PUBLIC SERVICE ELECTRIC AND GAS COMPANY

SALEM NUCLEAR GENERATING STATION

UNIT NO. 2

STARTUP REPORT

BY

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ACKNOWLEDGEMENT

The success of the startup program depended upon many people. The Reactor Engineer and his staff express their gratitude to the entire Salem Generating Station Staff. Special tanks to Fred Twogood, Ed Watjen, Al Hayes, Fred Baskerville and Lou Grubmeyer of Westinghouse for their contributions. Thanks to George Druffner of the Energy Laboratory and to John Dal Pan for his assistance in compiling this report.

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SECTION 1.0 INTRODUCTION

This report is in addition to the Startup Report submitted on May 1, 1981 which describe the testing from Core Load to the completion of Zero Power Physics Testing including Natural Circulation testing. Included in this report is the Power Range Test Program from 10% to 100% power testing. The period covered is from August 29, 1980 through October 13, 1981 with additional comments up to January, 1982.

Salem Unit No. 2 is a four loop pressurized water reactor of 3411 mWt rated capacity. The Nuclear Steam Supply System (NSSS) was supplied by Westinghouse Electric Corporation, the Architect Engineer was Public Service Electric and Gas Company and the Constructor was United Engineers and Constructors, Inc.

The facility's operating license was issued April 18, 1980. Preparations for core load were completed by May 22, 1980 and core loading commenced on May 23, 1980. Core loading was completed by May 27, 1980. Initial criticality was achieved on August 2, 1980 and the zero power physics test program was completed by August 12, 1980. Natural circulation tests were begun on August 23, 1980 and were partially completed August 29, 1980 before the Unit was shutdown to repair a leaking Control Rod Drive Mechanism vent. The natural circulation testing had been completed from a testing standpoint but were required to be reperformed for operator training of nine licensed operators as committed to in the license. The Unit entered Mode 5 (<200°F) to repair the leaky CRDM housing vent and remained in Mode 5. On April 22, 1981 a heat-up was commenced to enter Mode 2 (547^{o}F, <5% RTP) to complete Nat Circulation Testing in anticipation of receiving the Opera License allowing power asension testing.

During the period of time from August 29, 1980 through Apr 1981 the unit remained in Mode 5. Fire Protection System fications were made and Post -TMI design changes incorpora as Engineering Design Package and materials arrived on-sit major delaying factor was the completion and trial run of Emergency Plans of PSE&G and the states of New Jersey and The coordinated emergency drill was successfully conducte 8, 1981.

In late April, upon review of the work performed on the f system to meet regulatory requirements, it was determined additional modifications were required. The review, by t staff, consisted of examining the capability of the unit down from a remote location should a fire occur in the Co or elsewhere that could affect the safe operation of the the Control Room. The inspection team concluded that the up control system was adequate to safely shutdown the uni emergency. The team said, however, that some modificatio fire protection system must be made before the Facility F License could be issued.

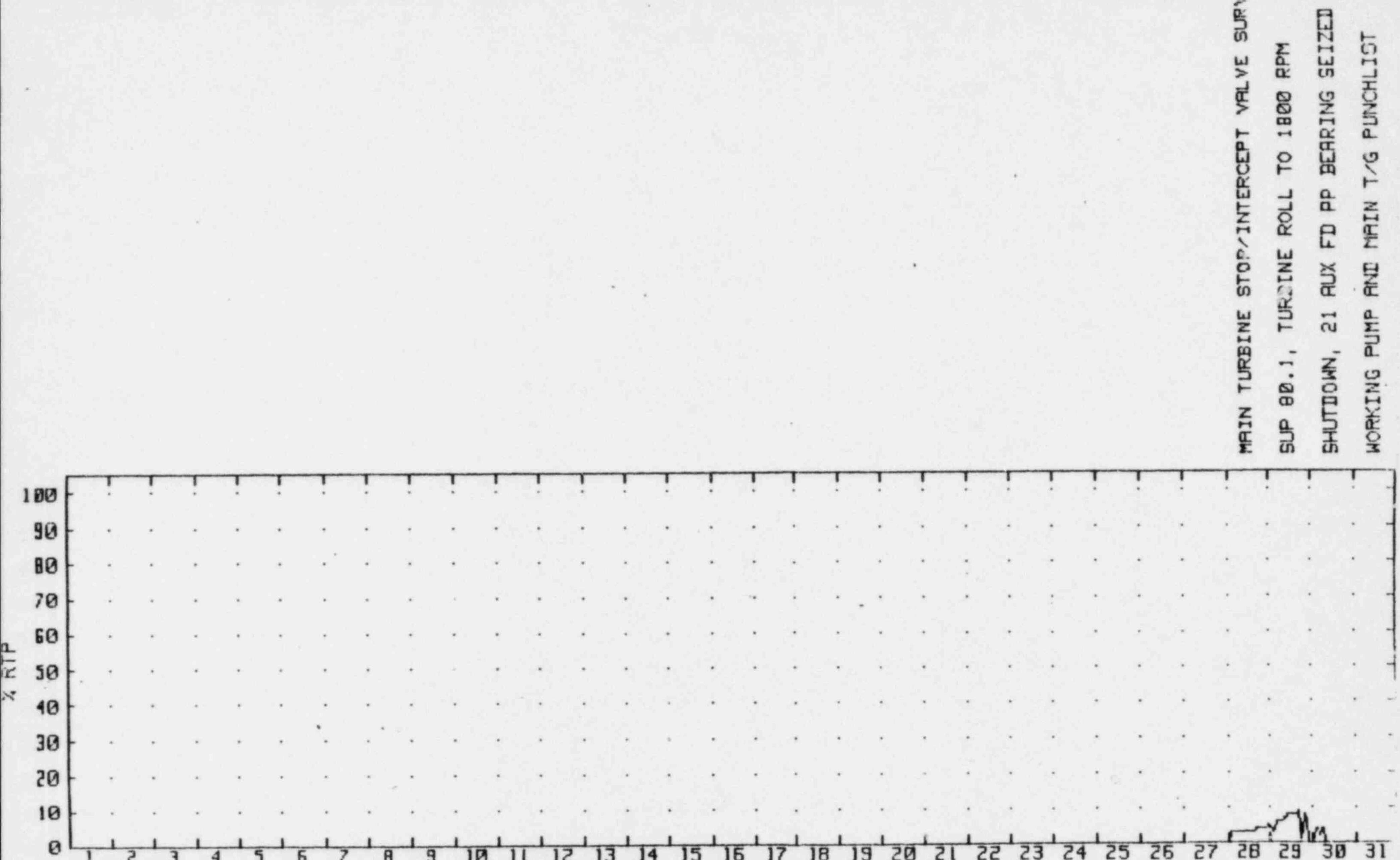
The modifications involved, in part, improved protection cables needed for the operation of the plant from a remot location. In the event of a fire that forces the evacuat of the Control Room, the plant must be able to be operate using alternate locations and controls. Other modifications included upgraded procedures for dealing with a fire emergency emergency and improvement of various fire barriers and automatic sprinklers.

Upon completion of those modifications the full power operating license was granted on May 19, 1981.

Figures 1.1 through 1.8 graphically display the power history of Unit 2 from May 1981 through December 1981. Along with the graph is an explanation of the testing at the particular power level and the day the test was performed. Also listed are the reasons for various trips and delays effecting the startup schedule. Figures 1.10 through Figure 1.14 show the planned vs. the actual number of days of testing at each power plateau. The total planned days were 166 whereas the actual days were 186. Several of the larger delays were:

1) the replacing of an intermediate range channel (3 1/2 days)
2) steam flow sensing line modifications (8 days)
3) main turbine generator governor adjustment (4 days)
4) condenser tube leakage requiring unit shutdown (5 days)
5) outage to modify steam generator separation equipment (15 days)
6) unplanned reactor trips (10 days)

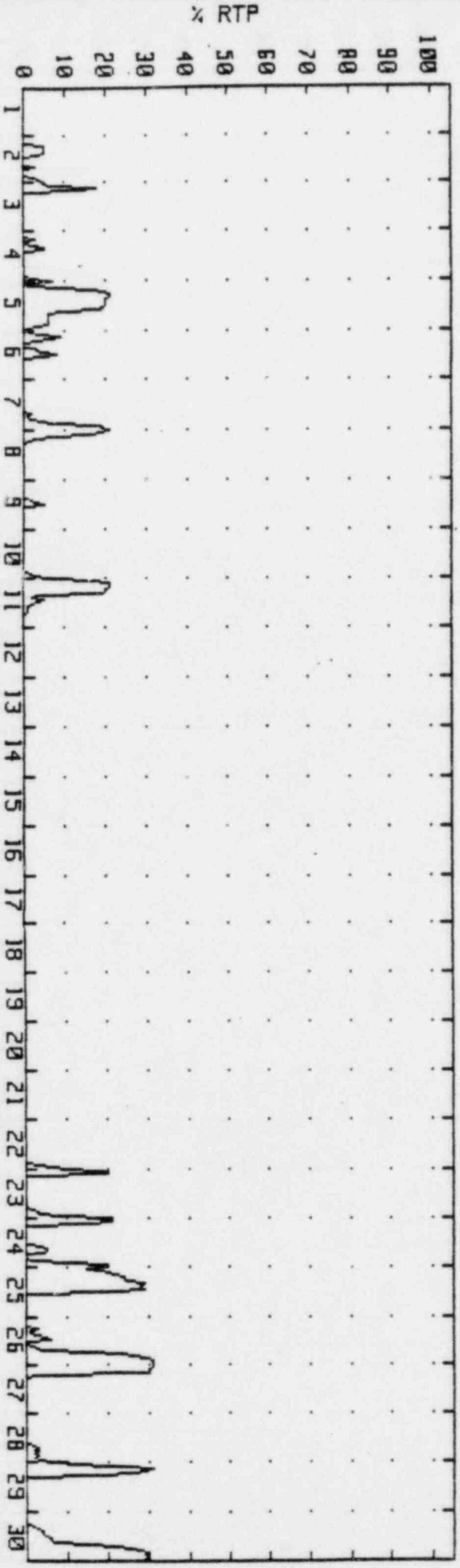
Following the steam generator outage in September 1981, to modify the moisture separation equipment, the moisture carryover test (Section 2.8) was reperformed and verified the steam moisture content to be acceptable. The following day Salem Unit 2 was declared commercial, October 13, 1981, completing the startup test program. Several main feedwater pump trips had occurred between October 1981 and December 1981. A test program was formulated to determine the cause of the believed "low suction pressure" trips (see Section 2.7 for details). In December 1981 the high steam flow indications, observed prior to the steam generator modifications, re-occurred. An additional moisture carryover test was conducted in January 1982 (see Sections 2.8 and 3.4 for details).



SALEM UNIT 2 CYCLE 1 HOURLY POWER FOR May 81

MONTHLY BURNUP WAS 324.5MWD AVG POWER WAS 2.4%RTP

Figure 1.1



WORKING 21 AUX FD PP BEARING
SUP 80.1, T/G DATA
SUP 80.1, SYNCHRONIZATION TO GRID
BALANCE MAIN T/G, RX SHUTDOWN
SUP 80.1, T/G 8 HR. RUN
SUP 81.3, T/G OVERSPEED TEST, UNSAT.
ADJUST GOVERNOR WEIGHTS, RE-TEST, UNSAT
ADJUST GOVERNOR WEIGHTS, RE-TEST, UNSAT
UNUSUAL EVENT, 2CV396 NIPPLE FAILURE
REPAIR 2CV396 VENT LINE
SUP 81.3, T/G MECH. OVERSPEED TEST, SAT.
MODIFY STEAM FLOW SENSING LINES
MODIFY STEAM FLOW SENSING LINES
REPLACE 23 AUX. FD. PP. CHECK VLVS.
CHECK SPEED CONTROL, 23 AUX. FD. PP.
RETURN TO 10% RTP
SUP 82.6, BLACKOUT
SUP ?2.5, SHUTDOWN OUTSIDE CONT. ROOM
RX TRIP, HI/LO S/G WATER LEVEL
RX TRIP, HI/LO S/G WATER LEVEL
RETURN TO 30% RTP

SALEM UNIT 2 CYCLE 1 HOURLY POWER FOR June 81
MONTHLY BURNUP WAS 3000MWD AVG POWER WAS 2.9%RTP

Figure 1.2

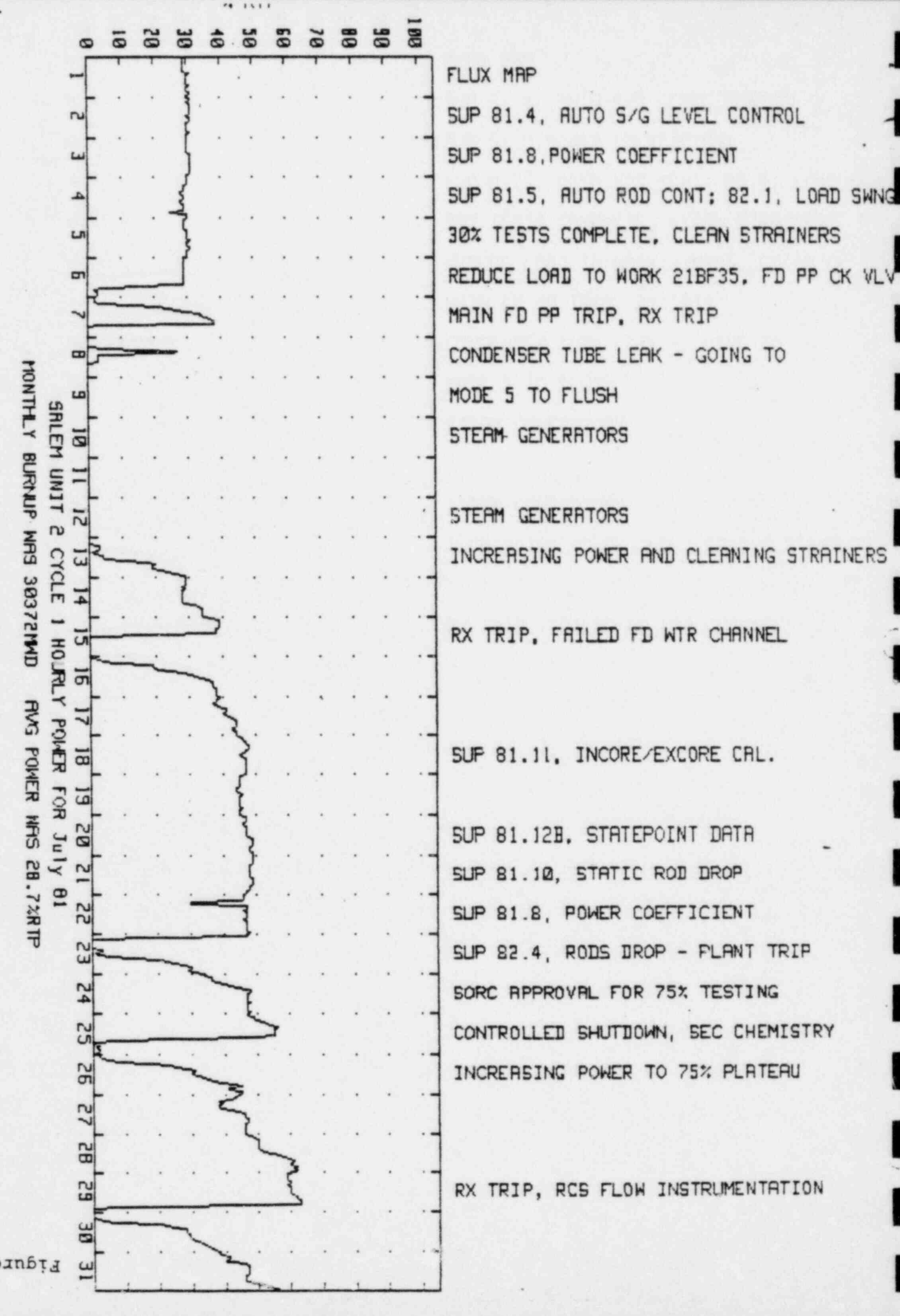
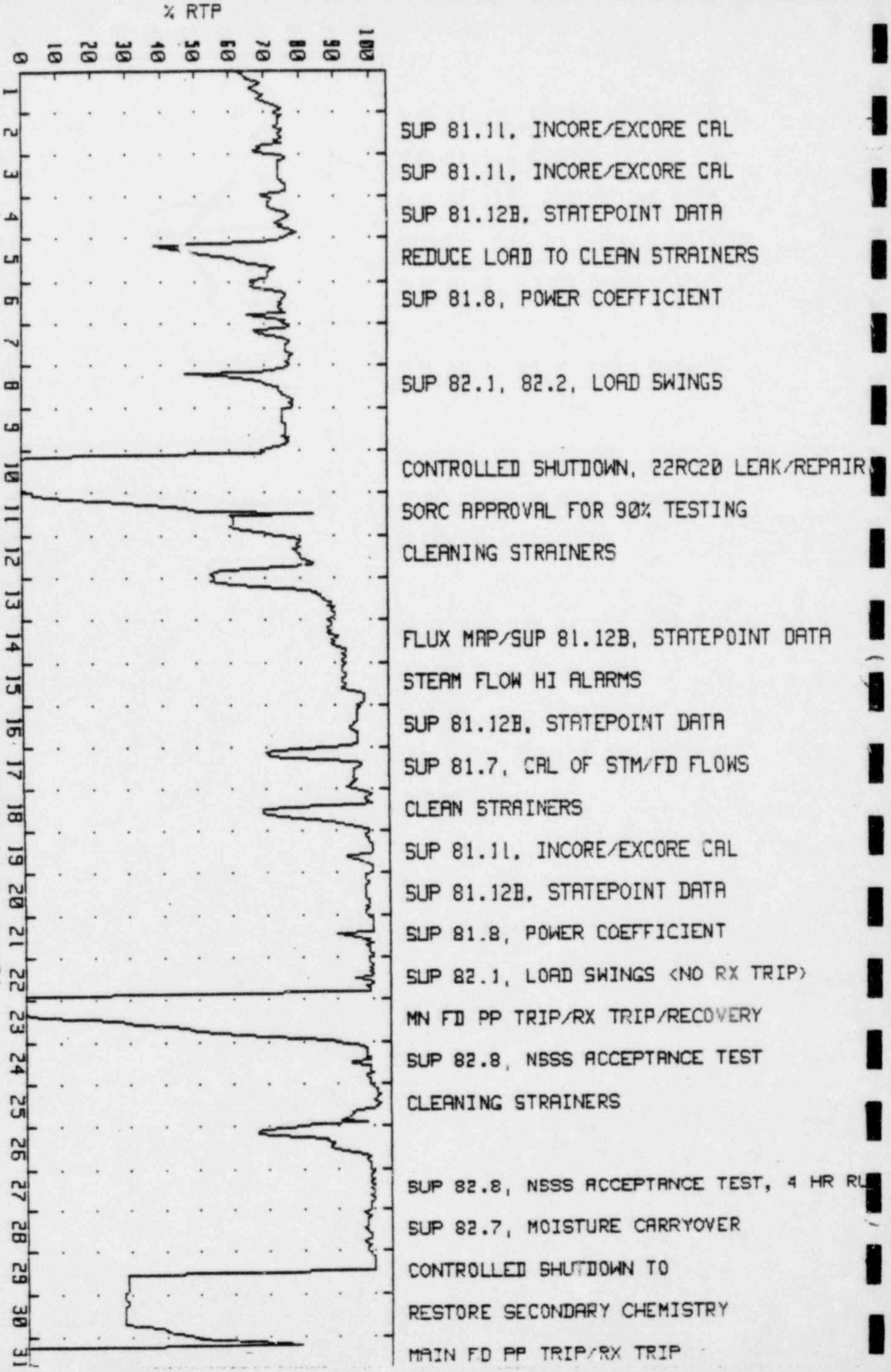

0
10
20
30
40
50
60
70
80
90
100
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
FLUX MAP
SUP 81.4, AUTO S/G LEVEL CONTROL
SUP 81.8, POWER COEFFICIENT
SUP 81.5, AUTO ROD CONT; 82.1, LOAD SWNG
30% TESTS COMPLETE, CLEAN STRAINERS
REDUCE LOAD TO WORK 21BF35, FD PP CK VLV
MAIN FD PP TRIP, RX TRIP
CONDENSER TUBE LEAK - GOING TO
MODE 5 TO FLUSH
STEAM GENERATORS
STEAM GENERATORS
INCREASING POWER AND CLEANING STRAINERS
RX TRIP, FAILED FD WTR CHANNEL
SUP 81.11, INCORE/EXCORE CAL.
SUP 81.12B, STATEPOINT DATA
SUP 81.10, STATIC ROD DROP
SUP 81.8, POWER COEFFICIENT
SUP 82.4, RODS DROP - PLANT TRIP
SORC APPROVAL FOR 75% TESTING
CONTROLLED SHUTDOWN, SEC CHEMISTRY
INCREASING POWER TO 75% PLATEAU
RX TRIP, RCS FLOW INSTRUMENTATION
SALEM UNIT 2 CYCLE 1 HOURLY POWER FOR July 81
MONTHLY BURNUP WAS 30372MWD AVG POWER WAS 28.7%RTP

Figure 1.3

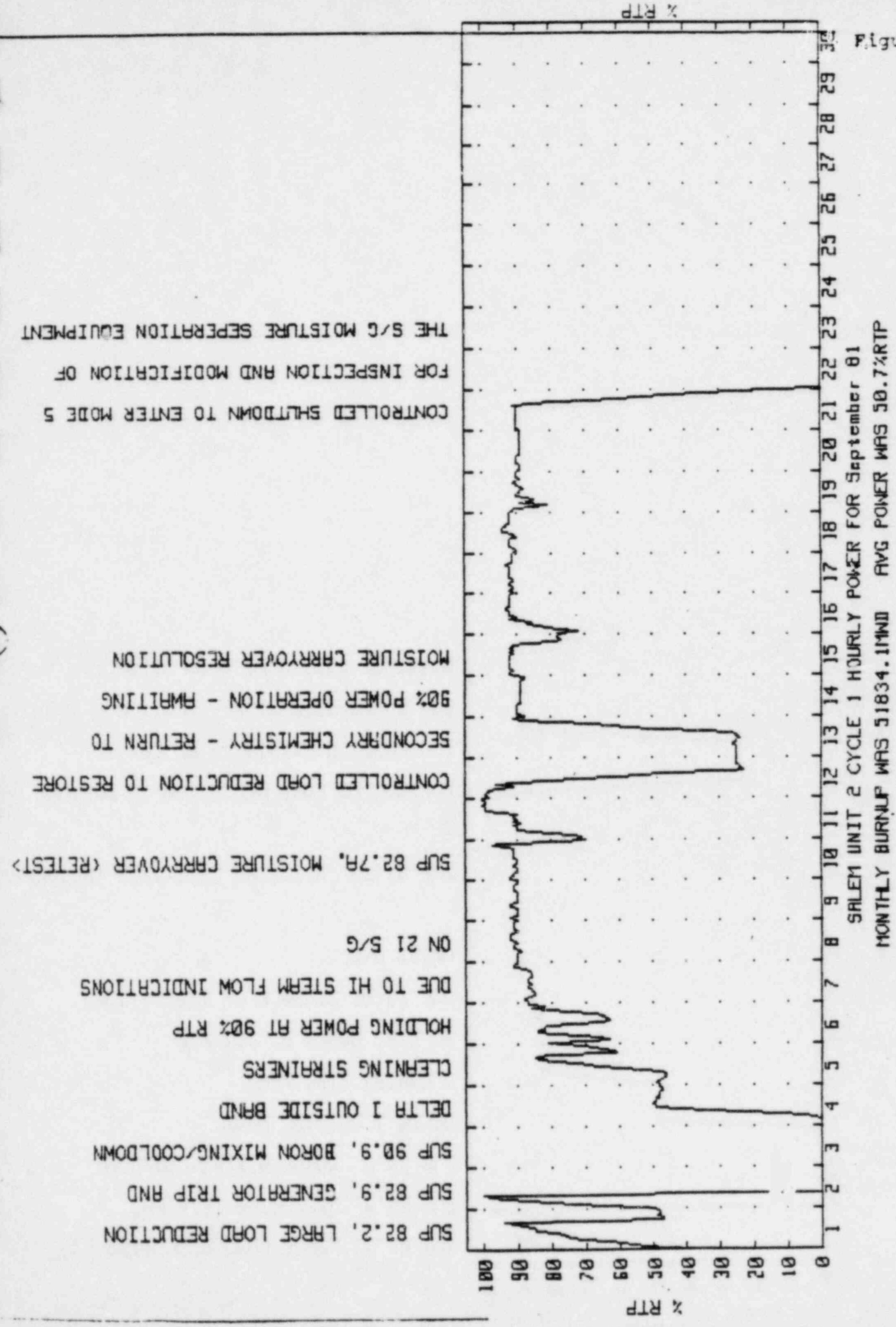


SALEM UNIT 2 CYCLE 1 HOURLY POWER FOR August 81

MONTHLY BURNUP WAS 79081.2MWD AVG POWER WAS 74.6%RTP

Figure 1.4

Figure 1.5


SUP 82.2, LARGE LOAD REDUCTION
SUP 82.9, GENERATOR TRIP AND
SUP 90.9, BORON MIXING/COOLDOWN
DELTA I OUTSIDE BAND
CLEANING STRAINERS
HOLDING POWER AT 90% RTP
DUE TO HI STEAM FLOW INDICATIONS
ON 21 S/G
SUP 82.7A, MOISTURE CARRYOVER <RETEST>
CONTROLLED LOAD REDUCTION TO RESTORE
SECONDARY CHEMISTRY - RETURN TO
90% POWER OPERATION - AWAITING
MOISTURE CARRYOVER RESOLUTION
CONTROLLED SHUTDOWN TO ENTER MODE 5
FOR INSPECTION AND MODIFICATION OF
THE S/G MOISTURE SEPERATION EQUIPMENT
% RTP
0
10
20
30
40
50
60
70
80
90
100
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
SALEM UNIT 2 CYCLE 1 HOURLY POWER FOR September 81
MONTHLY BURNUP WAS 51834.1MWD AVG POWER WAS 50.7%RTP

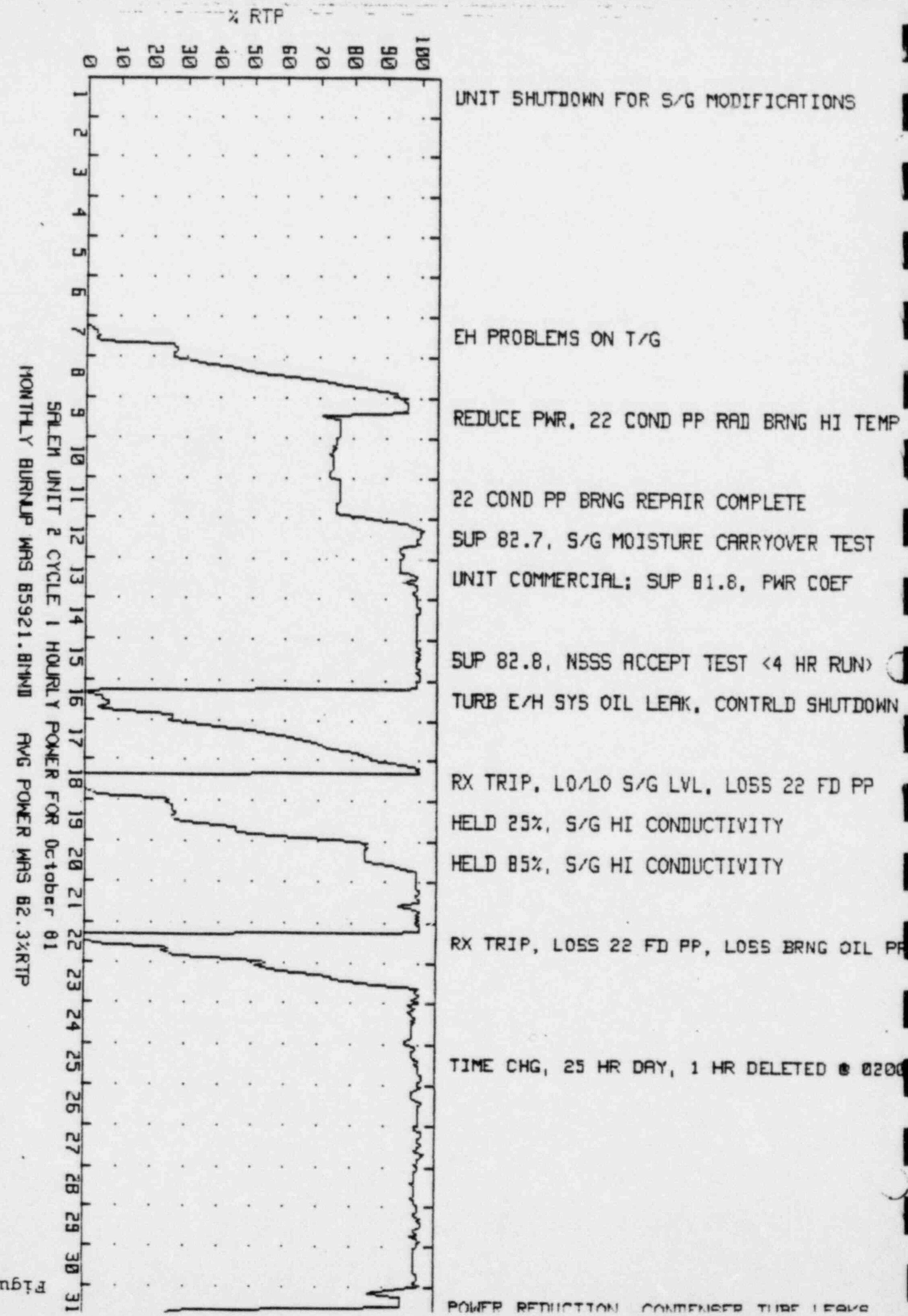
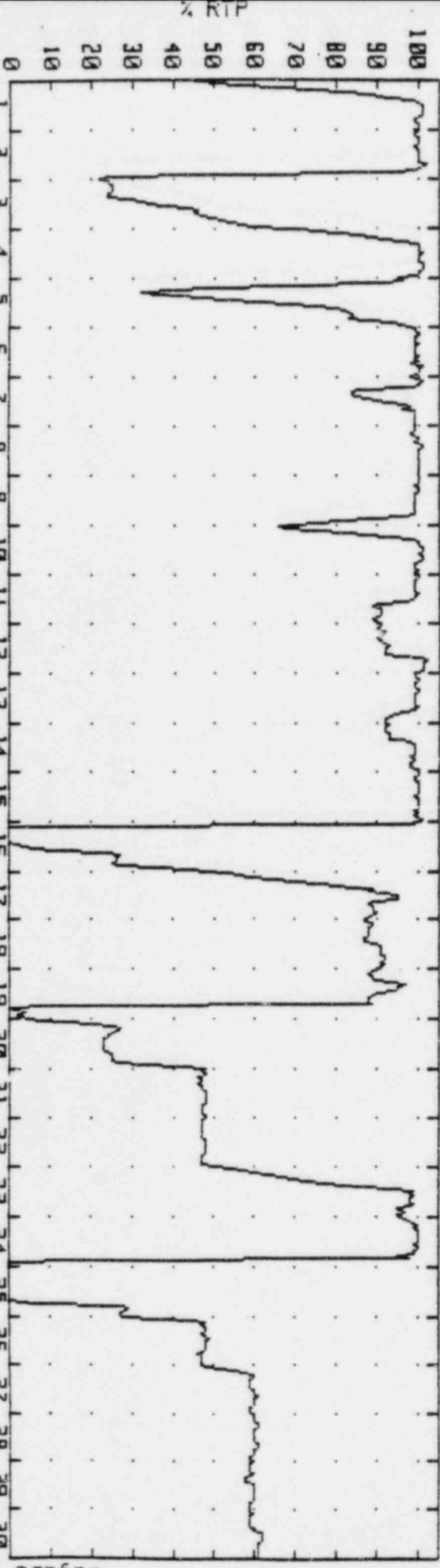

% RTP
0 10 20 30 40 50 60 70 80 90 100
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
SALEM UNIT 2 CYCLE 1 HOURLY POWER FOR October 81
MONTHLY BURNUP WAS 85921.8MWD AVG POWER WAS 82.3%RTP
UNIT SHUTDOWN FOR S/G MODIFICATIONS
EH PROBLEMS ON T/G
REDUCE PWR, 22 COND PP RAD BRNG HI TEMP
22 COND PP BRNG REPAIR COMPLETE
SUP 82.7, S/G MOISTURE CARRYOVER TEST
UNIT COMMERCIAL; SUP 81.8, PWR COEF
SUP 82.8, NSSS ACCEPT TEST <4 HR RUN>
TURB E/H SYS OIL LEAK, CONTRLD SHUTDOWN
RX TRIP, LO/LO S/G LVL, LOSS 22 FD PP
HELD 25%, S/G HI CONDUCTIVITY
HELD 85%, S/G HI CONDUCTIVITY
RX TRIP, LOSS 22 FD PP, LOSS BRNG OIL PP
TIME CHG, 25 HR DAY, 1 HR DELETED @ 0200
POWER REDUCTION, CONDENSER TUBE LEAKS

Figure 1.6



INCREASE POWER, CONDUCTIVITY RESTORED

REDUCE PWR, HI SEC CONDUCT.,   COND LK

INCREASE PWR, CONDUCTIVITY RESTORED 1000

REDUCE PWR, HI SEC CONDUCT.,   COND LK

REDUCE PWR, OSCILLATIONS 21 FD PP, 0645

REDUCE PWR, HI SEC CONDUCT.,   COND LK

INCREASE POWER TO 100% AT APPROX 0900

REDUCE PWR, HI QPTR N-43, 1600 HRS

PWR INCREASE, QPTR CORRECT, INC/EXC CAL

RX TRIP, LO FEED PUMP SUCTION, AT 0258

REDUCE PWR, HI QPTR N-43, 1500 HRS

RX TRIP, LO S/G FEED PUMP 22 PRES, 1706

50% PWR, S/G FD PP STRAINER CLEANOUT

INCR PWR, STRAINER CLEANOUT COMPLETE

RX TRIP, LO FEED PUMP SUCTION, 2009 HRS

REPLACED N I DETECTOR N-43

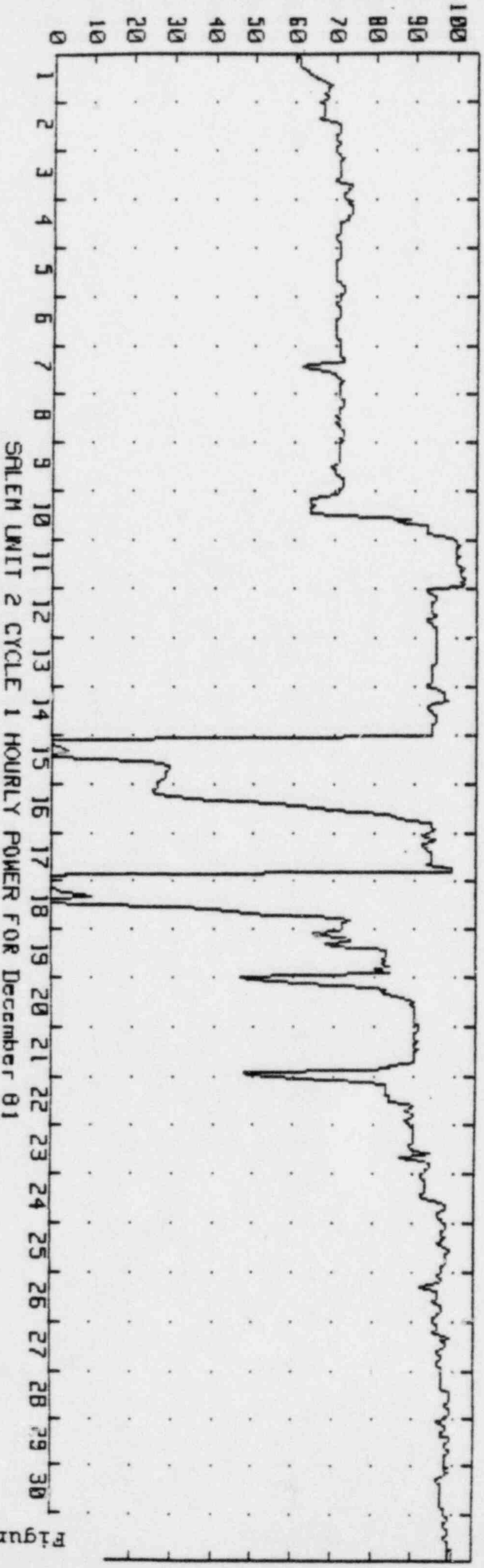
HOLDING 50% AFTER PWR INCR W/ ONE FD PP

HOLDING 60% PWR, S/G FD PP 21 REPAIR

SALEM UNIT 2 CYCLE 1 HOURLY POWER FOR November 81

MONTHLY BURNUP WAS 74880.3MWD   AVG POWER WAS 73.2%RTP

Figure 1.7



PWR TO 70%, CONTINUE S/G FD PP 21 REPAIR

REDUCED PWR, HTR DRN PUMP 22 STRNR MAINT

21 FD PP REPAIRED + ON LINE, INCR. POWER

PWR TO 95%, HI STEAM FLOW ON CH. 21

TRIP @ 0555, 22 FD PP, TRIP AGAIN @ 0910

TRIP @ 2004, S/G LO LVL, 22 FD PP TRIP

TRIP @ 0714, S/G LO LVL, 24 RCP TRIP

LD RED. TESTS; 0130: 75-50% 0623: 75-58%

1933: 85-75% 2220: 85-50%

LD RED. TEST; 2037: 85-47%

23/24/25 HTR BYPASS FD PP SUCT PRES TEST

LD RED. TESTS; 1354: 95-90% 1450: 95-85%

REDUCE POWER, HI STEAM FLOW S/G 21

SALEM UNIT 2 CYCLE 1 HOURLY POWER FOR December 81

MONTHLY BURNUP WAS 84687MWD AVG POWER WAS 80.1%RTP

Figure 1.8

Figure 1.9

Core Load thru Hot Functional

Planned/Actual

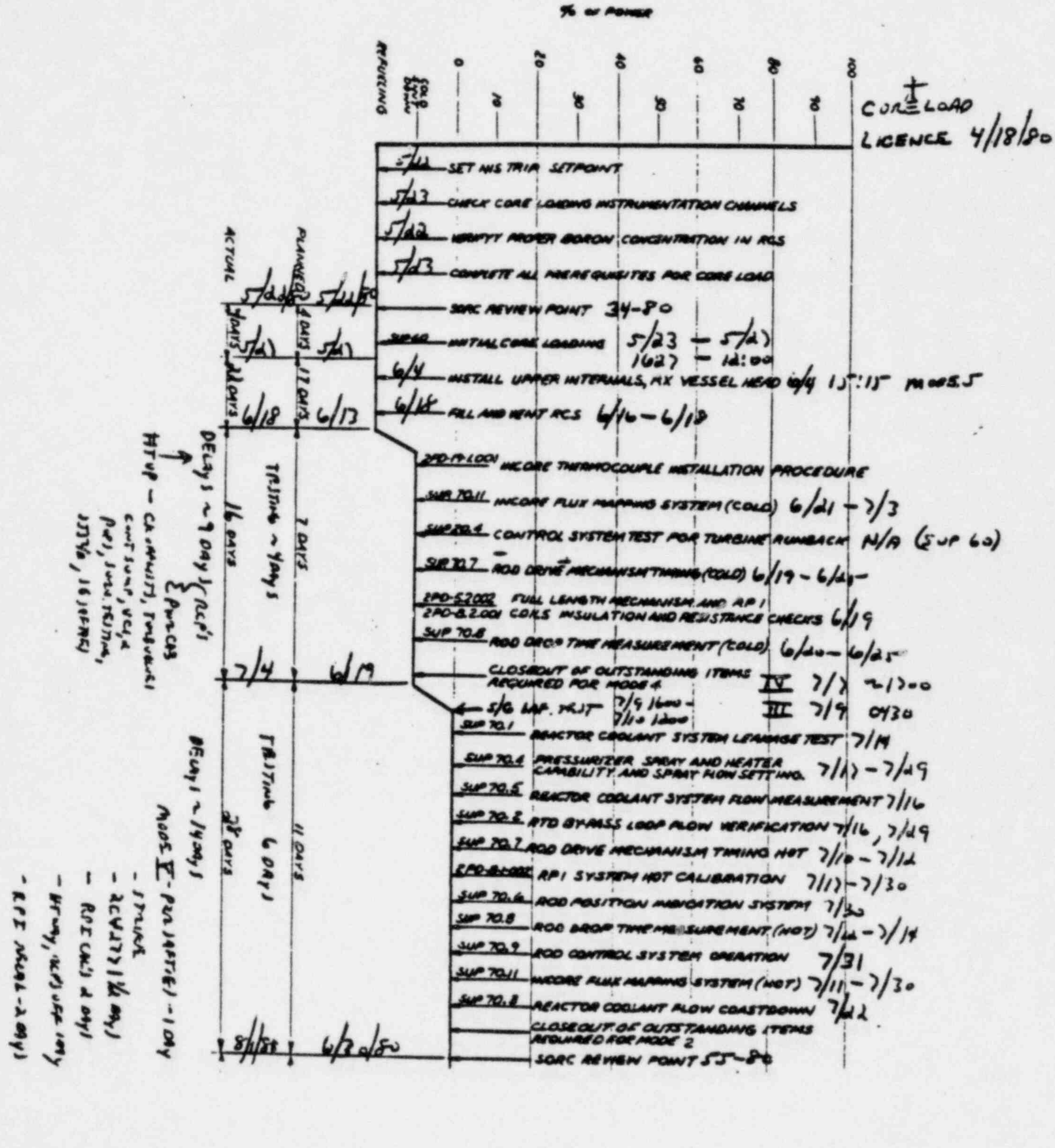


Figure 1.10

Low Power thru 10% Plateau Testing

Planned/Actual

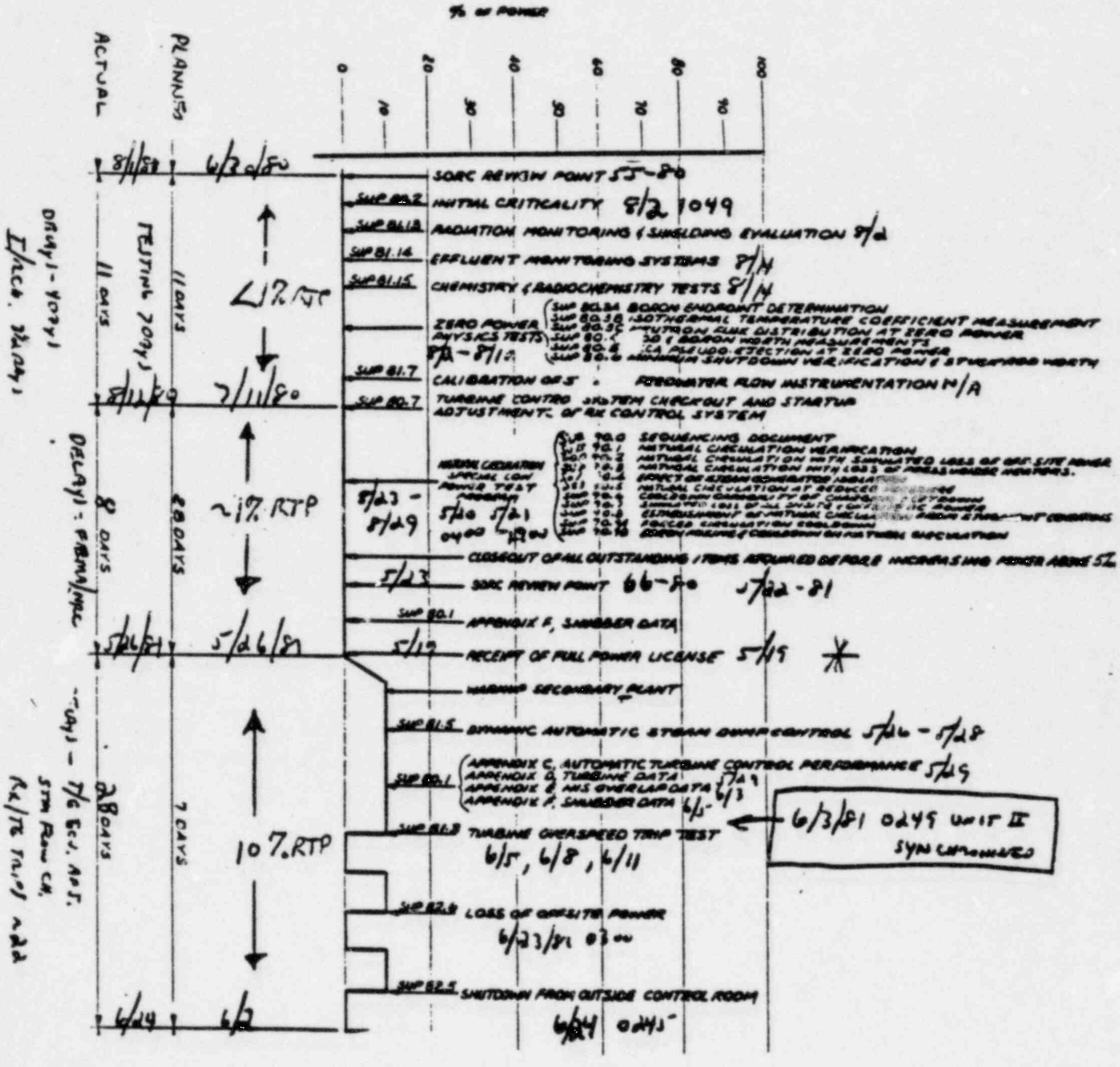


Figure 1.11

30% Testing

Planned/Actual

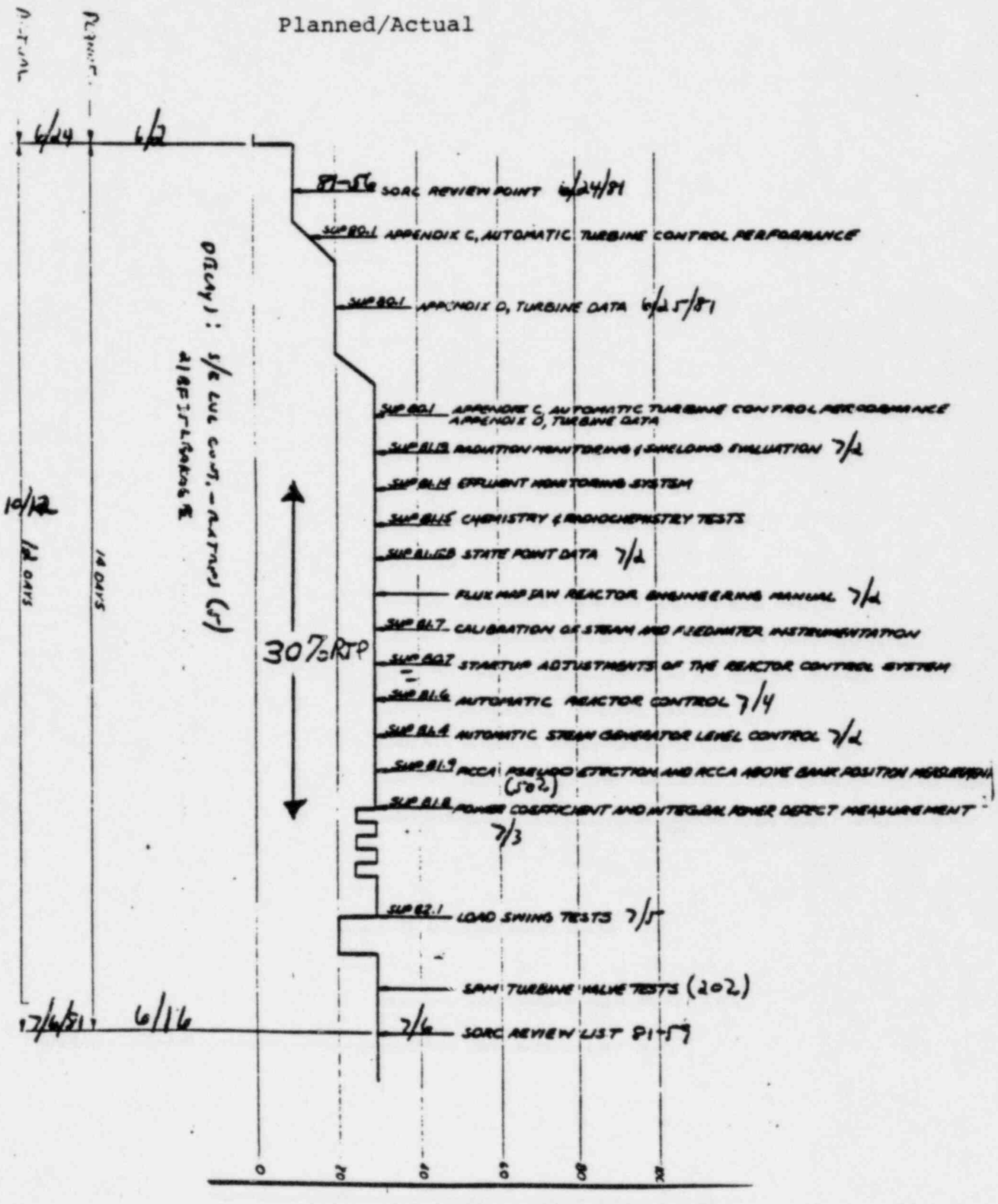


Figure 1.12

50% Testing

Planned/Actual

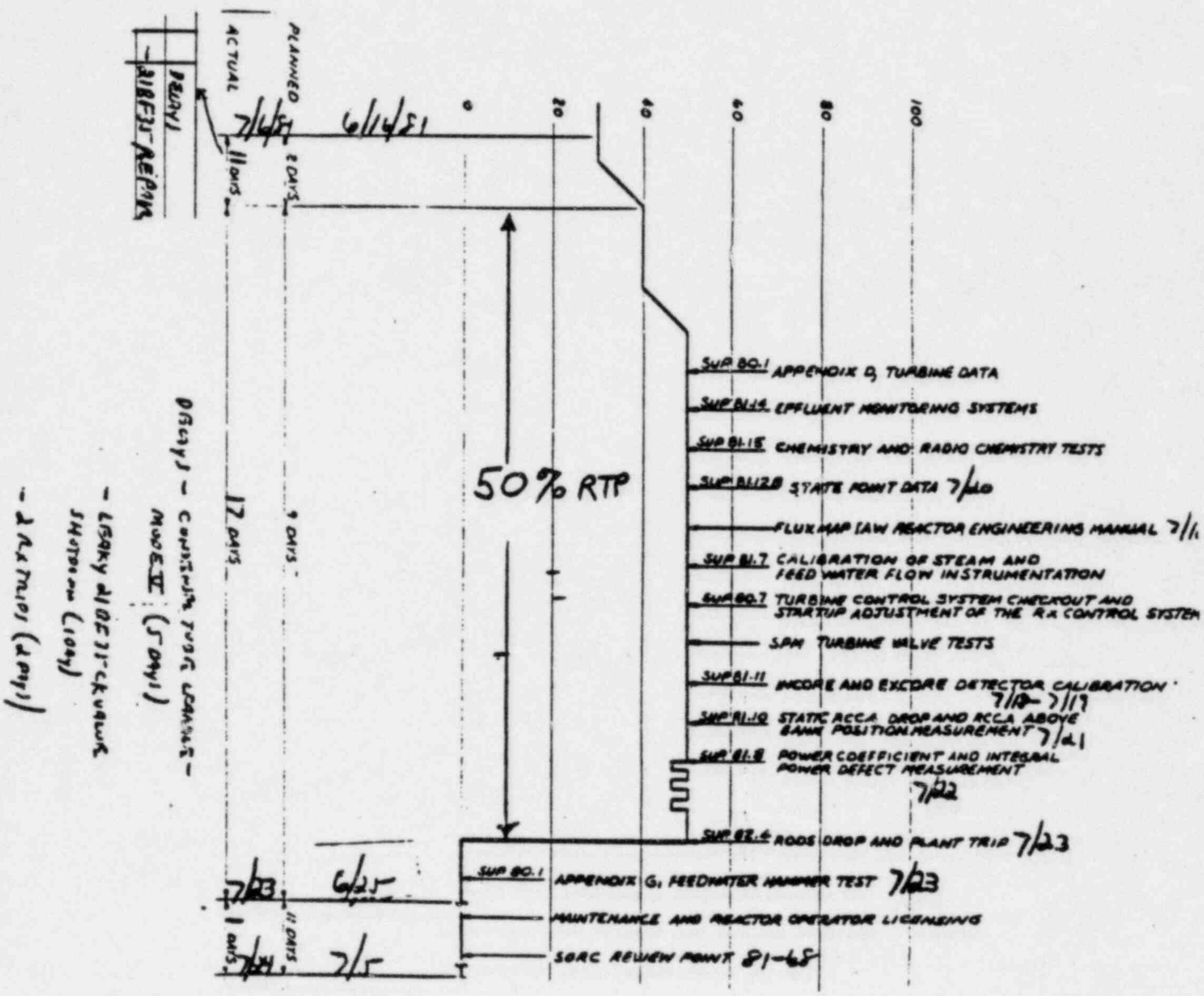


Figure 1.13

75% thru 90% Testing
Planned/Actual

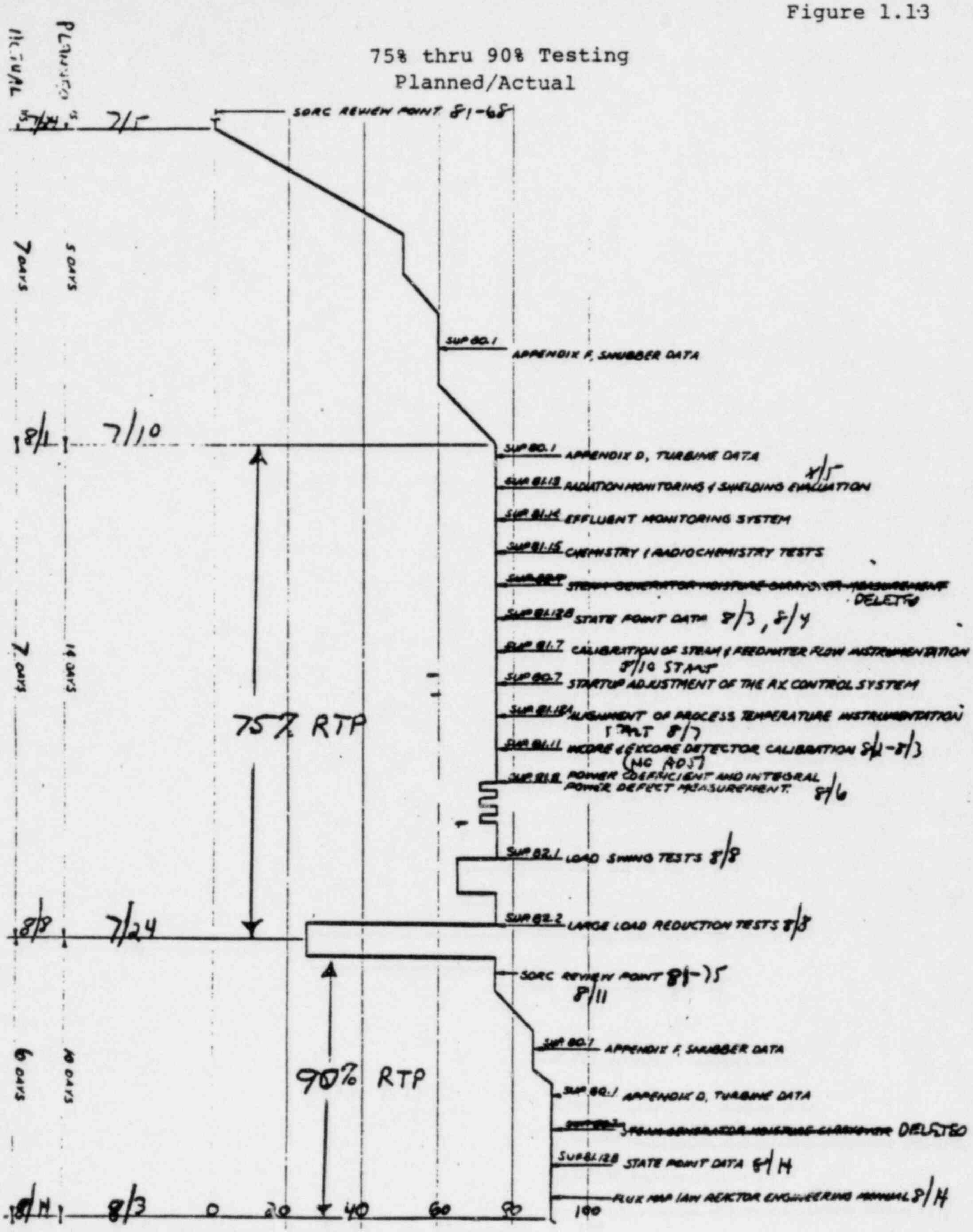
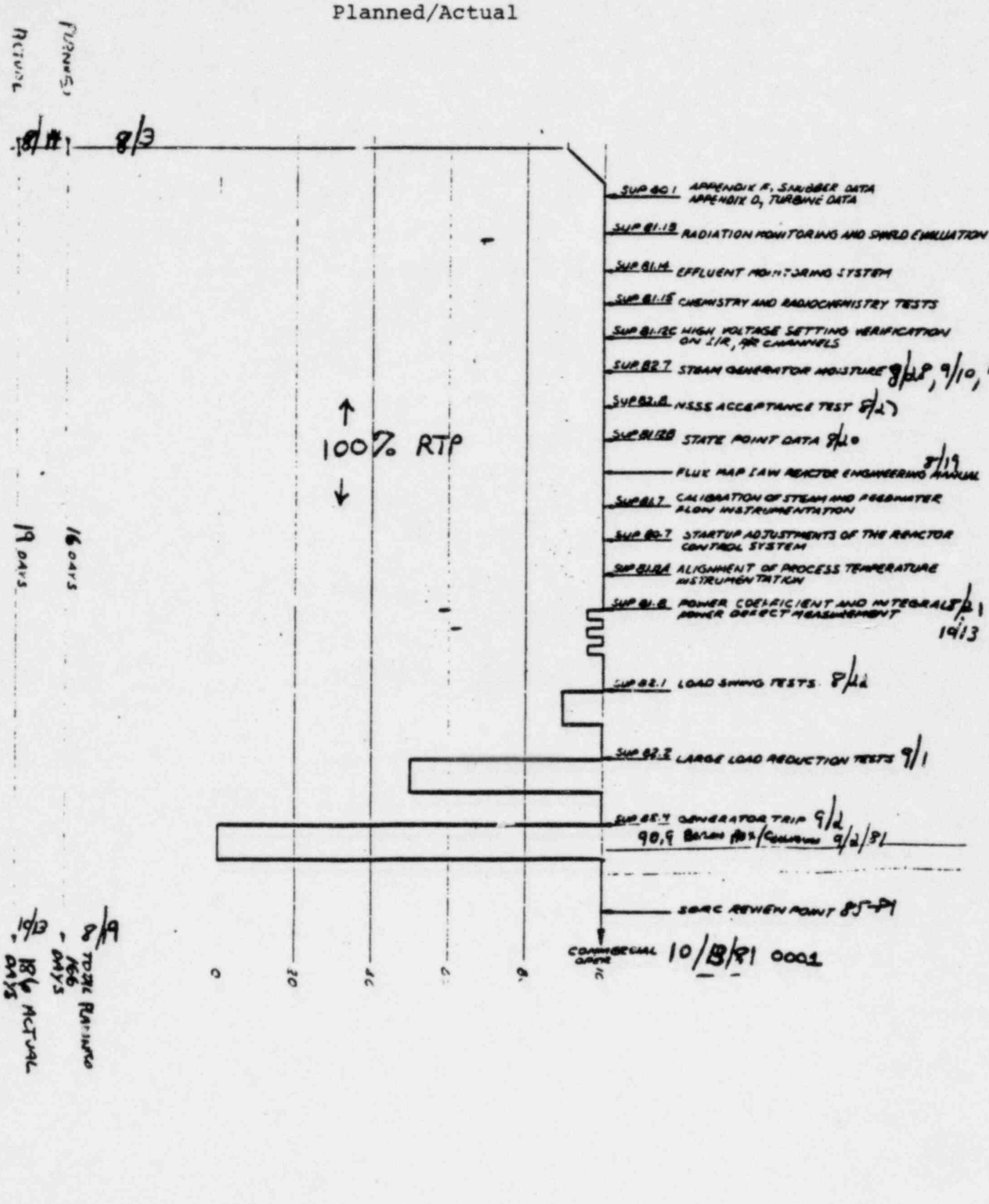


Figure 1.14

100% Testing

Planned/Actual



SECTION 2.0 INTEGRATED TESTING

This section deals with testing performed to evaluate overall plant response to rapid load changes and changes in system parameters to evaluate integraded systems response. Included in this section are tests performed by the Chemistry and Health Physics department which were part of the startup program.

2.1 SUP 81.5 - DYNAMIC AUTOMATIC STEAM DUMP CONTROL

This test was performed at the 10% power testing plateau with reactor power being varied between 1% and 10% depending on the test requirements. The turbine generator was not on the line at this time. The objectives of the test were to verify the proper operation of both modes (turbine trip and load rejection) of the T_{avg} steam dump control system and to obtain final settings for steam pressure control mode of the steam dump valves (12 valves).

To test the turbine trip mode of the steam dump control system, with the steam dump control system in manual and reactor power at about 1%, T_{avg} was raised $3^{o}F$ above the normal no load Tavg of $547^{o}F$. the steam dump system was then placed in automatic and since the turbine was tripped, T_{avg} was controlled by the turbine trip controller. The steam dump valves opened and T_{avg}

was controlled within a degree of the no load T_{avg} valve. Reactor power was then increased to about 6%, at 2%/minute, by rod withdrawal. The steam dump valves opened as reactor power increased and T_{avg} was controlled between $3^{o}F$ and $5^{o}F$ above the no load T_{avg} value. Reactor power was then decreased and the steam dump valves modulated closed, tracking reactor power.

In testing the response of the loss of load controller, the steam dump system control was initially placed in manual and reactor power increased to approximately 3%. The turbine was latched and the T_{ref} input to the loss of load controller was disconnected. A test signal was injected in place of T_{ref} signal, which was equivalent to a T_{ref} of $4^{o}F$ less than the no load of T_{ref} of 547^{o}. The steam dump controller was then switched to the T_{avg} mode of control. T_{avg} increased above the test signal by approximately $5^{o}F$ due to controller dead band and then by another $2^{o}F$ to provide a steam dump valve position equivalent to 3% reactor power. Power was then reduced to 1% and T_{avg} returned to its no load value. The T_{avg} comparator was found faulty and replaced and tested.

The response of the steam header pressure controller was easily verified. The steam dump control was placed in the steam header pressure control mode with a controller set-point of 1005 psi. Reactor power was increased to approximately 5% and the steam dump valves modulated open maintaining steam generator pressure at 1005 psi (T_{avg} was increased from 547°F to 550°F).

The only mechanical difficulty encountered during the tests were the "popping" open of the dump valves instead of modulating open as designed. The flow markings on the valve indicated the valve might have been installed incorrectly, but later investigations indicated the valves were installed correctly. The diaphram operated valve is designed to modulate from the fully closed position to the fully open position using supply air pressure of 9 psi thru 45 psi. Stroking of the valve required 25-35 psi to pop the valve off its seat at which point it would then modulate until closed. Disassembly of the valves for inspection of the intervals indicated no abnormal conditions. The valve vendor was contacted and arrived on site for observation of the valve operation during the 100% testing plateau. New internals were ordered and installed with no change in valve operation. The internals are to be modified and retested until the operation of the valve is acceptable. The modification consists of adjusting the trim of the internals of the valve to relieve the off-balancing of the valve disc during the opening stroke which is causing the valve disc to bind on the seating surface. Once the correct internals are designed for one valve the other 11 valves will be modified. This modification is also planned for Unit 1 valves.

The present operational characteristics of the valves are acceptable for plant operation as determined during plant trip tests and load swings; but the modulating rather than popping operation of the valves would provide smoother transient for steam generator pressure and levels, and RCS temperatures and pressures.

2.2 SUP 81.3 - TURBINE OVERSPEED TRIP TEST

The test of the mechanical turbine overspeed trip device was performed during the 10% power testing program. The purpose of the test was to verify that the turbine overspeed protection device would operate to trip the turbine in the event of an overspeed condition. Prior to the test, the turbine-generator was operating at approximately 10% power for eight hours in order to bring the machine to thermal equilibrium.

After the turbine-generator was unloaded and prior to the overspeed test, the operability of the overspeed mechanism was checked. At the pedestal end of the turbine, oil was introduced up to 48 psig to the overspeed trip mechanism to trip the mechanism. The manual trip lever moved from the normal to the trip position indicating that the mechanism was operating freely and had tripped.

To allow the turbine-generator to actually overspeed, the OVERSPEED PROTECTION CONTROLLER had to be removed from service. This was easily accomplished by use of a key switch on the control console. Using the E-H CONTROLLER, turbine speed was increased at a rate of 50 rpm/m until the Unit tripped.

The maximum allowable overspeed is 1998 rpm. During the three test runs, the Unit tripped at 1955, 2003 and 2000 rpm. It was determined that a weight adjustment of the governor was required. After the weight adjustment the oil-trip test was repeated with a trip oil pressure of 56 psig required. Oil pressure should have decreased following the adjustment. An inspection of the governor adjustment mechanism was made and retests of the oil-trip test were inconsistent (62 psig-90 psig) . The governor mechanism was disassembled and inspected with no abnormal conditions found. Upon reassembly the oil-trip retest was consistent and the mechanical overspeed test performed with the trip speed still too high. A recheck of the oil-trip pressure came up with inconsistent oil-trip pressure. The governor mechanism was disassembled and new parts installed that were machined to increase the clearances to allow more freedom of movement. Subsequent oil-trip retests and mechanical overspeed tests were successful. See Table 2.2.1 for the sequence of events.

TABLE 2.2.1

TURBINE OVERSPEED TRIP TEST HISTORY

Date	Event
6/5/81	Oil-trip 48 psig Mechanical trip 1955, 2003, 2000 rpm
6/6/81	Oil-trip after weight adjustment 58, 56, 56 psig Oil-trip after governor inspection 62-90 psig
6/7/81	Oil-trip (after governor disassembly and cleaning) 58, 58, 56 psig
6/8/81	Mechanical trip - 2000 rpm
6/9/81	Replacing governor internals/machining
6/11/81	Oil-trip 24, 22, 21 psig Mechanical trip 1836, 1841, 1840 rpm

2.3 SUP 82.6 - LOSS OF OFF-SITE POWER

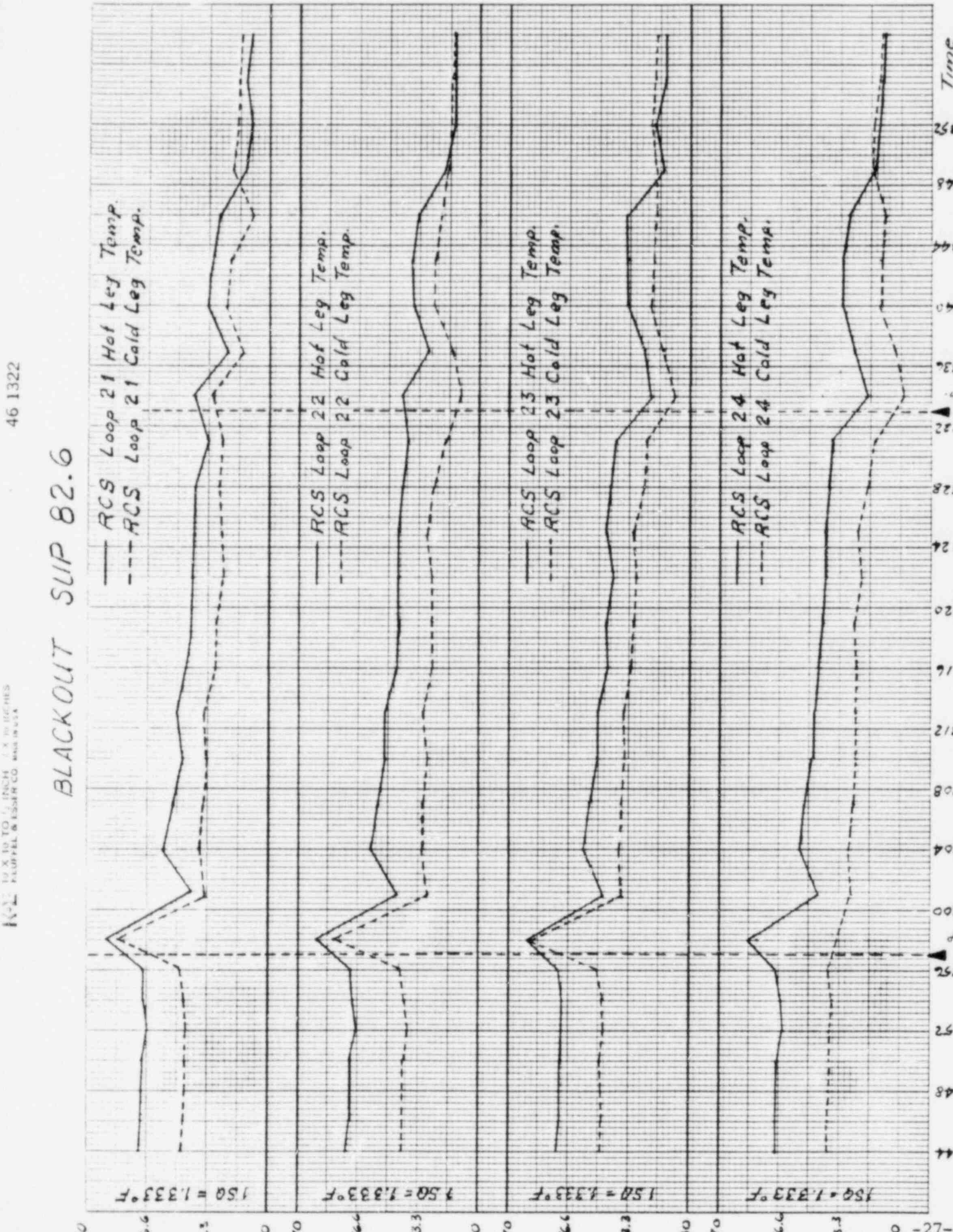
This startup procedure was completed during the 10% testing plateau. The purpose of the test was to demonstrate that the emergency power system was capable of maintaining the plant in a safe condition by carrying the required loads for at least thirty minutes following a plant trip caused by a total loss of off-site power.

With the turbine generator on the line at minimum load (10% reactor power) and with a normal electrical lineup, the blackout was initiated by opening the 13kV infeed breakers for 21 and 22 station power transformers followed closely by the operator opening the generator output breakers. All operations were carried out from the control console.

All systems, equipment and indicators operated properly. The three diesel generators picked up their respective blackout loads and ran for the required thirty minutes. No problems were encountered during the test.

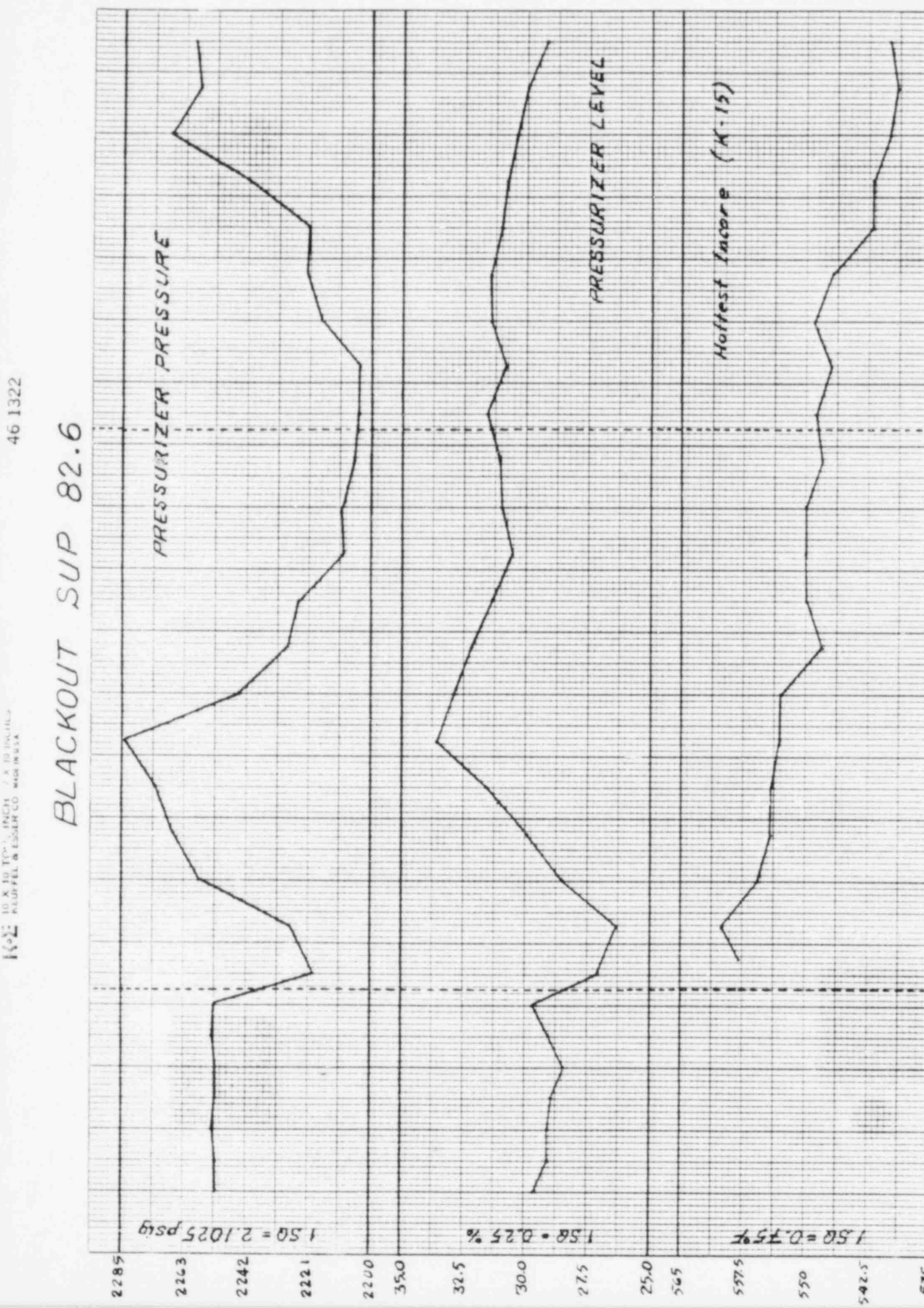
Figures 2.3.1 thru 2.3.9 indicate plant trends for pressure, levels and temperatures of the RCS and steam generators during the transient using Plant Computer data and Control Console recorder strip charts.

Figure 2.3.1



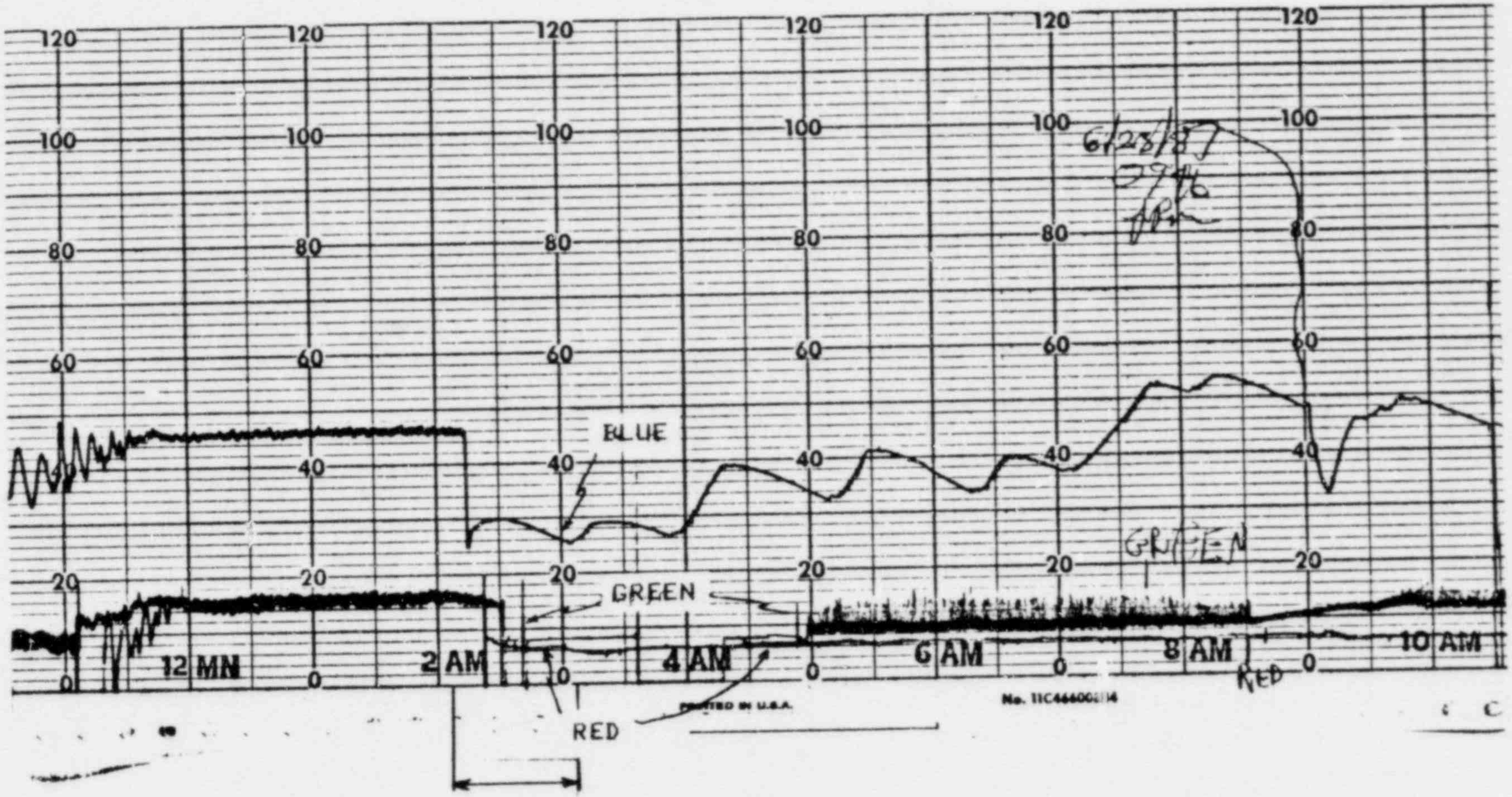
BLACKOUT SLIP 82.6
— RCS Loop 21 Hot Leg Temp.
--- RCS Loop 21 Cold Leg Temp.
— RCS Loop 22 Hot Leg Temp.
--- RCS Loop 22 Cold Leg Temp.
— RCS Loop 23 Hot Leg Temp.
--- RCS Loop 23 Cold Leg Temp.
— RCS Loop 24 Hot Leg Temp.
--- RCS Loop 24 Cold Leg Temp.
150 = 1.333°F
Time

Figure 2.3.2



BLACKOUT SUP 82.6
46 1322
PRESSURIZER PRESSURE
PRESSURIZER LEVEL
Hottest Incore (K-15)
Time
1 SQ = 24 Sec
1 SQ = 2.1025 psig
1 SQ = 0.25 %
1 SQ = 0.75°F
Rx Trip
Ref. Norm.
0244
0248
0252
0256
0300
0304
0308
0312
0316
0320
0324
0328
0332
0336
0340
0344
0348
0352
2285
2263
2242
2221
2200
35.0
32.5
30.0
27.5
25.0
565
557.5
550
542.5
535

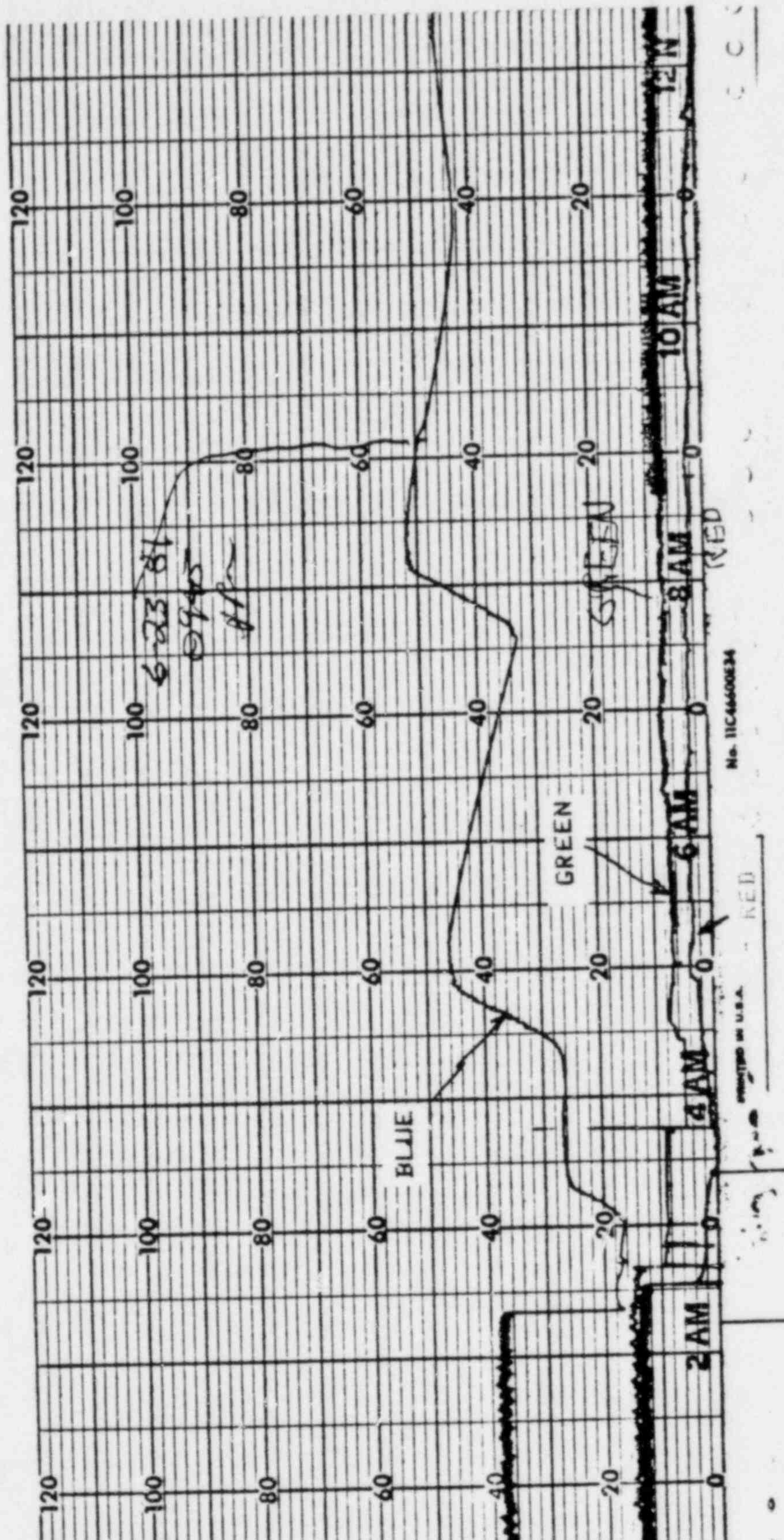
Figure 2.3.3



Red = 24 Steam Flow (%)
Green = 24 Feedwater Flow (%)
Blue = 24 S/G Level (%)

SUP 82.6 - Loss of Off-site Power
Salem Unit 2 6/23/81

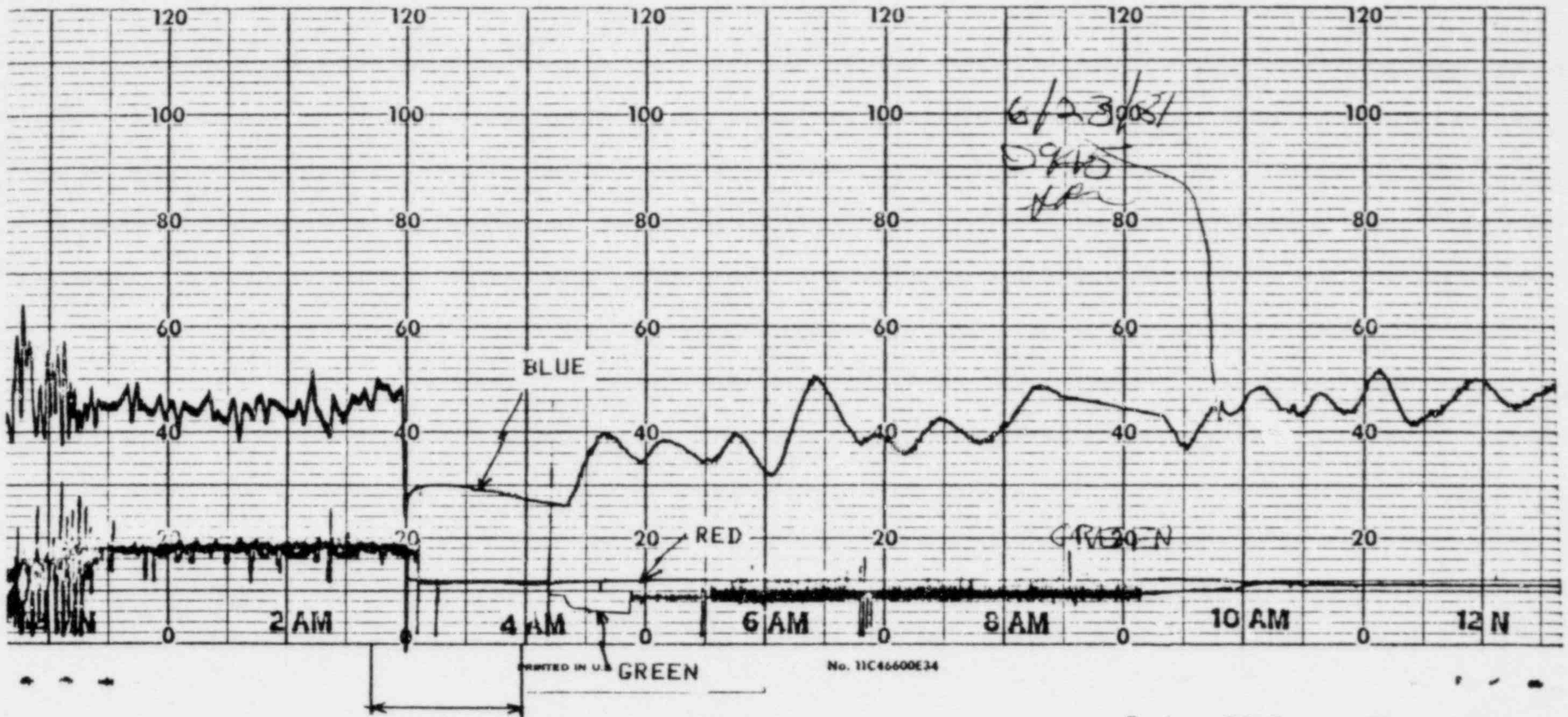
Figure 2.3.4



Red = 23 Steam Flow (%)
Green = 23 Feedwater Flow (%)
Blue = 23 S/G Level (%)

SUP 82.6 – Loss of Off-site Power
Salem Unit 2 6/23/81

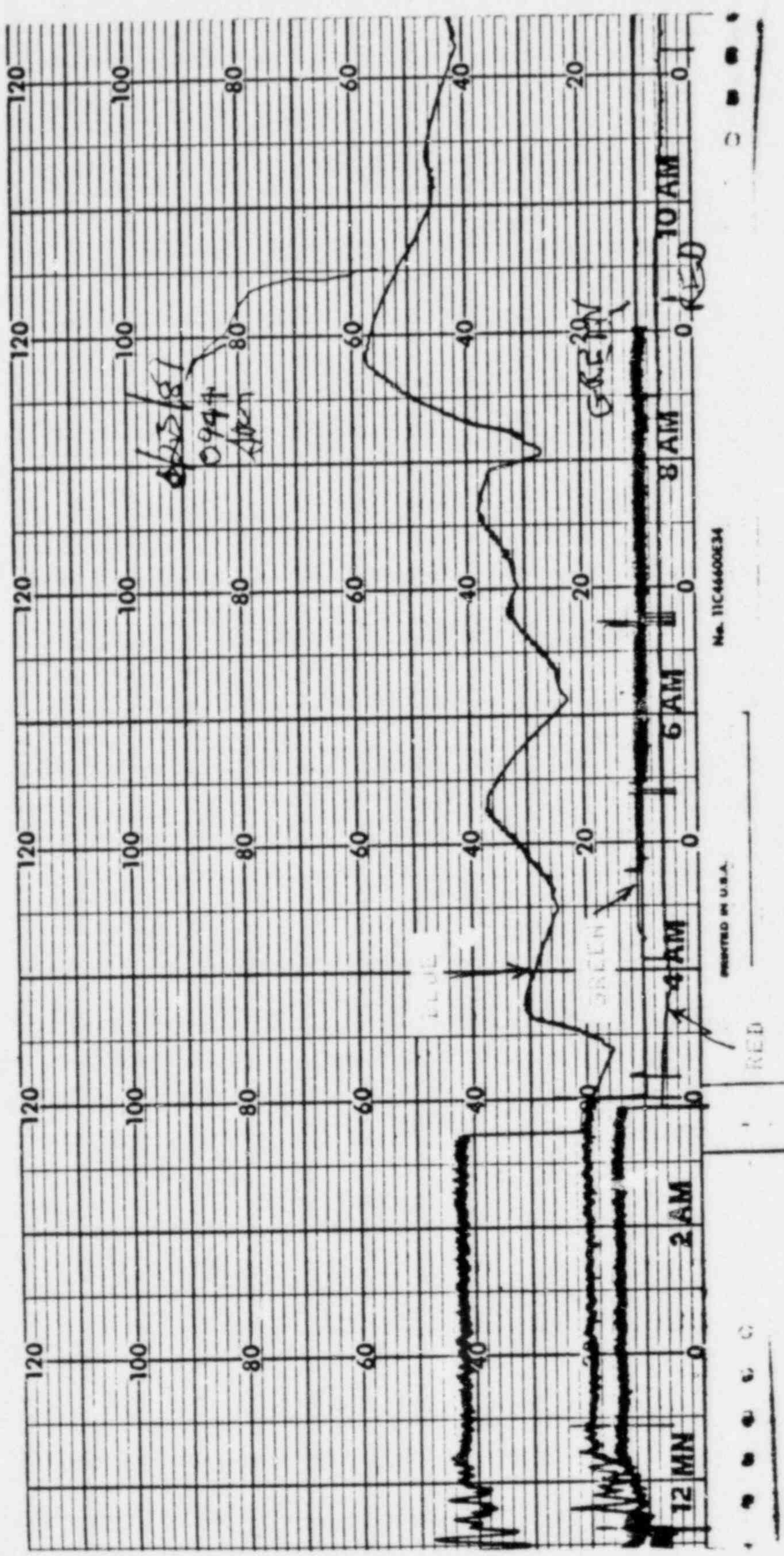
Figure 2.3.5



Red = 22 Steam Flow (%)
Green = 22 Feedwater Flow (%)
Blue = 22 S/G Level (%)

SUP 82.6 - Loss of Off-site Power
Salem Unit 2 6/23/81

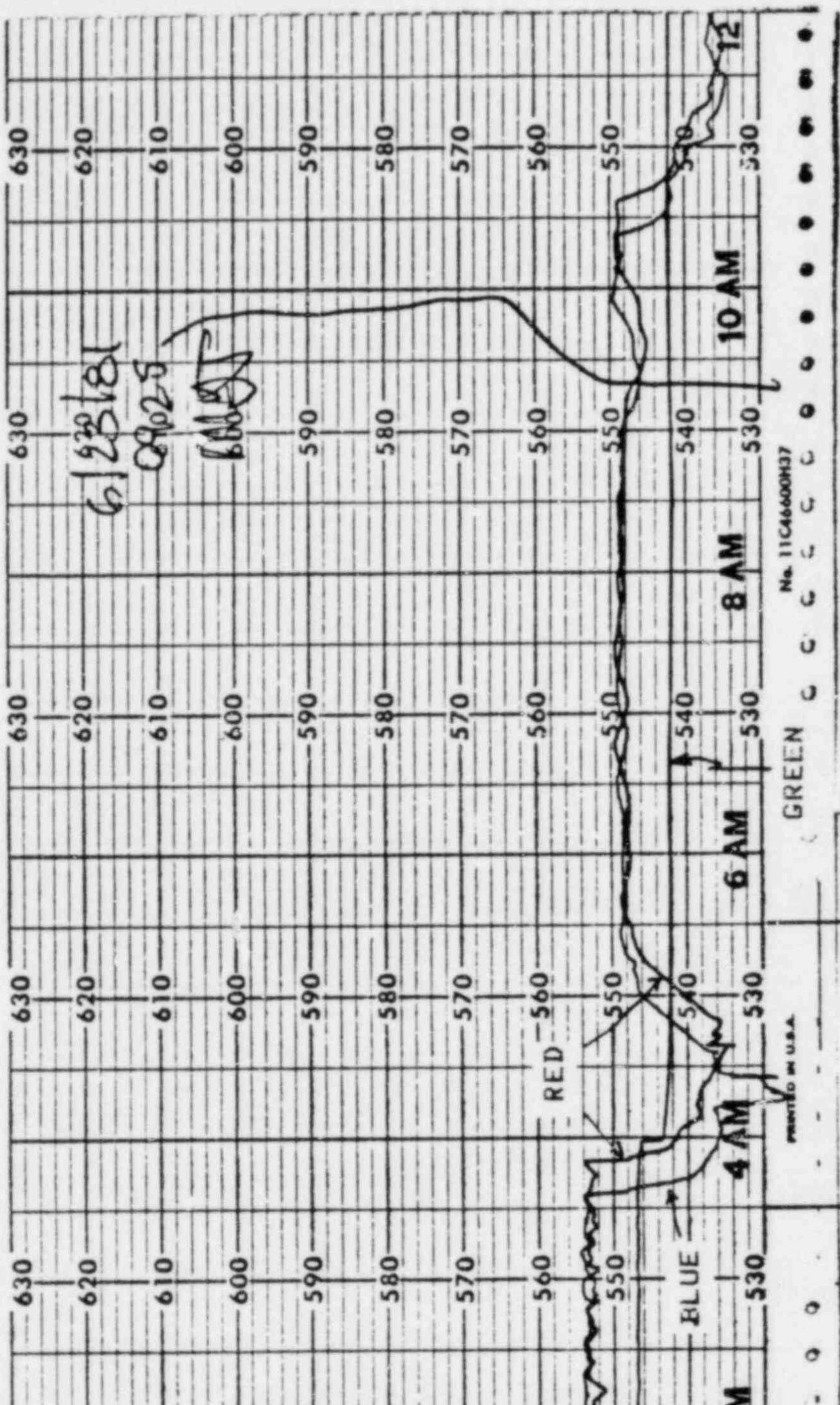
Figure 2.3.6



Red = 21 Steam Flow (%)
Green = 21 Feedwater Flow (%)
Blue = 21 S/G Level (%)

SUP 82.6 - Loss of Off-site Power
Salem Unit 2 6/23/81

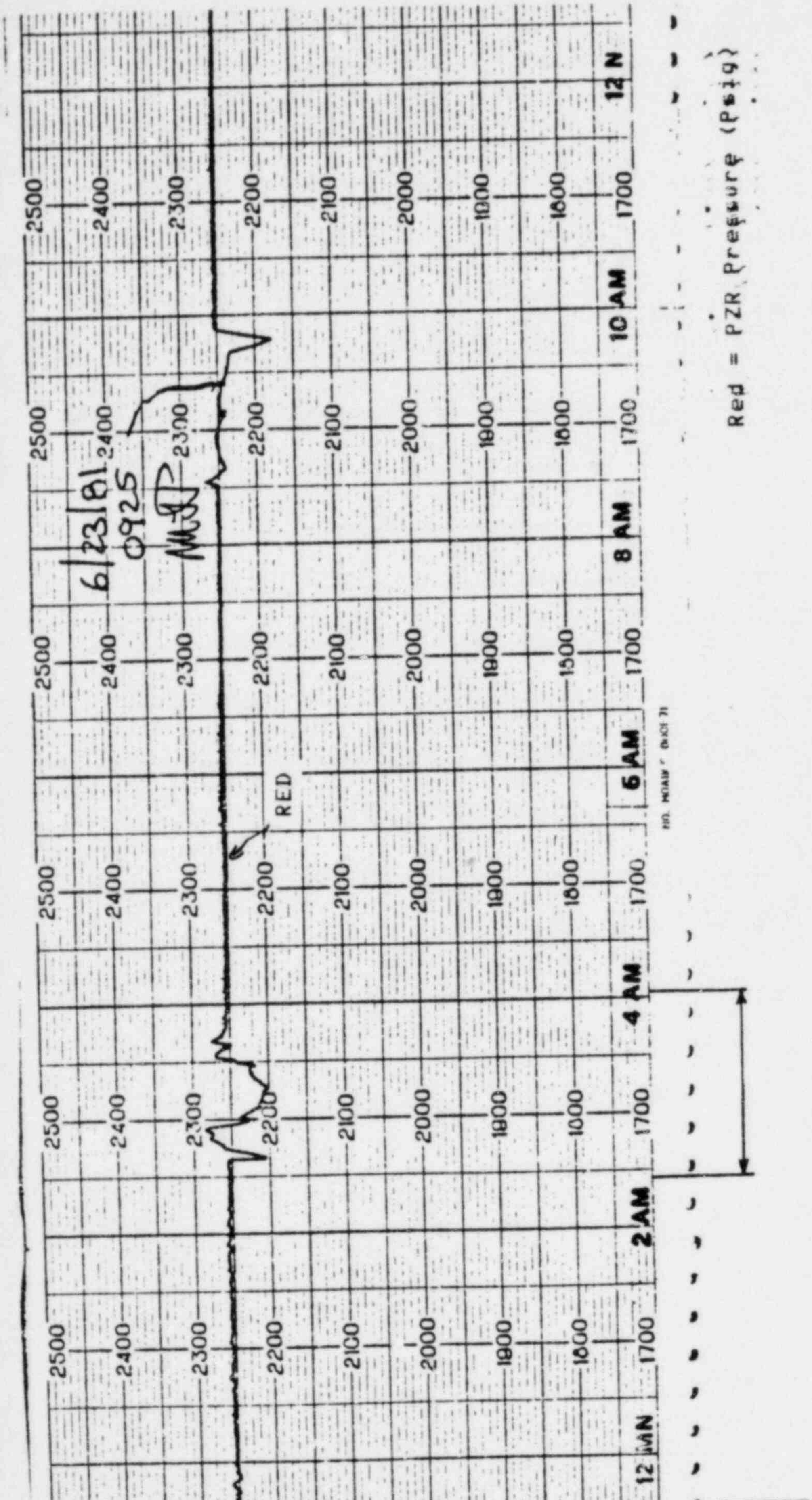
Figure 2.3.7



Red = Auctioned Tave (Deg F)
Green = Reference Tave (Deg F)
Blue = Loop Tave (Deg F)

SUP 82.6 - Loss of Off-site Power
Salem Unit 2
6/23/81

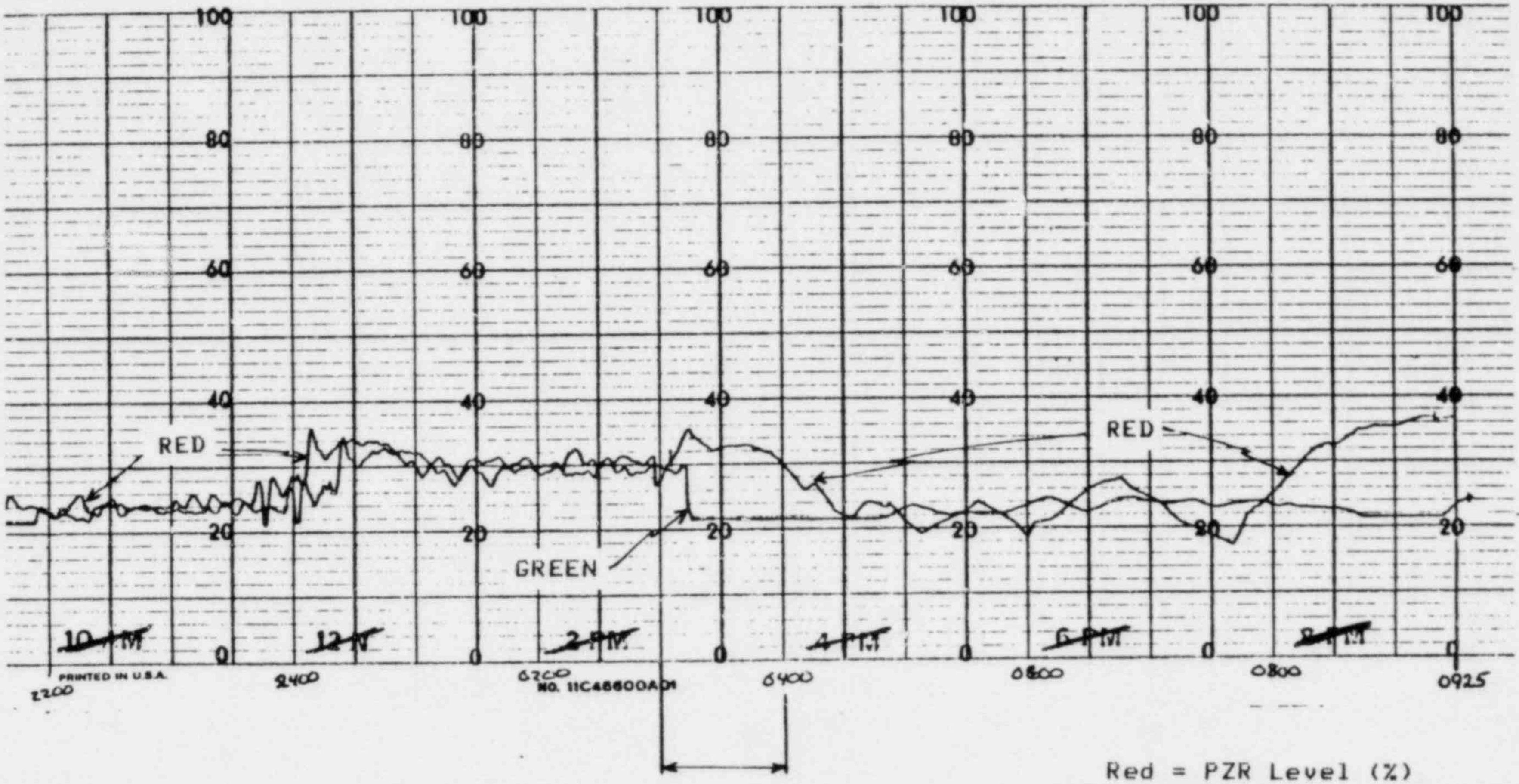
Figure 2.3.8



Red = PZR Pressure (Psig)

SUP 82.6 - Loss of Off-site Power
Salem Unit 2 6/23/81

Figure 2.3.9



Red = PZR Level (%)
Green = PZR Level Setpoint (%)

SUP 82.6 - Loss of Off-site Power
Salem Unit 2 6/23/81

2.4 SUP 82.5 - SHUTDOWN FROM OUTSIDE OF THE CONTROL ROOM

This was the last test performed at the 10% testing plateau. The purpose of this procedure was to verify that the plant could be shutdown from outside the Control Room and be maintained at hot standby for an hour utilizing the minimum shift crew. Limits on various parameters (pressurizer level, pressure, T_{avg}, steam generator levels) were included in the acceptance criteria. All control systems were kept in automatic and the Control Room was not evacuated for the test.

The procedure was modified to incorporate the requirements of Amendment 6 to the Operating License based on the results of a fire protection review. The additional requirements included:

1) local start of a diesel generator using alternative control power source
2) local operation of a 4kV breaker
3) local start of the containment fan cooler unit.
4) local operation of a motor operated and an air operated valve
5) local control of charging flow

This portion of the testing was performed while the plant was being maintained in HOT STANDBY at the remote control station.

The plant was operating at 10% RTP with the Control Room manned by the regular shift personnel (2 NCO's). The minimum shift crew was comprised of the following:

SRO - Senior Reactor Operator - 1

NCO - Nuclear Control Operator - 2

EO/UO Equipment/Utility Operator - 3

STA - Shift Technical Advisor - 1

Electrician - 1

The following stations were designated:

(1) Unit 1 Control Room SRO (1), STA (1) Electrician (1)

(2) Hot Shutdown Panel (213) NCO (1)

(3) Reactor Trip Switchgear NCO (1)

(4) Main Feedpump Local Control Panel EO (1)

(5) Auxiliary Feedwater Pump Panels EO (1)

(6) Main Turbine Turning GEAR UO (1)

The Shift Supervisor of Unit 2 simulated the evacuation of Unit 2 Control Room and established a Control Center in Unit 1 Control Room. From the center the shutdown and control of the plant in HOT STANDBY was maintained thru communications to the personnel at remote stations. The minimum shift crew was assigned their positions at this point. The NCO tripped the plant at the Reactor Trip Switchgear and de-energized the Rod Drive MG sets to insure that an ATWS (anticipated transient without scram) event would not occur and that all rods would drop to the bottom of the core. The EO and UO in the turbine building verified the 500 kV breakers and field breakers were open and the group buses had transferred from the Auxiliary Power Transformer to the Station Power Transformer. They also verified that the main turbine generator and main feedwater pumps had tripped, and placed them on their turning gears when they coasted to a stop. The NCO and EO at the Hot Shutdown Panel (213) verified the following:

(1) Pressurizer level controlling automatically at 22% $\pm$ 5%.

(2) Pressurizer pressure controlling automatically 2235 psig $\pm$ 50 psig

(3) Steam generator pressure 1000 psig $\pm$ 25 psig and level (wide range) 58% - 69%

At this point (75 minutes from reactor trip) a one hour hold period was commenced to demonstrate the ability to maintain the plant in a HOT STANDBY condition from the HOT SHUTDOWN PANEL. The NCO and EO at the HOT SHUTDOWN PANEL manually opened and closed the auxiliary feedwater pump discharge valves to maintain steam generator levels as indicated at the HOT SHUTDOWN PANEL (the auxiliary feedwater pumps and associated valves are located next to this panel) within the wide range indication of 58% - 69%.

Following the one hour hold period, the second phase of this test started while the plant was being remotely maintained in HOT STANDBY. Using the appropriate sections from the Fire Hazards Analysis - Emergency Equipment Operation the following operations were demonstrated as directed by the Unit 2 Shift Supervisor:

(1) Local start of #24 Fan Coil Unit

(2) Local start of #24 Service Water Pump

(3) Local operation of 22SW17 (header isolation)

(4) Local operation of 2CV55 (control charging)

(5) Local starting of a Diesel Generator

These operations were performed by the Shift Electrician who performed the control circuit modifications and a NCO who operated the equipment. All phases of this test were demonstrated successfully. The following graphs (Figure 2.4.1-2.4.11) indicate plant trends for pressures, levels and temperatures of the RCS and steam generators during the transient and stabilization period using Plant Computer data and Control Console recorder strip charts.

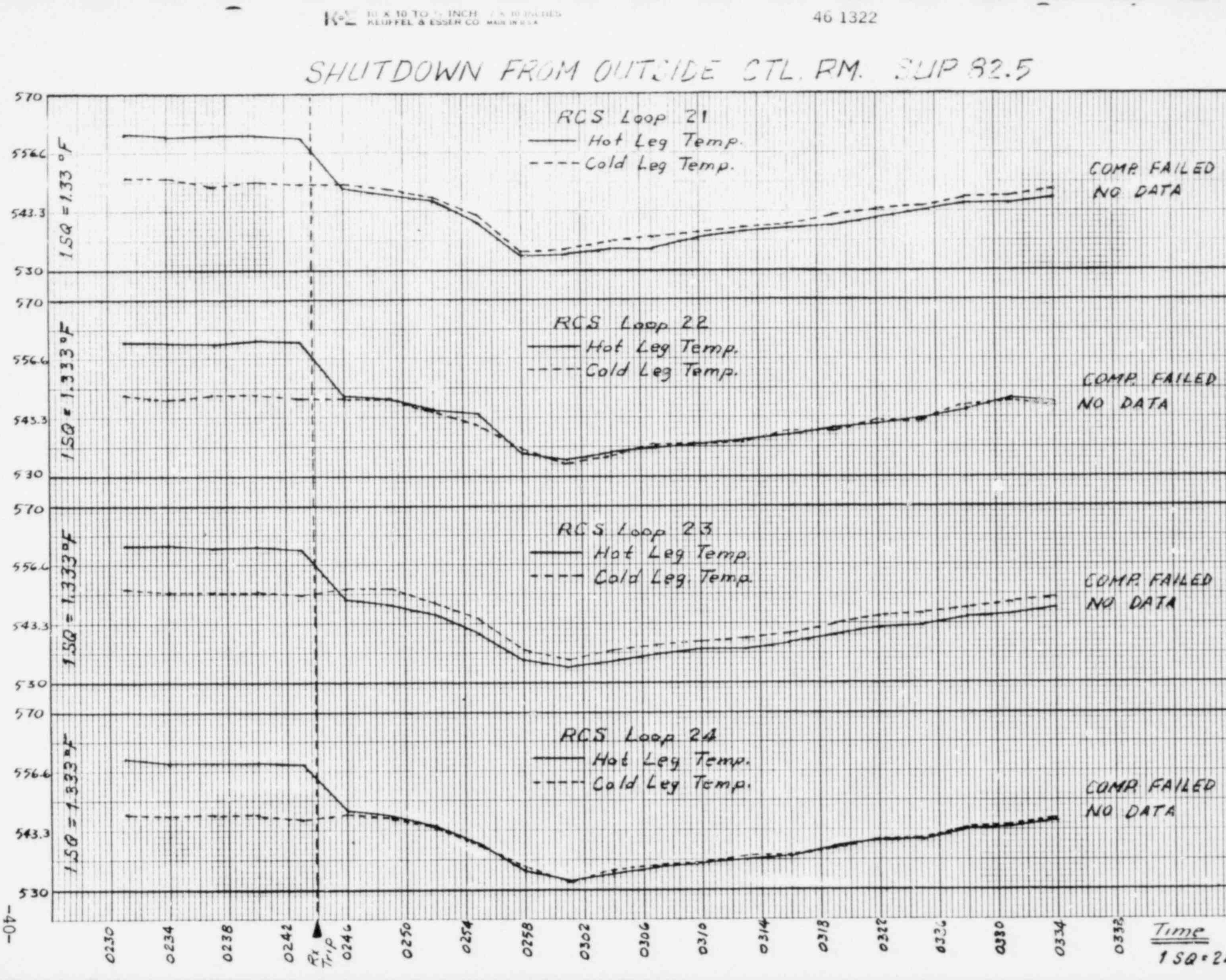
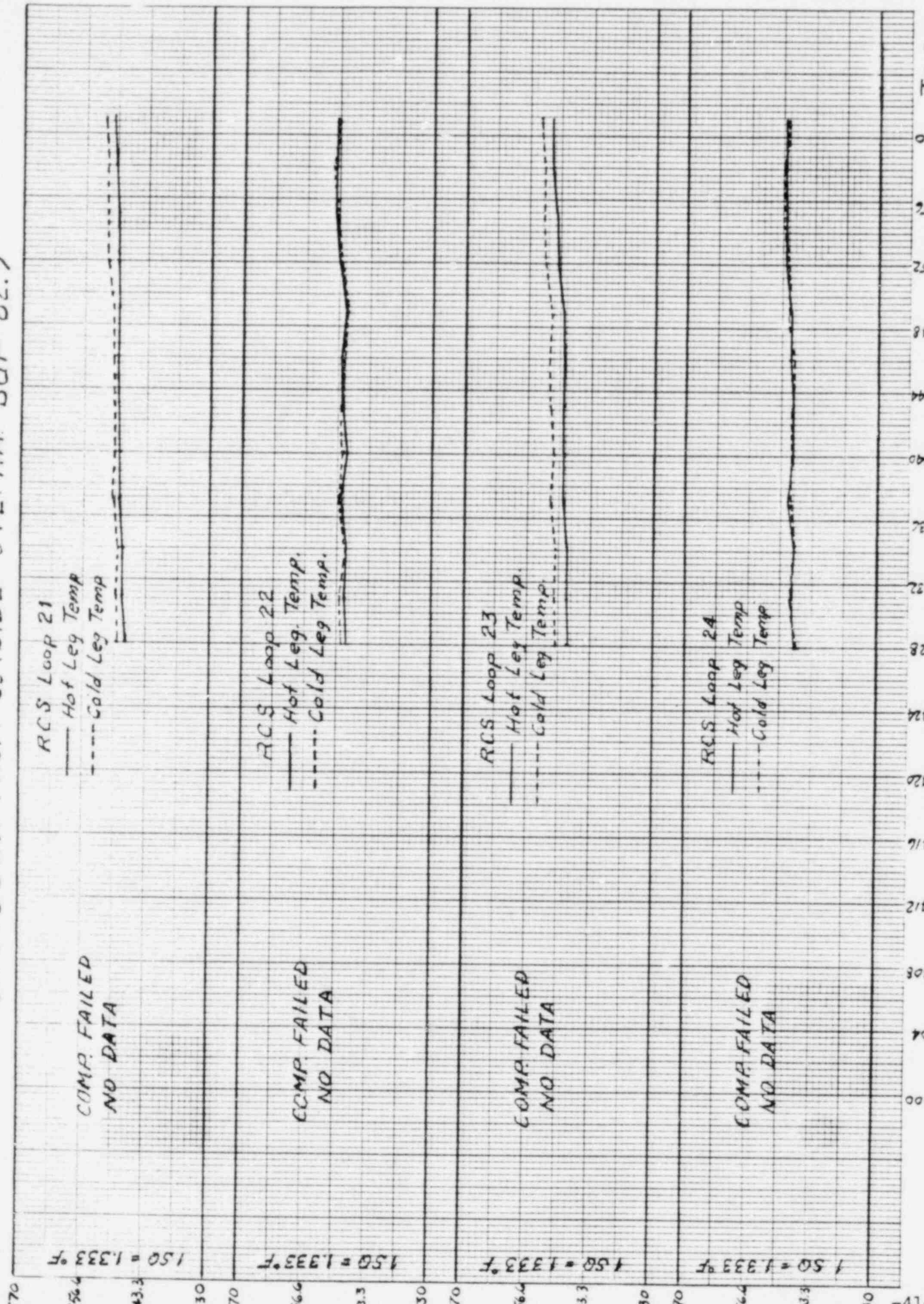

K+E 10 X 10 TO 1/2 INCH
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 1322
SHUTDOWN FROM OUTSIDE CTL. RM. SUP 82.5
RCS Loop 21
Hot Leg Temp.
Cold Leg Temp.
COMP. FAILED NO DATA
1 SQ = 1.33 °F
RCS Loop 22
Hot Leg Temp.
Cold Leg Temp.
COMP. FAILED NO DATA
1 SQ = 1.333 °F
RCS Loop 23
Hot Leg Temp.
Cold Leg Temp.
COMP. FAILED NO DATA
1 SQ = 1.333 °F
RCS Loop 24
Hot Leg Temp.
Cold Leg Temp.
COMP. FAILED NO DATA
1 SQ = 1.333 °F
570
556.6
543.3
530
0230
0234
0238
0242
Rx Trip
0246
0250
0254
0258
0302
0306
0310
0314
0318
0322
0326
0330
0334
0338
Time
1 SQ = 24 sec

Figure 2.4.1.

Figure 2.4.2



SHUTDOWN FROM OUTSIDE CTL. RM. SUP 82.5
RCS Loop 21
Hot Leg Temp
Cold Leg Temp
RCS Loop 22
Hot Leg. Temp.
Cold Leg Temp.
RCS Loop 23
Hot Leg Temp.
Cold Leg Temp.
RCS Loop 24
Hot Leg Temp
Cold Leg Temp
COMP. FAILED NO DATA
Time
0400
0404
0408
0412
0416
0420
0424
0428
0432
0436
0440
0444
0448
0452
0456
0500
570
556.6
543.3
530
1.50 = 1.333 °F

Figure 2.4.3

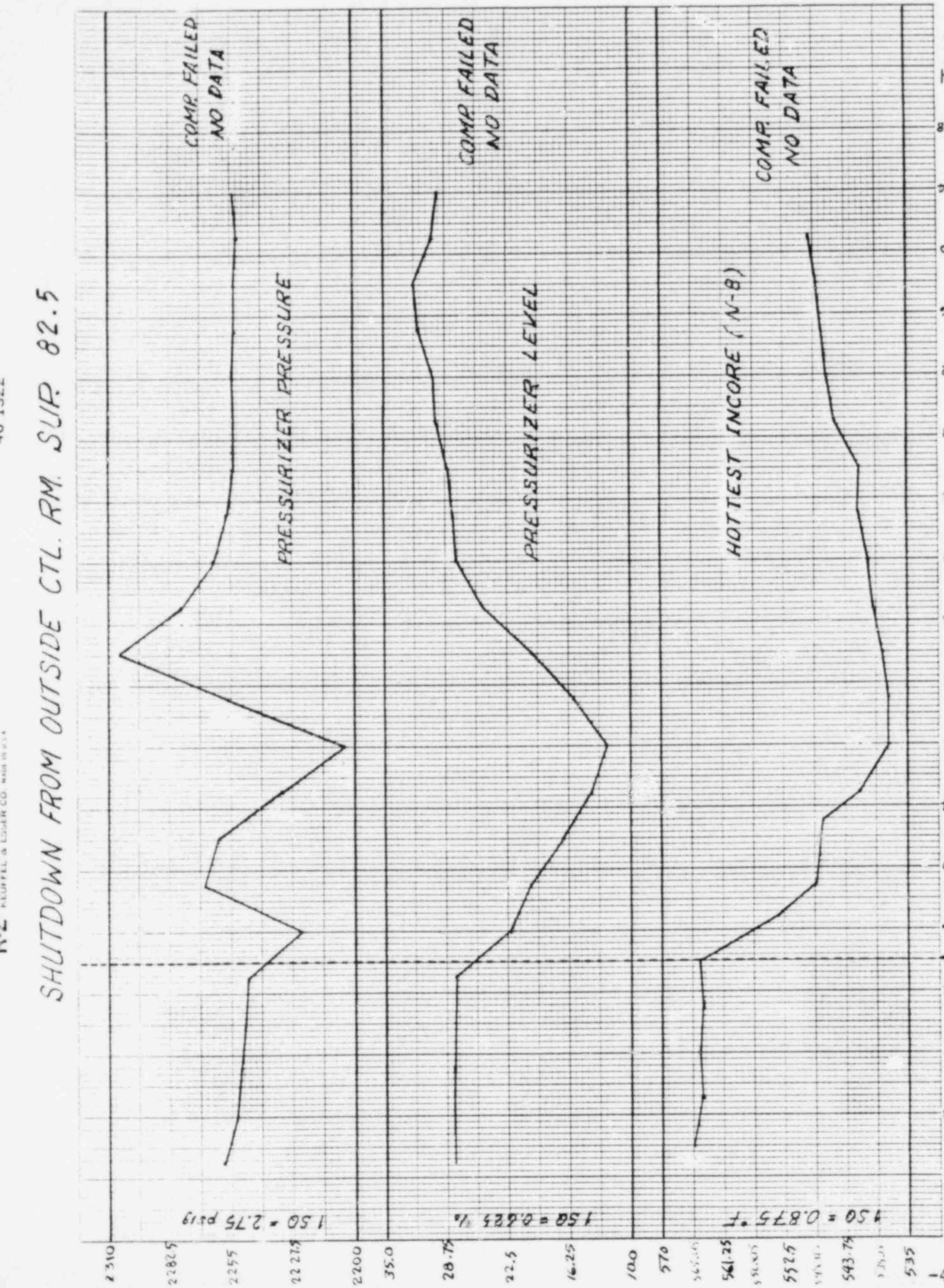
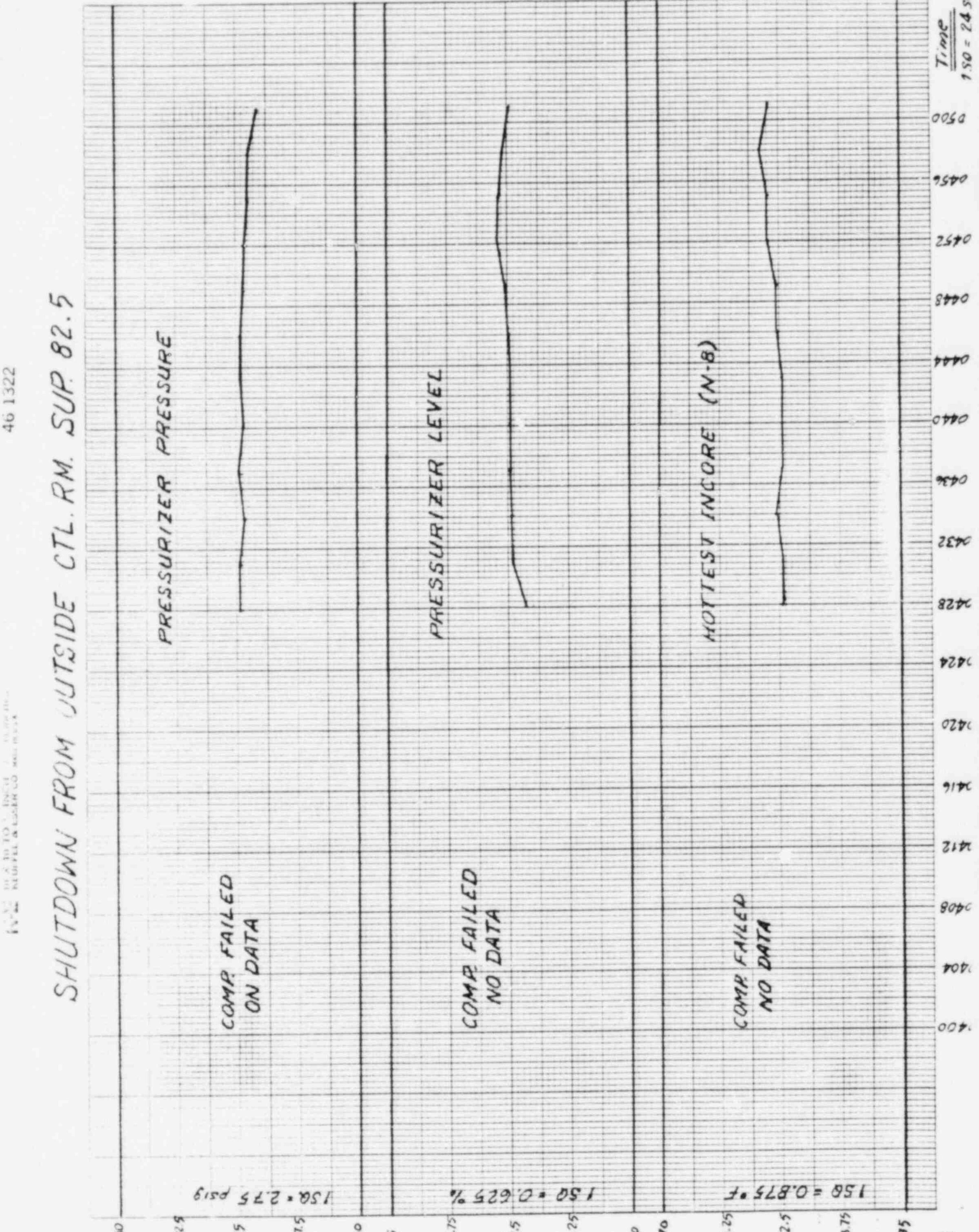
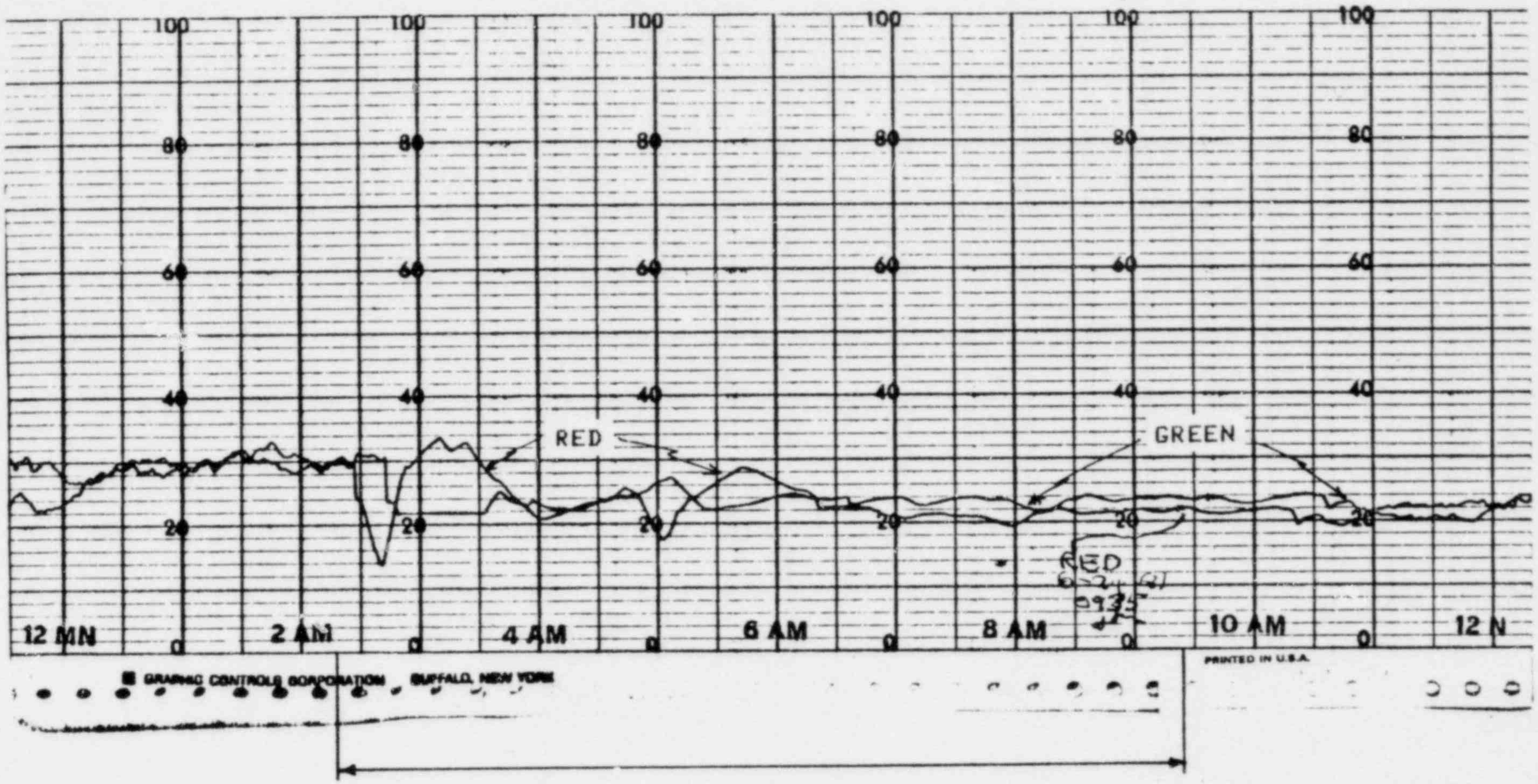

46 1322
SHUTDOWN FROM OUTSIDE CTL. RM. SUP. 82.5
PRESSURIZER PRESSURE
PRESSURIZER LEVEL
HOTTEST INCORE (N-8)
COMP. FAILED NO DATA
COMP. FAILED NO DATA
COMP. FAILED NO DATA
Time
1 SQ = 24 sec
1 SQ = 2.75 psig
1 SQ = 0.625 %
1 SQ = 0.875 °F
2310
2282.5
2255
2227.5
2200
35.0
28.75
22.5
16.25
10.0
570
561.25
552.5
543.75
535
0230
0234
0238
0242
0246
0250
0254
0258
0302
0306
0310
0314
0318
0322
0326
0330
0334
0338

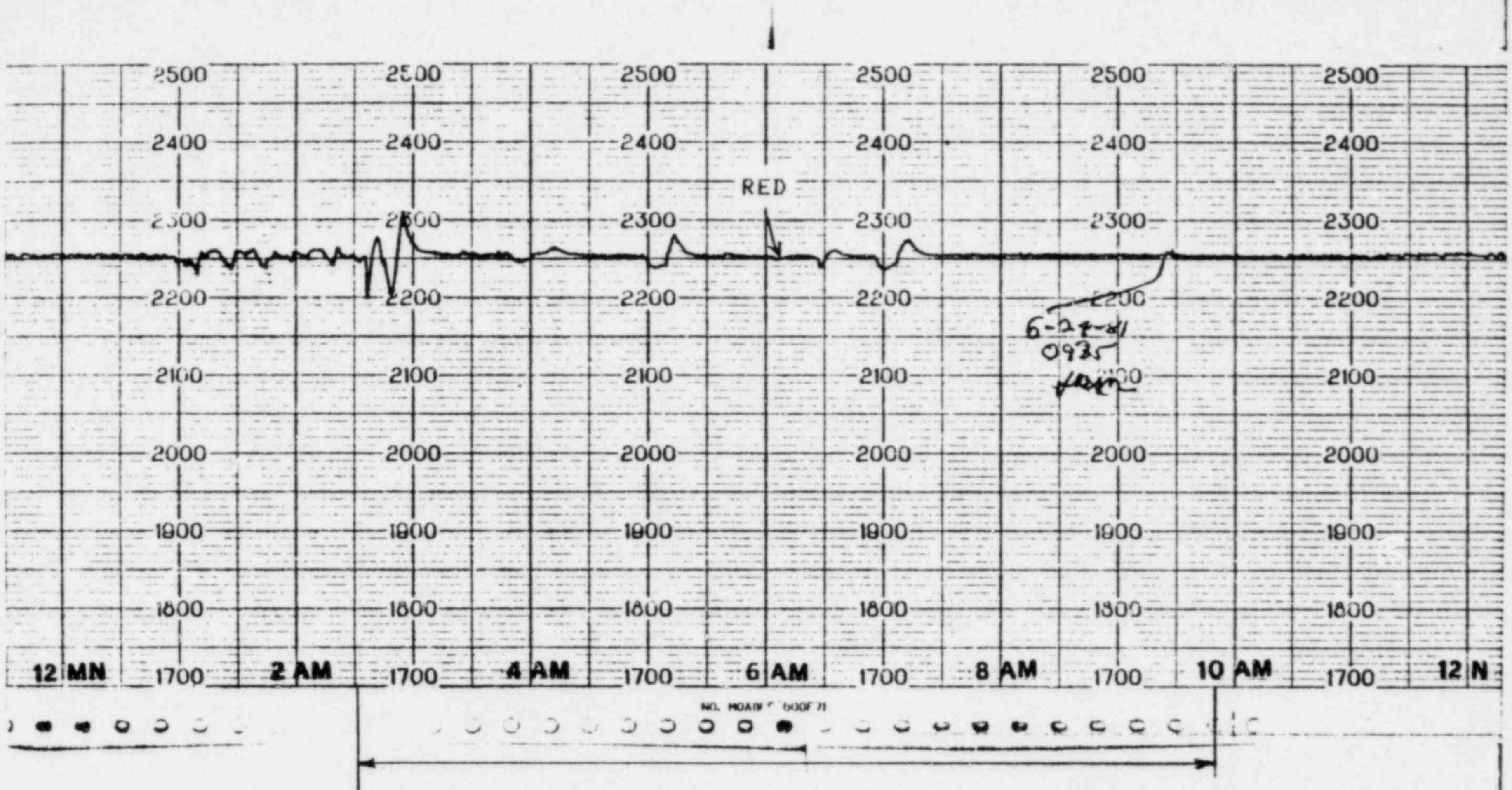
Figure 2.4.4


SHUTDOWN FROM OUTSIDE CTL. RM. SUP. 82.5
46 1322
PRESSURIZER PRESSURE
PRESSURIZER LEVEL
HOTTEST INCORE (N-8)
COMP. FAILED ON DATA
COMP. FAILED NO DATA
COMP. FAILED NO DATA
1 SQ = 2.75 psig
1 SQ = 0.625 %
1 SQ = 0.875 °F
Time 1 SQ = 24 sec.
2310
2282.5
2255
2227.5
2200
35
28.75
22.5
16.25
10
570
561.25
552.5
543.75
535
0400
0404
0408
0412
0416
0420
0424
0428
0432
0436
0440
0444
0448
0452
0456
0500



Red = PZR Level (%)
Green = PZR Level Setpoint (%)

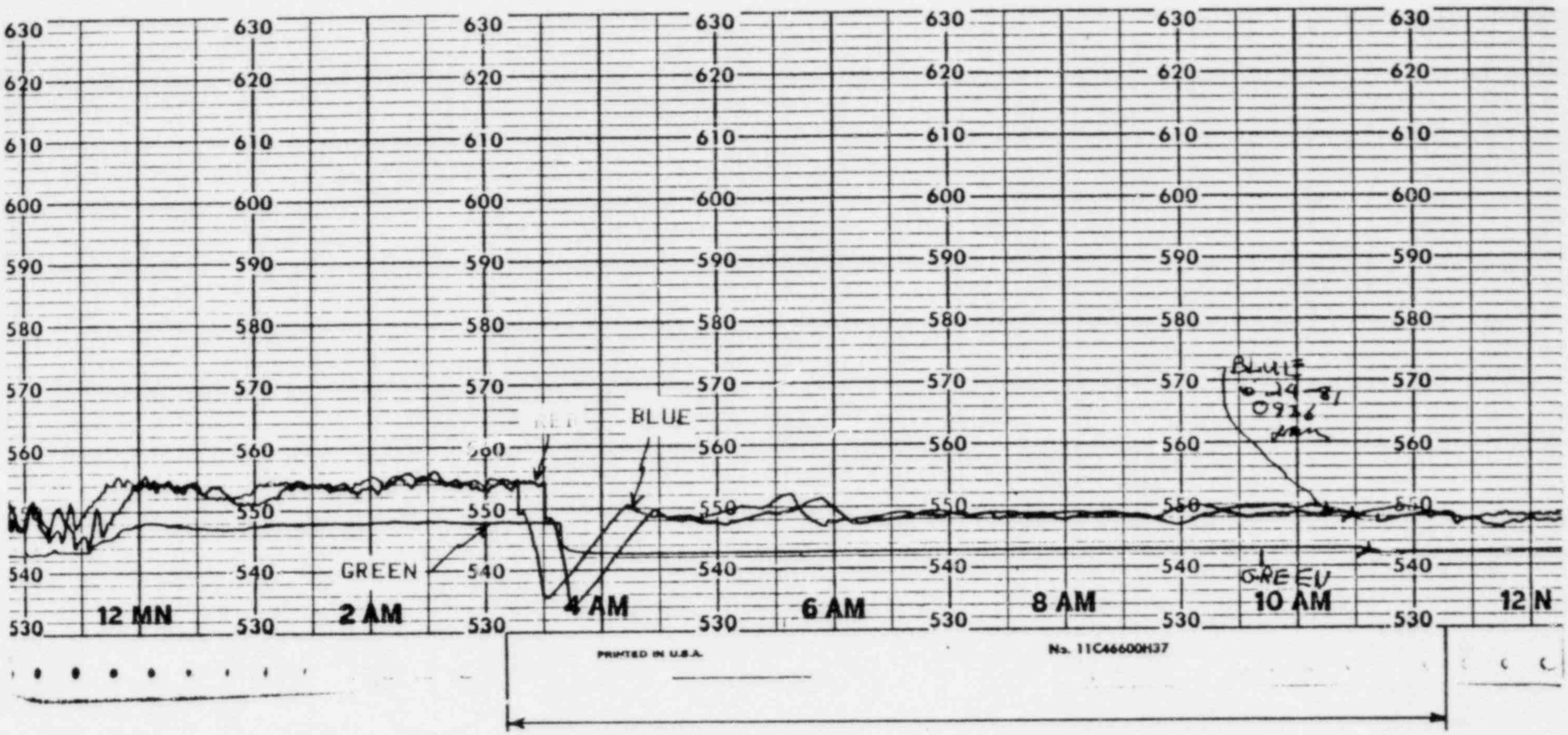
SUP 82.5 - Shutdown from Outside the Control Room
Salem Unit 2 6/24/81



Red = PZR Pressure (Psig)

SUP 82.5 - Shutdown from Outside the Control Room
Salem Unit 2 6/24/81

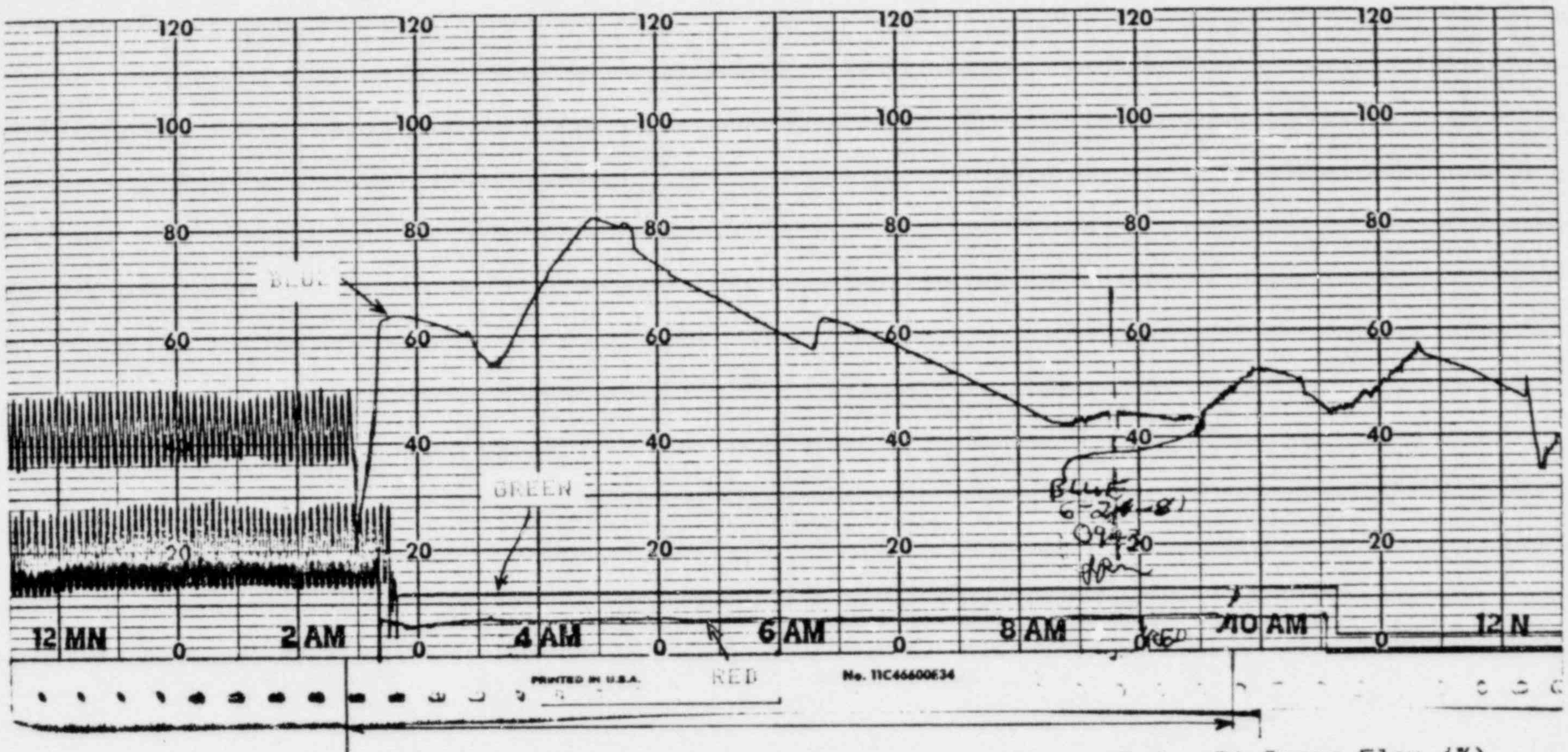
Figure 2.4.7



Red = Auctioned Tave (Deg F)
Green = Reference Tave (Deg F)
Blue = Loop Tave (Deg F)

SUP 82.5 – Shutdown from Outside the Control Room
Salem Unit 2 6/24/81

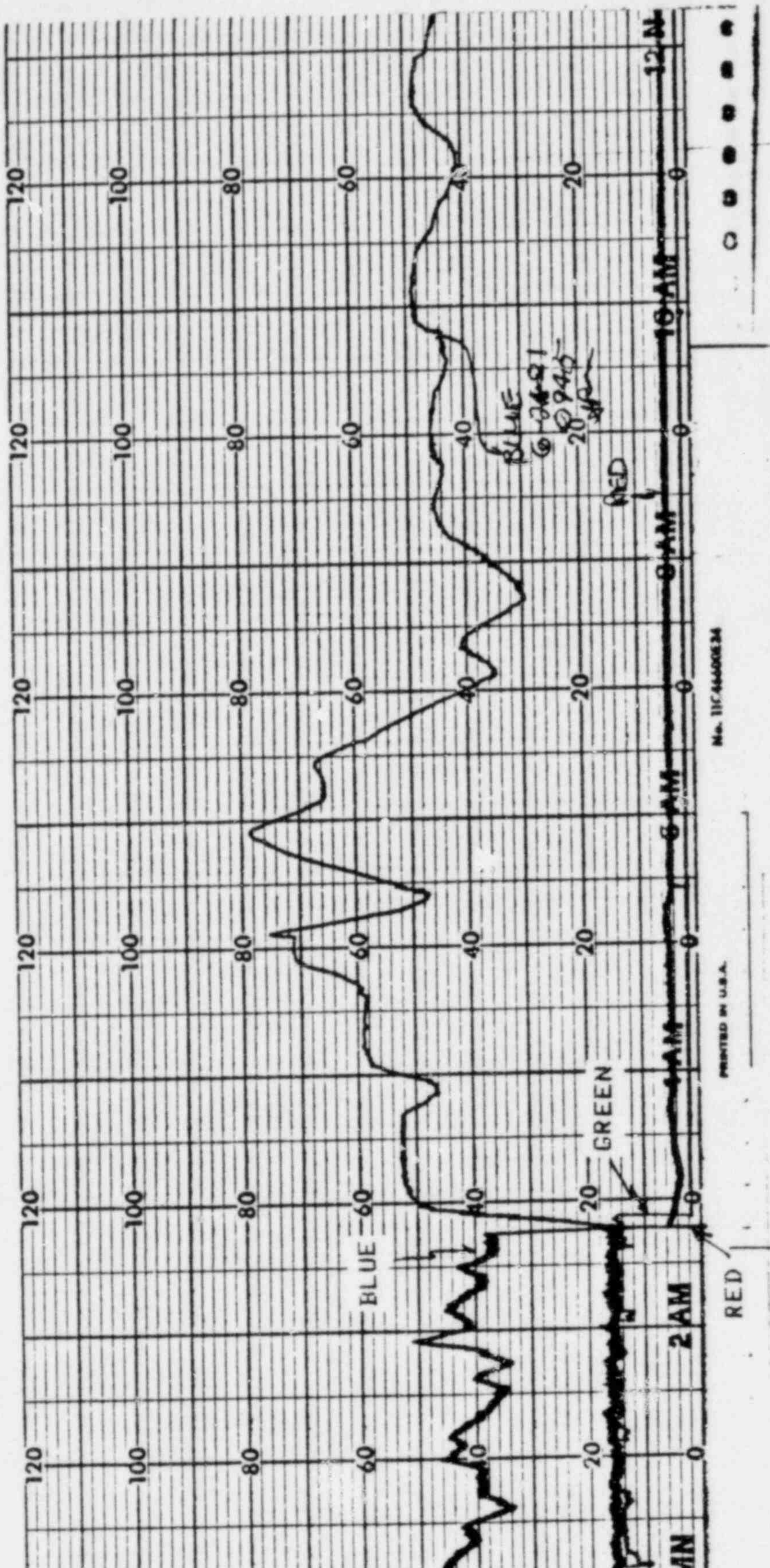
Figure 2.4.8



Red = 21 Steam Flow (%)
Green = 21 Feedwater Flow (%)
Blue = 21 S/G Level (%)

SUP 82.5 - Shutdown from Outside the Control Room
Salem Unit 2 6/24/81

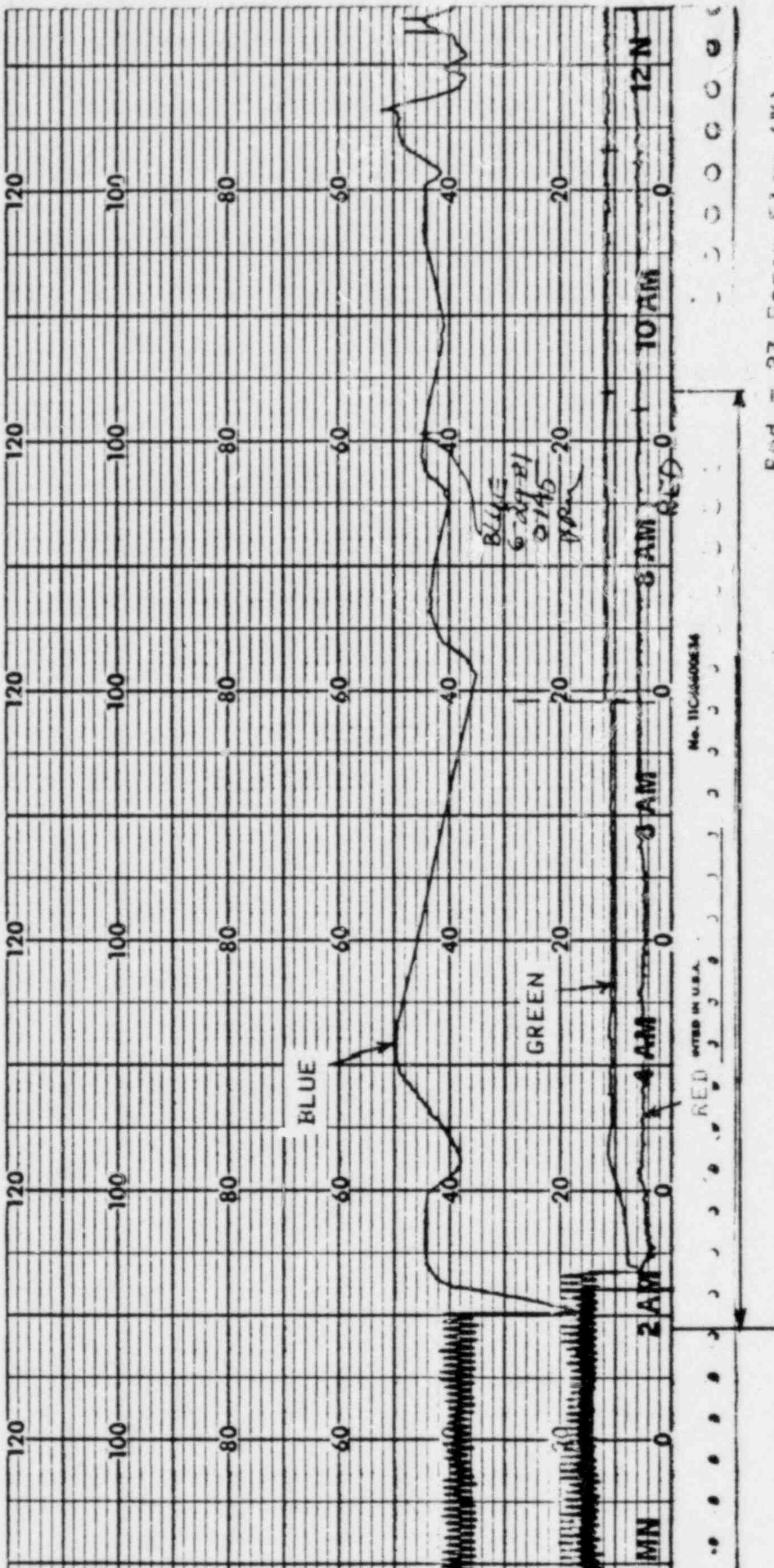
Figure 2.4.9



Red = 22 Steam Flow (%)
Green = 22 Feedwater Flow (%)
Blue = 22 S/G Level (%)

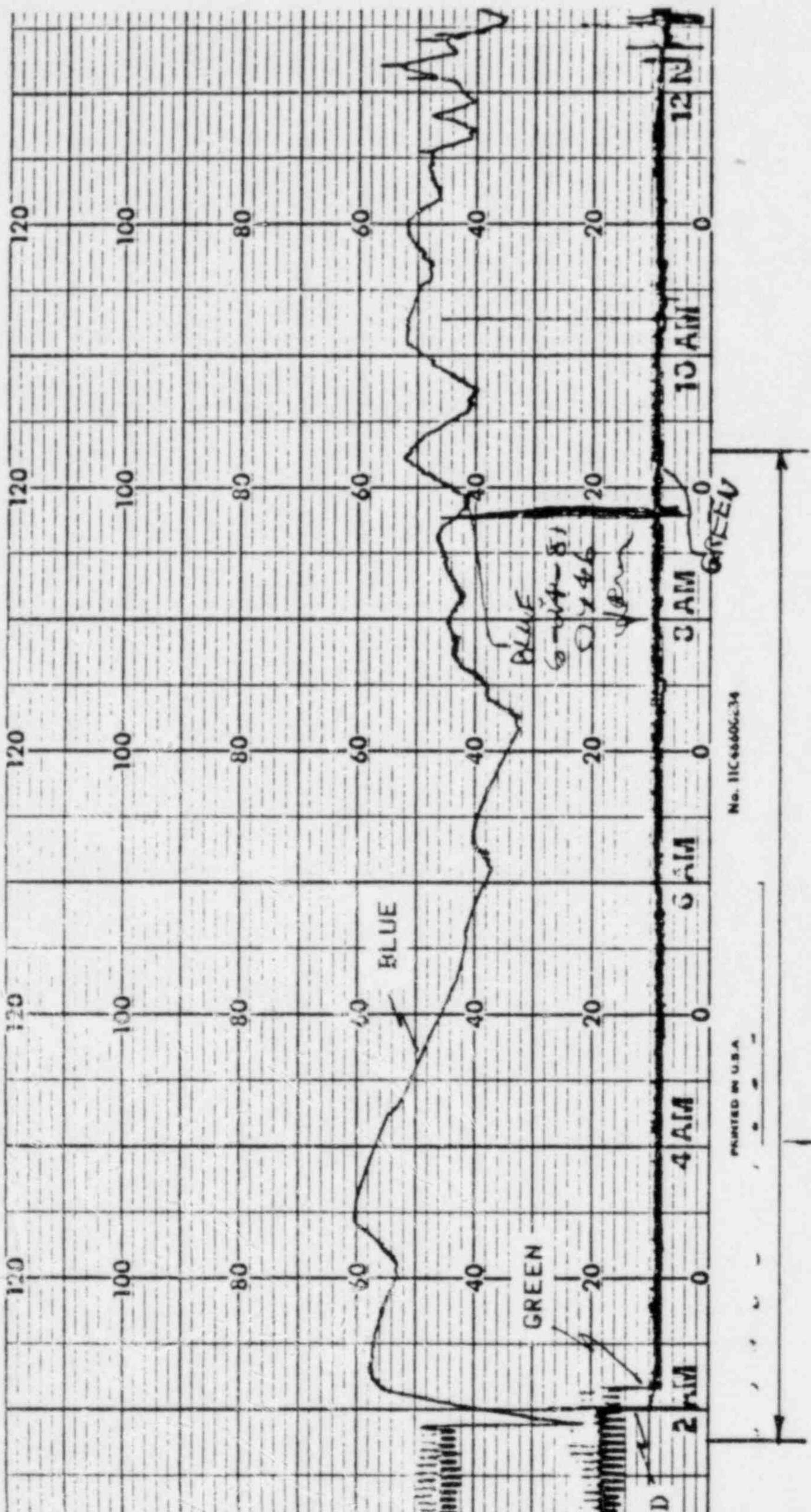
SUP 82.5 - Shutdown from Outside the Control Room
Salem Unit 2 6/24/81

Figure 2.4.10



Red = 23 Steam Flow (%)
Green = 23 Feedwater Flow (%)
Blue = 23 S/G Level (%)

SUP 82.5 - Shutdown from Outside the Control Room
Salem Unit 2 6/24/81



Red = 24 Steam Flow (%)
Green = 24 Feedwater Flow (%)
Blue = 24 S/G Level (%)

SUP 82.5 - Shutdown from Outside the Control Room
Salem Unit 2 6/24/81

2.5 SUP 82.1 - LOAD SWING TESTS

The load swing tests were a series of integrated plant response tests performed to verify that the plant was capable of automatically accepting a 10% step load change from 30%, 75% and 100% power. The load changes were initiated, using the turbine Electric Hydraulic control system, at a rate of 200% per minute. Each test consisted of two parts: a 10% load decrease followed, after equilibrium conditions had been reached, by a 10% load increase.

The load swing was evaluated based on the following criteria:

(1) The reactor and/or turbine did not trip

(2) Safety injection was not initiated

(3) Neither steam line relief valve or safety valve lifted

(4) Neither pressurizer relief valve or safety valve lifted

(5) No operator action required to restore plant conditions to steady state

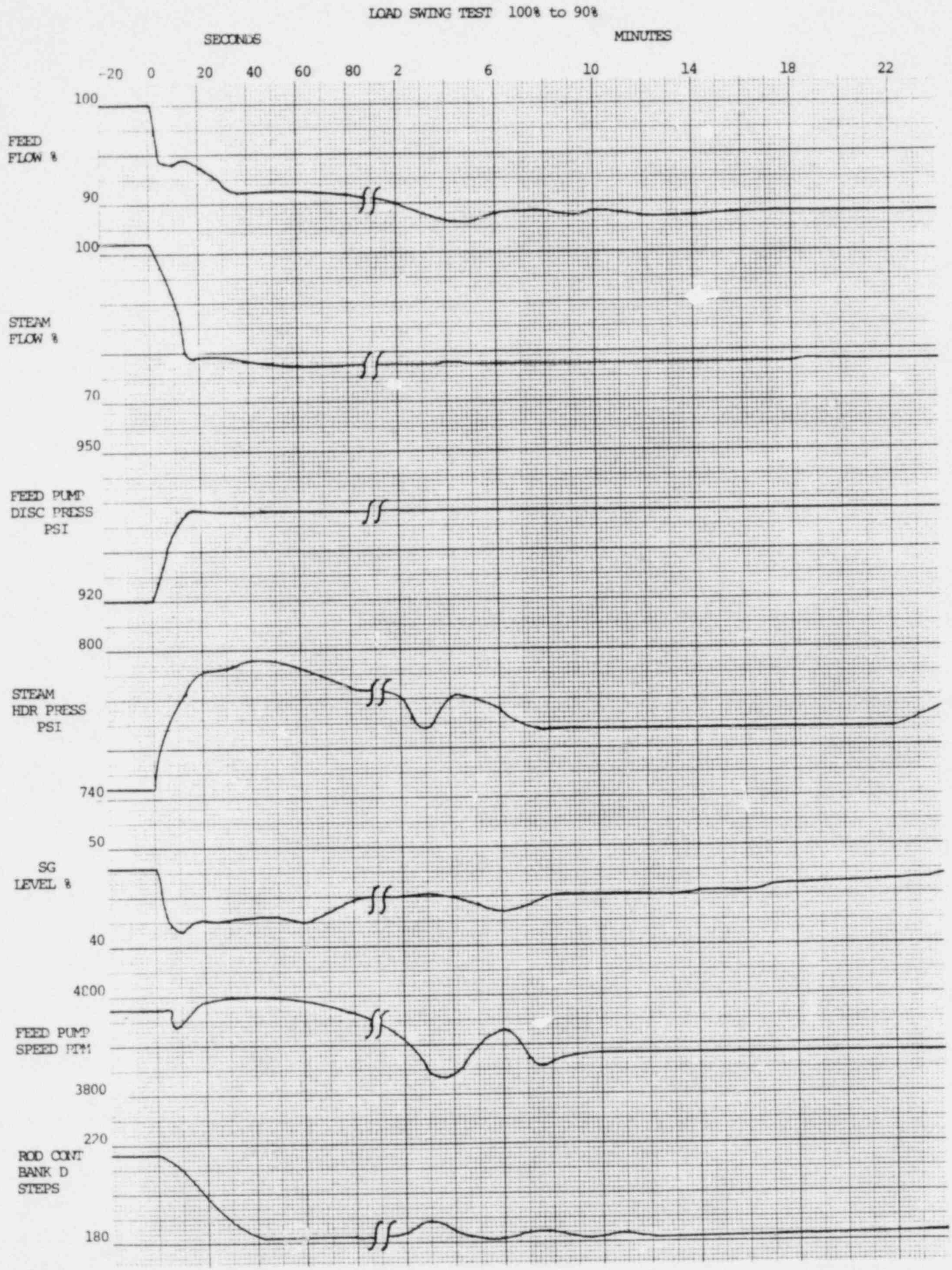
(6) Plant variables such as T_{avg}, feedwater flow, steam flow, etc. should not incur sustained oscillations or large variations

(7) Nuclear power overshoot less than 3% for the load decrease.

The initial load swing at 30% power was to 13%. The overshoot was due to setting the turbine load reference too low. Automatic steam generator level control cannot control at less than 15% RTP so operator action was required to control levels in the steam generators. The up power swing to 30% RTP had acceptable results. All other parameters during the 30% swings fell within the acceptable range.

Testing at 75% and 100% had similar results. The results from the 100% RTP swings are depicted in Figures 2.5.1 thru 2.5.4.

Figure 2.5.1


LOAD SWING TEST 100% to 90%
SECONDS
MINUTES
-20 0 20 40 60 80 2 6 10 14 18 22
100
FEED FLOW %
90
100
STEAM FLOW %
70
950
FEED PUMP DISC PRESS PSI
920
800
STEAM HDR PRESS PSI
740
50
SG LEVEL %
40
4000
FEED PUMP SPEED RPM
3800
220
ROD CONT BANK D STEPS
180

LOAD SWING TEST 100% to 90%

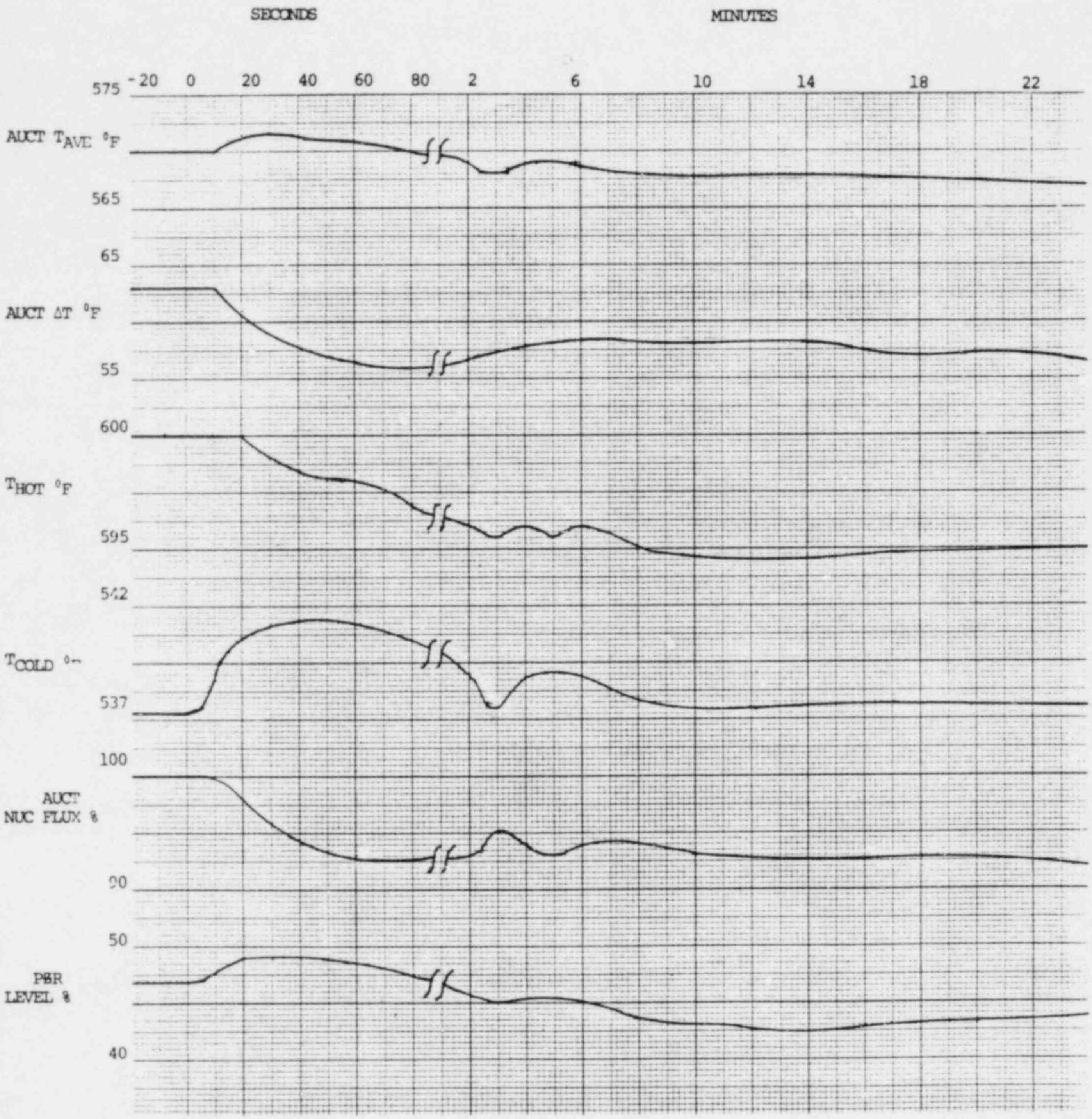
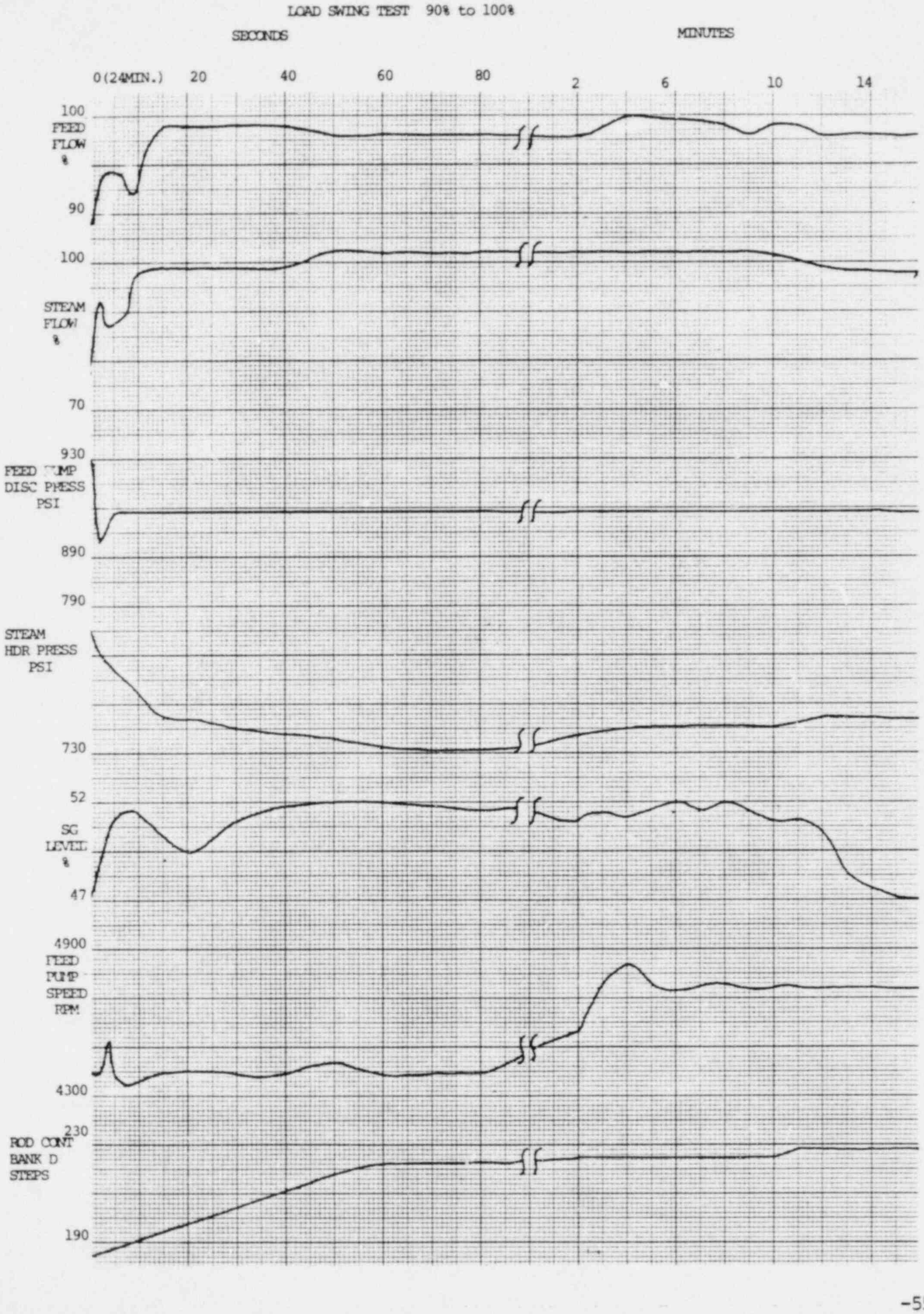
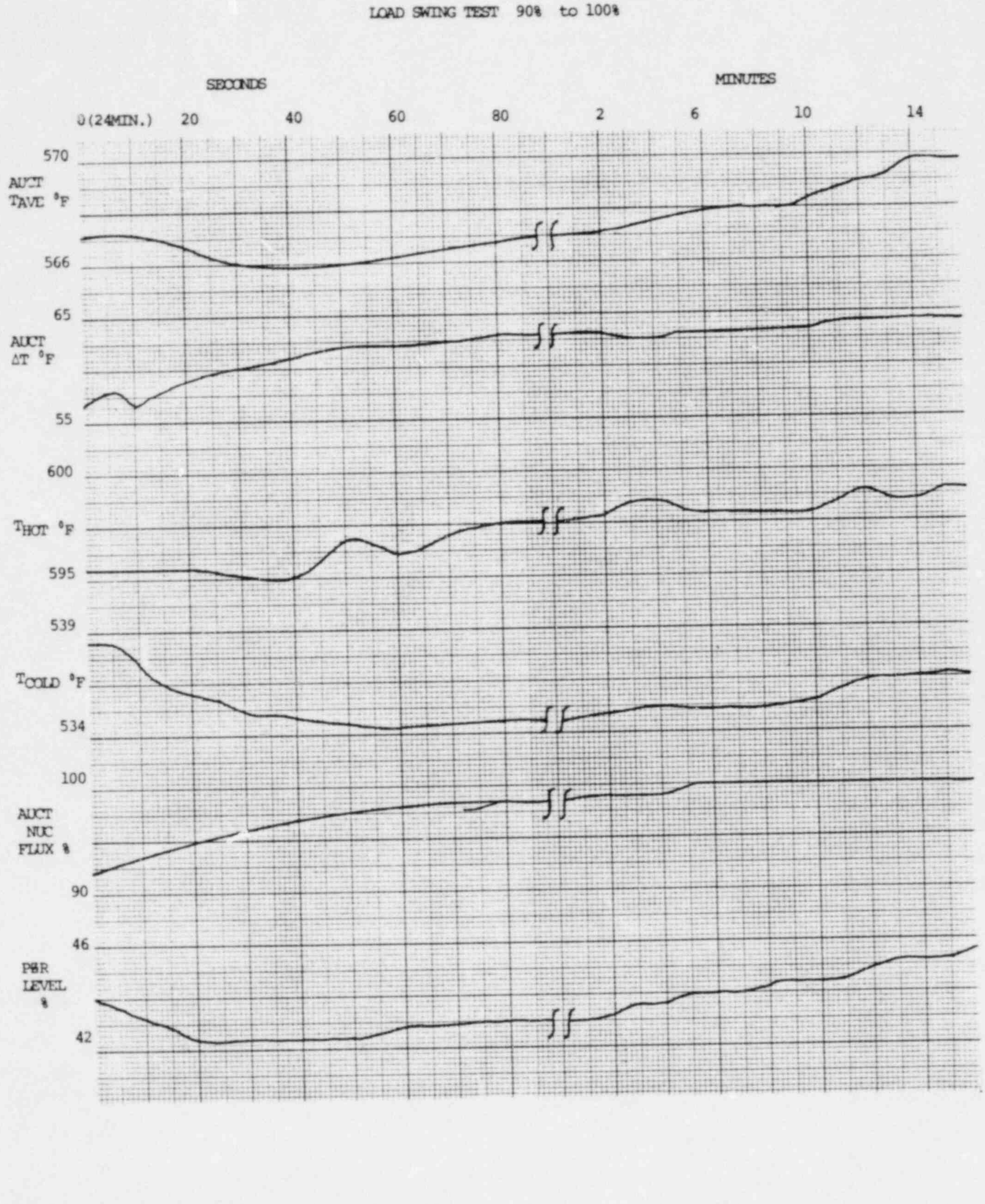


Figure 2.5.3



LOAD SWING TEST 90% to 100%
SECONDS
MINUTES
0(24MIN.)
20
40
60
80
2
6
10
14
100
FEED FLOW %
90
100
STEAM FLOW %
70
930
FEED PUMP DISC PRESS PSI
890
790
STEAM HDR PRESS PSI
730
52
SG LEVEL %
47
4900
FEED PUMP SPEED RPM
4300
230
ROD CONT BANK D STEPS
190

Figure 2.5.4


LOAD SWING TEST 90% to 100%
SECONDS
MINUTES
0(24MIN.)
20
40
60
80
2
6
10
14
570
AUCT
TAVE °F
566
65
AUCT
ΔT °F
55
600
THOT °F
595
539
TCOLD °F
534
100
AUCT
NUC
FLUX %
90
46
PZR
LEVEL
%
42

2.6 SUP 82.4 - RODS DROP AND PLANT TRIP

This test was performed at 50% power. The purpose of the test was to demonstrate the operation of the negative rate trip circuitry. Two rods were dropped from the rod group most difficult to detect by the excore detectors due to low worth and/or core location. In addition, it was the function of the test to review plant response and control systems behavior to a trip from an intermediate power level prior to the plant trip test from 100% power.

The two rods chosen were located in core positions B-4 and D-14. The acceptance criteria specified that a reactor trip must occur as a result of two of the four negative rate bistables tripping. (see figure 2.6.1 for the core location of the rods vs. the excore detectors).

The rods selected were dropped simultaneously from the Rod Control System DC Hold Power Cabinet. The negative rate bistables for N42 and N43 tripped simultaneously ($\pm$ .01 seconds) followed by N41 and N44 negative rate bistables .5 seconds later. The N41 and N44 bistables tripped following the reactor trip from the N42 and 43 bistables at a point where the control rods were dropped approximately 50% into the core. Also measured during the reactor trip was the control rod drop time of 1SC1 (core location E3) for comparison with the drop time at zero power. This rod was also monitored during the 100% trip per SUP 82.9, GENERATOR TRIP. See Table 2.6.1 for a summary of the results. The rod drop time was faster as measured during the reactor trip from power operation compared to zero power operation.

Following the trip the plant was stabilized at the no load T_{avg} of $547^{o}F$ successfully.

TABLE 2.6.1

1SC1 ROD DROP TEST RESULTS

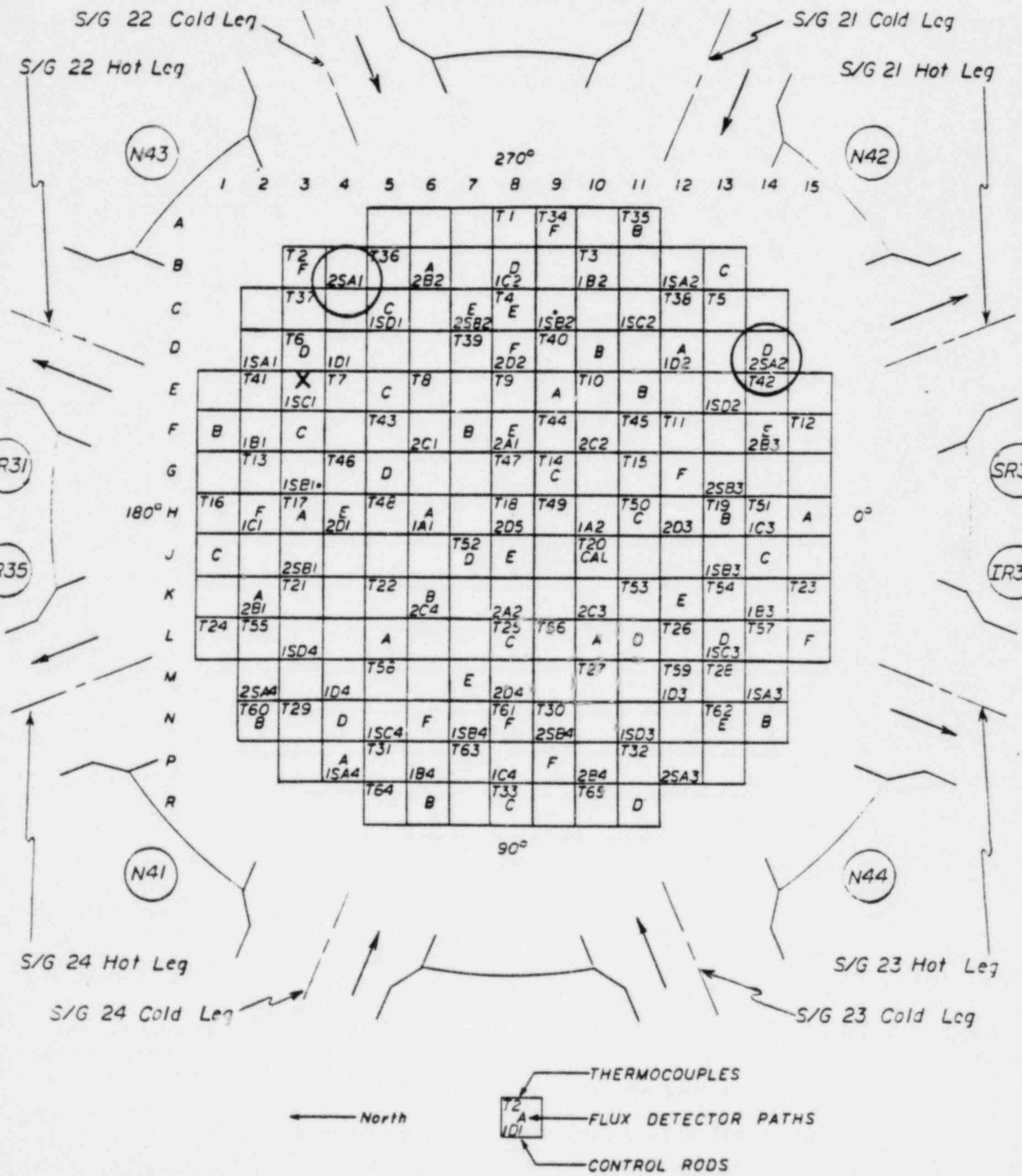
RCS Conditions	Initiations of Event To Dashpot Entry	Initiations of Event to Bottom of Dashpot
547 ^{o}F, 4 RCP's 0% Power	1.35 (Seconds)	1.88
563^{o}F, 4 RCP's 50% Power	1.26	1.82
570 ^{o}F, 4 RCP's 100% Power	1.30	1.85

Figure 2.6.1

SALEM NUCLEAR GENERATING STATION

UNIT NO. 2

RCC INCORE DETECTOR THIMBLE AND THERMOCOUPLE LOCATIONS



2.7 SUP 82.2 - LARGE REDUCTION TESTS

The LARGE LOAD REDUCTION TESTS were conducted to verify the capability of the primary and secondary systems to automatically accept a 50% load reduction from 75% and 100% of full power. The tests were further used to evaluate the interaction between control systems and to determine if system setpoints should be changed to improve transient response.

<u>75% POWER</u>

The first tests were conducted at the reactor power level of 75%. The load changes were initated by using the Electric Hydraulic system at a rate of change of 200% per minute.

The following list shows the range of selected parameter movements during the power reduction:

1.	Feed Water Temperature	401°F - 335°F
2.	Steam Header Pressure	792 psi - 878 psi
3.	Feed Flow	69% (avg) - 26% (avg)
4.	Steam Flow	69% (avg) - 26% (avg)
5.	Steam Generator Level	44% - 24% - 44%
6.	Control Bank D	228 steps - 122 steps
7.	Average Loop ΔT	46.5°F - 22°F
8.	Nuclear Power Flux	71% - 32%
9.	Pressurizer Level	39% - 29%
10.	Pressurizer Pressure	2260 psi - 2175 psi - 2300 psi 2250 psi
11.	Auctioneered T_{avg}	563°F - 570°F - 554°F
12.	Plant Load (MW-Gross)	765 megawatts - 285 megawatts

The following acceptance criteria items were met:

1. The reactor and turbine did not trip.
2. Safety injection was not initiated.
3. Pressurizer safety valves did not lift.
4. Steam generator safety valves did not lift.

During the transient the steam dump valves operated (condenser dumps) to restore T_{avg} to its program value. The dump valves did not open until there was a maximum demand signal. They are designed to modulate open based on an increasing demand signal but instead they "pop" open when they receive a maximum demand signal. (See SUP 81.5, Dynamic Automatic Steam Dump Control). This type of operation causes the steam generator levels to drop to a lower level than they normally would due to the shrink effect in the steam generators caused by the rapid increase in steam generator pressure. Once the cause of the popping operation is corrected and the valves modulate with demand, the steam generator pressure will peak at a lesser pressure assisting in reducing the amount that the steam generator levels are lowered to before they are restored to normal. The present operation of the steam dump valves is acceptable but is being reviewed.

100% POWER

The LARGE LOAD REDUCTION from 100% power was performed prior to the plant trip test. The load change was initiated at a rate of 200% per minute using the Electric Hydraulic system. The following acceptance criteria items were met:

1. The reactor and turbine did not trip.
2. Safety injection was not initiated.
3. Pressurizer safety valves did not lift.

The following list shows the range of selected parameter movement during the power reduction.

1.	Feed Water Temperature	$432^{\circ}F$ - $380^{\circ}F$
2.	Steam Header Pressure	774 psi - 984 psi - 852 ps
3.	Feed Flow	99% (avg) - 48% (avg)
4.	Steam Flow	98% (avg) - 46% (avg)
5.	Steam Generator Level	44% - 49% - 28%
6.	Control Bank D	228 steps - 141 steps
7.	Average Loop ΔT	$62.5^{\circ}F$ - $36.5^{\circ}F$
8.	Nuclear Power Flux	100% - 56%
9.	Pressurizer Level	50% - 34% - 59% - 34%
10.	Pressurizer Pressure	2235 psi - 2322 psi - 2108 p 2335 psi
11.	Auctioneered T_{avg}	$571^{\circ}F$ - $580^{\circ}F$ - $559^{\circ}F$
12.	Plant Load (MW-Gross)	1140 megawatts - 590 megawat

During the transient, the steam dump valves operated at a lower demand signal providing a smoother transient for steam generator level and pressure than was observed during the 75% testing plateau.

Prior to the commencing the load reduction the condensate polishers were bypassed providing an additional 75 psi at the feedwater pump suction. This was done based on observation during the 10% load swing from 100-90-100%. During the 10% load swing it was noted that the MSR Coil Drain Tanks dropped in level causing the Heater Drain Pumps to go in a recirculation mode reducing the feedwater pump suction pressure by approximately 60 psi. The cause of this transient is unknown at this time. To prevent reactor trip on loss of a feedwater pump on low suction pressure the polishers were bypassed to provide additional margin at the feedwater pump suction. During the 50% load reduction the feedwater pump suction decreased by approximately 90 psi again due to the loss of the Heater Drain Pump flow. This transient is being reviewed to determine its cause.

The overall transient was acceptable and is graphically displayed in Figures 2.7.1 and 2.7.2.

Following several feedwater pump trips from 100% RTP, due to a loss of feedwater pump suction pressure, the feed and condensate system was instrumented for continuous monitoring to determine the cause of the rapid reduction in suction pressure. Following a feedwater pump trip, the review of the data indicated the cause to be compounded by a rapid load reduction to restore suction pressure. Several load reductions (7) were made and reviewed to further determine the cause and effects.

During a load reduction condition the H.P. turbine extraction pressure decreases accordingly leaving the saturated liquid of the heater drain system in an unstable condition (subject to flashing). The instability results in decay of heater drain tank level which calls for the heater drain pump discharge valves to close and therefore heater drain flow (1/3 total feedpump demand suppled to feedpump) is reduced. The loss of flow supplied from heater drain system is proportionally more severe with greater load reduction resulting in a corresponding and instantaneous loss of feed pumps suction pressure.

Based on the load reduction tests, it has been determined that with the condensate polisher in service the system can correct for large reduction effects if the initial power level is below 85%. When operating at power levels in excess of 85% the following operation precautions are being observed to eleviate the possibility of a feedpump trip:

1) When operating above 85% power open bypass (2CN-47) around 23, 24 & 25 heaters, (gain of 30 psi on feedwater pump suction).

2) Heater Drain Pump recirculation (21HD17, 22HD17, 23HD17) valves are to be failed open to add stability to heater drain system.

3) The feedpump suction pressure alarm increased to 300 psig from 270 psig for early warning (feedpump trip at 215 psig).

4) If an alarm occurs and a rapid load reduction is necessary (provided their is no chemistry problem present) the condensate polisher bypass can be opened to recover feedpump suction pressure and the operator can then successfully complete a large load reduction (gain of 65 psi on feed pump suction).

5) If an alarm occurs and a sudden load reduction is not necessary, the load should be reduced in 1-10% increments until suction pressure is restored.

The following design charges are being reviewed to provide stability to the feed pump suction during steady state operation and transients.

1) Increasing the capability of the existing condensate pumps for greater head at the same flow (impeller change).

2) Diverting a percentage of condensate flow after the No. 2 feedwater heater to a spray sparger in the heater drain tanks.

3) The possibility of new condensate pumps, and an additional condensate pump or condensate polisher booster pumps.

4) Commonize the heater drain pump suctions so that one pump could be used as a standby pump. This change is also expected to stabilize the heater drain pump flow at steady state and transient conditions.

Figure 2.7.1

LOAD SWING TEST 100% to 50%

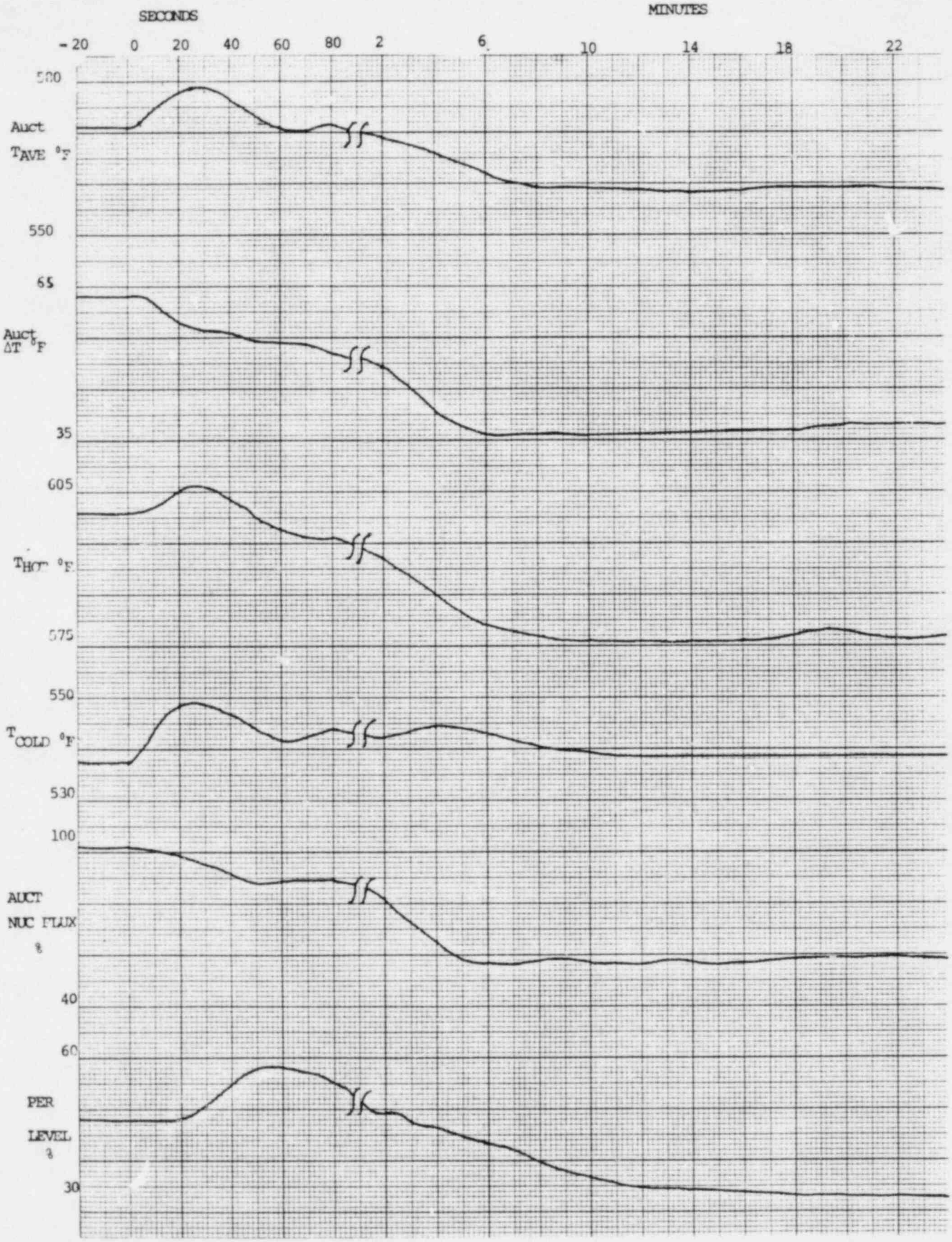
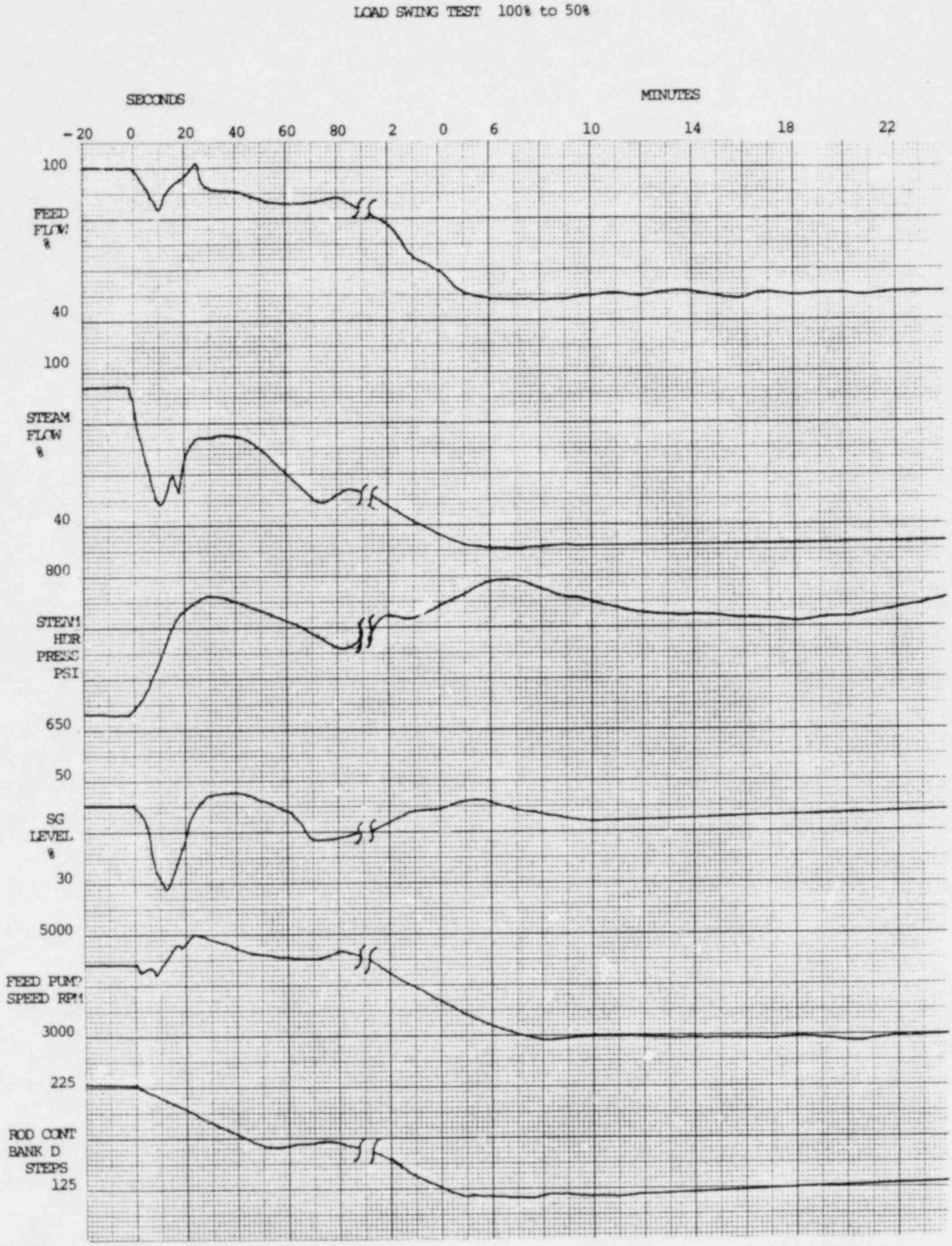


Figure 2.7.2


LOAD SWING TEST 100% to 50%
SECONDS
MINUTES
-20
0
20
40
60
80
2
0
6
10
14
18
22
100
FEED FLOW %
40
100
STEAM FLOW %
40
800
STEAM HDR PRESS PSI
650
50
SG LEVEL %
30
5000
FEED PUMP SPEED RPM
3000
225
ROD CONT BANK D STEPS
125

2.8 SUP 82.7 - STEAM GENERATOR MOISTURE CARRY OVER MEASUREMENT

The steam generator moisture carryover measurement was orignally scheduled to be performed at three power levels; 75, 90 and 100%.

Based on previous experience, Westinghouse (the turbine generator and NSSS supplier) recommended that we perform this test only at 100% RTP under various conditions. The variations included altering T_{avg}, steam generator levels, and reactor power to determine their effects on moisture carryover. The determination was made to conduct the test as recommended.

The test procedure requires the use of a radioactive tracer, Sodium 24, in the form of an aqueous solution of sodium nitrate. The traces had an activity of 1.2 curies at the time of its arrival on-site after being activated at the University of Missouri Test Reactor. The tracer was injected into the feedwater system using the chemical addition system. The phosphate feed pump (5 gpm) took suction from a 50 gallon drum to which the source was added (located on 100' elevation of the turbine building) and injected it into the main feedwater line of each steam generator just upstream of the main feedwater regulating valve. The injection lines were valved in and out to equalize the quantity of the source in each steam generator (3 minutes for each steam generator).

Three sets of samples were taken at each test condition. Each set consisted of a blowdown sample and a steam sample from each steam generator and a common feedwater sample for a total of 27 samples per test condition. The results were based on analysis of the blowdown and feedwater samples. The main steam samples were analyzed, but the results are used as a general indicator for comparison of each steam generator moisture removal performance.

During the performance of the first test, on 8/28/81, two vials containing the source were received and used for injection into the feedwater system. This resulted in uneven distribution of the source from one steam generator to the next.

When the test was re-run on 9/10/81 and 10/12/81 four vials were used each containing equal strength. Each vial was added to the 50 gallon drum separately and fully injected into one steam generator, the drum flushed to the generator and then a second generator lined up. The process repeated for each steam generator. This method provided excellent distribution of the source with less than 5% deviation in activity levels between any two steam generators.

The performance of the first moisture carryover test was conducted on August 28, 1981 at 100% RTP and 44% steam generator levels, and at 100% RTP and 40% steam generator levels. With normal levels (44%) in the steam generators the average carryover was .33%. With levels reduced to 40% the average carryover was .20%. The steam samples indicated that #21 steam generator moisture carryover was significantly higher than the other three steam generators. It was also noted that #21 steam flow signals were 10-20% higher than the other steam generators (see SUP 81.7, calibration of stream flow and feedwater flow instrumentation). A retest on September 10, 1981 had similar results with #21 steam generator having the greatest carryover. Even with reduced levels, the carryover on #21 steam generator was still greater than 1.0%. The determination was made to shutdown and inspect the internals of all four steam generators. The inspection did not uncover any faults. The second stage separation equipment was modified to provide additional moisture drainage paths for each steam generator to reduce any carryover. (See Figure 2.8.1)

A retest performed on October 12, 1981 indicated the average carryover was .13% with normal steam generator levels (44%). The carryover measured for #21 steam generator had been reduced to .17%. The acceptance criteria was less than .25% moisture carryover and was easily met. It was also noted that No.21 Steam Generator steam flow signals were reduced in magnitude by 10-20%. See Table 2.8.1 for a review of the carryover measurements.

Note:
An additional carryover test was performed on January 22, 1982 due to reoccurrence of high steam flows in December, 1981 for no apparent reason. The results from that test were similar to the results in October, 1981. See Section 3.4 for explanation.

STEAM GENERATOR MOISTURE CARRYOVER MEASUREMENT DATA REVIEW

Notes	Dates	Power Level (%)	SG Levels (%)	SG Pressure (PSIA)	T_{avg} (^{o}F)	Load (MWC)	Feed with Temp (^{o}F)	FD WTR Carryover (%)	Steam carryover (%) 21	22	23	24	Back Pressure (PSIA)
Before	8-29-81	99.7	44	802	572.2	1110	431	.342	-	-	-	-	3.4
MOD's		99.2	40	808	572.6	1140	431	.200	-	-	-	-	3.3
Retest	9-11-81	98.5	44	813	572.4	1134	432	.280	1.49	.69	.28	.02	2.3
for Verification		98.9	36	809	572.3	1140	432	.180	1.27	.44	.13	.01	2.3
of		91.8	44	813	569.9	1053	426	< Min. Detectable Activity					2.2
Carryover		96.7	44	812	571.4	1110	430	.080	-	-	-	-	2.4
After	10-12-81	100.1	36	791	570.6	1187	432	.125	.16	.14	.12	.01	1.7
SG		99.67	44	792	570.8	1180	432	.133	.15	.15	.11	.01	1.7
MOD's		94.33	44	792	567.6	1110	430	.05	-	-	-	-	1.7

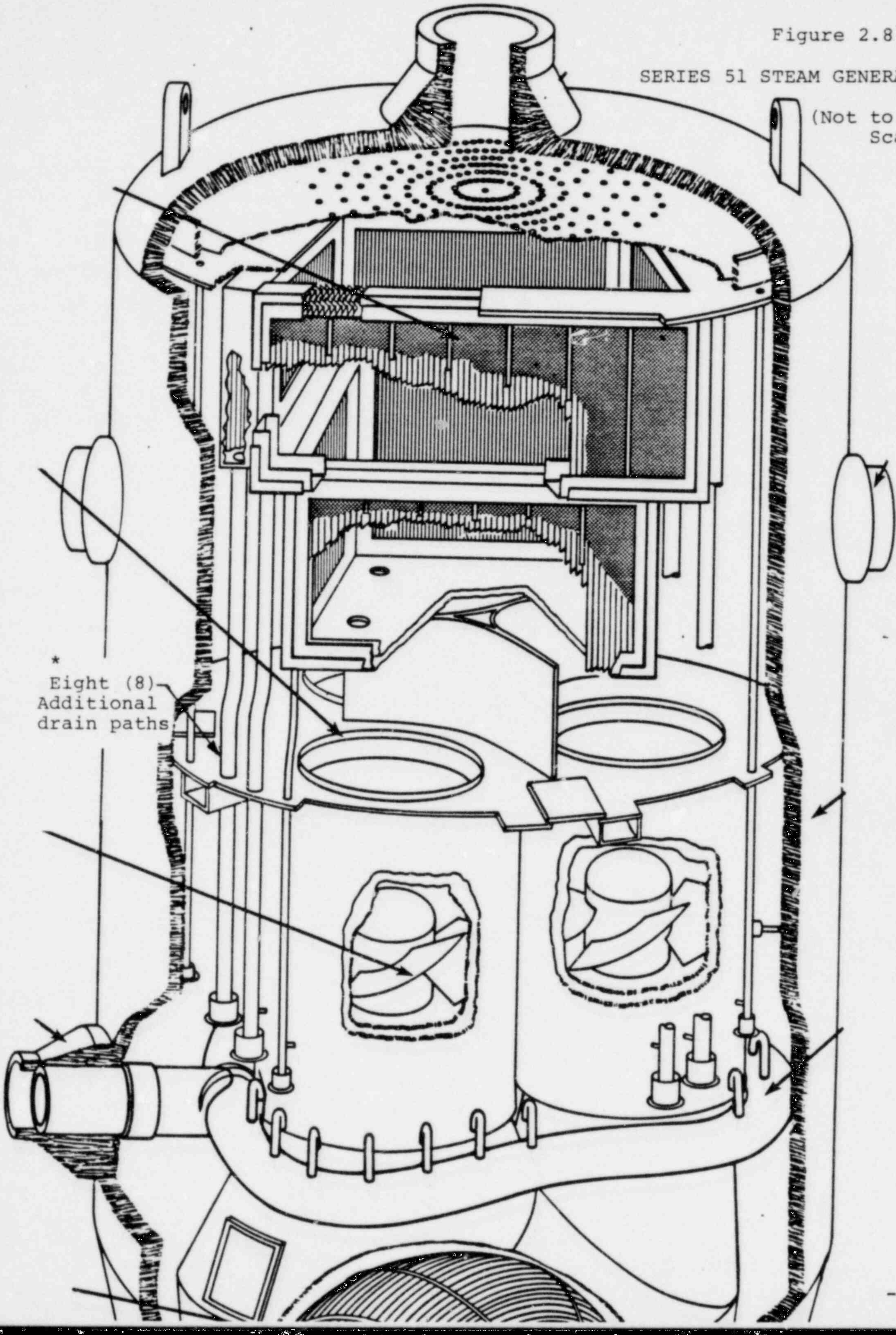
Table 2.8.1

109D(1):70

Figure 2.8.1

SERIES 51 STEAM GENERATOR

(Not to Scale)



2.9 SUP 82.8 - NSSS ACCEPTANCE TEST

This was one of the last tests performed during the startup of Unit 2. The test had two purposes: first, to demonstrate the reliability of the NSSS by maintaining the plant at rated output of 3411 MW_t (+0%, -5%) for 100 hours without a load reduction or plant trip resulting from an NSSS malfunction and second, to measure the gross electrical output and the turbine heat rate to verify the capability of the Unit.

The 100 hour run was attempted several times during the 100% testing plateau. Each time the unit was forced to reduce power to clean condensate, heater drain or feedwater pump strainers. The maximum run at greater than 95% power was 69 hours before a load reduction was required. Total accumulated time at greater than 95% power was 205 hours. Based on the fact that the load reductions were not NSSS related the 100 hour run was accepted on an accumulated basis. Since this run, Unit 2 has accumulated better than 100 hours of continuous operation at greater than 95% power.

The second part of the NSSS acceptance test was the measurement of the gross electrical output and the turbine heat rate. Normal plant instrumentation was used as a backup to a primary data logger which was fed from test instrumentation installed for the test run. The data logger received a data scan every 2 minutes whereas the plant instrumentation was read every

30 minutes. Data was accumulated over a 4 hour period with reactor power and turbine power held steady at 100% RTP. The results were corrected to design conditions and are listed below:

*Date	Goss Electrical Output	Corrected Heat Rate
8/27/81	1161.4 - (MW)	10,059 (BTU/KWH)
10/15/81	1172.4	9,963
10/21/81	1173.9	9,950

*The test run on 8/27/81 had 5 out of 6 circulating water pump operating. To reduce the errors involved in correcting for backpressure, data was taken with 6 circulating water pump on 10/15 and 10/21/81. The calorimetric results using plant vs. test instrumentation indicated less than a .5% difference for all three test runs.

2.10 SUP 82.9 - GENERATOR TRIP FROM 100% POWER

This was the last test performed during the startup of Salem 2. The test had three purposes: first, to verify the capacity of the primary and secondary plant systems to automatically accept a generator trip from 100% power and to bring the plant to a stable condition following the trip; second, to verify that the turbine overspeed mechanism operates to limit turbine speed in an actual overspeed condition; and finally, to determine the overall response time of the reactor coolant hot leg resistance temperature detectors (RTD). The RTD response time was defined as the time interval between the point where the neutron flux had decreased by 50% of its initial value to the point where the hot leg temperature had decreased by 33-1/3% of its initial loop ΔT value. In addition the rod drop time of a selected rod was monitored during the reactor trip.

The reactor was operating at 98% power when the trip was initiated at 0924 hrs. on September 2, 1981. The trip was initiated by the Control Room Operator simultaneously opening the main generator output breakers to the 500 KV bus (bus sections 1-9 and 9-10) to trip the generator. The main turbine tripped on overspeed at its trip setting of 1835 RPM in less than 1 second causing a reactor trip. The main steam stop valves (21-24MS167) were closed immediately after the reactor trip to contain as much heat as possible in the RCS to avoid delays in restoring T_{avg} required for SUP 90.9, BORON MIXING AND COOLDOWN TEST. This caused the steam generator pressure to increase higher than normally expected. The atmospheric relief valves (21-24MS10) operated as designed to maintain steam generator pressure at approximately 1000 psig. On No. 23 Steam Generator the setpoint of the first safety valve was reached (23MS15, 1070 psig) approximately 30 seconds following the trip. The actual pressure reached was 1050 psig indicating the safety valve is set on the "light side". The valve was reset and did not lift again.

The remainder of the test went smoothly. Listed below are some of the parameters that were monitored and how they varied during the test:

Pressurizer level ranged from 46% at the time of the trip, to a high of 46% and a low of 23%.

Pressurizer pressure ranged from 2240 psi prior to the test, to a high of 2240 psi and a low of 2010 psi.

When the generator output breakers were opened, turbine speed increased 90 rpm to 1890 rpm.

Steam generator levels decreased from 44% to 0% indicated level.

T_H of 597°F at the start of the test to 547°F.

T_{avg} of 570°F at the start of the transient to 547°F.

Maximum steam dump demand was generated 5 seconds after the generator trip.

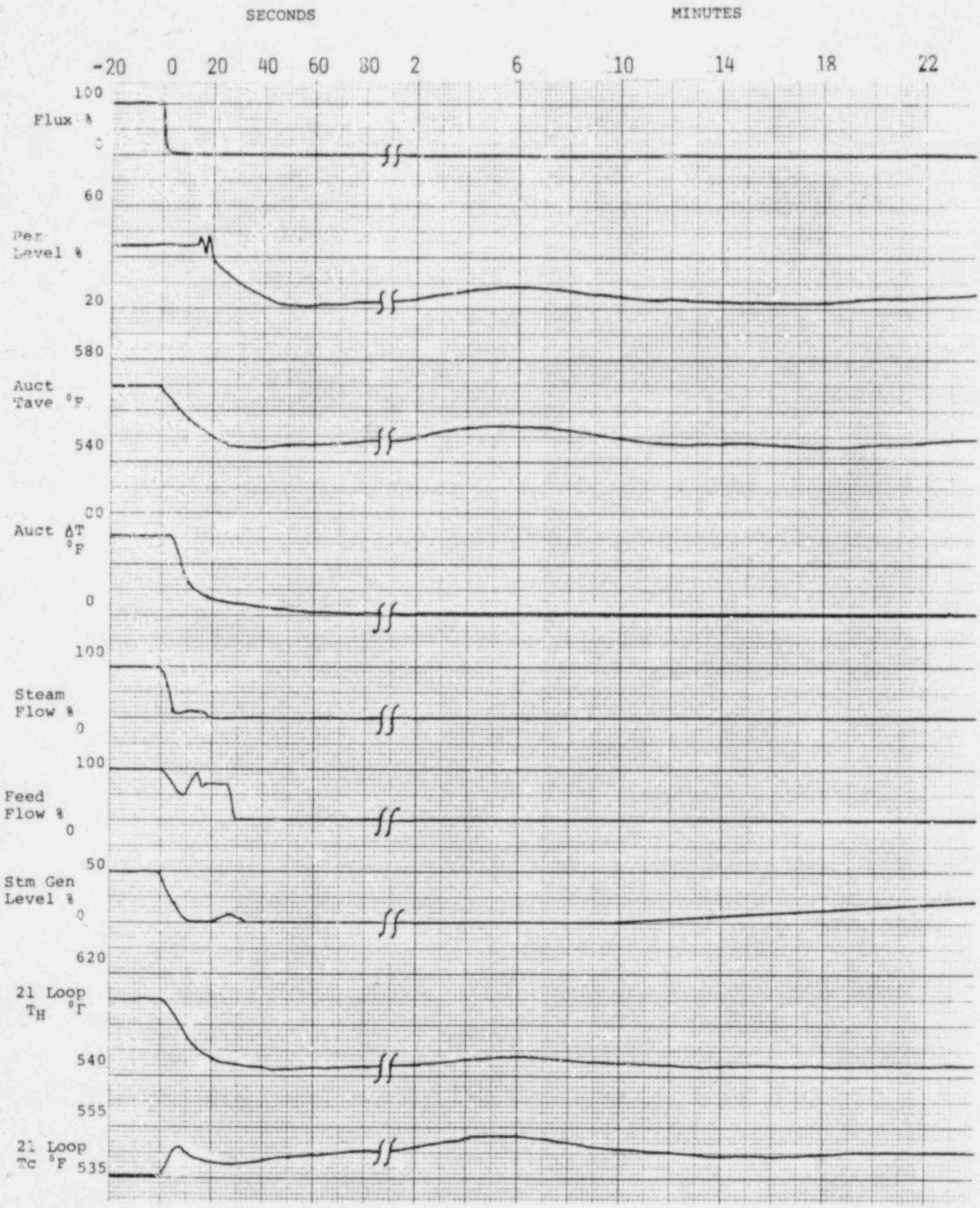
The steam dump valves started opening six seconds after the generator trip.

The RTD response time was measured to be 5.5 seconds versus a maximum of 6.3 seconds. The rod drop time was measured as 1.30 seconds from the fully withdrawn position at the time of decay of stationary gripper coil voltage to dashpot entry versus the Technical Specification maximum of 2.2 seconds. The rod measured was 1SC1.

The transient response of selected parameters is graphically displayed in Figures 2.10.1.

Figure 2.10.1

GENERATOR TRIP TEST



2.11 SUP 90.9 - BORON MIXING AND COOLDOWN

The objectives of this tests were:

(1) to borate the RCS and verify boron mixing while in the natural circulation mode.

(2) to demonstrate the capability to cooldown the RCS while in natural circulation.

This test was originally scheduled to be performed during the initial natural circulation test program after low power physics testing. During that time the reactor was maintained critical at approximately 3% RTP after the RCP's were secured. To perform a more realistic test the test was delayed until the Generator Trip Test (Section 2.10) when the reactor core had built-in decay heat following 1310 MWD/MTU of core burnup and 200 hours at greater than 95% RTP accumulated (see figures 1.1 thru 1.5 for reactor power history prior to the plant trip).

The Generator Trip Test was initiated on 9/2/81 at 0924 (see Section 2.10) and caused an immediate turbine trip and reactor trip. The plant was stabilized at a T_{avg} of $547^{o}F$. The pressurizer and RCS were sampled to obtain a baseline boron concentration (960 ppm). At 1056 hrs., the RCP's were tripped, time "0" on figure 2.11.1.

T_{avg} and Delta T stabilized after 15 minutes. T_{avg} increased to $558^{o}F$ and delta T to approx. $18^{o}F$. Auxiliary spray was initiated to maintain pressurizer pressure at 2235 psig (charging isolated and reinstated after 2 minutes). From this point on, auxiliary spray was used to control pressurizer pressure since normal spray is not effective without the driving head of the RCPs.

Starting at 1116 hrs. a boration of the RCS at 5 gpm was commenced to increase the RCS boron concentration by 100 ppm, from 960 ppm to 1060 ppm. By 1226 hrs.,367 gallons of boric acid had been added to the RCS, the boron concentration, as measured in loop 21 and 23 hot legs, was 1031 ppm. At 1410 hrs. the RCS samples indicated the concentration had stabilized at 1090 ppm. Using the auxiliary spray flow, the pressurizer boron concentration was increased to equal the RCS boron concentration. As indicated in figure 2.11.1, loop 23 T_{avg} and Delta T indicated a sharp increase in temperatur· This was due to diverting all charging flow to the pressurizer to equalize the RCS and pressurizer boron concentration. The increase in flow to the pressurizer through the auxiliary spray line caused an outsurge from the pressurizer through the surge line. The hotter water was sensed by loop 23 hot leg RTD.

The second phase of this test was to verify the ability to cooldown the RCS while in natural circulation. Cooldown was commenced at 1600 hrs. using the steam generator atmospheric relief valves (MS-10's) starting with an average T_{avg} of 555°F The cooldown rate was limited to less than 25°F per hour with an average cooldown rate of 19°F per hour. The cooldown was secured four (4) hours later at which time the average coolant temperature was 480°F. The only difficulty encountered during the cooldown was the controlling of the MS-10s to maintain the steam pressure difference between the steam generators to less than 100 psi to avoid a safety injection signal.

As can be seen in figure 2.11.2, between hours 2 and 3, the cooldown rate increased for a period of 15 minutes at greater than 25°F per hour. Charging was increased to maintain pressurizer level greater than 20% indicated level. The cooldown was temporarily secured until parameters stabilized and again initiated after 30 minutes of stabilization. During the first hour, pressurizer level and pressure increased due to manual control of pressurizer heaters and charging. Pressurizer pressure was allowed to slowly decrease during the cooldown to maintain the pressure/ temperature limitations.

Figure 2.11.1

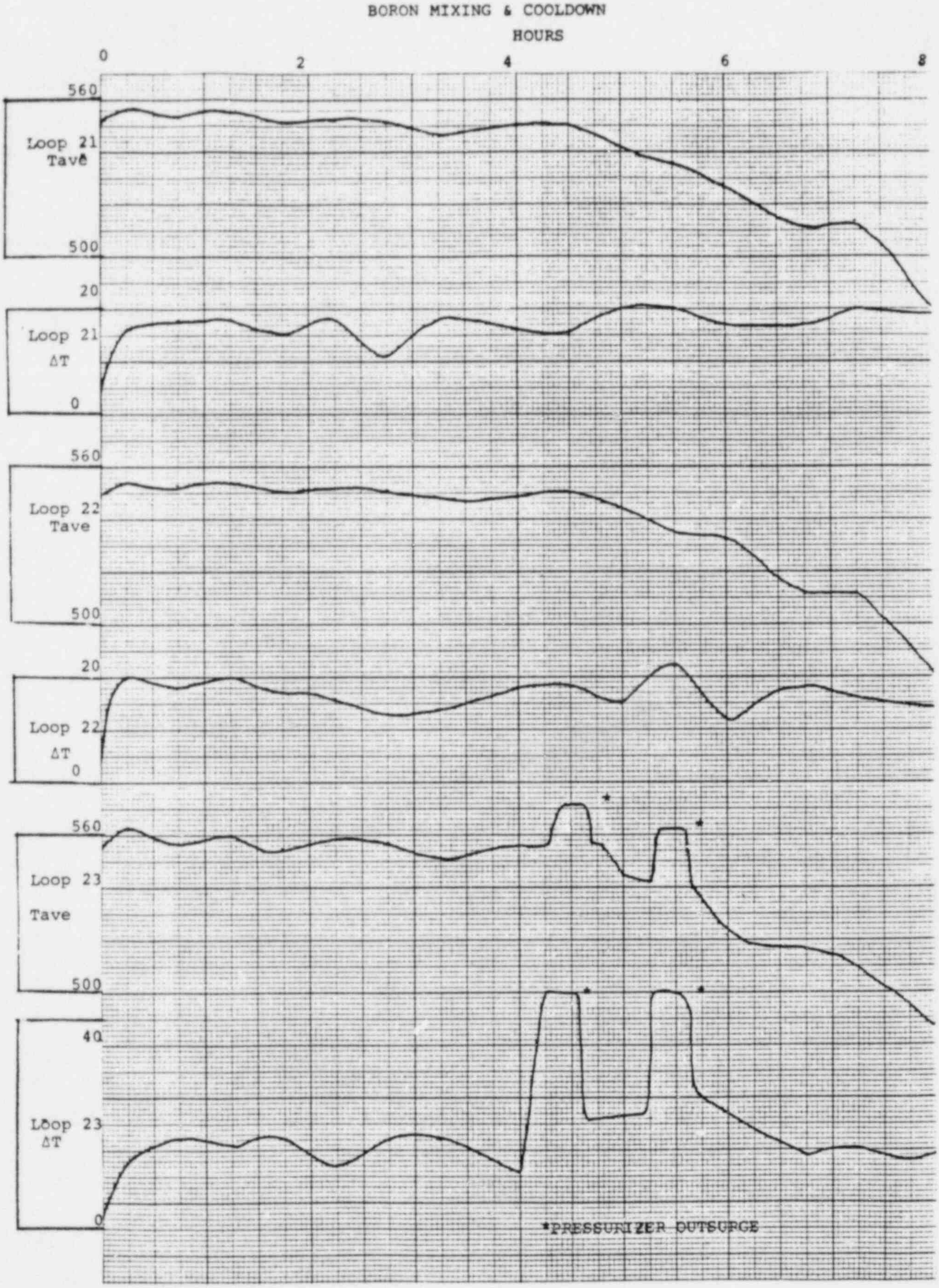
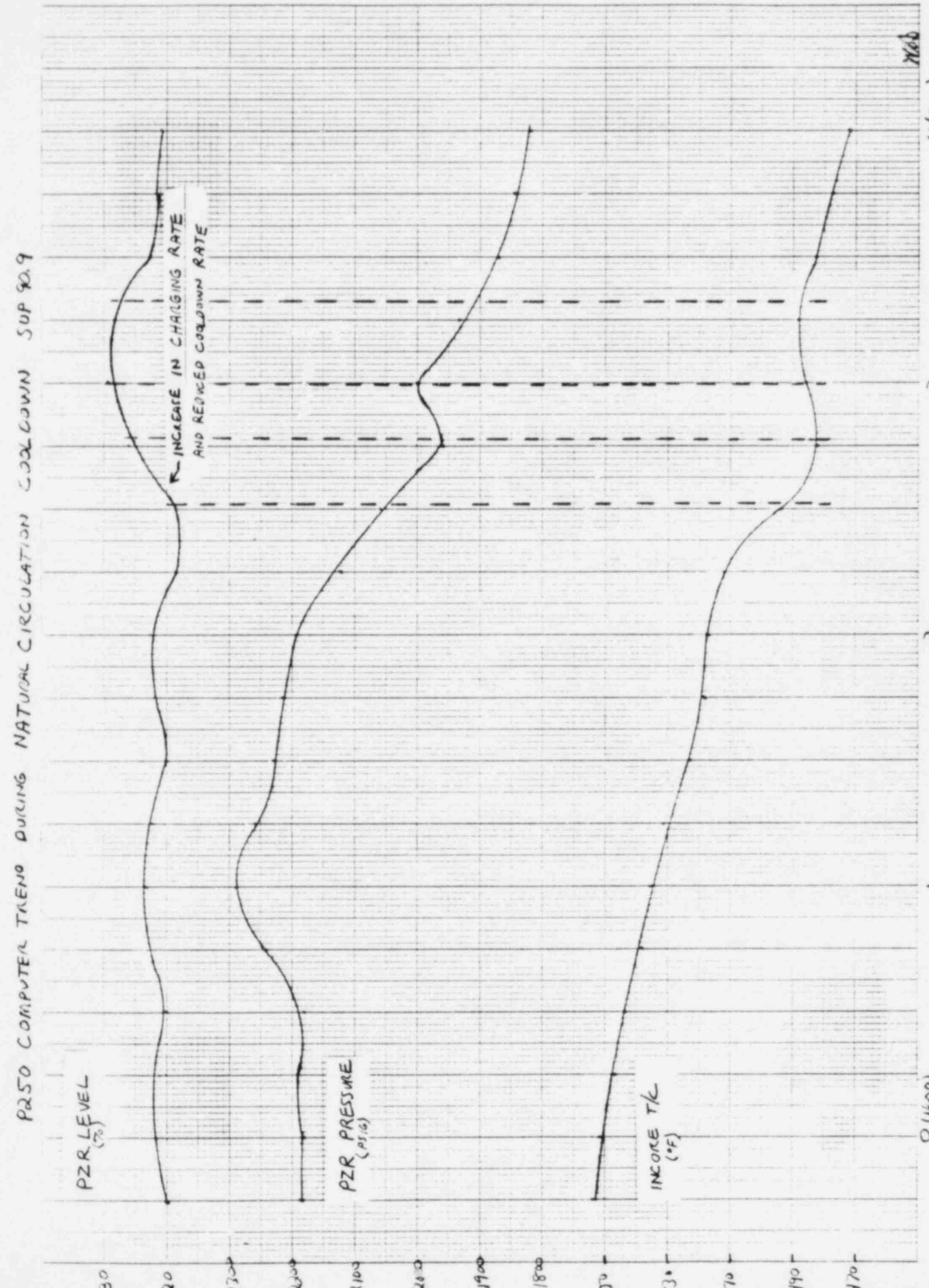

BORON MIXING & COOLDOWN
HOURS
0
2
4
6
8
560
Loop 21
Tave
500
20
Loop 21
ΔT
0
560
Loop 22
Tave
500
20
Loop 22
ΔT
0
560
Loop 23
Tave
500
40
Loop 23
ΔT
0
*PRESSURIZER OUTSURGE

Figure 2.11.2


P250 COMPUTER TREND DURING NATURAL CIRCULATION COOLDOWN SUP 90.9
PZR LEVEL (%)
PZR PRESSURE (PSIG)
INCORE T/C (°F)
INCREASE IN CHARGING RATE
AND REDUCED COOLDOWN RATE
TIME (HOURS)
0 (1600)
1
2
3
4 (2000)
30
20
1900
1800

2.12 RADIATION SHIELDING EVALUATION, EFFLUENT MONITORING, CHEMISTRY AND RADIOCHEMISTRY TESTS

2.12.1 SUP 81.13 - RADIATION MONITORING AND SHIELDING EVALUATION

The objectives of the shielding test were threefold: first, to obtain baseline radiation level data at 0%, 30%, 75% and 100% reactor power by measuring radiation levels at locations throughout the plant; second, to detect and identify localized high radiation levels and streaming to protect personnel from overexposure during plant power escalation and power operation; and finally, to obtain radiation data necessary to correct or reduce localized high radiation levels. At each power level, radiation levels were measured at 211 points throughout the plant. In all cases, the radiation levels were within the design limits. No hot spots or indications of streaming were found. At the present time in the shielding evaluation, it is anticipated that no additional shielding will be required.

2.12.2 SUP 81.14 - EFFLUENT MONITORING SYSTEMS

The purpose of this procedure was to verify the calibration of the effluent monitors by laboratory analysis of radioactive waste samples. These tests were to be performed as early in the power escalation as possible, and were to be repeated after operation at 30%, 50%, 75% and 100% power. The tests were performed on the following effluent monitoring systems:

<u>Containment Sampling System</u>:

Channels	2-R11A	(Particulate)
	2-R12A	(Noble Gas)
	2-12B	(Iodine)

<u>Plant Vent Sampling & Monitoring</u>:

Channels	2-R16	(Bypass Activity)
	2-R41A	(Particulate)
	2-R41B	(Iodine)
	2-R41C	(Noble Gas)

<u>Liquid Waste Monitoring</u>

Channel	2-R18	(Gross Common Activity)

To properly correlate the channel reading to the lab analysis, a minimum upscale reading was required. Once the minimum criteria was met, the actual response of the monitor was compared to the calculated response expected from radio-analysis in the laboratory. The acceptance criteria was that they agree within a factor of +2 to -0.5. All channels tested which had the minimum upsale reading fell within the acceptance criteria.

2.12.3 SUP 81.15 - CHEMISTRY AND RADIOCHEMISTRY TESTS

The purpose of this test was to verify the water chemistry requirements of the RCS and the radiochemistry requirements as set forth by Westinghouse can be maintained within the specified limits. The ability to control the water chemistry was demonstrated at low power, 30%, 50%, 75% and 100% RTP.

Table 2.12.3.1 lists the results of those measurements along with the specified limits. All parameters monitored were maintained within their specified limits.

TABLE 2.12.13.1

RCS CHEMISTRY

PARAMETER	UNIT	POWER LEVEL (%)					Acceptable Value
		<5	30	50	75	100	
PH		6.31	6.66	6.59	6.53	6.58	4.2 to 10.5
Chloride	ppm	<0.05	<0.05	<0.05	<0.05	<0.05	≤ 0.15
Flouride	ppm	<0.014	<0.014	<0.014	<0.014	<0.014	≤ 0.15
Lithium	ppm	0.78	1.8	1.84	1.71	1.61	0.7 to 2.2
Dissolve Oxygen	ppm	<0.005	<0.005	<0.005	<0.005	<0.05	≤ 0.10
Gross Beta-Gamma	uci/ml	3.92E-5	2.99E-1	3.59E-1	3.98E-1	5.49E-1	N/A
Dose EQuil. I-133	uci/gm	0.00	0.00	4.93E-4	0.0	4.99E-4	≤ 1.0

STEAM GENERATOR CHEMISTRY

PARAMETER	UNIT	POWER LEVEL (%)					Acceptable Value
		<5	30	50	75	100	
Gross Beta-Gamma (#21)	uci/ml	2.01E-7	1.36E-7	9.70E-8	1.01E-7	1.35E-7	<0.10
Gross Beta-Gamma (#22)	uci/ml	1.93E-7	1.36E-7	9.70E-8	1.01E-7	1.35E-7	<0.10
Gross Beta-Gamma (23)	uci/ml	2.08E-7	1.36E-7	9.70E-8	1.01-7	1.35E-7	<0.10
Gross Beta-Gamma (#24)	uci/ml	7.24E-7	1.36E-7	9.70E-8	1.13E-7	1.35E-7	<o.10

2.13 SUP 81.4 - AUTOMATIC STEAM GENERATOR LEVEL CONTROL

The objectives of the test procedure were the following:

(1) To verify the stability of the AUTO S/G level control system following simulated transients at low power conditions and adjust controller set points as required to achieve the required system response.

(2) To verify the proper operation of the variable speed feature of the feedwater pumps and adjust controller setpoints to achieve the required results.

The intent of this test was to verify the automatic level control prior to placing the steam generator level controller in automatic. During normal power operation the steam generators were placed in automatic level control at 15% RTP. During the power ascension to 30% RTP the level controls were placed in automatic to give the control room operators more flexibility, and to prevent unplanned reactor trips due to high/low steam generator levels. While at 30% RTP each steam generator level controller was tested individually. The level controller for the steam generator to be tested was placed in manual control. The level error signal induced called for increased feedwater flow. The time response of the system and the degree of level overshoot were monitored and controller adjustment made until an acceptable response was obtained (within 5 minutes for response and less than 5% overshoot). Each steam generator level controller was adjusted in this manner. The initial controller settings were derived from the PLS (Precautions, Limitations and Setpoints) document.

The second phase of this test verified the operation of the main feed pump speed controller by inducing a step speed change of 5%, and making controller adjustments until the overshoot and time for stability to be achieved was acceptable. Parallel operation of the feedwater pumps, to verify the bias portion of the control circuit, was deferred until 50% RTP when both feedwater pumps could be operated without bypass flow. Final adjustments were made and system response was acceptable.

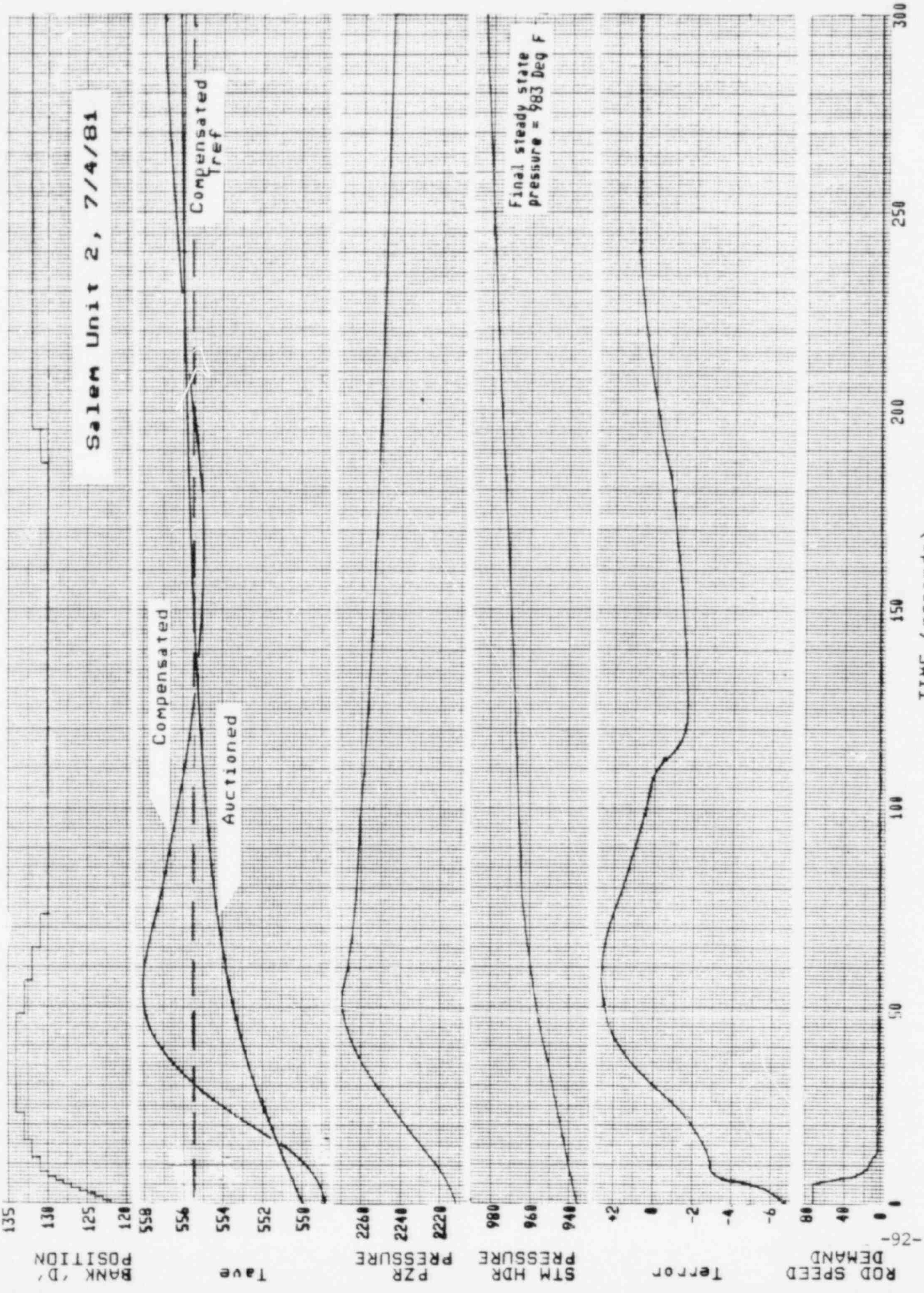
2.14 SUP 81.6 - AUTOMATIC REACTOR CONTROL

The objective of this procedure was to verify that the rod control system can automatically maintain the RCS T_{avg} at its proper value (T_{ref}) $\pm$ 1.5°F. Reactor power was held constant during this test. The operation of the automatic reactor control system during power level changes will be demonstrated during the performance of other scheduled transient tests.

The Rod Control System was transferred to manual control and Control Bank D withdrawn until T_{avg} was 6°F higher than its programmed value. The Rod Control System was then transferred to automatic control. The control rods inserted automatically to restore T_{avg} to its program value $\pm$ 1.5°F. Pressurizer level and pressure response were monitored along with T_{avg} during the transient with no anomalies noted. The transient was repeated starting out with T_{avg} 6°F below the program value again with no anomalies noted. From the time of the initiation of the transient to the time T_{avg} was restored to within $\pm$ 1.5°F of the program temperature was approximately 100 seconds with a maximum pressurizer level change of 8% from 32% and pressure change of less than 50 psi from 2235 psig. Figures 2.14.1 and 2.14.2 graphically display the transient when lowering and raising T_{avg}.

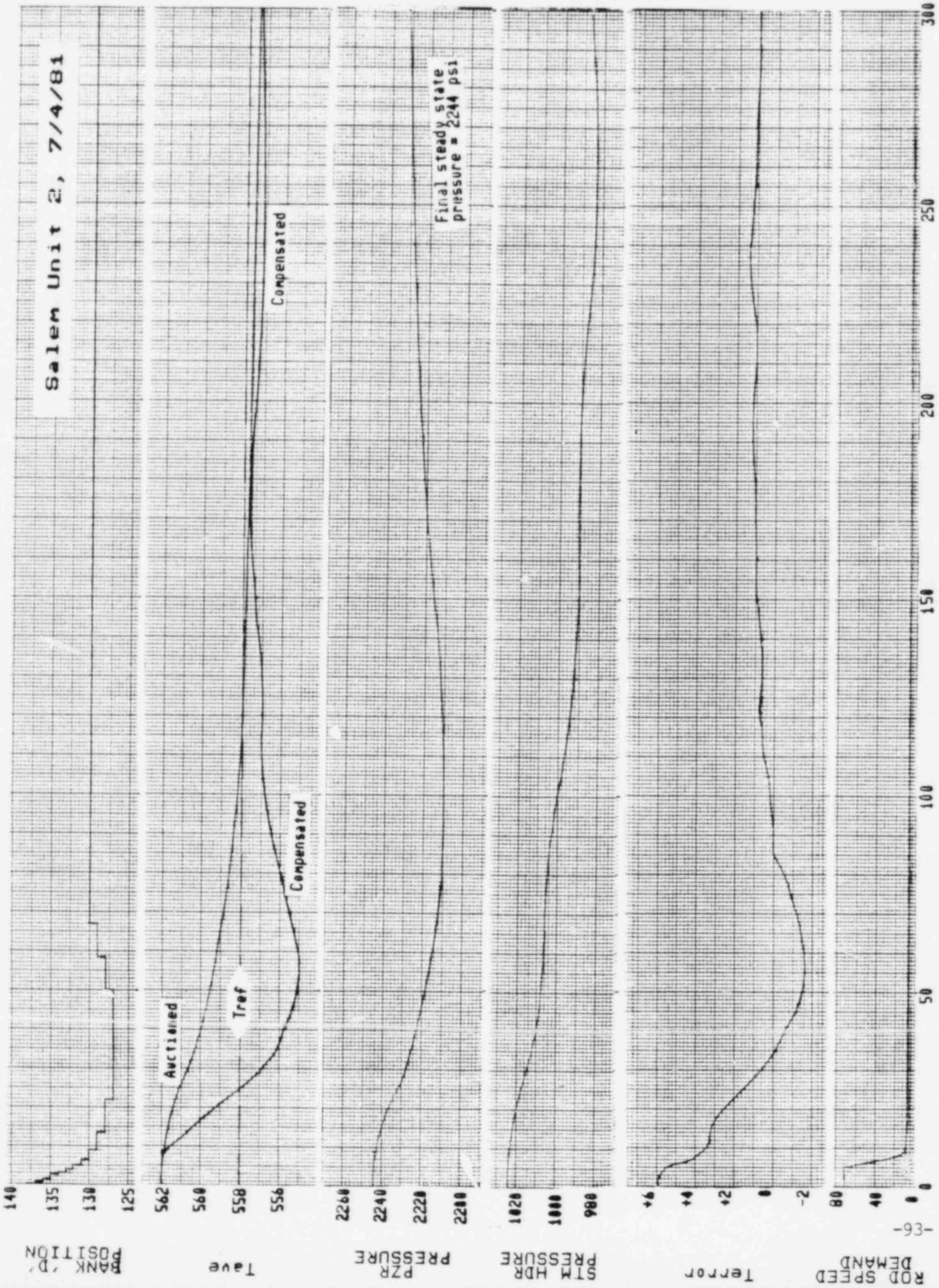
SUP 81.6 - AUTOMATIC REACTOR CONTROL
Recovery From Lowered Tave

Figure 2.14.1



SUP 81.6 - AUTOMATIC REACTOR CONTROL
Recovery From Raised Tave

Figure 2.14.2



2.15 SUP. 80. 1 - APPENDIX G, FEEDWATER HAMMER TEST

The purpose of this test was to verify that following a reactor/turbine trip the operation of the auxiliary feedwater system will not cause an unacceptable feedwater hammer in the main feedwater pipeline. The test was performed in conjunction with SUP 82.4, RODS DROP AND PLANT TRIP (Section 2.6) which initiated the reactor trip.

The initial conditions were with the reactor operating at 50% power and normal steam generator levels of 44% in each steam generator. The main feedwater line in the containment for No.21 Steam Generator was instrumented at key locations based on the piping configuration to monitor piping movement and fluid system pressure spikes. The piping was monitored at two separate locations in the x-y-z direction. The electrical signals, for piping movement and pressure spikes, were connected to a visicorder located outside the containment. See Figure 2.15.1 and 2.15.2 for instrumentation locations.

The reactor trip was initiated by SUP 82.4 on July 23, 1981. Following the reactor trip, the main feedwater system was isolated automatically; and the auxiliary feedwater pump started automatically. The flow to the steam generator was allowed to exceed 440 gpm (220,000 lbm/hr.). Following the reactor trip, the steam generator levels were reduced from 44% to < 11% in 9 seconds due to shrinking of the fluid/vapor volume in the steam generator. At this point the feedwater ring was uncovered (covered at a water level of 11%). The auxiliary feedwater pumps restored the level in the steam generators above 11% in 19 seconds. From the time the reactor trip was initiated to the time the feedwater level was restored above the feedwater ring, the maximum deflection of the piping was .35 inches at the z axes at both locations and at a frequency of 3.33 Hz. The z axes is the longitudinal direction of the pipe at hanger FWH-21-17 and perpendicular to the pipe at FWH-21-18. There was no dynamic pressure response noted following the reactor trip.

Figure 2.15.1

INSTRUMENTATION BRACKETS
FEEDWATER HANGER FWH-21-17

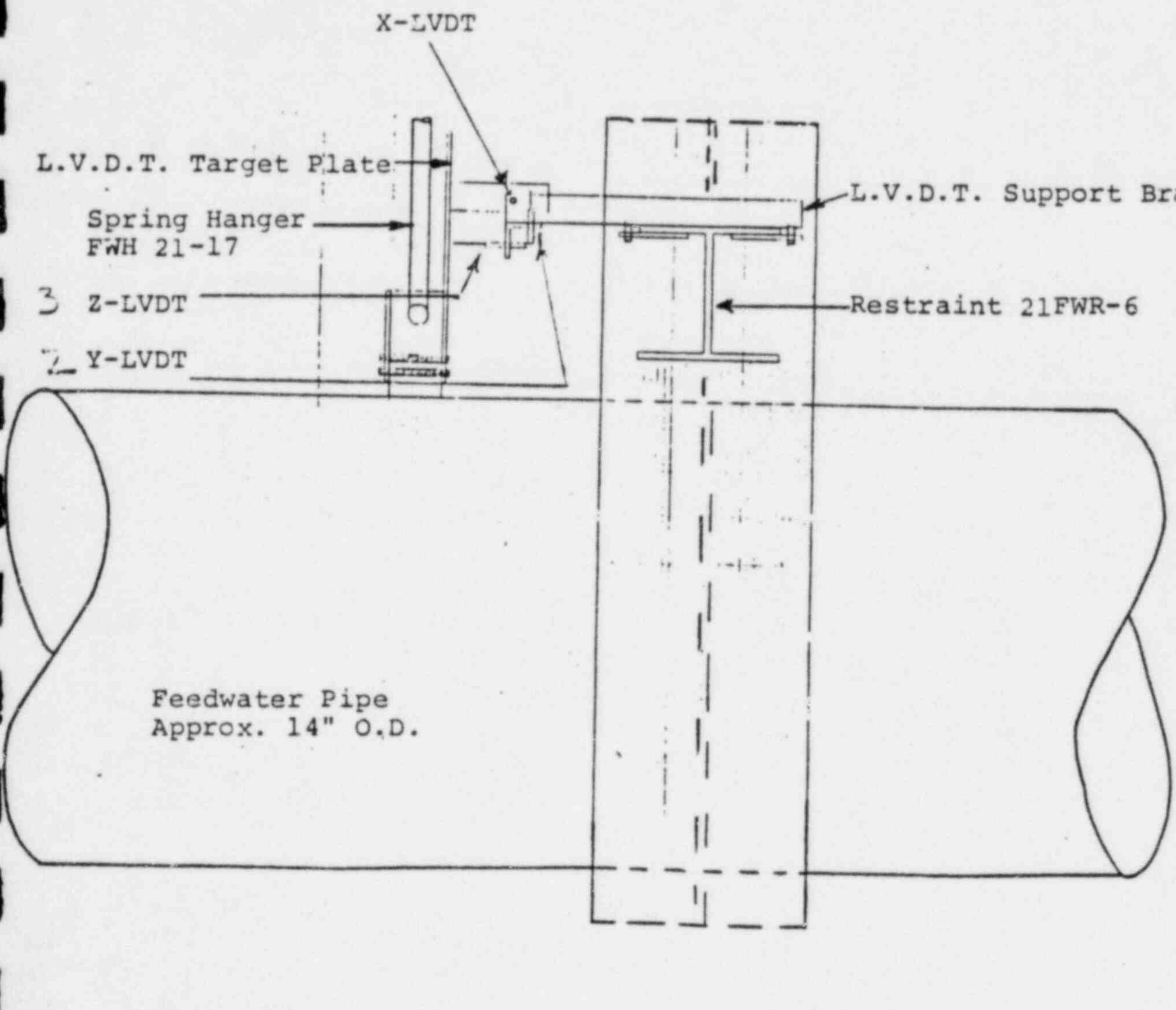
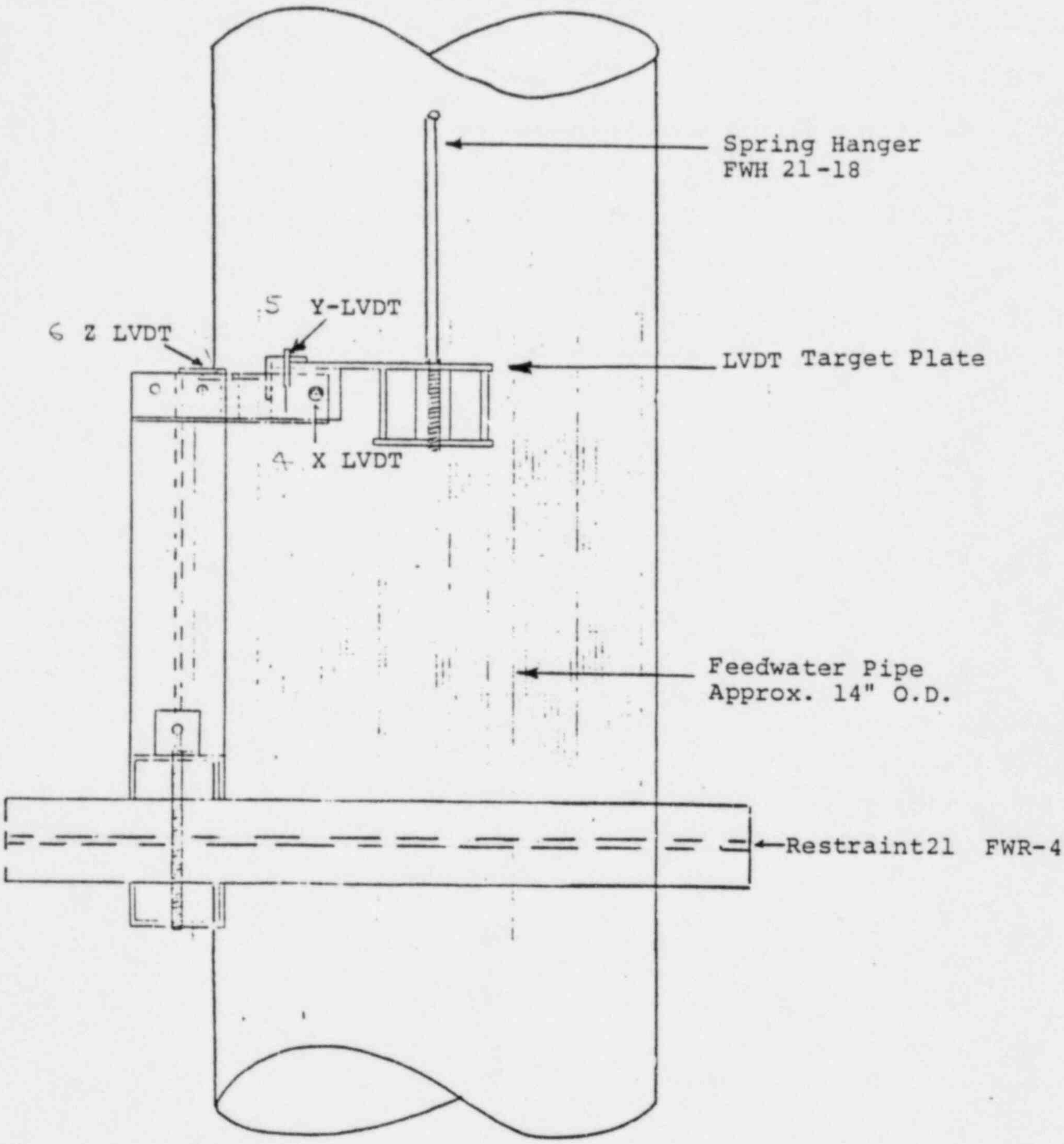


Figure 2.15.2

INSTRUMENTATION BRACKETS
FEEDWATER HANGER FWH-21-18



SECTION 3.0 CALIBRATION OF TEMPERATURE AND FLOW INSTRUMENTATION DURING POWER ESCALATION

INTRODUCTION

This section describes three related tests and their results. Certain plant instrumentation requires full power values of various plant parameters for calibration (e.g., primary loop average temperature (T_{avg}), reactor differential temperature (ΔT) and feedwater flow). Since these values are not known prior to operation, conservative values are initially set into the instrumentation for startup testing. Part of SUP 81.12 directed the collection of the required calibration data at lower power levels, from which full power values were then extrapolated. Other sections of SUP 81.12 derived values for calibrating nuclear instrumentation and ΔT trip setpoint circuitry. SUP 80.7 involved deriving the T_{avg} program for the rod control circuitry while SUP 81.7 calibrated the steam and feedwater flow transmitters.

3.1 SUP 81.12 A - ALIGNMENT OF PROCESS TEMPERATURE INSTRUMENTATION

The purpose of this procedure was to determine the full power reactor coolant system differential temperature for each reactor coolant loop for the purposes of calibrating the Overpower and Overtemperature differential temperature trip circuitry setpoints. Conservative value are initially used during plant startup testing and are revised based on measured values.

Data for this procedure was taken in SUP 81.12B, Statepoint Data Collection (Section 3.2). The initial valves used were derived from the Westinghouse Precautions, Limitations and Setpoints documents which recommended a conservative value of 55^{o}F. The loop statepoint data for differential temperature was taken at 30%, 50%, 75% 90% and 100% RTP. The data was reviewed following the 75% power data collection and plotted based on reactor power for each loop (see figures 3.1.1 thru 3.1.4). The derived full power differential temperatures were used as inputs to the Overpower and Overtemperature trip circuitry to allow operation above 85% RTP. Data taken at 90% RTP indicated no recalibration of the trip circuitry was required. At 100% RTP the trip circuitry was recalibrated using the measured differential temperatures at 100% RTP. See Table 3.1.1 for a review of the data collected.

TABLE 3.1.1

DIFFERENTIAL TEMPERATURE VS. POWER LEVEL

Power Level	Loop Differential Temperature				
	21	22	23	24	Avg.
30%	20.9	20.0	20.2	20.2	20.3
50%	32.2	31.9	31.8	31.6	31.9
75%	48.8	49.2	48.6	48.0	48.7
90%	58.4	58.8	58.3	57.4	58.2
100%	63.4	63.8	63.4	62.5	63.3

Power Level	Extrapolated Differential Temperature (To 100%)				
	21	22	23	24	Avg.
75%	64.7	65.2	64.4	63.6	64.5
90%	64.6	65.1	64.5	63.5	64.4
100%	63.8	64.1	63.7	62.8	63.6

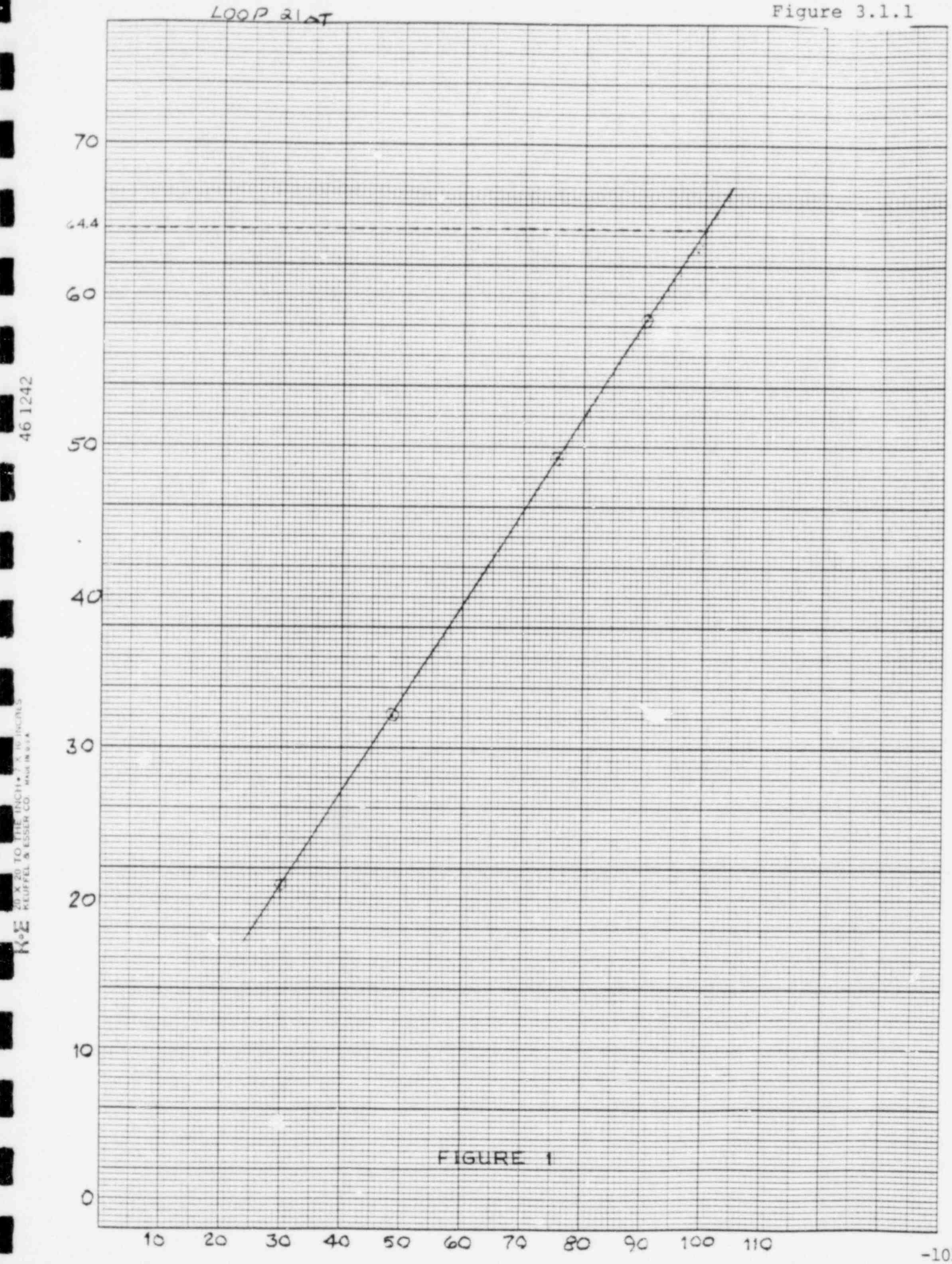
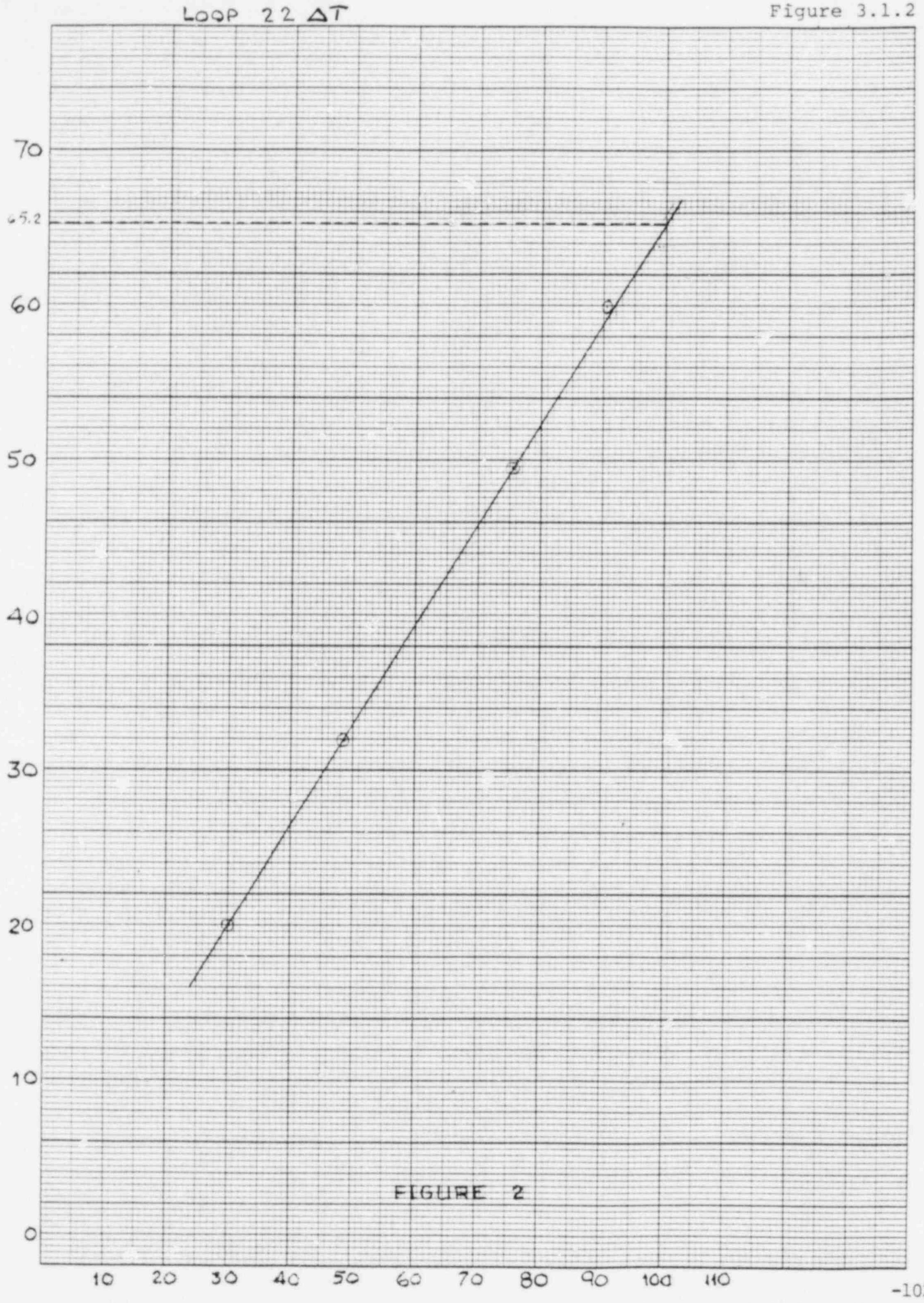

LOOP 21 ΔT
70
64.4
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
46 1242
K&E 20 X 20 TO THE INCH • 7 X 10 INCHES KEUFFEL & ESSER CO. MADE IN U.S.A.

FIGURE 1



LOOP 22 ΔT
65.2
70
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
FIGURE 2

LOOP 23 ΔT

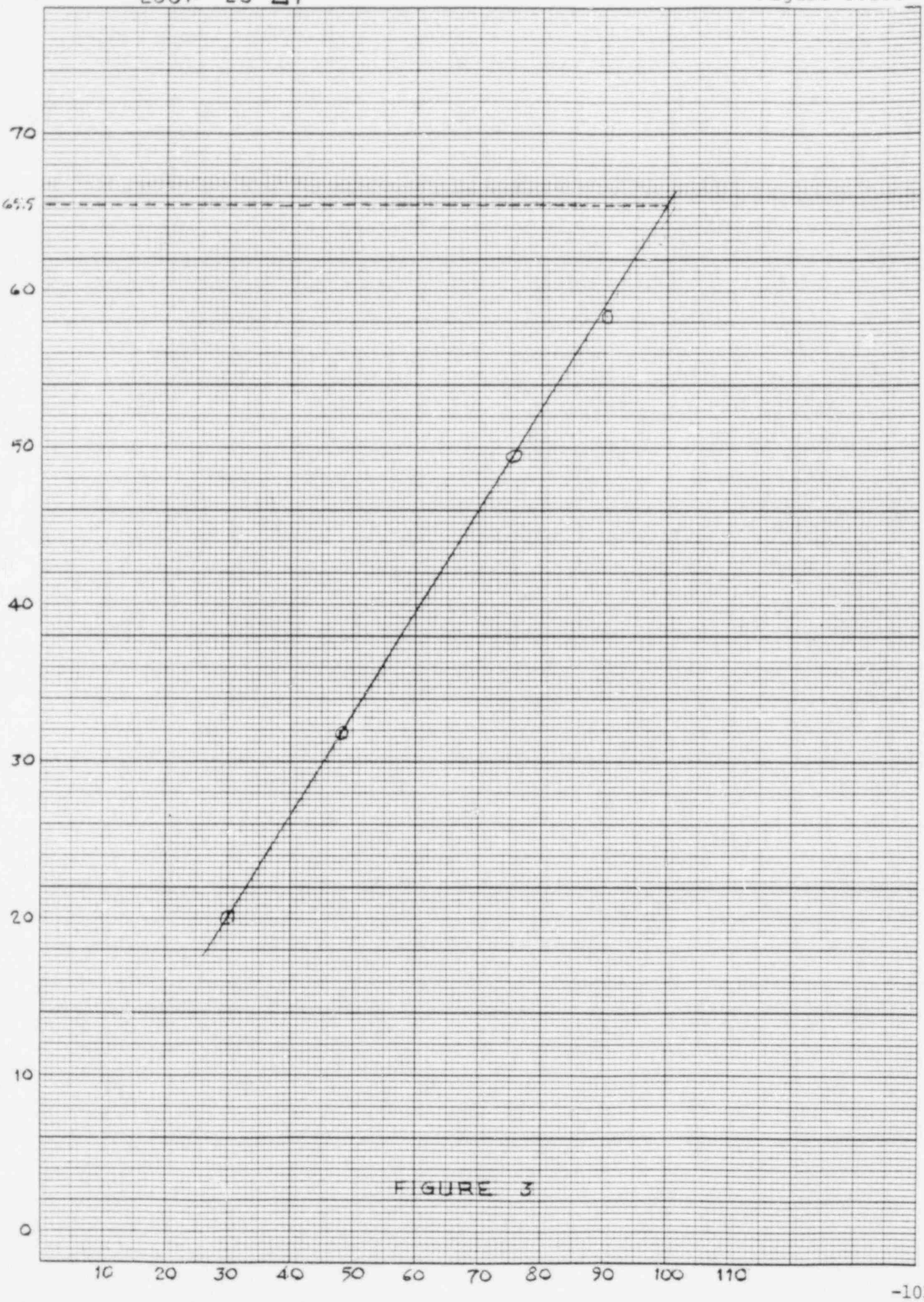
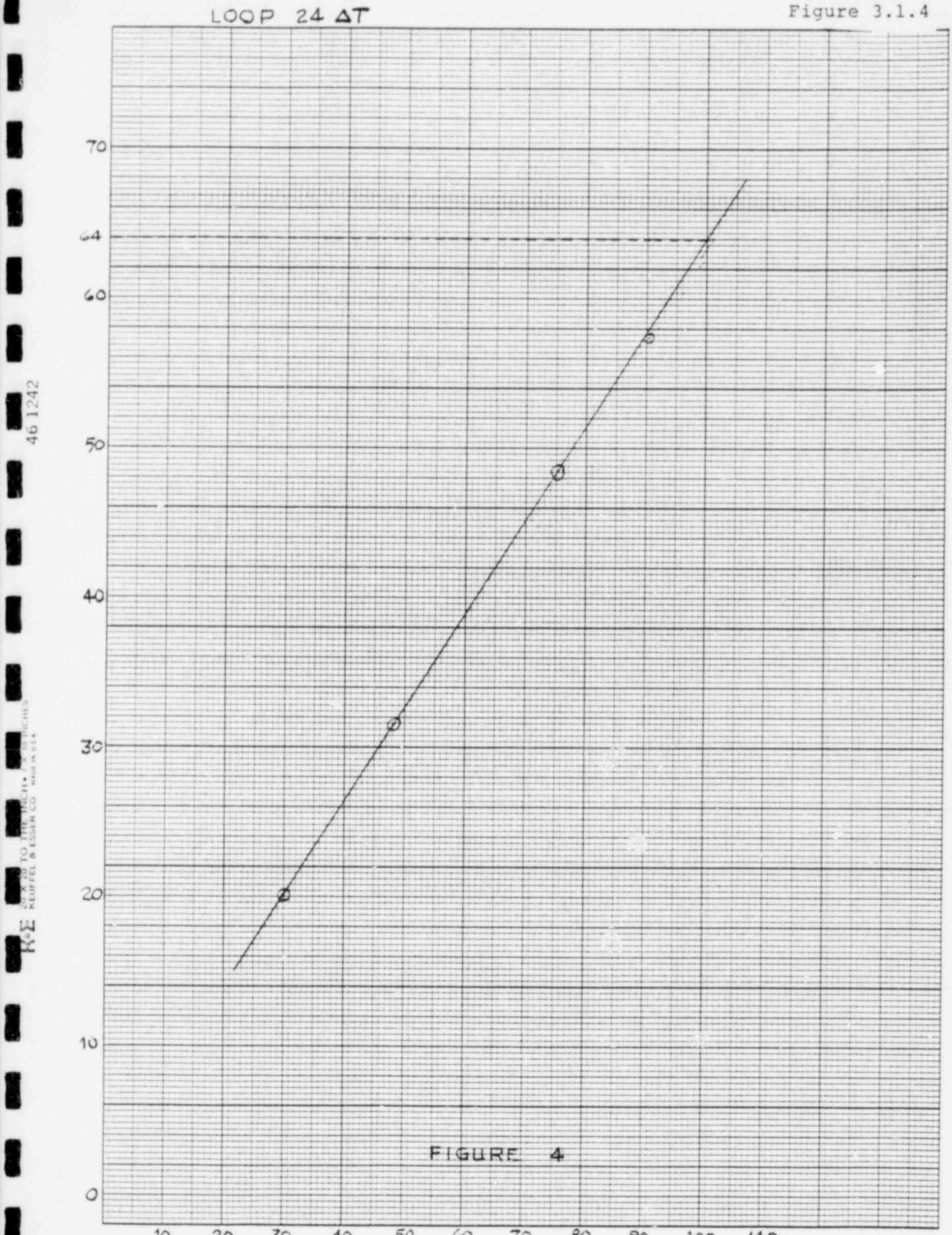


FIGURE 3


LOOP 24 ΔT
70
64
60
50
40
30
20
10
0
10
20
30
40
50
60
70
80
90
100
110
FIGURE 4
46 1242
K+E 20 X 20 TO THE INCH • 7 X 10 INCHES
KEUFFEL & ESSER CO. MADE IN U.S.A.

3.2 SUP 81.12B - STATEPOINT DATA

This section collected plant steady state performance (statepoint) data required to calibrate steam and feedwater flow channels, T_{avg} and Differential Temperature channels.

The statepoint data was taken at power levels of approximately 30%, 50%, 75%, 90% and 100% of rated thermal power. It was important to have steady state conditions when this data was recorded. These included being at a steady power level, xenon at equilibrium, no rod motion, T_{avg} equal to T_{ref}, and blowdown secured. The conditions minimized the errors induced since the data (eight sets) is collected over approximately one hour and averaged. The data included voltage readings from the process racks for T_h, T_c, T_{avg}, T_{ref}, steam flow D/P, RCS flow, turbine first stage pressure and Delta T. Information was obtained in the field for heat balance data for determining the reactor power level. Eight successive sets of data were recorded at each power level (105 data points per set). A summary sheet averaged the eight sets of data recorded. Table 3.2.1 displays a summary of the results of the measurements. Table 3.2.2 thru 3.2.5 are samples of the forms used for acquiring the field data. Table 3.2.6 is a summary of the 100% Statepoint Data.

The statepoint data taken at each new testing plateau included data for eight reactor heat balances. The steam generator feedwater temperature was determined from individual feed line thermocouples with a local Doric Model 400 Trendicator readout. The feed flow to each steam generator was determined by measuring the pressure differential on a calibrated venturi in each line. The control console steam generator pressure indicators were used to determine the steam enthalpy (assuming saturated steam).

Any time a heat balance was conducted, the NIS percent power indicators were recorded for comparison and possible adjustment. The excore detectors are affected by rod position and reactor inlet temperature (T_{cold}). It is important that T_{avg} be within 1 ^{o}F of T_{ref} and the control rods be at their normal operating position (ΔI band) whenever the calorimetric results are used to reset the percent power indicators.

Table 3.2.1
STATEPOINT DATA SUMMARY

PLATEAU POWER DATE TAKEN	30 7/3/81	50 7/20/81	75 8/ 3/81	90 8/14/81	100 8/20/81
CALORIMETRIC POWER	29.90	48.3	75.45	90.36	99.51
"D" BK ROD POSITION	153	228	228	228	228
FW TEMP (^{o}F)	325	367	398	421	430
FW FLOW (x10^{6} LB/HR)					
LOOP: 21	.9378	1.6358	2.6663	3.260	3.651
22	1.002	1.6603	2.7235	3.319	3.698
23	.9695	1.6594	2.6905	3.285	3.649
24	1.016	1.6751	2.7146	3.323	3.688
STEAM GEN PRESS					
GEN: 21	966	928	888	788	785
22	964	927	886	787	789
23	968	932	891	793	797
24	965	928	890	791	794
TAVE (^{o}F)					
LOOP: 21	559.7	562.9	571.0	565.5	569.7
22	560.3	564.0	572.4	567.2	571.5
23	560.1	563.4	571.5	566.4	570.6
24	559.7	563.2	571.5	566.3	570.8
DELTA T (^{o}F)					
LOOP: 21	20.9	32.2	48.8	58.4	63.4
22	20.0	31.9	49.2	58.8	63.8
23	20.2	31.8	48.6	58.3	63.4
24	20.2	[illegible]	48.0	57.4	62.5
NI PWER RANGE CURRENTS					
CHNL: 41U	123	[illegible]	319	350	381
41L	159	229	352	405	451
42U	136	228	342	371	408
42L	179	249	391	447	499
43U	125	212	317	347	375
43L	151	215	335	379	421
44U	119	203	305	334	364
44L	140	200	317	361	403

109D(2):18

Table 3.2.2

STATEPOINT DATA DIGITAL VOLTMETER READINGS   Salem, Unit ______

Date ____________, % RTP ____________, Run _____ of _____

LOOP	PARAMETER	DATA SOURCE (units)		RAW VALUE	FINAL VALUE
1	T_{hot}	TP 411-1 (R2)	volts		
1	T_{cold}	TP 411-2 (R2)			
1	T_{avg}	Input to TM 412B (R2)			
1	Delta T	Input to TM 411D (R2)			
1	RCS Flow	TP 416 (R12)			
2	T_{hot}	TP 421-1 (R6)	volts		
2	T_{cold}	TP 421-2 (R6)			
2	T_{avg}	Input to TM 422B (R6)			
2	Delta T	Input to TM 421D (R6)			
2	RCS Flow	TP 426 (R12)			
3	T_{hot}	TP 431-1 (R13)	volts		
3	T_{cold}	TP 431-2 (R13)			
3	T_{avg}	Input to TM 432B (R13)			
3	Delta T	Input to TM 431D (R13)			
3	RCS Flow	TP 436 (R12)			
4	T_{hot}	TP 441-1 (R15)	volts		
4	T_{cold}	TP 441-2 (R15)			
4	T_{avg}	Input to TM 442B (R15)			
4	Delta T	Input to TM 441D (R15)			
4	RCS Flow	TP 446 (R12)			
	T_{ref}	TP 505-4 (R123-2)			
	Turbine 1st Stage Press	TP 506-1 (R9)			
	Turbine 1st Stage Press	TP 505-1 (R5)			

Recorded by ____________________

Reviewed by ____________________

Table 3.2.3

STATEPOINT DATA, LOCAL READINGS

Salem

Unit No. ________

Date ________

Time ________

Test ________

Steam Gen Press: special gage (psig)

Run	S/G 1	S/G 2		S/G 3	S/G 4
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					

Steam Restrictor Differential Press (inches H_2O)

Run	S/G 1		S/G 2		S/G 3		S/G 4	
	Chan 1	Chan 2	Chan 1	Chan 2	Chan 1	Chan 2	Chan 1	Chan 2
1								
2								
3								
4								
5								
6								
7								
8								

	Feedwater Venturi D/P (inches H_2O)				Feedwater Temp (°F)			
	S/G 1	S/G 2	S/G 3	S/G 4	S/G 1	S/G 2	S/G 3	S/G 4
1								
2								
3								
4								
5								
6								
7								
8								

Recorded by ________________ Reviewed by ________________

STATEPOINT DATA, NIS and CONTROL ROOM READINGS Salem

Date ________ Time ________ Unit ____

Percent Power _____ Ref Test ____________

NIS Detector Currents (μ amps) and % Power

Table 3.2.4

Chan/Run→	1	2	3	4	5	6	7	8	
N41(upper)									
(lower)									
% Pwr									
N42 U									
L									
%									
N43 U									
L									
%									
N44 U									
L									
%									

Feedwater Flow (%)

S/G 1 (1)									
(2)									
S/G 2 (1)									
(2)									
S/G 3 (1)									
(2)									
S/G 4 (1)									
(2)									

Steam Flow (%)

S/G 1 (1)									
(2)									
S/G 2 (1)									
(2)									
S/G 3 (1)									
(2)									
S/G 4 (1)									
(2)									

Reactor Coolant Flow (%)

RCL 1 (1)									
(2)									
(3)									
RCL 2 (1)									
(2)									
(3)									
RCL 3 (1)									
(2)									
(3)									
RCL 4 (1)									
(2)									
(3)									

Recorded by ____________________

Reviewed by ____________________

Section 2.6

CALORIMETRIC CALCULATION DATA SHEET

Date ________ Time ________ Recorded by ____________________

Gross Gen Output ________ MWe RCS Boron Conc ________ ppm

Control Bank Position: Bank ____ at ______ steps

Tave - Tref ≤ 0.5°F: T_{error} ________ °F

	Loop 21	Loop 22	Loop 23	Loop 24
Tave (Console) °F	________	________	________	________
ΔT (Console) °F	________	________	________	________
Steam Pressure (Psig)	1 ________	1 ________	1 ________	1 ________
	2 ________	2 ________	2 ________	2 ________
	3 ________	3 ________	3 ________	3 ________
	Avg ________	Avg ________	Avg ________	Avg ________
Blowdown Flow (lbs/hr)	________	________	________	________
			Total Blowdown	________
Feedwater Temperature °F	________	________	________	________
Feedwater Flow ΔP (inches)	________	________	________	________

NIS CHANNEL:	N 41	N 42	N 43	N 44
Indicated Power (during Calorimetric)	________	________	________	________
Calculated % RTP (Sect 2.7)	________	________	________	________
Difference (NIS-Cal)	________	________	________	________

If calorimetric power <98% a tolerance no more negative than -2.0% is permissible for difference (NIS - CAL).

If calorimetric power ≥98% a tolerance no more negative than -1.0% is permissible for difference (NIS - CAL).

The average of the 4 NI's should be equal to or greater than the calorimetric.

NIS power after adjustment	________	________	________	________

Sen. Reactor Operator ____________________

STATEPOINT DATA - SUMMARY DATA SHEET

Date: 8/20/81 Salem Unit 2

Reference Test: Sup 81.12B 100%RTP 100 % RTP

		Run 1	Run 2	Run 3	Run 4	Run 5	Run 6	Run 7	Run 8	Averages	
% RTP		100.06	99.93	99.72	99.42	99.28	99.07	99.36	99.26		99.51
TURB 1st STG PSIA	505	561.48	560.81	560.81	560.98	559.97	558.29	559.64	558.29		560.04
	506	568.03	566.86	568.37	567.19	566.02	563.33	566.35	565.18		566.42
FW D/P (inches H2O)	SG1	708.300	702.800	691.700	691.100	691.600	689.700	685.700	691.500	694.050	
	SG2	718.000	715.500	715.200	709.900	709.700	704.400	708.700	708.300	711.213	
	SG3	698.700	692.500	694.300	691.400	680.200	678.300	688.100	682.300	688.225	
	SG4	710.300	715.300	712.600	702.300	703.900	697.500	705.600	699.000	705.813	699.825
FW FLOW (lb/hr *E6)	SG1	3.688	3.673	3.644	3.643	3.645	3.640	3.630	3.645	3.651	
	SG2	3.714	3.708	3.708	3.694	3.693	3.681	3.691	3.691	3.698	
	SG3	3.676	3.659	3.664	3.658	3.628	3.623	3.649	3.634	3.649	
	SG4	3.699	3.712	3.706	3.679	3.683	3.667	3.688	3.670	3.688	3.671
FW TEMP (Deg F)	SG1	429.000	429.000	429.000	429.000	428.500	428.000	428.000	428.000	428.563	
	SG2	430.500	430.000	430.000	430.000	430.000	429.000	430.000	429.500	429.875	
	SG3	430.000	430.000	430.000	429.000	429.000	429.000	429.000	429.000	429.375	
	SG4	431.000	430.500	430.000	430.000	430.000	430.000	430.000	430.000	430.188	429.500
S/G HEAT RATE (btu/hr *E7)	SG1	292.088	290.935	288.595	288.452	288.797	288.692	287.870	289.085	289.314	
	SG2	293.652	293.339	293.260	292.154	292.113	291.541	291.957	292.136	292.519	
	SG3	290.824	289.499	289.859	289.770	287.398	286.996	289.094	287.873	288.914	
	SG4	292.131	293.367	293.058	290.915	291.263	289.902	291.649	290.316	291.575	290.581
RCS Thot (Deg F)	Lp1	601.040	601.700	601.640	601.910	601.820	601.220	601.160	600.530	601.378	
	Lp2	603.050	603.440	603.620	603.590	603.650	602.870	602.900	602.510	603.204	
	Lp3	602.090	602.750	602.990	602.930	602.450	602.180	601.850	601.430	602.334	
	Lp4	601.550	601.880	602.090	602.120	601.790	601.670	601.010	601.070	601.648	602.141
RCS Tcold (Deg F)	Lp1	537.240	538.140	538.440	538.470	538.620	537.750	537.450	537.180	537.911	
	Lp2	539.360	539.640	539.820	539.490	539.360	539.550	538.950	538.710	539.360	
	Lp3	538.080	538.980	539.130	539.370	539.370	539.010	538.230	538.230	538.800	
	Lp4	538.860	539.340	539.520	539.610	539.520	539.520	538.590	538.710	539.209	538.820
RCS Tave (Deg F)	Lp1	569.225	570.075	570.150	570.150	570.275	569.650	569.350	568.975	569.731	
	Lp2	570.900	571.750	572.000	571.825	571.950	571.500	571.150	570.875	571.494	
	Lp3	570.200	570.925	570.975	571.125	570.825	570.700	570.150	570.025	570.616	
	Lp4	570.600	570.950	571.075	571.200	571.000	570.950	570.250	570.275	570.788	570.657
RCS Delta T (Deg F)	Lp1	63.875	63.600	63.175	63.450	63.225	63.300	63.425	63.325	63.422	
	Lp2	64.275	63.950	63.875	63.850	63.600	63.425	63.750	63.900	63.828	
	Lp3	63.775	63.500	63.500	63.475	63.075	63.175	63.550	63.375	63.428	
	Lp4	62.750	62.450	62.675	62.600	62.300	62.250	62.450	62.150	62.453	63.283
S/G 1 PRESSURE (psig)	1	800.000	805.000	805.000	810.000	810.000	810.000	805.000	805.000	806.250	
	2	775.000	775.000	780.000	780.000	780.000	780.000	775.000	775.000	777.500	
	3	780.000	780.000	785.000	785.000	790.000	780.000	785.000	785.000	783.750	789.167
S/G 2 PRESSURE (psig)	1	780.000	790.000	795.000	795.000	795.000	795.000	790.000	790.000	791.250	
	2	780.000	785.000	785.000	790.000	790.000	790.000	780.000	780.000	785.000	
	3	775.000	780.000	780.000	780.000	780.000	780.000	780.000	780.000	779.375	785.208
S/G 3 PRESSURE (psig)	1	775.000	775.000	775.000	775.000	780.000	780.000	775.000	770.000	775.625	
	2	775.000	780.000	780.000	780.000	780.000	780.000	775.000	780.000	778.750	
	3	780.000	785.000	790.000	790.000	790.000	790.000	790.000	790.000	788.125	780.833
S/G 4 PRESSURE (psig)	1	790.000	795.000	795.000	800.000	800.000	800.000	795.000	790.000	795.625	
	2	790.000	790.000	795.000	795.000	790.000	800.000	790.000	790.000	792.500	
	3	780.000	790.000	790.000	790.000	790.000	790.000	785.000	780.000	786.875	791.667

3.3 SUP 80.7 - TURBINE CONTROL SYSTEM CHECKOUT AND STARTUP ADJUSTMENTS OF THE REACTOR CONTROL SYSTEM

Automatic reactor rod control is achieved with a reference average temperature (T_{avg}) program. The turbine first stage pressure increases approximately linearly with turbine (or reactor) power. This pressure is converted to a reference temperature (T_{ref}). The control rods are driven by an error signal derived from the difference between the actual T_{avg} and the programmed T_{ref} ($T_{error} = T_{avg} - T_{ref}$) until the error is cancelled. The reference full power T_{avg} is set so that the full power steam generator pressure (turbine throttle pressure) is at the value recommended by the turbine manufacturer. By adjusting the full power reference T_{avg} (ΔT across the steam generator tubes being fixed) any desired steam generator pressure can be obtained. SUP 80.7 developed the Salem Unit 2 T_{avg} program.

For initial startup, the vendor recommended an initial full power T_{ref} value of 577.9^{o}F. This was expected to produce a full power turbine impulse pressure of 550 psia. No adjustments were to be made to the T_{ref} program until after 75% statepoint data had been collected.

After collecting data at 75% power, extrapolation of the measured steam generator pressure to 100% power showed that a drop of 62 psia would be necessary to maintain design pressure. This corresponded to a drop in T_{ref} program of $8.6^{o}F$. T_{ref} was then reprogrammed to $569.8^{o}F$ at full power. This was calculated to correspond to a full power first stage turbine pressure at 560 psia.

Proceeding to full power, the statepoint data showed the steam generator pressure to be approximately 800 psia. No further adjustments were made to the T_{ref} program. Full power first stage turbine pressure was measured at 560 psia.

Figure 3.3.1 shows the turbine first state pressure extrapolation. Figure 3.3.2 shows the T_{avg} extrapolation, and Figure 3.3.3. shows steam generator pressure vs. reactor power.

Figure 3.3.1

TURBINE FIRST STAGE PRESSURE VS REACTOR POWER

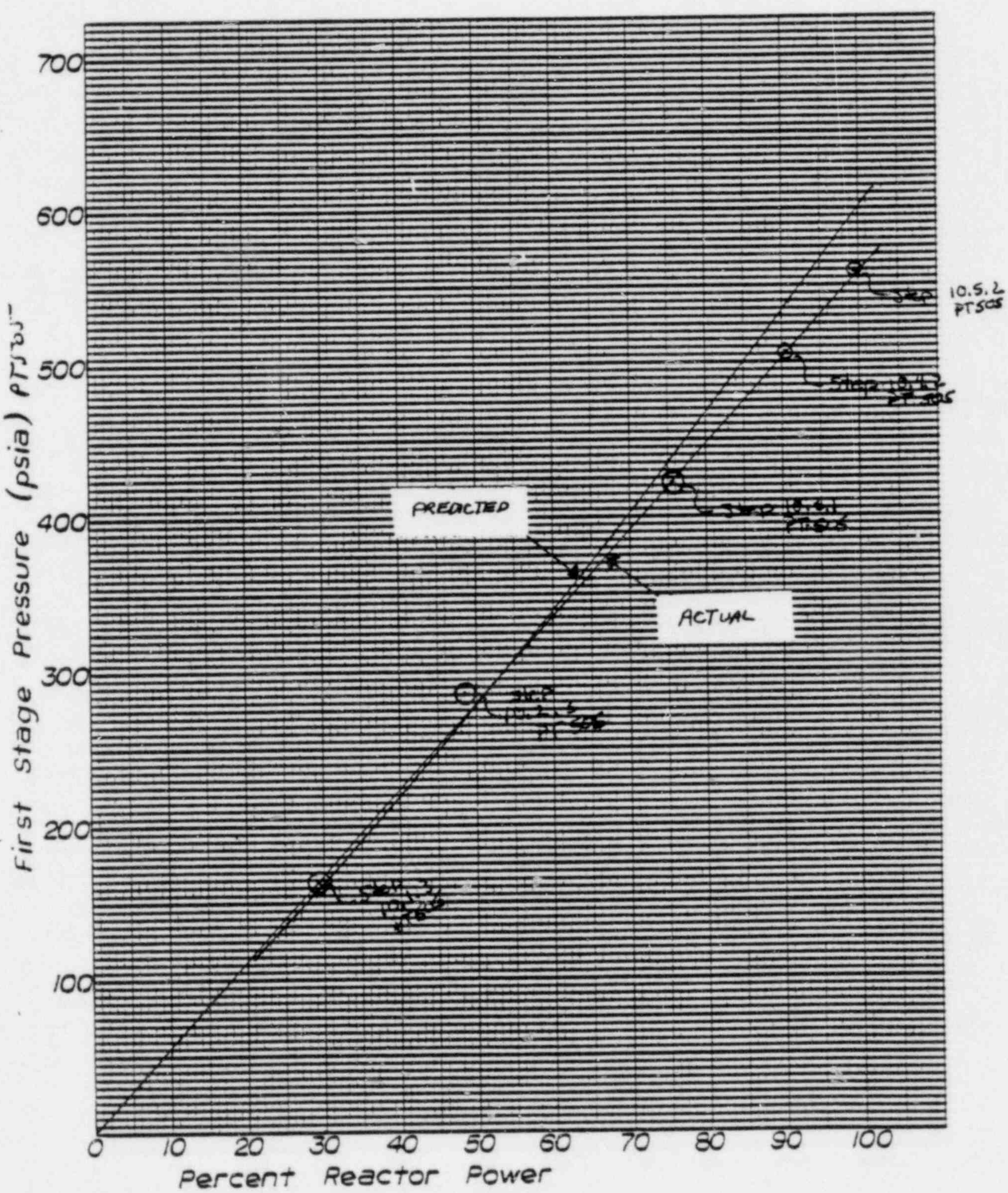


Figure 3.3.2

PROGRAMED REFERENCE TEMPERATURE vs. FIRST STAGE PRESS

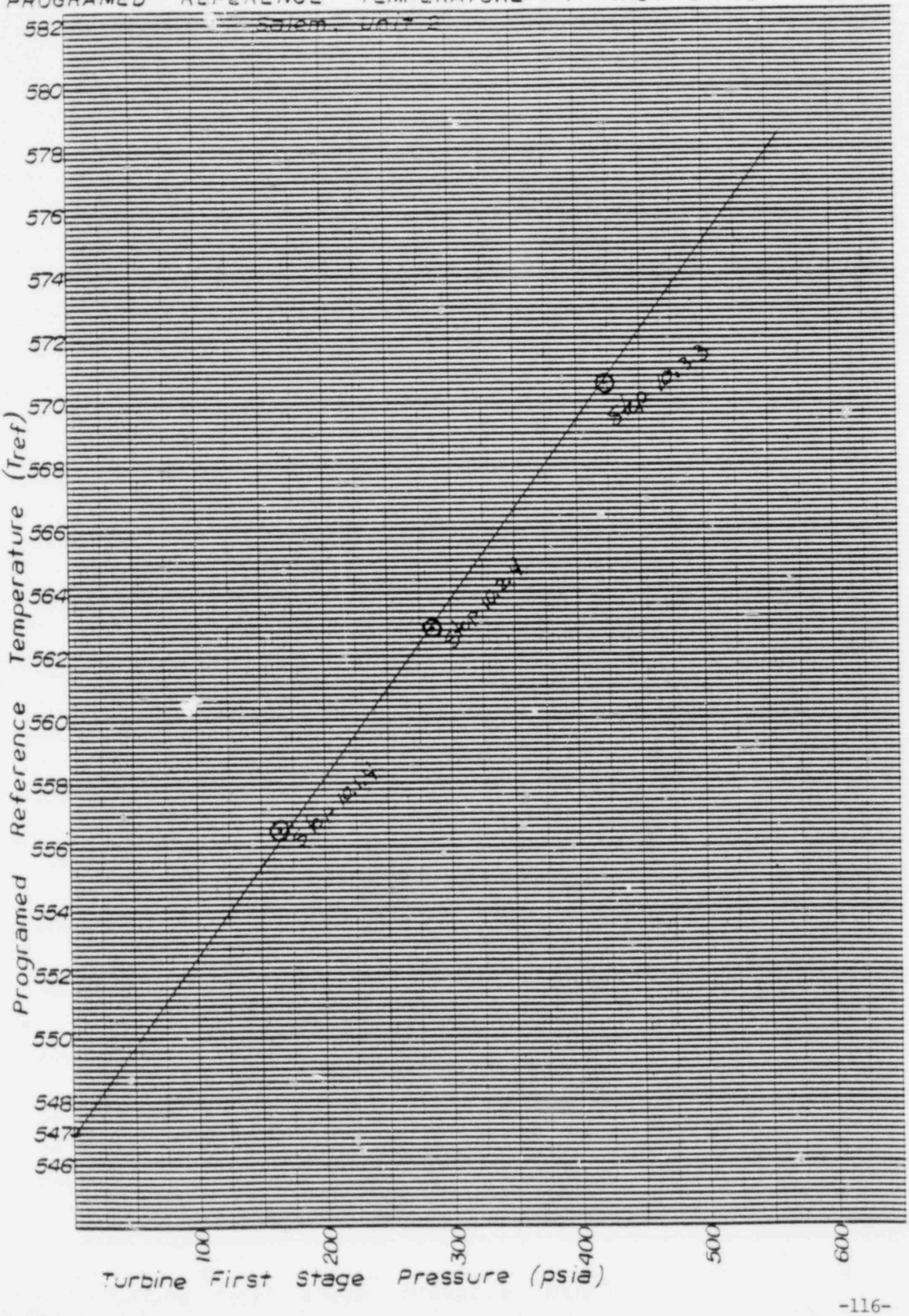
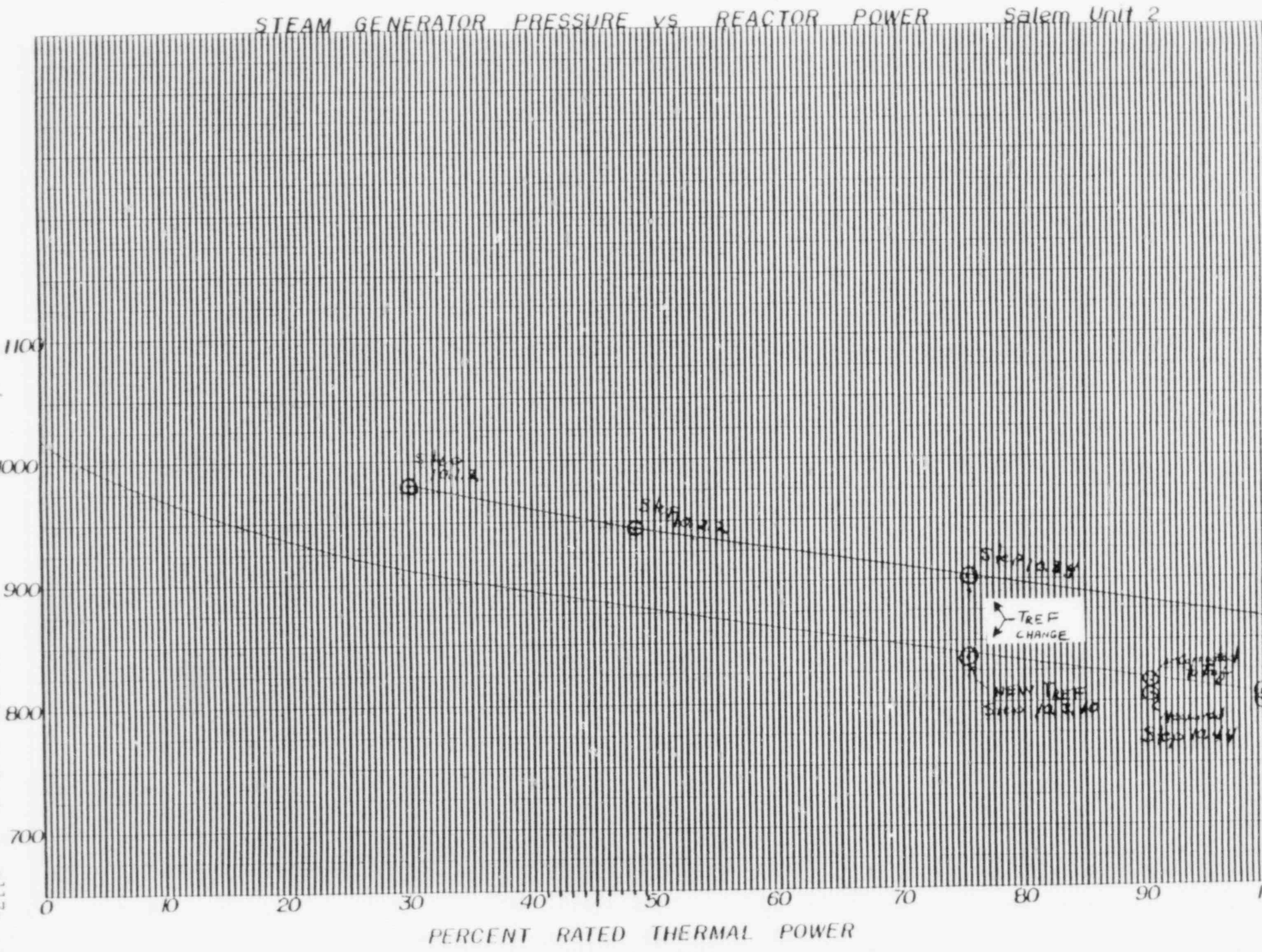


Figure 3.3.3


STEAM GENERATOR PRESSURE VS REACTOR POWER Salem Unit 2
STEAM GENERATOR PRESSURE (psia)
PERCENT RATED THERMAL POWER
1100
1000
900
800
700
0
10
20
30
40
50
60
70
80
90
100
TREF CHANGE
NEW TREF

3.4 SUP 81.7 - CALIBRATION OF STEAM AND FEEDWATER FLOW INSTRUMENTATION AT POWER

The purpose of this test was to calibrate the feedwater flow and steam flow signals to actual measured flow during low power testing, so that escalation to full power would be possible.

The feedwater and steam flow signals are used in the plant's control and protection instrumentation. These signals are derived from the differential pressure across a calibrated venturi for feed flow and a flow restrictor for steam flow. The differential pressure transmitters produce currents that are proportional to the Δp. The steam flow Δp signal is multiplied by the steam line pressure (steam is compressible) and then the square root of the product is taken. The feedwater dp signal is input directly through a square root extractor circuit. These square root signals are proportional to their respective flows. Calibrating these channels actually amounts to scaling these transmitters so that the full output corresponds to a Δp equivalent to 120% flow.

For initial startup, the feedwater Δp transmitters were scaled for predicted full power flows. Since steam flow restrictors are crude orifices, no calibration data was provided on them. Therefore, the steam flow transmitters were scaled to numbers provided by the vendor (based on past experience).

The statepoint data from the 30%, 50%, and 75% power levels was used to plot feedwater flow and temperature versus power as well as feedwater venturi p versus feed flow. Feedwater flows at 120% RTP were obtained by extrapolating these plots.

The feedwater venturi equation can be expressed as:

$$\text{Flow} = (\Delta p)^{1/2} \ (\gamma)^{1/2} \ (\text{fa}) \ (\text{Const.})$$

Cost. = Flow constant unique to that venturi

fa = Nozzel expansion factor

γ = Specific weight of feedwater

Using the extrapolated 120% feed flow (average of four loops), the 120% power expected differential pressure values can be obtained for each loop. The results are shown in Table 3.4.1 and Figures 3.4.1 thru 3.4.8.

$$\text{Flow} = (\Delta p)^{1/2} \ (\gamma)^{1/2} \ \text{Const.}$$

The restrictors, not being calibrated devices, have unknown constants. The constants were evaluated using the 75% measured data. Then the expected p values were determined using the average 120% extrapolated feed flows.

$$\Delta p = \frac{(\text{Flow})^2}{\gamma(\text{Const.})^2}$$

The results of these measurements are shown in Table 3.4.1, Table 3.4.2 and Figures 3.4.9 thru 3.4.16.

All steam flow channels appeared to be indicating correctly after calibration at 75% RTP. When reactor power was escalated above 90% No. 21 and No. 24 S/G steam flow channels started to indicate high. High flow alarms were received. A second set of "90%" Statepoint data (SUP 81.12B) was taken on August 15, 1981 to reconfirm the 90% Statepoint Data taken the previous day. This was actually at 91.88% RTP. Power was raised to 96% and held on August 16, 1981 to obtain another (unscheduled) set of Statepoint Data for recalibration of the steam flow channels. As a result of these measurements No. 21 S/G steam flow channels 1 and 2, and No. 24 S/G steam flow channel 2 were re-scaled to reduce the indicated steam flow. Power was raised to 100%, and full power (99.51%) Statepoint Data was taken on August 20, 1981. High steam flow signals were noted again in No. 21 S/G. The measured flow element d/p in No. 21 S/G steam line was higher than predicted from the 96% measurements. All other channels appeared close to predictions. It was speculated that high steam moisture content was causing the unusual high d/p on this flow element. Subsequent power reductions showed this No. 21 S/G steam flow signal too low at power levels below approximately 92%. On August 28, 1981 the first moisture carryover test (SUP 82.7, Section 2.8) was run at 100% RTP. This confirmed that there was high moisture content in No. 21 S/G steam ($\sim$1.5% vs. design of $\leq$ .25).

Station management felt that the abnormal behavior of No. 21 S/G steam flow channels made them inoperable. These 2 channels were re-scaled back to d/p values extrapolated from 75% Statepoint Data, and the reactor power level was limited to 92%. Above this power level these steam flow channels indicated abnormally high.

On September 11 and 12 a second moisture carryover test was run confirming previous measurements. Also extensive instrumentation was used to observe the steam flow channels' behavior. A safety analysis was run to allow this operation at 100% reactor power. On Sept. 21, 1981 Salem, Unit 2, was shutdown and cooled down to modify the steam generators by installing additional separator drain lines. Salem 2 was started up on October 8, and a third moisture carryover test was run on October 12, 1981. In parallel with this test, Statepoint Data was again taken to observe steam flow element d/p valves. The results showed the steam moisture content was within acceptable levels (.13%) and the high steam flow signals were greatly reduced. This 99.67% reactor power data was used to re-calibrate steam flow channels. Both channels of No. 21 S/G and channel 1 of No. 24 S/G were re-scaled . After re-scaling these steam flow signals were observed to be acceptable.

For the next two months the plant operated up to 100% power without any further high steam flow indications. On December 3, 1981 power was reduced to 70% due to a leak on No. 21 feedwater pump. Upon completion of the repairs to the pump (about 7 dsys), the plant was escalating in power when the steam flows were again indicating high flow. Statepoint data on 12/11/81, as shown in Table 3.4.2, indicates that the steam flow D/P's had increased. Figures 3.4.9 thru 3.4.16 plot the eight steam flow channel D/P's vs. feedwater flow during startup testing and show the same trend in higher than expected steam flows at < 90% RTP. Figures 3.4.12 thru 3.4.21 show steam generator level change and reactor power change.

From the figures and tables it can be concluded that the steam flow channels are affected by moisutre carryover. An additional moisture carryover test is scheduled for January 1982 to confirm the suspected carryover and determine the % of carryover. Based on the test results a determination would be made as to what additional steam generator modifications are required. The test results indicated the carryover was acceptable as found in October, 1981. Inspection of the steam flow nozzles is planned during the next plant shutdown to determine if corrosion/erosion of the nozzle area has occurred which could cause the higher dips measured in the steam flow signals.

TABLE 3.4.1

SUMMARY OF DATA FOR CLAIBRATION
OF STEAM AND FEEDWATER FLOW INSTRUMENTATION

(Pressure Differentials in inches water etxrapolated to 120%)

Values predicted afer 75% Statepoint Data

Extrapolated FW Flow = 4.369 10^6 lb/hr.

LOOP	VENTURI ΔP (FEED)	STEAM RESTRICTOR ΔP	
		CHANNEL 1	CHANNEL 2
21	983	168	155
22	999	207	212
23	984	188	197
24	993	169	171

Values predicted after 100% Statepoint Data and after Steam Generator modifications

Extrapolated FW Flow = 4.454 10^6 lb/hr

LOOP	VENTURI ΔP (FEED)	STEAM RESTRICTOR ΔP	
		CHANNEL 1	CHANNEL 2
21	1012	182	185
22	1048	215	211
23	1012	198	203
24	1044	183	182

TABLE 3.4.2

STEAM FLOW DATA REVIEW

		BEFORE S/G MODIFICATIONS			AFTER MODIFICATIONS	
DATE		8-10-81	8-14-81	8-16-81	8-22-81	10-12-81	12-11-81
% RTP		75.4	90.4	96.0	99.5	99.7	98.8
RAW D/P	21A	56.19	90.82	115.49	133.79	118.86	132.95
	21B	51.92	87.80	109.43	128.60	120.53	136.78
	22A	70.70	109.96	126.46	141.35	140.52	144.41
	22B	72.55	108.99	125.63	138.72	137.39	142.82
	23A	63.59	10[illegible].28	113.27	123.18	129.18	132.67
	23B	66.37	106.01	118.91	127.19	132.37	137.69
	24A	57.93	93.49	104.38	116.92	121.34	131.87
	24B	58.74	97.64	111.57	115.91	120.80	129.99
120% RTP EXTRA D/P	21A	168.24	169.07	195.53	205.73	182.18	207.38
	21B	155.45	163.26	185.27	197.75	184.75	213.35
	22A	206.98	204.51	213.14	217.35	215.38	225.30
	22B	212.39	202.71	211.74	213.31	210.58	222.79
	23A	188.39	188.35	192.41	189.41	198.00	206.94
	23B	196.62	197.16	201.98	195.58	202.90	214.78
	24A	168.67	173.87	175.64	179.79	182.59	205.70
	24B	171.04	181.60	187.73	178.24	181.79	202.77

109D(2):27

Figure 3.4.1

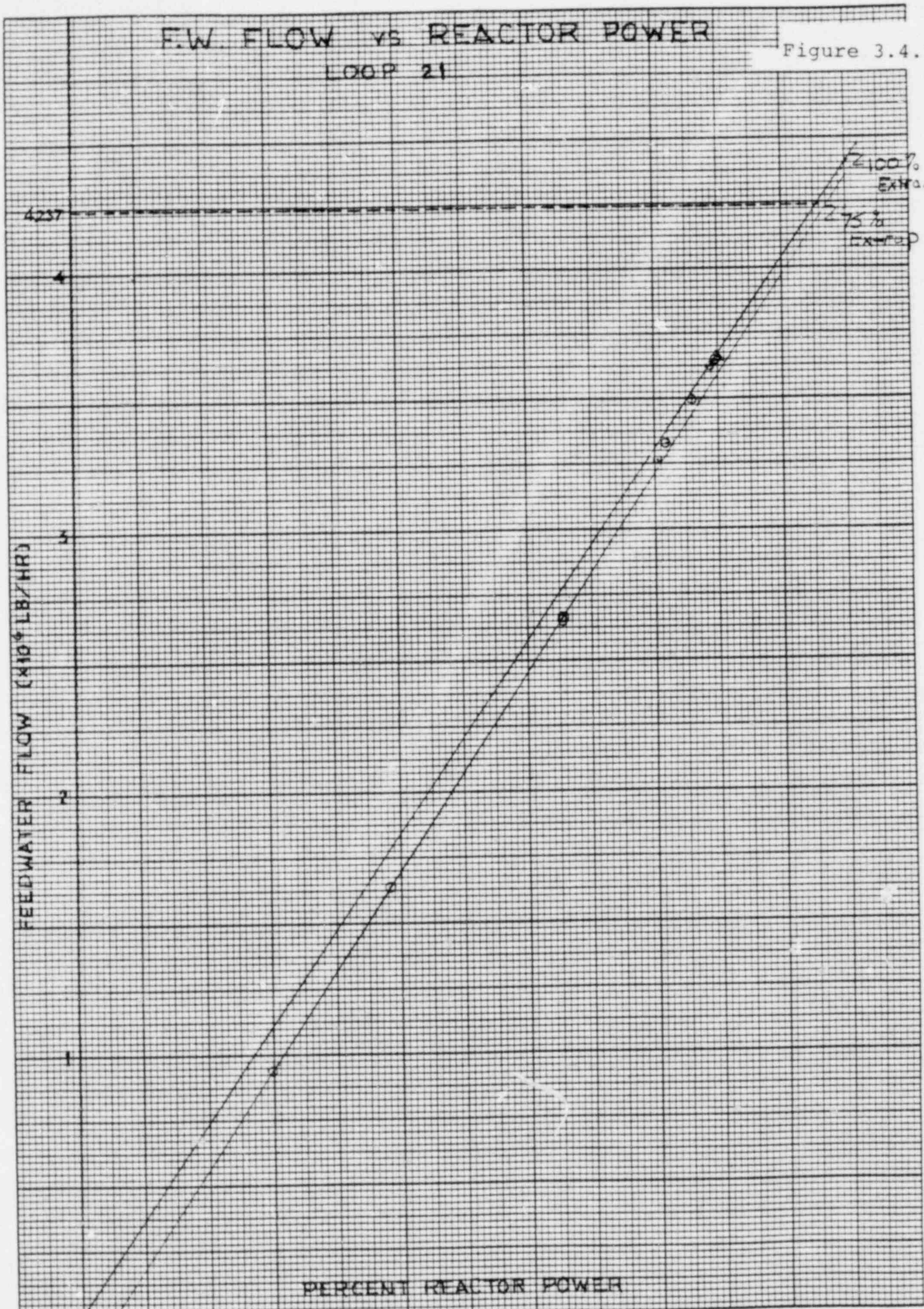
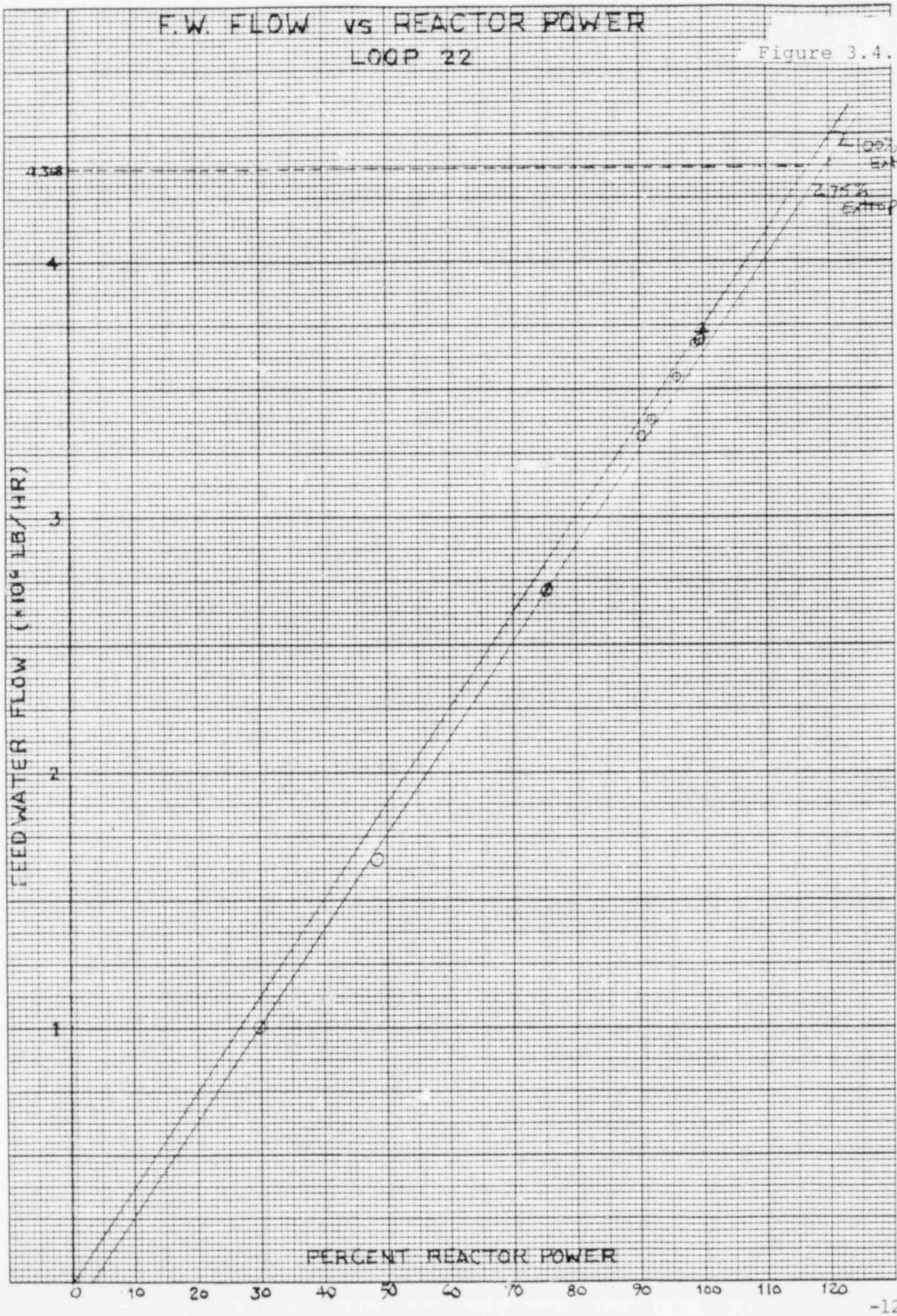

F.W. FLOW vs REACTOR POWER
LOOP 21
FEEDWATER FLOW (x10⁶ LB/HR)
PERCENT REACTOR POWER
4237
100% Extrap
75% Extrap
0 10 20 30 40 50 60 70 80 90 100 110 120
1 2 3 4

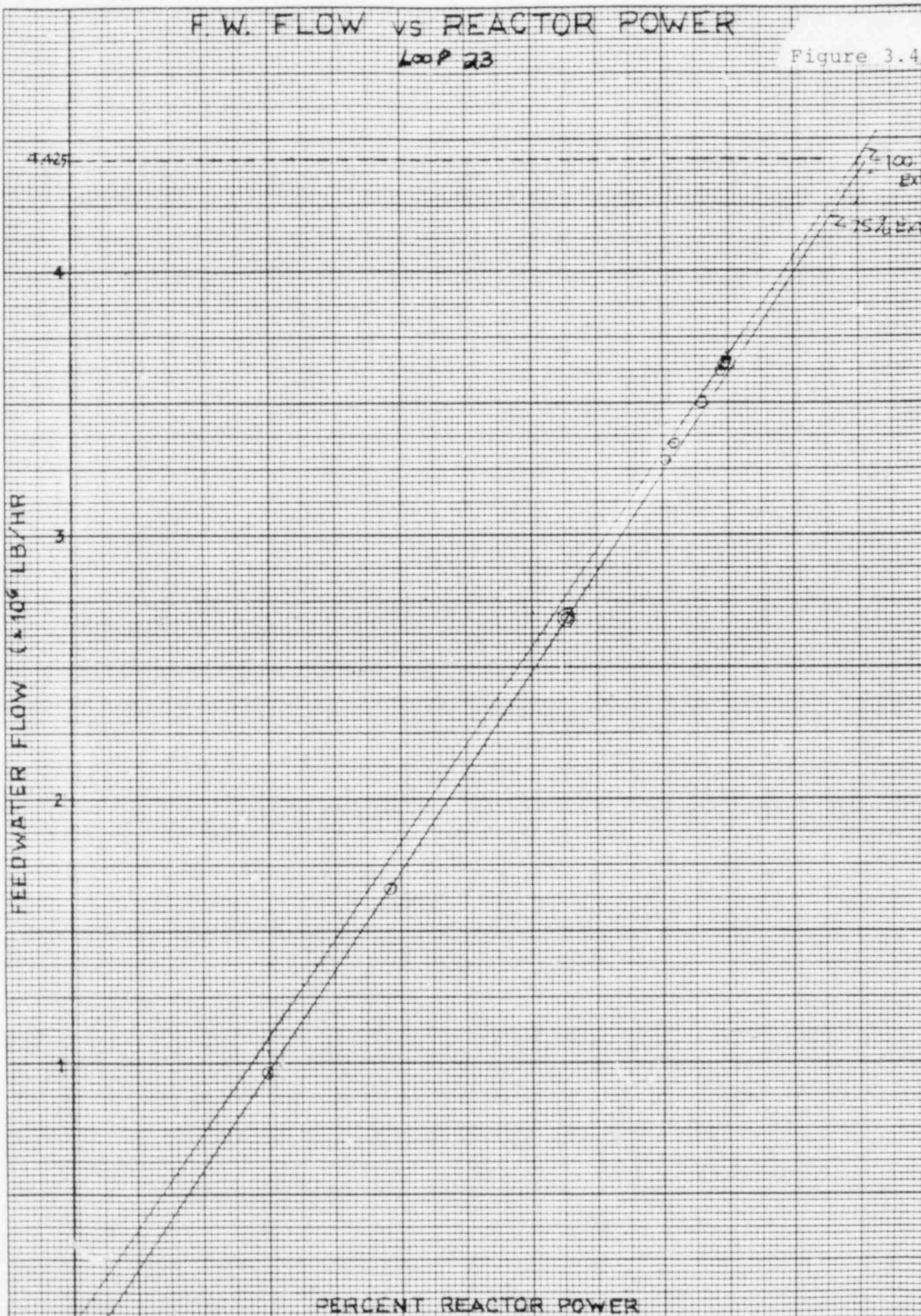
Figure 3.4.2



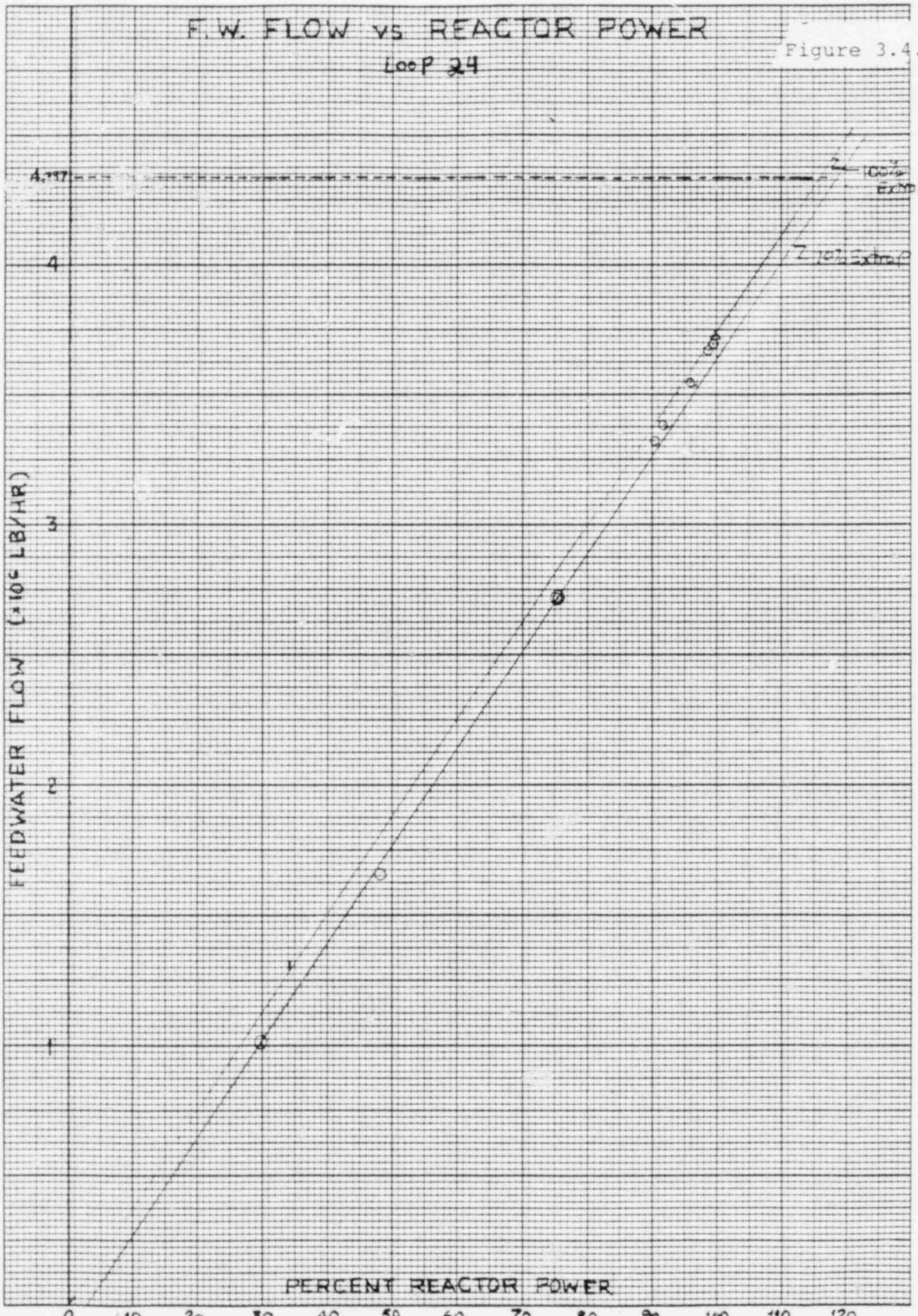
46 1242

K+E 20 X 20 TO THE INCH • 7 X 10 INCHES KEUFFEL & ESSER CO. MADE IN U.S.A.

Figure 3.4.3



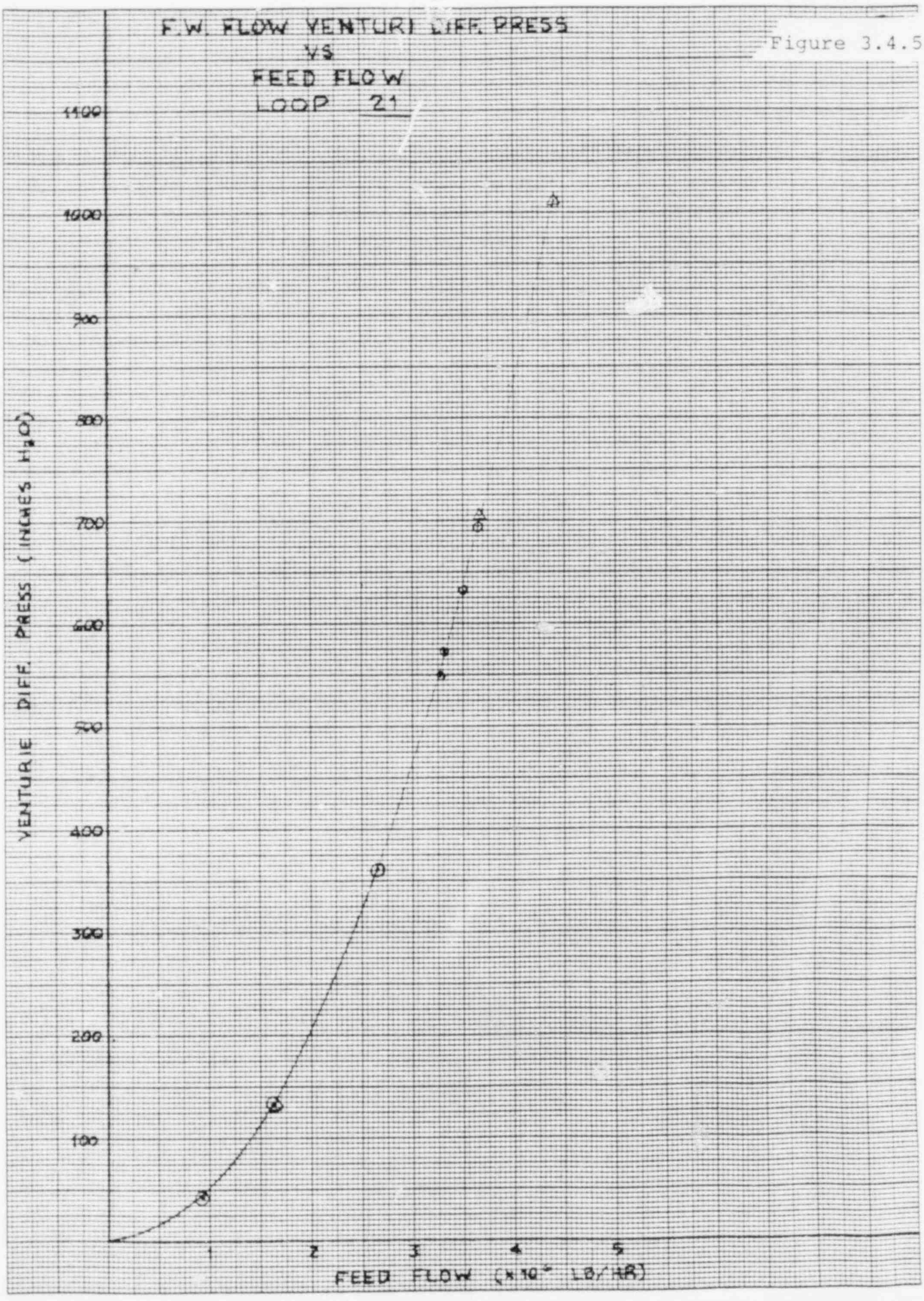
K•E 20 X 20 TO THE INCH • 7 X 10 INCHES KEUFFEL & ESSER CO. MADE IN U.S.A. 46 1242



F.W. FLOW vs REACTOR POWER
LOOP 24
FEEDWATER FLOW (x10⁶ LB/HR)
PERCENT REACTOR POWER
1
2
3
4
0
10
20
30
40
50
60
70
80
90
100
110
120

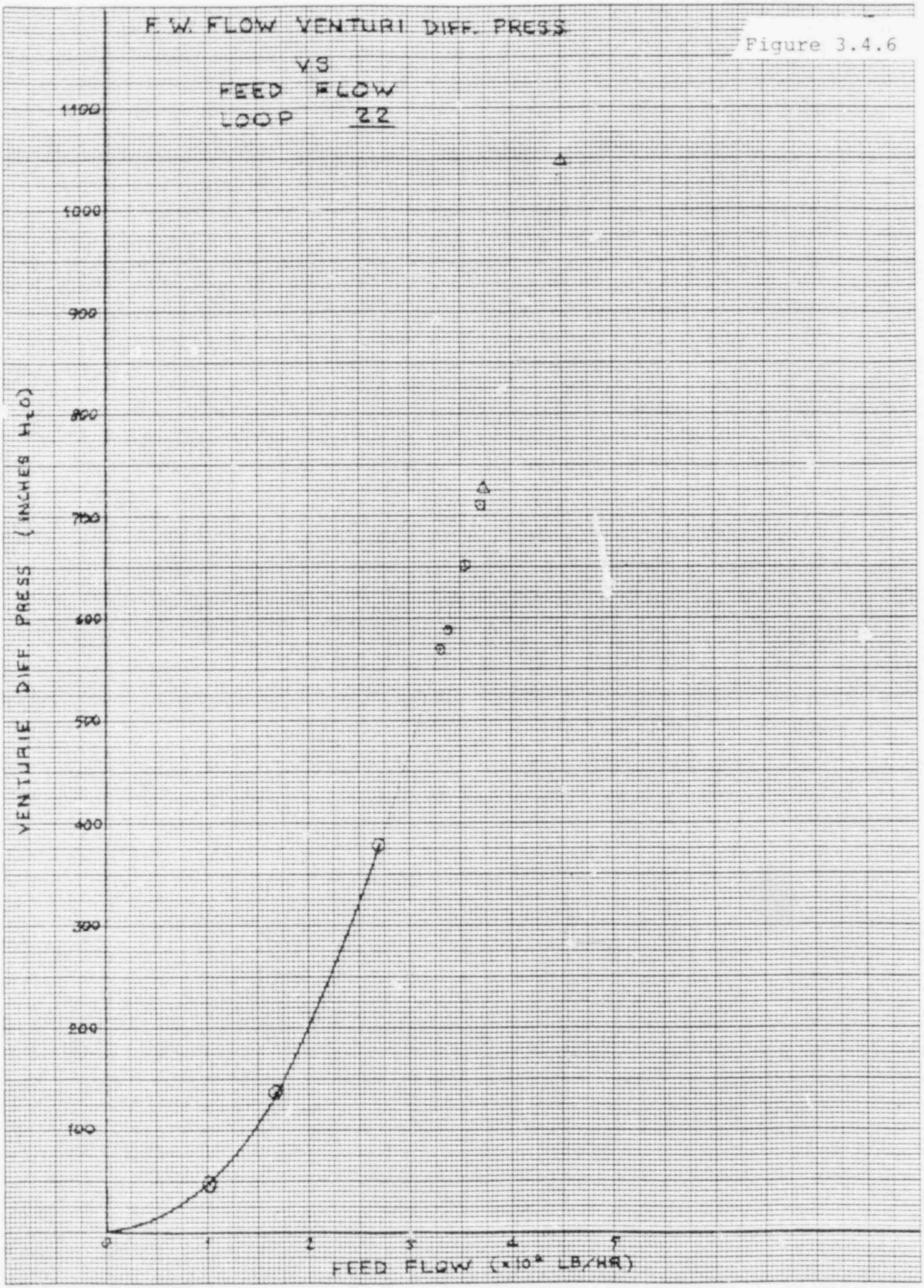
Figure 3.4.4

Figure 3.4.5



F.W. FLOW VENTURI DIFF. PRESS
VS
FEED FLOW
LOOP 21
VENTURIE DIFF. PRESS (INCHES H_2O)
1100
1000
900
800
700
600
500
400
300
200
100
1
2
3
4
5
FEED FLOW ($\times 10^6$ LB/HR)

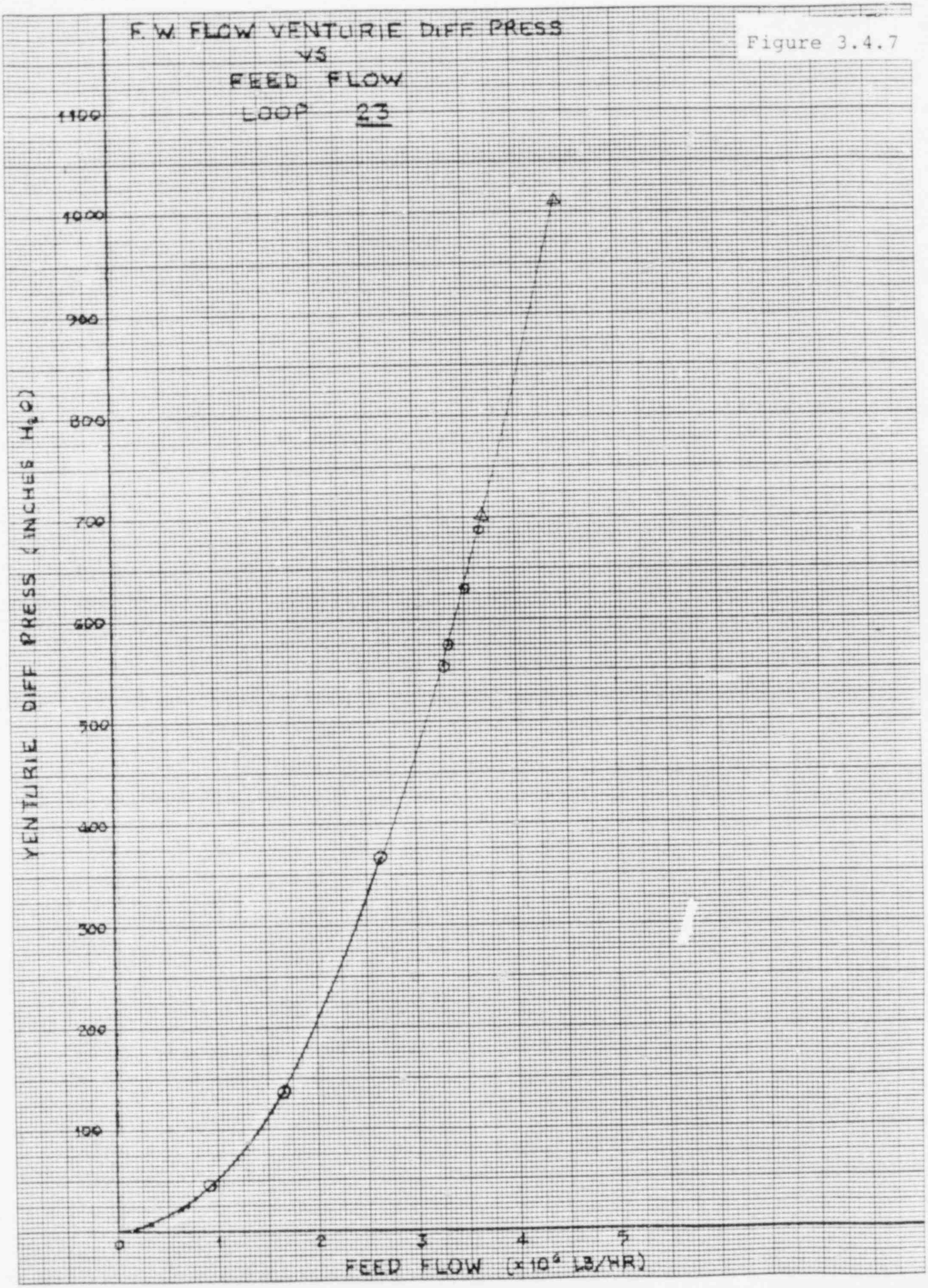
Figure 3.4.6



46 1512

K•E 10 X 10 TO THE CENTIMETER 18 X 25 CM
KEUFFEL & ESSER CO. MADE IN U.S.A.

Figure 3.4.7


F.W. FLOW VENTURIE DIFF PRESS
VS
FEED FLOW
LOOP 23
VENTURIE DIFF PRESS (INCHES H2O)
1100
1000
900
800
700
600
500
400
300
200
100
0
1
2
3
4
5
FEED FLOW (x10^6 LB/HR)

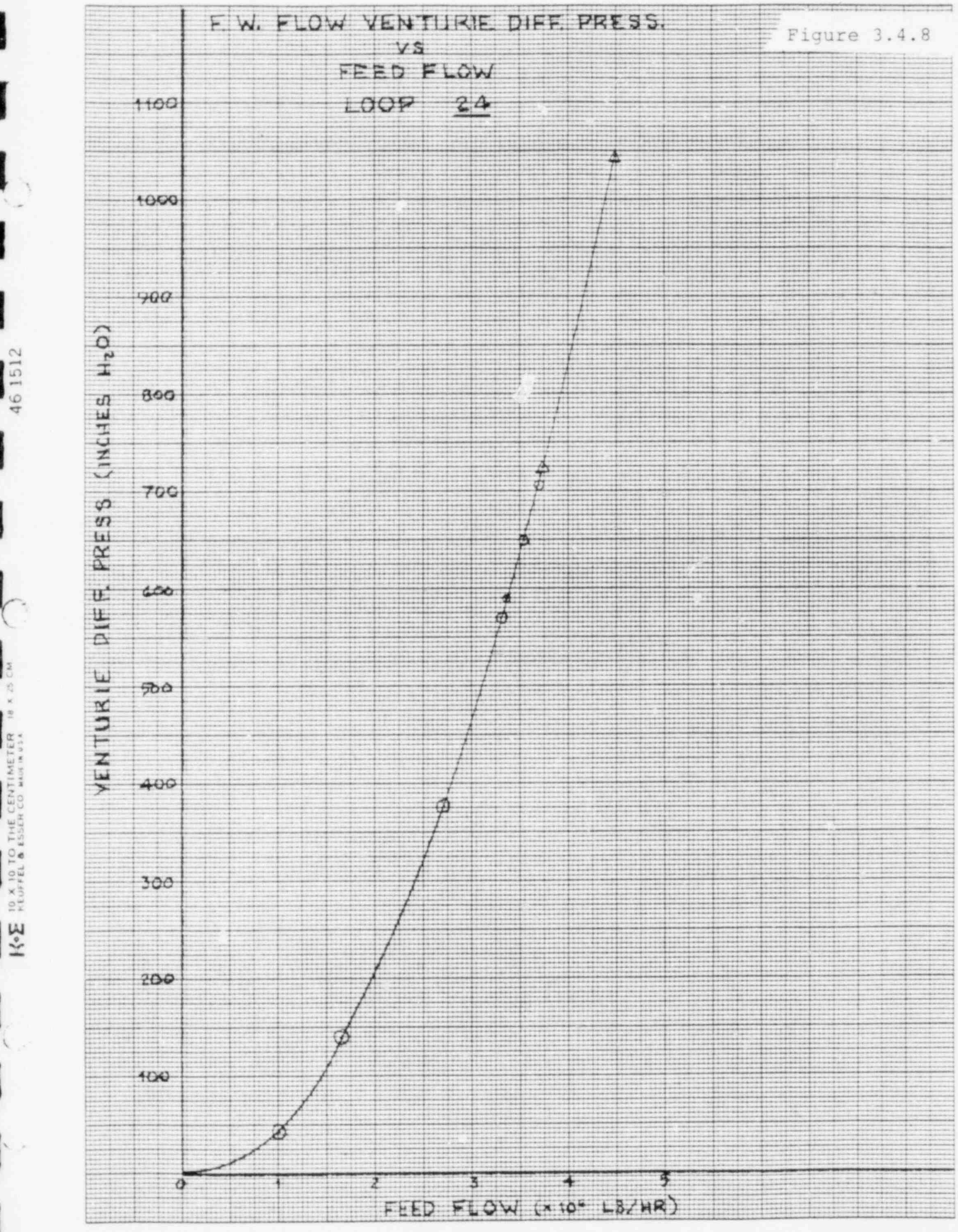
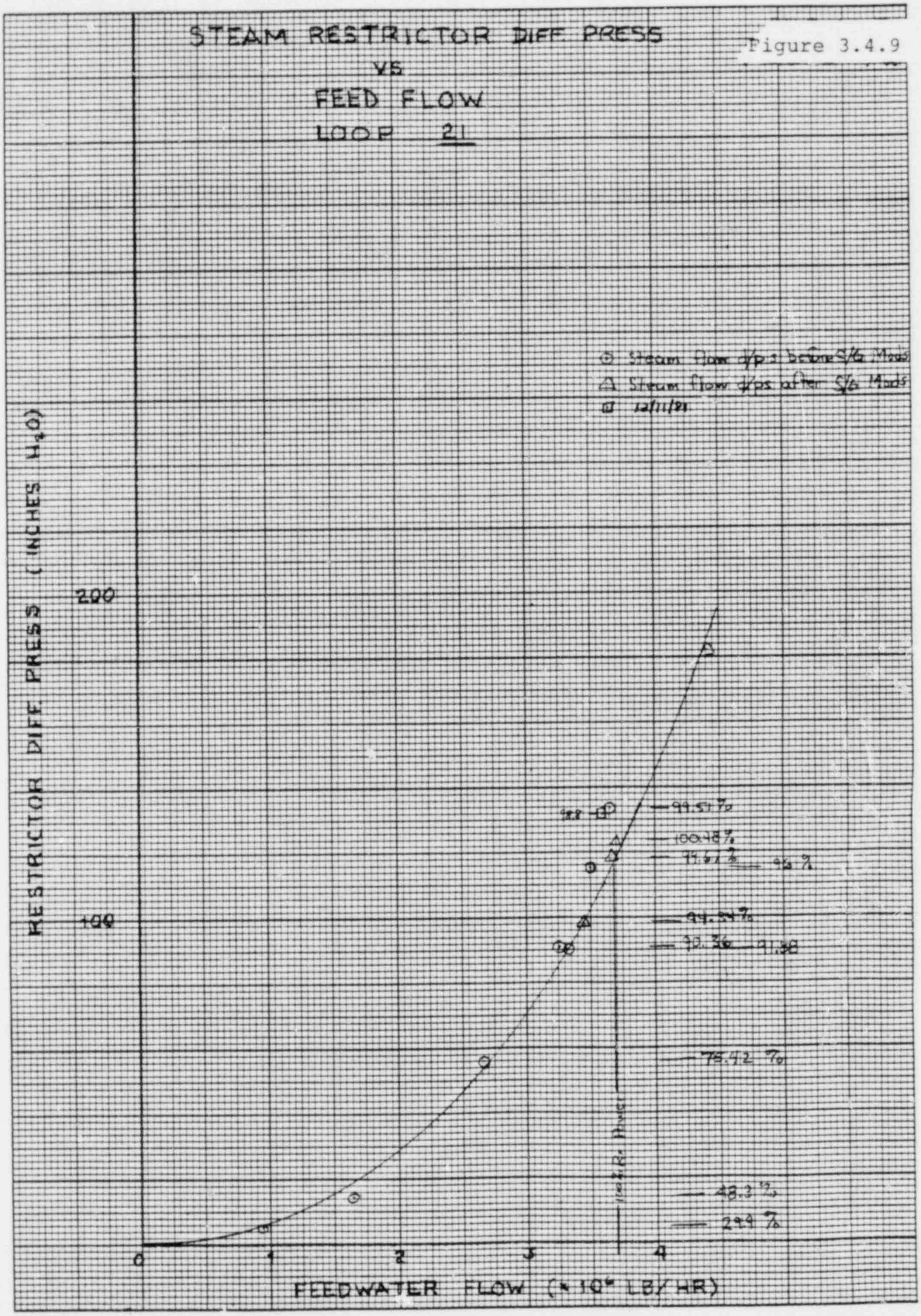

F. W. FLOW VENTURIE DIFF. PRESS.
VS
FEED FLOW
LOOP 24
Figure 3.4.8
1100
1000
900
800
700
600
500
400
300
200
100
0
1
2
3
4
5
VENTURIE DIFF. PRESS (INCHES H_2O)
FEED FLOW (×10⁶ LB/HR)
46 1512
K•E 10 X 10 TO THE CENTIMETER 18 X 25 CM
KEUFFEL & ESSER CO. MADE IN USA

Figure 3.4.9


STEAM RESTRICTOR DIFF PRESS
VS
FEED FLOW
LOOP 21
RESTRICTOR DIFF PRESS (INCHES H_2O)
200
100
0
1
2
3
4
FEEDWATER FLOW (x 10^6 LB/HR)
Steam flow d/ps before S/G Mods
Steam flow d/ps after S/G Mods
12/11/81
99.51 %
100.48 %
96 %
90.36
75.42 %
48.2 %
29.9 %

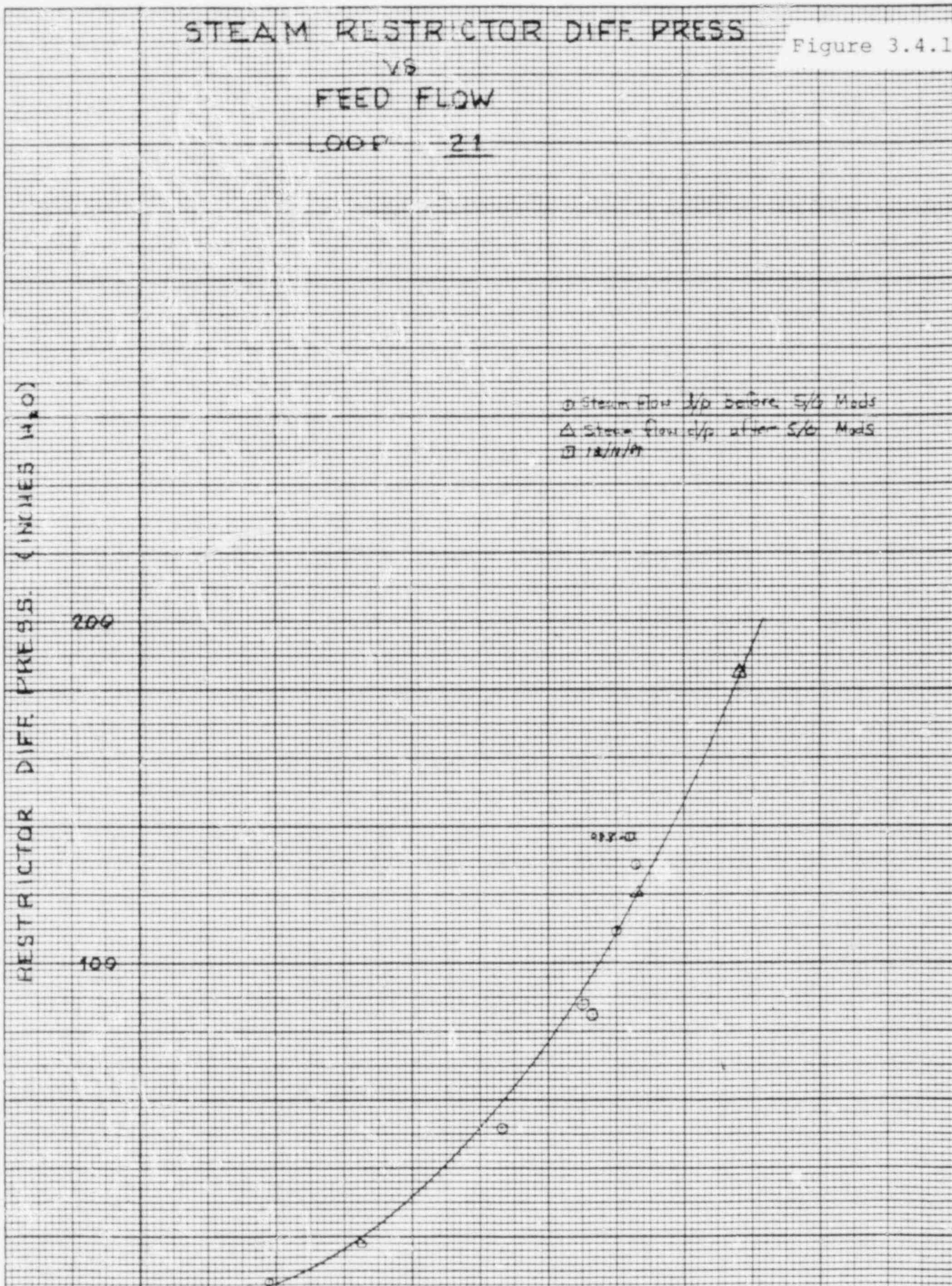
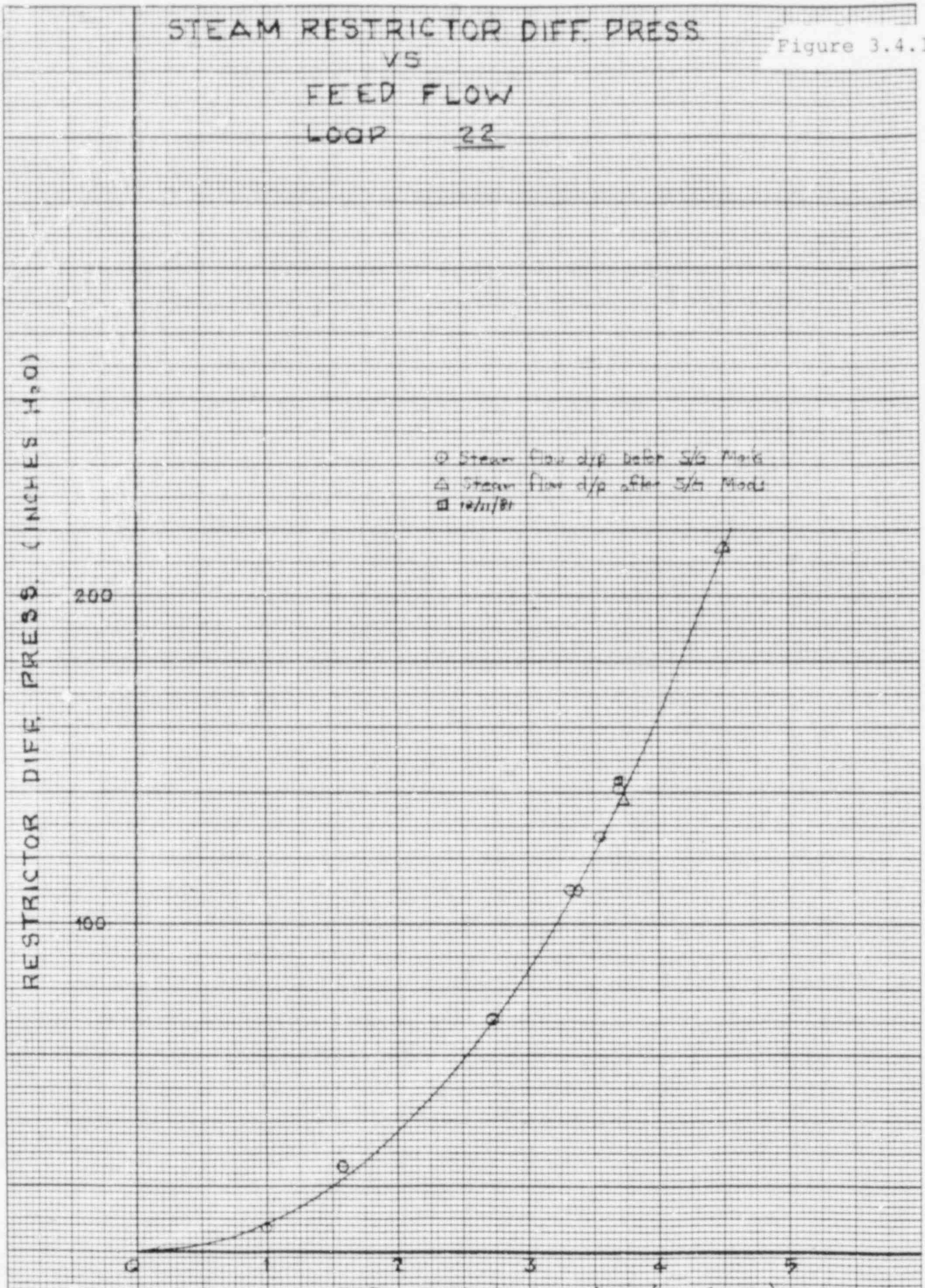

STEAM RESTRICTOR DIFF PRESS
VS
FEED FLOW
LOOP 21
○ Steam flow d/p before S/G Mods
△ Steam flow d/p after S/G Mods
RESTRICTOR DIFF PRESS. (INCHES H_2O)
200
100
0
1
2
3
4
5
FEEDWATER FLOW ($\times 10^6$ LB/HR)

Figure 3.4.10

Figure 3.4.11



K•E 20 X 20 TO THE INCH • 7 X 10 INCHES KEUFFEL & ESSER CO. MADE IN U.S.A. 46 1242

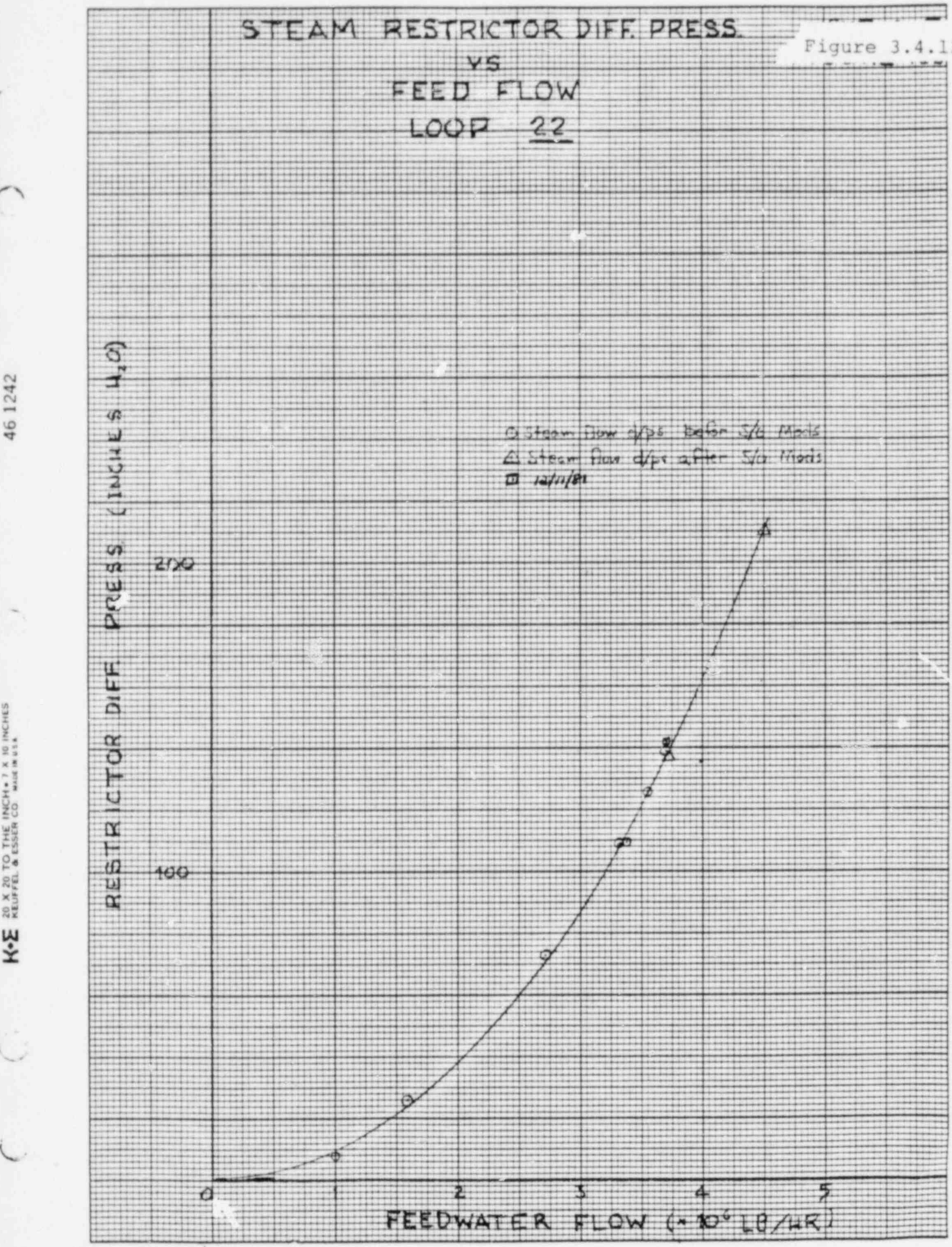

STEAM RESTRICTOR DIFF. PRESS.
VS
FEED FLOW
LOOP 22
RESTRICTOR DIFF. PRESS. (INCHES H_2O)
FEEDWATER FLOW (× 10^6 LB/HR)
200
100
0
1
2
3
4
5
Steam flow d/ps before S/G Mods
Steam flow d/ps after S/G Mods
12/11/81
K+E 20 X 20 TO THE INCH • 7 X 10 INCHES KEUFFEL & ESSER CO. MADE IN U.S.A.
46 1242

Figure 3.4.12

Figure 3.4.13

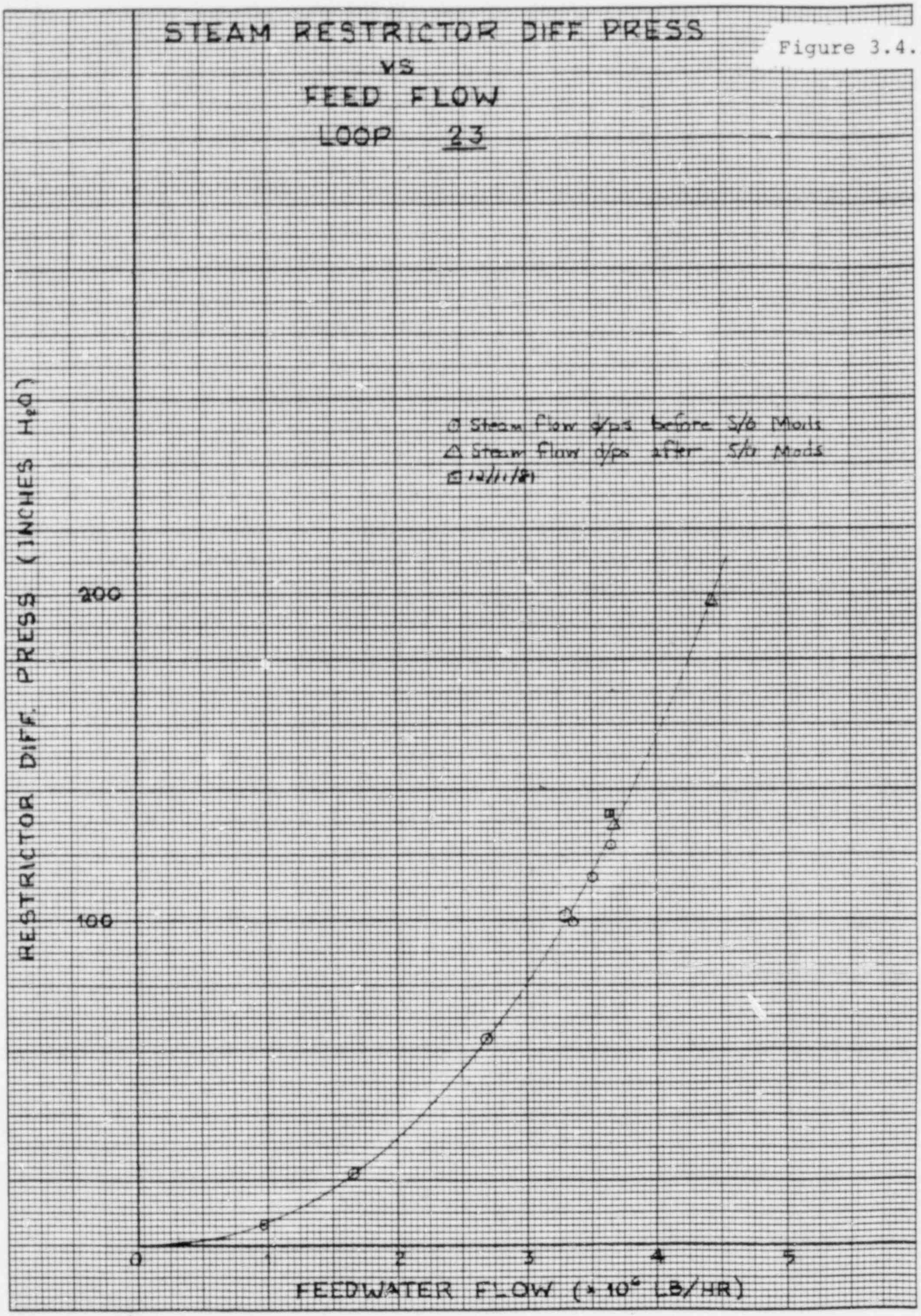

STEAM RESTRICTOR DIFF PRESS
VS
FEED FLOW
LOOP 23
⊙ Steam flow d/ps before S/G Mods
△ Steam flow d/ps after S/G Mods
⊡ 12/11/81
200
100
0
1
2
3
4
5
RESTRICTOR DIFF. PRESS (INCHES H_2O)
FEEDWATER FLOW ($\times 10^6$ LB/HR)

Figure 3.4.14

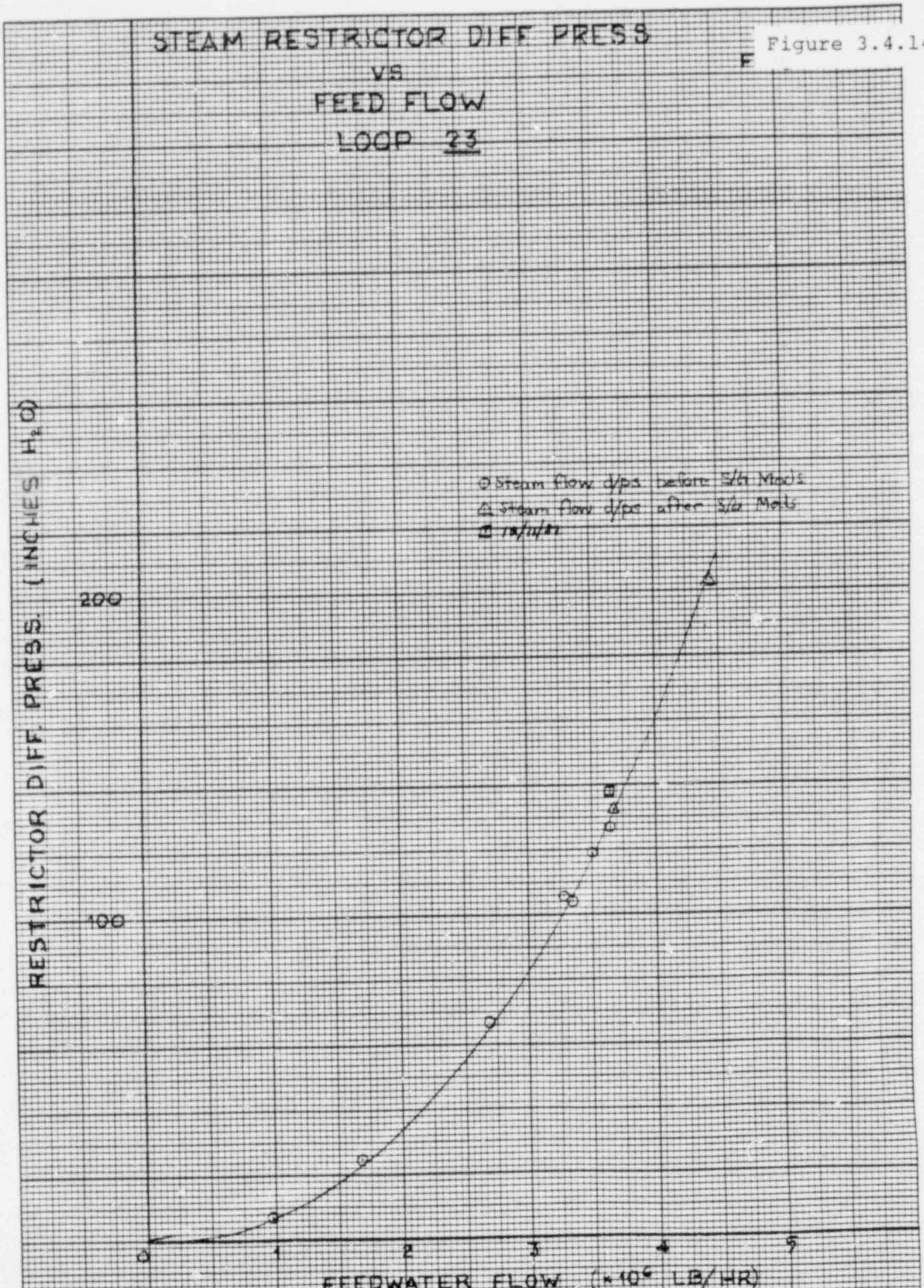
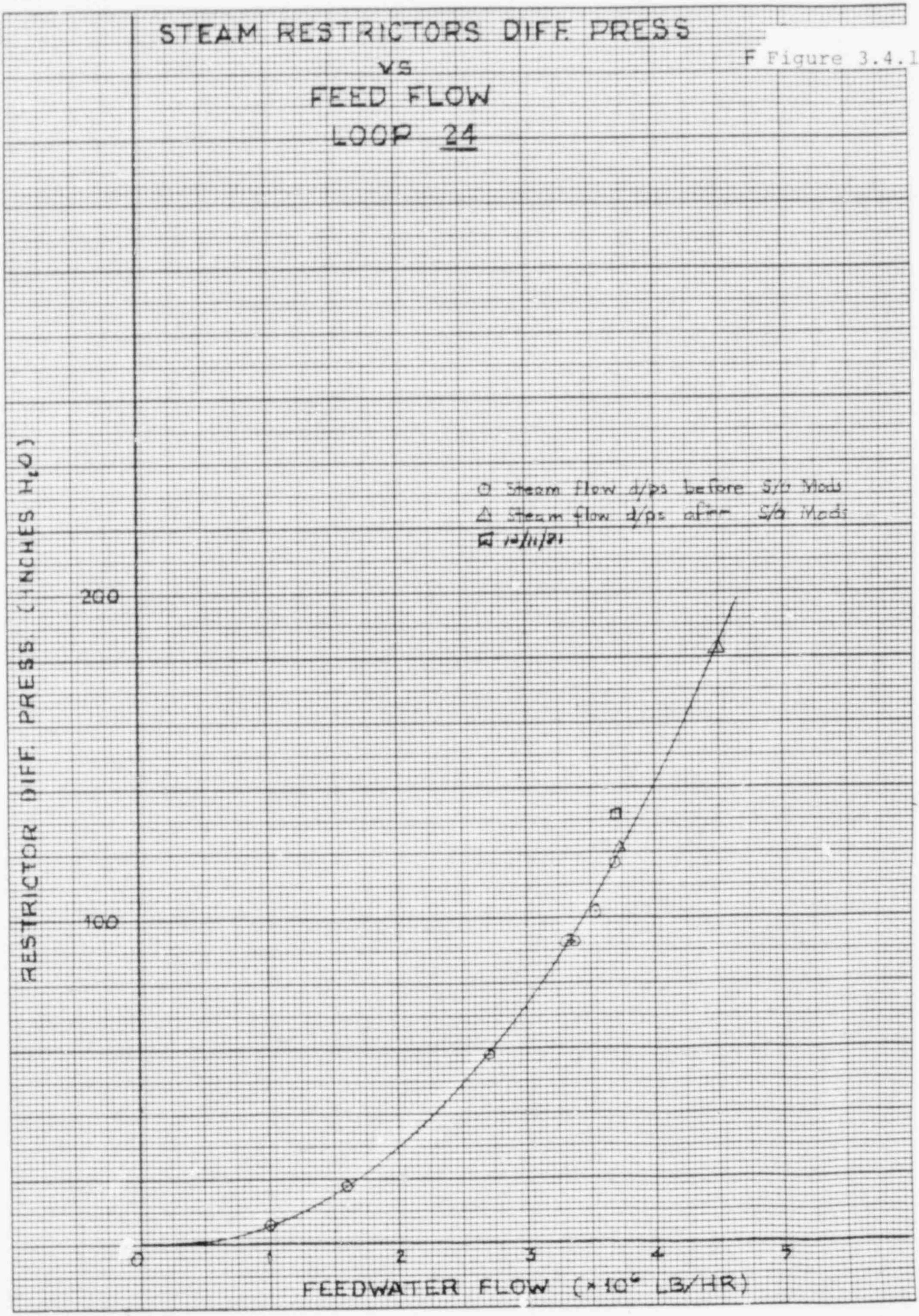

STEAM RESTRICTOR DIFF PRESS
VS
FEED FLOW
LOOP 23
RESTRICTOR DIFF. PRESS. (INCHES H_2O)
200
100
Steam flow d/ps before S/G Mods
Steam flow d/ps after S/G Mods
0
1
2
3
4
5
FEEDWATER FLOW (×10⁶ LB/HR)

Figure 3.4.15


STEAM RESTRICTORS DIFF PRESS
VS
FEED FLOW
LOOP 24
○ Steam flow d/ps before S/G Mods
△ Steam flow d/ps after S/G Mods
□ 12/11/78
RESTRICTOR DIFF PRESS (INCHES H2O)
200
100
0
1
2
3
4
5
FEEDWATER FLOW (×10⁶ LB/HR)

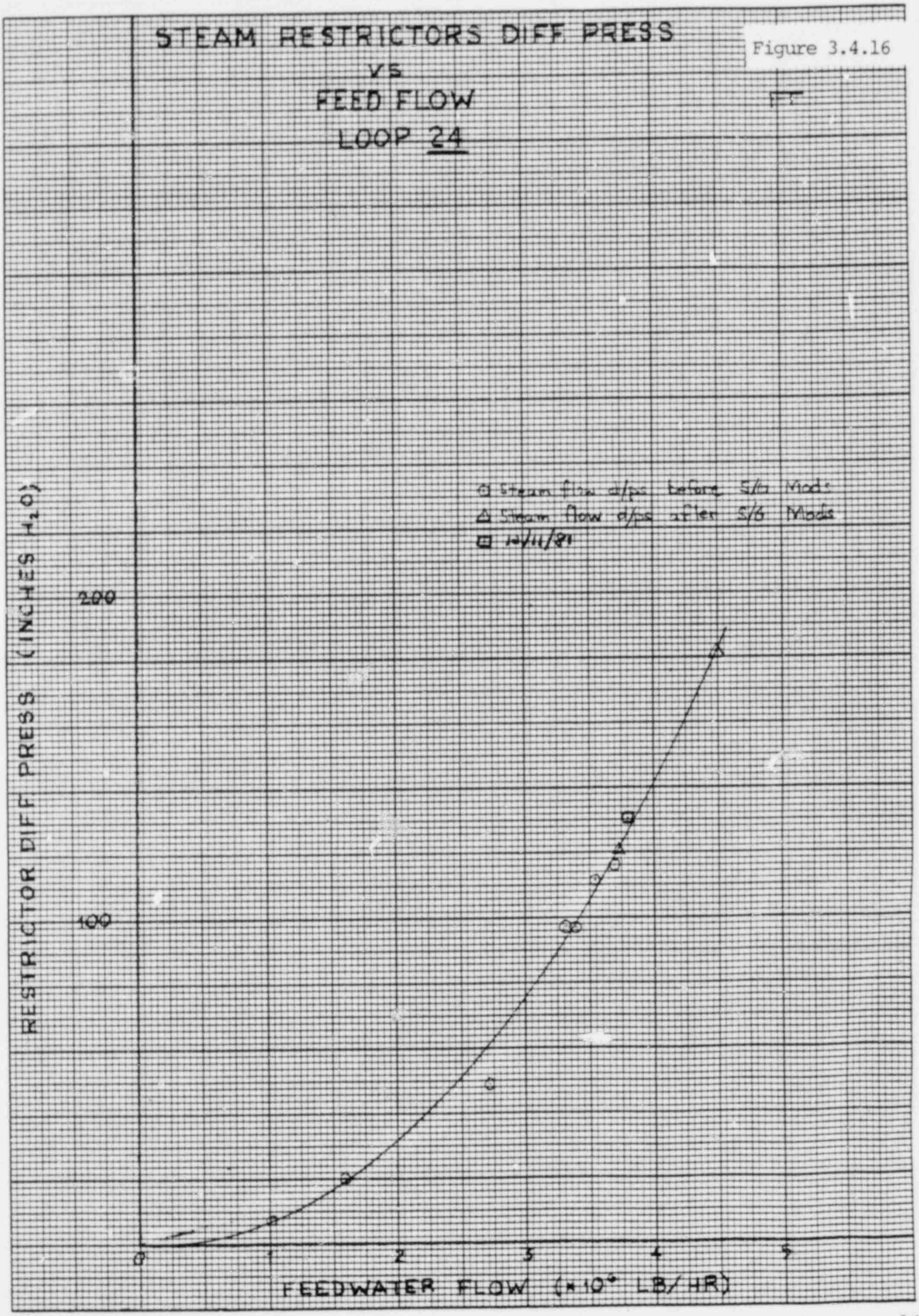
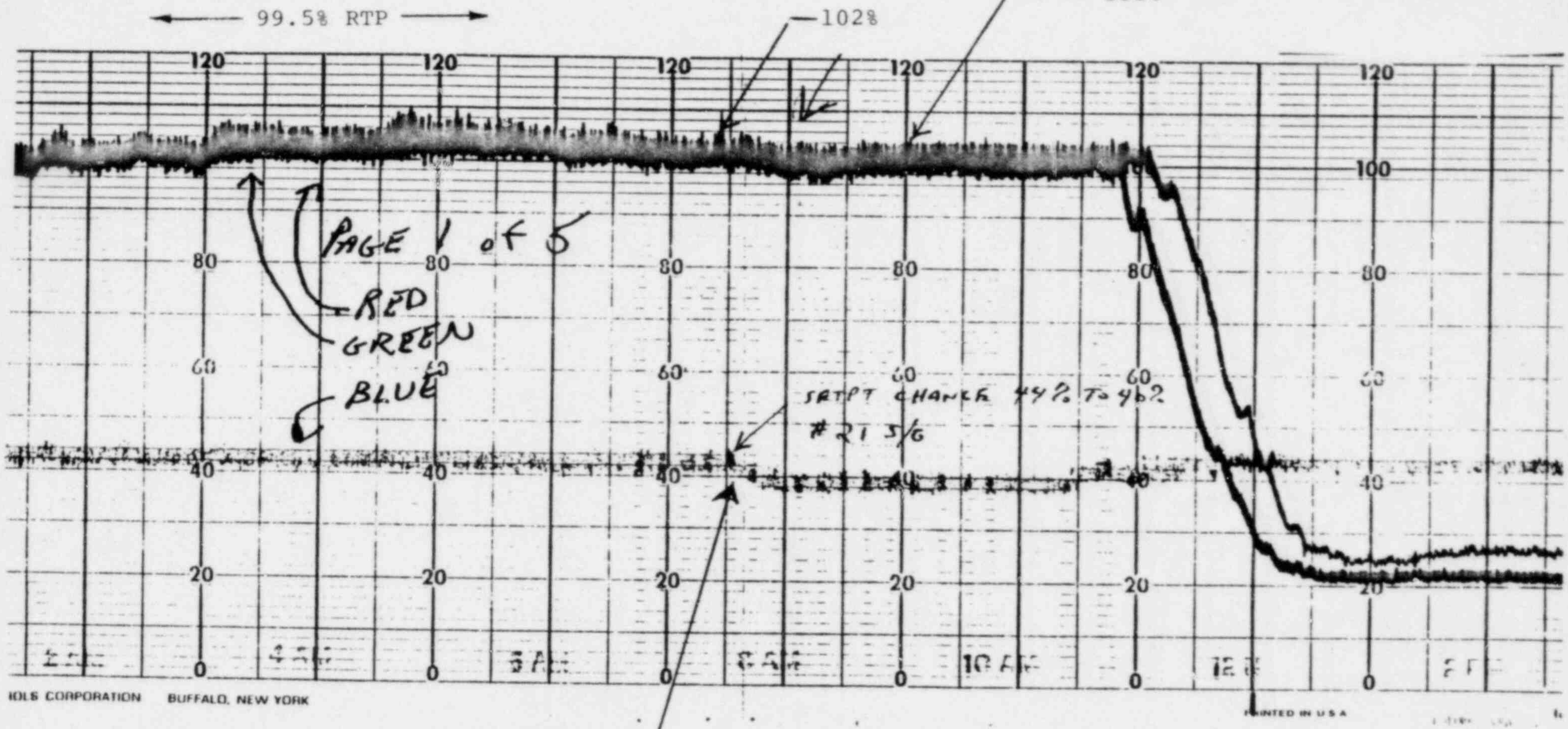

STEAM RESTRICTORS DIFF PRESS
VS
FEED FLOW
LOOP 24
Steam flow d/ps before 5/6 Mods
Steam flow d/ps after 5/6 Mods
12/11/81
RESTRICTOR DIFF PRESS (INCHES H_2O)
200
100
0
1
2
3
4
5
FEEDWATER FLOW (×10⁶ LB/HR)

Figure 3.4.16

No.21 STEAM GENERATOR STEAM?FEED FLOW AND LEVEL



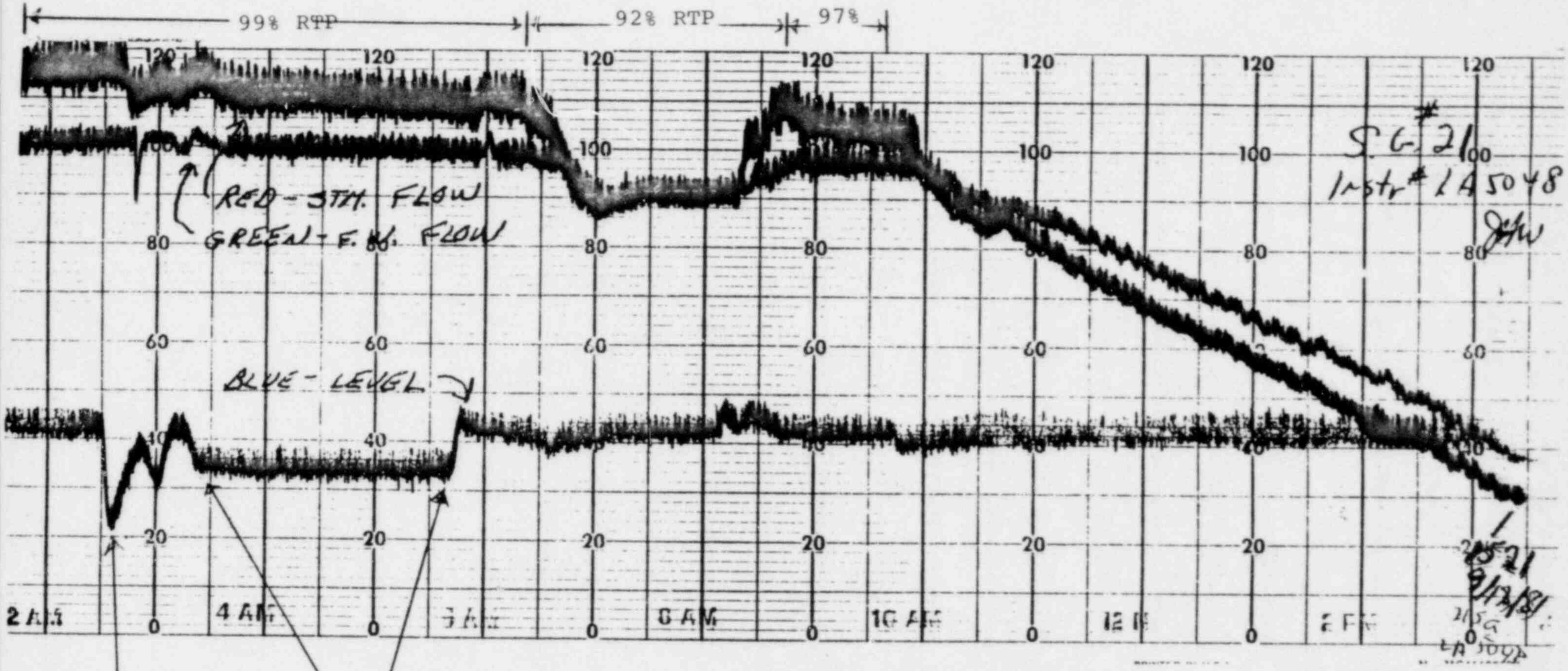
8/29/81
(Befor Mod's)

S G Level Change from
44% to 40%

NOTE: Steam flow transmitter calibrated to 97% statepoint data.

Figure 3.4.17

No. 21 STEAM GENERATOR STEAM/FEED FLOW AND LEVEL



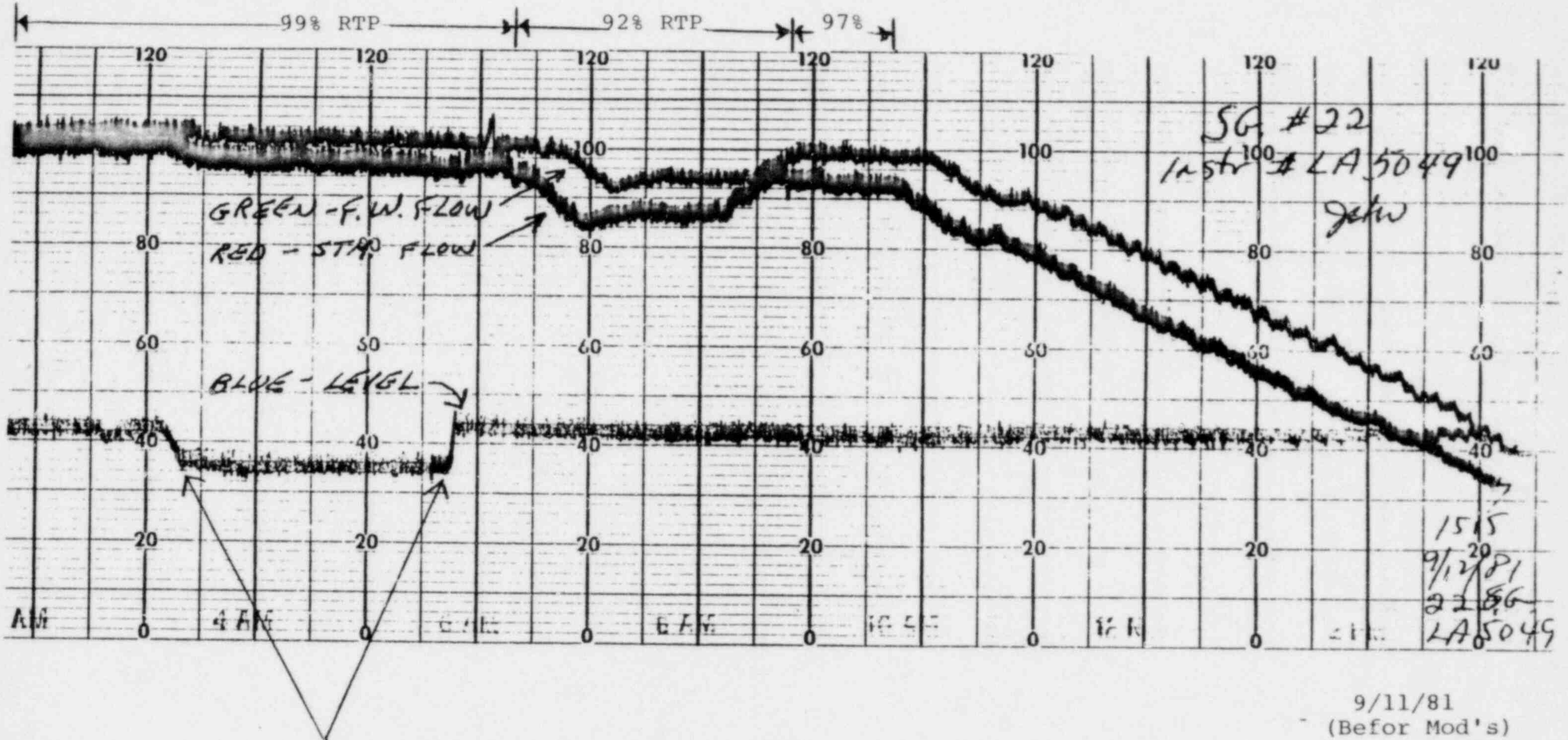
Note steam flow response to large level change.

S G Level change 44% to 36%

NOTE: Steam flow transmitters calibrated to 75% statepoint data.

Figure 3.4.18

No. 22 STEAM GENERATOR STEAM/FEED FLOW AND LEVEL

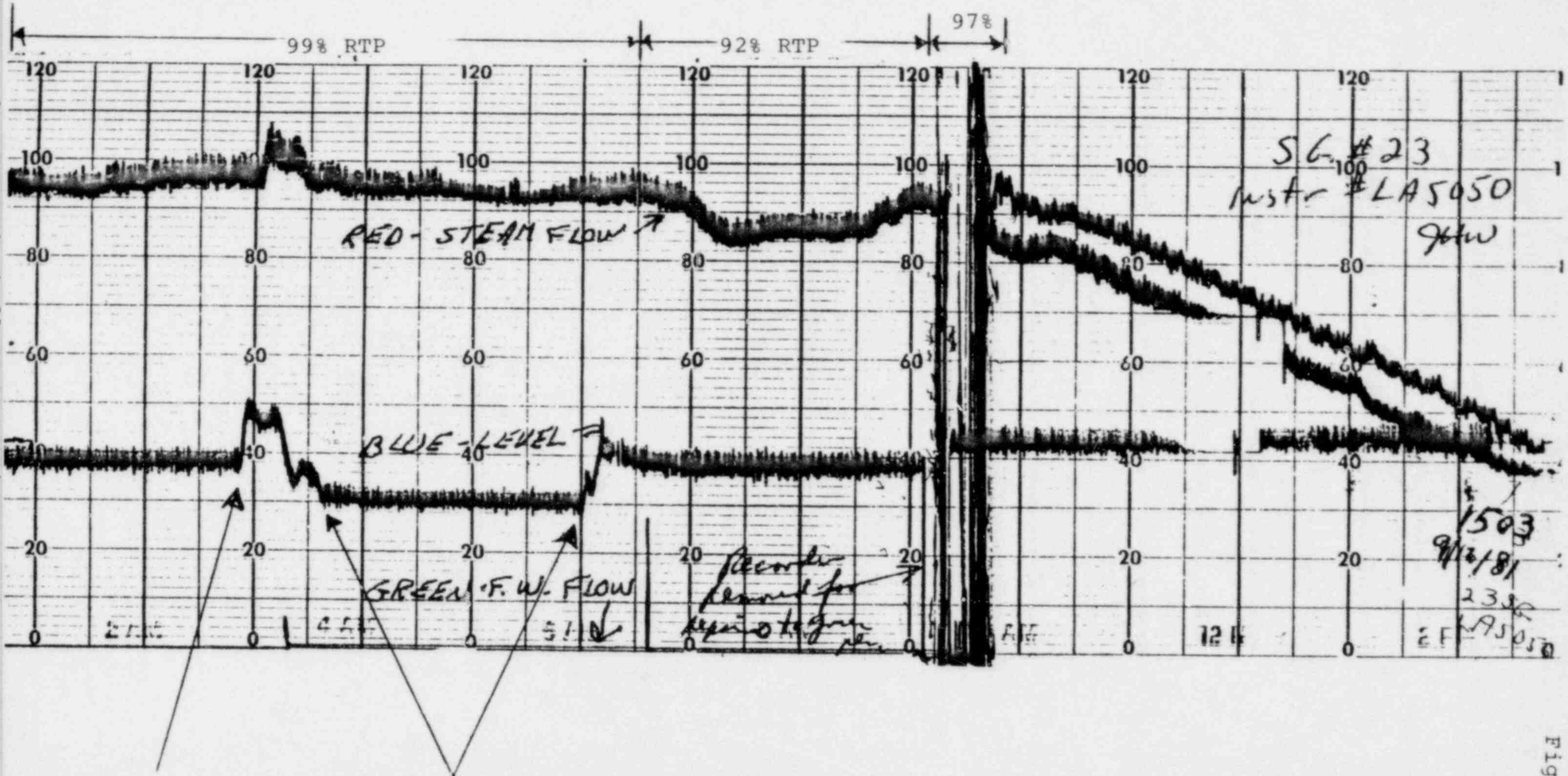


S G level change 44% to 36%

9/11/81
(Befor Mod's)

Figure 3.4.19

No. 23 STEAM GENERATOR STEAM/FEED FLOW AND LEVEL

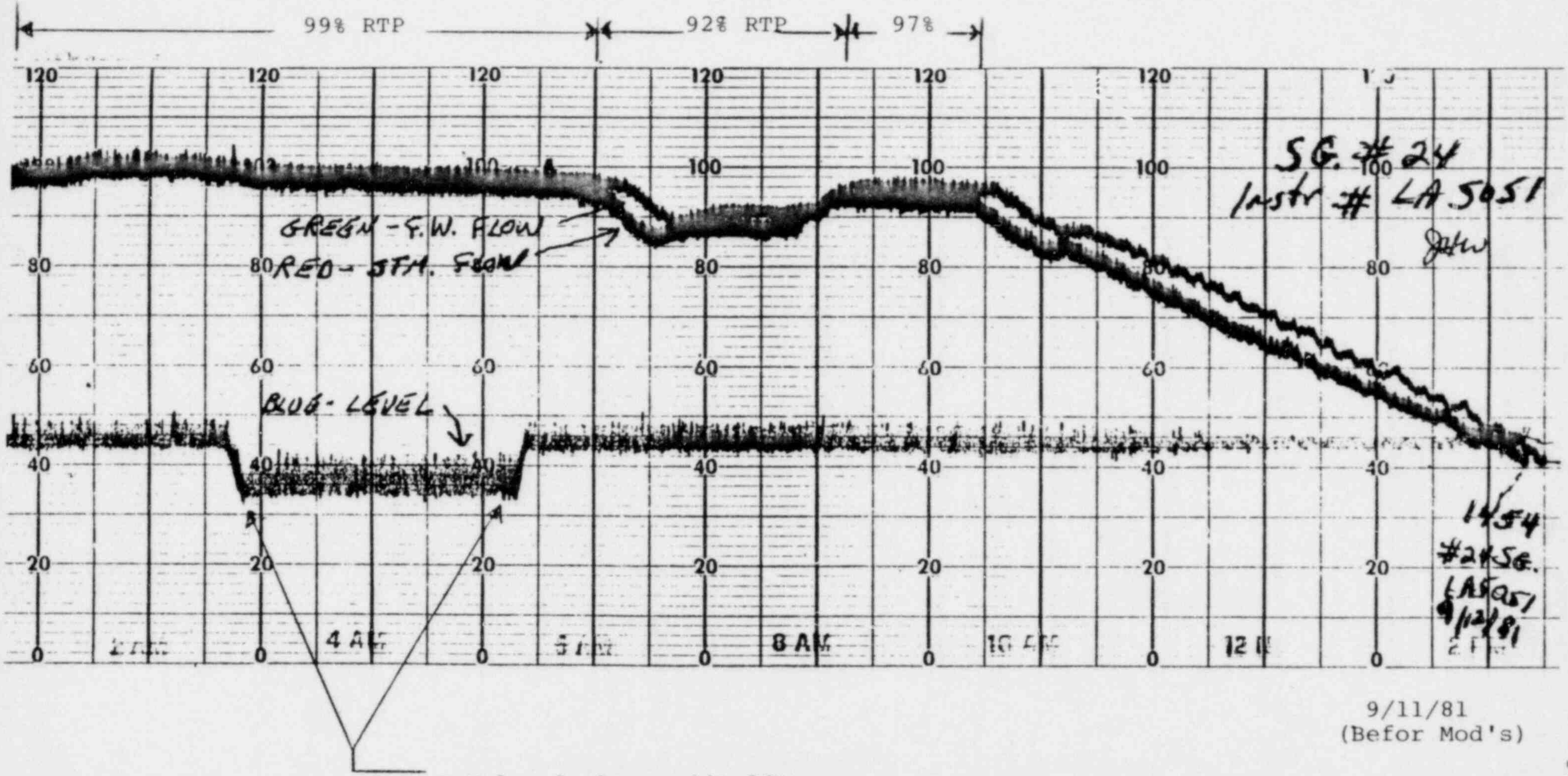


NOTE: With increase in S G level from 40 - 50% steam flow signal response.

S G level change 44%-36%

Figure 3.4.20

No. 24 STEAM GENERATOR STEAM/FEED FLOW AND LEVEL



9/11/81
(Befor Mod's)

S G level change 44%-36%

Figure 3.4.21

SECTION 4.0 PHYSICS TESTING

This section deals with testing to determine various physics parameters during power ascension testing. Those tests included dropped and ejected rod case, power coefficient tests, incore/excore calibration, NIS plateau checks and flux mapping.

4.1 POWER AND BURNUP DISTRIBUTION MEASUREMENTS

Power distribution measurements were performed throughout the startup program both at low power (< 5%) and during power escalation up to and including 100% power. Using the MID system, these measurements were made to verify design calculations, to show compliance with TECHNICAL SPECIFICATION and to provide calibration data for the excore detectors. Three dimensional core power distributions were derived from moveable detector data through the INCORE code using power to activation ratios obtained from design calculations.

During the power escalation program, flux maps were obtained at each of the major testing plateaus. At 50% power, maps were obtained for the pseudo rod ejection test and for the pseudo dropped rod tests. At power levels between 50 and 75% power, data was obtained for the incore/excore calibrations. At each plateau, flux maps were obtained in rod configuration which could be expected during normal operations in order to show compliance with TECHNICAL SPECIFICATIONS limits and to demonstrate conformance with acceptance criteria.

Figures 4.1.1 through 4.1.5 present the results of some of the more representative power distributions, along with the power level, rod position, and burnup at which these measurements were made. No abnormalities were detected by the incore detectors.

POWER TILTS vs CORE POWER

SALM INCORE MAP2010,20.5% PWR,BK D@57,1161PPM,11.3MWD/MTU,PT.47,48,6-6-8

CALCULATED POWER TILTS (NORMALIZED TO 1.000)

```
. 1.0071. .9879 .                    .                      .          .
  .     .     .                      .                         .9975   .
    .    .   .             1.0008 .  .9884                   .        .
.9945 . . .   .9889                  .                         .    .
. . . . . . . . .          . . . . . . . . . .               .9942  .  .9918
.9938 . . .   .9946                  .                         .    .
    .    .   .             1.0023 .  1.0085                  .        .
  .     .     .                      .                          1.0165   .
. 1.0107.1.0224 .                    .                      .          .
```

SALM INCORE MAP2011,29.3% PWR,BK D@155,1042PPM,59MWD/MTU,PT.48,47

CALCULATED POWER TILTS (NORMALIZED TO 1.000)

```
. 1.0103. .9924 .                    .                      .          .
  .     .     .                      .                        .  1.0014  .
    .    .   .             1.0011 .  .9967                   .        .
.9919 . . . 1.0009                   .                         .    .
. . . . . . . . .          . . . . . . . . .               .9932  .  1.0056
.9945 . . . 1.0103                   .                         .    .
    .    .   .              .9949 .  1.0073                  .        .
  .     .     .                      .                        .   .9998  .
.  .9953.1.0043 .                    .                      .          .
```

SALM INCORE MAP2030,100% PWR,BK D@219,895PPM,900MWD/MTU,PT.54,56,53,55

CALCULATED POWER TILTS (NORMALIZED TO 1.000)

```
. 1.0083. .9994 .                    .                      .          .
  .     .     .                      .                        .  1.0038  .
    .    .   .             1.0017 .  1.0011                  .        .
.9952 . . . 1.0029                   .                         .    .
. . . . . . . . .          . . . . . . . . .               .9942  .  1.0044
.9932 . . . 1.0060                   .                         .    .
    .    .   .              .9954 .  1.0017                  .        .
  .     .     .                      .                        .   .9975  .
.  .9976. .9974 .                    .                      .          .
```

Figure 4.1.2

POWER TILTS vs CORE POWER AND AXIAL OFFSET

SALM INCORE MAP2010,**20.5%** PWR,BK D057,1161PPM,11.3MWD/MTU,PT.47,48,6-6-8

RELATIVE POWER IN UPPER HALF OF CORE		RELATIVE POWER IN LOWER HALF OF CORE		PERCENT AXIAL OFFSET TOWARD TOP OF CORE	
(-,+)	(+,+)	(-,+)	(+,+)	(-,+)	(+,+)
.6874	.6891	1.3143	1.2877	-31.319	-30.286
.6975	.7057	1.3070	1.3114	-30.403	-30.029
(-,-)	(+,-)	(-,-)	(+,-)	(-,-)	(+,-)

POWER TILT IN UPPER HALF OF CORE		POWER TILT IN LOWER HALF OF CORE		CORE AVERAGE AXIAL OFFSET
(-,+)	(+,+)	(-,+)	(+,+)	
.9892	.9916	1.0070	.9867	-30.509
1.0038	1.0155	1.0014	1.0048	
(-,-)	(+,-)	(-,-)	(+,-)	

SALM INCORE MAP2011,**29.3%** PWR,BK D0155,1042PPM,59MWD/MTU,PT.48,47

RELATIVE POWER IN UPPER HALF OF CORE		RELATIVE POWER IN LOWER HALF OF CORE		PERCENT AXIAL OFFSET TOWARD TOP OF CORE	
(-,+)	(+,+)	(-,+)	(+,+)	(-,+)	(+,+)
.8504	.8562	1.1518	1.1372	-15.053	-14.096
.8566	.8647	1.1332	1.1500	-13.899	-14.161
(-,-)	(+,-)	(-,-)	(+,-)	(-,-)	(+,-)

POWER TILT IN UPPER HALF OF CORE		POWER TILT IN LOWER HALF OF CORE		CORE AVERAGE AXIAL OFFSET
(-,+)	(+,+)	(-,+)	(+,+)	
.9924	.9991	1.0077	.9949	-14.302
.9996	1.0090	.9914	1.0061	
(-,-)	(+,-)	(-,-)	(+,-)	

SALM INCORE MAP2030,**100%** PWR,BK D0219,895PPM,900MWD/MTU,PT.54,56,53,55

RELATIVE POWER IN UPPER HALF OF CORE		RELATIVE POWER IN LOWER HALF OF CORE		PERCENT AXIAL OFFSET TOWARD TOP OF CORE	
(-,+)	(+,+)	(-,+)	(+,+)	(-,+)	(+,+)
.9336	.9379	1.0699	1.0644	-6.807	-6.315
.9337	.9401	1.0571	1.0633	-6.197	-6.149
(-,-)	(+,-)	(-,-)	(+,-)	(-,-)	(+,-)

POWER TILT IN UPPER HALF OF CORE		POWER TILT IN LOWER HALF OF CORE		CORE AVERAGE AXIAL OFFSET
(-,+)	(+,+)	(-,+)	(+,+)	
.9970	1.0017	1.0059	1.0007	-6.367
.9972	1.0040	.9938	.9996	
(-,-)	(+,-)	(-,-)	(+,-)	

Figure 4.1.3

POWER DISTRIBUTION

20% RTP

MEASURED AND PERCENT. DIFF. OF FDHN SALM INCORE MAP2010,20.5% PWR,BK D057,1161PPM,11.3MWD/MTU,PT.47,48,6-6-8

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1					.666	.796	.945	.855	.937	.760	.632				
					3.1	2.3	1.8	1.2	1.0	-2.3	-2.3				
2			.505	.919	1.129	1.150	1.165	1.136	1.137	1.097	1.076	.881	.500		
			1.7	3.4	3.2	2.4	.0	-1.1	-2.4	-2.3	-1.6	-.9	.7		
3		.508	1.009	.881	1.143	1.196	1.180	1.057	1.158	1.132	1.088	.857	.993	.508	
		2.4	2.4	1.8	3.5	3.3	-.5	-2.4	-2.2	-2.2	-1.6	-1.0	.8	2.4	
4		.911	.886	.856	.993	1.197	1.011	.779	1.042	1.174	.974	.850	.879	.913	
		2.4	2.4	1.4	.9	.9	-5.9	-3.4	-3.0	-1.1	-.9	.7	1.6	2.6	
5	.665	1.102	1.114	.986	1.155	1.163	1.148	1.030	1.138	1.147	1.147	.999	1.121	1.107	.643
	2.9	.8	.8	.2	.9	.9	.4	-.2	-.4	-.5	.2	1.6	1.5	1.2	-.5
6	.794	1.096	1.130	1.171	1.144	1.165	1.023	1.077	1.029	1.169	1.155	1.180	1.149	1.114	.774
	2.1	-2.4	-2.4	-1.3	-.8	-.8	-1.1	-1.0	-.4	-.5	.2	-.6	-.8	-.8	-.5
7	.947	1.153	1.157	1.049	1.114	1.007	1.012	.874	1.012	.996	1.102	1.013	1.145	1.126	.919
	2.1	-1.0	-2.5	-2.3	-2.5	-2.5	-1.6	-1.3	-1.6	-3.6	-3.6	-5.7	-3.4	-3.4	-.9
8	.841	1.132	1.054	.790	1.007	1.060	.865	.667	.865	1.062	1.004	.773	1.037	1.111	.838
	-.5	-1.4	-2.7	-2.0	-2.4	-2.5	-2.3	-1.2	-2.3	-2.3	-2.7	-4.2	-4.3	-3.3	-.8
9	.921	1.147	1.150	1.043	1.106	.997	.990	.861	1.005	1.011	1.112	1.029	1.138	1.133	.921
	-.8	-1.6	-3.0	-2.9	-3.2	-3.5	-3.7	-2.7	-2.2	-2.2	-2.7	-4.2	-4.0	-2.7	-.7
10	.773	1.114	1.119	1.167	1.133	1.142	1.002	1.062	1.024	1.157	1.130	1.164	1.078	1.121	.776
	-.7	-.8	-3.4	-1.6	-1.8	-2.8	-3.1	-2.3	-.9	-1.6	-2.0	-2.0	-6.9	-.2	-.2
11	.660	1.117	1.129	.969	1.129	1.122	1.111	1.011	1.132	1.138	1.122	.965	1.171	1.158	.645
	2.1	2.1	2.2	-1.4	-1.4	-2.6	-2.8	-2.1	-1.0	-1.3	-1.9	-1.9	6.0	5.9	-.2
12		.929	.923	.872	1.000	1.207	1.068	.803	1.064	1.171	.972	.915	.917	.942	
		4.4	6.7	3.3	1.7	1.7	-.6	-.4	-.9	-1.3	-1.2	8.5	6.0	5.9	
13		.530	1.051	.905	1.133	1.183	1.207	1.086	1.206	1.180	1.180	.940	1.057	.526	
		6.7	6.7	4.7	2.5	2.1	1.7	.3	1.7	1.9	6.7	8.6	7.3	6.6	
14			.530	.928	1.128	1.152	1.188	1.171	1.208	1.178	1.167	.966	.533		
			6.7	4.4	3.1	2.6	1.9	2.0	3.7	4.9	6.7	8.6	7.3		
15					.670	.799	.946	.861	.961	.817	.690				
					3.7	2.7	1.9	1.9	3.6	5.0	6.8				

MEAS
DIFF

Figure 4.1.4

POWER DISTRIBUTION

30% RTP

MEASURED AND PERCENT. DIFF. OF FDHN SALM INCORE MAP2011,29.3% PWR,BK D@155,1042PPM,59MWD/MTU,PT.48,47

		R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1	MEAS					.603	.708	.847	.773	.840	.688	.580				
	DIFF					1.8	.8	1.6	1.8	.8	-2.1	-2.0				
2	MEAS			.510	.895	1.054	1.049	1.080	1.064	1.060	1.009	1.012	.865	.504		
	DIFF			2.6	2.6	1.9	1.0	.2	-.2	-1.7	-2.9	-2.2	-.9	1.3		
3	MEAS		.503	1.041	.940	1.131	1.138	1.170	1.107	1.153	1.074	1.082	.925	1.043	.515	
	DIFF		1.1	1.2	1.0	2.2	2.0	.3	-.3	-1.1	-3.7	-2.2	-.7	1.4	3.5	
4	MEAS		.877	.935	1.173	1.060	1.192	1.107	1.084	1.110	1.167	1.031	1.169	.942	.891	
	DIFF		.5	.4	.5	1.4	1.2	-2.0	-.7	-1.6	-.9	-1.3	.2	1.2	2.0	
5	MEAS	.589	1.024	1.100	1.040	1.175	1.149	1.175	1.115	1.175	1.145	1.166	1.050	1.112	1.039	.594
	DIFF	-.5	-1.0	-.6	-.5	1.0	.9	1.1	1.3	1.1	.5	.2	.4	.5	.4	.3
6	MEAS	.687	1.014	1.085	1.161	1.135	1.163	1.041	1.111	1.020	1.136	1.116	1.178	1.116	1.039	.705
	DIFF	-2.2	-2.3	-2.7	-1.4	-.3	1.2	1.5	1.6	-.5	-1.2	-2.0	.0	.1	.0	.3
7	MEAS	.828	1.065	1.141	1.107	1.147	1.024	1.056	.953	1.046	1.011	1.154	1.119	1.165	1.076	.845
	DIFF	-.7	-1.2	-2.1	-1.9	-1.3	-.1	.8	.9	-.2	-1.4	-.7	-.9	-.1	-.2	1.3
8	MEAS	.754	1.057	1.089	1.077	1.078	1.088	.946	.939	.945	1.094	1.098	1.090	1.108	1.065	.769
	DIFF	-.8	-.9	-2.0	-1.4	-2.1	-.4	.2	1.0	.1	.1	-.2	-.2	-.2	-.1	1.2
9	MEAS	.826	1.066	1.145	1.107	1.132	1.001	1.026	.939	1.070	1.041	1.174	1.128	1.169	1.077	.843
	DIFF	-.9	-1.1	-1.8	-2.0	-2.6	-2.4	-2.1	-.6	2.1	1.5	1.0	-.0	.3	-.0	1.1
10	MEAS	.704	1.039	1.086	1.161	1.122	1.128	1.003	1.084	1.028	1.162	1.149	1.189	1.129	1.058	.715
	DIFF	.2	.1	-2.6	-1.4	-1.5	-1.9	-2.2	-.8	.3	1.1	.9	.9	1.2	1.8	1.8
11	MEAS	.610	1.066	1.142	1.032	1.159	1.128	1.150	1.076	1.136	1.128	1.165	1.047	1.101	1.072	.613
	DIFF	3.0	3.1	3.2	-1.2	-.4	-1.0	-1.0	-2.3	-2.2	-.9	.1	.2	-.5	3.6	3.5
12	MEAS		.888	.935	1.179	1.060	1.194	1.116	1.067	1.099	1.166	1.040	1.164	.939	.907	
	DIFF		1.7	.5	1.1	1.4	1.3	-1.2	-2.4	-2.6	-1.0	-.5	-.2	.9	3.9	
13	MEAS		.502	1.038	.943	1.125	1.112	1.140	1.072	1.157	1.125	1.125	.933	1.045	.518	
	DIFF		.9	.9	1.3	1.7	-.3	-2.3	-3.5	-.7	.9	1.6	.2	1.5	4.1	
14	MEAS			.502	.885	1.053	1.035	1.052	1.044	1.087	1.085	1.071	.895	.514		
	DIFF			1.0	1.4	1.8	-.4	-2.3	-2.2	.8	4.5	3.5	2.5	3.3		
15	MEAS					.602	.694	.822	.751	.858	.734	.613				
	DIFF					1.6	-1.3	-1.4	-1.1	2.9	4.4	3.5				

Figure 4.1.5

POWER DISTRIBUTION

100% RTP

MEASURED AND PERCENT. DIFF. OF FDHN SALM INCORE MAP2030,100% PWR,BK D0219,895PPM,900MWD/MTU,PT.54,56,53,55

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
					.556.	.666.	.782.	.723.	.782.	.668.	.562.				
1					1.6.	2.4.	2.4.	2.7.	2.4.	2.7.	2.7.				
			.500.	.865.	.980.	1.003.	1.026.	1.019.	1.011.	.976.	.962.	.812.	.478.		
			6.8.	6.7.	1.7.	2.4.	.6.	.3.	-.8.	-.4.	-.2.	.1.	2.0.		
		.485.	.999.	.948.	1.099.	1.116.	1.158.	1.122.	1.143.	1.061.	1.063.	.917.	.983.	.486.	
		3.7.	3.8.	3.7.	1.8.	1.7.	.1.	-.4.	-1.1.	-3.3.	-1.5.	.3.	2.1.	3.9.	
		.829.	934.	1.231.	1.075.	1.192.	1.162.	1.214.	1.168.	1.180.	1.059.	1.226.	.929.	.828.	
4		2.3.	2.2.	.6.	.2.	.1.	-1.4.	.1.	-1.0.	-.9.	-1.3.	.3.	1.6.	2.2.	
	.568.	.977.	1.086.	1.067.	1.167.	1.152.	1.210.	1.203.	1.238.	1.184.	1.178.	1.070.	1.088.	.971.	.553.
	3.7.	1.3.	.6.	-.5.	-2.1.	-2.5.	-.7.	1.7.	1.6.	.3.	-1.2.	-.3.	.8.	.7.	1.1.
	.673.	.985.	1.070.	1.172.	1.151.	1.178.	1.087.	1.184.	1.097.	1.185.	1.150.	1.195.	1.109.	.989.	.657.
	3.5.	.5.	-2.5.	-1.7.	-2.5.	-1.9.	-1.2.	1.1.	-.3.	-1.3.	-2.6.	.3.	1.1.	1.0.	1.0.
	.782.	1.021.	1.131.	1.154.	1.178.	1.076.	1.127.	1.057.	1.132.	1.081.	1.209.	1.181.	1.165.	1.026.	.777.
7	2.3.	.1.	-2.2.	-2.1.	-3.3.	-2.1.	-1.1.	.2.	-.6.	-1.7.	-.7.	.2.	.8.	.6.	1.7.
	.701.	1.006.	1.104.	1.192.	1.155.	1.157.	1.050.	1.101.	1.041.	1.157.	1.178.	1.218.	1.134.	1.028.	.724.
	-.5.	-1.0.	-2.1.	-1.8.	-2.4.	-1.2.	-.4.	-.4.	-1.3.	-1.1.	-.4.	.4.	.6.	1.2.	2.9.
	.759.	1.008.	1.133.	1.151.	1.184.	1.070.	1.111.	1.033.	1.135.	1.096.	1.212.	1.163.	1.147.	1.031.	.787.
	-.6.	-1.1.	-2.0.	-2.4.	-2.9.	-2.7.	-2.4.	-2.1.	-.4.	-.3.	-.5.	-1.4.	-.8.	1.1.	3.0.
	.648.	.976.	1.072.	1.169.	1.158.	1.170.	1.070.	1.144.	1.082.	1.171.	1.144.	1.153.	1.054.	1.032.	.685.
10.	-.3.	-.4.	-2.3.	-1.9.	-2.0.	-2.5.	-2.7.	-2.3.	-1.6.	-2.5.	-3.2.	-3.2.	-3.9.	5.4.	5.3.
	.557.	.982.	1.101.	1.055.	1.179.	1.160.	1.198.	1.154.	1.191.	1.132.	1.161.	1.048.	1.069.	1.034.	.587.
11.	1.8.	1.8.	2.0.	-1.6.	-1.1.	-1.8.	-1.7.	-2.5.	-2.2.	-4.2.	-2.6.	-2.3.	-1.0.	7.2.	7.1.
		.830.	.942.	1.250.	1.083.	1.2[illegible]0.	1.156.	1.180.	1.143.	1.143.	1.056.	1.213.	.950.	.863.	
12		2.4.	3.1.	2.2.	.9.	.7.	-1.9.	-2.7.	-3.0.	-4.1.	-1.6.	-.8.	3.9.	6.5.	
		.489.	1.005.	.950.	1.095.	1.101.	1.130.	1.090.	1.139.	1.103.	1.113.	.940.	1.000.	.495.	
13		4.4.	4.4.	3.9.	1.5.	.3.	-2.2.	-3.3.	-1.5.	.5.	3.2.	2.9.	3.9.	5.7.	
			.490.	.839.	.987.	.988.	1.000.	.997.	1.020.	1.017.	1.000.	.840.	.490.		
14			4.6.	3.5.	2.3.	[illegible]	-1.9.	-1.9.	.1.	3.8.	3.[illegible]	3.6.	4.6.		
					.560.	.652.	.762.	.703.	.783.	.675.	.567.				MEAS
15					2.3.	.2.	-.3.	-.1.	2.5.	3.7.	3.6.				DIFF

4.2 SUP 81.9 - RCCA PSEUDO EJECTION AND RCCA ABOVE BANK MEASUREMENT

The objective of this test was to determine the worth of the most reactive RCCA "ejected" out of the core from the full power control bank insertion limit. The worth had to be conservative with respect to the value assumed in the Salem Final Safety Analysis Report, also various acceptance criteria on incore power and flux distribution had to be met.

Control bank "D" rods were positioned at their full power insertion limit of 188 steps (all other banks out). Steady state conditions were established with the reactor at 48% rated thermal power. Base case incore flux and thermocouple maps were taken with these conditions. All of the lift coils in control bank "D" were disconnected except for the lift coil for control rod 1D2, core location D12 (see Figure 4.2.1). This rod was withdrawn as requested by the Test Engineer and RCS temperature was allowed to increase compensating for the reactivity addition of the rod (increase in T_{avg} of 1.5^{o}F). Various incore thermocouples, incore flux detectors, and excore detectors were monitored during this rod withdrawal. After the rod 1D2 was fully withdrawn, another incore flux and thermocouple map was taken (ejected condition). The "ejected rod" was inserted back to 188 steps and the disconnect switches reconnected returning control bank "D" to normal operation. Turbine and reactor power were held constant during this test.

The ejected rod worth was measured and determined to be less than 20 pcm. During the rod withdrawal to 228 steps, the incore thermocouples showed no change in temperature. There was no indication of the rod withdrawal indicated on the excore detectors. The flux maps taken before and after the rod withdrawal are shown in Figures 4.2.2. thru 4.2.4. They indicate the effects of the ejected rod on power sharing and incore tilts.

The maximum Heat Flux Hot Channel Factor at the peak core location [FQ^T (Z)] was measured as 2.2172, well within the acceptance criteria of less than 6.09 with the rod ejected.

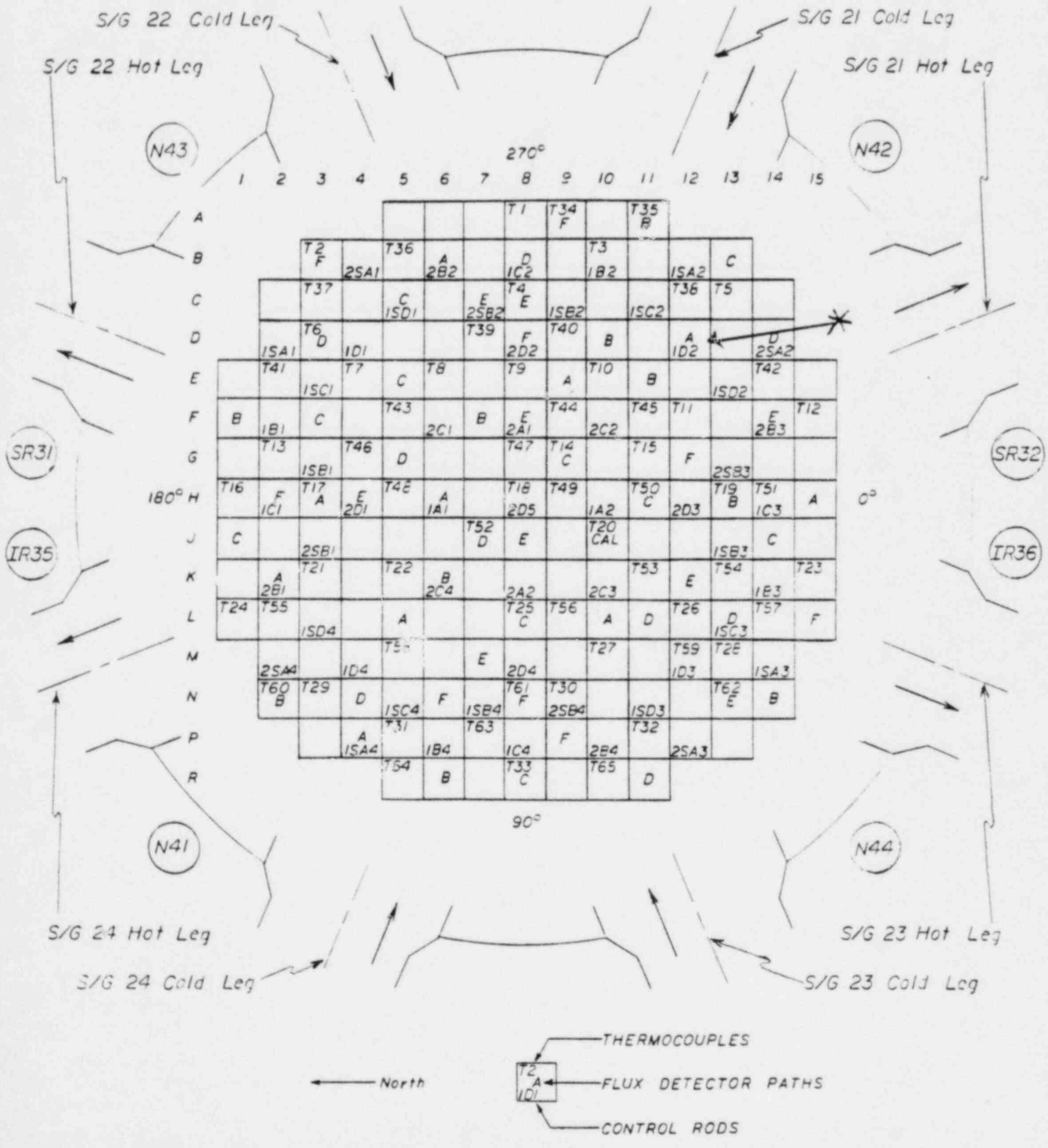
Figure 4.2.1

FIGURE 2.14

SALEM NUCLEAR GENERATING STATION

UNIT NO. 2

RCC INCORE DETECTOR THIMBLE AND THERMOCOUPLE LOCATIONS



BASE CASE FLUX MAP

FCR

1D2 EJECTION

MEASURED AND PERCENT. DIFF. OF FDHN SALM INCORE MAP2022,47.6% PWR,BK D0188,985PPM,245MWD/MTU,PT.54,56,53,55

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
					.588.	.693.	.817.	.748.	.808.	.676.	.571.				
1					3.3.	2.7.	2.8.	2.7.	1.7.	.2.	.3.				
			.505.	.878.	1.022.	1.033.	1.052.	1.044.	1.031.	.992.	.985.	.847.	.496.		
2			5.4.	5.3.	3.4.	2.8.	1.3.	.6.	-.8.	-1.3.	-.3.	1.6.	3.4.		
		.499.	1.021.	.944.	1.127.	1.138.	1.174.	1.119.	1.156.	1.071.	1.083.	.929.	1.017.	.505.	
3		4.0.	4.0.	3.5.	3.5.	3.4.	.9.	.1.	-.6.	-2.7.	-.5.	1.8.	3.5.	5.2.	
		.861.	.941.	1.216.	1.077.	1.211.	1.144.	1.165.	1.143.	1.176.	1.053.	1.211.	.939.	.863.	
4		3.3.	3.2.	1.9.	2.0.	1.9.	-1.2.	-.5.	-1.3.	-1.0.	-.2.	1.5.	3.0.	3.5.	
	.583.	.999.	1.103.	1.060.	1.192.	1.170.	1.204.	1.155.	1.205.	1.161.	1.183.	1.066.	1.110.	1.007.	.580.
5	2.5.	1.1.	1.3.	.5.	.8.	.6.	.2.	.4.	.2.	-.2.	.0.	.9.	2.0.	1.9.	2.0.
	.675.	.994.	1.069.	1.172.	1.154.	1.183.	1.062.	1.140.	1.047.	1.157.	1.125.	1.199.	1.117.	1.020.	.687.
6	.2.	-1.1.	-2.9.	-1.4.	-.7.	-.2.	-.8.	-.7.	-2.3.	-2.4.	-3.2.	.8.	1.5.	1.5.	2.0.
	.798.	1.033.	1.137.	1.130.	1.173.	1.044.	1.090.	.992.	1.085.	1.034.	1.174.	1.152.	1.169.	1.046.	.811.
7	.4.	-.6.	-2.2.	-2.4.	-2.4.	-2.5.	-1.8.	-2.1.	-2.3.	-3.5.	-2.3.	-.5.	.5.	.7.	2.1.
	.727.	1.033.	1.100.	1.145.	1.115.	1.111.	.980.	1.012.	.983.	1.121.	1.132.	1.169.	1.120.	1.046.	.744.
8	-.2.	-.4.	-1.6.	-2.2.	-3.2.	-3.2.	-3.3.	-2.9.	-2.9.	-2.3.	-1.6.	-.2.	.1.	.8.	2.2.
	.792.	1.034.	1.152.	1.128.	1.158.	1.024.	1.054.	.970.	1.094.	1.060.	1.200.	1.150.	1.161.	1.047.	.812.
9	-.3.	-.5.	-.9.	-2.6.	-3.7.	-4.4.	-5.1.	-4.2.	-1.5.	-1.0.	-.2.	-.7.	-.1.	.8.	2.2.
	.674.	1.005.	1.088.	1.162.	1.135.	1.146.	1.020.	1.101.	1.035.	1.178.	1.165.	1.191.	1.099.	1.036.	.694.
10.	.0.	-.0.	-1.1.	-2.2.	-2.3.	-3.3.	-4.8.	-4.1.	-3.3.	-.6.	.2.	.2.	-.2.	3.1.	3.0.
	.576.	1.001.	1.104.	1.035.	1.169.	1.137.	1.166.	1.100.	1.153.	1.147.	1.190.	1.063.	1.091.	1.028.	.592.
11.	1.2.	1.3.	1.3.	-2.0.	-1.2.	-2.2.	-3.0.	-4.4.	-4.1.	-1.4.	.7.	.7.	.2.	4.0.	3.9.
		.856.	.951.	1.218.	1.065.	1.198.	1.135.	1.131.	1.115.	1.171.	1.067.	1.212.	.938.	.872.	
12		2.7.	4.2.	2.1.	.9.	.8.	-2.0.	-3.4.	-3.7.	-1.5.	1.1.	1.6.	2.9.	4.6.	
		.499.	1.022.	.942.	1.102.	1.100.	1.143.	1.083.	1.143.	1.092.	1.116.	.936.	1.016.	.504.	
13		4.0.	4.0.	3.3.	1.2.	-.1.	-1.7.	-3.2.	-1.7.	-.8.	2.5.	2.6.	3.5.	5.1.	
			.499.	.856.	1.003.	1.005.	1.020.	1.020.	1.039.	1.030.	1.022.	.870.	.502.		
14			4.0.	2.7.	1.4.	-.0.	-1.8.	-1.7.	.1.	2.5.	3.5.	4.4.	4.8.		
					.576.	.669.	.786.	.722.	.807.	.691.	.588.				
15					1.2.	-.7.	-1.1.	-.9.	1.5.	2.5.	3.4.				

Figure 4.2.3

EJECTED ROD FLUX MAP

MEASURED AND PERCENT. DIFF. OF FDHN EACH INCORE MAP20.3,47.6% PWR,BK D0188,983PPM,245MWD/MTU,PT.49,50

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1					.5[illegible]3. 2.2.	.672. 2.6.	.796. 2.4.	.732. 2.4.	.834. 7.0.	.737. 11.8.	.620. 11.8.				
2			.540. 14.2.	.931. 14.2.	1.008. 2.2.	.980. 2.5.	1.040. .4.	.986. -.3.	1.052. 1.2.	1.003. 4.4.	1.022. 2.8.	.820. -.3.	.515. 7.7.		
3		.506. 7.1.	1.035. 7.0.	.990. 7.0.	1.075. 2.1.	1.110. 2.2.	1.099. -1.2.	1.080. -2.4.	1.088. -2.5.	1.059. -3.1.	1.042. -1.7.	.931. -.4.	1.055. 7.7.	.556. 15.8.	
4		.847. 3.8.	.955. 3.2.	1.181. -.8.	1.049. -.8.	1.126. -.8.	1.093. -4.2.	1.093. -3.2.	1.109. -3.2.	1.114. -2.6.	1.042. -2.4.	1.172. -2.3.	.979. 4.1.	.889. 6.8.	
5	.604. 9.6.	1.034. 4.7.	1.075. 2.1.	1.052. -.5.	1.118. -1.1.	1.126. -1.2.	1.120. -1.7.	1.111. -1.6.	1.128. -1.6.	1.125. -2.2.	1.107. -3.4.	1.042. -3.0.	1.056. -1.7.	.995. -1.8.	.562. -.9.
6	.734. 12.0.	1.011. 5.8.	1.075. -1.1.	1.123. -1.0.	1.124. -1.4.	1.108. -.9.	1.034. -.9.	1.071. -.8.	1.028. -2.3.	1.097. -3.2.	1.111. -4.2.	1.128. -2.7.	1.095. -1.9.	.968. -2.0.	.671. -1.1.
7	.871. 12.0.	1.094. 5.5.	1.099. -1.2.	1.121. -1.7.	1.115. -2.1.	1.025. -1.8.	1.025. -1.3.	.975. -1.3.	1.024. -2.4.	1.028. -3.2.	1.123. -3.5.	1.126. -3.7.	1.116. -2.9.	1.049. -2,6.	.798. -1.6.
8	.772. 7.9.	1.033. 4.5.	1.104. -.3.	1.103. -2.4.	1.101. -2.5.	1.058. -1.9.	.972. -1.5.	.971. -1.6.	.975. -2.5.	1.075. -2.7.	1.122. -3.3.	1.120. -3.0.	1.110. -3.5.	1.015. -2.1.	.750. -.4.
9	.838. 7.4.	1.085. 4.3.	1.124. .7.	1.120. -2.2.	1.117. -2.5.	1.025. -2.5.	1.022. -2.6.	.922. -2.3.	[illegible] -1.6.	1.062. -2.1.	1.155. -3.2.	1.150 -4.1.	1.131. -4.2.	1.082. -2.1.	.826. -.5.
10	.691. 5.0.	1.008. 4.8.	1.125. 2.8.	1.123. -1.8.	1.130. -1.8.	1.110. -2.1.	1.029. -3.1.	1.074. -2.8.	1.053. -2.9.	1.145. -3.0.	1.173. -3.8.	1.176. -4.0.	1.128. -4.5.	1.061. 2.2.	.726. 2.1.
11	.593. 7.0.	1.064. 7.0.	1.134. 6.9.	1.048. -1.8.	1.131. -1.4.	1.141. -1.6.	1.137. -2.3.	1.122. -3.2.	1.148. -3.8.	1.171. -4.0.	1.178. -4.6.	1.117. -4.9.	1.107. -5.3.	1.126. -3.3.	.625. 3.2.
12		.875. 6.3.	.987. 5.6.	1.215. 1.3.	1.068. -.6.	1.153. -.6.	1.132. -3.1.	1.112. -3.7.	1.147. -4.4.	1.174. -4.1.	1.115. -5.1.	1.292. -5.5.	1.070. 2.3.	.980. 7.2.	
13		.525. 9.8.	1.073. 9.6.	1.001. 6.4.	1.072. -.2.	1.113. -.3.	1.124. -2.2.	1.112. -3.4.	1.142. -3.2.	1.154. -2.1.	1.152. -1.4.	1.027. -2.2.	1.122. 2.3.	.595. 11.0.	
14			.529. 10.2.	.886. 6.5.	1.041. 2.8.	1.003. 1.6.	1.089. 1.1.	1.049. 1.1.	1.118. 1.2.	1.036. -.2.	1.099. .7.	.930. 1.7.	.519. 6.1.		
15					.598. 5.6.	.696. 2.5.	.849. 4.7.	.791. 5.1.	.872. 4.9.	.709. -.3.	.610. .7.				

Figure 4.2.4

INCORE POWER TILTS

BASE CASE

SALM INCORE MAP2022,47.6% PWR,BK D@188,985PPM,245MWD/MTU,PT.54,56,53,55

RELATIVE POWER IN UPPER HALF OF CORE

(-,+)	(+,+)
.9732	.9706
.9555	.9735
(-,-)	(+,-)

RELATIVE POWER IN LOWER HALF OF CORE

(-,+)	(+,+)
1.0375	1.0304
1.0168	1.0324
(-,-)	(+,-)

PERCENT AXIAL OFFSET TOWARD TOP OF CORE

(-,+)	(+,+)
-3.200	-2.989
-2.587	-2.937
(-,-)	(+,-)

POWER TILT IN UPPER HALF OF CORE

(-,+)	(+,+)
1.0025	.9999
.9947	1.0029 *
(-,-)	(+,-)

POWER TILT IN LOWER HALF OF CORE

(-,+)	(+,+)
1.0080	1.0011
.9879	1.0030 *
(-,-)	(+,-)

CORE AVERAGE AXIAL OFFSET

-2.928 *

EJECTED CASE

SALM INCORE MAP2023,47.6% PWR,BK D@188,985PPM,245MWD/MTU,PT.49,50

RELATIVE POWER IN UPPER HALF OF CORE

(-,+)	(+,+)
.9476	.9515
.9676	1.0241
(-,-)	(+,-)

RELATIVE POWER IN LOWER HALF OF CORE

(-,+)	(+,+)
1.0265	1.0119
1.0326	1.0382
(-,-)	(+,-)

PERCENT AXIAL OFFSET TOWARD TOP OF CORE

(-,+)	(+,+)
-3.997	-3.077
-3.252	-.688
(-,-)	(+,-)

POWER TILT IN UPPER HALF OF CORE

(-,+)	(+,+)
.9742	.9782
.9948	1.0528 *
(-,-)	(+,-)

POWER TILT IN LOWER HALF OF CORE

(-,+)	(+,+)
.9992	.9850
1.0052	1.0106 *
(-,-)	(+,-)

CORE AVERAGE AXIAL OFFSET

-2.754 *

4.3 SUP 81.10 - STATIC RCCA DROP AND RCCA BELOW BANK POSITION MEASUREMENTS

This test had the following objectives:

1) To determine the neutron flux distribution with a RCCA below bank indication.

2) To demonstrate the excore response to a RCCA below bank indication.

3) To determine the neutron flux distribution when a RCCA has been "dropped" from the controlling RCC configuration.

4) To determine the worth of the most reactive RCCA "dropped" from the full power RCC configuration.

This startup procedure was performed at 50% power with Control Bank D rod 2D3 in core location H-12 (see Figure 4.3.1). Prior to starting the test, a base case, all rods out, equilibrium xenon, flux map and a thermocouple map were taken.

The rod was "dropped" using a boron dilution. In order to drop the selected rod, all the lift coils in the bank containing the rod to be dropped were disconnected except the lift coil for the selected rod. A dilution was then started at a rate of 15 gpm. The reactivity addition caused by the dilution was monitored using the reactivity computer, and the selected rod was stepped in to balance the reactivity change. Reactor coolant system and pressurizer boron samples were taken every twenty minutes during the insertion. When the "dropped" rod was fully inserted, a movable detector flux map was recorded in addition to a thermocouple map and excore detector data.

The reactivity traces obtained during this test, in addition to chemical analysis and primary water integrator readings, were used to calculate the integral worth of the rod. Good correlation was previously established between both the primary water and the boric acid integrators and the amount of liquid added as measured by the induced reactivity perturbation. Employing these methods of determining the amount of reactivity added, it was found that the integral worth of "dropped" rod was 100.5 pcm using the traces and 110 pcm using the integrator readings and analysis. Each of these values are well within the FSAR acceptance criteria of less than 250 pcm even after a 10% measurement uncertainty was incorporated.

Figure 4.3.1 shows the location of the core of the dropped rod and its effects on the excore instrumentation and on T_{avg}. Figures 4.3.2 thru 4.3.4 show the effects of the dropped rod on power sharing and incore tilts.

The maximum Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$) was measured to be 1.6384 satisfying the Core Design Report acceptance criteria of less than or equal to 1.68.

SALEM NUCLEAR GENERATING STATION

UNIT NO. 2

RCC INCORE DETECTOR THIMBLE AND THERMOCOUPLE LOCATIONS

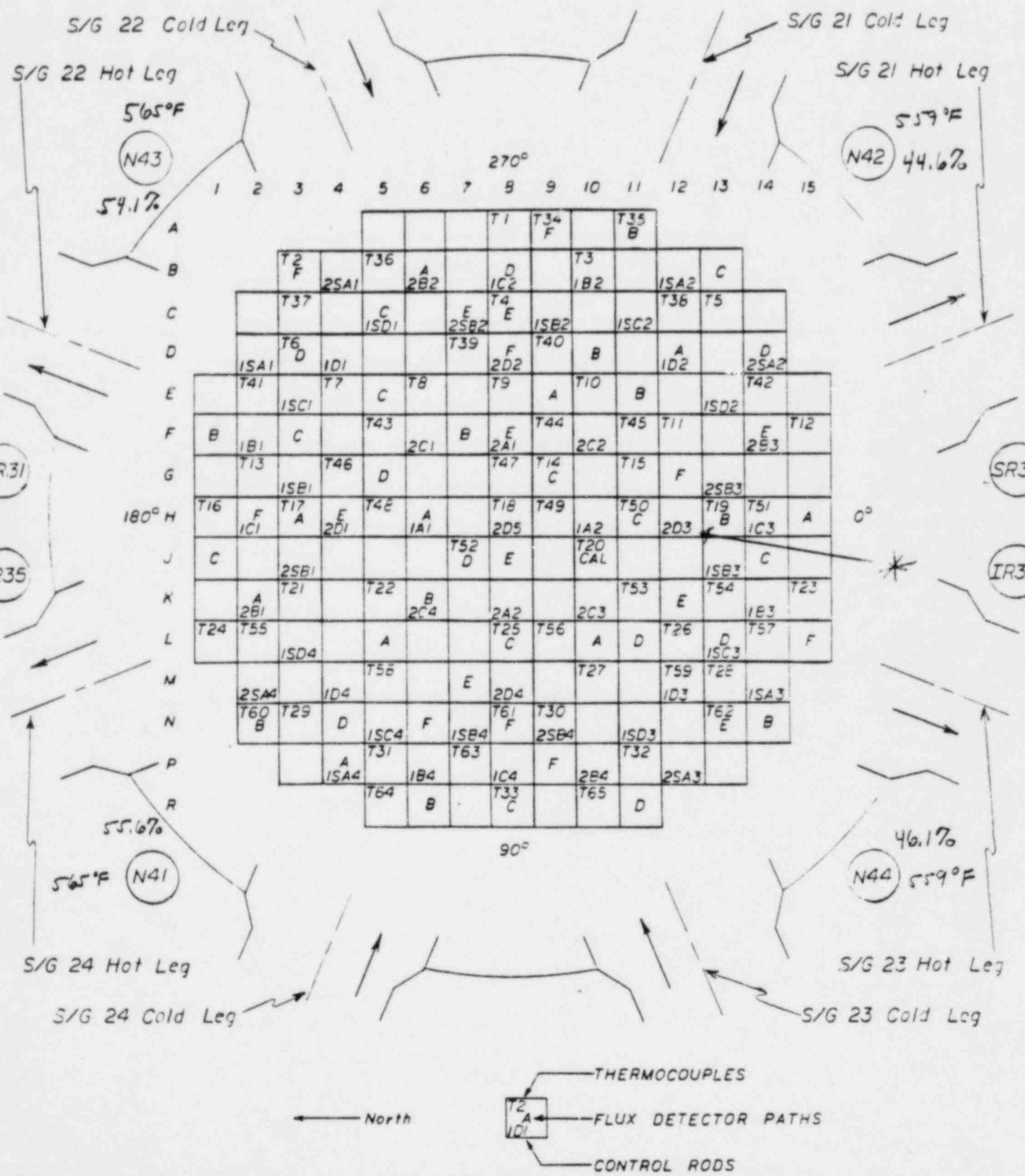


Figure 4.3.2

BASE CASE FLUX MAP

FOR

DROPPED ROD

MEASURED AND PERCENT. DIFF. OF FDHH . SALH INCORE MAP2015,48% PWR,BK D0228,993PPM,195MWD/MTU,PT.01

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1					.581.	.679.	.806.	.735.	.800.	.666.	.565.				
					2.1.	1.3.	1.6.	1.8.	1.1.	-.7.	-.7.				
2			.503.	.874.	1.023.	1.016.	1.040.	1.029.	1.022.	.979.	.984.	.849.	.497.		
			2.0.	2.0.	2.1.	1.4.	.3.	-.3.	-1.5.	-2.3.	-1.6.	-.8.	.8.		
3		.499.	1.040.	.954.	1.126.	1.121.	1.167.	1.122.	1.149.	1.055.	1.076.	.938.	1.035.	.504.	
		1.2.	1.2.	.8.	2.1.	2.1.	.6.	-.0.	-.9.	-3.9.	-2.4.	-.8.	.8.	2.4.	
4		.864.	.953.	1.280.	1.083.	1.195.	1.143.	1.202.	1.141.	1.168.	1.051.	1.271.	.952.	.868.	
		[illegible]	.7.	.5.	1.4.	1.4.	-1.1.	-.3.	-1.2.	-1.1.	-1.6.	-.2.	.6.	1.4.	
5	.572.	.978.	1.098.	1.063.	1.182.	1.153.	1.203.	1.161.	1.204.	1.146.	1.173.	1.068.	1.107.	1.006.	.572.
	.5.	-.4.	-.3.	-.5.	1.0.	1.0.	1.9.	2.1.	2.0.	.4.	-.2.	.4.	.4.	.4.	.5.
6	.664.	.985.	1.068.	1.161.	1.138.	1.164.	1.052.	1.130.	1.036.	1.139.	1.119.	1.179.	1.100.	1.005.	.674.
	-.9.	-1.7.	-2.8.	-1.5.	-.3.	1.1.	1.6.	1.7.	.0.	-1.1.	-2.0.	.0.	.5.	.3.	.5.
7	.792.	1.027.	1.134.	1.126.	1.162.	1.034.	1.082.	.994.	1.077.	1.027.	1.179.	1.149.	1.161.	1.038.	.803
	.4.	[illegible]	-2.4.	-2.4.	[illegible]	-.2.	.9.	.0.	.4.	-.9.	-.4.	-.6.	.2.	.0.	1.5
8	.718.	1.024.	1.095.	1.179.	1.109.	1.105.	.984.	1.049.	.983.	1.112.	1.139.	1.202.	1.123.	1.033.	.733
	-.8.	[illegible]	-2.4.	-2.3.	[illegible]	-.8.	.1.	.4.	-.1.	.4.	.1.	-.3.	.0.	.1.	1.4
9	.785.	1.025.	1.135.	1.128.	1.142.	1.012.	1.053.	.974.	1.090.	1.049.	1.194.	1.154.	1.163.	1.038.	.802
	-.8.	-1.2.	-2.1.	-2.3.	-2.7.	-2.3.	-1.9.	-.9.	1.6.	1.3.	1.2.	-.1.	.6.	.0.	1.3
10	.668.	.997.	1.068.	1.160.	1.122.	1.128.	1.014.	1.094.	1.034.	1.160.	1.149.	1.186.	1.106.	1.020.	.683.
	-.8.	-.5.	-2.7.	-1.6.	-1.7.	-2.0.	-2.1.	-1.1.	-.2.	.7.	.7.	.7.	.8.	1.8.	1.8.
11	.580.	1.024.	1.123.	1.052.	1.168.	1.129.	1.169.	1.112.	1.155.	1.130.	1.177.	1.069.	1.099.	1.034.	.587.
	1.9.	1.9.	1.8.	-1.5.	-.6.	-1.1.	-1.0.	-2.3.	-2.2.	-1.0.	.2.	.4.	-.3.	3.2.	3.2.
12		.860.	.952.	1.287.	1.081.	1.193.	1.141.	1.173.	1.124.	1.165.	1.066.	1.269.	.958.	.888.	
		1.3.	.6.	1.0.	1.3.	1.3.	-1.2.	-2.7.	-2.7.	-1.2.	-.3.	-.4.	1.3.	3.7.	
13		.497.	1.036.	.958.	1.124.	1.100.	1.136.	1.085.	1.147.	1.103.	1.124.	.951.	1.048.	.518.	
		[illegible]	.9.	1.3.	1.8.	.2.	-1.9.	-3.3.	-1.1.	.5.	1.7.	.6.	1.8.	4.1.	
14			.497.	.867.	1.018.	1.002.	1.020.	1.015.	1.045.	1.041.	1.034.	.877.	.509.		
			.9.	1.3.	1.6.	.0.	-1.7.	-1.6.	.7.	3.9.	3.2.	2.8.	3.3.		
15					.578.	.665.	.787.	.720.	.814.	.697.	.583.				
					1.1.	.9.	-.6.	-.3.	2.8.	3.9.	3.2.				

Figure 4.3.3

DROPPED ROD FLUX MAP

MEASURED AND PERCENT. DIFF. OF FDHN SALM. INCORE MAP2016,46% PWR,BK D@228,993PPM,200MWD/MTU,PT.52

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
					.688.	.819.	.959.	.883.	.997.	.885.	.749.				
1					5.0.	5.7.	5.3.	5.3.	9.4.	14.2.	14.2.				
			.661.	1.116.	1.204.	1.172.	1.245.	1.185.	1.263.	1.207.	1.228.	.993.	.622.		
2			16.5.	16.5.	5.0.	5.6.	4.0.	3.6.	5.5.	8.8.	7.1.	3.7.	9.6.		
		.614.	1.230.	1.187.	1.279.	1.312.	1.312.	1.298.	1.307.	1.291.	1.261.	1.125.	1.240.	.652.	
3		8.7.	8.7.	9.3.	5.0.	5.0.	2.4.	1.6.	2.1.	3.3.	3.5.	3.7.	9.6.	15.6.	
		.995.	1.128.	1.439.	1.268.	1.346.	1.311.	1.335.	1.328.	1.327.	1.254.	1.428.	1.151.	1.030.	
4		5.0.	4.6.	3.1.	4.1.	4.1.	.3.	1.1.	1.7.	2.7.	2.9.	2.4.	6.8.	8.7.	
	.700.	1.188.	1.243.	1.239.	1.315.	1.315.	1.294.	1.292.	1.300.	1.308.	1.301.	1.226.	1.220.	1.144.	.653.
5	9.4.	5.7.	3.7.	2.7.	3.0.	2.8.	.9.	1.3.	1.4.	2.3.	1.9.	1.7.	1.7.	1.8.	2.1.
	.834.	1.145.	1.221.	1.283.	1.281.	1.255.	1.161.	1.202.	1.154.	1.237.	1.251.	1.275.	1.227.	1.088.	.765.
6	11.2.	6.4.	.5.	1.6.	1.6.	1.7.	.6.	1.0.	.1.	.3.	-.7.	1.0.	1.0.	1.1.	2.1.
	.959.	1.208.	1.228.	1.246.	1.228.	1.107.	1.110.	1.050.	1.103.	1.095.	1.203.	1.227.	1.216.	1.143.	.881.
7	10.2.	5.5.	.2.	-.5.	-.7.	-1.7.	-1.0.	-1.7.	-1.6.	-2.8.	-2.8.	-2.1.	-.8.	-.2.	1.3.
	.836.	1.115.	1.203.	1.224.	1.173.	1.089.	.992.	1.009.	.991.	1.086.	1.162.	1.210.	1.182.	1.073.	.798.
8	5.9.	3.6.	.2.	-1.2.	-1.9.	-3.0.	-3.2.	-3.5.	-3.3.	-3.2.	-2.9.	-2.4.	-1.5.	-.3.	1.1.
	.890.	1.144.	1.186.	1.160.	1.113.	.979.	.940.	.894.	.972.	.999.	1.126.	1.155.	1.151.	1.103.	.853.
9	5.5.	3.5.	.8.	-2.6.	-3.8.	-5.1.	-6.5.	-5.7.	-3.3.	-3.1.	-2.7.	-2.9.	-2.1.	-.2.	1.2.
	.715.	1.018.	1.139.	1.075.	1.039.	.964.	.836.	.849.	.850.	.982.	1.056.	1.094.	1.088.	1.026.	.720.
10.	1.3.	1.4.	1.8.	-5.7.	-5.7.	-6.3.	-8.2.	-7.0.	-6.6.	-4.6.	-4.1.	-4.0.	-2.8.	2.1.	2.1.
	.592.	1.027.	1.074.	.979.	.981.	.906.	.790.	.696.	.778	.893.	.982.	.973.	.998.	1.042.	.601.
11.	.9.	.9.	.9.	-5.8.	-6.4.	-6.6.	-8.1.	-8.8.	-9.4	-8.0.	-6.3.	-6.3.	-6.3.	2.4.	2.4.
		.829.	.912.	1.101.	.886.	.850.	.667.	.403.	.663	.840.	.875.	1.061.	.912.	.873.	
12		-.2.	-1.4.	-4.8.	-6.9.	-7.0.	-10.5.	-11.3.	-11.1	-8.1.	-8.1.	-8.3.	-1.4.	5.0.	
		.485.	.950.	.857.	.859.	.798.	.690.	.602.	.697	.803.	.871.	.820.	.932.	.517.	
13		.7.	.6.	-1.8.	-7.0.	-7.9.	-10.8.	-11.6.	-10.0	-7.3.	-5.7.	-6.0.	-1.3.	7.5.	
			.466.	.735.	.809.	.721.	.713.	.657.	.726.	.735.	.824.	.735.	.473.		
14			.9.	-2.2.	-5.3.	-6.8.	-8.2.	-8.1.	-6.6.	-5.0.	-3.6.	-2.3.	2.5.		
					.459.	.504.	.579.	.525.	.593.	.514.	.461.				
15					-4.2.	-6.8.	-4.7.	-4.2.	-2.4.	-5.0.	-3.6.				

Figure 4.3.4

INCORE POWER TILTS

BASE CASE

SALM INCORE MAP2015,48% PWR,BK D0228,993PPM,195MWD/MTU,PT.S1

RELATIVE POWER IN UPPER HALF OF CORE		RELATIVE POWER IN LOWER HALF OF CORE		PERCENT AXIAL OFFSET TOWARD TOP OF CORE	
(-,+)	(+,+)	(-,+)	(+,+)	(-,+)	(+,+)
.9959	.9975	1.0086	.9980	-.633	-.027
.9922	1.0016	.9954	1.0108	-.160	-.455
(-,-)	(+,-)	(-,-)	(+,-)	(-,-)	(+,-)

POWER TILT IN UPPER HALF OF CORE		POWER TILT IN LOWER HALF OF CORE		CORE AVERAGE AXIAL OFFSET
(-,+)	(+,+)	(-,+)	(+,+)	
.9991	1.0007	1.0054	.9948	-.319
.9954	1.0048	.9922	1.0075	

DROPPED ROD

SALM INCORE MAP2016,48% PWR,BK D0228,993PPM,200MWD/MTU,PT.S2

RELATIVE POWER IN UPPER HALF OF CORE		RELATIVE POWER IN LOWER HALF OF CORE		PERCENT AXIAL OFFSET TOWARD TOP OF CORE	
(-,+)	(+,+)	(-,+)	(+,+)	(-,+)	(+,+)
1.0572	1.0513	1.2240	1.2070	-7.314	-6.895
.8199	.8131	.9127	.9148	-5.358	-5.884
(-,-)	(+,-)	(-,-)	(+,-)	(-,-)	(+,-)

POWER TILT IN UPPER HALF OF CORE		POWER TILT IN LOWER HALF OF CORE		CORE AVERAGE AXIAL OFFSET
(-,+)	(+,+)			
1.1302	1.1239	1.1497	1.1337	-6.363
.8765	.8693	.8573	.8593	
(-,-)	(+,-)	(-,-)	(+,-)	

BASE CASE THERMOCOUPLE MAP

0454 7/21 SALEM 2
INCORE T/C TREND

	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15
A								575	574		563				
B			555		579					576					
C			OF					584				580	582		
D			577				581		585						
E		576		582		583		582		586				578	
F					582				580		582	584			574
G		581		582				554	581		583				
H	573		581		578			OF	565		585	$\boxed{X}$	585	581	
J							580			583					
K			580		584						584		584		573
L	142	581						583	586			585		582	
M					581					584		584	581		
N		564	577					587	579				579		
P					577		581				580				
R					563			OF		570					

Figure 4.3.5

DROPPED ROD THERMOCOUPLE MAP

0550 7/21 SALEM 2
INCORE T/C TREND

	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15
A								576	576		564				
B			559		584					579					
C			OF					586				579	581		
D			583				585		586						
E		583		586		588		584		585				574	
F					588				580		578	576			570
G		587		588				557	581		577				
H	578		587		585			OF	565		575	$\boxed{X}$	572	572	
J							583			581					
K			586		589						580		577		568
L	142	588						586	588			582		577	
M					586					584		583	578		
N		568	582					590	581				576		
P					583		586				581				
R					565			OF		570					

Figure 4.3.6

4.4 SUP 81.8 - POWER COEFFICIENT AND INTEGRAL POWER DEFECT MEASUREMENT

The purpose of this test was to measure the differential power coefficient of reactivity and to measure the integral power defect. The test was conducted at 30%, 50%, 75% and 100% power.

The differential power coefficient is defined as the change in core reactivity per percent increase in core power for the programmed T_{avg} change. This coefficient consists of two components: the moderator temperature coefficient (pcm/^{o}F) and the doppler coefficient (pcm/% power). The moderator temperature coefficient contribution results from a programmed change in the reactor coolant system average temperature for a unit change in core power level. This component is negative under normal operating conditions. The doppler coefficient of reactivity is always negative for low enrichment uranium fuel due to the broadening of the U^{238} capture resonances. This effect is significant over the range from hot zero power to hot full power due to the large pellet temperature increase with power generation. The integral of the doppler coefficient with respect to power is defined as the doppler defect. Measurement of the doppler defect is required to verify that the shutdown margin assumed in the Safety Analysis is conservative.

During the power escalation program, the total power coefficient was measured over power levels ranging from 20% to 100% of full power. The measurement technique consisted of first decreasing and then increasing the power level 20%, in steps of approximately 10% using the E-H control system to change the generator electrical load. Reactor power was matched to turbine power by insertion of the controlling bank. Reactivity and T_{error} were monitored during the power changes. At the power level "end-points" additional data was gathered including heat balance information for determination of the actual power level change.

The power coefficient was determined from ratios of the change in reactivity to the change in power ($\Delta\rho / \Delta Q$) corrected for variations in the Xenon concentration and T_{avg} vs. Terror. Corrections to the measured data for Xenon changes over the duration of the measurements were based on Xenon histories generated from the point model Iodine/Xenon equations. No corrections were applied to account for possible effects of flux redistribution which was assumed to be negligible over the range of measurements. The doppler defect was determined by extracting the reactivity effect due to changing T_{avg} from the reactivity measurement during the power change.

Table 4.4.1 and Figure 4.4.1 present the data obtained and the measurement results. As can be seen in the figure, several measurements were close or appear to have exceeded the FSAR limits, especially at 100% RTP. Reviewing Table 4.4.1, it can be seen that those measurements nearest to exceeding the design criteria of $\pm$ 30%, were those measurements taken with the Control Bank D rods starting or ending at a position greater than 210 steps. Not calculating the required value was attributed to the difficulty in determining the rod worths in a very low worth region (200-228 steps). To confirm this the 100-90% RTP test was repeated with the starting position of control bank D at 205 steps. The design criteria was easily met. Figure 4.4.1 shows one point at 100% below the FSAR limit. The point was calculated from a power swing of 91-93% RTP with rods movement from 200-219 steps. This calculation was repeated 90-98% with rod movement from 175-210 steps and was well within the acceptance criteria. Reviewing the data obtained during Unit 1, Cycle 1 startup and comparing it to Figure 4.4.1, it can be seen that the data scattering is similar, thus further supporting this analysis.

TABLE 4.4.1

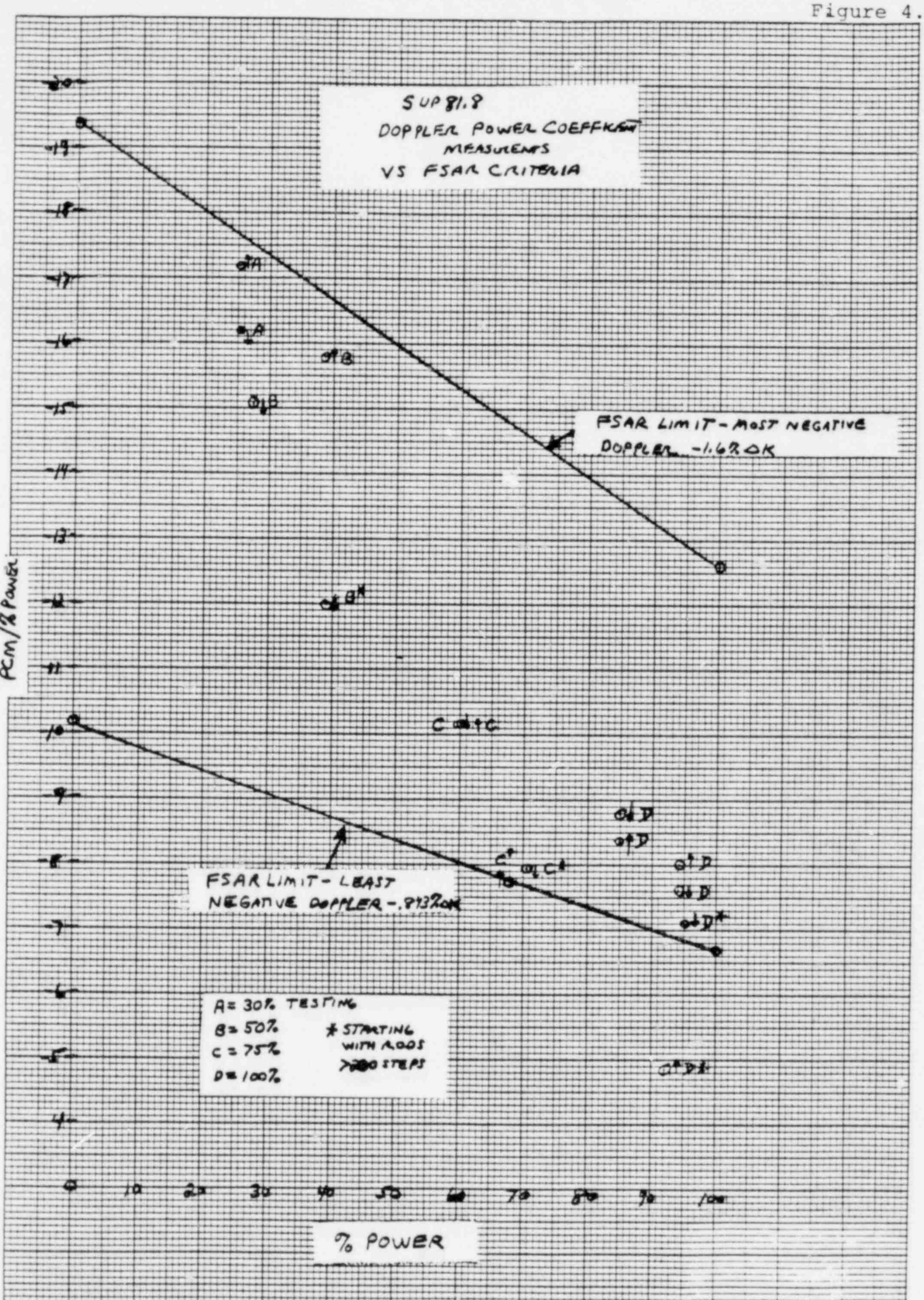
POWER AND DOPPLER

COEFFICIENT REVIEW

DATE	POWER LEVEL (%)		BANK D POSITION (STEPS)		POWER COEFFICIENT -(PCM/% POWER)		POWER COEFFICIENT -(PCM/% POWER)	
	START	FINISH	START	FINISH	MEASURED	DESIGN	MEASURED	DESIGN
7- 3-81	30.14	20.68	148	122	16.8		16.2	
					(17.4)*	14.9	(16.7)*	13.8
(30%)	20.68	29.58	122	150	17.9		17.2	
7-22-81	45.29	33.11	188	154	12.7	14.1	12.0	13.2
(50%)	33.11	22.36	154	131	15.8		15.1	
					(16.2)*	14.9	(15.5)*	13.7
	22.36	35.35	131	177	16.5		15.8	
8- 6-81	75.97	65.09	228	176	9.09		7.98	
(75%)	65.09	54.23	176	154	11.07		10.16	
					(11.23)*	14.34	(10.16)*	12.10
	54.23	66.06	154	193	11.39		10.15	
					(9.62)	14.21	(7.86)	12.24
	66.06	69.67	193	228	10.15		7.73	
8-21-81	99.76	90.29	211	180	8.90	13.8	7.1	11.5
(100%)	90.29	80.25	180	162	10.49		8.81	
					(10.21)*	14.0	(8.59)	12.1
	80.25	90.75	162	200	9.93		8.37	
	90.75	92.90	200	219	6.65	13.96	4.84	11.3
10-13-81	99.52	89.70	205	175	9.86		7.60	
					(10.09)*	13.8	(7.76)*	10.9
(100%)	89.70	98.38	175	210	10.32		7.95	

( )* average value

109D(2):37



SUP 81.8
DOPPLER POWER COEFFICIENT MEASUREMENTS VS FSAR CRITERIA
FSAR LIMIT - MOST NEGATIVE DOPPLER -1.6% ΔK
FSAR LIMIT - LEAST NEGATIVE DOPPLER -.893% ΔK
A = 30% TESTING
B = 50%
C = 75%
D = 100%
* STARTING WITH RODS >200 STEPS
PCM/% POWER
% POWER

4.5 SUP 81.11 INCORE - EXCORE DETECTOR FLUX DIFFERENCE CALIBRATIONS

The power range nuclear instrumentation system produces output voltage signals proportional to the currents in the top and bottom neutron detectors of each channel. These signals are used for axial power imbalance (delta flux) indication, upper and lower quadrant power indication, process computer monitoring of delta flux, and the generation of the $F(\Delta I)$ function which reduces the overtemperature T trip setpoint for adverse axial power distribution.

Because of a variation in detector sensitivity and placement, calibration of each output voltage is required to produce an excore indicated axial power distribution which reflects actual core conditions.

Although this test was formerly scheduled at 75% power as part of the startup program, it was actually performed at 50%, 75% and 100% power to comply with TECHNICAL SPECIFICATION surveillance requirements and to provide the necessary "tuning up" before reaching higher power levels.

The minimum requirement for performing an incore-excore calibration is three flux maps at different delta flux (ΔI) values, ideally with as large a spread in values of delta flux as possible. Concurrent with the flux maps, readings of power range currents, T_{error} and calorimetrics are performed.

Different values of ΔI are obtained by varying rod position. Typically, a reference flux map is taken with the control bank at 200 steps. The rods are then inserted until the ΔI is 1-2% from its negative limit and left there. ΔI continues to move slowly in the negative direction, turns around and becomes more positive. It is during the negative peak that the second flux map is taken. Then, the control rods are fully withdrawn (228 steps); the ΔI rises and slowly approaches a positive peak during which the third flux map is taken. Control rods can be inserted to prevent ΔI from exceeding its positive limit.

Below 90% power, TECHNICAL SPECIFICATIONS allow up to 16 hours outside of the target band limits on axial flux difference without penalty for the performance of this test. However, above 90%, no allowance is available and ΔI must remain inside the $\pm$ 5% band, which means a maximum spread in data of < 10% on ΔI. (To date this has not been a problem).

The linearity of channel response with measured incore power distribution for each of the four power range channels, a pre-requisite for adequate calibration, is demonstrated by the data presented in Figure 4.5.1 for 100% power calibration. As used in this calibration, excore axial offset, AO_{EX}, is defined as:

$$AO_{EX} = \frac{I_T - I_B}{I_T + I_B} \times 100\%$$

where I_T and I_B are the currents from the top and bottom detectors, and the incore axial offset AO_{INC} is defined as:

$$AO_{INC} = \frac{P_T - P_B}{P_T + P_B} \times 100\%$$

where P_T and P_B are the fractions of core power in top and bottom halves of the core as derived from the moveable detector flux map data.

Calibration of the output voltage signals requires a determination of the expected full power detector currents under the conditions of zero incore axial offset. Excore detector data was taken during the flux maps and scaled up to the full power condition through calorimetric measurements of core power. The excore detector currents vs. incore axial offset were fitted to a linear function and the calibration currents were derived by evaluating the function at zero axial offset. The results are plotted on Figures 4.5.2 through 4.5.5 and listed on Table 4.5.2.

Table 4.5.1 shows the data used to generate the figures for the 100% incore/excore calibration of August 22, 1981.

Table 4.5.1

100% POWER (8/22/81)

EXCORE DETECTOR FLUX DIFFERENCE CALIBRATION DATA SHEET

MAP #	CALORI-METRIC POWER (% RTP)	CHANNEL	Itop	Ibot	INCORE QUADRANT AXIAL OFFSET	EXCORE AXIAL OFFSET (%)	FP Itop	FP Ibottom
2030	98.16	41	385.3	441.7	-6.367	-6.82	392.5	450.0
		42	412.9	486.3		-8.16	420.6	495.4
		43	379.9	411.6		-4.01	387.0	419.3
		44	367.3	393.7		-3.47	374.2	401.1
2031	97.97	41	376.9	452.7	-10.817	-9.14	384.7	462.1
		42	402.5	500.0		-10.80	410.8	510.4
		43	369.8	420.5		-6.42	377.5	429.2
		44	358.3	402.8		-5.85	365.7	411.1
2032	98.23	41	390.4	429.1	-2.634	-4.72	397.4	436.8
		42	419.8	472.2		-5.87	427.4	480.7
		43	385.9	400.7		-1.88	392.9	407.9
		44	372.7	382.6		-1.31	379.4	389.5

Completed by _________________ Date _______ Time _______

Senior Reactor Operator _________________ Date _______ Time _______

The equations of the lines to be graphed (see Figure 27, Reactor Engineering Manual) and convenient endpoints are as follows:

41	TOP:	Y = 401.9 + 1.561 * X	(60, 495.6)	(-60, 308.2)
	BOTTOM:	Y = 429.3 + -3.074 * X	(60, 244.9)	(-60, 613.8)
42	TOP:	Y = 433.0 + 2.025 * X	(60, 554.5)	(-60, 311.5)
	BOTTOM:	Y = 471.6 + -3.615 * X	(60, 254.7)	(-60, 688.5)
43	TOP:	Y = 398.3 + 1.889 * X	(60, 511.6)	(-60, 284.9)
	BOTTOM:	Y = 401.7 + -2.590 * X	(60, 246.3)	(-60, 557.1)
44	TOP:	Y = 384.2 + 1.680 * X	(60, 485.0)	(-60, 283.4)
	BOTTOM:	Y = 383.2 + -2.634 * X	(60, 225.1)	(-60, 541.2)

100% POWER (8/22/81)

EXCORE DETECTOR FLUX DIFFERENCE CALIBRATION WORKSHEET

CHANNEL	INCORE QUADRANT AXIAL OFFSET (%)	FP Itop	FP Ibottom	FP Vtop	FP Vbottom	Delta V
41	+60	496	245	--------	-------	-------
42	+60	555	255	--------	-------	-------
43	+60	512	246	--------	-------	-------
44	+60	485	225	--------	-------	-------
41	+30	449	337	--------	-------	-------
42	+30	494	363	--------	-------	-------
43	+30	455	324	--------	-------	-------
44	+30	435	304	--------	-------	-------
41	+20	433	368	--------	-------	-------
42	+20	473	399	--------	-------	-------
43	+20	436	350	--------	-------	-------
44	+20	418	330	--------	-------	-------
41	+10	417	399	--------	-------	-------
42	+10	453	435	--------	-------	-------
43	+10	417	376	--------	-------	-------
44	+10	401	357	--------	-------	-------
41	+0	402	429	8.33	8.33	0
42	+0	433	472	8.33	8.33	0
43	+0	398	402	8.33	8.33	0
44	+0	384	383	8.33	8.33	0
41	-10	386	460	--------	-------	-------
42	-10	413	508	--------	-------	-------
43	-10	379	428	--------	-------	-------
44	-10	367	410	--------	-------	-------
41	-20	371	491	--------	-------	-------
42	-20	392	544	--------	-------	-------
43	-20	360	454	--------	-------	-------
44	-20	351	436	--------	-------	-------
41	-30	355	522	--------	-------	-------
42	-30	372	580	--------	-------	-------
43	-30	342	479	--------	-------	-------
44	-30	334	462	--------	-------	-------
41	-60	308	614	--------	-------	-------
42	-60	311	689	--------	-------	-------
43	-60	285	557	--------	-------	-------
44	-60	283	541	--------	-------	-------

Completed by __________________ Date _______ Time _______

Senior Reactor Operator __________________ Date _______ Time _______

WO #: _______________ Date Issued: _______ Date Completed: _______

Date Rx Engr Manual, Table 2 was Updated: ________

FIGURE 4.5.1

SALEM 2

REACTOR ENGINEERING MANUAL

100% PWR 8/22/81 UNIT 2

CHANNELS N-41, N-42, N-43, N-44

LINEARITY CHECK FOR IN/EX CALIBRATION

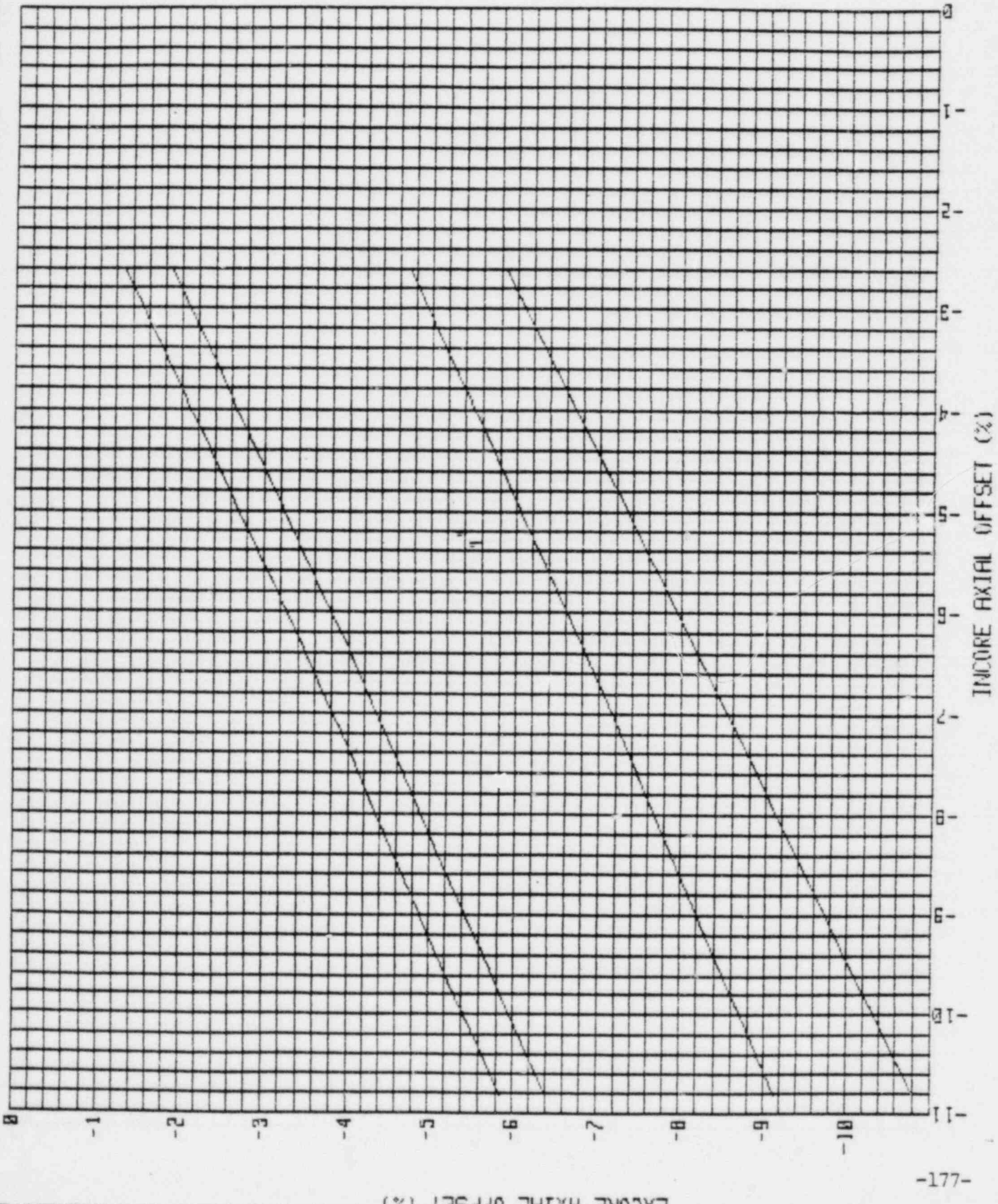


FIGURE 4.5.2

SALEM 2

REACTOR ENGINEERING MANUAL

100% PWR 8/22/81 UNIT 2

DETECTOR N-41

NORMALIZED DETECTOR CURRENTS

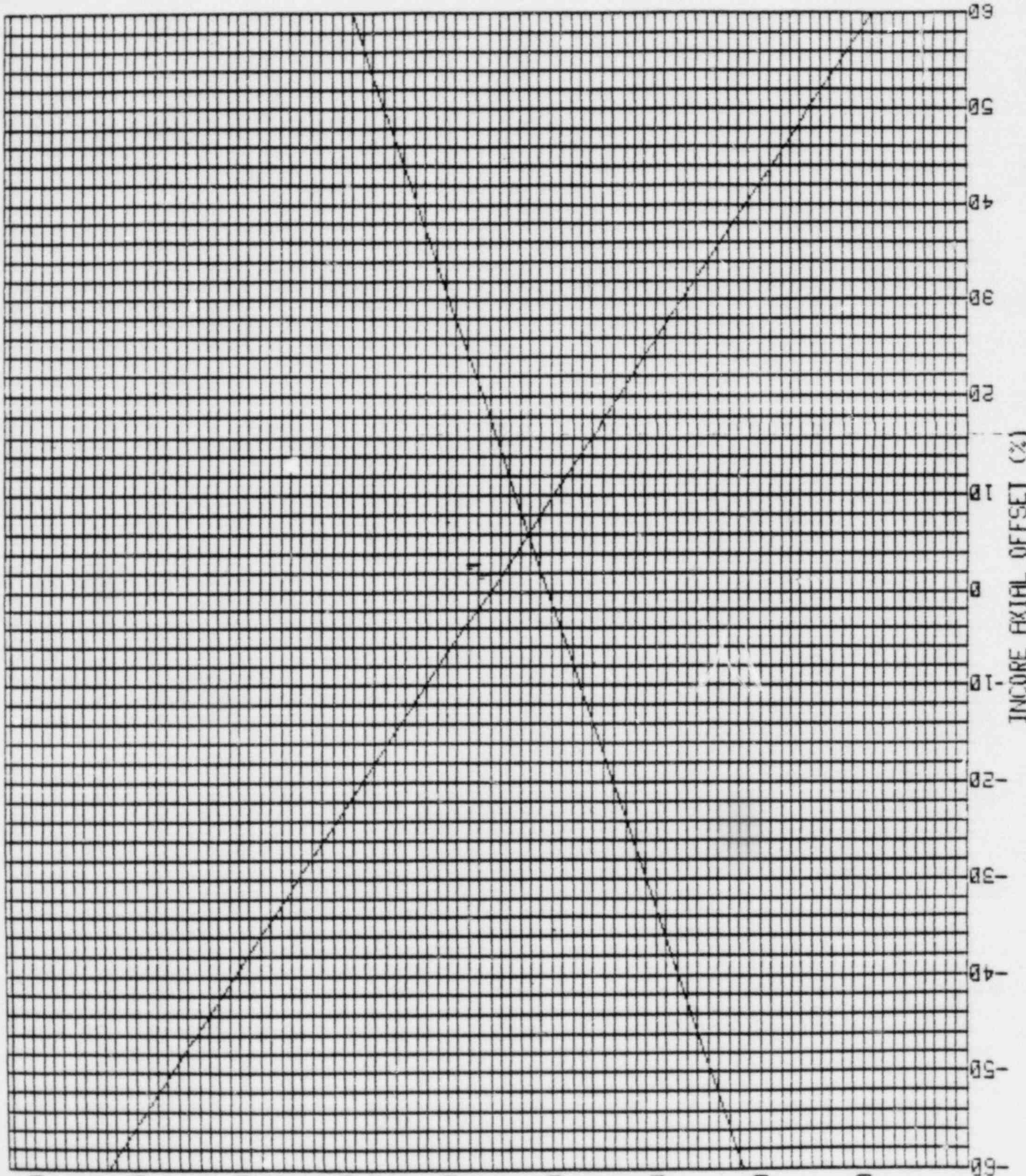


FIGURE 4.5.3

SALEM 2

REACTOR ENGINEERING MANUAL

100% PWR 8/22/81 UNIT 2

DETECTOR N-42

NORMALIZED DETECTOR CURRENTS

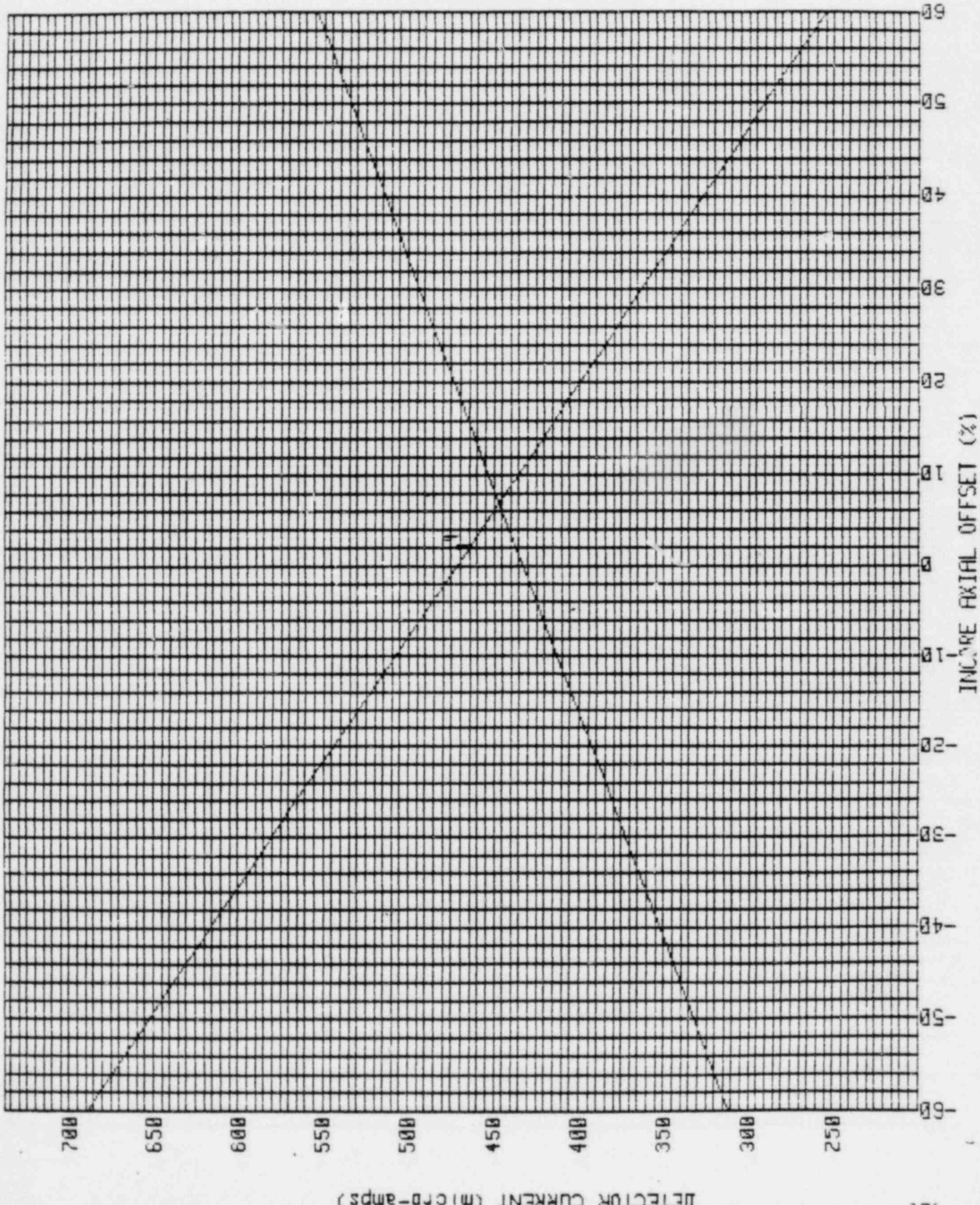


FIGURE 4.5.4

SALEM 2

REACTOR ENGINEERING MANUAL

100% PWR 8/22/81 UNIT 2

DETECTOR N-43

NORMALIZED DETECTOR CURRENTS

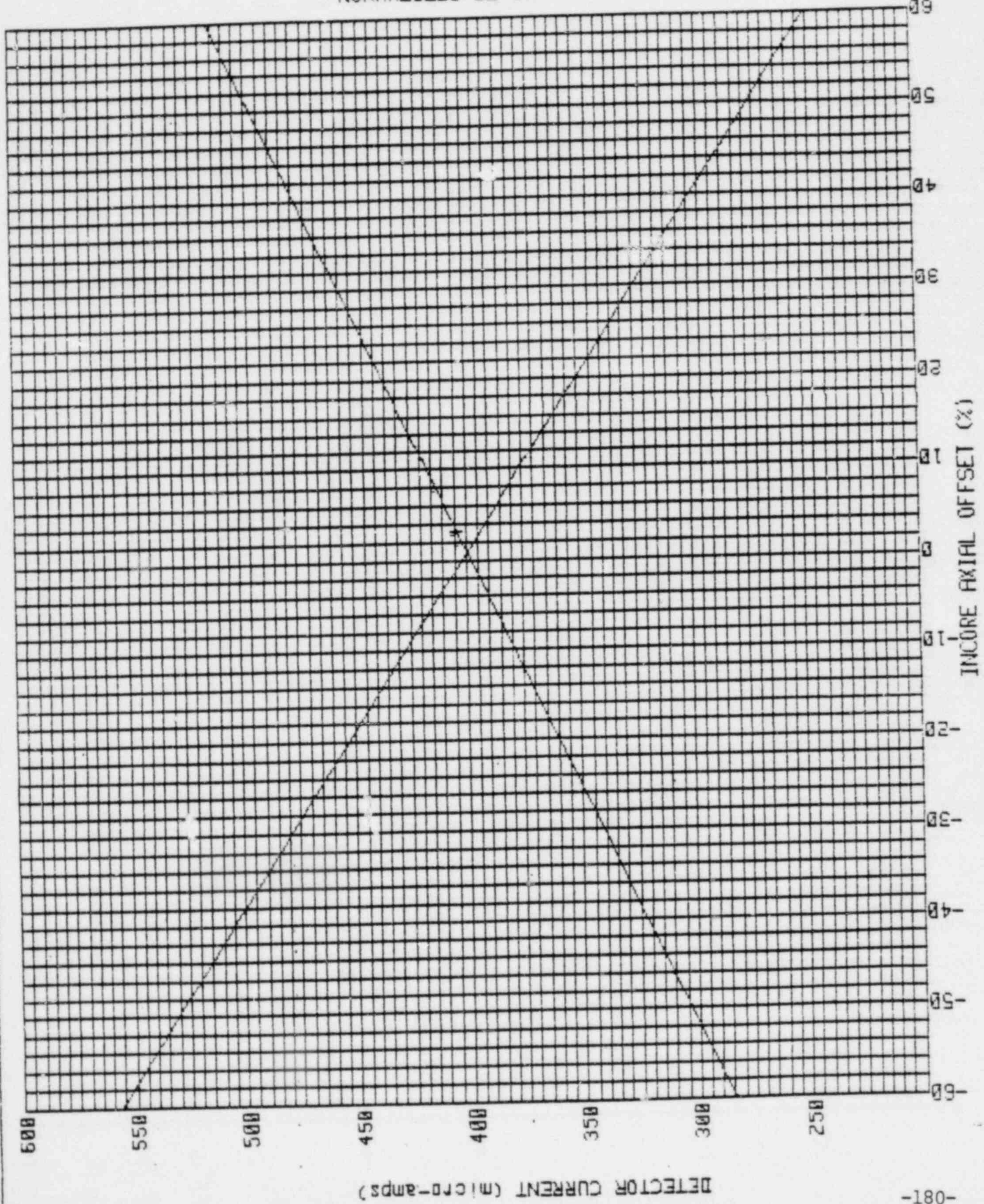


FIGURE 4.5.5

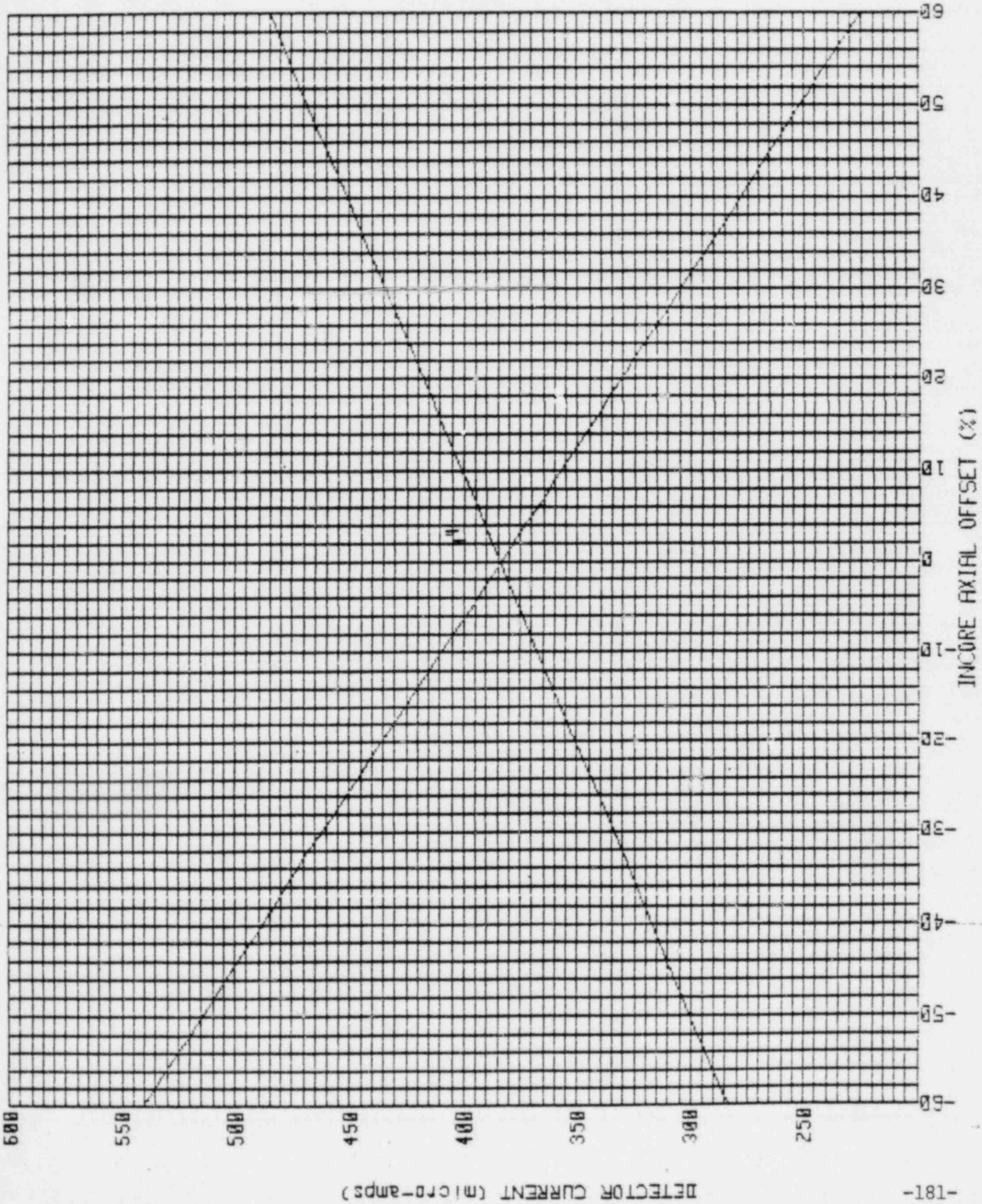
SALEM 2

REACTOR ENGINEERING MANUAL

100% PWR 8/22/81 UNIT 2

DETECTOR N-44

NORMALIZED DETECTOR CURRENTS



4.6 SUP 91.12C - INTERMEDIATE AND POWER RANGE CHANNEL HIGH VOLTAGE SETTING VERIFICATION

The objective of this test was to verify that the 800 volt detector settings for each detector of the intermediate and power range channels is correct. This is done by varying the detector voltage from 200 - 1200 volts in 50 volt increments while at greater than 95% RTP. The 800 volts that the detector is manually set for is checked to insure it is at least 100 volts above the "knee " of the curve drawn comparing voltage to detector output every 50 volts.

The intermediate detectors had no change in detector output from 200 volts to 1200 volts. The power range detectors varied approximately 5 microamps over the same voltage range with the exception of Detector N43. Detector N43 varied 50-60 microamps mostly in the area of 200-300 volts as can be seen in Figure 4.6.1 from plateaus performed on 10/26/81 and 11/19/81. Initially their was no concern over the variance in voltage because the voltage the detector operates at (800 volts) was well above the knee of the curve at ~400 volts.

An incore/excore detector calibration was performed at 50% and 100% RTP during initial startup testing. The 100% RTP calibration was performed at 900 MWD/MTU on August 19, 1981. The calibration was repeated on October 26, 1981 after a core burnup of 2230 MWD/MTU when quadrant tilts were indicated by the excore detectors. The incore detectors indicated their was no incore tilt. The excore detectors were recalibrated. On November 9, 1981 tilts were indicated again on the excore detectors. Again the incore detectors indicated no incore tilt. The extrapolated full power currents for the four power range detectors were plotted as core burnup (see Figure 4.6.2). Reviewing core power distribution vs. burnup in the Core Design Report, the periphery assemblies are expected to produce less power as the core nears 3000 MWD/MTU and then start producing more power after 3000 MWD/MTU. Since the neutrons that the excore detectors "see" is directly proportional to the neutron production in the periphery fuel assemblies, it is expected that the output current from the excore detectors will vary with periphery assembly power sharing. This can be seen in Figure 4.6.2. The slope of the currents with burnup are similar for power range detector N41, N42 and N44. Detector N43 slope is sharper causing the indicated tilts and requiring more frequent incore/excore detector calibration (weekly). Review of the incore flux maps indicated that all quadrant periphery fuel assemblies were sharing the core power equally, as designed. On November 24, 1981 following a plant shutdown the N43 detector was replaced. The excore detectors were recalibrated and tilt indications have not reoccurred to date (January, 1982, 4600 MWD/MTU).

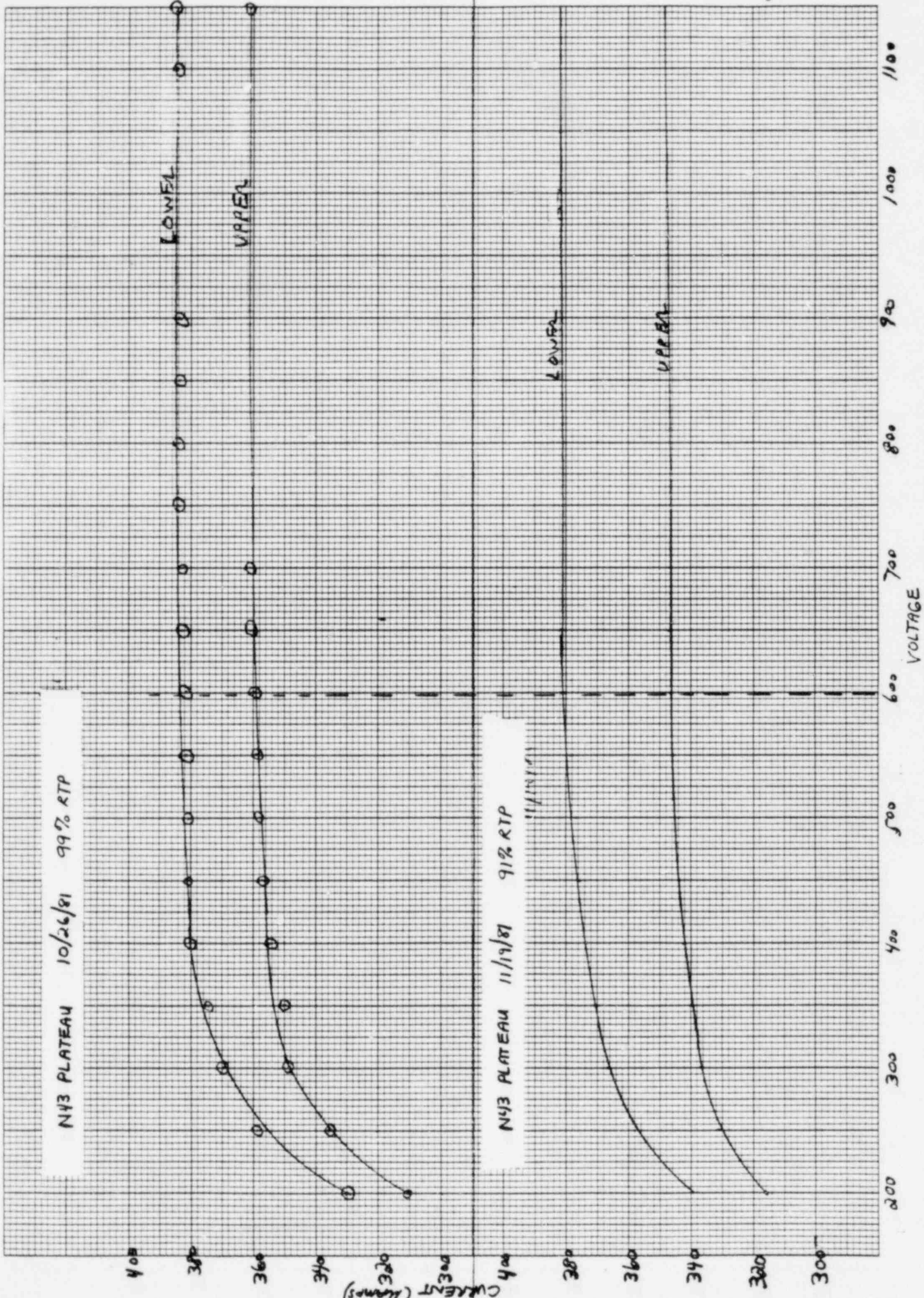
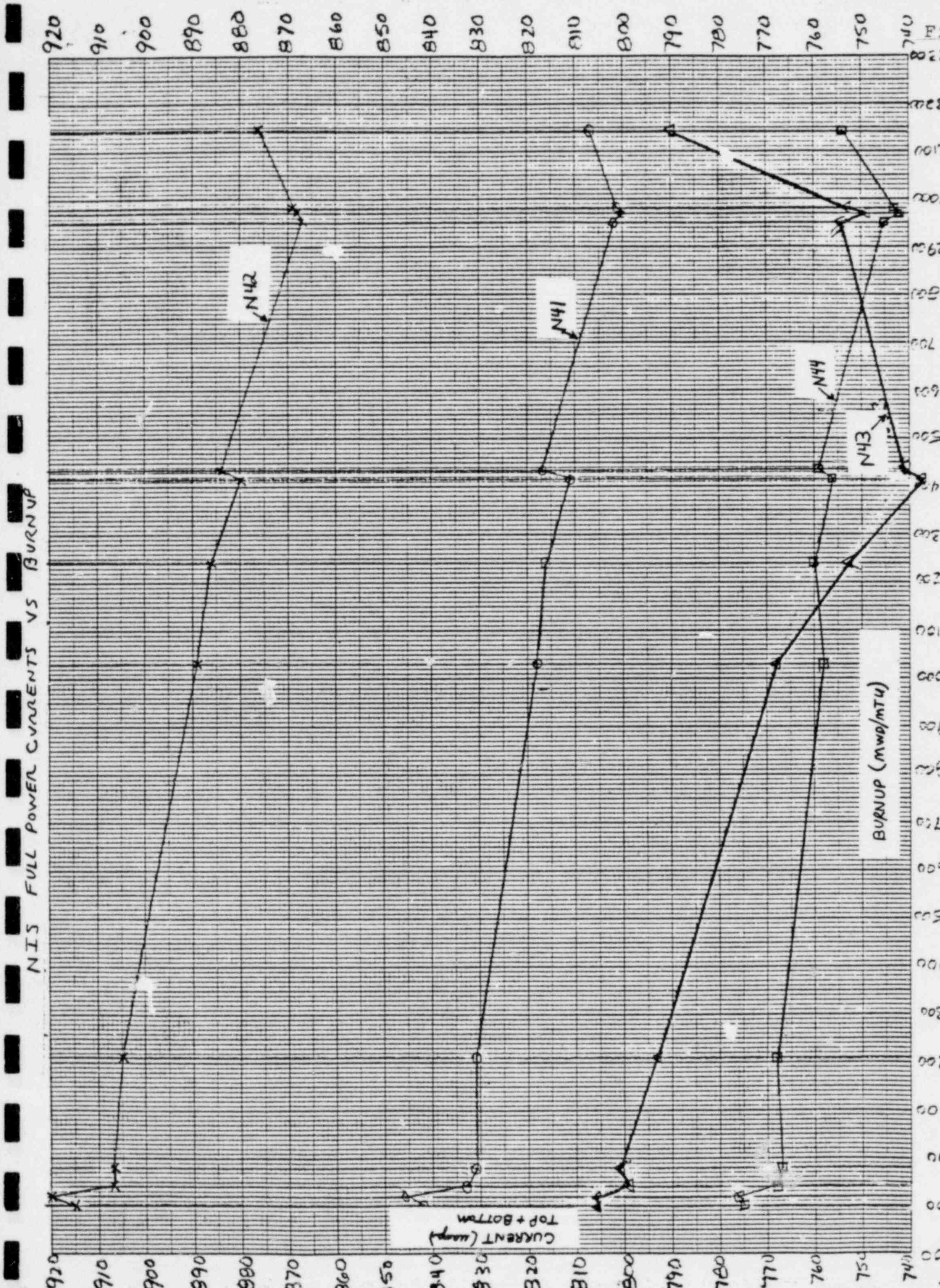

N43 PLATEAU 10/26/81 99% RTP
N43 PLATEAU 11/19/81 91% RTP
LOWER
UPPER
LOWER
UPPER
VOLTAGE
CURRENT (μAMPS)
200
300
400
500
600
700
800
900
1000
1100
400
380
360
340
320
300

Figure 4.6.2


NIS FULL POWER CURRENTS VS BURNUP
N42
N41
N44
N43
BURNUP (MWD/MTU)
CURRENT (μamp) TOP + BOTTOM