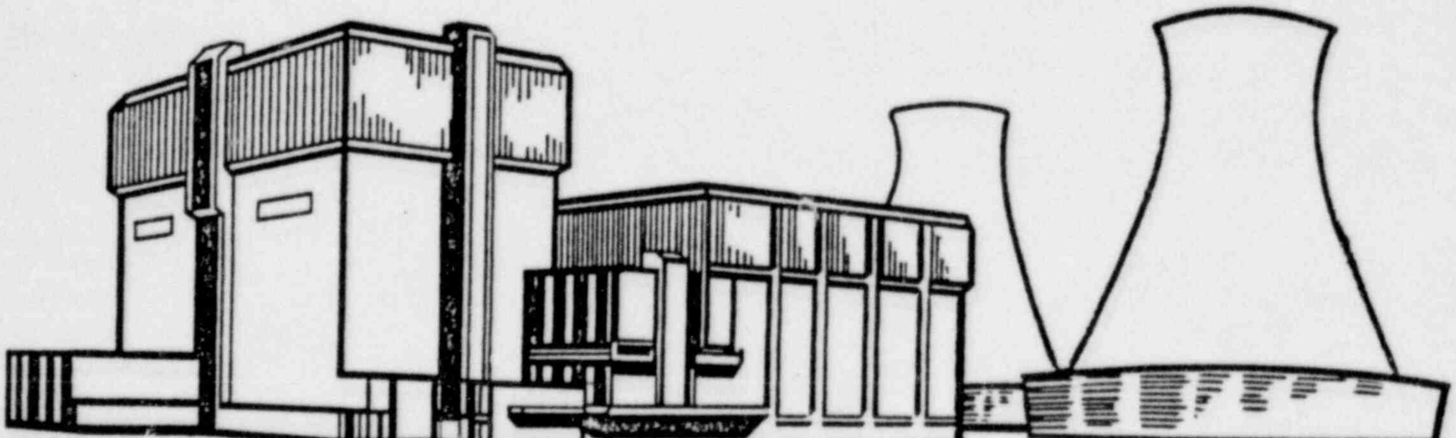
PHILADELPHIA ELECTRIC COMPANY

ELECTRIC SERVICE GAS

UNIT NO. 1

REPORT OF INITIAL PLANT STARTUP

DECEMBER, 1984 - REVISION 2



LIMERICK GENERATING STATION

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PHILADELPHIA ELECTRIC COMPANY

LIMERICK GENERATING STATION
UNIT NO. 1
DOCKET NUMBER 50-352

REPORT OF INITIAL PLANT STARTUP - REVISION 2
DECEMBER, 1984

SUBMITTED TO
THE UNITED STATES NUCLEAR REGULATORY COMMISSION
PURSUANT TO
FACILITY OPERATING LICENSE NO. NPF-39

Rev. 2
March 1986

PHILADELPHIA ELECTRIC COMPANY

LIMERICK GENERATING STATION

UNIT NO. 1

STARTUP REPORT

Preparation Directed by:
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Limerick Generating Station

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SECTION 1

INTRODUCTION

1.1 REPORT ABSTRACT

This Startup Report, written to comply with Technical Specifications paragraphs 6.9.1.1 thru 6.9.1.3, consists of a summary of the Startup Test Program portion of the Initial Test Program performed at Unit 1 of the Limerick Generating Station. This Revision 2 (March 1986) includes the events starting with initial fuel loading and ending with the completion of the Warranty Run following Test Condition 6. Changes and additions to Revision 1 (December 1985) report are identified by a vertical revision bar symbol in the margin. Since Limerick Unit 1 has completed the Startup Test Program and commenced commercial operation, Revision 2 of this report is the final complete version and satisfies the requirements of Technical Specification 6.9.1.3.

The report addresses each of the Startup Tests identified in chapter 14 of the FSAR and includes a description of the measured values of the operating conditions or characteristics obtained during the test program with a comparison of these values to the Acceptance Criteria. Also included is a description of any corrective actions required to obtain satisfactory operation.

This report also provides a brief description of the plant, a description of the Startup Test Procedure format and the objectives of each test.

1.2 LIMERICK PLANT DESCRIPTION

The Limerick Generating Station is a two unit nuclear power plant. The two units share a common control room, refueling floor, turbine operating deck, radwaste system, and other auxiliary systems.

The Limerick Generating Station is located on the east bank of the Schuylkill River in Limerick Township of Montgomery County, Pennsylvania, approximately 4 river miles downriver from Pottstown, 35 river miles upriver from Philadelphia, and 49 river miles above the confluence of the Schuylkill with the Delaware River. The site contains 595 acres - 423 acres in Montgomery County and 172 in Chester County.

Each of the LGS units employs a General Electric Company boiling water reactor (BWR) designed to operate at a rated core thermal power of 3293 MWt (100% steam flow) with a corresponding gross electrical output of 1092 MWe. Approximately 37 MWe are used for auxiliary power, resulting in a net electrical output of 1055 MWe. See Table 1.2-1 for Limerick Plant Parameters.

The containment for each unit is a pressure suppression type designated as Mark II. The drywell is a steel-lined concrete cone located above the steel-lined concrete cylindrical pressure suppression chamber. The drywell and suppression chamber are separated by a concrete diaphragm slab which also serves to strengthen the entire system.

The Architect Engineer and Constructor was Bechtel Power Corporation.

The plant is owned and operated by the Philadelphia Electric Company.

TABLE 1.2-1
Limerick 1 Plant Parameters

Parameter	Value
Rated Power (MWt)	3293
Rated Core Flow (Mlb/hr)	100
Reactor Dome Pressure (psia)	1020
Rated Feedwater Temperature (Deg. F)	420
Total Steam Flow (Mlb/hr)	14.159
Vessel Diameter (in)	251
Total Number of Jet Pumps	20
Core Operating Strategy	Control Cell Core
Number of Control Rods	185
Number of Fuel Bundles	764
Fuel Type	8 x 8 (Barrier)
Core Active Fuel Length (in)	150
Cladding Thickness (in)	0.032
Channel Thickness (in)	0.100
MCPR Operating Limit	1.22
Maximum LHGR (KW/ft)	13.4
Turbine Control Valve Mode	Full Arc
Turbine Bypass Valve Capacity (% NBR)	25
Relief Valve Capacity (% NBR)	87.4
Number of Relief Valves	14
Recirculation Flow Control Mode	Variable Speed M/G Sets

1.3 INITIAL TEST PROGRAM

The Initial Test Program encompasses the scope of events that commences with system/component turnover and terminates with the completion of power ascension testing. The Initial Test Program is conducted in two separate and sequential subprograms: the Preoperational Test Program and the Startup Test Program. At the conclusion of these subprograms the plant is ready for normal commercial power operation. Testing during the Preoperational and Startup Test Programs is accomplished in four distinct and sequential phases.

Major Test Phases - Initial Test Program

a. Phase I - Preoperational Testing

b. Phase II - Initial Fuel Loading and Zero Power Testing

c. Phase III - Low Power Testing

d. Phase IV - Power Ascension Testing

Preoperational testing is completed during the Preoperational Test Program. Initial fuel loading and zero power testing, low power testing, and power ascension testing are completed during the Startup Test Program.

Startup Test Program

That part of the Initial Test Program which commences with the start of nuclear fuel loading and terminates with the completion of power ascension testing.

Initial Fuel Loading and Zero Power Testing Phase

That part of the Startup Test Program which includes chemical and radiological baseline data collection just prior to nuclear fuel loading, the movement of fuel assemblies from the fuel pool to the reactor core, and reactor open vessel tests. Initial criticality is achieved in this test phase.

Low Power Testing Phase

That part of the Startup Test Program which includes the initial reactor heatup to rated reactor temperature and pressure and testing up to and including 5 percent rated reactor power.

Power Ascension Test Phase

That part of the Startup Test Program during which testing is performed at various power levels from 5 percent up to and including 100 percent rated reactor power. Testing during the Power Ascension Test Phase is accomplished in four distinct and sequential Test Plateaus.

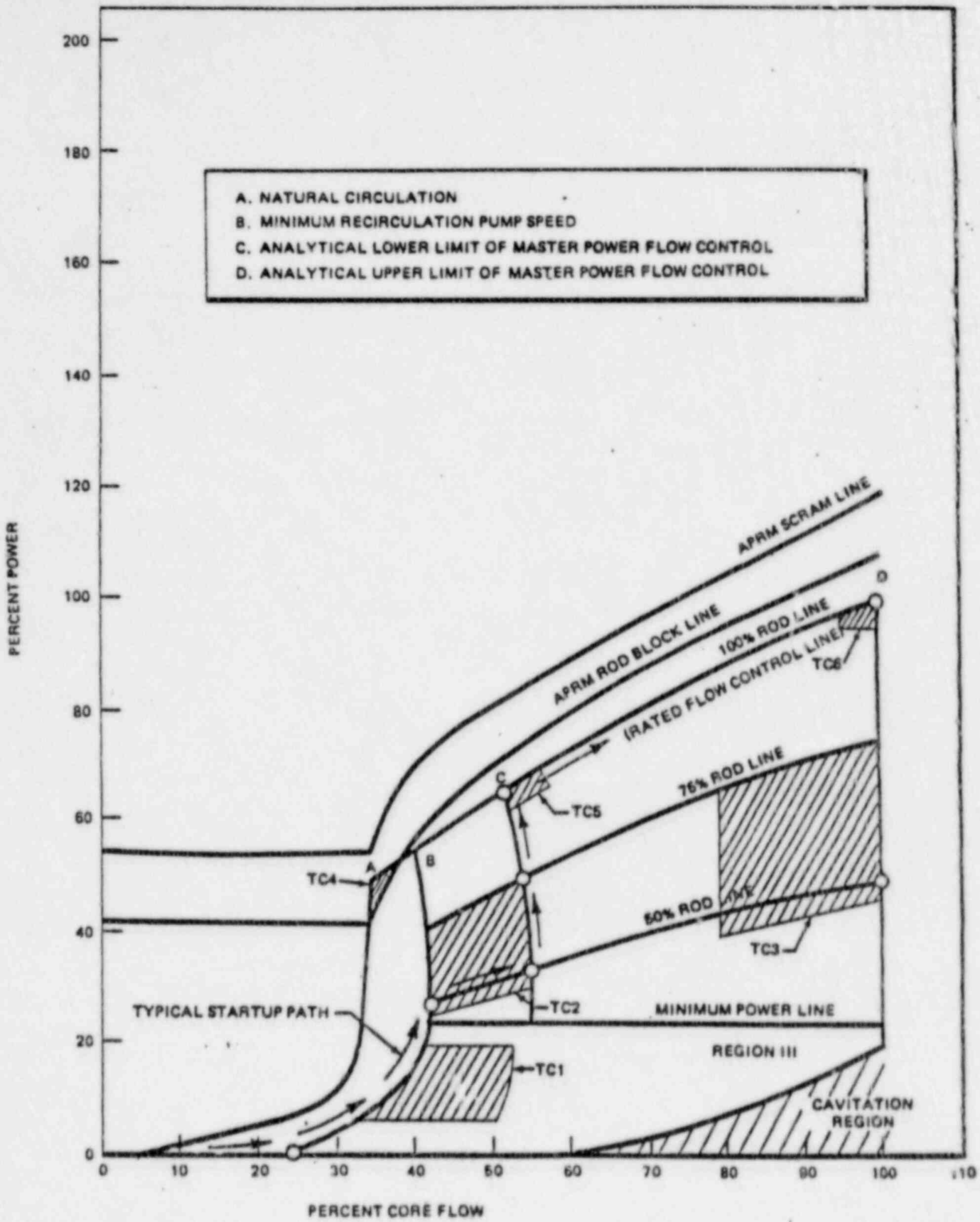
Test Plateau A - Plant conditions cannot exceed those defined as Test Condition 1.

Test Plateau B - Plant conditions cannot exceed those defined as Test Condition 2.

Test Plateau C - Plant conditions cannot exceed those defined as Test Condition 3.

Test Plateau D - Testing at plant conditions up to and including 100% power (Test Conditions 4, 5, 6 and Warranty Run).

The definition of Test Condition is provided in Figure 1.3-1, sheets 1 and 2.



Operational Power/Flow Map

Figure 1.3-1 Sheet 1

TEST CONDITION (TC) REGION DEFINITIONS

Test Condition No.	Power-Flow Map Region and Notes
1	Before or after main generator synchronization between 5% and 20% thermal power within +10, -0% of M-G Set minimum operating speed line in Local Manual mode.
2	After main generator synchronization between the 45% and 75% control rod lines between M-G Set minimum speeds for Local Manual and Master Manual modes.
3	From 45% to 75% control rod lines - core flow between 80% and 100% of its rated value.
4	On the natural circulation core flow line - within +0, -20% of the intersection with the 100% power rod line.
5	Within +0, -5% of the 100% control rod line - within -0, +5% of the analytical lower limit of Master Flow Control.
6	Within +0, -5% of rated 100% power - within +0, -5% of rated 100% core flow rate.

Figure 1.3-1 Sheet 2

1.4 MAJOR STARTUP TEST PROGRAM ADMINISTRATIVE CONTROLS

Startup testing and power escalation is sequenced in six distinct Test Plateaus.

1. Test Phase II - Initial Fuel Loading and Zero Power Testing (Test Condition Open Vessel)
2. Test Phase III - Low Power Testing (Test Condition Heatup)
3. Test Plateau A - Test Condition 1
4. Test Plateau B - Test Condition 2
5. Test Plateau C - Test Condition 3
6. Test Plateau D - 100% Rod Line Testing & Warranty Run

A Test Plateau Review is performed prior to commencing startup testing in the next higher plateau. The following items shall be completed prior to the Test Plateau Review:

a. All Startup Tests scheduled for the current Test Plateau have been implemented or deferred, the analyses have been completed, and the test results have been reviewed and approved.

b. All Startup Test Change Notices affecting tests scheduled for the current Test Plateau have been approved.

c. All Test Exception Reports affecting tests scheduled for the current Test Plateau have been resolved.

A list of all tests scheduled to be run during a specific Test Plateau is contained in Startup Test Procedure 99. This procedure was the primary means to document that all major administrative controls were satisfied.

Startup Test Change Notices (STCN) were written to document test procedure changes which were not made via a complete revision to the test procedure. STCN's were processed and approved independent of test results.

Test Exception Reports (TER) were written to document the description and resolution of all test exceptions as well as the subsequent actions required to close out the exception. The processing and approval of Test Exception Reports was independent of test results. All test exceptions which were resolved but not completely closed prior to the Plateau Review were evaluated and carried over into subsequent test phases.

Major modifications to the Startup Test Program as set forth in the Low Power License NPF-27 (less than five percent) could not be made without receiving prior NRC approval. Under the Full Power Operating License NPF-39 condition No. 2.C (6), changes to the Startup Test Program could be accomplished in accordance with the provisions of 10 CFR 50.59 and needed to be reported to the NRC within one month of the change.

One modification to the Startup Test Program involved deletion of STP-37, Main Steam System and Turbine Performance and Plant Dynamic Response Verification. This change was made after determining that the objectives of the procedure and requirements of Regulatory Guide 1.68 were being met by other existing STP(s). This change was reported to the NRC in a letter dated October 22, 1985.

Another modification to the Startup Test Program involved (1) deleting the performance of subtest STP-1.4, the Reactor Water Cleanup System (RWCU) Performance Testing, during Test Condition 3 and (2) deleting the performance of subtest STP-30.4, Recirculation Pump Runback. These changes were made after determining that the requirements of Regulatory Guide 1.68 were being met by other existing STP(s) and performance of these two subtests were not necessary. These changes were reported to the NRC in a letter dated December 11, 1985.

A third change to the Startup Test Program involved performance of subtest STP-25.3, MSIV Full Closure. This test was performed at 91.7 percent power in lieu of the condition stipulated in the FSAR as "about 100 percent rated thermal power". This change was reported to the NRC in a letter dated March 4, 1986.

SECTION 2

SUMMARY

2.1 OVERALL EVALUATION

The Limerick Generating Station Unit 1 Startup Test Program has been successfully completed. The Startup Test Program commenced with fuel loading on October 26, 1984. Test Condition (TC) Heatup was completed on March 4, 1985. Additional low power testing was performed during the period April 1 through April 17, 1985 in conjunction with the initial roll and testing of the Main Turbine Generator. The full power license was obtained on August 8, 1985 immediately followed by the commencement of TC 1 testing. Testing through TC 4 and 5 was successfully completed on November 30, 1985 and TC 6 including Warranty Run was completed on January 28, 1986.

All testing identified in Chapter 14 of the FSAR for Test Conditions Open Vessel, Heatup and TC 1 through 6 have been performed. Individual test results are described in section 4. Open items resulting from test performance are documented by Test Exception Reports. The Plant Operations Review Committee is responsible for final resolution and close out of these items.

TABLE 2-1

LIMERICK 1 MILESTONES

Jul - 1970	Started Construction, Temporary Permit
Jun - 1974	NRC Issued Construction Permit
Dec - 1976	RPV Set
Jul - 1982	Started Preoperational Test Program (Energized High Voltage Switchgear)
Aug - 1983	Code Hydro
Oct - 1984	Preoperational Test Program Completed
Oct 26, 1984	Received Low Power License
Oct 26, 1984	Started Fuel Load
Nov 13, 1984	Completed Fuel Load
Nov 25, 1984	Install RPV Head, Cold Shutdown (Operational Condition 4
Nov 30, 1984	Completed Vessel Hydro
Dec 21, 1984	Completed Prerequisites for Initial Criticality
Dec 22, 1984	Initial Criticality
Dec 22, 1984	Open Vessel Testing Completed
Dec 30, 1984	Commenced Test Condition Heatup Testing
Jan 14, 1985	Established Initial Rated Pressure and Temperature
Mar 4, 1985	Completed Low Power Testing
Apr 1, 1985	Commenced Test Condition Heatup retests.
Apr 11, 1985	Initial Main Turbine Roll
Apr 13, 1985	Initial Generator Synchronization (with reactor power <5
Apr 17, 1985	Completed Test Condition Heatup Retests.
Aug 8, 1985	Received Full Power License

TABLE 2-1 (cont'd)

LIMERICK 1 MILESTONES

Aug 10, 1985	Commenced Test Condition 1 Testing
Aug 16, 1985	Completed Test Condition 1 Testing. Court Ordered Full Power License Stay Prohibiting Testing Above 5% Power.
Aug 21, 1985	Third Circuit Court of Appeals Lifted Full Power License Stay.
Aug 22, 1985	Commenced Test Condition 2 Testing.
Sep 16, 1985	Completed Test Condition 2 Testing
Sep 24, 1985	Commenced Test Condition 3 Testing
Nov 14, 1985	Completed Test Condition 3 Testing
Nov 26, 1985	Commenced Test Condition 5 Testing
Nov 30, 1985	Completed Test Condition 5 Testing
	Commenced Test Condition 4 Testing
Nov 30, 1985	Completed Test Condition 4 Testing
Dec 3, 1985	Commenced Test Condition 6 Testing
Jan 23, 1986	Completed Test Condition 6 Testing
	Commenced Warranty Run Testing
Jan 29, 1986	Completed Warranty Run Testing
Feb 1, 1986	Commercial Operation Declared

TABLE 2-2

STARTUP TEST PROGRAM CHRONOLOGY

Oct 18, 1984	Commenced first Startup Test, STP-5.1, "CRD Insert - Withdrawal Checks".
Oct 26, 1984	Received Low Power License.
Oct 26, 1984	Commenced Fuel Loading at 2230.
Oct 31, 1984	Experienced first "RPS Trip" due to IRM B Upscale caused by reconnecting cable.
Nov 9, 1984	Experienced second "RPS Trip" due to loss of power to RPS channels B and D caused by electrical fault in static inverter.
Nov 13, 1984	Last fuel bundle loaded at 0054.
Nov 25, 1984	RPV head installed. Entered Operational Condition 4.
Nov 27, 1984	Commenced operational hydrostatic test.
Nov 29, 1984	Completed operational hydrostatic test.
Dec 21, 1984	Entered Operational Condition 2 Commenced reactor startup at 2305.
Dec 22, 1984	Initial criticality achieved at 0318.
Dec 29, 1984	Completed Plateau Review of Test Condition Open Vessel (Phase II - Initial Fuel Loading and Zero Power Testing).
Dec 30, 1984	Commenced Test Condition Heatup Heated reactor to 275 degrees F. Inspected drywell piping to evaluate freedom of expansion.
Jan 2, 1985	Increased reactor pressure to 100 psig.
Jan 5, 1985	Increased reactor temperature to 450 degrees F.
Jan 6, 1985	Increased reactor pressure to 600 psig. Performed scram timing of selected CRD's.
Jan 9, 1985	Increased reactor pressure to 800 psig. Performed scram timing of selected CRD's.

STARTUP TEST PROGRAM CHRONOLOGY

Jan 10, 1985	Initially reached rated reactor pressure and temperature.
Jan 31, 1985	SCRAM #1. While valving in instrument for "Jet Pump Developed Head" RPS trip on Low Level 3 resulted from perturbation to common reference leg shared by Reactor Protection System instruments. Commenced outage.
Feb 16, 1985	Completed Outage. Resumed Heatup testing.
Mar 1, 1985	SCRAM #2. Reactor was manually scrammed on completion of active Heatup testing. Entered Low Power Outage.
Mar 4, 1985	Drywell piping inspected (freedom of expansion) after cooldown. Test Condition Heatup Complete.
Apr 1, 1985	Completed Low Power Outage. Commenced Test Condition Heatup Retests.
Apr 11, 1985	Initial Main Turbine Roll
Apr 13, 1985	Initial Generator Synchronization
Apr 17, 1985	Reactor Shutdown at completion of Test Condition Heatup retests. Commenced Outage.
Jul 31, 1985	Completed Plateau Review of Test Condition Heatup (Phase III - Low Power Testing).
Aug 8, 1985	Received Full Power License
Aug 10, 1985	Commenced Test Condition 1 Testing (IRM/APRM Overlap)
Aug 12, 1985	Placed Reactor Mode Switch in Run, entered Operational Condition 1. Increased reactor power to 10%.
Aug 14, 1985	Main Generator Synchronized and loaded. Increased reactor power to 19%.
Aug 16, 1985	Completed Test Condition 1 Testing. Decreased Power to <5% as a result of Stay issued by Appeals Court on Full Power License.

STARTUP TEST PROGRAM CHRONOLOGY

Aug 21, 1985	Completed Plateau Review of Test Plateau A (Test Condition 1). Third Circuit Court of Appeals lifted Stay on Full Power License.
Aug 22, 1985	Test Condition 2 testing commenced at 24% power, on the 50% rod-line.
Sep 6, 1985	SRV capacity test at rated pressure, STP-26.2
Sep 7, 1985	Turbine trip within Bypass Valve capacity at 21.5% power for STP-27.1
Sep 11, 1985	SCRAM #3. Low reactor water level. Condensate pump trip caused low feed pump suction pressure resulting in a feed pump trip.
	Plant cooldown from Remote Shutdown panel for STP-28.2
Sep 12, 1985	Restarted reactor
	SCRAM #4. Manual scram from Remote Shutdown panel for STP-28.1.
Sep 13, 1985	Restarted reactor.
Sep 16, 1985	SCRAM #5. Loss of Offsite Power test, STP-31.1 at 20% power completed. Reactor scrammed on low reactor water level. Test Condition 2 testing completed.
Sep 17, 1985	Restarted reactor.
Sep 23, 1985	Test Condition 2 Plateau Review completed.
Sep 24, 1985	Test Condition 3 testing commenced.
Sep 25, 1985	Recirc flow raised to 100%; 42% power.
Oct 8, 1985	SCRAM #6. Turbine trip from 50% power for STP-27.3
	Commenced Outage for condenser inspection and feedwater cleanup.
Oct 14, 1985	Completed Outage. Restarted reactor.

STARTUP TEST PROGRAM CHRONOLOGY

Oct 15, 1985	SCRAM #7. At 3% power on low reactor water level during reactor startup.
	Restarted reactor.
Nov 7, 1985	Double Recirc Pump trip for STP-30.2
Nov 9, 1985	HPCI Cold Quick Start to Reactor Vessel, STP-15.5.
Nov 14, 1985	SCRAM #8. Turbine trip from 75% power for STP-27.3.
	Test Condition 3 testing completed.
Nov 15, 1985	Restarted reactor.
	Test Condition 3 Plateau Review completed.
Nov 16, 1985	Manual reactor shutdown.
	Commenced outage for CIV repairs.
Nov 18, 1985	Completed outage. Restarted reactor.
Nov 20, 1985	Manual reactor shutdown.
	Commenced outage for IRM detector replacement.
Nov 24, 1985	Completed outage. Replaced 1 SRM and 3 IRM detectors.
	Restarted reactor.
Nov 26, 1985	Test Condition 5 testing commenced.
Nov 30, 1985	Test Condition 5 testing completed.
	Double Recirc pump trip to natural circulation. Test Condition 4 testing commenced.
	Test Condition 4 testing completed.

TABLE 2-2 (cont'd)

STARTUP TEST PROGRAM CHRONOLOGY

Dec 3, 1985	Test Condition 6 testing commenced.
Dec 8, 1985	SCRAM #9. "B" Reactor Recirculation pump speed excursion after resetting MG Set scoop tube lockup.
Dec 10, 1985	Restarted reactor
Dec 18, 1985	SCRAM #10. Full MSIV Closure from 91.6% power for STP-25.3.
Dec 19, 1985	Restarted reactor.
Jan 2, 1986	SCRAM #11. Turbine trip from 99% power for STP-27.4
	Commenced outage to replace Main Turbine Steam cross-around relief valve and failed expansion joint.
Jan 9, 1986	Restarted reactor.
Jan 13, 1986	SCRAM #12. Manual scram from 25% power to investigate a problem with Main Turbine Control Valve #4.
Jan 20, 1986	Restarted reactor.
Jan 23, 1986	Test Condition 6 testing completed.
	Warranty Run testing commenced.
Jan 29, 1986	Warranty Run testing completed.
Jan 31, 1986	Test Conditions 4, 5, 6 and Warranty Run Plateau Review completed.
Feb 1, 1986	Commercial operation declared.

TABLE 2-3 STARTUP TEST PERFORMANCE DATES (1 of 2)

STP No.		OPEN VESSEL	HEATUP	TC1	TC2	TC3	TC4	TC5	TC6	WARRANTY RUN
1	Chemical and Radiochemical	10/24/84 12/03/84	01/11/85 01/18/85	08/15/85 08/16/85	08/23/85 09/11/85	10/04/85 11/13/85	-	-	01/02/86 01/31/86	-
2	Radiation Measurements	10/04/84 11/15/84	01/15/85 01/16/85	-	08/23/85 08/26/85	10/03/85 10/03/85	-	-	12/27/85 12/27/85	-
3	Fuel Loading	10/26/84 11/13/84	-	-	-	-	-	-	-	-
4	Shutdown Margin Demonstrations	12/21/84 12/22/84	-	-	-	-	-	-	-	-
5	Control Rod Drive System	10/18/84 11/18/84	01/06/85 01/28/85	-	09/12/85 09/12/85	10/08/85 11/14/85	-	-	12/18/85 12/18/85	-
6	SRM Performance and Control Rod Sequence	12/22/84 12/23/84	-	-	-	-	-	-	-	-
9	Water Level Reference Leg Temperature	-	01/26/85 01/26/85	08/15/85 08/16/85	08/28/85 08/28/85	09/29/85 09/29/85	11/30/85 11/30/85	11/27/85 11/27/85	12/26/85 12/26/85	-
10	IRM Performance	12/21/84 12/22/84	12/30/84 12/30/84	08/10/85 08/10/85	09/12/85 09/17/85	-	-	-	-	-
11	LPRM Calibration	-	01/16/85 01/25/85	08/14/85 08/16/85	-	09/28/85 09/28/85	-	-	12/27/85 12/28/85	-
12	APRM Calibration	-	12/31/84 01/02/85	08/16/85 08/16/85	08/29/85 06/29/85	09/29/85 09/29/85	-	11/27/85 11/27/85	12/28/85 12/28/85	01/25/86 01/25/86
13	Process Computer	11/29/84 12/04/84	01/23/85 01/29/85	08/12/85 08/16/85	08/23/85 08/29/85	10/04/85 11/02/85	-	-	01/01/86 01/01/86	-
14	RCIC System	-	01/02/85 03/01/85	08/16/85 08/16/85	-	-	-	-	-	-
15	HPCI System	-	01/04/85 02/26/85	-	-	11/15/85 11/14/85	-	11/25/85 11/25/85	-	-
16	Selected Process Temperatures	-	01/27/85 01/27/85	-	-	09/29/85 11/08/85	11/30/85 11/30/85	-	01/22/86 01/22/86	-
17	System Expansion	12/13/84 12/14/84	12/30/84 03/05/85	-	08/22/85 09/15/85	-	-	-	01/23/86 01/23/86	-
18	TIP Uncertainty	-	-	-	-	10/24/85 10/24/85	-	-	01/22/86 01/23/86	-
19	Core Performance	-	-	08/16/85 08/16/85	08/28/85 08/28/85	09/29/85 09/29/85	11/30/85 11/30/85	11/27/85 11/27/85	12/28/85 12/28/85	01/25/86 01/25/86
20	Steam Production	-	-	-	-	-	-	-	-	01/23/86 01/24/86
21	Core Power - Void Mode Response	-	-	-	-	-	11/30/85 11/30/85	11/30/85 11/30/85	-	-

TABLE 2-3 STARTUP TEST PERFORMANCE DATES (2 of 2)

STP No.		OPEN VESSEL	HEATUP	TC1	TC2	TC3	TC4	TC5	TC6	WARRANTY RUN
				08/13/85	09/06/85	10/24/85	11/30/85	11/26/85	12/30/85	
22	Pressure Regulator	-	-	08/14/85	09/06/85	10/24/85	11/30/85	11/27/85	12/30/85	-
23	Feedwater System			08/13/85	08/31/85	10/31/85	11/30/85	11/27/85	12/29/85	
A	Water Lvl Stpt Change	-	-	08/13/85	09/14/85	11/04/85	11/30/85	11/27/85	12/29/85	-
									01/12/86	
B	Loss of FW Heating	-	-	-	-	-	-	-	01/12/86	-
									01/22/86	
C	FW Pump Trip	-	-	-	-	-	-	-	01/22/86	-
	Maximum Runout								01/21/86	
D	Capability	-	-	-	-	-	-	-	01/21/86	-
	Turbine Valve					10/07/85			12/29/85	
24	Surveillance	-	-	-	-	10/07/85	-	-	12/29/85	-
	Main Steam		02/26/85	08/16/85	08/2[illegible]/85	10/25/85		11/27/85	01/11/86	
25	Isolation Valves	-	02/26/85	08/16/85	08/24/85	10/25/85	-	11/27/85	01/11/86	-
			01/06/85		09/06/85					
26	Relief Valves	-	01/06/85	-	09/06/85	-	-	-	-	-
					09/06/85	09/26/85		11/26/85	01/02/86	
27	Main Turbine Trip	-	-	-	09/07/85	11/14/85	-	11/26/85	01/02/86	-
	Shutdown from Outside				09/11/85					
28	Control Room	-	-	-	09/12/85	-	-	-	-	-
	Recirculation Flow					10/18/85			12/29/85	
29	Control System	-	-	-	-	10/19/85	-	-	12/29/85	-
					08/29/85	09/29/85	11/30/85		01/22/86	
30	Recirculation System	-	-	-	08/29/85	11/07/85	11/30/85	-	01/22/86	-
	Loss of TG and				09/16/85					
31	Offsite Power	-	-	-	09/16/85	-	-	-	-	-
			01/18/85	08/09/85	08/11/85	10/04/85			12/30/85	
32	HVAC System	-	01/21/85	08/09/85	09/15/85	11/05/85	-	-	12/30/85	-
	Piping Steady		01/12/85		08/23/85	09/24/85		11/26/85	12/27/85	
33	State Vibration	-	01/15/85	-	09/15/85	11/03/85	-	11/26/85	12/27/85	-
	Offgas Performance		01/18/85	08/15/85		10/04/85		11/29/85	01/02/86	
34	Verification	-	01/25/85	08/15/85	-	10/04/85	-	11/29/85	01/02/86	-
	Recirculation Flow					09/25/85			12/04/85	
35	Calibration	-	-	-	-	10/24/85	-	-	12/04/85	-
	Piping Dynamic		01/15/85		09/06/85	11/14/85			01/02/86	
36	Transients	-	01/15/85	-	09/06/85	11/14/85	-	-	01/02/86	-
	Reactor Water		01/12/85							
70	Cleanup System	-	01/14/85	-	-	-	-	-	-	-
	Residual Heat		01/15/85						01/03/86	
71	Removal System	-	01/15/85	-	-	-	-	-	01/03/86	-

TABLE 2-4

SCRAM SUMMARY

No.	Date	T.C.	Cause
1	1/31/85	H/U	Unplanned #1 - scram on RPS Low Level 3 due to valving in instrument for "Jet Pump Developed Head" which had common reference leg with Narrow Range Reactor level.
2	3/01/85	H/U	Planned #1 - Manual scram on completion of T.C. Heatup in conjunction with commencing maintenance outage.
3	9/11/85	2	Unplanned #2 - scram on low level, due to loss of feed water. Condensate pump trip caused feed pump trip due to low feed pump suction pressure.
4	9/12/85	2	Planned #2 - Manual scram from Remote Shutdown panel during STP-28.1.
5	9/16/85	2	Planned #3 - scram on low level during Loss of Site Power test, STP-31.1.
6	10/08/85	3	Planned #4 - Turbine Trip from 50% power during STP-27.3
7	10/15/85	3	Unplanned #3 - scram on low level during plant startup.
8	11/14/85	3	Planned #5 - Turbine trip from 75% power during STP-27.3.
9	12/08/85	6	Unplanned #4 - Scram on high APRM after resetting "B" Recirc. MG Set scoop tube lock-up.
10	12/18/85	6	Planned #6 - Full MSIV Isolation from 91.6% power for STP-25.3
11	1/02/86	6	Planned #7 - Turbine Trip from 99% power for STP-27.4
12	1/13/86	6	Planned #8 - Manual Scram from 25% power to investigate Main Turbine Control valve #4 failure to fully close.

SECTION 3

STARTUP TEST PROCEDURES

3.1 STARTUP TEST PROCEDURE FORMAT AND CONTENT

Startup Test Procedures are generally written to demonstrate and verify the performance of a system or control system, to monitor the unit's response to a major transient, or to perform a specific activity. Because of the nature of Startup testing, and to facilitate procedure control, each Startup Test Procedure consists of a Main Body and one or more Subtests.

The Main Body of a Startup Test Procedure provides an overall test description, lists the test objectives, references and acceptance criteria and contains information necessary to successfully prepare for the implementation of Subtests. The Main Body consists of the following sections:

1. Objectives
2. Description
3. Acceptance Criteria
4. References
5. Procedure
6. Appendices (optional)

The Subtests contain the step-by-step instructions necessary for final preparations for the test, the actual performance of the test, and the analysis of data collected during the test. A Subtest consists of the following sections:

1. Discussion
2. Precautions
3. Test Equipment
4. Prerequisites
5. Initial Conditions
6. Test Instructions
7. Analysis
8. Appendices (optional)

A Startup Test Procedure contains as many Subtests as required to satisfy all the Acceptance Criteria listed in the Main Body and to effectively conduct testing at various plant conditions. If the same identical Subtest was performed more than once, provisions were made to identify plant conditions at which the Subtest was implemented.

3.2 ACCEPTANCE CRITERIA

Acceptance criteria may be either quantitative or qualitative. Quantitative acceptance criteria specify that test or equipment expected values are in accordance with test requirements (FSAR, equipment specification, test specifications, etc.). These criteria state expected values such as flows, temperatures, pressures, currents, voltages, etc., required under specific conditions. Such values are specified as maximums or minimums, or tolerances are provided. Qualitative acceptance criteria specify test or equipment functions (an event does or does not occur), such as automatic start, sequencing, or shutdown occurring under specified conditions.

Acceptance criteria are categorized as Level 1 or Level 2 which are defined below:

a. A Level 1 criterion normally relates to the value of a process variable assigned in the design of the plant, component, systems or associated equipment. If a Level 1 criterion were not satisfied, the plant would be placed in a suitable hold condition, until resolution was obtained. Tests compatible with the hold condition would be continued. Following resolution, applicable retesting would be reperformed to verify that the requirements of the Level 1 criterion were satisfied.

b. A Level 2 criterion is associated with expectations relating to the performance of systems. If a Level 2 criterion were not satisfied, operating and testing plans would not necessarily be altered. Investigations of the measurements and of the analytical techniques used for the predictions would be performed.

SECTION 4

RESULTS

4.1 STP-1, CHEMICAL AND RADIOCHEMICAL

OBJECTIVES

The principal objectives of this test are a) to secure information on the chemistry and radiochemistry of the reactor coolant, and b) to determine that the sampling equipment, procedures and analytic techniques are adequate to supply the data required to demonstrate that the chemistry of all parts of the entire reactor system meet specifications and process requirements.

Specific objectives of the test program include evaluation of fuel performance, evaluations of demineralizer operations by direct and indirect methods, measurement of Reactor Water Cleanup system efficiency, measurements of filter performance, confirmation of condenser integrity, demonstration of proper steam separator-dryer operation, and calibration of certain process instrumentation. Data for these purposes is secured from a variety of sources: plant operating records, regular routine coolant analysis, radiochemical measurements of specific nuclides, and special chemical tests.

ACCEPTANCE CRITERIA

Level 1

Chemical factors defined in the Technical Specifications and Fuel Warranty must be maintained within the limits specified.

The activity of gaseous and liquid effluents must conform to license limitations.

Water quality must be known at all times and must remain within the guidelines of the Water Quality Specifications.

Level 2

None

RESULTS

STP-1.1, Pre-Fuel Load Data

Chemical and radiochemical characteristics of reactor water, stored makeup water, standby liquid, closed cooling system water, and floor drain water were measured. Results showed that all water chemistry values were within applicable limits. Baseline data for stack effluents and radiological dose rates were established. All test acceptance criteria were satisfied. Refer to Table 4.1-1 for test results.

STP-1.2, Chemistry Data

Chemical and radiochemical characteristics of reactor water, control rod drive water, condensate demineralizer influent and effluent, feedwater, stored makeup water and floor drain water were measured at various times during power ascension. With three test exceptions, results showed that all water chemistry values were within applicable limits. Baseline data for North and South stack effluents and radiological dose rates were established. Differential pressure across each condensate filter/demineralizer was monitored to observe operation and performance and to predict rates of scale and corrosion product buildup. All test acceptance criteria were satisfied. Refer to Table 4.1-1 for test results.

STP-1.3, Gaseous Effluent Sampling and Analysis

In Test Condition 1, 3 and 6 offgas radiation monitor readings were compared with readings from grab samples taken at the same locations to develop a corelation between the two. Additionally, the radiolytic gas production rate was determined. There are no acceptance criteria associated with this test.

Table 4.1-1 - Chemical and Radiochemical Data Sheet

Sheet 1

Test Condition	Open Vessel Pre-Fuel Load	Open Vessel Post-Fuel Load	Heatup <5% Power	15-25% Power TC-2	45-55% Power TC-3	65-80% Power TC-3	90-100% Power TC-6	Limit or Design Value
Date	10-24-84	12-3-84	1-11-85	8-29-85	10-5-85	10-31-85	1-2-86	
MW Thermal	0	0	144.9	920.6	1590	2241	3275.6	
MW Electrical	0	0	0	228.4	422	663.5	1070	
STP	1.1	1.2	1.2	1.2	1.2	1.2	1.2	
REACTOR WATER								
Conductivity, umho/cm at 25 deg C	0.9	0.4	0.2	0.66	0.46	0.441	0.325	NOTE (1)
Chloride, ppB	≤20	≤20	≤20	<2	10.4	<20	<20	NOTE (1)
pH at 25 deg C	7.5	7.8	6.2(a)	8.2	8.19	8.1	8.12	NOTE (1)
Gamma Isotopic, uCi/gm: I-131	X X	X X	≤1.7 E-5	<LLD	1.41E-6	1.55E-6	3.84E-6	B.O.D.
I-132	X X	X X	≤2.8 E-7	1.13E-5	9.17E-7	3.64E-5	8.21E-5	B.O.D.
I-133	X X	X X	≤2.1 E-6	1.71E-5	6.85E-6	3.09E-5	6.16E-5	B.O.D.
I-134	X X	X X	≤2.4 E-7	8.56E-5	2.37E-6	2.53E-4	5.29E-4	B.O.D.
I-135	X X	X X	≤1.9 E-6	3.36E-5	4.87E-6	8.06E-5	1.51E-4	B.O.D.
Dose Equivalent I-131, uCi/gm	X X	X X	≤2.1 E-5	9.31E-6	1.64E-5	2.23E-5	4.51E-5	≤0.2
Turbidity, NTU	≤0.61	≤0.61	≤0.61	0.04	0.055	0.08	0.05	B.O.D.
Silica, ppB	10	20	194	191	147	197	254	B.O.D.
Boron, ppB	≤50	≤50	≤50	*	≤10	<10	< 10	B.O.D.

B.O.D. = Baseline Operation Data
(a) = Uncorrected for CO2 absorption
* = Test Exception
XX = Data not required at that condition

Table 4.1-1 - Chemical and Radiochemical Data Sheet

Sheet 2

Test Condition	Open Vessel Pre-Fuel Load	Open Vessel Post-Fuel Load	Heatup ≤5% Power	15-25% Power TC-2	45-55% Power TC-3	65-80% Power TC-3	90-100% Power TC-6	Limit or Design Value
Date	10-24-84	12-3-84	1-11-85	8-29-85	10-5-85	10-31-85	1-2-86	
MW Thermal	0	0	144.9	920.6	1590	2241	3275.6	
MW Electrical	0	0	0	228.4	422	663.5	1070	
STP	1.1	1.2	1.2	1.2	1.2	1.2	1.2	
REACTOR WATER (CONTINUED)								
Gross Activity: Filtrate, cpm/ml, 2 hour	X X	X X	374	6.35E3	*	1.74E4	3.64E4	B.O.D.
Crud, cpm/mg Fe, 2 hour	X X	X X	1.2 E5	*	*	2.54E3	2.89E8	B.O.D.
Filtrate, cpm/ml, 7 day	X X	X X	17	79.9	*	200	337	B.O.D.
Crud, cpm/mg Fe, 7 day	X X	X X	4.5 E4	*	*	187	8.05E6	B.O.D.
CHEMICAL ANALYSIS OF FILTRATE								
Iron, ppB	X X	X X	X X	X X	X X	X X	6.6	B.O.D.
Copper, ppB	X X	X X	X X	X X	X X	X X	26.9	B.O.D.
Nickel, ppB	X X	X X	X X	X X	X X	X X	11.5	B.O.D.
Chromium, ppB	X X	X X	X X	X X	X X	X X	0.3	B.O.D.
CHEMICAL ANALYSIS OF CRUD								
Iron, ppB	X X	X X	X X	X X	X X	X X	39.6	B.O.D.
Copper, ppB	X X	X X	X X	X X	X X	X X	<2.0	B.O.D.
Nickel, ppB	X X	X X	X X	X X	X X	X X	1.7	B.O.D.
Chromium, ppB	X X	X X	X X	X X	X X	X X	2.7	B.O.D.

B.O.D. = Baseline Operating Data
* = Test Exception
XX = Data not required at that condition

Table 4.1-1 - Chemical and Radi_chemical Data Sheet

Sheet 3

Test Condition	Open Vessel Pre-Fuel Load	Open Vessel Post-Fuel Load	Heatup ≤5% Power	15-25% Power TC-2	45-55% Power TC-3	65-80% Power TC-3	90-100% Power TC-6	Limit or Design Value
Date	10-24-84	12-3-84	1-11-85	8-29-85	10-5-85	10-31-85	1-2-86	
MW Thermal	0	0	144.9	920.6	1590	2241	3275.6	
MW Electrical	0	0	0	228.4	422	663.5	1070	
STP	1.1	1.2	1.2	1.2	1.2	1.2	1.2	
CONTROL ROD DRIVE WATER								
Conductivity, umho/cm at 25 deg C	X X	X X	0.07	0.07	0.07	0.067	0.055	≤0.1
Dissolved Oxygen, ppB	X X	X X	80*	20	30	50	30	≤50
FUEL AND EQUIPMENT STORAGE POOLS								
Conductivity, umho/cm at 25 deg. C	0.7	X X	X X	X X	X X	X X	XX	≤3.0
Chloride, ppB	≤20	X X	X X	X X	X X	X X	X X	≤500
pH at 25 deg. C	7.2	X X	X X	X X	X X	X X	X X	5.3-7.5
Heavy Elements (Fe, Cu, Ni), ppB	67	X X	X X	X X	X X	X X	X X	≤100
Total Insolubles, ppM	0.025	X X	X X	X X	X X	X X	X X	≤1.0
Turbidity, NTU	≤0.61	X X	X X	X X	X X	X X	X X	B.O.D.
CONDENSATE DEMIN. INFLUENT								
Conductivity, umho/cm at 25 deg C	X X	X X	0.2	0.376	0.269	0.151	0.07	B.O.D.
Chloride, ppB	X X	X X	≤20	<2	3.4	<20	<20	B.O.D.
pH at 25 deg C	X X	X X	7.0	7.7	7.8	7.48	6.7	B.O.D.
Iron, insoluble, ppB	X X	X X	28	10	14.4	14.7	12.0	B.O.D.
Silica, ppB	X X	X X	12	<10	<10	<10	<10	B.O.D.

B. O. D. = Baseline Operating Data

* = Test Exception

XX = Data not required at that condition

Table 4.1-1 - Chemical and Radiochemical Data Sheet
Sheet 4

Test Condition	Open Vessel Pre-Fuel Load	Open Vessel Post-Fuel Load	Heatup ≤5% Power	15-25% Power TC-2	45-55% Power TC-3	65-80% Power TC-3	90-100% Power TC-6	Limit or Design Value
Date	10-24-84	12-3-84	1-11-85	8-29-85	10-5-85	10-31-85	1-2-86	
MW Thermal	0	0	144.9	920.6	1590	2241	3275.6	
MW Electrical	0	0	0	228.4	422	663.5	1070	
STP	1.1	1.2	1.2	1.2	1.2	1.2	1.2	
CONDENSATE DEMIN EFFLUENT								
Conductivity, umho/cm at 25 deg. C	X X	X X	0.08	0.07	0.071	0.067	0.055	≤0.1
Chloride, ppB	X X	X X	≤20	<2	4.6	<20	<20	B.O.D.
pH, at 25 deg. C	X X	X X	6.3 (a)	7.1	7.0	6.94	6.9	B.O.D.
Iron, insoluble, ppB	X X	X X	<1	0.5	1.85	3.1	0.5	B.O.D.
Dissolved Oxygen, ppB	X X	X X	80	20	30	50	30	B.O.D.
Silica, ppB	X X	X X	≤10	<10	<10	<10	<10	B.O.D.
FEEDWATER								
Conductivity, umho/cm at 25 deg. C	X X	X X	0.08	0.08	0.087	0.092	0.067	≤0.1
Chloride, ppB	X X	X X	≤20	<2	<2	<20	<20	B.O.D.
pH at 25 deg. C	X X	X X	6.7	6.8	7.41	7.5	7.8•	6.5-7.5
Iron, soluble, ppB	X X	X X	X X	X X	2.82	0.95	0.027	≤15
insoluble, ppB	X X	X X	•	•	1.93	2.3	0.070	Total
Copper, soluble, ppB	X X	X X	•	•	1.48	1.89	0.32	≤2
insoluble, ppB	X X	X X	•	•	0.05	0.09	0.02	Total
Nickel, soluble, ppB	X X	X X	X X	X X	1.23	2.12	1.04	≤15
insoluble, ppB	X X	X X	X X	X X	0.10	0.15	0.06	Total
Chromium, soluble, ppB	X X	X X	X X	X X	0.63	0.07	0.11	≤15
insoluble, ppB	X X	X X	X X	X X	0.06	0.06	0.01	Total

B. O. D. = Baseline Operating Data

• = Test Exception (a) = Uncorrected for CO2 Absorbtion
XX = Data not required at that condition

Table 4.1-1 - Chemical and Radiochemical Data Sheet

Sheet 5

Test Condition	Open Vessel Pre-Fuel Load	Open Vessel Post-Fuel Load	Heatup <5% Power	15-25% Power TC-2	45-55% Power TC-3	65-80% Power TC-3	90-100% Power TC-6	Limit or Design Value
Date	10-24-84	12-3-84	1-11-85	8-29-85	10-5-85	10-31-85	1-2-86	
MW Thermal	0	0	144.9	920.6	1590	2241	3275.6	
MW Electrical	0	0	0	228.4	422	663.5	1070	
STP	1.1	1.2	1.2	1.2	1.2	1.2	1.2	
FEEDWATER (CONTINUED)								
Total Soluble Metals (ppB) Fe, Cu, Ni, Cr	X X	X X	X X	X X	6.16	5.03	1.50	≤15
Total Filtrate Metals (ppB) Fe, Cu, Ni, Cr	X X	X X	X X	X X	2.14	2.6	0.10	≤15
Metallic Impurities, ppB (Filtrate and Solids)	X X	X X	*	*	8.3	7.63	1.60	≤15
DEMINERALIZED WATER STORAGE TANK								
Conductivity, umho/cm at 25 deg. C	0.7	0.6	0.6	0.7	0.773	0.73	0.731	≤1.0
Chloride, ppB	≤20	≤20	≤20	<2	<20	<20	<20	≤50
pH at 25 deg. C	6.4	6.4	7.3	7.4	6.1	7.7	7.5	6.0-8.0
Boron, ppB	≤50	≤50	≤50	<10	≤10	<10	<10	≤100
Silica, ppB	X X	≤10	10	<10	<10	<10	<10	B.O.D.
CONDENSATE STORAGE TANK								
Conductivity, umho/cm at 25 deg. C	0.9	0.54	0.6	0.84	0.832	0.72	0.830	≤1.0
Chloride, ppB	≤20	≤20	≤20	<2	<2	<20	<20	≤50
pH at 25 deg. C	7.1	6.5	6.6	7.8	6.0	7.05	7.4	6.0-8.0
Boron, ppB	≤50	X X	X X	X X	X X	X X	X X	≤100
Silica, ppB	X X	10	≤10	<10	<10	20	19	B.O.D.

B. O. D. = Baseline Operating Data * = Test Exception
XX = Data not required at that condition

Table 4.1-1 - Chemical and Radiochemical Data Sheet

Sheet 6

Test Condition	Open Vessel Pre-Fuel Load	Open Vessel Post-Fuel Load	Heatup <5% Power	15-25% Power TC-2	45-55% Power TC-3	65-80% Power TC-3	90-100% Power TC-6	Limit or Design Value
Date	10-24-84	12-3-84	3-11-85	8-29-85	10-5-85	10-31-85	1-2-86	
MW Thermal	0	0	144.9	920.6	1590	2241	3275.6	
MW Electrical	0	0	0	228.4	422	663.5	1070	
STP	1.1	1.2	1.2	1.2	1.2	1.2	1.2	
FLOOR DRAIN SAMPLE TANK NO. 2								
Liquid Effluent Activity	X X	<8.5 E-8	≤1.4 E-7	No Liquid	No Liquid	<LLD	0.1	NOTE (2)
LAUNDRY DRAIN SAMPLE TANK								
Liquid Effluent Activity	X X	No Liquid	No Liquid	No Liquid	No Liquid	No Liquid	No Liquid	NOTE (2)
SUPPRESSION POOL								
Conductivity, umho/cm at 25 deg C	2.2	0.90	1.12	1.81	1.7	1.62	1.77	B.O.D.
Chloride, ppB	≤20	30	≤20	<20	<2	38	<20	≤500
pH at 25 deg C	7.2	6.8	6.8	6.9	7.4	7.5	6.45	B.O.D.
Silica, ppB	78	X X	X X	X X	X X	X X	X X	B.O.D.
Turbidity, NTU	≤0.61	X X	X X	X X	X X	X X	X X	B.O.D.
STANDBY LIQUID CONTROL SYSTEM								
Pentaborate, weight %	13.8	X X	X X	X X	X X	X X	X X	B.O.D.
Density of Solution, gm/cc	1.068	X X	X X	X X	X X	X X	X X	B.O.D.
Solution volume in tank, gal	4660.7	X X	X X	X X	X X	X X	X X	B.O.D.
Weight of sodium pentaborate, lbs	5727	X X	X X	X X	X X	X X	X X	5590min.
REACTOR ENCLOSURE COOLING WATER								
Corrosion Inhibitor, ppm	500	X X	X X	X X	X X	X X	X X	500-3000
pH at 25 deg. C	9.2	X X	X X	X X	X X	X X	X X	9.0-9.7
Chloride, ppB	≤20	X X	X X	X X	X X	X X	X X	≤10,000

B. O. D. = Baseline Operating Data
XX = Data not required at that condition

Table 4.1-1 - Chemical and Radiochemical Parameters Data Sheet

Sheet 7

Test Condition	Open Vessel Pre-Fuel Load	Open Vessel Post-Fuel Load	Heatup <5% Power	15-25% Power TC-2	45-55% Power TC-3	65-80% Power TC-3	90-100% Power TC-6	Limit or Design Value
Date	10-24-84	12-3-84	1-11-85	8-29-85	10-5-85	10-31-85	1-2-86	
MW Thermal	0	0	144.9	920.6	1590	2241	3275.6	
MW Electrical	0	0	0	228.4	422	663.5	1070	
STP	1.1	1.2	1.2	1.2	1.2	1.2	1.2	
TURBINE ENCLOSURE COOLING WATER								
Corrosion Inhibitor, ppm	506	X X	X X	X X	X X	X X	X X	500-3000
pH at 25 deg. C	9.0	X X	X X	X X	X X	X X	X X	9.0-9.7
Chloride, ppB	500	X X	X X	X X	X X	X X	X X	≤10,000
MAKEUP WATER EFFLUENT								
Conductivity, umho/cm at 25 deg. C	0.06	X X	X X	X X	X X	X X	X X	B.O.D.
Chloride, ppB	≤20	X X	X X	X X	X X	X X	X X	B.O.D.
Silica, ppB	≤10	X X	X X	X X	X X	X X	X X	B.O.D.
pH at 25 deg. C	7.1	X X	X X	X X	X X	X X	X X	B.O.D.
Boron, ppB	≤50	X X	X X	X X	X X	X X	X X	B.O.D.

B.O.D. = Baseline Operating Data
XX = Data not required at that condition

Table 4.1-1 - Chemical and Radiochemical Data Sheet

Sheet 8

Test Condition	Open Vessel Pre-Fuel Load	Open Vessel Post-Fuel Load	Heatup <5% Power	15-25% Power TC-2	45-55% Power TC-3	65-80% Power TC-3	90-100% Power TC-6	
Date	10-24-84	12-3-84	1-11-85	8-29-85	10-5-85	10-31-85	1-2-86	
MW Thermal	0	0	144.9	920.6	1590	2241	3275.6	
MW Electrical	0	0	0	228.4	422	663.5	1070	
STP	1.1	1.2	1.2	1.2	1.2	1.2	1.2	
GASEOUS EFFLUENTS								Limit or Design Value
Off-Gas Activity, uCi/sec	X X	X X	X X	29.8	39.3	40.6	135	≤330,000
N-13, uCi/sec	X X	X X	X X	467	410	1.2E3	3.31E3	B.O.D.
Off-Gas Flow Rate, cfm	X X	X X	X X	19	14	10	15	B.O.D.
Activity Pattern Recoil, %	X X	X X	X X	100	100	100	100	B.O.D.
Diffusion, %	X X	X X	X X	0	0	0	0	B.O.D.
Equilibrium, %	X X	X X	X X	0	0	0	0	B.O.D.
Off-Gas System Effluent (Post-Treatment) CPM	X X	X X	X X	70	<LLD	<LLD	<LLD	B.O.D.
Pre-Treatment Monitor Reading, mr/hr	X X	No Calib.	A=0 B=0	7.5 B=9.0	A=16 B=14	28	A=38 B=40	B.O.D.
North Stack Monitor Reading Particulate uCi/cc	X X	<3.5 E-12	≤1.8 E-12	3.5E-13	3.23E-15	3.23E-15	2.34E-11	B.O.D.
Iodine uCi/cc	X X	<1.7 E-12	<2.3 E-12	3.3E-13	2.45E-13	2.63E-13	2.43E-14	B.O.D.
Noble Gas uCi/cc	X X	<1.4 E-7	≤3.4 E-7	5.2E-8	1.38E-7	4.66E-7	9.80E-8	B.O.D.
Flow Rate, scfm	X X	1.0 E5	1.8 E5	3.1E5	2.0E5	2.6E5	2.13E5	B.O.D.
South Stack Monitor Reading Particulate uCi/cc	X X	<3.5 E-12	≤1.8 E-12	6.4E-12	3.3E-15	3.23E-15	5.75E-12	B.O.D.
Iodine uCi/cc	X X	<4.7 E-13	≤1.8 E-12	3.7E-14	3.8E-14	8.82E-14	2.87E-13	B.O.D.
Noble Gas uCi/cc	X X	<1.2 E-7	≤1.6 E-6	4.1E-7	3.7E-7	8.9E-7	2.05E-7	B.O.D.
Flow Rate, scfm	X X	1.0 E5	2.3 E5	1.99E5	2.0E5	2.1E5	1.62E5	B.O.D.
Noble Gas body dose rate, mrem/yr	X X	≤1.0 E-3	≤1.0 E-3	<500	<500	<500	<500	≤500
Noble Gas skin dose rate, mrem/yr	X X	≤1.0 E-3	≤1.0 E-3	<3000	<3000	<3000	<3000	≤3000
Particulate, iodine and tritium dose rate, mrem/yr	X X	≤1.0 E-3	≤ 1.0 E-3	<1500	<1500	<1500	<1500	≤1500

XX = Data not required at that condition

Table 4.1-1

Notes for Chemical and Radiochemical Data Sheets

NOTE (1)

	Conductivity umho/cm at 25 Degrees C	Chloride ppB	pH at 25 Degrees C
Pre-Fuel Load Limits	≤3.0	≤500	5.3-7.5
Limits for Power Operation	≤1.0	≤200	5.6-8.6
Limits for Startup or Hot Shutdown	≤2.0	≤100	5.6-8.6
Limits applicable at all other times	≤10.0	≤500	5.3-8.6

NOTE (2)

Concentrations of radioactive material released in liquid effluents to unrestricted areas are limited to levels specified in 10CFR Part 20 Appendix B, Table II, Column 2 for nuclides other than dissolved or entrained noble gases.

Summary of Test Exceptions and Recommendations:

a. Control Rod Drive water (Condensate Demineralizer Effluent) dissolved oxygen was 80 ppB in TC Heatup, compared with a recommended maximum of 50 ppB.

   Corrective Action: Investigate possible sources of air in-leakage. Source of air in-leakage identified and corrected during initial roll of the Main Turbine. Subsequent dissolved oxygen levels within required limit.

b. Feedwater metals were not analyzed because the necessary in-line sampling equipment had not been installed at the time of the test.

   Corrective Action: This sample head, designed to hold a filter and ion exchange paper for crud and filtrate metals analysis, has been installed. Samples were taken in subsequent test conditions with satisfactory results.

c. Feedwater pH was measured as greater than 7.5. Measured value was 7.8.

<u>Corrective Action</u>: Feedwater pH measurement was determined to be inaccurate and not consistent with a measured conductivity of 0.067 micro mho/cm.

STP-1.4, Reactor Water No Cleanup Test

This test was performed to calculate some of the operational considerations of the RWCU system. The RWCU system was secured and conductivity was allowed to increase over several hours. Then the RWCU system was restored to service and run until an equilibrium value was obtained at which point the test was completed.

There were no acceptance criteria applicable to this subtest.

STP-1.5, Radiation Buildup on Piping

Radiation levels on the Reactor Recirculation, Main Steam Lines and Reactor Water Cleanup System piping and components were obtained following reactor shutdown. These readings were recorded 5 days following reactor shutdown with 391.4 Equivalent Full Power Hours (EFPH) of reactor operation.

No acceptance criteria were associated with this test. Analysis consisted of obtaining baseline radiation data for radiation buildup evaluation.

4.2 STP-2, RADIATION MEASUREMENTS

OBJECTIVES

The objectives of this test are to a) determine the background radiation levels in the plant environs prior to operation for base data to assess future activity buildup and b) monitor radiation at selected power levels to assure the protection of personnel during plant operation.

ACCEPTANCE CRITERIA

Level 1

The radiation doses of plant origin and the occupancy times of personnel in radiation zones shall be controlled consistent with the guidelines of the standards for protection against radiation as outlined in 10CFR20 "Standards for Protection Against Radiation".

Level 2

None

RESULTS

STP-2.1, Radiation Surveys

Radiation Surveys were taken in the plant environs prior to fuel load and first reactor criticality, at rated temperature and pressure (critical at <5% CTP), at test condition 2 (23.2% CTP), at Test Condition 3 (48.5% CTP) and at Test Condition 6 (98.9% CTP). Approximately 380 Radiation Base Point (RBP) locations were surveyed and measurements were also made in transit from one RBP to the next.

All radiation dose rates at Test Condition 2 and 3 were measured to be well below the design values, with a maximum gamma dose rate of 6 mRem/hr recorded for one RBP in TC3 for the Turbine building (zone V).

Radiation dose rates at Test Condition 6 were less than the maximum design dose rate except for one point. This point was at the entrance to room 332 in the turbine enclosure beneath the moisture separators. Radiation zone drawing is being changed to reflect as-built condition of the plant. Although the dose rates at this location exceeded the design predicted values, they were well within the Level 1 acceptance criteria.

4.3 STP-3, FUEL LOADING

OBJECTIVE

The objective of this test is to load fuel safely and efficiently to the full core size.

ACCEPTANCE CRITERIA

Level 1

The partially loaded core must be subcritical by at least 0.38% delta k/k with the analytically determined strongest rod fully withdrawn.

Level 2

None

RESULTS

STP-3.1, Fuel Load

The initial core of Limerick Unit 1 was successfully loaded with 764 fuel assemblies in 17 days. Adequate shutdown margin was demonstrated after 144 bundles were loaded. Control rod functional tests (STP-5.1) were performed in parallel with loading the fuel. The full core verification was performed to show that all fuel assemblies were properly loaded, oriented, and seated in the core. The Level 1 Acceptance Criterion was satisfied.

The Level 1 acceptance criterion stated that the partially loaded core must be subcritical by at least 0.38% delta k/k with the analytically highest worth control rod fully withdrawn. After 144 fuel assemblies were loaded, rods 38-19, 22-19, 30-35 and 30-27 (analytically determined to have a total worth greater than that of the highest worth control rod) were withdrawn one notch at a time while observing the nuclear instrumentation. The nuclear instrumentation did not indicate a continuous positive period thus demonstrating subcriticality.

Prior to the start of fuel loading, four fuel loading chambers were assembled, placed in the core, and connected to the permanent SRM preamplifiers. The rod block setpoint was set one decade lower at 1x10**4 CPS and the scram setpoint at 2x10**4 CPS due to the fact that non-saturation of the SRMs had not yet been demonstrated. The reactor protection system was placed in the non-coincidence scram mode (shorting links removed). High voltage and discriminator curves were obtained for each FLC.

The average initial source pin strength (8-13-84) was 1304 curies/pin. The average source strength at the start of fuel loading was 555 curies/pin.

The entire core complement of fuel assemblies was prepared, inventoried, and stored in the fuel pool prior to the start of fuel loading. Fuel was loaded into the core from the center out in a roughly spiral pattern of increasing size.

Before fuel was loaded, each control rod was tested for position indication, coupling, and scrammed verifying proper operation of the control rod and ensuring that the blade guides did not interfere with control rod travel. Fuel loading commenced using the LGS Core Component Transfer Authorization Sheet (CCTAS) as the guiding document. Starting near the center of the core, four fuel assemblies were loaded around the central neutron source. The loading continued in the fuel cell units that sequentially completed each face of the ever increasing square core.

A plot of inverse count rate (1/M) was taken during fuel load to verify subcriticality through the entire fuel load. The plot was taken after loading each fuel assembly until 16 assemblies were loaded. Subsequent to that, 1/M plots were taken every 4 assemblies until 256 fuel assemblies were loaded. After 256 assemblies were loaded 1/M plots were taken every 16 assemblies. Plotting frequencies were increased if the current 1/M plot predicted that criticality would occur prior to the next planned 1/M plot. On several occasions during the early stages of fuel loading, criticality was predicted by the 1/M plot before the next scheduled plotting point. The reason for this was the geometrical effects encountered when less than four fuel cells are loaded and the strong effects as fuel is loaded adjacent to the neutron sources. The interpretation of the geometry affected 1/M plots allow disregarding one or more 1/M intercepts because the obvious geometric effect invalidates the theoretical basis for the 1/M plots.

Several minor problems were encountered with fuel loading equipment. A brief summary is given:

There were several instances of fuel bundles being stuck in the Spent Fuel Storage Pool (SFSP). One bundle (LY8310 at coordinate GG-23 in SFSP) required a force of 1640 pounds to remove it from the SFSP (special approval from General Electric Co. was obtained to exceed 1200 lb grapple load limit). The bundle was inspected and found to have some scratches on the channel but was determined to be acceptable. Another bundle (LY8076 at coordinate SS-23 in SFSP) required repeated application of force by lifting the grapple until it was freed. This bundle was also inspected and found acceptable. The SFSP locations were inspected while the bundles were out and indicated no obstructions to removal of the bundle.

Other bundles were thought to be "hanging up" on insertion into the core. Further inspection revealed faulty indication of grapple position.

During the fuel loading sequence, there were several problems with the SRM channels. At one point during the loading, SRM D was declared inoperable. Since fuel was being loaded in that quadrant, FLC A had to be respositioned to core location 09-20 to allow continuation of fuel loading in accordance with LGS Technical Specifications (SRM monitoring required in the quadrant of core alterations and one adjacent quadrant).

4.4 STP-4, SHUTDOWN MARGIN DEMONSTRATION

OBJECTIVES

The purpose of this test is to demonstrate that the reactor will be sufficiently subcritical throughout the first fuel cycle with any single control rod fully withdrawn.

ACCEPTANCE CRITERIA

Level 1

The shutdown margin (SDM) of the fully loaded, cold (68 degrees F), xenon-free core occuring at the most reactive time during the cycle must be at least 0.38% delta K/K with the analytically strongest rod (or it's reactivity equivalent) withdrawn. If the SDM is measured at sometime during the cycle other than the most reactive time, compliance with the above criteria is shown by demonstrating that the SDM is 0.38% delta K/K plus an exposure dependent correction factor which corrects the SDM at that time to the minimum SDM.

Level 2

Criticality should occur within $\pm$1.0% delta K/K of the predicted critical.

RESULTS

STP-4.1, In Sequence Critical

The shutdown margin for the initial fuel loading was measured to be 2.3% delta K/K. This included a temperature correction factor for 150.5 Deg F of 0.00454 delta K/K and a period correction factor for 147.5 seconds of 0.000506 delta K/K. The measured shutdown margin of 2.3% delta K/K easily meets the level 1 criterion of having a shutdown margin of greater than 0.38% delta K/K. The critical rod position (K-eff=1.00) occurred with 2260 notches withdrawn in sequence A. In order to satisfy the level 2 criterion, criticality had to be achieved between 1378 notches withdrawn (K-eff=0.9902) and 2326 notches withdrawn (K-eff=1.0100). These notch totals represent $\pm$1.0% delta K/K of the predicted critical rod pattern. Criticality occurred approximately 0.51% delta K/K from predicted. These results satisfy the level 2 criterion.

This test was performed by bringing the reactor critical and then establishing a steady positive period. By measuring the period and accounting for the moderator temperature the minimum shutdown margin for this fuel cycle was measured to be 2.3% delta K/K. For this fuel cycle, the minimum core shutdown margin occurs at the beginning of the cycle and, therefore, the exposure correction factor equals zero.

4.5 STP-5, CONTROL ROD DRIVE SYSTEM

OBJECTIVES

The objectives of this test are to demonstrate that the Control Rod Drive (CRD) System operates properly over the full range of primary coolant operating temperatures and pressures, and to determine the initial operating characteristics of the CRD system.

ACCEPTANCE CRITERIA

Level 1

Each CRD must have a normal withdraw speed less than or equal to 3.6 inches per second, indicated by a full 12 foot stroke in greater than or equal to 40 seconds.

The mean scram time of all operable CRD's must not exceed the following times (Scram time is measured from the time the pilot scram valve solenoids are de-energized):

Position Inserted to From Fully Withdrawn	Scram Time (Seconds)
45	0.43
39	0.86
25	1.93
05	3.49

The mean scram time of the three fastest CRD's in a two by two array must not exceed the following times (Scram time is measured from the time the pilot scram valve solenoids are de-energized):

Position Inserted to From Fully Withdrawn	Scram Time (Seconds)
45	0.45
39	0.92
25	2.05
05	3.70

Level 2

Each CRD must have normal insert and withdrawn speeds of 3.0 ± 0.6 inches per second, indicated by a full 12 foot stroke in 40 to 60 seconds.

With respect to the control rod drive friction tests, if the differential pressure (dp) variation exceeds 15 psid for a continuous drive in, a settling test must be performed, in which case the differential settling pressure should not be less than 30 psid nor should it vary by more than 10 psid over a full stroke.

RESULTS

STP-5.1, Insert - Withdraw Checks

One week before fuel load, functional checks were performed on each CRD. These checks consisted of measuring CRD insertion and withdrawal times, measuring insertion and withdrawal drive flows (running and stall), checking for proper coupling, and verifying proper RPIS operation. Eight rods initially did not meet the Level 2 Acceptance Criterion; six rods had withdrawal times greater than 60 seconds, one rod had an insertion time greater than 60 seconds, and one rod had an insertion time less than 40 seconds. After adjusting the needle valves (on the appropriate directional control valves), all of these 8 rods satisfied the Level 2 Acceptance Criterion on retest.

Functional checks of all CRDs were repeated during fuel load at the completion of the loading of each control cell. Six rods initially did not meet the Level 2 Acceptance Criterion; three rods had withdrawal times greater than 60 seconds, two rods had insertion times less than 40 seconds, and one rod had both of these problems. After adjusting the needle valves (on the appropriate directional control valves), all of these rods satisfied the Level 2 Acceptance Criteria on retest.

STP-5.2, Zero Reactor Pressure Friction Testing

Following the completion of fuel loading and CRD functional checks, each CRD was friction tested. All CRDs satisfied the Level 2 Acceptance Criteria. However, one CRD did have a dp variation greater than 15 psid during a continuous insertion requiring performance of a settling test; the CRD (02-31) did satisfy the Level 2 Acceptance Criteria for settling testing.

STP-5.3, Zero Reactor Pressure Scram Testing

Following completion of friction testing, each CRD was scram tested. All applicable Level 1 Acceptance Criteria were satisfied since the average scram times to position 45, 39, 25 and 05 for all operable control rods were less than 0.43, 0.86, 1.93 and 3.49 seconds, respectively, and the mean scram times of the three fastest rods in every 2 x

2 array to position 45, 39, 25 and 05 were less than 0.45, 0.92, 2.05 and 3.70 seconds, respectively. The mean scram time of all operable CRDs and associated criteria are listed below:

Position Inserted to From Fully Withdrawn	Mean Scram Time (Seconds)	Level 1 Criteria (Seconds)
45	0.26	0.43
39	0.44	0.86
25	0.89	1.93
05	1.60	3.49

STP-5.4, Scram Testing of Selected Rods

From the results of previous CRD testing, four rods were selected for further testing.

This test was performed at the following test conditions: at zero reactor pressure with accumulator pressure just above the low pressure alarm point; at 600 psig reactor pressure with normal accumulator pressure; and at 800 psig reactor pressure with normal accumulator pressure. Each control rod was scrammed three times at every test condition. All scram times were less than 7.0 seconds.

STP-5.5, Rated Reactor Pressure Friction Testing

At rated temperature and pressure, all CRD's were individually friction tested. Only 3 CRDs required settling tests and each of these satisfied the applicable Level 2 Acceptance Criterion.

STP-5.6, Rated Reactor Pressure Scram Testing

At rated temperature and pressure all CRDs were individually scram tested. All CRDs satisfied the applicable Level 1 Acceptance Criteria. The mean scram times of all CRDs are as follows:

Position Inserted to From Fully Withdrawn	Average Elapsed Scram Time to Position (Seconds)	Maximum Allowable Average Elapsed Scram Time to Position (Seconds)
45	0.33	0.43
39	0.63	0.86
25	1.37	1.93
05	2.46	3.49

STP-5.7, Rated Reactor Pressure Insert/Withdraw Checks and Scram Testing of Selected Rods

From the results of STP-5.5 and 5.6, four rods were selected for further testing.

Each selected CRD satisfied the applicable Level 1 and Level 2 Acceptance Criteria on insert and withdrawal speeds and all scram times (with zero accumulator pressure) were less than 7.0 seconds. The insert and withdrawal speeds are summarized below:

	Stroke Time	
Selected Rod	Insert (sec)	Withdraw (sec)
10-39	45.1	43.6
26-39	48.5	43.6
30-35	48.1	42.6
38-27	43.2	56.8

STP-5.8, Scram Timing of Selected Rods During Planned Scrams of The Startup Test Program

The four rods tested in STP-5.7 were tested in this test. The scram time for these rods was measured during full core scrams in conjunction with STP-28.1, Shutdown from Outside the Control Room at TC-2, STP-27.3, Turbine Trip at TC-3, STP-25.3, MSIV Full Isolation at TC-6, and STP-27.4, Turbine Trip at TC-6. All scram times were less than 7.0 seconds.

4.6 STP-6, SRM PERFORMANCE AND CONTROL ROD SEQUENCE

OBJECTIVES

The objective of this test is to demonstrate that the operational neutron sources, SRM instrumentation, and rod withdrawal sequences provide adequate information to achieve criticality and increase power in a safe and efficient manner.

ACCEPTANCE CRITERIA

Level 1

There must be a neutron signal to noise count ratio of a least 2.1 on the required operable SRMs.

There must be a minimum count rate of 3 counts/second on the required operable SRMs.

Level 2

None

RESULTS

STP-6.1, SRM Signal to Noise Ratio and Minimum Count Rate Determination

STP-6.2, Approach to Criticality - SRM Response to Control Rod Withdrawal

STP-6.3, SRM Non-Saturation Demonstration

Prior to initial critical testing, the shorting links were removed placing the RPS in the noncoincident scram mode. In addition, the SRM rod block and scram setpoints were conservatively adjusted one decade less than their normal values (set to 1x10**4 and 2x10**4 CPS, respectively).

Prior to rod withdrawal, each SRM was withdrawn to demonstrate SRM signal to noise ratio and minimum count. For each SRM, the observed minimum count rate and signal to noise ratio is identified in the following table.

SRM	Min. Count Rate	S/N
A	14	139
B	15	149
C	18	179
D	14	139

These results satisfy the Acceptance Criteria.

Control rods were then withdrawn in accorcance with the approved RWM rod sequence for startup. During control rod withdrawals, to avoid rod blocks or scrams, SRM detectors were partially withdrawn, as required, to maintain the observed count rate greater than 100 CPS and less than 1x10**4 CPS. In addition, during the control rod withdrawals from all rods-in to criticality, SRM channel readings were recorded for each control rod withdrawal. Upon achieving criticality, the SRM count rate was increased until SRM/IRM overlap was demonstrated. Reactor power was maintained in the intermediate range and the shorting links were installed returning the RPS to the coincident scram mode. SRM nonsaturatation was then demonstrated by bypassing each SRM and inserting it into the core until the observed count rate exceeded 3x10**5 CPS. SRM rod block and scram setpoints were then restored to their normal values.

4.7 STP-9, WATER LEVEL REFERENCE LEG TEMPERATURE

OBJECTIVES

The objectives of this test are to measure the level instrumentation reference leg temperature, recalibrate the water level instruments if the measured temperature is significantly different from the value assumed during the initial end points calibration, and to obtain baseline data on the Narrow Range and Wide Range water level instrumentation.

ACCEPTANCE CRITERIA

Level 1

None

Level 2

The difference between the actual reference leg temperature(s) and the value(s) assumed during initial calibration shall be less than that amount which will result in a scale end point error of 1% of the instrument span for each range.

RESULTS

STP-9.1, Reference Leg Temperature Comparison

With the reactor at rated temperature and pressure in Test Condition Heatup, the following parameters were recorded from various plant instruments and temporary test equipment and subsequently analyzed: reactor water level, reactor building temperature, and drywell temperature readings.

The difference between the measured reference leg temperatures and the temperatures assumed during the initial instrument calibration were less than the amounts that produced a scale end point error of 1% of the measured instrument span for each range, thereby satisfying the acceptance criterion.

STP-9.1 was performed in TC-1, 2, 3, 4, 5 and 6 to determine whether changes in plant conditions had affected reactor water level end point calculations. The principal variables are reference leg temperature and reactor building temperature. There were small changes in the sets of temperatures from assumed initial calibration conditions. Consequently, end point calculations were made only for those instruments on the reference leg with the largest temperature change. A calculation was made to determine the amount of reference leg temperature change required to cause a 1% of scale end point error. In each Test Condition, 1 through 6, the temperatures of the reference leg and the Reactor building were well within the ranges calculated not to produce an end point error of 1%. Therefore, the applicable acceptance criteria were satisfied.

4.8 STP-10, IRM PERFORMANCE

OBJECTIVES

The objectives of this test are to adjust the Intermediate Range Monitoring (IRM) System to obtain an optimum overlap with the SRM and APRM systems.

ACCEPTANCE CRITERIA

Level 1

Each IRM channel must be on scale before the SRM's exceed their rod block setpoint.

Each APRM must be on scale before the IRM's exceed their rod block setpoint.

Level 2

Each IRM channel must be adjusted so that one-half decade overlap with the SRM's is assured.

Each IRM channel must be adjusted so that one decade overlap with the APRM's is assured.

RESULTS

STP-10.1, SRM/IRM Overlap

SRM/IRM overlap was demonstrated during the sequence of testing that began with initial criticality and ended with SRM non-saturation testing. Rods were pulled and the SRM's were partially withdrawn when the count rates approached the lowered SRM rod block setpoint (1x10**4 CPS). Following each detector withdrawal, a normalized count rate was calculated so that the fully inserted SRM count rate could be determined. Rods were then pulled until all IRM downscale lights cleared (5/125 of full scale on Range 1) and the increase in count rate was terminated. Data was then taken which adequately demonstrates the SRM/IRM overlap. Once overlap was satisfactorily demonstrated, RPS was taken out of the noncoincident scram mode by the installation of the shorting links.

The following indications were recorded after SRM count rates were stabilized:

SRM	Normalized Reading (CPS)	IRM	Range 1 Reading (0-40 scale)
A	3.24x10**4	A	3.5
B	4.39x10**4	B	3.0
C	1.35x10**4	C	4.0
D	2.07x10**4	D	2.5
		E	3.6
		F	3.5
		G	5.0
		H	4.5

Similar results were obtained after final gain adjustments were made during Test Condition 2.

All IRM readings were above the downscale value of 5/125 (1.6 on 0-40 scale).

The applicable Level 1 criterion was satisfied when each IRM channel was on scale before the SRM's exceeded the normal rod block setpoint of 1x10**5 CPS (normalized reading).

The applicable Level 2 criterion was verified when the IRM downscale lights cleared and all SRM's indicated less than 5x10**4 CPS (half decade from rod block setpoint).

STP-10.2, IRM Range 6-7 Continuity

During the initial reactor heatup, with IRM's A-H on range 6, reactor power was increased and stabilized to acquire readings between 50 to 80/125. Then each IRM was switched to range 7 and the reading observed. If the readings on channels 6 and 7 did not agree within ±5%, the IRM in question was bypassed and the high frequency preamplifier (R-44) was adjusted as necessary.

All IRM's, with the exception of IRM B (which was inoperative), were left with a range 7 reading within ±5% of the corresponding range 6 reading. Each high frequency amplifier for IRM ranges 7 through 10 had to be adjusted to satisfy the ±5% test objective. IRM B was satisfactorily adjusted during a subsequent startup.

Following adjustment of all IRM channels, the as left readings were recorded as indicated below:

IRM	Range 6 Reading (0-125 scale)	Range 7 Reading (0-40 scale)
A	70.0	7.0
B	70.0	7.0
C	70.0	7.0
D	75.0	7.4
E	84.0	8.5
F	57.0	5.8
G	84.0	8.5
H	53.0	5.5

This test was also conducted during Test Condition 2 after final gain adjustments were made. Similar results were obtained.

STP-10.3, IRM/APRM Overlap

IRM/APRM overlap was demonstrated during the initial power increase above 5% CTP in Test Condition 1.

All IRM's except "C" were left with adequate IRM/APRM overlap. Each IRM high frequency amplifier gain had to be adjusted to satisfy the test objective. See table below.

IRM	Range 8 Reading (0-125 scale)	APRM Reading	Gain Adjustment
A	102	7.7	yes
B	102	7.5	yes
C	Inop.	7.6	
D	100	8.5	yes
E	98	7.3	yes
F	100	9.1	yes
G	101		yes
H	100		yes

With the exception of IRM C, which was inoperative at the time of the test, all applicable acceptance criteria were satisfied. Similar results were obtained in Test Condition 2 after final gain adjustments were made. IRM C is now in service and will be tested in a subsequent Test Condition.

4.9 STP-11, LPRM CALIBRATION

OBJECTIVES

The objectives of this test are to calibrate the Local Power Range Monitoring (LPRM) System and to verify LPRM Flux Response.

ACCEPTANCE CRITERIA

Level 1

None

Level 2

Each LPRM reading will be within 10% of it's calculated value.

RESULTS

STP-11.1, Verification of Proper Connection of LPRM Detectors and Readout Equipment

The purpose of this test was to observe and document Local Power Range Monitor (LPRM) response to flux changes and proper connection to the readout equipment. This test was performed in conjunction with control rod scram and friction testing at rated pressure during Test Condition Heatup. As each control rod was individually friction and scram tested, the response of each LPRM detector in the nearest LPRM string was observed on panel 10C603.

165 of the 172 LPRM detectors properly responded to local changes in neutron flux (adjacent control rod movement), thus assuring proper connection to the LPRM readout equipment. The seven remaining LPRM detectors (16-19A, 24-49A, 24-49B, 24-41A, 24-41B, 32-57A and 32-57B) did not respond to local changes in neutron flux and were retested at a higher power level in Test Condition 1 (see STP-11.4). There are no acceptance criteria associated with this test.

STP-11.2, LPRM Calibration Without The Process Computer

The purpose of this test was to calibrate the LPRM system, in Test Condition 1, such that the indication was proportional to the neutron flux at each detector. Gain adjustment factors (GAF) for each detector were calculated by using the off line computer program, Backup Core Limits Evaluation. Of the 172 LPRM's, twelve detectors were bypassed and declared inoperable. 108 of the remaining detectors had final GAF's $\geq$ 0.9 and $\leq$ 1.1, thus satisfying the applicable acceptance criteria. 52 of the detectors had final GAF's outside of the acceptance criteria limits. Immediately following the completion of Test Condition 1, at approximately 23% CTP, an additional LPRM calibration was performed utilizing the Process Computer. These results were satisfactory with only three operable LPRM's with GAF's outside of the 0.9 and 1.10 limits. These three LPRM's and the bypassed detectors will be addressed by subsequent calibrations.

STP-11.3, LPRM Calibration With Process Computer

This test was performed during Test Condition 3 and 6 at 70% and 99% core thermal power, respectively. The purpose of this test is to provide documentation and verification of proper LPRM calibration using the Process Computer in accordance with Plant Surveillance Test Procedure ST-3-074-505-1, TIP Calibration of LPRMs. Using the process computer program OD-1 a complete set of TIP traces is stored. The individual LPRM amplifier input calibration currents required to provide a full scale meter reading on each LPRM meter are then determined. The process computer program P-1 is used to calculate the correct LPRM readings and the amplifier input currents are then divided by the LPRM Gain Adjustment Factors (GAFs) to determine new input calibration currents. The OD-1 is reperformed and new LPRM GAFs are determined.

The acceptance criterion was satisfied for all LPRMs with the exception of the following LPRMs which were inoperative and bypassed:

TEST CONDITION 3:

48-17D	48-49A	40-33A	32-41A
40-41A	16-17A	32-49D	16-33A
16-09A	32-49C	56-17B	32-33C
40-33C			

These LPRMs, with the exception of 32-41A and 56-17B, were subsequently returned to service and the acceptance criteria satisfied by performance of ST-3-074-505-1. The inoperative LPRMs will be calibrated and returned to service upon repair.

TEST CONDITION 6:

16-17C 32-41A 48-49A 40-57C

These inoperative LPRMs will be calibrated and returned to service upon repair. LPRM 56-17B had a GAF of 0.58 and has been recalibrated via normal surveillance procedures.

STP-11.4, LPRM Operational Verification During Rod Withdrawal

The purpose of this test is to document the response of those LPRM detectors that failed to properly respond to changes in flux during the performance of STP-11.1. With the reactor operating at approximately 11% CTP in Test Condition 1, control rods were moved adjacent to the LPRM's of interest and detector response was observed. All seven detectors responded properly to local changes in neutron flux.

4.10 STP-12, APRM CALIBRATION

OBJECTIVES

The objective of this test is to calibrate the Average Power Range Monitor (APRM) System.

ACCEPTANCE CRITERIA

Level 1

The APRM channels must be calibrated to read equal to or greater than the actual core thermal power.

Technical specification and fuel warranty limits on APRM scram and Rod Block shall not be exceeded.

In the startup mode, all APRM channels must produce a scram at less than or equal to 15% of rated thermal power.

Level 2

If the above criteria are satisfied, then the APRM channels will be considered to be reading accurately if they agree with the heat balance or the minimum value required based on peaking factor, MLHGR, and fraction of rated power to within (+7,-0)% of rated power.

RESULTS

STP-12.1, Constant Heatup Rate APRM Calibration

The purpose of this test was to perform an initial calibration of the APRMs and to verify APRM rod block and scram setpoints. The Gain Adjustment Factors used for the calibration were calculated using a core thermal power determined from a constant reactor coolant heatup rate heat balance. All acceptance criteria were satisfied.

The first part of this test involved taking plant data every 10 minutes during a reactor heatup. The heatup was established and maintained by withdrawing control rods for 1 hour and 50 minutes. The data used to calculate core thermal power (CTP) was the data taken during the 1 hour period in which the heat up rate was the most constant. During this 1 hour period, the average heatup rate was 58 degrees F/hr.

For each data set in this 1 hour period, a core thermal power was calculated. Using this CTP, an APRM gain adjustment factor (AGAF) was calculated for each APRM, for each data set. These AGAFs were averaged providing an average AGAF for each APRM. While these calculations were being performed, steady state plant conditions were established for the calibration.

Each APRM was then calibrated taking the as found reading, multiplying it by the AGAF, and adjusting the gain until the meter read this product (desired reading). However, on each APRM, the gain was reduced to its minimum value before the APRM reading reached the desired reading; the result was that each APRM was reading greater than actual CTP.

The APRMs were calibrated during steady state conditions as follows:

APRM	AGAF	As Found Reading (Expanded X10 Scale)	Desired Reading	As Left Reading (Expanded X10 Scale)
A	0.324	2.9	0.94	1.00
B	0.246	3.0	0.74	1.05
C	0.263	3.1	0.82	1.05
D	0.211	4.0	0.84	1.40
E	0.228	3.5	0.80	1.15
F	0.237	3.6	0.85	1.30

The rod block and scram setpoints for each APRM channel were checked to verify that they would cause a rod block and scram at 12% and 15% indicated CTP, respectively. All APRMs satisfied this criteria with one exception. APRM B produced a rod block at an indicated meter reading of 12.5% rated CTP. The input voltage to the meter was then checked and found to be 0.894 volts which corresponds to an actual CTP of 11.2%.

The scram and rod block setpoints on each APRM channel were recorded as follows:

APRM	Rod Block Setpoint	Scram Setpoint
A	11.5	15
B	11.2	15
C	11	14
D	11.5	14
E	12	15
F	12	15

STP-12.2 Low Power APRM Calibration

This test was performed at Test Condition 1 at approximately 20% CTP. The purpose of the test was to calibrate the APRM channels against core thermal power. This test was conducted by performing a heat balance using appropriate process computer points and instrument readings. Core thermal power was calculated to be 698.82 MWt.

All APRMs were calibrated to read greater than actual core thermal power as shown below:

APRM	Final Reading (% rated CTP)
A	21.5
B	22.0
C	22.0
D	22.5
E	23.0
F	22.5

In addition, the flow biased scram and rod block setpoints were verified to be less than the allowable values given in Technical Specifications. All applicable acceptance criteria were satisfied.

STP-12.3, High Power APRM Calibration

STP-12.3 was performed five times at 47%, 60%, 63%, 98%, and 99% CTP during Test Conditions 2, 3, 5, 6 and Warranty Run respectively.

The purpose of this test was to calibrate the APRM channels against core thermal power. This test was conducted by performing a heat balance utilizing the process computer program OD-3.

All APRM's were calibrated to read equal to or greater than actual core thermal power.

In addition, the flow biased scram and rod block setpoints were verified to be less than the allowable values given in Technical Specifications. All applicable acceptance criteria were satisfied.

4.11 STP-13, PROCESS COMPUTER

OBJECTIVES

The objective of this test is to verify the performance of the Process Computer under plant operating conditions.

ACCEPTANCE CRITERIA

Level 1

None

Level 2

The MCPR calculated by BUCLE and the Process Computer either:

- are in the same fuel assembly and do not differ in value by more than 2% or

- for the case in which the MCPR calculated by the Process Computer is in a different assembly than that calculated by BUCLE, for each assembly, the MCPR and the CPR calculated by the two methods shall agree within 2%.

The maximum LHGR calculated by BUCLE and the Process Computer either:

- are in the same fuel assembly and do not differ in value by more than 2%, or

- for the case in which the maximum LHGR calculated by the Process Computer is in a different assembly than that calculated by BUCLE, for each assembly, the maximum LHGR and the LHGR calculated by the two methods shall agree within 2%.

The MAPLHGR calculated by BUCLE and the Process Computer either:

- are in the same fuel assembly and do not differ in value by more than 2%, or

- for the case in which the MAPLHGR calculated by the Process Computer is in a different assembly than that calculated by BUCLE, for each assembly, the MAPLHGR and APLHGR calculated by the two methods shall agree within 2%.

The LPRM gain adjustment factors calculated by BUCLE and the Process Computer agree to within 2%.

RESULTS

STP-13.1, Static System Test Case

The Static System Test Case associated with Process Computer/TIP machine interface was satisfactorily performed. Proper OD-1 operation, including interface with the TIP machines, agreement between computer and TIP machine index settings, and generation of CRT and typer messages, was demonstrated. There are no acceptance criteria associated with this test.

STP-13.1 consisted of loading a plant simulator overlay to modify the OD-1 program and subroutines so that simulated values for plant parameters could be used prior to actual plant operation during Test Condition Open Vessel. OD-1 was then run with various simulated plant conditions such as low feedwater flow and unknown control rod positions to verify that the appropriate failure checks were made and the correct CRT and typer messages were generated. The TIP machines were then operated to verify proper computer/TIP machine interface. The TIP indexes were switched to each position to verify that the computer correctly monitored the index settings. Various TIP operation failure checks, such as waiting too long to start a traverse, stopping the traverse mid-core, moving a control rod, failing the simulated TIP signal, and varying the APRM signal, during traverses, were also tested. Finally, a complete set of TIP traverses was performed.

STP-13.2, TIP Alignment at Rated Temperature

The TIP Alignment test at Test Condition Heatup was performed with the reactor operating at rated temperature and pressure. There were no acceptance criteria, but the purpose of this test was to determine if the core top (NCCT) and core bottom (NCCB) limits or the x-y plotter span required adjustments. Each of the TIP guide tubes was probed, and the full-in index position (NCFI) at hot conditions was verified to be greater than or equal to the value at cold conditions. No limit adjustments were required, but several TIP channels required plotter adjustments. TIP machine E could not be tested at this time due to moisture in the guide tubes.

Following repair, TIP Machine E was successfully tested at rated temperature and pressure in Test Condition 1. No core limit adjustments or X-Y plotter adjustments were required.

STP-13.3, Program Testing at Test Condition 1

Program Testing was performed during Test Condition 1 at 19.5% of rated core thermal power. During this test the TIP core limits were checked against the limits set in STP-13.2, TIP Alignment at Rated Reactor Pressure, performed during Test Condition Heatup. The average difference between the axial TIP traces, and the design values, were found to be less than or equal to one inch, therefore, no change to the TIP core limits were necessary.

A complete OD-1, Whole Core LPRM Calibration and BASE distribution was performed confirming correct TIP-Computer interface. The operation of OD-18, LPRM Alarm Trip Recalibration could not be performed due to a power reduction and was successfully performed during subsequent power operation. There were no acceptance criteria for this test.

STP-13.4, Dynamic System Test Case

This test was performed during Test Condition 2 in order to perform basic operational checks on the Process Computer using actual plant data. There were no acceptance criteria for this test. Analysis consisted of evaluation of proper Process Computer program functions. The following checks were performed:

1. Correct initialization of the Process Computer was verified including verification that all exposure data was zero.

2. Proper scanning by plant sensors.

3. The Process Computer was proven to be able to initialize data using OD-15.

4. The operability of programs enabled by OD-15 were verified (P-4, OD-5, OD-7, OD-8, OD-15, OD-19, and OD-20).

5. The ability of the Process Computer to correctly perform a whole-core LPRM calibration was verified by checking the results against manual calculations.

6. The Process Computer power distribution and core thermal limits calculations were verified to be correct.

7. The Process Computer programs P2 and P3 were verified to be performing properly.

8. The proper operation of the LPRM digital filtering initialization function and the LPRM drift diagnostic test was verified.

The following Process Computer programs were declared operational upon successful completion of this test:

P-1, P-5, OD-1, OD-6, OD-10, OD-12, OD-14, OD-16, OD-17

STP-13.5, Program Testing at Test Condition Two

This test was initially performed during Test Condition 2, and was reperformed at 48% core thermal power during Test Condition 3 due to indeterminate results obtained in Test Condition 2.

This test performed an operability check on OD-2 and OD-9 by verifying that the computer read variables from the correct positions in the Process Computer core memory and that the computer's calculations were correct. OD-2 and OD-9 were declared operational upon successful completion of this test. There were no acceptance criteria for this test.

STP-13.6, Program Testing at Test Condition Three

This test was performed at 71.8% core thermal power during Test Condition 3. The purpose of this test is to verify the operation and calculations of the P-1 program and OD-10, Option 22 edits for asymmetric rod pattern conditions.

The test compared values of the symmetric and asymmetric modes for the P-1 program and the OD-10, Option 22 edit. All asymmetric values were within 15% of the symmetric values verifying the operability of these programs in the asymmetric mode. There were no acceptance criteria for this test.

STP-13.7, Data Transmittal

This test was performed at 99.7% power during Test Condition 6. The purpose of this test was to collect data for detailed analysis by GE/San Jose Engineering. There were no acceptance criteria for this test.

STP-13.8, Acceptance Criteria Verification

This test was performed during Test Condition 2 at 22.6% core thermal power (CTP), twice during Test Condition 3 at 48% and 71.3% CTP, and during Test Condition 6 at 99.9% CTP. The purpose of this test was to verify the accuracy of the thermal limits calculated by the Process Computer by comparing them to the values calculated by an offline computer program called Back Up Core Limits Evaluation (BUCLE). The acceptance criteria requires that the Process Computer values agree within 2% of the BUCLE values.

All acceptance criteria were satisfied with the exception of the following: In Test Condition 3, at 71.3% core thermal power, the values calculated by the two methods for LPRM Gain Adjustment Factors (GAFs) did not agree to within ±2%. With a maximum deviation of 3% observed, these results were evaluated as acceptable. One possible cause of the 3% deviation may have been system round off errors coupled with performance of this test not immediately following an OD-1, Whole Core LPRM Calibration. During the next performance of this test at Test Condition 6, the maximum deviation of the GAFs was only 1%.

STP-13.9, Program Testing During Power Changes

This test was performed between 21.5% and 76.6% core thermal power (CTP) during Test Condition 6. The purpose of this test was to verify that the Process Computer is capable of following power and core flow changes and can accurately calculate APRM trip levels, and thermal limits during substantial changes in CTP. These checks were made during a power increase from 21.5% to 43.1% due only to control rod motion and during a power increase from 62.0% to 76.6% due only to a core flow increase. The process computer operated satisfactorily in all areas for both changes.

STP-13.10, PCIOMR

This test was performed between 30% and 96% rated core thermal power during Test Condition 6. It consisted of performing functional and operational checks on the OD-11

(PCIOMR) software during both power ramping and steady state conditions. The OD-11 software monitors preconditioning of nuclear fuel and was found to perform satisfactorily.

4.12 STP-14, RCIC SYSTEM

OBJECTIVES

The objectives of this test are to verify the proper operation of the Reactor Core Isolation Cooling (RCIC) System over its expected operating pressure and flow ranges, and to demonstrate reliability in automatic starting from cold standby when the reactor is at power conditions.

ACCEPTANCE CRITERIA

Level 1

The average pump discharge flow must be equal to or greater than 100% rated value after 30 seconds have elapsed from automatic initiation at any reactor pressure between 150 psig and rated.

The RCIC turbine shall not trip or isolate during auto or manual start tests.

Level 2

In order to provide an overspeed and isolation trip avoidance margin, the transient start first and subsequent speed peaks shall not exceed 5% above the rated RCIC turbine speed.

The speed and flow control loops shall be adjusted so that the decay ratio of any RCIC system related variable is not greater than 0.25.

The turbine gland seal condenser system shall be capable of preventing steam leakage to the atmosphere.

The delta P switches for the RCIC steam supply line high flow isolation trip shall be calibrated to actuate at the value specified in the plant technical specifications (about 300%).

The RCIC system must have the capability to deliver specified flow against normal rated reactor pressure without the normal AC site power supply.

RESULTS

STP-14.1, RCIC Functional Demonstration CST to CST at 150 psig

STP-14.2, Functional Demonstration and Controller Optimization at Rated Pressure CST to CST

STP-14.3, Stability Check CST to CST at 150 psig

STP-14.4, Controller Optimization During RPV Injection at Rated Pressure

STP-14.5, Stability Check CST to RPV at 150 psig

STP-14.6 RCIC Cold Quick Start at Rated Pressure - CST to RPV

STP-14.7, Surveillance Tests CST to CST

STP-14.8, RCIC Endurance Run

STP-14.9, Loss of AC Power to RCIC Components.

The results of RCIC testing during Test Condition Heatup were satisfactory. All problems noted during the tests were resolved. Minor steam leakage previously observed around the turbine shaft on the governor end has been resolved and proper gland seal condenser operation verified.

The initial RCIC subtest, STP-14.1, was a RCIC run at a reactor pressure of 150 psig from Condensate Storage Tank (CST) to CST. The test consisted of a manual start, flow steps in manual and automatic, and a quick start. All acceptance criteria were satisfied.

The next RCIC subtest, STP-14.2, was a RCIC run at 920 psig reactor pressure from CST to CST. This test consisted of a manual start, inner and outer loop control system tuning, flow steps in manual and automatic, and a quick start. A Level 2 acceptance criteria was not met due to a small steam leak at the RCIC turbine governor bearing end.

The following RCIC subtest, STP-14.3, was a RCIC run at 150 psig reactor pressure from CST to CST. The subtest consisted of a quick start followed by automatic and manual flow step changes to check RCIC stability after tuning in STP-14.2. There were Level 2 test exceptions with oscillatory behavior observed in flow, control valve position, and EGM output signals during the automatic flow decrease step. These parameters were evaluated and considered acceptable. Another problem noted during the subtest was the flow controller demanding full flow due to turbine control valve binding, which was subsequently resolved.

The next RCIC subtest, STP-14.4, was a vessel injection at 920 psig reactor pressure. During the manual RCIC start divergent oscillations were seen when the flow controller was placed in automatic. A turbine trip then occurred on low suction pressure which did not satisfy the Level 1 criteria. The RCIC system was retuned and the required quick start successfully completed. A Level 2 acceptance criteria was not met with minor steam leakage on the turbine governor end.

The following subtest, STP-14.5, was a reactor vessel injection at 150 psig. For this test, all acceptance criteria were satisfied.

The next RCIC subtest, STP-14.6, consisted of two cold quick starts, at rated pressure, to the reactor vessel with no RCIC operation for 72 hours beforehand. The first cold quick start was successfully completed. There was a Level 2 test exception due to transient start first speed peak (5000 RPM) being greater than the limit of 4725 RPM. An evaluation was made of the data and a second cold quick start was successfully conducted 72 hours later with a first speed peak of 4200 RPM. The 5000 RPM speed peak was evaluated as acceptable.

On the second cold quick start steam leakage was again seen around the turbine governor end. In addition, RCIC steam flow delta P switch isolation setpoints were verified to be set conservatively.

The last RCIC subtest in Test Condition Heatup was STP-14.7, the RCIC surveillance from CST to CST at 150 psig. The subtest was conducted with all acceptance criteria satisfied.

STP-14.7 was performed again in Test Condition 1 with the reactor at rated pressure. All level 1 and level 2 criteria were satisfied except for the speed peak limit of 4725 rpm was exceeded. The speed peak on this run was 5301 rpm. A test exception was written and two hot quick starts were performed to the vessel. Speed peaks of 4813 rpm and 4537 rpm were obtained. A third hot quick start was performed to the CST. The resulting speed peak was 5034 rpm. Since RCIC was still operable per plant technical specifications, testing continued. This condition continues to be monitored closely with each surveillance test performance in conjunction with further evaluation and final disposition of the Test Exception.

STP-14.8, RCIC Endurance Run and STP-14.9 Loss of AC Power to RCIC Components were performed in parallel with STP-14.7 in Test Condition 1. STP-14.9 and 14.8 consisted of a quick start to the CST, followed by continuous operations for 2 hours and 15 minutes, and finally, two consecutive quick starts to the reactor vessel. The above mentioned testing was successfully performed with no AC power supplied to RCIC components, including the room cooler. All applicable acceptance criteria were satisfied with RCIC oil temperature, room temperature and battery voltage remaining within the prescribed limits.

Equipment problems encountered during the RCIC testing that required system modification, consisted of binding of the RCIC turbine control valve and turbine governor end gland seal leakage. The binding of the control valve was solved by shimming the servo, allowing freer stroke, and the relocation of the servo helped to more correctly align the control valve linkage. The steam leakage from the turbine governor end has been resolved and proper gland seal condenser operation verified.

A RCIC test results summary is provided in Table 4.12-1.

TABLE 4.12-1
RCIC TEST RESULTS SUMMARY

				Level 1		LEVEL 2			
TEST #	DATE	T.C.	PRESSURE PSIG	TIME TO RATED FLOW $\leq$30 sec.	TRIP	SPEED PEAK $\leq$4725	OSCILLATIONS	SEAL LEAKAGE	DELTA P SWITCH SETTINGS
14.1	1/03/85	HU	150	11.5	NO	2555	NONE	NONE	N/A
14.2	1/11/85	HU	RATED	17.5	NO	4400	NONE	YES	N/A
14.3	2/18/85	HU	150	21.7	YES [1]	2357	ACCEPTABLE [2]	NONE	N/A
14.4	2/27/85	HU	RATED	18.6	YES [3]	4211	NONE	YES	N/A
14.5	3/01/85	HU	150	5.6	NO	2422	NONE	YES	N/A
14.5	4/03/85	HU	150	6.8	NO	2290	NONE	NONE	N/A
14.6	4/06/85	HU	RATED	18.8 [4]	YES [4]	4462 [4]	NONE	NONE	N/A
14.6	4/09/85	HU	RATED	18.7	NO	5000 [5]	NONE	NONE	N/A
14.6	4/12/85	HU	RATED	18.6	NO	4200	NONE	YES	OK
14.7	4/17/85	HU	150	7.1	NO	2423	NONE	NONE	N/A
14.7 [6]	8/15/85	1	RATED	17.4	NO	5301 [7]	N/A	N/A	N/A

NOTES

1. Manual turbine trip on loss of manual control due to control valve binding.
2. Minor limit cycles observed on step change. Accepted as is.
3. Following manual start, when controller placed in auto, divergent oscillations occurred resulting in a low suction pressure turbine trip. Control system retuned and test completed successfully.
4. Turbine trip on low suction pressure during cold quick start. Listed results are for a successful hot quick start which followed.
5. High speed peak evaluated as acceptable with adequate margin to overspeed trip maintained.
6. STP-14.8 and 14.9 performed concurrently.
7. Speed peak to be resolved at a later date.

4.13 STP-15, HPCI SYSTEM

OBJECTIVES

The objectives of this test are to verify the proper operation of the High Pressure Coolant Injection (HPCI) System over its expected operating pressure and flow ranges, and to demonstrate reliability in automatic starting from cold standby when the reactor is at rated pressure conditions.

ACCEPTANCE CRITERIA

Level 1

The average pump discharge flow must be equal to or greater than 100% rated value after 30 seconds have elapsed from automatic initiation at any reactor pressure between 200 psig and rated.

The HPCI turbine shall not trip or isolate during auto or manual start tests.

Level 2

In order to provide an overspeed isolation trip margin, the transient first peak shall not come closer than 15% (of rated speed) to the overspeed trip, and subsequent speed peaks shall not be greater than 5% above the rated turbine speed.

The speed and flow control loops shall be adjusted so that the decay ratio of any HPCI system related variable is not greater than 0.25.

The turbine gland seal condenser system shall be capable of preventing steam leakage to the atmosphere.

The delta P switches for the HPCI steam supply line high flow isolation trip shall be calibrated to actuate at the value specified in plant technical specifications (about 300%).

RESULTS

STP-15.1, Functional Demonstration CST to CST at 200 psig

STP-15.2, Functional Demonstration and Controller Optimization at Rated Pressure CST to CST

STP-15.3, Stability Check CST - CST at 200 psig

STP-15.7, HPCI Endurance Run

The results of HPCI testing during Test Condition (TC) Heatup, TC3 and TC5 were satisfactory. All problems noted during the tests were resolved. Minor steam leakage observed at the stop valve stem and control valve lifting rod bushing during TC Heatup has been resolved and proper gland seal condenser operation verified.

An outage was commenced after the initial phase of Test Condition Heatup. During this outage various modifications to components and instrumentation were performed. The most prominent modification was the addition of a bypass line in the HPCI hydraulics. All Heatup testing was performed prior to the modifications with the exception of the final performance STP-15.2 which was conducted after the modification at rated pressure.

The initial HPCI subtest, STP-15.1, was a HPCI run at a reactor pressure of 200 psig from Condensate Storage Tank (CST) to CST. This test consisted of a manual start, flow steps in both automatic and manual, and a quick start. Problems, which are outlined in Table 4.13-1, were encountered with CST to Suppression Pool (SP) suction valve swap overs and a Level 2 criteria was not met due to gland seal steam leakage. All other applicable acceptance criteria were satisfied.

The next HPCI subtest, STP-15.2, was a HPCI run at 920 psig reactor pressure from CST to CST. This test consisted of a manual start, inner and outer loop tuning, flow steps in manual and automatic, and a quick start. This subtest encountered several problems including suction valve swap overs from CST to SP, divergent oscillations during tuning, hydraulic control problems and low suction pressure trips. Due to these problems, several tests were necessary before satisfactory results were obtained for system performance and acceptance criteria. The hydraulic control problems, as outlined in Table 4.13-1, were resolved as a result of a bypass line modification that bypassed Auxiliary Oil Pump Oil around the EGR and directly to the control valve. As a result, this subtest was repeated after the modification with the results shown in Table 4.13-1.

The next HPCI subtest, STP-15.3, was a HPCI run at 200 psig reactor pressure from CST to CST. This subtest consisted of a quick start followed by flow step changes in automatic and manual to check HPCI stability at low reactor pressure after control system tuning. The test initially did not meet the Level 1 criteria of time to rated flow but was successfully completed during a retest (see Note 4 Table 4.13-2). After the hydraulic bypass line modification, HPCI stability was tested during a functional test at 190 and 200 psig to reconfirm the results of STP-15.3.

The last subtest performed during Test Condition Heatup was STP-15.7, the HPCI Endurance Run. For this test the system was to be run CST to CST for approximately 2 hours or until pump and turbine oil temperatures stabilized. The system was run successfully for 75 minutes at which time all oil temperatures had stabilized.

STP-15.4, Controller Optimization During RPV Injection at Rated Pressure

This test was performed at 68% rated power during TC3 with the HPCI pump discharging to the reactor vessel. This test consisted of verifying the HPCI flow controller response by introducing flow demand step changes in both automatic and manual flow control. All applicable acceptance criteria were satisfied with no control system tuning required. Additionally, the peak HPCI turbine exhaust pressure was shown to be at least 10 psig below the high exhaust pressure turbine trip setpoint, thus ensuring an adequate margin to trip was maintained. The HPCI steam flow delta P switch isolation setpoints were also verified to be set conservatively.

STP-15.5, HPCI Cold Quick Start at Rated Pressure - CST to RPV

This test was performed at rated reactor pressure during TC3 in order to fully demonstrate the operation of the HPCI system under anticipated conditions. It consisted of a cold (no HPCI operation for at least 72 hours) quick start to the reactor vessel. This test was performed twice; the first performance was unsuccessful due to not satisfying a Level 1 Acceptance Criterion of time to rated flow <25 seconds (actual time - 31.3 seconds). Following this first run, the ramp generator slope (control system inner loop) and proportional gain (control system outer loop) were reduced. In addition, the time to rated flow acceptance criterion was re-evaluated by General Electric Co. and revised from 25 seconds to 30 seconds to agree with the plant Technical Specification limit.

This test was then repeated at 68% rated power and all applicable acceptance criteria were satisfied with time to rated flow of 21.3 seconds. Additionally, the peak HPCI turbine exhaust pressure was shown to be at least 10 psi below the high exhaust pressure trip setpoint, thus ensuring that an adequate margin to trip was maintained.

STP-15.6, HPCI Surveillance Tests - CST to CST

This test was performed twice - once in TC3 and once in TC5. It was performed in order to acquire surveillance data with the final HPCI controller settings for future HPCI surveillance tests; this data will be used to gauge system performance in the future.

During TC3, this test was performed at rated reactor pressure following completion of STP-15.5. All applicable acceptance criteria were satisfied. Additionally, the peak HPCI turbine exhaust pressure was shown to be at least 10 psig below the high HPCI turbine exhaust pressure trip setpoint, thus ensuring that an adequate margin to trip was maintained.

During TC5, this test was performed at 234 psig reactor pressure. All applicable acceptance criteria were satisfied.

A discussion of problems encountered during HPCI testing is provided in Table 4.13-1.

Refer to Table 4.13-2 for a summary of HPCI test results.

TABLE 4.13-1

HPCI Equipment Problems

1) Barometric Condenser Vacuum Pump - The pump tripped on overload when required to run for more than several minutes. This caused the additional problem of allowing some gland seal steam leakage. The pump trip problem was resolved during a planned outage. The pump discharge check valve was disassembled and found to be rusted and the discharge line was full of water. The valve was then cleaned and reassembled and the discharge line drained. Finally, the float in the barometric condenser was inspected and found to be stuck in a high water level position which indicated that the condenser water level had been higher than expected. This discovery, combined with the water found in the discharge line, was evidence that the vacuum pump had been pumping water which could have caused the overload condition. Subsequent operation of the HPCI system was performed without any further tripping of the Barometric Condenser Vacuum Pump.

2) Balance Chamber Adjustment - It was suspected that the balance chamber pressure adjustment of 165 psig was low enough to allow the observed open of the HPCI turbine stop valve on system startup. The stop valve was observed to spike fully open and then settle out. Adjustment to the upper end of the band at 185 psig was planned during an outage. However, during the outage the turbine stop valve bonnet was replaced and the hydraulic bypass modification (see problem #4) was completed. The bypass modification made the balance chamber pressure less limiting and improved performance was observed during Test Condition (TC) Heatup with a final pressure adjustment of 108 psig in the balance chamber at a reactor pressure of 900 psig.

   Review of transient recorder plots for TC-3 HPCI testing indicated stop valve open/close rapid transient for the following tests: STP-15.5 on 11/5 and 11/9/85 and STP-15.6 on 11/13/85. This stop valve performance has been evaluated as acceptable. HPCI system performance and operability remain unaffected due to the hydraulic bypass modification which maintains the HPCI control valve shut during this stop valve transient.

HPCI Equipment Problems (Cont.)

3) Control Valve Linkage - The Control Valve Linkage caused the slow opening of the control valve on several occasions due to servo pitting and a tight fit. The HPCI servo was replaced and combined with the hydraulic bypass line modification ultimately solved this problem by insuring a more constant oil supply. This assured the control valve being driven to the correct position since the oil supply for the servo is not dependent solely on oil supply from the EGR.

4) HPCI Hydraulics - A modification was made during the outage to the HPCI Turbine Hydraulic System. This modification added a bypass line to send oil from the auxiliary oil pump directly to the turbine control valve instead of using the EGR to supply oil to the valve. This reduced stop valve spiking problems previously experienced since the control valve adsorbed more of the differential pressure and thus the balance chamber adjustment became less limiting.

5) CST to SP Suction Valve Swap Over - The suction valve swap over of HPCI from the normal line up to the CST to the SP, caused by oscillations in the CST level transmitter, was solved by adding a time delay to the valve swap over signal and snubbers to the instrument lines. This allows flow to stabilize after the starting surge of HPCI and therefore bypass the initial large oscillations seen by the CST level transmitter. The problem developed because of the need for the instrument taps to be located on seismic class 1 piping. This made the HPCI suction piping the best choice since the CST's were non seismic. However, that location made the level transmitters susceptible to the effects of the HPCI starting flow surge, and necessitated the use of the time delay.

TABLE 4.13-1

HPCI Equipment Problems (Cont.)

6) HPCI Low Suction Pressure Trip - the HPCI turbine tripped on low suction pressure several times during testing due to the location of the transmitter and the starting flow surges seen when running the system CST to CST. A procedural change was made to more closely simulate a vessel injection by allowing HPCI discharge pressure to reach 400 psig before opening the HV55-1F008 (Test Loop Shutoff) valve. This allowed HPCI flow only after a back pressure was developed and lessened the severity of the starting flow surge. In addition, the hydraulic bypass modification limited the acceleration of the HPCI turbine. This also had the effect of limiting the starting flow surge and eliminated the HPCI turbine low suction pressure trip problem.

TABLE 4.13-2
HPIC TEST RESULTS SUMMARY

				Level 1		LEVEL 2			
TEST #	DATE	T.C.	PRESSURE PSIG	TIME TO RATED FLOW ≤30 sec.	TRIP	SPEED PEAK INITIAL/SUBSEQ. <4609 <4399	OSCILLATIONS	SEAL LEAKAGE	DELTA P SWITCH SETTINGS
15.1	1/04/85	HU	200	18.5	YES [1]	1400 / 3053	NONE	YES	N/A
15.2 [2]	2/26/85	HU	RATED	20.1	NO	4240 / 4387	NONE	YES	N/A
15.2 [3]	4/05/85	HU	RATED	19.8	NO	1356 / 4356	NONE	YES	N/A
15.3	2/19/85	HU	200	26.8 [4]	NO	1615 / 3000	N/A	NO	N/A
15.3	2/20/85	HU	200	19.7	NO	1477 / 3104	NONE	YES	N/A
15.4	11/09/85	3	RATED	N/A	NO	N/A	NONE	NO	OK
15.5	11/05/85	3	RATED	31.3 [6]	NO	3875 / 3938	N/A	NO	N/A
15.5	11/09/85	3	RATED	21.33	NO	2355 / 4007	N/A	NO	N/A
15.6	11/13/85	3	RATED	N/A	NO	2283 / 4185	N/A	NO	N/A
15.6	11/25/85	5	200	N/A	NO	1524 / 3119	N/A	NO	N/A
15.7	1/17/85	HU	RATED	N/A	NO	N/A	N/A	N/A	N/A

NOTES

1. One manual and one automatic trip (low suction pressure) on CST to SP suction swap during system startup. One manual trip when CST return valve (F011) failed to open (SP suction interlock) on startup. Successfully completed subsequent startup with results as shown.
2. Results shown are for the last performance of STP-15.2 prior to the hydraulic bypass modification.
3. Post hydraulic modification results.
4. Stop valve went shut for a short time on a momentary low suction pressure trip signal resulting in excessive time to rated flow. STP-15.3 repeated on 2/20/85.
5. Trip dp calculated from quick start data from STP-15.2 performed on 4/05/85.
6. HPCI control system adjustment made and STP-15.5 reperformed on 11/09/85.

4.14 STP-16, SELECTED PROCESS TEMPERATURES

OBJECTIVES

The objectives of this test are (1) to assure that the measured bottom head drain temperature corresponds to bottom head coolant temperature during normal operations, (2) to identify any reactor operating modes that cause temperature stratification, (3) to determine the proper setting of the low flow control limiter for the recirculation pumps to avoid coolant temperature stratification in the reactor pressure vessel bottom head region.

ACCEPTANCE CRITERIA

Level 1

The reactor recirculation pumps shall not be started, flow increased, nor power increased unless the coolant temperatures between the steam dome and bottom head drain are within 145 degrees F.

The recirculation pump in an idle loop must not be started, active loop flow must not be raised and power must not be increased unless the idle loop suction temperature is within 50 degrees F of the active loop suction temperature and the active loop flow rate is less than or equal to 50% of rated loop flow. If two pumps are idle, the loop suction temperature must be within 50 degrees F of the steam dome temperature before pump startup.

Level 2

During two pump operation at rated core flow, the bottom head temperature, as measured by the bottom head drain line thermocouple, should be within 30 degrees F of the recirculation loop temperatures.

RESULTS

STP-16.1, Minimum Recirculation Pump Speed Determination

The Selected Process Temperatures test at Test Condition Heatup was performed with the reactor operating at rated temperature and pressure at approximately 5% power. There were no acceptance criteria, but the existing scoop tube positioner low speed stop settings were shown to prevent exceeding the Technical Specification limit on the bottom head to steam dome temperature difference (145 Deg. F) during normal plant operation with the recirculation pumps operating.

The reactor steam dome pressure was constant at 930 psig throughout the test resulting in a constant steam dome saturation temperature of 536 Deg. F. The temperature difference between the steam dome and the bottom head drain varied by less than 4 Deg. F from a maximum of 18 Deg. F as recirculation speed varied from 27% to 18%, control rod drive flow varied from 60 gpm to 40 gpm, and reactor water cleanup flow varied from 78 gpm to 139 gpm.

The variations in recirculation, control rod drive and reactor water cleanup flows had a negligible impact on the steam dome to bottom drain temperature difference, and the Technical Specification limit of 145 Deg. F was not approached. No temperature stratification was observed; hence, the present recirculation pump low speed mechanical stop settings (18% of rated MG set speed) are acceptable.

STP-16.2, Bottom Head Drain Temperature

This test was performed during Test Condition 3 at rated pressure and 62% power. The accuracy of the bottom head drain temperature was verified by comparing its measurement with the recirculation loop coolant temperature at rated flow when adequate mixing in the vessel lower head can be assumed.

The average difference in the temperatures was 6.18 degrees F. Thus the applicable acceptance criteria were satisfied.

STP-16.3, Recirculation Pump Trip Recovery Data

This test was performed four times at 73.6%, 69%, 47.9%, and 100% rated power during recirculation pump trips of one pump and two pumps in Test Condition 3, Test Condition 4 (natural circulation) and during Test Condition 6 (one pump) respectively. The recorded data was used to verify that adequate mixing is occurring to avoid reactor vessel thermal shock during flow increases or idle recirculation pump restarts.

All temperature differences were within the limits set by the acceptance criteria. The maximum steam dome to bottom head drain temperature difference was 37.7 degrees F. during one pump operation prior to Test Condition 4. The maximum steam dome to idle recirc loop temperature difference was 39.25 degrees F. for loop B during the two pump trip in Test Condition 3. The maximum recirc loop A to recirc loop B temperature difference was 16.9 degrees F. during one pump operation prior to two pump recovery in Test Condition 3.

During the performance of this test in TC-6, all applicable criteria were satisfied.

4.15 STP-17, SYSTEM EXPANSION

OBJECTIVES

This test verifies that safety related piping systems and other piping systems as identified in the FSAR expand in an acceptable manner during plant heatup and power escalation. Specific objectives are to verify that:

Piping thermal expansion is as predicted by design calculations.

Snubbers and spring hangers remain within operating travel ranges at various piping temperatures.

Piping is free to expand without interferences.

ACCEPTANCE CRITERIA

Level 1

There shall be no obstructions which will interfere with the thermal expansion of the Main Steam (inside drywell) and Reactor Recirculation piping systems.

The displacements at the established transducer locations shall not exceed the allowable values.

Level 2

The displacements at the established transducer locations shall not exceed the expected values.

Snubbers and spring hangers do not become extended or compressed beyond allowable travel limits (working range) and snubbers retain swing clearance.

Measured displacements compared with the calculated displacements are within the specified range.

Residual displacements measured following system return to ambient temperature do not exceed the greater of ± 1/16 in. or ± 25%of the maximum displacements measured during system initial heatup.

RESULTS

STP-17.1, Measured Pipe Displacements (Selected BOP Systems)

The results of the testing verified that the balance-of-plant piping scoped for thermal expansion testing in the

Startup Test Program, per FSAR Table 3.9.7, was free to move without unplanned obstruction or restraint during heatup and cooldown, that the system piping behaved in a manner consistent with assumptions of the stress analysis, and that there was agreement between calculated and measured values of displacement.

The thermal movements of system piping were measured during Test Condition Open Vessel (baseline), Test Condition Heatup, and following reactor initial cooldown from normal operating temperature.

Piping movements were measured using both remotely monitored instrumentation and direct manual/visual methods. Spring hangers and snubbers on specified piping segments were inspected to verify that these devices did not become extended or compressed beyond their working range.

System expansion testing was performed on selected segments of the following BOP piping systems:

a. Main Steam (loops B and C, outside drywell)

b. Residual Heat Removal (shutdown cooling mode supply/return, LPCI, and head spray inside drywell)

c. Core Spray (Loop A, inside drywell)

d. High Pressure Coolant Injection (turbine steam supply)

e. Reactor Core Isolation Cooling (turbine steam supply)

f. Reactor Water Cleanup (from the regenerative heat exchanger to the RPV)

Initial piping positions were determined, relative to structural reference points, prior to reactor heatup in order to estabish baseline data.

System expansion testing for Main Steam was performed during initial reactor heatup at reactor moderator temperatures of 275 degrees F, 450 degrees F, and rated reactor temperature and pressure.

System expansion testing for High Pressure Coolant Injection and Reactor Core Isolation Cooling was performed at reactor moderator temperatures of 350 degrees F, 450 degrees, and rated reactor temperature and pressure.

System expansion testing for Residual Heat Removal, Core Spray, and Reactor Water Cleanup was performed at rated reactor temperature and pressure.

Residual displacements for all tested system were determined subsequent to the cooldown from the initial reactor heatup.

Problems encountered during the performance of this test were minor in nature and include the following:

1. Several expansion values and residual displacements fell outside of the stated tolerances. These values were analyzed for their affect on the involved piping by Bechtel Engineering. Following this review they were deemed acceptable and required no further action.

2. During testing it was determined that the temperature assumptions used by Bechtel Engineering for the main steam piping did not agree with actual test conditions. The piping was assumed to be hot up to the turbine nozzles for the initial calculations. During Test Condition Heatup the turbine stop valves are closed, thus the downstream piping is at or near ambient conditions. The actual expansions were compared against calculated valves for the prevailing conditions by Bechtel Engineering. The test data was found to be satisfactory for the existing pipe temperatures. A subsequent retest was performed during turbine operation to verify the original expansion values. The results of the retest were satisfactory.

3. Two abandoned whip restraints on the RCIC steam supply line were determined to present a restraint to the thermal movement of the piping. They were removed. A retest was performed during a subsequent heatup and the results were satisfactory.

4. The RHR head spray line initial displacements were outside of the stated tolerances. Bechtel Engineering reviewed the actual displacements and found the stresses acceptable. However, due to the line's inaccessable location (during operation), additional instrumentation was added to increase the information available for analysis. The line was retested during a subsequent heatup. The displacements were essentially the same as the initial heatup. Bechtel Engineering reviewed the retest data and found the stresses to be acceptable for all future plant operations.

STP-17.2, Measured Pipe Displacements (Feedwater and RWCU Systems)

This test monitors the feedwater piping system downstream of the high pressure heaters and RWCU piping, where expansion is controlled by feedwater temperature, during power ascension.

The results of the testing, to date, verify that the balance-of-plant feedwater piping scoped for thermal expansion testing in the Startup Test Program, per FSAR Table 3.9.7, is free to move without unplanned obstruction or restraint during the heatup thus far accomplished. Measurements indicate that the system piping is behaving in a manner consistent with assumptions of the stress analysis and that there is agreement between calculated and measured values of displacement. Final data for feedwater and RWCU piping displacement will be obtained during the next suitable plant outage when the piping returns to ambient temperature.

Thermal expansion data has been taken at Test Condition Open Vessel (Baseline Measurements), at Test Condition 2 (275 degrees F Feedwater Temperature), and during Test Condition 6 (420 degrees F feedwater temperature).

Piping movements were measured using both remotely monitored instrumentation and direct manual/visual methods. Spring hangers and snubbers on specified piping segments were inspected to verify that these devices did not become extended or compressed beyond their working range.

Problems encountered during the performance of this testing were minor in nature and include the following:

1. One remote measurement device, a lanyard potentiometer - DT.YB.06, was determined to have failed at 275 degrees F. Following engineering evaluation, it was determined that sufficient data was available from this test and previous data to accept the test results as run. This detector was subsequently repaired and retested successfully at 420 degrees F.

2. One expansion value, that of DT.YB.04, fell outside of stated tolerances at 275 degrees F. This measurement was analyzed, by Bechtel Engineering, for it's effect on the involved piping. Following this review, it was deemed acceptable and required no further action. It was acceptable when tested at 420 degrees F.

STP-17.3, Measured Pipe Displacements (Main Steam Inside Drywell and Reactor Recirculation)

This subtest provides the means for collecting thermal expansion data on the Main Steam lines (inside the drywell) and Reactor Recirculation piping under specific conditions. Data collection was accomplished using the Emergency Response Facilities Data System (ERFDS) and the specific system remote monitoring instrumentation (Lanyard Potentiometers and Resistance Temperature Devices, RTD's) installed on each Main Steam line and Recirculation loop.

Thermal expansion data collection was taken at Open Vessel, Test Condition Heatup at 275 ± 25 degrees F, 425 ± 25 degrees F, and normal operating temperature, and Test Condition 6.

Remotely monitored instrumentation are in two locations on each steam line and four locations on each reactor recirculation loop. For these NSSS triaxial transducers, Level 1 limits are calculated for the existing pipe temperature and Level 2 limits apply only at rated conditions. All Level 1 limits were met at 275 Deg F. At 425 Deg F, point SB-LZ on the B Main Steam Line did not meet its Level 1 limit. A combination of visual inspections of steam line "B" and re-evaluation of the criteria by GE Plant Piping Design resulted in a revision to the Level 1 criteria for SB-LZ. Permission was granted to continue testing and heatup to rated conditions. For Heatup at rated conditions, 19 remotely monitored points fell outside of their Level 2 limits. These test exceptions were documented and discussed with GE Plant Piping Design. The resolution was to monitor all NSSS transducers during the second and third heatup cycles. The test results for all these cycles clearly illustrate that the piping expansion was nearly identical for all heatup cycles monitored. The piping movements experienced during the first, second and third heatups were judged to be acceptable by GE Plant Piping Design.

At Test Condition 6, thermal expansion data was obtained from remotely monitored instrumentation and the results yielded no Level 1 criteria violations. Twenty two of the remotely monitored points fell outside of their Level 2 limits. The resolution to the exceptions was that the test results were acceptable and satisfied the startup test specification requirements.

STP-17.4, Visual Pipe Inspections (Main Steam Inside Drywell and Reactor Recirculation)

This test monitored the main steam inside drywell and recirculation piping systems by visual inspections of the piping, hangers and snubbers during Test Condition Open Vessel (baseline data), Test Condition Heatup (at 275 ± deg F and normal operating temperature), and following two complete heatup cycles.

Visual inspections of the Recirculation and Main Steam piping and supports at T.C. Open Vessel showed no evidence of obstructions to normal system expansion. No cables were found stretched, no position indicators were out of their travel range, and no hangers were bottomed out.

Visual inspections were performed during Heatup at 275 Deg F, at Rated Temperature, and shutdown after two heatup cycles were complete. Of the 110 piping restraints associated with this test, a total of seven Main Steam and Recirculation hangers were found to be outside of their hot and cold design settings. This data was evaluated by GE Plant Piping Design and was determined to be acceptable. All snubbers were within their normal operating range. No hangers were found fully extended or compressed and no cables were found stretched. No restrictions to thermal expansion were noted.

4.16 STP-18, TIP UNCERTAINTY

OBJECTIVES

The objective of this test is to determine the reproducibility of the Traversing Incore Probe system readings.

ACCEPTANCE CRITERIA

Level 1

None

Level 2

The total TIP uncertainty (including random noise and geometrical uncertainties) obtained by averaging the uncertainties for all data sets shall be less than 6%.

RESULTS

STP-18.1, Tip Uncertainty Determination

In this test, the random noise, geometric, and total TIP uncertainties were calculated from TIP data taken during TC-3 and TC-6 when the TIP system was operated in conjunction with the Process Computer programs OD-1, OD-2, and OD-10.

For the random noise component in TC-3, six TIP traverses were performed on the common channel for each TIP machine but only four and five successful OD-2 and OD-10, Option 59 edits were obtained for TIP machines 2 and 3, respectively. Therefore, the uncertainties were calculated using the four consecutive TIP traces from each TIP machine.

The applicable Level 2 criterion was satisfied in both test conditions. The values of the uncertainites are listed below:

Test Condition 3:

Geometric Uncertainty = 3.152%
Random Noise Uncertainty = 0.943%
Total TIP Uncertainty = 3.290%

Test Condition 6:

Geometric Uncertainty	=	2.7
Random Noise Uncertainty	=	1.6%
Total TIP Uncertainty	=	3.2%

4.17 STP-19, CORE PERFORMANCE

OBJECTIVES

The objectives of this test are to:

a) Evaluate the core thermal power and core flow rate; and

b) Evaluate whether the following core performance parameters are within limits:

- Maximum Linear Heat Generation Rate (MLHGR),
- Minimum Critical Power Ratio (MCPR),
- Maximum Average Planar Linear Heat Generation Rate (MAPLHGR).

ACCEPTANCE CRITERIA

Level 1

The Maximum Linear Heat Generation Rate (MLHGR) of any rod during steady-state conditions shall not exceed the limit specified by the Plant Technical Specifications (13.4 kw/ft).

The steady-state Minimum Critical Power Ratio (MCPR) shall exceed the minimum limit specified by the Plant Technical Specifications.

The Maximum Average Linear Heat Generation Rate (MAPLHGR) shall not exceed the limits specified by the Plant Technical Specifications.

Steady-state reactor power shall be limited to the rated core thermal power (3293 MWt).

Core flow shall not exceed its rated value (100 Mlb/hr).

Level 2

None

RESULTS

STP-19.1, Core Performance - BUCLE Calculation

In Test Condition 1, the off-line computer program, Backup Core Limits Evaluation (BUCLE), was used to calculate the core thermal limit parameters MLHGR, MCPR, and MAPLHGR. A manual heat balance was also performed to calculate the reactor core thermal power. All acceptance criteria were satisfied.

The reactor core thermal power and core flow rate during the test were 724 MWt and 43 Mlb/hr, respectively. These were less than the Level 1 criterion limits of 3293 MWt and 100 Mlb/hr.

The values of MFLPD, MFLCPR, and MAPRAT were calculated to be 0.262, 0.307, and 0.242, respectively, using the off-line computer program BUCLE. Since all of these thermal limit parameter ratios were less than 1.0, the Level 1 acceptance criteria were satisfied.

STP-19.2, Process Computer Calculation

This test was performed at 38%, 60%, 42%, 62%, 98% and 99% core thermal power (CTP) during Test Conditions 2, 3, 4, 5, 6 and Warranty Run respectively. The purpose of this test is to verify the process computer calculation of thermal limits using core performance parameters and heat balance data. All acceptance criteria were satisfied as shown below:

	Test Condition						
	2	3	4	5	6	WR	Limit
CTP(%)	38.6	60.1	41.9	62.3	98.3	99.1	100
Core flow (%)	46.7	88.98	39.98	54.41	100	96.4	100
CMFLPD	0.475	0.567	0.362	0.536	0.879	0.899	1.00
CMFCP	0.556	0.534	0.580	0.695	0.818	0.838	1.00
CMAPR	0.466	0.547	0.363	0.531	0.876	0.904	1.00

4.18 STP-20, STEAM PRODUCTION

OBJECTIVES

The objectives of this test are to demonstrate that the Nuclear Steam Supply System (NSSS) can provide steam sufficient to satisfy all appropriate warranties as defined in the NSSS contract.

ACCEPTANCE CRITERIA

Level 1

The NSSS parameters as determined by using normal operating procedures shall be within the appropriate license restrictions.

The NSSS shall be capable of supplying 14,159,000 pounds per hour of steam of not less than 99.7% quality at a pressure of 985 psia at the discharge of the second main steam isolation valve, as based upon a final reactor feedwater temperature of 420 degrees F and a control rod drive feed flow of 32,000 pounds per hour at 80 degrees F. The reactor feedwater flow must equal the steam flow less the control rod drive feed flow.

Level 2

None

RESULTS

STP-20.1, Two Hour Demonstration

This subtest was performed in conjunction with STP-20.2, 100 Hour Demonstration, at the beginning (0 hr.), middle (50 hr.) and end (98 hr.) of that demonstration. In each case, data was taken at ten minute intervals for two hours then averaged. The averaged data was used in heat balance calculations to determine core thermal power. Steam moisture content was determined by the carryover from the reactor and steam line pressure drop. NSSS steam production performance was evaluated by adjusting the warranted steam flow for actual plant operating conditions and comparing it to actual steam flow.

Hand calculations of core thermal power showed that the process computer heat balance calculation was approximately 30 MWt low. This discrepancy was traced to improperly spanned feedwater flow transmitters which provide an input to the process computer. These transmitters were re-spanned, resulting in an increase of approximately 25 MWt to the value of core thermal power calculated by the process computer.

Results of the two hour run are summarized below. All criteria were satisfied.

	Steam Quality	Adjusted* Actual Steam Flow (Mlb/hr)	Adjusted* Rated Steam Flow (Mlb/hr)
RUN-1	99.86%	14.34	14.34
RUN-2	99.91%	14.43	14.43
RUN-3	99.89%	14.28	14.28

* Adjustments were required due to differences between actual and rated conditions as defined by NSSS warranty.

STP-20.2, 100 Hour Demonstration

This subtest consists of operating the reactor at or near rated core thermal power for a 100 hour period. Hourly OD-3's were performed to verify thermal limits and rated core thermal power were not exceeded during the demonstration.

The most limiting thermal limit values recorded by the process computer during the 100 hour demonstration were:

Parameter	Limit	Process Computer Value
(CMAPR) MAPRAT	<1.0	.907
(CMFLCP) MFLCPR	<1.0	.841
(CMFLPD) MFLPD	<1.0	.903
(PCTPWR X0.01) FRTP	<1.0	.995

Re-spanning of the feedwater flow transmitters resulted in an increase of 25 MWt to the core thermal power value calculated by the process computer. Therefore, the following core thermal power results observed during the 100 hour demonstration have been adjusted upward by 25 MWt.

	Process Computer Value	Actual Adjusted Value
Minimum Core Thermal Power =	3233.2 (98.1%)	3258.2 (98.9%)
Maximum Core Thermal Power =	3290.6 (99.9%)	3315.6 (100.7%)
Average Core Thermal Power =	3266.8 (99.2%)	3291.8 (99.9%)

This operation was evaluated by General Electric and is considered to be acceptable for the following reasons:

1. Plant and core conditions were monitored by the process computer and all indicated parameters were within rated conditions. It was reported, however, that all hot bundle thermal margins were better than required limits (by about 10%) even when the miscalibration factor is considered.

2. All transient safety evaluations in the FSAR are conservatively done (e.g., with tech spec limits and at end-of-cycle conditions), and were also done at 104.3% of 3293 MWt power conditions. Therefore, adequate transient protection was always present.

3. Loss of Coolant Accident analyses in the FSAR cover at least 102% of 3293 MWt power conditions. This includes 102% hot bundle conditions as well as total power. Therefore, the LOCA/ECCS evaluations bounded all operations during the 100 hour demonstration.

Conclusion

Plant operation during the Steam Production test was well within the design and licensing basis of the plant and within the allowances provided for feedwater flow and other potential power measurement inaccuracies. The plant operation was acceptable.

4.19 STP-21, CORE POWER-VOID MODE RESPONSE

OBJECTIVES

The objective of this test is to measure the stability of the core power-void dynamic response and to demonstrate that its behavior is within specified limits.

ACCEPTANCE CRITERIA

Level 1

The decay ratio of any oscillatory core variable must be less than 1.0 at all test points.

Level 2

System related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.50.

RESULTS

STP-21.1, Core Power - Void Mode Response to Control Rod Movement

This test was performed at test conditions 4 and 5 to observe reactor response (specifically APRM and LPRM) to a control rod movement which produced an LPRM change of approximately 5% from steady state values. Recirculation pumps were tripped (natural circulation) in Test Condition 4 and at minimum speed in Test Condition 5. Choice of a control rod to affect an LPRM response took into consideration the control rods notch worth and proximity to most limiting assemblies, and, thereafter, the LPRM was chosen to be near the control rods tip.

For Test Condition 4, the LPRM 32-41-C was used to monitor the continuous insertion of control rod 30-39 from notch position 26 to 16 (5 notches). The LPRMs reading dropped from 27 to 21.

For Test Condition 5, the LPRM 32-25-C was used to monitor the insertion of control rod 30-23 from notch positions 24 to 18 (3 notches final). The control rod was inserted an amount of notches, and then withdrawn, until a 5% difference from steady state was obtained. The LPRM's reading were 39 (initial), 38 (1 notch), 37 (2 notches) and finally 34 (3 notches).

During these events reactor transient response was recorded and core stability was demonstrated to be acceptable.

All acceptance criteria were satisfied for both test conditions.

STP-21.2, Core Power - Void Mode Response to Reactor Pressure Changes

This test was performed at Test Conditions 4 and 5 to observe reactor response (specifically APRM and LPRM) to a rapid change in core pressure (an approximate 10 psi setpoint step change to the pressure regulator in control). Recirculation pumps were tripped (natural circulation) in Test Condition 4 and at minimum speed in Test Condition 5. For these transients, the Turbine Load Limit and Load Set were set high to allow only control valves to control reactor pressure.

For both test conditions, pressure regulator "A" was placed in control with a pressure setpoint bias of 3 psi.

During these pressure changes, reactor transient response was recorded and core stability was demonstrated to be acceptable.

All acceptance criteria were satisfied for both tests.

4.20 STP-22, PRESSURE REGULATOR

OBJECTIVES

The objectives of this test are as follows:

To demonstrate optimized controller settings for the pressure control loop by analysis of the transients induced in the reactor pressure control system by means of the pressure regulators set point changes.

To demonstrate the take-over capability of the back-up pressure regulator upon failure of the controlling pressure regulator, and to set spacing between the setpoints at an appropriate value.

To demonstrate smooth pressure control transition between the turbine control valves and the bypass valves when reactor steam generation exceeds the steam flow used by the turbine.

To demonstrate the stability of the reactivity-void feedback loop to pressure perturbations in conjunction with STP-21, Core Power Void-Mode Response.

ACCEPTANCE CRITERIA

Level 1

The transient response of any pressure control system related variable to any test input must not diverge.

Level 2

Pressure control system related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25. (This criterion does not apply to tests involving simulated failure of one regulator with the backup regulator taking over.)

The pressure response time from initiation of pressure setpoint change to the turbine inlet pressure peak shall be $\leq$10 seconds.

Pressure control system deadband, delay, etc., shall be small enough that steady state limit cycles (if any) shall produce steam flow variations no larger than $\pm$0.5 percent of rated steam flow.

The peak neutron flux and/or peak vessel pressure shall remain below the scram settings by 7.5 percent and 10 psi respectively for all pressure regulator transients performed at Test Condition 6.

The variation in incremental regulation (ratio of the maximum to the minimum value of the quantity, "incremental change in pressure control signal/incremental change in steam flow", for each flow range) shall meet the following:

% of Steam Flow Obtained With Valves Wide Open	Variation
0 to 85%	$\leq$4:1
85% to 97%	$\leq$2:1
97% to 99%	$\leq$5:1

RESULTS

STP-22.1, Pressure Regulator Response - Control Valve Operation (Test Conditions 2, 3, 4, 5 and 6)

STP-22.2, Pressure Regulator Response - Control Valve and Bypass Valve Operation (Test Condition 3)

STP-22.3, Pressure Regulator Response - Bypass Valve Operation (Test Conditions 1, 2, 4, 5 and 6)

These tests were performed during the Test Conditions noted. System response to nominal 10 psi step changes and failure to the backup regulator (TC 1, 2, 3 and 6 only) were recorded and analyzed. All acceptance criteria were satisfied. The transient response to test inputs did not diverge thus satisfying the Level 1 criterion. With respect to the applicable Level 2 criteria, the following was observed:

1) All pressure control system decay ratios were less than 0.25.

2) The maximum response time to pressure setpoint changes was 8.875 seconds for STP-22.2, during Test Condition 3, which is within the required 10 second criterion.

3) The pressure control system did not display steady state limit cycles. Steam flow variations were not greater than ±0.5% of rated steam flow.

4) During STP-22.3 at TC-6, a problem was identified during the B pressure regulator failure test. The margin to scram was 7.16% which was less than the 7.5%

required. General Electric evaluated this result and found it acceptable based on the small amount of deviation and the fact that the neutron flux is not being passed through a thermal flux simulating first order time delay.

5) The peak vessel pressure remained >10 psi below the scram setting for all TC-6 steps.

6) The variation in incremental regulation was calculated as:

% of Steam Flow With Valves Wide Open	Incremental Regulation Maximum	Minimum	Variation	Limit
0-85%	-.4375	-.395	1.23	≤4:1
85%-97%	-.266	-.14	1.9	≤2:1
97%-99%	This range not reached during testing			≤5:1

4.21 STP-23, FEEDWATER SYSTEM

OBJECTIVES

The objectives of this test are:

To demonstrate that the feedwater system has been adjusted to provide acceptable reactor water level control.

To demonstrate an adequate response to a feedwater temperature reduction.

To demonstrate the capability of the automatic core flow runback feature to prevent low water level scram following the trip of one feedwater pump at high power operation.

To demonstrate that the maximum feedwater runout capability is compatible with the licensing assumptions.

ACCEPTANCE CRITERIA

Level 1

The transient response of any level control system-related variable to any test input must not diverge.

For the feedwater heater loss test, the maximum feedwater temperature decrease due to a single failure case must be ≤100 deg. F. The resultant MCPR must be greater than the fuel thermal safety limit.

The increase in simulated heat flux cannot exceed the predicted Level 2 value by more than 2%. The predicted value will be based on the actual test values of feedwater temperature changes and initial power level.

Maximum speed attained shall not exceed the speeds which will give the following flows with the normal complement of pumps operating.

a. 135% NBR at 1075 psia

b. 146% NBR at 1020 psia

Level 2

Level control system-related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25.

The open loop dynamic flow response of each feedwater actuator (turbine) to small (<10%) step disturbances shall be:

a.	Maximum time to 10% of a step disturbance	$\leq$1.1 sec
b.	Maximum time for 10% to 90% of a step disturbance	$\leq$1.9 sec
c.	Peak overshoot (% of step disturbance)	$\leq$15%
d.	Settling time, 100% $\pm$5%	$\leq$14 sec

The average rate of response of the feedwater actuator to large (>20% of pump flow) step disturbances shall be between 10 percent and 25 percent rated feedwater flow/second. This average response rate will be assessed by determining the time required to pass linearly through the 10 percent and 90 percent response points.

As steady-state generation for the 3/1 element systems, the input scaling to the mismatch gain should be adjusted such that the level error due to biased mismatch gain output should be within $\pm$1 inch.

The increase in simulated heat flux cannot exceed the predicted value referenced to the actual feedwater temperature change and initial power level.

The reactor shall avoid low water level scram by three inches margin from an initial water level halfway between the high and low level alarm setpoints.

The maximum speed must be greater than the calculated speeds required to supply:

a. With rated complement of pumps - 115% NBR at 1075 psia

b. One feedwater pump tripped conditions - 68% NBR at 1025 psia.

RESULTS

STP-23.1, FW System Startup Controller Level Step

STP-23.1 was successfully performed during TC-1. The level control system did not diverge as a result of any test input, and therefore, complied with the single Level 1 criterion for this subtest. The Level 2 criterion, however, was not satisfied for a level controller step input of -5 inches. The observed decay ratio was 0.33 rather than the required 0.25. A test exception was written to accept the 0.33 decay ratio as it did not significantly affect system operation. A controller step input of +5 inches displayed the required decay ratio.

STP-23.2, Feedwater System Manual Flow Step

STP-23.2 was run for each pump (A, B and C) in Test Condition 2 (28% and 43% power) and Test Condition 3 (68% power). In these subtests, positive and negative flow steps were introduced using a function generator on the inputs of the 1A, 1B, and 1C Reactor Feed Pump Turbine (RFPT) speed controllers. The transients were monitored and recorded to verify compliance with the acceptance criteria.

The Test Condition 2 testing was performed at low enough power and feedwater flow levels that did not allow complete evaluation of control system performance, but was sufficient to support ascension to Test Condition 3.

Test Condition 3 testing for RFPT A demonstrated that all of the control system-related variables were well damped in their response to the transients. All of these variables had decay ratios less than or equal to 0.25. Further, it was determined that the open loop dynamic flow response tests of each feedwater actuator to small step disturbances and the average rate of responses of the actuators to large disturbances achieved adequate results for this test condition.

Test Condition 3 testing for RFPT B demonstrated that all of the control system-related variables were adequately damped in their response to the transients. It also demonstrated that the average rate of responses of the feedwater actuator (turbine) to large step disturbances were within the acceptance criteria. Further, it was determined that a steady state hydraulic oscillation existed in the "B" feedwater system making the controller appear to respond with a decay ratio greater than 0.25 and made settling time indeterminant. These oscillations also affected the open loop flow response criteria for rise time for the 5% step change. Since the oscillations are not considered a control related problem, the "as is" condition has been considered not to cause a degradation of level control ability and will be evaluated further.

Test Condition 3 testing for RFPT C demonstrated that all of the control system-related variables were well damped in their response to the transients. It also demonstrated that all of these variables had decay ratios less than or equal to 0.25. Further, it was determined that the open loop dynamic flow responses of the feedwater actuator to small step disturbances was the best reasonably achievable and provided an adequate response to control reactor water level. The average rate of responses of the actuators to large disturbances is expected to provide acceptable margins to high and low water level trips and will be evaluated further.

In summary, all of the feedwater control systems demonstrated reasonable results such that the intent of the testing is satisfied. No additional tuning was performed and the Reactor Feed Pump manual flow steps test (STP-23.2) was not performed in TC-6. Final evaluation of feedwater flow response remains an open item.

STP-23.3 Feedwater System Level Setpoint Changes

This test was performed at 27% and 71% core thermal power in Test Conditions 2 and 3 respectively.

In this subtest, the Master Feedwater Controller was used to demand positive and negative step changes in Reactor Water Level in one and three element control. Also, reactor water level was observed when switching between one and three element control.

There were no divergent control system related variable responses to any transient. The decay ratio for each variable was less than or equal to 0.25 and the steady state reactor water level error due to switching between one and three element control remained within the applicable criteria. All testing was performed with satisfactory results.

Startup test, STP-23.3 was also performed at 65%, 41%, and 99% core thermal power in Test Conditions 5, 4, and 6 respectively.

There were no divergent control system related variable responses to any transient. In TC 4 and TC-5, the level error induced by switching between three and one element control was greater than the 1 inch specified by the Level 2 criteria. Appropriate adjustments were made and STP-23.3 performed during TC-6 showed the FW level error between one and three element control to satisfy the Level 2 criteria.

STP-23.4, Loss of Feedwater Heating, was performed in TC-6. In this subtest, adequate response to a feedwater temperature reduction was demonstrated. The failure was simulated by isolating extraction steam to the sixth stage feedwater heaters. The acceptance criteria require that the feedwater temperature decrease not exceed 100 deg. F, the resultant MCPR must be greater than the fuel thermal safety limit, and the increase in simulated heat flux cannot exceed the predicted value by more than 2%. All of the acceptance criteria were satisfied in this subtest.

STP-23.5, Feedwater Pump Trip, was performed in TC-6 when the "C" Reactor Feedpump turbine was tripped. This subtest demonstrated the capability of the automatic recirculation pump runback feature to prevent a low water level scram following a trip of one reactor feedpump. This test also demonstrated the RFPT speed controllers' ability to prevent high and low water level trips as discussed under STP-23.2. The acceptance criterion required that the reactor avoid a low water level scram by three inches from an initial water level halfway between the high and low level alarm setpoints. This criterion was satisfied.

STP-23.6, RFPT Data, was not performed but was incorporated into STP-23.7. There were no Acceptance Criteria to satisfy.

STP-23.7, Maximum Feedwater Runout Capability, was performed in TC-6 for all three RFPT's. This subtest consists of determining if the maximum feedwater runout capability is compatible with the licensing assumptions by verifying that maximum feedwater flows do not exceed the flows specified in the FSAR. These flows are 135% NBR at 1075 psia and 146% NBR at 1020 psia (Level 1 criteria), and 115% NBR at 1075 psia and 68% NBR at 1025 psia (Level 2 criteria). These criteria were satisfied.

4.22 STP-24, TURBINE VALVE SURVEILLANCE

OBJECTIVES

The objectives of this test are to demonstrate acceptable procedures and maximum power levels for periodic surveillance testing of the main turbine control, stop and bypass valves without producing a reactor scram.

ACCEPTANCE CRITERIA

Level 1

None

Level 2

Peak neutron flux must be at least 7.5% below the scram trip setting.

Peak vessel pressure must remain at least 10 psi below the high pressure scram setting.

Peak steam flow in each line must remain 10% below the high flow isolation trip setting.

RESULTS

STP-24.1, Stop Valve Testing

The Stop Valve Testing was performed in Test Condition 3 and 6. In this test, each Main Turbine Stop Valve (MSV) was stroked from full open to full closed and back open, to verify a 7.5% peak neutron trip margin, a peak vessel pressure margin of 10 psi below the trip setpoint, and a peak steam flow of 10% below the high flow isolation setting. This was accomplished using the test pushbuttons on the EHC Turbine Control Panel.

Extrapolation of the results of stop valve testing in Test Condition 6 shows that periodic surveillance testing can be performed at 100% core thermal power without violating Level 2 acceptance criteria.

STP-24.2, Control Valve Testing

The Control Valve Testing was performed in Test Condition 3. This test called for individual cycling of each Main Turbine Control Valve (CV) from its initial position to fully closed and then returning to its initial position.

Reactor pressure is maintained by repositioning other CVs or Bypass Valves as demanded by the pressure regulator. Recorded data was used to determine that the peak neutron flux was at least 7.5% below the scram trip setting, peak vessel pressure remained at least 10 psi below the high pressure scram setting, and peak steam flow in each line remained 10% below the high flow isolation trip setting.

Extrapolation of the results of control valve testing in Test Condition 6 shows that periodic surveillane testing can be performed at 99% core thermal power without violating Level 2 acceptance criteria.

STP-24.3, Bypass Valve Testing

The Bypass Valve Testing was performed in Test Condition 6. In this test, each bypass valve was stroked from full closed to full open and back closed, to verify a 7.5% peak neutron trip margin, a peak vessel pressure margin of 10 psi below the trip setpoint, and a peak steam flow of 10% below the high flow isolation setting. This was accomplished using the selector switch and test pushbutton on the EHC Turbine Control Panel.

The results of STP-24.1 and STP-24.2 showed that this test could be successfully performed at 99% core thermal power. However, an administrative limit of 95% core thermal power was placed on the test.

All acceptance criteria were satisfied at 94.9% core thermal power.

4.23 STP-25, MAIN STEAM ISOLATION VALVES

OBJECTIVES

The objectives of this test are to functionally check the Main Steam Isolation Valves (MSIV's) for proper operation at selected power levels, to determine the MSIV closure times, and to determine the maximum power level at which full closure of a single MSIV can be performed without causing a reactor scram.

The full isolation is performed to determine the reactor transient behavior that results from the simultaneous full closure of all MSIV's at a high power level.

ACCEPTANCE CRITERIA

Level 1

MSIV stroke time shall be no faster than 3.0 seconds. MSIV closure time shall be no slower than 5.0 seconds.

The positive change in vessel dome pressure occurring within 30 seconds after closure of all MSIV's must not exceed the Level 2 criteria by more than 25 psi. The positive change in simulated heat flux shall not exceed the Level 2 criteria by more than 2% of rated value.

Feedwater control system settings must prevent flooding of the steam lines.

Reactor must scram to limit the severity of the neutron flux and simulated heat flux transients.

Level 2

The reactor shall not scram. The peak neutron flux must be at least 7.5 percent below the trip setting. The peak vessel pressure must remain at least 10 psi below the high pressure scram setting.

The reactor shall not isolate. The peak steam flow on each line must remain 10 percent below the high steam flow isolation trip setting.

The temperature measured by thermocouples on the discharge side of the safety/relief valves must return to within 10 degree F of the temperature recorded before the valve was opened.

The positive change in vessel dome pressure and simulated heat flux occurring within the first 30 seconds after the closure of all MSIV valves must not exceed the predicted values. Predicted values will be referenced to actual test conditions of initial power level and dome pressure and will use beginning of life nuclear data.

If water level reaches the reactor vessel low water level (Level 2) setpoint, RCIC and HPCI shall automatically initiate and reach rated system flow.

Recirculation pump trip shall be initiated if water Level 2 is reached.

RESULTS

STP-25.1, MSIV Functional Test

This test was performed during Test Conditions Heatup, 1 and 2, functionally checking the Main Steam Isolation Valves (MSIVs) and measuring their closure times. During Test Condition 1, MSIV F022A did not meet the criteria for stroke time (2.84 seconds actual versus 3.0 seconds criteria). Subsequent adjustments were made and MSIV F022A was retested at similar conditions during Test Condition 2, giving satisfying results. During the tests, the reactor did not scram and peak APRM readings remained at least 7.5% below the scram setpoint. The scram setpoint for Test Condition Heatup was 15%, and, for Test Condition 1, the scram setpoint was 61% (69.2% for MSIV F022A retest). The reactor did not isolate and the peak steam flow on each line remained less than 126% (10% below the high steam flow isolation trip setpoint). The peak vessel pressure remained less than 1027 psig (10 psig below the high pressure scram setpoint). All applicable acceptance criteria were satisfied.

STP-25.2, Full Closure of Fastest MSIV

This test was performed during Test Conditions 3, 5 and 6 to demonstrate the highest power level at which the fastest MSIV (F022B) could be closed without causing a scram. During the tests, the reactor did not scram. Peak APRM readings remained at least 7.5% below the scram setpoint, with the exception of Test Condition 6. The reactor did not isolate and the peak steam flow remained less than 126% (10% below the high steam flow isolation trip setpoint). The peak vessel pressure remained less than 1027 psig (10 psig below the high pressure setpoint).

STP-25.2 provides plots of expected margins to scram. The as measured margins to scram (6.5%) are less than the predicted 7.5%. The APRM margin to scram is the limiting criteria for determination of the maximum power level for stroking the fastest MSIV. Since the MSIVs are not required by Tech Specs to be stroked while the reactor is operating, no further tests were performed. From the results, it is estimated that the maximum power level for routine performance of this test is at 74.8% (75.8%-1% to maintain a 7.5% margin to scram) with core flow $\geq$77.3% rated.

STP-25.3, Full MSIV Closure

The purpose of this test is to demonstrate the reactor's transient behavior to a full closure of all MSIVs near 100% power.

The MSIV closure times were all greater than or equal to 3.0 seconds and less than or equal to 5.0 seconds. The positive change in vessel dome pressure occurring within 30 seconds after closure of all MSIVs was less than the Level 2 criteria by >25 psi. The positive change in simulated heat flux did not exceed the Level 2 criteria by greater than 2%. The main steam lines did not become flooded, the reactor scrammed, and no relief valves were lifted.

The positive change in vessel dome pressure and simulated heat flux occurring within the first 30 seconds after the closure of all MSIV valves did not exceed the predicted values. Water level monitored by ERFDS reached a level of -40.89 inches and was less than the Level 2 setpoint for 3 seconds.

HPCI initiated but did not inject due to the short time that water level was less than the Level 2 trip, and one ATWS channel reached the Level 2 setpoint tripping both recirculation pumps.

The reason that RCIC and the other ATWS channel did not sense a Level 2 trip is that they each sense water level through separate instrumentation which did not reach the Level 2 setpoint due to minor differences in level indication and trip unit calibration.

4.24 STP-26, RELIEF VALVES

OBJECTIVES

The objectives of this test are a) to verify that the Relief Valves function properly (can be manually opened and closed, b) to verify that the Relief Valves reseat properly after actuation, c) to verify that there are no major blockages in the Relief Valve discharge piping, and d) to demonstrate system stability to Relief Valve operation.

ACCEPTANCE CRITERIA

Level 1

There should be a positive indication of steam discharge during the manual actuation of each Relief Valve.

The flow through each Relief Valve shall compare favorably with value assumed in the FSAR accident analysis at normal operating Reactor pressure.

Level 2

Pressure control system-related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be less than or equal to 0.25.

The temperature measured by the thermocouples on the discharge side of the valves shall return to within 10 DEG F of the temperature recorded before the valve was opened.

During the low pressure functional test, the steam flow through each Relief Valve, as measured by Bypass Valve position, shall not be less than 90% of the average Relief Valve steam flow.

During the rated pressure functional test, the steam flow through each Relief Valve, as measured by Generator Gross MWe, shall not be lower than the average valve response by more than 0.5% of rated MWe.

RESULTS

STP-26.1, Relief Valve Low Pressure Test

During Test Condition Heatup with reactor pressure at 300 psig, each Relief Valve was manually cycled to verify proper operation. Each valve was maintained open for approximately 10 seconds to allow system variable to stabilize.

Positive indication of Relief Valve discharge was verified by review of transient plots of Bypass Valve position. The steam flow through each valve, as measured by Bypass valve position, was greater than 90% of the average Relief Valve flow.

During the initial Relief Valve lift, with reactor pressure at 375 psig, Bypass Valves went fully shut. The Relief valve was immediately shut. Reactor pressure was then reduced to 300 psig, additional Bypss Valve capacity was obtained, and the test was successfully completed.

All applicable acceptance criteria were satisfied with the following exceptions: Relief Valves C, D, G, J, L and S did not meet the Level 2 criterion for discharge side temperatures returning to within 10 Deg. F of the initial temperature. Valve position, as indicated by the Acoustic Monitoring System, indicated that all valves were fully shut. Final resolution is pending disposition of the Test Exception Report.

STP-26.2, Relief Valve Rated Pressure Test

This test was performed during Test Condition 2. Each relief valve was manually cycled and maintained open for approximately 10 seconds to allow system variables to stabilize. Positive indication of Relief Valve discharge was verified by the change in gross generator output (MWe).

All relief valves actuated and flow through each valve compared favorably with the value assumed in the FSAR accident analysis at normal operating reactor pressure satisfying the Level 1 criteria.

All Level 2 criteria were satisfied with the following exceptions: 1) Relief Valves B, C, F, G, K, M and N did not meet the criterion for discharge side temperatures returning to within 10 degrees F of the initial temperature. 2) The data point for Relief Valve PSV41-1F013-B was inoperable so temperature data could not be taken. All acoustic monitors indicated that relief valves (including PSV41-1F013-B) were closed following their opening for this test. The test results were evaluated and determined to be acceptable based on the acoustic monitor indication.

4.25 STP-27, MAIN TURBINE TRIP

OBJECTIVES

The objectives of this test are to demonstrate the response of the Reactor and its control systems to protective trips of the Main Turbine and to evaluate the response of the bypass and safety/relief valves.

ACCEPTANCE CRITERIA

Level 1

For Turbine and Generator Trips at power levels greater than 50% Nuclear Boiler Rated, there should be a delay of less than 0.1 seconds following the beginning of Control or Stop Valve closure before the beginning of Bypass Valve opening. The Bypass Valves should be opened to a point corresponding to greater than or equal to 80% of their capacity within 0.3 seconds from the beginning of Control or Stop Valve closure motion.

Feedwater System settings must prevent flooding of the steam lines following these transients.

The positive change in vessel dome pressure occurring within 30 seconds after either Generator or Turbine Trip must not exceed the Level 2 criteria by more than 25 psi.

The positive change in simulated Heat Flux shall not exceed the Level 2 criteria by more than 2% of Rated Value.

The recirculation pump and motor time constants for the two-pump drive flow coastdown transient should be $\leq$4.5 seconds from 1/4 to 2 seconds after the pumps are tripped.

The total time delay from the start of the Turbine Stop Valve or Control Valve motion to the complete suppression of the electrical arc between the fully open contacts of the RPT circuit breakers shall be less than or equal to 175 milliseconds.

Level 2

There shall be no MSIV closure during the first three minutes of the transient and operator action shall not be required during that period to avoid the MSIV closure.

The positive change in vessel dome pressure occurring within the first 30 seconds after the initiation of either Generator or Turbine Trip must not exceed predicted values.

The positive change in simulated Heat Flux occurring within the first 30 seconds after the initiation of either Generator or Turbine Trip must not exceed predicted values.

Feedwater level control shall avoid loss of feedwater flow due to a high (L8) water level trip during the event.

Low (L2) water level recirculation pump trip, HPCI and RCIC shall not be initiated.

The temperature measured by thermocouples on the discharge side of the Relief Valves must return to within 10 Degree F of the temperature recorded before the valve was opened.

For the Turbine Trip within the Bypass Valves capacity, the Reactor shall not scram.

The measured Bypass Valve capability shall be equal to or greater than that used in the FSAR analysis (25% of Nuclear Boiler Rated Steam Flow).

RESULTS

STP-27.1, Turbine Trip Within Bypass Valve Capacity

This test was performed at 22% core thermal power during Test Condition 2. The main turbine was tripped manually by depressing the Turbine Trip pushbutton which shut the four Main Turbine Stop and Control Valves. The bypass valves opened to maintain pressure control and the reactor did not scram, thus satisfying the single Level 2 acceptance criterion.

STP-27.2, Bypass Valve Capacity Check

This test was performed at 77% and 37% core thermal power during Test Conditions 3 and 5 respectively. The bypass valve capacity Level 2 acceptance criterion was not satisfied in Test Condition 3. An engineering analysis was performed by General Electric which demonstrated that the bypass valve capacity was not safety or operationally limiting at the value obtained. A retest was performed in Test Condition 5 utilizing an improved test method.

In Test Condition 5 reactor power was increased while generator output was held constant. As power increased bypass valves opened to maintain reactor pressure. A plot was obtained of the change in reactor power versus bypass valve position.

From this graph the capacity of the bypass valves was determined. Total bypass valve capacity was calculated to be 27.3% of rated core thermal power, thus satisfying the applicable acceptance criterion.

STP-27.3, Turbine Trip at Test Condition 3

This test was performed at 75% core thermal power during Test Condition 3. The turbine was tripped by manually pulling the Front Standard Trip Handle which caused the four Main Turbine Stop and Control Valves to close.

All Level 1 acceptance criteria were met with the exception of the following: No simulated heat flux signals were available. It was determined that Heat Flux Level 1 and Level 2 criteria were satisfied based on an evaluation by General Electric.

All Level 2 acceptance criteria were satisfied with the exception of the following: 1) see the above comment for the level 1 heat flux criterion 2) the maximum reactor water level was greater than level 8 at 68 inches.

STP-27.4, Turbine Trip at Test Condition 6

This test was performed at 99% core thermal power during Test Condition 6. The turbine was tripped manually by depressing the Main Turbine Trip pushbutton which caused the four Main Turbine Stop and Control Valves to close.

All Level 1 acceptance criteria were satisfied.

All Level 2 acceptance criteria were satisfied with the exception of reactor water level, which reached a level of 69.8 inches. This is in excess of the Level 2 criteria which states that RPV level shall not exceed Level 8 (54"). A test exception was written which provides for further analysis to be conducted on the feedwater system by General Electric control system specialists.

4.26 STP-28, SHUTDOWN FROM OUTSIDE THE CONTROL ROOM

OBJECTIVES

The objectives of this test are to demonstrate that the Reactor a) can be safely shutdown from outside the Control Room, b) can be maintained in a Hot Standby condition from outside the Control Room and c) can be safely cooled from hot to cold shutdown from outside the Control Room. In addition, it will provide an opportunity to demonstrate that the procedures for Remote Shutdown are clear and comprehensive and that operational personnel are familiar with their applications.

ACCEPTANCE CRITERIA

Level 1

None

Level 2

During a simulated Control Room evacuation, the Reactor must be brought to the point where cooldown is initiated and under control, and Reactor vessel pressure and water level are controlled using equipment and controls located outside the Control Room.

The Reactor can be safely shutdown to a Hot Standby condition from outside the Control Room using the minimum shift crew complement.

The Reactor coolant temperature and pressure can be lowered sufficiently (at a rate that does not exceed the Technical Specification Limit) from outside the Control Room to permit operation of the Shutdown Cooling Mode of the Residual Heat Removal System.

The Shutdown Cooling Mode of the Residual Heat Removal System can be initiated from outside the Control Room with a heat transfer path established to the Ultimate Heat Sink.

The Shutdown Cooling Mode of the Residual Heat Removal System can be used to reduce Reactor coolant temperature at a rate which does not exceed the Technical Specification Limit.

RESULTS

STP-28.1, Reactor Shutdown to Hot Standby Demonstration

This subtest was implemented in Test Condition 2 at 16.9% rated thermal power. A reactor scram, full MSIV isolation and turbine trip was initiated from the Auxiliary Equipment Room in accordance with Special Event procedure SE-1 with the Remote Shutdown Panel manned.

Reactor Pressure Vessel (RPV) parameters were stabilized initially at 830 psig and +54 in. water level. No automatic Relief Valve lifts occurred.

A controlled Depressurization/Cooldown was initiated in accordance with SE-1 and maintained for 35 minutes. Final RPV parameters were obtained at 610 psig and +42in. water level.

The applicable Level 2 acceptance criteria were satisfied during the performance of this subtest. All system operations from the Remote Shutdown Panel were satisfactory.

STP-28.2, Reactor Cooldown Demonstration

This subtest was implemented in Test Condition 2, separately from STP-28.1. Initial RPV parameters were 210 psig pressure and >60 in. indicated (at Remote Shutdown panel) water level.

Controlled cooldown/depressurization was initiated using RCIC/Relief Valves until a final RPV pressure of 70 psig was obtained. At that point, the Shutdown Cooling mode of RHR was initiated in accordance with SE-1.

Cooldown/depressurization was continued in Shutdown Cooling until a greater than 50 degrees F RPV temperature decrease was obtained in that mode. Final RPV parameters were obtained at 20 psig and >60 in. indicated RPV level (read at Remote Shutdown panel).

During this subtest, the remaining Level 2 acceptance criteria were satisfied.

4.27 STP-29, RECIRCULATION FLOW CONTROL SYSTEM

OBJECTIVES

The objectives of this test are to demonstrate the flow control capability of the plant over the entire pump speed range, in both Individual Local Manual and Combined Master Manual operation modes and to determine that the controllers are set for the desired system performance and stability.

ACCEPTANCE CRITERIA

Level 1

The transient response of any recirculation system-related variable to any test input must not diverge.

Level 2

A scram shall not occur due to Recirculation flow control maneuvers. The APRM neutron flux trip avoidance margin shall be $\geq$7.5% when the power maneuver effects are extrapolated to those that would occur along the 100% rated rod line.

The decay ratio of any oscillatory controlled variable must be $\leq$0.25.

Steady-state limit cycles (if any) shall not produce turbine steam flow variations greater than $\pm$0.5% of rated steam flow.

The speed demand meter must agree with the speed meter within 6% of rated generator speed.

RESULTS

STP-29.1, Local Manual Recirculation Flow Control

The Local Manual Recirculation Flow Control tests were performed during the ascension to Test Condition 3. In these subtests, the Recirculation Flow Control Systems' responses to step changes in generator speed demand, together with related reactor parameters response, were recorded to verify stability. Nominal $\pm$5% generator speed demand steps were injected into the recirc flow control loops where the delta speed versus delta demand curves show the greatest gain. A voltage step generator was used to introduce the transients.

For "A" Loop, there were no divergent oscillations. No scram occurred and the APRM neutron flux trip avoidance margin was acceptable. The decay ratios of the oscillatory variables were acceptable. Dynamic oscillations were tested acceptable, but the steady state oscillations require further analysis. Also, the speed meter output and demand signals did not agree within the required 6%. Steady state oscillations and RPM to voltage calibration minor problems are still under investigation.

For "B" Loop, there were no divergent oscillations. A scram did not occur and the margin to scram was acceptable. Decay ratios and dynamic oscillations were acceptable, but the steady state oscillations require further analysis. The speed demand meter agreed adequately with the speed meter for "B" Loop. Steam flow oscillation analysis could not be performed due to difficulties in retrieving recorded data. Steady state oscillations and steam flow oscillation analysis minor problems are still under investigation.

STP-29.2, Master Manual Recirculation Flow Control

The Master Manual Recirculation Flow Control test was performed in Test Condition 3 and 6. The test is performed by introducing an approximately +5% speed demand by setting the local controllers operating in manual at +5% of the Master Controller setting and switching the local controllers to automatic.

This testing was successfully performed with all acceptance criteria satisfied.

4.28 STP-30, RECIRCULATION SYSTEM

OBJECTIVES

The objectives of this test are to:

Obtain recirculation system performance data during steady-state conditions, pump trip, flow coastdown, and pump restart.

Verify that the feedwater control system can satisfactorily control water level on a single recirculation pump trip without a resulting turbine trip and associated scram.

Record and verify acceptable performance of the circuit for a two-recirculation pump trip.

Verify the adequacy of the recirculation runback to avoid a scram upon simulated loss of one feedwater pump.

Verify that no recirculation system cavitation will occur in the operable region of the power-flow map.

ACCEPTANCE CRITERIA

Level 1

The reactor shall not scram during the one pump trip recovery.

The recirculation pump and motor time constant for the two pump drive flow coastdown transient should be $\leq$4.5 seconds from 1/4 to 2 seconds after the pumps are tripped and $\geq$3.0 seconds from 1/4 to 3 seconds after the pumps are tripped.

Level 2

The reactor water level margin to avoid a high level trip shall be $\geq$3.0 inches during the one pump trip.

The APRM margin to avoid a scram shall be $\geq$7.5% during the pump trip recovery.

The core flow shortfall shall not exceed 5% at rated power.

The measured core delta P shall not be >0.6 PSI above prediction.

The calculated jet pump M ratio shall not be less than, 0.2 points below prediction.

The drive flow shortfall shall not exceed 5% at rated power.

The measured recirculation pump efficiency shall not be >8% points below the vendor tested efficiency.

The nozzle and riser plugging criteria shall not be exceeded.

The recirculation pumps shall runback upon a trip of the runback circuit.

Runback logic shall have settings adequate to prevent recirculation pump operation in areas of potential cavitation.

RESULTS

STP-30.1, Recirculation System One Pump Trip

The Recirculation System One Pump Trip was performed in Test Condition 3 at 73% power and in Test Condition 6 at 100% power. In these tests, a single recirculation pump was tripped to demonstrate the ability to avoid a high reactor water level with resultant main turbine and reactor feedwater pump trip.

During this subtest a reactor scram did not occur in either TC-3 or TC-6. In TC-3, the reactor water level margin to high level trip was ≥3.0 inches and the APRM margin to scram was ≥7.5% during the pump trip recovery. In TC-6, the APRM margin to scram was ≥7.5% during the pump trip recovery, but the reactor water level margin to high level trip was only 0.84 inches. This is below the 3 inch margin criterion and the final disposition of the test exception will follow completion of the evaluation.

STP-30.2, Recirculation Pump Trip (RPT) of Two Pumps

The Recirculation Pump Trip (RPT) of Two Pumps was performed in Test Condition 3 at 69% power. In this test, both recirculation pumps were simultaneously tripped using the RPT Breaker trip circuit. The recirculation flow coastdown was monitored to verify that the flow reduces quickly enough to limit the reactor power spike and not so quickly that flow reduction precedes the drop in heat flux which could cause a limiting Critical Power Ratio (CPR) transient.

Both recirculation pumps were tripped and data was recorded. The subsequent data reduction showed that the pump and meter time constant was $\leq$4.5 seconds from 1/4 to 2 seconds from pump trip and $\geq$3.0 seconds from 1/4 to 3 seconds after the pump trips.

All applicable acceptance criteria were satisfied.

STP-30.3, Recirculation System Performance

Recirculation System performance was performed in Test Condition 2, Test Condition 3, Test Condition 4 and Test Condition 6. The purpose of the test was to verify that the measured pump efficiency was not >8% below the vendor tested efficiency and that the nozzle and riser plugging criteria were not exceeded.

The test was performed by holding the plant in a steady state condition approximately one minute while plant parameters are monitored and data recorded. The collected data is used to calculate if the above criteria are satisfied.

All applicable acceptance criteria were satisfied.

STP-30.5, Recirculation System Cavitation

The Recirculation System Cavitation test was performed in Test Condition 3. The purpose of this test was to verify that the recirculation cavitation runback logic settings were adequate to prevent operation in possible cavitation areas. This was accomplished without taking a runback by defeating the runback circuitry, establishing core flow at $\geq$95%, and driving in control rods to reduce reactor power and therefore reactor feed flow. Subcooled feedwater provides net positive suction head to the recirculation pumps at high recirculation system flow. When the runback circuitry was activated at approximately 20% feed flow, no recirculation system cavitation was noted.

The applicable acceptance criterion was satisfied.

4.29 STP-31, LOSS OF TURBINE GENERATOR AND OFFSITE POWER

OBJECTIVES

This test determines electrical equipment and reactor system transient performance during a loss of main turbine-generator coincident with loss of all sources of offsite power.

ACCEPTANCE CRITERIA

Level 1

All safety systems, such as the Reactor Protection system, the diesel-generators, and HPCI must function properly without manual assistance, and HPCI and/or RCIC system action, if necessary, shall keep the reactor water level above the initiating level of Low Pressure Core Spray, LPCI, Automatic Depressurization System, and MSIV Closure. Diesel generators shall start automatically.

Level 2

Proper instrumentation display to the reactor operator shall be demonstrated, including power monitors, pressure, water level, control rod position, suppression pool temperatures, and reactor cooling system status. Displays shall not be dependent on specially installed instrumentation.

Reactor pressure shall not exceed 1250 psig.

If safety/relief valves open, the temperature measured by thermocouples on the discharge side of the safety/relief valves must return to within 10 degrees F of the temperature recorded before the valve was opened.

Normal cooling systems shall be capable of maintaining adequate drywell cooling and adequate suppression pool water temperature.

RESULTS

STP-31.1, Loss of Turbine Generator and Offsite Power

STP-31 was performed in Test Condition 2 at 20.8% of Rated Thermal Power. To perform this test, the electrical distribution system was aligned to power all plant loads from the affected unit. The main turbine and the appropriate breaker were tripped to simulate a loss of turbine generator with a loss of all offsite power.

The Reactor Protection System properly inserted a scram and the reactor water level remained above the HPCI, RCIC, LPCI, ADS, and MSIV level setpoints.

All reactor operator instrumentation properly displayed the required parameters. Reactor Pressure peaked well below 1250 psig at 911.7 psig. No Relief Valves opened as determined by the acoustic monitoring system and reactor pressure response. The drywell and suppression pool cooling systems performed satisfactorily to maintain adequate temperatures and pressures in these two areas. Diesel generators D11, D12, D13 and D14 started automatically and properly energized their respective Safeguard buses. All acceptance criteria were satisfied.

4.30 STP-32, ESSENTIAL HVAC SYSTEM OPERATION AND CONTAINMENT HOT PENETRATION TEMPERATURE VERIFICATION

OBJECTIVES

The objectives of this test are to demonstrate, under actual/normal operating conditions, that the various HVAC systems will be capable of maintaining specified ambient temperatures and relative humidity within the following areas:

a) Primary Containment (drywell and suppression chamber)

b) Reactor Enclosure and Main Steam Tunnel

c) Control Room

d) Control Enclosure

e) Radwaste Enclosure

In addition, this test shall verify that the concrete temperature surrounding Main Steam and Feedwater containment penetrations remains within specified limits.

ACCEPTANCE CRITERIA

Level 1

The drywell area volumetric average air temperature is not to exceed 135 degrees F.

Level 2

The drywell area and suppression chamber are maintained between 65 degrees F and 150 degrees F.

The reactor pressure vessel (RPV) support skirt surrounding air temperature is maintained above a minimum of 70 degrees F.

The concrete temperatures surrounding primary containment Main Steam line and Feedwater line penetrations are maintained at less than or equal to 200 degrees F.

All areas listed in Subtest 32.3 for the control enclosure are maintained between 65 degrees F and 104 degrees F except the battery rooms, which are maintained at 88 degrees maximum (at float charge rate) and the auxiliary equipment room, which is maintained between 74 degrees F and 78 degrees F and relative humidity between 45% R.H. and 55% R.H.

The Control Room is maintained at a temperature between 74 degrees F and 78 degrees F and relative humidity between 45% R.H. and 55% R.H.

The following areas of the Reactor Enclosure are maintained between 65 degrees F and 104 degrees F: rooms 111, 118, 200, 207, 210, 304, 402, 406, 500, 506A, 506B, 506C, 506D, 507, 508, 509, 511, 519, 601, 602, 605, 612, and 618.

The following areas of the Reactor Enclosure are maintained between 65 degrees F and 110 degrees F: rooms 502, 503, 504, and 505.

The following areas of the Reactor Enclosure are maintained between 65 degrees F and 115 degrees F: rooms 102, 103, 203, 204, 108, 109, 110, 113, 114, 117, 288, 289, 501, 510, 522, 523, and 599.

The following areas of the Reactor Enclosure are maintained between 65 degrees F and 120 degrees F: rooms 209, 306, 307, 309, 407, and 518.

The following areas of the Radwaste Enclosure are maintained between 65 degrees F and 76 degrees F: rooms 410, 411, 412, 415, 417 and 418.

<u>RESULTS</u>

STP-32.1, Primary Containment Temperature

This test specifies minimum equipment configuration for system performance verification.

For Test Condition Heatup at rated reactor temperature and pressure, both chilled water pumps were placed in service to maintain volumetric average temperature below 135 degrees F. The test procedure was revised to permit two pump operation for Test Condition Heatup. Test results were as follows:

Drywell Volumetric Average Temp	= 127 degrees F
Highest Drywell Temp.	= 146 degrees F
Lowest Drywell Temp.	= 90 degrees F
Max Wetwell Air Temp.	= 155 degrees F*
RPV Skirt Temp.	= >70 degrees F

* Level 2 criteria not satisfied. Resolved by identifying possible air space stratification and instrument inaccuracy.

Prior to entering into Test Condition 1, all external surfaces of six of the eight unit coolers were cleaned, internal cooler surfaces inspected and chilled water temperatures/flows adjusted to improve performance. Subsequent testing (thermal power <5%) with minimum system configuration indicated volumetric average temperature could be maintained below 135 degrees F (stabilized at 132 degrees F).

For Test Condition 3, both chilled water loops were again required to be in operation (periodically 2 loop operations in conjunction with two pump operation) to maintain drywell temperatures within specification. Test results were as follows:

Drywell Volumetric Average Temp	= 133 degrees F
Highest Drywell Temp.	= 158 degrees F*
Lowest Drywell Temp.	= 102 degrees F
Max Wetwell Air Temp.	= 160 degrees F*

For Test Condition 6, both chilled water loops and chilled water pumps were required to be in operation to maintain drywell temperatures within specification. Test results were as follows:

Note: With reactor power >60% two pump/two loop equipment configuration is required essentially all the time.

Drywell Volumetric Average Temp	= 127 degrees F
Highest Drywell Temp.	= 142 degrees F
Lowest Drywell Temp.	= 105 degrees F
Max Wetwell Air Temp.	= 164 degrees F*

*Level 2 criteria not satisfied. Hot spot in drywell due to location of sensor adjacent to main steam piping (to be relocated). Hot spot in wetwell due to sensor location and air space stratification.

Throughout the test program inspections during plant outages have uncovered exposed areas of piping in need of additional or revised insulation. When time permits, modifications to the existing pipe insulation and internal tube cleaning of the Unit Coolers are planned.

STP-32.2, Hot Penetration Concrete Temperature

For Test Conditions Heatup through Test Condition 6, concrete temperatures remained well under the 200 degree limit with the maximum recorded temperature of 163 degrees F on feedwater line "A (90 degree quadrant) and minimum recorded temperature of 97 degrees F on main steam line "C" (0 degree quadrant).

STP-32.3, Control Enclosure Temperature and Relative Humidity

For Test Conditions Heatup through Test Condition 6, test results are as follows:

For Test Condition Heatup, initial test data was declared invalid due to system malfunctions including loss of relative humidity control and instrument calibration problems. Retest of the system ("B" CW loop) was performed in Test Condition 1 with temperatures and relative humidity in the Auxiliary Equipment room exceeding acceptance criteria. These test exceptions were resolved through an Engineering safety evaluation expanding the allowable temperature band from 76 degrees F $\pm$2 degrees F to 60 to 82 degrees F and the relative humidity band from 45% to 55% to 30% to 90% relative humidity.

For Test Conditions 2, 3, and 6, test data was acceptable based on the Engineering Safety Evaluation expanding ranges of temperature and relative humidity. General Control Enclosure areas remained between 65 and 104 degrees F. Battery Rooms remained below 88 degrees F.

STP-32.4, Control Room Temperature and Relative Humidity

For Test Conditions Heatup through Test Condition 6, test results are as follows:

For Test Condition Heatup, initial test data was declared invalid due to system malfunctions including loss of relative humidity control and instrument calibration problems. The test (CW loops A & B) was successfully reperformed following repairs to the system. Acceptance criteria minimum temperature of 74 degrees F and maximum relative humidity of 55% were not met for several rooms and areas. These test exceptions were resolved through an Engineering safety evaluation, expanding the allowable temperature band from 76 degrees F $\pm$ 2 degrees F to 65 to 78 degrees F and relative humidity band from 45% to 55% to 30% to 90% relative humidity.

For Test Conditions 3 & 6, test data was acceptable based on the Engineering safety evaluation expanding ranges of temperature and relative humidity.

STP-32.5, Reactor Enclosure and Main Steam Tunnel Temperature

For Test Conditions Heatup through Test Condition 6, test results are as follows:

For Test Condition Heatup all recorded room temperatures were within acceptance criteria but test data was declared invalid due to several system damper failures and temperature stratification in the main supply ducts. This test was reperformed (with the exception of the HPCI and RCIC unit coolers in operation) in Test Condition 1 (outside air temperature was 84 degrees F) with several test exceptions relating to high delta temperatures (air supply temp/air exhaust temp) in the Main Steam Pipe Chase Area and the Reactor Water Cleanup Pump Area. During this test, outside air temperatures required plant operations to maintain the air supply cooling coils (Drywell Chilled Water System) in service.

For Test Condition 3 (outside air temperature was 63 degrees F) test exceptions were identified due to high delta temperatures in certain areas of the Reactor Enclosure and maximum temperatures in the Main Steam Pipe Tunnel area reached 127 degrees F (air supply cooling coils not in service). Test exceptions are being evaluated by Engineering.

For Test Condition 6 (outside air temperature was 36 degrees F) test exceptions were identified due to high delta temperatures in certain areas of the Reactor Enclosure and maximum temperatures in the Main Steam Pipe Tunnel reached 130 degrees F. (air supply cooling coils not in service). Test exceptions are being evaluated by Engineering.

STP-32.6, Radwaste Enclosure Temperature

For Test Condition Heatup and Test Condition 3, all rooms were maintained within the temperature criteria limits with the exception of room 415 (Radwaste Control Room) which exceeded the maximum temperature by 1 degree F (Test Condition Heatup) and Radiation Chem Lab which fell below the minimum temperature by 1.5 degrees F (Test Condition 3). These test exceptions were evaluated and found acceptable.

For Test Condition 6 all but one room exceeded the maximum temperature of 76 degrees F by 2 to 4 degrees F. Test exceptions are being evaluated by Engineering.

4.31 STP-33, PIPING STEADY STATE VIBRATION

OBJECTIVE

The objective of this test is to verify that the steady state vibration of Main Steam, Reactor Recirculation and selected BOP piping systems is within acceptable limits.

ACCEPTANCE CRITERIA

Level 1

Operating Vibration: The measured amplitude (peak to peak) of each remotely monitored point shall not exceed the allowable value for that point.

Level 2

Operating Vibration: The measured amplitude (peak to peak) of each remotely monitored point shall not exceed the expected value for that point.

The steady state vibrations of visually examined balance of plant piping are acceptable if the vibration levels are judged by a qualified test engineer to be neglible. Vibration levels judged to be potentially significant are evaluated as determined necessary by BPC Project Engineering.

The vibration measured by a remote accelerometer is acceptable if the acceleration frequency spectrum falls in the negligible region of the acceptance chart for that accelerometer. If the acceleration frequency spectrum crosses the negligible region boundary, the test results shall be evaluated by BPC Project Engineering.

RESULTS

STP-33.1, Main Steam Piping (Inside Drywell) Steady State Vibration

This subtest provided the means for collecting vibration data on Main Steam piping at steady state conditions with various nominal main steam flows. Data was recorded by the Emergency Response Facilities Data System (ERFDS) from the remote monitoring instrumentation (24 lanyard potentiometers and 2 resistance temperature devices). Data was collected at Test Condition 2 (25% rated main steam flow), Test Condition 3 (50% and 75% rated main steam flow) and Test Condition 6 (100% rated main steam flow). All lanyard potentiometer vibration criteria were satisfied.

STP-33.2, Recirculation Piping Steady State Vibration

This subtest provided the means for collecting vibration data on Recirculation piping at steady state conditions with various moninal recirculation pump flows. Data was recorded by the Emergency Response Facilities Data System (ERFDS) from the remote monitoring instrumentation (24 lanyard potentiometers and 3 resistance temperature devices). Data was collected at Test Condition 2 (minimum recirc flow), Test Condition 3 (50% and 75% rated recirc flow), Test Condition 5 (minimum recirc flow) and Test Condition 6 (100% recirc flow). All lanyard potentiometer vibration criteria were satisfied.

STP-33.3, Main Steam, Main Steam Bypass, and Feedwater Steady State Vibration

The results of the testing showed that steady state vibratory response for Main Steam, Main Steam Bypass, and Feedwater Piping (BOP Scope) was within acceptable design limits.

Data was taken manually and recorded on ERFDS (Emergency Response Facilities Data System) from remotely mounted vibration sensors. Recorded data was processed as applicable, and compared with design limits.

The test was conducted during Test Condition 2 (nominal 25% rated power), Test Condition 3 (nominal 50% and 75% rated power), and Test Condition 6 (nominal 100% rated power). All three feedwater loops, external to the drywell, were tested at each power level.

No piping steady state vibratory response problems were encountered during the tests. The test results were forwarded to Bechtel Engineering for review. Based on their analysis of the test data, they deemed that the acceptance criteria had been met.

STP-33.4, HPCI Steam Piping Steady State Vibration

The results of the testing showed that steady state vibratory response for the HPCI Steam Piping was within acceptable design limits.

Data was recorded on ERFDS (Emergency Response Facility Data System) from remotely mounted vibration sensors. Recorded data was processed as applicable, and compared with design limits.

The test was performed in Test Condition Heatup with the HPCI turbine running on nuclear steam at a nominal throttle pressure of 920 psig and the HPCI pump discharging at rated head and flow. Pump suction was from, and discharged into, the condensate storage tank.

No piping steady state vibratory response problems were encountered during the test. The test results were forwarded to Bechtel Engineering for review. Based on their analysis of the test data, they deemed that the acceptance criteria had been met.

STP-33.5, RCIC Steam Piping Steady State Vibration

The results of the testing showed that steady state vibratory response for the RCIC Steam Piping was within acceptable design limits.

Data was recorded on ERFDS (Emergency Response Facility Data System) from remotely mounted vibration sensors. Recorded data was processed as applicable, and compared with design limits.

The test was performed with the RCIC turbine running on nuclear steam at a nominal throttle pressure of 920 psig and the RCIC pump discharging at rated head and flow. Pump suction was from, and discharged into, the condensate storage tank.

No piping steady state vibratory response problems were encountered during the test. The test results were forwarded to Bechtel Engineering for review. Based on their analysis of the test data, they deemed that the acceptance criteria had been met.

STP-33.6, Reactor Water Cleanup Piping Steady State Vibration

The results of the testing showed that steady state vibratory response for the reactor water cleanup piping was within acceptable design limits.

Data was recorded on ERFDS (Emergency Response Facility Data System,) from remotely mounted vibration sensors. Recorded data was processed as applicable, and compared with design limits.

The test was conducted during the implementation of STP-70.2 and STP-70.3 with the reactor at rated temperature and pressure during Test Condition Heatup. The referenced STP's cover the hot shutdown mode of the RWCU System in which bottom head drain line flow is maximized at approximately 120 gpm and the normal mode in which suction flow from the recirculation line is maximized at approximately 290 gpm. Two of three RWCU pumps operate during these modes.

No piping steady state vibratory response problems were encountered during the test. The test results were forwarded to Bechtel Engineering for review. Based on their analysis of the test data, they deemed that the acceptance criteria had been met.

STP-33.7 RHR Shutdown Cooling Mode Piping Steady State Vibration

The results of the testing showed that steady state vibratory response for the RHR shutdown cooling mode piping was within acceptable limits.

Data was taken manually and recorded on ERFDS (Emergency Response Facilities Data System) from remotely mounted vibration sensors. Recorded data was processed as applicable, and compared with design limits.

The test was conducted during the implementation of STP-71.4 at a reactor temperature of approximately 325 degrees F. Data was collected on "A" RHR loop only (typical of both loops). The flow in the A loop was nominally 10,000 gpm (rated flow).

No piping steady state vibratory response problems were encountered during the test. The test results were forwarded to Bechtel Engineering for review. Based on their analysis of the test data, they deemed that the acceptance criteria had been met.

1HF-005, RHR Low Pressure Coolant Injection Steady State Vibration Test

The results of the testing showed that steady state vibratory response for the RHR Low Pressure Coolant Injection Piping was within acceptable design limits.

Steady state vibrations were evaluated by qualified test engineers using visual and tactile judgement and hand held vibration monitors. These engineers were qualified to standards set by Bechtel Project Engineering.

The object of this test was to verify, by means of visual examination by qualified test engineers, that the tested piping met the steady state vibration limits.

The procedure was implemented, prior to fuel load, during operation of RHR Loops A and D with pumps 1AP202 and 1DP202, respectively, discharging to the reactor vessel at rated flow of approximately 10,000 gpm.

No piping steady state vibratory response problems were encountered during the test.

1HF-006, Core Spray Piping Steady State Vibration Test

The results of the testing showed that steady state vibratory response for the Core Spray Piping was within acceptable design limits.

Steady state vibrations were evaluated by qualified test engineers using visual and tactile judgement and hand held vibration monitors. These engineers were qualified to standards set by Bechtel Project Engineering.

The objective of this test was to verify, by means of visual examination by qualified test engineers, that the tested piping met the steady state vibration limits.

The test was conducted, prior to fuel load, when both core spray pumps, 1AP206 and 1CP206, were in operation and discharging to the reactor vessel at a minimum combined rated flow of 6350 gpm.

No piping steady state vibratory response problems were encountered during the test.

1HF-017, Head Spray Piping Steady State Vibration Test

The results of the testing showed that steady state vibratory response for the RHR Head Spray Piping was within acceptable design limits.

Steady state vibrations were evaluated by qualified test engineers using visual and tactile judgement and hand held vibration monitors. These engineers were qualified to standards set by Bechtel Project Engineering.

The objective of this test was to verify, by means of visual examination by qualified test engineers, that the tested piping met the steady state vibration limits.

The procedure was implemented, in Test Condition Open Vessel, during operation of RHR loop A running in the shutdown cooling mode and head spray flow at approximately 1,000 gpm.

No piping steady state vibratory response problems were encountered during the test.

4.32 STP-34, OFFGAS PERFORMANCE VERIFICATION

OBJECTIVES

The objectives of this test are to verify that the Offgas Recombination and Ambient Charcoal System operates within the technical specification limits and expected operating conditions.

ACCEPTANCE CRITERIA

Level 1

The allowable dose and dose rates from releases of radioactive gaseous and particulate effluents to areas at and beyond the SITE BOUNDARY shall not be exceeded.

Allowable limits on the radioactivity release rates of the six noble gases measured at the after condenser discharge shall not be exceeded.

The hydrogen content of the offgas effluent downsteam of the recombiner shall be equal to or less than 4% by volume.

The total flow rate of dilution steam plus offgas when the steam jet air ejectors are in operation shall exceed 9555 lbs/hr.

Level 2

System flows, pressures, temperatures and dewpoint shall be within expected performance values.

The preheater, catalytic recombiner, after condenser, Hydrogen Analyzers, cooler condenser, activated charcoal beds and the HEPA filter shall be performing their required functions adequately. The automatic drain systems function adequately.

TEST RESULTS

STP-34.1, Offgas Performance Verification

For Test Condition Heatup and Test Conditions 1, 3, 5, and 6 results are as follows:

Dose and dose rates from releases of radioactive gaseous and particulate effluents at the site boundary have all been within Technical Specification Limits. Isotopes analysis indicated Lower Limit of Detection (LLD).

Radioactive release rates of the six noble gases measured at the after condenser discharge have all been well under the Technical Specification Limit of 330,000 MCi/sec. For Test Condition 3 total observed value was 37.82 MCi/sec, for Test Condition 5 total observed value was 82.44 MCi/sec, and Test Condition 6 total observed value was 124.07 MCi/sec.

The hydrogen content of the offgas effluent downstream of the recombiner has been less than 1% by volume for all test conditions. The total flow rate of dilution steam plus offgas has continued to exceed the 9555 lbs/hr minimum. Offgas flow rates were in excess of 200 scfm during test condition H/U (total flow was >14,000 lbs/hr) but subsequent testing after a condenser leak was found and plugged reduced in-leakage to approximately 15-35 scfm.

Several instruments (dew point meters, hydrogen concentration meters and pressure indicators) were not performing satisfactorily during Test Condition H/U but subsequent retests have cleared all of these problems prior to test performance at Test Condition 1. System flow, pressures, temperatures (except recombiner preheater inlet temperature) and dew points were within expected values. All system major components performed their required functions adequately.

The recombiner preheater inlet temperature controller is set to maintain a temperature of 350 degrees F (380 degrees F design). Maintaining a 380 degrees F setpoint causes high condensate levels in the preheater. Engineering has evaluated this problem and has recommended maintaining preheater temperature at 350 degrees F.

4.33 STP-35, RECIRCULATION SYSTEM FLOW CALIBRATION

OBJECTIVES

The objectives of this test are to perform a complete calibration of the recirculation system flow instrumentation, including specific signals to the plant process computer and to adjust the recirculation flow control system to limit maximum core flow to 102.5% of rated core flow.

ACCEPTANCE CRITERIA

Level 1

None

Level 2

Jet pump flow instrumentation shall be adjusted such that the jet pump total flow recorder will provide correct core flow indication at rated conditions.

The APRM/RBM flow bias instrumentation shall be adjusted to function properly at rated conditions.

The flow control system shall be adjusted to limit maximum core flow to 102.5% of rated.

RESULTS

STP-35.1, Recirculation System Flow Calibration

In Test Condition 3 at 42.7% power and 88% indicated core flow, single tap jet pump, double tap jet pump and recirculation loop data was recorded and a calculation was performed to determine total core flow. Calculated core flow was 100.66%. Core flow was reduced to <100% and the jet pump loop flow summers were adjusted to provide the correct loop and total core flows. In addition, the APRM/RBM flow bias instrumentation was adjusted to function properly at rated core flow conditions.

In Test Condition 3 at 49.5% power and 98% indicated core flow the core flow was again calculated. Calculated core flow was 93.74%. Jet pump loop summers and the APRM/RBM flow bias instrumentation were adjusted based upon these results.

In Test Condition 6 at 99.4% thermal power and 95.9% indicated core flow, the core flow was again calculated. Calculated core flow was 95.95. Jet pump loop summers were not recalibrated but the APRM/RBM flow bias instrumentation was readjusted to function properly at rated core flow conditions.

For these tests in Test Conditions 3 and 6 all applicable acceptance criteria were satisfied.

STP-35.2, Recirculation System Flow Limiter Adjustment

In Test Condition 6, the recirculation pump MG set scoop tube mechanical and electrical high speed stops were adjusted to limit total core flow to less than or equal to 105 and 102.5 percent of total core flow respectively. The actual high speed electrical stops for "A" and "B" Recirculation Pumps limit core flow to 102 and 102.2 percent of total core flow respectively. The actual mechanical high speed stops for the "A" & "B" Recirculation Pumps limit core flow to 103.7 and 102.5 percent of total core flow respecitvely.

For this test in Test Condition 6, the applicable acceptance criterion was satisfied.

4.34 STP-36, PIPING DYNAMIC TRANSIENTS

OBJECTIVES

The objectives of this test are to verify that the following pipe systems are adequately designed and restrained to withstand the following respective transient loading conditions:

Main Steam - Main Turbine Stop Valve/Control Valve closures at approximately 20-25%, 60-80%, and 95-100% of rated thermal power.

Main Steam and Relief Valve Discharge - Main Steam Relief Valve actuation.

Recirculation - Recirculation Pump trips and restarts.

High Pressure Coolant Injection steam supply - High Pressure Coolant Injection turbine trips.

Feedwater - Reactor feed pump trips/coastdowns.

ACCEPTANCE CRITERIA

Level 1

Operating Transients: The measured amplitude (peak to peak) of each remotely monitored point shall not exceed the allowable value for that point.

Level 2

Operating Transients: The measured amplitude (peak to peak) of each remotely monitored point shall not exceed the expected value for that point.

The maximum measured loads, displacements, and/or velocities are less than or equal to the acceptance limits specified.

In the judgment of the qualified test engineers, no signs of excessive piping response (such as damaged insulation; markings on piping, structural or hanger steel, or walls; damaged pipe supports; etc.) are found during a post-transient walkdown and visual inspection of the piping tested and associated branch lines.

RESULTS

STP-36.1, Main Steam Piping Vibration during Main Turbine Stop Valve and Control Valve Closure

This test was performed in conjunction with STP-27.1, Turbine Trip Within Bypass Valve Capacity, in TC-2, STP-27.3, Turbine Trip at TC-3 and STP-27.4, Turbine Trip at TC-6.

Data was recorded on the Emergency Response Facilities Data System (ERFDS) from remotely mounted sensors. Recorded data was processed as applicable, and compared with the applicable acceptance criteria values.

NSSS Scope:

Transient vibration data was recorded during the Main Turbine Trips performed in TC2, 3 and 6 for Main Steam piping inside the drywell. Remotely mounted sensors, 24 lanyard potentiometers in total, were installed and monitored on each Main Steam Line. All transient vibration results obtained satisfied the applicable Level 1 and 2 acceptance criteria for both tests.

BOP Scope:

The results of the testing, thus far, show that the dynamic vibratory response of the main steam supply piping, outside the Drywell, during main turbine stop and control valve closure was within acceptable design limits.

Problems encountered during the performance of the tests were minor in nature and include the following:

1. At Test Condition 2, load sensing clevis pin DL.YA.13 exceeded allowable values. Further analysis revealed that the majority of the loading was the thermal pre-load on the strut in which the pin was installed. The test data was reanalyzed to conservatively determine the dynamic component of the total recorded load. Based on this analysis, the dynamic loading was evaluated as acceptable.

   It was also determined that pressure transducer DP.NA.02 was inoperative. The remaining instruments illustrated an acceptable piping response and no damage was noted during a visual inspection of the piping system.

2. At Test Condition 3, load sensing clevis pins DL.SA.07, DL.SA.08, and DL.SA.12 exceeded their criterion values.

   The test results were forwarded to Bechtel Engineering for further evaluation. Based on their analysis of the provided test data, they deemed the results acceptable. No further action was required.

3. At Test Condition 6, load sensing clevis pins DL.SA.11, DL.SA.12, DL.YA.13, DL.SA.07 and DL.SA.08 exceeded their allowed criterion values.

   The test results were fowarded to Bechtel Engineering for further evaluation. Based on their analysis of the provided test data, they deemed the results acceptable. No further action was required.

STP-36.2, Main Steam and Relief Valve Discharge Piping Vibration during SRV Operation

This test was performed in conjunction with STP-26.2, Relief Valve Rated Pressure Test in TC-2.

Data was recorded on the Emergency Response Facilities Data System (ERFDS) from remotely mounted sensors. Recorded data was processed as applicable, and compared with the applicable acceptance criteria values.

NSSS Scope:

As each Relief Valve was cycled at rated reactor pressure, transient vibration was recorded for Main Steam piping inside the Drywell. Remotely mounted sensors, 24 lanyard potentiometers in total, were installed and monitored on each Main Steam Line. All transient vibration results obtained satisfied the applicable level 1 and 2 acceptance criteria.

BOP Scope:

This test was performed for the cycling of Relief Valve J with the reactor at rated pressure.

The results of this test showed that the dynamic vibratory response of the main steam relief valve piping during a steam relief valve opening was within acceptable design limits.

Problems encountered during the performance of the test were minor in nature and include the following:

1. Load sensing clevis pin, DL.YR.05 was determined to be inoperative. The remaining instruments illustrated an acceptable piping response and no damage was noted during a visual inspection of the piping system. Bechtel Engineering concluded that no further action was required.

2. Load sensing clevis pin DL.YR.04 exceeded allowable values. Further analysis revealed that the majority of the loading was the thermal preload on the strut in which the pin was installed. The test data was re-analyzed to conservatively determine the dynamic component of the total recorded load. Based on this analysis, the dynamic loading was evaluated as acceptable.

STP-36.3, Recirculation Piping Vibration during Selected Transients

This test provided the means for collecting vibration data for the recirculation piping for the following transients:

Event	Test Condition
Recirc Pump A Trip	3
Recirc Pump A Restart	3
Recirc Pump B Trip	6
Recirc Pump B Restart	6
Two Pump Trip	3
RHR A SDC Initiation & Shutdown	6
RHR B SDC Initiation & Shutdown	6

Data collection was accomplished using the Emergency Response Facilities Data System (ERFDS) and remote monitoring instrumentation (24 lanyard potentiometers and 3 resistance temperature devices). For all tests, vibration acceptance criteria were satisfied.

STP-36.4, HPCI Steam Supply Piping Vibration During HPCI Turbine Stop Valve Closure

The results of this test showed that the dynamic vibratory response of the HPCI steam supply piping during a stop valve closure was within acceptable design limits.

Data was recorded on ERFDS (Emergency Response Facility Data System) from remotely mounted vibration sensors. Recorded data was processed as applicable, and compared with design limits.

The test was performed with the HPCI turbine running on nuclear steam at a nominal throttle pressure of 920 psig and the HPCI pump discharging at rated head and flow. Pump suction was from, and discharge was to, the condensate storage tank. The HPCI turbine stop valve was tripped remotely.

No piping dynamic vibratory response problems were encountered during the test.

Test data was provided to Bechtel Engineering in the forms of loads and acceleration power spectral density plots. Based on their analysis of the provided test data, they deemed that the acceptance criteria had been met.

STP-36.5, Feedwater Piping Vibration during Reactor Feedpump Trip/Coastdown

This test was performed in conjunction with STP-23.5, Reactor Feedpump Trip at Test Condition 6. "C" Feedpump was tripped with nominal full load flow in each loop.

Data was recorded on the Emergency Response Facilities Data System (ERFDS) from remotely mounted sensors. Recorded data was processed as applicable, and compared with the acceptance criteria values. All data was within acceptable design limits.

The involved feedwater piping outside the drywell was walked down by Bechtel Engineering. No problems were noted.

Based on operational considerations, review of the test data, and the results of the walkdown external to the drywell, Bechtel Engineering waived the requirement to perform a walkdown on the feedwater piping inside the drywell.

Based on the walkdown, as completed, and the analysis of the test data the dynamic loading was evaluated as acceptable.

4.35 STP-70, REACTOR WATER CLEANUP SYSTEM

OBJECTIVES

The objective of this test is to demonstrate specific aspects of the mechanical operability of the Reactor Water Cleanup (RWCU) System.

ACCEPTANCE CRITERIA

Level 1

None

Level 2

The temperature at the tube side outlet of the non-regenerative heat exchangers shall not exceed 130 Deg F in the blowdown mode and shall not exceed 120 Deg. F in the normal mode.

The pump available NPSH shall be 13 feet or greater during the Hot Shutdown mode as defined in the process diagram.

The cooling water supplied to the non-regenerative heat exchangers shall be less than 6% above the flow corresponding to the heat exchanger capacity (as determined from the process diagram) and the existing temperature differential across the heat exchangers. The outlet temperature shall not exceed 180 Deg. F.

Pump vibration shall be less than or equal to 2 mils peak-to-peak (in any direction) as measured on the bearing housing, and 2 mils peak-to-peak shaft vibration as measured on the coupling end.

RESULTS

STP-70.1, Blowdown Mode Performance Verification

The RWCU System was tested during Test Condition Heatup at rated temperature and pressure in the Blowdown Mode with one RWCU pump running, and one RWCU NRHX group in service. The RWCU System was aligned to divert all flow to the main condenser and the system flow was then increased until 148 gpm was obtained. The steady state RWCU NRHX outlet temperature was less than 130 Deg. F and the steady state NRHX RECW outlet temperature was less than 180 Deg. F when the system flow reached 148 gpm. It was then discovered that the RECW throttle valve was 6-1/2 turns open instead of the required 3-1/2 turns. The valve was adjusted to 3-1/3 turns open and the data was retaken. The other NRHX was placed into service and testing repeated with similar results. All applicable acceptance criteria was satisfied.

STP-70.2, Hot Shutdown Mode Performance Verification

The RWCU System was tested during Test Condition Heatup at rated temperature and pressure in the Hot Shutdown Mode with two RWCU pumps running and two F/D's in service. A bottom head drain flow of 120 gpm was first established and then, while maintaining balanced F/D flows, the F/D flows were adjusted to obtain a RWCU System flow of 354 gpm. The applicable Level 2 Acceptance Criterion was satisfied since the available NPSH for the RWCU pump with the lowest suction pressure (RWCU pump A) was greater than 13 feet.

STP-70.3, Normal Mode Performance Verification

The RWCU System was tested in the Normal Mode with two RWCU pumps running, two filter/demineralizers (F/D's) in service, and one NRHX group in service. While maintaining balanced F/D flow, F/D flow was adjusted until RWCU System flow reached 354 gpm. The steady state RWCU NRHX outlet temperature was less than 120 Deg. F and the steady state NRHX RECW outlet temperature was less than 150 Deg. F when RWCU System flow reached 354 gpm.

The other NRHX group was placed in service and testing repeated with similar results. Vibration measurements were then taken on each RWCU pump - pump bearing housing vibration in the horizontal, vertical, and axial directions and shaft vibration on the coupling end.

All applicable acceptance criteria were satisfied.

4.36 STP-71, RESIDUAL HEAT REMOVAL SYSTEM

OBJECTIVES

The objectives of this test are to demonstrate the ability of the Residual Heat Removal (RHR) System to remove residual and decay heat from the nuclear system so that refueling and nuclear servicing can be performed. Additionally, this test will demonstrate the ability of the RHR System to remove heat from the suppression pool.

Level 1

The RHR System shall be capable of operating in the Suppression Pool Cooling Mode at the heat exchanger capacity specified.

The RHR System shall be capable of operating in the Shutdown Cooling Mode at the heat exchanger capacity specified.

Level 2

None

RESULTS

STP-71.1, Suppression Pool Cooling Mode

The Residual Heat Removal (RHR) System was demonstrated for heat exchanger performance capacity in the suppression pool cooling mode at Test Condition Heatup. Inlet and outlet temperatures were recorded from the RHR system and RHR Service Water System streams every five minutes during a twenty minute duration test. Heat exchanger capacities for RHR loops A and B successfully met the Level 1 acceptance criteria.

As shown in the table below, the average heat removal rate for both heat exchangers were higher than the process diagram values. As a result, the actual performance of the heat exchangers is greater than the design performance.

Average RHR Heat Exchanger Performance Parameters

	A Heat Exchanger	B Heat Exchanger	Process Diagram
RHR System Heat Removal Rate (MBtu/hr)	69.0	62.3	26.0

STP-71.4, Shutdown Cooling Mode

The Residual Heat Removal (RHR) system was demonstrated for heat exchanger performance capacity in the shutdown cooling mode after STP-27.4, Turbine Trip at TC-6. Inlet and outlet temperatures were recorded from the RHR system and RHR Service Water System streams at specified time intervals during the performance of the test. Heat exchanger capacities for RHR loops A and B successfully met the Level 1 criterion.

As shown in the table below, the average heat removal rate for both heat exchangers was higher than the process diagram values. As a result, the actual performance of the heat exchangers is greater than the design performance.

AVERAGE RHR HEAT EXCHANGER PERFORMANCE PARAMETERS

	A Heat Exchanger	B Heat Exchanger	Process Diagram
RHR System Heat Removal Rate (MBTU/hr)	438.3	494.7	203.8

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March 20, 1986

Docket No. 50-352

Dr. Thomas E. Murley, Administrator
Region I
U. S. Nuclear Regulatory Commission
631 Park Avenue
King of Prussia, PA 19406

SUBJECT: Final Report of Initial Plant Startup
December, 1984 - Limerick Generating Station, Unit No. 1

Dear Dr. Murley:

Philadelphia Electric Company completed the Startup Test Program for Limerick Generating Station Unit 1 on January 23, 1986. Enclosed are two copies of the final revision of the Initial Plant Startup Report for Limerick Generating Station Unit No. 1 - December, 1984. This revision includes the events starting with initial fuel loading and ending with the completion of the Warranty Run following Test Condition 6. Changes and revisions to Revision 1 (December 1985) are identified by vertical bars in the margin. This revision is submitted to satisfy the requirements of Technical Specification 6.9.1.3 for Operating License NPF-39.

Very truly yours,

W m Alden

Engineer-In-Charge
Licensing Section
Nuclear Generation Division

PBB:vdw

cc: Director, Office of Inspection & Enforcement, NRC
E. M. Kelly, Senior Resident Site Inspector

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