TENNESSEE VALLEY AUTHORITY

6N 38A Lookout Place
Chattanooga, Tennessee 37402-2801


October 19, 1990

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Gentlemen:

TENNESSEE VALLEY AUTHORITY - SEQUOYAH NUCLEAR PLANT UNIT 1 - DOCKET NO. 50-327 - FACILITY OPERATING LICENSE DPR-77 - LICENSEE EVENT REPORT (LER) 50-327/90022

The enclosed LER provides details of a Unit 1 reactor trip from 60 percent power, which occurred on September 19, 1990. The reactor trip resulted from a turbine trip that occurred following the actuation of main generator protection relays. This event is being reported in accordance with 10 CFR 50.73(a)(2)(iv) as a reactor protection system actuation.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

J. R. Bynum, Vice President
Nuclear Operations

Enclosure
cc (Enclosure):

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NRC Form 366 (6-89)

U.S. NUCLEAR REGULATORY COMMISSION

Approved OMB No. 3150-0104
Expires 4/30/92

# LICENSEE EVENT REPORT (LER)

FACILITY NAME (1) Sequoyah Nuclear Plant, Unit 1

DOCKET NUMBER (2) 0|5|0|0|0|3 |2 |7

PAGE (3) 1 OF 0 8

TITLE (4) Sequoyah Unit 1 reactor trip as a result of a turbine trip caused from corroded and shorted terminals on the spare (A phase) main transformer's gas relay

| EVENT DAY (5) | | | LER NUMBER (6) | | | REPORT DATE (7) | | | OTHER FACILITIES INVOLVED (8) | |
|---|---|---|---|---|---|---|---|---|---|---|
| MONTH | DAY | YEAR | YEAR | SEQUENTIAL NUMBER | REVISION NUMBER | MONTH | DAY | YEAR | FACILITY NAMES | DOCKET NUMBER(S) |
| | | | | | | | | | | 0\|5\|0\|0\|0\| |
| 0 9 | 1 9 | 9 0 | 9 0 | 0 2 2 | 0 0 | 1 0 | 1 9 | 9 0 | | 0\|5\|0\|0\|0\| |

OPERATING MODE (9): 1

POWER LEVEL (10): 0 6 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following)(11)

| | | | |
|---|---|---|---|
| __ 20.402(b) | __ 20.405(c) | XX 50.73(a)(2)(iv) | __ 73.71(b) |
| __ 20.405(a)(1)(i) | __ 50.36(c)(1) | __ 50.73(a)(2)(v) | __ 73.71(c) |
| __ 20.405(a)(1)(ii) | __ 50.36(c)(2) | __ 50.73(a)(2)(vii) | __ OTHER (Specify in Abstract below and in Text, NRC Form 366A) |
| __ 20.405(a)(1)(iii) | __ 50.73(a)(2)(i) | __ 50.73(a)(2)(viii)(A) | |
| __ 20.405(a)(1)(iv) | __ 50.73(a)(2)(ii) | __ 50.73(a)(2)(viii)(B) | |
| __ 20.405(a)(1)(v) | __ 50.73(a)(2)(iii) | __ 50.73(a)(2)(x) | |

LICENSEE CONTACT FOR THIS LER (12)

NAME: J. W. Proffitt, Compliance Licensing

TELEPHONE NUMBER: AREA CODE 6 1 5 | 8 4 3 - 6 6 5 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

| CAUSE | SYSTEM | COMPONENT | MANUFACTURER | REPORTABLE TO NPRDS | CAUSE | SYSTEM | COMPONENT | MANUFACTURER | REPORTABLE TO NPRDS |
|---|---|---|---|---|---|---|---|---|---|
| X | T B | R L Y | A 5 0 0 | N | | | | | |
| | | | | | | | | | |

SUPPLEMENTAL REPORT EXPECTED (14)

__ YES (If yes, complete EXPECTED SUBMISSION DATE) | X NO

EXPECTED SUBMISSION DATE (15) MONTH | DAY | YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On September 19, 1990, with Unit 1 operating at approximately 60 percent reactor power, 2235 pounds per square inch gauge (psig), and 564 degrees Fahrenheit (F), a turbine trip followed by a reactor trip occurred at 0357 Eastern daylight time. The turbine tripped as a result of "A" phase main transformer differential relay (sudden pressure) operation caused from corroded and shorted terminals on the transformer gas relay. Because the reactor power was greater than the reactor trip interlock for automatic block of reactor trip on turbine trip permissive (P-9), a reactor trip occurred as a result of the turbine trip. Operators responded to the trip using Emergency Operating Procedure 1-E-0, "Reactor Trip or Safety Injection," and stabilized the reactor at hot standby conditions (Mode 3) at 547 degrees F and 2235 psig. All reactor protection systems operated as designed, and no anomalies occurred. The sudden pressure relay was replaced, and the equipment was returned to service.

NRC Form 366A (6-89), U.S. NUCLEAR REGULATORY COMMISSION Appr[illegible]d OMB No. 3150-0104 E[illegible]pires 4/30/92

# LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

| FACILITY NAME (1) | DOCKET NUMBER (2) | LER NUMBER (6) YEAR | SEQUENTIAL NUMBER | REVISION NUMBER | PAGE (3) |
|---|---|---|---|---|---|
| Sequoyah Nuclear Plant Unit 1 | 0 5 0 0 0 3 2 7 | 9 0 | 0 2 2 | 0 0 | 0 2 OF 0 8 |

TEXT (If more space is required, use additional NRC Form 366A's) (17)

## DESCRIPTION OF EVENT

On September 19, 1990, with Unit 1 operating at approximately 60 percent reactor power, 2235 pounds per square inch gauge (psig), and 564 degrees Fahrenheit (F), a turbine trip followed by a reactor trip occurred at 0357 Eastern daylight time (EDT). The turbine tripped as a result of A phase main transformer differential relay (sudden pressure) operation. Because the reactor power was operating above the reactor trip interlock for automatic block of reactor trip on turbine trip permissive (P-9), a reactor trip occurred as a result of the turbine trip.

Operators responded to the trip using Emergency Operating Procedure 1-E-0, "Reactor Trip or Safety Injection," and ES-0.1 "Reactor Trip Response," and stabilized the reactor at hot standby conditions (Mode 3) at 547 degrees F and 2235 psig. All reactor protection systems operated as designed, and no anomalies were noted. Following stabilization of the unit, a senior reactor operator (SRO) proceeded to the relay room and observed two targets actuated. These were the Unit 1 B phase main transformer sudden pressure relay (this relay reset immediately) and the Unit 1 A phase main transformer sudden pressure relay (the spare transformer had been placed in service as A phase September 16, 1990, following problems with the A phase transformer). The spare (A phase) transformer's sudden pressure relay did not reset when initiated by the SRO. Attempts were made for 9 minutes to reset the relay. At 24 minutes following the event, the relay was reset.

The three transformers were inspected and determined to be intact and had normal conservator oil levels. The relief valve semaphore (flag) on the spare A phase transformer was up, and the relief valves semaphores on the B and C phase transformers were down. There was no visible oil leaking from the transformers and no sheen on the water runoff from the sprinkler system.

Earlier in the shift, it had been noted that the spare transformer (A phase) indicated winding temperatures were "bottomed out" (25 degrees Celsius [C]) on Recorder 1-TR-57-110 for main transformer temperatures while both B and C phase transformers were normal (45 degrees C). Approximately two hours before the trip, the transformers had been inspected locally, which indicated that winding temperatures were [illegible] degrees C for spare (A phase), 49 degrees C for B phase, and 41 degrees C for C phase.

On September 14, 1990, Unit 1 reactor had tripped as reported in LER 50-327/90021 dated October 15, 1990. Approximately three minutes following the opening of the generator output breakers, a sudden pressure relay actuation occurred on the A phase main transformer. This actuation can be initiated by either the sudden pressure relay or the surge contacts on the gas relay as a result of oil surging in the conservation tank. No unusual conditions were noted upon examination of the transformer. It was noted that both cooler groups were operating in the "preferred" mode (coolers operate anytime the transformer is energized). Operations' personnel had placed both cooler groups in the "preferred" mode to cause continuous operation of the coolers and prevent high temperature alarms that had been occurring during the summer. Further testing was initiated on the A phase main transformer.

transformer as called for in its spared-out position. Following the completion of the installation and checkout activities, the spare A phase main transformer was ready for operation.

On September 16, 1990, at 2235 EDT with Unit 1 reactor power at approximately 13 percent and the turbine at 1800 revolutions per minute, the unit operator was performing Step V.C.63 of General Operating Instruction 2, "Plant Startup From Hot Standby to Minimum Load," to increase the generator voltage to match running (grid) voltage. Upon reaching approximately 60 percent of rated voltage, the shift operations supervisor asked if the LVBC system was operating. The unit operator then noted that the spare A phase transformer's LVBC system light was not lit. A turbine trip occurred at 2237 EDT. Approximately nine seconds following the generator trip, a sudden pressure relay actuation occurred on both the spare A phase and B phase main transformer. This initiated the appropriate main transformer deluge systems and sprayed down the two transformers. Operations' personnel verified that there was no fire present at the transformers, reset the sudden pressure relays, and terminated the spraydown. The reactor did not trip during this event because reactor power was below 50 percent. The other systems responded as expected.

Initiation of the "Transformer 1 Differential Relay Operation" alarm was confirmed to be a result of the sudden pressure circuit. Tests were conducted on the spare A phase and B phase main transformers. After operating for several minutes, both cooler groups were shutdown simultaneously. Within a few seconds of these shutdowns, the main control room reported a sudden pressure circuit actuation. It was concluded that the sudden pressure circuit actuations had occurred on the spare A phase and B phase transformers when the cooler groups had shutdown. This had occurred as soon as voltage decayed below the cooler activation point of 55 percent normal voltage, because the transformers were not warm enough to activate the thermostatically-controlled cooler groups.

The relay was subsequently functionally tested with no abnormalities identified. The spare transformer was placed in service and the plant proceeded with startup activities. The turbine did not trip again and there were no indications of problems with the transformer until the trip on September 19, 1990.

CAUSE OF EVENT

The cause of the reactor trip was the result of a turbine trip from approximately 60 percent power causing Permissive P-9 to actuate. The turbine trip resulted from corroded and shorted terminals on the spare (A phase) main transformer's gas relay. During performance of the spare main transformer checkout, a condition of corrosion was noted on the gas relay terminal strip. This condition was not adequately communicated to supervision. This corrosion eventually lead to the reactor trip on September 19, 1990. Therefore, the root cause of the trip was the corroded and shorted terminals on the spare transformer's gas relay. The corrosion shorted the gas relay resulting in initiation of the turbine trip signal.

Additionally, during the investigation of this event, the need for improved and clear definition of responsibilities between Transmission & Customer Service (T&CS) and plant maintenance was identified.

TEXT (If more space is required, use additional NRC Form 366A's) (17)

On Saturday, September 15, 1990, tests performed revealed two bushings with test results requiring further investigation. It was determined that replacement of the bushings would take approximately two days; the decision was made to utilize the spare transformer. A work request (WR) had been initiated so that planning and preparation for placing the spare transformer in service could be ongoing while analysis of the A phase main transformer test data was still in progress. During the planning of this WR, it was determined that no procedure existed for placement of the spare Unit 1 main transformer in service, although such a procedure existed for the Unit 2 and intertie spare transformers. Planning of the WR was developed utilizing TVA's drawings that gave directions on how to spare-out a transformer plus review of the Unit 2 procedure. Special attention was paid to the proper installation of the isophase bus links because several individuals involved in the planning recalled an incorrect installation at Browns Ferry Nuclear Plant (BFN) that resulted in transformer failure. The system engineer for the main transformers reviewed the WR to ensure that the work instructions were correct.

It was noted during the transformer inspection activities that the flexible conduit going to the spare main transformer's gas relay was pulled loose. An electrician was sent to repair the loose conduit. While correcting the discrepancy, the electrician removed the junction box cover to the gas relay and noted water and corrosion on the terminals. The electrician climbed down from the transformer and related these findings to his foreman. Both proceeded to the transformer to investigate the findings further. During this activity, the electrician and foreman were told that the transformer was not grounded, and therefore they needed to get down from the transformer. The foreman told the electrican to clean up the water, then get down from the transformer. The electrician quickly completed his cleanup, replaced the junction box cover, and climbed down off the transformer. These findings were not relayed to the foreman's supervisor.

Checkout of the spare main transformer and activities to spare-out A phase main transformer continued through September 16. Functional tests of the transformer and its subsystems that were performed under the WR included a verification that the fans and oil pumps would run. A check of the gas relay functions (alarm and trip contacts) was performed from the ground utilizing the installed test lines. During these activities on the transformer, the following deficiencies were identified;

1. A defective contactor on one of the low voltage bus cooling (LVBC) pump motor circuits.

2. Incorrect rotation of one of the LVBC pumps.

3. Fan Motors 5 and 6 were not operating.

4. Isolated phase bus air flow baffles were not installed in the spare transformer's bus.

The contactor was replaced and the rotation of the LVBC pump was corrected. Fan Motors 5 and 6 were defective, and the decision was made not to replace the motors. The air flow baffles found missing were properly installed on the A phase main

| FACILITY NAME (1) | DOCKET NUMBER (2) | LER NUMBER (6) YEAR | SEQUENTIAL NUMBER | REVISION NUMBER | PAGE (3) |
|---|---|---|---|---|---|
| Sequoyah Nuclear Plant Unit 1 | 0\|5\|0\|0\|0\|3\|2\|7 | 9\|0 | -- 0\|2\|2 -- | 0\|0 | 0\|5 OF 0\|8 |

TEXT (If more space is required, use additional NRC Form 366A's) (17)

ANALYSIS OF EVENT

Reactor Coolant System (RCS) Pressure

Prior to the event, RCS pressure was controlled at or near 2238 psig. When the reactor trip occurred, the pressurizer pressure dropped to approximately 2110 psig within one minute. The decrease in pressure can be attributed to the cooldown. Pressure recovered to 2230 psig within the following 30 minutes. An increase in pressure to approximately 2260 psig was noted approximately 45 minutes after the trip. This is attributed to variations in RCS average temperature (Tavg) at this time. Pressure returned to normal approximately 60 minutes after the trip. As discussed in the Final Safety Analysis Report (FSAR), Section 15.2.8, the AFW system was capable of removing redundant residual heat to prevent overpressurization of the RCS.

RCS Temperature

Pretrip Tavg was at approximately 563 degrees F. Posttrip Tavg had declined because of the reactor trip. When Tavg continued to decline at 547 degrees F, the operator took manual control of the AFW system in accordance with the guidelines of ES-0.1. The decline in Tavg was stopped at approximately 545 degrees F and was subsequently stabilized at 547 degrees F. Tavg reacted well within the analysis described in the FSAR. In this event, RCS Tavg started at 563 degrees F at 0357 EDT and reached a minimum value of approximately 545 degrees F at 0400 EDT. Temperature stabilization occurred soon after this time at approximately 547 degrees F. A cooldown to approximately 544 degrees F occurred approximately 30 minutes after the trip when steam generator blowdown was placed in service. Tavg stabilized at 548 degrees F within 60 minutes. The average cooldown rate in this case was 563-544 degrees F in the first 45 minutes or 25.3 degrees F per hour.

Heatup and Cooldown Limits

Technical specifications require a cooldown limit of 100 degrees F in any one hour time period. These limits were not exceeded.

Feedwater Flow

Main feedwater (MFW) flow was approximately 8.4 x 10E06 pounds per hour (pph) prior to the trip, and dropped rapidly upon reactor trip. MFW flow spikes noted on 1-FR-3-35 and 1-FR-3-90 and attributed to recorder "glitches," as the MFW control system would not respond as rapidly as indicated on the recorders.

AFW started as designed flow to the steam generator from AFW continued at greater than 440 gallons per minute per steam generator as expected while steam generator levels remained below 33 percent. Manual control of AFW was taken by the operators in accordance with ES-0.1. The technical specifications, FSAR requirements, and the analysis were not challenged.

| FACILITY NAME (1) | DOCKET NUMBER (2) | LER NUMBER (6) YEAR | SEQUENTIAL NUMBER | REVISION NUMBER | PAGE (3) |
|---|---|---|---|---|---|
| Sequoyah Nuclear Plant Unit 1 | 0 5 0 0 0 3 2 7 | 9 0 | 0 2 2 | 0 0 | 0 6 OF 0 8 |

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Steam Flow

Steam flow pretrip was at approximately 8.4 x 10E06 pph and dropped rapidly upon reactor trip. Flow continued to (1) steam dumps and (2) the turbine-driven auxiliary feedwater pump (TDAFWP) from Steam Generator No. 1 until the TDAFW pump was removed from service.

Steam Pressure

Pretrip steam generator pressures were approximately 880 psig. Posttrip steam generator pressure rose to 985 psig within 10 minutes, then slowly decreased due to the cooling affect of AFW. Steam pressure returned to no-load pressure, and Tavg returned to 548 degrees F. The technical specifications, FSAR requirements, and analysis were not challenged.

Steam Generator Level

Prior to the event, all steam generator levels varied at or near 44 percent. At posttrip, all steam generator levels recovered to approximately 35 percent to 40 percent within 45 minutes.

The technical specifications and FSAR were not challenged by the above.

Containment Pressure, Temperature,and Radiation

No perturbations were observed in containment pressure, temperature, or radiation. The technical specifications, FSAR requirements, and analysis were not challenged.

Pressurizer Level

Pressurizer level was approximately 43.2 percent pretrip (on program). Response of the pressurizer level to the transient closely parallel that of RCS pressure and temperature. The level dropped due to cooling of the RCS.

At approximately 60 minutes into this event, pressurizer level was stabilized at approximately 30 percent. Pressurizer level reacted within the bounds of a reactor trip event as described in the FSAR.

Shutdown Margin

The deviation from program is attributed to deviation in Tavg. Pretrip, the reactor was operating above the minimum insertion limits, and by definition, adequate shutdown margin was available. Following the trip, expected cooldown occurred as had been previously discussed. Adequate shutdown margin was maintained in accordance with ES-0.1 and SI-38, "Shutdown Margin."

| FACILITY NAME (1) | DOCKET NUMBER (2) | LER NUMBER (6) YEAR | SEQUENTIAL NUMBER | REVISION NUMBER | PAGE (3) |
|---|---|---|---|---|---|
| Sequoyah Nuclear Plant Unit 1 | 0 5 0 0 0 3 2 7 | 9 0 | -- 0 2 2 -- | 0 0 | 0 7 OF 0 8 |

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Reactor Power

The reactor was operating at approximately 60 percent rated thermal power before the trip occurred. This was in accordance within technical specifications and FSAR limits. Technical specifications require operation within the safety limits curve. This curve was not challenged. Upon receipt of the trip signal, the shutdown and control banks dropped into the core, and reactor power rapidly decreased as expected. No technical specification or FSAR limit were challenged.

CORRECTIVE ACTIONS

The following checks of the transformers were performed:

1. Oil samples from the three transformers were obtained and analyzed for combustible gas. No unusual levels of gas were indicated.

2. An inspection of the pressure relief device on the spare A phase and B phase indicated that they had not actuated. No evidence oil on the devices was noted, which is characteristic of actuation. The semaphore (flag) on the spare A phase was likely moved to the actuated position by the force of the suppression spray.

3. The gas relay on each transformer was inspected. The terminal connections in the spare A phase were heavily corroded at the time of the inspection causing an intermittent ground path energizing the gas relav auxiliary. The gas relays on the other transformers were free of corrosion.

4. The other terminal connections were inspected for signs of corrosion and moisture. No degradation was found on any of the four transformers.

5. A wire check and a functional check on the control and protective devices on the spare A phase transformer were performed. Deficiencies associated with termination of wiring supplying remote transformers temperature indication and a winding temperature heater compensation circuit cable were identified and corrected.

6. A visual inspection of the gas relay flapper to confirm freedom of movement and proper connections was performed. A test was performed to determine the effect that oil flow would have when cooling oil pumps were tripped. The flapper on the gas relay for each transformer were observed to move during this test. Each flapper, except for the C phase relay, moved sufficiently to operate the gas relay auxiliary. This explains why the sudden pressure actuation was activated by the spare A phase and/or B phase transformers during the turbine trips.

7. Discussions with the transformer vendor (ASEA) during the investigation confirmed that the vendor was aware of the over-sensitivity of the flapper in the gas relay during this type of transient. ASEA had recommended modifications to other customers to correct the condition at the respective customer's request. TVA's BFN was one of the customers. ASEA has made permanent changes to the production of the relays to prevent this problem.

| FACILITY NAME (1) | DOCKET NUMBER (2) | LER NUMBER (6) YEAR | SEQUENTIAL NUMBER | REVISION NUMBER | PAGE (3) |
|---|---|---|---|---|---|
| Sequoyah Nuclear Plant Unit 1 | 0\|5\|0\|0\|0\|3\|2\|7 | 9\|0 | -- 0\|2\|2 -- | 0\|0 | 0\|8 OF 0\|8 |

TEXT (If more space is required, use additional NRC Form 366A's) (17)

8. An evaluation of previous modifications and maintenance was performed to determine if there was any apparent affect on the sudden pressure trip circuitry that could have caused the recent series of transformers sudden pressure actuation. No apparent causes were found.

9. An evaluation was performed on the gas relay oil piping configuration to determine if air could be pulled into the relay, which could cause false operation. No leaks were identified nor is the piping configuration conducive to air ingress.

The immediate action taken by the operators was to stabilize the unit in accordance with the applicable plant instructions. A posttrip review team was assembled to assess the cause of the trip and response to the unit.

TVA performed a temporary alteration that eliminated the sudden pressure transformer differential generator trip by the gas relay's flow switch. This change was based on the gas relay's trip function is parallel to the sudden pressure trip function and vendor concurrence. TVA is currently evaluating the overly sensitive gas relay flow switch to determine if further corrective actions are needed. Additional corrective actions will include the initiation of procedures for initial energization, operation and inspection of transformers to ensure that deficiencies are addressed, and the equipment is ready for operation.

Additionally, TVA is evaluating the transformer problem to determine the correct lines of responsibilities between plant management and T&CS with regard to transformer maintenance to promote improved effectiveness in this area.

COMMITMENT

TVA will establish a procedure for installation and checkout of the Unit 1 spare main transformer prior to utilization of the spare transformer but no later than November 1, 1991.

ADDITIONAL INFORMATION

Discussions with corporate maintenance personnel and former BFN personnel determined that the problem with the sudden pressure circuit actuation had been identified and corrected at BFN. Correspondence dated April 29, 1969, indicates that similar problems with the gas relay had been identified, and the manufacturer had provided recommendations to BFN to correct this spurious operation.

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