UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

MAY 5 1981

TO ALL LICENSEES OF OPERATING PLANTS AND HOLDERS OF CONSTRUCTION PERMITS

Gentlemen:

SUBJECT: ENGINEERING EVALUATION OF THE H. B. ROBINSON REACTOR COOLANT SYSTEM LEAK ON JANUARY 29, 1981 (GENERIC LETTER NO. 81-22)

Enclosed is our Engineering Evaluation Report for the Robinson Event. The primary reason for our evaluation was the loss of approximately 6,000 gallons of reactor coolant water from two separate leaks in the letdown train of the Chemical and Volume Control Letdown System (CVCS).

The evaluation is being forwarded for your information and training purposes. The evaluation of the event did not identify any safety concerns or any required immediate actions. There are four areas, however, which are under consideration for further action:

1. Whether a requirement should be placed upon operating plants to establish a procedure for identification and recovery from a spurious safety injection actuation (if such a procedure is not already in place).

2. Whether criteria for terminating SI should include provisions for isolating charging since charging flow could be considered high pressure safety injection for very small breaks.

3. Whether there is a need for a direct reactor trip on a safety injection actuation at other Westinghouse plants which do not have a direct trip.

4. Whether operation of the isolation valves in the CVCS at Robinson is causing the system to be operated in a manner which is contrary to its design bases.

If you have any questions regarding this evaluation, please contact your Project Manager.

Sincerely,

Darrell G. Eisenhut

Darrell G. Eisenhut, Director
Division of Licensing
Office of Nuclear Reactor Regulation

See Jacket

Enclosure: As stated

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Rec'd w/ Ltr. dtd 1571 #27 5/5/81

ENGINEERING EVALUATION OF THE H. B. ROBINSON

REACTOR COOLANT SYSTEM LEAK ON JANUARY 29, 1981

by the

Office for Analysis and Evaluation
of Operational Data

March 23, 1981

Prepared by: Wayne D. Lanning
Lead Reactor Syste
Engineer

NOTE: This report documents results of studies completed to date by the Office for Analysis and Evaluation of Operational Data with regard to a particular operating event. The findings and recommendations contained in this report are provided in support of other ongoing NRC activities concerning this event. Since the studies are ongoing, the report is not necessarily final, and the findings and recommendations do not represent the position or requirements of the responsible program office of the Nuclear Regulatory Commission.

IDHE-5 Info Ltr.

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1. EVENT DESCRIPTION

A sequence of events is contained in Table 1. Problems with both oil pumps in the turbine electro-hydraulic (E-H) system forced the plant to initiate a plant shutdown. During the process a safety injection signal was generated by a high steam flow coincident with low RCS average temperature. The high steam flow signal was generated by the governor valves spiking open, believed to be caused by the erratic operation of the turbine E-H system. The low average temperature was the result of overcooling the RCS by excessive injection of boric acid solution. The safety injection (SI) signal tripped the reactor. The reactor power had been reduced from 100% to approximately 6% at the time of trip. The duration of the high steam flow/low average temperature signal was apparently not of sufficient duration to latch the "A" train nor close the main steam line isolation valves. Both were manually actuated. A containme fire alarm was received shortly after the SI.

After having determined that a spurious SI had occurred, the operators initiated actions (e.g., reset SI, feedwater isolation, restore letdown) to continue to hot standby condition. During the automatic isolation of the CVCS letdown line due to the spurious SI, it is believed that the outermost isolation valves (see Figure 1, valves 204A&B) closed faster than the two open orifice isolation valves (CVC-200B and C), or that leakage past the orifice isolation valves resulted in the opening of the relief valve and the rupturing of the bellows on the relief valve (CVC-RV-203). In addition, a pressure surge due to the isolation valves closing caused a drain cap to be blown off. Unaware of these two failures, letdown flow was reestablished. Subsequently, containment pressure and dew point increased. The containment pressure and humidity increases attached additional significance to the already decreasi

RCS pressure. Letdown was secured (valves closed and sequence unknown) about 15 minutes after letdown was reestablished. A containment entry was made. A leak was identified in the letdown system area but no fire existed. The heat sensitive fire alarm detected the steam from the leak in the letdown system, which implies that this leak occurred in the CVCS during the first SI. Approximately 3,000 gallons was estimated to be in the containment sump based on level indication in the control room.

After the letdown was thought to be isolated, the pressurizer pressure continued to decrease and the level to increase. A second safety injection occurred on low pressurizer pressure. Both trains of safeguards equipment actuated. The level increase was the result of continued charging flow and heatup of the primary system (the MSIVs had been closed to recover average temperature earlier). The cause for the depressurization could not be identified positively.

Four hours after the first entry, a second containment entry was made and the leak was identified to be from a drain line which was still leaking. The drain line is located upstream of the orifice isolation valves (see Figure 1). The cap on the drain pipe was missing and valve (CVC-200E) was manually closed. Water in the containment sump had now increased to approximately 4,500-6,000 gallons. Evidently, the two level control valves (CVC-LCV-460A&B) were leaking at five to seven gallons per minute between 0650 and 1120. After the drain valve was closed during the second containment entry, the RCS pressure continued to decrease.

Many steps were taken to determine the cause of the decreasing RCS pressure after letdown had been isolated; e.g., isolating charging line auxiliary spray, checking pressurizer relief and safety valve leakage, and increasing pressurizer heater output. The cause was identified when the operators stopped two of the three reactor coolant pumps in the loops with the pressurizer spray scoops and the pressure began to increase. One of the two pressurizer spray valves was not fully closed. Positive identification of spray valve RC-455B as the leaking valve was made later. The spray valve position is indicated by demand, not stem position, which delayed identification of the cause for depressurization.

During this event, steam generator samples indicated a primary-to-secondary leak of approximately 0.5 gpm based on activity of 10^{-4} µC/ml. Steam generator "B" was isolated on the secondary side. Subsequent samples indicated decreasing activity and no leak. The licensee has concluded that the increased activity was the result of "crud" being agitated during isolation of the steam generators during the event.

Repairs were made to the spray valve and the relief valve bellows. The cap was replaced on the drain line and all drain valves were verified closed. The unit was back online on February 1, 1981.

2. EVALUATION OF THE EVENT

2.1 Operator Actions

Operators responded to the events in a systematic and timely fashion. Data entered into the logs were detailed and accurate. After the plant was stabilized, the license contacted Westinghouse to ensure that their diagnoses were correct and no other unforeseen problems existed.

One shortcoming identified was the lack of a procedure for recovery from a spurious safety injection actuation. Guidelines should be available to the operators to differentiate between a real and spurious SI actuation. The licensee indicated that a procedure will be written for recovery from a spurious SI (identification criteria not included). For this event, resetting the SI had [illegible]. However, pressurizer pressure, level and average temperature had still been decreasing prior to the SI and had "stabilized" for only about [illegible] minutes before resetting SI. In retrospect, there was still a small [illegible] coolant leak and the spray valve was open. However, SI had been initiated on signals indicative of a steam line break and since secondary system conditions were stable and the governor valve position recorder indicated spurious valve opening, the operators correctly diagnosed the SI signal as spurious for this event.

An area of improvement would have been to test the safety injection actuation and main steamline isolation signals since one train of SI failed to latch and the MSIVs failed to close. Both were manually actuated. Although both SI trains actuated on the second safety injection signal, this was not adequate verification of operability on high steam flow/low average temperature actuation before returning to power. These tests could have helped substantiate that the signal was not of sufficient duration to latch the SI relay and close the MSIVs.

2.2 Charging Flow Termination

Although SI actuation occurred twice, no boric acid was injected into the [illegible] based on samples of the boric acid injection tank. This was because the RCS system pressure exceeded the shutoff head (1,500 psig) of the SI pumps at the times of actuation. Hence, the charging pumps were making up [illegible] inventory during the event.

[illegible] the attempts to identify the cause for the depressurization and recognizing that pressurizer spray could cause the depressurization, the charging flow was isolated (closed valve CVC-HCV-121) to terminate a possible leak from the auxiliary spray valve (Figure 1). This operator action did not terminate all makeup flow to the RCS. The flow path was maintained to the RCP seals which would provide makeup flow (approximately 60 gpm). RCS conditions (approximately) at this time were: Pressure = 1,600 psig; Tavg = 548°F; pressurizer level = 56% and increasing; normal steam generator level for the condition; and margin to saturation was approximately 50-55°F.

The charging line was isolated from 0726 to sometime after 1932 (shift foreman's log). No consequences resulted from isolating the normal charging flow for this event although SI flow was not available due to the pump head limits. However, it is suggested that NRR determine whether isolating the charging flow is advisable for small loss-of-coolant accidents or when the system pressure is above the shutoff head of the SI pumps. Westinghouse has indicated that no credit was taken for charging flow for the ECCS analyses. The emergency procedure for depressurization (EI-1) does not include criteria for terminating charging flow. The charging pumps are a part of the CVCS and not considered a part of the safety injection system at Robinson. However, the charging pumps provide high pressure makeup flow when the RCS pressure exceeds the shutoff head of the SI pumps. Ensuring that charging flow is not interrupted for the systems employing low/medium heat SI pumps may be desirable to enhance safety.

2.3 Safety Injection Actuation

The first safety injection actuation occurred on a "high steam line flow/low Tavg" signal. The licensee's review of the event indicated that the momentary spike-opening of the turbine governor valves caused the steam flow, in at least two steam lines, to exceed the steam flow set point for a period of about 25 msec. The combination of high steam flow in 2/3 steam lines and the existing low average temperature of the reactor coolant generated a main steam isolation valve (MSIV) closure signal and a SI actuation signal.

However, only train B of safeguards equipment responded - the other train of safeguards equipment and all the MSIVs did not actuate. Licensee's observations are that the MSIVs require a signal duration of one second to close and that the SI actuation relays, including SI logic train latching relay, require a signal duration greater than 25 msec to actuate. Since the SI signal was of less than 25 msec duration, only the train B latching relay actuated. Reactor trip, emergency diesel start, feedwater isolation and other safeguards equipment actuations for train B occurred as a consequence of SI train B actuation.

Reviewing the logic diagram of Robinson's Safeguard Actuation Signals (Dwg CP 300-5379-2759 sh B, rev 5) it is seen that the reactor trip signal is initiated on SI actuation along with emergency diesel start, feedwater isolation and safeguards sequence actuation. A review of a later Westinghouse logic diagram (typical) shows that the reactor trip signal is derived separately from the SI actuation signal; i.e., the reactor trip signal is taken of "upstream" of the SI actuation signal, similar to the MSIV closure signal on Robinson. This could mean that on certain spurious SI actuation events of short signal duration, SI, feedwater isolation and auxiliary feedwater system actuations may occur with no simultaneous reactor trip occurring. The comparison of logic diagrams also shows that the P-4 interlock (reactor trip breaker position) in the the Reset/Block feature of SI logic of later Westinghouse units is not provided in the Robinson design. Additional ana... would be needed to ascertain the significance of different reactor trip lo... for Westinghouse plants. The need to provide a direct reactor trip on spu... safety injection actuation is referred to NRR for review.

2.4 Pressurizer Spray

The open spray valve could not be identified due to lack of spray flow indication or actual spray valve position. The failure of the valve to close evidently did not affect the capability of the valve to open as evidenced by subsequent testing. The Licensee is evaluating the possibility of relocating and replacing the spray valves during the next refueling outage. Previous problems have been experienced with the spray valves and their location in containment reduces their accessibility for maintenance.

2.5 Relief Valve Bellows Failure

The licensee has experienced previous failures of this Crosby relief valve (number JB-36, Type B, shop drawing number H51380). Basic information about the valve and the discharge piping configuration were obtained from CP&L and Crosby Valve Company and are as follows:

Relief Valve

- 2" diameter inlet, 3" diameter outlet
- Set pressure, 600 psig
- System pressure, 300 psig (approximate)
- Dynamic backpressure, 25 psig (specified)
- Bellows tested to 150 psig

Piping

- A horizontal run exits from the relief valve before turning vertically up for at least 12 feet to the pressurizer relief tank.

CP&L indicated that the bellows fails every time the relief valve lifts. Since the bellows has been tested to 150 psig, it would appear that the system is operating quite differently from the anticipated mode. The dynamic backpressure probably exceeds 150 psig (six times the specified 25 psig). A mechanism that could cause the high pressure might be stagnate water from either steam condensation or valve leakage in the line from the relief valve to the pressurizer relief tank. Boric acid crystal formations may also be a possibility. When the valve opens, water or other debris in this line could restrict steam flow and cause a high dynamic backpressure until the line is cleared. Also, if the line is filled with stagnate borated water, the bellows may be susceptible to corrosion attack, but corrosion has not been identified from previous failures and replacements. From an operational viewpoint, the failure mode for the bellows should be identified and changes necessary to prevent additional failures should be implemented. The operation of the CVCS isolation valves may be a major contributor to the bellows failures and is discussed in Section 2.6.

2.5 Letdown Isolation Valves

The isolation valves played a dominant role in the sequence of events at Robinson. The failure of the bellows on the relief valve was attributed to the closing of the out board valves (CVC-204A&B) before the closing of the orifice isolation valves (CVC 200B&C) upstream of the relief valve. Consequently, the set point (600 psig) of the relief valve was reached since this part of the CVCS was pressurized by the reactor coolant system which was at approximately 1,800 psi. The design pressure downstream of the valves (CVC-200 series) is 600 psig. The sequential operation of the isolation valves is evidently causing this part of the CVCS to be pressurized to at least the setpoint of the relief valve, as evidenced by the opening of the relief valve whenever the CVCS is isolated.

In addition to the isolation valves, valves LCV-460 A and B (Figure 1) were closed in an attempt to isolate the leaking drain valve/pipe. Both of these valves leaked which permitted an additional 3,000 gallons (approximately) to leak into the containment after the letdown system was thought to be isolated. The licensee did not perform any maintenance on these valves to ensure their operation before returning to power since these are not containment isolation valves. These valves are part of the reactor coolant pressure boundary and are designed to close on low pressurizer level to conserve RCS inventory.

The design and operation of this part of the CVCS raises two concerns: first, the potential for overpressurizing the system to 2,200 psig assuming the downstream isolation valves (CVC-204A&B) are closed; and secondly, the capability to isolate a potential break downstream of valves LCV-460A&B. The licensee has indicated that the relief valve is designed to prevent overpressurization of the CVCS. The failure of the bellows does not appear to affect the pressure relieving function of the relief valve. In addition, the flow control valves (CVC-LCV-460A&B) have been designed to isolate a break downstream of these valves for the maximum size break and RCS conditions.

The functional and testing requirements for the flow control valves are not clear. These valves should be ASME Class 1 since there are no valves upstream and the valves downstream are classified as ASME Class 2. However, these flow control valves are not identified in the Robinson Inservice Inspection and Testing Program (Reference 4). Since these valves are on the RCS pressure boundary and are designed to isolate the RCS on low pressurizer level, it is not clear why maintenance on the valves was not required after they were known to leak and before returning to power.

Both of these concerns could lead to a small loss-of-coolant event inside containment. This postulated event is within the scope of an analyzed small break loss-of-coolant accident and not a new safety concern. However, from an operational consideration, overpressurizing the CVCS could be prevented, provided the orifice isolation valves were closed before the outboard isolation valves. Correcting the valve closing sequence for isolation would also reduce the challenge to the relief valve.

2.7 Leakage Inside Containment

The licensee has acknowledged that the quantity of water that leaked into containment can only be approximated. The estimated 6,000 gallons (corresponding to approximately 15" in the sump) is a small fraction of the range of indication in a 65,000-gallon capacity sump (See Figure 2). A mass balance was not possible since neither charging flow nor volume control tank level are recorded. The major leak was after letdown flow had been reestablished between 0635 and 0650. This could account for approximately one half of the 3,000 gallons indicated at 0650. The drain valve could have also been leaking at an unknown reduced rate from the initial SI until letdown was restored (approximately ten minutes). The ruptured bellows on the relief valve also contributed some amount to the inventory in the sump. These sources in combination with the inaccuracy of the sump measurements can lead to the conclusion that all the leak sources had been identified.

2.8 Drain Valve and Pipe Cap

The leaking valve was CVC-200F (see Figure 1) not CVC-204C as reported by IE (Reference 1). This helps to understand the leak rates and quantity of water reported in the LER (Reference 2) and the IE evaluation.

The licensee's explanation for the missing cap on the pipe was that when the orifice isolation valves closed, a pressure pulse was applied to the valve and cap. Since the valve was partially open and the cap not tightly secured, the cap was blown off. The licensee believed that vibration in the CVCS (induced by the charging pumps) caused movement of the valve and cap. The valve position was last verified on October 11, 1980 during a refueling outage. Since the drain pipe is located close to the pressure reducing orifices, the flow instabilities at these orifices could also induce vibration in the CVCS.

All drain pipes with valves have been verified closed. Most valves have been chained and locked.

2.9 Failure of Fire Protection Isolation Valve

When a Phase A isolation signal was generated by the safety injection actuation, one (FP-248) of the four containment isolation valves failed to close due to a tripped breaker. Since the other isolation valve in the line closed, containment isolation was achieved. This failure had no bearing on the leak and was a separate reportable event.

3. CONCLUSIONS

The event at H. B. Robinson involved four separate, somewhat unrelated failures: (1) pump failures in the turbine EHC system; (2) two separate leaks in the CVCS (related failures); (3) an undetected open pressurizer spray valve; and (4) leaking valves in the CVCS. The event did not appear to include any safety concerns.

The following areas of review concering this event are referred to NRR for consideration:

a. Whether a requirement should be placed upon operating plants to establish a procedure for identification and recovery from a spurious safety injection actuation (if such a procedure is not already in place).

b. Whether criteria for terminating SI should include provisions for isolating charging since charging flow could be considered high pressure safety injection for very small breaks.

c. Whether there is a need for a direct reactor trip on a spurious safety injection actuation at other Westinghouse plants which do not have a direct trip.

d. Whether operation of the isolation valves in the CVCS at Robinson is causing the system to be operated in a manner which is contrary to its design bases. The closing sequence for the isolation valves appears to cause part of the CVCS to be pressurized to the setpoint of the relief valve and may be contributing to the failure of the relief valve bellows whenever the system is isolated.

AEOD did not find any basis for a need to study this event further. A formal response from NRR is not requested.

This event and the operator's response provide a good example of an operating experience which should be disseminated to other licensees for information and training purposes.

4. REFERENCES

(1) Memorandum, H. Woods to E. Jordan, Subject: H.B. Robinson Event on January 29, 1981, dated February 12, 1981.

(2) Licensee Event Report 81-005, H.B. Robinson Steam Electric Plant, Unit 2, Docket 50-261, dated February 12, 1981.

(3) Meeting with Carolina Power and Light Company in Bethesda on February 20, 1981.

(4) Letter, E. E. Utley, CP&L to S. Varga, Subject: H. B. Robinson Steam Electric Plant Unit No. 2, Inservice Inspection and Testing Program, dated March 10, 1981.

Table 1
SEQUENCE OF EVENTS

January 29, 1981
Plant at 100%
Primary to secondary leak of approximately 0.3 gpm.

0500 "A" EHC oil pump seal leak, "B" EHC pump already out of service due to vibration.

0541 Started load reduction.

0542 Added boric acid to RCS.

0543 Started "C" charging pump, "B" charging pump running, "A" charging pump inoperable.
Opened CVC-200B orifice isolation valve, CVC-200C already open.

0549-
0609 Continued to add boric acid.

0613 Stopped "1" feedwater pump and condensate pump due to erratic FWP behavior.

0620 Tavg reached low Tavg setpoint (543°F) alarm.

0623 Generator output breaker opened.
Turbine governor valves spike open.
SI signal and MSIV closure signal on high steam flow/low Tavg.

SI train "B" automatically started.
Phase A isolation; safeguard B emergency equipment started.
Reactor trip on SI signal.
Tavg = 532°F.
Pzr pressure = 2210 psig.
Pzr level = 13%.

0625 Fire alarm in containment.
Pressurizer relief tank level alarm due to opening of CVC-RV-203 relief valve.
Bellows probably ruptured and drain cap was blown off.
MSIVs closed manually.
SI train "A" started manually. Started "A" DG, AFWP, RHR, manually.
Letdown valves CCV-460A&B manually closed (should have automatically closed on PZR level of 13%).

0627 Reset SI and feedwater isolation.

0634 Attempted to restore letdown flow but CVC-200A would not open (instrument air system isolated on Phase A isolation).
Restored letdown flow after resetting isolation signals.
Pressurizer pressure started decreasing sharply (-2000 psig).
Containment dew point and pressure started increasing.

0637 Received condensate collection alarm from the coolers.
Diesel generators A and B stopped manually.

0645 Isolated letdown flow. (Isolation valves closed from control room.)
Containment dew point and pressure decreased.
Pressurizer pressure still decreasing (1840 psig).
Tavg increasing.
Pressurizer pressure increasing.
Notified NRC by ENS.

0650 Containment sump level indicated approximately 3000 gallons.

0700 First containment entry to check for leak and fire.

0705 Second SI actuation on low préssurizer pressure.
Both trains and all equipment started.
Pressurizer pressure = 1715 psig.
Pressurizer level = 50%.

0705-
0727 Operators attempting to determine cause of depressurization.

0722 Steam dumps opened manually to control pressurizer level.

0727 Reactor coolant pumps B and C stopped and charging line isolated to eliminate possibility of leaking auxiliary spray valves.
Increased pressurizer heater output to maximum.
Pressurizer pressure started increasing.

0729 Continued cooldown using steam dumps.

0735 Pressurizer pressure increasing (= 1720).
Tavg constant = 540.
Pressurizer level = 50%.

0738 Stopped diesel generators A&B.

0741 Stopped "B" RHR pump.

0745 Opened breakers on containment sump pumps.

0825 Secured SI pumps.

1000 Continued plant cooldown.
Sample on "B" steam generator indicated 0.5 gpm primary to secondary leak. Isolated "B" steam generator.
Second sample showed decreased leakage (0.25 gpm).

1120 Second containment entry. Found CVC-200E open and cap missing.
Found bellows on relief valve CVC-203 ruptured.
Contacted Westinghouse.

1210 Blocked low pressure SI.

1230 Closed CVC-200E.
Isolated letdown by closing CVC-309O.
Containment sump level was 4,500-6,000 gallons.

1445 "B" charging pump out of service due to leaking relief valve

1830 Aligned "A" charging pump for operation after completing surveillance tests.

(late entry) Tested pressurizer spray valves.

1913 Started "B" RCP.

1932 Started "C" RCP.

(Later) Placed charging line and CVCS letdown in service. Removed excess letdown line from service.

2315 Spray valve RCS-455B identified as leaking spray valve
No additional primary to secondary leak identified.

January 30, 1981 at 1700 plant on-line

APPENDIX A

INFORMATION PROVIDED BY LICENSEE . MEETING ON FEBRUARY 20, 1981

Contents:

1. Draft Plant Operating Experience Report
2. Operators Log
3. Shift Foreman Log
4. Strip Charts
5. Figure 1 - CVCS Diagram (excerpt)
6. Figure 2 - Containment Sump Volume

PLANT OPERATING EXPERIENCE REPORT

1. Event Date

January 29, 1981

2. Identification of Occurrence

A) A spurious safety injection signal initiated by a "High Steam Line Flow/Low T_{avg}" signal.

B) Reactor Coolant System leak through letdown line drain valve CVC-200E.

C) Primary plant depressurization leading to a second safety injection signal initiated by a "Low Pressurizer Pressure" signal.

3. Conditions Prior to Occurrence

A plant shutdown to hot standby was in progress to repair a secondary plant problem. The unit had been operating at 100% reactor power (725 MWe) with normal Reactor Coolant System pressure and temperature.

4. Description of Occurrence (All Times Are Approximate)

A) At 0624 hours on January 29, 1981, a safety injection signal initiated "B" train of safeguards. "A" train equipment was manually started at 0625 hours.

B) At 0635 hours on January 29, 1981, the chemical and volume control letdown system was restored and system pressure began decreasing with an increasing containment pressure and dew point. Letdown was secured at 0650 hours.

C) At 0705 hours on January 29, 1981, a safety injection signal initiated both trains of safeguards.

-DRAFT-

5. <u>Designation of Apparent Cause of Occurrence</u>

At approximately 0400 hours, "A" turbine electro hydraulic (E-H) oil pump developed a seal leak. "B" E-H oil pump had been taken out of service earlier due to high vibrations. At 0541 hours, the decision was made to shut down to hot standby before receiving a trip signal due to the loss of E-H oil. Attachment No. 1 contains additional information on the failure of the E-H Oil System.

At 0624 hours, immediately following opening the generator output breakers, the reactor tripped and a safety injection was initiated by a "High Steam Line Flow/Low T_{avg}" signal. Only "B" train of the safeguards was activated. "A" train equipment was manually started at 0625 hours. It was determined that the erratic operation of the E-H Oil System and the fact that the operators were switching from "A" E-H oil pump to "B" E-H oil pump caused the governor valves to spike open. The resultant steam flow spike was high enough to cause a "High Steam Line Flow/Low T_{avg}" signal but it was of insufficient duration to fully latch the "A" safeguards train seal-in relay. The seal-in relays in the safeguard trains are latching relays that require a finite period of time in the energized mode to mechanically latch them into the closed position. Attachment No. 2 contains additional information on the partial safety injection.

The steam line isolation signal that was generated from the "High Steam Line Flow/Low T_{avg}" signal was of insufficient duration to allow the main steam isolation valves to go shut. The open signal was reinstated so quickly

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5. <u>Designation of Apparent Cause of Occurrence</u> (Continued)

after the isolation signal that the valves were unable to travel far enough to isolate the steam flow. The main steam isolation valves were manually shut to reduce the secondary steam demand following the reactor trip, thereby promoting the return of T_{avg} to the no load setpoint.

At 0627 hours it was determined that safety injection conditions did not exist and that the initiation was spurious. The safety injection and feedwater isolation signals were reset. The chemical and volume control letdown system was restored at 0635 hours. The Reactor Coolant System pressure had been slowly decreasing, but when letdown was returned to service, the containment pressure and dew point began increasing. Another indication of abnormal containment conditions was a fire alarm from the area of the containment operating deck which was received at approximately 0624. Letdown was secured at 0650 hours with Reactor Coolant System pressure at 1850 psig. The initial containment entry made at 0700 hours to investigate the abnormal conditions confirmed that the RCS leakage was from the letdown line and that no fire existed. A subsequent containment entry at 1120 hours further identified the source of the leak as valve CVC-200E, a drain valve on the letdown line, which was found open and the pipe cap missing. The leak that resulted from the open drain valve was approximately 5 to 7 gpm with the letdown air operated valves closed and approximately 100 gpm with letdown flow established. The leak was completely stopped by shutting valve CVC-200E. The letdown flow was not restored until after the condition was found and repaired. Additional information regarding the RCS leak and containment fire alarm can be found in Attachment No. 3.

5. <u>Designation of Apparent Cause of Occurrence</u> (Continued)

However, even with the letdown control valves closed, the pressurizer pressure continued to decrease, leading to the second safety injection initiation at 0705 hours from a "Low Pressurizer Pressure". Both trains of the safeguards equipment functioned as designed. At 0727 hours, charging was isolated (except reactor coolant pump seal injection) to eliminate auxiliary spray and "B" and "C" reactor coolant pumps were secured to prevent the pressurizer spray valves from circulating cooler water from the Reactor Coolant System into the pressurizer through the spray valves, decreasing the pressure. It was subsequently discovered that the pressurizer spray valve from "C" reactor coolant loop had probably opened and not fully reseated. The pressurizer pressure immediately started to increase. The reactor coolant system was stabilized at approximately 2050 psig and 535°F with pressure controlled by the pressurizer heaters and temperature controlled by the secondary steam dump. Attachment No. 4 contains additional information on the reactor coolant system pressure transient caused by the spray valve malfunction.

Coincidental with the decreasing pressurizer pressure, pressurizer level was increasing. This was caused by two factors. 1) The charging flow from two charging pumps was maintaining or increasing the system volume, including the system losses through CVC-200E. The slightly open pressurizer spray valve was causing the pressure to decrease. 2) The density changes in the reactor coolant due to the slowly increasing RCS temperatures and the heat up of the relatively cold water added by the charging system caused the system to expand. These factors combined to cause an increasing pressurizer level. The margin to subcooling remained

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5. <u>Designation of Apparent Cause of Occurrence</u> (Continued)

greater than 55°F throughout the entire transient. The minimum subcooling margin occurred at 0720 hours, with reactor coolant system pressure at 1620 psig and temperature at 551°F.

The relief valve on the letdown line, CVC-RV-203, lifted following the first safety injection initiation. This was apparently due to the isolation valves, CVC-204A and CVC-204B, closing slightly faster than the orifice isolations, CVC-200A, CVC-200B and CVC-200C, or leakage past one or more of the orifice isolation valves. This caused the pressure between the valves to increase above the set pressure for CVC-RV-203 (600 psig). The valve reset after the letdown isolations closed, but the bellows had ruptured. Attachment No. 3 also contains additional information regarding valve CVC-RV-203.

6. <u>Analysis of Occurrence</u>

Several problems with the turbine E-H Oil System had occurred within approximately one week preceeding the reactor trip and safety injection on January 29, 1981 which could have contributed to the initiation of the event. These problems are summarized as follows:

1) The E-H oil had become contaminated with water due to a ruptured E-H oil cooler approximately one week prior to this event. However, the E-H oil had been purified (replaced) and restored to specification prior to this event. It is not felt that this contributed to the following problems.

2) On January 28, 1981 "B" E-H pump unloader developed a fatigue crack in its discharge nipple. While replacing this nipple, air was introduced into the "B" E-H oil pump portion of the system. When

6. Analysis of Occurrence (Continued)

"B" E-H oil pump was restarted, it caused excessive vibrations throughout the E-H Oil System. "A" E-H oil pump was restarted and "B" E-H oil pump was secured after a brief period of operation.

3) The seal leak which developed on "A" E-H oil pump on January 29, 1981 which necessitated the turbine shutdown is felt to have been caused by either age or the excessive-system vibration.

4) As the seal leak on "A" E-H oil pump became larger during the remaining moments of the turbine shutdown, the operators decided to run "B" E-H oil pump despite the vibration problem in order to allow the leak to be isolated so a normal turbine shutdown could be completed. Coincidentally, "B" E-H oil pump was started as the generator output breakers were opened. When the generator output breakers are opened the turbine switches from load control to speed control.

One, or some combination, of the above probably caused the turbine governor valves to spike open. The exact cause cannot be determined. This caused the first safety injection initiated on a low reactor coolant system average temperature coincident with high steam line flow. The high steam flow was of a very short duration, thus only "B" safeguards train was activated and the main steam isolation valves remained open.

Letdown line drain valve CVC-200E had vibrated open since it had last been verified shut on October 11, 1980. It is postulated that the pressure transient caused by the letdown line isolation caused the pipe cap to blow off. Thus, a Reactor Coolant System leak existed.

6. Analysis of Occurrence (Continued)

The continued decrease in pressurizer pressure was caused by the failure of the pressurizer spray valve from "C" reactor coolant system loop (RCS-455B) to fully shut after opening during the transient. The event identification was complicated by the letdown relief line lifting to the pressurizer relief tank which indicated that there were two separate leaks. The Reactor Coolant System pressure decrease was stopped when "B" and "C" reactor coolant pumps were secured and the charging line was isolated to eliminate auxiliary spray. With the pressure decrease stopped, operator control of the Reactor Coolant System was re-established and normal hot shutdown conditions were established.

Following the first safety injection at 0624 hours, the fire protection containment isolation valve FP-248 did not shut automatically and had to be manually closed. Attachment No. 5 contains additional information on the performance of the fire protection containment isolation valve.

A summary of the P250 computer output for this event is provided as Attachment No. 6.

7. Corrective Action

A) The E-H oil was completely replaced with new oil.

B) "A" E-H oil pump and unloader were replaced.

C) The unloader and discharge nipple on "B" E-H oil pump were replaced.

D) The valve stem on RCS-455B was lubricated, stroked and valve positioner was adjusted to ensure the valve will fully close. RCS-455A was also checked for proper operation.

7. Corrective Action (Continued)

E) CVC-200E was locked closed and the pipe cap was replaced. Similar valves in the letdown and charging lines were also locked closed or otherwise verified to be secured.

F) The breaker over current trip setpoints on the four Fire Protection System containment isolation valves have been adjusted and checked to insure proper valve performance.

G) The event was fully analyzed by the plant staff and Westinghouse, and the results discussed with the NRC, Region II, to ensure that all safety concerns were identified and resolved prior to returning the unit to operation.

Unit 2 Operating Supervisor

Manager - Operations and Maintenance

General Manager

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SEQUENCE OF EVENTS

0541 Unit shutdown was initiated due to E-H System trouble.

0620 Tavg reached the low Tavg setpoint (543°F) during plant shutdown.

0624 Generator output breaker is opened removing unit from system.

Load on unit is 4%.

Turbine governor valve(s) spike open (see Attachment No. 1).

High Steam Flow/Low Tavg signal generated.

MSIV's closure signal (see Attachment No. 2).

SI signal, train "B" actuates (see Attachment No. 2).

CV isolation valve FP-248 fails to close (see Attachment No. 5).

Minimum Tavg = 532°F (based on incore thermocouple).

PZR pressure = 2100 psig.

PZR level = 13%.

0625 Fire alarm at CV operating deck (see Attachment No. 3).

Pressurizer relief tank level alarms from CVC-203 discharge (see Attachment No. 3).

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0625 (Contd.) Primary pressure begins to decrease (see Attachment No. 4).

MSIVs manually closed.

SI train "A" equipment manually started.

Letdown valves 460A & B manually shut.

0627 Manually reset SI.

0635 Restored letdown.

Containment dew point and pressure begin to increase.

0650 Isolated letdown (suspected leak in letdown system).

0656 Tavg reaches maximum value of 552°F and holds steady.

PZR pressure = 1750 psig.

PZR level = 50%.

0700 Containment entry to check for leak and fire (see Attachment No. 3).

0705 Second SI signal due to low PZR pressure, 1715 psig.

Both "A" and "B" trains activated.

0705-0727 Operators attempt to determine cause of depressurization. The following equipment was checked:

0705-0727 (Contd.)

a) PZR safety valves flow indicators.

b) PZR PORV discharge line temperature.

c) PZR block valve position.

d) PZR relief tank level.

e) PZR relief tank pressure.

f) PZR spray valve position (the valves indicated closed but since this indication is demand indication the valve controllers were again manually closed).

0722 The RCS temperature was lowered slightly using the secondary steam dumps to help control the increasing pressurizer level.

Tavg = 549°F.

PZR pressure = 1620 psig.

PZR level = 62%.

0727 The charging line was isolated to eliminate the possibility of auxiliary spray causing the depressurization. RCP "B" and "C" were stopped to eliminate the possibility of main spray flow causing the depressurization.

Pressurizer pressure begins to rise.

0735 Tavg = 543°F.

PZR pressure = 1715 psig.

PZR level = 50%.

0820 PZR pressure stabilized.

Tavg = 535°F.

PZR pressure = 2050 psig.

PZR level = 45%.

1120 Made second containment entry and isolated CVC-200E at 1230 hours.

1120 (1-29-81)
to 1700 (2-1-81) Review and analysis of transient with Westinghouse. Discussions of transient with NRC Region II.

2315 (1-29-81) RCS-453B positively identified as leaking spray valve.

1700 (2-1-81) Plant on-line.

ATTACHMENT NO. 1

E-H SYSTEM FAILURE

The E-H System had experienced several problems prior to the transient on 1-29-81. During the previous week the E-H fluid had become contaminated with water. (This contamination was restored to within specification.) On Wednesday morning, 1-28-81, a stainless steel nipple on the E-H System unloader on "B" pump cracked. This caused a loss of approximately X gallons of E-H fluid. The fluid and nipple were replaced and "B" pump restarted. However, the pump was immediately stopped due to noise and vibration. Several attempts were made to troubleshoot the problem but no definite cause was found. The system was left operating satisfactorily with one pump in service. At 0500 on 1-29-81 the second E-H pump, "A", developed a seal leak which caused E-H fluid to leak out of the system. At 0541 the operators began to take the unit off line to repair the E-H System. At 0624 while the unit was being separated from the system, the E-H System generated a pressure surge to the governor valves which resulted in the valves momentarily opening. Three factors could have contributed to the pressure surge. The turbine control was switching to speed control. The operators were trying to start "B" E-H oil pump to supply E-H oil during the final moments of the turbine shutdown. The E-H System had been contaminated by water during the previous week. This caused a momentary high steam flow to be sensed on at least 2 steam lines. The spike shows up on all three steam flow charts. The effect of this flow spike is described in Attachment No. 2.

The failure of "A" pump seal on the E-H System was due to age and transferred vibration from "B" pump. Subsequent to these pump failures, the unloader of pump "B" has been replaced and pump "A" was replaced in its entirety. The complete system was restored to service and is operating satisfactorily.

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ATTACHMENT NO. 2

PARTIAL SI AT 0624 HOURS

On January 29, 1981 at 0541 a unit shutdown was commenced to do repair work on the turbine E-H System. At approximately 0620 hours Tavg dropped below the low Tavg setpoint of 543°F due to an inadvertent overshoot during plant shutdown. At 0624 with the unit at ~6% power the generator output breakers were opened disconnecting the unit from the system. At this time the turbine E-H control system switched to speed control and due to pressure instabilities in the E-H control system the turbine governor valves spiked open. A review of the event indicates that the spike caused an indicated steam flow in at least two steam lines to exceed the steam flow setpoint for a time period less than 25 msec. This indicated high steam flow in 2/3 steam lines combined with the low Tavg mentioned earlier generated a main steam isolation valve closure signal and a SI signal. The duration of this signal would be the same as the steam flow spike. It has been observed during periodic tests that the MSIVs require a signal duration of approximately 1 sec. to close and so none of the MSIVs closed on the momentary high flow/low Tavg signal. (The MSIVs were manually closed immediately by the operators in order to stabilize RCS temperature.) The SI signal is divided into 2 trains "A" and "B". Each of these trains contains several relays including a mechanical latching relay (Westinghouse Type MG6) which is used to lock in the SI train until manually reset. A signal duration greater than 25 msec. is required to insure that all relays close and the latching relays lock in. Since the SI signal was less than 25 msec. only the latching relay for train "B" fully engaged. The operators immediately noticed that train "A" had not engaged and so they manually started the train "A" equipment. Containment isolation Phase A was initiated by train "B". No SI water was injected into the system since RCS pressure was ~2100 psig and the

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ATTACHMENT NO. 2 (Continued)

shut off head of the SI pumps is 1500 psig. SI was manually reset at 0627 since the SI initiation was identified as spurious.

Once train "A" was manually initiated the SI System performed as expected, with the exception of CV isolation valve FP-248 (see Attachment No. 5). The actuation of the SI System did not effect the physical course of events during the transient, however it did obscure the cause of the RCS depressurization (stuck pressurizer spray valve). No repairs to the SI logic or components are considered necessary.

ATTACHMENT NO. 3

LETDOWN LINE LEAK

At 0624 an SI signal latched in the "B" train relay which generated a Phase A containment isolation. As part of the Phase A containment isolation five letdown valves closed (CVC-200A, B, C and CVC-204A, B). During this time the relief valve on the letdown line, CVC-RV-203, lifted. This was apparently due to the isolation valves, CVC-204A and CVC-204B, closing slightly faster than the orifice isolations, CVC-200A, CVC-200B and CVC-200C, or leakage past one or more of the orifice isolation valves. This then caused the pressurizer relief tank level to increase from approximately 70% (normal level) to 75.2% full. The pressure transient while causing relief valve CVC-RV-203 to lift also caused the relief valve bellows to rupture. At this same time, when the CVC-200A, B & C valves closed, a pressure surge was applied to CVC-200E. This valve is normally closed but had apparently vibrated partially open during plant operations. The valve position was last verified on 10-11-80. One possible cause for the vibration at CVC-200E is the positive displacement charging pumps. These pumps have a history of vibration induced problems for which solutions are currently under development. CVC-200E is also capped but the cap apparently was not tightly secured as evidenced by the stripped threads on the end of the pipe. When the pressure surge was applied to the CVC-200E cap the cap was blown off, causing a primary leak estimated at approximately 100 gpm. This estimate was based on the pipe diameter and quantity of water discharged to the CV sump. This leak was quickly reduced to 5-7 gpm when valves 460A & B were shut by the operators. Apparently some leakage occurred past these air operated control valves. The 100 gpm leak was restarted when letdown was re-established at 0635 causing containment dew point and pressure to rise (∿.25 psi). At 0650 letdown was isolated and the leak rate again dropped to 5-7 gpm. Based on the sump level indication less than 6000 gallons of primary coolant was discharged into the containment sump. When the 100 gpm leak occurred te at 0624 it apparently caused a heat sensitive fire detector to go off in containment. The detector was located above the drain valve on the operating deck. Since the operators had indication of RCS leakage and a fire in the containment, an individual using respiratory protection was sent into the containment to investigate. This individual confirmed the leakage and identified the source as the letdown line but was unable to identify the exact leak point because his air supply was low. During the inspection no evidence of fire was found.

To prevent future occurrences the CVC-200E pipe threads were dressed and a new end cap installed. CVC-200E and several other valve/pipe cap arrangements which could be exposed to the same condition were inspected and physically locked or verified secured in the closed position.

ATTACHMENT NO. 4

PRIMARY SYSTEM DEPRESSURIZATION

The main concern during the transient of 1-29-81 was an unexplained decrease in RCS pressure. The pressure dropped from 2200 psig to 1620 psig in approximately one hour. Many steps were taken during the first hour of the transient to determine what was causing the depressurization. The pressurizer (Pzr) safety valves were checked by looking at the accoustic flow indicators downstream of the valves. No flow was indicated. The Pzr PORVs were checked by looking at the pipe temperature downstream of the valves. Again, no flow was indicated. The Pzr block valves were checked to verify that they were shut. The Pzr relief tank level and pressure were also checked to verify that they were not increasing. The main Pzr spray valves were then switched to manual control and closed by the operator. The indication on the RTGB showed the valve to be closed, however, since this indication is only of demand position, the operator tried to insure that the valves had closed by manually closing them. The charging line was then isolated to see if the auxiliary spray valve, CVC-311, was leaking. Additionally, RCP "B" and "C" were stopped so that flow through the main spray valves 455A & B was not possible. Pzr pressure began increasing. Later that night (2315 hours) spray valve 455B was positively identified as the leaking valve.

An inspection of the valve showed that the stem was binding on the valve packing. One reason the binding problem was not identified earlier is that the spray valves do not move much during power operation. RCS pressure control is accomplished by varying the Pzr heaters with the spray valve partially opened. The valve was repaired by lubricating the stem. The valve was then tested four times to insure proper operation. In addition, the electro-mechanical positioner zero setpoint was discovered to be slightly off and therefore was reset.

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ATTACHMENT NO. 5

CONTAINMENT ISOLATION VALVE FAILURE (FP-248)

At 0624 on 1-29-81 a SI signal generated a Phase A containment isolation. As part of this isolation the newly installed fire protection containment isolation valves FP-248, FP-249, FP-256, FP-258 were signaled to shut. FP-248 did not shut. The valve was then manually shut. The cause of failure was a tripped breaker which would not allow power to the motor operator. Subsequent review indicated that the trip point on the magnetic overload breaker was not set high enough to insure proper operation.

The breakers had been tested successfully upon installation, however, the current demand of the valve motors can change with time and so if the trip point is not set with enough margin the breaker can pass a test and yet fail at a later time.

The setpoints on all four valves have been readjusted to compensate for the above problem and tested. This should correct any future problems with these valves.

ATTACHMENT NO. 6

SUMMARY OF P250 COMPUTER OUTPUT

Time	Event
0620	Alarm - Low Tavg Permissive Set
0620	Alarm - Low Tavg 541.2 (setpoint is 543.0)
0623	ORR - Control Rod Bank C Inserted (reactor trip)
0624	Alarm - RHR Pump "B" BKR Closed (SI signal)
0624	Alarm - Low Tavg 532.7 (minimum Tavg)
0625	INCR - Hi PZR Relief Tank 75.2% (Valve CVC-203 lifts)
0627	RETRN - RHR Pump "B" BKR Open (SI reset)
0705	Alarm - PZR Low P & L SI (Second SI signal)
0705	Alarm - RHR Pump "B" BKR Closed
0705	Alarm - RHR Pump "A" BKR Closed
0726	Alarm - RCLB Lo Flow (RCP "B" stopped)
0727	Alarm - RCLC Lo Flow (RCP "C" stopped)

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Operators Log

1991

00-08 — Thursday

Reviewed previous shift logs, Status ... Indicate All vital valves in proper position ... plant condition, RC-535/536 are shut due to Porv's leakage, Rod roll on Temp power supply per MWO #562. Loop B3 ... Control ... Generator Temp being controlled on bypass ... On B/C S/G in progress. OWP's ... #25 are in effect. SG leak rate in progress, Stm Driven feedwater pump GOS, CVPR #81-15 in progress

0115 Completed PT 12.1

0145 Rods to manual due to ... condition

0154 Completed PT ... 6mm

0215 Started "A" SW pump

0221 Added 30 Gals PW to RCS

0230 Completed CVPR #81-15

0232 Reset ... from 12.5K to 17.5K

0541 Started load decrease due to EH oil pump ...

0542 Added 10 Gals BA & 20 Gals PW

0543 Started "C" Chg pump and 200 G orifice

0547 Shift plant Aux's

0549 ADDED 20 Gals BA 15 PW

0551 " " " " "

0556 " " " " " "

0601 " " " " " "

0604 " " " " " "

0606 "C" ... acting very erratic @ 55% ...

0609 ADDED 20 Gals BA; 15 Gals PW

0613 Stopped "B" ... and "B" Cond pump

0616 ADDED 10 Gals BA; 15 Gals PW

0624 Open North and South ...

0624 Received SI from ... Thug/... ...

0625 Manually initiated "A" Train (SI), also Started A & B SI pump, ... "A" ... "A" ... on

0625 Received Fire Alarm in CV. No Fire was found ...

JAN 29 1981

Thursday

0527 - Lost SI on Fw Isol

0545 - Stopped "B" MFW pump

H. B. Robinson Plant Unit # 2
Critical Configuration

Date 1-29-81 Time 0541 Oper [illegible]

Bank Position (Steps)

A 224 B 224 C 200 D 214

Tave 575 °F Pressure 2235 PSIG

Boron Concentration 665 PPM

Reactor Power Level 3×10^3 Amps 100 %

0621 Stopped RHR Y due to vibs. CV-200A will not open

0637 Cond. Collection Alm. Struck RCS Alt.

0650 Started "B" MFW pump, FW Isol. LTDN

0635 Received low press SI, verified safety equipment started

0700 investigating CV for leakage

0700 Stopped "B" RHR pump

0635 Restored LTDN - RCS press. Started Decreasing

0727 Stopped B & C RCP's and PZR press Started increasing

0729 Started Cooling down

0731 Stopped A & C RHR

Alt. Struck LWLSA 84 & 85 on B & C SG

Unit S/D, Alx's on S/U X-former Source Range

@ 2000 CPS, Cool Down in progress. All 230 KV

OCB's are C/ose except 52/1 & 52/4

[illegible signature]
[illegible signature]

08:16 THURSDAY 1-29-81

Relieved previous shifts. RCS status lights indicate all vital valves in proper position for plant conditions except those valves with keys open [illegible] tech. specs. [illegible] 535-1536 shut due to [illegible]. [illegible] temp. [illegible] 40° [illegible] & Temp control bypassed ~~[illegible]~~ ~~[illegible]~~ [illegible] in effect. [illegible] feedwater pump OOS. Unit off line. SI in progress. [illegible] & press [illegible]. SI has been reset along with [illegible] high head injection running (not feeding). Investigating [illegible] RCL. "B" RHR pump running. "A" Ref running.

[illegible signature]

0130 Started [illegible] test (110.6 GPM)

0130 RCS boron [illegible] ppm

0738 Started A/B diesels

0741 Started "B" RHR pump

0745 [illegible] on [illegible] pumps

0745 Filled B ref. standpipe to clear [illegible]

0815 Filled B ref. standpipe

0822 Started [illegible] pump

0825 Started SI pumps

0830 Holding RCS press @ 2200

0839 Started [illegible] for [illegible] removal

0846 Started RCS [illegible]

0847 All S/G blowdown isolated

0852 Stopped NUN-4 & NUN-1

[illegible] RCS boron 1026 ppm

0910 Started [illegible] on "B" [illegible]

0916 PT 7.3 & 20.1 completed

0915 Started [illegible] RCS

0922 Filled "B" ref standpipe

0933 SI [illegible] 156 / 155 (same as last shift)

0957 [illegible] [illegible] [illegible]

1002 "A" [illegible] valve [illegible] N2 on VCT

1007 "B" S/G [illegible] valve [illegible]

1005 Blocked [illegible] SI

1012 Started RCS C/D @ 510°

(cont)

0800 (CONT'D) THURSDAY 1-25-81

1022 [illegible] BYPASS ON "B" MSIV

1025 [illegible] ON "B" [illegible] TO [illegible] FLOW [illegible]

1030 RCS DRAIN 1074 [illegible]

1035 [illegible] BATCH TO "B" [illegible] (21,2[illegible] [illegible])

1038 CLOSED SAMPLE LINES ON "B" S/G & CHECKED ABOVE [illegible] BELOW SEAT DRAINS CLOSED ON "B" S/G

1041 UNIT DISCONNECTS OPEN

1107 TURBINE ON [illegible]

1145 CLOSED [illegible] 369 D TO ISOLATE LEAK IN S.G

1143 FILLED "B" [illegible] STANDPIPE

[illegible] [illegible] [illegible] [illegible] 7.0 E-4

1213 BLOCKED LOW PRESSURE SI

1230 DRAINED BATCH TO B [illegible] BATCH 22,950

1445 B CHARGING PUMP [illegible] AS PER [illegible] [illegible]

1500 PUMPED BATCH FROM A [illegible] EVAP [illegible] 21,3[illegible] [illegible] [illegible] 45

1500 HOLDING RCS TEMP @ 480°F

UNIT SHUTDOWN, AUX'S ON STARTUP TRANSFORMER, ALL 230 KV OCB'S ARE CLOSED EXCEPT FOR 52/8 & 52/9, RCS AT 480°F AND 1800 PSIG, TURBINE ON TURNING GEAR, [illegible] 31 @ [illegible] CPS, [illegible] @ 3[illegible] CPS.

RELIEVED BY [illegible]

THURSDAY 1-26-81

1600-2400 - [illegible] [illegible] VITAL VALVES [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] AND TEMP [illegible]

109

No 7631

12/18/81

DATE TIME

[illegible]

[illegible]

2) [illegible]

Steam drum [illegible] pump, [illegible] gauge,

HVE 151:54, [illegible] display [illegible] oil

[illegible]

[illegible]

[illegible]

[illegible]

5) Completed [illegible]

6) Completed [illegible]

7) [illegible] oil [illegible] pump [illegible]

8) [illegible] oil

[illegible]

[illegible] found [illegible] in sound for condition

11) @ 3635 [illegible] still [illegible]

[illegible]

[illegible]

[illegible] still [illegible]

12) [illegible] second [illegible] still [illegible]

[illegible]

[illegible] procedure

[illegible] in progress, [illegible]

[illegible]

[illegible]

Thursday June 29 1988

[illegible] Previous Shift logs & [illegible]
[illegible] [illegible] [illegible] [illegible] [illegible]
[illegible] S/U AFW Pump A charging [illegible] [illegible]
[illegible] A CCW Discharge Valve Motor and [illegible] oil Pump
[illegible] Jumper Tags [illegible] [illegible]
installed on A Circ Water Pump; [illegible]
[illegible] in Progress. [illegible] in Progress [illegible]
SI in Progress with RCS Pil's Stopped
[illegible] Press increasing slowly. Fee Water Valve [illegible]
[illegible] Close on SI Signal and was closed Manually
[illegible] 84 & 85 were [illegible] on [illegible]
[illegible] at 0624 hrs and SI Equipment [illegible]
[illegible] Secondary leakout [illegible] at [illegible]
[illegible] 110.64 GPM
[illegible] P1 9.0B
[illegible] 1020 hrs - B S/G Sample shows [illegible] 10^{-4} [illegible]
[illegible] and [illegible] 5 gpm leak Isolated [illegible] S/G
[illegible] Secondary side
Sample from the Bottom of Tank [illegible]
[illegible] 21776 [illegible] [illegible] [illegible] SI
[illegible] SI actuation
[illegible] Sample of B S/G showing [illegible]
[illegible] and Pri-Sec leakage [illegible]
[illegible] Entry @ 1120 hrs and [illegible]
[illegible] Order Valve [illegible]
[illegible] with CVC-[illegible] and [illegible]
[illegible] Drain Valve @ 1230 hrs
[illegible] Final Sample Result of 0950 hrs [illegible]
[illegible] 10^{-4} [illegible]
[illegible] [illegible] [illegible] [illegible]
[illegible] [illegible] [illegible]
[illegible] [illegible] [illegible]
[illegible] [illegible] [illegible]
[illegible] [illegible] [illegible]
[illegible] [illegible] [illegible]
[illegible] [illegible] [illegible]
[illegible]
N-31 @ 8.0 CPS [illegible]
[illegible] [illegible] [illegible]

H. B. ROBINSON
UNIT 2

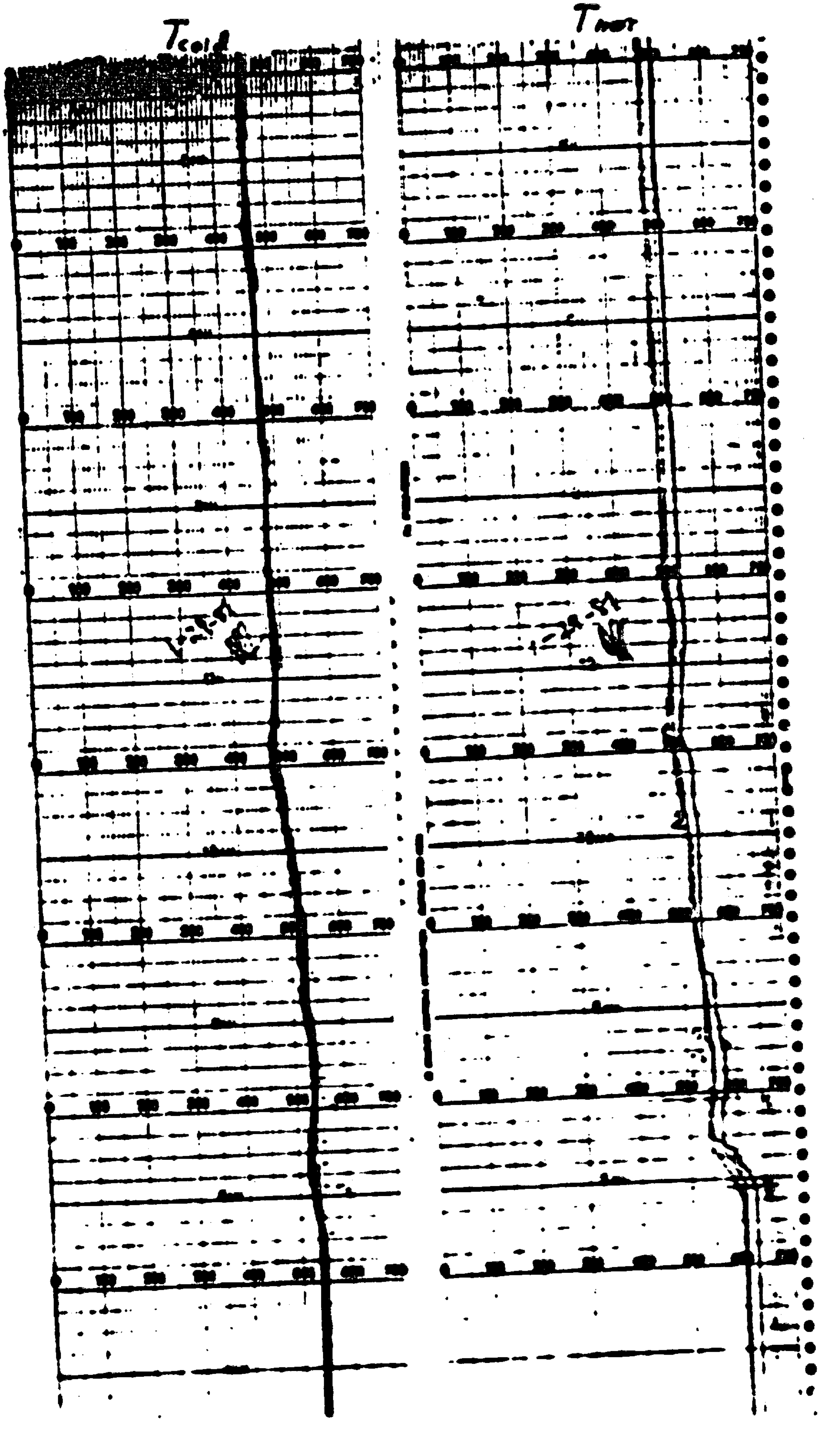
No 7533

UNIT | [illegible] | TIME

1600-2400

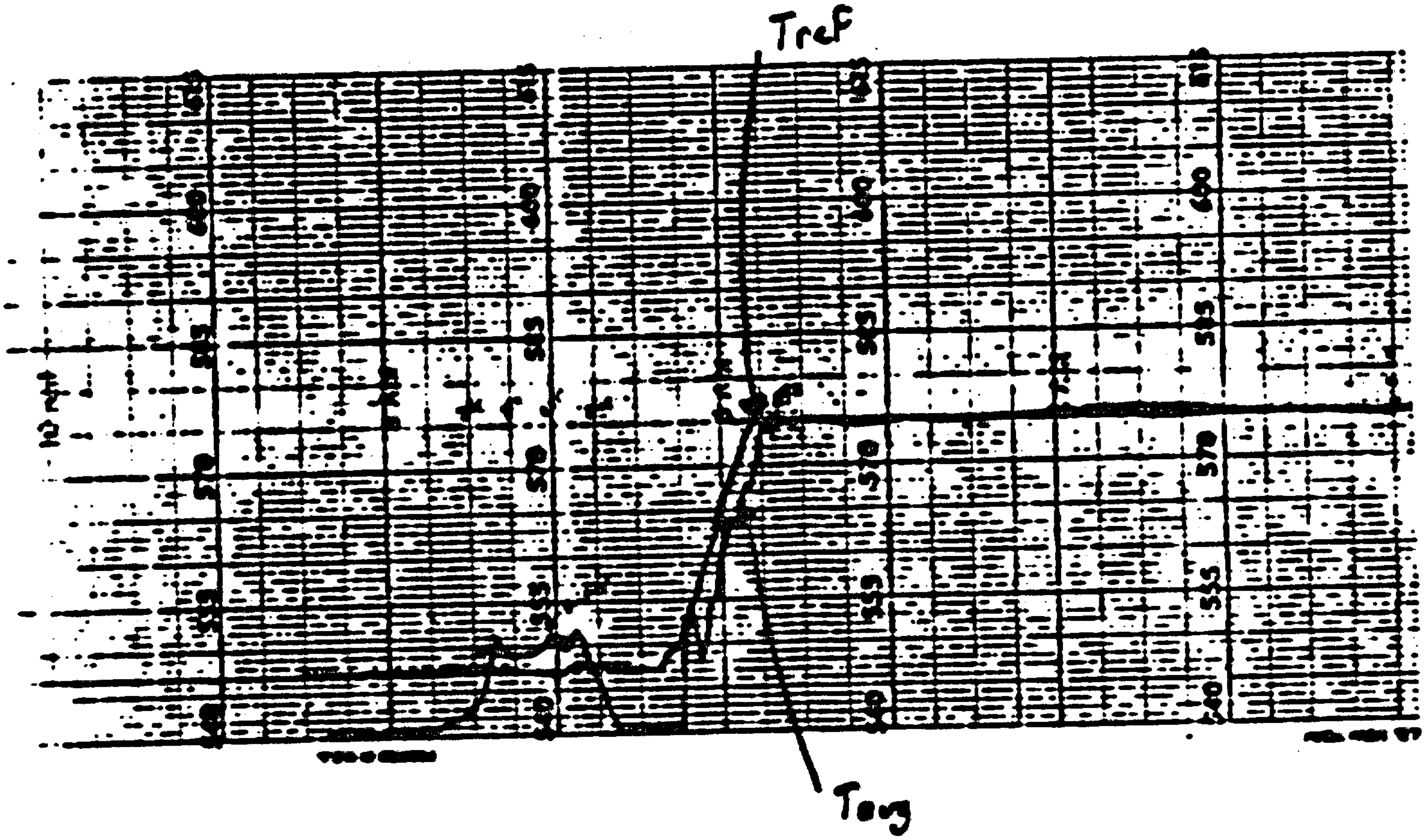
1) Reviewed previous shifts logs [illegible]
2) Condition as found: [illegible] [illegible] [illegible] [illegible] [illegible]
[illegible] 6-11, SD and [illegible] water pump, A [illegible] charging
[illegible], HVE-15 & 15A. 'A' [illegible] [illegible]
are inoperable. [illegible] [illegible] 661, 662, 663,
664 [illegible] [illegible] at 'A' circulating water pump.
[illegible] water valve 1020A (FP-248) failed to close
on ST & is under maintenance; A RCP running,
RCS at 491°F & 1800 psi; LWR-86 on 'B' monitor
tank in progress.

3) [illegible] [illegible] for valve 1020B (FP-248) while
maintenance is to be performed on valve
1020A (FP-248).
4) Completed PT-8.1 RCS leakrate .2434 gpm
5) 1830 hours [illegible] up 'A' charging pump for
operation. PT-15.2 not performed due to [illegible]
[illegible] [illegible] & RCS pressure & [illegible]
[illegible] [illegible] & [illegible] [illegible]
6) 1913 hours started 'B' RCP as per special
procedure and OP-298.
7) 1932 hours started 'C' RCP as per special
procedure and OP-298.
8) Received load of liquid nitrogen
9) Isolated generator of hydrogen.
10) Transferred 2 batches of boric acid to
'B' boric acid storage tank. 'B' BAST 21233 ppm
11) [illegible] charging line and [illegible] letdown line
in service; [illegible] [illegible] [illegible] [illegible]
[illegible] from service.
12) Completed LWR-86 on 'B' monitor tank.
13) [illegible] - [illegible] [illegible] [illegible] valves
open and closed, [illegible] them [illegible]
operation and left them in the closed
condition. [illegible] was completed prior
to starting 'B' & 'C' RCP's.
14) Completed PT-212
Condition: Unit [illegible] for maintenance
RCS at 498°F & 1700 psi; N1-31 [illegible] N1-32 [illegible]

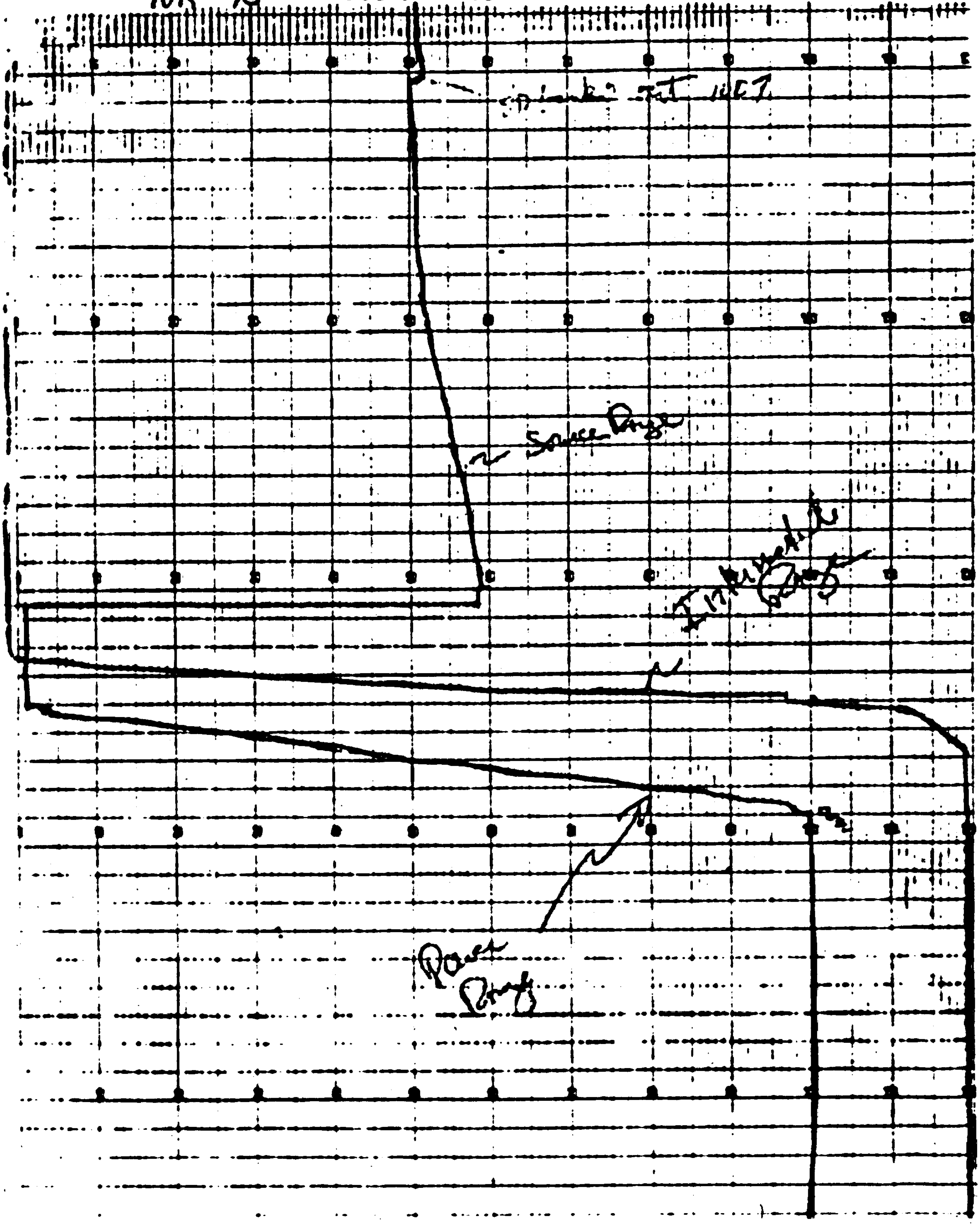


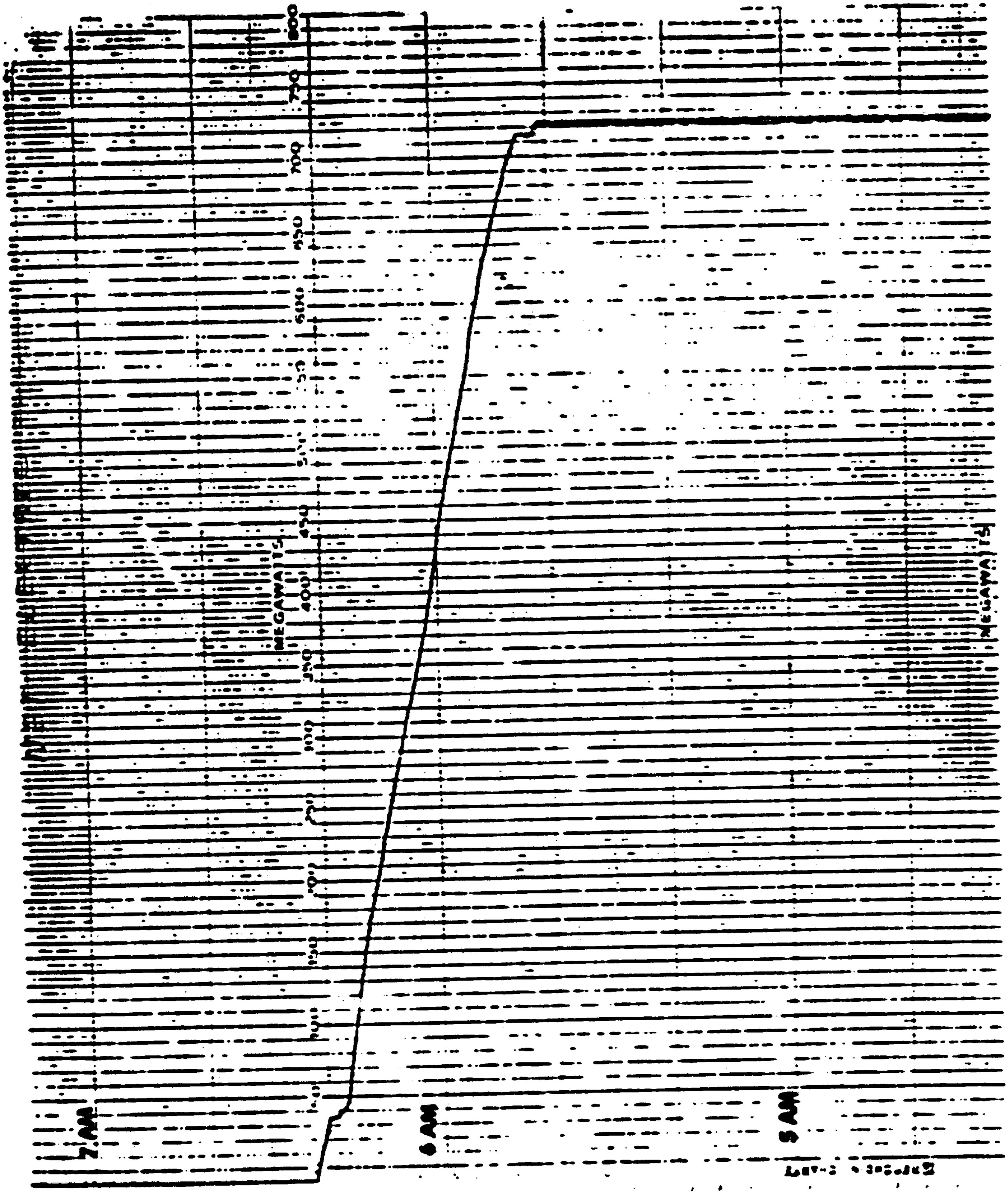
Tcold
Thot

TR-408
Tavg/Tref



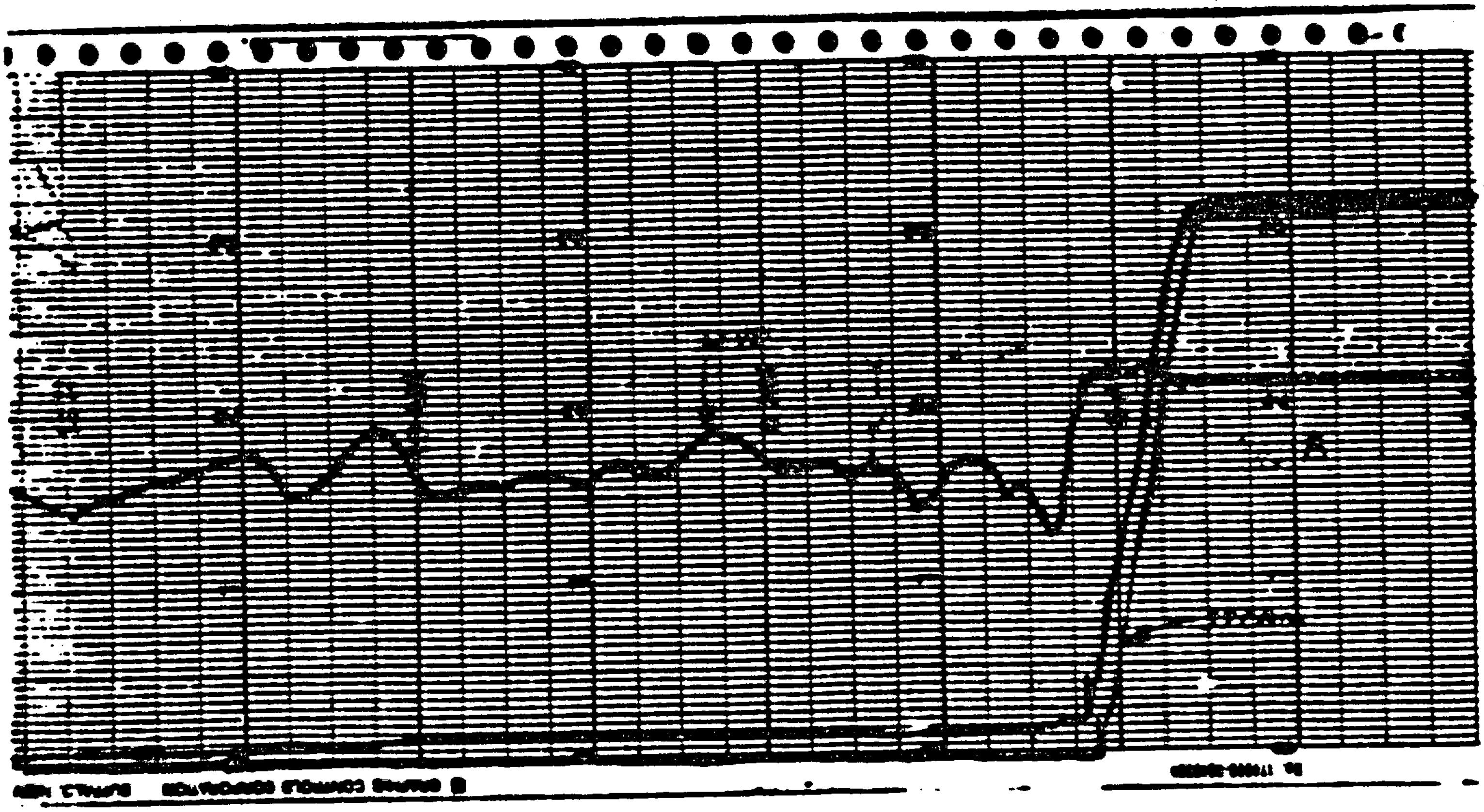
NR 45 Nuclear Power



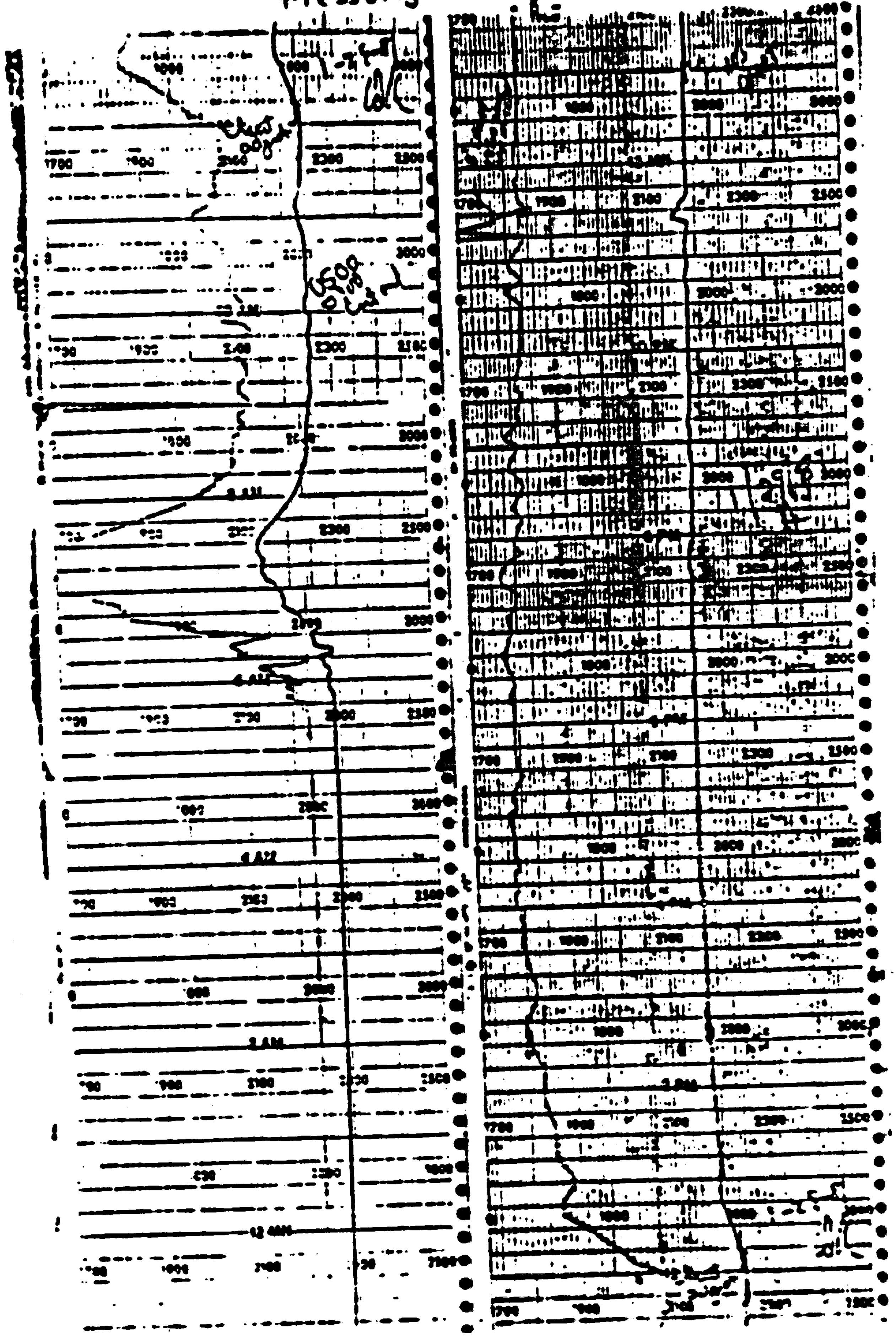

MEGAWATTS
800
750
700
650
600
450
400
7 AM
6 AM
5 AM
MEGAWATTS

LEVEL
FEED
STEAM

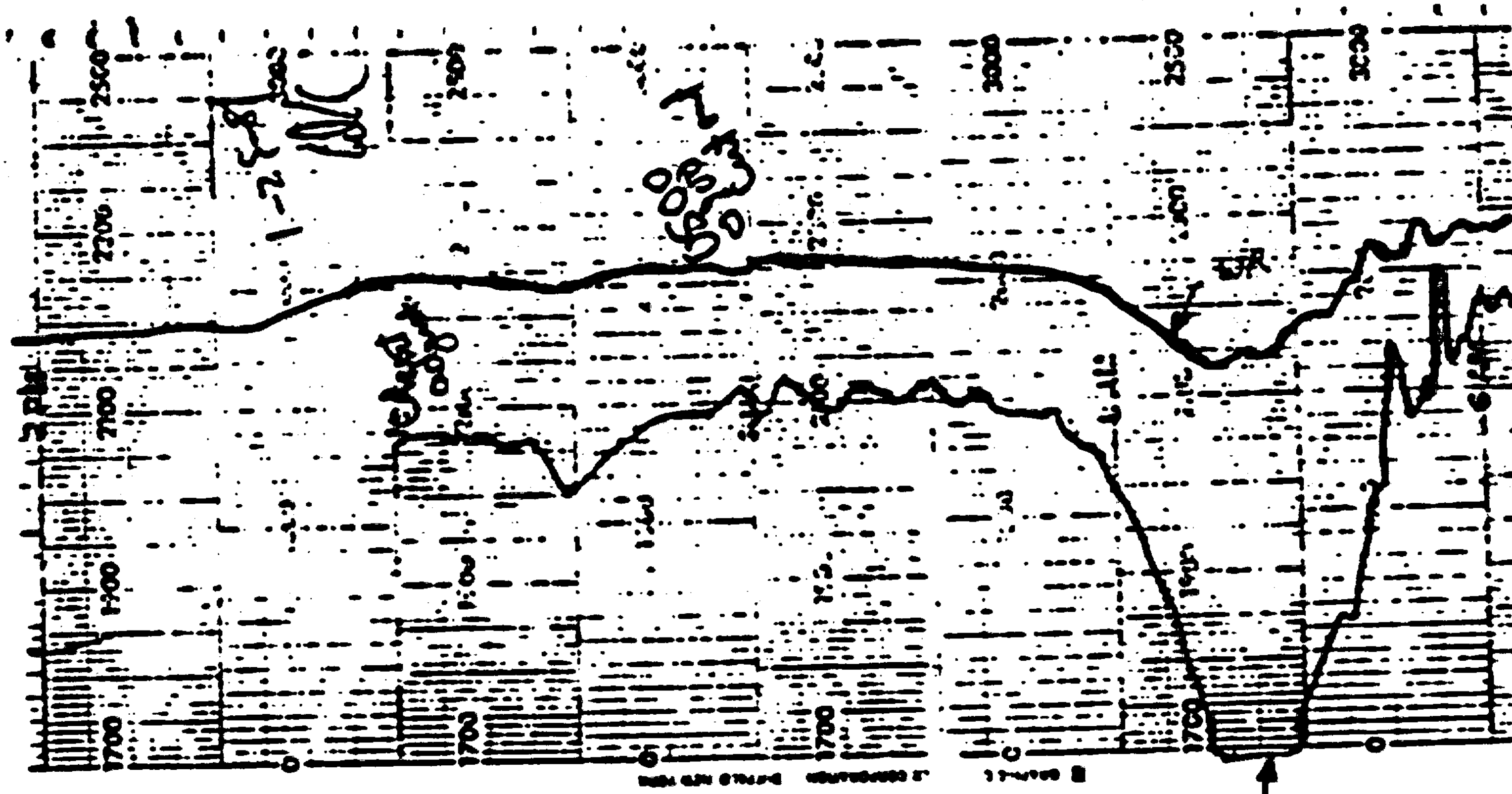
STEAM GENERATOR A LEVEL
FEEDWATER FLOW/STEAM FLOW



Pressurizer Pressure (NR + WR)

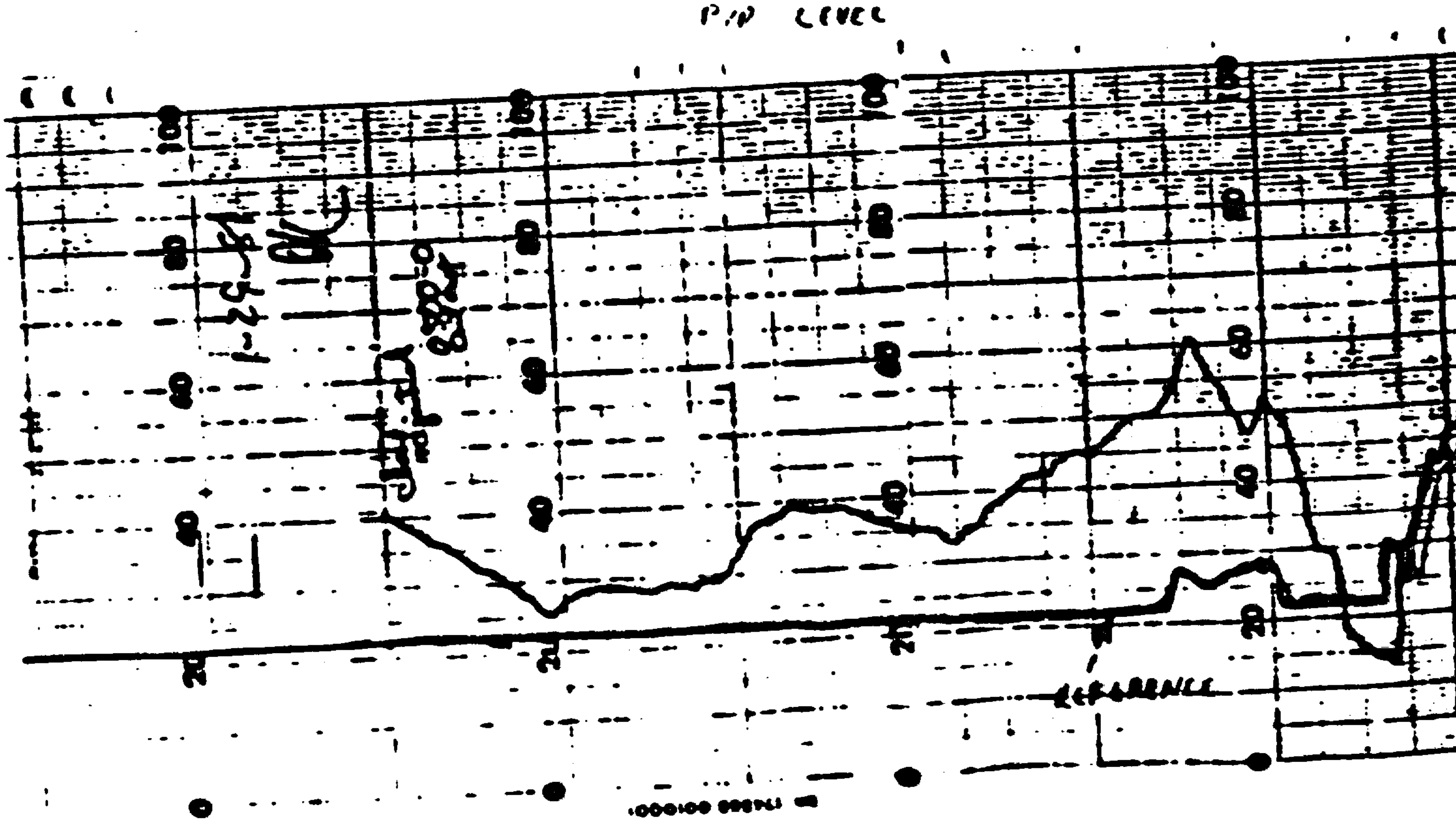


PRESSURIZER PRESSURE



PZR NR

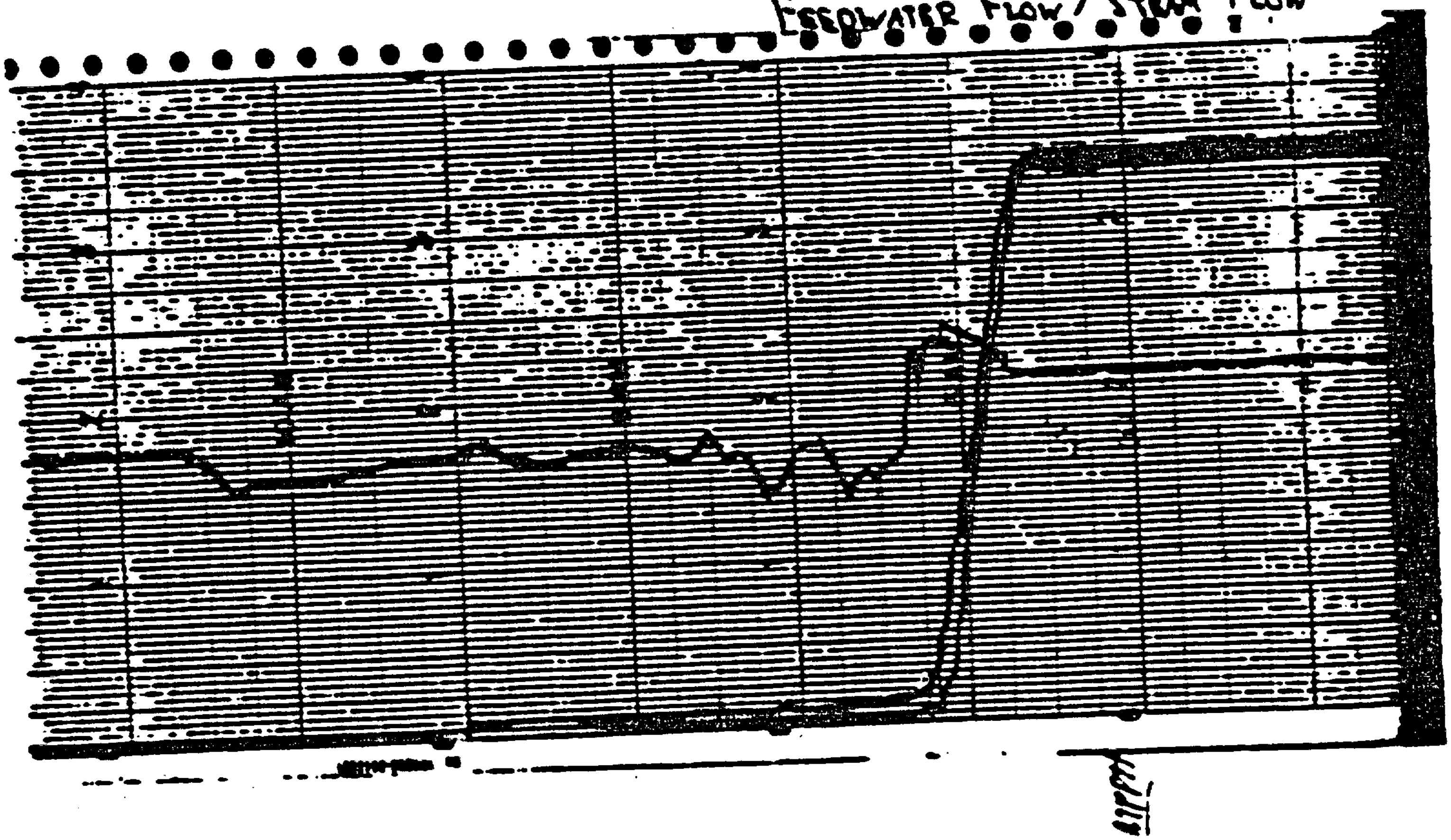
P/D LEVEL



REFERENCE

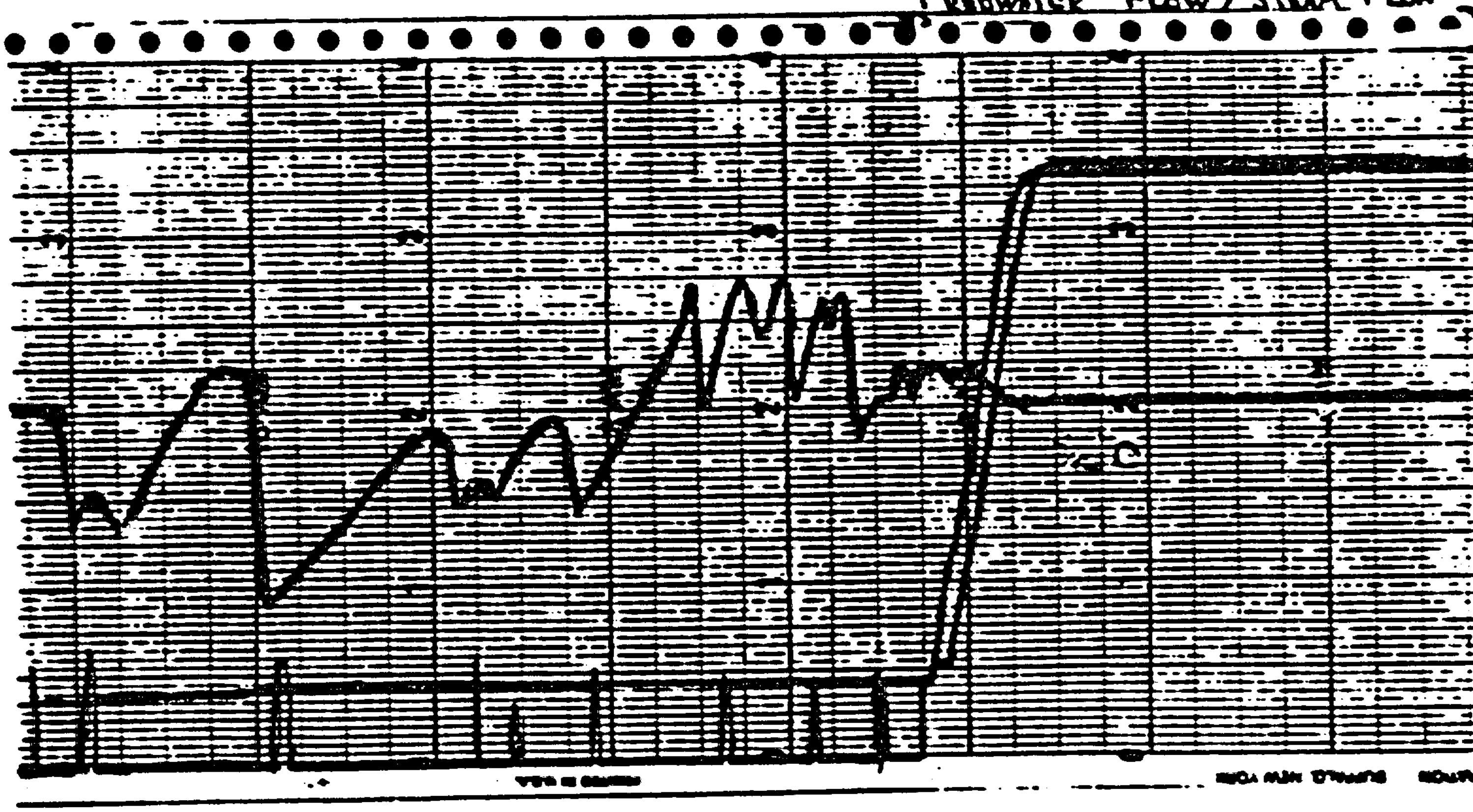
L[illegible]
F[illegible]
STEAM

STEAM GENERATOR B LEVEL
FEEDWATER FLOW/STEAM FLOW

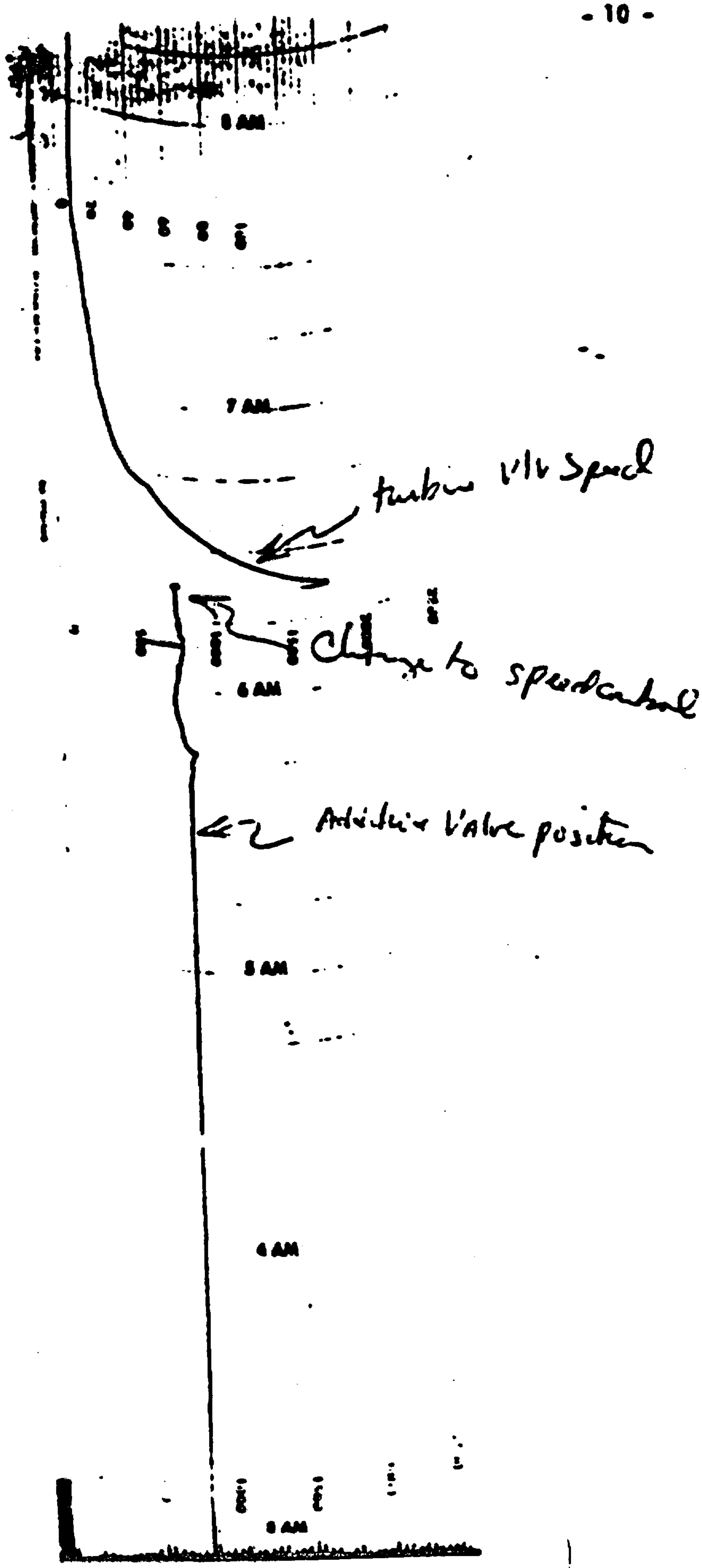


Steam

Steam Generator C Level
Feedwater Flow/Steam Flow



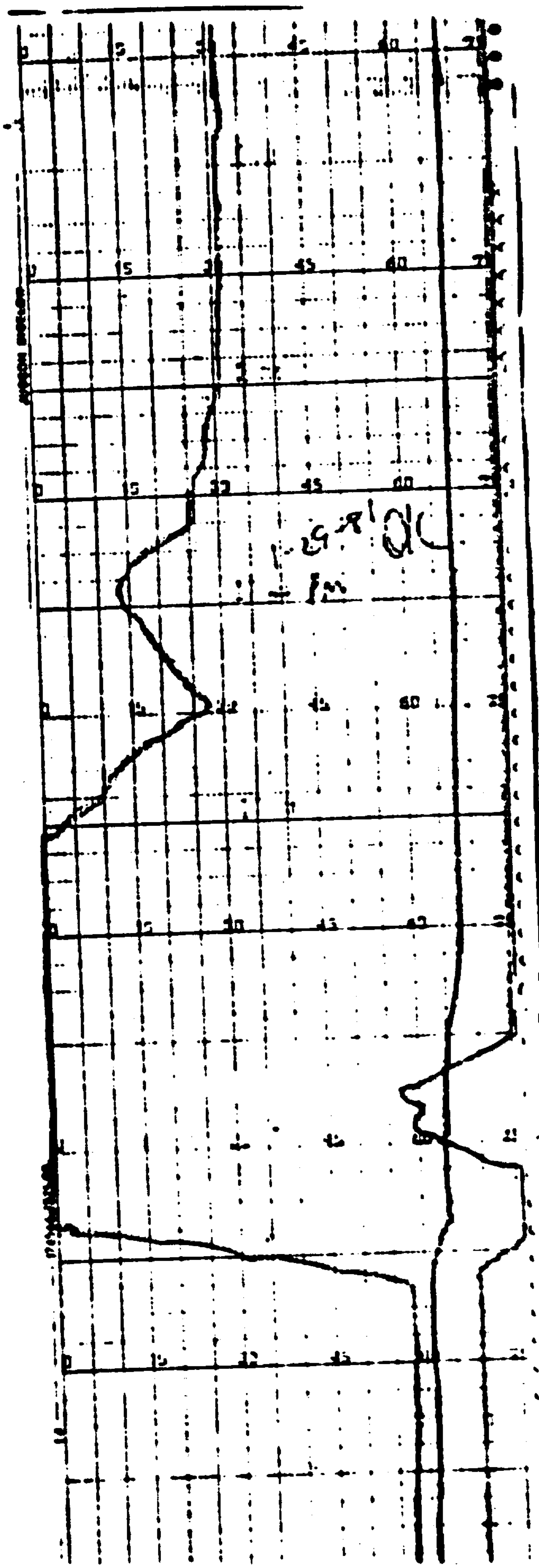
Turbine Governor Valve Position

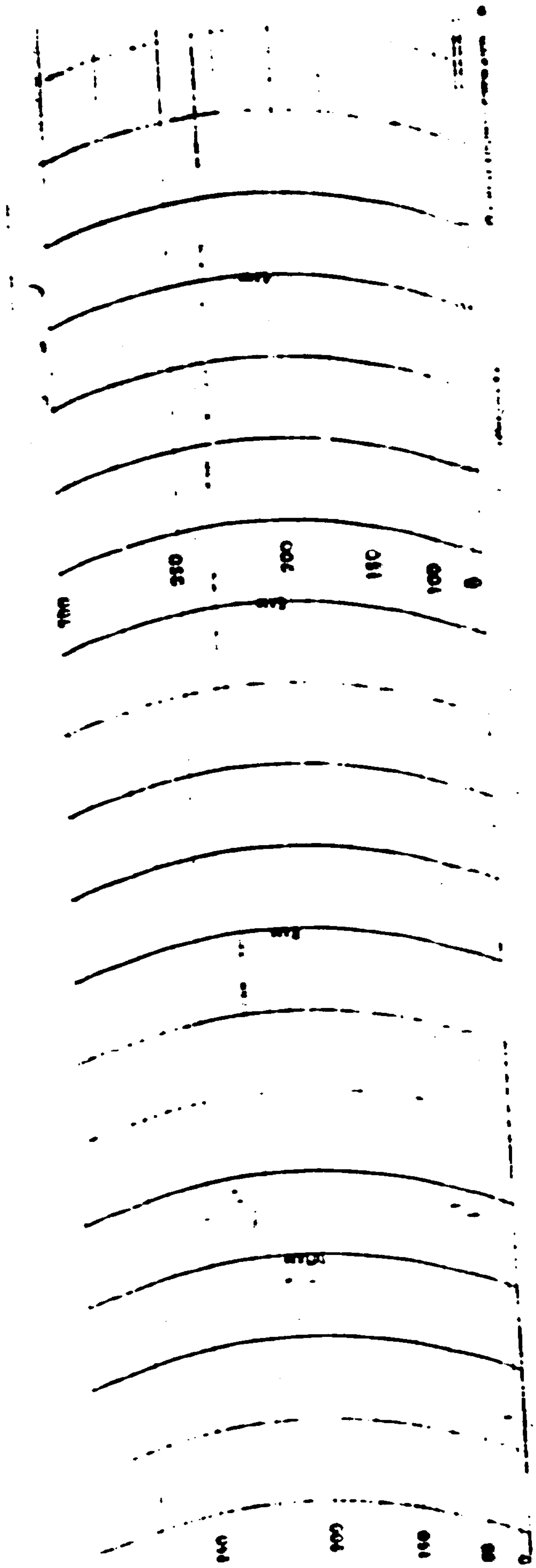


Loca A LT 21/

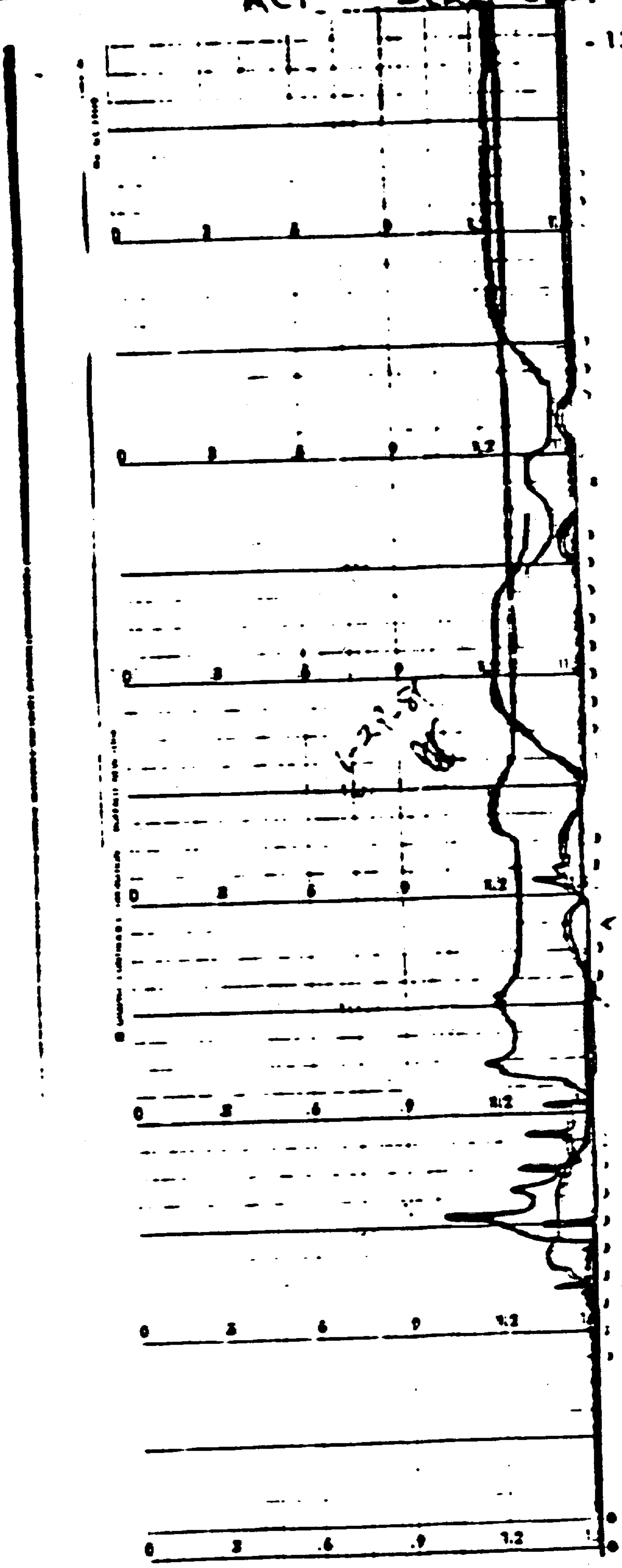
OVER T -

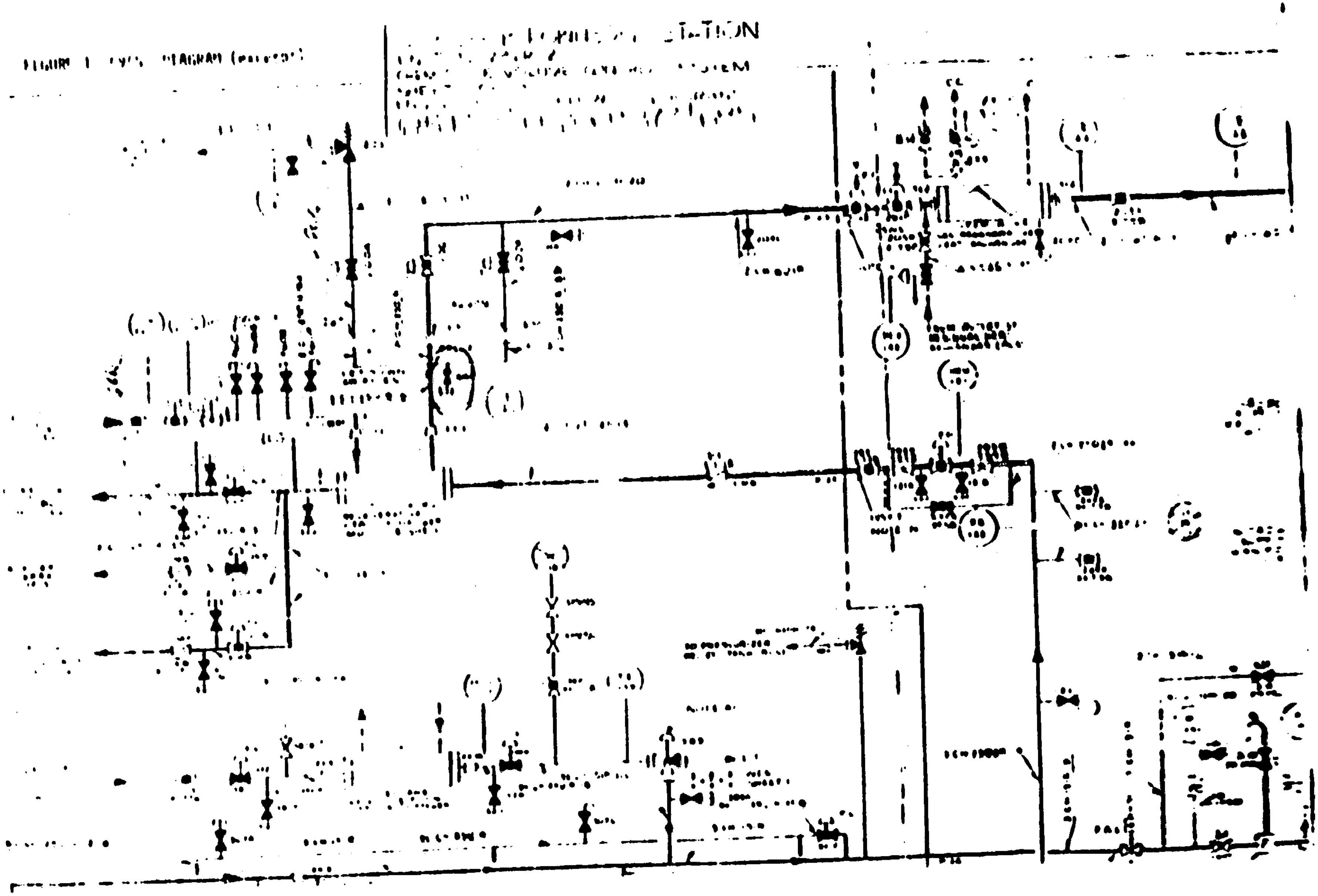
CNT in





RCP Seal Leak (NR)





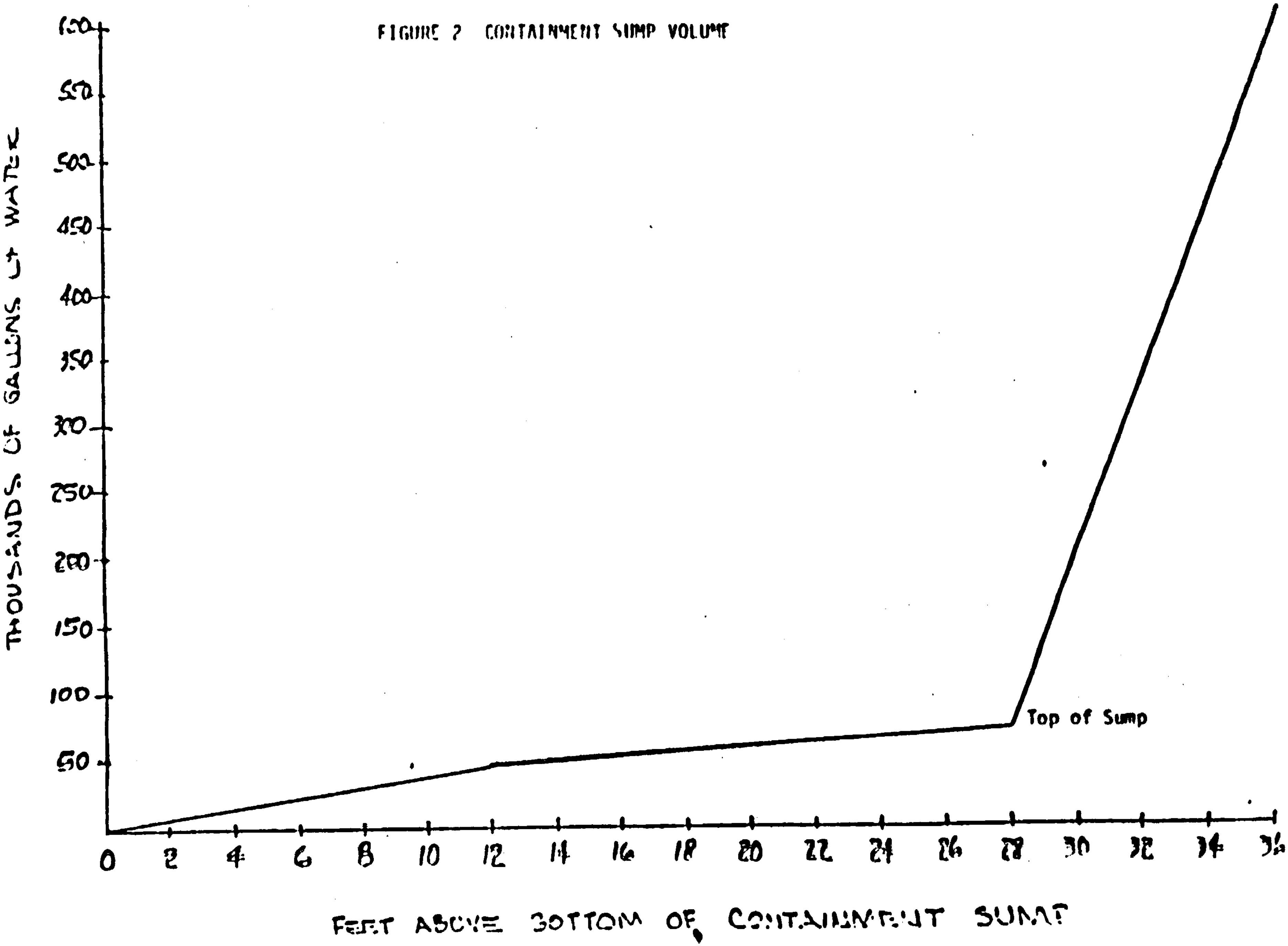


FIGURE 2 CONTAINMENT SUMP VOLUME

MODIFICATION NO. 5-15
REVISION 3