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Northern States Power Co. Minneapolis, Minn. 55401 L.O. Mayer	7-20-72	7-24-72	X			

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CLASS:	INPUT	NO CYS REC'D	DOCKET NO:
(U) PROP INFO		40	50-263

DESCRIPTION: Ltr rpt a problem on 7-10-72 when the generator loss of field relay tripped initiating a turbine lockout & subsequently a reactor scram fm 100% power.....

ENCLOSURES:

PLANT NAMES: Monticello Plant

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ACKNOWLEDGED

FOR ACTION/INFORMATION

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NSP

NORTHERN STATES POWER COMPANY

MINNEAPOLIS, MINNESOTA 55401

July 20, 1972

Mr A Giambusso
Deputy Director for Reactor Projects
Directorate of Licensing
United States Atomic Energy Commission
Washington, D. C. 20545

Dear Mr Giambusso:

MONTICELLO NUCLEAR GENERATING PLANT
Docket No. 50-263 License No. DPR-22

Turbine Trip at 100% Power and Subsequent Events

A condition occurred at the Monticello Nuclear Generating Plant recently which we are reporting in accordance with provisions of 6.6.B.3 of Appendix A, Technical Specifications of the Provisional Operating License DPR-22. The Region III Regulatory Operations Office has been notified of the occurrence.

At 1549 hours on July 10, 1972, the generator loss of field relay tripped initiating a turbine lockout and, subsequently, a reactor scram from 100% power.

Initial Conditions

Prior to the trip the reactor was operating at 100% power with the following conditions existing:

1. Nitrogen was being added to the drywell and torus with the Standby Gas Treatment System in operation and lined up to take suction on the 2 inch vent bypass lines.

2. The High Pressure Coolant Injection (HPCI) System was out of service with the monthly high steam flow isolation surveillance test in progress. Prior to removing the HPCI System from Service the Core Spray, Low Pressure Coolant Injection, and Reactor Core Isolation Coolant System were demonstrated operable.

3. Routine Traversing Incore Probe (TIP) traces were being taken.

Sequence of Events

The following events took place during and subsequent to the trip as determined by interviews with the operators on duty, computer monitoring of plant parameters, control room indication, recorders and annunciators.

4040

1. Generator loss of field relay tripped causing the turbine lockout relay to trip at time zero.

2. Turbine lockout relay tripped the generator field breaker, both recirculation pump motor-generator set supply breakers, and initiated an automatic closed transfer of station auxiliary power from 11 auxiliary transformer to 1R transformer. Also, the turbine master hydraulic trip solenoid #3 was actuated thereby initiating closing the steam inlet valves and tripping the control valve fast closure pressure switches. Both diesel generators were started by the power transfer relays.

3. A reactor scram was received at 0.151 seconds by control valve fast closure as determined from the computer sequence of events log. Control rod drive 22-31 stopped at notch '02' and was manually inserted to the full in position, after the scram.

4. Primary containment isolation Group I valve closure was initiated shortly after the scram. All MSIV's reached the 90% open position within 1.170 seconds after the turbine lockout relay trip as determined from the sequence of events log.

5. All high reactor pressure scram relays tripped within 1.210 seconds after the turbine lockout relay trip.

6. The low reactor water level scram relays tripped within 1.837 seconds after the turbine lockout relay trip. This initiated the following:

   a. Drywell vent, purge and isolation valve Group II closure
   b. Isolation valve Group III closure
   c. Start standby gas treatment system
   d. Isolate O_2 analyzer
   e. TIP withdrawal
   f. Reactor building ventilation isolation

   TIP #1 did not full retract and isolate. Reactor water level stabilized above the low-low level trip point and was returned to near normal.

7. As reactor pressure continued to increase at least 3 of the relief valves and one of the safety valves lifted. Maximum reactor pressure was 1141 psig.

8. Between 8.035 seconds and 8.538 seconds after the turbine lockout relay trip, channels D and C of the primary containment isolation and reactor protection system tripped on high drywell pressure. The plant evacuation siren was initiated.

   Separate containment pressure switches initiated the Emergency Core Cooling System, starting the Low Pressure Coolant Injection and Core Spray pumps. HPCI System was initiated but did not start since the HPCI steam line isolation valves were closed for surveillance testing. The LPCI loop selection logic selected recirculation loop B for injection and shut its suction and discharge valves. The automatic blowdown system high drywell pressure relay sealed in.

A 0.85 psi drywell pressure increase was recorded.

9. Both channels noted in (8) above, reset within 12.754 seconds after the turbine lockout relay trip. The time interval each channel was tripped is given below:

Channel	Interval Actuated
D	5.619 seconds
C	3.954 seconds

The evacuation siren automatically reset.

10. The high reactor pressure scram relays reset after approximately 12 seconds in the tripped condition.

11. The control room operators observed that reactor pressure continued to decrease, and 'A' relief valve was not fully closed. The relief valve control switch was manually operated and the valve closed. Minimum reactor pressure was approximately 600 psi.

12. After observing that a non ECCS condition existed, the ECCS pumps were stopped about 5 minutes after the turbine lockout relay tripped.

13. After observing a Group I non isolation condition existed, the MSIV's were opened about 8 minutes after the turbine lockout relay trip.

14. Plant conditions were stabilized following scram recovery procedures.

Analysis and Corrective Action

After plant conditions were stabilized it was decided to place the plant in a cold shutdown condition, de-inert the drywell, and make a thorough investigation into all events associated with the shutdown. The following information was determined and corrective action initiated:

Generator Excitation

It was found that a poorly soldered transistor in the voltage error signal amplifier of the generator amplidyne control circuit caused the loss of generator field. The amplifier was repaired and returned to service. Testing conducted prior to and during the generator startup verified proper amplidyne operation.

Failure of Control Rod Drive at Location 22-31 to Fully Insert

During the scram control rod drive at location 22-31 was automatically scrammed from notch '48' (full out) to notch '02' (6" from full in). The control room operator after observing the '02' notch indication, manually inserted the drive to the '00' notch position (full in). This event is similar to that observed during the May 23, 1972 scram, and reported to you in a letter dated June 19, 1972.

The scram time data as determined from the scram timing recorder for control rod drive 22-31 verified that the Technical Specification scram insertion time for the 10%, 50%, and 90% insertion was satisfied.

Prior to plant restart the drive was exercised. Normal operation was verified by withdrawing and inserting the control rod drive using normal drive water pressure.

Main Steam Isolation Valve Closure

A Group I isolation valve closure was automatically initiated during the turbine trip and scram. The Group I valves consist of the main steam line isolation valves, the main steam line drain isolation valves and the recirc loop sample isolation valves.

A review of the sequence of events log determined that the main steam line isolation valves were less than 90% open approximately one second after the turbine lockout was received. There was no indication in the sequence of events log or computer alarm record that any of the five isolation signals actuated. A review of plant charts indicated that none of the isolation trip levels should have been reached. Interviews with the control room operators did not disclose that any of the isolation parameters had actually tripped. A test was conducted to verify that the computer alarm points were operable by shorting the alarm contacts at the isolation relays. All points tested satisfactorily.

To insure that the Group I isolation logic system operates properly, surveillance tests were performed to test each of the five isolation parameters. The tests verified proper instrument setpoints, relay operation, annunciator operation and computer printout.

In the Group I isolation logic, trip signals are generated by contacts which open when the trip relay is de-energized, whereas inputs to the computer program are derived from closing back-contacts of these relays. Therefore it is possible, under a rapid trip-and-reset, to initiate the isolation without obtaining an event-sequence record of the initiating parameter. A review of startup test records confirmed that similar action had occurred during the 75% power trip test. Present conclusions are that a rapid trip-and-reset did occur, most probably from post-trip disturbance of main steam line high flow switches. Computer inputs from these relays are being revised to actuate from front contacts, to improve identification of the initiating parameter.

TIP Machine #1 Failure to Retract and Isolate

During the Group II isolation TIP machine #1 did not withdraw into the shield chamber and isolate. This was a result of two failures associated with the instrumentation of machine #1. A position programmer card and a limit switch, both of which sense the TIP probe position, failed to provide the proper logic to allow automatic TIP withdrawal at the time of the isolation.

The position programmer card was replaced and the limit switch adjusted. Proper TIP withdrawal and isolation was verified.

Relief Valves

Based on the recorded response of the thermocouples located in the relief valve discharge piping and the peak reactor pressure of 1141 psig, it appeared that the "D" relief valve did not open properly. Also, as previously noted, the "A" relief valve did not reseat properly.

The thermocouple data is given below:

Relief Valve	Temperature Rise (°F)
A	135
B	105
C	92
D	2

All relief valves were inspected in place. A manufacturer's representative was on site to assist in the relief valve inspection. The results of the inspection are discussed below:

'A' Relief Valve

The main stem and piston were found to move freely with no sign of binding. The second stage piston and stem were inspected and found in good condition. The pilot disc was found free with no signs of galling. Rust particles were found in the second stage piston chamber. It is probable that rust had lodged across the orifice and prevented dissipation of pressure from the piston chamber when the pilot was closed. The activation of the air operator (manual opening from the control room switch) could have dislodged the rust particle. There were no signs of second stage stem leakage, that is, no scars on the seat or disk, no corrosion and no wire drawing was evident. The second stage discharge line was inspected and found to be clear.

The set pressure was checked and found to be correct.

'B' and 'C' Relief Valves

The second stage piston chambers were examined for rust. Both were clean. The set pressures were checked and found to be correct.

'D' Valves

The main stem and piston were found to move freely with no sign of binding. The second stage piston and stem were found in good condition. The pilot disc was free with nosigns of galling. The pilot filter was clean. No signs of bellows or pilot gasket leakage were evident. The set pressure could not be determined prior to valve disassembly due to excessive leakage of a nitrogen test fitting. No reason for the apparent valve malfunction was found.

All of the thermocouples in the valve discharge pipes were checked and proper response was verified. Following reassembly all valves were tested with nitrogen and correct pressure settings were verified. Prior to plant startup, pressure switches were installed in each of the relief valve discharge lines and wired to plant process computer sequence of events log. This will provide a confirming signal of relief valve actuation and will indicate the exact time of actuation. During the plant restart all relief valves were operated at approximately 150 psig and again at 1000 psig reactor pressure. All valves operated properly. The valves will be tested again within approximately one month.

Safety Valve Momentary Actuation

After the scram and isolation, recorded drywell pressure increased from 14.7 to 15.55 psia. Thermocouples located in the discharge nozzle of the safety valves indicated a 120° F rise for 'A' valve and a 30° F rise for 'D' valve. A drywell inspection revealed no damage. Both 'A' and 'D' safety valves were set to relieve at 1210 psig.

A similar safety valve actuation event occurred on February 26, 1972 as reported to you in a letter dated June 2, 1972. During the outage of June 3, 1972 safety valve 'A' was replaced with a factory tested spare.

Additional monitoring of safety valve actuation is being installed. A rupture link was placed on each of the four safety valve discharge nozzles prior to plant startup. When the wiring is completed to the plant process computer the time of safety valve lifting will be recorded on the sequence of events log.

In addition to the investigation program undertaken by General Electric on this matter, separate effort by NSP includes:

1. A technical consultant has been retained to develop an analytical model of the steam lines to provide pressure transient information in response to turbine-trip events and valve interaction influences. A preliminary report is expected August 15 and final report by late September.

2. The safety valve which lifted February 26, 1972 has been removed and returned to the manufacturer for a specific test program. These tests are now in progress and should be completed before August 1, 1972.

3. We have retained technical assistance to design a field test to measure transient pressures in response to turbine trip or isolation along the length of a steam line. The intent of such test is to corroborate conclusions of the analytical study.

Drywell Pressure Instrumentation

During the scram and isolation the maximum drywell pressure increase, as noted by the recorder in the control room was 0.85 psi; however, the 2 psi drywell high pressure switches were actuated. The sequence of events log from the process computer indicated that only two channels of drywell high pressure instrumentation were actuated. These channels are connected to the drywell penetration

X-29. The untripped channels (A and B) are connected to drywell penetration X-50. The control room recorder is connected to the same penetration that supplies the A channel.

An inspection of the drywell revealed duct tape covering both drywell pressure taps on the X-50 penetration. Examination of the tape covering the pressure taps showed small holes in the tape which allowed response to slow pressure changes but apparently acted to damp response to rapid changes. The drywell pressure recorder is used during normal operation to determine the need for venting the drywell and monitoring pressure during inerting and venting operations. No unusual recorder response had been noticed during past operations. During the February 26, 1972 scram and subsequent momentary lifting of the 'A' safety valve, the recorder did indicate an increase in drywell pressure. No ECCS initiation occurred at that time.

The tape was removed from both lines. Testing of all four ECCS and RPS sensing lines, and all other drywell and torus pressure sensing and sampling lines was conducted to verify that the lines were not plugged or restricted. All sensing lines in the drywell were visually inspected to assure no obstructions existed. All pressure switches which initiate action on high drywell pressure were checked and found to be in calibration.

Drywell Venting

Prior to the Group II isolation, nitrogen was being added to the drywell and torus, with the 2 inch vent lines open and exhausting through the Standby Gas Treatment System. When the isolation was reset the vent and purge valves opened since the control switches had been left in the "open" position. They remained open for about one minute before they were manually closed. The estimated activity release during the time the valves were open after the isolation was reset was insignificant. All release rates were within the Technical Specification limits.

Recirculation Pump Discharge Valve Problem

When #11 recirculation pump was restarted, the discharge valve would not open. Following drywell entry the valve was manually opened. The valve was stroked electrically and a limit switch was found out of adjustment which allowed the valve to seat with excessive force. Subsequent valve operations resulted in the valve sticking at approximately 5" from the fully closed position. The valve stem threads were found damaged in this area. The threads were repaired and subsequent operation of the valve was satisfactory.

Yours very truly,

L. O. Mayer

L O Mayer, P.E.
Director Nuclear Support Services

LOM/ma

cc: B H Grier