KANSAS GAS & ELECTRIC COMPANY

WOLF CREEK GENERATING STATION

STARTUP REPORT FOR CYCLE 1

NOVEMBER 27, 1985

Docket No. STN 50-482

License No. NPF-42

IE26
1/39

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INTRODUCTION

This report presents the results of initial startup testing at the Wolf Creek Generating Station from initial fuel load until the completion of the Power Ascension Test Program. The plant performed exceptionally well during the startup phase allowing the entire post fuel load test program to be completed in 169 days.

Wolf Creek is a Standardized Nuclear Unit Power Plant System (SNUPPS) unit located in Coffey County, Kansas. The Nuclear Steam Supply System (NSSS) is a four loop, Westinghouse pressurized water reactor (PWR) rated at 3411 megawatts thermal (MWT) (3425 MWT including reactor coolant pump (RCP) heat). General Electric provided the turbine generator for Wolf Creek. Bechtel Power Corporation was the architect for the entire power block. Sargent & Lundy acted as architect-engineer for the site-related portions of the project that were not part of the SNUPPS design. Daniel International Corporation was the site constructor for Wolf Creek.

License No. NPF-32 was issued by the Nuclear Regulatory Commission (NRC) on March 11, 1985, which authorized Kansas Gas & Electric to proceed with initial fuel loading and low power testing, including initial criticality and low power physics tests, at power levels not in excess of 5% rated thermal power (RTP). The first fuel assembly was inserted into the core on March 12, 1985, and fuel loading was completed on March 17, 1985. After the installation of the upper internals and the reactor vessel head, the RCS was filled and vented. Cold plant testing was authorized on March 27, 1985, and was completed on April 17, 1985. The RCS was at hot standby conditions (557^{o}F, 2235 psig) on April 30, 1985. Post core loading precritical testing was completed and approved on May 19, 1985.

The reactor was taken critical on May 22, 1985, and low power physics testing was commenced. Low power physics testing was completed on June 3, 1985. On June 4, 1985, the NRC lifted the 5% power restriction and issued license number NPF-42 for full power operation.

Wolf Creek entered Mode 1 (>5% power) for the first time on June 6, 1985. The turbine generator was synchronized to the grid on June 13, 1985. The 100% plant trip test, performed on August 28, 1985, was the final test in the Power Ascension Test Program. Following a brief maintenance outage the unit was declared commercial on September 3, 1985, at 0114.

1.0 INITIAL CORE LOADING

The initial core loading test sequence consisted of activities required prior to and during the actual loading of fuel. Many of these tests were required to be performed within certain time periods prior to the fuel load.

The Nuclear Instrumentation System (NIS) was tested well in advance of core load. Proper functioning of the system was verified including all alarm and trip mechanisms. Numerous deficiencies were encountered during the performance of this procedure, however, all were resolved prior to closing the procedure. Most of the deficiencies dealt with computer points not giving expected responses and were successfully resolved by having the computer group rebuild the points. Two cases of equipment failure were discovered during the test, one of which was a high voltage supply and the other a control board meter. Both pieces of equipment were replaced and successfully tested.

Following the functional check of the NIS, the source range preamplifier and pulse amplifier gains were adjusted for optimum settings. This was accomplished using a portable neutron source with a strength of approximately one curie. The neutron source was placed near the source range detector housing and the high voltage bias adjusted to obtain data which was then plotted. By determining the point at which the curve deviated from a best fit straight line, optimum bias settings were chosen. These settings were then verified by disabling the high voltage power supply bias supply and checking that the count rate settled out below 5 counts per second. Actual testing was performed using surveillance (STS) procedures which satisfied the same requirements as the startup procedures. No problems were experienced with those portions of the STS procedures that were related to the startup testing.

The remainder of the requirements of the core loading test sequence were restricted by time limits. Some of the limits were imposed by Technical Specifications, others by Westinghouse or plant administrative recommendations.

The first such limit was that within 7 days prior to core load, temporary nuclear monitoring instrumentation should be setup and checked and that valve lineups be performed in preparation for chemistry sampling. The temporary instrumentation package, which consisted of 3 neutron detectors and all associated equipment, was supplied by Westinghouse for use during core load. The equipment was setup on the refueling deck inside the containment building and settings adjusted in accordance with a Westinghouse pre-shipment calibration. A neutron source was placed near the detectors and the high voltage varied to obtain data for voltage plateaus. The results of the plateaus proved to be consistent with the pre-shipment calibration indicating no changes in settings were necessary. The high voltage operating setpoint to be used was determined to be 2100 volts on all three detectors. Due to the time requirements, this test was repeated three times because the operating license was not received as anticipated.

As required by Plant Technical Specifications, containment ventilation, containment penetrations, and the refueling machine were proven operable within 100 hours of core load. Again, these procedures were repeated as the license was delayed.

Verification of valve lineups and boron concentration sampling commenced 72 hours prior to the anticipated core load time and was repeated several times due to delays in license receipt. Sample results indicated that the boron injection tank was out of specification high and the boric acid storage tank was out of specification low. By recirculating the tanks, both were brought within specification. A sample from the excess letdown heat exchanger line could not be obtained since the reactor coolant system fill elevation was below that of the sample point. This line was then isolated and valves tagged shut to prevent any possible mixing of the two systems.

After being placed in the reactor vessel and within 8 hours of the start of core load, the temporary detectors were response checked. This verified that the count rate would increase when exposed to a neutron source and was accomplished by lowering a source into the vessel and placing it next to the detectors. The initial position of the detectors within the reactor vessel is shown on Figure 1.0-2. Also during this 8 hour period, an analog channel operational test was performed on the NIS source range channels.

On March 11, 1985, operating license NPF-32 was issued to Wolf Creek. Prerequisites to the core loading procedure were completed and a briefing was held with all involved personnel to confirm responsibilities. Background count rates were determined for all detectors, temporary and permanent. ICRR monitoring was performed concurrently throughout the entire core load. As expected, very low background count rates were obtained which were on the order of 0.02 to 0.05 counts per second.

As reference counts were taken, temporary detector A did not respond reliably. Since temporary detector B was not considered to be a responding detector until late in the core loading sequence, it was switched with detector A thus making detector B the inoperable detector. Detector B was never declared operable but there were at least two available responding detectors at all times.

After verifying that all requirements for core load were completed and that the refueling equipment was operating properly, the Plant Manager's permission to begin core load was obtained. At 0747 on March 12, 1985, the first fuel assembly, assembly C04, was removed from the spent fuel storage pool and placed into the upender. The first problem was encountered when the transfer cart would not traverse all the way to the containment building. Assembly C04 was returned to the spent fuel pool in order to troubleshoot the transfer cart. It was found that the emergency pullout cable was tangled in the cart device mechanism. A scuba diver was sent down to remove the cable. Instead of replacing the cable, it was decided to use the cart without the cable since this was a new core and with no high radiation present, a diver could, if necessary, go down to attach a new cable at a later time. At 1216, after a 4.5 hour delay, assembly C04 was again removed from storage and this time successfully loaded into core position L-15.

As assembly C04 was moved over the reactor vessel area, the high flux at shutdown alarm sounded. The alarm was then blocked as this was not unexpected. Assembly C04, as well as the second assembly loaded, assembly C30, contained the primary sources. The sources within these assemblies were Californium - 252 (Cf-252) which were previously installed on January 12, 1985. Since this was a new core, the water was only at the level of the nozzles within the reactor vessel and just above the transfer tube within the transfer canal. Therefore, there was no moderator between the fuel assembly and the source range detector housing which allowed an increased number of neutrons to reach the detector. The high flux at shutdown alarm remained blocked until both assemblies were installed in the core.

Core loading operations were suspended after the first fuel assembly was unlatched in the core to investigate a problem with the spent fuel bridge crane. The hoist of the crane was "chattering" as the fuel assemblies were being lifted. Since core loading was performed in a semi-dry condition, the lack of bouyancy presented an increased weight to be lifted by the hoist. The original setpoints for the hoist were for wet conditions and were thus adjusted to compensate for the present dry condition. After doing so, the crane was functionally checked and upon successful completion, core loading resumed. Following this 3 hour delay, the second assembly was removed from storage at 1602.

Since the first two assemblies loaded were source bearing assemblies, the count rate significantly increased as expected. The count rate from source range channel N31 increased to 6.24 counts per second and N32 to 8.75 counts per second. Before proceeding with core loading, the high flux at shutdown setpoints were adjusted to five times these values. Core loading then continued as illustrated in Figures 1.0-1 through 1.0-10.

As each fuel assembly was being inserted into the reactor vessel, outputs of responding temporary detectors were monitored on a strip chart recorder at the core loading station inside the containment building. Permanent plant instrumentation was monitored in the control room. After verifying the core was not approaching criticality, the fuel assemblies were unlatched from the manipulator crane. Count rate data from four operable detectors (2 temporary, 2 permanent) were obtained by averaging the results of three counting periods. This data was then used to plot an inverse count rate ratio (ICRR) curve.

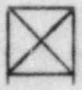
The source bearing assemblies were loaded into the core first, however, effective reactivity monitoring could not be achieved until the sources were moved to their final position and a cluster of assemblies built around them. Therefore, ICRR monitoring was not initiated until after step 10 of the loading sequence. Data was then obtained throughout the loading sequence and ICRR plots updated following each step of the sequence. These plots are included in Figures 1.0-11 through 1.0-15.

At no time was core loading interrupted due to high count rates or unexpected changes in the ICRR. However, there was some concern following step 87. After this assembly (assembly A04) was loaded, only one of the responding detectors was indicating greater than 2 counts per second. The Final Safety Analysis Report requires at least two detectors indicate this count rate. This did not present an immediate concern since another detector that was not identified as a responding detector did indicate this

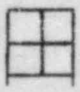
FIGURE 1.0-1

CORE LOADING SEQUENCE LEGEND

Legend for Core Loading Figures



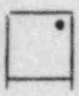
Assembly loaded in permanent position in previous step.



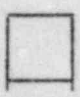
Assembly loaded in temporary position in previous step.

Assembly loaded into position during loading step Number N.

Location of Temporary Detector A (B and C).



Assembly with primary source insert.



Not as yet loaded.

Note: Arrows indicate detector or fuel movement.

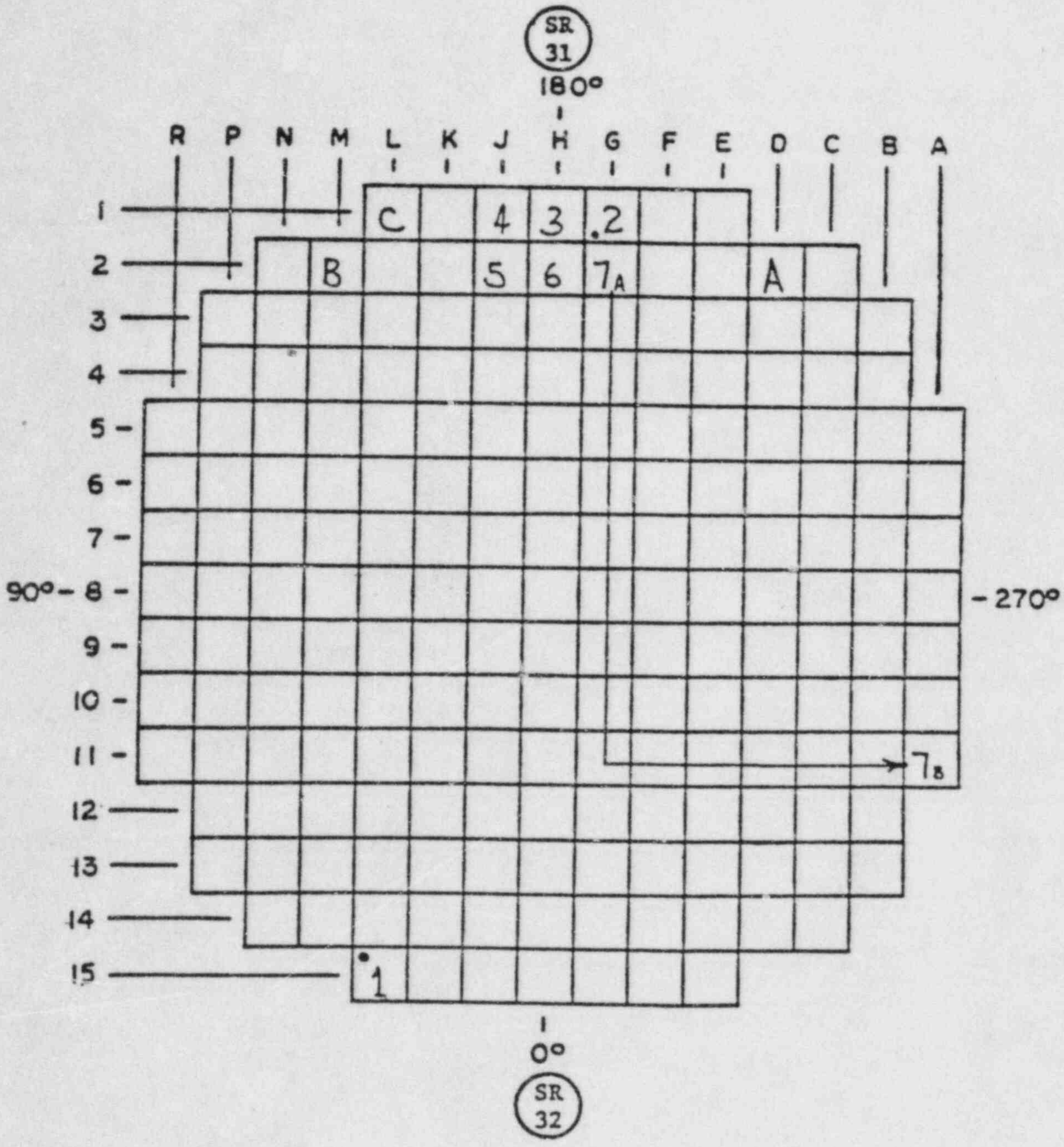


Figure 1.Ø-2 CORE LOADING SEQUENCE STEPS Ø to 7B

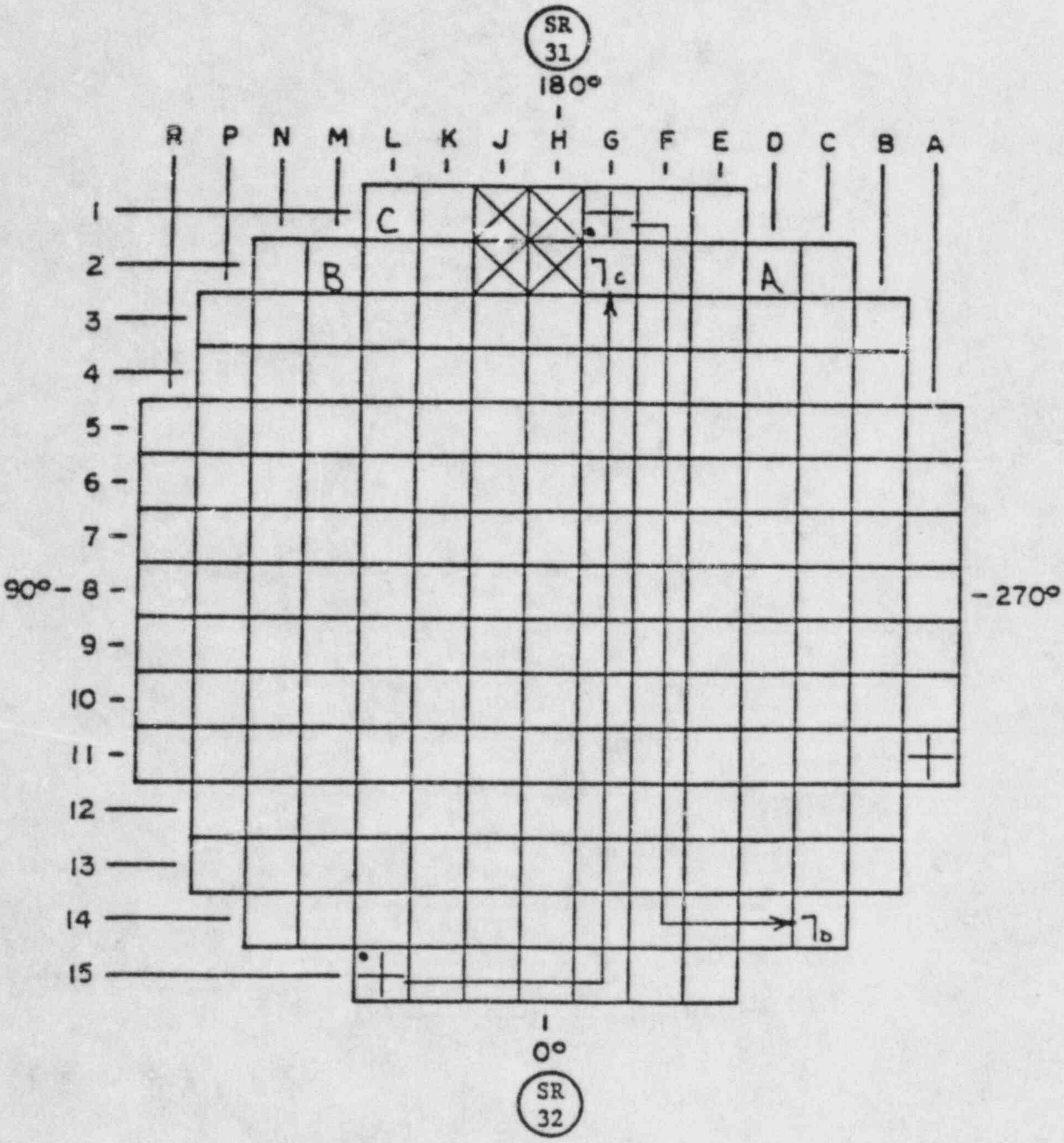


Figure 1.Ø-3 CORE LOADING SEQUENCE STEPS 7C to 7D

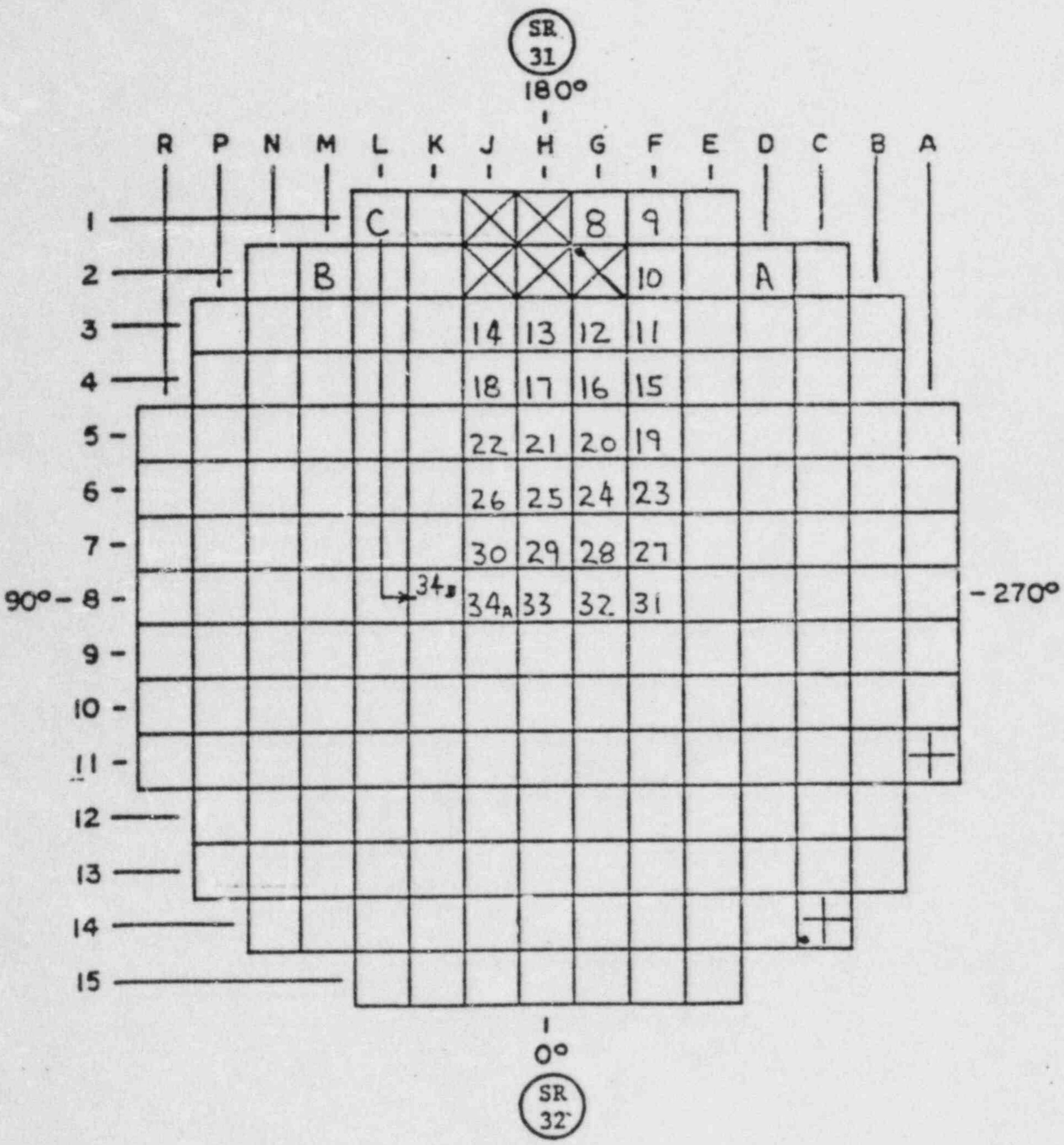


FIGURE 1.0-4 CORE LOADING SEQUENCE STEPS 8 TO 34B

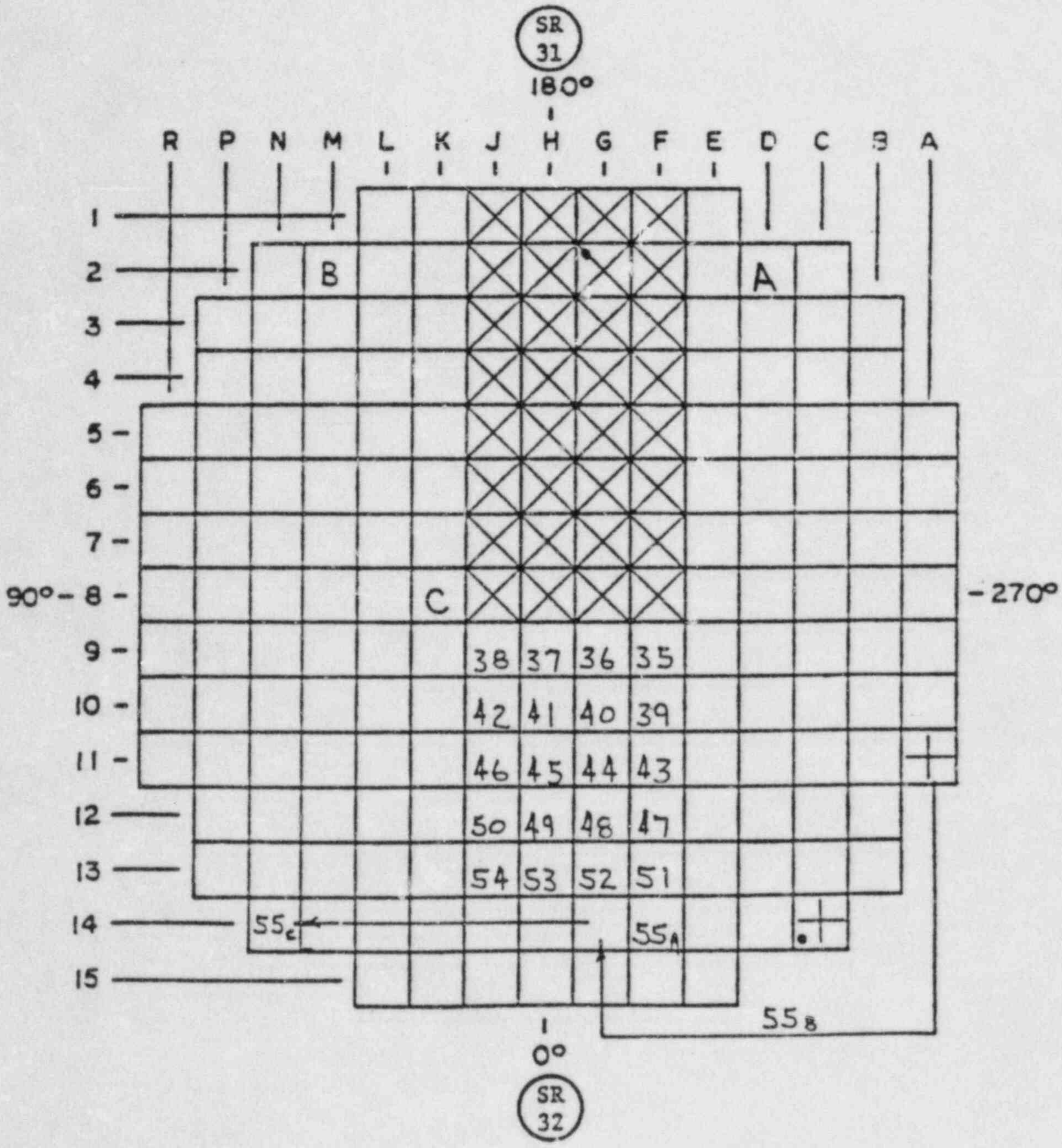


FIGURE 1.0-5 CORE LOADING SEQUENCE STEPS 35 TO 55C

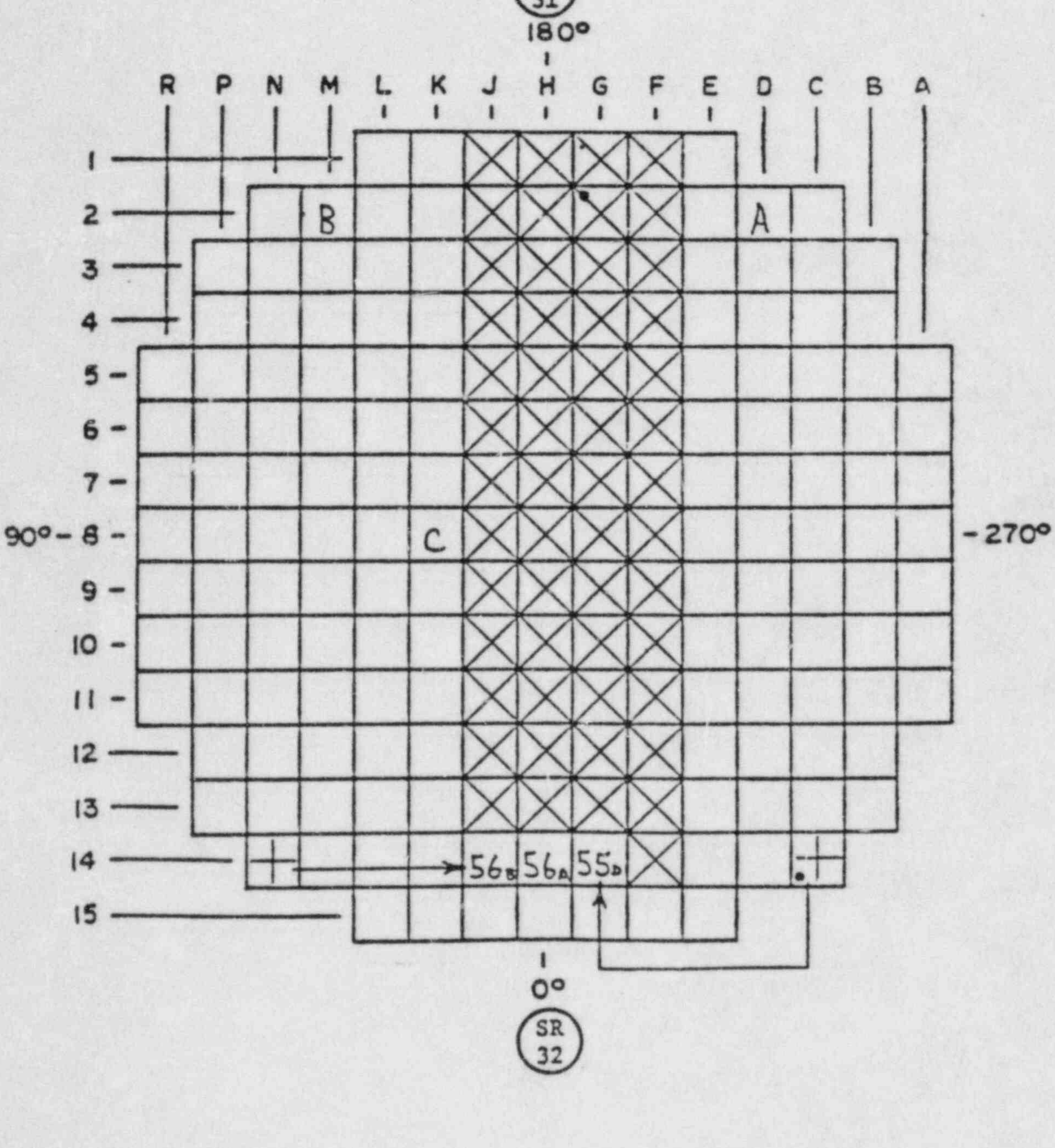


FIGURE 1.Ø-6 CORE LOADING SEQUENCE STEPS 55D TO 56B

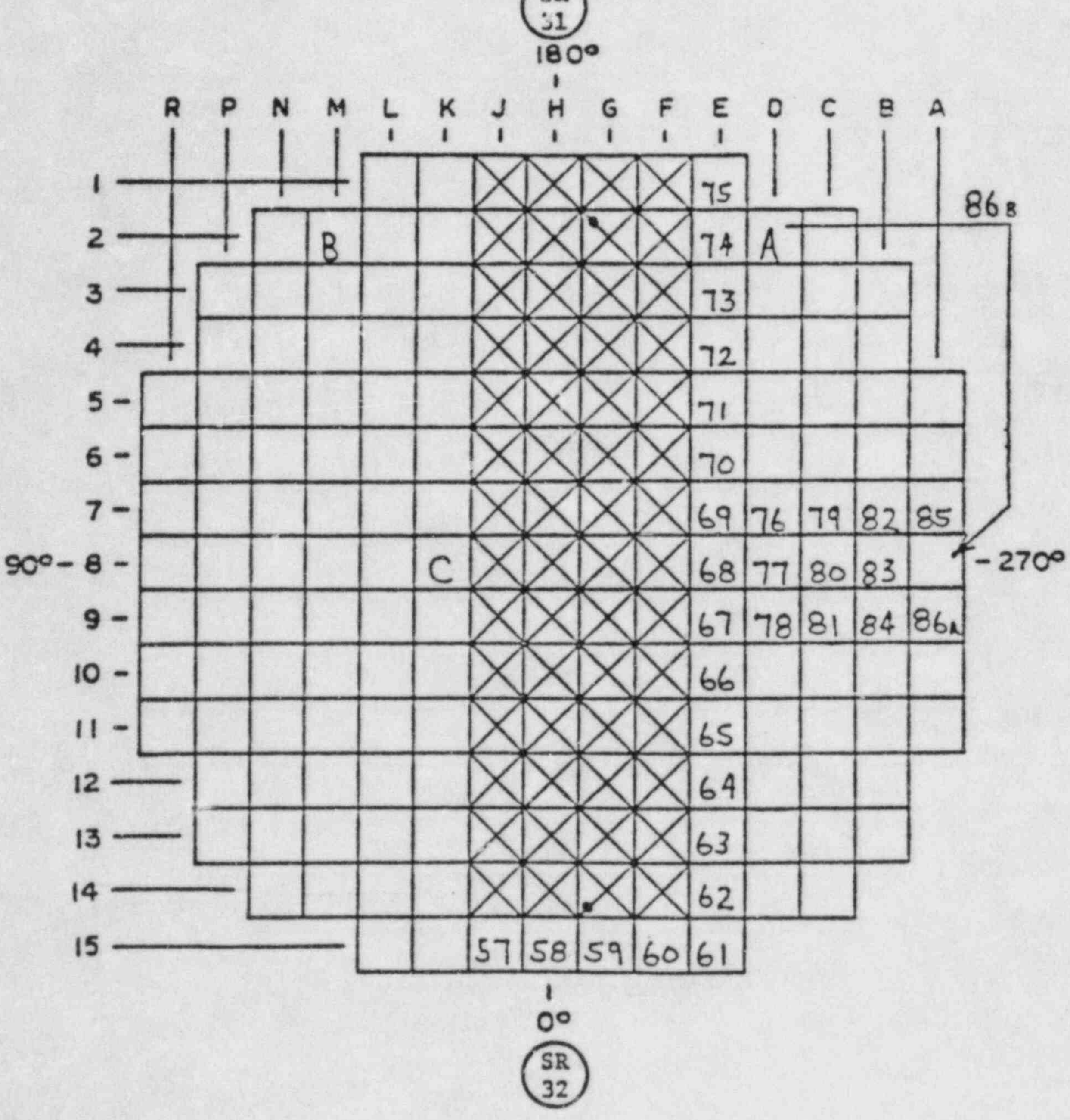


FIGURE 1.0-7 CORE LOADING SEQUENCE STEPS 57 TO 86B

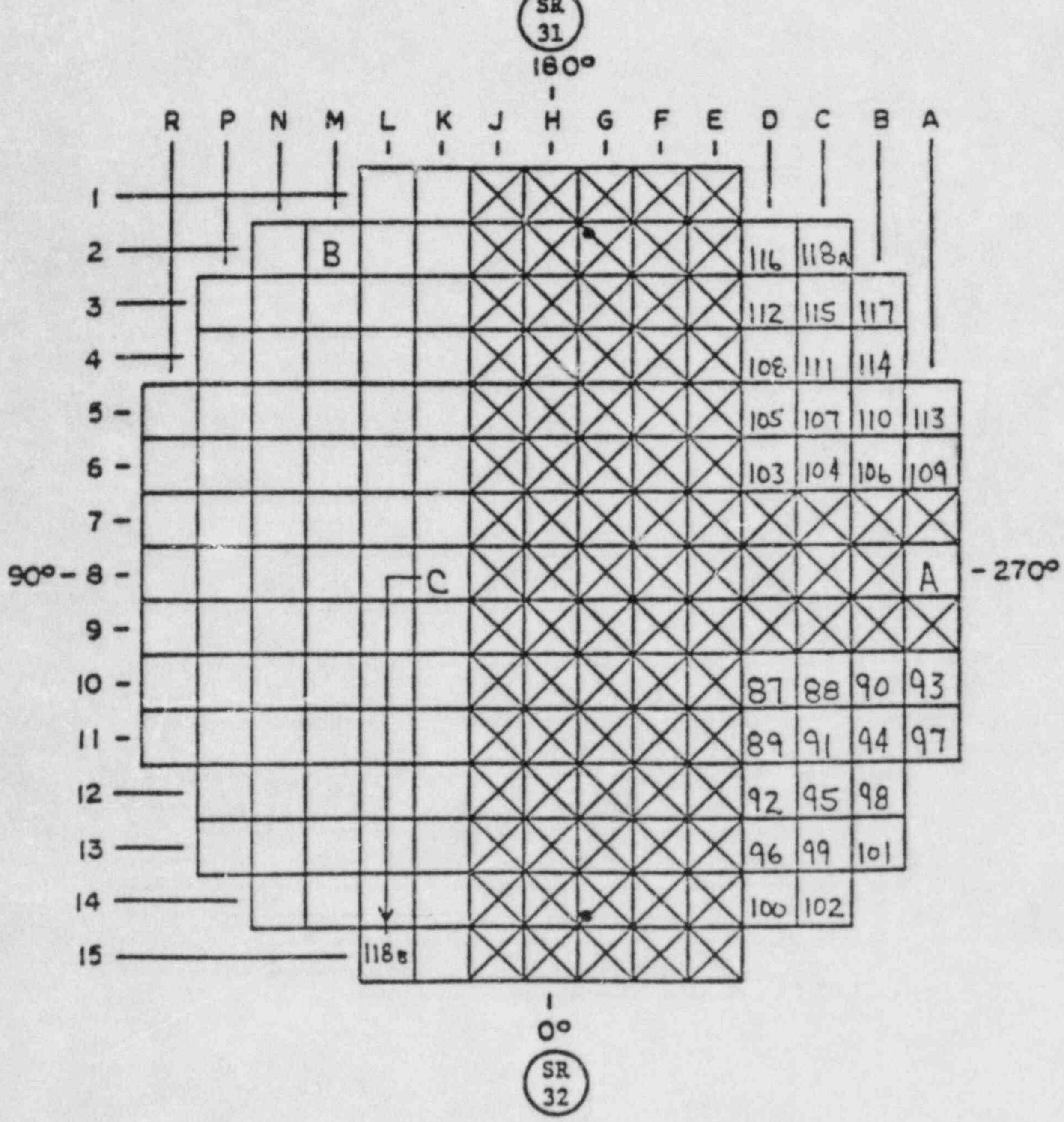


FIGURE 1.Ø-8 CORE LOADING SEQUENCE STEPS 87 to 118B

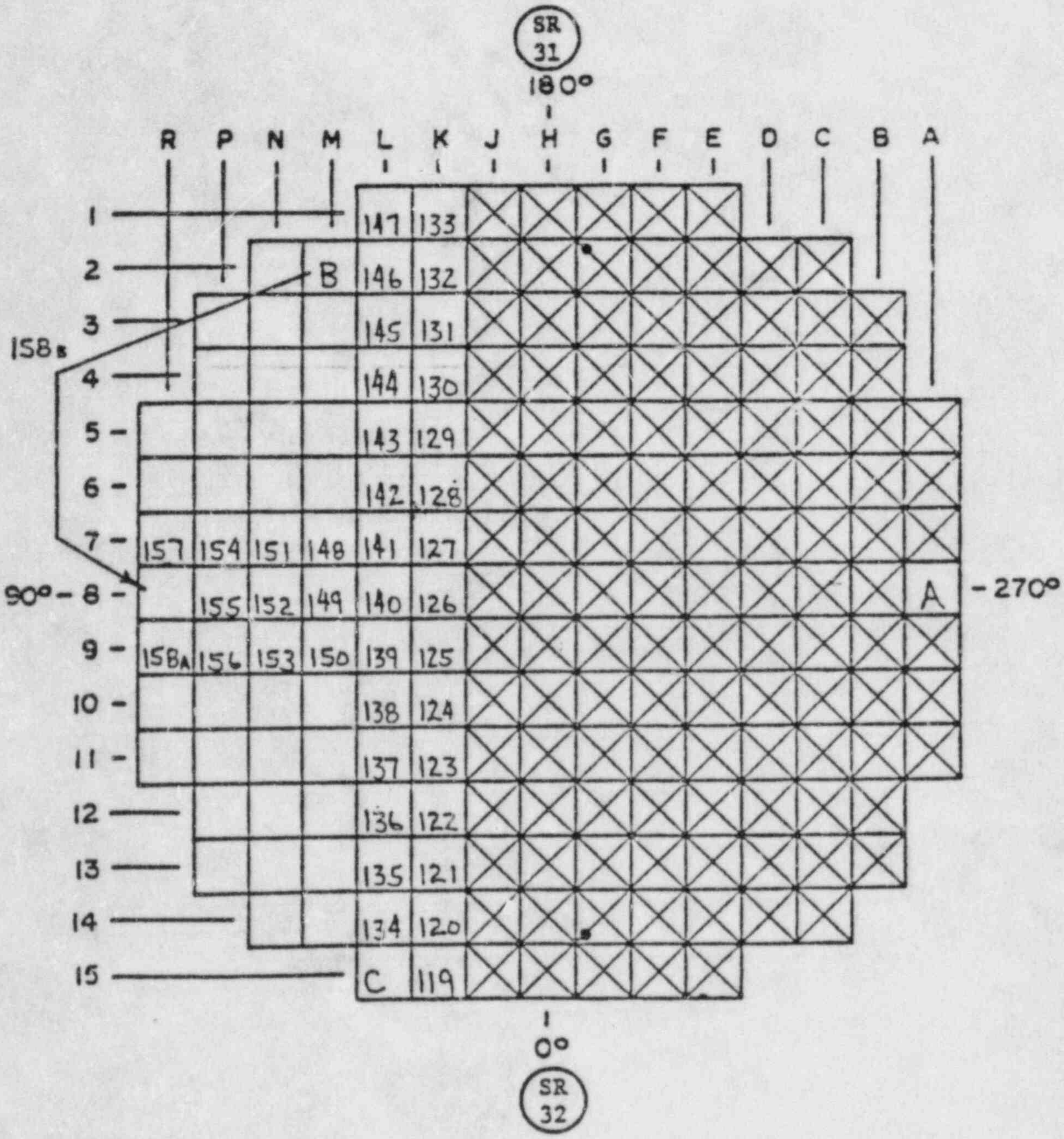


FIGURE 1.0-9 CORE LOADING SEQUENCE STEPS 119 to 158B

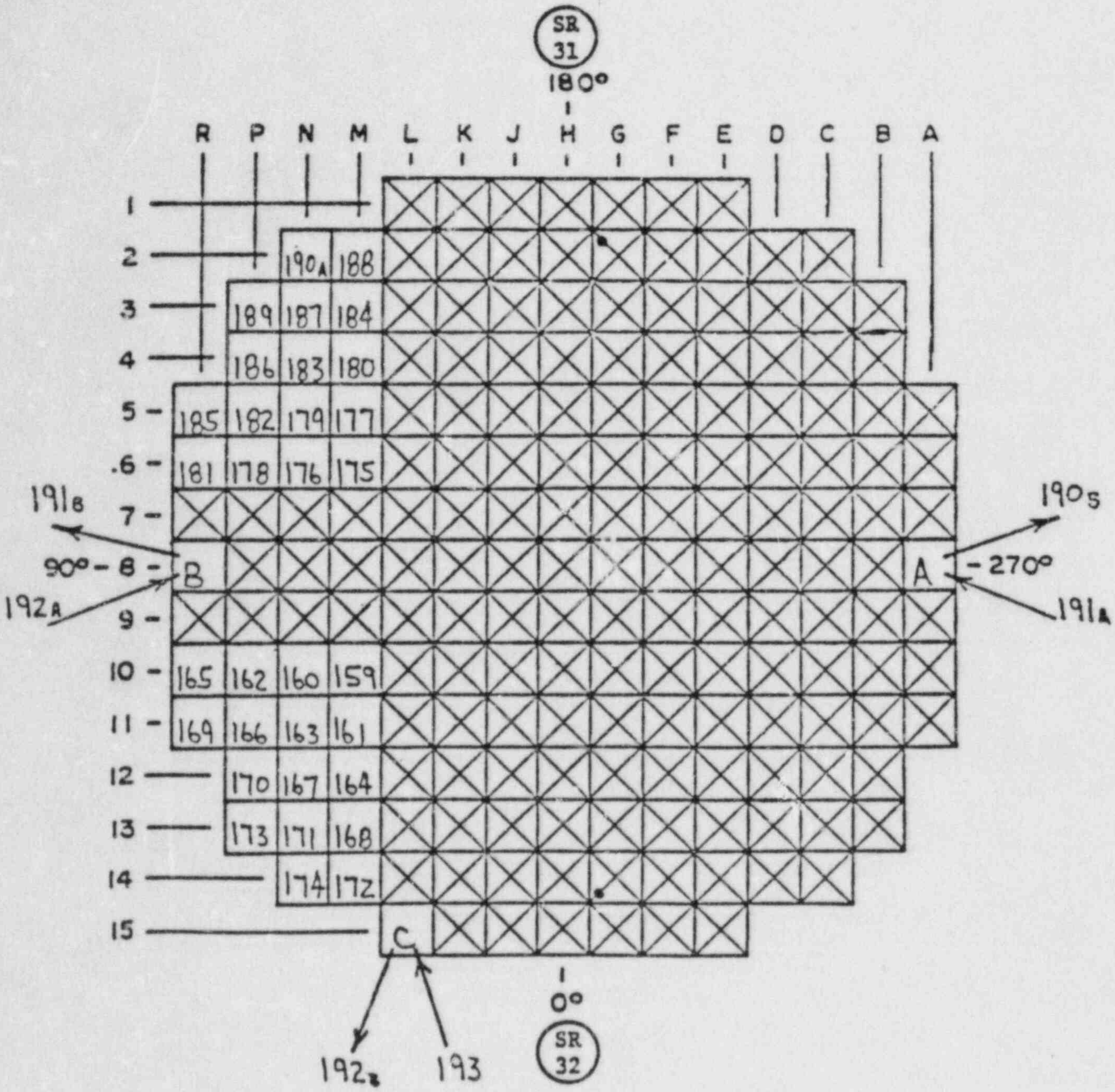


FIGURE 1.Ø-1Ø CORE LOADING SEQUENCE STEPS 159 to 193

FIGURE 1.0-11

ICRR PLOT FOR CORE LOADING

(Source Range N31)

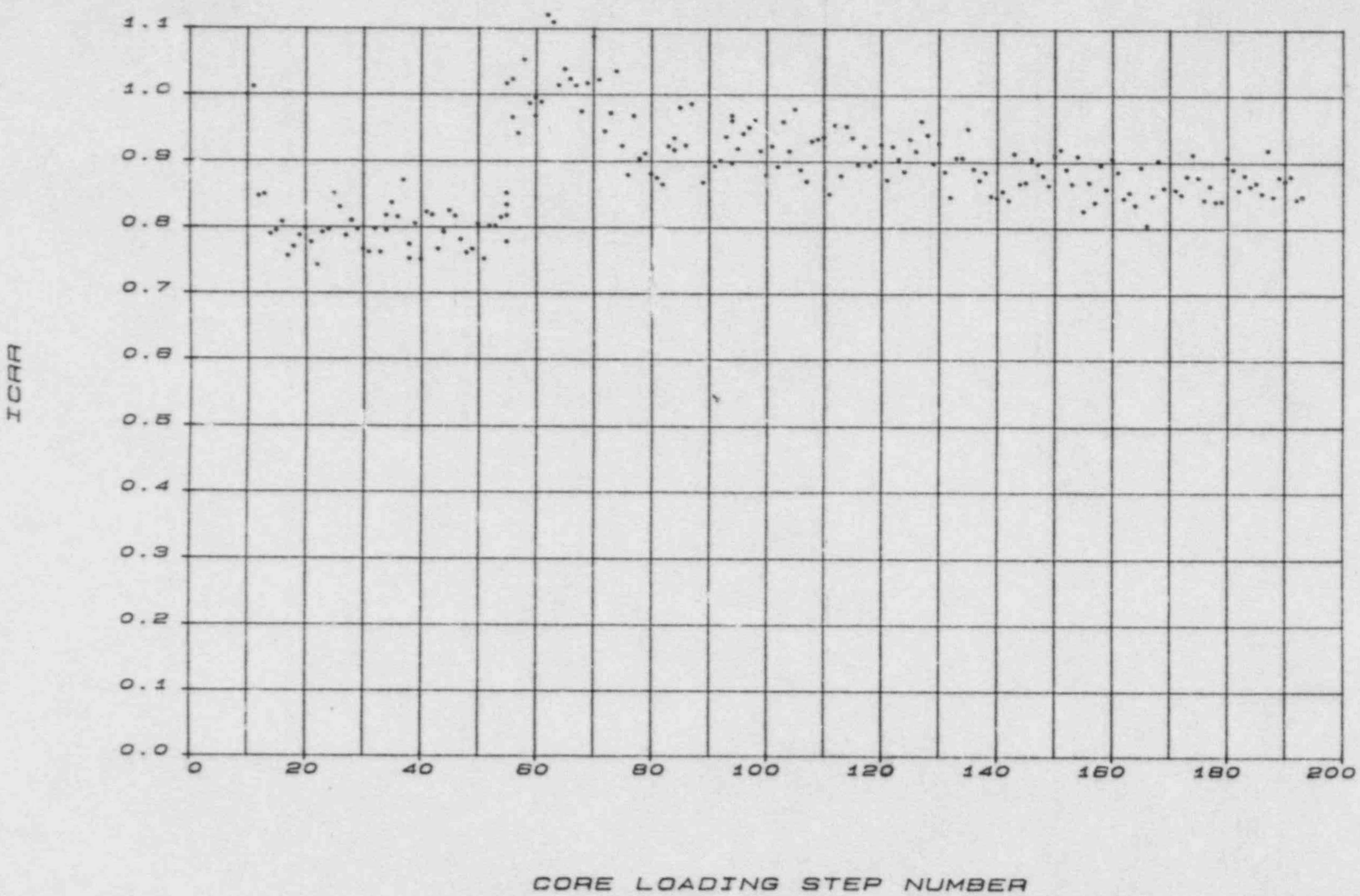


FIGURE 1.0-12

ICRR PLOT FOR CORE LOADING

(Source Range N32)

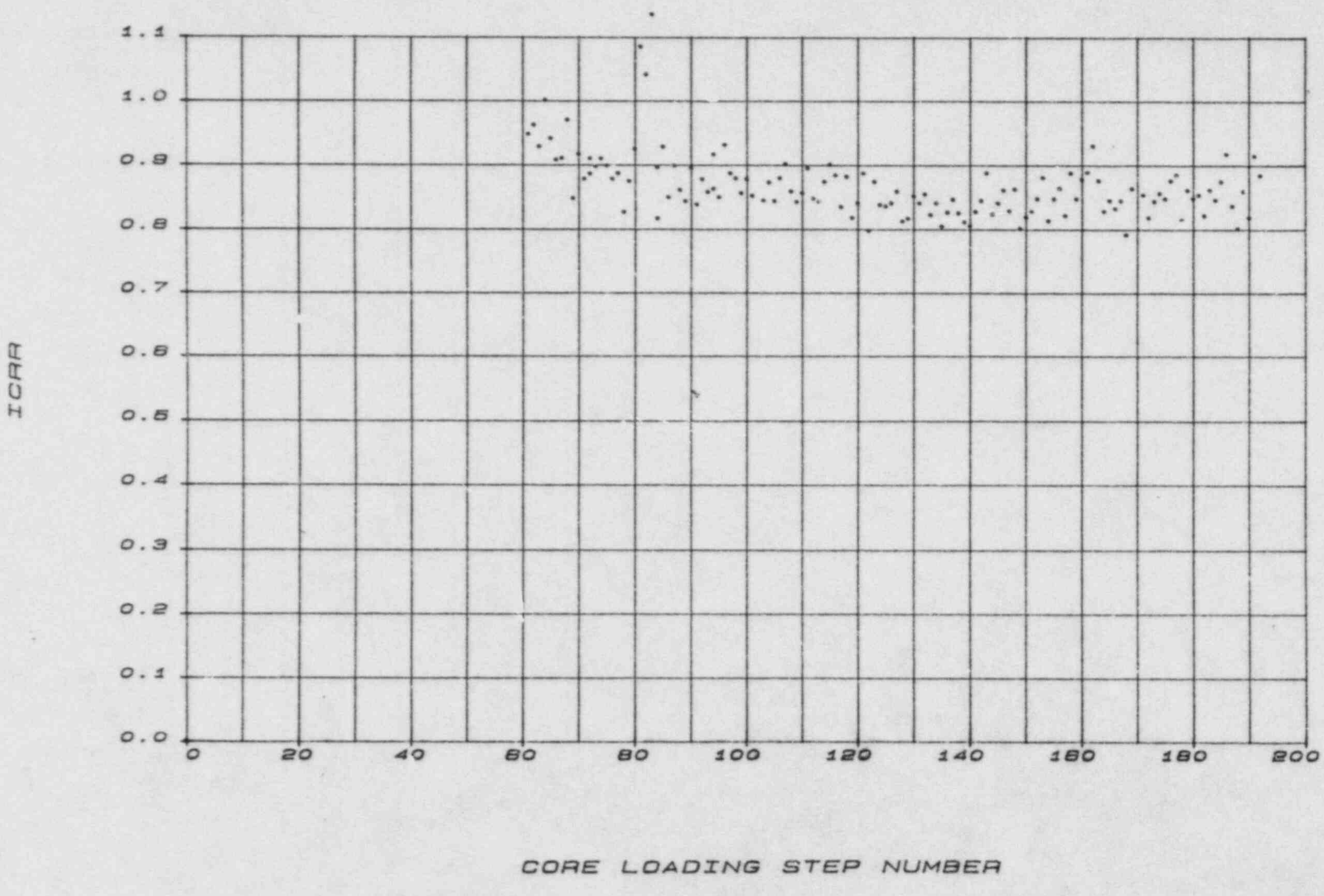


FIGURE 1.0-13

ICRR PLOT FOR CORE LOADING

(Temporary Channel A)

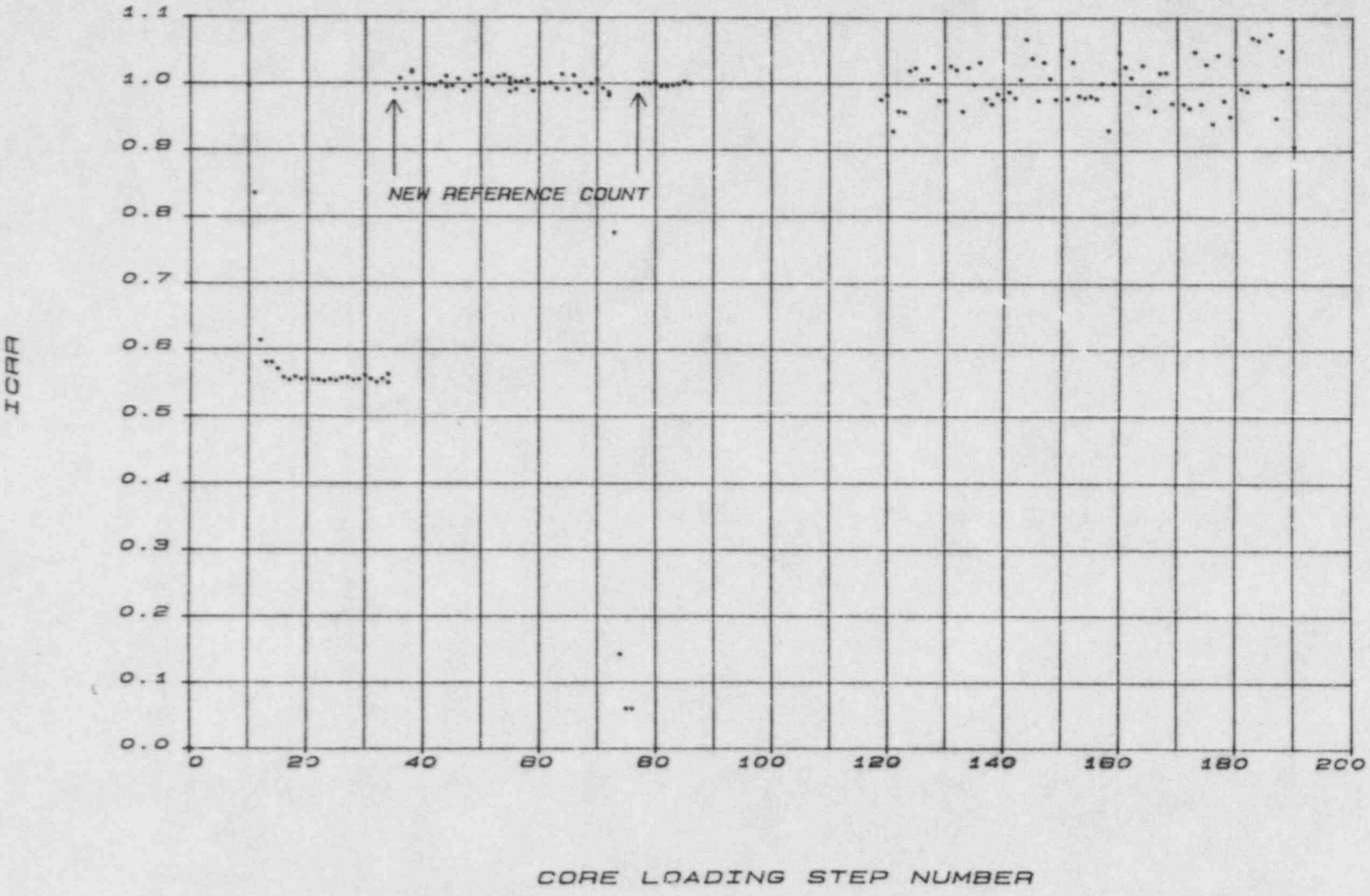


FIGURE 1.0-14
ICRR PLOT FOR CORE LOADING

(Temporary Channel B)

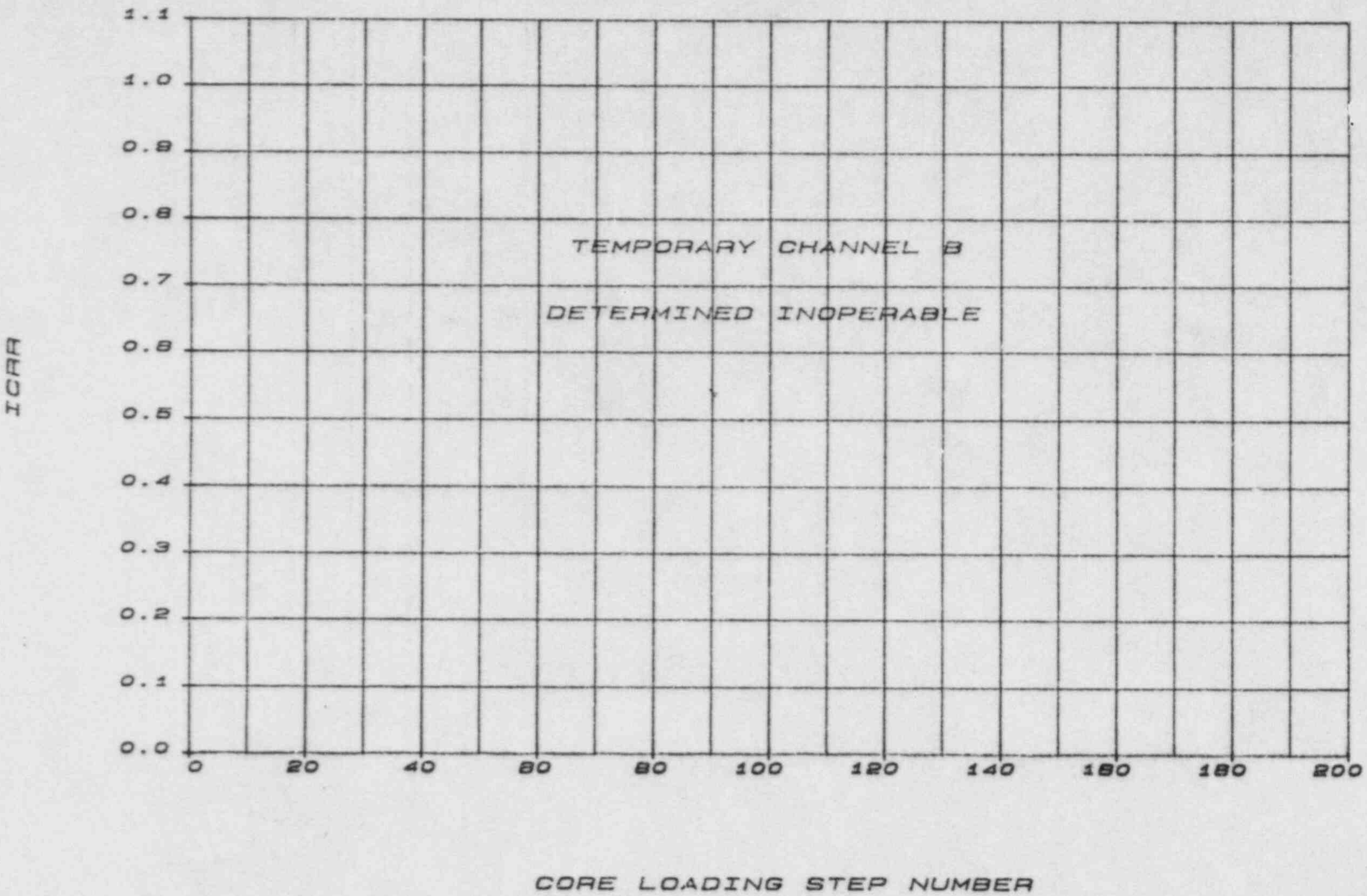
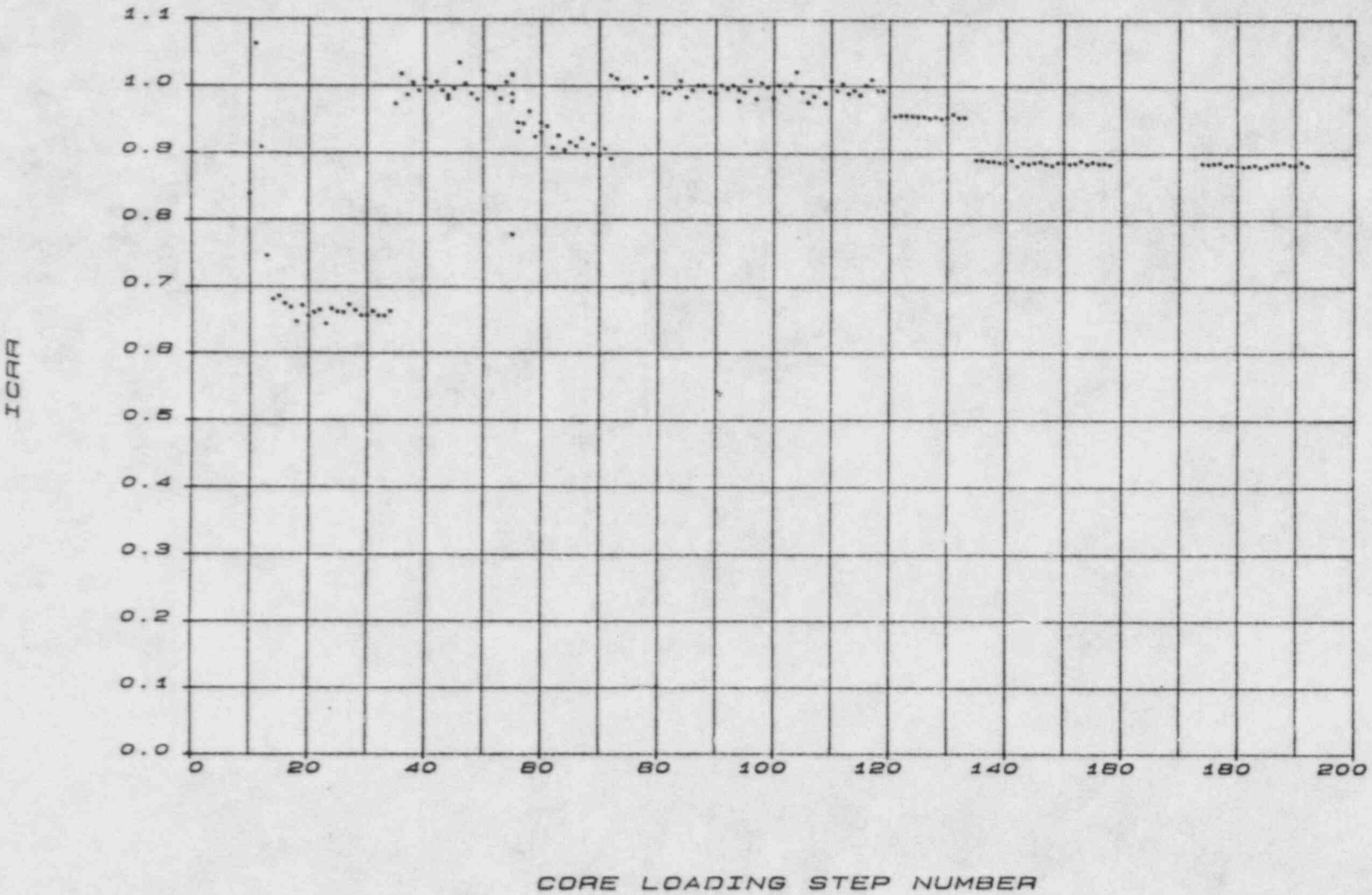


FIGURE 1.0-15

ICRR PLOT FOR CORE LOADING

(Temporary Channel C)



value thus satisfying the FSAR requirement. However, the concern was that toward the end of the loading sequence, the temporary detectors have to be removed in order to place the final fuel assemblies in the core. This would only leave the two NIS detectors which were not indicating the required 2 counts per second. The situation was evaluated and the requirement of 2 counts per second was changed to 0.5 counts per second following a 10CFR50.59 evaluation.

Boron samples of the reactor coolant system taken throughout the core load resulted in an average value of 2104 ppm with a range of 2098 ppm to 2120 ppm. Residual Heat Removal System temperatures averaged 95°F, ranging from 83°F to 101°F.

With the exception of the transfer cart and the spent fuel bridge crane hoist, no significant equipment problems occurred during the core loading operation. A few instances of minor difficulties were encountered with the temporary monitoring equipment all of which were resolved in short periods of time.

Core loading was successfully completed at 0600 on March 17, 1985, as the last assembly was unlatched in core position L-15. The total elapsed time for loading the complete core of 193 fuel assemblies was 118.25 hours. Including delay time the average assembly loading rate was 1.63 assemblies per hour. Core loading operations continued 24 hours a day using two 12 hour shifts.

Immediately following completion of the core load, a video map of the core was taken to verify proper fuel assembly positioning and that the proper insert was contained in each fuel assembly. An underwater television camera and video cassette recorder were used for this verification. The video tape was than reviewed for double verification. The results of the map are illustrated in Figure 1.0-16. Upon completion of the map review, the initial core loading operation was complete and accomplished in an exemplary manner.

FIGURE 1.Ø-16 WOLF CREEK GENERATION STATION - CYCLE 1
FINAL CORE LOADING MAP

N 31

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1					C27 116DS	C43 B10P-9D	C50 43DS	C12 B10P-11D	C07 4DS	C50 B10P-12D	C26 128DS				
2			C36 B9P6D	C32 R50	C54 12P2D	A38 R17	C01 20P9D	A22 R43	C04 19PS1	A16 R51	C28 12P5D	C02 R34	C63 A9P1D		
3		C56 B9P5D	C51 92DS	B46 20P25D	A30 R28	B03 16P12D	A40 R14	B45 16P17D	A42 R47	B19 16P3D	A33 R13	B47 20P24D	C15 77DS	C17 A9P4D	
4		C47 R26	B28 20P2D	B24 R22	B48 20P11D	A43 0SS1	B34 16P28D	A52 R52	B43 16P13D	A01 38DS	B49 20P33D	B59 R35	B39 20P8D	C05 R04	
5	C06 48DS	C42 12P4D	A49 R12	B16 20P22D	A51 23DS	B20 16P2D	A32 25DS	B61 16P18D	A23 46DS	B09 16P31D	A14 75DS	B22 20P5D	A28 R02	C25 12P1D	C45 79DS
6	C38 A10P4D	A06 R05	B37 16P32D	A05 53DS	B62 16P16D	A41 R29	B10 20P19D	A26 R20	B31 20P3D	A10 R31	B63 16P23D	A46 66DS	B14 16P8D	A62 R48	C34 A10P2D
7	C41 83DS	C03 20P27D	A13 R16	B12 16P4D	A53 33DS	B15 20P32D	A15 9DS	B07 20P20D	A03 5DS	B13 20P7D	A63 97DS	B06 16P11D	A61 R19	C55 20P15D	C40 24DS
8	C22 A10P1D	A37 R53	B18 16P30D	A36 R40	B38 16P26D	A60 R08	B11 20P26D	A29 R39	B53 20P17D	A35 R41	B32 16P10D	A21 R01	B57 16P20D	A24 R11	C13 A10P3D
9	C20 54DS	C61 20P21D	A58 R30	B50 16P22D	A64 34DS	B33 20P6D	A47 40DS	B17 20P4D	A44 45DS	B02 20P23D	A56 47DS	B64 16P7D	A48 R36	C11 20P18D	C24 39DS
10	C09 A10P6D	A02 R25	B56 16P25D	A17 88DS	B35 16P27D	A18 R10	B23 20P34D	A11 R15	B01 20P13D	A55 R23	B26 16P21D	A04 56DS	B05 16P29D	A39 R37	C39 A10P5D
11	C53 125DS	C08 12P8D	A25 R09	B04 20P31D	A50 112DS	B42 16P19D	A27 17DS	B58 16P5D	A20 44DS	B52 16P15D	A59 134DS	B40 20P14D	A65 R49	C64 12P6D	C49 14DS
12		C19 R18	B54 20P10D	B36 R54	B51 20P28D	A31 73DS	B30 16P24D	A12 R07	B60 16P6D	A07 0SS2	B21 20P12D	B27 R33	B55 20P16D	C18 R32	
13		C35 A9P2D	C59 55DS	B29 20P30D	A08 R55	B41 16P9D	A57 R45	B44 16P1D	A45 R27	B25 16P14D	A54 R06	B08 20P29D	C33 127DS	C46 B9P8D	
14			C16 A9P3D	C23 R44	C21 12P7D	A09 R38	C31 20P1D	A34 R46	C30 19PS2	A19 R03	C62 12P3D	C57 R42	C48 B9P7D		
15					C44 98DS	C14 B10P7D	C52 30DS	C10 B10P-10D	C37 90DS	C58 B10P8D	C29 65DS				

N 32

Top - Fuel Assembly ID
Bottom - Insert ID
XXDS - Thimble plug
RXX - Control Rod Assembly
YYPXXD - Burnable poison with YY poison rods (symmetrical)
XYYPXD - Burnable poison with YY poison rods (non-symmetrical)
XXPSX - Primary Source Assembly
XSSX - Secondary Source Assembly

2.0 POST CORE LOADING PRECRITICAL TESTING

After completion of initial core loading, preparations were begun to perform the post core loading precritical testing phase of the Startup Test Program. This test phase performed the final testing and alignment of various plant systems prior to initial criticality. This involved testing at cold shutdown conditions (RCS average temperature <200°F), testing during plant heatup and pressurization and testing at hot no-load conditions (RCS average temperature 557 +0,-5°F, RCS pressure 2235 ± 25 psig).

The upper internals were installed in the reactor vessel on March 17, 1985, and the reactor vessel head was set on March 18, 1985. With the completion of the tensioning of the reactor vessel head studs on March 21, 1985, the plant entered Mode 5 (Cold Shutdown). The fill and vent of the Reactor Coolant System was completed on March 29, 1985. During the Cold Shutdown period the following testing was performed:

1) CRDM polarity checks,
2) Cold, no flow rod control system,
3) Cold, full flow rod control system,
4) Initial incore movable detector tests,
5) Thermal and dynamic testing of the main steam and feedwater systems (initial data collection),
6) Initial testing of the reactor vessel level instrumentation system (RVLIS).

Cold shutdown testing was completed on April 14, 1985, and the plant entered Mode 4 (Hot Shutdown) on April 17, 1985.

During the heatup phase, the following testing took place:

1) RCS RTD/TC cross calibration,
2) Continuation of the thermal and dynamic testing of the main steam and feedwater systems,
3) Special test of the pressurizer power operated relief valves (PORV) at operating RCS pressure (2235 psig),
4) RVLIS data collection.

The plant entered Mode 3 (Hot Standby) on April 26, 1985. Testing at 450°F RCS average temperature was completed on April 28, 1985. Loose parts noise was noted on Channel 2 of the Loose Parts Monitor. Investigation of the noise continued during the heatup and subsequent testing at 557°F. The noise was determined to be caused by a vibrating thimble (tube 42) in the incore monitoring system. This was evaluated as a minor problem and did not impact later testing.

The RCS was at 557°F, 2235 psig on April 30, 1985. Testing performed at this plateau included:

1) Setting of continuous spray flow valves,

2) Verification of pressurizer spray and heater effectiveness,

3) Verification of RCS flow rate,

4) Determination of transport time in the RCS RTD bypass loops,

5) Hot, full flow control rod system,

6) Hot, no flow control rod system,

7) Checkout of the incore movable detector system,

8) Measurement of the reactor coolant loop flow coastdown time,

9) Precritical alignment of the Tavg and delta T instrumentation,

10) Precritical alignment of the Nuclear Instrumentation System (NIS),

11) Initial data collection at hot no-load temperature and pressure for startup adjustments of the reactor control system.,

12) Checkout of the loose parts monitoring system,

13) Checkout of the thermocouple core monitor system,

14) Background data collection for the biological shield testing,

The final test of the rod control system prior to initial criticality was completed on May 18, 1985. All precritical testing was completed and the Plant Safety Review Committee approved the test packages on May 19, 1985.

The following pages of this section contain detailed discussions of the post core loading precritical test program. Those ongoing procedures that were completed later in the Startup Test Program are discussed in Section 4 of this Startup Report:

1) Power Ascension Thermal and Dynamic Test - Section 4.7,

2) Biological Shielding Testing - Section 4.8,

3) RVLIS - Section 4.11.2.

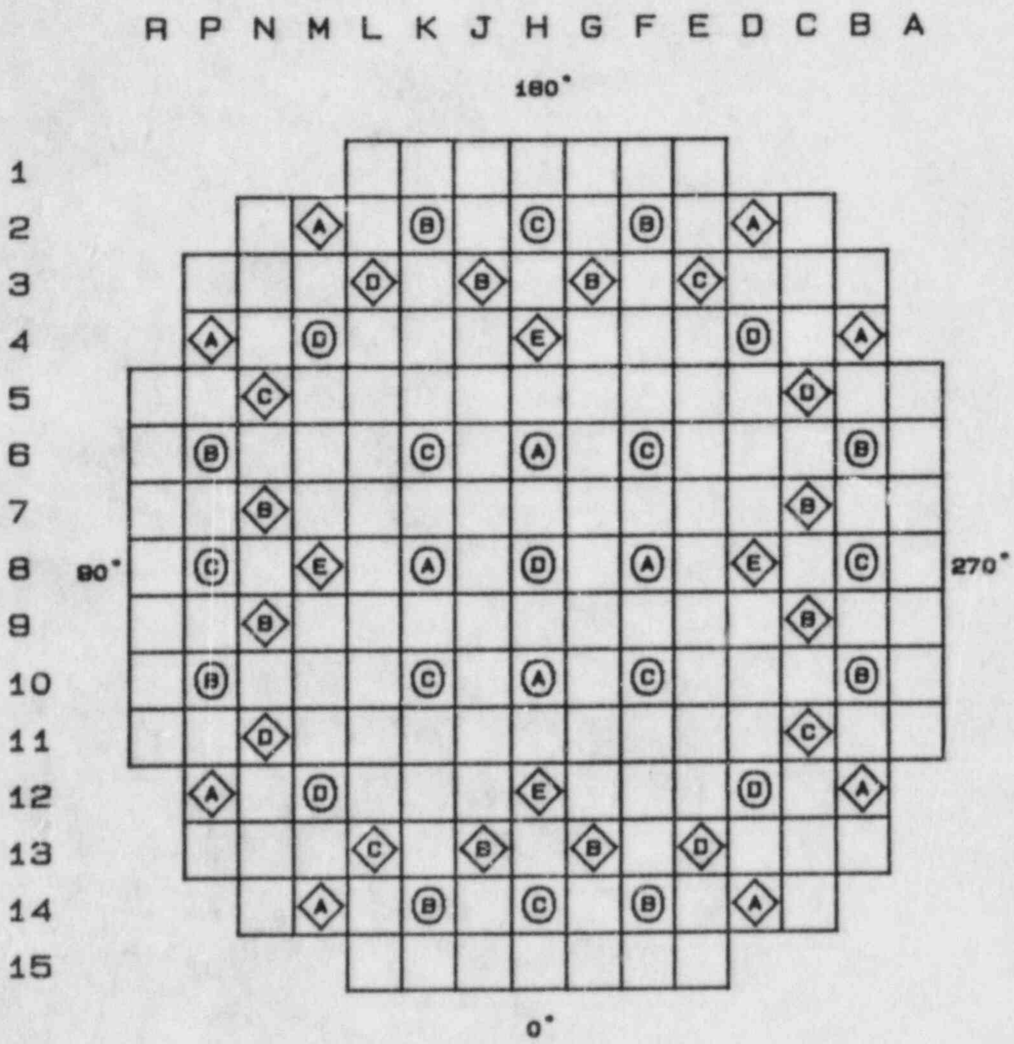
2.1 CONTROL ROD TESTING

A major portion of the testing performed during the post core loading phase of the test program was involved with the various components of the rod control system. The full length control rod system consists of 53 rod cluster control assemblies (RCCA) with each assembly consisting of individual rods constructed of hafnium encapsulated in cold worked stainless steel tubing. The assemblies are divided into 5 shutdown banks (SBA, SBB, SBC, SBD and SBE) and 4 control banks (CBA, CBB, CBC, CBD). Each bank, except shutdown banks SBC, SBD and SBE, is divided into two groups. Shutdown banks SBC, SBD and SBE have only one group. Each group consists of 4 rods each except control banks CBA (2 rods in each group) and CBD (2 rods in group 1 and 3 rods in group 2). The rod banks are located in the core as shown in Figure 2.1-1.

The full length rods are moved by a Westinghouse magnetic jack type drive mechanism. Each control rod drive mechanism (CRDM) contains three magnetic induction coils which energize in a cyclic sequence to move the rods. Loss of power to these coils causes the rods to drop to the fully inserted position. The rod control system is designed to allow individual movement of the various banks or movement of the control banks in the overlap mode. In the overlap mode, one control bank is withdrawn until it reaches a predetermined setpoint where the next control bank in the sequence begins to move in synchronization with the first bank. During control bank withdrawal the sequence is CBA - CBB - CBC - CBD. Control bank insertion in overlap reverses the withdrawal sequence: CBD - CBC - CBB - CBA. During the stepping of a bank, each rod group alternates motion to provide a more uniform reactivity change. In addition to rod movement by bank, an individual rod can be moved by use of the lift disconnect panel. This allows an out of position rod to be restored to the bank position.

FIGURE 2.1-1

CONTROL ROD LOCATIONS



BANK		NO. CLUSTERS
◇ SHUTDOWN BANK	A	8
	B	8
	C	4
	D	4
	E	4
○ CONTROL BANK	A	4
	B	8
	C	8
	D	5

2.1.1 COLD AND HOT ROD CONTROL SYSTEM TESTING

During the post core loading test sequence, major tests of the rod control system were performed under four different sets of RCS conditions:

1) Cold, no flow (<200^{O}F, >350 psig)

2) Cold, full flow (<200^{O}F, >350 psig)

3) Hot, full flow (>551^{O}F, 2235 $\pm$25 psig)

4) Hot, no flow ($\geq$500^{O}F, 2235 $\pm$25 psig)

The cold, no flow and hot, full flow tests performed checks of CRDM operation and of rod position indication, verified rod movement over the entire range of travel, verified proper slave cycler timing (cold, no flow only) and determined the rod drop time for each individual rod. The effectiveness of the thimble dashpot region for decelerating the control rod was verified during each rod drop. The cold, full flow and hot, no flow tests measured rod drop times and verified thimble dashpot effectiveness only.

The initial testing performed was the slave cycler timing. One rod in a power cabinet was withdrawn to 54 steps and coil current traces (lift coil, movable gripper coil and stationary gripper coil) were taken during a six step withdrawal and a six step insertion sequence. The rod was then inserted to rod bottom and the process was repeated until one rod in each power cabinet (five) had been tested. Each slave cycler operated satisfactorily.

The remaining testing was done by rod bank. For the cold, full flow and hot, no flow testing, only those steps necessary to measure the rod drop times were performed.

Each rod bank was withdrawn to 54 steps while taking rod position indication data at intermediate points. At 54 steps, each rod was individually withdrawn 6 steps and inserted 6 steps while recording coil currents. An additional 4 step withdrawal, 4 step insertion trace was taken for Westinghouse evaluation. These traces were used to determine that CRDM operation was satisfactory.

When coil current traces had been collected for each rod in the test bank, the bank was withdrawn to 228 steps while taking rod position data at intermediate points. Test equipment was then setup to monitor stationary gripper coil current and digital rod position indication (DRPI) coil output. Each rod was dropped individually by pulling the movable gripper coil fuse and then pulling a stationary gripper coil fuse while taking a visicorder trace. These traces were used to determine the drop time for each rod and the effectiveness of the thimble dashpot region to decelerate

the dropped rod.

After all rods in the test bank had been dropped, the bank was withdrawn to 228 steps and then inserted until the rod bottom LED's energized to demonstrate satisfactory operation over the entire range of travel (withdrawal and insertion).

This procedure was then repeated for each Rod Bank (control and shutdown) until all banks had been tested under the applicable test conditions. After all the rods had been dropped, the standard deviation (sigma) was determined and any rod having a drop time outside a ± two-sigma limit was dropped six additional times to ensure performance reliability during subsequent operation.

The following test results were obtained from this series of tests:

1) The slave cycler for each rod control system power cabinet functioned satisfactorily during control rod withdrawal and insertion operations,

2) CRDM operability was demonstrated at cold, no flow and hot, full flow conditions. All CRDM's operated satisfactorily,

3) The performance of the DRPI system was demonstrated at cold, no flow and hot, full flow conditions. The DRPI system and related rod position indications satisfied all acceptance criteria,

4) All rods operated satisfactorily when withdrawn and inserted over their entire range of travel at both cold, no flow and hot, full flow conditions,

5) The rod drop times for each individual full-length shutdown and control rod were less than 2.2 seconds under all test conditions: cold, no flow; cold, full flow; hot, full flow; hot, no flow. The rod drop times are summarized in Table 2.1.1-1,

6) During cold, full flow rod drop testing, rod D-2 (SBA) was outside the upper two-sigma limit (1.47 seconds) with a drop time of 1.48 seconds. Six additional rod drops were performed with a minimum time of 1.48 seconds and a maximum time of 1.51 seconds. This range of 0.030 seconds was greater than the 0.020 seconds allowable. After engineering evaluation, the drop times for D-2 were determined to be acceptable. The D-2 drop time was within the two-sigma limit for the remaining two tests at hot plant conditions.

   During hot, full flow rod drop testing rod B-10 (CBB) was outside the lower two sigma limit (1.33 seconds) with a drop time of 1.32 seconds. Rod B-10 was dropped six additional times with drop times of 1.33 to 1.34 seconds,

7) The rod drop traces were consistent with no signs of binding or other abnormalities under all test conditions. The rod deceleration through the thimble dashpot region was similiar for all rods at each set of test conditions. The thimble dashpot region was effective for decelerating the control rod during each rod drop.

TABLE 2.1.1-1
ROD DROP TIME SUMMARY

Rod Drop Time to Dashpot Entry

ROD BANK	CORE Coord.	Cold, No Flow	Cold, Full Flow	Hot, Full Flow	Hot, No Flow
CBA	H-6	1.22	1.44	1.36	1.18
	H-10	1.22	1.45	1.37	1.19
	F-8	1.20	1.43	1.35	1.18
	K-8	1.21	1.46	1.33	1.19
CBB	F-2	1.21	1.44	1.36	1.20
	B-10	1.22	1.40	1.32*	1.20
	K-14	1.21	1.44	1.35	1.20
	P-6	1.21	1.43	1.36	1.21
	B-6	1.19	1.42	1.36	1.21
	F-14	1.20	1.41	1.35	1.20
	P-10	1.20	1.41	1.36	1.21
	K-2	1.22	1.44	1.37	1.22
CBC	H-2	1.21	1.43	1.37	1.21
	B-8	1.22	1.44	1.35	1.20
	H-14	1.20	1.45	1.34	1.20
	P-8	1.21	1.41	1.34	1.21
	F-6	1.21	1.42	1.37	1.21
	F-10	1.21	1.44	1.37	1.20
	K-10	1.22	1.43	1.36	1.19
	K-6	1.22	1.44	1.38	1.22
CBD	D-4	1.22	1.44	1.35	1.21
	M-12	1.20	1.43	1.35	1.21
	D-12	1.21	1.41	1.34	1.20
	M-4	1.21	1.43	1.35	1.23
	H-8	1.20	1.45	1.37	1.19
SBA	D-2	1.19	1.48*	1.36	1.21
	B-12	1.18	1.40	1.35	1.19
	M-14	1.20	1.44	1.36	1.20
	P-4	1.21	1.42	1.39	1.21
	B-4	1.19	1.44	1.33	1.20
	D-14	1.19	1.45	1.38	1.21
	P-12	1.18	1.41	1.36	1.22
	M-2	1.20	1.46	1.39	1.22

TABLE 2.1.1-1 (Cont)
ROD DROP TIME SUMMARY

Rod Drop Time to Dashpot Entry

ROD BANK	CORE Coord.	Cold, No Flow	Cold, Full Flow	Hot, Full Flow	Hot, No Flow
SBB	G-3	1.21	1.44	1.36	1.22
	C-9	1.22	1.43	1.34	1.2Ø
	J-13	1.2Ø	1.44	1.36	1.2Ø
	N-7	1.2Ø	1.43	1.36	1.22
	C-7	1.2Ø	1.4Ø	1.34	1.19
	G-13	1.2Ø	1.43	1.36	1.19
	N-9	1.19	1.41	1.36	1.2Ø
	J-3	1.2Ø	1.44	1.38	1.23
SBC	E-3	1.19	1.43	1.34	1.22
	C-11	1.2Ø	1.41	1.33	1.2Ø
	L-13	1.19	1.43	1.34	1.21
	N-5	1.2Ø	1.43	1.34	1.23
SBD	C-5	1.2Ø	1.42	1.36	1.22
	E-13	1.19	1.42	1.36	1.2Ø
	N-11	1.19	1.4Ø	1.34	1.21
	L-3	1.21	1.44	1.39	1.23
SBE	H-4	1.21	1.42	1.35	1.21
	D-8	1.19	1.4Ø	1.36	1.22
	H-12	1.21	1.46	1.36	1.2Ø
	M-8	1.22	1.42	1.35	1.23
Average		1.2Ø	1.43	1.36	1.21

*Redropped six times

The following problems were encountered during the performance of these test procedures:

1) During withdrawal of CBD, DRPI indication for Rod K14 was lost. Detector encoder card A4Ø6 in DRPI Data Cabinet A was found to be defective and was replaced (cold, no flow test),

2) During withdrawal of CBD, computer indication of rod position remained at zero. A power supply in cabinet RJØ48 was found powered down for investigation of an unrelated problem causing the zero indication on the computer. The computer data was collected after the power supply was energized (cold, no flow test),

3) During withdrawal of SBC, demand position as displayed by the computer indicated zero when all other indications were 18 steps withdrawn. During investigation, the group step counter for SBC would not increment/decrement during rod movement. The following items were corrected during the investigation:

   a) The K19 relay in the Logic Cabinet was found to be sticking and was replaced,

   b) The slave cycler card for shutdown banks C, D and E (Power Cabinet SCDE) had failed and was replaced,

   c) The A & B DRPI coil cables for rod C11 were interchanged at the Reactor Vessel head connections. These cables were reconnected in their correct locations,

   d) A cable was found terminated in RJØ49 instead of RJØ48. Since this termination was correct per the scheme drawings, a Temporary Modification was used to correct the termination. The Temporary Modification was later made permanent.

The required rod position indication was then collected when SBC was withdrawn for rod drop testing (cold, no flow test).

2.1.2 ROD CONTROL SYSTEM TEST

Prior to initial criticality, the full length rod control system was tested to verify satisfactory performance of the required control and indication functions and to verify that a manual rod block prevents manual withdrawal of the full length control rods. All the acceptance criteria of the test were met.

This final operational check was performed by rod bank. Each rod bank was withdrawn to either 18 steps (shutdown banks) or 48 steps (control banks) while monitoring proper operation of the group step counters, individual rod position indication (DRPI), rod speed indication and the console indicating lights. A set of rod position indication data (DRPI) was then taken. Each group in the withdrawn bank was individually put on the DC hold bus and the fusible disconnects for the appropriate power cabinet were opened. After verifying that rod position did not change, the fusible disconnects were closed and the DC hold switch for the rod group under test was returned to the off position. The bank was then inserted to the zero step condition (rod bottom). This process was repeated until all rod groups had been checked on the DC hold bus. The DC hold bus performed satisfactorily for all rod groups. No problems were noted with Rod Position Indication or any other control or indication function.

Bank overlap was checked using overlap setpoints that allowed the control banks (CBA, CBB, CBC, CBD) to be withdrawn in MANUAL to approximately 30 steps. After the overlap and rod position data had been collected, the control rods were inserted in MANUAL to verify that the bank overlap function worked satisfactorily. The bank overlap system functioned to start and stop the control banks (CBA, CBB, CBC, CBD) at the correct setpoints.

A manual rod withdrawal block was simulated by lifting the lead of cable 5SFS10AH at TP-PP-16 in RP040. An attempt was then made to withdraw Control Bank A in MANUAL. Control Bank A did not withdraw. The lead was then relanded and the ability to withdraw Control Bank A was demonstrated.

2.2 INCORE MOVABLE DETECTOR SYSTEM

The Incore Movable Detector System or Flux Mapping System is designed to provide a three-dimensional reactor core power profile through the use of movable fission chambers (neutron detectors) being moved axially in radial positions throughout the core. By placing the detectors into selected positions within the core, detector currents are provided and stored. This data is then processed yielding necessary information for reactor core surveillance.

The Flux Mapping System consists of two major items: a flux mapping console and a detector drive system. The detector drive system consists of four (4) trains each providing a mechanical means of routing a detector into any one of 58 guide thimbles in the reactor core. The guide thimble positions are shown in Figure 2.2-1. Each detector is routed through a 6-path transfer device, a 15-path transfer device, and the seal table before reaching the guide thimble. Via the 6-path transfer device, each detector is capable of accessing another train's 15-path transfer device. The Flux Mapping Console provides a means of remotely controlling the detector drive system including all the drive units and transfer devices. Two identical sections within the flux mapping console provides backup capability should one of the sections fail. The detector currents, which are a measure of neutron intensity, and therefore core power, is reported to a CRT, printer, floppy disk, and the Westinghouse P2500 plant process computer.

After core loading, the guide thimbles were inserted in the core and final installation of the detector drive system was completed.

The operation of the system was verified in two parts:

1) The operability of the detector drive system was demonstrated.

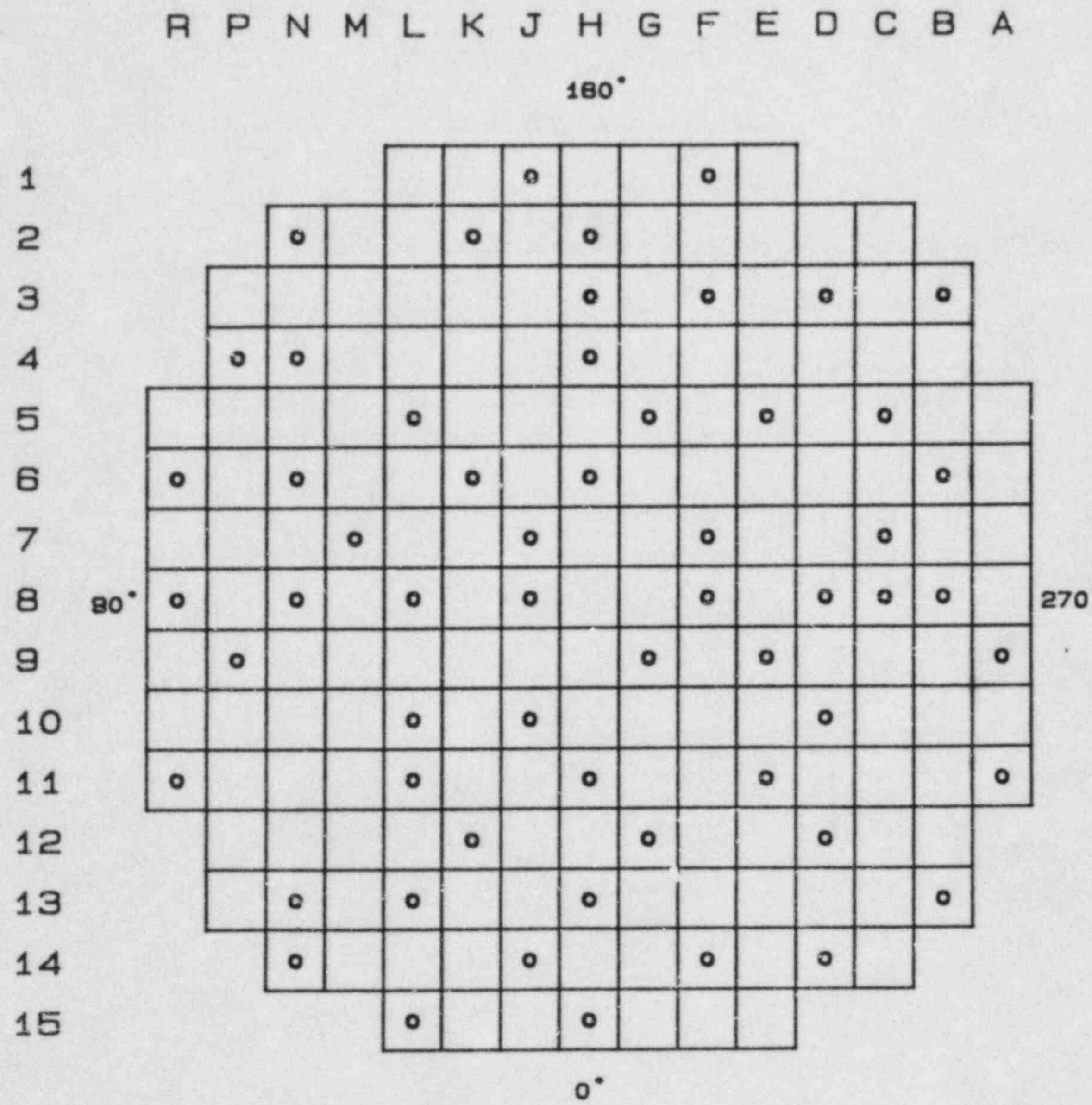
2) The operability of the integral Flux Mapping System using the remotely stationed flux mapping console was demonstrated.

OPERABILITY OF DETECTOR DRIVE SYSTEM

The checkout of the drives and transfer mechanisms was done using a manual controller operated locally, and four dummy detectors (detector shaped but without co-axial output cable and fission chamber). Each one of the four detectors was run into all thimble combinations for that drive and the safety mechanisms were checked with regard to transfer rotation with a detector inserted and winding of retracted detectors onto the takeup reel. The path length of each thimble combination was measured to give an initial path limit value for subsequent checkout of the integral system. Problems were encountered with operation of the portable controller due to printed circuit card failures, but repairs were made to the necessary components to enable its use. Spring tension on the detector takeup reels required adjustment for proper detector withdrawal operation and a flexible braided storage path thimble required replacement. With these problems corrected, checkout of the detector drive system was successfully completed.

FIGURE 2.2-1

MOVABLE DETECTOR LOCATIONS



o Movable Detector (58)

OPERABILITY OF THE FLUX MAPPING SYSTEM

The checkout of the integral system was done from the flux mapping consoles inside the control room. The menu driven consoles consist of the input computer terminal, printer, floppy disc unit, and data link to NSSS computer. The two redundant consoles were tested for all modes of operation. Initial checkout of the system was accomplished using the four dummy detectors to verify the thimble path lengths for all detector path combinations. Following path length verification, the dummy detectors were replaced with the operating fission chambers. During the checkout, numerous computer card failures were encountered which were corrected by card replacement or card/chassis reseating. Several problems with detector drive motors not being de-energized when the detector position encoder indicated no detector motion were corrected by adjustment of controlling relays. Problems with data link failure to the Westinghouse P2500 process computer were corrected by giving flux mapping a higher priority level on the computer system. Due to system failures, it was not possible to verify all four detectors could individually obtain a full flux map from all 58 thimbles. However, it was shown that the system could be used to insert any one of the four detectors in any of the 58 thimbles. Subsequent work on the flux mapping system verified the integral flux mapping system functioned as designed.

During flux mapping in the power ascension program, the top of fuel and path length limits were revised based on grid strap data depressions to give proper detector position/core height correlation. Initial flux maps were run using only two detectors for a full flux map due to detector/computer card failures, but the necessary data for flux map analysis was obtained. Card contacts and failures continued to be a source of problems during subsequent flux maps but reseating and/or replacement of the questionable cards enabled use of all four detectors during the test program.

2.3 PRESSURIZER CONTINUOUS SPRAY FLOW SETTING AND PRESSURIZER HEATER AND SPRAY CAPABILITY TESTS

The reactor coolant system pressurizer establishes primary plant pressure by maintaining a saturated liquid and vapor environment in the pressurizer at the desired pressure. Activation of the two spray valves in the spray lines from two RCS cold legs to the pressurizer and immersion heaters within the pressurizer acts to control saturation pressure, thereby controlling RCS pressure. The continuous spray bypass valves are in parallel with the power operated spray valves. These valves provide a small continuous spray flow to warm the pressurizer spray lines and nozzle in order to limit thermal stresses when the spray valves actuate and to assure that the boron concentration in the pressurizer is not dissimilar from that in the reactor coolant loops.

PRESSURIZER CONTINUOUS SPRAY FLOW SETTING

This test was performed to establish a setting for the pressurizer continuous spray throttle valves to obtain an optimum continuous spray flow and to establish the setpoint for the pressurizer spray line low temperature alarms. Each continuous spray throttle valve was opened in discrete increments while monitoring pressurizer spray line temperature. Spray line temperature was allowed to reach equilibrium prior to opening the valve further. Equilibrium spray line temperature was plotted against valve turns open. The continuous spray throttle valves were set at the break point on the curve where further valve opening had a minor effect on equilibrium spray line temperature.

Valve	Setting	Equilibrium Spray Line Temperature
BB-VØ82	5 1/4 turns open	535°F
BB-VØ83	5 turns open	532°F

The spray line low temperature alarm bistables were set at 1Ø $\pm$ 5°F below the equilibrium spray line temperatures.

Bistable	Setpoint
TB-451	521°F
TB-452	521°F

A review of the RCS chemistry data demonstrated that the new settings for the continuous spray throttle valves assured that the boron concentration in the pressurizer was not dissimilar from that in the RCS. The completion of this test satisfied an outstanding test discrepancy from the Preoperational Hot Functional Test Program.

PRESSURIZER HEATER AND SPRAY CAPABILITY TEST

The purpose of this test was to determine the rate of pressure reduction caused by the opening of both pressurizer spray valves and the rate of pressure increase caused by the operation of all the pressurizer heaters.

While at hot, no-load conditions (557^{O}F, 2235 psig), the pressurizer spray valves were opened fully. Pressurizer pressure, pressurizer level, pressurizer water temperature and spray line temperatures were recorded on a strip chart recorder. The transient was stopped when pressurizer pressure had fallen to approximately 2000 psig by shutting the pressurizer spray valves and the RCS was returned to 557^{O}F, 2235 psig. The results of this transient are shown as Figure 2.3-1.

While monitoring the same parameters as in the spraydown test, the pressurizer heaters were tested by energizing both banks of backup heaters and injecting a full demand signal to the control heaters. When pressurizer pressure reached 2300 psig, the pressurizer heaters were secured and the RCS was returned to 557^{O}F, 2235 psig. The results of this transient are shown as Figure 2.3-2.

The pressurizer response to the opening of the pressurizer spray valves PCV455B and PCV455C was within the allowable range as shown on Figure 2.3-1. However, an engineering evaluation of the data determined that both spray valves should open within 5 seconds.

An additional test section was written and performed to determine the stroke time from full closed to full open for the pressurizer spray valves at 557^{O}F, 2235 psig. The opening times were:

Valve	Opening Time
PCV 455B	3.9 seconds
PCV 455C	6.97 seconds

An additional engineering evaluation, determined that these opening times in conjuction with the previously determined pressure decrease rate were acceptable.

The pressurizer response to actuation of all pressurizer heaters was within the allowable bands as shown on Figure 2.3-2 indicating an acceptable response.

FIGURE 2.9-1

NOMINAL PRESSURE RESPONSE TO OPENING OF

BOTH PRESSURIZER SPRAY VALVES

(With Allowable Band)

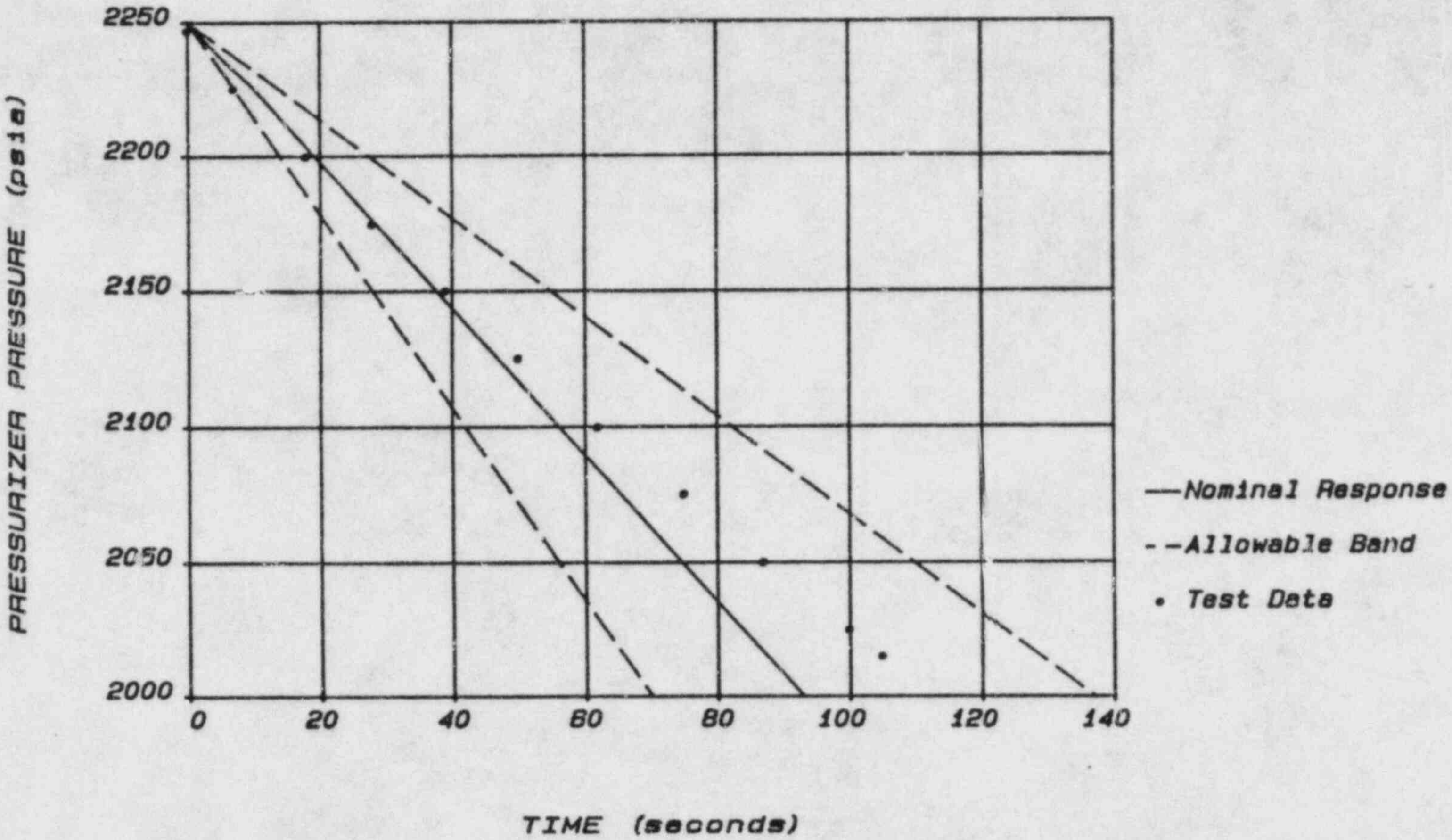
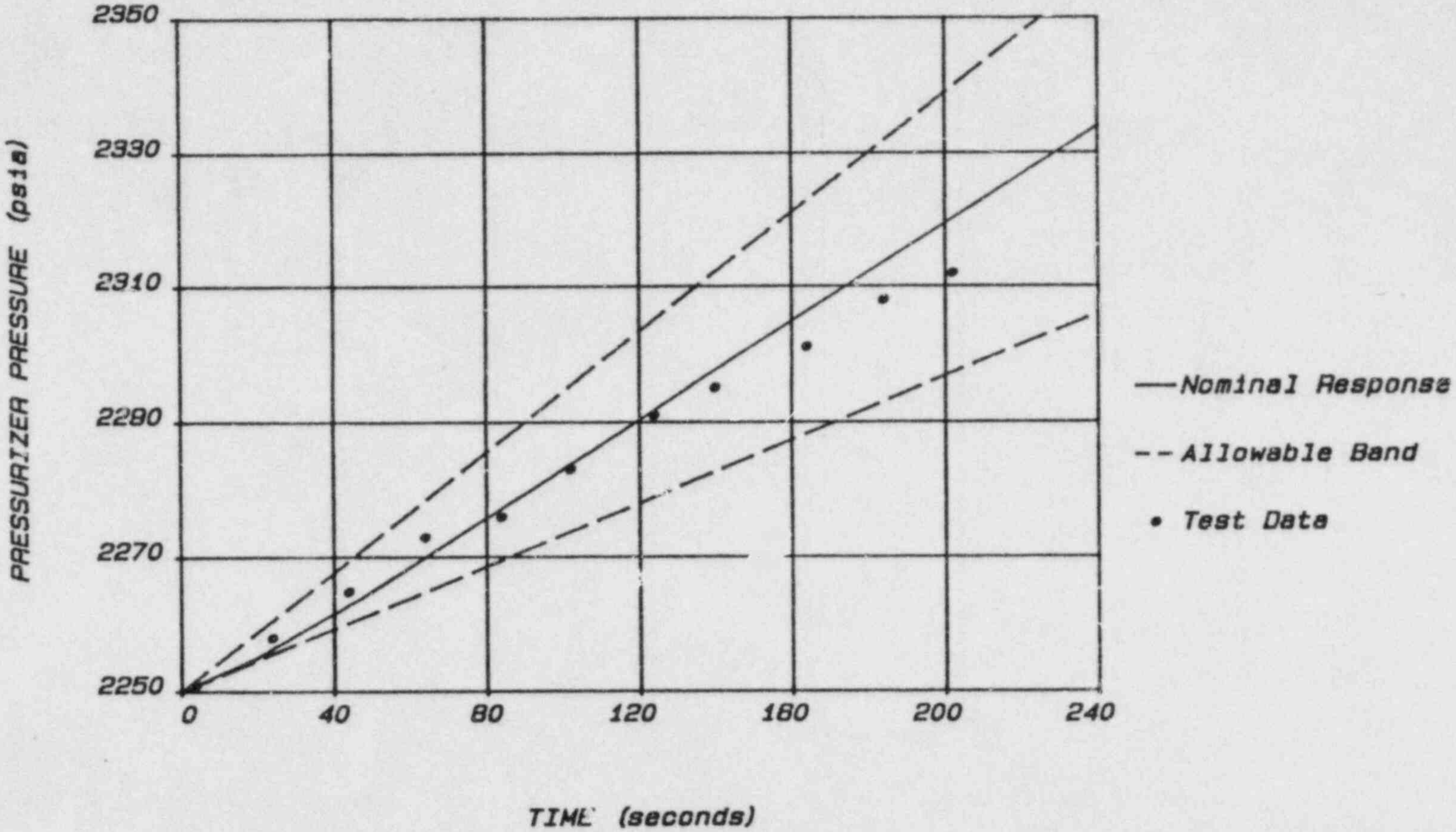


FIGURE 2.3-2

PRESSURIZER RESPONSE TO ACTUATION

OF ALL PRESSURIZER HEATERS

(With Allowable Band)



2.4 REACTOR COOLANT SYSTEM FLOW MEASUREMENT

Reactor Coolant System (RCS) flow indication is obtained from measurement of the differential pressure across the RCS coolant loop piping elbow which connects the steam generator piping and the reactor coolant pump suction (cross-over eg). Each RCS loop has three differential pressure flow transmitters which provide visual flow indication in the control room, flow information to the plant computer, and voltage signals to the protection system for the loss of flow reactor trip. This test was performed at hot, no-load conditions (557 $\pm$ 2^{o}F, 2235 $\pm$ 15 psig) to determine that RCS flow, as indicated by the loop elbow differential pressures, was equal to or greater than 90 percent of the thermal design value.

With four reactor coolant pumps (RCP's) operating and the plant at the required steady state conditions, data was collected from the plant computer and the main control board indicators. This data was then averaged and converted to gpm. The total flow as determined from the plant computer was 435,221 gpm as compared to the minimum required flow of 344,520 gpm. The results are shown in Table 2.4-1.

As a result of this test, the twelve differential pressure flow transmitters were adjusted to indicate 100% flow at hot no-load conditions and four RCP's operating. Verification that RCS flow rate is greater than or equal to the thermal design flow rate using calorimetric data was done during the power ascension phase of the Startup Test Program and is discussed in Section 4.4.1 of this report.

TABLE 2.4-1
RCS LOOP FLOW DETERMINATION
PRIOR TO INITIAL CRITICALITY

	Plant Computer		Main Control Board Indicator	
	Percent	GPM	Percent	GPM
RCS Loop 1	110.3	108,999	111.0	109,668
RCS Loop 2	110.1	108,749	109.8	108,515
RCS Loop 3	109.1	108,594	110.0	108,680
RCS Loop 4	110.2	108,878	110.3	109,009
Total Flow	-	435,221	-	435,873

Acceptance Criteria, Total Flow $\geq$ 344,520 gpm

2.5 REACTOR COOLANT SYSTEM FLOW COASTDOWN TEST

This test was performed to measure the rate at which reactor coolant flow changes subsequent to a simultaneous trip of all four reactor coolant pumps and to determine the reactor coolant system low-flow reactor trip time delay.

While operating at hot, no-load conditions, the permissive P-8 was simulated by lifting leads in the nuclear instrumentation cabinets. This ensured that low flow ($\leq$90%) in one reactor coolant loop would open the reactor trip breakers. Reactor coolant system flow, reactor coolant pump breaker status and reactor trip breaker status was recorded on a high speed chart recorder. The four reactor coolant pumps were then simultaneously tripped by simulating an underfrequency condition with a test circuit installed in the safeguards test cabinet (SB-030).

The chart recorder trace was analyzed to determine normalized loop flow fractions at discrete points in time following the RCP trips. At each time, the loop flow fractions for all four loops were averaged to determine the core flow fraction. The relationship:

$$F'(t) = \left(\frac{1}{F(t)}\right)^{0.895} - 1$$

where F(t) = core flow fraction

was then used to determine F'(t) (the inverse flow fraction) for each second during the first ten seconds following the reactor coolant pump trip. Using the method of least squares, F'(t) was fit as a function of time for the period of 2 seconds through 10 seconds:

$$F'(t) = At + B$$

where A = slope
B = Y-intercept

The Westinghouse acceptance criterion for the flow coastdown was:

$$TAU_M = \frac{1}{A} = \text{Flow Coastdown Parameter}$$

$$TAU_M > 11.70 \text{ seconds}$$

The test data TAU_M was 12.56 seconds which was satisfactory. Table 2.5-1 summarizes these calculations.

The chart recorder data was also used to determine the low flow reactor trip time delay. The loop inverse flow fractions were least squares fit for a period from three to ten seconds following the reactor coolant pump trip. The least squares fitting parameters were then used to calculate the sensor delay time for each loop:

$$f' = 1/f$$

where f = loop flow fraction

$$f'(t) = At + B$$

TABLE 2.5-1
FLOW COASTDOWN RATE CALCULATIONS

Time (sec)	Core Average Flow Fraction (F(t))	$F'(t) = \left(\frac{1}{F(t)}\right)^{0.895} - 1$
0	1.0	0
1	0.945	0.052
2	0.873	0.129
3	0.807	0.212
4	0.749	0.295
5	0.699	0.378
6	0.660	0.450
7	0.619	0.536
8	0.588	0.608
9	0.566	0.691
10	0.529	0.768

Method of Least Squares used to fit data:

$$F'(t) = At + B$$

A = slope   B = Y - intercept
A = .0796   B = .0258

TAU_M = Flow Coastdown Parameter

$= \frac{1}{A}$

= 12.56 seconds

Westinghouse acceptance criterion $TAU_M > 11.70$ seconds

NOTE: Data fit for period from 2 through 10 seconds.

$$\text{Sensor delay time} = T_D = \frac{(1 - B)}{A}$$

The longest sensor delay time was 0.533 seconds in loop 4. Combining the sensor delay time (T_D) with the time from when the first loop flow decreased to the low-flow trip setpoint (90%) until the second reactor trip breaker had opened (T_1 = 0.109 seconds) and the gripper release time (Tg = 0.15 seconds) yielded a low-flow reactor trip time delay of 0.792 seconds. The Westinghouse acceptance criterion was less than or equal to 1.0 seconds, therefore the results were satisfactory. Table 2.5-2 summarizes these calculations.

The results of this test confirmed, based on the Westinghouse acceptance criteria, that the flow coastdown following a trip of all four reactor coolant pumps is adequate to prevent the departure from nucleate boiling ratio (DNBR) from decreasing below the limiting value of 1.3.

TABLE 2.5-2
LOW-FLOW REACTOR TRIP TIME DELAY
CALCULATIONS

Time (sec)	Loop Inverse Flows (1)			
	Loop 1	Loop 2	Loop 3	Loop 4
0	1.0	1.0	1.0	1.0
1	1.058	1.056	1.065	1.055
2	1.139	1.136	1.158	1.148
3	1.241	1.236	1.243	1.234
4	1.345	1.327	1.335	1.332
5	1.443	1.412	1.438	1.426
6	1.539	1.502	1.508	1.518
7	1.659	1.574	1.623	1.616
8	1.709	1.679	1.711	1.706
9	1.833	1.742	1.816	1.809
10	1.914	1.880	1.873	1.901
A (2)	0.096	0.089	0.092	0.095
B (2)	0.961	0.967	0.969	0.949
Td (3)	0.406	0.371	0.339	0.533

NOTES:

1. Inverse loop flow = $f' = 1/f$ where f = loop flow fraction
2. A and B are least squares fitting parameters for f' as a function of t : $f'(t) = At + B$. Data is fit from 3 through 10 seconds.
3. T_D = Sensor Time Delay = $(1 - B)/A$

Time from first loop flow at low flow trip setpoint until second reactor trip breaker trips: $T_1 = 0.109$ sec

Maximum sensor delay time: $T_D = 0.533$ sec

Gripper release time (from rod drop data): $T_G = 0.15$ sec

Low-flow reactor trip time delay $(T_1+T_D+T_G)$: $T_{LF} = 0.792$ sec

Westinghouse acceptance criterion: $T_{LF} \leq 1.0$ seconds

2.6 RTD BYPASS FLOW MEASUREMENT

Each loop in the RCS contains a loop bypass manifold in which resistance temperature detectors (RTD's) are placed to monitor hot and cold leg temperatures. Signals from the temperature detectors are used to compute the reactor coolant delta T (temperature of the hot leg, T_{HOT}, minus the temperature of the cold leg, T_{COLD}) and an average reactor coolant temperature (Tavg). This information is used by the reactor protection system as well as the process instrumentation system.

The manifolds for the cold leg temperatures draw a sample from the RCS flow at the reactor coolant pump discharge. The manifolds for the hot leg temperatures draw samples from RTD scoops in the reactor vessel outlet piping. The bypass lines join downstream of each set of temperature detectors (hot and cold) and discharge into a common line. The combined bypass flow passes through a flow element before discharging into the suction side of the reactor coolant pump.

The purpose to this test was to measure the RTD bypass flow rate in each loop to ensure transport times of less than or equal to one second through the loops. The one second transport time was a design parameter for the overall RTD time response. The following combinations of flows were measured:

1) The combined hot and cold leg bypass flow rate was measured,

2) The cold leg bypass flow rate was measured with the hot leg isolated,

3) The hot leg bypass flow rate was measured with the cold leg isolated.

New low flow alarm setpoints were calculated at 90 percent of the total bypass flow for each loop. Since the sum of the individual hot and cold leg bypass flows with the other leg isolated was greater than the measured total bypass flow, a correction was applied to obtain the actual flows based on the ratio of the measured hot and cold leg bypass flows. Table 2.6-1 summarizes the results and shows that the calculated bypass flows are greater than that required for a one second transport time through the bypass loops. In addition, with total bypass flow at the low flow alarm value of 90% and cold leg flow at its normal value, the hot leg flow still has a transport time less than 1 second.

The new low flow alarm setpoints were incorporated into the Wolf Creek Generating Station Total Plant Setpoint Document (TPSD). The completion of this test satisfied an outstanding test discrepancy from the Preoperational Hot Functional Test Program.

TABLE 2.6-1
RTD BYPASS FLOW MEASUREMENT RESULTS

Loop No.	Total Bypass Loop Flow (gpm)	Calculated Low Flow Alarm Setpoint (gpm) (1)	Leg	Minimum Required Flow (gpm) (2)	Measured Flow	Calculated Flow	Calculated Flow Hot Leg Bypass at Low Flow Alarm Setpoint (3)
1	265	238.5	Hot	103.43	155	146.7	120.2
			Cold	67.62	125	118.3	-
2	265	238.5	Hot	103.43	155	149.4	122.9
			Cold	67.62	120	115.6	-
3	295	265.5	Hot	103.43	185	176.0	146.5
			Cold	67.62	125	119.0	-
4	282	253.8	Hot	113.88	178	168.4	140.2
			Cold	67.62	120	113.6	-

Notes:

(1) 90 percent of total bypass flow

(2) Based on actual pipe volumes and one second transport time

(3) Total Bypass Flow at 90%, cold leg flow constant

2.7 PRELIMINARY DATA COLLECTION FOR INSTRUMENT CALIBRATION

While operating at hot, zero power conditions prior to initial criticality several preliminary data collection procedures were performed for procedures that were to be performed during the Power Ascension portion of the test program. The calibration procedures are discussed in more detail in Section 4 of this Startup Test Report.

An alignment was performed of the delta T and Tavg process instrumentation at hot isothermal conditions (557 $\pm 2^{o}$F). Using test cards, known resistances were input into RCS loop T_{HOT} and T_{COLD} instrument loops and the loop outputs were verified as well as delta T. Then at hot isothermal conditions actual instrument loop outputs were recorded. RCS spare T_{HOT} and T_{COLD} outputs were compared to the normal instruments with satisfactory results. Overtemperature delta T and overpressure delta T setpoints were also verified.

Data was collected for those components which are used to develop the rod speed control signals. This procedure was performed with four RCP's operating and the RCS at 557 + Ø,-5^{o}F and 2235 $\pm$25 psig. Parameters monitored for each loop were T_{HOT}, T_{COLD}, Tavg, Feedwater Flow, Steam Generator Pressure, Turbine Impulse Pressure, and in addition, auctioneered NIS power, auctioneered Tavg and T_{REF} were also monitored.

Test instrumentation was installed to monitor feedwater flow and steam generator pressure during later tests. In addition, the zero of the steam flow and feedwater flow transmitters was verified at the process cabinets while the plant was in hot standby conditions. With the steam generator isolated, the transmitter voltages were measured at the process cabinets to ensure no zero shift. One transmitter, AB-FT-542, had to be replaced because of static pressure shift.

2.8 NUCLEAR INSTRUMENTATION SYSTEM

The nuclear instrumentation system (NIS) was tested to verify that all voltage settings, trip settings, and alarm settings in the NIS were within expected tolerances and that all ranges were functioning properly. This was accomplished by completing a series of instrument and control channel calibration surveillance procedures written specifically to ensure the NIS is operable in accordance with Technical Specifications.

A total of twelve separate procedures were performed to complete this verification. One test was performed on each individual source range, intermediate range and power range drawer. The scaler timer and audio count rate drawer, comparator and rate drawer and the flux deviation and miscellaneous controls drawers were also checked out. No major problems or deficiencies were found during any of this testing.

A more detailed summary of all testing on the nuclear instrumentation system is given in section 4.4.3.

2.9 RTD/TC CROSS CALIBRATION TESTS

The purpose of this test procedure was to provide a functional check out of the reactor coolant system resistance temperature detectors (RTD's) and the incore thermocouples (TC's) and to generate isothermal cross calibration data for subsequent determination of individual RTD installation correction factors.

The test was performed at four different temperature plateaus: 250°F, 345°F, 450°F and 557°F (within $\pm$5°F). At each temperature plateau, RTD resistances were read directly at the field wires using test boxes with multiposition switches and a digital voltmeter. Concurrently, TC readouts were obtained from the plant computer, and steam generator saturation pressures were obtained from temporary test gauges installed on the main steam lines. The RTD resistances were then converted to temperatures using vendor curves; the saturation pressures were converted to temperatures using the ASME Steam Tables, and the TC temperatures were averaged. All of these temperatures were compared and isothermal correction factors were calculated.

The initial performance of this test commenced on April 16, 1985 and was essentially complete on April 30, 1985. The results are summarized in Table 2.9-1. The acceptance criteria for this test were:

1) All converted average RTD temperatures were within $\pm$2°F of the calculated RCS average temperature for the given temperature plateau.

2) All average steam saturation temperatures for each temperature plateau were within $\pm$2°F of the calculated RCS average temperature.

3) All thermocouple average temperatures for each temperature plateau are within $\pm$2°F of the calculated RCS temperature.

All acceptance criteria were met except for the steam saturation temperature at the 345°F plateau. Based on the accuracies of the Heise guages used to determine the steam pressure ($\pm$1.5 psi) and the consistency of the RTD average, this was determined to be acceptable.

Although acceptance criteria were met, as discussed above, during the initial performance of the test, further investigation of the data by Westinghouse resulted in a decision to repeat the cross-calibration test. The main concern was whether the RCS was in a truly steady state or isothermal condition when the initial data was collected. In the second performance of this test, additional precautions were taken to achieve the highest degree of steady state and isothermal conditions in the RCS. In addition, data was collected with the RTD-manifold-return valves in both the closed and the open position. The normal configuration is with the RTD-manifold-return valves open but Westinghouse determined that closing the valves would result in exposing both hot-leg and cold-leg narrow range RTD's to water at a single temperature thereby giving better test data.

TABLE 2.9-1
RESULTS OF INITIAL RTD/TC CROSS CALIBRATION TEST

RTD No.	Calculated Installation Correction Factors, ^{O}F			
	$250^{O}F$	$345^{O}F$	$450^{O}F$	$557^{O}F$
TE-410A	-0.5	0.0	-0.1	-0.1
TE-410B	-0.7	-0.4	-0.1	-0.3
TE-411A	-0.5	-0.1	-0.2	-0.1
TE-411B	-0.7	-0.3	-0.1	-0.3
TE-413A	-0.1	0.4	0.3	0.3
TE-423A	0.5	0.6	0.6	0.7
TE-433B	0.3	0.2	0.3	0.3
TE-443B	-0.3	0.0	0.2	-0.3
TE-430A	0.4	0.4	0.5	0.0
TE-430B	0.2	-0.5	-0.3	0.1
TE-431A	0.5	-0.5	-0.5	0.1
TE-431B	0.3	-1.4	-1.1	0.1
TE-420A	0.2	-0.2	-0.5	-0.1
TE-420B	0.0	-0.3	-0.2	0.1
TE-421A	0.2	-0.1	-0.3	-0.1
TE-421B	0.1	-0.3	-0.1	0.1
TE-413B	-0.4	0.1	0.3	0.1
TE-433A	0.6	0.4	0.5	0.3
TE-440A	0.0	-0.4	-0.8	-0.2
TE-440B	-0.2	0.1	0.3	-0.4
TE-441A	0.0	0.7	0.7	0.0
TE-441B	-0.2	0.9	0.9	-0.8
TE-423B	-0.1	-0.3	0.0	0.3
TE-443A	0.3	0.4	0.4	0.2
Avg RTD Temp. ^{O}F	248.3	340.7	447.3	556.8
Steam Sat Temp ^{O}F	248.6	339.4	444.8	556.0
T = $_{RTD}$ - T_{SAT} ^{O}F	-.3	1.3	2.5	0.8
Avg TC Temp ^{O}F	249.8	342.3	447.6	556.7
T = T_{AVG}-T_{TC} ^{O}F	-1.5	-1.6	-0.3	0.1

After reducing power from 30%, this second test was performed on June 30, 1985. Data was collected at 375°F, 450°F and 557°F with the RTD-manifold-return valves both open and shut. The results of the second test are summarized in Table 2.9-2. The acceptance criteria remained the same for this test with the exception of:

1) All converted average RTD temperatures were within ±1.7°F of the calculated RCS average temperature for the given temperature plateau (±2.0°F in the initial test).

In all cases, this more stringent acceptance criterion was met (TE-413B was 1.7°F at the 375°F plateau with the RTD bypass return valves open). For both the 450°F plateau cases, the average TC temperature was more than 2.0°F less than the average RTD temperature (closed - 2.4°F, open - 2.8°F). This was determined to be acceptable since the instrument accuracy of the thermocouple is ±5°F. At the 375°F plateau with RTD bypass return valves open, T_{SAT} was 2.2°F. A review of the data showed that this may have been caused by a slight non-isothermal condition in the RCS. Since T_{SAT} was in specification for the remaining six cases, this was determined not to be a problem.

The value of obtaining data with the RTD manifold return valves closed was highly questionable. Note for example the 375°F data for the loop 1 RTD's. The two hot leg RTD's (-410A and -411A) were cooler than the average by 0.4°F and 0.6°F, respectively, while the two cold leg RTD's (-410B and -411B) were higher in temperature than the RCS average temperature. For the open-manifold case, this trend was reversed. In general, the quality of the data for the open-manifold case was better than that of the closed-manifold case.

The scatter in data (indicated by large installation correction factors) appears to decrease at the higher temperature plateaus. This could have been due to several factors, two of the most likely being:

1) A higher degree of isothermal conditions were obtained at the higher temperatures.

2) The RTD calculations are more accurate at higher temperatures.

In general, the test was satisfactorily completed. The most important acceptance criterion (individual RTD temperatures not different by more than 1.7°F from the average) was satisfied for all RTD's at all temperature plateaus for both open and closed manifold cases. Those acceptance criteria not satisfied at all points were determined to be acceptable. The test results were supplied to Westinghouse for possible determination of an improved calibration curve for the RTD's. Completion of this test satisfied an outstanding test discrepancy from the Preoperational Hot Functional Test Program.

TABLE 2.9-2
RESULTS OF SECOND RTD/TC CROSS CALIBRATION TEST

RTD No.	Calculated Installation Correction Factors, ^{o}F						
	$375^{o}F$		$450^{o}F$		$557^{o}F$		
	Valves CL	Valves OP	Valves CL	Valves OP	Valves CL	Valves OP	Valves OP
TE-410A	0.4	-0.2	0.7	-0.1	0.8	0.1	0.2
-410B	-0.2	0.0	-0.3	-0.2	-0.6	-0.4	-0.1
-411A	0.6	-0.3	0.7	-0.1	0.8	0.0	0.2
-411B	-0.1	0.1	-0.1	0.1	-0.3	-0.1	0.3
-413A	-0.2	1.1	0.0	0.3	0.0	0.3	0.5
-423A	0.2	0.4	0.2	0.5	0.1	0.5	0.5
-433B	-0.5	-0.2	-0.3	0.0	-0.5	0.2	0.3
-443B	0.1	0.4	0.0	0.3	-0.3	0.0	0.0
-430A	-0.7	-0.6	-0.2	-0.3	0.1	-0.1	0.0
-430B	-0.9	-0.7	-0.7	-0.5	-0.8	-0.1	-0.1
-431A	-0.5	-0.4	-0.1	-0.3	0.1	-0.1	-0.1
-431B	-1.1	-0.8	-0.8	-0.5	-0.8	-0.2	-0.2
-420A	0.1	-0.7	0.4	-0.4	0.9	-0.1	-0.2
-420B	-0.1	-0.1	-0.2	0.0	-0.3	0.0	-0.2
-421A	0.3	-0.5	0.4	-0.3	0.8	-0.1	-0.2
-421B	0.0	0.1	-0.1	0.1	-0.2	0.0	-0.3
-413B	1.4	1.7	0.6	0.9	-0.1	0.2	0.3
-433A	-0.4	-0.1	-0.1	0.2	-0.2	0.3	0.3
-440A	0.4	-0.3	0.4	-0.2	0.7	0.0	-0.1
-440B	-0.1	0.2	-0.2	0.1	-0.3	-0.2	-0.3
-441A	0.8	0.2	0.6	0.0	0.8	0.1	0.0
-441B	0.2	0.4	-0.3	0.0	–	-0.5	-0.6
-423B	0.3	0.6	-0.4	-0.1	-0.6	-0.1	-0.3
-443A	0.0	0.4	0.1	0.4	0.1	0.3	0.3
Avg RTD Temp	371.9	372.1	449.4	449.7	556.9	556.2	556.6
Steam Sat. Temp	369.9	369.9	448.1	448.0	556.6	555.7	555.4
$T = T_{RTD} - Tsat$	2.0	2.2	1.3	1.7	0.3	0.5	1.2
Ave TC Temp	371.4	370.7	447.0	446.9	555.4	554.4	554.2
$T = T_{RTD} - T_{TC}$	0.5	1.4	2.4	2.8	1.5	1.5	2.4

2.10 THERMOCOUPLE CORE SUBCOOLING MONITOR SYSTEM TEST

The Thermocouple Core Subcooling Monitor System (TCCM) consists of two trains which monitor fifty incore thermocouples, primary system pressure and selected T_{HOT} and T_{COLD} RTD's. The TCCM therefore normally monitors primary system pressure and temperature. More importantly, the microprocessor controlled system will calculate saturation temperature and pressure during an accident condition and will alarm when the margin to saturation is reduced to a preset level and again if the core ever reaches the saturation level.

The purpose of this test was to perform a preoperational type functional checkout of the TCCM. The checkout included verifying all thermocouples were functioning properly and the TCCM LCD displays, alarms, calculations, outputs and printers were working correctly.

With the plant at normal operating temperature and pressure, normal TCCM displays were verified to be functioning properly. Then, in order to be able to change input parameters, normal field inputs were disconnected and a signal injection test box was connected to the TCCM. Only one train at a time was taken out of service for testing so that the other train was always operable. Using the test box, test engineers were able to inject a wide range of normal and abnormal temperature and pressures. This method tested that LCD displays gave proper outputs, calculations performed by the TCCM were correct, alarms activated at the expected setpoints and verified that proper outputs were being sent to the plant computer, analog indicators and the TCCM printers. A final check was performed after the signal test box was removed to ensure all the normal field inputs were reading properly.

During the test, Train B gave some unexpected displays when certain test signals were injected into the system. After troubleshooting, it was discovered part of the A/D converter circuitry was out of calibration. A recalibration of Train B was performed and all the discrepancies were cleared.

During the final verification of normal field inputs, it was discovered some of the thermocouples were not reading properly. Further investigation determined that three thermocouples were defective. Since the plant must be in Mode 6 in order to repair or replace the incore thermocouples, this problem will probably not be corrected until the first refueling. However, since Technical Specifications only require 2 thermocouples per core quadrant to be operable, the system still far exceeds the minimum requirements.

2.11 SPECIAL TEST PROCEDURE FOR THE PRESSURIZER RELIEF VALVES

The pressurizer power operated relief valves (PORV's) are solenoid actuated valves which respond to a signal from a pressure sensing system or to manual control. Motor-operated block valves are provided to isolate each power operated relief valve if excessive leakage develops or if the PORV fails to close. The power-operated relief valves provide the safety-related means for reactor coolant system depressurization to achieve cold shutdown.

During the preoperational hot functional test program, the following discrepancies were noted against the PORV's:

BB-PCV-455A - did not reliably and consistently close when operated from an initially ambient valve body temperature

BB-PCV-456A - did not reliably and consistently close when operated from an initially ambient valve body temperature and leaked through the seat with the result that a water seal could not form in the inlet piping.

The purpose of this test was to test the PORV's after rework and demonstrate satisfactory operation. With RCS pressure at 2235 $\pm$ 15 psig and a water seal formed at the valve inlets, each PORV was tested individually by opening the valve in manual and allowing pressurizer pressure to decrease by 200 psi. The pressurizer heaters were deenergized during the test. The PORV was then closed. RCS pressure was then restored to 2235 psig and the other PORV was tested. A high speed chart recorder was used to monitor valve opening and closing times.

Both BB-PCV-455A and BB-PCV-456A operated satisfactorily. The opening and closing times were within specification and there was no problem with valve closure. There were also no indications of valve seat leakage. The results are shown in Table 2.11-1. This test closed an outstanding test discrepancy from the Preoperational Hot Functional Test Program.

TABLE 2.11-1
RESULTS OF PORV OPENING/CLOSING TEST

Valve	Opening Time	Acceptance Criteria	Satisfactory Closure After 200 psig Pressure Drop *
BB-PCV-455A	0.28 seconds	$\leq$ 2 seconds	Yes
BB-PCV-456A	0.4 seconds	$\leq$ 2 seconds	Yes

*Both BB-PCV-455A and BB-PCV-456A closed in less than 1 second.

2.12 LOOSE PARTS MONITORING SYSTEM

The purpose of this procedure was to obtain baseline data from the loose parts monitoring system after the reactor core had been loaded. With plant conditions at normal operating temperature and pressure (557°F, 2235 psig) and four RCP's in operation, tape recordings of the noise from each of the twelve accelerometers (channels) was obtained. A reference signal was introduced using the installed simulator while recording channels 1 through 4. Decibel levels were also obtained using the installed meter for each of the twelve accelerometers.

Channel 2, which is one of two accelerometers mounted on incore thimble guide tubes at the bottom of the reactor vessel, indicated a high vibration. An alarm was present for vibration and loose parts at the loose parts monitoring panel and the main control panel for channel 2.

After a review of the data by Westinghouse, it was determined that the noise was not characteristic of a loose part. For the following reasons, the noise was suspected to be normal thimble tube vibrations:

1) The noise only occurs on one (1) accelerometer as opposed to both accelerometers at the bottom of the vessel.

2) The noise stops when the RCP's are turned off (lack of full flow).

3) Thimble tube vibration is consistent with qualitative experience at other Westinghouse plants with similar signals.

Based on Westinghouse analysis of the test data and additional monitoring of channel 2 with four RCP's in operation, the alert level alarm for channel 2 was increased from 1.813 volts to 3.0 volts.

3.0 INITIAL CRITICALITY AND LOW POWER TEST SEQUENCE

The initial criticality and low power test segment of the startup program encompassed a number of activities ranging from bringing the reactor critical for the first time to verifying design parameters of the core. An integrated test procedure was used to accomplish these activities. It started by bringing the reactor critical immediately followed by determining the power range to be used for further testing. Nuclear Instrumentation System checkouts were also incorporated into this portion of the test. Control rod bank worths, isothermal temperature coefficients, and boron endpoints were measured for various rod configurations. The worths of the most reactive rod and a pseudo ejected rod were then determined followed by restoration of the reactor to a normal configuration. An additional rod swap test was performed to gather information to be used by the KG&E Nuclear Fuels group. This dealt with swapping shutdown bank B, whose worth was known, with the remaining control rod banks to determine their worth i.e., insert shutdown bank A, withdraw shutdown bank B or vise versa. Data was gathered on site, however, the analysis was done by the fuels group as this test was conducted for information only. A combined effort of KG&E and Westinghouse personnel was utilized to complete this extensive sequence of testing in a timely manner.

It should be noted that natural circulation testing was not performed during the low power test sequence. The performance of this test was committed to by the first SNUPPS unit only as identified on page 640.6-1 of Volume 11 of the Final Safety Analysis Report (FSAR).

On May 22, 1985 at 0745, the plant was brought critical. Immediately following, the zero power physics testing began. All testing within this segment was completed below a power level of 5 percent rated thermal power as allowed by the operating license.

Acceptance criteria used for test results were based on the core design report which was provided by Westinghouse. A summary of the results of the tests performed during this segment of the startup program follows:

1) Isothermal temperature coefficients at CBC and CBD inserted, CBD inserted and the all-rods-out configurations were measured to be within 1.5 pcm/$^{\circ}$F of the expected values thus meeting the acceptance criteria of $\pm$ 3.0 pcm/$^{\circ}$F. A positive moderator temperature coefficient was calculated for the all rods out configuration. Consequently, rod withdrawal limits were developed for use during the first cycle,

2) Control bank worths for control banks A through D were measured to be within 4.0% of the predicted values, well within the acceptance criterion of $\pm$10%,

3) Shutdown Bank worths for shutdown banks C through E were measured to be within 2.6% of the predicted values, well within the acceptance criterion of $\pm$10%,

4) Total rod worth was measured to be within 5.4% of the predicted value meeting the ±10% acceptance criterion,

5) Critical boron concentrations were measured for six different control rod configurations. With the exception of the all-rods-out configuration (ARO), all concentrations met the acceptance criterion

of ±10% of the predicted values. An evaluation of the all-rods-out case yielded no impact on the safety analysis from the critical boron concentration being 3 ppm out of tolerance high,

6) The differential boron worth was measured to be within 0.19 pcm/ppm of the predicted value well within the ±10% acceptance criterion,

7) Core power distributions determined using flux maps were acceptable for the configurations of all-rods-out, CBD-in, hot-zero power insertion limit, and pseudo ejected rod.

3.1 INITIAL CRITICALITY

In preparation for bringing the reactor critical, the Nuclear Instrumentation System source range channels N31 and N32 were verified operational and, within twelve hours of criticality, analog channel operational test surveillance procedures were performed on each of the intermediate and power range channels. Reference counts were obtained for the source range channels using a 132 second interval and ten seperate counting periods for use in ICRR monitoring. The reference counts were 1181 counts for channel N31 and 1300 counts for channel N32.

The initial approach to criticality began at 1032 on May 21, 1985 at which time the reactor coolant system (RCS) boron concentration was 2041 ppm and all control and shutdown banks were fully inserted. Beginning with Bank A, the shutdown banks were withdrawn in 50 step increments stopping to obtain counts for use in plotting inverse count rate ratios (ICRR's). These ICRR plots for rod withdrawal verified the core would not be critical with the next 50 step withdrawal and are illustrated in Figures 3.1-1 and 3.1-2. Rod withdrawal continued with the control banks until control bank D was at 160 steps.

Dilution to criticality began at 2040 on May 21, 1985 with a dilution rate of 60 gallons per minute. Boron concentration in the RCS was determined every 20 minutes. Plots of inverse count rate ratio versus time of dilution, RCS boron concentration, and makeup water addition were made during the approach to criticality in order to predict criticality. These plots are shown in Figures 3.1-3 through 3.1-8. The dilution rate was changed to 30 gallons per minute at 0650 on May 22 and criticality was achieved at 0745 with boron concentration of 1343. Control bank D was then used to maintain the reactor just critical.

Just after the reactor went critical, readings were taken to determine overlap between the NIS source and intermediate range channels. When intermediate range channels showed a positive indication, i.e, greater than 10^{-11} amps, both source and intermediate range indications were recorded. The indications were again recorded when the intermediate range indication showed 10^{-10} amps. It was not possible to get overlap readings at any higher level since the source range reactor trip is at 10^5 counts per second even though the source range scale indicates up to 10^6 counts per second. The overlap data is shown in Section 4.4 of the report and shows overlap between the source and intermediate range is greater than the required 1 1/2 decades.

With the reactor stabilized and just critical, the range of core power for physics testing was determined. This was accomplished using a reactivity computer, supplied by Westinghouse, with an input signal coming from NIS power range channel N-42. Control bank D was withdrawn thereby increasing the flux level until the effects of nuclear heating were observed (i.e. increase in RCS average temperature). This occurred at a power level of 5.2×10^{-7} amps on the reactivity computer picoammeter, and 8×10^{-7} amps on both NIS intermediate range channels N35 and N36. The testing range was declared to be 1/10 to 1/100 of these values or 5.2×10^{-8} to 5.2×10^{-9} amps on the reactivity computer.

FIGURE 3.1-1

ICRR DURING ROD BANK WITHDRAWAL

CHANNEL N31

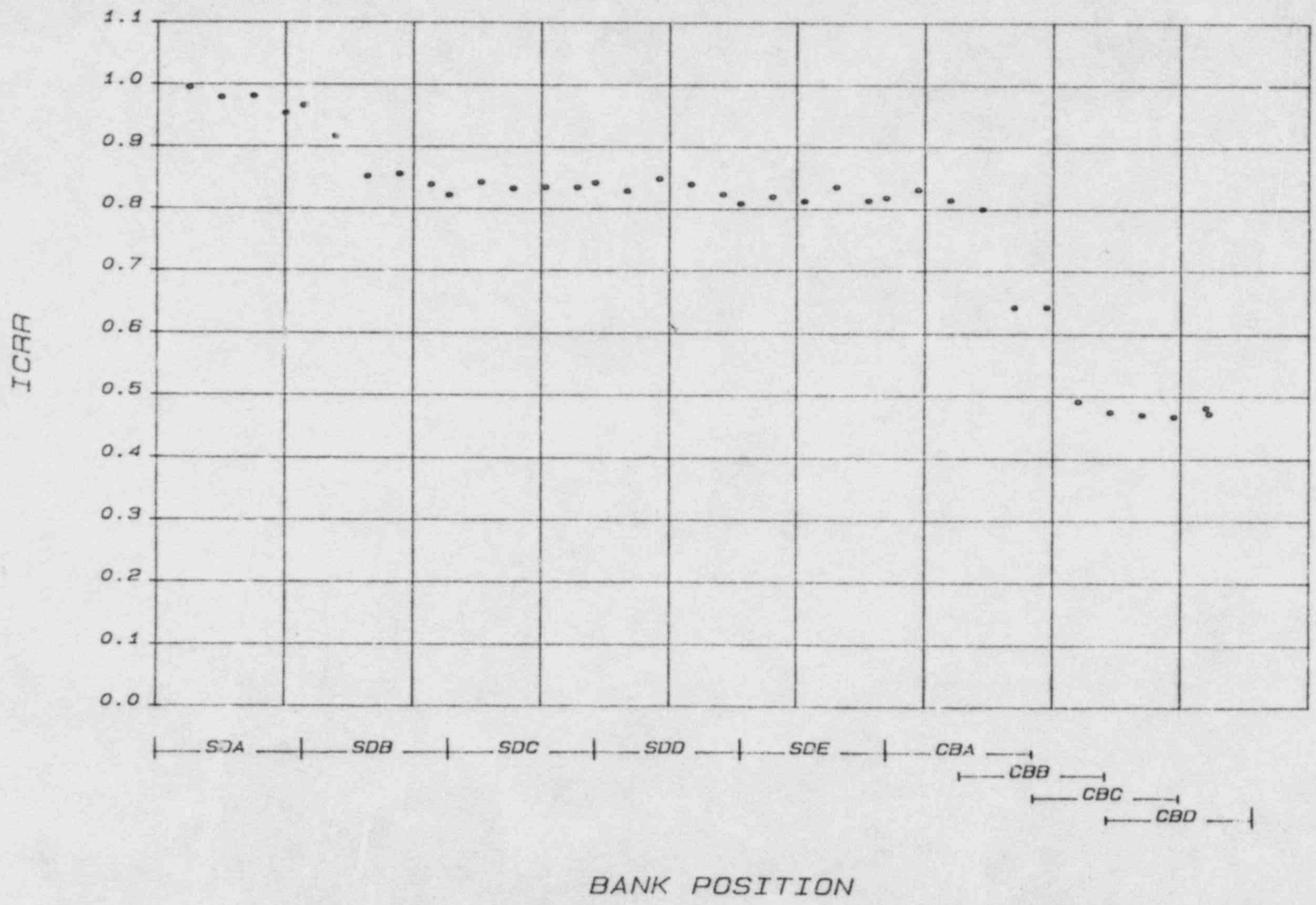


FIGURE 3.1-2

ICRR DURING ROD BANK WITHDRAWAL

CHANNEL N32

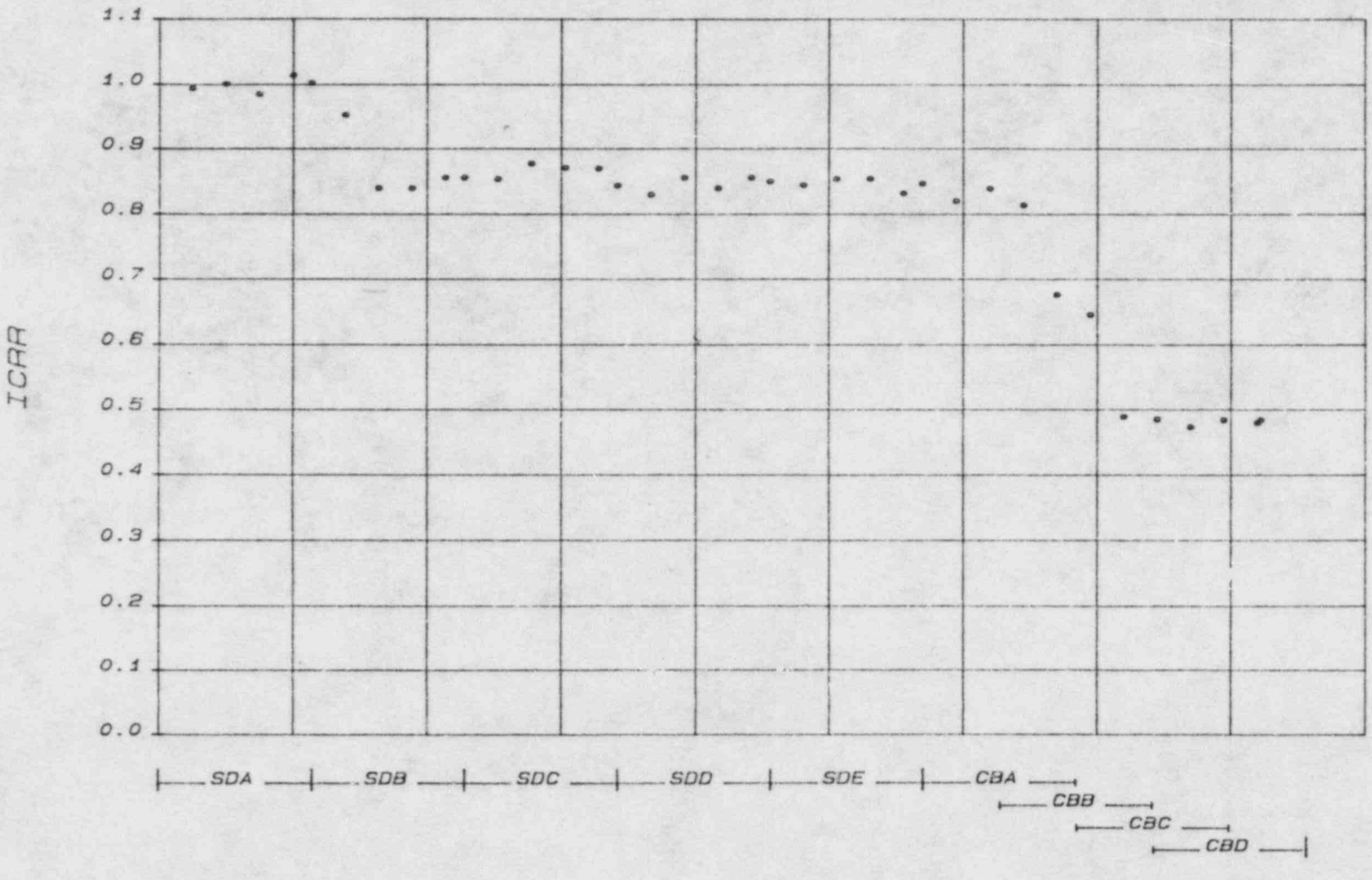


FIGURE 3.1-3

ICRR VS. RCS BORON CONCENTRATION

CHANNEL N31

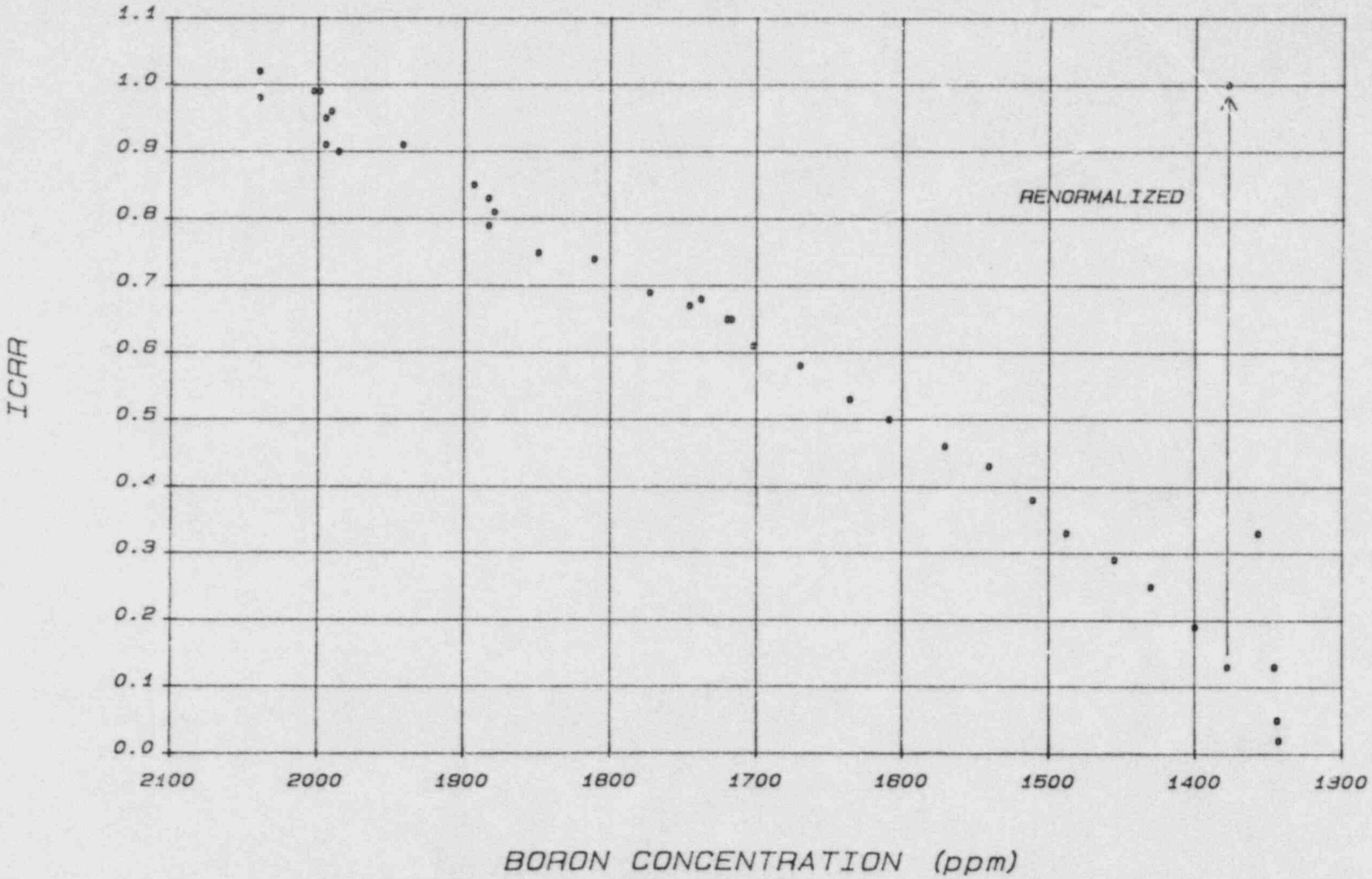


FIGURE 3.1-4

ICRR VS. RCS BORON CONCENTRATION

CHANNEL N32

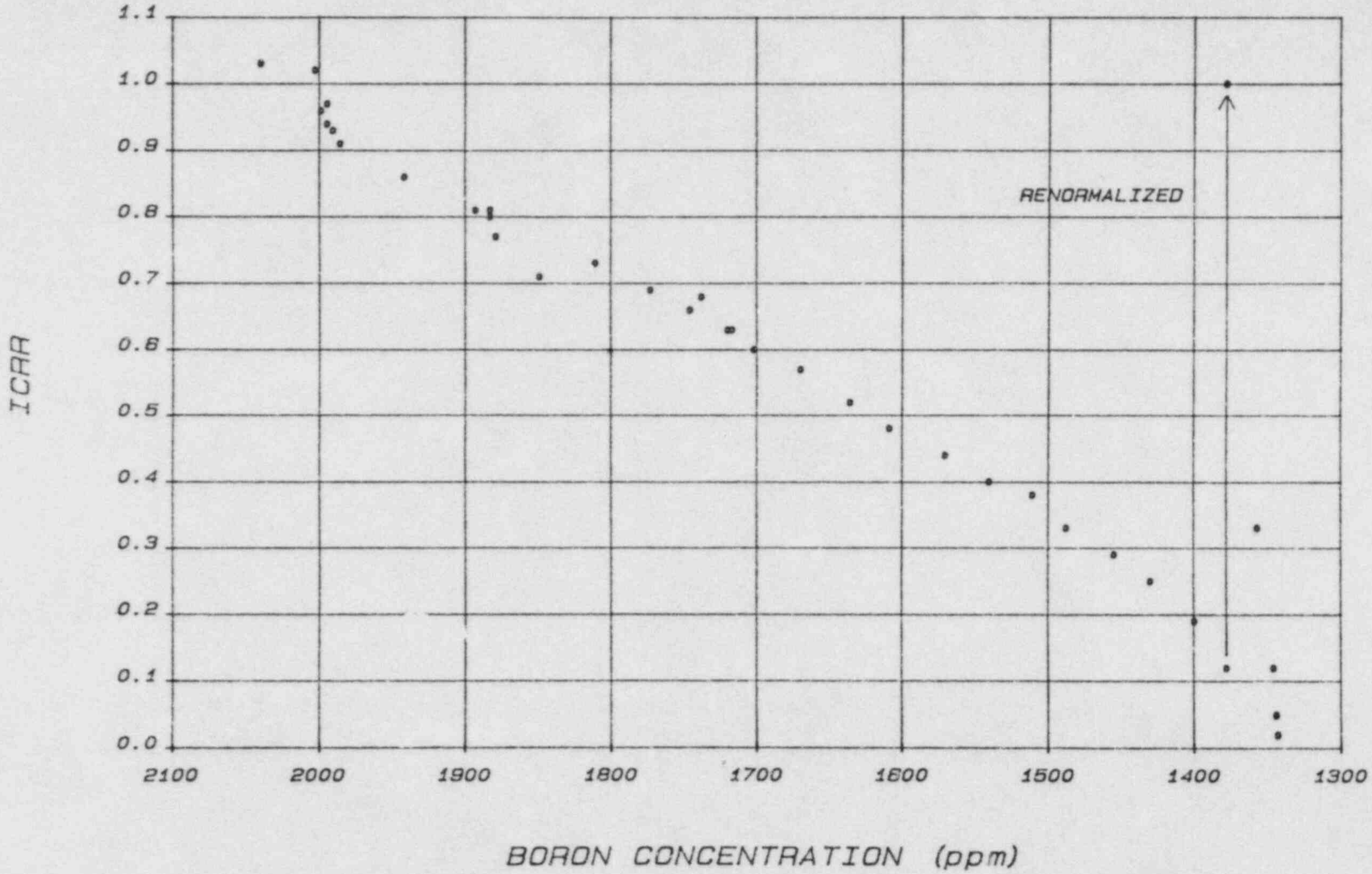


FIGURE 3.1-5

ICRR VS. TIME OF RCS DILUTION

CHANNEL N31

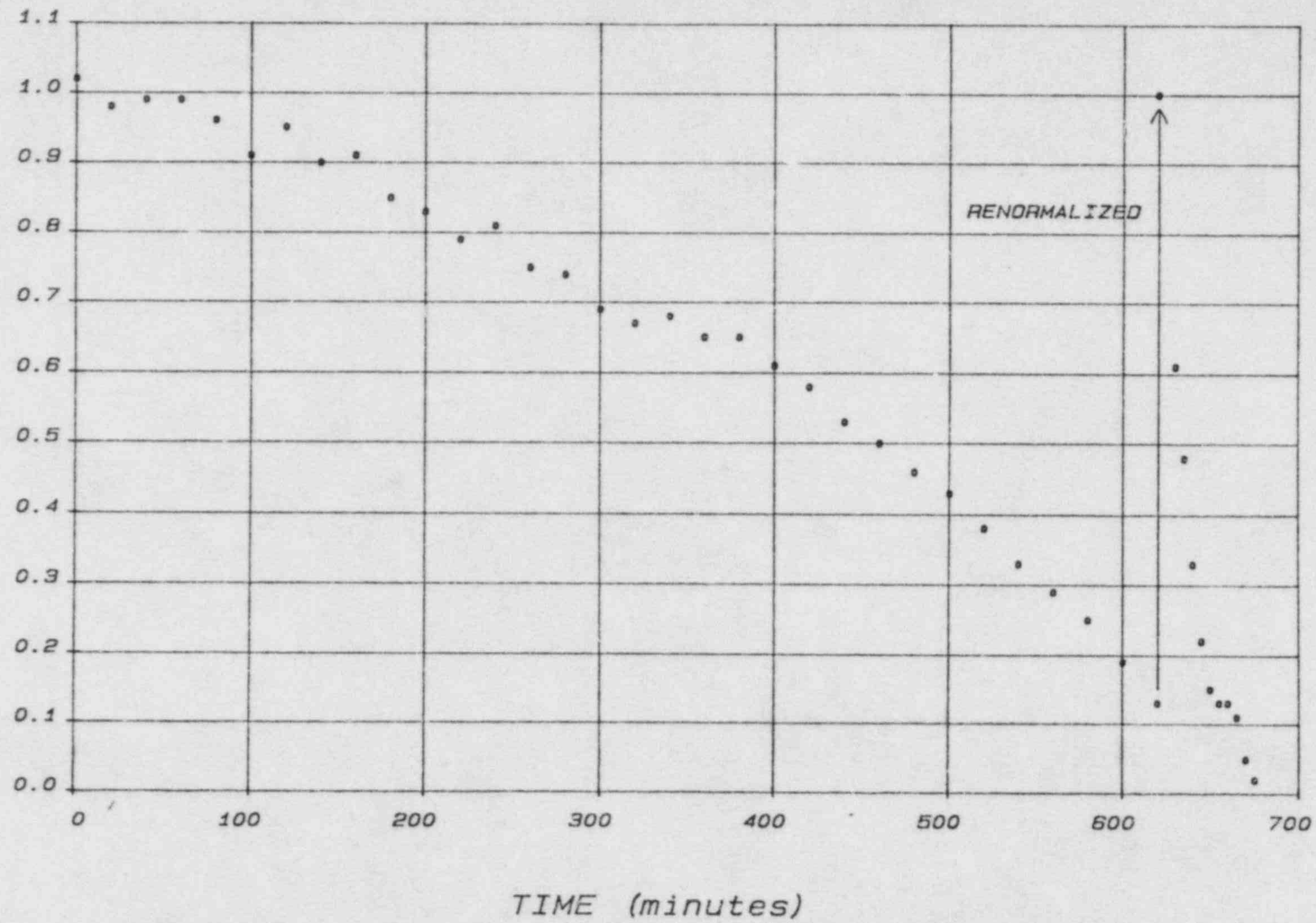


FIGURE 3.1-6

ICRR VS. TIME OF RCS DILUTION

CHANNEL N32

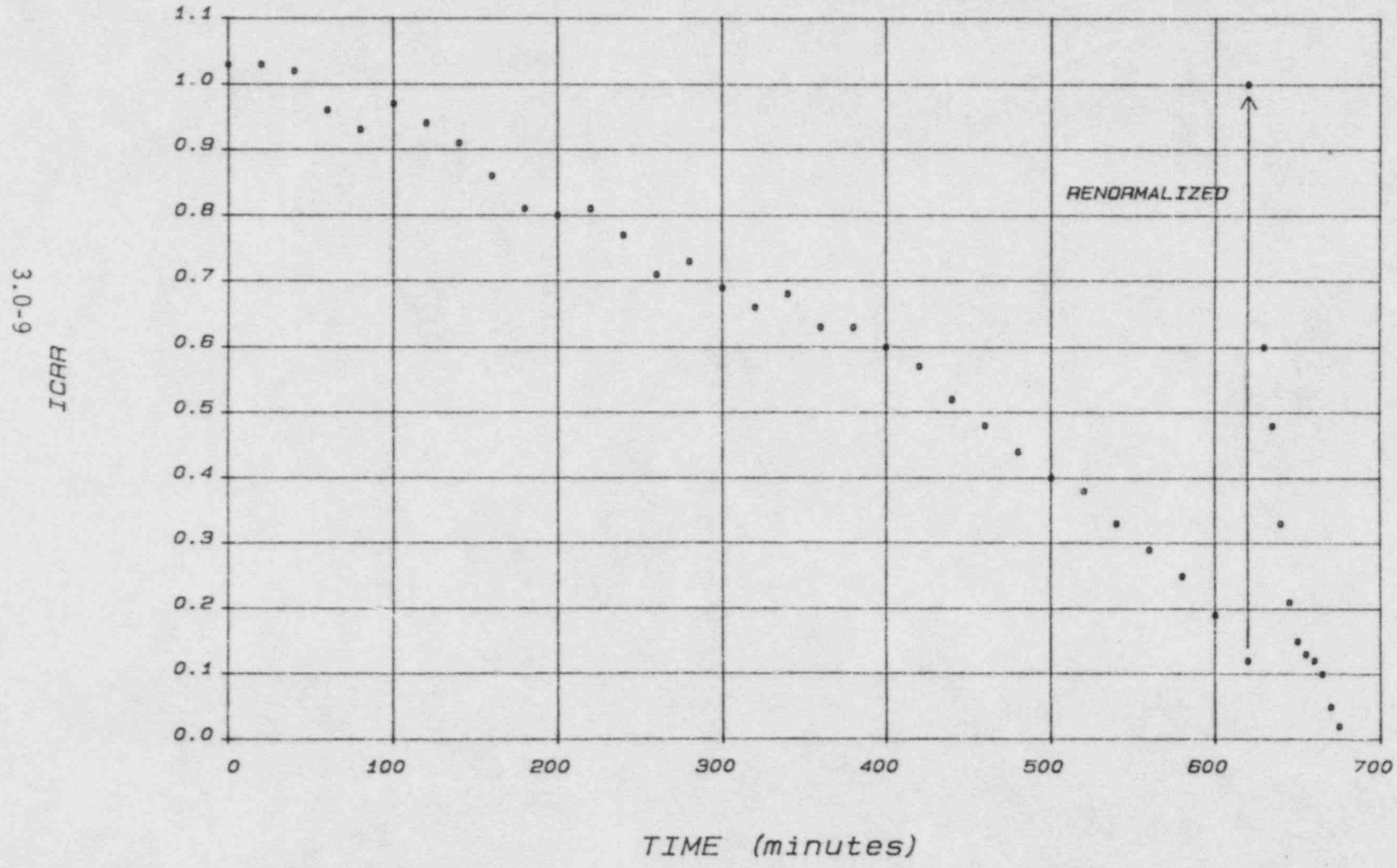


FIGURE 3.1-7

ICRR VS. REACTOR MAKEUP WATER ADDITION

CHANNEL N31

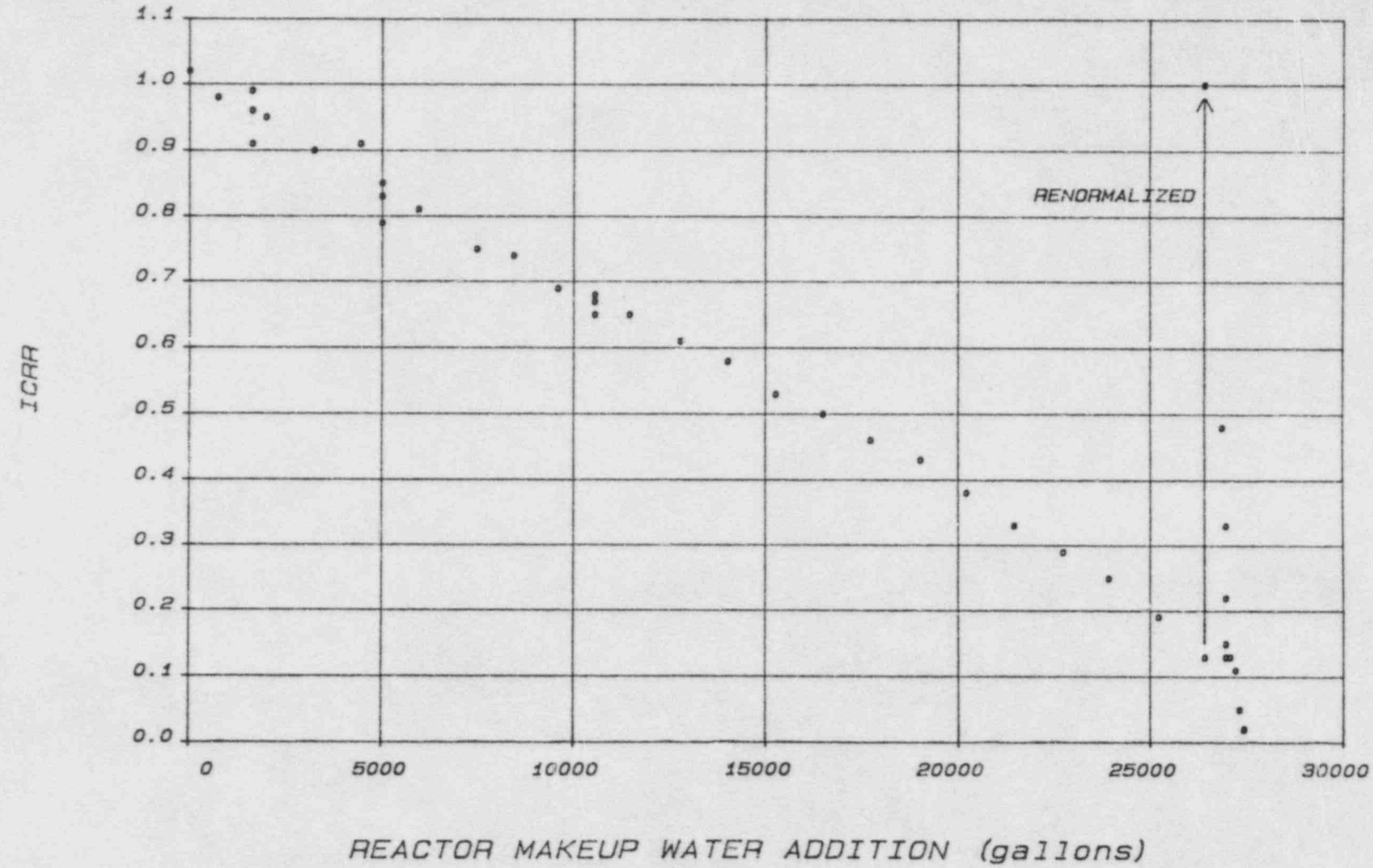
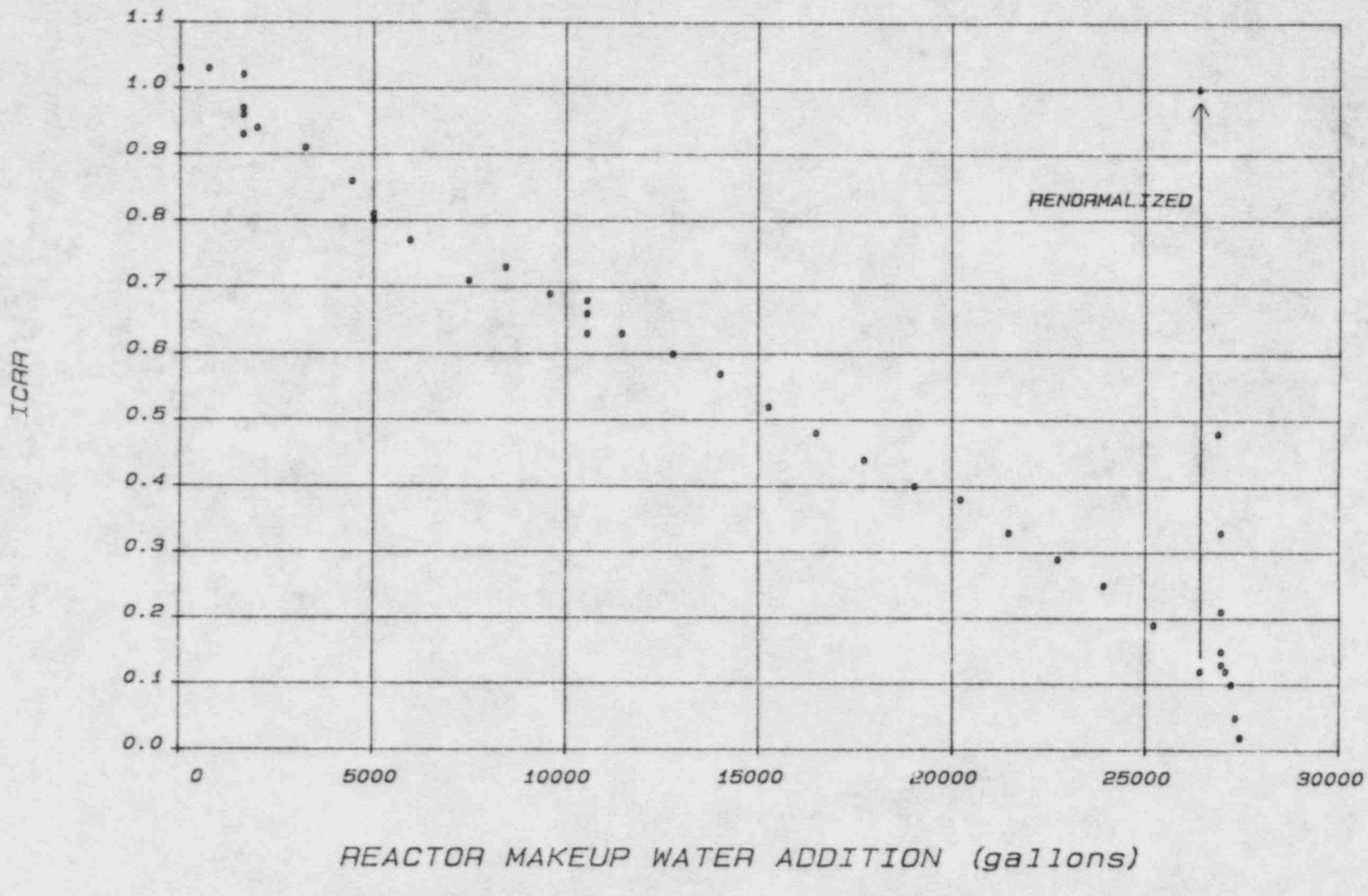


FIGURE 3.1-8

ICRR VS. REACTOR MAKEUP WATER ADDITION

CHANNEL N32



After the testing range was determined, a reactivity computer checkout was performed. Positive and negative reactivity insertions were introduced by control rod movement with calculations of the change in reactivity made using the neutron flux doubling time. Comparing these calculated values to theoretical values developed from the inhour equation, resulted in an average difference of 0.7%. Reactivity changes of approximately 25, 50 and 75 pcm were used for the calculations.

Only one significant problem was encountered during the approach to criticality. Water had been pumped from the spent fuel pool into the refueling water storage tank (RWST). Rod withdrawal was suspended until the boron concentration of the RWST could be verified to be within Technical Specification requirements. After a 45 minute delay, verification was made and rod withdrawal resumed.

3.2 CONTROL ROD BANK WORTH MEASUREMENTS

Control rod bank reactivity worths were measured by monitoring reactivity changes associated with RCS boron and control rod bank exchanges. Differential reactivity worths, being the ratio of the change in reactivity to the corresponding change in bank position, and integral reactivity worths, being the total reactivity change due to the travel of the entire rod bank height, were obtained via these exchanges. After establishing a constant RCS boron dilution or boration rate, the control rod banks were periodically inserted or withdrawn to compensate for the changing boron concentration. The changes in reactivity due to control rod bank movement were indicated on a strip chart recorder connected to the reactivity computer.

From an all-rods-out starting condition, boron endpoints and individual control rod bank reactivity worths for control banks A through D and shutdown banks C through E were obtained by RCS dilution. The worth of the most reactive rod, rod F-1Ø, was then determined by withdrawing it and compensating with the insertion of shutdown banks A and B. When rod F-1Ø was full out, insertion of shutdown banks A and B continued by RCS dilution until the banks were fully inserted.

The reactor, which had previously been tripped to realign rod F-1Ø, was then brought critical with shutdown banks withdrawn and the control banks inserted. Initiating RCS boration, the control banks were withdrawn in order to measure their worth in the overlap mode. Upon completion, the rods were repositioned at the hot zero power insertion limit. By RCS boration, rod D-12 was then withdrawn to simulate an ejected rod and its reactivity worth measured. Rod D-12 was then realigned and the reactor manually tripped as this was the end of rod worth measurements.

A summary of the results of the rod worth measurements is presented in Table 3.2-1. The differential and integral reactivity worths of all cases have been plotted in Figures 3.2-1 through 3.2-1Ø.

As indicated in Table 3.2-1, all measured rod worths were within the acceptance criteria. One significant problem experienced during rod worth measurements was that at one point, individual rod groups within a rod bank became misaligned when switching back and forth from bank to bank on the selector switch. The largest misalignment encountered was four steps. Upon completion of rod worth testing, the reactor was tripped and the step counters reset in order to realign the rods. The only other problem encountered was during the worth measurements of the most reactive rod, F-1Ø. Technical Specification 4.1Ø.1.2 requires that prior to this event, the rods must be tripped from the 5Ø% withdrawn position to show insertion capability. When withdrawing control bank C to demonstrate this, a counts doubling occurred causing automatic boration of the RCS. After terminating the boration, rod withdrawal continued slowly in anticipation of possible criticality. The reactor did go critical prior to reaching the 5Ø% position but was quickly brought subcritical by rod insertion. Following an evaluation, which determined that control Bank C was worth more than predicted in this configuration (all other rods inserted), the RCS was borated conservatively and testing proceeded without any further difficulties.

TABLE 3.2-1

WOLF CREEK GENERATING STATION
CYCLE 1 BOL PHYSICS TEST
CONTROL ROD BANK WORTH SUMMARY

Bank/Rod Configuration*	Measured Worth (pcm)	Acceptance Criteria (pcm)
CBD	650.4	650 ± 65
CBC (CBD @ 0)	1194.3	1240 ± 124
CBB (CBD,CBC @ 0)	1010	970 ± 97
CBA (CBD,CBC,CBB@0)	658	680 ± 68
SDE (CB @ 0)	846.9	870 ± 87
SDD (CB, SDE @ 0)	758	740 ± 74
SDC (CB,SDE,SDD@0)	954.7	960 ± 96
ARI - 1	6322.5	6680 ± 668
Ejected Rod D-12	548.5	≤ 860

*CB = Control banks
SD = Shutdown banks
ARI = All rods in

FIGURE 3.2-1

DIFFERENTIAL AND INTEGRAL BANK WORTH

(CBD)

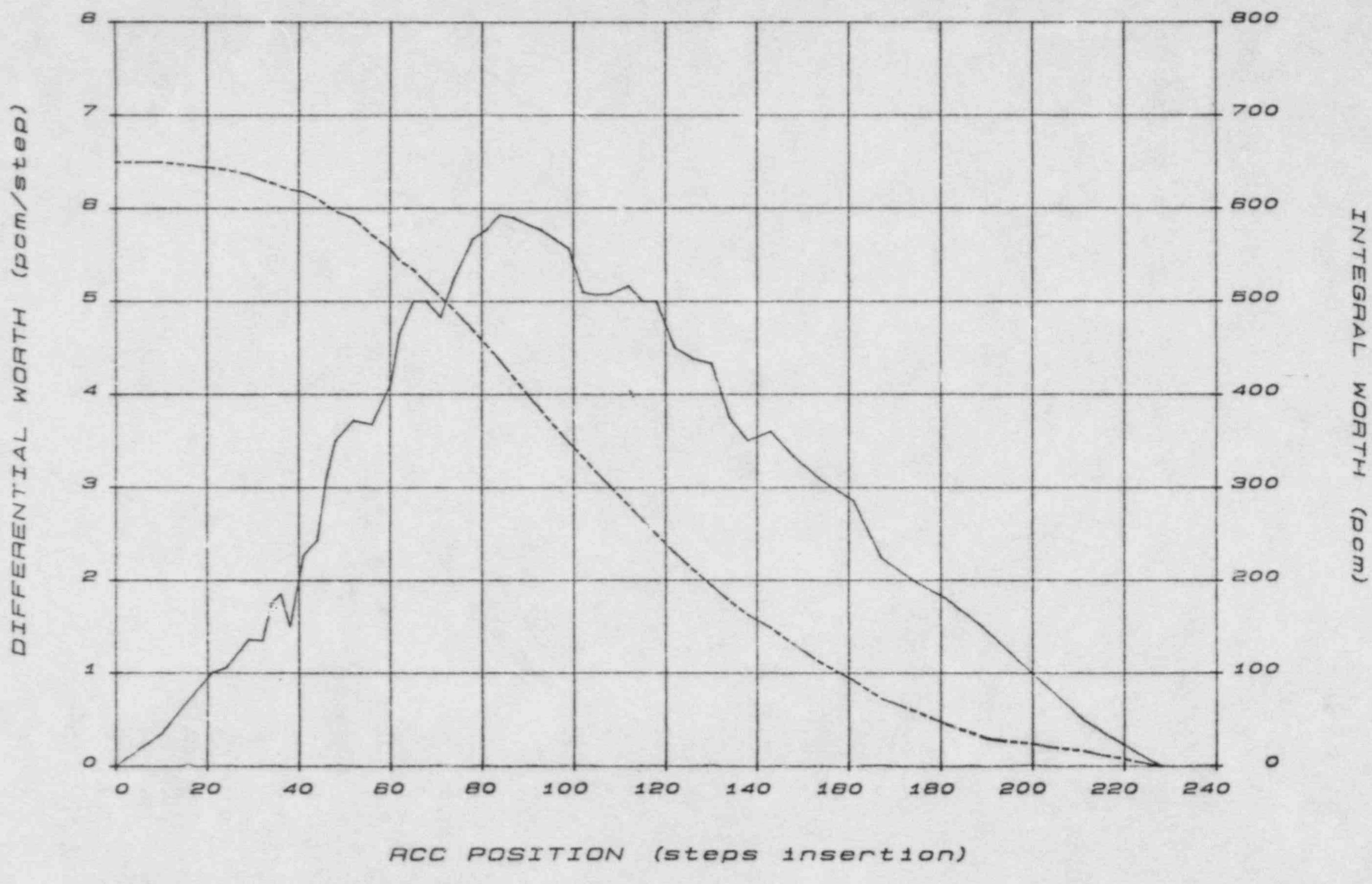


FIGURE 3.2-2

DIFFERENTIAL AND INTEGRAL BANK WORTH
(CBC)

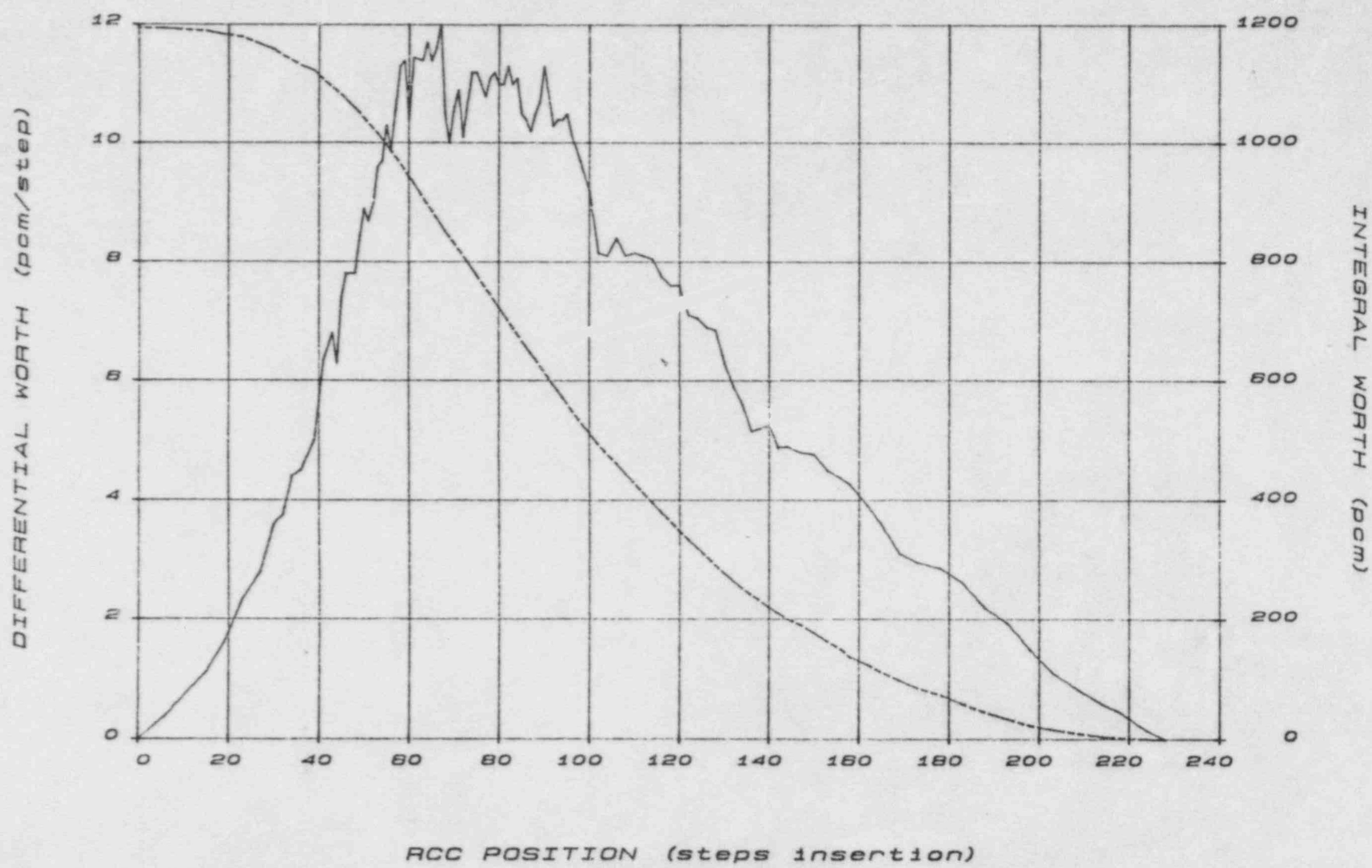


FIGURE 3.2-3

DIFFERENTIAL AND INTEGRAL BANK WORTH
(CBB)

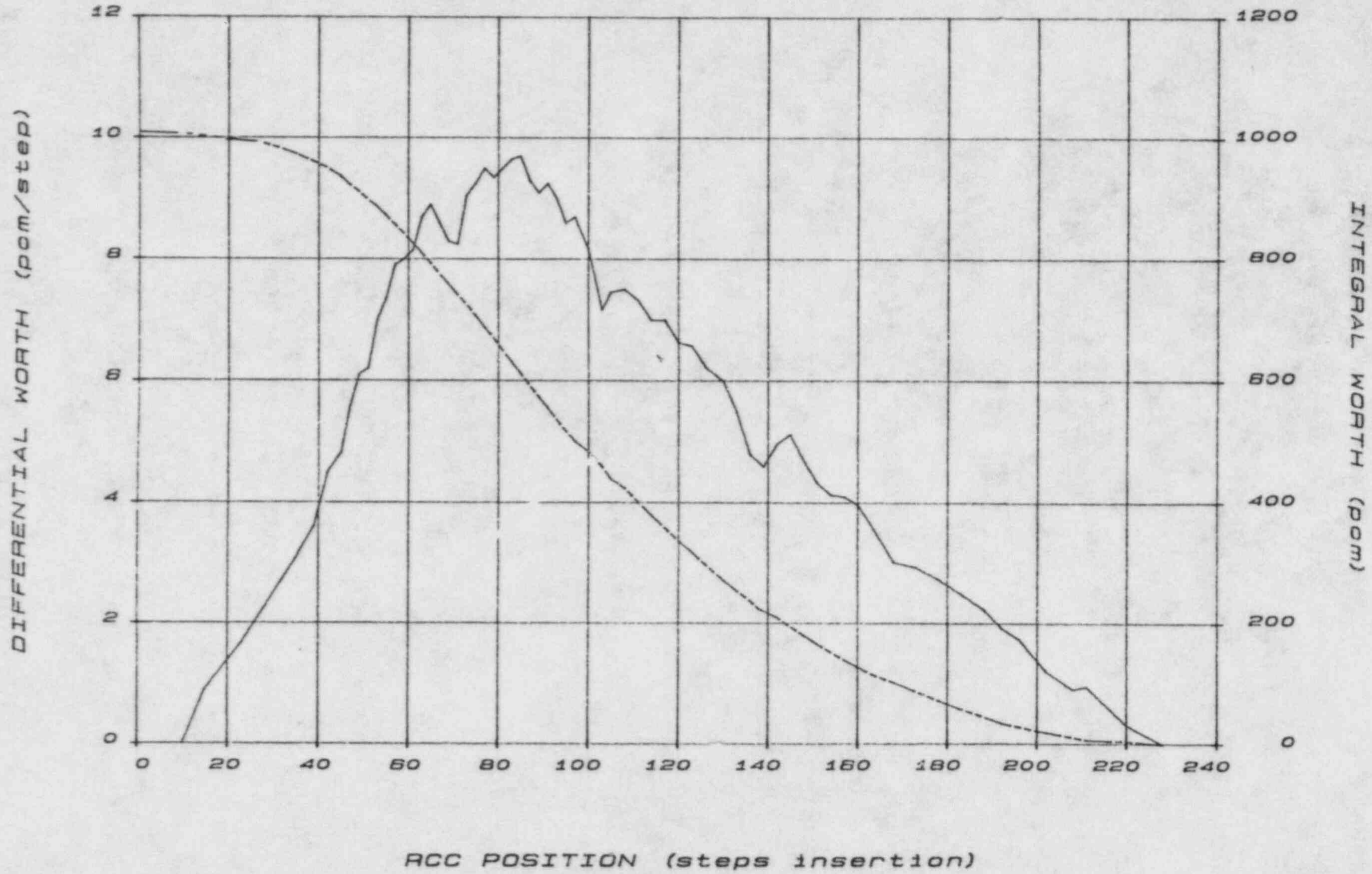


FIGURE 3.2-4

DIFFERENTIAL AND INTEGRAL BANK WORTH

(CBA)

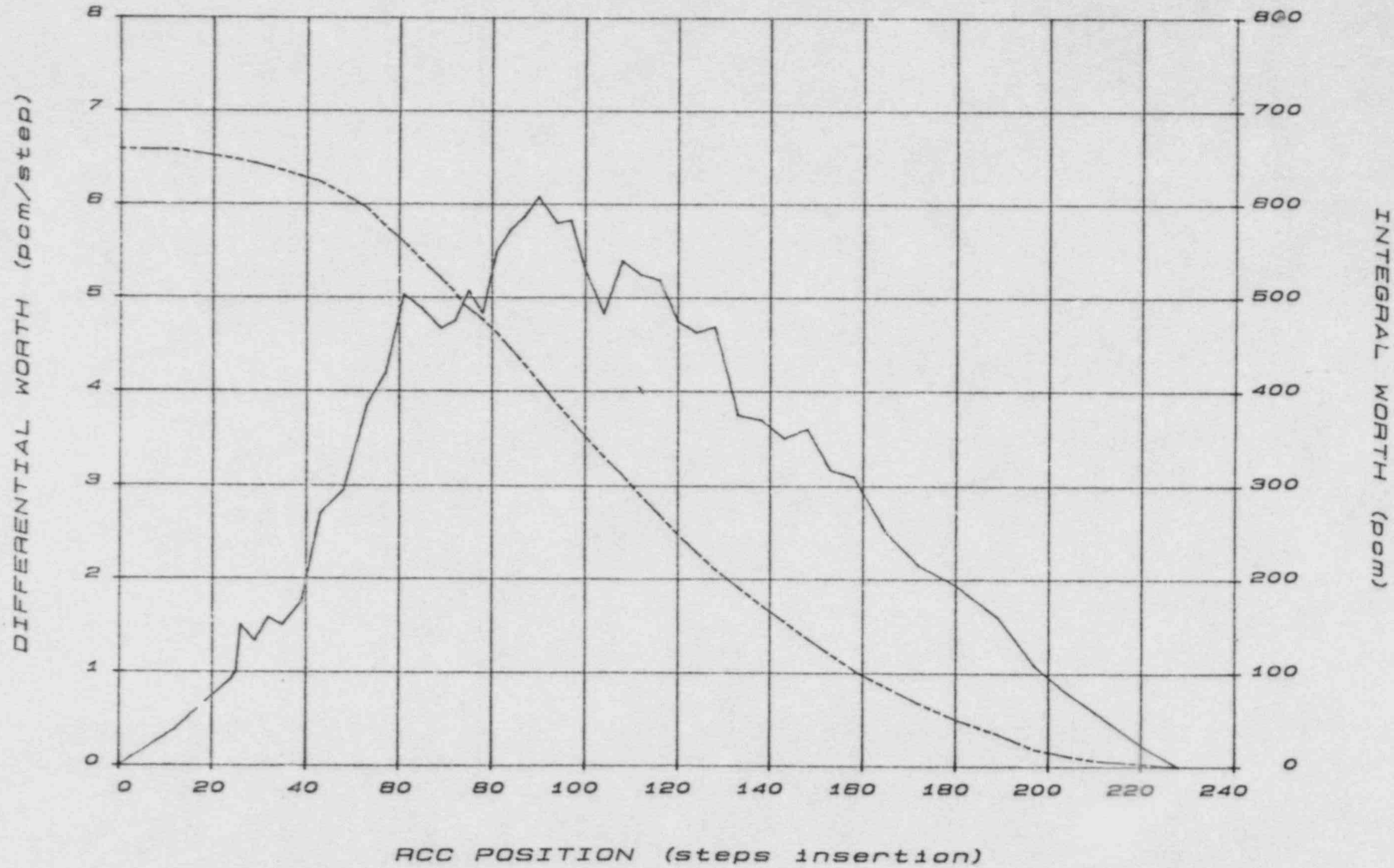


FIGURE 3.2-5

DIFFERENTIAL AND INTEGRAL BANK WORTH

(SDE)

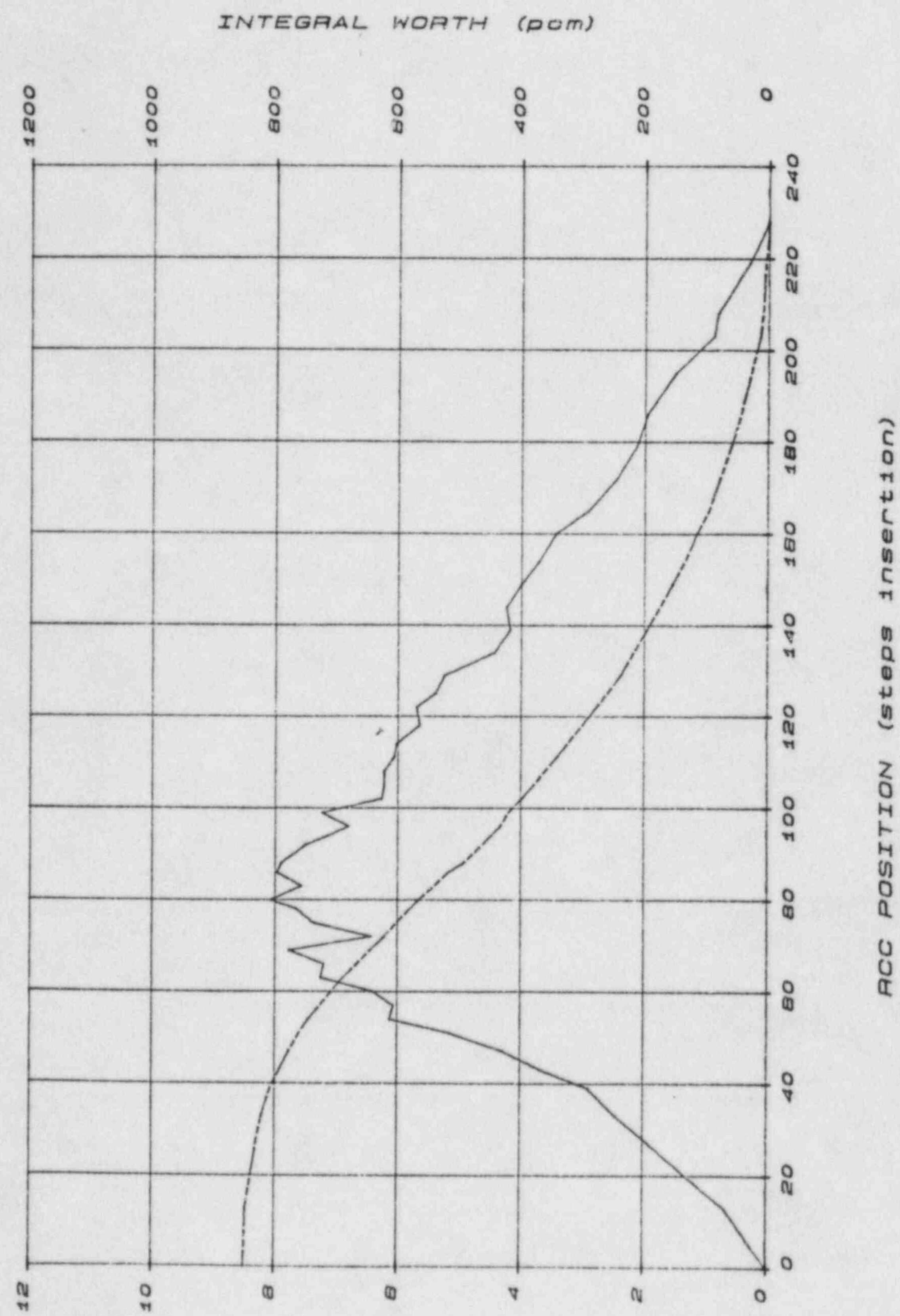


FIGURE 3.2-6

DIFFERENTIAL AND INTEGRAL BANK WORTH

(SDD)

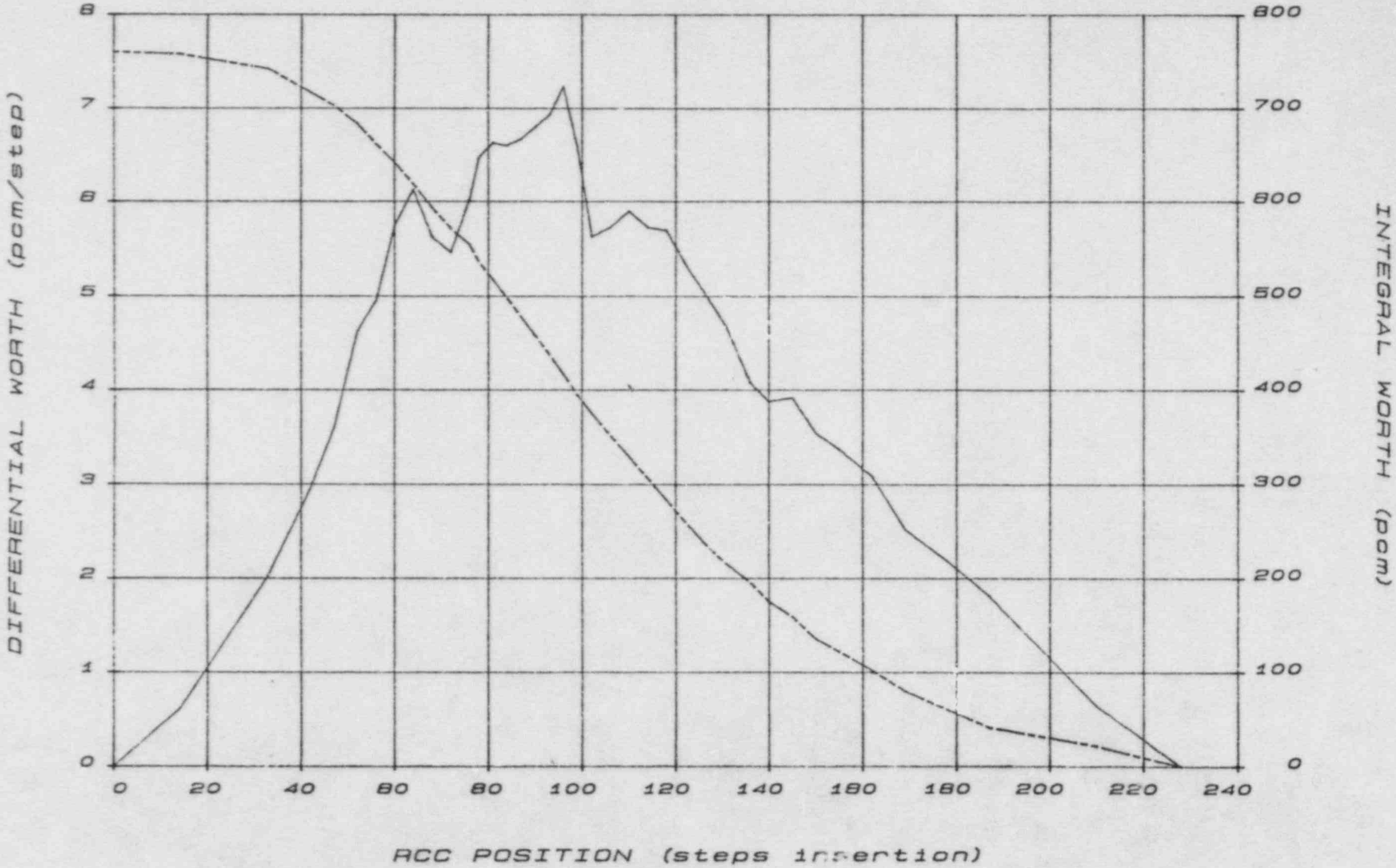


FIGURE 3.2-7

DIFFERENTIAL AND INTEGRAL BANK WORTH
(SDC)

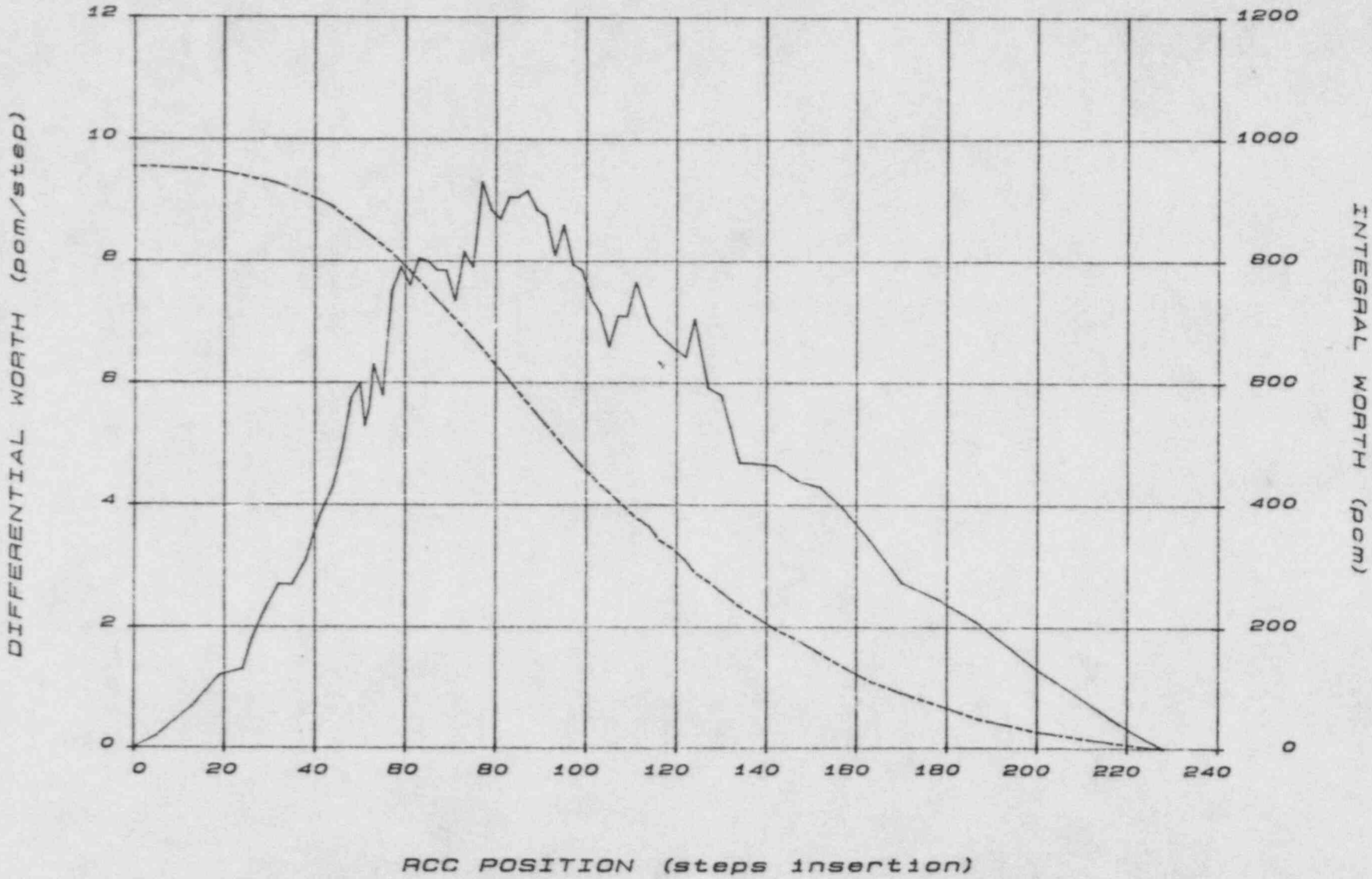


FIGURE 3.2-8

DIFFERENTIAL AND INTEGRAL BANK WORTH

(CBD, D-12, EJECTED ROD)

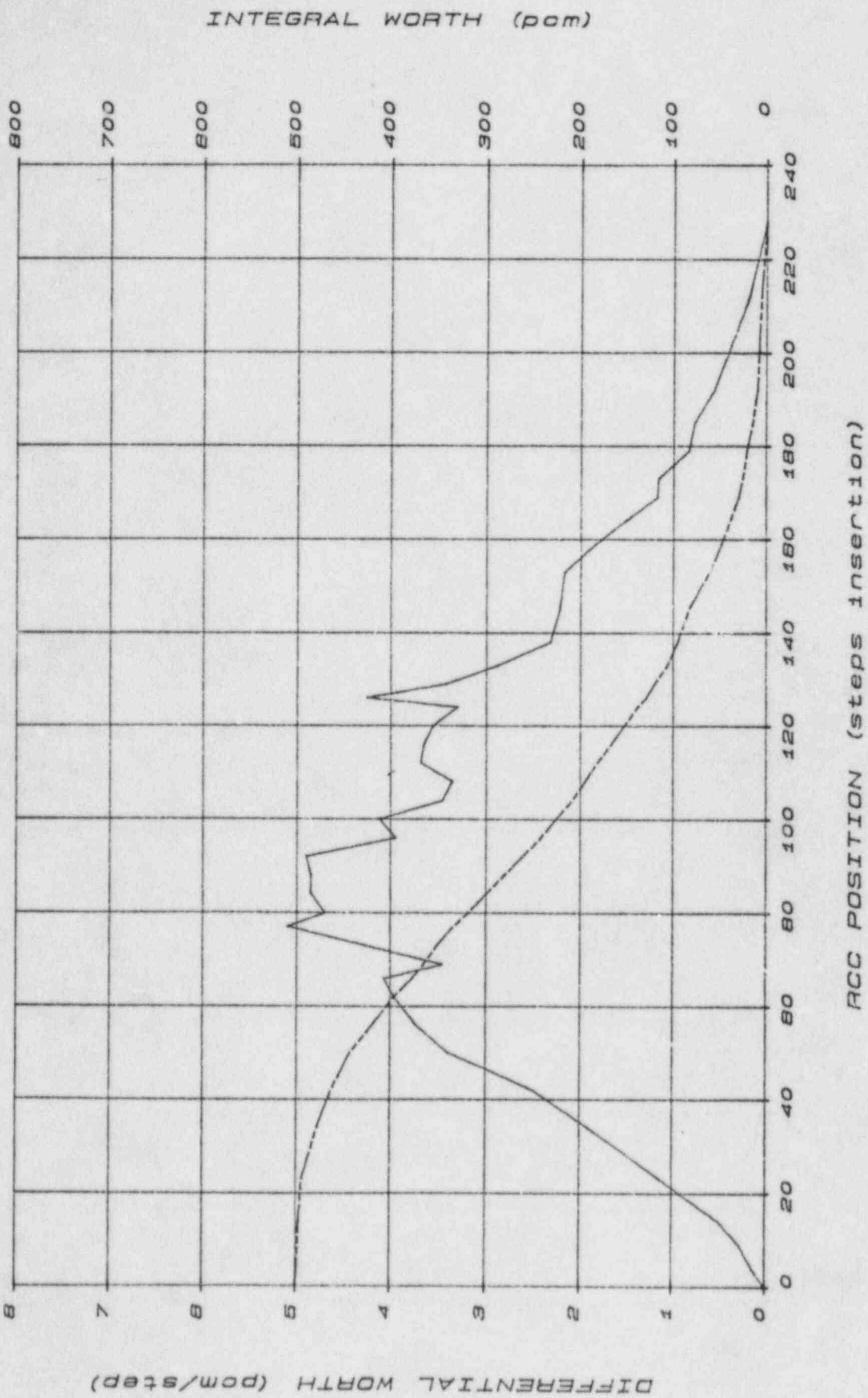


FIGURE 3.2-9

DIFFERENTIAL AND INTEGRAL BANK WORTH

(SDB, F-10, STUCK ROD)

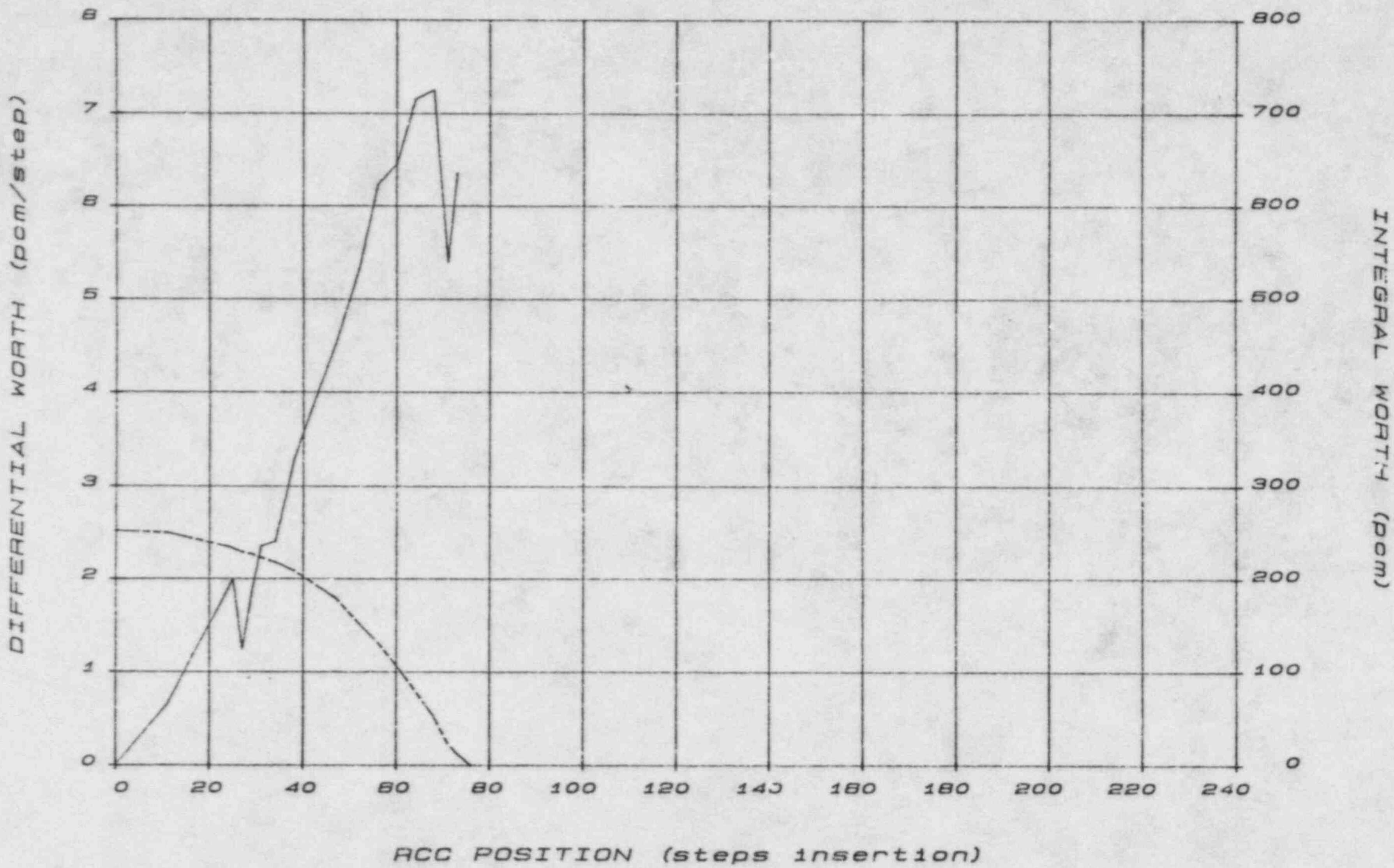
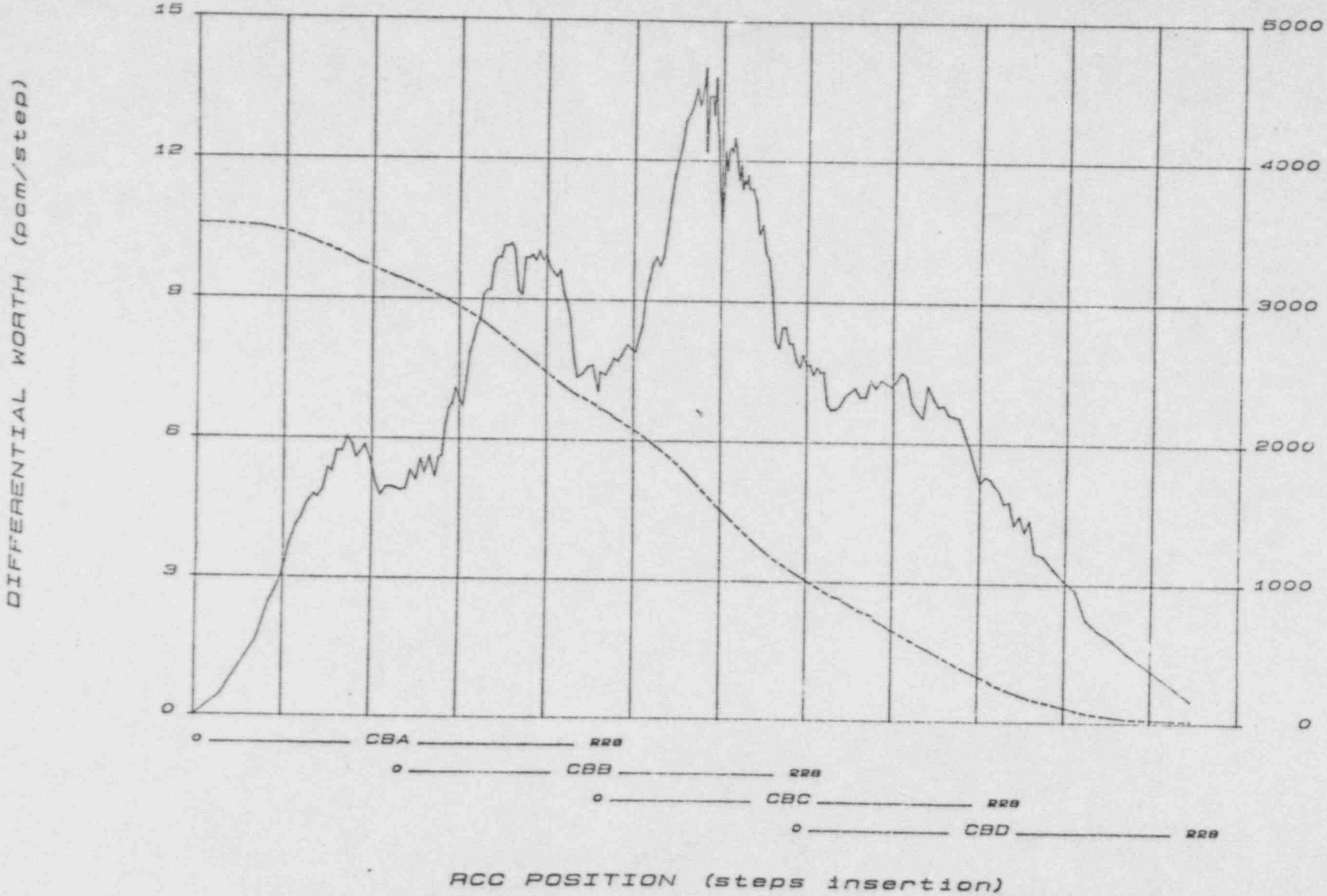


FIGURE 3.2-10
DIFFERENTIAL AND INTEGRAL BANK WORTH
(OVERLAP)



3.3 ISOTHERMAL TEMPERATURE COEFFICIENT

The isothermal temperature coefficient measurements were accomplished using a constant heatup or cooldown rate of approximately 10 $^{\circ}$F per hour. With reactor power within the physics testing range, 5.2×10^{-8} to $5.2 \times 10^{-}$ amperes, a cooldown of approximately 5 $^{\circ}$F was made by adjustment of the steam dump system. Reactivity changes during the cooldown were recorded by the reactivity computer. This process was then repeated for a heatup of approximately 5 $^{\circ}$F. Pressurizer level was maintained steady or slightly increasing during the process in order to eliminate boron reactivity effects due to outflow from the pressurizer.

Isothermal temperature coefficient measurements were performed at three different control rod configurations; all-rods-out; control bank D-in; and control banks D and C-in. A heatup and cooldown was performed for each configuration. The isothermal temperature coefficient was taken to be the average of the values of the slopes of the heatup and cooldown plots from the reactivity computer.

The results of the isothermal temperature coefficient measurements were all within the acceptance criteria as presented in Table 3.3-1. Using the value of the isothermal temperature coefficient, the moderator temperature coefficient (MTC) was calculated for the all-rods-out configuration. This is simply the isothermal temperature coefficient minus the Doppler (fuel) temperature coefficient. The MTC is required to be negative (i.e. as temperature increases, negative reactivity is introduced), however, the results of the calculation was a positive 1.03 pcm/ $^{\circ}$F. This required rod withdrawal limits to be instated which would preclude operation of the plant with a positive moderator temperature coefficient. These limits are illustrated in Figure 3.3-1.

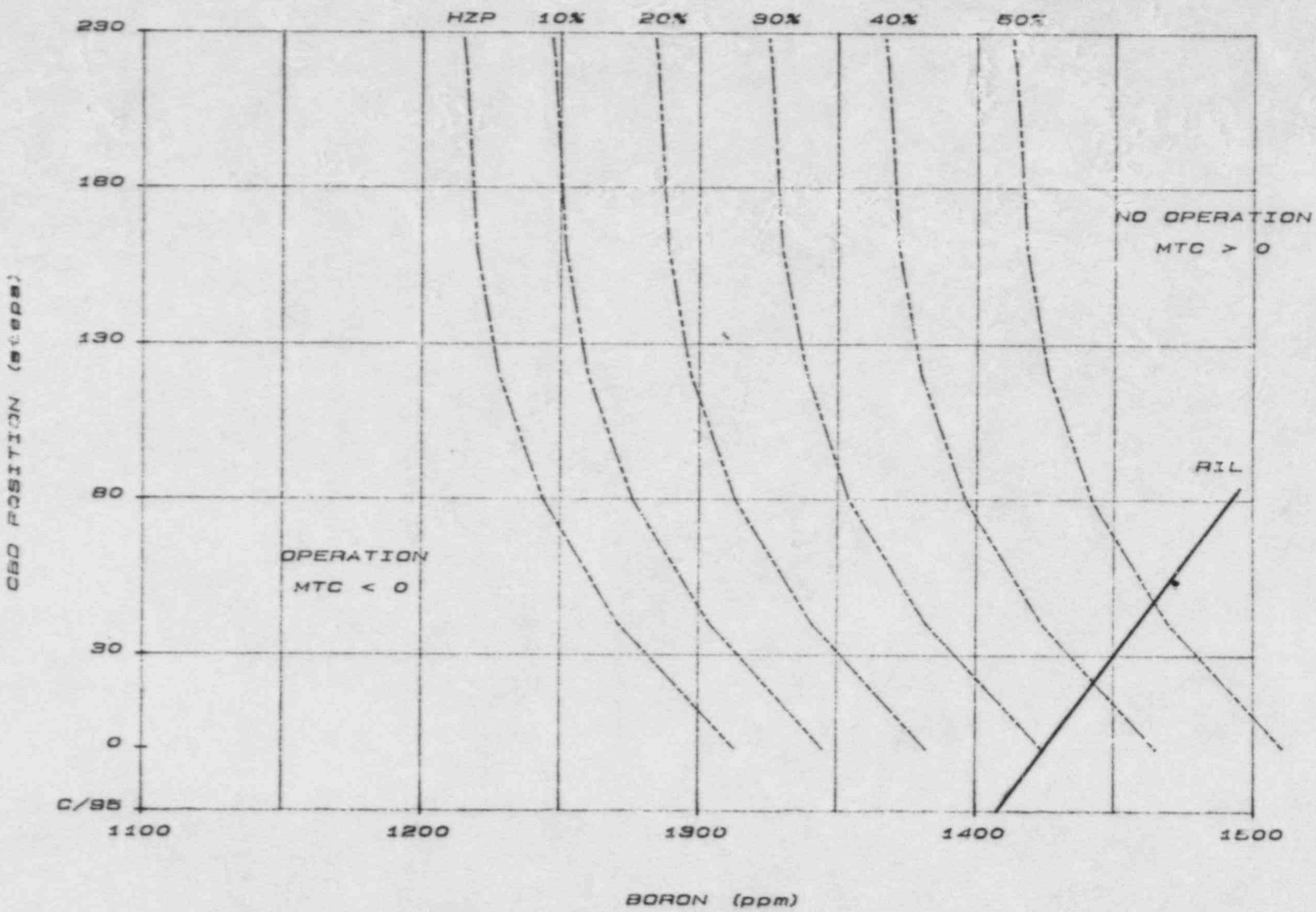
No major problems were encountered during the isothermal temperature coefficient measurements and with rod withdrawal limits in place, all test results were satisfactory.

TABLE 3.3-1

ISOTHERMAL TEMPERATURE COEFFICIENT RESULTS SUMMARY

Rod/Bank Configuration	Measured Value (pcm/°F)	Acceptance Criteria (pcm/°F)
ARO	-0.92	-2.03 ± 3.0
CBD @ 0	-2.05	-3.36 ± 3.6
CBD, CBC @ 0	-5.47	-6.66 ± 3.0

FIGURE 3.3-1
ROD WITHDRAWAL LIMITS
MTC < 0



3.4 BORON ENDPOINT AND BORON WORTH MEASUREMENTS

Boron endpoints were measured in an integrated test procedure which also measured the control bank worths. With the reactor at hot zero power, RCS boron concentrations were measured at several rod bank configurations for comparison to design predictions. The RCS conditions were stabilized with the controlling rod bank at the desired endpoint position. Critical boron concentrations were then measured for the endpoints.

Results of the endpoint measurements are presented in Table 3.4-1. With the exception of the all-rods-out configuration endpoint, all measured endpoints were within 6.2 percent of the design predictions. In the all-rods-out case, the measured concentration was 3 ppm outside the allowable tolerance. The situation was evaluated by Westinghouse with the result that no impact on the safety analysis was presented, therefore the measured endpoint was acceptable.

A differential boron worth was calculated using values of measured boron concentrations and rod worths. Dividing the total worth of the control banks (in overlap) by the difference of the critical boron concentrations from the all-rods-out to the control banks in configuration resulted in a differential boron worth of -10.08 pcm/ppm, well within the ± 10% of design prediction tolerance as indicated in Table 3.4-2.

TABLE 3.4-1

BORON ENDPOINT SUMMARY

Control Rod Configuration	Measured Value (ppm)	Acceptance Criteria (ppm)
ARO	1352.2	1299 ± 50
CBD @ 0 (ARO-CBD)	65.3*	63 ± 6
CBD, CBC @ 0 (CBD-CBC)	126.9*	123 ± 12
CBD, CBC, CBB @ 0 (CBC-CBB)	87.9*	93 ± 9
CBD, CBC, CBB, CBA @ 0 (CBB-CBA)	69.3*	65 ± 7
ARI - 1 (ARO -(ARI-1))	605.9*	625 ± 63

*Values are the difference between successive endpoint measurements.

TABLE 3.4-2

DIFFERENTIAL BORON WORTH SUMMARY

Differential Boron Worth =	Measured Value (pcm/ppm)	Acceptance Criteria (pcm/ppm)
$\frac{\text{Control Bank Worth (overlap)}}{C_B\text{(ARO)} - C_B\text{ (CBA @ 0)}}$	-10.08	-10.27 ± 1.03

3.5 POWER DISTRIBUTION MEASUREMENTS

The core power distributions were measured using the incore flux mapping system. Data from this system was then analyzed using the Westinghouse INCORE computer program.

Four flux maps were obtained during the low power physics testing segment of the startup program. The maps were taken at different control rod bank configurations which were all-rods-out, control bank D at Ø steps, hot zero power insertion limits, and a pseudo-ejected rod. Incore power tilts, reaction rates, and hot channel factors were reviewed for the flux maps all of which resulted in acceptable values. Results of the maps along with acceptable values are given in Table 3.5-1.

Analysis of the first flux maps indicated abnormalities between thimbles R-Ø8 and N-Ø8. After a detailed examination of plant documentation, it was determined that the two thimbles had been interchanged at the seal table. The problem will be remedied during the first refueling by appropriate repositioning of the thimbles at the transfer device. The flux map data is currently being corrected for each map by manually interchanging the data for thimbles R-Ø8 and N-Ø8.

Several equipment problems hampered the running of the flux maps. In most cases, not all of the detector drives were available for operation. However, constant maintenance and the redundant design of the system allowed the flux maps to be obtained.

TABLE 3.5-1

POWER DISTRIBUTION SUMMARY

Map Number	Control Rod Configuration	Incore Tilt		Reaction Rate Error		Enthalpy Rise Hot Channel Factor $F_{\Delta H}^{N}$		$F_Q(Z)$		Axial Offset	
		Measured	Acceptable	Measured	Acceptable	Measured	Acceptable	Measured	Acceptable	Measured	Acceptable
C1M002	ARO	1.0157	≤1.04	-6.0%	≤ ±10%	1.4305	1.39±0.14	2.3467	N/A	-1.788	N/A
C1M001	CBD @ 0	1.0125	≤1.04	-8.8%	≤ ±10%	1.5792	1.57±0.16	2.7702	N/A	-16.577	N/A
C1M003	Hot zero power insertion limit	1.0174	≤1.04	-9.5%	≤ ±10%	1.5775	N/A	2.7654	N/A	-36.928	N/A
C1M004	Pseudo rod Ejection	1.9513	N/A	+50.8	N/A	3.8293	N/A	6.6099	≤7.03	-33.363	N/A

4.0 POWER ASCENSION TESTING

Following the completion of low power physics testing, the power ascension phase of the startup test program was begun. The testing in this phase of the test program included various at-power physics tests, control system dynamic response tests, overall transient and trip testing of the plant, and calibration and alignment of plant instrumentation and control systems. Additional testing included a steam generator moisture carryover test, the NSSS acceptance test, thermal and dynamic testing of the main steam and main feedwater systems, biological shield surveys and turbine generator testing.

Several tests identified in the Final Safety Analysis Report (FSAR) were not performed. The loss of heater drain pump test was committed to be performed by the first SNUPPS unit only as identified on page 640.6-1 of the Volume 11 of the FSAR. The pseudo rod drop test was exempted from the Startup Program by the NRC due to potential Technical Specification violations during performance of the test.

The NRC lifted the 5% power restriction on June 4, 1985. The low power physics test sequence was approved by the PSRC and the Plant Manager authorized the start of power ascension testing on June 5, 1985. The turbine generator was synchronized to the grid on June 13, 1985. The initial phase of power ascension testing was approved by the PSRC and, after Plant Manager authorization, power was increased to 30% on June 19, 1985. The plant was shutdown from outside the control room on June 29, 1985. Power was increased to 50% on July 6, 1985. The rods drop and plant trip test was performed on July 16, 1985, and testing at 50% power was completed on July 18, 1985. After PSRC review and approval of the test procedures, the Plant Manager authorized the start of 75% power testing on July 19, 1985.

Testing at 75% power was started on July 20, 1985 and completed on July 29, 1985. The PSRC reviewed and approved the 75% power test procedures and the Plant Manager authorized the start of the 90% power test sequence on July 30, 1985. The plant was at 90% power on August 4, 1985, testing was completed on August 6, 1985 and, after PSRC approval of the test procedures, the Plant Manager authorized the start of 100% power testing on August 8, 1985.

The plant was initially brought to 100% power at 1607 on August 8, 1985. A 100 hour continuous run at 100% power was completed at 2007 on August 12, 1985. Power was then decreased to 55% power while vibration problems with the "B" main feedwater pump were investigated. The plant was returned to 100% power on August 21, 1985.

The 100% power plant trip test was successfully performed on August 28, 1985, and after a checkout of the NIS system to verify that the system had not degraded during 100% power operation, the 100% power test sequence was completed. The remaining test packages were approved by the PSRC on August 30, 1985. The unit was declared commercial at 0114, September 3, 1985.

4.1 AT POWER PHYSICS TESTING

The At-Power Physics Tests are a series of tests to verify accuracy of the physics models used in core design and accident analyses, to verify that hot channel factors and control rod worths in a rod ejection accident are conservative, and to obtain calibration data for the Nuclear Instrumentation System (NIS). A summary of the physics tests performed during power ascension follows:

1) Incore Movable Detector and Thermocouple Mapping at Power - Flux maps were taken at power levels of 30%, 50%, 75%, 90%, and 100% full power. The hot channel factors were measured to be within WCGS Technical Specifications. All measurement parameters met their design and accident analysis acceptance criteria after clarification by Westinghouse,

2) Axial Flux Difference Instrumentation - Flux map results were used to calibrate the Nuclear Instrumentation System to axial power distribution in each section of the core. Resetting of the NIS circuitry was accomplished to duplicate certain key flux map parameter results,

3. Power Coefficient Determination - A comparison of the Doppler Only Power Verification Factor showed the measured value was well within the design value tolerance of ±5%,

4. Pseudo Rod Ejection Test - With control rod D-12 pulled to 228 steps, core power distributions associated with a flux map taken at that time indicated hot channel factors were within the limits of WCGS Technical Specifications and the partial worth of the ejected rod was within the value for design tolerances.

4.1.1 INCORE MOVABLE DETECTOR MAPPING AT POWER

The core power distributions were measured during the power ascension portion of the startup testing program using the incore movable detector flux mapping system. The results of the flux maps are give in Table 4.1.1-1. The flux map taken with an ejected rod will be discussed in Section 4.1.4.

The flux maps taken and listed in Table 4.1.1-1 were taken over a range of 30% to 100% power at various control rod configurations. The flux maps were taken to provide results to verify the accuracy of the physics models used in the core design, to verify operation of the reactor within WCGS Technical Specification power distribution requirements during typical operation, to obtain calibration data for the Nuclear Instrumentation System (NIS), and to obtain baseline data for the target axial flux distribution surveillance. As shown in Table 4.1.1-1, normally 58 thimbles are used for a full flux map. Several flux maps taken during the incore/excore detector calibration used only 16 thimbles because it was only desired to monitor the axial offset.

The measured power distribution parameters are compared with WCGS Technical Specification limits in Table 4.1.1-1. The power distribution for all flux maps met their design, accident, and WCGS Technical Specification limits. The predicted vs. measured axial powers were within the 10% value as required by design when clarification was obtained from Westinghouse indicating that this was only applicable for the larger unrodded core region during normal operation.

All power distribution measurement results were acceptable when compared with the design, accident analysis, and Technical Specification limits. The core exhibits a small natural tilt to quadrant II, NIS channel N43. The small natural tilt does not exceed the WCGS Technical Specification limits.

TABLE 4.1.1-1

WCGS INCORE FLUX MAP SUMMARY DURING POWER ASCENSION

Map No.	No. Thimbles Used	Date	%P	Core B/U MWD/MTM	Rod Pos.	F_Q Max.	F_Q Loc.	F_Q Limit	$F_{\Delta H}$ Max.	$F_{\Delta H}$ Loc.	$F_{\Delta H}$ Limit	F_{XY} Max.	F_{XY} AX. PT.	F_{XY} Limit
C1M005*	58	6/27/85	30	134	HFPRIL	2.2070	D5	4.640	1.4216	D7	1.6986	1.5662	9	1.950
C1M006*	58	6/27/85	30	134	HFPRIL D12@228	2.2384	E14	4.640	1.5304	E14	1.6986	1.8390	9	1.9494
C1M007	58	7/9/85	50	229	D@202	2.0976	D9	4.640	1.4228	D9	1.639	1.4515	39	1.705
C1M008	58	7/9/85	50	280	D@200	2.1117	D9	4.640	1.4246	D9	1.639	1.6186	9	1.705
C1M009	58	7/21/85	68	370	D@202	2.0086	D12	3.412	1.3468	D9	1.5854	1.4752	39	1.649
C1M010	58	7/26/85	75	523	D@210	1.9891	D9	3.093	1.3538	D9	1.5645	1.3665	39	1.6275
C1M012#	16	7/26/85	75	533	D@152	2.2292	H11	3.093	1.3950	H11	1.5645	1.5242	9	1.7955
C1M013	58	7/27/85	75	533	D@158	2.2523	D9	3.093	1.3798	D9	1.5645	1.5307	9	1.7955
C1M019#	16	7/27/85	75	533	D@210	1.9932	H11	3.093	1.3491	H11	1.5645	1.3585	36	1.6275
C1M020	58	7/27/85	75	537	D@210	2.0373	D4	3.093	1.3635	D4	1.5645	1.3721	17	1.6275
C1M021	58	8/6/85	92	737	D@214	2.0360	D9	2.522	1.3634	D9	1.5138	1.3670	23	1.5748
C1M023	58	8/12/85	100	932	D@215	2.0313	H5	2.320	1.3621	D9	1.49	1.3663	16	1.55
C1M024	58	8/22/85	100	1192	D@218	2.0250	H5	2.320	1.3632	H5	1.49	1.3703	16	1.55

Map No.	AO	Radial Tilt N41	Radial Tilt N42	Radial Tilt N43	Radial Tilt N44	Incore AO (%) N41	Incore AO (%) N42	Incore AO (%) N43	Incore AO (%) N44
C1M005*	-12.214	0.9903	1.0137	1.0134	0.9826	-11.956	-12.501	-12.106	-12.240
C1M006*	-6.014	0.9461	1.0935	0.9945	0.9659	-8.484	-0.468	-7.571	-7.535
C1M007	-4.269	0.9896	1.0172	1.0128	0.9805	-4.382	-3.907	-4.618	-4.171
C1M008	-5.410	0.9894	1.0159	1.0130	0.9817	-4.497	-6.001	-5.299	-5.844
C1M009	-7.762	0.9890	1.0105	1.0100	0.9905	-7.601	-8.084	-7.905	-7.458
C1M010	-6.468	0.9915	1.0084	1.0106	0.9895	-6.379	-6.629	-6.577	-6.287
C1M012#	-21.813	1.000	1.000	1.000	1.000	-21.813	-21.813	-21.813	-21.813
C1M013	-25.133	0.9915	1.0073	1.0120	0.9892	-25.013	-25.406	-25.165	-24.949
C1M019#	-1.171	1.000	1.000	1.000	1.000	-1.171	-1.171	-1.171	-1.171
C1M020	2.389	0.9907	1.0084	1.0111	0.9898	2.493	2.381	2.349	2.334
C1M021	-10.035	0.9937	1.0082	1.0106	0.9875	-9.863	-10.049	-10.244	-9.985
C1M023	-10.962	0.9946	1.0065	1.0109	0.9881	-10.767	-10.996	-11.098	-10.986
C1M024	-9.926	0.9945	1.0060	1.0100	0.9895	-9.719	-9.924	-10.102	-9.958

*Flux Maps for ejected rod verification.

#Quarter core flux maps.

NOTE: Map's #'s C1M011, C1M014-C1M018 were quarter core maps taken during the incore-excore calibration and not used. C1M022 is non-existent.

4.1.2 AXIAL FLUX DIFFERENCE INSTRUMENTATION CALIBRATION

This test consisted of three sections:

1) A preliminary Incore-Excore calibration after the trip at 50% Rated Thermal Power and prior to escalation above 50% power. It was done using the incore flux maps taken at 30% and 50% power,

2) The Incore-Excore calibration at 75% power using a series of full core and quarter core flux maps taken at the 75% power level,

3) A "fine tuning" of the Incore-Excore calibration at 100% power.

The Axial Flux Difference Instrumentation Calibration is based on a number of flux maps taken at various axial offsets (AO) to determine a correlation between Incore and Excore detectors (AO is defined as difference of % power in top half of core and bottom half of core divided by the sum of % power in top and bottom of core). Plots of Incore AO vs. Excore AO were generated for each excore channel. The slope of a least squares straight line drawn through the AO points yields the correction factor to correlate the NIS excore detectors to the measured incore power distribution. The correction factor is equal to the least squares straight line slope and is shown in Table 4.1.2-1 for each channel. The correction factor is entered into the plant computer at the computer addresses shown in Table 4.1.2-1.

Another plot of excore (NIS channel) top and bottom detector current vs. incore AO is used to predict 100% power current values from each detector. 100% power currents are used because at that power level, delta q (defined as % power in top half of core minus % power in bottom half of core) is equal to AO and subsequent calculations can be minimized. The resulting least squares fit straight line is used to derive expected current values which are input into the NIS circuitry to check control board and computer values for consistency at specific AO values. Figure 4.1.2-2 shows 100% power current values input into the NIS circuitry to calibrate the excore system to the incore measurement.

The preliminary calibration at 50% power indicated that delta q values from the plant computer did not favorably compare with predicted values. A closer analysis showed the computer was using an average power from all NIS channels instead of only the channel being tested at this point in time, as assumed in calculating the predicted value. The predicted values were corrected to actual NIS indications and close agreement between predicted and actual computer values resulted. Since this was only a preliminary calibration, it was decided power escalation to 75% could be safely achieved, and a more accurate Axial Flux Calibration done at that power level.

A series of flux maps were taken at various AO values for the Axial Flux Calibration at 75% power by inducing an axial xenon oscillation in the reactor core. The flux maps used were maps C1M010, C1M012, C1M013, C1M019, and C1M020 shown in Table 4.1.1-1. These maps allowed for use of five points to obtain the least squares straight line values to perform an accurate Axial Flux Calibration. Inputting the 100% power current values into the NIS circuitry resulted in a discrepancy between predicted and

TABLE 4.1.2-1

INCORE/EXCORE CORRECTION FACTOR

POWER LEVEL	Correction Factor			
	KØ554 (N41)	KØ552 (N42)	KØ551 (N43)	KØ553 (N44)
5Ø%	1.35Ø	2.192	1.6Ø2	1.525
75%	1.8188	1.8418	1.7949	1.9342
1ØØ%	1.8188	1.8418	1.7949	1.9342

TABLE 4.1.2-2

100% NIS CURRENT VALUES

Power Plateau (%)	A.O. (%)	NIS Channel Currents (μa)							
		41		42		43		44	
		Top	Bottom	Top	Bottom	Top	Bottom	Top	Bottom
50	-30	213.0	329.5	231.3	327.3	207.2	329.3	229.9	341.1
	-75	135.8	430.5	164.2	375.4	117.2	395.4	168.7	430.2
	-35	204.4	340.9	223.8	332.6	197.2	336.6	223.1	351.0
	0	264.5	262.2	276.0	295.2	267.2	285.2	270.7	281.7
	+7	276.5	246.7	286.4	287.7	281.2	274.9	280.2	267.8
	+75	393.2	93.9	387.7	214.9	417.2	174.9	372.7	133.2
	+30	316.0	194.9	320.7	263.1	327.2	241.1	311.5	222.3
75	-30	226.3	316.1	239.7	341.7	226.6	339.2	236.1	328.4
	-75	154.3	378.1	167.6	411.3	157.2	411.2	165.8	389.1
	-35	218.3	323.0	231.7	349.5	218.8	347.2	228.3	335.1
	0	274.4	274.7	287.9	295.4	272.8	291.2	283.1	287.9
	+7	285.6	265.0	299.1	284.6	283.6	280.0	294.0	278.4
	+75	394.4	171.2	408.1	179.5	388.5	171.1	400.3	186.6
	+30	322.4	233.3	336.0	249.0	319.1	243.1	330.0	247.4
100%	0	274.7	269.6	284.8	287.4	272.5	285.6	281.4	282.4

measured values from the delta I penalty generator and certain process computer values for delta q. A new gain for the delta I penalty generator was calculated using voltage signals to prevent otherwise required gain changes each time an Axial Flux Calibration was done. The newly calculated gains produced the expected function generator output thereby satisfying the acceptance criteria. The delta I penalty function generator gain values for each NIS channel are shown in Table 4.1.2-3. The process computer flagged all values with AO ±75% as unreliable. This was understandable since the computer was scaled for voltages of +10 to -10 volts and ±75% AO values would correspond to voltage magnitudes greater than 10 volts. With the preceding discrepancies explained and/or corrected, the Axial Flux Calibration was satisfactorily completed at 75% power and power escalation to 100% was allowable for Axial Flux Calibration verification purposes.

At 100% power, a flux map was taken (map C1M023 as shown on Table 4.1.1-1) to verify the Axial Flux Calibration values input at 75% power were 1) correct, or 2) needed "fine tuning". It was determined a "fine tuning" of the NIS was needed to give the required accuracy between the control board delta I meters, process computer delta q, and flux map (Incore) AO measurement. A one point correction for detector currents was done to give the required identical values, within acceptable tolerances, for process computer delta q, and control room delta I meter values (at 100% power percent delta I = percent delta q = AO).

With the "fine tuning" completed another flux map was taken at 100% power to verify that the "fine tuning" gave successful correlation between control room delta I indication, process computer delta q output, and flux map (Incore) AO results. The results shown in Table 4.1.2-4 indicate the Axial Flux Calibration at 100% power was within the required accuracy.

The Axial Flux Difference Instrumentation Calibration showed improved accuracy each time it was checked from 50% power to 100% power. Each adjustment to the NIS circuitry brought the incore/computer/control room meters into closer agreement until the final adjustment at 100% power verified incore delta q vs. control room meter delta q and computer delta q was within the design acceptance criteria of 1.5% and the control room meter delta q vs. computer delta q was within the design acceptance criteria of ±0.5%.

TABLE 4.1.2-3

GAIN VALUES FOR DELTA I FUNCTION GENERATOR

%P	N41	N42	N43	N44
5Ø	1.661	2.48Ø	1.978	2.Ø73
75	1.Ø	1.Ø	1.Ø	1.Ø
1ØØ	1.832	1.845	1.8ØØ	1.965

TABLE 4.1.2-4
DELTA q VALUES AT SPECIFIED POWER PLATEAUS

Power Plateau	N41				N42				N43			
	Meas.	Meter	Comp.	Meter/Comp Error	Meas.	Meter	Comp.	Meter/Comp Error	Meas.	Meter	Comp	Meter/Comp Error
5Ø%	+3Ø	+3Ø	+18.4	11.6	+3Ø	+3Ø	+15.3	14.7	+3Ø	+3Ø	+17.4	12.6
	+7	+7	+4.4	2.6	+7	+7	+3.8	3.2	+7	+7	+4.Ø	3.Ø
	Ø	Ø	*	-	Ø	Ø	Ø.1	-Ø.1	Ø	Ø	*	-
	-3Ø	-3Ø	-19.3	-1Ø.7	-3Ø	-3Ø	-16.4	-13.6	-3Ø	-3Ø	-12.1	-17.9
75%	+3Ø	+3Ø	+22.3	7.7	+3Ø	+3Ø	+22.2	7.8	+3Ø	+3Ø	+21.7	8.3
	+7	+7	+5.3	1.7	+7	+7	+5.2	1.8	+7	+7	+5.1	1.9
	Ø	Ø	Ø	Ø	Ø	Ø	Ø	Ø	Ø	Ø	Ø	Ø
	-3Ø	-3Ø	-22.4	-7.6	-3Ø	-3Ø	-21.2	-8.8	-3Ø	-3Ø	-22.2	-7.8
1ØØ%	-1Ø.8	-9.Ø	-9.Ø	-Ø	-11.Ø	-9.Ø	-9.4	-Ø.4	-11.1	-9.Ø	-1Ø.3	-1.3
	-9.7	-9.8	-1Ø.Ø	-Ø.2	-9.9	-1Ø.1	-1Ø.Ø	Ø.1	-1Ø.1	-9.8	-1Ø.1	-Ø.3
Acceptance Error				Ø.6	-			Ø.6	-			Ø.6

Power Plateau	N44				Max. Meas./Comp error	
	Meas.	Meter	Comp.	Meter/Comp Error		Ch. No.
5Ø%	+3Ø	+3Ø	+14.9	15.1	15.1	N44
	+7	+7	+3.4	3.6	3.6	N44
	Ø	Ø	Ø	Ø	-	-
	-3Ø	-3Ø	-14.Ø	-16.Ø	-17.9	N43
75%	+3Ø	+3Ø	+22.2	7.8	8.3	N43
	+7	+7	+5.3	1.7	1.9	N43
	Ø	Ø	-11.9	11.9	-11.9	N44
	-3Ø	-3Ø	-22.6	-7.4	-8.8	N42
1ØØ%	-11.Ø	-11.Ø	-9.Ø	-2.Ø	-2.Ø	N44
	-1Ø.Ø	-11.1	-1Ø.7	Ø.4	Ø.7	N44
Acceptable Error				Ø.6	1.5	-

*Computer flagged as unreliable

4.1.3 POWER COEFFICIENT DETERMINATION

Power coefficient measurement was done during the power ascension program to verify values used in the nuclear design and accident analysis prediction for the Doppler Only Power Coefficient.

The measurement values were achieved at power plateaus of 30, 50, 75, and 90% power by causing a series of small load swings at the turbine-generator. These series of load swings resulted in corresponding temperature swings in the Reactor Coolant System, but of opposite sign to the turbine-generator load swing. The Reactor Coolant System temperature change for each turbine-generator load change was recorded and used in a subsequent calculation to determine a Doppler Coefficient Verification Factor. The measured Doppler Coefficient Verification Factor (C^M) is the ratio of the change in core average temperature and the change in power due to the doppler effect. This ratio is equivalent to the predicted ratio of the Doppler Only Power Coefficient and the isothermal temperature coefficient (C^P). Since for small changes of temperature, the void coefficient portion of the power coefficient is insignificant, the ratio is also proportional to the power coefficient.

The predicted value of the verification factor was calculated using the design values for the Doppler Only and isothermal temperature coefficients. The measured value of the Doppler Coefficient Verification Factor was compared with the predicted value. The results of the comparison are shown in Table 4.1.3-1. The results show the values used for the nuclear design and accident analysis prediction are very close to those measured and that the measured values are well within the required acceptance criteria.

TABLE 4.1.3-1

DOPPLER COEFFICIENT VERIFICATION FACTORS

Power Level (%)	C^M ($^oF/\%$)	C^P ($^oF/\%$)	$C^M + C^P$	Acceptable $C^M + C^P$
30	-2.35	2.34	0.01	< 0.5
50	-1.90	1.89	0.01	< 0.5
75	-1.16	1.21	0.05	< 0.5
90	-1.087	1.18	0.093	< 0.5

4.1.4 PSEUDO ROD EJECTION TEST

This test is used to verify that the values in the design and accident analysis for ejection of the most reactive rod from the Hot Full Power Rod Insertion Limit (HFP RIL) are conservative.

Two main parameters are measured by this test for comparison with design values: 1) the positive reactivity worth added from the HFP RIL to the full out position for control rod D-12 (designated as most reactive rod) and 2) the core power peaking factors resulting from ejection of rod D-12 from the core with all other control rods at the HFP RIL.

The worth of control rod D-12 was measured by pulling only rod D-12 from the HFP RIL to the full out position and measuring the resulting change in moderator/coolant temperature, Tavg. The mathematical product of the isothermal temperature coefficient and temperature change results in the reactivity worth of rod D-12 from the HFP RIL to 228 steps withdrawn. The results and acceptance criteria for D-12 rod worth are shown in Table 4.1.4-1.

Following D-12 rod worth determination, rod D-12 was reinserted to the HFP RIL and the calculated worth was equated to boron worth. Rod D-12 was subsequently borated to the full out position with all other rods remaining at the HFP RIL and a full core flux map was obtained. Pertinent core peaking factor results from analysis of a flux map before and after rod D-12 ejection, are shown in Table 4.1.4-2.

TABLE 4.1.4-1

D-12 ROD WORTH FROM HFP RIL

%P	30
delta rod position (steps)	67
reactivity change (pcm)	17.04
1.10 times reactivity change (pcm)	18.74
acceptable reactivity change	< 230

TABLE 4.1.4-2

FLUX MAP RESULTS FROM ROD D-12 EJECTION

Core Parameters	Prior to D-12 ejection		D-12 ejected	
	Measured	Limit	Measured	Limit
F delta H Nuclear	1.4216	1.6986	N/A	N/A
Fxy	1.5662	1.95	N/A	N/A
FQ (Z)	2.2070	4.64	2.2415	2.26
QPTR	1.0137	1.02	N/A	N/A

4.2 CONTROL SYSTEM DYNAMIC RESPONSE

Prior to the completion of the 30% power plateau testing, the proper response of the reactor control system, the steam dump control system and the steam generator level control was verified. The purpose of these tests was to verify that the controller settings resulted in relative stable operation. The steam generator level control system section also discusses testing done at higher power levels. The overall plant response to transient and trip testing is discussed in section 4.3.

4.2.1 DYNAMIC AUTOMATIC STEAM DUMP CONTROL

The steam dump (turbine bypass) system consists of twelve valves which are designed to handle 40% of full turbine steam flow at full load pressure. Seven valves discharge into the low pressure condenser, four valves discharge into the intermediate condenser, and a single valve discharges into the high pressure condenser. The system is designed to:

1) Allow a 50 percent step electrical load reduction without reactor trip (Section 4.3.2). The system will allow a turbine and reactor trip from full power without lifting the main steam safety valves,

2) Control steam generator pressure at no-load conditions,

3) Bypass steam to the main condenser during plant startup and permit a normal manual cooldown of the RCS from a hot standby condition to a point consistent with the initiation of residual heat removal system operation.

The steam dump system, during normal operating transients for which the plant is designed, is automatically regulated by the RCS temperature control system to maintain the programmed coolant temperature (Tavg mode). The programmed coolant temperature (Tref) is derived from the high pressure turbine first stage impulse pressure, which is a load reference signal. The difference between Tref and measured Tavg is used to activate the steam dump system under automatic control. The system operates the valves in two fundamental modes. In one mode, two groups of six valves each trip open sequentially in approximately 3 seconds. This operational mode is activated during a large reactor-to-turbine power mismatch (load rejection controller). In the second mode, four groups of three valves each modulate open sequentially in approximately 10 seconds (plant trip controller).

When the plant is at no load and there is no turbine load reference, the system is operated in the pressure control mode. The measured main steam header pressure is compared to the pressure set by the operator in the control room. The pressure control mode is also used for plant cooldown.

Both the Tavg mode and the steam pressure mode of control were individually tested. In the steam pressure mode, reactor power was raised from approximately 2 percent to approximately 10 percent to verify that the steam dump system would adjust valve position to maintain the steam header pressure at the set value.

In the Tavg mode, two individual tests were performed; one to verify proper plant trip controller response, and one to verify load rejection controller response. The plant trip controller response test was performed by simulating a P-4 reactor trip signal and then adjusting Tavg by changing reactor power to verify proper automatic steam dump operation. The load rejection controller response test was performed by simulating a sudden loss of load at approximately 6 percent reactor power and verifying proper automatic steam dump operation. During the testing, steam dump system parameters were monitored using strip chart recorders.

The following acceptance criteria were satisfied during the testing:

1) The plant trip controller (AB-TC-500D) responded properly to maintain Tavg at 562 $\pm$ 2 ^{o}F at approximately 6% power. After steady state power was achieved there were no divergent oscillations in temperature,

2) The load rejection controller (AB-TC-500A) responded properly to maintain Tavg at 561 $\pm$ 2 ^{o}F at approximately 6% power. After steady state power was achieved, there were no divergent oscillations in temperature,

3) The steam header pressure controller (AB-PK-507) responded properly to maintain pressure at the normal no-load pressure of 1092 $\pm$ 25 psig.

No control system adjustments were required as a result of this test. The test was completed on June 11, 1985, after several days delay while adjustments were made to the automatic steam generator level control system.

4.2.2 AUTOMATIC REACTOR CONTROL

To control RCS average temperature (Tavg) as power is increased or decreased a reference temperature, Tref, corresponding to turbine load as indicated by first stage turbine impulse pressure, is provided to the reactor control system. Tref is then compared to the actual Tavg in the RCS loops. The auctioneered high Tavg from the four loop Tavg's is used as the basis for the comparison. If a difference of more than 1.5^{O}F exists, the rod control system, when in the automatic mode, will insert or withdraw the control rods to align Tavg with Tref. The purpose of this test was to verify initial satisfactory operation of the system in automatic. Additional testing to perform adjustments on the system is discussed in Section 4.4.5.

To verify system operation, Tavg was increased by approximately 6^{O}F by withdrawing the control rods in MANUAL. Rod control was then placed in AUTO and various parameters were monitored on strip chart recorders as the plant responded. The process was then repeated for a 6^{O}F decrease in Tavg by inserting the control rods in MANUAL and then placing the rod control system in AUTO.

This test was performed with the plant at steady state 30% power conditions on June 27, 1985. For both the increase and decrease in Tavg, control rods immediately started to move when the rod control system was placed in AUTO. Tavg was within 1.5^{O}F of Tref in less than one minute in both cases. The following acceptance criteria were satisfied:

1) No manual intervention was required to bring plant conditions to equilibrium values following the initiation of the transients,

2) Tavg returned to within $\pm$ 1.5^{O}F of Tref following the initiation of the transients,

3) Temperature variations were less than 5^{O}F peak-to-peak and temperature oscillations had a period of greater than one minute following the initiation of the transient,

When the data was analyzed slight temperature oscillations of less than 0.5^{O}F with a period of approximately twenty seconds were noted both before and after the initiation of the transient. However, there was no temperature oscillation caused by the reactor control system during the transient, therefore, the period was infinity and acceptance criterion 3) above was satisfied. Westinghouse concurred that the results were satisfactory.

4.2.3 AUTOMATIC STEAM GENERATOR LEVEL CONTROL TEST

This series of tests was performed to verify the satisfactory operation of the various components of the automatic steam generator level control system at steady state conditions as well as under increasingly severe plant transients. The head capacity curves of both steam driven main feedwater pumps were also verified.

Initial testing was performed at approximately 10% reactor power to verify the ability of the bypass feedwater control valves to control steam generator level at zero electrical load in automatic. Level offsets were introduced in each steam generator and then the bypass feedwater control valves were placed in automatic and allowed to restore level. The nuclear feed forward signal in the bypass valve control circuitry was checked by performing 3% power decreases and increases and monitoring valve performance.

The next test was performed in the 10% - 19% power range to verify the initial satisfactory operation of the main feedwater control valves. The bypass valves were closed, the main feedwater control valves were in manual, the feedwater pumps were in auto and the pump speed controls were in auto. A level offset was introduced in each steam generator and the applicable control valve was placed in automatic and allowed to restore level. 3% and 1% power changes were also introduced with the main feedwater control valves in automatic. Overall operation was satisfactory. Slight setting changes were made in the controls for the C steam generator to reduce coupling with the B steam generator. Two defective controller cards were replaced in the pump speed control system.

Testing at 30% power included verification of the operating characteristics of the steam driven main feedwater pumps. Both pumps exceeded predicted performance. Main feedpump speed control performed satisfactorily under these conditions. A ten percent power decrease was performed and then a ten percent power increase. Overall operation of the steam generator level control system was satisfactory although levels in the B and D steam generators went below 40% briefly at the beginning of the transient.

Pump performance was again verified to be satisfactory at 50% power. Steam generator level control was monitored during a 25% power decrease and then a 15% power increase. The power increase was terminated at 40% due to a xenon transient. As a result of these transients adjustments were made to the main feedwater valve controllers and the master pump speed controller. Also, the feedwater pump delta P/speed controller did not achieve the desired setpoint at 25% power for the differential between feedwater header pressure and steam header pressure. The steam flow indication loops were realigned.

At 75% power, steam generator level control was monitored during the large load reduction test (Section 4.3.2). The overall response of the control systems was satisfactory during the transient, although levels went outside the 40-60% band and were outside the 45-55% band after 5 minutes. As noted previously at 25% power, the feedwater pump delta P/speed controller was still not operating satisfactorily at 25% power thus requiring further adjustment.

During 100% power testing, data was collected during the 10% load swing test (Section 4.3.1). Control system performance was satisfactory. The control systems were then monitored during the large load reduction test (Section 4.3.2). Level did go outside the 40% -60% band with a low level of 34.5% in the "D" steam generator. After review of the data, Westinghouse determined that response was satisfactory since no levels had been outside of initial level ±15%. The feedwater pump delta P/speed controller performed satisfactorily during the transients.

In summary, the steam generator water level controls were satisfactorily adjusted to handle normal operation as well as major oscillations. The main feedwater pumps head and capacity curves were better than expected.

4.3 TRANSIENT AND TRIP TESTS

Plant response to transients of varying magnitude was determined during the power ascension phase of the startup program. These tests were utilized to analyze the overall behavior of the major plant control systems during a power swing or an actual plant trip. The need for further control system adjustments was determined by monitoring various plant parameters before, during and after each transient.

The specific tests performed consisted of a series of 10% power load swings at 30%, 75% and 100% power, a 50% load reduction at 75% and 100% power, a trip to determine ability to shutdown and maintain hot standby external to the control room, a trip at 50% power to verify the ability of the nuclear instruments to detect dropped rods, and a unit trip at 100% power.

4.3.1 LOAD SWING TESTS

The purpose of the load swing tests was to verify the proper nuclear plant transient response, including automatic control system performance, when 10% load changes, both decrease and increase, were introduced at the turbine generator. Tests were performed at the 30%, 75% and 100% power test plateaus.

The tests were started with stable plant conditions at the desired test plateau and the following systems in automatic:

1) Steam Generator Main Feedwater Control,
2) Pressurizer Pressure Control,
3) Pressurizer Heater Groups A and B,
4) Pressurizer Heater Group C in CLOSE,
5) Pressurizer Level Control,
6) Steam Dump Control in Tavg Control Mode,
7) Main Feedwater Pump Turbine Speed Control.

After initial plant data was collected to verify plant stability, the electro-hydraulic controller (EHC) was used to achieve a 10% load decrease as rapidly as possible. When the plant was in a stable condition additional data was collected. During the transient certain parameters were monitored on multichannel strip chart recorders.

The EHC controller was then used to increase the plant output as rapidly as possible to achieve a 10% load increase and attain a final plant level at approximately the original test plateau. After the plant was in a stable condition, a final set of data was collected.

The acceptance criteria for these tests were:

1) No reactor trip was generated,

2) No turbine trip was generated,

3) Safety injection was not initiated,

4) Neither the steam generator relief valves nor safety valves lifted,

5) Neither the pressurizer relief valves nor safety valves lifted,

6) No manual intervention was required to bring the plant conditions to steady state,

7) Nuclear power overshoot was less than 3% for load increase,

8) Nuclear power undershoot was less than 3% for load decrease.

The data from the three test plateaus is summarized in Tables 4.3.1-1 through 4.3.1-6.

TABLE 4.3.1-1
LOAD SWING FROM 30% TO 20% POWER

Parameter	Initial	During Transient Minimum	During Transient Maximum	Final
Plant Operating Level (MWe-Gross)	290	-	-	190
Nuclear Power (%)	32	20	32	22
Tavg - auctioneered (°F)	566	561.5	566	562
Tref (°F)	566	-	-	563
Delta T - Loop 1 (%)	38	25	38	27
Overpower Delta T Setpoint (%)	108	-	-	108
Overtemperature Delta T Setpoint (%)	140	-	-	147
Pressurizer Pressure (psig)	2230	2219	2283	2230
Pressurizer Level (%)	35	29	36	30
Steam Header Pressure (psig)	1030	1024 (1)	1068 (1)	1030
Steam Flow ($lb_M/hr \times 10^6$)				
Loop 1	1.1	-	-	0.7
Loop 2	1.15	-	-	0.8
Loop 3	1.2	-	-	0.85
Loop 4	1.0	-	-	0.55
Narrow Range Steam Generator Level (%)				
Loop 1	49	38	57	48
Loop 2	50	40	58	50
Loop 3	49	40	58	50
Loop 4	49	39	56	49
Feedwater Temperature (°F)				
Loop 1	347.7	-	-	316.8
Loop 2	347.8	-	-	317.3
Loop 3	347.8	-	-	317.0
Loop 4	347.2	-	-	316.1
Feedwater Flow ($lb_M/hr \times 10^6$) Loop 1	1.0	-	-	0.4
Loop 2	0.9	-	-	0.4
Loop 3	1.0	-	-	0.45
Loop 4	1.0	-	0	0.5
Feedwater Pump Discharge Pressure, psig	1120	(1) 1064	(1) 1155	1110
Feed Pump A Speed (RPM)	3900	3870	4200	3600
Feed Pump B Speed (RPM)	1000	(1) -	(1) -	1000
Control Bank D Position (steps)	194/195	-	-	146/145

(1) From test recorders
Time to reach equilibrium following load change: 4 minutes.

TABLE 4.3.1-2
LOAD SWING FROM 20% TO 30% POWER

Parameter	Initial	During Transient		Final
		Minimum	Maximum	
Plant Operating Level (MWe-Gross)	190	-	-	290
Nuclear Power (%)	22	22	32.5	32
Tavg - auctioneered (^{0}F)	562	559	565.5	565.5
Tref (^{0}F)	563	-	-	565.5
Delta T - Loop 1 (%)	27	27	38.5	38
Overpower Delta T Setpoint (%)	108	-	-	109
Overtemperature Delta T Setpoint (%)	147	-	-	138
Pressurizer Pressure (psig)	2230	2215	2275	2225
Pressurizer Level (%)	30	26.5	36.5	34
Steam Header Pressure (psig)	1030	983 (1)	1030 (1)	1028
Steam Flow (lb_M/hr x 10^6)				
Loop 1	0.7	-	-	1.1
Loop 2	0.8	-	-	1.15
Loop 3	0.85	-	-	1.2
Loop 4	0.55	-	-	1.0
Narrow Range Steam Generator Level (%)				
Loop 1	48	41	57.5	48
Loop 2	50	41.5	61	50
Loop 3	50	40.5	58	49
Loop 4	49	43	59.5	49
Feedwater Temperature (^{0}F)				
Loop 1	316.8	-	-	347.9
Loop 2	317.3	-	-	348.0
Loop 3	317.0	-	-	348.4
Loop 4	316.1	-	-	347.6
Feedwater Flow (lb_M/hr x 10^6) Loop 1	0.4	-	-	0.95
Loop 2	0.4	-	-	0.90
Loop 3	0.45	-	-	1.0
Loop 4	0.5	-	-	1.0
Feedwater Pump Discharge Pressure, psig	1110	(1) 1021	(1) 1196	1120
Feed Pump A Speed (RPM)	3600	(1) 3720	(1) 3785	3900
Feed Pump B Speed (RPM)	1000	(1) 1000	(1) 1000	1000
Control Bank D Position (steps)	146/145	-	-	194

(1) From test recorders
Time to reach equilibrium following load change: 3 minutes.

TABLE 4.3.1-3
LOAD SWING FROM 75% TO 65% POWER

Parameter	Initial	During Transient		Final
		Minimum	Maximum	
Plant Operating Level (MWe-Gross)	775	-	-	650
Nuclear Power (%)	75.5	60	75.5	62.5
Tavg - auctioneered (^{0}F)	579	575	581	576
Tref (^{0}F)	581	-	-	578
Delta T - Loop 1 (%)	75	64	76	67
Overpower Delta T Setpoint (%)	109	-	-	109
Overtemperature Delta T Setpoint (%)	122	-	-	128
Pressurizer Pressure (psig)	2250	2219	2288	2230
Pressurizer Level (%)	54	45	56	46
Steam Header Pressure (psig)	1000	1014 (1)	1066 (1)	1000
Steam Flow ($lb_M/hr \times 10^6$)				
Loop 1	2.7	-	-	2.3
Loop 2	2.5	-	-	2.2
Loop 3	2.7	-	-	2.3
Loop 4	2.5	-	-	2.3
Narrow Range Steam Generator Level (%)				
Loop 1	48	42	53	48
Loop 2	49	42	53	50
Loop 3	49	42	55	50
Loop 4	49	42	52	48
Feedwater Temperature (^{0}F)				
Loop 1	416.6	-	-	403.3
Loop 2	416.9	-	-	403.6
Loop 3	416.8	-	-	403.7
Loop 4	416.1	-	-	402.8
Feedwater Flow ($lb_M/hr \times 10^6$) Loop 1	2.7	-	-	2.3
Loop 2	2.7	-	-	2.2
Loop 3	2.8	-	-	2.3
Loop 4	2.7	-	-	2.3
Feedwater Pump Discharge Pressure, psig	1180	(1) 1188	(1) 1204	1140
Feed Pump A Speed (RPM)	4400	(1) 4200	(1) 4608	4100
Feed Pump B Speed (RPM)	4600	(1) 4392	(1) 4824	4300
Control Bank D Position (steps)	199/198	-	-	146/145

(1) From test recorders
Time to reach equilibrium following load change: 5 1/2 minutes.

TABLE 4.3.1-4
LOAD SWING FROM 65% TO 75% POWER

Parameter	Initial	During Transient Minimum	During Transient Maximum	Final
Plant Operating Level (MWe-Gross)	660	-	-	760
Nuclear Power (%)	62.5	62	74.5	74.5
Tavg - auctioneered (°F)	576	575	580	580
Tref (°F)	578	-	-	582
Delta T - Loop 1 (%)	66	66	76	75
Overpower Delta T Setpoint (%)	109	-	-	109
Overtemperature Delta T Setpoint (%)	117	-	-	121
Pressurizer Pressure (psig)	2238	2220	2275	2235
Pressurizer Level (%)	47	44	53	53
Steam Header Pressure (psig)	1010	975 (1)	1014 (1)	1010
Steam Flow ($lb_M/hr \times 10^6$)				
Loop 1	2.3	-	-	2.85
Loop 2	2.25	-	-	2.8
Loop 3	2.45	-	-	2.85
Loop 4	2.35	-	-	2.8
Narrow Range Steam Generator Level (%)				
Loop 1	48	42	55	48
Loop 2	47	43	58	50
Loop 3	48	42	57	49
Loop 4	48	43	55	49
Feedwater Temperature (°F)				
Loop 1	402.7	-	-	415.1
Loop 2	403.0	-	-	415.2
Loop 3	403.0	-	-	415.5
Loop 4	402.1	-	-	414.5
Feedwater Flow ($lb_M/hr \times 10^6$) Loop 1	2.4	-	-	2.8
Loop 2	2.4	-	-	2.8
Loop 3	2.45	-	-	2.85
Loop 4	2.4	-	-	2.8
Feedwater Pump Discharge Pressure, psig	1150	(1) 1077	(1) 1116	1160
Feed Pump A Speed (RPM)	4100	(1) 4032	(1) 4392	4400
Feed Pump B Speed (RPM	4300	(1) 4104	(1) 4536	4500
Control Bank D Position (steps)	148	-	-	199

(1) From test recorders
Time to reach equilibrium following load change: 5 minutes.

TABLE 4.3.1-5
LOAD SWING FROM 100% to 90% POWER

Parameter	Initial	During Transient Minimum	During Transient Maximum	Final
Plant Operating Level (MWe-Gross)	1050	-	-	930
Nuclear Power (%)	99.8	87.5	99.8	87.5
Tavg - auctioneered (°F)	587.5	585	587.5	585
Tref (°F)	588.5	-	-	585
Delta T - Loop 1 (%)	101	90.5	101	90.5
Overpower Delta T Setpoint (%)	108	-	-	108
Overtemperature Delta T Setpoint (%)	112	-	-	115
Pressurizer Pressure (psig)	2230	2210	2300	2220
Pressurizer Level (%)	61	57	65	57
Steam Header Pressure (psig)	1000	1000 (1)	1040 (1)	1010
Steam Flow ($lb_M/hr \times 10^6$)				
Loop 1	2.99	-	-	2.61
Loop 2	2.91	-	-	2.53
Loop 3	2.95	-	-	2.61
Loop 4	2.95	-	-	2.57
Narrow Range Steam Generator Level (%)				
Loop 1	48	42	50	48
Loop 2	50	44	53	50
Loop 3	48	45	53	49
Loop 4	49	46	52	49
Feedwater Temperature (°F)				
Loop 1	439.1	-	-	429.5
Loop 2	439.3	-	-	429.7
Loop 3	439.5	-	-	429.6
Loop 4	438.6	-	-	428.7
Feedwater Flow ($lb_M/hr \times 10^6$) Loop 1	2.99	-	-	2.65
Loop 2	2.87	-	-	2.49
Loop 3	2.95	-	-	2.57
Loop 4	2.95	-	-	2.53
Feedwater Pump Discharge Pressure, psig	1200	(1) 1188	(1) 1240	1190
Feed Pump A Speed (RPM)	5000	(1) 4714	(1) 5143	4700
Feed Pump B Speed (RPM)	5200	(1) 5000	(1) 5429	4900
Control Bank D Position (steps)	222	-	-	162

(1) From test recorders
Time to reach equilibrium following load change: 6 1/2 minutes.

TABLE 4.3.1-6
LOAD SWING FROM 90% to 100% POWER

Parameter	Initial	During Transient Minimum	During Transient Maximum	Final
Plant Operating Level (MWe-Gross)	935	-	-	1010
Nuclear Power (%)	89	89	93	93
Tavg - auctioneered (^{o}F)	585.5	581.5	582	582
Tref (^{o}F)	585	-	-	587
Delta T - Loop 1 (%)	91	91	98	98
Overpower Delta T Setpoint (%)	109	-	-	109
Overtemperature Delta T Setpoint (%)	116	-	-	120
Pressurizer Pressure (psig)	2245	2220	2250	2250
Pressurizer Level (%)	59	52	59	54
Steam Header Pressure (psig)	1010	962 (1)	1014 (1)	962
Steam Flow (lb_M/hr x 10^6)				
Loop 1	2.65	-	-	2.91
Loop 2	2.57	-	-	2.84
Loop 3	2.65	-	-	2.84
Loop 4	2.61	-	-	2.80
Narrow Range Steam Generator Level (%)				
Loop 1	48	46	54	48
Loop 2	50	47	58	50
Loop 3	50	45	56	50
Loop 4	49	47	55	49
Feedwater Temperature (^{o}F)				
Loop 1	429.7	-	-	436.4
Loop 2	429.9	-	-	436.8
Loop 3	429.9	-	-	436.5
Loop 4	429.2	-	-	436.0
Feedwater Flow (lb_M/hr x 10^6) Loop 1	2.65	-	-	2.91
Loop 2	2.53	-	-	2.80
Loop 3	2.57	-	-	2.84
Loop 4	2.57	-	-	2.84
Feedwater Pump Discharge Pressure, psig	1200	(1) 1123	(1) 1188	1155
Feed Pump A Speed (RPM)	4750	(1) 4571	(1) 4714	4800
Feed Pump B Speed (RPM)	4950	(1) 4857	(1) 5143	5000
Control Bank D Position (steps)	194	-	-	223

(1) From test recorders
Time to reach equilibrium following load change: 6 1/2 minutes.

The test at 30% power was performed on June 29, 1985. All of the acceptance criteria as outlined above were satisfied. There were several parameters that went outside their expected band:

1) Maximum pressurizer pressure was 53 psig above initial pressure ($\leq$50 psig expected),

2) Steam generator levels were expected to be within $\pm$ 10% of initial levels but steam generator A dropped 11% on the load decrease and steam generator B increased 11% on the load increase,

3) Tavg was not expected to overshoot (undershoot) its final value on load increase (decrease) but on the load decrease 0.5 $^{\circ}$F undershoot was noted.

These slight deviations from expected valves were reviewed by Westinghouse and determined to be acceptable.

The test at 75% power was performed on July 28, 1985. All of the acceptance criteria as previously outlined were satisfied. During the initial 10% power decrease, the operators had to take manual control of feedwater pump speed control to maintain steam generator feed flow. After adjustments to the gain on the feed flow/steam flow mismatch cards (FY510D - FY540D), the 10% power decrease and the 10% power increase were performed without further difficulty. As for the 30% power test, several parameters, including steam pressure overshoot/undershoot, steam generator level swing and Tavg undershoot were outside the Westinghouse expected range by a slight amount but this was determined not to impact the test results and no additional control system adjustments were required.

The test at 100% power was performed on August 22, 1985. All of the acceptance criteria as previously outlined were satisfied. The power increase was actually closer to 7% than 10%. Rods had to be withdrawn somewhat prior to the power increase to bring axial flux difference within Technical Specifications limits. This left insufficient rod worth to complete the 10% power increase. A review of the test data showed that all systems performed satisfactorily and that there was no need for further testing. As noted in the previous load swing tests, some parameters were slightly outside the Westinghouse expected values including RCS pressure swing and steam pressure overshoot. These were reviewed by Westinghouse and determined not to impact the test results. No control system adjustments were required.

4.3.2 LARGE LOAD REDUCTION TESTS

The large load reduction tests were performed during the 75 percent and 100 percent power testing plateaus to verify the ability of the primary plant, secondary plant and the automatic reactor control systems to sustain a 50 percent step load reduction. The data obtained was used to evaluate the interaction between the control systems and to determine if any setpoint or gain adjustments were necessary.

During each load reduction test, selected plant parameters were trended on multi-channel strip chart records. Stable operation was verified with rod control, steam generator MFW control, pressurizer pressure and spray control, pressurizer level control and feedwater pump turbine speed control systems in automatic. Steam dump control was in the Tavg mode. Using the standby load set, generator load was reduced by 50 percent within approximately 1 minute with all test recorders in high speed. No manual intervention with the control systems was allowed during and following the 50 percent load reduction. The plant was allowed to stabilize with control systems in automatic.

The large load reduction test at 75 percent power was performed on July 28, 1985. Without manual intervention, the automatic control systems did sustain the load reduction and allow the plant to be returned to stable conditions. All acceptance criteria were satisfied:

1) The reactor did not trip,

2) The turbine did not trip,

3) Safety injection did not initiate,

4) Steam generator safety valves did not lift,

5) Pressurizer safety valves did not lift,

6) No manual intervention was required to reach equilibrium plant conditions.

The actual load reduction was 627 MWe (54.5%). As a result, the steam dump valves did not shut until after 9 minutes, 40 seconds after start of transient (expected 8 minutes) and Tavg peaked 6 ^{o}F above its initial value (5 ^{o}F expected). A Westinghouse evaluation determined that both these values were consistent with a 54.5% power decrease. The test data is summarized in Table 4.3.2-1. No control system setpoints or gains were changed as a result of this test.

The large load reduction test at 100 percent power was performed on August 29, 1985. Without manual intervention, the plant systems reached equilibrium conditions. All the major acceptance criteria were met as discussed above for the 75% power test. No control system setpoints or gains were changed as a result of this test. The test data is summarized in Table 4.3.2-2.

TABLE 4.3.2-1
LARGE LOAD REDUCTION
TEST FROM 75% POWER

Parameter	Initial	During Transient		Final
		Minimum	Maximum	
Nuclear Power (%)	75.5	20	75	26
Tavg - auctioneered (°F)	580	562	586	564
Tref (°F)	581	-	-	565
Delta T (%)	77	26	77	32
Overpower Delta Setpoint (%)	109	-	-	109
Over temperature Delta T Setpoint (%)	121	-	-	144
Pressurizer Pressure (psig)	2240	2140	2320	2240
Pressurizer Level (%)	52	30	59	31
Steam Header Pressure (psig)	1014	1014	1118	1040
Steam Flow ($lb_M/hr \times 10^6$)				
Loop 1	2.75	-	-	0.9
Loop 2	2.6	-	-	1.0
Loop 3	2.8	-	-	1.0
Loop 4	2.7	-	-	1.0
Narrow Range Steam Generator Level (%)				
Loop 1	48	31	62	47
Loop 2	50	33	66	50
Loop 3	50	31	66.5	50
Loop 4	50	34.5	64.5	49
Feedwater Temperature (°F)				
Loop 1	416.4	-	-	333.2
Loop 2	416.8	-	-	333.4
Loop 3	416.6	-	-	333.8
Loop 4	415.8	-	-	332.9
Feedwater Flow ($lb_M/hr \times 10^6$) Loop 1	2.75	-	-	0.8
Loop 2	2.75	-	-	0.45
Loop 3	2.8	-	-	0.65
Loop 4	2.7	-	-	0.8
Feedwater Pump Discharge Pressure, psig	1162	1136	1240	1136
Control Bank D Position (steps)	181	-	-	95/94

Time to reach equilibrium following load change: 36 minutes.

TABLE 4.3.2-2
LARGE LOAD REDUCTION
TEST FROM 100% POWER

Parameter	Initial	During Transient Minimum	During Transient Maximum	Final
Nuclear Power (%)	99.5	53	99.5	53
Tavg - auctioneered (^oF)	588	573	588	573
Tref (^oF)	588	-	-	573
Delta T (%)	100	62	100	62
Overpower Delta T Setpoint (%)	108	-	-	108
Over temperature Delta T Setpoint (%)	110	-	-	131
Pressurizer Pressure (psig)	2235	2155	2340	2255
Pressurizer Level (%)	62	44	62	44
Steam Header Pressure (psig)	1020	1020	1118	1027
Steam Flow ($lb_M/hr \times 10^6$)				
Loop 1	3.8	-	-	2.1
Loop 2	3.6	-	-	2.0
Loop 3	3.7	-	-	2.2
Loop 4	3.6	-	-	2.1
Narrow Range Steam Generator Level (%)				
Loop 1	48	31.5	56	48
Loop 2	50	33	57	50
Loop 3	49	33	58	50
Loop 4	49	32.5	58	50
Feedwater Temperature (^oF)				
Loop 1	438.2	-	-	392.0
Loop 2	438.6	-	-	392.3
Loop 3	438.5	-	-	392.2
Loop 4	437.6	-	-	391.3
Feedwater Flow ($lb_M/hr \times 10^6$) Loop 1	3.8	-	-	2.1
Loop 2	3.6	-	-	1.9
Loop 3	3.7	-	-	2.0
Loop 4	3.7	-	-	2.0
Feedwater Pump Discharge Pressure, psig	1188	1162	1331	1162
Control Bank D Position (steps)	217	-	-	97

Time to reach equilibrium following load change: Approximately 12 minutes (based on steam dump demand trace).

4.3.3 SHUTDOWN AND MAINTENANCE OF HOT STANDBY EXTERNAL TO THE CONTROL ROOM

The purpose of this test was to demonstrate that, using plant operating procedures (OFN-13 - Control Room Not Habitable), the plant can be taken from $\geq$ 10 percent power to hot standby conditions and then maintained in hot standby for at least 30 minutes with a minimum shift crew using controls and instrumentation external to the Control Room. The minimum shift crew was that specified in OFN-13.

This test was performed on June 29, 1985. During the evacuation of the Control Room by the minimum shift crew, a standby crew remained in the Control Room to monitor plant conditions. The standby crew was to take no actions during the transient. The reactor was tripped at 1111 by manually tripping the reactor trip breakers from the Control Room. The minimum shift crew then evacuated the Control Room to take control of the plant at the Auxiliary Shutdown Panel (ASP) and other duty stations as outlined by OFN-13 and as directed by the Shift Supervisor. Hot standby conditions were established at 1147 and maintained until 1220.

During this period, pressurizer pressure, pressurizer level, steam generator level and RCS temperature were maintained from outside the Control Room. The acceptance criteria of the procedure were met.

4.3.4 RODS DROP AND PLANT TRIP

This test was performed at the end of the 50 percent power test plateau to demonstrate operation of the negative rate trip circuitry by dropping two RCCA's from a common rod group and to review plant response and control systems behavior to a plant trip from an intermediate power level prior to the plant trip test from 100 percent power.

During the performance of the test, a high speed chart recorder was used to monitor the state of the reactor trip breakers, the rod-on-bottom alarms, nuclear instrumentation system (NIS) power and negative rate trip bistable output. While at steady state plant conditions (50 ± 5% power), the two control rods (D-4 and M-12) in group 1 of control bank D (CBD) were transferred to the DC hold bus. The drop of the two rods was initiated by removing the stationary gripper coil fuses for D-4 and M-12 in power cabinet 1AC and then deenergizing the DC hold bus.

The trip test was performed July 16, 1985 with satisfactory results. The two dropped rods did cause a reactor trip due to power range high negative rate and all rods dropped normally. The pressurizer safety valves did not lift, the steam generator safety valves did not lift, and safety injection was not initated, thus satisfying all the acceptance criteria for the test.

In addition, the reactor trip generated a turbine trip. The steam dumps operated to reject heat to the condenser and feed flow, steam flow, and steam generator narrow range levels all went to zero as indicated on the process instrumentation.

The traces on the high speed chart recorder did not show a change of state for the NIS negative rate bistables because the recorder was set up with a 5 to 120 VAC range. Investigation determined the NIS negative rate bistables tripped at 9 VAC therefore the event recorder bistable in the recorder did not show a change of state. However, the negative rate bistable trip was shown by the indicator lights on the front panel of the NIS negative rate trip drawer and by the first-out indicators on the main control board. Both of these had to be reset prior to subsequent startup.

Table 4.3.4-1 summarizes the data from this test.

TABLE 4.3.4-1
RODS DROP AND PLANT TRIP
TEST DATA SUMMARY

Plant Parameter	Before Trip	During Transient		After Trip
		Minimum	Maximum	
Tavg Auctioneered, ^{O}F	568.5	555.Ø	568.5	554.5
Tref , ^{O}F	571.5	-	-	558.Ø
Delta T - Loop 1 , %	55	2	55	2
Overpower Delta T Setpoint - Loop 1, %	134	-	-	>15Ø
Overtemperature Delta T Setpoint - Loop 1, %	1Ø9	-	-	1Ø8
Pressurizer Pressure, psig	2225	2125	2245	2245
Pressurizer Level, %	38	24	38	25
Narrow Range, Steam Generator Level - Loop 1, %	49	Ø	53	14

4.3.5 PLANT TRIP FROM 100 PERCENT POWER

The purpose of this test was:

1) To verify the ability of the primary and secondary plant and the plant automatic control systems to sustain a trip from 100 percent power and to bring the plant to stable conditions following the transient,

2) To determine the overall response time of the reactor coolant hot leg resistance temperature detectors and,

3) To evaluate the data resulting from this test to determine if changes in the control system setpoints are warranted to improve transient response based on actual plant operation.

For the performance of this test, the plant was operated at 100 percent power with the following control systems in automatic:

1) Reactor Rod Control,
2) Steam Generator Main Feedwater Control,
3) Pressurizer Pressure and Spray Control,
4) Pressurizer Heater Groups A and B,
5) Pressurizer Heater Group C in close position,
6) Pressurizer Level Control,
7) Steam Dump Control in Tavg control mode,
8) Main Feedwater Pump Turbine Controls.

All shutdown and control rod banks were fully withdrawn except control bank D which was positioned to maintain axial flux difference within the limits specified in WCGS Technical Specifications.

Various plant parameters were input to strip chart recorders to monitor the plant performance during the trip. After initial data was recorded and the test recorders were operational, the plant trip was initiated by momentarily jumpering two terminals of the Turbine Sequential Trip relay (AR in Cabinet MA 104B) which opened both Main Generator Output Breakers.

After the trip, the plant was restored to a stable condition using normal plant operating procedures.

The plant was tripped from 100% power at 0512 on August 28, 1985. Using the opening of Generator Output Breaker #2 as time zero, the turbine tripped at 0.075 seconds and the reactor trip breakers opened at 0.155 seconds. The steam dump valve demand signal went to 100% (open) at 0.225 seconds and then modulated to 0% (closed) at 46.885 seconds. The steam dump valves were placed in pressure control mode at 0517. Feedwater isolation signal was received at 0514.

The following major acceptance criteria of the test were met during the trip:

1) All control rods dropped,

2) Reactor Coolant System Pressure remained less than 2450 psig (maximum pressure of 2260 psig was reached at 16.5 minutes during plant recovery),

3) Steam Header Pressure remained less than 1150 psig (maximum pressure of 1090 psig was reached at 5.965 seconds),

4) Safety Injection was not initiated,

5) Using the strip chart recordings, the overall Hot Leg RTD response times were determined for each loop as:

Loop 1	6.000 seconds
Loop 2	5.900 seconds
Loop 3	5.630 seconds
Loop 4	5.880 seconds

All response times were less than the required 8.4 seconds.

The overall Hot Leg RTD response time includes response of the RTD itself, and was defined for the purpose of this test as the interval of time measured between the point where the neutron flux has decreased by 50 percent of its initial value to the point where the hot leg temperature signal (as measured by the RTD output) has decreased by a value equivalent to 33 1/3 percent of the initial loop delta T value in degrees Fahrenheit.

The remaining major acceptance criterion required that neutron flux drop below 15 percent power within 2 seconds of the last generator output breaker opening. Since the pen for Generator Output Breaker #1 stopped inking when the recorder was shifted to high speed just prior to the trip, it was impossible to determine the exact time this breaker opened. However, a review of the recorder traces and plant performance as discussed above indicate that the generator output breakers opened at essentially the same time. Based on the opening time of generator output breaker #2, Nuclear Flux was below 15 percent at 1.325 seconds.

In addition, a review of the strip chart recording showed that the plant control systems responded satisfactorily to this transient and no changes to control system setpoints were required to improve plant response.

Table 4.3.5-1 summarizes the data from this test.

TABLE 4.3.5-1
PLANT TRIP FROM 100 PERCENT POWER
TEST DATA SUMMARY

Plant Parameter	Before Trip	During Transient		After Trip
		Minimum	Maximum	
Tavg Auctioneered, °F	588.2	555	588.2	555
Tref, °F	588.5	-	-	557
Delta T - Loop 1, %	99.5	4	99.5	4
Overpower Delta T Setpoint - Loop 1, %	108	-	-	108
Overtemperature Delta T Setpoint - Loop 1, %	110	-	-	146
Pressurizer Pressure, psig	2230	1990	2255	2255
Pressurizer Level, %	62	27.5	62	27.5
Narrow Range Steam Generator Level - Loop 1, %	48	0	48	16

4.4 INSTRUMENTATION CALIBRATION AND ALIGNMENT

During the power ascension test program, a series of tests was performed to calibrate and align various plant control and instrumentation systems. The first test discussed determined thermal power as well as collecting statepoint data at various steady state power levels. The data collected was then used for the calibration of the steam and feedwater flow instrumentation and startup adjustments of the reactor control system. In addition, testing was performed to operationally align the nuclear instrumentation system and the process temperature instrumentation.

4.4.1 THERMAL POWER MEASUREMENT AND STATEPOINT DATA COLLECTION

This series of tests had three purposes:

1) To provide a method for determining reactor thermal power,

2) To collect control and protection instrumentation calibration data at steady state power levels (statepoints) during the power ascension test program,

3) To determine RCS flowrate using calorimetric data (50%, 75%, 90%, 100%).

After the initial test setup was verified during the post core loading precritical testing (section 2.7), data was collected at 30%, 40%, 50%, 75%, 90%, 98% and 100% power. The control and protection instrumentation data served as an input to the calibration of the steam and feedwater flow instrumentation (section 4.4.2) and to the startup adjustments of the reactor control system (section 4.4.5).

Test instrumentation was installed to monitor feedwater flow to each steam generator and steam pressure in each steam generator. To improve the potential accuracy of the test data, the range of the feedwater flow test instruments was increased as power was increased. The initial set of instruments were 0-5 psid while the final set of instruments was 0-50 psid. Using the information from the test instruments as well as feedwater temperature from process instrumentation and the ASME Steam Tables, the enthalpy rise across each steam generator was calculated. Steam quality was assumed to be 1.0 (see section 4.5 for actual moisture carryover) and for all but the 100% power test steam generator blowdown was isolated. After correcting the heat input to the steam generators for the actual RCP heat input as determined during the preoperational hot functional test, the actual percent of design power was determined.

RCS flow was determined using calorimetric data at 50%, 75%, 90%, 98% and 100% power. The flow calculation used the thermal heat output for each RCS loop as determined by the calorimetric, T_{HOT} and T_{COLD} for each loop, the enthalpies of the water in the RCS hot legs and cold legs, and the specific volume of the cold leg water to determine the RCS loop flow. The total RCS flow was the sum of the loop flows. The data is summarized in Table 4.4.1-1. RCS flow was greater than the minimum allowable flow at all test plateaus.

TABLE 4.4.1-1
RCS FLOW FROM CALORIMETRIC
MEASUREMENT

Loop	Nominal Power Level 50%	75%	90%	98%	100%
1	106,795 gpm	105,648 gpm	108,107 gpm	105,480 gpm	103,890 gpm
2	103,069 gpm	106,374 gpm	105,484 gpm	101,621 gpm	99,210 gpm
3	105,036 gpm	103,521 gpm	103,813 gpm	103,481 gpm	100,460 gpm
4	103,796 gpm	101,778 gpm	103,665 gpm	102,939 gpm	102,150 gpm
Total	418,696 gpm	417,321 gpm	421,069 gpm	413,521 gpm	405,710 gpm
Acceptance Criteria	>382,800 gpm	>388,542 gpm	>388,542 gpm	*	>388,542 gpm

* The test at 98% power was performed for information only, therefore there was no acceptance criteria in the procedure.

4.4.2 CALIBRATION OF STEAM AND FEEDWATER FLOW INSTRUMENTATION

The purpose of this test was to collect data during the power ascension testing to allow the calibration of the steam flow transmitters against feedwater flow. Test instrumentation was used to measure the feedwater flow element differential pressure and the flow calculations were performed as part of the thermal power measurement (section 4.4.1). In addition, the flow data collected was compared to design values for steam flow and feed flow.

During the post core loading precritical testing, the static zero shift of the installed instrumentation was verified. One steam flow transmitter had to be replaced (Section 2.7). The remainder of the testing used data collected at 30%, 50%, 75% and 100% power plateaus during the thermal power measurement test (Section 4.4.1).

At 30% and 50% power, data was accumulated and it was verified that the steam flow/feedwater flow mismatch alarm did not actuate. After the 75% data was analyzed, the steam flow transmitters were respanned and additional data was collected. Also, the Tref program was adjusted prior to the second set of data resulting in higher steam pressure and lower flows for a given power level (section 4.4.5). The steam flow/feedwater flow mismatch did not actuate.

The 100% power data was collected with steam generator blowdown in service. After correcting for the blowdown flow, it was determined that the following acceptance criteria were satisfied:

1) The steam flow/feedwater flow mismatch alarm did not actuate,

2) Steam flow indication on the main control board was within $\pm$ 4.0% of feedwater flow indication on the main control board,

3) Plots of feedwater flow from the test instrumentation versus feedwater flow from installed plant instrumentation were within $\pm$2.5% of the ideal (design) curves,

4) Plots of feedwater flow from the test instrumentation versus steam flow from installed plant instrumentation were within $\pm$3.0% of the ideal (design) curves.

Although all acceptance criteria were satisfied, the 100% power data was analyzed to determine optimum spans for the steam flow transmitters. The spans were adjusted after the completion of the test program and additional steam flow and feedwater transmitter output data was collected at 100% power.

4.4.3 OPERATIONAL ALIGNMENT OF NUCLEAR INSTRUMENTATION

The Nuclear Instrumentation System (NIS), because of its importance in monitoring reactor operation, was checked and calibrated throughout the startup test program. Earlier sections of this report have detailed NIS testing which was performed before initial fuel load, during post-core load testing and during initial criticality and low power physics testing. This section summarizes all testing and calibration done on the NIS throughout the test program including the additional testing done during power ascension testing.

PRIOR TO FUEL LOAD

Testing before fuel load was done in three separate phases as described in Section 1.0. First, an extensive preoperational-type functional test was performed on all the circuits, alarms, bistables and meters in all three ranges of the NIS. Second, the high voltage, discriminator voltage and preamplifier settings were determined and the source ranges calibrated accordingly. Finally, just hours prior to the movement of the first fuel assembly, analog channel operational tests (ACOT) surveillance procedures were performed on each source range channel.

POST CORE LOAD TESTING

As detailed in Section 2.8, additional functional testing was done on all of the NIS utilizing channel calibration surveillance procedures.

INITIAL CRITICALITY

Just prior to initial criticality, analog channel operational test (ACOT) surveillance procedures were performed on each intermediate and power range channel. After initial criticality, readings were taken to determine the amount of overlap between the source and intermediate range. This data is shown in Table 4.4.3-1.

POWER ASCENSION TESTING

The power ascension testing had three main objectives:

1) To determine overlap between the intermediate and power ranges,

2) To plot power range detector currents versus reactor power,

3) To adjust power range indication to agree with secondary calorimetric calculations.

Overlap testing began at 0% power and continued through 100%. Readings were taken on both intermediate and power range channels to verify that there is at least 1 1/2 decades of overlap between the two ranges. The overlap data is shown in Table 4.4.3-2.

Power range detector current and reactor power readings were taken from 10% to 100% power to verify detector linearity. Figures 4.4.3-1 through 4.4.3-4 depict curves plotting detector current against power and shows that all

TABLE 4.4.3-1
NUCLEAR INSTRUMENTATION OVERLAP DATA
SOURCE RANGE AND INTERMEDIATE RANGE

SOURCE RANGE

	First Positive Indication On Intermediate Range ($>10^{-11}$ Amps)	Intermediate Range Indicates 10^{-10} Amps
Channel N31	-	-
Main Control Board	8×10^{2}	1×10^{4}
NI Drawer	1.25×10^{2}	6.5×10^{3}
Channel N32	-	-
Main Control Board	8×10^{2}	1×10^{4}
NI Drawer	1.25×10^{2}	7×10^{3}

INTERMEDIATE RANGE

	First Positive Indication On Intermediate Range ($>10^{-11}$ Amps)	Intermediate Range Indicates 10^{-10} Amps
Channel N35	-	-
Main Control Board	1×10^{-11}	1×10^{-10}
NI Drawer	1×10^{-11}	1×10^{-10}
Channel N36	-	-
Main Control Board	1×10^{-11}	1×10^{-10}
NI Drawer	1×10^{-11}	1×10^{-10}

TABLE 4.4.3-2
NUCLEAR INSTRUMENTATION OVERLAP DATA
INTERMEDIATE RANGE AND POWER RANGE

INTERMEDIATE RANGE	0%	10%	30%	40%
Channel N35				
Main Control Board	7×10^{-6}	3.5×10^{-5}	1.7×10^{-4}	3.0×10^{-4}
NI Drawer	6.5×10^{-6}	5×10^{-5}	1.5×10^{-4}	2.8×10^{-4}
Channel N36				
Main Control Board	7×10^{-6}	4.0×10^{-5}	1.9×10^{-4}	3.0×10^{-4}
NI Drawer	6×10^{-6}	5×10^{-5}	1.7×10^{-4}	2.9×10^{-4}
POWER RANGE				
Channel N41				
Main Control Board	1%	10%	34%	43%
NI Drawer	1.5%	10.1%	34%	42.5%
Channel N42				
Main Control Board	1%	10%	36%	42%
NI Drawer	1.5%	11%	37%	42.5%
Channel N43				
Main Control Board	1%	11%	36%	44%
NI Drawer	1.5%	10.8%	35.25%	42.75%
Channel N44				
Main Control Board	0%	10%	35.5%	42%
NI Drawer	1.5%	11%	36%	42.5%

TABLE 4.4.3-2 (CONT)
NUCLEAR INSTRUMENTATION OVERLAP DATA
INTERMEDIATE RANGE AND POWER RANGE

<u>INTERMEDIATE RANGE</u>

	50%	75%	90%	100%
Channel N35				
Main Control Board	3.5×10^{-4}	4.5×10^{-4}	6×10^{-4}	6×10^{-4}
NI Drawer	3×10^{-4}	4.5×10^{-4}	5.5×10^{-4}	6×10^{-4}
Channel N36				
Main Control Board	3.5×10^{-4}	5×10^{-4}	6×10^{-4}	7×10^{-4}
NI Drawer	3.2×10^{-4}	5.1×10^{-4}	6×10^{-4}	7×10^{-4}

<u>POWER RANGE</u>

	50%	75%	90%	100%
Channel N41				
Main Control Board	49%	75%	92%	100%
NI Drawer	48%	75%	92%	100%
Channel N42				
Main Control Board	49%	75%	92%	100%
NI Drawer	48%	75%	92%	100%
Channel N43				
Main Control Board	49%	76%	93%	101%
NI Drawer	48%	75%	92%	100%
Channel N44				
Main Control Board	49%	75%	92%	100%
NI Drawer	48%	76%	92%	100%

*NOTE: Overlap readings at 0%, 10% and 30% were taken before Power Range Gain was adjusted to match secondary caloriometric.

FIGURE 4.4.3-1

CHANNEL CURRENT VS. REACTOR POWER

CHANNEL N41

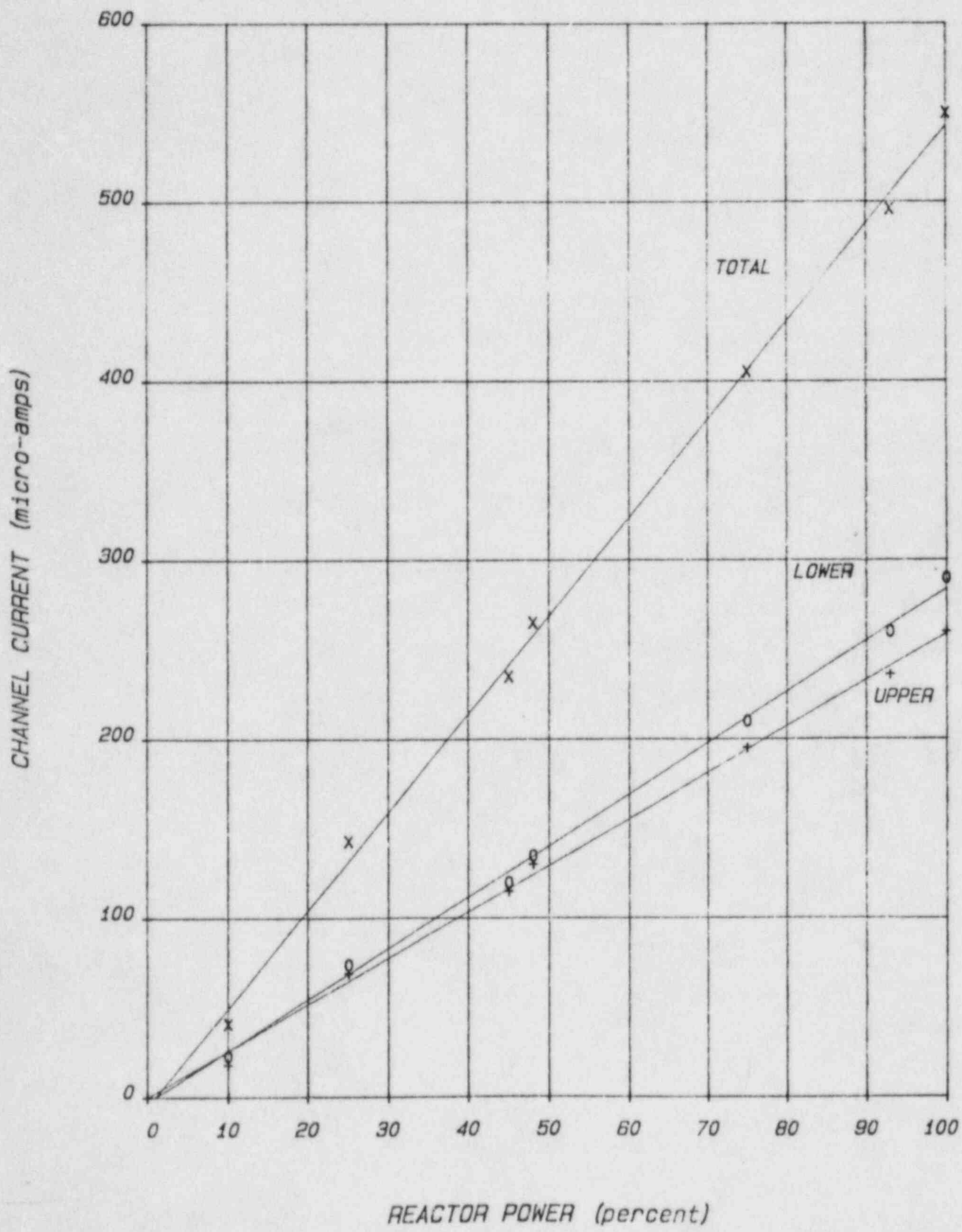


FIGURE 4.4.3-2

CHANNEL CURRENT VS. REACTOR POWER

CHANNEL N42

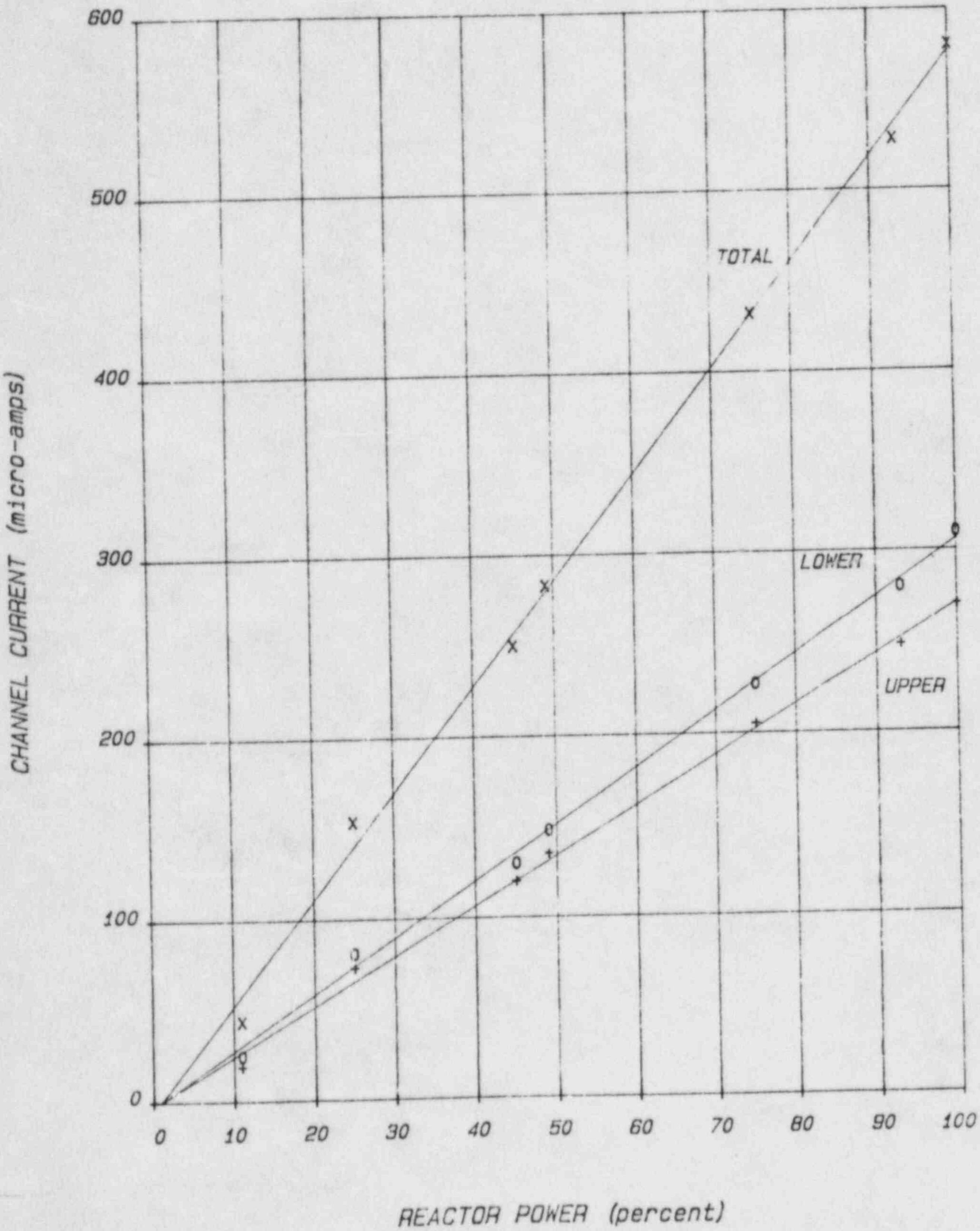


FIGURE 4.4.3-3

CHANNEL CURRENT VS. REACTOR POWER

CHANNEL N43

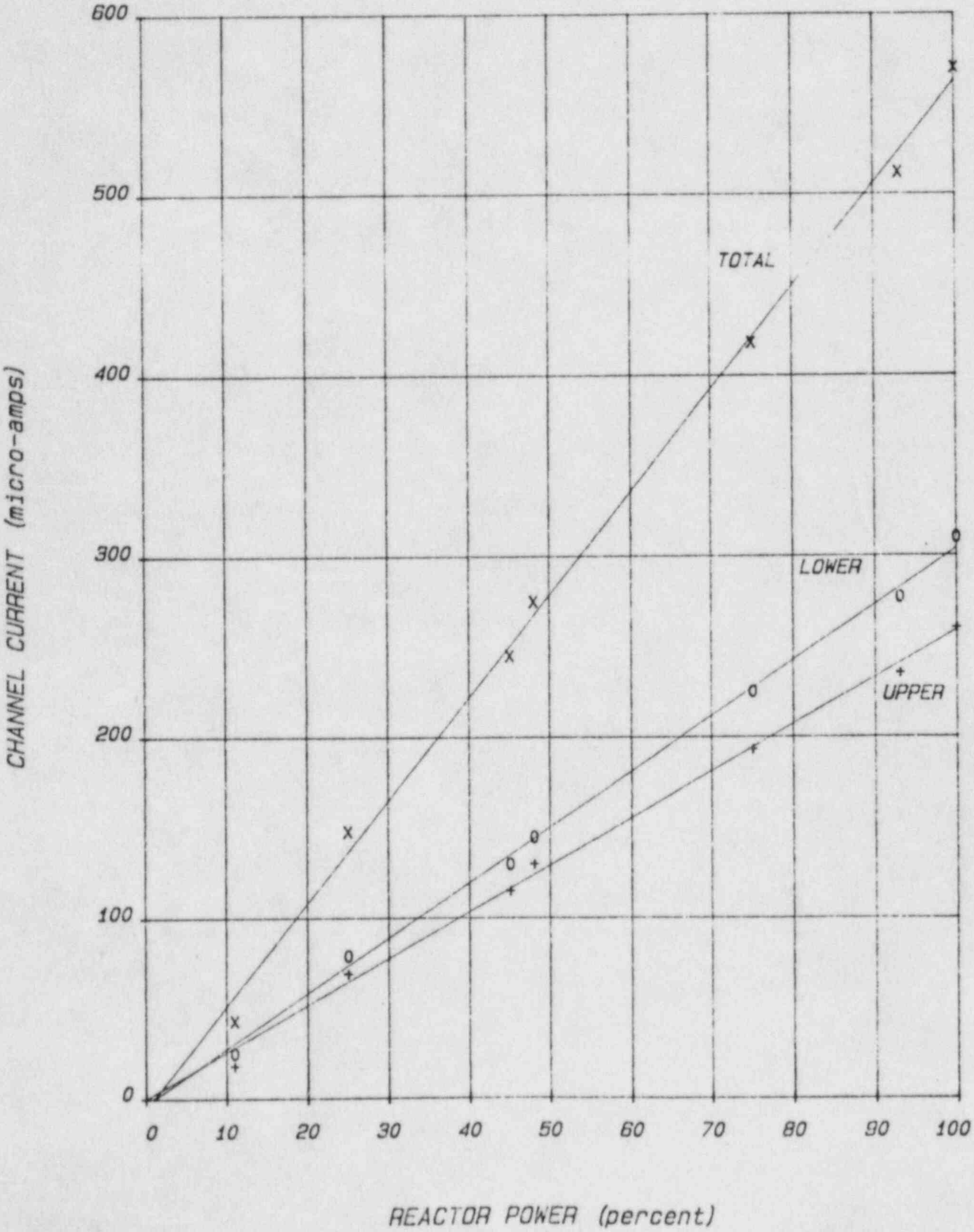
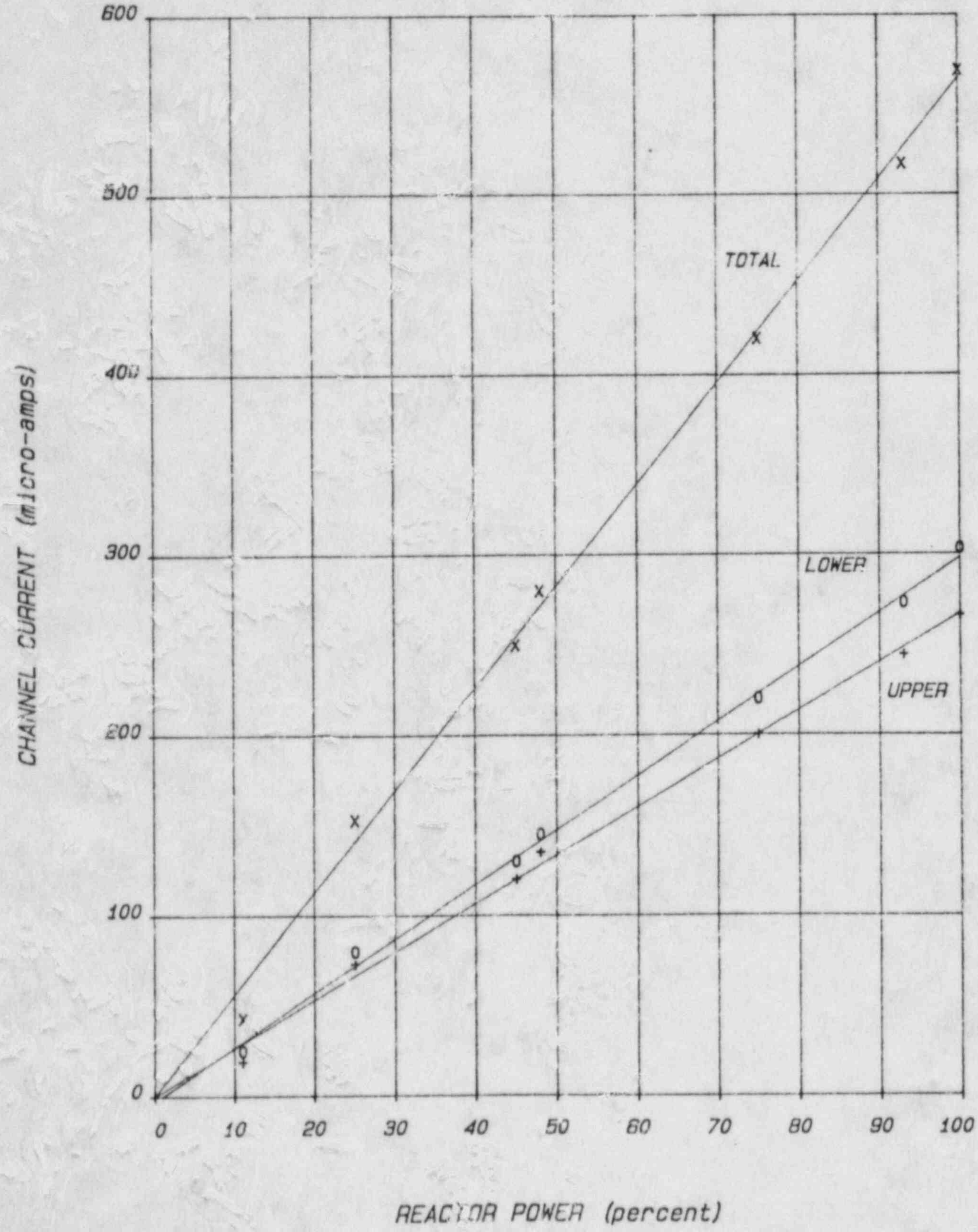


FIGURE 4.4.3-4

CHANNEL CURRENT VS. REACTOR POWER

CHANNEL N44



detectors responded linearly.

Beginning at 30% power, the power range channels were adjusted to match reactor power as calculated using a secondary calorimetric. This adjustment is required by Technical Specifications to be done on a daily basis. Therefore, normally the operations surveillance procedure was used to make this adjustment. A few times, however, the adjustments were made based on a calorimetric value from the Startup Test Program. Either method was acceptable and the test program was made more flexible by allowing either type of calorimetric to be used to make the power range adjustments.

When the plant reached 100% power, additional testing was performed to make final adjustments to the NIS. The high voltage settings on both the intermediate and power range detectors were verified acceptable by plotting a plateau curve. The intermediate range 25% reactor trip bistables were also reset using the actual 100% power intermediate range current readings.

After the plant was tripped from 100% power, a test was performed to set the intermediate range compensation voltage and verified the source range detectors had survived 100% power operations by completing a voltage plateau check on each source range detector.

4.4.4 OPERATIONAL ALIGNMENT OF PROCESS TEMPERATURE INSTRUMENTATION

The process instrumentation receives temperature data from the primary coolant system RTD's. This data is used to generate delta T and Tavg values for use by the plant control and protection systems.

Prior to initial criticality while at hot, isothermal conditions (557 $\pm 2^{O}F$), an alignment was performed of the delta T and Tavg process instrumentation. See section 2.7 for a discussion of this test.

During the power ascension test program, data was collected at a series of power plateaus to align the delta T and Tavg instrumentation. The nominal power levels were 30%, 50%, 75%, 90% and 100%. With the plant at steady state conditions, voltage readings were measured and recorded for each protection channel T_{HOT}, T_{COLD} and Tavg at the applicable protection cabinet. The recorded voltages were then converted to temperatures and the measured Tavg was compared with the Tavg calculated from the measured T_{HOT} and T_{COLD}. Also, at all power levels except 100%, T_{HOT} and T_{COLD} spare RTD resistances were measured for each protection cabinet. These measured spare RTD resistances were then converted to temperature and compared to the applicable loop T_{HOT} and T_{COLD}. The core exit TC values were also recorded as additional information.

At 30%, 50%, 75% and 90% power levels the following acceptance criteria were satisfied:

1) The loop Tavg summator output converted to ^{O}F shall agree within $\pm 0.5^{O}F$ of the Tavg value calculated from the measurements of the loop operational T_H and T_C RTD's,

2) The loop operational T_H RTD output converted to ^{O}F shall agree within $\pm 1.2^{O}F$ of the value computed from the measured output of the loop installed spare T_H RTD converted to ^{O}F,

3) The loop operational T_C RTD output converted to ^{O}F shall agree within $\pm 1.2^{O}F$ of the value computed from the measured output of the loop installed spare T_C RTD converted to ^{O}F.

At 75% power, using the temperature and calorimetric data from the previous tests as well as the 75% power test, the 100% power loop delta T's and Tavg's were extrapolated:

	Delta T, ^{O}F	Tavg, ^{O}F
Loop 1	56.28	583.3
Loop 2	55.56	582.4
Loop 3	56.97	583.6
Loop 4	56.37	583.6

The loop delta T's compared reasonably well with the expected best estimate value of 56.8^{O}F quoted in design documents. The extrapolated maximum loop Tavg for 100% power fell outside the original acceptance criteria but further test data at 75% power showed that it was satisfactory (See Section 4.4.5). As a result of the extrapolated 100% power delta T's, new gains were calculated for the delta T summator cards:

Loop	New Delta T Summator Card Gain
1	1.45
2	1.44
3	1.40
4	1.41

At 100% power, no loop Tavg exceeded 588.5^{O}F and no loop delta T exceeded 59.4^{O}F. However, to bring the loop delta T summator output converted to % power within $\pm$1% of the calorimetric power (100.1%), it was necessary to increase the outputs of loops 1, 3, and 4 delta T summators. This was accomplished by calculating new gains:

Loop	Original Power	New Delta T Summator Card Gain
1	97.5%	1.445
3	98.63%	1.420
4	98.63%	1.451

In addition, although not required by the acceptance criteria, the output of the loop 2 delta T summator card was optimized by adjusting the gain to 1.459 (original power 99.15%). Table 4.4.4-1 summarizes the temperature data at the 100% power plateau.

TABLE 4.4.4-1
TEMPERATURE ALIGNMENT DATA AT 100% POWER

Loop No.	R/E Converter Output °F	Delta T Summator Output Power (%)	Delta T Summator Output °F	Delta T Calculated °F	Tavg Summator Output °F	Tavg Calculated °F
1	T_{HOT} 615.3 T_{COLD} 559.9	97.5	54.87	55.4	587.6	587.6
2	T_{HOT} 614.4 T_{COLD} 559.5	99.15	55.09	54.9	587.1	587.0
3	T_{HOT} 616.5 T_{COLD} 560.0	98.63	56.19	56.5	588.2	588.3
4	T_{HOT} 615.4 T_{COLD} 559.7	98.63	55.59	55.7	587.5	587.6

Calorimetric Power = 100.1%

4.4.5 STARTUP ADJUSTMENTS OF THE REACTOR CONTROL SYSTEM

The reactor control system in the automatic mode positions control rods to maintain Tavg in the reactor coolant system at a reference temperature, Tref. If Tavg is different from Tref by $\pm 1.5^{\circ}$F or more, the reactor control system steps the control rods to restore Tavg to the desired temperature band. The reactor control system uses the highest loop Tavg for comparison to Tref. Turbine power based on first stage turbine impulse pressure and nuclear power signals are used to form a power mismatch contribution to the rod control system. The combined temperature error signal (Tavg-Tref) and the power mismatch signal determine rod speed as well as direction of motion.

The purpose of this series of tests was to determine the Tavg program resulting in the highest possible steam pressure and thus optimum plant efficiency without exceeding pressure limitations for the turbine, or the design full power Tavg (588.5°F). As discussed in section 2.7, baseline data was collected in the postcore loading precritical tests at 557°F and 2235 psig. Additional data was collected at 30%, 50%, 75% and 100% power in conjunction with the thermal power measurements, section 4.4.1. Data collected for each loop included T_{HOT}, T_{COLD}, Tavg, feedwater flow, and steam generator pressure. First stage turbine impulse pressure was also recorded as well as Tref, auctioneered Tavg and auctioneered NIS power.

After the 75% data was collected, first stage turbine impulse pressure, Tavg and steam generator pressure were extrapolated to 100% power with the following results:

First stage turbine impulse pressure	~ 685 psia
Tavg	~ 584°F
Steam generator pressure	~ 935 psia

Since Tavg and steam generator pressure were extrapolated to be low, the gain and bias for the control cards TY-505A and TY-505E were checked. The bias on TY-505A was lower than the required value of 7.921. Additional data was then taken and extrapolated to 100% power:

First stage turbine impulse pressure	~ 691.8 psia
Tavg	~ 587.5°F
Steam generator pressure	~ 990.5 psia

At 100% power, the final set of data was collected with Tref found to be slightly greater than 588.5°F. The output of control card TY-505A was adjusted to correct Tref to 588.5°F at nominal 100% power. After this correction, steam generator pressures were:

Loop 1	1007 psia
Loop 2	1010 psia
Loop 3	1004 psia
Loop 4	1010 psia

At the same time, first stage turbine impulse pressure was an average of 712.8 psia. Various control cards were adjusted to match the actual turbine impulse pressure vs. plant power. The steam generator pressures at 100% power were determined to be satisfactory.

As a result of this test, the reactor control system was adjusted to provide a sufficient supply of steam at rated pressure to support 100% power operation.

4.5 STEAM GENERATOR MOISTURE CARRYOVER MEASUREMENT

This test was performed to determine the average moisture carryover content in the steam from the steam generators at 100% power. The radioactive tracer method was used to determine the moisture carryover.

With the plant operating at 100% steady state conditions, a one curie liquid radioactive tracer (sodium-24 in the form of a sodium nitrate solution) was mixed with approximately 20 gallons of demineralized water in a temporary mixing tank and then injected into each steam generator feedwater line using the four feedwater hydrazine ammonia addition pumps. The feedwater lines transported the radioactive tracer into each steam generator. A large volume of demineralized water was then injected to flush out the chemical addition lines. Steam generator blowdown flow had previously been secured to prevent dilution (and loss) of the radioactive tracer. Also, the condensate polishing system and the condensate makeup reject line back to the condensate storage tank had previously been isolated to prevent dilution (and loss) of the radioactive tracer.

After a 30 minute stabilization period to allow mixing of the radioactive tracer in the steam generators and carryover of the radioactive tracer with moisture into the condensate/feedwater systems, three sets of samples were taken at 15 minute intervals from each of the four steam line probes, from each steam generator upper shell, and from the main feedwater system. The samples were then analyzed for sodium -24 activity. Using the results of the sample analysis, a percent moisture carryover was calculated for each set of steam generator upper shell samples and steam line samples. Since the steam generator upper shell results were considered to be more accurate, the steamline samples were used as a backup.

This test was satisfactorily performed on August 10, 1985 with the plant at 99.74% power as determined by the plant calorimetric procedure. The moisture carryover results are summarized in Table 4.5-1. The average moisture carryover was 0.015% as compared to an acceptance criterion of 0.25%.

TABLE 4.5-1
STEAM GENERATOR MOISTURE
CARRYOVER TEST RESULTS

Sample Point	Sample Set	Percent Carryover
Steam Generator Upper Shell	1	.Ø166%
	2	.Ø168%
	3	.Ø122%
	Average	.Ø15%
Main Steam Probe*	1	.Ø167%
	2	.Ø168%
	3	.Ø122%
	Average	.Ø15%

*Backup

4.6 NSSS ACCEPTANCE TEST

The purpose of the NSSS Acceptance Test was 1) to demonstrate the availability and reliability of the Nuclear Steam Supply System and 2) to measure the NSSS power output. The test did not verify any safety criteria, but rather verified the NSSS vendor had supplied an acceptable system for contractual and warranty purposes.

The reliability of the NSSS is demonstrated by maintaining the plant at rated output for 250 hours without incurring a load reduction or plant trip due to a NSSS malfunction. Ideally, the 250 hours should be continuous uninterrupted operation. However, it is acceptable to have only 100 hours of continuous 100% power operation with the remaining 150 hours being accumulated time rather than continuous. Power may be reduced during the 150 hour portion, but the accumulation of time is stopped until power is returned to rated output.

The measurement of the NSSS output is achieved by calculating the enthalpy rise across the steam generators. This enthalpy rise is determined by measuring the inlet feedwater flow, temperature and pressure and its outlet steam pressure. The steam flow is considered to be equal to the feedwater flow since steam generator blowdown is isolated during the test.

The reliability portion of the test commenced at 1607 on August 8, 1985, and 100 hours of continuous operation was achieved at 2007 on August 12, 1985. At no time during that period was power reduced below its acceptable value of 3425 + 0,-5% MWT. Immediately following the completion of 100 hours of operation, the plant was reduced to approximately 60% power to investigate vibration problems with one of the main feedwater pumps.

The pump vibration problem was corrected and at 0630 on August 21, 1985, power was returned to the acceptable range (3254-3425) for testing and the additional accumulation of 150 hours began. On August 22, 1985, power was reduced below the test band for 3 hours and 14 minutes during the performance of another test procedure.

The measurement of the NSSS output portion of this test was conducted on August 23, 1985. Four sets of feedwater and steam data were collected over a four hour period. The results proved to be very consistent and well within the acceptance criteria of 3425 +0, -2% MWT with the calculated values being 3417.5 MWT, 3410 MWT, 3422.4 MWT, and 3416.7 MWT. These values also easily met the additional requirements that each calculated value be within ±1% of the average of the 4 calculated calorimetric values. The variation from the average was less than 0.2%.

The total accumulation of 250 hours was officially signed complete at 1634 on August 27, 1985. Computer trends and operations calorimetric procedures were used to verify that the power output remained inside the acceptable range during the test. The 250 hour run was completed without any NSSS malfunction and the only problem encountered during the test was due to secondary plant.

The test was considered successful in that it proved the NSSS is capable of sustained operation at rated output and is capable of producing an output at the warranted rating of 3425 MWT. Though not a strict test acceptance criterion, the test was also used to document that the secondary side of the plant was capable of operating at 95% of its rated electrical output.

4.7 POWER ASCENSION THERMAL AND DYNAMIC TEST

The purpose of this test was to monitor those systems or portions of systems that could not be monitored during the preoperational hot functional test thermal expansion program because systems did not reach normal operating temperature and also to remonitor those points that did not meet the acceptance criteria for the preoperational hot functional test. The testing included:

1) Demonstrating that the following systems (or portions of systems) which were not monitored during hot functional testing are free to expand thermally as designed:

    a) Main Steam System, from the main steam headers to the condenser via the condenser dump lines,

    b) Main Steam System, from the main steam header to the the steam generator feedwater pump turbines,

    c) Main Feedwater System, from the steam generator feedwater pumps to the steam generators,

2) Monitoring the dynamic response of the main steam system to a plant trip from 100 percent power,

3) Remonitoring the snubbers and spring hangers whose measured movements during hot functional testing were outside of acceptance criteria or associated piping did not reach the normal operating temperature,

4) Visually monitoring (measurement, if required) steady-state vibration of pressurizer surge piping with reactor coolant system primary loop at normal operating mode (RCS at 557 $^{O}F \pm 10\ ^{O}F$, four RCP 's running).

For the thermal expansion portion of the test, 81 lanyard transducers and 37 resistance temperature detectors (RTD's) were installed at selected locations to measure piping movements and corresponding temperatures in the main steam and main feedwater systems. These instruments were connected to a data acquisition system (DAS) provided by Westinghouse where data was collected and printed out at the selected temperature plateaus. At these temperature plateaus, walkdown inspections were performed to verify that no piping was being restrained, other than by design, from thermal growth, swing clearances were checked on all required snubbers and snubber and spring hanger settings were recorded.

For the dynamic response to the 100% power plant trip, 41 lanyard transducers and 4 pressure transducers were installed at selected locations in the main steam system. The instruments were connected to the Westinghouse DAS where the dynamic response for each channel was recorded on a FM tape recorder and a digital data acquisition system.

This testing was begun with the start of the post core loading precritical test program and continued through the power ascension test program until the 100% power plant trip was performed on August 28, 1985. During this time, all monitored systems were heated up to normal operating temperature and cooled down to ambient. The one exception was the main feedwater system which was heated up to 340 $\pm$ 10^{o}F, cooled down to ambient, heated up to 445 $\pm$ 10^{o}F (normal operating temperature) and cooled down to 340 $\pm$ 10^{o}F. Pre-test ambient data, intermediate heat up plateau data (when plant conditions allowed), normal operating temperature (hot) data and post-test ambient data were collected. All data was reviewed and approved onsite by a Bechtel stress engineering team. All acceptance criteria pertaining to thermal expansion were satisfied.

A visual inspection was performed of the pressurizer surge piping and displacement and velocity data was taken at various locations using a vibration monitor. The RCS was at normal operating temperature and pressure with 4 RCP's operating. The highest peak to peak displacement was 3 mils with a velocity of 0.1 in/sec giving a frequency = $\frac{.1 \text{ in/sec}}{.003 \text{ in}}$ = 33.3 Hz.

The data obtained were within allowable limits.

For the 100% power plant trip, data was collected on the FM tape recorder 2 minutes prior to the trip and 3 minutes following the trip. Data was collected on the digital data acquisition system approximately 30 seconds prior to the trip and 60 seconds after the trip. The time history plots for each channel were obtained for the period of the monitored transient. These plots were evaluated by Bechtel Stress Engineering. This evaluation concluded that while all piping movements were within the allowance of applicable codes, some additional pipe supports should be added to the steam dump piping. This will be accomplished as permitted by plant conditions.

4.8 BIOLOGICAL SHIELD TESTING

The purpose of this test was to measure and record the neutron and gamma-ray radiation levels in accessible areas of the plant where radiation levels above background were anticipated and to determine locations, if any, where shielding was deficient thereby ensuring that plant personnel would not be subjected to overexposure from radiation as a result of inadequate shielding. The test procedure established the Health Physics requirements for the biological shield survey point selection and survey techniques as well as methods of documentation.

To meet the requirements of this test, a series of four biological shield surveys were performed during the period from May 17, 1985 to August 9, 1985.

The first survey was performed on May 17, 1985 prior to initial criticality. This Preoperational Survey was intended to provide baseline data and demonstrate that no sources of radiation were present that would effect subsequent surveys. The survey was successfully performed with no abnormal findings.

The Low Power Survey was performed on May 24, 1985, with reactor power at 3%. No unexpected radiation readings were noted. General readings taken inside steam generator labyrinths were in excess of 100 mrem per hour. The containment hatches were posted as High Radiation Areas in accordance with 10CFR20 and procedural requirements. The readings found were within the expected ranges due to N-16 shine from primary piping.

The Intermediate Power Survey was originally started on July 6, 1985, in containment. This portion of the survey was terminated due to extensive flux mapping interference with gamma readings. The survey outside containment was performed on July 8, 1985 with reactor power at 49.4%. One abnormal neutron reading near two electrical penetrations was noted. The area was resurveyed with another instrument and no neutron readings were detected. It is believed that EM interference affected meter deflection. The containment portion of the Intermediate Power Survey was completed on July 15, 1985, with reactor power at 48%. No readings beyond expected extrapolated values were noted.

The Containment portion of the High Power Survey was performed on August 8, 1985, with reactor power at 100%. No unusual radiation readings were noted. The balance of the survey was performed on August 9, 1985 and no unusual readings outside containment were noted.

4.9 PLANT PERFORMANCE TEST

This test was used to monitor performance of various plant systems during the power ascension test program. Specific test objectives were:

1) To monitor the balance of plant and electrical systems under loaded conditions,

2) To obtain data to verify the ability of ventilation systems to maintain ambient temperature within design limits,

3) To verify evacuation alarm audibility in high noise areas,

4) To monitor concrete temperatures surrounding hot penetrations.

During the power ascension test program, baseline data was collected at steady state conditions. Plant systems monitored during this test included:

Main Steam
Feedwater
Feedwater Heater Extraction; Drains and Vents
Station Service and Essential Service Water
Transformer Electrical Load Centers
AC Inverters
125 V AC and DC
Containment Cooling
Auxiliary Building Ventilation
Control Building Ventilation
Steam Tunnel Ventilation
Auxiliary Feedwater Pump Room Ventilation
Auxiliary Boiler Room Ventilation
Radwaste Building Ventilation
Turbine Building Ventilation
Component Cooling Water
Steam Generator Blowdown
Condensate Demineralizer Water

The acceptance criteria of the test were satisfied:

1) The audibility of the evacuation alarms was verified throughout the plant,

2) The containment air coolers maintained containment air temperature less than 120°F throughout the power ascension test program.

In addition, baseline data was collected for many systems in the plant. One plant parameter was found to be significantly outside its predicted range. Condensate pump C suction pressure was 7.5 psia whereas 3.3 to 5.0 psia was expected. This condition is being investigated but does not impact system operation.

4.10 TURBINE GENERATOR TESTS

The General Electric turbine generator was checked out with a series of tests which monitored the turbine, generator and associated support systems from the time the turbine was first brought on line until the plant was at 100% of rated power. Testing was performed with the generator off line and with the plant at 20%, 40%, 60%, 75%, 90% and 100% of rated power.

The turbine was first brought to rated speed using nuclear power at 0308 on June 12, 1985. Turbine bearing vibration was monitored during acceleration to check for critical speeds. While at rated speed, several tests were performed; General Electric performed a checkout of the exciter, the turbine lube oil system was checked, turbine steady state vibration was recorded, EHC control circuits were tested, the generator core monitor was started up and adjusted for proper flow, and a number of other parameters were monitored and recorded using permanent plant and test instrumentation and the plant computer.

After all exciter checks had been completed, the generator was first synchronized to the grid at 1857 on June 12, 1985. The unit tripped almost immediately due to a minor problem with the turbine control circuits. The second time the generator was synched it again tripped due to a slightly different control circuit problem. At approximately 0230 on June 13, 1985 the generator was successfully synched and Wolf Creek began supplying electrical power for the first time using nuclear fuel. However, the turbine only ran for a few hours before it was shut down due to high vibration. It was determined that the vibration was due to the fact the turbine was operated nearly 24 hours without a load. When the generator was finally put on line and the turbine loaded down, it cooled off rapidly causing the vibration. After the turbine had been off line and cooled off, it was brought back on line and the generator synched without any vibration problems.

With the generator on line and the load at approximately 20%, additional turbine generator monitoring was performed. All parameters which had been checked with the generator offline were again monitored and recorded. A final checkout of the exciter was performed and the generator hydrogen seal oil flow was measured. A check of the reverse power relay and turbine overspeed tests were also performed.

Turbine generator monitoring continued at various testing plateaus through 100% power. Parameters which had previously been checked were again monitored and recorded. In addition to those previously mentioned, these parameters included generator stator bar temperatures, EHC control signal parameters, power load unbalance circuitry, thermal expansion movement, seal and lube oil pressures, turbine performance data, MSR parameters and a number of other miscellaneous parameters. As before, permanent plant and test instrumentation as well as the plant computer were utilized for recording data.

Some additional checks were done at 100% power. The main field and alterrex field carbon brush vibration was measured and a full load check and recalibration of pressure transducers to reflect actual versus design

settings was performed.

Although a number of minor problems were found and subsequently corrected, the only problem of any major significance was in the dynamic noise testing. Several different types of measurements were performed to check control valve instability and dynamic noise. The problem was first encountered at 40% power and was seen in each succeeding plateau in varying degrees with each type of measurement. The problem has been partially corrected by fixing a ground loop found in the EHC control cabinet. General Electric feels the problem will be fully resolved after a filtering circuit is installed in the control valve signal amplifier circuitry.

4.11 SPECIAL TESTS

Two special tests were performed during the post fuel load test program. The first monitored the performance of the moisture separator reheaters. (MSR's) The second special test collected baseline data on the reactor vessel level instrumentation system (RVLIS).

4.11.1 MOISTURE SEPARATOR REHEATER TEST

The General Electric turbine utilizes four moisture separator reheaters to reheat steam discharging from the high pressure turbine before sending it to the three low pressure turbines. The steam is reheated by tapping high temperature, high pressure steam off the main steam line.

The main steam is supplied to the reheaters in two stages. The first stage has no control circuitry. It is manually turned on and off by operators. The second stage, however, has a more complex control circuit. From 5% to 65% turbine load the reheater outlet pressures are monitored to control main steam flow to the reheaters using a low load control valve. When the turbine load increases above 65% a high load control valve then opens up. (This is an on-off control valve, not proportional control).

Since the operation of the reheater was not being checked in the turbine generator testing, a special test was written to monitor operation of the moisture separator reheaters (MSR's), especially the second stage reheat control circuitry while the turbine was being loaded.

The test was performed while the turbine was being loaded during startup and power ascension after the 50% plant trip. Both the first and second stage reheat supply lines were put into service using the normal plant operating procedures. Then, while the turbine was being loaded, data was recorded on moisture separator reheater valve positions, inlet temperatures, inlet pressures, flow rates, outlet temperatures, outlet pressures, and controller outputs. The data was recorded every 5% to 75% of rated load. This data was then analyzed and compared to expected values.

The moisture separator and first stage reheater drain tank condenser dump valves closed as expected at approximately 10% load. The second stage reheater drain tank condenser dump valves closed at approximately 20% load as expected. The reheat supply line drains closed when the associated reheat supply lines were opened. The second stage reheat low load control circuitry controlled flow as expected as the turbine load was increased to 65%. And finally at approximately 65% load the high load valve opened up as it should have. The only problems encountered were some computer points which did not indicate properly.

The test showed that the overall performance of the reheaters maintained all the low pressure turbine inlet temperatures within $50^{o}F$ as required by General Electric. Though the reheaters met the minimum requirements, it is felt the overall system performance could be improved by tuning the system. This tuning and additional monitoring will be done as a part of normal plant performance testing and monitoring.

4.11.2 REACTOR VESSEL LEVEL INSTRUMENTATION SYSTEM (RVLIS)

RVLIS is a redundant safety grade system which provides reactor vessel water level indication. The system utilizes two sets of two d/p cells. These cells measure the pressure differential between the bottom of the reactor vessel and the top of the vessel. Cells of differing ranges are utilized to cover different flow behavior with and without RCP operation:

1) Reactor Vessel Narrow Range (Delta P_B)

   This instrument provides an indication of reactor vessel level from the bottom of the reactor vessel to the top of the reactor during natural circulation conditions.

2) Reactor Vessel Wide Range (Delta P_C)

   This instrument provides an indication of reactor core and internals pressure drop for any combination of operating RCP's. Comparison of the measured pressure drop with the normal, single-phase pressure drop will provide an approximate indication of the relative void content or density of the circulating fluid. The indication of coolant density is significant only when subcooling margin is near zero. This instrument monitors coolant conditions on a continuing basis during forced flow conditions.

To provide the required accuracy for level measurement, temperature measurements of the impulse lines are provided. These temperatures, together with existing reactor coolant temperature measurements and wide-range RCS pressure, are employed to compensate the d/p transmitter outputs for differences in system density and reference leg density . This would be particularly important during the change in the environment inside the containment following an accident.

The RVLIS test collected baseline data on system operation under a variety of plant conditions. Specific test objectives were to:

1) Check the RVLIS wide range compensating function by recording dynamic head and full range level indicator readings with all RCP's running over full RCS power/pressure/temperature,

2) Obtain plant specific RVLIS dynamic head and full range level indications for Ø, 1, 2, 3 and 4 RCP's operation at both cold shutdown and hot standby conditions,

3) Record RVLIS RTD and other inputs at selected points during heatup after fuel load,

4) Observe hydraulic isolater operation during heatup and initial plant operation.

Data collection started with the post core loading precritical test sequence and was completed with the plant at 100% power.

The hydraulic isolators operated per design. With the exception of one data point, all indications were within the expected ranges. The one exception was for full range indication LI-1321 at a hot zero flow condition where the expected range was 104 $\pm$6%. The actual recorded reading was 111%.

More difficulty was experienced with agreement between the full range indicators and with agreement between the dynamic range indicators. There are two indicators of each type and a two pen recorder with one pen assigned to each type. Required agreement for a given type of indication (full range or dynamic) was within 2% for all three indicators. In some cases the actual agreement was 3% or greater.

Although the system operates as designed, investigation is continuing to determine the cause for excessive difference between the indicators of a given type. This work will be completed and the system fully operational by startup following the first refueling.

APPENDIX A

CHRONOLOGY OF THE POST FUEL LOAD STARTUP PROGRAM

March 11, 1985	-	NRC issued Low Power License authorizing initial fuel load and pre-critical testing, initial criticality and low power physics testing.
March 12, 1985	-	Commenced fuel loading - Entered Mode 6.
March 17, 1985	-	Completed fuel loading.
March 21, 1985	-	Reactor vessel studs tensioned - Entered Mode 5.
March 26, 1985	-	Reactor coolant system filled.
March 27, 1985	-	Initial fuel load procedures approved by PSRC. Received authorization from the Plant Manager to commence post core load precritical testing at 1300.
March 31, 1985	-	Commenced cold control rod testing.
April 10, 1985	-	Completed cold control rod testing.
April 17, 1985	-	Entered Mode 4 (>200^{O}F) at 0750.
April 26, 1985	-	Entered Mode 3 (>350^{O}F) at 2300.
April 30, 1985	-	RCS At 557^{O}F, 2235 psig at 0500.
May 4, 1985	-	Commenced hot control rod testing.
May 7, 1985	-	Completed hot control rod testing.
May 19, 1985	-	Post core loading pre-critical testing approved by the PSRC. Received authorization from the Plant Manager to commence initial criticality and low power testing at 2330.
May 21, 1985	-	Commenced diluting for initial criticality at 0840 - Entered Mode 2.
May 22, 1985	-	Reactor critical at 0745.
May 31, 1985	-	Completed low power physics testing at 1130.
June 4, 1985	-	NRC lifted 5% power restriction on license.
June 5, 1985	-	Initial criticality and low power physics testing approved by the PSRC. Received authorization from the Plant Manager to commence initial synchronization and 20% power test sequence at 1555.

June 6, 1985	-	Entered Mode 1 at 2222.
June 13, 1985	-	Turbine-generator synchronized to the grid at 0204.
June 18, 1985	-	Initial synchronization and 20% power test sequence complete at 2200.
June 19, 1985	-	Testing approved by the PSRC. Received authorization from the Plant Manager to commence the power ascension and 50% power test sequence at 0830.
June 29, 1985	-	Performed plant shutdown external to the control room.
July 6, 1985	-	Plant at 50% power.
July 16, 1985	-	Performed rods drop and plant trip test.
July 18, 1985	-	Power ascension and 50% power testing complete at 0200.
July 19, 1985	-	Testing approved by PSRC. Received authorization from the Plant Manager to commence the 75% power test sequence at 1312.
July 20, 1985	-	Plant at 75% power.
July 29, 1985	-	75% power test sequence complete at 0645.
July 30, 1985	-	Testing approved by the PSRC. Received authorization from the Plant Manager to commence the 90% power test sequence.
August 4, 1985	-	Plant at 90% power.
August 6, 1985	-	90% power test sequence complete at 1630.
August 8, 1985	-	Testing approved by the PSRC. Received authorization from the Plant Manager to commence the 100% power test sequence.
	-	Plant at 100% power at 1607.
August 12, 1985	-	100 hour continuous run complete at 2007. Power reduced to ~55% because of main feed pump "B" vibration problems.
August 21, 1985	-	Plant at 100% power.
August 28, 1985	-	Performed 100% plant trip at 0513. 100% test sequence complete.
August 30, 1985	-	Testing approved by PSRC.
September 3, 1985	-	Unit declared commercial at 0114

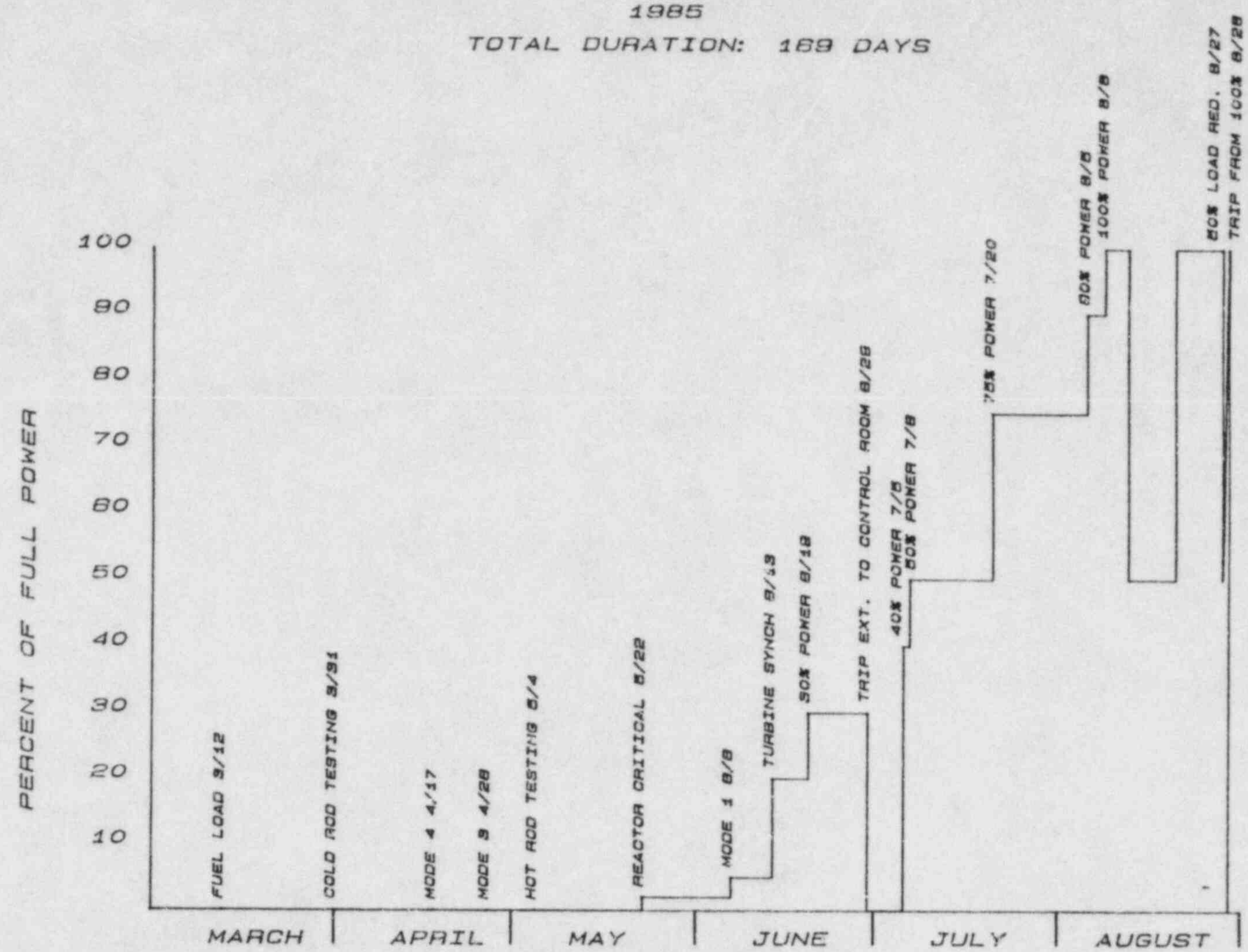
APPENDIX B

POWER ASCENSION TESTING SYNOPSIS

WOLF CREEK GENERATING STATION

1985

TOTAL DURATION: 169 DAYS



APPENDIX C
UNPLANNED REACTOR TRIPS
DURING POST FUEL LOAD TEST PROGRAM

Date/Time	Power Level	Cause
June 6, 1985/2247	6% - 7%	Low-low steam generator level due to feedwater control oscillations
June 13, 1985/0401	12%	Low-low steam generator level due to main feedwater pump trip
June 23, 1985/1333	30%	Inadvertently opened reactor trip breaker during performance of surveillance procedure
July 9, 1985/1115	50%	Low-low steam generator level due to test recorder connections
July 10, 1985/0820	~45%	Hi-hi steam generator level caused MFWI and low-low steam generator level due to feedwater control valve leakage
July 11, 1985/0230	12% - 15%	
July 23, 1985/0815	75%	Loose lug in PN07/PN08 caused loss of S/G feedwater pump
July 31, 1985/0030	75%	Positive rate trip on NIS channel N41 due to spike with another channel in test
August 7, 1985/0626	91%	Turbine trip due to hi-hi moisture separator reheater drain tank level

TOTAL: 9 unplanned reactor trips

KANSAS GAS AND ELECTRIC COMPANY

THE ELECTRIC COMPANY

GLENN L. KOESTER
VICE PRESIDENT - NUCLEAR

November 27, 1985

RECEIVED
DEC - 3 1985

Mr. R.D. Martin, Regional Administrator
U.S. Nuclear Regulatory Commission
Region IV
611 Ryan Plaza Drive, Suite 1000
Arlington, Texas 76011

KMLNRC 85-259
Re: Docket No. STN 50-482
Subj: Startup Report for Wolf Creek Generating Station

Dear Mr. Martin:

The enclosed Startup Report is submitted pursuant to Technical Specification 6.9.1.

Yours very truly,

John A Bailey
for Glenn L. Koester
Vice President - Nuclear

GLK:see

Attachment

xc: PO'Connor (2), w/a
JTaylor (36), w/a
JCummins, w/a

85-1098

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