UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

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Report Nos.: 50-338/93-02 and 50-339/93-02

Licensee: Virginia Electric and Power Company
Glen Allen, VA 23060

Docket Nos.: 50-338 and 50-339 License Nos.: NPF-4 and NPF-7

Facility Name: North Anna 1 and 2

Inspection Conducted: January 4-8, 1993

Inspectors: H. Whitener/for 1-29-93
M. Thomas Date Signed

H. Whitener 1-29-93
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Approved by: Caudle Julian for 1/29/93
M. Branch, Chief Date Signed
Test Programs Section
Engineering Branch
Division of Reactor Safety

SUMMARY

Scope:

This routine, announced inspection was conducted in the areas of design changes and modifications, engineering support activities, and licensee event report followup.

Results:

Violations or deviations were not identified in the areas inspected.

- The licensee has implemented a process for prioritizing and scheduling plant modifications that address nuclear safety.
- The quality and technical content of the design change packages reviewed were considered good.
- The licensee has established and is implementing a Design Basis Documentation (DBD) program. The design change process has mechanisms for providing feedback to the DBD program when a plant design change has been implemented.

- The licensee has effective controls to ensure that applicable design documents are updated in a timely manner to reflect the as-built plant.

- The engineering staff provided adequate and timely support to the plant.

- The engineering training program was considered to be above average. The number of managers and supervisors in engineering who have operations experience or hold SRO certification was considered a strength.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   D. Benson, Manager, Nuclear Engineering
   *G. Bischof, Assistant Superintendent, Station Engineering
   D. Heacock, Superintendent, Station Engineering
   *G. Kane, Station Manager
   *P. Kemp, Acting Assistant Station Manager, Nuclear Safety and Licensing
   *J. Leberstien, Staff Engineer, Licensing
   *G. Modzelewski, Supervisor, Civil Engineering, Station Engineering
   *R. Riley, Supervisor, Project Engineering, Nuclear Engineering
   D. Roberts, Supervisor, Station Nuclear Safety
   *J. Smith, Manager, Quality Assurance
   *J. Stall, Acting Assistant Station Manager, Operations and Maintenance

   Other licensee employees contacted during this inspection included engineers, operators, security force members, and administrative personnel.

   NRC Resident Inspectors

   *M. Lesser, Senior Resident Inspector
   *D. Taylor, Resident Inspector
   S. Lee, Resident Inspector

   *Attended exit meeting

   Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Design Changes and Plant Modifications (37700)

   a. Plant Modifications to Improve Reactor Safety

      The inspectors reviewed the initiatives taken by the licensee to identify and implement plant modifications to improve reactor safety. Documentation reviewed during this effort included:

      - Procedure VPAP-0304, Requests for Engineering Assistance/Engineering Transmittals, Rev. 0

      - North Anna Modification Request Guidelines

      - North Anna Power Station 1993 Capital Budget Scope Statement, July 16, 1992

      - North Anna Power Station Minor/Major Modifications Projects Installed, Units 1 and 2, January 4, 1993

      - North Anna Power Station Minor/Major Modifications Projects Issued, Units 1 and 2, January 4, 1993

- 1993 Unit 1 Outage Modification List

- 1993 Unit 2 Outage Modification List

The inspectors determined that the Assistant Superintendent Design Engineering (Station Engineering) was responsible for the initial screening and prioritizing of design changes to the plant. The MMRT approves the design change priority, the assignment to a NES organization and the assignment to an implementing organization. The MMRT consists of the Assistant Station Manager O&M, Superintendent Operations, Superintendent Radiological Protection, Superintendent Station Engineering, Superintendent Nuclear Site Services, Superintendent Outage and Planning, and the Superintendent Maintenance.

Based on discussions with licensee engineering personnel, and review of the above documentation the inspectors concluded that the licensee has a satisfactory prioritization process for identifying and implementing plant design changes to improve reactor safety.

b. Planning, Development and Implementation of Plant Modifications

The inspectors reviewed the DCPs listed below to: 1) determine the adequacy of the 10 CFR 50.59 evaluations performed; 2) verify that the DCPs were reviewed and approved in accordance with TS and applicable administrative controls; 3) verify the subject modifications were installed (for those that could be physically inspected) in accordance with the DCP package; 4) verify that applicable plant operating and design documents (drawings, plant procedures, FSAR, TS, etc.) were revised to reflect subject modifications; 5) verify that the modifications were reviewed and incorporated into the operations training program as applicable; and 6) verify that post modification test requirements were specified and that adequate testing was performed. The following DCPs were reviewed:

* DCP 92-104, Rebuilding of Selected SW MOVs

  This DCP involved the inspection and rebuilding of the Unit 1 16-inch SW butterfly valves 1-SW-MOV-103A,B,C,D and 1-SW-MOV-104A,B,C,D in order to reduce the high seating torque experienced during seating of the valves. These valves provide isolation of the RSHX and are safety related. Modifications to the valves included installing a stainless steel sleeve in the stub shaft and valve shaft bore; increasing the diameter (from 7/16-inch to 5/8-inch) of the groove pins holding the disc to the valve shaft; and replacing the thrust collar with one shrunk fit to the valve shaft. The new thrust collar design was also installed on the 24-inch SW butterfly valves 1-SW-MOV-101A,B,C,D; 1-SW-MOV-102A,B; 1-SW-MOV-105A,B,C,D; and 1-SW-MOV-106A,B.

The 24-inch valves are located in the SW supply and return lines to the RSHXs. The inspectors reviewed the safety evaluation for adequacy. Areas addressed in the safety evaluation included, but were not limited to, seismic, material compatibility, effects of weight changes, and post modification test requirements.

During review of the DCP and associated field changes, the inspectors noted that the diagnostic testing performed on the valves was being used for information purposes only. The data were not used for acceptance of the work performed under the DCP nor for setting of the torque switch and the torque switch bypass. The basis provided in the change was that the test equipment accuracy had not been independently validated. The diagnostic equipment was used to aid the MOV Engineer in evaluating the effect that the repairs made to the valve internals had on the motor operators. The valves were stroke tested and the motor operator current checked to verify operability. Evaluation of the diagnostic test data by the MOV Engineer indicated that there were no conditions internal to the valves which would be detrimental to the motor operator. During discussions with the inspectors, licensee personnel indicated that a letter modifying GL 89-10 commitments on DP testing of quarter turn valves would be sent to the NRC. The licensee's GL 89-10 program will be reviewed during subsequent inspections.

The inspectors determined from the information reviewed that this DCP was implemented in accordance with licensee procedures and controls.

* DCP 91-205, Auxiliary Feedwater Total Flow Indication Removal

This DCP involved removing the AFW total flow indicator from the Unit 2 control room. In addition, the logic card which summed the three individual AFW flow loops and associated cabling were removed from the process cabinets in the emergency switchgear room. The flow indicators were installed under DCP 87-31. During a review of the EOPs to identify revisions which might be required as a result of DCP 87-31, the licensee determined that use of the total flow indicator did not provide accurate information for all credible situations. This modification was never installed on Unit 1. The inspectors reviewed the safety evaluation to verify that items considered included human factors, instrument accuracy calculation, and Appendix R.

The inspectors concluded that the safety evaluation bounded the scope of the work covered by the DCP and the DCP was implemented in accordance with licensee procedures. The inspectors did note, however, that the original design

review for DCP 87-31 could have prevented the unnecessary plant modification that was later removed. The inspectors noted that the licensee's design cnange process has been enhanced since the original review of DCP 87-31 which provides for a more thorough upfront review of DCPs.

* DCP 92-252, Missile Protection for EDG Fuel Transfer Piping

This DCP involved installing a structural steel plate missile barrier in each of the Unit 1 and Unit 2 EDG rooms in order to protect short runs of exposed 1-1/2 inch and 1-inch diameter EDG fuel oil transfer lines from tornado generated missile hazards. The two lines supply fuel oil to each EDG, one primary supply and one standby supply. The fuel supply lines are located near the intake louvers in each EDG room. The intake louvers for each EDG room were not designed to protect the short run of fuel oil transfer piping from a missile hazard. The inspectors reviewed the safety evaluation to verify that items considered included seismic, Appendix R, and TS surveillance requirements.

The inspectors concluded that the safety evaluation addressed the scope of work and the DCP was implemented in accordance with licensee procedures.

* DCP 84-71, Pressurizer Safety and Relief Valve Discharge Pipe Support Modifications

In response to NUREG-0737, Item II.D.1, Virginia Electric and Power Company (VEPCO) analyzed the transient fluid loads which would result when the pressurizer safety valves (PSVs) and/or Power Operated Relief Valves (PORVs) lift and system pressure accelerates the loop seal cold water through the valve and discharge piping. The analysis indicated that significantly high fluid transient loads would result in unacceptable stress levels and pipe support loads. It was determined that the installation of reflective metal thermal insulation on the loop seals (loop seal ovens) to maintain a water temperature greater than 400°F and modification of the PSV discharge piping supports would adequately accommodate the fluid transient loading. The loop seal ovens have been installed on both Units and the PSV discharge pipe support modifications has been completed on Unit 2. DCP 84-71 was issued to modify the PSV discharge pipe support system in Unit 1. The proposed modification included addition of supports, deletion of supports and modification of existing supports.

Review of the pipe support modification package (DCP 84-71) showed that the project was worked over three outages and

was closed out in 1992 without completion of the support modifications. The DCP was to be implemented in the 1985 refueling outage. However, the license determined that the project was so extensive that completion in a single outage would significantly extend the outage time. Consequently the controlling procedure was revised twice, once in Field Change (FC) FC-4 in 1985 and again by FC-47 in 1987. The project was divided into three phases as follows:

> Phase I - Modification upgrade of load capacity of an existing support. For instance replacement of a 1½ inch hydraulic snubber with a 3½ inch hydraulic snubber. In this phase, support functions were not changed and supports were not added, deleted or relocated. The original stress analysis remained valid.
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> Phase II - In this phase all additional supports required for the piping upgrade were to be installed except they would not be connected to the piping. Therefore, the original pipe stress analysis remained valid.
>
> Phase III - All physical connections for added supports to the piping will be made and disconnection between piping and existing supports to be removed will be performed. These changes to support function and location of supports are validated by the revised pipe stress model.

Phase I and Phase II were implemented. Phase III was not implemented. Consequently, the as left pipe support system conforms to the original stress analysis. The close out was considered prudent since 1) the DCP had become difficult to work under significantly different design control procedures, 2) the package had become complex (75 revisions) and difficult for craftsmen to follow and, 3) management was considering a different resolution to Item II.D.1 which may not require the support modifications.

The DCP 84-71 close out was documented in the package and included a system walkdown, verification of document updates and revision of system description to reflect the as-installed system configuration. Post modification testing was not required.

The licensee's Engineering Review and Safety Analysis was adequate and included evaluation of areas such as fire hazards, seismic analysis, environmental qualification, ALARA, NRC concerns, impact of other design changes, electrical systems, human factors, impact on regulatory

documents and impact on design basis documents. The licensee provided a letter to the NRC dated November 12, 1992, which indicated that the modification to meet NUREG 0737, Item II.D.1 on Unit 1 will consist of draining off the loop seal water to provide a steam environment at the PSVs. This modification has been deferred until the NRC has completed the review of the Westinghouse Owners Group final report on PSV setpoint drift since NRC positions on draining the loop seal might affect the planned modification.

* DCP 92-182, RVLIS Tubing Configuration Change, Unit 2

This DCP was issued due to leakage at the Reactor Vessel Level Indication System (RVLIS) tee connection at the seal table. When reviewing the condition the licensee found that subsequent to installation of the RVLIS seal table fittings on Unit 2 and prior to the Unit 1 installation, the Westinghouse drawing 1598E06 which controlled the installation was revised. The change at the tee connection at the seal table reduced the number of fittings and potential leakage paths.

The design was previously approved per DCP 81-01 (installation of the system) and Westinghouse drawing 1598 E 06, Revision 2. The inspectors determined that 10 CFR 50.59 safety evaluations adequately addressed the DCP.

c. Maintenance of the Design Basis Document Through The DCP Process

The licensee initiated a system design basis documentation (SDBD) program in November 1988. Scheduled completion date is December 1995. The SDBDs will be performed for about 80 systems. Thirty of these are safety related systems. The rest are balance of plant and systems important to safety.

The inspectors determined that the licensee has established a computerized data base to identify any activities which may impact a SDBD. For instance, a plant modification which will impact the system design basis will be identified and maintained in this data base. Changes to the design basis are accumulated in this data base and can be reviewed through the Data Management Information System (DMIS) as needed. The design basis documents are periodically reviewed and updated.

In addition to the system DBDs the licensee is preparing an Accident Analysis DBD.

d. Configuration Control

The inspectors reviewed selected controls developed and implemented by the licensee to ensure that applicable design documents and procedures affected by completed DCPs were updated in a timely manner to reflect the as-built plant. Documents reviewed included procedures VPAP-0301, Design Change Process and ADM-6.10, Annotation and Revision of Station Drawings. These documents describe the controls for updating applicable priority and non-priority plant documents as a result of a DCP; and for annotating, revising, and distributing station drawings.

Priority documents include drawings, procedures, and other controlled documents which are needed to support operation of the plant. Priority documents are required to be revised before returning the affected system or component to operable status.

Controlled drawings at North Anna comprise three categories which are priority drawings, test loop diagrams, and non-priority drawings. Priority drawings are those required in the control room, TSC, and operation/maintenance coordinator's office. For DCPs and EWRs, priority drawings are required to be revised prior to test completion, technical review, or operational readiness review as applicable. In all cases priority drawings are required to be revised within 24 hours of the technical review. Priority DURs are required to be revised within 15 days of a notification to update following the completion of an engineering review and verification. DURs are a means of informing engineering of drafting and typographical errors or to reflect plant as-built conditions. Test loop diagrams are required to be updated within 30 days after receipt of a notification to update. Non-priority drawings are required to be updated within 90 days after receipt of a notification to update.

The inspectors reviewed selected documents that were affected by the DCPs discussed above and verified that the documents were updated in accordance with the licensee's administrative controls. In addition, the inspectors also reviewed performance indicators which showed that, as of November 30, 1992, drawings issued by engineering were issued on time.

The inspectors concluded that the licensee had adequate controls for ensuring that applicable documents were updated in a timely manner to reflect the as-built plant.

e. PRA Application in Design Control

Discussions with licensee management revealed that the licensee recently completed an IPE for North Anna. The final report was submitted to the NRC by letter dated December 14, 1992. The licensee's letter indicated that several hardware modifications designed to further enhance the flood protection system have been

implemented. Completed modifications included DCP 92-015, Individual Plant Examination (IPE) Internal Flooding Civil Modifications and DCP 92-161, Charging Pump Cubicle Floor Drain Backflow Preventer. Licensee personnel indicated that the completed PRA is available for use by NES personnel in the design control process. The inspectors concluded that the completed PRA for North Anna is another tool that is now available to the design organization. Use of the PRA should enhance the design control process.

3. Organization, Staffing, and Training

The inspectors reviewed the licensee's organization and staffing to determine whether the licensee's engineering organization was adequately staffed to provide effective engineering support to the plant.

The Nuclear Engineering organization is comprised of seven departments which report via managers to the Vice President Nuclear Engineering Services. This includes the special group established for the steam generator replacement project. Station Engineering is part of NES and reports through the Manager Nuclear Engineering to the Vice President NES. Day to day real time support was primarily provided by Station Engineering.

The staffing levels within NES have not changed significantly over the last year. The staffing levels were sufficient to support plant activities. The inspectors reviewed various performance indicators for selected engineering activities which showed that Engineering provided timely support to the plant during 1992. Drawings which required updating were completed prior to their due dates. Engineering established a goal for the number of backlogged (greater than 90 days old) minor modifications not to exceed 50. The backlog was reviewed on a monthly basis. The actual backlog never reached 40 during any month in 1992. CTS items and DRs assigned to Engineering were answered before their due dates.

The inspectors concluded from reviewing the completed DCPs and the various performance indicators that NES provided adequate and timely support to the plant.

In addition to reviewing the licensee's organization and staffing, the inspectors also reviewed the training provided to the Engineering staffs. Training was provided in accordance with the requirements specified in the Nuclear Technical Staff and Technical Staff Managers Training Program, Revision 9. The program specifies initial and continuing training requirements for both site and corporate engineering personnel. The training program specifies fundamental training required for all engineers and additional training for the various disciplines. Included in the fundamental training is three weeks of systems training. In addition to the training specified in the program, the inspectors noted that engineering personnel receive 10 CFR 50.59 Safety Evaluation

training. The inspectors verified that selected engineers involved in the DCPs discussed in paragraph 2.b. of this report had received 10 CFR 50.59 training within the last year. The inspectors also noted that several of the supervisors and managers in Engineering (site and corporate) have received operations training. Several of the supervisors and managers have either worked in the plant as a SRO or have SRO certifications.

The inspectors concluded that the licensee's training program for the engineering staff was adequate. The inspectors considered the operations training and experience in NES to be a strength.

4. Review of Licensee Event Reports (LERs)

The inspectors reviewed LERs 91-002 (Unit 1), 92-002 (Unit 1), 90-005 (Unit 2) and 92-003 (Unit 2). The reports identify certain pressurizer safety valves (PSVs) and main steam safety valves (MSSVs) where the measured lift pressure did not meet the setpoint pressure Technical Specification (TS) limit within +/- one percent. The as found lift pressure was determined by Wyle Laboratory using steam as a test medium.

The licensee concluded that there was no significant safety implications from the high lift pressure setpoint drift since the as found lift pressure settings were bounded by the safety analysis for overpressure transients. Specifically, the expected pressure was less than design basis pressure. Also, there was no significant safety impact for the safety valves where the setpoint drift was on the low side of the setpoint tolerance since the shift did not activate the valves and result in a challenge to safety systems. The licensee concluded that the safety valves would have performed their safety functions if required.

Immediate corrective action was to have the valves refurbished and the setpoints adjusted to meet the TS setpoint limit within +/- one percent tolerance.

The concerns relating to PSV setpoint shift were identified to licensees in NRC Information Notice (IN) 89-90, Pressurizer Safety Valve Lift Setpoint Shift, and Supplements 1 and 2 to IN 89-90. These notices identified a potential problem with pressurizer safety valve lift setpoint shifting related to setting a setpoint with steam flow and operating the valves with a loop seal filled with water.

In letters to the NRC dated December 21, 1990, October 31, 1991, and November 12, 1992, the licensee proposed, as long term resolution to the setpoint drift problem, to drain the loop seals and operate the PSVs in a steam environment as is used for setting the lift pressure. However, modification of the loop seals has been deferred pending the results of the NRC review of the Westinghouse Owners Group report (WCAP 12910) on pressurizer safety valve setpoint shift.

In addition to the above corrective actions, the licensee is considering submittal of a request for a license amendment to expand the setpoint tolerance. In this regard the licensee is currently reviewing an analysis and draft license amendment request to change the setpoint tolerance for the MSSVs from +/- one percent to +/- three percent.

Since the setpoint problem and corrective action is essentially the same for the four LERs the inspector considered it appropriate to close LERs 91-002 (Unit 1) and 90-005 (Unit 2). The licensee's long term corrective action will be tracked by LERs 92-002 (Unit 1) and 92-003 (Unit 2) which remain open. The LER status is left as follows:

(Closed) LER 50-338/91-002, Pressurizer and Main Steam Safety Valve Setpoints Out of Tolerance Due to Setpoint Drift

(Closed) LER 50-339/90-005, Pressurizer Safety Valve Setpoints Out of Tolerance Due to Setpoint Drift

(Open) LER 50-338/92-002, Pressurizer Safety Valve Setpoint Out of Tolerance Due to Setpoint Drift

(Open) LER 50-339/92-003, Pressurizer and Main Steam Safety Valve Setpoints Out of Tolerance Due to Setpoint Drift

5. Exit Interview

The inspection scope and results were summarized on January 8, 1993, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

6. Acronyms and Initialisms

AFW	Auxiliary Feedwater
CTS	Commitment Tracking System
DBD	Design Basis Documentation
DCP	Design Change Package
DR	Deviation Report
DUR	Drawing Update Request
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EWR	Engineering Work Request
FSAR	Final Safety Analysis Report
GL	Generic Letter
IPE	Individual Plant Examination
MMRT	Modification Management Review Team
MOV	Motor Operated Valve
NES	Nuclear Engineering Services

O&M	Operations and Maintenance
PRA	Probabilistic Risk Assessment
RSHX	Recirculation Spray Heat Exchanger
SRO	Senior Reactor Operator
SW	Service Water
TS	Technical Specifications
TSC	Technical Support Center