear groups, and local officials, providing a free flow of information concerning the event and their findings. Following the determination of the root cause for the tube rupture, the licensee issued a report titled, North Anna Unit 1 Tube Rupture Event Report, and conducted meetings in Atlanta and Washington, D.C., with all interested personnel providing information on the event and their conclusions. The licensee has also responded to inquiries from other countries with nuclear programs. The licensee has been very responsive and helpful to the nuclear industry concerning the steam generator tube rupture event.

Reviews of inservice inspection of safety-related components and pipe welds, fasteners, steam generator tubing, etc., were performed during three inspections. Within the area, the inspectors determined that the activities were well planned and

performed in a safe and controlled manner. The licensee has committed additional resources to portions of the ISI/IST program as evidenced by the implementation of the computer aided drafting program designed to maintain ISI isometric drawings updated to match as-built plant conditions. Documentation was concise, accurate and retrievable. Quality control involvement was considered adequate.

During the last SALP period, problems were identified involving the startup following the refueling outages. The licensee had numerous problems during and following the refueling outages for both units during this SALP period. The problems this time were not the excessive leak rates of the previous SALP period, but were related to personnel and procedure errors. Examples of the outage related problems are as follows.

Unit 1 Outages

As discussed previously in this section, the refueling bridge operator attempted to move a spent fuel assembly with the assembly still partially inserted in the spent fuel pool racks. A licensee identified violation (LIV) occurred which involved performance of core alterations without a fully operational charging pump as required by TS. This occurred because the control room operator failed to recognize that a charging pump was not energized on a bus with an operable Emergency Diesel Generator (EDG). Violations (c) and (d) of section IV.A resulted from a management decision to place Unit 1 in a condition that resulted in partial voiding of the vessel without the operator's knowledge. Failure to establish appropriate plant conditions was due to inadequate procedures and inappropriate operator actions, and lead to several non-compliances and a potentially undesirable condition of the unit. The June 29, 1987 reactor trip from 18 percent power during the attempt to start up from the Unit 1 refueling resulted directly from an improperly performed tag out of the feedwater heater level divert system.

During a Unit 1 outage in January 1988, violation (i) of the maintenance section also demonstrated an additional example of inattention to detail. The operators failed to properly install the scale for the RCS level standpipe due to an inadequate procedure. This contributed to a 1,000 gallon RCS leak to the containment sump.

Unit 2 Outages

On September 8, 1987, during the removal of Unit 2 fuel assemblies, an assembly was damaged during transfer from the crane mast to the upender. Violation (f) of section IV.A has five examples, four of which involve the Unit 2 refueling

outage. The second example of violation (f) involved the lifting of the Pressurizer Power Operated Relief Valve (PORV) at its low pressure setpoint (challenge to the Low Temperature Overprotection System). The event occurred because of the failure of an operator to follow a procedure while testing a safety injection isolation valve. The third example of violation (f) involved the unexpected generation of a reactor trip signal with the unit in Mode 4 and the scram breakers closed. The fourth and fifth examples of violation (f) involved power range instrument N44 which was inoperable but not placed in trip by the operator as required by TS. When the need to place the instrument in trip was recognized, the operator did not follow the proper procedure. This resulted in an inadvertent cooldown of the RCS below TS limits. There were two LIVs identified during Unit 2 outages. The first LIV involved a core alteration (latching of 10 control rods) with both containment doors open in violation of TS requirements. This was a result of an operator failing to follow procedure. The second LIV involved the control room operator changing modes to Mode 3 with the automatic start function of the auxiliary feedwater pumps defeated. This was due in part to operator error and an inadequate procedure. Violation (c) of section IV.D involved the accidental discharge of an accumulator into a partially drained and depressurized reactor. Violation (b) of section IV.D involved the overloading of one of the Unit 2 EDGs which was similar to a violation during the last SALP on the same EDG using the same procedure. Violation (f) of section IV.D involved the failure to properly conduct post-maintenance testing of a steam flow instrument. Finally, violation (a) of section IV.A which resulted in a $100,000 civil penalty, involved an operator error and management's tolerance of non-conforming conditions. This occurred during the Unit 2 restart from the refueling outage when the operators allowed two of the steam flow instruments to remain inoperable up to 27 percent reactor power without placing them in trip as required by TS. The operators and station management felt that the instruments were inaccurate at low power and the zero reading was not indicative of inoperable equipment. However, TS require these instruments to be channel checked and the licensee's procedures require the instruments to be declared inoperable if the channel check acceptance criteria are not met. Even though the operators were aware that the acceptance criteria were not being met, it was several hours before they declared the instruments inoperable and placed them in trip as required by TS.

The above discussion serves to illustrate some of the operations, maintenance and surveillance problems that occurred during outage-related conditions. The lack of attention to detail was recognized by the NRC and the licensee to be a major problem even though taken separately, most of the events were of relatively minor safety significance. There is a tendency, particularly during non-routine operations, for the licensee to use existing procedures, with temporary changes, to fit the

current situation. Several events were attributed to using a procedure in which the initial conditions were inappropriate. The NRC had several meetings with the licensee to discuss these events and the licensee's corrective actions. Following the problems with the Unit 1 and Unit 2 restart from the refueling outages, the licensee conducted studies to determine if there were any common root causes to the events. As a result of the licensee's efforts, mode change check sheets were developed for the operators, memos were generated to each of the departments requiring a review and signoff that all items their department is responsible for are completed prior to a unit restart. Operations procedures were changed where appropriate and tours of all areas of the plant are required to be conducted by station management specifically looking for non-conforming conditions prior to a unit startup. In addition, the Station Manager issued a memo and conducted meetings with all station personnel to describe the previous events and to emphasize the importance of adherence to procedures and attention to detail.

There was only one violation specifically assigned to the outage section; however, based on the above discussion and review of the violations in the other sections, it is evident that a large portion of the violations and problems experienced by the licensee occurred during outage related situations. Most of these problems continue to involve inattention to detail and improper adherence to procedures and instructions.

One violation was identified during the assessment period:

- Severity Level IV - Failure to follow a procedure resulting in the movement of a fuel assembly while still partially inserted in a spent fuel rack (87-15), Unit 1 only.

2. Conclusion

Category 3

3. Board Recommendations

The Board's principal concern in this functional area is the events which have occurred during and following outages; specifically, Unit 1 restart in June 1987 and Unit 2 restart in October 1987. Improvements are needed in root cause determination, scheduling, accountability and the personnel and procedural aspects previously mentioned in the operations functional area. Additional NRC and licensee management attention is recommended in this area.

I. Quality Programs and Administrative Controls Affecting Quality

1. Analysis

During the assessment period, inspections were performed by the resident and regional inspection staff.

For the purposes of this assessment, this area is defined as the ability of the licensee to identify and correct their own problems. It encompasses all plant activities, all plant personnel, as well as those corporate functions and personnel that provide services to the plant. The plant and corporate QA staff have responsibility for verifying quality. The rating in this area specifically denotes results for various groups in achieving quality as well as the QA staff in verifying that quality.

A QA effectiveness review was performed in January and February 1988. Each functional area is discussed in the appropriate sections of this report. A problem with containment isolation trip valves was identified with surveillance testing as discussed in the surveillance section of this report; consequently, QA personnel were interviewed to determine if they had discovered similar problems during their routine audit and surveillance activities. Audits and surveillances from 1985-1987 were reviewed: the surveillance problem had not been identified. It appeared that QA personnel could not or did not have the capability to identify a problem of this type. This matter was also discussed during an Enforcement Conference conducted on March 28, 1988. Violation (a) was issued against QA in this area and this finding is indicative of a weakness in that audits are compliance vice performance oriented.

A review was performed on all SALP sections in an attempt to capture perceived strengths and weaknesses related to management controls affecting quality.

The following are some perceived weaknesses in management controls affecting quality:

> The licensee has not demonstrated the ability to correct recurring problems related to: personnel problems during outages such as lack of attention to detail and inadequate or failure to follow procedures, for not administratively closing out work orders which leads to inaccurate maintenance history and poor root cause determinations, personnel failing to follow or inadequate maintenance procedures, improper testing of ASME Section XI valves, and poor past maintenance testing practices.

The following are some perceived strengths in management controls affecting quality:

> The licensee has demonstrated the ability to either identify or correct previously identified problems as evidenced by: reducing the number of reactor trips by successfully implementing a reactor trip reduction program,

reducing the number of unplanned manual shutdowns, decreasing the number of corrective maintenance backlog work orders for both safety and non-safety related items, and successful recovery from a steam generator tube rupture event.

During an Operational Assessment performed from March 28 - April 1, 1988 and April 11-15, 1988, there appeared to be good interface between plant groups and good participation by personnel in plant status meetings. The various status meetings provide a discussion of plant conditions and ongoing planned maintenance and/or testing activities. There is good management control at the meetings and adequate multi-discipline management attendance. The licensee appeared to have active management involvement in daily activities.

The Nuclear Safety Engineering (NSE) group has shown improvement in providing adequate on-going reviews and assessment of plant operations. Additionally, the NSE provided adequate reviews of significant operating experience reports, industry events, NRC Notices and Bulletins, and licensee event reports.

The NSE was also responsible for coordinating the Human Performance Evaluation System (HPES) program. A HPES pilot program was implemented onsite in 1985. The program was designed to uncover specific adverse administrative practices and human engineering hardware deficiencies which contributed to inappropriate actions. The program allows anyone to report a potential problem that may affect safe operation, reliability, availability or an inappropriate action concerning personnel performance. The program was formalized in 1986; a review of HPES reports and resultant actions indicate that this program has had a positive impact in reducing human errors in plant operations. The HPES program is considered a strength.

The Operational Assessment Team identified that the QA audit and surveillance groups spend approximately 60 percent of their time performing collateral tasks, detracting from their basic responsibilities. QA met its audit schedules, but the collateral tasks had caused audit reports to be delayed in being issued. During the first quarter of the year, the QA surveillance group missed several scheduled surveillances. Further review indicated that this was due to special surveillances being implemented in response to industry wide INPO and NRC issues. A review of the missed scheduled surveillances indicated that no TS requirements were impacted. The licensee is restructuring responsibilities within the QA department to allow the audit and surveillance personnel to devote the majority of their time to auditing and surveillance responsibilities.

The licensee utilizes an "Inspector of the Day" program to provide daily coverage, seven days a week, of plant activities. This program is considered a strength.

The Quality Maintenance Team (QMT) concept was implemented in 1986 and the licensee's goal is to develop 18 teams. These teams will perform their own QC inspection and their own radiological control functions. The intent is to build quality in, rather than inspecting it in, the maintenance activity. The team building is approximately 70% complete, the mechanical maintenance teams were the first groups to be formed and the program is now expanding to the electrical and I&C disciplines. The licensee had provided designated personnel from Corporate, Surry, and North Anna to form a Quality Managing Steering Team and a Quality Managing Working Team. These teams meet frequently to discuss problem areas in QMT and possible enhancements. This program is still being evaluated; however, it is considered a strength.

One QMT program area was considered to be a weakness. The QMT is required to perform a pre-job briefing and a post job briefing, the QC department appears to be attending only the pre-job briefings, no observations are made during the post maintenance briefings to ensure that the team is addressing the quality aspect or problems encountered. Considering the Licensee's high expectation of the QMT program, there hasn't been a Licensee QA assessment to determine if the program is meeting goals.

Two violations occurred during this reporting period.

a. Severity Level IV violation for failure to audit the surveillance area to the necessary depth to verify effective program implementation (88-02).

b. Severity Level V violation for failure to take prompt corrective action involving anticipated excessive temperature in the main steam valve house (86-28).

2. Conclusion

Category 2

Trend: Declining

3. Board Recommendations

Additional plant management effort needs to be applied in order to improve the ability to self-identify problems such as the surveillance testing of containment isolation valves, the outage related occurrences and poor post-maintenance testing.

J. Licensing Activities

1. Analysis

The licensee has demonstrated a high level of management involvement and control in assuring quality in licensing activities. The licensee's management has demonstrated active participation in licensing activities and has kept abreast of current and anticipated licensing actions. Particularly noteworthy during this SALP period was the licensee's response to the new technical issues and resolution of the NA-1 SGTR event of July 15, 1987. The licensee's response to this event received a high index of merit from the NRR technical staff.

The licensee's management actively pursues an aggressive and continuous upgrade in the NA-1&2 Technical Specifications (TS) for continuity and similarity. This effort is substantiated by the number of TS changes submitted on a continuing basis by the licensee. It is noted that the licensee's management has in the past and for the subject SALP period actively supported licensing issues and resolutions which represent analyses or methodologies which have been first of a kind. A case in point was the licensee's submittals addressing the fluid elastic instability (high cycle fatigue) of the SGTR double-ended break.

The licensee's management actively pursues an aggressive policy of quality control on proposed amendment changes to assure that the final submittal to NRR represents a quality product. The quality of the licensee's submittals has reduced the amount of NRR staff effort required for review and resolution of licensing issues.

The licensee almost always understands the issues involved. Whenever technical issues are addressed in depth, knowledgeable people are involved who can address an issue not only from the licensee's standpoint but also from a knowledge of NRC regulations, criteria and generic issues. Interface with the NRR staff at meetings and site visits is open, professional, candid and responsive to staff needs.

The licensee accepts its responsibility for plant safety and operability and assesses, evaluates and implements technical modifications when required without waiting for NRC requirements. A recent example of this responsibility was the licensee's prompt initiation of the comprehensive eddy current testing program for Unit 1 steam generators and a similar program for Unit 2.

On occasions when the licensee may deviate from staff guidance, the licensee has consistently provided good technical justification for such deviations. When unusual events have occurred, the licensee has used conservative approaches in dealing with the situations, and performed indepth analyses of significant safety issues raised by such events. During the recent evaluation of the SGTR at Unit 1, the licensee contracted

an engineering consultant as an independent third party to monitor and critique the licensee and vendor efforts in providing high-quality eddy current testing profiles and evaluation of the data. This is not the first time that the licensee has made use of an independent third party to monitor licensee and vendor efforts.

The licensee makes frequent visits to NRC to discuss forthcoming requests for staff actions prior to formal submittals. These frequent visits have provided additional continuity in the licensee's formal submittals regarding NRC regulations and criteria. In addition, when technical issues can be better addressed or complemented by site visits, the licensee is cooperative and provides the necessary staff to discuss appropriate matters.

The licensee's quality of responses has been excellent. The licensee's submittals for the extension to a 40-year license (most notably the environmental aspects), the tie-in, startup and operation of the replacement service water spray system, and the technical evaluation and modifications for the SGTR event are a few examples of excellent quality content.

The licensee, at the request of the NRR Project Manager (PM), has significantly improved the quality of the no significant hazards evaluations for TS amendment requests. The quality of these submittals has alleviated, in part, a large work load for NRR in noticing the licensee's many TS changes for NA-1&2 in the Federal Register.

The licensee's management and staff maintain excellent liaison with the NRR PM. It is common practice for the licensee to expeditiously report to the PM any event reported to the NRC Emergency Response Center. Also, the licensee notifies the PM well in advance of forthcoming requests for amendments or review of safety issues.

The licensee's tracking system for licensing issues, which uses in part, input from the NRR Regulatory Information Tracking System, has resulted in an enhanced capability to assign priorities to licensing actions and maintain schedules and provide applications to NRR on a more selective and orderly month-by-month basis.

As noted in the previous SALP report, the licensee's submittals for requesting relief in the area of inservice inspection and testing were provided on a "last minute" basis, indicating poor control and scheduling. This matter has substantially improved during the subject SALP period. In addition, the licensee has recently requested an exemption for Unit 1 which would put the second 10-year interval for inservice inspection and testing on a common start date for both units. This single IST program for both units has distinct advantages in terms of the licensee and

NRC manpower requirements and should result in increased plant safety through simplification and standardization of plant testing procedures.

However, the licensee's request for an administrative change to the NA-1&2 and Surry TS regarding the licensee's corporate reorganization (April 1, 1988) was not submitted in a timely manner even though the NRC was advised of the scheduled change.

Within the licensee's corporate nuclear program and licensing organization, adequate staffing exists to provide submittals for NRR evaluation in a timely manner. This corporate staff, both at the supervisory and working levels, possesses a level of expertise (nuclear, engineering, operations, etc.) necessary to assess, evaluate and prepare high quality licensing responses to NRR. In addition, operation-qualified personnel are integrated into the corporate levels of management which provide guidance in licensing matters which involve operations. During the administrative changes on April 1, 1988, an appreciable number of systems engineers were added to North Anna staff.

In general, the PM has observed that the licensee has been well-prepared at the appropriate enforcement conferences. In addition, the licensee has been candid and straightforward in accepting responsibility for certain actions or weaknesses contributing to specified violations.

Three violations were identified during the assessment period.

a. Severity Level IV - Failure to have approved safety evaluations concerning operation with leaking explosive plugs in the steam generator and foreign objects in the steam generator (87-24), Unit 1 only.

b. Severity Level IV - Inadequate LER for inoperable steam flow transmitters (87-38), Unit 2 only.

c. Severity Level V - Failure to establish adequate quality control measures to ensure TS amendments are correctly incorporated into TS (86-25).

2. Conclusion

Category 1

3. Board Recommendations

Although the board assigned a category one rating in the functional area of licensing, it should be noted that there were several instances, as discussed in the evaluation, where the responsiveness of the licensee's submittals fell short of the category one criteria. The licensee should strive for improvement in this area during the next rating period to

eliminate deficiencies of this type. No change in NRC's staff resources is recommended.

K. Training and Qualification Effectiveness

1. Analysis

During this assessment period, an inspection was performed by regional inspection staff.

Substantial improvements were noted in the training area. Systematic, task-oriented training had been implemented in those programs reviewed. Management involvement in program planning and implementation was evident and well-defined in procedures. Training materials were detailed and student contact hours were well above minimum requirements. The only weaknesses noted were minor. Training is also discussed in radiological controls, fire protection, and emergency preparedness sections of this report.

The training facilities were noteworthy, including the mockups for general employee training and the mockups for maintenance training. The training department staff was competent, appeared to have good morale, and was very helpful in the conduct of the inspection.

All eleven basic training programs have been accredited by INPO. North Anna and Surry are members of the National Academy for Nuclear Training.

The licensee is also improving the qualifications of the operations instructors by placing them in SRO training classes. At the time of the inspection (November 16-20, 1987), three instructors were in a SRO training class which was to have been completed by March 1988. Two instructors were to be placed in the next SRO training class. This effort by the licensee demonstrates their commitment to the quality of instruction. Completion of this training should significantly improve the technical capabilities of the staff.

The licensee has corporate staff dedicated to the evaluation of the training program. The evaluation included indicators and criteria for determining the adequacy of each training area. A schedule is maintained that evaluates each area on a monthly, quarterly, semi-annual, or annual basis. A discrepancy report is written when an indicator does not meet its acceptable level. The discrepancy report requires the person responsible for the indicator to sign and attach an action plan if necessary. Management is then required to review the discrepancy report and sign off. The inspectors found this audit capacity of the training program to be very good.

Two sets of replacement operator license examinations were administered during this SALP period. The operating and written examinations administered in February 1987 resulted in 6 of 6 Senior Reactor Operator (SRO) candidates and 5 of 5 Reactor Operator (RO) candidates passing. The operating and written examinations administered in March 1988 resulted in 10 of 10 SRO candidates and 10 of 10 RO candidates passing. The requalification program was not evaluated during this SALP period.

The replacement examination passing rate for 31 candidates over this SALP period was 100 percent and is considerably higher than industry average.

No violations or deviations were identified in this area during this assessment.

2. Conclusion

Category: 1

3. Board Recommendations

None

V. SUPPORTING DATA AND SUMMARIES

A. Licensee Activities

Unit 1 began the SALP period in an outage to allow replacement of damaged low pressure turbine blades. The unit returned to power operation on September 25, 1986. On December 25, Unit 1 reduced power to 25 percent to perform ultrasonic inspections of the feedwater piping as a result of the Surry feedwater pipe rupture event. The unit was back up to power on December 27.

On March 28, 1987, Unit 1 began a power coastdown in preparation for the refueling outage and commenced the actual shutdown for the refueling outage on April 19. This completed 170 days of continuous on line operation.

The refueling outage was completed by June 17, however, during the heatup the licensee discovered an electrical ground on the "A" Reactor Coolant Pump (RCP) motor that resulted in an additional 12 days of outage. On June 21, during the RCP repair, the licensee discovered that established plant conditions had resulted in the voiding of the vessel head. On June 29, the licensee completed the 72 day refueling outage.

On July 14, Unit 1 achieved 100 percent for the first time since it was shut down April 19, for the refueling outage. However, on July 15, Unit 1 experienced a double ended steam generator tube rupture (SGTR). The tube rupture outage lasted for 90 days and on

October 13, Unit 1 was placed back on line. The unit was maintained at less than 50 percent power per the revised Confirmation of Action Letter which was issued by the NRC on October 9, 1987. On November 5, the NRC lifted the 50 percent power restriction and Unit 1 achieved 100 percent power.

On November 26, because of a failed RCP seal, Unit 1 had to shutdown to replace the seal package.

On January 13, 1988, the licensee discovered a resin intrusion into the steam generators which forced another shut down. The condensate, feedwater and steam generator systems were flushed and the unit was restarted on February 8, and achieved 100 percent power on February 12.

On March 17, the licensee elected to shutdown Unit 1 to repair a containment isolation valve which had been questioned by the NRC.

On March 24, Unit 1 developed a greater than 10 gallons per minute (gpm) identified Reactor Coolant System (RCS) leak. The unit commenced a TS required shutdown and declared an unusual event. This shutdown and event was terminated at 30 percent on March 25, after the licensee reduced the leak rate to less than 10 gpm. The unit achieved 100 percent power later on March 25, and remained there up to the end of the SALP period.

Unit 2

Unit 2 entered the SALP period operating at 100 percent power. On October 16, the unit was shut down due to an increasing RCS leak rate which was just below the TS limit. The unit restarted and achieved 100 percent power on October 22. On May 23, 1987, after 217 days of continuous operation, Unit 2 shut down to replace a RCP seal package which had failed. The unit achieved 100 percent power on June 4 and maintained that power level until June 17, at which time the unit commenced a coastdown for the refueling outage.

On August 24, Unit 2 commenced the shutdown for the refueling outage. On November 3, Unit 2 commenced a startup following the refueling outage. After numerous personnel and equipment problems, the unit achieved 100 percent on November 15. The unit operated at 100 percent power until February 12, 1988, at which time the unit was shut down voluntarily to test and repair some containment isolation valves due to NRC concerns. The unit restarted and achieved 100 percent power on February 14 and remained at 100 percent power through the rest of the SALP period.

B. Inspection Activities

During the assessment period, routine inspections were performed at the North Anna facility by the resident and regional inspection staffs. From September to December 1986, eight inspections were conducted. During 1987, 41 inspections were conducted which included

Control Room Habitability (May), Steam Generator Tube Rupture (July), Operations Training (September), and Equipment Qualification (December). During 1988, 12 inspections occurred which included Quality Assurance Assessment (February), Health Physics ALARA (April), and Operational Assessment (April/May).

C. Investigation and Allegation Review

There were no significant investigations or allegation activities processed during this assessment period.

D. Escalated Enforcement Actions

1. Civil Penalties

A Severity Level III violation for failure to declare the "A" steam generator flow channel III and "B" steam generator flow channel IV inoperable ($100,000 civil penalty).

2. Orders - None

E. Licensee Conferences Held During Appraisal Period

Enforcement Conference held on September 24, 1987, to discuss a skin overexposure.

Enforcement Conference held on January 21, 1988, to discuss equipment qualification problems and inoperable steam flow instrument issues.

Management meeting held on February 26, 1988, to discuss assessment of operations and future goals.

Enforcement Conference held on March 28, 1988, concerning trip valve operability issues.

F. Confirmation of Action Letters

See section H.9 below.

G. Review of Licensee Event Reports Submitted by the Licensee

During the assessment period (to mid May 1988), there were 57 LERs reported. The distribution of these events by cause, as determined by the NRC staff, was as follows:

	Unit 1	Unit 2	Total
Component Failure	14	5	19
Design	1	0	1
Construction, Fabrication or Installation	3	0	3
Personnel			
- Operating Activity	6	5	11
- Maintenance Activity	7	1	8

	Unit 1	Unit 2	Total
- Test/Calibration Activity	4	6	10
- Other	1	0	1
Out of Calibration	2	1	3
Other	1	0	1
Total	39	18	57

H. Licensing Activities

1. Commission Briefings

	Date
NA-1 SGTR Event, July 15, 1987	11/09/87

2. Significant Licensing Activities

° Amend License To Extend Duration of Full Power Operating License To 40 Years	12/30/86
° Completion Service Water Piping Corrosion and Preservation Program	02/27/87
° Tie-in New Replacement Spray System	03/27/87
° Permit Use of W Fuel Assemblies Using Advanced Zirconium Rod Cladding Alloy	05/13/87
° Loss of Reactor Coolant System Inventory While in Mode 5	06/17/87
° NA-1 SGTR Event	07/15/87
- CAL Requiring NRC Approval Before Restart	07/16/87
- Augmented Inspection Team SGTR	07/15/87-08/14/87
- AIT Report	08/28/87
- SER Supporting 50% Power	10/05/87
- CAL Restart and Operate at 50% Power	10/09/87
- CAL Operation at 100% Power	11/05/87
- SER Supporting 100 Power	12/11/87
° Revised TS for Leak-Before Break SGTR	Pending

Reliefs Granted

- Relief From Hydrostatic Test Requirements ANSI/B 31.7 — 09/30/86
- Relief Request No. 6, IST Pumps and Valves — 02/18/88

4. Schedular Extensions Granted

None

5. Emergency Technical Specifications

- Suspend 30 Day Turbine Throttle Valve Test For Remainder Cycle 5 — 08/06/87

6. Exemptions Granted

- Appendix R Reanalysis Exemption Requests — 11/06/87
- One Time Exemption From 1987 Emergency Exercise — 03/28/88
- Extend NA-1 Current 120 Month Interval IST to Common Date For NA-1&2 Second 10-Year Interval — 04/26/88

7. Discretionary Enforcement

- March 16, 1988, Unit 1, surveillance requirements for trip isolation valve inservice inspection and testing.
- April 1, 1988, both units, organizational changes.

8. Orders Issued

None

9. Confirmatory Action Letters

- Requiring NRC approval for Restart of NA-1 (SGTR) — 07/16/87
- Allowing NA-1 Restart and Operation at 50% Power — 10/09/87
- Allowing NA-1 To Operate at 100% Power — 11/05/87

10. Hearings

None

11. License Amendments Issued

Unit 1/Unit 2	Title of Amendment	Date
85/72	Revise TS for negative EOC moderator temperature coefficient and equilibrium moderator temperature coefficient	09/08/86
86/--	Reinstate TS 3.4.9.1.C	09/26/88
87/73	Revise TS, Section 6, Administrative Controls	11/10/86
88/74	Revise TS, Section 4.7.14, Surveillance Requirements, Fire Pump Diesel Engine	11/12/86
89/75	Revise License For 40 Years From Date Of Operating License Issuance	12/30/86
90/--	Revise TS, Table 3.6.1 To Reflect Installation of New Containment Valve	03/10/87
91/76	Revise TS For Tie-In, Startup and Operation of Replacement Spray System	03/27/87
92/77	Revise TS 3/4.12 Radiological Monitoring to Conform to NRC Guidance	03/31/87
93/78	Revise TS By Increasing Boron Concentration In the Refueling Water Storage Tank, Casing Cooling Tank and Accumulators	04/14/87
--/79	Revise License Condition 2.C (15)(c) To Permit 2nd Inspection of Recirc Spray Pumps Inside Containment To 1987 Refueling Outage	05/13/87
94/--	Add License Condition to Allow Two Fuel Assemblies Containing Fuel Rods With Advanced Zironium Base Alloy Cladding	05/13/87
95/80	Revise TS, 3/4.3.3.7 For Fire Detection Instrumentation Inside Containment	05/13/87
--/81	Revise TS 3.7.1.7 Relating To Surveil	08/06/87

	lance Testing Of Turbine Governor Valve For Remainder Of Cycle 5	
--/82	Revise TS 3/4.6.3 To Correct Inconsistency For Containment Isolation Signal	10/22/87
96/83	Revise TS Associated With Primary Coolant Specific Activity Limits To Comply With GL 85-19	03/11/88
97/84	Modify TS 4.8.1.1.3 and 4.8.2.3.2 For Surveillance Requirements For Emergency Diesel Generators and Station Batteries	03/25/88
98/85	Revise TS By Placing Hydrogen Recombiner Containment Isolation Valve Under Administrative Control For Modes 1 Through 4	03/29/88
99/86	Revise TS, Section 6, Administrative Controls, To Reflect Reorganizational Changes In Offsite And Onsite Corporate Structure	04/28/88

I. Enforcement Activity

FACILITY SUMMARY

FUNCTIONAL AREA	NO. OF DEVIATIONS AND VIOLATIONS IN EACH SEVERITY LEVEL					
	D	V	IV	III	II	I
UNIT NO.	1/2	1/2	1/2	1/2	1/2	1/2
Plant Operations	1/1	1/1	7/4	0/1		
Radiological Controls		1/1	6/4			
Maintenance		2/1	7/4			
Surveillance			3/4			
Fire Protection	0/1		2/2			
Emergency Prepardness						
Security			3/3			
Outages			1/0			
Quality Programs & Administrative Controls Affecting Quality		1/1	1/1			
Licensing		1/1	1/1			
Training						
TOTAL	1/2	6/5	31/23	0/1		

J. Reactor Trips

Unit 1

Nine unplanned reactor trips both manual and automatic and five unplanned manual shutdowns occurred during this evaluation period.

The reactor trips are listed below.

1) September 15, 1986 - The reactor was manually tripped while in Mode 4 with the "A" shutdown bank fully withdrawn and the "B" shutdown bank in the process of being withdrawn. The reactor trip breakers were opened as required by TS 3.1.3.3 when the "B" shutdown bank Individual Rod Position Indicators (IRPI) were declared inoperable.

2) April 19, 1987 - The reactor automatically tripped from 66% power during the shutdown for the refueling outage due to a high negative flux rate trip signal. The trip signal resulted from a dropped control rod which dropped due to a blown fuse.

3) June 29, 1987 - The reactor automatically tripped from 18% power during a startup following the refueling outage. The cause of the trip was a high 5A feedwater heater level turbine trip signal which resulted from an improper tagout.

4) July 15, 1987 - The reactor was manually tripped from 100% power when the operators received indication of a large leak from the RCS. The leak resulted from a steam generator tube rupture.

5) November 23, 1987 - The reactor automatically tripped from 100% power due to a high 5A feedwater heater level turbine trip signal. The feedwater heater level trip signal was generated from a failed feedwater heater level switch.

6) January 8, 1988 - The reactor was manually tripped when the operator received indication of a loss of all of the main circulating water pumps and the resulting increase in main condenser pressure.

7) January 13, 1988 - The reactor automatically tripped from 15% power during a startup due to a high-high steam generator turbine trip signal. The trip signal resulted from cold feedwater and the inability of the operator to control steam generator level.

8) March 18, 1988 - The reactor received an automatic reactor trip signal from a low steam generator water level coincident with a steam flow/feed flow mismatch. The unit was in Mode 4 with the scram breakers open at the time of the trip signal. The steam flow/feed flow mismatch trip signals had been placed in trip for testing purposes and the operator allowed the steam generator level to drop below the low level trip setpoint, not realizing that a reactor trip signal would be generated.

9) March 19, 1988, - The reactor automatically tripped from 3% power during a startup due to a spike on turbine impulse pressure. The spike simulated greater than 10% reactor power with the main turbine tripped resulting in a reactor trip signal.

Unit 2

Two unplanned automatic reactor trips and three unplanned manual shutdowns occurred during this evaluation period. The reactor trips are listed below:

1) August 24, 1987 - The reactor automatically tripped during the shutdown for the refueling outage due to a failed intermediate range detector. The failed detector resulted in an intermediate range high flux trip signal being generated. The unit was subcritical at the time of the trip.

2) October 31, 1987 - The reactor received an automatic trip signal with the unit in Mode 4 and the reactor trip breakers closed. The trip signal was inadvertently generated during the performance of a surveillance test of the response time of the auxiliary feedwater pumps.

K. North Anna Gaseous and Liquid Effluent Release (Both Units)

Gaseous Effluent

Activity Released (Curies)	1985	1986	1987
1. Gaseous Effluents			
Fission and Activation Products	8.05E+3	5.71E+3	1.05E+3
Iodines and Particulates	8.6E-2	2.34E-2	4.38E-2
2. Liquid Effluents			
Fission and Activation Products	5.1E0	9.41E-1	1.3E0
Tritium	1.48E+3	1.56E-3	8.36E+2