ENCLOSURE

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555
September 24, 1987

Docket No. 50-338

MEMORANDUM FOR: Albert Gibson, Director
Division of Reactor Safety, RII

FROM: Gus C. Lainas, Assistant Director
for Region II Reactors
Division of Reactor Projects I/II
Office of Nuclear Reactor Regulation

SUBJECT: TIA - NORTH ANNA UNIT 1 (NA-1) STEAM GENERATOR TUBE FAILURE EVENT

The purpose of this memorandum is to update our interface agreement dated July 28, 1987, relative to the recent North Anna, Unit 1, steam generator tube rupture (SGTR) event. A copy of the July 28, 1987 interface agreement is provided in Enclosure 1. The first 3 items specified in this agreement have been completed. Items 4 and 5 still remain to be done.

Virginia Electric and Power Company (VEPCO) and Westinghouse (W) have been evaluating this event and have just recently finalized the tube break mechanism and modifications required prior to restart.

On September 10, 1987, VEPCO and W briefed the NRR and Region II (RII) staff on the NA-1 steam generator inspection, the SGTR failure mechanism and the modifications to be made prior to restart. Final reports from VEPCO and W were submitted to NRR on September 15, 1987. VEPCO and W met with the NRR and the RII staff on September 21, 1987 to discuss questions from the staff regarding these final reports. On September 23, 1987, VEPCO will submit a basis for restart with plant operations limited to 50% of full power pending staff authorization of full power operation. The NRR Project Manager, Leon Engle, has already discussed restart limited to 50% of full power with RII representatives. Also, on September 25, 1987, VEPCO will submit as part of its final SGTR report, a safety evaluation revising dose rates for the UFSAR SGTR accident analyses based on the installation of SG downcomer resistance plates. Finally, full power operation is dependent on the NRR SER regarding the NA-1 SGTR event, and the evaluation and adequacy of the SG repairs.

Therefore, based on the above, a revised interface agreement is necessary as is an updated schedule for meeting major milestone requirements. A revised schedule is provided in Enclosure 2 to this memorandum. The listed dates are based on the best available information at this time.

The following actions specify both RII and NRR responsibilities, as well as the joint actions required prior to restart (50% power) and full power operations (100% power).

1. RII and NRR met with licensee on September 21, 1987.

2. The NRR draft SER for restart (50% power) is scheduled to be prepared by September 30, 1987. (The NRR NA project manager will have lead responsibility for preparing the draft SER.)

3. The NRR draft SER for restart (50% power) is scheduled to be sent to NRR EMTB and PSB and RII for concurrence on September 30, 1987.

4. NRR and RII concurrence on draft SER (50% power) is scheduled for October 2, 1987.

5. NRR SER for restart (50% power) is scheduled to be issued on October 5, 1987.

6. RII is requested to verify the following items prior to restart (Mode 2).

   The adequacy of the licensee's operating procedures for SG leakage rate surveillance

   That SG tube R9 C51 has been stabilized in conformance with vendor (W) recommendations.

   That flow restrictor plates have been installed in conformance with vendor recommendations.

   That applicable procedures have been followed for loose parts accountability.

7. RII/NRR agreement on approval for restart (50% power) is scheduled to be completed by October 5, 1987.

8. RII is scheduled to issue not later than October 6, 1987 a revised CAL to licensee which would limit power operations to 50% power.

9. RII will verify the operability of the newly installed N-16 monitor prior to power ascension greater than 30%.

10. NRR EMTB, PSB and PRBP SER input for full power operations is scheduled to be submitted to the PM by October 9, 1987.

11. NRR SER (100% power) is scheduled to be complete by October 14, 1987.

12. NRR and RII concurrence on NRR SER is scheduled to be complete by October 16, 1987.

13. NRR SER (100% power) is scheduled to be issued October 19, 1987.

14. RII/NRR approval for full power operations is scheduled to be complete on October 19, 1987.

It is noted that additional actions and responsibilities may be identified as the staff's review of these matters progresses.

The contact for the above actions will be L. Engle, who can be reached on FTS 49-29795.

Gus C. Lainas, Assistant Director
for Region II Reactors
Division of Reactor Projects I/II
Office of Nuclear Reactor Regulation

Enclosures:
As stated

cc: T. Murley
J. N. Grace
L. Reyes
J. Sniezek
F. Miraglia
R. Starostecki
J. Richardson
A. Thadani
L. Cunningham
F. Cantrell
C. Y. Cheng
R. Craig

October 8, 1987

Docket No. 50-338

MEMORANDUM TO: Luis A. Reyes, Director
Division of Projects, Region II

FROM: Gus C. Lainas, Assistant Director
for Region II Reactors
Division of Reactor Projects-I/II

SUBJECT: SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION RELATED TO RESTART AND OPERATION OF NORTH ANNA, UNIT NO. 1 (NA-1), AT 50 PERCENT POWER

The subject NA-1 Safety Evaluation (SE) dated October 5, 1987 is enclosed in accordance withthe revised TIA dated September 24, 1987 regarding the NA-1 steam generator tube rupture event.

As stated in the NA-1 SE, the NRR staff finds that interim operation at reduced power (less than or equal to 50 percent power) is acceptable. Region II concurrence on the subject SE was received on October 2, 1987 in a telecon between F. Cantrell, Region II, and the NRR Project Manager, L. Engle.

NRR will review, in conjunction with R-II, the results of operation at 50 percent power as well as the licensee's evaluation of SG tube performance. Prior to authorization for operation at greater than 50 percent power, the staff will evaluate the operating results and other information and issue a final safety evaluation report.

Original signed by
Gus C. Lainas, Assistant Director
for Region II Reactors
Division of Reactor Projects-I/II

Enclosure: As stated

cc w/enclosure:
T. Murley
J. Sniezek
R. Starostecki
F. Miraglia
J. Richardson
A. Thadani

DISTRIBUTION
Docket File
PD22 Rdg.
G. Lainas
H. Berkow
L. Engle
D. Miller

D/54

*Please see previous concurrence

LA:PDII-2*	PM:PDII-2*	D:PDII-2*	AD:DRPA*
DMiller	LEngle	HBerkow	GLainas
10/06/87	10/06/87	10/06/87	10/06/87

Docket No. 50-338

MEMORANDUM TO: Luis A. Reyes, Director
Division of Projects, Region II

FROM: Gus C. Lainas, Assistant Director
for Region II Reactors
Division of Reactor Projects-I/II

SUBJECT: SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION RELATED TO RESTART AND OPERATION OF NORTH ANNA, UNIT NO. 1 (NA-1), AT 50 PERCENT POWER

The subject NA-1 Safety Evaluation (SE) dated October 5, 1987 is enclosed in accordance withthe revised TIA dated September 24, 1987 regarding the NA-1 steam generator tube rupture event.

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Gus C. Lainas, Assistant Director
for Region II Reactors
Division of Reactor Projects-I/II

Enclosure: As stated

cc w/enclosure:
T. Murley
J. Sniezek
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F. Miraglia
J. Richardson
A. Thadani

DISTRIBUTION
Docket File
PD22 Rdg.
G. Lainas
H. Berkow
L. Engle
D. Miller

LA:PDII-2	PM:PDII-2	D:PDII-2	AD:DP2A
DMiller	LEngle	HBerkow	GLainas
10/6/87	10/6/87	10/6/87	10/6/87

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION
RELATED TO RESTART AND OPERATION AT 50% POWER
FACILITY OPERATING LICENSE NO. NPF-4
VIRGINIA ELECTRIC AND POWER COMPANY
OLD DOMINION ELECTRIC COOPERATIVE
NORTH ANNA POWER STATION, UNIT NO. 1
DOCKET NO. 50-338

INTRODUCTION

By letter dated September 22, 1987, the Virginia Electric and Power Company (the licensee) requested that the North Anna Power Station, Unit No. 1 (NA-1) be permitted to start up and operate at 50 percent of full power. Following the July 15, 1987 NA-1 Steam Generator Tube Rupture (SGTR) event, the licensee agreed to obtain concurrence from the NRC prior to NA-1 restart (Mode 2). This agreement was specified in the NRC Confirmatory Action Letter (CAL) issued July 22, 1987. The licensee has completed the evaluation of the SGTR event and has submitted by letters dated September 15 and 25, 1987 the evaluation of the SGTR event, including the SGTR failure mechanism and modifications to be made prior to restart. The NRC review of these matters may extend beyond early October, 1987 when NA-1 is scheduled to be ready for restart. Therefore, as noted above, the licensee has requested NRC concurrence for restart and operation of NA-1 at 50 percent of full power pending NRC authorization for full power operations. In order to place these matters in proper perspective, a brief description of the NA-1 SGTR event and the licensee's investigation of this event is provided below.

Prior to 0630 hours on July 15, 1987, NA-1 was operating at 100% power. At 0630 hours, the Main Steam Line "C" radiation monitor registered a Hi-Hi alarm and the Control Room Operator (CRO) noted pressurizer (PZR) level and pressure decreasing. Therefore, the CRO increased charging flow to the Reactor Coolant System (RCS). The unit was manually tripped at 0635 hours and approximately 20 seconds later a Lo-Lo pressure safety injection signal actuated automatic trip. At 0639 hours a Notification of Unusual Event was declared and at 0650 hours feedwater flow to SG "C" was isolated. However, the level of SG "C" was identified to be increasing, indicating an SG tube rupture or break (SGTR). At 0654 hours an alert was declared and at 0705 hours Safety Injection (SI) was terminated. At 0710 hours emergency procedures were initiated for post-SGTR cooldown using backfill. The Technical Support Center was activated at 0757 hours and the local emergency operations facility activated at 0915 hours. The unit entered Mode 4 (Hot Shutdown) at 1108 hours and at 1218 hours the RHR system was placed in service. The unit entered Mode 5 (Cold Shutdown) at 1330 hours and the event was terminated at 1335 hours.

No automatic actuation of primary or secondary safe[illegible] relief valves occurred. Total radioactivity release was less than 1% of Technical Specification (TS) limits. The tube leakage rate (as determined later) was in the range of 560-637 gallons per minute (GPM). Offsite environmental monitoring teams detected no increase in radioactivity above normal background levels. The SGTR event was

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determined to be bounded by the Updated Final Safety Evaluation Report (UFSAR). The maximum leak rate (560-637 gpm) was less than the UFSAR value of 710 gpm. Core safety limits were not challenged and shutdown and thermal margins were maintained.

Once access to the NA-1 SGs A, B, and C was gained, the licensee's evaluation of the SGTR event was oriented to: (1) Determining the root cause of the failure; (2) Ascertaining the condition of the SGs, particularly with respect to the failure mechanism; and (3) Performing the necessary corrective actions to preclude the future occurrence of a tube rupture event.

On July 21, 1987, VEPCO identified a ruptured tube in SG-C. The tube location was Row 9, Column C51 (R9 C51) on the cold leg side at the seventh support level. A fiber optic examination identified the failed tube to be the classical double-ended guillotine break. On August 12, 1987, VEPCO successfully completed the removal of tube R9 C51 on the cold leg side up to and including the break at the seventh support level. The tube was immediately sent to Westinghouse for an extensive nondestructive/destructive examination to determine the fracture morphology and the failure propagation mechanism. The results of these examinations and the determination of the tube failure mechanism are provided in the licensee's final report dated September 15, 1987, and are discussed below.

In order to provide justification for future restart of NA-1, VEPCO has conducted an extensive inspection of all three SGs. The inspection has been the most extensive eddy-current testing program undertaken at a U.S. domestic facility with emphasis on detecting circumferential defects.

Eddy current testing (ECT) is the principal method used for performing tube inspections. This inspection method involves the insertion of a test coil inside the tube that traverses the tube length. The test coil is excited by an alternating current, which creates a magnetic field that induces eddy currents in the tube wall. Disturbances of the eddy currents caused by flaws in the tube wall produces corresponding changes in the electrical impedance as seen at the test coil terminals. Instruments are used to translate these changes in test coil impedance into output voltages which can be monitored by the test operator. The depth of the flaw can be determined by the observed phase angle response. The test equipment is calibrated using tube specimens containing artificially induced flaws of known depth.

The ECT testing program has included the inspection of every tube support junction and straight tube sections in all three SGs with an 8x1 pancake array probe. This probe (8x1) has the sensitivity to detect all inner-diameter defects, either axial or circumferential, and with defects 20% or deeper and with a length of 3/16 of an inch or longer. Also, the 8x1 probe is able to detect outer-diameter cracks and intergranular attack on either the inner-or outer-diameter. In addition, all indications detected by the 8x1 probe have been tested with the Rotating Pancake (RPC) probe. Finally, profilometry has been conducted on selected intersections.

A Westinghouse Intelligent Eddy Current Data Analysis System (IEDA) has been used as an aid in flagging suspect bobin coil indications, which are then dispositioned by data analysts. The data from each tube has been independently reviewed by two different analysts. One analyst has used the Westinghouse IEDA system and the other analyst has used the Zetec Digital Data Analysis System.

All data analysts are certified at least Level II in accordance with American Society of Nondestructive Testing (ASNT) requirements. The analysts have been given additional training by Westinghouse and required to pass a test that covers the specific data analysis being used for the present NA-1 eddy current tests.

Finally, it is noted that an NRC Augmented Inspection Team (AIT) was dispatched to the NA facility. The AIT was charged with determining whether the licensee's actions in response to the July 15, 1987 SGTR were adequate to protect the health and safety of the public and that appropriate action was being initiated to determine the cause of the event. In addition, the procedures followed by the licensee relative to the SGTR were evaluated to assess the adequacy of in-place procedures to cope with serious events of this type.

The NRC AIT Report was issued August 28, 1987. The Report, in part, concluded that, "The overall results achieved were outstanding in that the operator tripped the plant, isolated the leak and brought the plant to cold shutdown in seven hours without using the S/G power-operated relief valves. This contributed to a negligible release to the environment."

Our discussion and evaluation of these matters with respect to restart of NA-1 for operations not to exceed 50% of full power are provided below.

DISCUSSION

Steam Generator Inspection

As noted above, the licensee conducted an extensive SG ECT inspection of the NA-1 SGs A, B and C. Identified indications were either present in the April 1987 refueling outage with no discernable change indicated or in previously uninspected portions of each SG. Additionally, a review of the data from the last outage using the present analysis rules revealed several tubes that should have been plugged at the previous outage. This apparent, though not actual, change in the SG condition is due to the change in the analysis rules and increased awareness by the analysts of North Anna specific ECT signals. A review and comparison of the SG C hot leg data demonstrates that there is essentially no change in tube condition from the April 1987 refueling outage to July 1987 (when the event occurred). Of significant importance was the fact that there were no indications of circumferential nature found at any tube support plate locations, including the seventh tube support plate.

The number of tubes inspected is shown below. Each steam generator contains 3388 tubes. However, a number of tubes have been plugged from previous SG inspections. The number of non-plugged tubes are: SG A - 3179; SG B - 3210; and SG C - 3117.

The number of tubes to be removed from service based on the SGT inspection by indication type are indicated in the following table.

STEAM GENERATOR TUBES TO BE PLUGGED AS RESULT OF SGTR EVENT
(By Indication Type)

S/G	Clear[1] Indications	Distorted[2] Indications	Tube[3] Sheet Indications	8x1 Possible[4] Indications	Other[5]	Total[6] tubes to be Plugged
A	0	6	6	11	2	25
B	0	3	5	12	1	21
C	2	2	20	11	4	39

[1]Clear Indications (defective) - bobbin indications of greater than 40 percent "thru-wall" depth.

[2]Distorted Indications - bobbin indications of undetermined "thru-wall" depth at tube support plates.

[3]Tubesheet indications - bobbin indications of undetermined "thru-wall" depth at tubesheet.

[4]8x1 Possible Indications - indications identified by 8x1 probe.

[5]Tubes with broken probes or which would not pass 8x1 probe - includes failed tube.

[6]Plugging summary is as of 9/14/87 based on ECT results - does not include tubes to be plugged as a preventative measure based on fatigue considerations or other concerns.

Tube Failure Mechanism

Upon arrival at Westinghouse, tube R9 C51 (the tube with the circumferential break) was immediately subject to a series of non-destructive/destructive tests to determine the tube failure mechanism. Visual examinations and macroscopic examinations of the tube fracture surface were conducted to determine crack origins and crack propagation paths. Scanning Electron Microscope (SEM) and Transmission Electron Microscope (TEM) fractographic examinations were also performed to confirm tube crack origins and crack propagation paths.

Mechanical properties of the tube were determined and found to agree closely with the 1971 tube certification data applicable to NA-1. Microstructure was typical of mill-annealed Alloy 600 for NA-1. Grain size was small, ASTM 9.5.

Based on the above, the cause of the failure was determined to be fatigue. No evidence of any significant intergranular corrosion was observed on or immediately adjacent to the fracture surfaces. High cycle fatigue striations were present and were measured to obtain the stress intensity which led to initiation of the fatigue crack and crack propagation. The mode of crack propagation concluded that leakage occurred between the time of total through-wall development of the crack front and the final circumferential break.

The orientation and spacing of the striations support the conclusion that normal design operational loadings were not sufficient to lead to the fatigue failure. Therefore, some other loading mechanism was acting on the tube to produce the failure. Measurements of the striation spacing provided necessary data to determine the range of loadings that led to eventual fatigue of the tube. Adverse flow mechanisms were evaluated, such as turbulence, vortex shedding, and fluid elastic excitation. Review of the data supports the conclusion that fluid elastic excitation was the most probable mechanism that could provide sufficient loadings or alternating stresses to induce fatigue.

An additional method was utilized to determine these loadings and verify the striation spacing measurements and resultant loading conditions. This method used tube dent data (obtained through profilometry and physical measurements) and finite element analysis to establish mean stress data through the dent. This mean stress data, the dented configuration and fatigue curve were then used to determine the alternating stress intensity required to initiate a fatigue crack. This calculated range of stress intensity supported the similar conclusion determined from striation spacing measurements that tube failure was induced by fatigue.

A fluid elastic stability ratio was defined for failed tube R9 C51. The stability ratio represents a measure of the potential for tube vibration due to instability during service. Values greater than unity (1.0) indicate fluid elastic instability. The fluid elastic stability ratio is defined as the effective velocity divided by the critical velocity. The calculated flow ratio was determined for current NA-1 flow parameters. Calculations determined that the tube would be more susceptible to fluid elastic instability due to lower damping caused by denting. Simulated shaker tests supported the conclusion that in this region of low damping, tube R9 C51 would be fluid elastically unstable.

As discussed above, the results of the present SG inspection indicated no eddy current indications of a circumferential nature at any seventh support plate location. This is consistent with the fatigue mechanism described above. The majority of the fatigue process lies in the cyclic loading (via alternating stress) to initiate a crack (or cracks) in the tube. Once the fatigue crack initiates, the time required to propagate the crack is comparatively small.

Antivibration Bars (AVBs) limit the high vibration amplitudes needed to achieve the alternating stress necessary for fatigue crack initiation. The depths of AVB penetration into the SG tube bundle can be estimated from eddy current indications that can then be translated to a SG inspection map which provides an indication of non-uniform AVB insertion depths.

A large number of AVB indications were identified during the current SG inspection. This is not unusual in a Series 51 Westinghouse SG. However, a few indications were identified as far down as Row 8. Therefore, extensive eddy current testing was performed to identify AVB indications. The inspection revealed that the majority of the Row 9, 10 and 11 tubes were supported by AVBs. However, failed tube R9 C51 was not supported by an AVB.

Correlation with the known deflections required to provide sufficient stress to initiate fatigue show that the AVBs limit the tube motion to below the required deflection limit. This data provided further support to the conclusion that the loading mechanism for R9 C51 was fluid elastic excitation.

In summary, the licensee concludes that the tube failure was due to high cycle fatigue. The fatigue mechanism was determined to be a combination of stresses imposed by tube denting at the seventh support plate and vibration due to fluid elastic instability.

Corrective Actions

The licensee has implemented a series of corrective actions and modifications to preclude similar tube failures at NA-1. These include the installation of a downcomer flow resistance plate in order to reduce the loadings experienced by susceptible tubes. Preventive SG tube plugging is being implemented to further reduce the probability of tube rupture. In addition, an enhanced monitoring program is being implemented to provide sufficient notification of tube leakage in order to shut down NA-1 prior to a tube rupture. These matters are discussed below.

(1) Downcomer Flow Resistance Plates

The NA-1 SGs A, B and C are being modified to include a downcomer flow resistance plate (DFRP). The DFRP will reduce the steam generator recirculation flow and is expected to result in the improvement in tube "stability ratio" needed to preclude further tube failures of active tubes by the fluid elastic instability mechanism. As noted above, "stability ratio" is a relative measure of the potential for tube vibration due to fluid elastic instability. Evaluations by the licensee have concluded that a 10% improvement in stability ratio should provide the necessary reduction in fatigue usage (reduced amplitude of vibration) to preclude further tube failures by this mechanism over the remaining life of the steam generators. The installation of the DFRPs will be completed prior to NA-1 restart.

For operations at greater than 59 percent power, the Final Safety Analysis Report (FSAR) will be revised to include the DFRP (reduced mass flow) in the SGTR accident analysis. A reanalysis of the SGTR event with the DFRP has resulted in a calculated offsite dose which is greater than reported in the UFSAR. The increase in dose consequences for the SGTR event occurs only for rated thermal power levels above approximately 59%, and the consequences are still well within established acceptance criteria as defined in the UFSAR and the bases for NA-1 TS 3/4.4.8.

(2) Preventive Plugging

Preventive plugging will take place on the potentially susceptible tubes in Row 8 through 11. The essential criterion for identifying specific tubes for preventive plugging is that they not be supported by at least one AVB. All such tubes will be plugged. On the cold leg side, each tube meeting this plugging criteria will be plugged with a sentinel plug. The sentinel plug will permit internal pressurization of the tube and low level leakage in the event a through-wall crack develops in the plugged tube. This will serve as an early warning detection method for occurrence of a similar circumferential break of

October 16, 1987

DMB 016

Docket No. 50-338

MEMORANDUM FOR: Herbert Berkow, Director
Project Directorate - II-2
Division of Reactor Projects I/II

FROM: John W. Craig, Chief
Plant Systems Branch
Division of Engineering and Systems Technology

SUBJECT: NORTH ANNA, UNIT 1 - MODIFICATIONS TO LEAKAGE DETECTION CAPABILITY FOLLOWING THE JULY 15, 1987 STEAM GENERATOR TUBE RUPTURE EVENT (TAC NO. 65791)

Plant Name: North Anna Power Station, Unit No. 1
Licensee: Virginia Electric and Power Company
Docket No.: 50-338
Review Status: Complete

The Plant Systems Branch (PSB) has reviewed the Virginia Electric and Power Company's submittals dated September 15 and 25, 1987 regarding the steam generator tube rupture (SGTR) event of July 17, 1987 at North Anna, Unit 1. PSB review was limited to the modifications for the augmented surveillance program for monitoring steam generator primary-to-secondary leakage. This program is based on the use of several existing radiation monitors and sampling systems, and the installation of a new N_{16} gamma detection system to quantify primary-to-secondary leakage. The program is designed to detect leakage during the early stages of fatigue failure so that an orderly shutdown can be accomplished prior to an actual SGTR.

Based on our review, we find the proposed primary-to-secondary leakage surveillance program to be beyond the measures taken by the majority of utilities to detect a possible SGTR event and in excess of current licensing criteria. The existing requirements on reactor coolant leakage are identified in current Technical Specification Section 3.4.6.2 which specifies an allowable limit of one gpm unidentified leakage, one gpm total primary-to-secondary leakage through all steam generators not isolated from the reactor coolant systems, 500 gallons per day of leakage through any one steam generator not isolated from the reactor coolant system, and 10 pgm identified leakage from the reactor coolant system. With any of the above leakage conditions present, the plant is to be in at least hot standby within 6 hours and cold shutdown within the following 30 hours. The licensee plans to install new N_{16} monitors in addition to the existing leakage detection capability for ensuring that the above technical specification limits are not exceeded. These monitors will alarm in the control room and will provide a continuous control room indication in gallons per day (gpd). The alarms will have three settings of 10, 60, and 100 gpd above the initial reactor coolant activity level. One N_{16} monitor will be installed on the main steam header initially (prior to restart) and subsequently one N_{16} monitor will be installed on each steam generator thus providing an immediate indication of which steam generator has an excessively leaking tube. We find the licensees proposed design to be acceptable.

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Our Safety Evaluation Report input on this subject is provided in Enclosure 1 and our SALP input is provided in Enclosure 2. We consider our efforts on TAC No. 65791 to be complete.

Original signed by

John W. Craig, Chief
Plant Systems Branch
Division of Engineering and Systems Technology

Enclosures:
As Stated

cc w/enclosures:
L. Engle

CONTACT: A. Gill
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DISTRIBUTION
Docket File
PSB Rdg
Plant File
JWermiel
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Amar Y. Gill	JW	JC
PSB:DEST	PSB:DEST	PSB:DEST
AGill;cf	JWermiel	JCraig
10/13/87	10/13/87	10/16/87

1

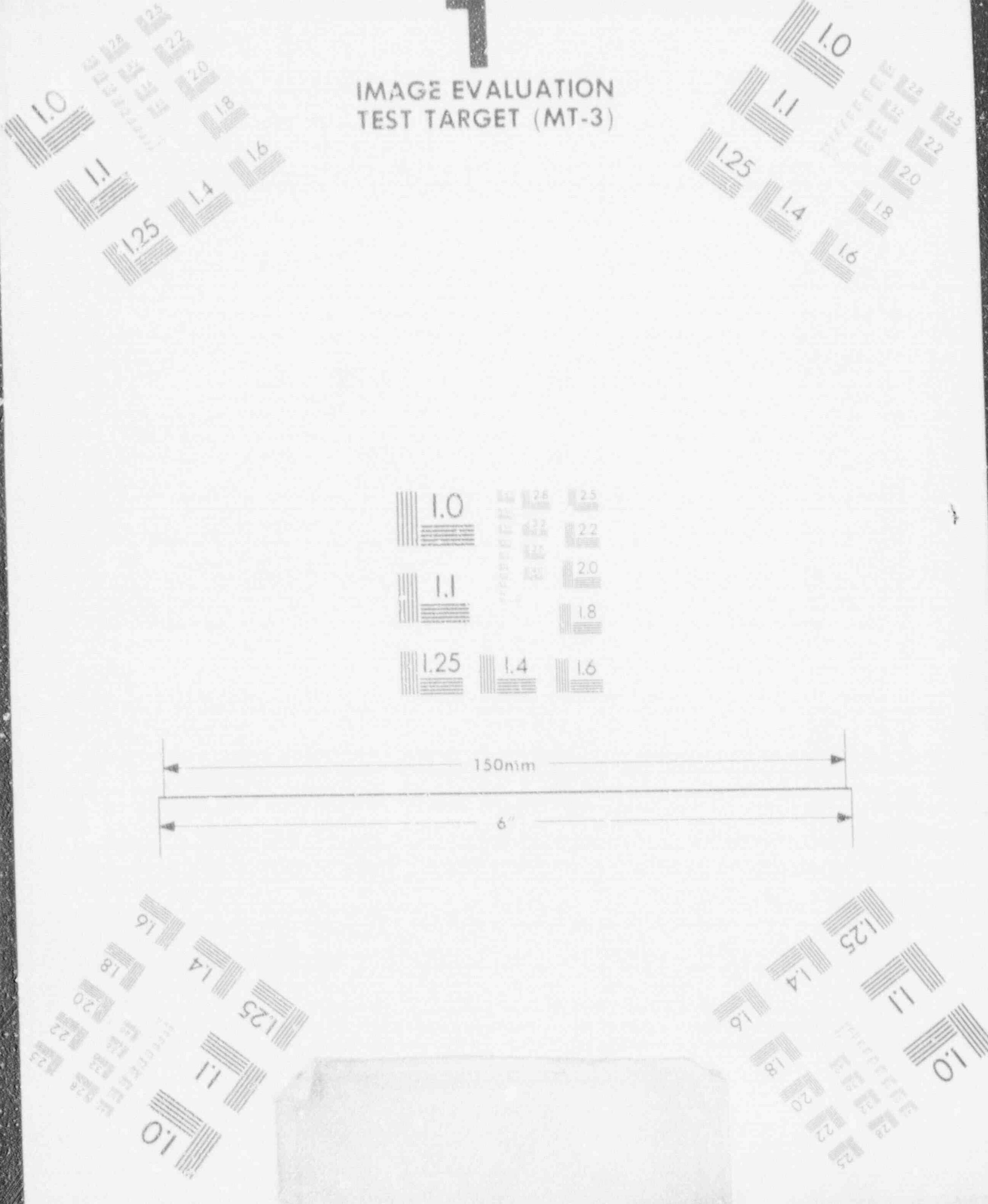
IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION
TEST TARGET (MT-3)



1

IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6"

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IMAGE EVALUATION TEST TARGET (MT-3)

150mm

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Enclosure 1

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION
PLANT SYSTEMS BRANCH
MODIFICATION TO LEAKAGE DETECTION CAPABILITY FOLLOWING
THE JULY 15, 1987 STEAM GENERATOR TUBE RUPTURE EVENT
NORTH ANNA POWER STATION, UNIT NO. 1
DOCKET NO. 50-338

1.0 INTRODUCTION

By letters dated September 1' and 25, 1987, the licensee submitted their evaluation of the North Anna, Unit 1 steam generator tube rupture event of July 15, 1987 including their assessment of SGTR failure mechanism and planned modifications to be made to the leakage detection capability in order to detect a significant steam generator tube degradation prior to occurrence of a tube rupture.

2.0 DISCUSSION

The licensee has developed an augmented surveillance program for detection of primary-to-secondary leakage by identifying the early stages of fatigue failure, so that an orderly shutdown can be accomplished before tube failure occurs. The program includes recording and trending of selected radiation monitor data, sample isotopics, and more frequent calculation of primary coolant leakage in order to detect leak rates between 10 gallons per day (gpd) and 100 gpd in a timely manner. This capability will provide assurance that even with fatigue failure, there is adequate time for shutting down the unit prior to exceeding 100 gpd. This licensee volunteered reactor coolant leakage limit is more conservative than existing technical specification limits which require reactor shutdown when one of the following is exceeded:

1. One (1) gpm unidentified leakage
2. One (1) gpm total leakage through all unisolated steam generators
3. Five hundred (500) gpd leakage through any one unisolated steam generator
4. Ten (10) gpm identified leakage

Currently primary-to-secondary radiation monitors are located on the condenser air ejector discharge, three main steamlines, and three steam generator blowdown lines. In addition to these indications, the licensee is installing new N_{16} detectors, one on the main steam header (to be operable prior to restart) and subsequently, one on each main steam line from the steam generator. These detectors will indicate leakage in gallons per day and will provide continuous readout in the control room.

The N_{16} monitors will have three alarm settings that will annunciate in the control room at 10 to 20, 60, and 100 gpd above the initial reactor coolant activity level. The alarm setpoint will be periodically evaluated and adjusted based on primary-to-secondary leakage calculations in order to respond to a leak rate of approximately 10 gpd above the maximum current value. The condenser air ejector alarm will be set consistent with the N_{16} first alarm. The N_{16} second alarm will be set at 60 gpd in order to detect the initial crack propagation of a fatigue failure. The third N_{16} alarm will be set at the administratively imposed shutdown limit of 100 gpd.

The licensee will provide operating procedures for SG leakage rate surveillance prior to unit restart and will verify operability of these N_{16} monitors prior to power ascension greater than 30 percent. The licensee will record and/or evaluate the monitors data for indications of leakage (trend and magnitude) during mode 1 operation. The steam generator blowdown monitors and the condenser air ejector discharge monitor will be recorded and evaluated every four hours. In addition to the above monitors, samples from the air ejector exhaust will be taken and analyzed every 8 hours and from the primary reactor coolant system and secondary coolant (steam generator blowdown) every 24 hours. The result will then be used to calculate the primary-to-secondary leakage during mode 1 operation. Sample activity levels will also be trended. The licensee will then use the radiation detector and sampling data to calculate primary-to-secondary leakage every 8 hours based on air ejector exhaust isotopic activities and every 24 hours based on secondary coolant isotopic activities. The primary isotopic activities will be used to relate the air ejector and secondary isotopic activities to primary-to-secondary leakage. In addition, the condenser air ejector radiation monitor count rate readings will be used to estimate primary-to-secondary leakage every 4 hours and the radiation monitor alarm setpoint will be adjusted to respond if leakage increases to and stays at 10 gpd above the most recent maximum leakage measurement.

3.0 CONCLUSION

Based on the above, the staff concludes that the licensees proposed modification for the augmented surveillance program for monitoring steam generator primary-to-secondary leakage exceeds the requirements identified in the existing technical specifications and will provide early indication of steam generator tube degradation prior to occurrence of a rupture. The staff, therefore, finds the licensees program to be acceptable.

Enclosure 2

PSB SALP INPUT

Plant Name: North Anna Power Station, Unit No. 1
Licensee: Virginia Electric and Power Company
Docket No.: 50-338
SER Subject: Modifications to Leakage Detection Capability Following the July 15, 1987 Steam Generator Tube Rupture Event (TAC No. 65791)

PERFORMANCE PARAMETERS:
(1) Management Involvement in Assuring Quality
(2) Approach to Resolution of Technical Issues from a Safety Standpoint
(3) Response to NRC Initiatives
(4) Staffing (Including Management)
(5) Reporting and Analysis of Reportable Events
(6) Training and Qualification Effectiveness
(7) Any other SALP Functional Area

PERFORMANCE PARAMETER	NARRATIVE DESCRIPTION OF LICENSEE'S PERFORMANCE	CATEGORY/RATING
(1)	Not applicable	
(2)	The licensee's proposed steam generator leakage detection capability is beyond that required by existing criteria and will insure early detection of steam generator tube fatigue prior to occurrence of a rupture.	1
(3)	The licensee was very prompt and responsive to staff questions and participated in two meetings to assist the staff in performing an expedious review.	1
(4)	Not applicable	
(5)	Not applicable	
(6)	Not applicable	
(7)	Not applicable	

Overall Rating: 1