TENNESSEE VALLEY AUTHORITY

WATTS BAR NUCLEAR PLANT, UNIT 1

INITIAL STARTUP REPORT
TO THE
UNITED STATES
NUCLEAR REGULATORY COMMISSION

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1.0 INTRODUCTION

The Initial Startup Report for the Watts Bar Unit 1 nuclear plant discusses the results of testing performed from initial core load through full power operation. This report is written to comply with Regulatory Guide 1.16, "Reporting of Operating Information - Appendix A Technical Specifications" (Revision 4). This Regulatory Guide requires that a summary report be written to address each of the power ascension tests identified in Chapter 14 of the WBN Unit 1 FSAR and other license commitments. The report includes a description of the measured values of the operating conditions or characteristics obtained during the testing program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation are also described.

The Initial Startup Report addresses the requirements of Regulatory Guide 1.16 by describing each of the tests and problems encountered during testing.

Regulatory Guide 1.16 (Rev. 4) requires submittal of the Initial Startup Report to the NRC within: (1) 90 days following completion of the Startup Test Program, (2) 90 days following resumption or commencement of commercial operation, or (3) 9 months following initial criticality, whichever is earliest. Item (1) is being satisfied since the Startup Test Program was completed on May 23, 1996.

WBN Unit 1 received a limited operating license (5% RTP) on November 9, 1995. Initial core load commenced with movement of the first fuel assembly at 0345 on November 10, 1995, and core load was completed at 1301 on November 13, 1995. Initial criticality was achieved at 1848 on January 18, 1996, and a full power operating license was received on February 7, 1996. Further testing was successfully completed at the following plateaus:

1.0 INTRODUCTION (continued)

Test Plateau, % RTP	Date Completed
30	March 9, 1996
50	April 5, 1996
75	April 15, 1996
90	April 28, 1996
100	May 23, 1996

Core load, precritical testing, initial criticality and low power physics testing, and power ascension testing are discussed in separate sections of the report. The report details the test objectives, methodology, test results, and significant problems (i.e., those which affect the acceptance criteria) encountered for each of the tests performed.

This report also provides the alert level settings for the Loose Parts Monitoring System as required by Regulatory Guide 1.133, "Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors," Section C.3.a.2.a.

2.0 POWER ASCENSION TEST PROGRAM OVERVIEW

The PATP was developed from commitments described in Chapter 14 of the WBN Unit 1 FSAR; requirements specified in Regulatory Guide 1.68 (Rev. 2), "Initial Test Programs for Water-Cooled Nuclear Power Plants"; and other licensing commitments discussed in the USNRC's SER, NUREG-0847, and supplements. Testing of the NSSS generally followed generic Westinghouse test methodology.

2.1 Administration of the Program

Overall management of the PATP was directed by the plant manager who was responsible for:

- Development and implementation of the PATP to ensure the PATP was conducted in a safe and orderly manner while complying with license provisions and other commitments.

2.1 **Administration of the Program** (continued)

- Advising senior management on PATP activities.
- Establishing a TRG as a subcommittee of the PORC to review PATP activities.
- Providing final approval of revisions to Power Ascension Tests (PATs) and Power Escalation Tests (PETs).
- Ensuring the PATP was conducted in accordance with applicable WBN Administrative Procedures.
- Providing approval to proceed to the next PATP test plateau.
- Providing final approval of all PATP test results and the PATP final report.

The technical support manager, reporting to the plant manager, was responsible for:

- Notifying the plant manager of major problems and of the completion of each major test phase (i.e., test sequence) of the program.
- Developing and implementing plans and schedules for the PATP.
- Ensuring testing activities, including planning and scheduling, resulted in a safe and orderly PATP and safe plant operations that were not dependent on the performance of untested systems.
- Coordinating and directing overall PATP testing and related activities and requirements with appropriate support groups.
- Supervising of PATP test personnel assigned to Technical Support.
- Assigning responsibilities to organizations for specific testing requirements.
- Participating in the review activities of the TRG, and acting as Chairman of the TRG.

2.1 Administration of the Program (continued)

- Ensuring the post-performance test results (i.e., test packages) were reviewed by TRG.

- Ensuring test directors for the PATP were qualified, and met the minimum qualifications of Item 1 and either Item 2 or Item 3 below:

  1. a. Knowledgeable of the test program administration, the system design and operational requirements, and expected plant operational characteristics during the test, and

     b. Trained as test directors in accordance with SSP-8.01, Conduct of Testing

  2. a. Possessed a bachelor degree in engineering or physical science, and

     b. Had two years experience in power plant testing or operation. Included in the two years was one year nuclear power plant testing, operating or training on a nuclear facility

  3. a. Possessed a high school diploma or equivalent, and

     b. Had five years experience in power plant testing. Included in the five years were two years of nuclear power plant experience. Credit for up to two years of related technical experience could be substituted for experience on a one-for-one basis.

Technical and administrative oversight of the PATP was performed by TRG which was composed of one representative, or their alternates, from each of the following organizations:

2.1 Administration of the Program (continued)

- Plant Operations
- Technical Support
- Site Nuclear Engineering
- Corporate Nuclear Fuels
- Nuclear Assurance
- Westinghouse

TRG was charged with reviewing PATP testing activities for technical adequacy and affect/impact on nuclear safety, and advising PORC and the plant manager on the disposition of those items reviewed. The responsibilities of TRG included final review and recommendation of approval of all PATP test procedures, revisions, and test results.

Following completion of testing at each major test sequence of the PATP, test results were reviewed by TRG to ensure required tests had been performed and acceptance criteria satisfied; test deficiencies had been properly dispositioned and appropriate retesting had been completed; and the test results had been reviewed by appropriate designated personnel prior to proceeding to the next major test sequence. This review ensured that all required systems were operating properly and that testing for the next major test sequence could be conducted in a safe and efficient manner.

2.2 Implementation of the Program

The WBN PATP utilized information gained from operating and testing experience at other nuclear plants. This information was used in the development of the PATP test procedures and schedules and to alert personnel to potential problem areas. Test procedures were developed utilizing information obtained from TVA's NER Program. The NER program identifies and evaluates experience gained from other TVA nuclear plants, INPO, NRC, equipment suppliers, and from other utilities. Significant operational experience and events were reviewed and integrated into appropriate PATP test procedures to ensure nuclear safety and reliability. To the extent practical, simulator-based training and trial use of the PATP test procedures were performed on the WBN Unit 1 simulator to familiarize personnel with systems and plant operation and to assure technical adequacy of the procedures under simulated plant conditions prior to field use during power operation.

2.2 Implementation of the Program (continued)

The testing program was cautiously conducted by qualified personnel using approved plant administrative, test, and operating procedures. The plant was taken from core load to full power in a highly controlled, conservative, and documented manner which demonstrated, where practical:

- The plant is ready to operate in a manner which will not endanger the health and safety of the public.
- The plant has been properly constructed, and plant performance is satisfactory in terms of established design criteria.
- The plant meets licensing requirements and provides assurance of plant reliability for operation.
- The plant is capable of withstanding anticipated transients and postulated accidents.

The PATP was specified in seven PAT sequence procedures:

- 1-PAT-2.0, Initial Core Loading Sequence
- 1-PAT-3.0, Post Core Loading Precritical Test Sequence
- 1-PAT-4.0, Initial Criticality and Low Power Test Sequence
- 1-PAT-5.0, Test Sequence for 30% Plateau
- 1-PAT-6.0, Test Sequence for 50% Plateau
- 1-PAT-7.0, Test Sequence for 75% Plateau
- 1-PAT-8.0, Test Sequence for 100% Plateau

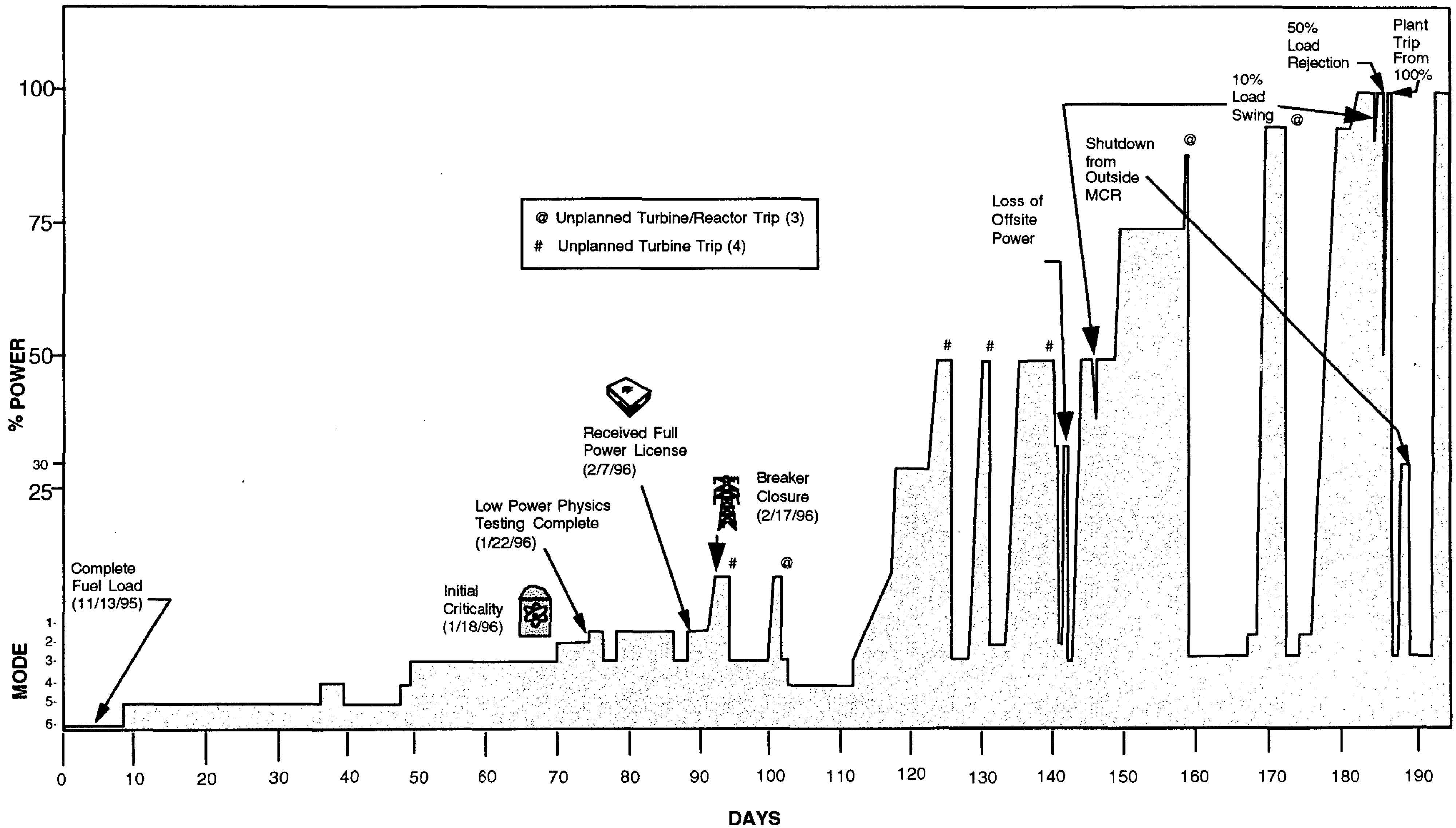
Each PAT sequence procedure called out the performance of other PATs, as well as other designated plant procedures such as PETs, SIs, TRIs, TIs, and FHIs. The sequence procedures specified the logical performance of required tests and procedures through each test plateau. The sequence procedures also specified general prerequisites, precautions and limitations, and additional operational steps at each test plateau. The detailed test and normal plant procedures called out by the sequence procedures defined step-by-step actions, specific prerequisites and limitations, signoffs, data taking requirements, and test acceptance and review criteria.

2.2 Implementation of the Program (continued)

The PATP commenced with the receipt of the limited operating license (5% RTP) on November 9, 1995, and progressed with core loading, precritical testing, initial criticality and low power physics testing, and power ascension testing. Core load procedures directed the initial core load in a prescribed manner which ensured core loading was accomplished in a safe and orderly fashion. Precritical testing brought the plant to hot standby conditions, made measurements, and demonstrated that the plant was ready for critical operation. Initial criticality on January 18, 1996, brought the Unit 1 reactor critical for the first time. Zero power physics testing performed measurements on the critical reactor to demonstrate conformance with design predictions prior to power operation. PAT brought the plant to full power, made minor plant instrumentation adjustments, and demonstrated the plant's ability to withstand selected transients. Figure 2.2-1 depicts the time line for the PATP.

Plant events not directly associated with the PATP added to the duration of the program. These events are included in the chronology. Incident Investigations were performed on each of these events to determine root cause and corrective action. Copies were made available to the NRC site Resident.

Figure 2.2-1
WBN Power Ascension Test Program



3.0 WATTS BAR UNIT 1 STARTUP CHRONOLOGY

10/25/95	-Began 1-PAT-2.0, Initial Core Load Sequence
10/31/95	-PET-102, Pre-Power Escalation NIS Calibration Data, was begun and field complete
11/1/95	-Began 1-PAT-2.2, Core Loading Instrumentation and Neutron Source Requirements, Section 6.1
11/4/95	-Began 1-PAT-2.1, Reactor Coolant Sampling For Core Loading
11/7/95	-1-PAT-2.2, Core Loading Instrumentation and Neutron Source Requirements, Section 6.1, was field complete
11/8/95	-Retrieved seven pieces of foreign material consisting of paint chips and a metal sliver from the core plate
11/9/95	-Lower core plate inspection complete -Placed temporary dunkers (BF3 detectors) on core plate per PET-105, Refueling and Core Alterations -Received fuel load and low power testing license
11/10/95	-Began fuel loading per PET-105
11/12/95	-Fuel loading suspended due to malfunctioning scaler timer -Scaler timer replaced and fuel loading resumed
11/13/95	-Fuel loading complete -1-PAT-2.2 was field complete -1-PAT-2.1 was field complete -TI-28, Physical Verification of Core Load Prior to Vessel Closure, was field complete -Began 0-PAT-3.9, Spent Fuel Pool Cooling System
11/14/95	-1-PAT-2.0, Initial Core Load Sequence, was field complete -RCI-126, Radiation Baseline Survey, was field complete -0-PAT-3.9, Section 6.1, was field complete -Began 1-PAT-3.0, Post Core Loading Precritical Test Sequence

3.0 **Watts Bar Unit 1 Startup Chronology** (continued)

11/17/95	-Entered Mode 5
11/20/95	-Began 1-PAT-3.6, Incore Movable Detectors
11/21/95	-1-PAT-1.4, Pipe Vibration Monitoring, was begun -1-PAT-1.8, Thermal Expansion of Piping Systems, was begun
11/22/95	-1-PAT-5.1, Dynamic Automatic Steam Dump Control, Section 6.1, was begun and field complete
11/24/95	-1-PAT-5.1, Section 6.2, was field complete
11/26/95	-Corrected three control rod drive mechanism cables that were connected incorrectly -TP-85-01, Individual Rod Drive Mechanism Verification, was field complete
11/28/95	-1-PAT-3.10, Reactor Trip System, was field complete
11/29/95	-1-PAT-3.1, Control Rod Drive Mechanism Timing, was field complete -1-PAT-5.1 retest No. 1 was field complete
12/5/95	-RCI-126, Radiation Baseline Survey, was field complete
12/6/95	-0-PAT-3.9, Spent Fuel Cooling System, Section 6.0 was field complete. Retest determined to be required when flow orifices are replaced. -1-PAT-5.1 retest No. 2 on 1-FCV-1-108 was field complete
12/15/95	-Entered Mode 4
12/18/95	-Unit returned to mode 5 to investigate low lift pump oil pressure on RCP 4
12/19/95	-Retesting for 0-PAT-3.9 complete
12/21/95	-0-PAT-3.9 was field complete

3.0 Watts Bar Unit 1 Startup Chronology (continued)

12/27/95	-1-PAT-1.11 at 300°F was field complete -Clogged strainer on RCP 4 lift pump cleaned and unit returned to Mode 4
12/28/95	-Unit entered Mode 3 -1-PAT-1.11 at 350 to 370°F was field complete
12/29/95	-1-PAT-1.11 at 400°F was field complete
12/30/95	-1-PAT-1.11, RVLIS Performance Test, at 450°F was field complete -1-PAT-1.11, RVLIS Performance Test, at 500°F was field complete -Unit reached 557°F and 2237 psig
1/1/96	-1-PAT-1.7, Operational Alignment of Process Temperature Instrumentation, Section 6.1, was field complete -1-PAT-3.3, RCS Flow Measurement, was field complete -1-PAT-3.1, Control Rod Drive Mechanism Timing, was field complete
1/2/96	-1-PAT-3.11, Adjustment of Steam Flow Transmitters at Minimal Steam Flow, was field complete
1/3/96	-1-PAT-1.6, Startup Adjustments of Reactor Control System, was field complete
1/5/96	-1-PAT-3.4, Rod Position Indication System, Sections 6.3.1 and 6.4, were field complete -Stopped performance of 1-PAT-3.4, Section 6.3.2, due to rod control bank D moving one half step at a time
1/8/96	-1-PAT-3.2, Pressurizer Spray Capability and Continuous Spray Flow Setting, was field complete -1-PAT-3.4, Rod Position Indication System, Section 6.1 was field complete

3.0 Watts Bar Unit 1 Startup Chronology (continued)

1/11/96	-1-PAT-3.8, Rod Drop Testing, was field complete -1-PAT-3.4, Rod Position Indication System, Sections 6.2 and 6.3.2 were field complete -1-PAT-3.7 , Reactor Coolant Flow Coastdown, was field complete -1-PAT-1.11, RVLIS Performance Test, at 557°F was begun and field completed
1/12/96	-1-PAT-3.4, Rod Position Indication System, was field complete -1-PAT-3.0, Post Core Loading Precritical Test Sequence, was field complete -1-PAT-4.0, Initial Criticality and Low Power Test Sequence, was started
1/14/96	-Declared start of physics testing -PET-103, Reactivity Computer Setup, was field complete -PAT activities were halted to recalibrate the RPIs due to their response while moving rods in overlap
1/17/96	-RPI recalibration complete -Resumed physics testing -Entered Mode 2
1/18/96	-Unit 1 reactor critical -PET-201, Initial Criticality, was field complete
1/19/96	-PET-203, Determination of Power Range for Physics Testing, was field complete
1/20/96	-1-PAT-1.10, Plant Process Computer, was field complete
1/21/96	-PET-204, Rod and Boron Worth Measurements, was field complete -Increased reactor power to approximately 3.2% -PET-304, Operational Alignment of NIS, was field complete - RCI-126, Radiation Baseline Survey, was field complete -Low Power Physics Tests were field complete

3.0 Watts Bar Unit 1 Startup Chronology (continued)

1/22/96	-1-PAT-1.5, Loose Parts Monitoring System, was field complete -1-PAT-4.0, Initial Criticality and Low Power Test Sequence, was field complete
1/31/96	-Began 1-PAT-5.0, Test Sequence for 30% Plateau
2/7/96	-Received full power operating license
2/8/96	-Entered Mode 1 -1-PAT-5.1, Dynamic Automatic Steam Dump Control, Sections 6.3, 6.4, and 6.5 were completed -Unit entered Mode 1 for the first time
2/9/96	-PET-304, Operational Alignment of NIS, Section 6.3 was field complete
2/10/96	-Main turbine tripped while attempting to synchronize to the grid for the first time. The trip was attributed at this time to particulate in the lube oil. -Unit taken to Mode 3 to filter main turbine lube oil
2/11/96	-1-PAT-5.0, Test Sequence for 30% Plateau, was suspended until full investigation and corrective action for the main turbine trip is completed
2/16/96	-Reentered 1-PAT-5.0, Test Sequence for 30% Plateau -Main turbine lube oil filtering completed -Unit entered Mode 1 -Main turbine tripped while attempting to synchronize to the grid due to a noise spike on a turbogenerator protective relay. Troubleshooting of the relay proved that the spike was repeatable each time the relay was initially energized. This was also determined to be the cause of the first trip.
2/17/96	-Main turbine was synchronized to the grid -Main turbine taken off line due to low suction pressure on the hotwell, condensate booster, and main feed water pumps. The low suction pressure was attributed to clogged startup strainers in the hotwell pump suction.

3.0 **Watts Bar Unit 1 Startup Chronology** (continued)

2/18/96	-1-PAT-5.0, Test Sequence for 30% Plateau, was suspended until work on the piping of one of the impulse transmitters is completed
2/19/96	-Strainer cleaning completed -Main turbine was synchronized to the grid -Main turbine was taken off line and reactor manually tripped due to low pressure on the hotwell, condensate booster, and main feed water pumps. The manual trips of the main turbine on 2/17/96 and 2/19/96 were attributed to inaccurate hotwell level indication.
3/5/96	-A design change to the hotwell level indication was made and the unit was returned to power and successfully synchronized to the grid
3/6/96	-Reentered 1-PAT-5.0 -Unit reaches 30% test plateau -1-PAT-1.11, RVLIS Performance Test, was field complete
3/7/96	-1-PAT-5.3, Automatic Steam Generator Level Control Transients, Section 6.2 was field complete -Completed TI-41, Incore Flux Mapping -1-PAT-1.10, Plant Process Computer, was field complete
3/8/96	-1-PAT-1.5, Loose Parts Monitoring System, was field complete -PET-301, Core Power Distribution Factors, was field complete -PET-304, Operational Alignment of NIS, was field complete
3/9/96	-1-PAT-5.4, Calibration of Steam and Feedwater Flow Instrumentation, Section 6.2 was field complete -1-PAT-1.6, Startup Adjustments of Reactor Control System, was field complete -1-PAT-1.7, Operational Alignment of Process Temperature Instrumentation, was field complete -1-PAT-5.0, Test Sequence For 30% Plateau, was field complete

3.0 Watts Bar Unit 1 Startup Chronology (continued)

3/10/96	-Began 1-PAT-6.0, Test Sequence for 50% Plateau
3/11/96	-NIS trip set points were adjusted for the 50% plateau -Power increased to approximately 46% -Suction pressure to the condensate booster pump decreased to approximately 100 psi due to condensate demineralizer bed high ΔP. Reactor power was decreased to regenerate/mechanically clean the beds -Reactor power stabilized at approximately 42% RTP -Xenon equilibrium conditions were reached and a measurement of Fq (Heat Flux Hot Channel Factor) was required by Technical Specification 3.1.2.
3/13/96	-Reactor power was increased to approximately 48% RTP -Performed 1-PAT-1.8, Thermal Expansion of Piping Systems -Performed 1-PAT-1.5, Loose Parts Monitoring -Performed 1-PAT-1.11, RVLIS Performance Test -Performed RCI-126, Radiation Baseline Survey -PET-301, Core Power Distribution Factors, was field complete -1-PAT-1.10, Plant Process Computer, was field complete -PET 304, Operational Alignment of NIS, was field complete -Turbine manually tripped due to decreasing condenser vacuum. Decreasing vaccuum was due to the condensate to the MFP turbine condenser being isolated without sealing steam being isolated. Subsequent heatup of the MFP turbine condenser and flow directly to the suction of the condenser vaccuum pumps caused condenser vaccuum to decrease. -Reactor was manually tripped
3/14/96	-1-PAT-6.0 was suspended due to the unit shutdown on 3/13/96
3/17/96	-1-PAT-6.0 was reentered on 3/17/96 with the unit at 40% RTP -1-PAT-6.1 was started, then exited due to control rods (control bank D) stepping problems

3.0 **Watts Bar Unit 1 Startup Chronology** (continued)

3/18/96	-A loss of load was experienced after reaching approximately 44% RTP during the power increase to 49% due to the main turbine governor valves going closed -Operators manually tripped the turbine -The reactor was stabilized in Mode 2
3/20/96	-Entered Mode 1 and began power increase to approximately 49% RTP -Load increase was delayed due to #3 and #7 heater chemistry parameters being out of specification, #3 heater drain tank level control valve, 1-LCV-6-106A malfunction, and a body-to-bonnet leak on 1-FCV-3-100.
3/24/96	-1-PAT-6.1, was field complete -1-PAT-6.2, Automatic Steam Generator Level Control Transients at 50% Power, was started -1-PAT-6.2 was suspended due to feedwater oscillations which occurred during the step change to program level on #1 steam generator -1-PAT-6.2 was rescheduled until after 1-PAT-5.2, Loss of Offsite Power, because main feedwater regulating valve, 1-LCV-3-48 to #2 steam generator would not return to automatic after being placed in manual due to the feedwater oscillations
3/25/96	-1-PAT-6.3, Calibration of Steam and Feedwater Flow Instrumentation at 50% Power, was field complete; however, computer point U1118, which is used to establish initial conditions, was determined to be reading higher than actual and a retest became necessary
3/26/96	-1-PAT-1.6, Startup Adjustments of Reactor Control System, was field complete -1-PAT-1.7, Operational Alignment of Process Temperature Instrumentation, was field complete
3/27/96	-Retest of 1-PAT-6.3 was field complete -Reactor Coolant Pump #3 tripped when attempting to transfer to its normal feed -The turbine was manually tripped -Reactor power was reduced to 3% RTP

3.0 Watts Bar Unit 1 Startup Chronology (continued)

3/28/96 -The unit was synchronized to the grid
-1-PAT-3.3, RCS Flow Measurement, was field complete
-Power was increased to approximately 30% RTP
-1-PAT-5.2, Loss of Offsite Power, was field complete
-1-PAT-1.8, Thermal Expansion of Piping Systems, was field complete

4/3/96 -The unit was returned to 46% RTP
-1-PAT-6.2 was field complete
-Secondary side perturbations due to problems with the pump runout protection on the #3 heater drain tank pumps delayed testing. The problem was with the 1-LCV-6-106 valve going to the 30% throttle position when swapping the #3 heater drain tank pumps. A TACF was installed.
-1-PAT-1.2, Load Swing Test, was field complete
-1-PAT-1.4 was field complete.

4/5/96 -1-PAT-6.0, Test Sequence for 50% Plateau, was field complete
-Began 1-PAT-7.0, Test Sequence for 75% Plateau
-The NIS trip set points were adjusted, in accordance with the revised NOB sheets, for the 75% plateau
-Power increase to 75% began
-Upon reaching approximately 62% RTP during the initial power increase to 75% RTP, reactor power was reduced to approximately 52% RTP due to an alarm on high temperatures on the main generator stator. The high temperatures were due to a Raw Cooling Water System temperature control valve going closed when the valve control feedback arm dislodged.

4/6/96 -The feedback arm was repaired and power increase resumed
-Reactor power was increased to approximately 72%.
-PET 304, Operational Alignment of NIS, was field complete

3.0 Watts Bar Unit 1 Startup Chronology (continued)

4/7/96	-1-PAT-1.11, RVLIS Performance Test, was field complete -1-PAT-1.9, Automatic Steam Generator Level Control, was field complete
4/8/96	-1-PAT-1.10, Plant Process Computer, was field complete -1-PAT-1.5, Loose Parts Monitoring System, was field complete -Flux map data in accordance with TI-41, Incore Flux Mapping, was collected on 4/8/96 and the associated SIs were completed. -PET-301, Core Power Distribution Factors, was field complete
4/9/96	-1-PAT-1.4, Pipe Vibration Monitoring, was field complete -1-PAT-1.8, Thermal Expansion of Piping Systems, was field complete -1-PAT-6.1, Startup Adjustments of Reactor Control System, was field complete
4/10/96	-1-PAT-1.7, Operational Alignment of Process Temperature Instrumentation, was field complete -1-PAT-1.6, Startup Adjustment of Reactor Control System, was field complete
4/11/96	-1-PAT-7.1, Calibration of Steam and Feedwater Flow Instrumentation At 75% Power, was field complete -1-PAT-3.3, RCS Flow Measurement, was field complete
4/14/96	-The RCS loop ΔT Tzeros were reset to the new programmed values based on the results of the performance of 1-PAT-1.7 -The steam flow transmitter recalibrations to the new programmed values, based on the results of the initial performance of 1-PAT-7.1 at the 75% test plateau, were completed

4/15/96	-Retest of 1-PAT-7.1 was field complete. Retest was required after recalibrating the steam flow transmitters. -1-PAT-7.0, Test Sequence for 75% Plateau, was field completed -Began 1-PAT-8.0, Test Sequence for 100% Power -The NIS trip set points were adjusted for the 100% plateau, and power increase began -Reactor power was increased to approximately 84% RTP when a manual turbine/reactor trip was initiated due to the turbine governor valves going closed. The governor valve closure was caused by a signal to the turbine OPC solenoid from AMSAC during an automatic periodic (every 14 days) self test. This was also determined to be the probable cause of the loss of load on 3/18/96.
4/21/96	-The applicable automatic portion of the AMSAC self test was defeated and the unit returned to power -Upon reaching approximately 14% power, the "A" MFW pump tripped due to low vacuum. Reactor power was reduced to approximately 2% RTP while recovering from the MFW pump trip.
4/26/96	-Reactor power was increased to 88% RTP
4/27/96	-Testing at the 90% plateau began after reaching xenon equilibrium with the performance of a flux map to support PET-301, Core Power Distribution Factors. -1-PAT-1.6, Startup Adjustments of Reactor Control System, was field complete -1-PAT-1.7, Operational Alignment of Process Temperature Instrumentation, was field complete -The results of 1-PAT-1.7 required the RCS ΔT's to be reprogrammed prior to increasing power to 100% RTP.

3.0 Watts Bar Unit 1 Startup Chronology (continued)

4/28/96 -Power was increased to approximately 91% RTP
-RCS flow measurement was field complete
-Adjustment of the feedwater heater levels resulted in the isolation of an intermediate string of heaters which caused a secondary side perturbation. Power was reduced to approximately 79% RTP to stabilize the plant.
-The standby MFP was started and the "B" MFP was taken out of service to repair a leak in the recirculation valve body. A turbine runback was received within seconds after tripping the "B" MFP. Power decreased to approximately 72% which is the turbine runback reset.
-Upon taking the "B" MFP out of service, the "B" MFP turbine condenser drain tank was isolated. Steam seals remained on the "B" MFP which heated up the "B" MFP condenser drain tank. This resulted in pressurizing both the "B" and "A" MFP turbine condenser drain tanks which caused the "A" MFP to trip on low vacuum which resulted in a turbine/reactor trip.

5/1/96 -Investigation resulted in a modification to MFP turbine condenser vacuum line, and the unit was returned to Mode 1

5/3/96 -Secondary side swings, increasing condenser back pressure, and increasing condensate temperature to the condensate polishers prevented reaching 100% RTP

5/8/96 -Power increased to 98% RTP
-1-PAT-1.9, Automatic Steam Generator Level Control, was field complete
-1-PAT-1.11, RVLIS Performance Test, was field complete
-1-PAT-1.8, Thermal Expansion of Piping Systems, was field complete
-1-PAT-1.5, Loose Parts Monitoring, was field complete
-RCI-126, Radiation Baseline Survey, was field complete

3.0 **Watts Bar Unit 1 Startup Chronology** (continued)

5/8/96 (cont.)	-1-PAT-1.10, Plant Process Computer, was started and suspended on 5/8/96 due to a load reduction to approximately 95% RTP. The load reduction was due to increasing condenser back pressure and condensate temperature to the condensate polishers. -Reactor power was increased again to approximately 98% RTP and 1-PAT-1.10 was resumed and field completed. -Review of the 1-PAT-1.9 performance data identified the need for a retest. The retest was field complete on 5/8/96. -TI-41, Incore Flux Mapping, was field complete -1-PAT-1.7, Operational Alignment of Process Temperature Instrumentation, was field complete -1-PAT-8.4, Calibration Of Steam and Feedwater Flow Instrumentation at 100% Power, was field complete -Review of the performance data for 1-PAT-1.7 identified the need for a retest
5/9/96	-1-PAT-1.7 retest was performed -Unit 1 achieved 100% RTP for the first time as indicated by the highest reading NIS channel -PET-301, Core Power Distribution Factors, was field complete
5/10/96	-1-PAT-1.6, Startup Adjustments of Reactor Control System, was field complete -1-PAT-3.3, RCS Flow Measurement, was field complete -Section 6.11 of PET 304, Operational Alignment of NIS, was field complete
5/11/96	-1-PAT-1.2, Load Swing Test, was field complete
5/12/96	-1-PAT-1.3, Large Load Reduction Test, was field complete -1-PAT-8.6, Plant Trip From 100% Power (Turbine Trip), was field complete

5/14/96	-The unit was returned to 30% RTP -1-PAT-8.5, Shutdown From Outside the Control Room, was field complete -Upon completion of 1-PAT-8.5, the unit entered a planned outage. -The unit was returned to 557°F (mode 3) and steady state data for 1-PAT-8.4 was collected during the outage.
5/15/96	-1-PAT-1.4, Pipe Vibration Monitoring, was field complete
5/16/96	-Reperformance of 1-PAT-1.11 was field complete after new constants for RVLIS were installed.
5/18/96	-1-PAT-1.8, Thermal Expansion of Piping Systems, was field complete
5/23/96	-PET-304, Operational Alignment of NIS, was field complete -1-PAT-8.0, Test Sequence for 100% Plateau, was field complete

4.0 INITIAL FUEL LOAD

4.1 Overview and Summary of Initial Core Loading

The initial core loading at WBN Unit 1 was accomplished in 81.25 hours from November 10, 1995, to November 13, 1995, as directed by 1-PAT-2.0, Initial Core Loading Sequence.

Core loading was performed "dry" with the refueling cavity empty and the reactor vessel filled above the centerline of the reactor vessel nozzles with refueling concentration (i.e., > 2000 ppm) borated water. To maintain containment integrity, the fuel transfer canal was partially flooded to at least one foot above the upper lip of the fuel transfer tube for the duration of core loading. The core loading sequence was performed in accordance with FATFs. Actual movement of fuel was performed in accordance with FHI-7, Fuel Handling and Movement, as directed by PET-105, Refueling and Core Alterations.

Neutron monitoring stations for ICRR determinations were established in containment to monitor the Westinghouse-supplied temporary core load detectors, and in the main control room to monitor permanent source range detectors N-131 and N-132. ICRR plots were maintained at these stations during all core loading sequence steps and during delays in core loading to ensure that an adequate subcritical margin was maintained at all times.

As a visual aid in tracking fuel movement evolutions and to ensure the core load configuration was in accordance with the approved loading pattern prescribed on the FATFs, an electronic tag board was maintained in the main control room.

RCS boron concentration and RHR temperatures were also monitored during core load to ensure that boron concentration and temperatures remained within prescribed limits.

4.1 Overview and Summary of Initial Core Loading (continued)

Some fuel assemblies were required by plan to be moved more than once, particularly those bearing primary neutron sources. As such, the core loading sequence required 208 steps to load the 193 fuel assemblies. After the core was loaded, a video tape verification of proper fuel assembly, fuel assembly insert placement, and orientation was conducted. The final core load configuration was consistent with the Westinghouse Core Loading Plan for Cycle 1.

4.2 Initial Core Loading Sequence (1-PAT-2.0)

This test started on 10/25/95, prior to entry into Mode 6 to establish prerequisite conditions in support of commencement of initial core loading. The test continued through verification of core loading and was field complete on 11/13/95, prior to insertion of the vessel internals in preparation for Mode 5 entry.

1.0 Test Objective

The objectives of this test were to: 1) sequence the procedures that established the prerequisites required for the initial core loading of Unit 1, and 2) define the sequence of operations and tests which were to be conducted during and following completion of the initial core loading.

The following PATs/PETs were sequenced for performance by 1-PAT-2.0:

- 0-PAT-3.9 — Spent Fuel Pool Cooling System
- 1-PAT-2.1 — Reactor System Sampling for Core Load
- 1-PAT-2.2 — Core Loading Instrumentation and Neutron Source Requirements
- PET-102 — Prepower Escalation NIS Calibration
- PET-105 — Refueling and Core Alterations
- RCI-126 * — Radiation Baseline Survey

Note: * Indicates that the test is performed at multiple test plateaus. The description of the testing is documented in the section (plateau) in which it was completed.

2.0 Test Method

None associated with this sequence document

3.0 Test Results

All acceptance criteria were contained within the tests sequenced by this test.

4.0 Problems

Problems encountered are addressed in the following discussions of each test sequenced by 1-PAT-2.0.

4.3 Reactor System Sampling for Core Load (1-PAT-2.1)

This test was performed as part of test sequence 1-PAT-2.0, Initial Core Loading. Testing was started on 10/30/95 and field completed on 11/13/95.

1.0 Objective

The purpose of this test was to furnish guidelines for:

1.1 Verifying proper boron concentration, prior to fuel loading, in all portions of the RCS and directly connected portions of auxiliary systems required for core loading.

This condition was accomplished by circulating the RCS and auxiliary systems with borated water and measuring the boron concentration in the systems.

1.2 Preventing inadvertent dilution during core loading by minimizing the potential for the introduction of unborated water into the RCS.

This condition was accomplished by verifying that all sources of unborated water into the RCS were under control to prevent discharge into the RCS, and monitoring RCS boron concentration during core loading.

2.0 Test Method

1-SI-62-1, Uncontrolled Boron Dilution Paths, was performed by Operations and verified complete. Safety Injection System valves 1-FCV-63-5, 1-FCV-63-22, 1-FCV-63-156, and 1-FCV-63-157 were verified to be closed, and the handswitches for the Safety Injection System Pumps 1A-A and 1B-B were placed in the PULL-TO-LOCK position.

4.3 Reactor System Sampling for Core Load (1-PAT-2.1)
(continued)

Borated water was circulated through the following portions of NSSS:

Charging Pump A-A
Charging Pump B-B
Charging Pump C
Letdown Lines/RHR to Letdown
RHR Pump A-A
RHR Pump B-B

Chemistry sampled the following locations to ensure uniform boron concentrations existed:

RCS Loop 1 Hot Leg
RCS Loop 3 Hot Leg
Reactor Vessel Surface
Reactor Vessel 1/3 Down
Reactor Vessel 2/3 Down
Reactor Vessel Bottom
VCT (Charging Pump Suction)
RHR Pump A-A (Pump Miniflow)
RHR Pump B-B (Pump Miniflow)
RWST
Cold Leg Accumulator 1
Cold Leg Accumulator 2
Cold Leg Accumulator 3
Cold Leg Accumulator 4
Boric Acid Tank A
Boric Acid Tank B
Boron Injection Tank
RHR Loop A (Upstream of Heat Exchanger)
RHR Loop B (Upstream of Heat Exchanger)
Fuel Transfer Canal

3.0 <u>Test Results</u>

All required acceptance criteria for this test were met as delineated below:

3.1 The boron concentration of samples obtained from designated sample points were within the limits of 2000 ppm $\leq C_B \leq$ 2100 ppm. See Problem 1.

4.3 Reactor System Sampling for Core Load (1-PAT-2.1) (continued)

3.2 The boron concentration of samples obtained from the boric acid tanks were within the limits of 6120 ppm $\leq C_B \leq$ 6990 ppm.

4.0 Problems

[1] It was determined that the cold leg accumulator #2 boron concentration was less than the required 2000 ppm. The first sample indicated that the CLA #2 was at 1936 ppm, and the second sample indicated 1940 ppm C_B. Technical Specification limit for the CLAs is 1900 to 2100 ppm C_B when the RCS > 1000 psig. The acceptance criteria of this test was 2000 to 2100 ppm C_B. CLA #2 was drained and refilled to return the boron concentration to within the required range. The final sample indicated 2021 ppm C_B. No further actions were required.

4.4 Core Loading Instrumentation and Neutron Source Requirements (1-PAT-2.2)

This test was performed as part of test sequence 1-PAT-2.0, Initial Core Loading. Testing was started on 11/01/95 and field completed on 11/13/95.

1.0 Objectives

The objectives of this test were:

1.1 To demonstrate proper initial alignment of the temporary core loading nuclear instrumentation prior to fuel load.

1.2 To demonstrate proper response of temporary core loading instrumentation and permanent source range detector channels to neutron flux within eight hours of the start of core loading.

1.3 To demonstrate proper response of the temporary core loading instrumentation and permanent source range detector channels prior to resumption of core loading following a delay of eight hours or longer.

2.0 Test Method

The initial alignment of the temporary core loading instrumentation was confirmed by varying the high voltage power supply setting of each detector and recording the detector's response. The detector response versus high voltage power supply setting was then plotted for each detector and the optimum high voltage setting for the detector was determined from the plot. A similar plot was generated by varying the pulse height discriminator voltage setting for each detector and observing the detector response.

4.4 Core Loading Instrumentation and Neutron Source Requirements (1-PAT-2.2) (continued)

A response check of the temporary core loading instrumentation and permanent source range detectors was performed within eight hours prior to starting fuel loading by placing a neutron source in close proximity to each detector and verifying that the detector sensed an increased count rate. Three options were available for performing these checks: (1) use of a portable source, (2) use of a dummy fuel assembly loaded with a primary source, or (3) use of the first source bearing fuel assembly. Option (3) was used.

For delays in core loading of eight hours or longer, response checks can be performed using either a portable neutron source or by movement or withdrawal of a source bearing fuel assembly. Alternately, a statistical evaluation of the observed count rate for each detector can be performed.

3.0 <u>Test Results</u>

All required acceptance criteria for this test were met as delineated below:

3.1 Each channel of instrumentation indicated a positive (negative) change in count rate as neutron flux level was increased (decreased) near the associated detector during the response check performed within eight hours of fuel load. See Problem 1.

3.2 The high voltage power supply and pulse height discriminator settings for each channel of temporary core loading instrumentation during initial alignment checks were in close agreement (i.e., ± 100 volts for the high voltage power supply and ± 1 volt for the pulse height discriminator voltage) with the settings obtained during preshipment checkout.

4.4 Core Loading Instrumentation and Neutron Source Requirements (1-PAT-2.2) (continued)

4.0 Problems

[1] Temporary channel C did not provide audible indication locally. Retesting was successfully completed when sufficient neutron flux was available. This testing demonstrated proper audible indication locally.

4.5 Prepower Escalation NIS Calibration Data (PET-102)

This test was performed as part of test sequence 1-PAT-2.0, Initial Core Loading. Testing was started on 10/31/95 and completed on 10/31/95.

1.0 Objective

This instruction provides NIS PR and IR excore detector calibration data and initiates calibration before initial startup following a refueling outage, in support of replacement or repositioning of a detector or any other changes which have been made that could affect the level of incident neutrons falling upon the detectors.

2.0 Test Method

The normal method for off-normal instances such as initial startup without known detector calibration parameters, engineering analysis and judgment, was used to determine conservative NIS calibration data.

3.0 Test Results

All required acceptance criteria for this test were met as delineated below:

3.1 The SIs for the NIS channel(s) were completed. This accomplished the calibration and verification of the associated NIS channel(s).

4.0 Problems

There were no significant problems encountered during the performance of this test.

4.6 Refueling and Core Alterations (PET-105)

This test was performed as part of test sequence 1-PAT-2.0, Initial Core Loading. Testing was started on 11/02/95 and completed on 11/13/95. Fuel load was successfully completed in 81.25 hours from Mode 6 entry to the unlatching of the last assembly in the vessel.

1.0 Objective

The specific objectives of this test were as follows:

1.1 Identify the activities and requirements for fuel loading which ensure that fuel loading is conducted in a cautious and controlled manner:

1.1.1 Specify the placement of temporary core load instrumentation during fuel load (initial core load).

1.1.2 Specify the sequence for loading fuel assemblies into the reactor vessel such that the final core configuration is consistent with that specified in the NuPOP for current fuel cycle.

1.1.3 Specify the fuel assembly identification number and type of insert for each core location.

1.1.4 Establish the requirements for periodic and continuous neutron monitoring during each step of the core loading process.

1.1.5 Prescribe the steps necessary for obtaining and evaluating neutron monitoring data during core loading.

1.1.6 Identify the neutron monitoring channels to be used during each step of the core loading sequence to ensure subcritical conditions are maintained.

2.0 Test Method

Only data from "responding" detectors identified by the data package was used in evaluating the safety of continued core loading. Prior to completing the loading of the initial nucleus of eight fuel assemblies, significant changes in the ICRR data were expected to occur due to geometry effects arising from changes in detector-to-fuel assembly coupling. Therefore, the ICRR values were not calculated and plotted during the loading of the initial nucleus of eight assemblies.

Changes in neutron flux level during and following fuel assembly insertion was monitored for indications of abnormal and/or unstable reactivity behavior.

ICRR "base count" renormalization was performed following movement or repositioning of a detector and/or a source-bearing fuel assembly during core loading sequence following the loading of the initial nucleus of eight fuel assemblies.

All fuel movement was performed in accordance with FHI-7, Fuel handling and Movement.

The tagboard in the main control room was updated, as required, to reflect the actual physical location of all fuel assemblies and fuel related components at all times during the core loading evolution.

3.0 Test Results

All required acceptance criteria for this test were met as delineated below:

3.1 The core was successfully loaded in accordance with the Cycle 1 Westinghouse Core Load Plan.

Verification of successful core loading was provided via TI-28, Physical Verification of Core Load Prior to Vessel Closure. Refer to Figure 4.6-1, Core Load Verification Map.

4.6 Refueling and Core Alterations (PET-105) (continued)

4.0 Problems

There were no significant problems encountered during the performance of this test.

Figure 4.6-1
Core Load Verification Map

180°

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A	
					C27 PD177	C43 8P4	C60 PD182	C12 12P15	C07 PD151	C28 8P1	C26 PD129					1
			C36 PD110	C51 R07	C54 16P36	A43 R55	C01 24P19	A01 R56	C04 23P51	A16 R17	C50 16P50	C02 R04	C63 PD194			2
		C56 PD117	C32 12P5	B46 24P20	A30 R37	B34 16P43	A40 R29	B45 20P62	A42 R41	B19 16P41	A33 R44	B07 24P6	C15 12P9	C17 PD84		3
		C47 R43	B28 24P10	B24 R47	B48 20P46	A38 P059	B03 20P35	A52 R13	B43 20P39	A22 PD203	B49 20P66	B59 R52	B39 24P16	C42 R54		4
	C06 PD185	C05 16P37	A49 R20	B16 20P51	A51 R31	B20 20P45	A32 PD137	B61 20P57	A23 PD112	B09 20P58	A06 R48	B22 20P61	A28 R45	C25 16P59	C45 PD133	5
	C38 8P2	A14 R11	B37 16P44	A05 PD99	B62 20P65	A41 R16	B10 24P22	A26 R06	B31 24P12	A10 R09	B63 20P63	A62 PD180	B14 16P31	A46 R27	C34 8P3	6
	C41 PD122	C03 24P5	A13 R19	B12 20P48	A53 PD70	B15 24P21	A15 PD123	B47 20P50	A03 SS1	B13 24P1	A24 PD61	B06 20P60	A61 R32	C55 24P9	C40 PD154	7
90°	C33 12P14	A37 R12	B02 APS1	A36 R21	B38 20P42	A60 R08	B11 20P53	A29 R14	B52 20P49	A35 R34	B26 20P67	A21 R05	B57 BPS1	A63 R38	C21 12P13	270° 8
	C20 PD244	C61 24P18	A58 R50	B50 20P41	A64 PD116	B33 24P13	A47 SS2	B42 20P59	A02 PD53	B18 24P15	A56 PD111	B54 20P54	A48 R15	C11 24P8	C24 PD72	9
	C09 8P7	A44 R18	B56 16P58	A39 PD39	B35 20P55	A18 R49	B23 24P3	A11 R39	B01 24P4	A55 R03	B32 20P56	A04 PD79	B05 16P56	A17 R57	C39 8P6	10
	C53 PD76	C08 16P57	A25 R46	B04 20P52	A50 R01	B17 20P37	A09 PD77	B51 20P68	A34 PD95	B52 20P47	A59 R23	B40 20P38	A65 R25	C64 16P42	C49 PD264	11
		C19 R53	B64 24P17	B36 R33	B58 20P36	A31 PD89	B30 20P43	A12 R26	B55 20P44	A19 PD105	B21 20P40	B27 R35	B60 24P11	C30 R51		12
		C35 PD83	C59 12P16	B29 24P2	A08 R42	B41 16P51	A57 R30	B44 20P64	A45 R36	B25 16P47	A54 R24	B08 24P7	C22 12P10	C46 PD186		13
			C16 PD96	C23 R02	C13 16P49	A27 R28	C31 24P14	A20 R40	C18 23PS2	A07 R22	C57 16P54	C62 R10	C48 PD138			14
					C44 PD124	C14 8P8	C52 PD164	C10 12P12	C37 PD147	C58 8P5	C29 PD143					15

0°

Axx Rxx	Assembly ID Insert ID

2.1 w/o U_{235}

2.6 w/o U_{235}

3.1 w/o U_{235}

5.0 PRECRITICAL TESTING

5.1 Post Core Loading Precritical Test Sequence (1-PAT-3.0)

This test started on 11/14/95 and was completed on 01/12/96.

1.0 Test Objective

This procedure was the controlling document for establishing the required prerequisite conditions necessary to permit testing in Mode 6 through Mode 3 following the completion of 1-PAT-2.0, Initial Core Loading Sequence. This procedure also governed the sequence of tests performed in Mode 6 through Mode 3.

The following PATs/PETs were sequenced for performance by 1-PAT-3.0:

- 0-PAT-3.9 — Spent Fuel Pool Cooling System
- 1-PAT-1.4 * — Pipe Vibration Monitoring
- 1-PAT-1.6 * — Startup Adjustments of Reactor Control System
- 1-PAT-1.7 * — Operational Alignment of Process Temperature Instrumentation
- 1-PAT-1.8 * — Thermal Expansion of Piping Systems
- 1-PAT-1.11* — RVLIS Performance Test
- 1-PAT-3.1 — Control Rod Drive Mechanism Timing
- 1-PAT-3.2 — Pressurizer Spray Capability and Continuous Spray Flow Setting
- 1-PAT-3.3 * — RCS Flow Measurement
- 1-PAT-3.4 — Control Rod Position Indication
- 1-PAT-3.5 — Rod Control System
- 1-PAT-3.6 — Incore Movable Detectors
- 1-PAT-3.7 — Reactor Coolant Flow Coastdown
- 1-PAT-3.8 — Rod Drop Testing
- 1-PAT-3.10 — Reactor Trip System
- 1-PAT-3.11 — Adjustment of Steam Flow Transmitters at Minimal Steam Flow
- 1-PAT-5.1 * — Dynamic Automatic Steam Dump Control
- RCI-126 * — Radiation Baseline Survey

Note: * Indicates that the test is performed at multiple test plateaus. The description of the testing is documented in the section (plateau) in which it was completed.

5.1 **Post Core Loading Precritical Test Sequence (1-PAT-3.0)** (continued)

2.0 <u>**Test Method**</u>

None associated with this sequence document

3.0 <u>**Test Results**</u>

All acceptance criteria were contained within the tests sequenced by this test.

4.0 <u>**Problems**</u>

Problems encountered are addressed in the following discussions of each test sequenced by 1-PAT-3.0.

5.2 Spent Fuel Pool Cooling System (0-PAT-3.9)

This test was started on 11/14/95 and was field completed on 12/21/95.

1.0 Objective

The objectives of this test were to:

(1) Demonstrate the capability of the SFP Cooling System to provide required water flow in cooling and cleaning operational modes, including skimmer operation, for the SFP.

(2) Verify correct water flows to heat exchangers and correct flows in all cooling loops.

(3) Demonstrate the ability to fill and empty the transfer canal with the refueling gate installed in the nonrefueling mode.

(4) Verify that no visible vortexing occurs during system operation (except for vortexing due to skimmer operation), and verify proper operation of the antisiphon devices.

2.0 Test Method

The SFP water temperature annunciator was tested using a heat gun.

The four Spent Fuel pumps (three cooling pumps and one skimmer pump) were verified to meet their pump characteristics curves. The pumps were run individually and in parallel with each other. The SFP and transfer canal were filled and emptied with the refueling gate installed in the nonrefueling mode.

3.0 Test Results

All required acceptance criteria for this test were met as delineated below:

3.1 The SFP cooling pumps flowed at a rate of 2230 to 2370 gpm with a total developed head of 125 feet or greater. Actual data is shown below.

SFP Pump	A	B	C-S Train A	C-S Train B
Measured Flow (gpm)	2300	2230	2300	2300
Head (feet)	126.4	126.0	126.8	128

3.2 The SFP cooling pumps flowed at a rate of 2330 to 2470 gpm with approximately 100 gpm flow through the filter/demineralizer flow path. See Problem 1.

SFP Pump	A	B	C-S Train A	C-S Train B
Measured Flow (gpm)	2400	2400	2400	2410
Filter Flow (gpm)	100	100	100	100

3.3 The SFP skimmer pump flow was 98 to 100 gpm with a total developed head of 50 feet or greater. The actual measured flow was 100 gpm at a total developed head of 50.127 feet. See Problem 2.

3.4 The SFP skimmer strainer pressure drop was equal to or less than 1 psid at 98 to 100 gpm. The actual measured pressure drop was 0.8 psid.

3.5 No vortexing was observed in the SFP during any SFP cooling pump operation. See Problem 2.

3.6 The SFP strainers (2) pressure drop was equal to or less than 2 psid at approximately 2300 gpm. The actual measured pressure drop was 1.45 psid for Train A and 2.0 psid for Train B.

3.7 The SFP skimmer filter pressure drop was equal to or less than 20 psid at approximately 100 gpm maximum flow. The actual measured pressure drop was 7.7 psid.

3.8 The SFP filter pressure drop was equal to or less than 20 psid at approximately 100 gpm flow through the SFP demineralizer. The actual measured pressure drop was 4.5 psid.

3.9 The transfer canal gate leakage was less than 50 gpm. There was no observable leakage through the transfer gate.

3.10 The SFP LEVEL HI/LO alarmed at annunciator window 1-XA-55-6C-128-A and cleared at the proper water levels.

3.11 The transfer canal was dewatered with the SFP initially filled to normal operating level.

3.12 SFP pumps A-A, B-B, and C-S operated from their local control stations with proper pump status indicator lights. The C-S pump operated from either the A or B train power from the respective 0-HS-78-35A or 0-HS-78-35B handswitch. See Problem 3.

3.13 The SFP high water temperature alarm at annunciator window 1-XA-55-6C-128-B alarmed and cleared.

3.14 The SFP and transfer canal discharge pipe antisiphon design and the transfer canal drain line design prevented siphoning.

3.15 The SFP skimmer pump was operated from its local control station with proper pump status indicator lights.

4.0 Problems

[1] The indicated flow would not increase beyond 2180 gpm in either A or B train.

The flow orifices, 0-OR-78-31 & 32, were changed from 4.125 in. to 4.490 in. Retesting gave correct system flow using the new orifices.

5.2 Spent Fuel Pool Cooling System (0-PAT-3.9) (continued)

[2] The total developed head of the skimmer pump was calculated at 47.355 feet using installed plant gauges, but the skimmer did not remove debris from the SFP surface.

A retest was performed using Heise gauges, and the pump head was calculated to be >50 feet at 100 gpm. A design change was issued to allow surface vortexing and retest #5 proved the skimmers would remove debris from the SFP surface.

[3] The B-B pump breaker failed to trip from its local push-button and did not give proper indication.

A broken contact "finger" in the B-B pump breaker was found and was reworked. The breaker was retested satisfactorily.

5.3 Control Rod Drive Mechanism Timing (1-PAT-3.1)

This test was performed in Mode 5 with RCS pressure greater than 300 psig during the period from 11/28/95 to 11/29/95. Testing was also performed at no load RCS temperature and pressure conditions in Mode 3 during the period from 1/1/96 to 1/10/96 as directed by 1-PAT-3.0, Post Core Loading Precritical Test Sequence.

1.0 Objective

The objectives of this test were to verify:

(1) Each rod control system slave cycler provides its associated power cabinet with the appropriate command signals to obtain proper sequence timing of current supplied to the CRDM coils.

(2) CRDM coil current amplitudes are within acceptable ranges.

(3) Operability of each shutdown and control rod drive mechanism via the ability to withdraw and insert rods, and proper stepping rate for shutdown and control rods in bank select mode.

Sound pickup instrumentation was installed adjacent to the rod travel housing on all 57 CRDMs to monitor proper pull-in and drop-out events related to gripper latching during CRDM timing checks performed in Mode 5. The acoustic monitoring instrumentation was not used for Mode 3 testing.

2.0 Test Method

The lift, moveable, and stationary gripper coil current signatures for all 57 rods were obtained using a test recorder which was connected to appropriate test point connections located on the monitoring test panel in the rod control system power cabinets. CRDM latching mechanism acoustic signals were also connected to the test recorder during Mode 5 testing. Data was recorded for each CRDM individually as the associated rod bank was withdrawn 10 steps from the fully inserted position and then inserted to 0 steps withdrawn.

5.3 Control Rod Drive Mechanism Timing (1-PAT-3.1) (continued)

To demonstrate that the rod speed module was properly set for the shutdown and control rod stepping rates and was transmitting the proper voltage signals to the logic cabinet, voltage readings were obtained during Mode 5 testing from Test Point 1 on pulser card A101 located in the rod control system logic cabinet when the rod bank select switch was rotated to the Control Bank A and Shutdown Bank A positions. A similar voltage reading was also obtained from Test Point 2 located on SCD pulser card A314 located in the rod control system logic cabinet when the rod bank select switch was rotated to the Shutdown Bank C position.

The test recorder traces collected were subsequently reviewed and a number of system characteristics were verified.

3.0 <u>Test Results</u>

All required acceptance criteria were met for Mode 5 and Mode 3 as delineated below.

3.1 The input voltage to the pulser cards in the logic cabinet was within a range of -6.774 to -6.698 Vdc for control rods and -8.617 to -8.541 Vdc for shutdown rods operated in bank select mode.

The measured Mode 5 voltages were within acceptable tolerances:

Shutdown Bank A	-8.6091 Vdc
Shutdown Bank C	-8.6020 Vdc
Control Bank A	-6.7470 Vdc

3.2 Each slave cycler provided its associated power cabinet with the appropriate command signals to obtain proper sequence timing of the associated CRDM coils during rod withdrawal and insertion operations. Specifically, the times at which the lift, movable, and stationary current orders changed, after the start of rod motion, were within 10 msec of the expected times for rod withdrawal and insertion cycles.

5.3 Control Rod Drive Mechanism Timing (1-PAT-3.1) (continued)

The Mode 5 and Mode 3 CRDM timing traces were reviewed and the timing of the current orders met the 10 msec criteria.

3.3 The current amplitudes for the CRDM coils fell within the following acceptable ranges during withdrawal and insertion operations except as noted:

1. Lift coil (full): 38.4 to 46 amperes (equivalent to 480 to 575 mVdc as measured across a 0.0125 ohm resistor)

2. Lift coil (modulated or reduced): 15.2 to 17.6 amperes (equivalent to 190 to 220 mVdc as measured across a 0.0125 ohm resistor)

3. Movable gripper coil: 7.68 to 9.2 amperes (equivalent to 480 to 575 mVdc as measured across a 0.0625 ohm resistor)

4. Stationary gripper coil (full): 7.68 to 9.2 amperes (equivalent to 480 to 575 mVdc as measured across a 0.0625 ohm resistor)

5. Stationary gripper coil (hold or reduced): 4.22 to 4.8 amperes (equivalent to 264 to 300 mVdc as measured across a 0.0625 ohm resistor).

For Items 1 and 2 above, the Mode 5 CRDM traces were reviewed and the current amplitudes were recorded. The recorded amplitudes were all within the expected range except for the lift coil currents for CRDMs F-02 and H-02 (see Problem 1).

For Item 5 above, the Mode 3 CRDM traces were reviewed and the current amplitudes were also recorded. The recorded amplitudes were all within the expected range except for the stationary gripper coil currents for CRDMs K-08 and H-08 (see Problem 2).

3.4 The operability of each shutdown and control rod latching mechanism was demonstrated by the ability to withdraw and insert the rods.

All Mode 5 and Mode 3 CRDM timing traces showed characteristics of proper rod motion.

3.5 The rod stepping rate was 46 to 50 steps/minute for control rods and 62 to 66 steps/minute for shutdown rods operated in the bank select mode.

All Mode 5 and Mode 3 control rod stepping rates were verified to be within the range of 47 to 49 steps/minute. All shutdown rod stepping rates were verified to be within the range of 63 to 64 steps/minute.

4.0 <u>Problems</u>

[1] The Mode 5 measured full and reduced lift coil currents for CRDM F-02 were 610 and 230 mVdc, respectively, which were higher than the upper expected values. The measured full lift coil current for CRDM H-02 was 630 mVdc which was higher than the upper expected value. The currents measured in Mode 3 were found to be within the expected range. The Mode 3 data was utilized to disposition the Mode 5 data. No further testing was required.

[2] The Mode 3 measured reduced stationary gripper coil currents for CRDMs K-08 and H-08 were 263 and 247 mVdc, respectively, which were slightly lower than the lower expected value. The data was reviewed by WBN and Westinghouse, and the results were found to be acceptable with no adverse impact on system operation.

5.4 Pressurizer Spray Capability and Continuous Spray Flow Setting (1-PAT-3.2)

This test established the optimal throttle positions for the pressurizer spray manual bypass valves, verified the spray line temperature low alarm, and ensured the effectiveness of the normal pressurizer spray by initiating full spray to reduce RCS pressure by approximately 250 psi and compared the time to reduce pressure with Westinghouse performance curves.

This test was started on 1/3/96 and was field complete on 1/10/96.

1.0 Objective

The specific objectives of this PAT were as follow:

1.1 The pressure response to the opening of both normal pressurizer spray valves is within the allowable range specified by NSSS performance curves.

1.2 The pressurizer bypass spray valves are throttled to an optimum position such that during steady state operation:

A. Spray line temperature is high enough to prevent the PZR SPRAY TEMP LO alarm from actuating,

B. The equilibrium temperature for each spray line is greater than or equal to 540°F.

C. Pressurizer control bank heaters can maintain RCS pressure above 2220 psig without backup heater operation, and

D. Surge line temperature is high enough to prevent the PZR SURGE LINE TEMP LO alarm from actuating.

5.4 **Pressurizer Spray Capability and Continuous Spray Flow Setting (1-PAT-3.2)** (continued)

2.0 **Test Method**

This test established the optimal throttle positions for the Pressurizer Spray Manual Bypass Valves by closing the bypass valves and verifying the PZR SPRAY TEMP LO alarm enunciates. The bypass valves were then opened one at a time in small increments, and spray line temperature versus valve position was determined. The PZR SPRAY TEMP LO was verified to clear as the valves are opened. The valves were then adjusted to achieve approximately 50% to 70% demand on the variable pressurizer heaters at 550°F.

The effectiveness of the normal pressurizer sprays was tested by closing the sprays in manual, securing the pressurizer heaters, placing the pressurizer spray controllers 1-PIC-68-340B and 340D in AUTO, and raising the demand on the controllers to 100%. Full demand was left on the controllers until the sprays reduced RCS pressure by approximately 250 psi. The time to reduce pressure was then compared with Westinghouse performance curves.

3.0 **Test Results**

All required acceptance criteria were met as delineated below.

3.1 The pressurizer spray response data was within the allotted response time as depicted on Figure 5.4-1.

3.2 Initially, the pressurizer spray and spray bypass valves were closed and the PZR SPRAY TEMP LO alarm was verified to actuate at approximately 530°F. Next, setting of the spray bypass valves was completed and the plant maintained at steady state conditions for one hour. The PZR SPRAY TEMP LO alarm and the PZR SURGE LINE TEMP LO alarm were both verified not to actuate. The equilibrium temperature for both spray lines were verified to be greater than 540°F. The pressurizer control bank heaters were verified to be able to maintain RCS pressure above 2220 psig without backup heater operation.

5.4 Pressurizer Spray Capability and Continuous Spray Flow Setting (1-PAT-3.2) (continued)

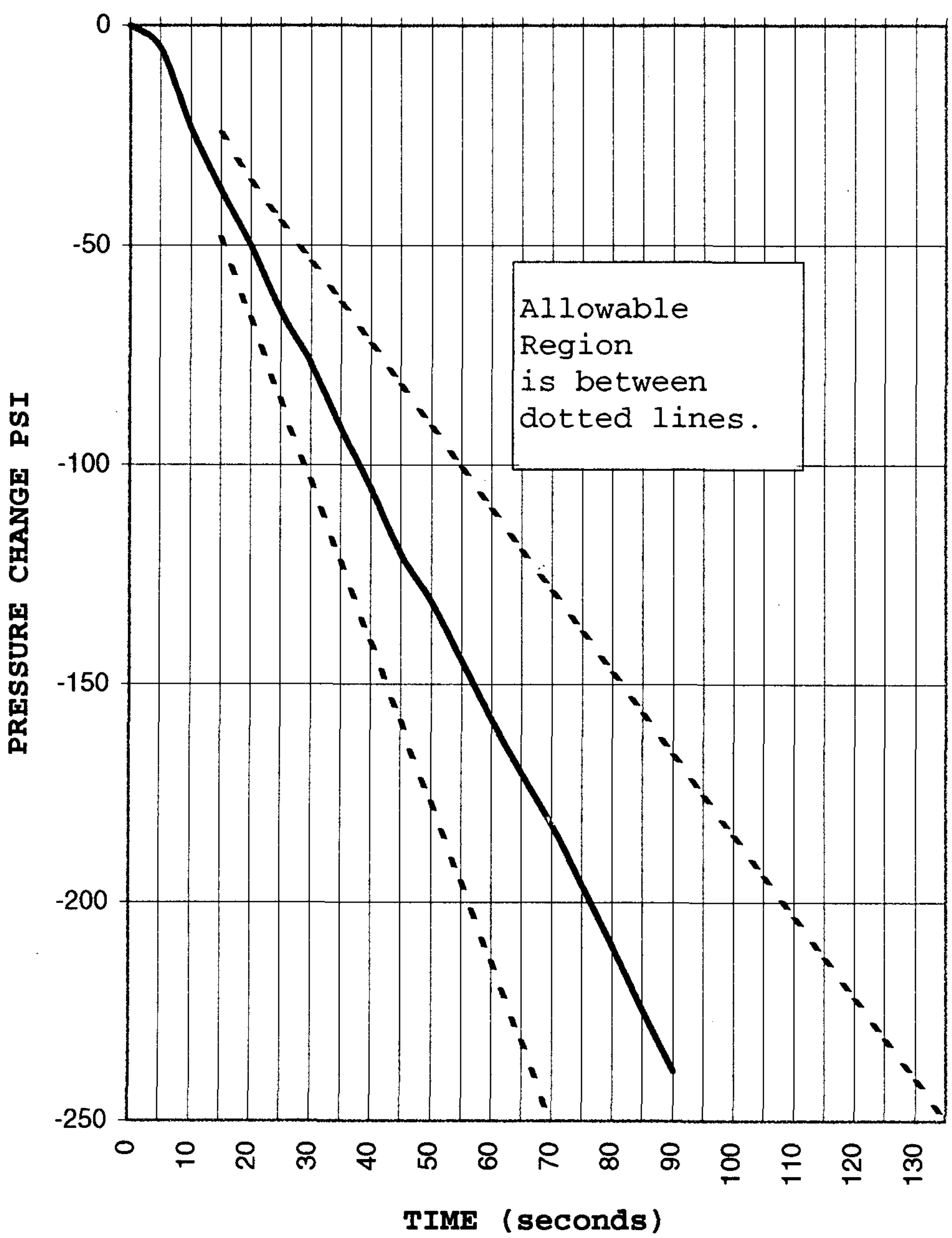
4.0 <u>Problems</u>

There were no significant problems encountered during the performance of this test.

5.4 **Pressurizer Spray Capability and Continuous Spray Flow Setting (1-PAT-3.2)** (continued)

Figure 5.4-1

Pressurizer Spray Response



5.5 Rod Position Indication System (1-PAT-3.4)

This test was performed in Mode 3 as directed by 1-PAT-3.0, Post Core Loading Precritical Test Sequence, with the RCS at nominal temperature (555 to 559°F) and pressure (2220 to 2250 psig) with all RCS coolant loops in operation. Testing was started on 1/5/96 and field completed on 1/12/96.

1.0 Objective

The objective of this test was to verify the Rod Position Indication System satisfactorily performed required indication and alarm functions and each rod operated satisfactorily over its entire range of travel. Specifically, this test verified the following:

1.1 Proper calibration of each individual RPI channel by checking RPI detector voltage output versus rod position as indicated by the step counters and analog indicators over each rod's full length of travel.

1.2 For shutdown and control banks having two groups, the group step counters for both groups were demonstrated to be within ± 1 step of each other over their full length of travel (i.e., 231 steps).

1.3 Proper calibration of each control and shutdown rod's rod bottom bistable which provides dropped rod or rod bottom indication, and actuation of the RODS AT BOTTOM alarm.

1.4 Proper calibration of the bypass bistable modules for Control Banks B, C, and D.

1.5 Proper operation of P2500 computer actuated rod deviation alarm.

1.6 Proper operation of power and logic cabinet "urgent" failure indication.

1.7 Proper operation of power and logic cabinet "non-urgent" failure alarm.

1.8 Proper operation of CONTROL BANK D WITHDRAWAL LIMIT alarm.

1.9 Proper operation of RPI AUX POWER ON alarm.

1.10 Proper operation of RPI SYSTEM IN TEST alarm.

2.0 <u>Test Method</u>

Rod banks were individually withdrawn in bank select mode in increments of 20 steps over the full length of rod travel. The following information was recorded at each 20 step increment:

1. RPI detector DC output voltage for each rod (DVM readings were taken at the POSITION SIGNAL jacks in the RPI racks).

2. MCR RPI reading for each rod from RPI indicators.

3. MCR group step counter reading(s).

4. P2500 readings for individual rod position and rod bank step count.

Actuation of the ROD DEVN & SEQ PWR RANGE TILT COMPUTER ALARM generated by the P2500 due to incorrect rod stepping sequence was verified during the withdrawal of Shutdown Banks A through D and Control Banks A through C. The bistable setpoint setting for the BANK D WITHDRAWAL LIMIT alarm was also checked during Control Bank D withdrawal.

Rod banks, operated individually, were then inserted until the individual rod bottom indicators on MCR panel were lit, at which time the information specified in Items 1 through 4 was recorded. Once all of the rod bottom indication lamps were lit, the bank was stepped in to the fully inserted position.

For Control Banks B, C, and D, Items 1 through 4 were recorded along with the P/A converter reading at the time the associated bypass bistable lamp was lit and again when the associated MCR rod bottom indication lights were lit.

Checks of the P2500 generated rod deviation alarms (Rod-to-Rod and Rod-to-Bank) and the Rod Control System URGENT alarm were performed by:

- Withdrawing SBA to 50 steps
- Positioning the appropriate SBA rod disconnect switches as specified by the procedure.
- Moving SBA in bank select mode until the P2500 (plant process computer) generated rod-to-rod and rod-to-bank deviation alarms, and URGENT alarms were actuated.

SBA was then fully inserted at the conclusion of this phase of testing.

Checks of the logic cabinet NON-URGENT alarm were simulated by pulling appropriate fuses to simulate faulty main +15, -15, and +100 Vdc power supplies. logic cabinet URGENT alarm checks were performed by checking the printed circuit card interlock circuit in seven card racks of the logic cabinet by removal of specific cards in the rack (this resulted in breaking the -15 Vdc path and actuated the URGENT alarm circuitry).

Power cabinet NON-URGENT alarm checks were performed via removal of appropriate power cabinet fuses which simulated failure of either of the two paralleled +24 Vdc power supplies OR either of the two paralleled -24 Vdc power supplies.

Two sets of DC power supplies, connected in an auctioneered arrangement, furnish the positive and negative voltages ($\pm$13 Vdc) required by the operational amplifier buffer amplifiers of the RPI signal conditioning modules. Failure of any of the four DC power supplies actuate the RPI AUX POWER ON alarm. Failure of both the +13 (1PS) and -13 (2PS) main power supplies was simulated via removal of fuse R3-14FU to check actuation of the RPI AUX POWER ON alarm. Failure of both the +13 (3PS) and -13 (4PS) auxiliary power supplies was simulated via removal of fuse R3-15FU (following the replacement of fuse R3-14FU) to check actuation of the RPI AUX POWER ON alarm.

The RPI SYSTEM IN TEST and RODS AT BOTTOM alarms were checked simultaneously by first withdrawing each rod bank individually in rod bank select mode until all rods were withdrawn 50 steps. The TEST/OPERATE toggle switch on a single RPI signal conditioning module was then placed in the TEST position to verify actuation of the RPI SYSTEM IN TEST alarm. Placing the toggle switch to TEST also caused a 0 Vdc output signal to the associated rod bottom bistable which deenergized the rod bottom relay and actuated the RODS AT BOTTOM alarm. The toggle switch was then returned to the TEST/OPERATE position, and the scenario was repeated for the next signal conditioning module until all modules had been tested.

3.0 Test Results

All required acceptance criteria for this test were met as delineated below.

3.1 Each rod operated over its entire range of travel within the limits ($\pm$ 7 steps) of RPI DC detector output voltage versus rod position calibration curve. Refer to Problem 1 for evaluation and disposition.

3.2 The BANK D WITHDRAWAL LIMIT alarm was actuated when Control Bank D was withdrawn between 217 to 223 steps.

3.3 The ROD DEVN & SEQ PWR RANGE TILT computer alarm was actuated when the P2500 computer detected the following conditions:

(a) Deviation between rod position indicator for a rod and the corresponding bank demand position was $\geq$ 12 steps.

(b) Deviation between two rods in a bank was $\geq$ 12 steps. See Problem 2.

(c) Rod Position Program detected incorrect rod stepping sequence.

3.4 The rod bottom bistable modules actuated at the correct setpoint setting (14 to 26 steps withdrawn) as indicated by the MCR RPI indicators.

3.5 The P/A rod bottom bypass bistable modules for Control Banks B, C, and D actuated at the correct setpoint setting (32 to 38 steps withdrawn) as indicated by the P/A converter digital display. See Problem 3.

3.6 An URGENT FAILURE induced in each of the power cabinets and the logic cabinet caused local URGENT FAILURE alarm indicator lamp to light and the CONTROL ROD URGENT FAILURE alarm to actuate. See Problem 4.

3.7 The RPI SYSTEM IN TEST alarm was actuated when the TEST/OPERATE switch on the RPI signal conditioning module for each control and shutdown rod was placed in the TEST position.

3.8 A NON-URGENT FAILURE induced in each of the power cabinets and the logic cabinet caused the local NON-URGENT FAILURE alarm indicator lamp to light and the CONTROL ROD NON-URGENT FAILURE alarm to actuate.

3.9 For shutdown and control rod banks having two groups, the MCR group step counters for both groups were indicating within $\pm$ 1 step of each other over their full length of travel (i.e., 231 steps).

3.10 The loss of one or more of the main or auxiliary 13 Vdc power supplies for the RPI signal conditioning modules caused actuation of the RPI AUX POWER ON alarm.

3.11 The RODS AT BOTTOM alarm was actuated, and the rod bottom indicator lamps at the RPI cabinets were lit when one or more rods were fully inserted.

4.0 Problems

[2] All rods in Shutdown Bank A failed to meet acceptance criteria 3.1 during testing performed on 1/7/96. A DN was written to document this problem. Since the purpose of testing was to obtain and record data following completion of hot RPI calibrations to verify proper calibration, and all SBA RPI indicators were within ± 12 steps of the SBA demand counters over their full length of travel, testing was continued to obtain a complete set of data for all rod banks.

The DN was made generic for all rod banks tested as testing progressed and data was reviewed. Review of the test data indicated that several RPIs in SBB, SBD, and CBC were close to or exceeded the Technical Specification Limiting Condition of Operation (LCO) requirement for RPI indication to be within ± 12 steps of the associated group step counter position indication. RPI hot calibrations were reperformed for all RPI in banks SBB, SBD, and CBC. A retest was subsequently performed and completed on 1/10/96. Review of the retest data indicated the Technical Specification ± 12 step limit was not exceeded. The retest results indicated that most recalibrated RPIs still failed to meet acceptance criteria 3.1 at 0 steps.

For those RPIs which failed to met the arithmetic ± 7 step voltage equivalent tolerance at 0 steps, justification to accept the results "as-is" is given:

- Alternate methods are available to the control room operator for determining that a rod is fully inserted (i.e., MCR rod bottom indicator lamps, local indication lamps at the RPI cabinets, and P2500 RPI "CxxxxA" values).

5.5 **Rod Position Indication System (1-PAT-3.4)** (continued)

- Accurate control board RPI indication to comply with the Technical Specification LCO requirements is the primary concern for Operations personnel when moving rods in the active fuel region so that a rod misalignment(s) can be detected. Due to the nonlinearity of the RPI detector LVDT, calibration of the RPI board indicators to accurately indicate rod position in the active fuel region may require the RPI signal conditioner output to read outside the arithmetic ± 7 step voltage equivalent tolerance when rods are fully inserted. RPI signal conditioner output readings which are outside the arithmetic ±7 step voltage equivalent tolerance are therefore judged to be acceptable when rods are fully inserted provided a 10.9 step voltage equivalent upper statistical limit is NOT exceeded in the active fuel region.

[2] Both a rod-to-rod and a rod-to-bank P2500 deviation alarm occurred at approximately the same time during P2500 deviation alarm testing performed on 1/11/96. The test procedure was intended to verify proper operation of only the rod-to-rod deviation alarm. A procedure change was made to ensure that U0053 (Shutdown Bank A position) was set to 56 steps. Additional steps were also added to allow retesting to verify proper operation of the rod-to-rod deviation alarm. Re-testing was successfully completed 1/12/96.

[3] The test procedure indicated that CBD rod bottom bypass bistable indication lamp should energize as CBD was inserted, but testing performed on 1/7/96 indicated that the indication lamp was already lit prior to reaching the bypass bistable setpoint. Review of plant drawings confirmed that the indication lamp deenergizes as the rod bank reaches the bistable setpoint during bank insertion. A procedure change was written to correct this deficiency. Retesting was successfully completed on 1/7/96.

5.5 Rod Position Indication System (1-PAT-3.4) (continued)

[4] Logic cabinet URGENT ALARM indication lamp did not light when pulser card A101 was removed from rack A3 during testing performed on 1/5/96. A continuity check indicated the indicator lamp was burned out. Operations requested that testing be discontinued until replacement indicator lamp bulbs could be obtained (none were available on-site). To restore System 85 configuration and back out of the test, card A101 was reinstalled in accordance with the test procedure which required 2nd-party verification to ensure card A101 was properly seated. Approximately one hour after reinstallation of card A101, Operations personnel repositioned rods and discovered that the rod groups were 1/2 stepping. Reactor trip breakers were opened. Test personnel performed a walkdown of the logic cabinet at 1650 on 1/5/96 and discovered that card A101 was not fully re-seated. Card A101 was pulled and properly reseated. Following completion of this action, the Rod Control System was returned to OPERABLE status.

Retesting of the logic cabinet URGENT ALARM was successfully completed on 1/8/96. Following reinstallation of card A101 per the test procedure, SBA Group 2 step counter incremented from 000 to 001 steps prompting Operations personnel to suspend further test performance until an evaluation was performed by Technical Support personnel.

5.6 Rod Control System (1-PAT-3.5)

This test was performed in Mode 3, as directed by 1-PAT-3.0, Post Core Loading Precritical Test Sequence, with the RCS at nominal temperature (555 to 559°F) and pressure (2220 to 2250 psig) with all reactor coolant pumps in service. Testing was started and field completed on 1/11/96.

1.0 Objective

The objective of this test was to perform a final check of the overall performance of the Rod Control System prior to initial criticality. During the test, each rod bank was operated individually to verify proper operation of all MCR rod position indicators and direction of motion. In addition, a check was performed to verify proper operation of the rod speed and control rod bank overlap circuitry.

2.0 Test Method

Each rod bank was withdrawn individually in bank select mode from the fully inserted position to 35 steps withdrawn. Prior to, following rod bank withdrawal to 35 steps, and following rod bank insertion to the full in position, the following information was collected:

1. Rod position detector DC analog output voltage for each rod in the rod bank obtained by connecting a DMM (selected scale 0 - 5 Vdc) to the appropriate signal conditioning module's POSITION SIGNAL jacks in the auxiliary instrument room.

2. Rod Position Indicator reading for each rod in the rod bank obtained by reading MCR RPI indicators.

3. Group step counter readings obtained by reading MCR group step counters.

Following placement of 1-RBSS, ROD BANK SELECT SWITCH, to the proper bank position and prior to rod bank withdrawal, the rod stepping rate demand from MCR indicator 1-ISI-85-412, ROD SPEED DEMAND, was checked to verify the demand stepping rate was in accordance with the PLS requirements. During rod bank withdrawal to 35 steps and during rod bank insertion to the full in position, a check was performed to verify proper operation of the MCR rod bottom indication lights and the rod motion status lights.

5.6 Rod Control System (1-PAT-3.5) (continued)

A check of the bank overlap circuitry was also performed by setting the bank overlap thumbwheel switches (S1-S6), located in the Rod Control System logic cabinet, such that a rod bank overlap of 10 steps would occur as rod banks were withdrawn to 25 steps in MANUAL mode and subsequently inserted to full in using MANUAL mode. At the point where sequential rod bank motion occurred during bank withdrawal and insertion, MCR group step counter readings were recorded to verify that appropriate rod bank motion occurred within one step of the bank overlap switch settings.

Following completion of this test, the bank overlap switches were properly reset for the current month's fully withdrawn limit.

3.0 Test Results

All required acceptance criteria for this test were met as delineated below:

3.1 The MCR direction indicator lights functioned properly to indicate the rod movement status and direction of rod motion during rod withdrawal and insertion operations.

3.2 The MCR rod group step counters functioned properly to indicate group position and direction of rod motion during rod withdrawal and insertion operations.

3.3 For shutdown and control rod banks having two groups, the MCR group step counters for both groups were indicating within $\pm$ 1 step of each other during rod withdrawal and insertion operations.

3.4 The MCR RPI indicators functioned properly to indicate individual rod position and direction of motion during rod withdrawal and insertion operations.

3.5 The MCR RPI indicators were within $\pm$ 12 steps of their associated rod bank step counter during rod withdrawal and insertion operations.

3.6 The MCR rod speed demand indicator functioned properly and indicated that the rod stepping rate was within the range of 46 to 50 steps/minute for control banks in bank select and MANUAL modes and 62 to 66 steps/minute for shutdown banks A and B in bank select mode. The actual indicated rod stepping rates were 47 steps/minute for CBA and CBB, 48 steps/minute for CBC and CBD, and 64 steps/minute for SBA and SBB.

3.7 The control rod bank overlap circuitry functioned properly during the sequential withdrawal and insertion of control rods in MANUAL mode.

4.0 <u>Problems</u>

There were no significant problems encountered during the performance of this test.

5.7 Incore Movable Detectors (1-PAT-3.6)

This PAT was performed as part of 1-PAT-3.0, Post Core Loading Precritical Test Sequence. The test was started on 11/20/95 and was field complete on 12/6/95.

1.0 Objectives

This test performed functional checks of the incore movable detector system to demonstrate the operability of the various system components, controls, and interlocks.

2.0 Test Method

Testing was performed with the plant in Mode 5 prior to initial criticality. Using a dummy cable assembly and live detector assemblies, the following items were either verified or measured:

2.1 The 5-path and 10-path transfer devices operate properly.

2.2 Preliminary top- and bottom-of-core setpoint settings are determined by measurement for NORMAL, CALIBRATE, EMERGENCY, and COMMON GROUP modes.

2.3 Preliminary top and bottom limit setpoints are determined by measurement for STORAGE mode.

2.4 Interlock function of WITHDRAW LIMIT and SAFETY LIMIT switches operate properly.

2.5 Interlock function of multiple drive shutoff logic operates properly to disable all drive motors to prevent possible insertion of two detectors into the same 10-path transfer device in AUTO mode.

2.6 Drive unit motor does not operate for either AUTO or MANUAL modes when OPERATION SELECTOR switch is placed in OFF position.

2.7 STOP push button functions properly to terminate insertion and withdrawal in AUTO mode.

5.7 Incore Movable Detectors (1-PAT-3.6) (continued)

2.8 Interlock function of WITHDRAW LIMIT switch operates properly to prevent rotation of the 5-path and 10-path transfer devices.

2.9 All detector drives operate properly in the AUTO and MANUAL control modes.

2.10 All detector drive motors operate at proper low speed for RECORD mode in AUTO control mode.

2.11 The system is capable of supplying the P2500 plant process computer with proper contact closure signals.

2.12 Position comparator circuitry functions properly to stop drive motors at bottom-of-core and top-of-core limits in the AUTO mode.

2.13 Capability to obtain a full core map was demonstrated in AUTO mode.

2.14 Leak Detection and Alarm System operates properly. Specifically, audible alarm and alarm lamp on POWER DISTRIBUTION panel actuate and RESET switch functions properly to silence alarm.

2.15 Path display indicators function properly to indicate the thimble being accessed.

2.16 The capability of the incore movable detector system to supply the P2500 plant process computer and strip chart recorders is demonstrated with simulated neutron flux signals.

2.17 The signals supplied by the incore movable detector system to the strip chart recorders and P2500 plant process computer are demonstrated to be the proper magnitude or adjustments are performed to ensure the proper magnitude.

3.0 Test Results

All required acceptance criteria were met as delineated below:

5.7 Incore Movable Detectors (1-PAT-3.6) (continued)

3.1 Preliminary bottom- and top-of-core limit setpoints for each drive unit were determined using the dummy cable assembly for NORMAL, CALIBRATE, EMERGENCY, AND COMMON GROUP modes, and preliminary top and bottom limit settings were determined for STORAGE mode.

3.2 The WITHDRAWN and SAFETY limit switch settings were demonstrated to operate properly for each drive unit.

3.3 Proper switching and mode indication were verified for the five- and ten-path transfer devices for all drive units.

3.4 Proper operation of each drive unit in MANUAL and AUTOMATIC mode was demonstrated.

3.5 Contact closure inputs supplied to the P2500 plant process computer from each drive unit was demonstrated.

3.6 The Leak Detection and Alarm System was demonstrated to operate properly.

3.7 All interlock functions of the multiple drive shutoff logic were verified.

3.8 Measured low drive speed for withdrawal in RECORD mode during AUTOMATIC control was within design tolerances of 2.367 to 2.433 inches/second.

3.9 Multiple drive capability using six detector cable assemblies in AUTOMATIC modes was demonstrated.

3.10 The STOP push button functioned properly to terminate insertion and withdrawal in AUTOMATIC mode.

3.11 The interlock function of the WITHDRAW LIMIT switch operated properly to prevent rotation of the five- and ten-path transfer devices.

3.12 The drive unit motors did not operate in either MANUAL or AUTOMATIC mode when the OPERATION SELECTOR switch was placed in the OFF position.

3.13 The capability of the incore detector system to supply the P2500 plant process computer and strip chart recorders was demonstrated with simulated neutron flux signals. See Problem 3.

3.14 Path display indicators functioned properly to indicate the thimble being accessed by the dummy cable assembly. See Problem 4.

4.0 <u>Problems</u>

[1] While adding water to the Leak Detection and Alarm System, the alarm would not stay energized. The corrective action was to impede the discharge flow to keep the alarm in. This was successful and the test was completed satisfactorily.

[2] When Detector A was selected to COMMON GROUP, during the multiple drive logic checks, the stop light lit before Detector B was selected. The stop light would not clear. This was due to an error in the test procedure. The test was revised and testing was completed satisfactorily.

[3] With the signal generator connected in accordance with the test, a signal was not received on the strip chart recorder. The test was revised to reverse the polarity. The strip chart recorder responded appropriately and the test was completed satisfactorily.

[4] While inserting the dummy cable, the clutch slipped and the "D" drive was stopped at 263.6 inches. The corrective action was to manually withdraw the dummy in LO speed, noting that the red light deenergized at approximately 261 inches. Withdrawal continued to approximately 240 inches. The dummy was inserted in LO speed manual to 400 inches. The controls were then returned to automatic mode, and the dummy inserted to the bottom of the core successfully. No further actions were necessary.

5.8 Reactor Coolant Flow Coastdown (1-PAT-3.7)

This test was performed in Mode 3 at normal operating temperature and pressure. The test was started and field completed on 1/11/96.

1.0 Objectives

1.1 To measure the rate at which reactor coolant flow changes subsequent to a simultaneous trip of all four reactor coolant pumps. The measured flow coastdown time constant is determined from the flow versus time data and compared to the design flow coastdown time constant.

1.2 To Measure the delay time associated with the low flow reactor trip and compare it to that value assumed in the accident analysis.

1.3 To record the RCP Motor voltage decay during the transient.

2.0 Test Method

All four reactor coolant pumps were simultaneously tripped, causing the reactor trip breakers to open on Low RCS Flow. Measurements were made by recording reactor coolant loop elbow tap differential pressures (d/p), RCS low flow bistable state, reactor trip breaker position, reactor coolant pump breaker position and reactor coolant pump motor voltage decay data. The timing of the undervoltage relay and associated time delay timer in the RCP's undervoltage circuit.

3.0 Test Results

All required acceptance criteria were met as delineated below:

3.1 The measured flow coastdown time constant (TAU_m) is greater than the design flow coastdown time constant (TAU_d) of 11.79 seconds.

TAU_m was measured to be 13.70347 seconds.

3.2 The total low flow trip delay time is less than 1.2 seconds.

5.8 Reactor Coolant Flow Coastdown (1-PAT-3.7) (continued)

Low flow trip delay time, T_{lf}, was measured to be 0.904773 seconds.

3.3 All four reactor coolant pumps trip within 100 msec of each other.

All four pumps tripped within 15 msec of each other.

4.0 Problems

There were no significant problems encountered during the performance of this test.

5.9 Rod Drop Testing (1-PAT-3.8)

This test was performed in Mode 3 with the RCS at nominal temperature and pressure with all RCS coolant pumps in operation as directed by 1-PAT-3.0, Post Core Loading Precritical Test Sequence. Testing was started on 1/7/96 and field completed on 1/11/96.

1.0 Objective

This test was performed prior to initial criticality to verify that: (1) all CRDMs unlatch and all rods are fully inserted into the core when the RTBs are opened, and (2) the drop time of each shutdown and control rod, from the fully withdrawn position, is less than the Technical Specification limit ($\leq$ 2.7 seconds) from the time the RTBs change status (i.e., the breakers open following a reactor trip) until dashpot entry occurs with:

A. RCS $T_{avg} \geq 551^{\circ}F$, and

B. All reactor coolant pumps operating.

Additional objectives of this test were to measure the "rod release" times for all shutdown and control rods, and verify that all decelerating dashpots were performing properly.

This test demonstrated rod freedom of movement (i.e., tripability) and ensured that the reactor internals and rod drive mechanism would not interfere with rod motion or adversely impact the drop times during operation in Modes 1 and 2.

2.0 Test Method

The measurement of the rod drop times was performed in accordance with 1-SI-85-1, Rod Drop Time Measurement. This Surveillance Instruction withdrew all shutdown and control rod banks to 50 steps and then manually tripped the reactor to simultaneously drop all rod banks, thereby demonstrating rod tripability. Single rod banks were then withdrawn to 231 steps, and the reactor was manually tripped to simultaneously measure the rod drop times for all of the rods in the selected bank. This process was repeated until all rod banks had been drop tested.

5.9 **Rod Drop Testing (1-PAT-3.8)** (continued)

The parameter monitored for each dropped rod was the time-variant response of the voltage induced in the associated RPI detector primary coil by the motion of the CRDM drive shaft. The change in the status of the RTBs was also monitored for reference timing purposes. Test recorders were also used to monitor RTB status and the time variant response of the stationary gripper voltage using design test point connections on the monitoring test panel in the appropriate Rod Control System power cabinet.

Using the rod drop test data, a determination was made of the: (1) rod drop time for each shutdown and control rod, and (2) "rod release" time for each shutdown and control rod which is defined as the time between RTB status change and onset of RPI primary coil induced voltage (i.e., inward rod motion).

For those rods whose rod drop time fell outside a 2-sigma limit from the average drop time for all shutdown and control rods, three additional rod drops were performed for the appropriate rod bank(s). The 2-sigma rod drop testing was performed to satisfy USNRC Regulatory Guide 1.68, Rev. 2 testing requirements.

An analysis of the rod drop test data for the time between dashpot entry and rod bottom was also performed (as required by Regulatory Guide 1.68, Rev. 2) to verify that all decelerating dashpots were performing correctly so as to preclude mechanical damage to the shutdown and control rods.

3.0 <u>Test Results</u>

All required acceptance criteria for this test were met, as delineated below.

3.1 All CRDMs unlatched upon opening the RTBs.

5.9 Rod Drop Testing (1-PAT-3.8) (continued)

3.2 All shutdown and control rods dropped from the fully withdrawn position (231 steps) in $\leq$ 2.7 seconds from the time the RTBs changed status (i.e., breakers open following a reactor trip) until dashpot entry.

The average drop time for all shutdown and control rods was determined to be 1.503 seconds with the longest drop time being 1.57 seconds and the shortest drop time being 1.46 seconds.

3.3 The rod release time for all shutdown and control rods is <150 milliseconds following power interruption to the CRDMs.

The maximum rod release time was 40 milliseconds.

4.0 <u>**Problems**</u>

There were no significant problems encountered during the performance of this test.

5.10 Reactor Trip System (1-PAT-3.10)

This test was performed in Mode 5 as directed by 1-PAT-3.0, Post Core Loading Precritical Test Sequence. Testing was started on 11/18/95 and field completed on 11/27/95.

1.0 Test Objective

The objective of this test was to demonstrate proper functioning of the Reactor Trip System. This objective was accomplished by demonstrating that:

1.1 The reactor trip breakers can be opened manually from the main control room.

1.2 Closure of both reactor trip bypass breakers actuates interlocks and causes a reactor trip.

1.3 With one reactor trip bypass breaker closed, placing the opposite SSPS train in test causes both reactor trip breakers and the bypass breaker to open.

1.4 The reactor trip bypass breakers maintain the rod drive mechanisms energized when the associated reactor trip breaker is opened for test.

2.0 Test Method

2.1 Check of manual reactor trip capability from the main control room:

Shutdown Bank A was withdrawn to 50 steps so that all MCR rod bottom indication lights for Shutdown Bank A were extinguished. The reactor was then manually tripped using handswitch 1-RT-1 and the Shutdown Bank A rod drive mechanisms were verified to have unlatched by observing that the rod bottom lamps for all 57 rod drive mechanisms were lit. The RTBs were then closed and Shutdown Bank A was again withdrawn to 50 steps and manually tripped using handswitch 1-RT-2.

2.2 Reactor Trip Bypass Breaker Interlock:

Testing was performed, with all shutdown and control rods fully inserted, to demonstrate interlocks permit momentary closure of both reactor trip bypass breakers and then causes a reactor trip due to the generation of simultaneous general warning reactor trip signals to the reactor trip breakers.

2.3 Check of reactor trip when reactor trip bypass breaker BYB is Closed and SSPS Train A is Placed in Test:

Both RTBs were closed and Bypass Breaker BYB was then racked in and closed. SSPS Train A mode selector switch on output relay test panel (1-R-48) was subsequently placed in TEST to demonstrate that both RTBs and Bypass Breaker BYB trip.

2.4 Check of reactor trip when reactor trip bypass breaker BYA is closed and SSPS Train B is placed in test:

Both RTBs were closed and then bypass breaker BYA was racked in and closed. SSPS Train B mode selector switch on output relay test panel (1-R-51) was subsequently placed in TEST to demonstrate that both RTBs and bypass breaker BYA trip.

2.5. Check of Reactor Trip Bypass Breakers to Prevent a Reactor Trip while Testing the Reactor Trip Breakers:

Testing was performed to verify main reactor trip breaker RTA will open without causing a reactor trip when bypass breaker BYA is racked in and closed following injection of a simulated reactor trip signal from SSPS Train A. Identical testing was also performed for Train B.

3.0 Test Results

All required acceptance criteria for this test were met, as delineated below:

3.1 Reactor trip breakers (RTA and RTB) opened manually.

3.2 Electrical interlocks tripped both reactor trip and bypass breakers when both bypass breakers were momentarily closed.

3.3 With one reactor trip bypass breaker (BYA or BYB) closed, placing the opposite SSPS train in test caused both reactor trip breakers (RTA and RTB) and the bypass breaker (BYA or BYB) to open due to simultaneous general warning reactor trip signals being sent to the reactor trip breakers (RTA and RTB).

3.4 Each reactor trip breaker (RTA or RTB) opened without causing a reactor trip and maintained the rod drive mechanism energized when its associated bypass breaker (BYA or BYB) was racked in and closed following injection of a simulated Reactor Protection System trip signal on the associated SSPS train.

4.0 Problems

There were no significant problems encountered during the performance of this test.

5.11 Adjustments of Steam Flow Transmitters at Minimal Steam Flow (1-PAT-3.11)

This test was performed as part of test sequence 1-PAT-3.0, Post Core Loading Precritical Test Sequence. The test began on 1/2/96 and was field completed on 1/3/96.

1.0 Objectives

The objective of this test was to verify/adjust the output of the eight steam flow transmitters for "zero" output with minimal steam flow.

2.0 Test Method

The plant was in Mode 3 at normal operating temperature and normal operating pressure. Steam flow was reduced to minimal by shutting an MSIV. With the MSIV closed, each steam flow transmitter on the associated main steam line was verified/adjusted for a "zero" output. This was repeated for each main steam line.

3.0 Test Results

There were no acceptance criteria for this test at this test plateau. Overall acceptance criteria for steam and feedwater flow instrumentation calibration are addressed in 1-PAT-8.4, Calibration of Steam and Feedwater Flow Instrumentation at 100% Power, in Section 7.4 of this report.

4.0 Problems

There were no significant problems encountered during the performance of this test.

6.0 INITIAL CRITICALITY AND LOW POWER PHYSICS TESTING

6.1 Initial Criticality and Low Power Test Sequence (1-PAT-4.0)

This test started on 01/12/96 and was completed on 01/22/96.

1.0 Test Objective

This procedure was the controlling document for establishing the required prerequisite conditions necessary to permit a change from Mode 3 to Mode 2 conditions. This procedure also governs the sequence of testing in Mode 2.

The following PATs/PETs were sequenced for performance by 1-PAT-4.0:

- 1-PAT-1.4 * Pipe Vibration Monitoring
- 1-PAT-1.5 * Loose Parts Monitoring System
- 1-PAT-1.8 * Thermal Expansion of Piping Systems
- 1-PAT-1.10* Plant Process Computer
- PET-103 Reactivity Computer Setup
- PET-201 Initial Criticality
- PET-203 Determination of Power Range for Physics Testing and ADRC Checkout
- PET-204 Rod and Boron Worth Measurements
- PET-301 * Core Power Distribution Factors
- PET-304 * Operational Alignment of NIS

Note: * Indicates that the test is performed at multiple test plateaus. The description of the testing is documented in the section (plateau) in which it was completed.

2.0 Test Method

None associated with this sequence document.

3.0 Test Results

All acceptance criteria were contained within the tests sequenced by this test.

6.1 Initial Criticality and Low Power Test Sequence (1-PAT-4.0) (continued)

4.0 Problems

Problems encountered are addressed in the following discussions of each test sequenced by 1-PAT-4.0.

6.2 Reactivity Computer Setup (PET-103)

This test started on 01/12/96 and was completed on 01/21/96.

1.0 Test Objective

The objectives of this test were to define the specific steps for the ADRC necessary to:

1.1 Perform a calibration and verification of operability of the system prior to plant hookup via hardware and software self-checks.

1.2 Remove a selected NIS power range detector from service and connect it to the ADRC prior to performance of low power physics testing.

1.3 Terminate field connections to the ADRC for monitoring RCS T_{avg}.

1.4 Determine the gamma leakage compensation currents following plant hookup in Mode 3 conditions.

1.5 Remove field connections from the ADRC and restore the NIS power range detector to service following completion of low power physics testing.

2.0 Test Method

The RCS T_{avg} signal was taken from RCS Loop 4 via a test point located in the auxiliary instrument room and connected to the ADRC. NIS power range Channel N-44 was disconnected and connected to the ADRC.

Gamma leakage compensation current determination was performed in Mode 3 with the RCS temperature (T_{avg}) between 551 and 560°F and drifting less than 1°F/hr by performing the "Leakage Current Determination / Compensation" Program on the ADRC.

3.0 Test Results

All required acceptance criteria for this test were met as delineated below:

3.1. The absolute value of the PREDICTED vs MEASURED error (i.e., the percent difference between the ADRC "predicted" reactivity and the "measured" reactivity) was ≤ 1.0% during the ADRC internal exponential test.

3.2 The ADRC was hooked up to measure live plant signals for the lower and upper segment of one NIS power range detector channel.

3.3 The ADRC was hooked up to measure live plant signals for the RCS T_{avg} for one loop.

3.4 The gamma leakage compensation currents were determined and stored in the ADRC.

4.0 Problems

There were no significant problems encountered during the performance of this test.

6.3 Initial Criticality (PET-201)

This test started on 01/13/96 and was completed on 01/18/96.

1.0 Test Objective

The objective of this test was to achieve initial criticality in a cautious and controlled manner.

2.0 Test Method

Channel operational tests were performed on the three operable NIS power range (i.e. the fourth channel was connected to the reactivity computer) and the two intermediate range detector channels within 12 hours prior to invoking Technical Specification 3.1.10 to permit declaring the start of physics testing. One NIS power range detector channel was removed from service and connected to the ARDC by performance of PET-103, Reactivity Computer Setup. The shutdown banks were then fully withdrawn followed by control banks in their normal overlap sequence to position Control Bank D at 160 steps. The RCS was then diluted using the ALTERNATE DILUTE mode. After dilution, criticality was achieved by Control Bank D withdrawal.

ICRR data was monitored using the source range detector channels to assess the magnitude and rate of positive reactivity addition during the approach to criticality. Approximately 33,000 gallons of primary makeup water is required to dilute the RCS from a boron concentration of 2000 ppm until criticality is achieved or can be achieved by Control Bank D withdrawal.

3.0 Test Results

All required acceptance criteria for this test were met as delineated below:

3.1 The SRF for the source range detectors were within the range of 0.53 to 1.48 prior to withdrawing shutdown and control banks from the fully inserted position.

The SRF values for NIS channels N131 and N132 were 1.06 and 0.95 respectively.

6.3 **Initial Criticality (PET-201)** (continued)

3.2 Prior to withdrawing shutdown and control banks from the fully inserted position, the source range detectors indicated a count rate of ≥ 1/2 counts/second above the "background" count rate.

The count rates for NIS channels N131 and N132 were 13.33 cps and 12.90 cps respectively.

3.3 Prior to withdrawing shutdown and control banks from the fully inserted position, the signal-to-noise ratio (S/N) for the source range detectors was shown to be > 2.

The signal to noise ratios for NIS channels N131 and N132 were 4.72 and 12.90, respectively.

3.4 The reactor achieved initial criticality in a safe and orderly manner via successful completion of this procedure.

Critical conditions were Control Bank D at 167 steps withdrawn with the RCS boron concentration at 1293 ppm and within the estimated critical position error band of 1202 ppm and 1402 ppm.

Refer to Figures 6.3-1 through 6.3-6 for ICRR data obtained during the test.

4.0 Problems

There were no significant problems encountered during the performance of this test.

Figure 6.3-1
ICRR vs Time (N131)

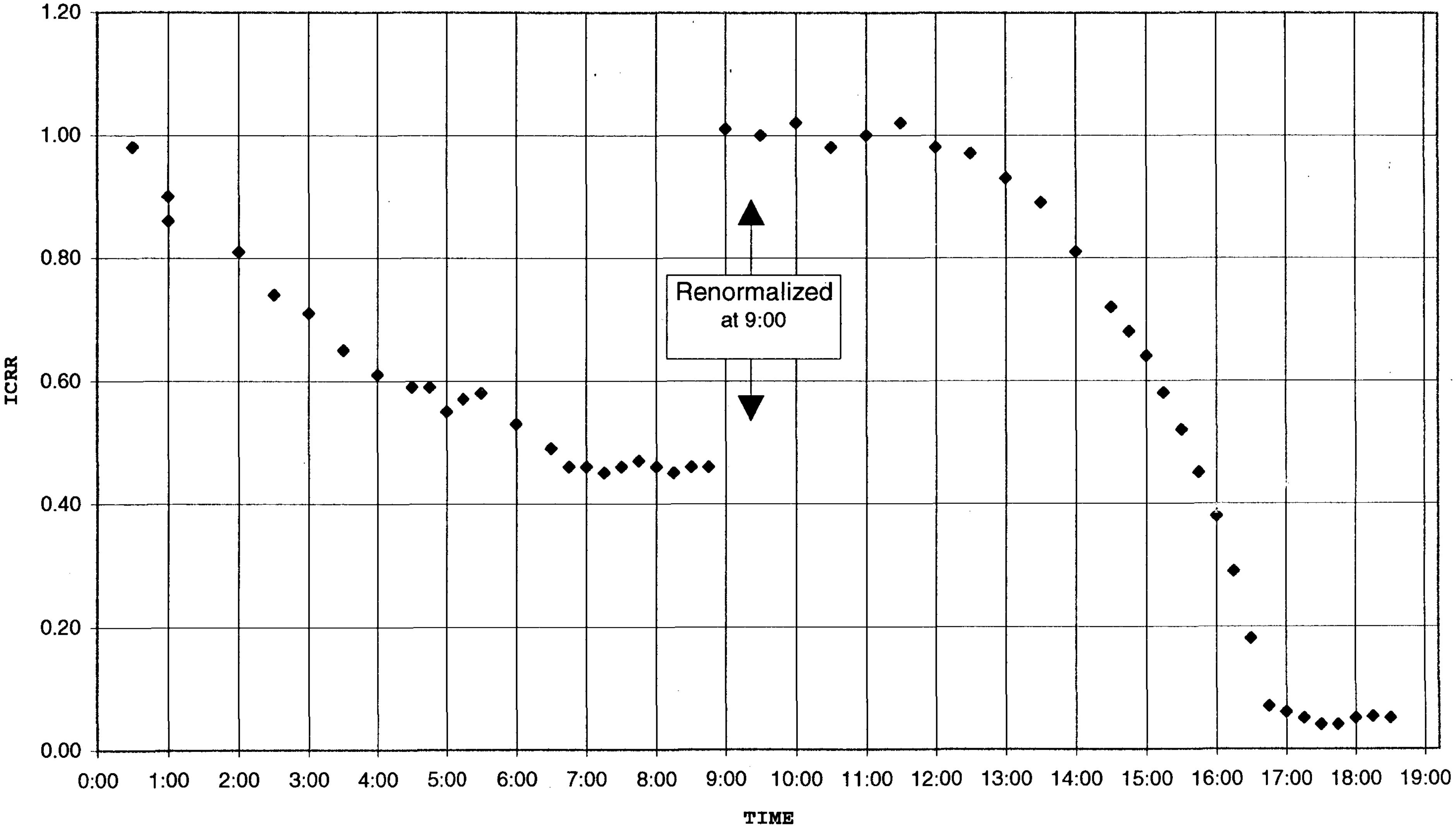


Figure 6.3-2
ICRR vs Time (N132)

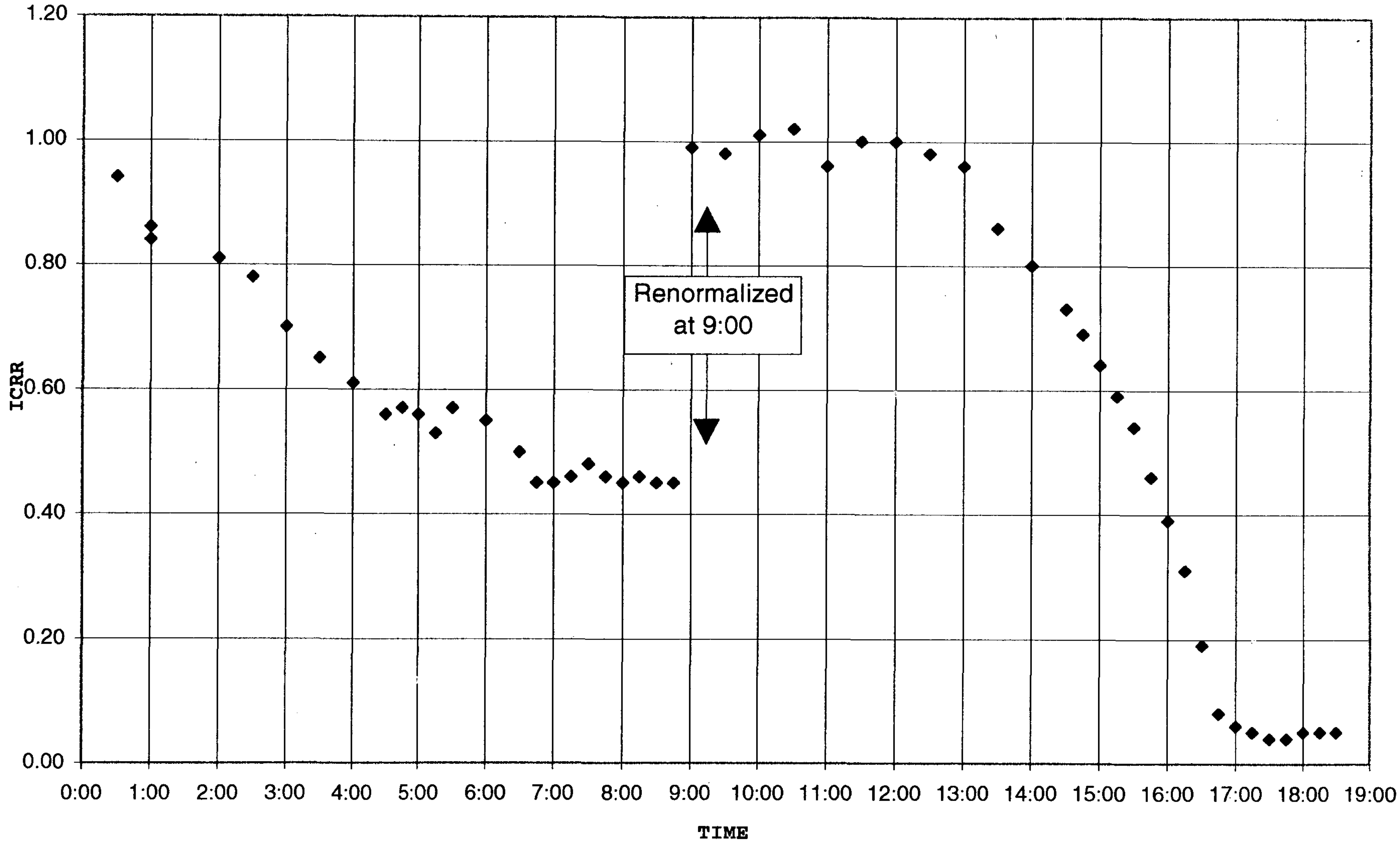


Figure 6.3-3
ICRR vs Boron Concentration (N131)

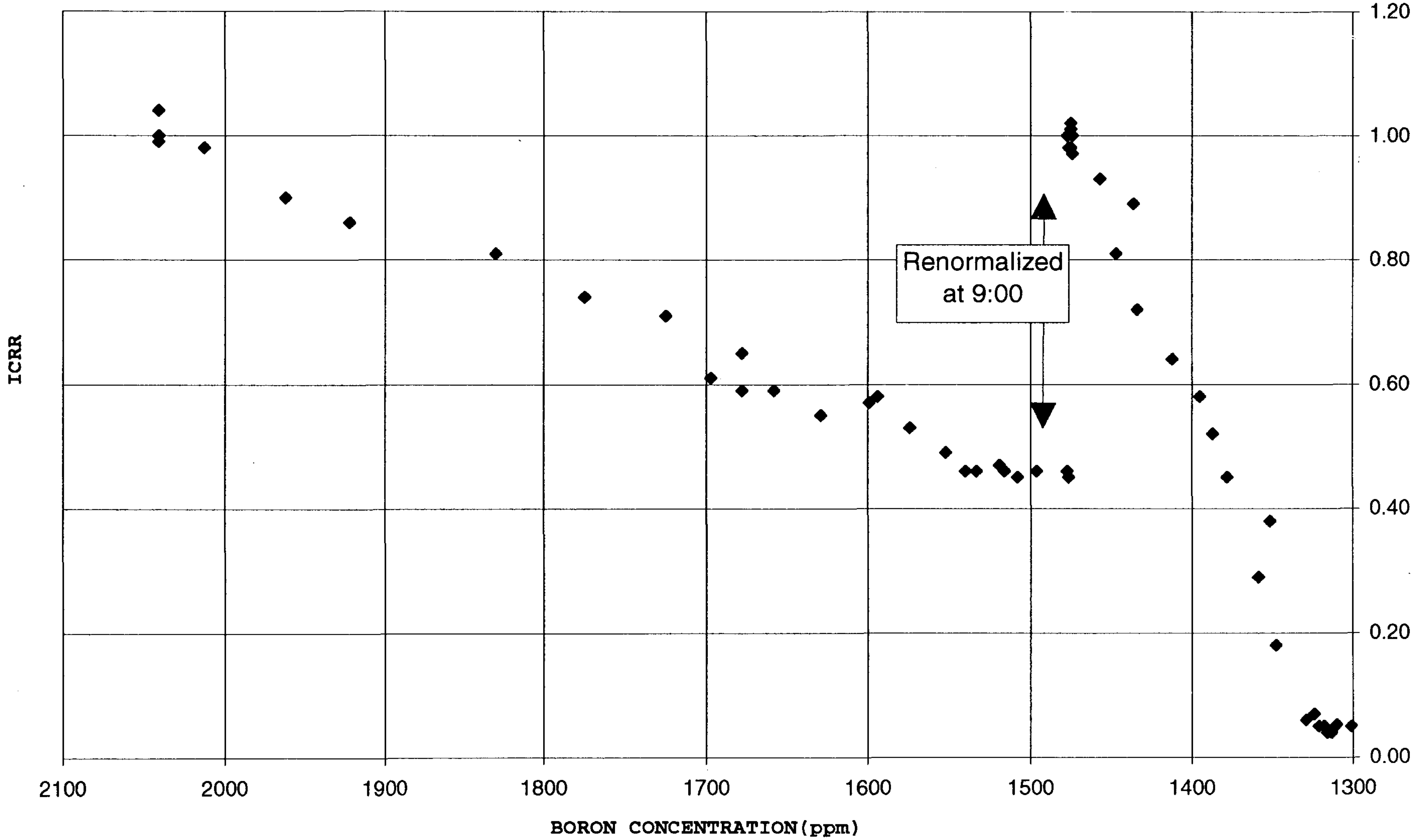


Figure 6.3-4
ICRR vs Boron Concentration (N132)

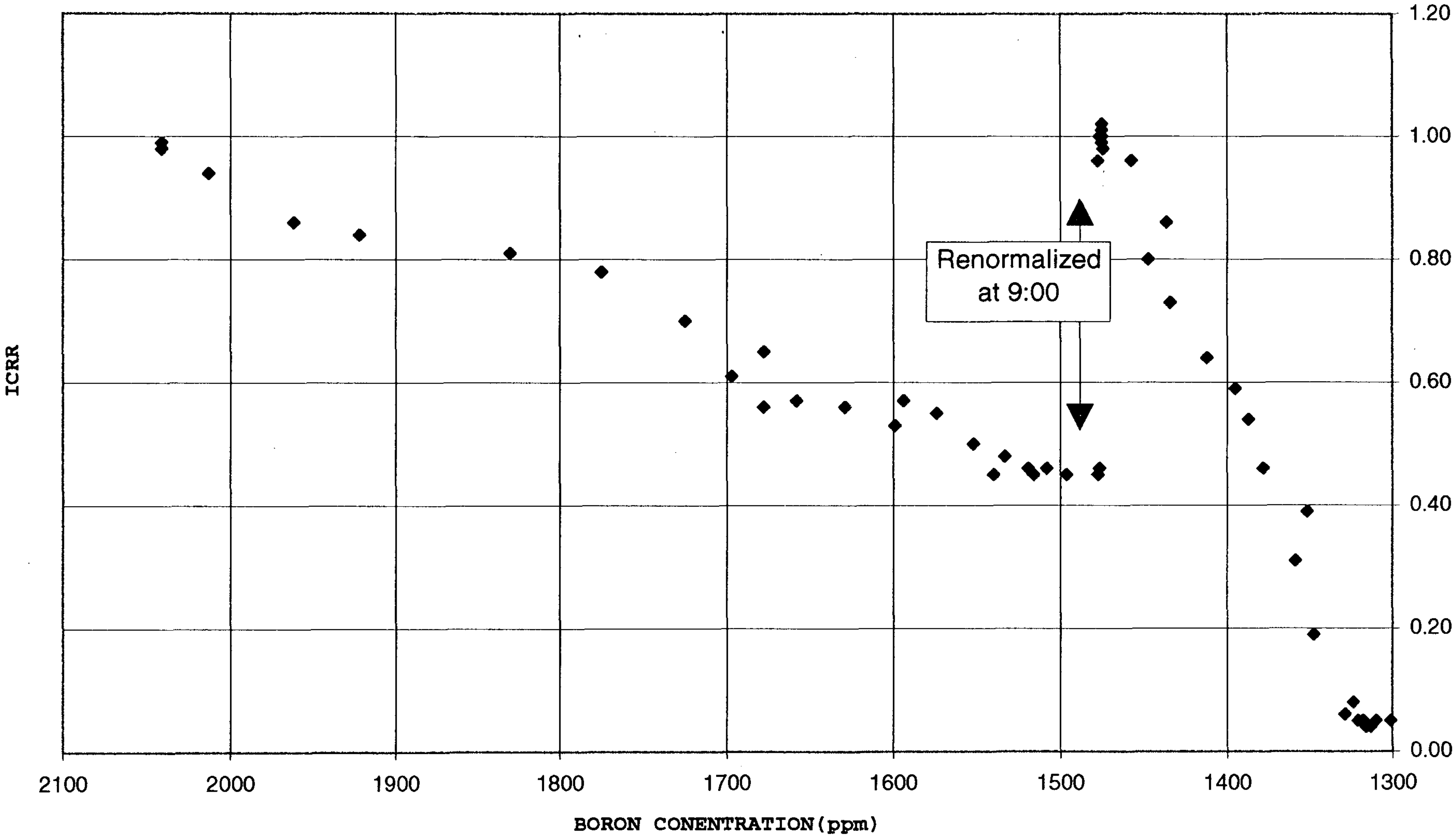


Figure 6.3-5
ICRR vs Primary Water (N131)

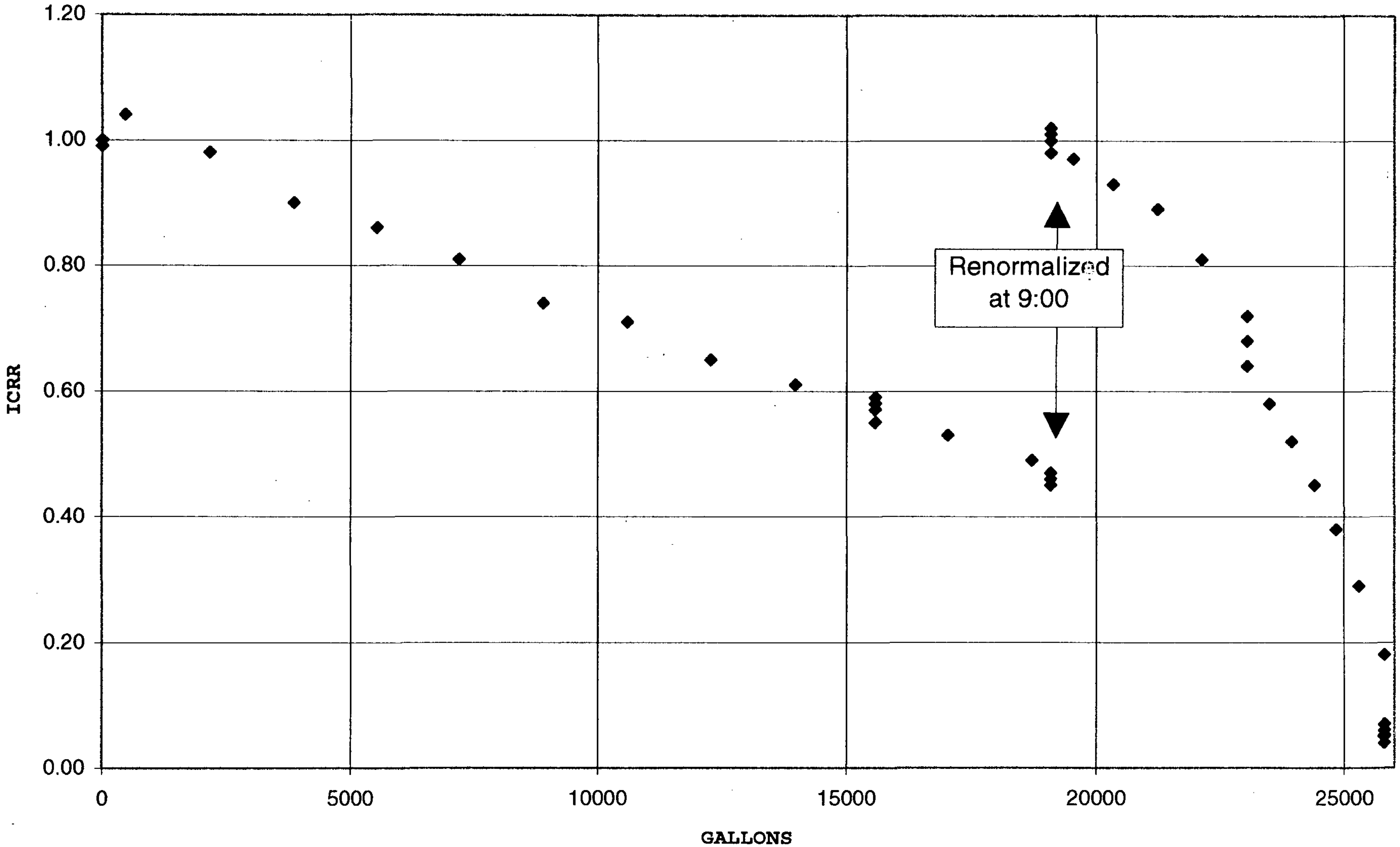
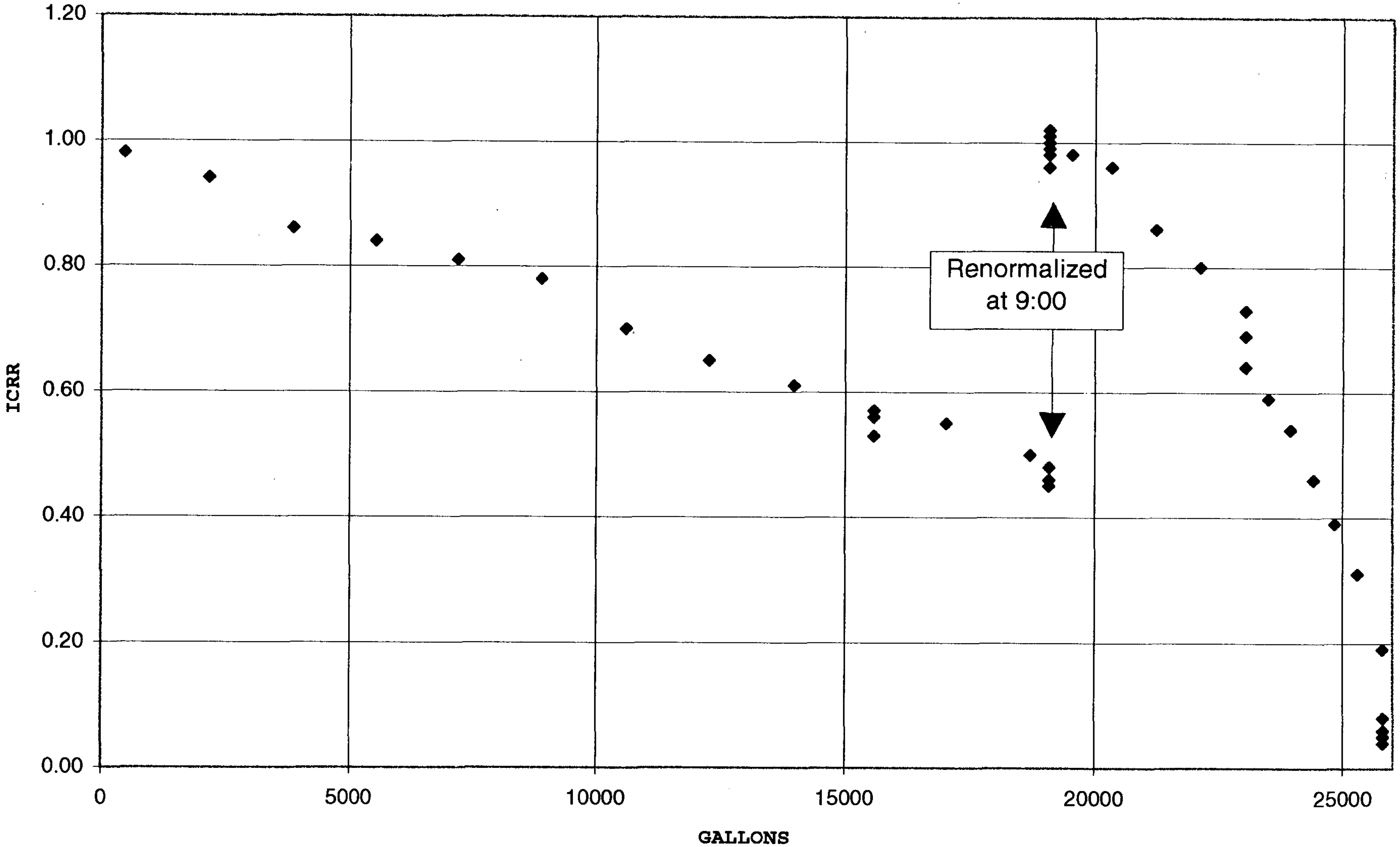


Figure 6.3-6
ICRR vs Primary Water (N132)



6.4 Determination of Power Range for Physics Testing and ADRC Checkout (PET-203)

This test started on 01/17/96 and was completed on 01/19/96.

1.0 Test Objective

The objectives of this test were as follows:

1.1 To determine the proper neutron flux level to be used during the performance of low power physics testing.

1.2 To demonstrate the proper dynamic behavior of the Westinghouse ADRC in response to reactivity changes occurring in the core as a result of Control Bank D motion.

2.0 Test Method

This procedure determined the proper neutron flux level to be used during the performance of low power physics testing. A small amount of positive reactivity was added to the reactor core by withdrawal of Control Bank D. The onset of nuclear heat was observed by a smooth addition of negative reactivity which cannot be attributed to control rod motion, changes in RCS boron concentration, or variation of moderator temperature. The upper limit of the neutron flux level range for low power physics testing was subsequently established by selecting the picoammeter range setting at or below 30% of the "nuclear heat" current readings. The peak-to-peak reactivity signal at the lower limit of flux for low power physics testing was verified not to exceed 2 pcm.

3.0 Test Results

All required acceptance criteria for this test were met as delineated below:

6.4 Determination of Power Range for Physics Testing and ADRC Checkout (PET-203) (continued)

3.1 The neutron flux level at which nuclear heating effects are observed was determined, and an upper neutron flux limit for low power physics testing was established less than or equal to 30% of the observed picoammeter currents at nuclear heating.

3.2 The absolute value of the PREDICTED vs MEASURED error (i.e., the percent difference between the ADRC "predicted" reactivity and the "measured" reactivity) was ≤ 4.0% during the ADRC reactor exponential test.

4.0 Problems

There were no significant problems encountered during the performance of this test.

6.5 Rod and Boron Worth Measurements (PET-204)

This test was performed during Mode 2 physics testing at nominal operating temperature and pressure as directed by 1-PAT-4.0, Initial Criticality and Low Power Test Sequence.

This test either performed or called out the performance of the following low power physics tests:

- All Rods Out Critical Boron Concentration
- Control Bank D IN Critical Boron Concentration
- Control Bank D Worth by Boron Exchange (i.e., dilution)
- Control Banks A, B, and C, and Shutdown Banks A, B, C, and D Worth's by the Bank Exchange Method (i.e., rod swap)
- ITC Measurement (via performance of 1-SI-0-23)

Testing started on 1/19/96 and was field completed on 1/22/96.

1.0 Objective

The objectives of this test were to define the steps for low power physics testing necessary to:

1.1 Verify the design value of ARO critical boron concentration (C_B).

1.2 Determine the HZP C_B at specified control bank configurations.

1.3 Determine the integral reactivity worth (pcm) and differential reactivity worth (pcm/step) of the reference rod bank and the integral worth of the remaining control and shutdown banks.

1.4 Determine the average differential boron worth (pcm/ppm) over the full range of Control Bank D travel.

1.5 Verify the MTC is negative or zero at BOL.

2.0 Test Method

To determine the ARO critical boron concentration (ARO C_B) following initial criticality, Control Bank D was repositioned by boration to near the ARO configuration. After equilibrium critical conditions had been established, the RCS boron concentration was measured by chemical analysis. The residual worth of Control Bank D was then measured several times by bank withdrawal to the ARO configuration.

Determination of the rod residual worth, known as an endpoint measurement, was accomplished by measurement with the reactivity computer. The parts per million (ppm) boron equivalent of this endpoint measurement was then determined and subsequently added to the initial condition measured C_B to determine the effective ARO C_B. The ARO C_B is often referred to as the ARO boron endpoint concentration (ARO C_{BE}).

The differential and integral worth of Control Bank D was measured by the boron exchange method. This method set up an RCS dilution at a constant rate and repositioned Control Bank D, as necessary, to compensate for the reactivity change. The change in reactivity per unit change in Control Bank D position was measured using the reactivity computer to determine the differential Control Bank D worth. The integral worth was subsequently calculated by summing the differential worths over the full range of Control Bank D travel.

The average differential boron worth (pcm/ppm) over the full range of Control Bank D travel was calculated by dividing the integral worth of Control Bank D by the difference between the ARO C_{BE} and the Control Bank D fully inserted (CBD IN) C_B.

The integral bank worths of the remaining control and shutdown rod banks were measured by the rod swap method. The rod swap method was performed by alternately inserting a "test" rod bank and compensating for the reactivity change by withdrawing Control Bank D until the "test" bank was fully inserted. The reactivity changes were monitored with the reactivity computer to maintain neutron flux level and to reestablish a critical condition once the "test" bank was fully inserted. The worth of the "test" bank was then calculated using the integral worth of Control Bank D.

The MTC measurement was accomplished by performance of 1-SI-0-23, Moderator Temperature Coefficient Determination at BOL. RCS T_{avg} was gradually decreased by approximately -4°F by increasing secondary load. The changes in reactivity and RCS T_{avg} were measured by the reactivity computer. RCS T_{avg} was then gradually increased by approximately +4°F by decreasing secondary load. Again, the changes in reactivity and RCS T_{avg} were measured using the reactivity computer.

The reactivity and T_{avg} data were used to calculate cooldown and heatup ITC values. An average ITC value was computed. The MTC was subsequently computed by subtracting the design fuel temperature coefficient (Doppler) from the average ITC value.

3.0 <u>Test Results</u>

All required acceptance criteria for this test were met as delineated below:

3.1 The ARO C_{BE} was within ± 1000 pcm of the design "No Rods" critical boron concentration (ppm) found in Table 4-8 of the current cycle's NuPOP. For Cycle 1, the ARO C_{BE} is between 1214 and 1414 ppm (i.e., 1314 ppm ± 100 ppm).

The ARO C_{BE} was 1299 ppm which is -15 ppm from the design "No Rods" critical boron concentration (ppm) found in Table 4-8 of the current cycle's NuPOP.

3.2 The integral worth of Control Bank D was within 15% of its predicted worth and the integral worth of Control Banks A, B, and C and Shutdown Banks A, B, C, and D were within 30% or 200pcm of their predicted worths, whichever was <u>greater</u>:

6.5 **Rod and Boron Worth Measurements (PET-204)** (continued)

Bank	Predicted Integral Bank Worth (pcm)	Measured Integral Bank Worth (pcm)
Shutdown A	436 ± 200	431.0
Shutdown B	1080 ± 30%	1047.9
Shutdown C	463 ± 200	494.1
Shutdown D	464 ± 200	494.9
Control A	943 ± 30%	829.8
Control B	862 ± 30%	871.2
Control C	1011 ± 30%	939.9
Control D	1417 ± 15%	1342.0

The Integral and Differential Worths of Control Bank D is depicted in Figure 6.5-1.

3.3 The sum of the measured bank worths for all control and shutdown rod banks was ≥ 6008 pcm (i.e., 6676 pcm - 10%).

The sum of the measured bank worths for all control and shutdown rod banks was 6540.8 pcm.

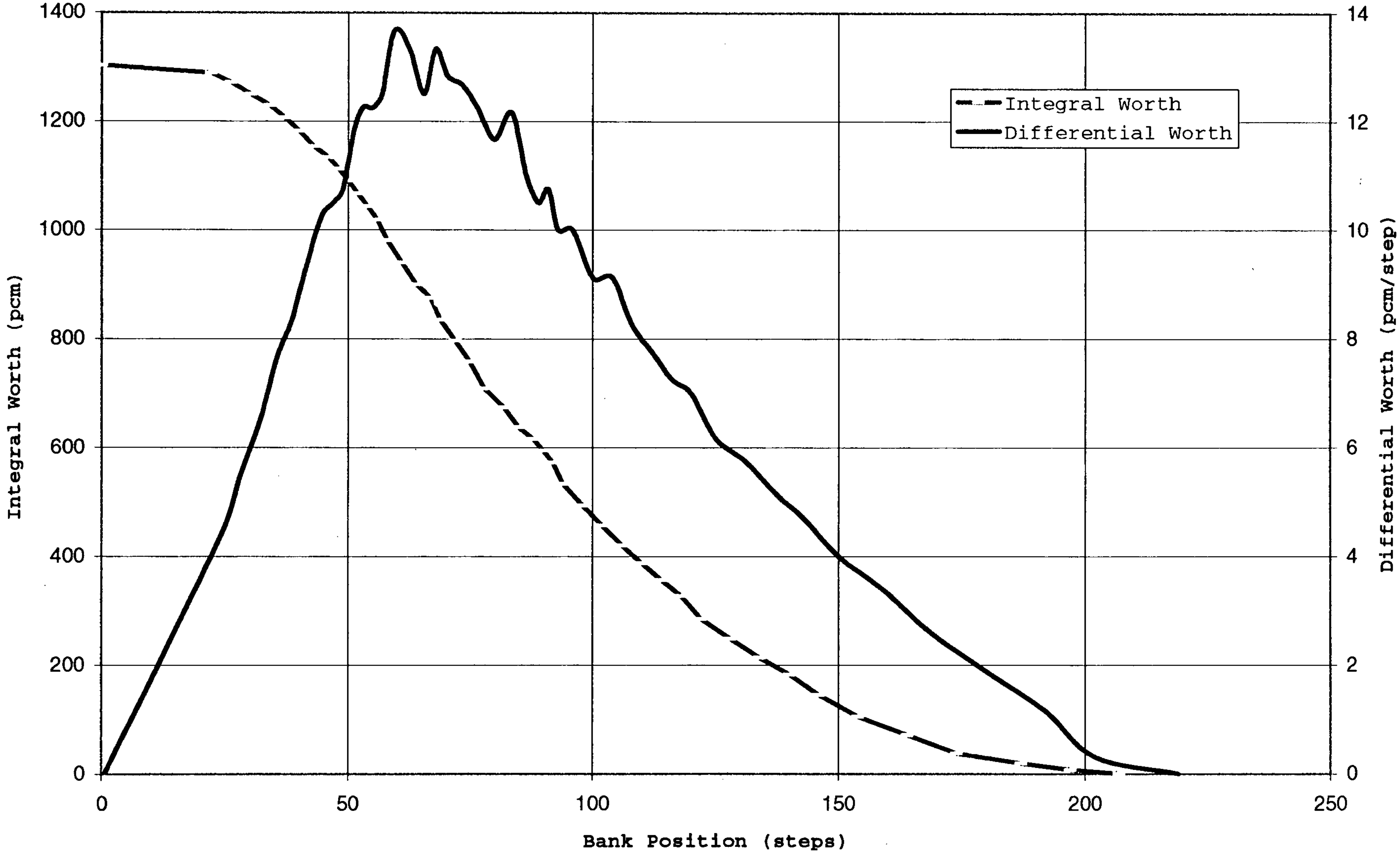
3.4 The MTC (per 1-SI-0-23) was less than or equal to the MTC BOL limit of 0.0 $\Delta k/k/^{\circ}F$.

The MTC was determined to be -0.57 $\Delta k/k/^{\circ}F$.

4.0 Problems

There were no significant problems encountered during the performance of this test.

Figure 6.5-1
Integral and Differential Worth of Control Bank D



7.0 POWER ASCENSION TESTING

7.1 Test Sequence for 30% Plateau (1-PAT-5.0)

This test started on 01/31/96 and was completed on 03/09/96.

1.0 Test Objective

This procedure was the controlling document for establishing the required prerequisite conditions necessary to permit power escalation from Mode 2 conditions with reactor power ≥5% RTP to 30% RTP. This procedure also governs the sequence of testing at the 30% power plateau.

The following PATs/PETs were sequenced for performance by 1-PAT-5.0:

- 1-PAT-1.4 * Pipe Vibration Monitoring
- 1-PAT-1.5 * Loose Parts Monitoring System
- 1-PAT-1.6 * Startup Adjustments of Reactor Control System
- 1-PAT-1.7 * Operational Alignment of Process Temperature Instrumentation
- 1-PAT-1.8 * Thermal Expansion of Piping Systems
- 1-PAT-1.10* Plant Process Computer
- 1-PAT-1.11* RVLIS Performance Test
- 1-PAT-5.1 Dynamic Automatic Steam Dump Control
- 1-PAT-5.3 Automatic Steam Generator Level Control, Transients at Low Power
- 1-PAT-5.4 Calibration of Steam and Feedwater Flow Instrumentation at 30% Power
- PET-301 * Core Power Distribution Factors
- PET-304 * Operational Alignment of NIS

Note: * Indicates that the test is performed at multiple test plateaus. The description of the testing is documented in the section (plateau) in which it was completed.

2.0 Test Method

None associated with this sequence document

7.1 Test Sequence for 30% Plateäu (1-PAT-5.0) (continued)

3.0 Test Results

All acceptance criteria were contained within the test sequenced by this test.

4.0 Problems

Problems encountered are addressed in the following discussions of each test sequenced by 1-PAT-5.0.

7.1.1 Dynamic Automatic Steam Dump Control (1-PAT-5.1)

This test was performed as part of test sequences 1-PAT-3.0, Post Core Loading Precritical Test Sequence, and 1-PAT-5.0, Test Sequence for 30% Plateau. The test began on 11/22/95 and was field complete on 2/8/96. This test procedure is performed only once during the PATP. For Sections 6.1 and 6.2, the plant can be in any mode, since testing does not require steam flow. For Sections 6.3 through 6.5, the plant is to be in Mode 1 or 2, at less than 10% power with the main turbine not synchronized to the grid. Performance of Sections 6.1 and 6.2 can be at anytime that the steam dumps are not required for RCS temperature control and is specified in 1-PAT-3.0, Post Core Loading Precritical test Sequence. Performance of Sections 6.3 through 6.5 is specified in 1-PAT-5.0, Test Sequence for 30% Plateau. This summary describes the testing results for Sections 6.1 through 6.5.

1.0 Objectives

1.1 To verify operation of the Steam Dump Control System.

1.2 To verify valve stroking requirements with no steam dump flow, the valves are modulated open and closed, and tripped open.

1.3 To verify the functional requirements of the three controllers (steam pressure, plant trip, and load rejection) with steam dump flow.

2.0 Test Method

This test demonstrated the functional requirements of the Steam Dump Control System. The valves were modulated open and closed, and tripped open to verify valve stroking requirements with no steam dump flow. At low power (less than 10%), the automatic operation of the three controllers in the Steam Dump Control System were tested with steam dump flow. Each controller's response to small power transients was observed. The steam pressure controller was tested by varying reactor power and ensuring that the control system maintained steam header pressure. The plant trip controller was tested by simulating a reactor trip, varying reactor power, and ensuring that the

7.1.1 Dynamic Automatic Steam Dump Control (1-PAT-5.1) (continued)

control system modulated the steam dump valves to control T_{avg} at the no load T_{avg} value. The load rejection controller was tested by simulating the loss of turbine load permissive, varying reactor power, and ensuring that the control system modulated the steam dump valves to reduce the T_{avg} - T_{ref} temperature error signal. If required, controller tuning was performed to achieve plant stability and prevent divergent controller output.

3.0 Test Results

All required acceptance criteria were met as delineated below:

3.1 After varying reactor power, the steam pressure controller maintained steam header pressure stable as demonstrated by neither the steam header pressure signal nor the steam dump demand signal showing divergent oscillations on the recorder traces.

3.2 After varying reactor power, steam pressure controller maintained steam header pressure stable as demonstrated by the steam dump control system remaining in automatic throughout the transient.

3.3 After varying reactor power, the plant trip controller maintained a stable T_{avg} as demonstrated by neither the RCS T_{avg} signal nor the steam dump demand signal showing divergent oscillations on the recorder traces.

3.4 After varying reactor power, the plant trip controller maintained a stable T_{avg} as demonstrated by the steam dump control system remaining in automatic throughout the transient.

3.5 After varying reactor power, the load rejection controller maintained a stable T_{avg} as demonstrated by neither RCS T_{avg} signal nor the steam dump demand signal showing divergent oscillations on the recorder traces.

7.1.1 **Dynamic Automatic Steam Dump Control (1-PAT-5.1)** (continued)

3.6 After varying reactor power, the load rejection controller maintained a stable T_{avg} as demonstrated by the steam dump control system remaining in automatic throughout the transient.

4.0 <u>Problems</u>

There were no significant problems encountered during the performance of this test.

7.1.2 Automatic Steam Generator Level Control, Transients at Low Power (1-PAT-5.3)

This test was performed as part of test sequence 1-PAT-5.0, Test Sequence for 30% Plateau. The test began on 2/11/96 and was field complete on 3/7/96.

1.0 Objectives

1.1 The objective of this test is to demonstrate the proper operation and automatic response of the Steam Generator Level Control System for each steam generator during steady-state operation.

1.2 This test procedure is performed only once during the PATP as specified in 1-PAT-5.0, Test Sequence for 30% Plateau. Section 6.1 tested the Feedwater Bypass Control Valve System while the plant was in Mode 1 at less than 10% power with the main turbine not synchronized to the grid. Section 6.2 monitored the transfer from the feedwater bypass control valves to the main feedwater control valves and the initial operation of Main Feedwater Pump Speed Control System. For Section 6.2 the plant was in Mode 1 at approximately 30% power after the MFW forward flush/back flush heatup.

2.0 Test Method

This test procedure demonstrated the Steam Generator Level Control System's ability to respond and control steam generator level during steady-state low power operation. The control system was tested by observing each feedwater bypass control valve's response to 5% step changes in the level setpoint. One steam generator was tested at a time for both increasing and decreasing setpoint changes. In addition, steam generator level response was observed during the changeover from the feedwater bypass control valves to the main feedwater reg valves. The initial placing of the feedwater turbine speed control in automatic was observed to verify proper system operation. If required, controllers were tuned using work order(s) to meet nominal performance requirements specified by the NSSS vendor.

3.0 Test Results

The Feedwater Bypass Control Valve Control System automatically responded to maintain steam generator level following a (5 percent) change in level setpoint as demonstrated by the following:

3.1 The indicated steam generator level undershoot was less than 4.0% below the final setpoint following a level setpoint decrease.

This criteria was successfully met by the Feedwater Bypass Control Valve Control System. Results are shown below.

STEP DECREASE	**SG No. 1**	**SG No. 2**	**SG No. 3**	**SG No. 4**
Undershoot	0.5%	0.6%	0.7%	1.5%

3.2 The indicated steam generator level overshoot was less than 4.0% above the final setpoint following a level setpoint increase.

This criteria was successfully met by the Feedwater Bypass Control Valve Control System. Results are shown below.

STEP DECREASE	**SG No. 1**	**SG No. 2**	**SG No. 3**	**SG No. 4**
Overshoot	0.7%	1.6%	1.0%	1.6%

7.1.2 **Automatic Steam Generator Level Control, Transients at Low Power (1-PAT-5.3)** (continued)

3.3 Indicated steam generator level returned to and remained within ±2% of the level setpoint within 37.5 minutes following a decreasing level setpoint change.

This criteria was successfully met by the Feedwater Bypass Control Valve Control System. Results are shown below.

STEP DECREASE	**SG No. 1**	**SG No. 2**	**SG No. 3**	**SG No. 4**
Time (min)	2.5	2.0	2.0	1.4

3.4 Indicated steam generator level returned to and remained within ±2% of the level setpoint within 37.5 minutes following an increasing level setpoint change.

This criteria was successfully met by the Feedwater Bypass Control Valve Control System. Results are shown below.

STEP DECREASE	**SG No. 1**	**SG No. 2**	**SG No. 3**	**SG No. 4**
Time (min)	1.5	1.2	1.3	1.0

3.5 Indicated steam generator level returned to and remained within ±2% of the average program level within 10 minutes following the transfer of level control to the main feedwater reg valves in automatic.

This criteria was successfully met by the Steam Generator Level Control System. Results are shown below.

7.1.2 **Automatic Steam Generator Level Control, Transients at Low Power (1-PAT-5.3)** (continued)

	SG No. 1	SG No. 2	SG No. 3	SG No. 4
Time (min)	9.53	0.00*	9.19	3.68

* SG level never went outside of ±2.0% of program level.

4.0 Problems

There were no significant problems encountered during the performance of this test.

7.1.3 Calibration of Steam and Feedwater Flow Instrumentation at 30% Power (1-PAT-5.4)

This test was performed as part of 1-PAT-5.0, Test Sequence for 30% Plateau. The test began on 3/7/96 and was field complete on 3/9/96.

1.0 Objectives

The objectives of this test were to verify the calibration of feedwater flow and steam flow instrumentation by comparing indicated flows with calculated flows, and to collect data for determining the calibration spans for each steam flow transmitter.

2.0 Test Method

Data was collected with the plant stable at the test plateau. Critical parameters were collected via M&TE, plant computer, and/or a data acquisition system. feedwater flow and steam flow for each steam generator was calculated from collected data. The calculated flows and M&TE measurements were compared with the readings from permanent instrumentation. At a higher power level, calculated feedwater flow and measured ΔP from each steam flow transmitter will be used to determine the spans for the steam flow transmitters. A curve fit was performed after data was obtained from several test plateaus to determine the spans.

3.0 Test Results

There were no acceptance criteria for this test performance at this plateau. See Section 7.4.12 for final acceptance results.

4.0 Problems

There were no significant problems encountered during the performance of this test.

7.2 Test Sequence for 50% Plateau (1-PAT-6.0)

This test started on 03/10/96 and was completed on 04/05/96.

1.0 Test Objective

This procedure was the controlling document for establishing the required prerequisite conditions necessary to permit power escalation from 30% to 50% RTP. This procedure also governs the sequence of testing at the 50% power plateau.

The following PATs/PETs were sequenced for performance by 1-PAT-6.0:

• 1-PAT-1.2	*	Load Swing Test
• 1-PAT-1.4	*	Pipe Vibration Monitoring
• 1-PAT-1.5	*	Loose Parts Monitoring System
• 1-PAT-1.6	*	Startup Adjustments of Reactor Control System
• 1-PAT-1.7	*	Operational Alignment of Process Temperature Instrumentation
• 1-PAT-1.8	*	Thermal Expansion of Piping Systems
• 1-PAT-1.10	*	Plant Process Computer
• 1-PAT-1.11	*	RVLIS Performance Test
• 1-PAT-3.3	*	RCS Flow Measurement
• 1-PAT-5.2		Loss of Offsite Power
• 1-PAT-6.1		Automatic Reactor Control System
• 1-PAT-6.2		Automatic Steam Generator Level Control Transients at 50% Power
• 1-PAT-6.3		Calibration of Steam and Feedwater Flow Instrumentation at 50 % Power
• PET-301	*	Core Power Distribution Factors
• PET-304	*	Operational Alignment of NIS
• RCI-126	*	Radiation Baseline Survey

Note: * Indicates that the test is performed at multiple test plateaus. The description of the testing is documented in the section (plateau) in which it was completed.

2.0 Test Method

None associated with this sequence document.

7.2 Test Sequence for 50% Plateau (1-PAT-6.0) (continued)

3.0 Test Results

All acceptance criteria were contained within the tests sequenced by this test.

4.0 Problems

Problems encountered are addressed in the following discussions of each test sequenced by 1-PAT-6.0.

7.2.1 Loss of Offsite Power (1-PAT-5.2)

This test was performed as part of 1-PAT-6.0, Test Sequence for 50% Plateau. The test began and was field completed on 3/28/96.

1.0 Objectives

The objective of this test was to demonstrate that the unit's response to a turbine generator trip with a coincident loss of offsite power was in accordance with design. This test demonstrated that the diesel generators automatically start, load, and provide power to the controls, indications, and equipment necessary to maintain the unit in hot standby (Mode 3) conditions for a minimum of 30 minutes.

2.0 Test Method

Initial conditions were reactor power at approximately 30% of RTP and the main generator synchronized to the TVA grid with an electrical load greater than or equal to 120 Mwe. The unit's electrical distribution system was in the normal at-power lineup, and the alternate offsite power supplies were blocked from auto transfer. The turbine was manually tripped, followed immediately by opening the breakers supplying offsite power to the common buses and shutdown buses. The emergency diesel generators started and loaded. The reactor tripped upon loss of power to the RCPs which tripped on undervoltage. The plant was maintained in a stable Mode 3 condition for 30 minutes, with only the equipment available during a loss of offsite power.

3.0 Test Results

All required acceptance criteria were met as delineated below:

7.2.1 Loss of Offsite Power (1-PAT-5.2) (continued)

3.1 Diesel generators supplied their respective shutdown boards following the loss of offsite power transient.

3.2 Pressurizer and steam generator safety valves did not open during the test.

3.3 Safety injection was not initiated during the test.

3.4 Hot standby (Mode 3) conditions were maintained for at least 30 minutes after the initiation of the turbine trip without restoring offsite power.

4.0 <u>Problems</u>

There were no significant problems encountered during the performance of this test.

7.2.2 Automatic Reactor Control System (1-PAT-6.1)

This test was performed at the 50% test plateau as directed by 1-PAT-6.0, Test Sequence for 50% Plateau. Testing was started on 3/17/96 and suspended on 3/18/96. Testing was resumed and field completed on 3/24/96.

1.0 Objective

The objective of this test was to demonstrate the ability of the Automatic Rod Control System (ARCS) to maintain auctioneered RCS average temperature (auctioneered T_{avg}) within acceptable limits during both steady-state and transient conditions without the necessity of operator action or intervention.

2.0 Test Method

With the ARCS in MANUAL mode and the RCS at steady-state conditions with the T_{avg} - T_{ref} mismatch $\leq 1^{\circ}$F, the ARCS was placed in AUTO control mode to demonstrate that steady-state conditions could be maintained. Subsequently, with the ARCS in MANUAL mode, RCS T_{avg} was varied from the reference temperature (T_{ref}) by approximately +6 $^{\circ}$F by manually withdrawing Control Bank D from 174 to 185 steps while holding turbine load constant. The ARCS was then placed in AUTO to demonstrate the ability to restore and stabilize RCS auctioneered T_{avg} to within $\pm 1.5^{\circ}$F of T_{ref} via proper positioning of Control Bank D. The same test was also performed for an RCS auctioneered T_{avg} change of approximately -6°F relative to T_{ref} by inserting Control Bank D from 176 to 161 steps while holding turbine load constant.

3.0 Test Results

All required acceptance criteria were met as delineated below. No control system settings were changed based on the performance of this test.

3.1 No manual operator action or intervention is required to return the plant to stable conditions (i.e., auctioneered RCS T_{avg} within $\pm 1.5^{\circ}$F of T_{ref}) for both steady-state and transient conditions when the ARCS is placed in AUTO control mode.

7.2.2 **Automatic Reactor Control System (1-PAT-6.1)** (continued)

3.2 For steady-state operation, and for both increasing and decreasing T_{avg} temperature transients, the ARCS responds properly to automatically position control rods and return auctioneered RCS T_{avg} to within $\pm 1.5^{\circ}F$ of T_{ref} when the ARCS is placed in AUTO control mode. See Problem 1.

- Figures 7.2.2-1 through 7.2.2-3 depict the time-variant response of RCS auctioneered T_{avg} versus T_{ref} during steady-state and transient conditions.

- Figures 7.2.2-4 through 7.2.25-6 depict rod speed and direction demand during steady-state and transient conditions.

4.0 Problems

[1] Section 6.1 (Steady-State Operation) of this test was initially performed on 3/18/96. With the ARCS in MANUAL and the RCS at steady-state conditions, the ARCS was placed in AUTO mode to demonstrate steady-state conditions could be maintained for approximately 10 minutes without Operator action or intervention. Within approximately 5 seconds following transfer of the ARCS from MANUAL to AUTO, Control Bank D withdrew 3 steps while digital readings on MCR temperature recorder 1-TR-68-2B indicated T_{avg} was greater than T_{ref} by approximately $0.7^{\circ}F$. Although the ARCS functioned properly in AUTO and maintained RCS auctioneered T_{avg} within $\pm 1.5^{\circ}F$ of T_{ref} during the approximately 10 minute observation period, testing was suspended following completion of Section 6.1. Evaluation of the test data to determine if calibration of specific ARCS electronic components was required since Control Bank D withdrawal immediately following transfer from MANUAL to AUTO, with the observed T_{avg} - T_{ref} mismatch, was not expected. During the data evaluation period, main generator problems occurred which required taking Unit 1 off-line. Calibration checks of variable gain module IJY-92-412B and

special divider module IJY-92-412E on the power mismatch loop were performed while Unit 1 was off-line. These checks failed to identify any calibration problems.

Detailed review of the data collected during performance of Section 6.1 on 3/18/96 indicated that a power mismatch error of approximately 0.8°F to 1.0°F and a compensated T_{avg} - T_{ref} mismatch error of approximately -0.7°F to -0.8°F existed at the time of transfer of the ARCS from MANUAL to AUTO. The combined error was
sufficient to exceed the -1.5°F threshold for outward rod motion, which is consistent with the observation made during testing on 3/18/96.

Since the required plant conditions for resumption of 50% RTP testing were not reestablished until 3/24/96, a complete reperformance of this test was successfully completed on 3/24/96.

Figure 7.2.2-1

RCS Auctioneered T_{avg} vs T_{ref}
Steady-State Operation

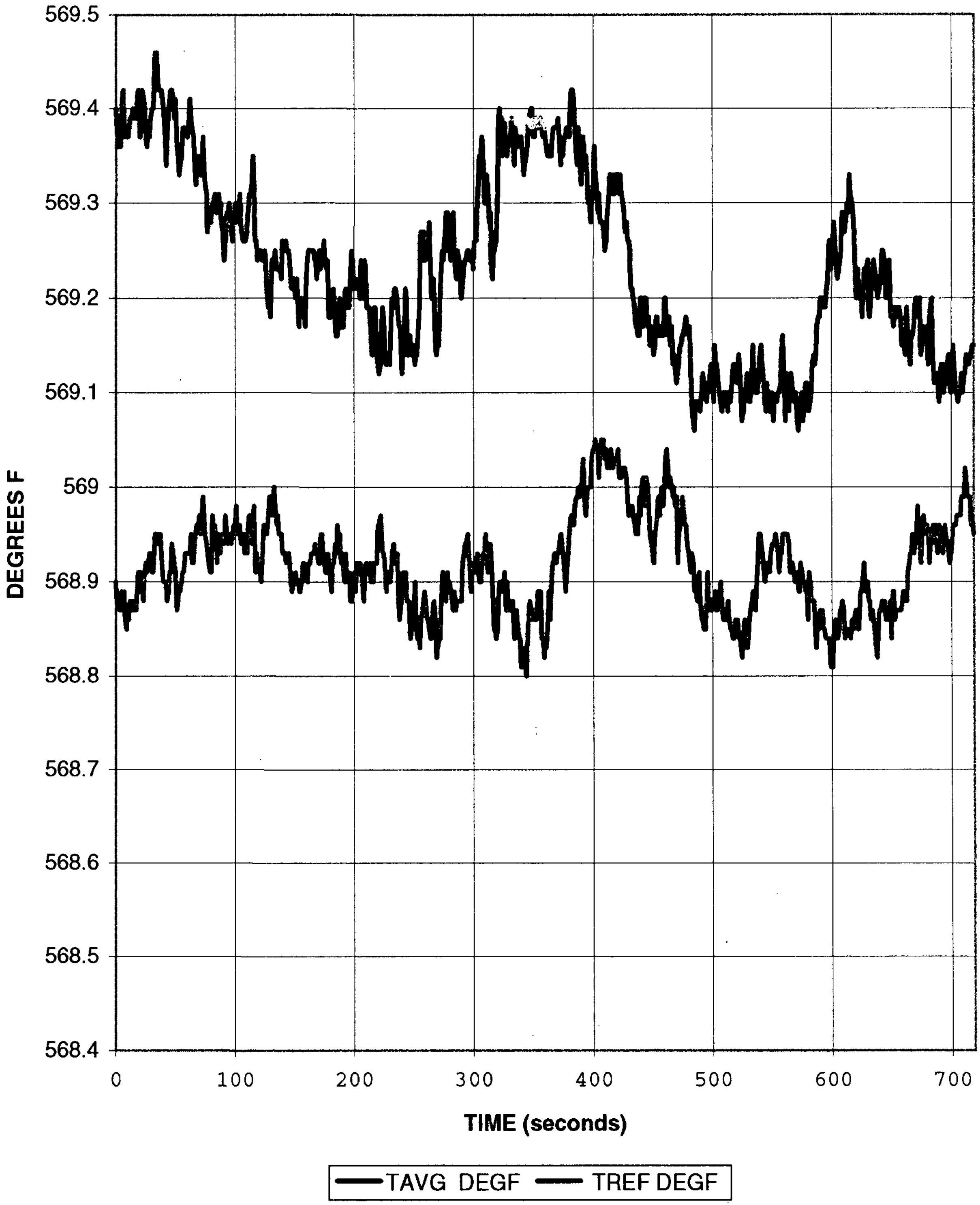


Figure 7.2.2-2

RCS Auctioneered Tavg vs Tref
Increasing Tavg Transient

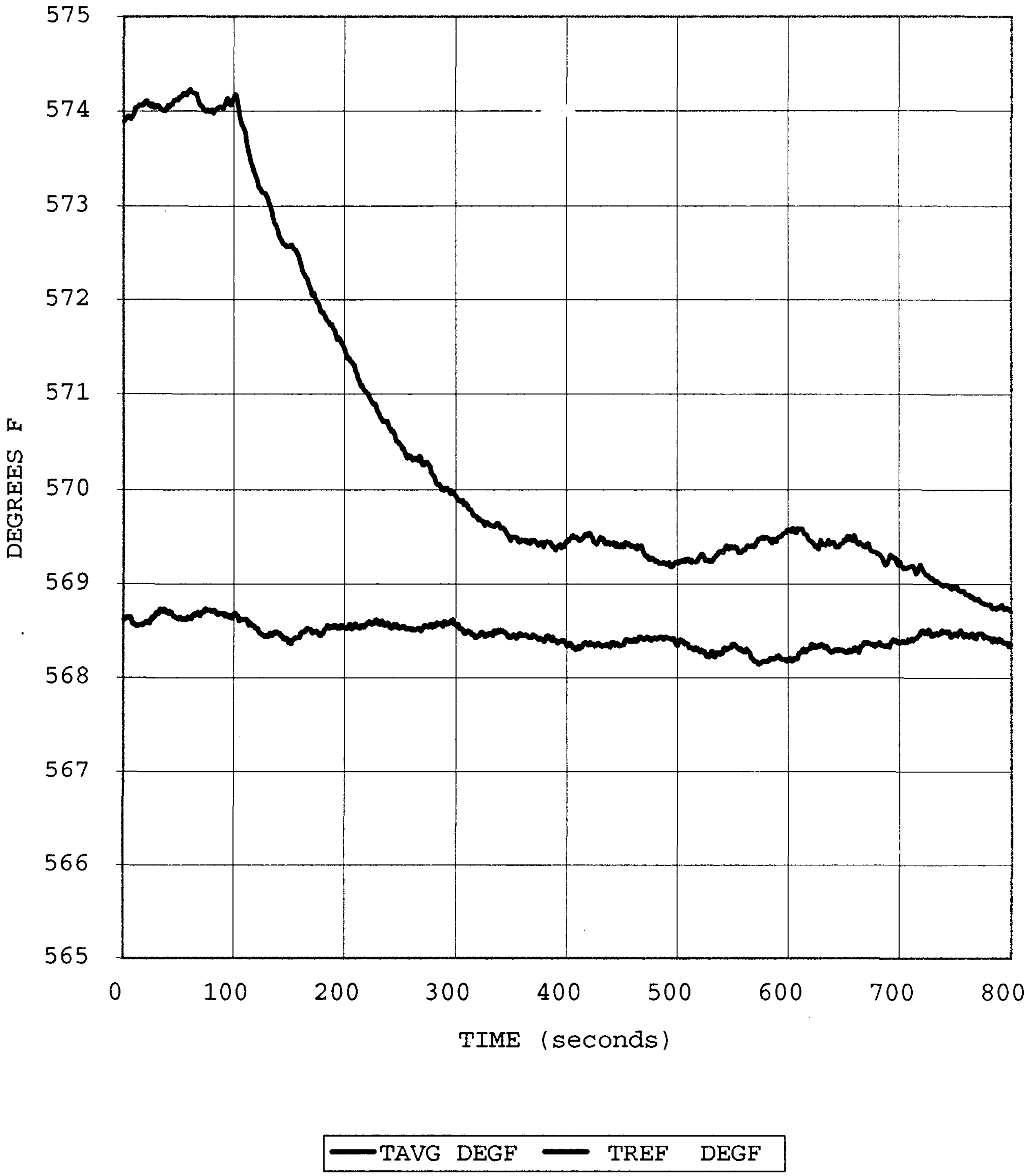


Figure 7.2.2-3

RCS Auctioneered Tavg vs Tref
Decreasing Tavg Transient

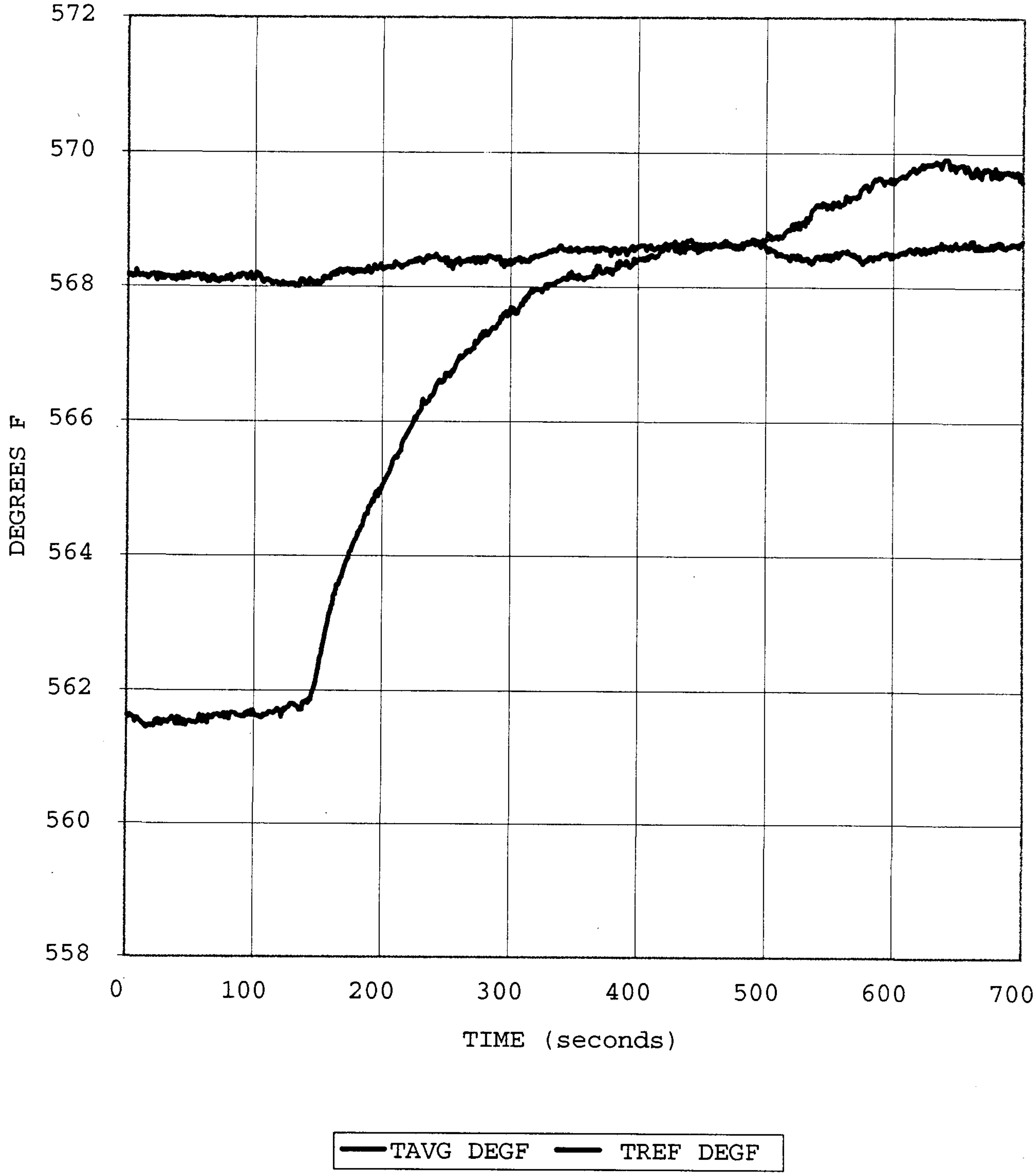


Figure 7.2.2-4

Rod Speed and Direction Demand
Increasing Tavg Transient

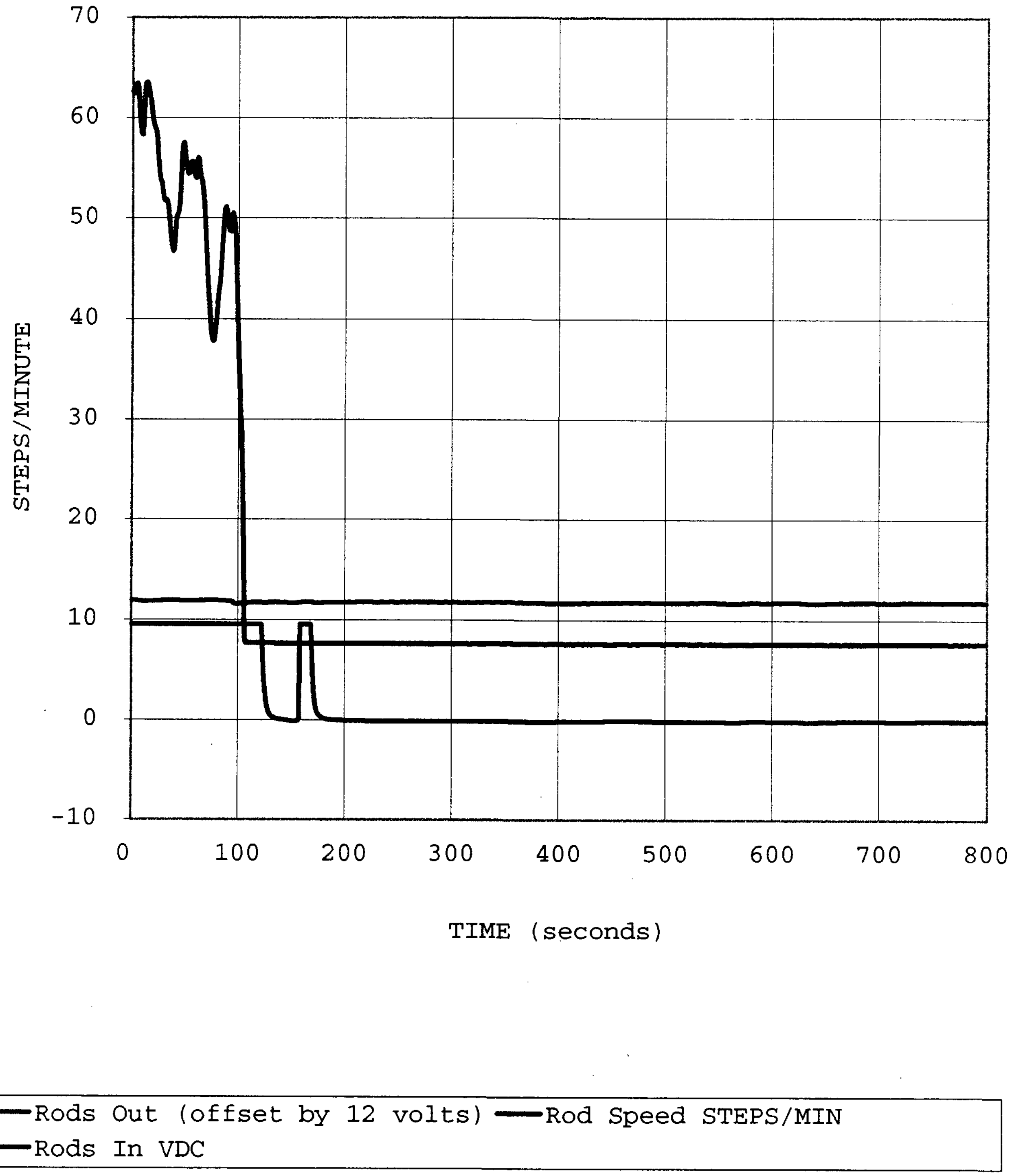


Figure 7.2.2-5

Rod Speed and Direction Demand
Decreasing Tavg Transient

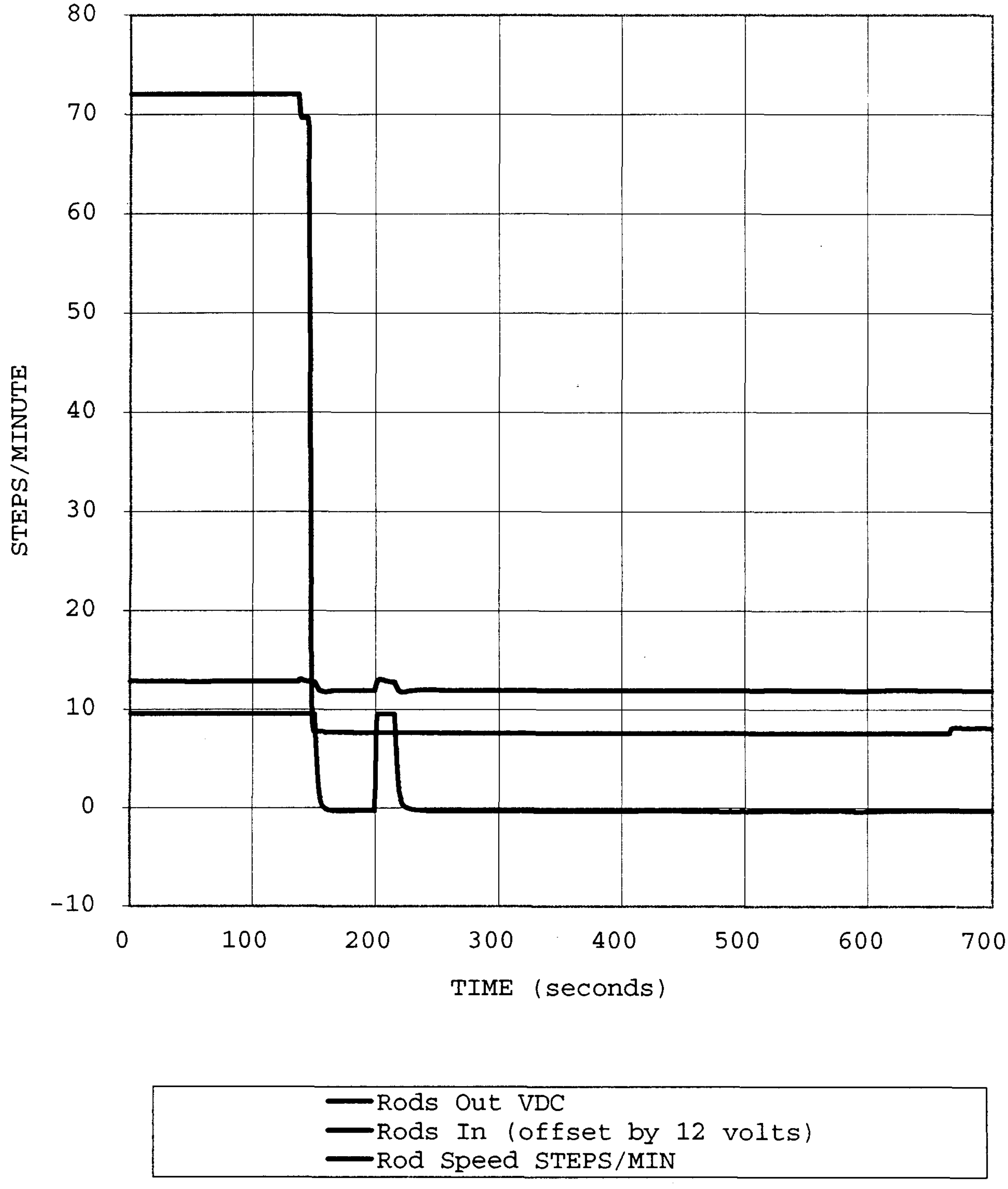


Figure 7.2.2-6

Pressurizer Pressure
Increasing T_{avg} Transient

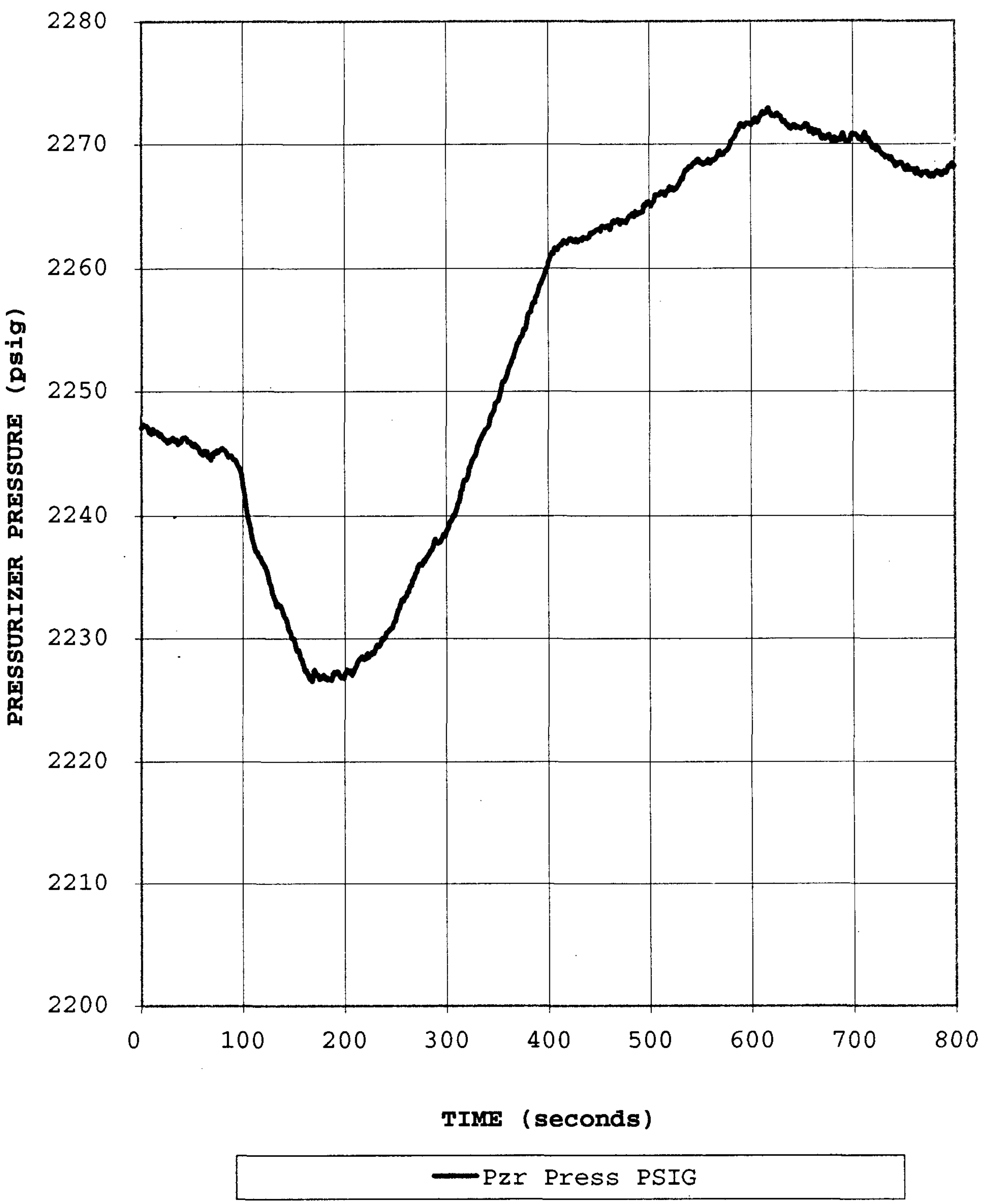


Figure 7.2.2-7

Pressurizer Pressure
Decreasing Tavg Transient

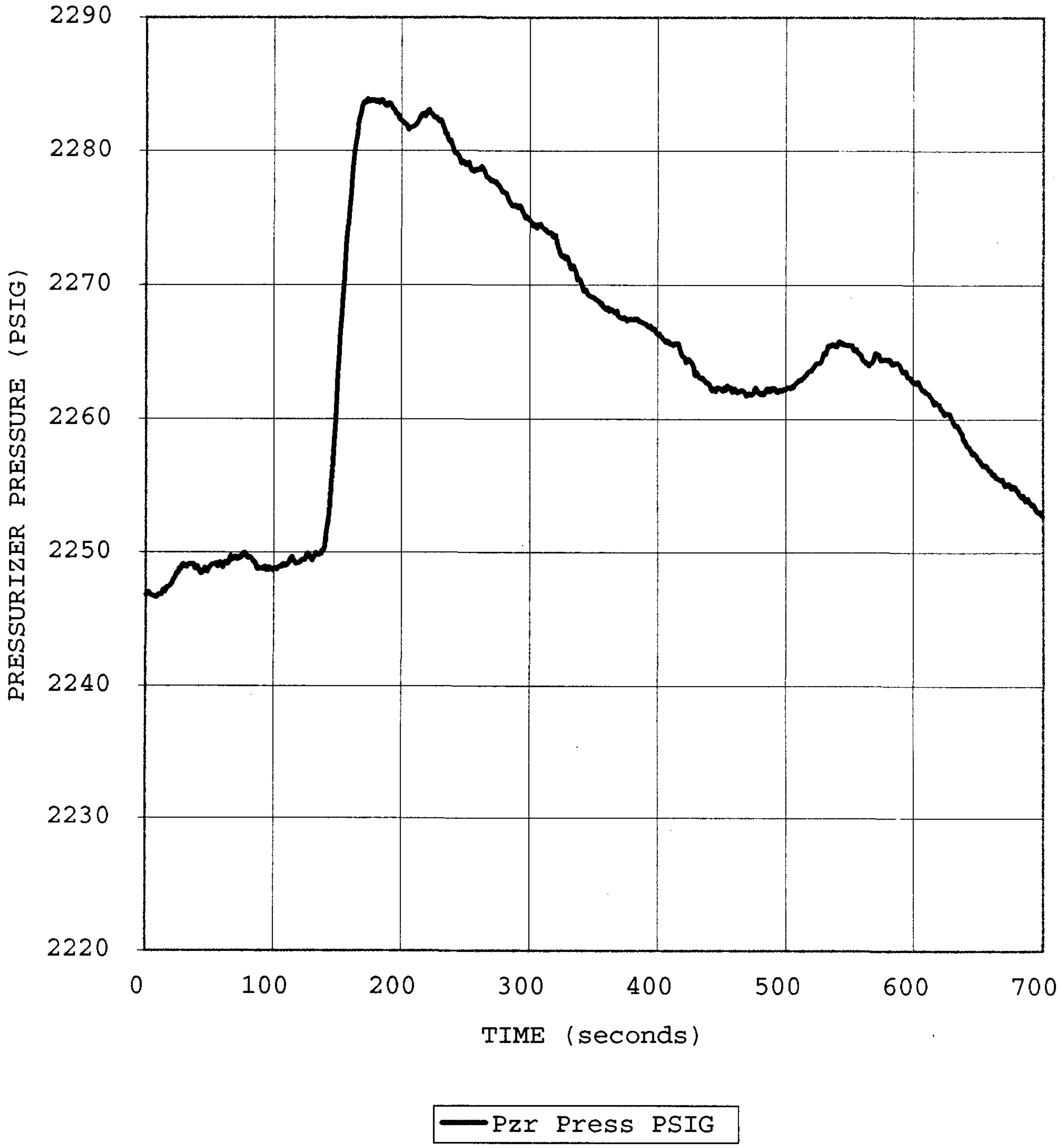


Figure 7.2.2-8

Pressurizer Level and Level Setpoint
Increasing Tavg Transient

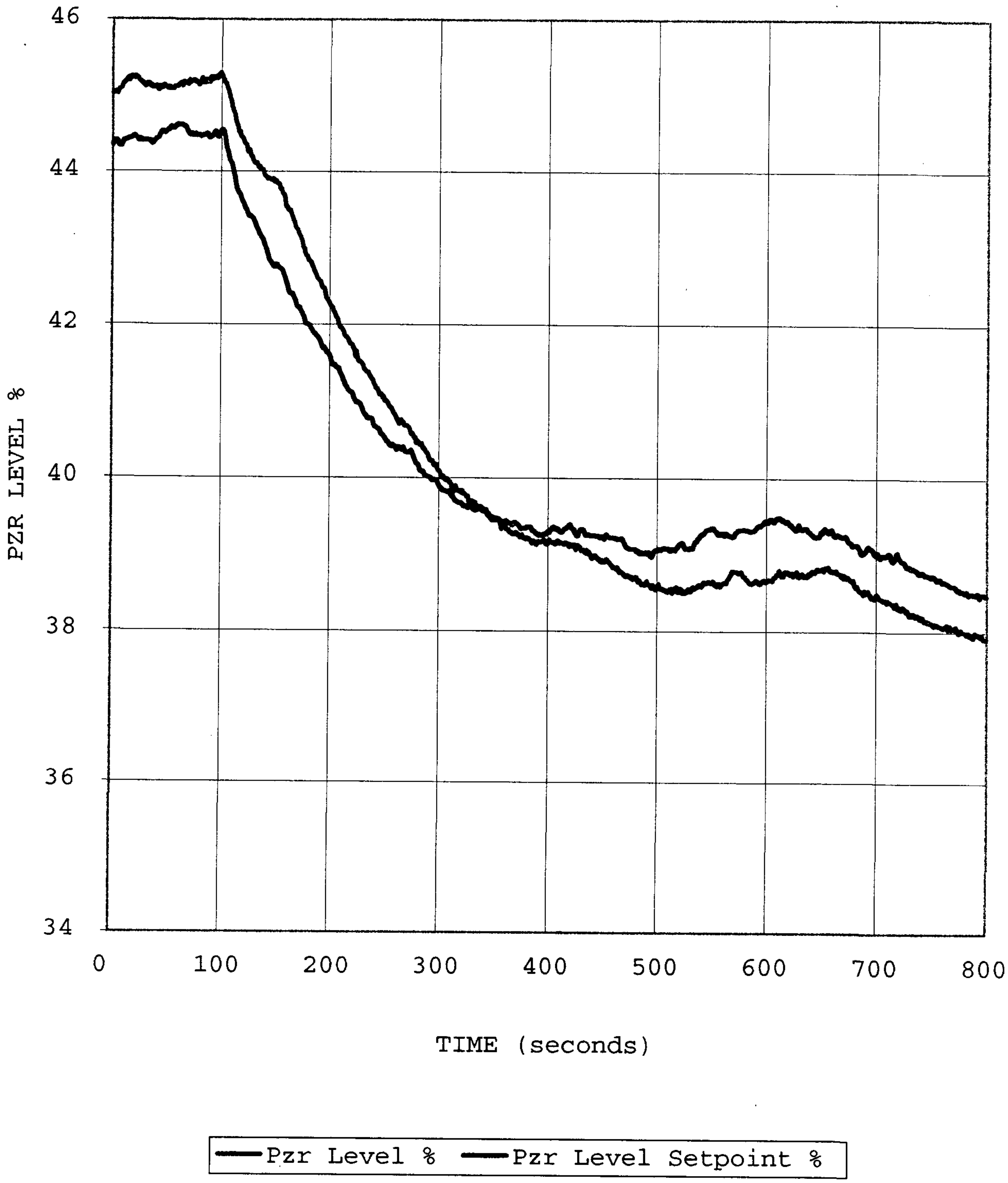
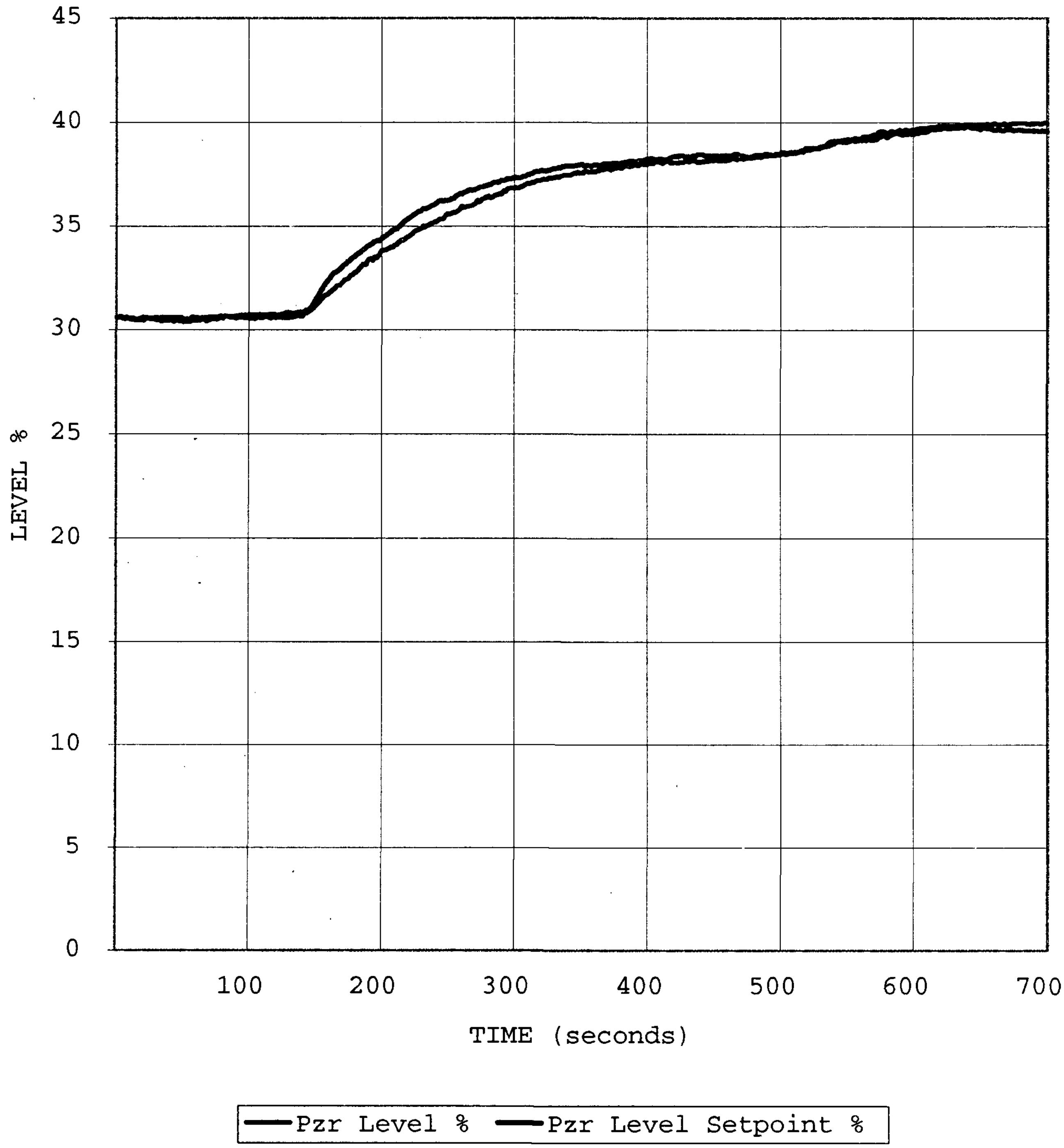


Figure 7.2.2-9

Pressurizer Level and Level Setpoint
Decreasing Tavg Transient



7.2.3 Automatic Steam Generator Level Control Transients at 50% Power (1-PAT-6.2)

This test was performed as part of test sequence 1-PAT-6.0, Test Sequence For 50% Plateau. The test began on 3/24/96 and was field complete on 4/4/96.

1.0 Objectives

The objective of this test was to demonstrate the proper operation and automatic response of the Steam Generator Level Control System for each steam generator during steady-state operation.

2.0 Test Method

This test procedure demonstrated the operation of the Steam Generator Level Control System at 50% power. The control system was tested by observing each main feedwater reg valve's response to 5% level setpoint step changes. One steam generator was tested at a time for both decreasing and increasing setpoint changes. In addition, correct operation of the main feedwater pump master speed controller was tested by observing the response to 25 Psi transients on the feedwater header. Steady-state data was also collected and reviewed. Any required controller tuning was performed via the work order process.

3.0 Test Results

All required acceptance criteria were met as delineated below:

3.1 Acceptance criteria for Section 6.1 (Main Feedwater Reg Valves -- Level Setpoint Changes) See Problem 1.

The Main Feedwater Regulating Valve Control System automatically responded to maintain steam generator water level following a (5%) change in level setpoint as demonstrated by the following:

[A] The indicated steam generator level undershoot was less than 4.0% below the final setpoint following a level setpoint decrease.

7.2.3 Automatic Steam Generator Level Control Transients at 50% Power (1-PAT-6.2) (continued)

This criteria was met for all steam generators.

[B] The indicated steam generator level overshoot was less than 4.0% above the final setpoint following a level setpoint increase.

This criteria was met for all steam generators.

[C] Indicated steam generator level returned to and remained within ±2% of the level setpoint within ten minutes following a decreasing Level Setpoint change.

This criteria was met for all steam generators.

[D] Indicated steam generator level returned to and remained within ±2% of the level setpoint within ten minutes following a increasing level setpoint change.

This criteria was met for all steam generators.

3.2 Acceptance criteria for Section 6.2 (feedwater pump speed control)

The Main Feedwater Pump Speed Control System remained in automatic with pump speed and feedwater pressure not displaying divergent oscillations following small pressure transients.

[A] The Main Feedwater Pump Speed Control System remained in automatic following a feedwater pressure transient.

The Main Feedwater Pump Speed Control System remained in automatic following both the pressure increase and decrease transients for the main feedwater pumps A and B.

7.2.3 Automatic Steam Generator Level Control Transients at 50% Power (1-PAT-6.2) (continued)

[B] The indicated main feedwater header pressure oscillations are less than ±3.0% (±39.0 Psi) within five minutes following a feedwater pressure transient.

This criteria was met for both main feedwater pumps.

3.3 Acceptance criteria for Section 6.3 (steady-state data collection)

[A] The indicated main feedwater header pressure oscillations were less than ±3.0% (±39.0 PSI) during steady-state operation.

This criteria was successfully met by the Main Feedwater Speed Control System. During steady-state operation an oscillation of 0.9% was recorded.

[B] Indicated steam generator level was within ±2% of the average program level during steady-state operations.

This criteria was successfully met by the Steam Generator Level Control System.

4.0 <u>**Problems**</u>

[1] The test was aborted during performance of section 6.1.1 of the test. All feedwater reg valves and MFP speed cycled during the transient.

Feedwater reg valves were groomed under the WO process. Retest No. 1 was successfully performed.

7.2.4 Calibration of Steam and Feedwater Flow Instrumentation at 50% Power (1-PAT-6.3)

This test was performed as part of 1-PAT-6.0, Test Sequence For 50% Plateau. The test began on 3/24/96 and was field complete on 3/29/96.

1.0 Objectives

The objectives of this test were to verify the calibration of feedwater flow and steam flow instrumentation by comparing indicated flows with calculated flows, and to collect data for determining the calibration spans for each steam flow transmitter.

2.0 Test Method

Data was collected with the plant stable at the test plateau. Critical parameters were collected via M&TE, plant computer, and/or a data acquisition system. Feedwater flow and steam flow for each steam generator were calculated from collected data. The calculated flows and M&TE measurements were compared with the readings from permanent instrumentation. At a higher power level calculated feedwater flow and measured ΔP from each steam flow transmitter will be used to determine the spans for the steam flow transmitters. A curve fit is performed after data is obtained from several test plateaus to determine the spans. New spans will not be entered into the steam flow transmitters until at least 75% power.

3.0 Results

There were no acceptance criteria for this test performance at this test plateau. See Section 7.4.12 for final acceptance results.

4.0 Problems

There were no significant problems encountered during the performance of this test.

7.3 Test Sequence for 75% Plateau (1-PAT-7.0)

This test started on 04/05/96 and was completed on 04/15/96.

1.0 Test Objective

This procedure was the controlling document for establishing the required prerequisite conditions necessary to permit power escalation from 50% to 75% RTP. This procedure also governs the sequence of testing at the 75% power plateau.

The following PATs/PETs were sequenced for performance by 1-PAT-7.0:

- 1-PAT-1.4 * Pipe Vibration Monitoring
- 1-PAT-1.5 * Loose Parts Monitoring System
- 1-PAT-1.6 * Startup Adjustments of Reactor Control System
- 1-PAT-1.7 * Operational Alignment of Process Temperature Instrumentation
- 1-PAT-1.8 * Thermal Expansion of Piping Systems
- 1-PAT-1.9 * Automatic Steam Generator Level Control
- 1-PAT-1.10* Plant Process Computer
- 1-PAT-1.11* RVLIS Performance Test
- 1-PAT-3.3 * RCS Flow Measurement
- 1-PAT-7.1 Calibration of Steam and Feedwater Flow Instrumentation at 75% Power
- PET-301 * Core Power Distribution Factors
- PET-304 * Operational Alignment of NIS

Note: * Indicates that the test is performed at multiple test plateaus. The description of the testing is documented in the section (plateau) in which it was completed.

2.0 Test Method

None associated with this sequence document.

7.3 **Test Sequence for 75% Plateau (1-PAT-7.0)** (continued)

3.0 **<u>Test Results</u>**

All acceptance criteria were contained within the test sequenced by this test.

4.0 **<u>Problems</u>**

Problems encountered are addressed in the following discussions of each test sequenced by 1-PAT-7.0.

7.3.1 Automatic Steam Generator Level Control (1-PAT-1.9)

This test was performed as part of 1-PAT-7.0, Test Sequence for 75% Plateau. The test began and was field complete on 4/7/96.

1.0 Objectives

The objective of this test was to demonstrate the proper operation and automatic response of the Steam Generator Level Control System for each steam generator during steady-state operation.

2.0 Test Method

This test collected data on Steam Generator Level Control System to verify proper system operation. Measured parameters (levels, flows, pressures, valve positions, etc.) were compared with predicted values and analyzed for stability.

This test was specified at 75% power in 1-PAT-7.0, Test Sequence For 75% Power, and at 100% power in 1-PAT-8.0, Test Sequence For 100% Power.

3.0 Test Results

There were no acceptance criteria for the performance of this test at this test plateau. See Section 7.4.12 for final acceptance results.

4.0 Problems

There were no significant problems encountered during the performance of this test.

7.3.2 Calibration of Steam and Feedwater Flow Instrumentation at 75% Power (1-PAT-7.1)

This test was performed as part of 1-PAT-7.0, Test Sequence For 75% Plateau. This test began on 4/11/96 and was field complete on 4/15/96.

1.0 Objectives

The objectives of this test were to verify the calibration of feedwater flow and steam flow instrumentation by comparing indicated flows with calculated flows, and to collect data for determining the calibration spans for each steam flow transmitter.

2.0 Test Method

Section 6.1 collected data with the plant stable at the test plateau. Critical parameters were collected via M&TE, plant computer, and/or a data acquisition system. Feedwater flow and steam flow for each steam generator was calculated from collected data. The calculated flows and M&TE measurements were compared with the readings from permanent instrumentation. The calculated feedwater flows and measured ΔP from each steam flow transmitter was used, in conjunction with the similar data from the 30% and 50% test plateaus, to determine the spans for the steam flow transmitters. A curve fit was performed using the obtained data to determine the spans.

Section 6.2 was performed after the steam flow transmitters were calibrated to the new spans. This section is similar to Section 6.1 and was performed to reestablish a baseline for the Steam Flow Transmitters.

3.0 Test Results

There were no acceptance criteria for the performance of this test at this test plateau. See Section 7.4.12 for final acceptance results.

4.0 Problems

There were no significant problems encountered during the performance of this test.

7.4 Test Sequence for 100% Plateau (1-PAT-8.0)

This test started on 4/15/96 and was completed on 5/23/96.

1.0 Test Objective

This procedure was the controlling document for establishing the required prerequisite conditions necessary to permit power escalation from 75% to 90% RTP, and subsequent power escalation from 90% to 100% RTP. This procedure also governs the sequence of testing at the 90% and 100% power plateau.

The following PATs/PETS were sequenced for performance by 1-PAT-8.0:

- 1-PAT-1.2 * Load Swing Test
- 1-PAT-1.3 Large Load Reduction Test
- 1-PAT-1.4 * Pipe Vibration Monitoring
- 1-PAT-1.5 * Loose Parts Monitoring System
- 1-PAT-1.6 * Startup Adjustments of Reactor Control System
- 1-PAT-1.7 * Operational Alignment of Process Temperature Instrumentation
- 1-PAT-1.8 * Thermal Expansion of Piping Systems
- 1-PAT-1.9 * Automatic Steam Generator Level Control
- 1-PAT-1.10* Plant Process Computer
- 1-PAT-1.11* RVLIS Performance Test
- 1-PAT-3.3 * RCS Flow Measurement
- 1-PAT-8.4 Calibration of Steam and Feedwater Flow Instrumentation at 100% Power
- 1-PAT-8.5 Shutdown From Outside the Control Room
- 1-PAT-8.6 Plant Trip From 100% Power (Turbine Trip)
- PET-301 * Core Power Distribution Factors
- PET-304 * Operational Alignment of NIS
- RCI-126 * Radiation Baseline Survey

Note: * Indicates that the test is performed at multiple test plateaus. The description of the testing will be documented in this section (plateau).

7.4 Test Sequence for 100% Plateau (1-PAT-8.0) (continued)

2.0 Test Method

None associated with this sequence document

3.0 Test Results

All acceptance criteria were contained within the test sequenced by this test.

4.0 Problems

Problems encountered are addressed in the following discussions of each test sequenced by 1-PAT-8.0.

7.4.1 Load Swing Test (1-PAT-1.2)

This test was performed as part of test sequences 1-PAT-6.0, Test Sequence for 50% Plateau, and 1-PAT-8.0, Test Sequence at 100% Plateau. The 50% plateau performance of this test was started and field completed on 4/3/96. The 100% plateau performance of this test was started and field completed on 05/11/96.

1.0 <u>Objectives</u>

The specific objectives of this PAT are as follows:

1.1 To demonstrate the ability of primary and secondary side systems, including automatic control systems to sustain 10% step changes in turbine generator load.

1.2 To satisfy the test requirements described in FSAR Table 14.2-2, Sheet 34.

2.0 <u>Test Method</u>

This procedure demonstrated the ability of primary and secondary plant systems, including automatic control systems, to sustain 10% load changes without manual intervention.

The plant was at steady-state conditions with control systems in automatic prior to starting this transient test. A rapid 10% decrease in load was initiated using the turbine-generator control system. Primary and secondary plant parameters were monitored during the transient. Once stability was achieved, load was rapidly increased by 10% using the turbine-generator control system, and plant parameters were again monitored.

Test data was evaluated to determine if control system setpoint changes were required to improve plant transient response.

7.4.1 Load Swing Test (1-PAT-1.2) (continued)

3.0 Test Results

All required acceptance criteria of this test were met for the 50% plateau performance and the 100% plateau performance as delineated below:

3.1 A safety injection was not initiated.

3.2 Neither the reactor nor the turbine tripped.

3.3 None of the pressurizer safety valves lifted.

3.4 None of the steam generator safety valves lifted.

3.5 None of the pressurizer power-operated relief valves lifted.

3.6 None of the steam generator power-operated relief valves lifted.

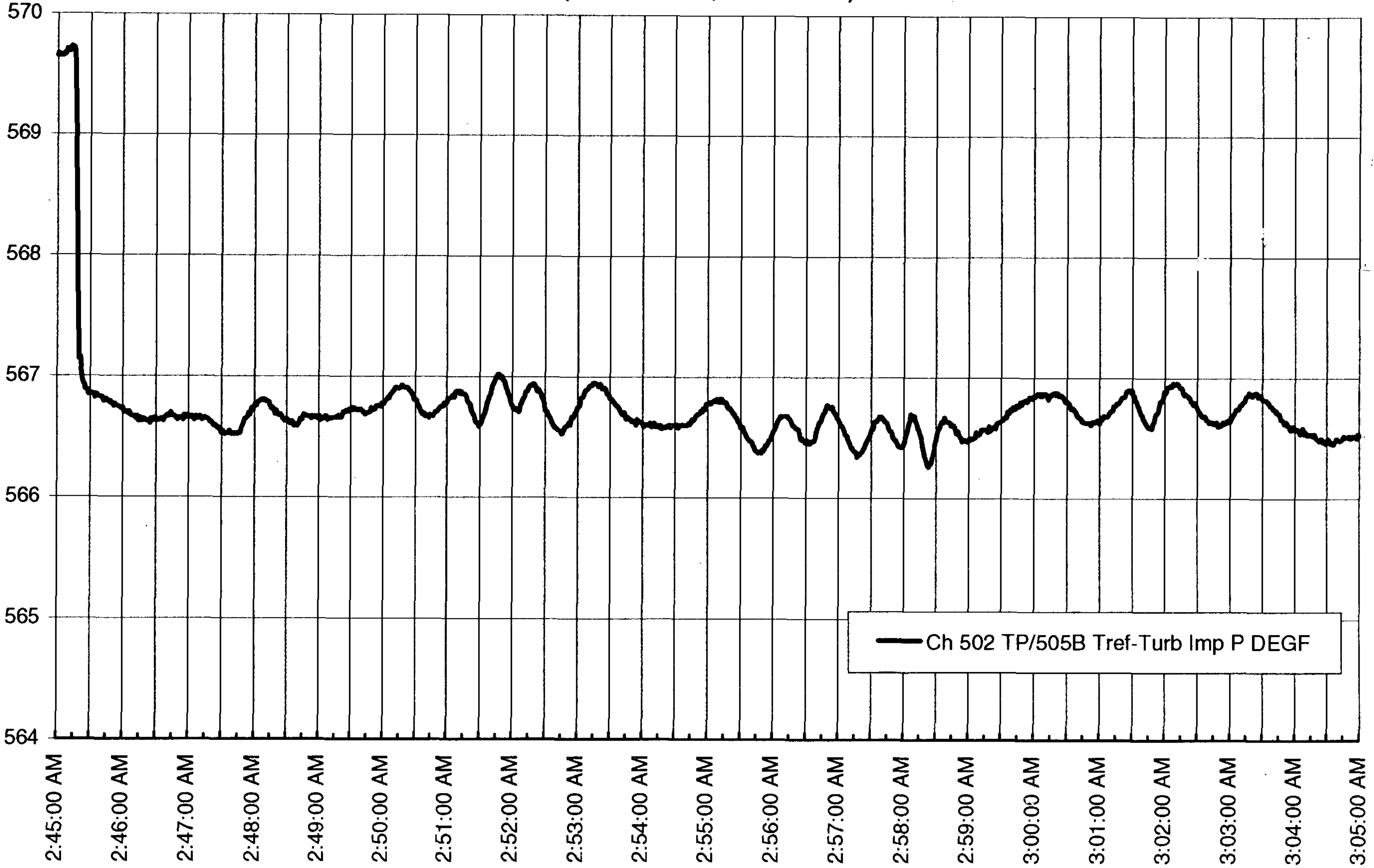
3.7 Stability was achieved without manual intervention.

Figures 7.4.1-1 through 7.4.1-12 depict the test performance results at the 50% test plateau. Figures 7.4.1-13 through 7.4.1-24 depict the performance results at the 100% test plateau.

4.0 Problems

There were no significant problems encountered during the performance of this test at both the 50% and 100% plateaus.

Figure 7.4.1-1
Impulse Pressure vs. Time
(10% Decrease, 50% Plateau)



7.4.1 Load Swing Test (1-PAT-1.2) (continued)

Figure 7.4.1-2
NIS Power vs. Time
(10% Decrease, 50% Plateau)

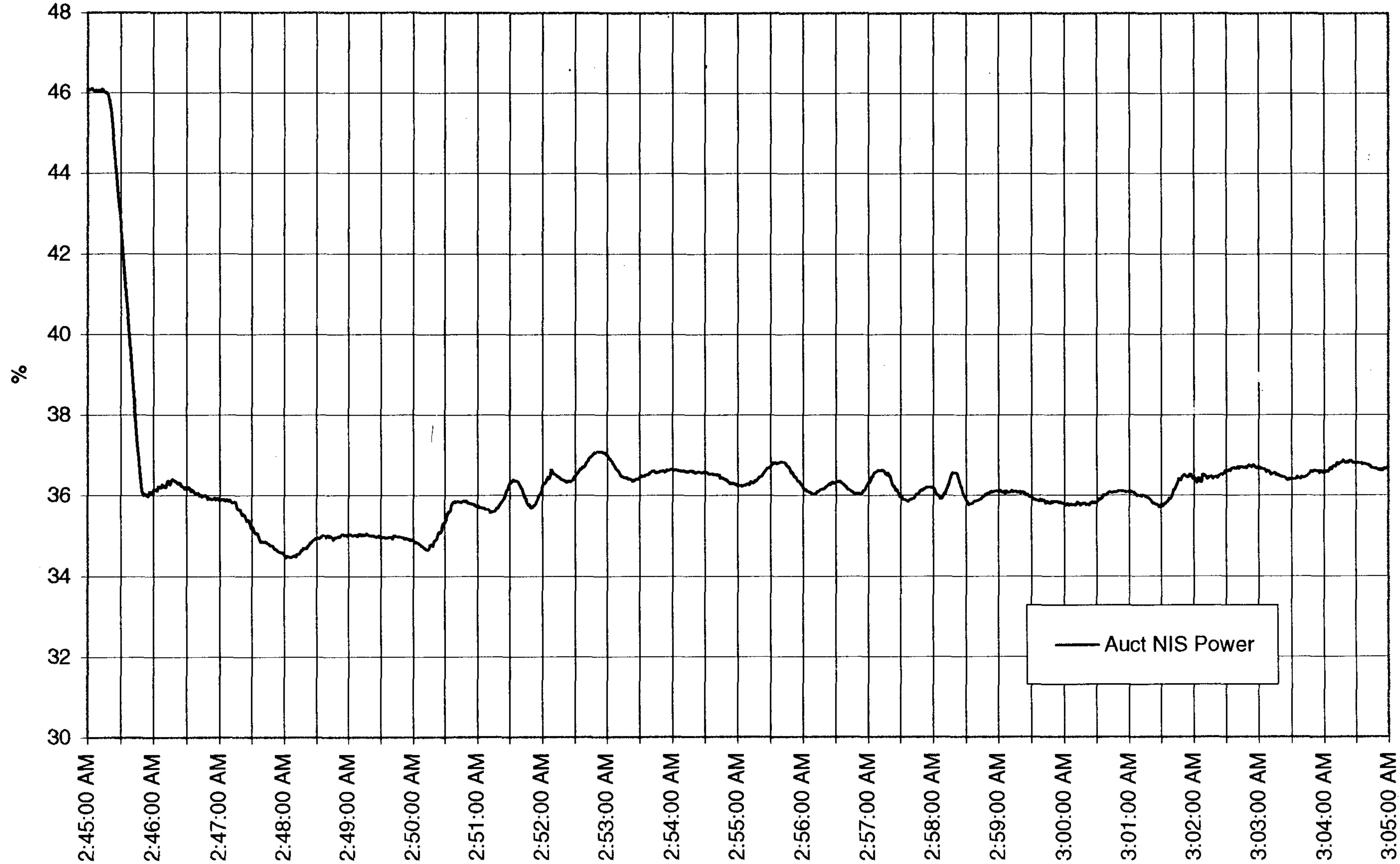
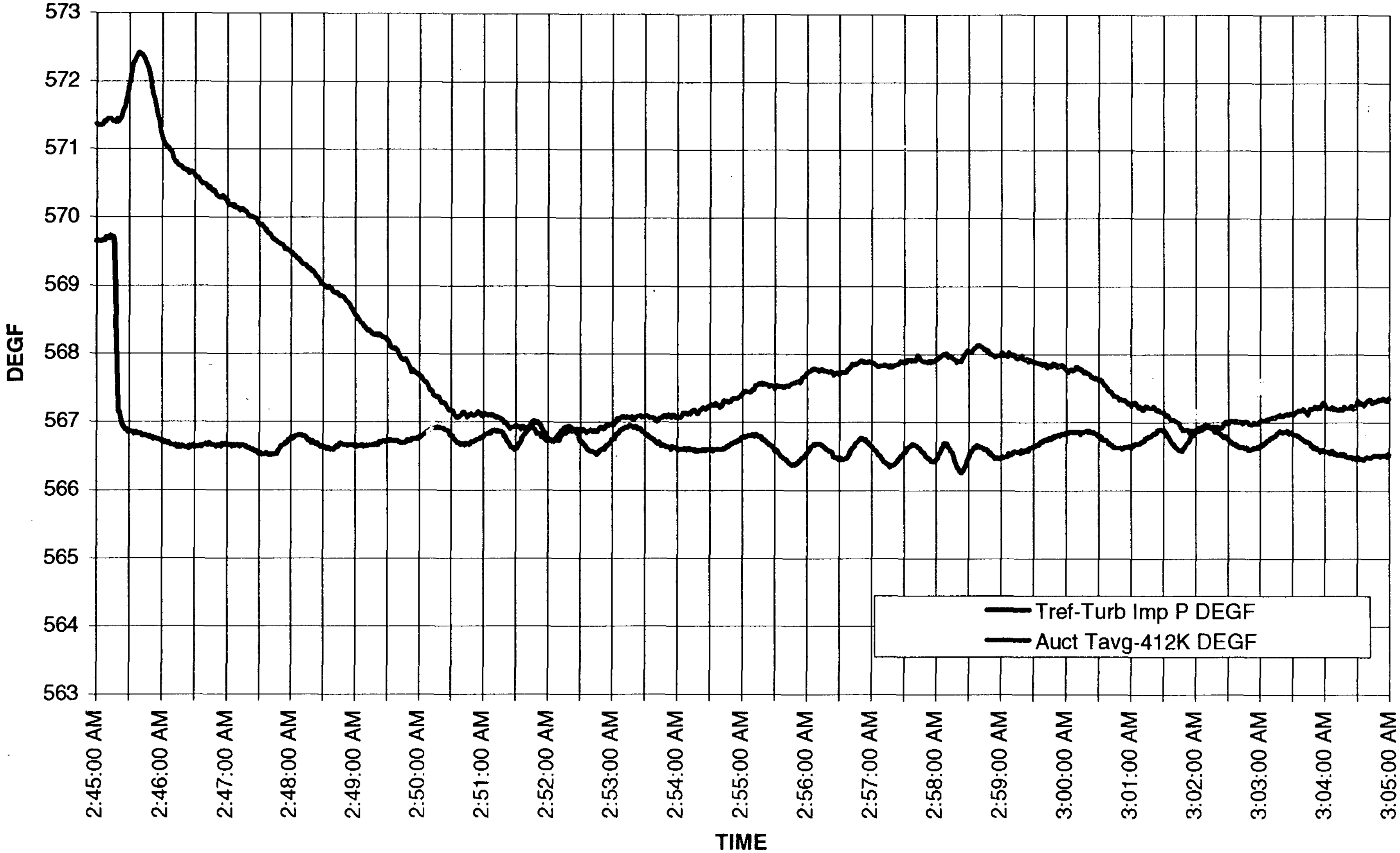


Figure 7.4.1-3
Tavg/Tref vs. Time
(10% Decrease, 50% Plateau)



7.4.1 **Load Swing Test (1-PAT-1.2)** (continued)

Figure 7.4.1-4
Pressurizer Pressure vs. Time
(10% Decrease, 50% Plateau)

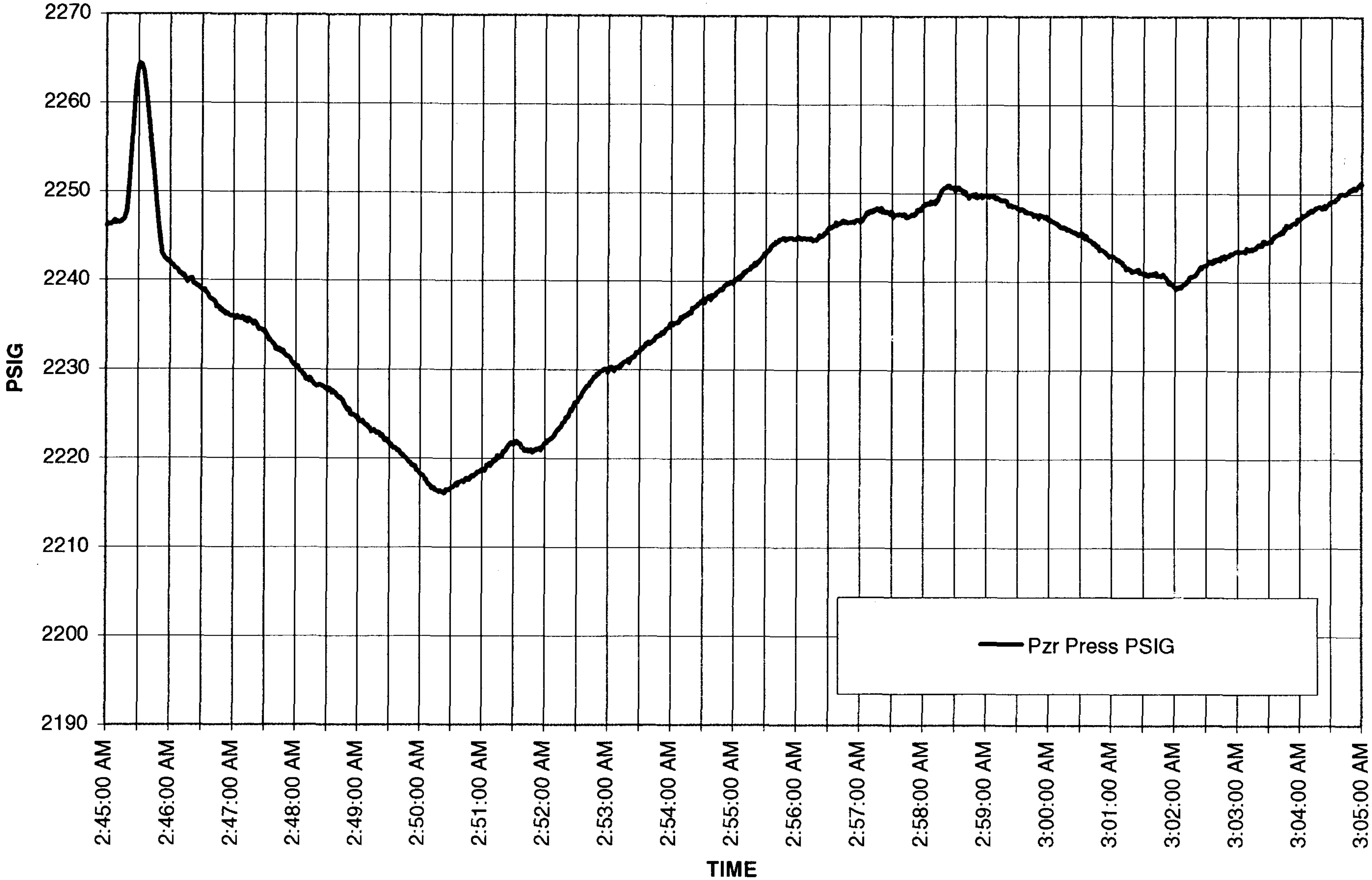


Figure 7.4.1-5
Steam Header Pressure/Feedwater Header Pressure vs. Time
(10% Decrease, 50% Plateau)

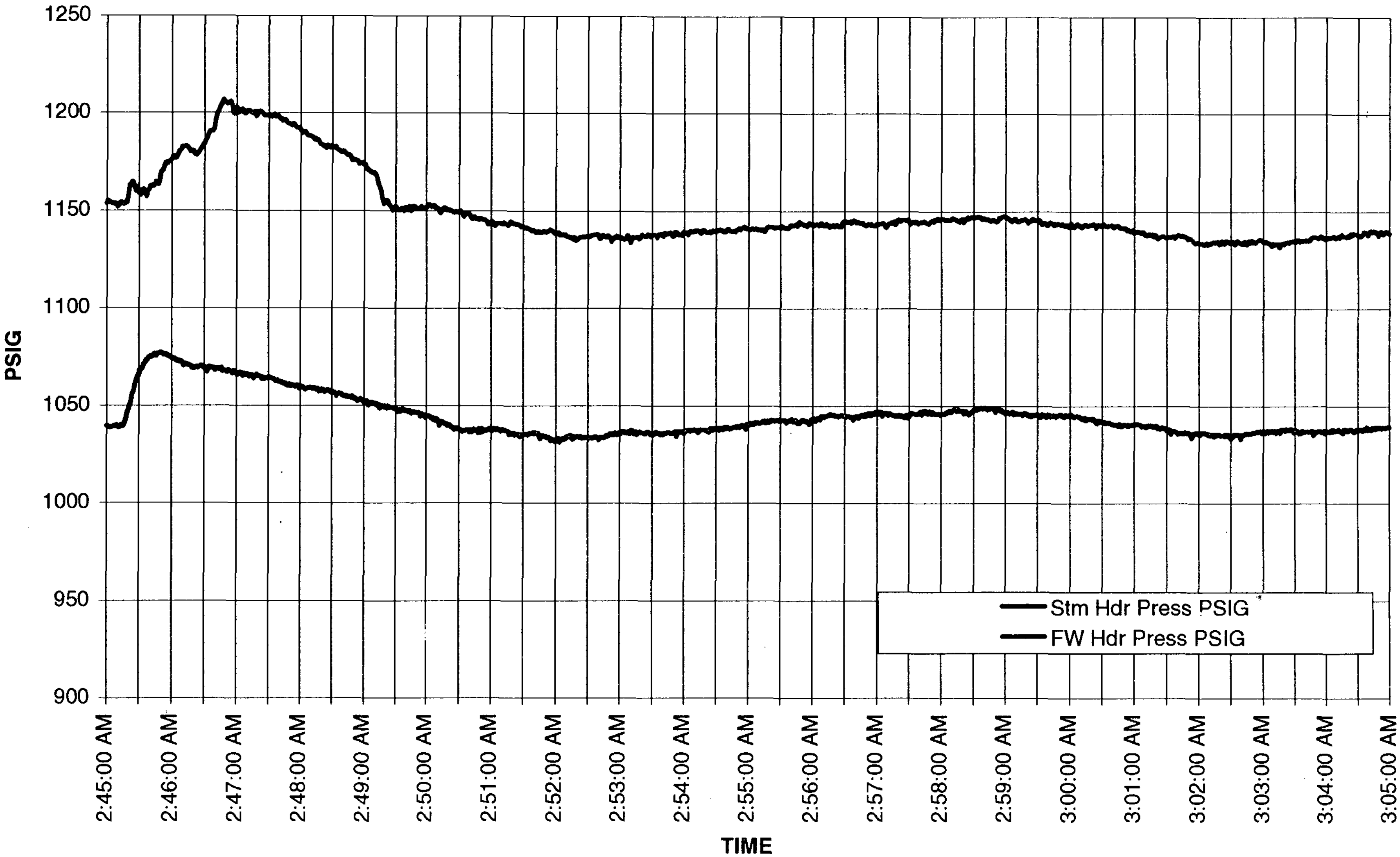


Figure 7.4.1-6
Steam Generator Level vs. Time
(10% Decrease, 50% Plateau)

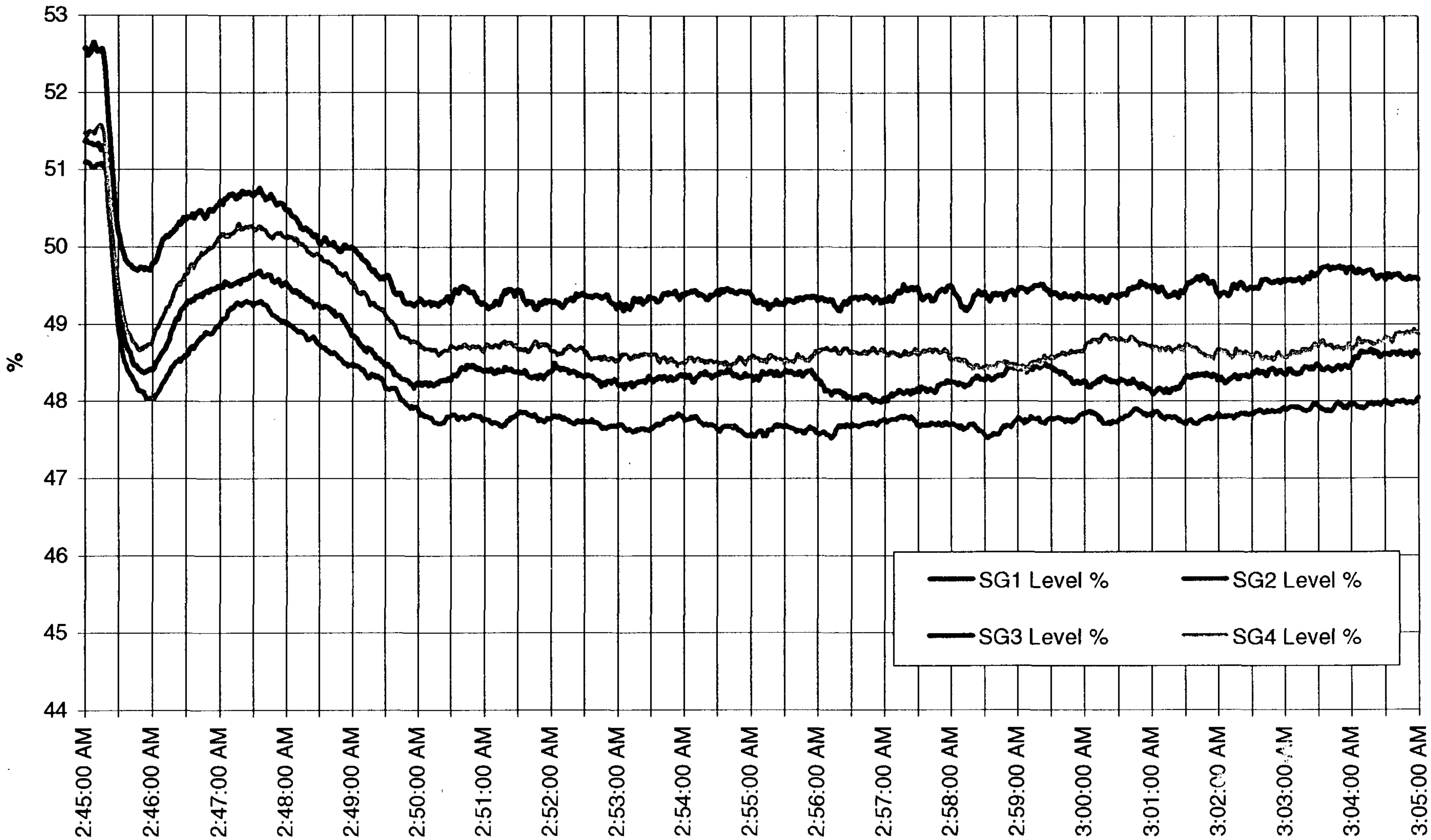


Figure 7.4.1-7
Impulse Pressure vs. Time
(10% Increase, 50% Plateau)

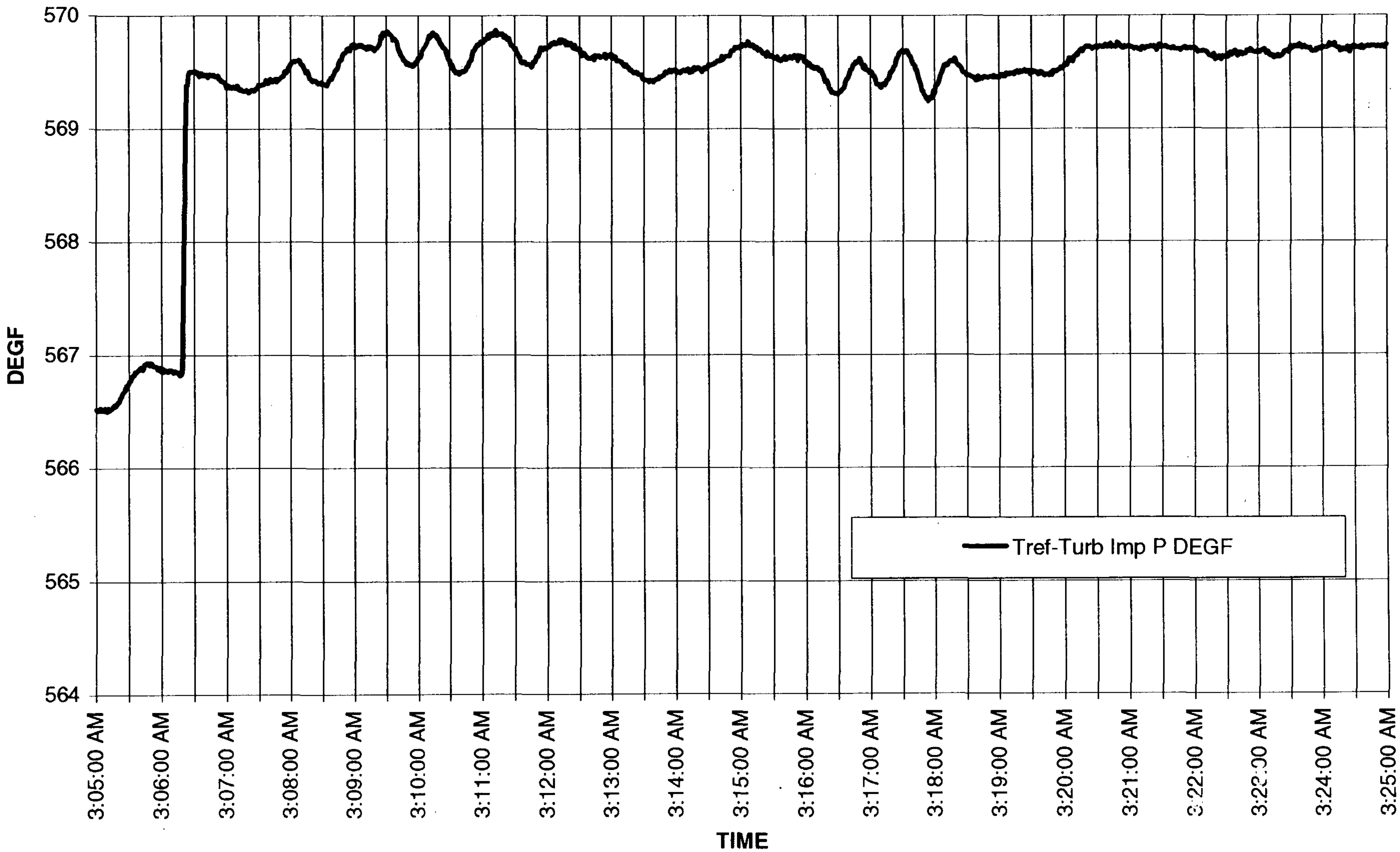


Figure 7.4.1-8
NIS Power vs. Time
(10% Increase, 50% Plateau)

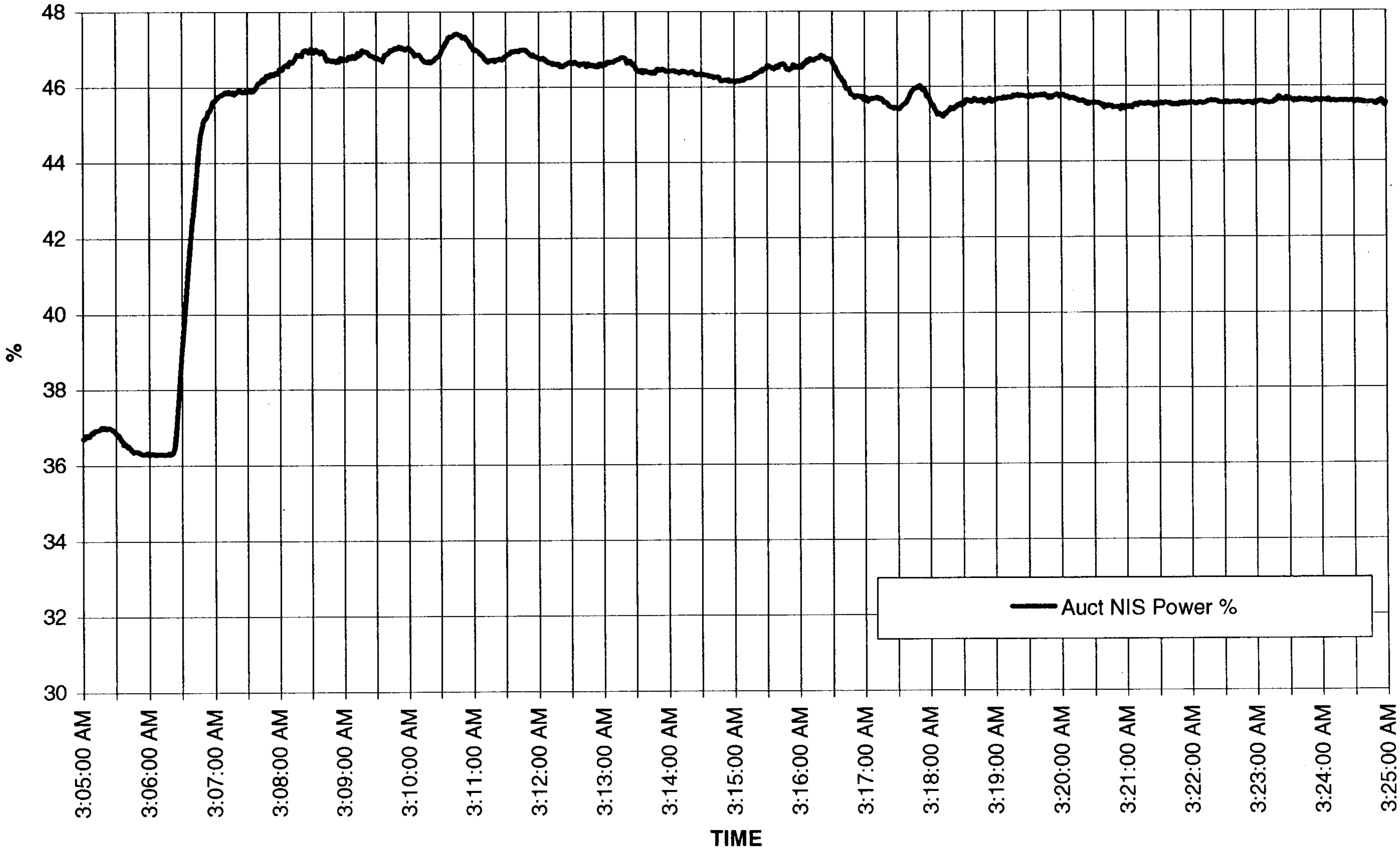


Figure 7.4.1-9
Tavg/Tref vs. Time
(10% Increase, 50% Plateau)

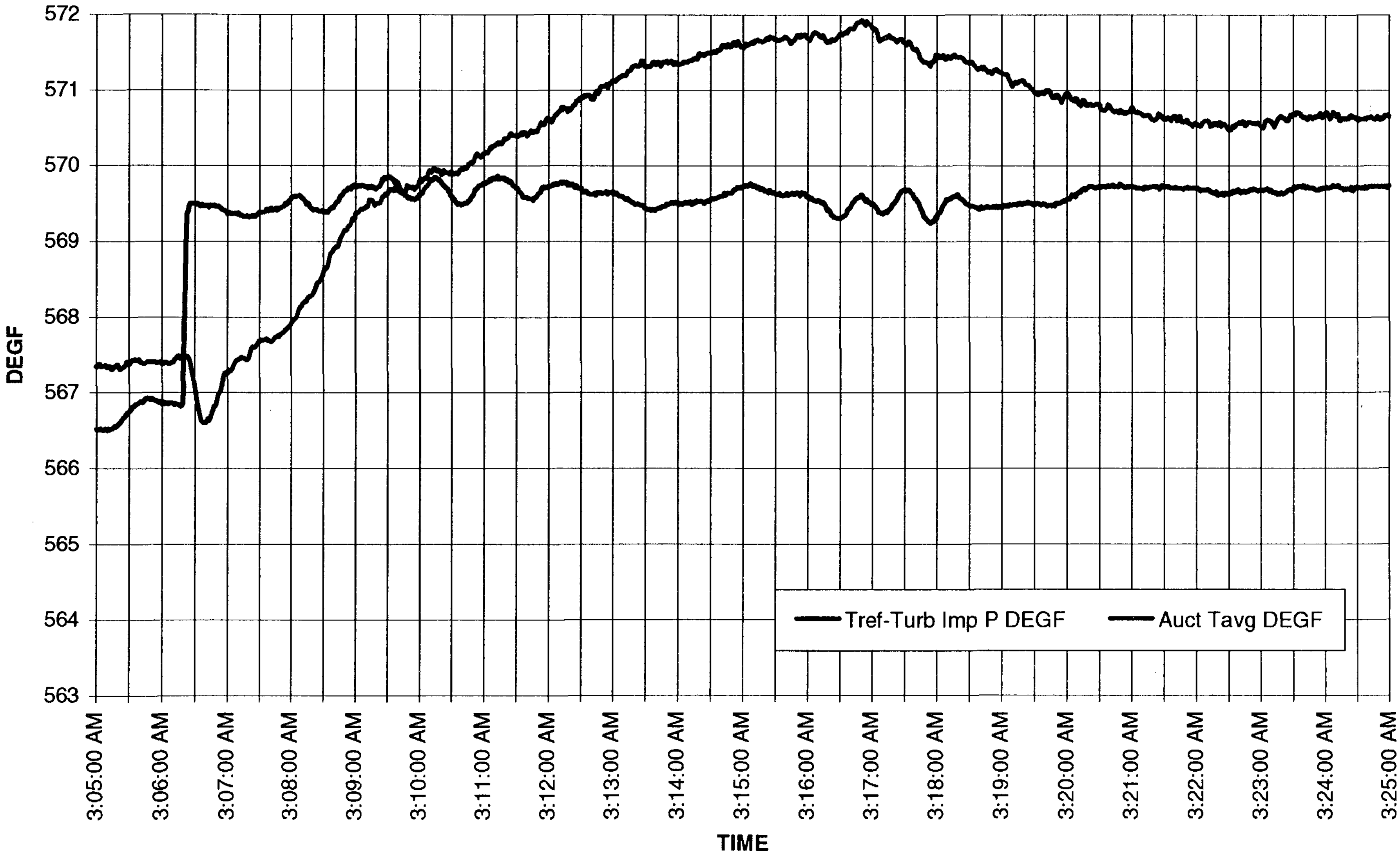


Figure 7.4.1-10
Pressurizer Pressure vs. Time
(10% Increase, 50% Plateau)

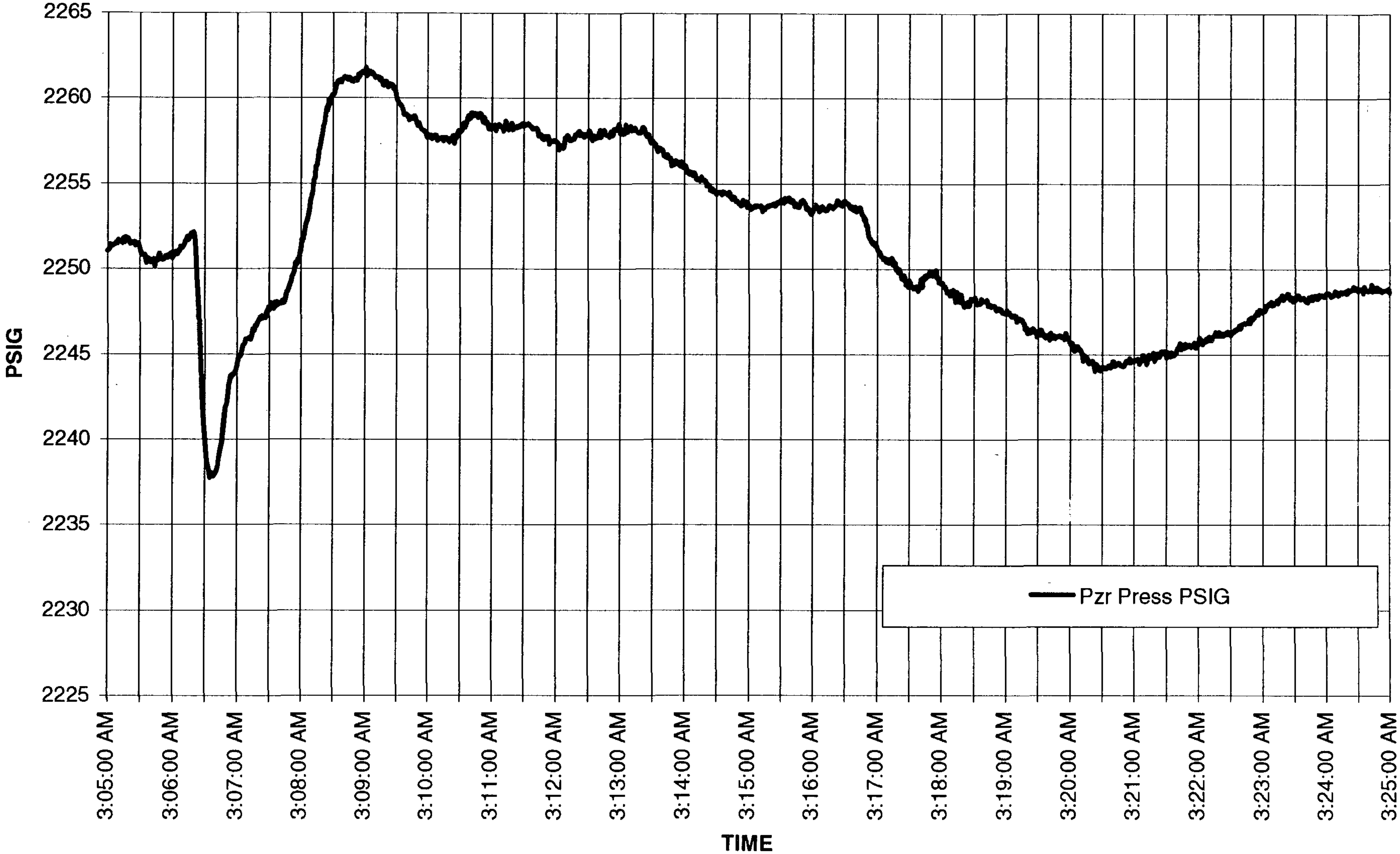


Figure 7.4.1-11
Steam Header Pressure/Feedwater Header Pressure vs. Time
(10% Increase, 50% Plateau)

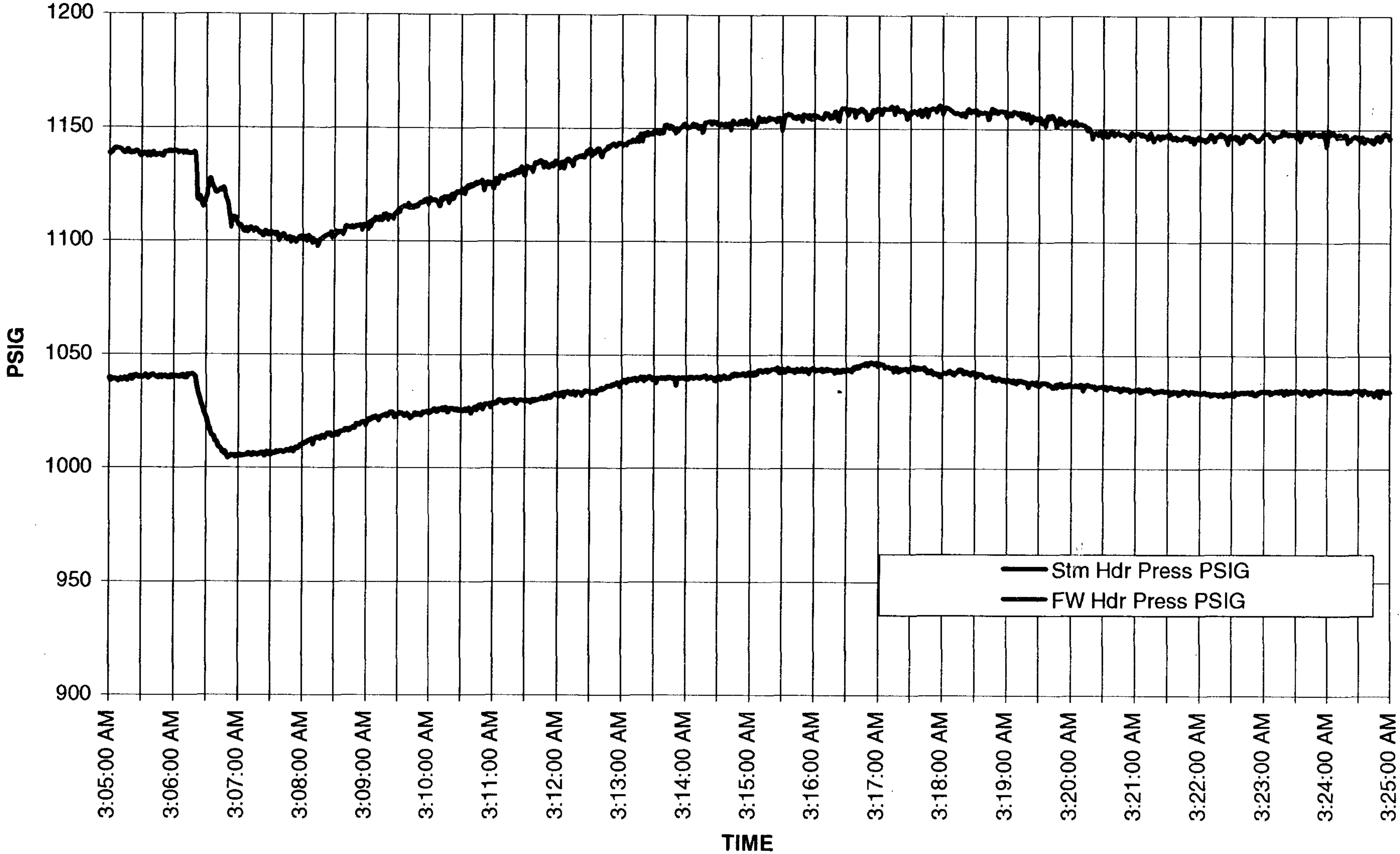


Figure 7.4.1-12
Steam Generator Levels vs. Time
(10% Increase, 50% Plateau)

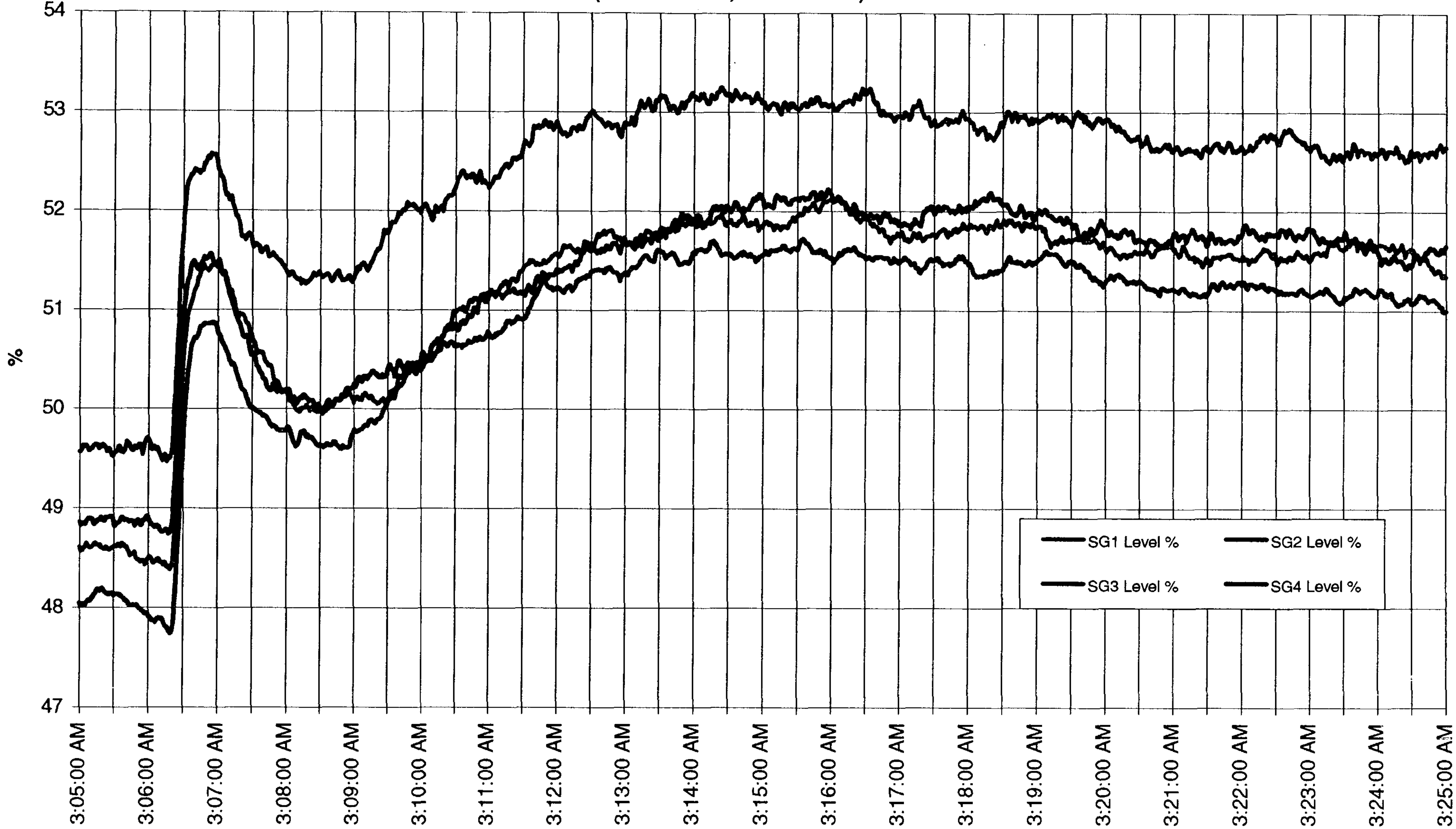


Figure 7.4.1-13
Impulse Pressure vs. Time
(10% Decrease, 100% Plateau)

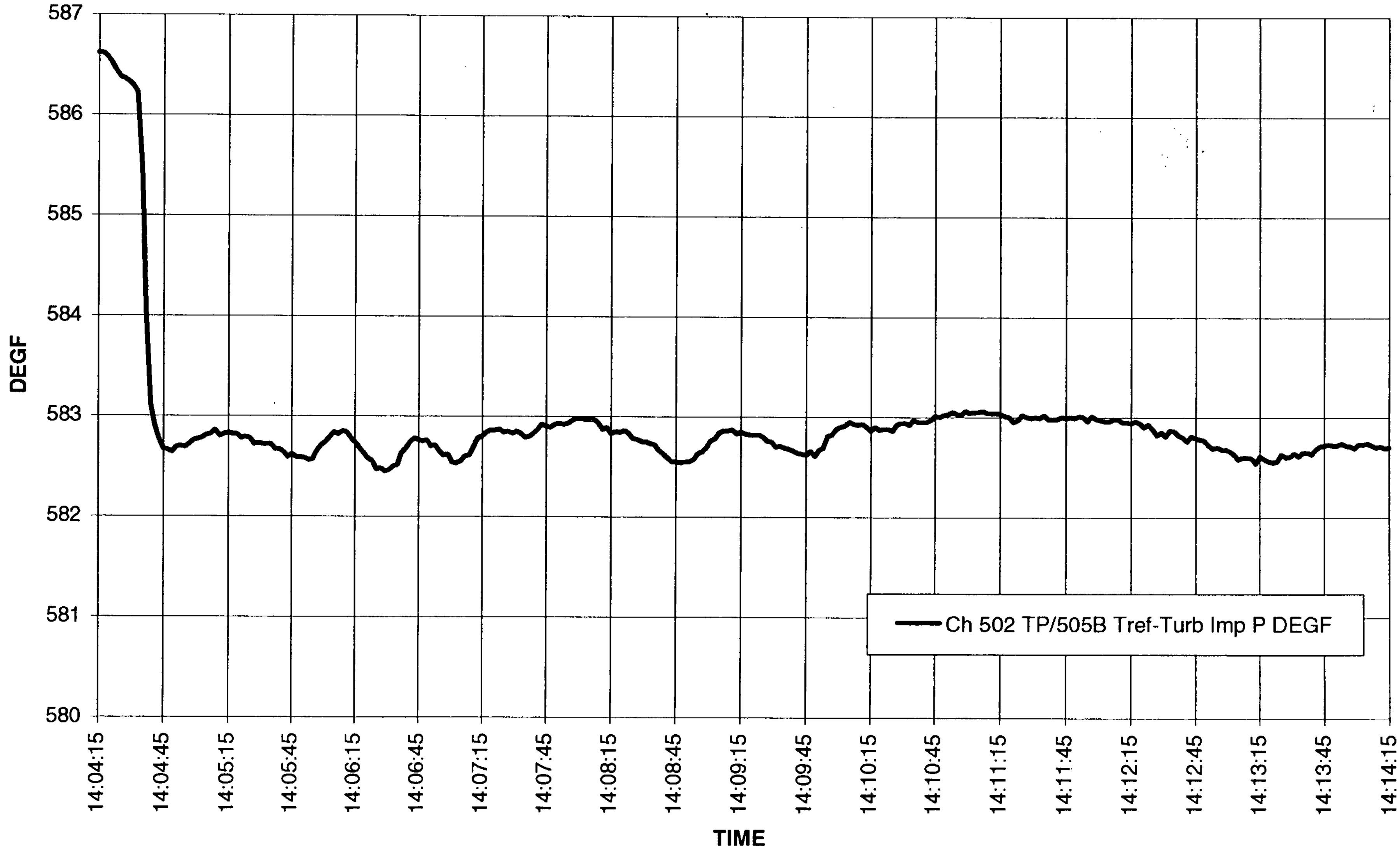


Figure 7.4.1-14
NIS Power vs. Time
(10% Decrease, 100% Plateau)

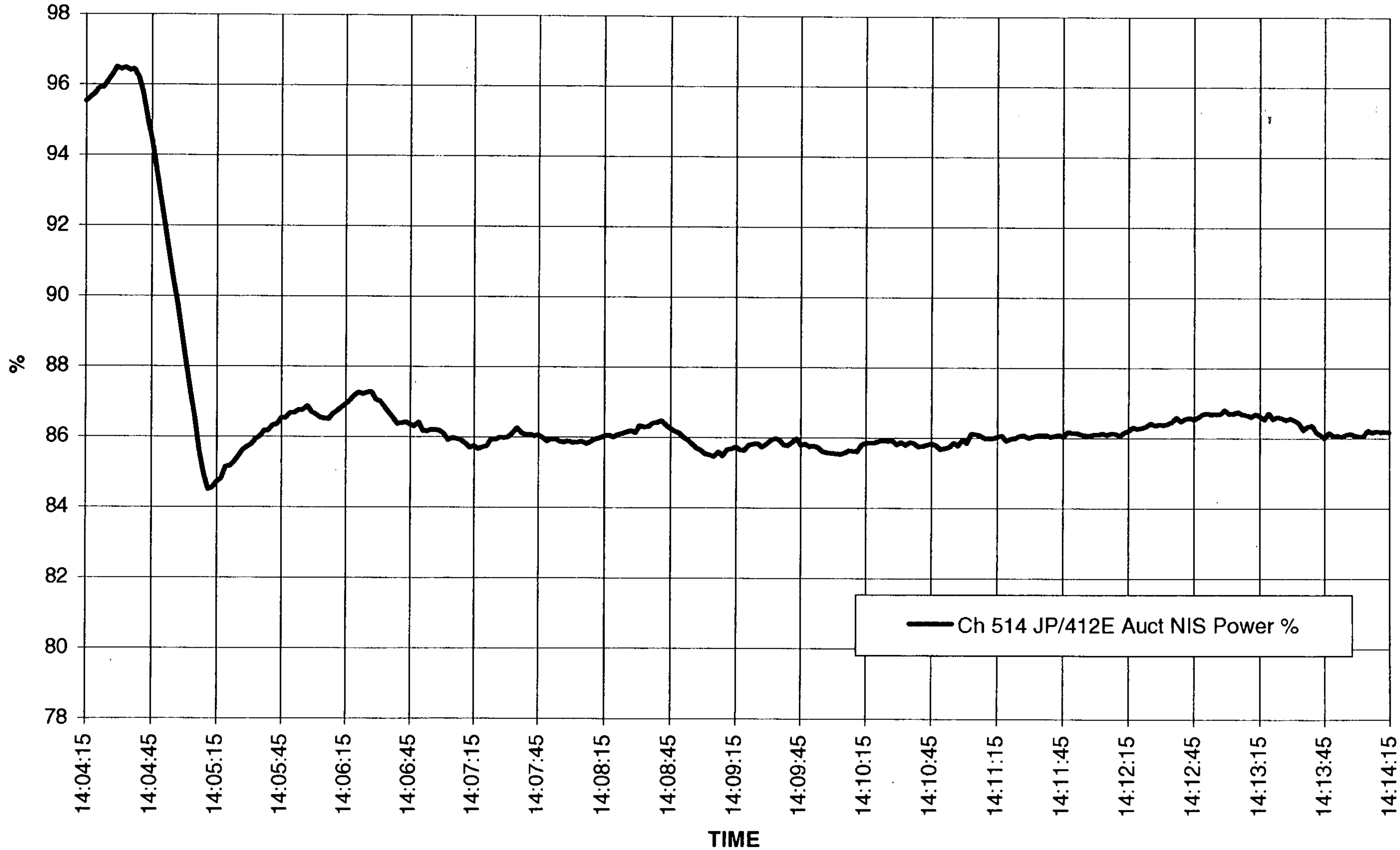


Figure 7.4.1-15
Tavg/Tref vs. Time
(10% Decrease, 100% Plateau)

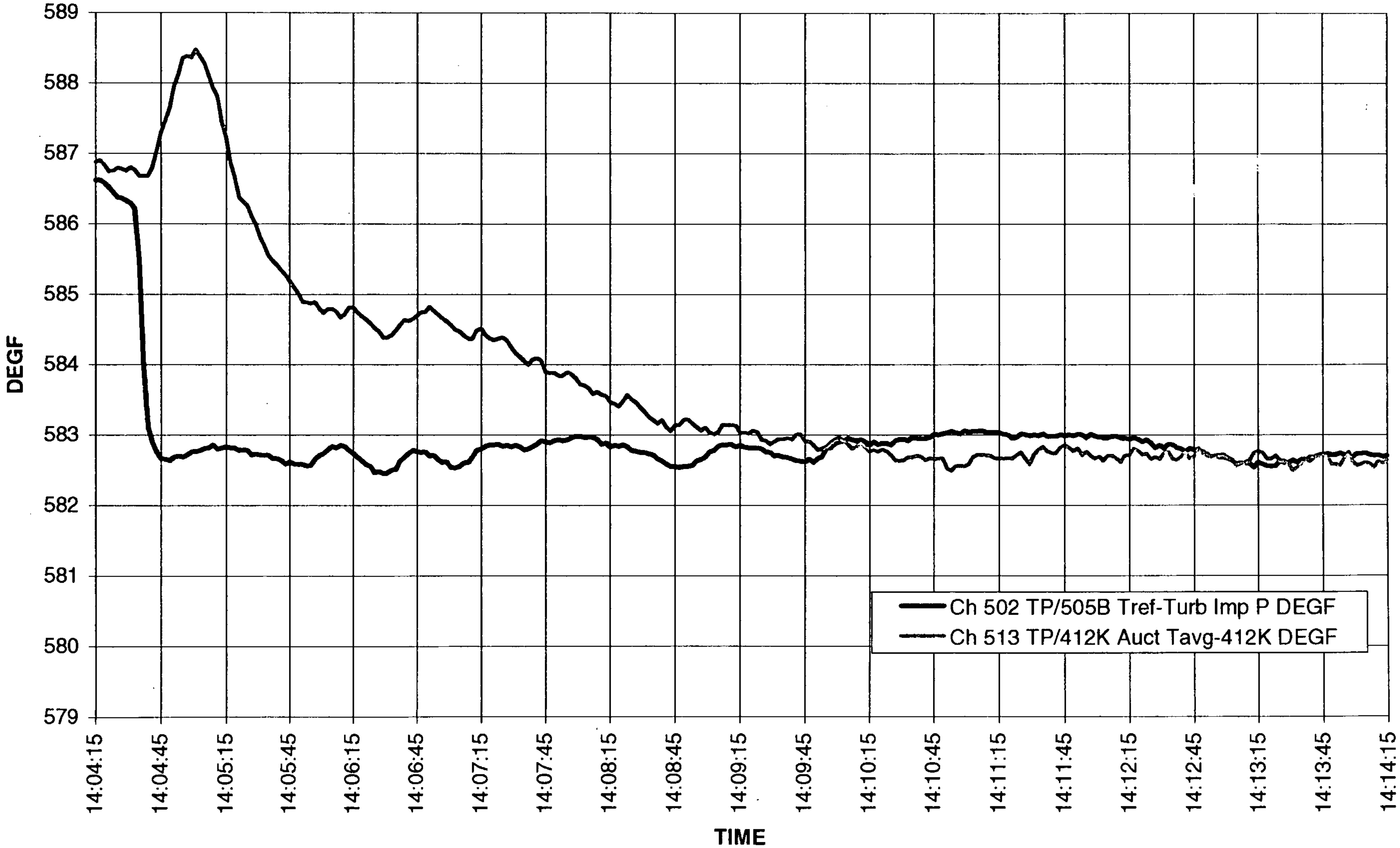


Figure 7.4.1-16
Pressurizer Pressure vs. Time
(10% Decrease, 100% Plateau)

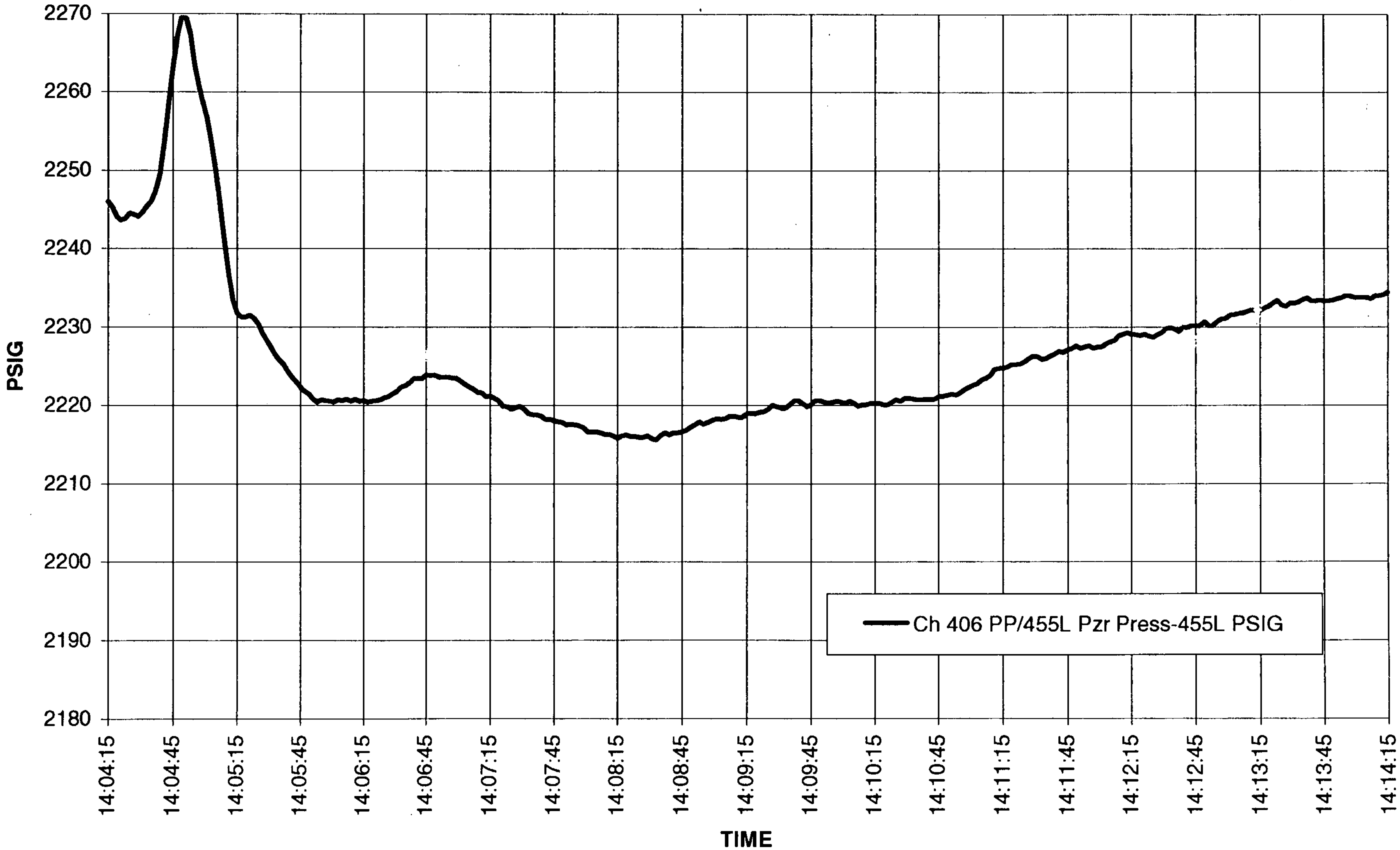


Figure 7.4.1-17
Steam Header Pressure/Feedwater Header Pressure vs. Time
(10% Decrease, 100% Plateau)

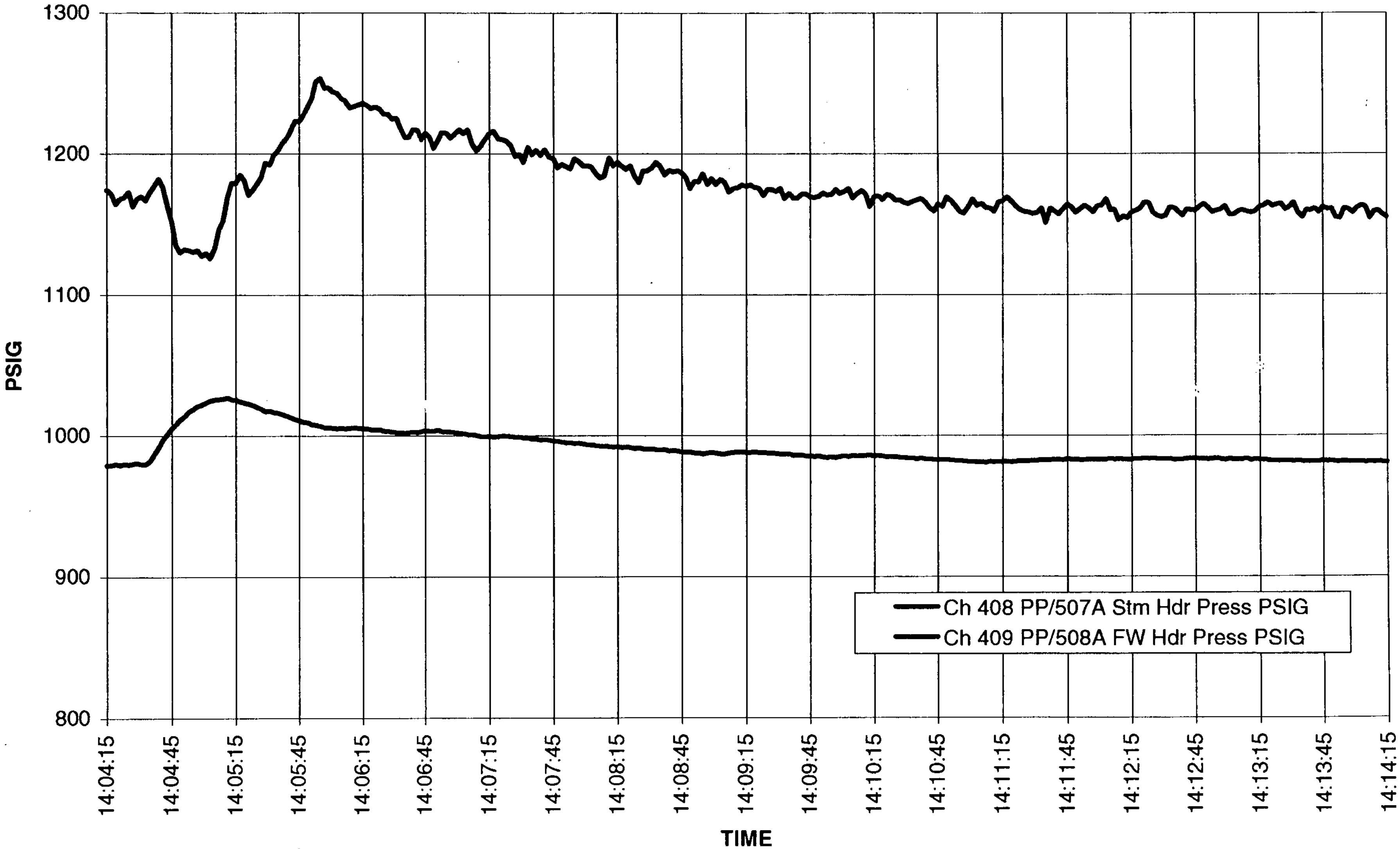


Figure 7.4.1-18
Steam Generator Levels vs. Time
(10% Decrease, 100% Plateau)

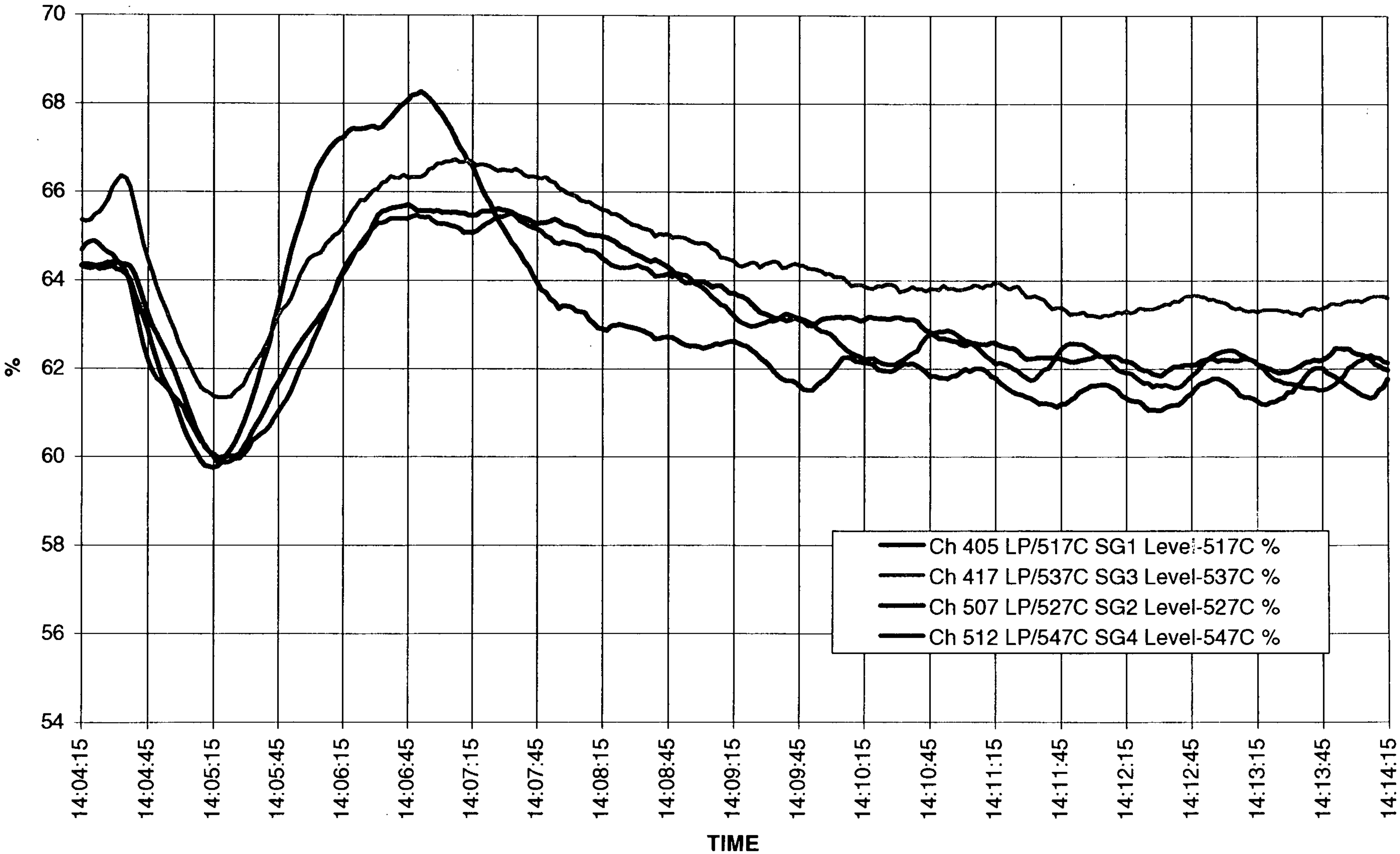


Figure 7.4.1-19
Impulse Pressure vs Time
(10% Increase, 100% Plateau)

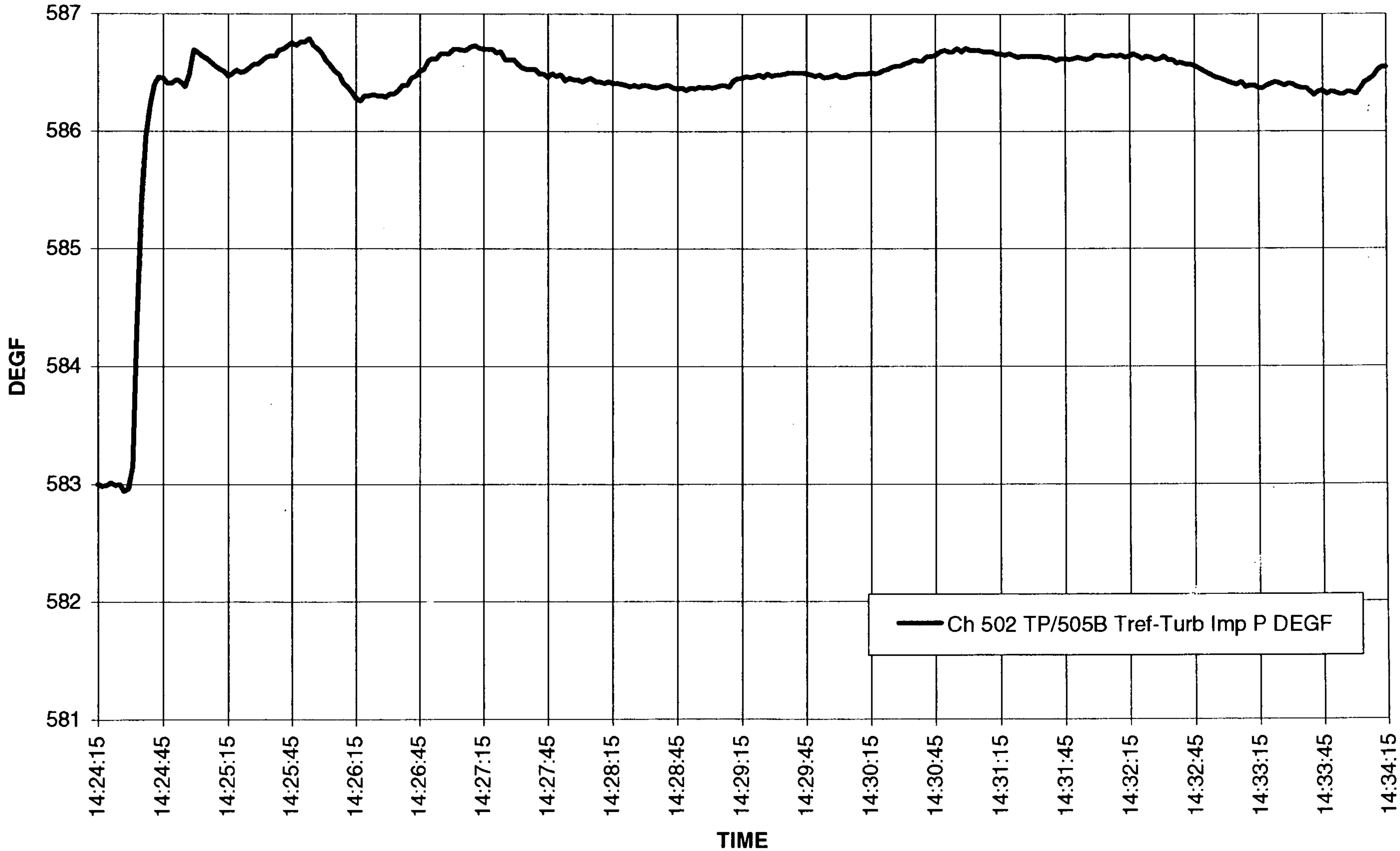


Figure 7.4.1-20
NIS Power vs. Time
(10% Increase, 100% Plateau)

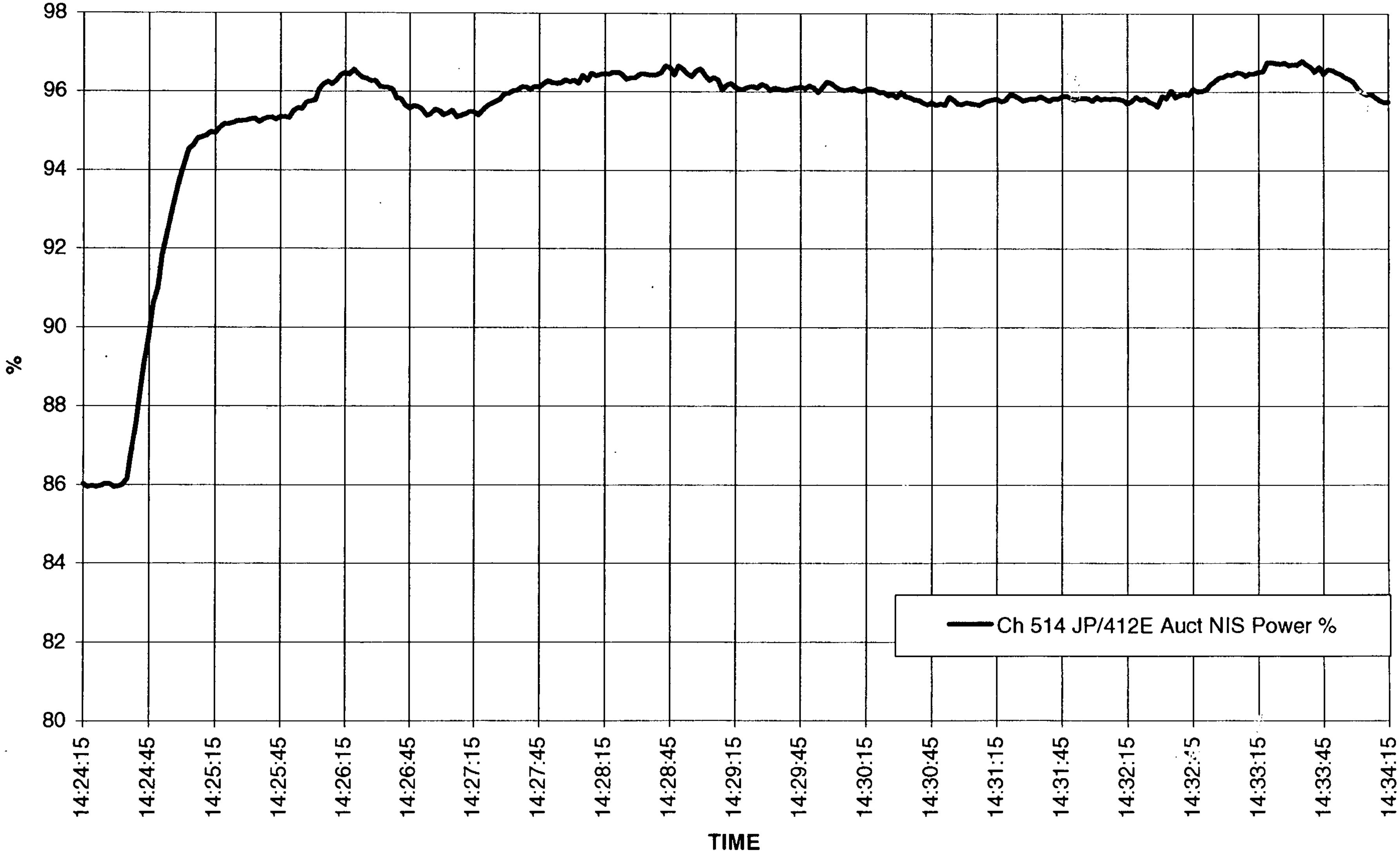
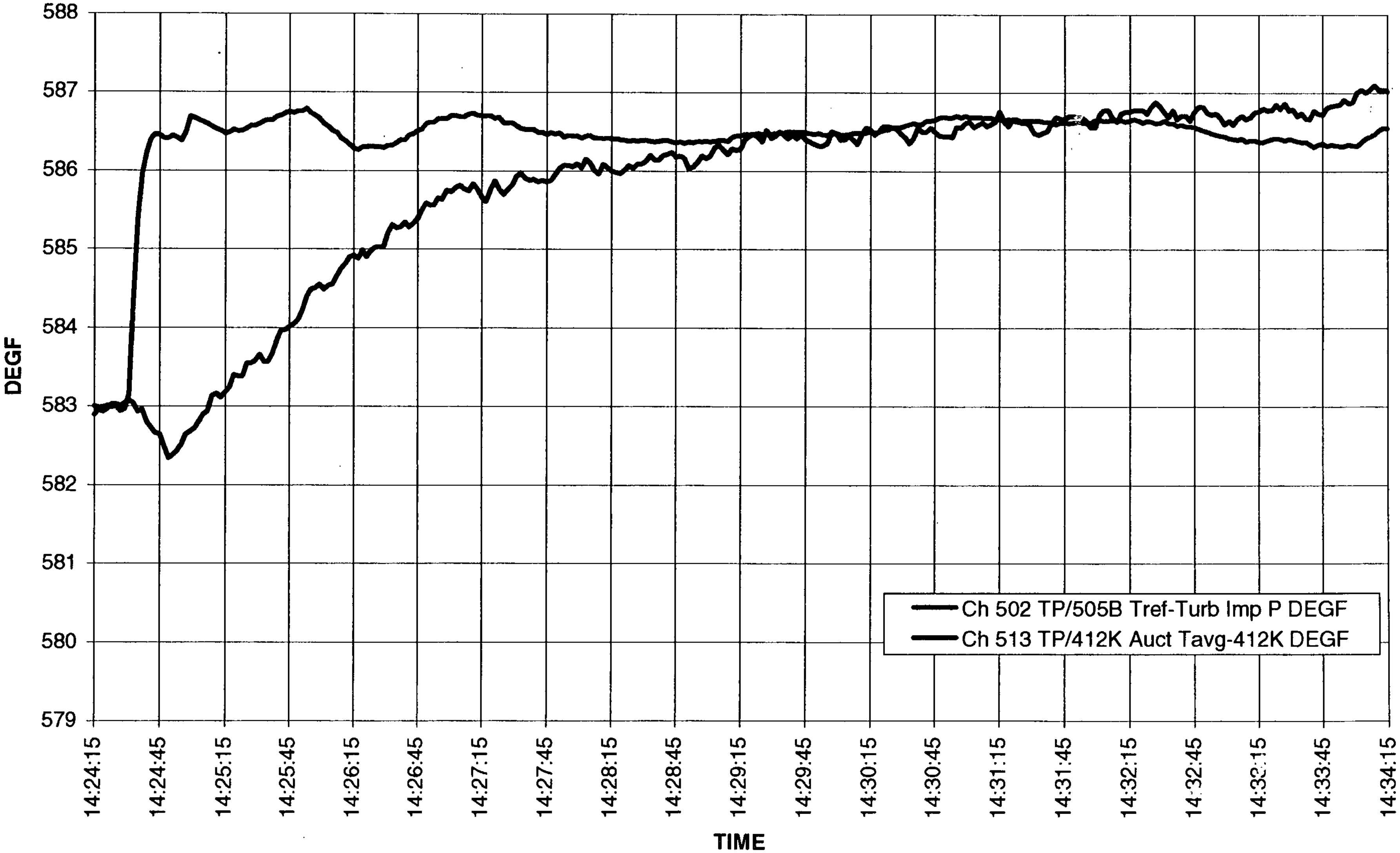


Figure 7.4.1-21
Tavg/Tref vs Time
(10% Increase, 100% Plateau)



7.4.1 [illegible] Swing Test (1-PAT-1.2) (continued)

Figure 7.4.1-22
Pressurizer Pressure v.s Time
(10% Increase, 100% Plateau)

Figure 7.4.1-23
Steam Header Pressure/Feedwater Header Pressure vs. Time
(10% Increase, 100% Plateau)

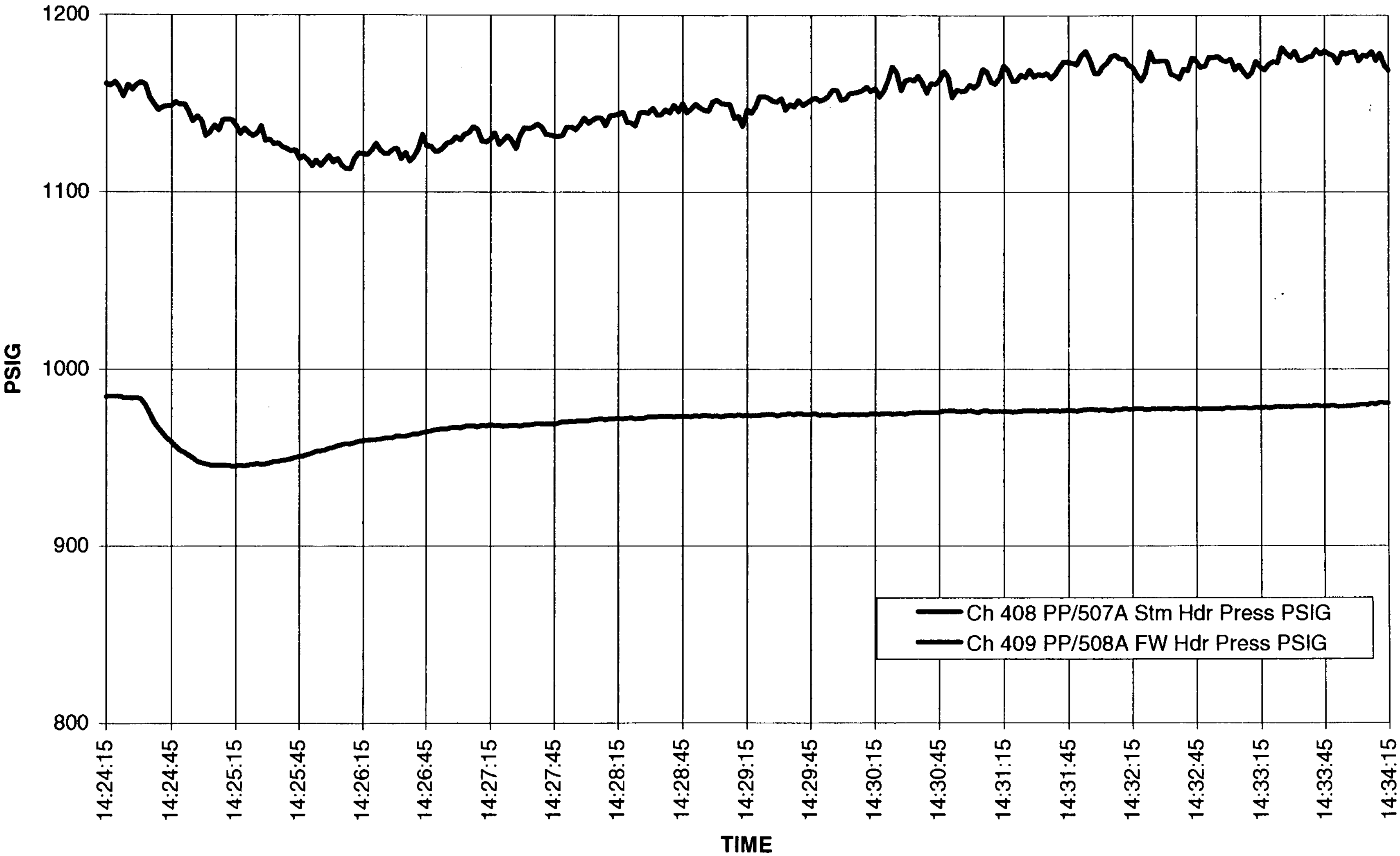
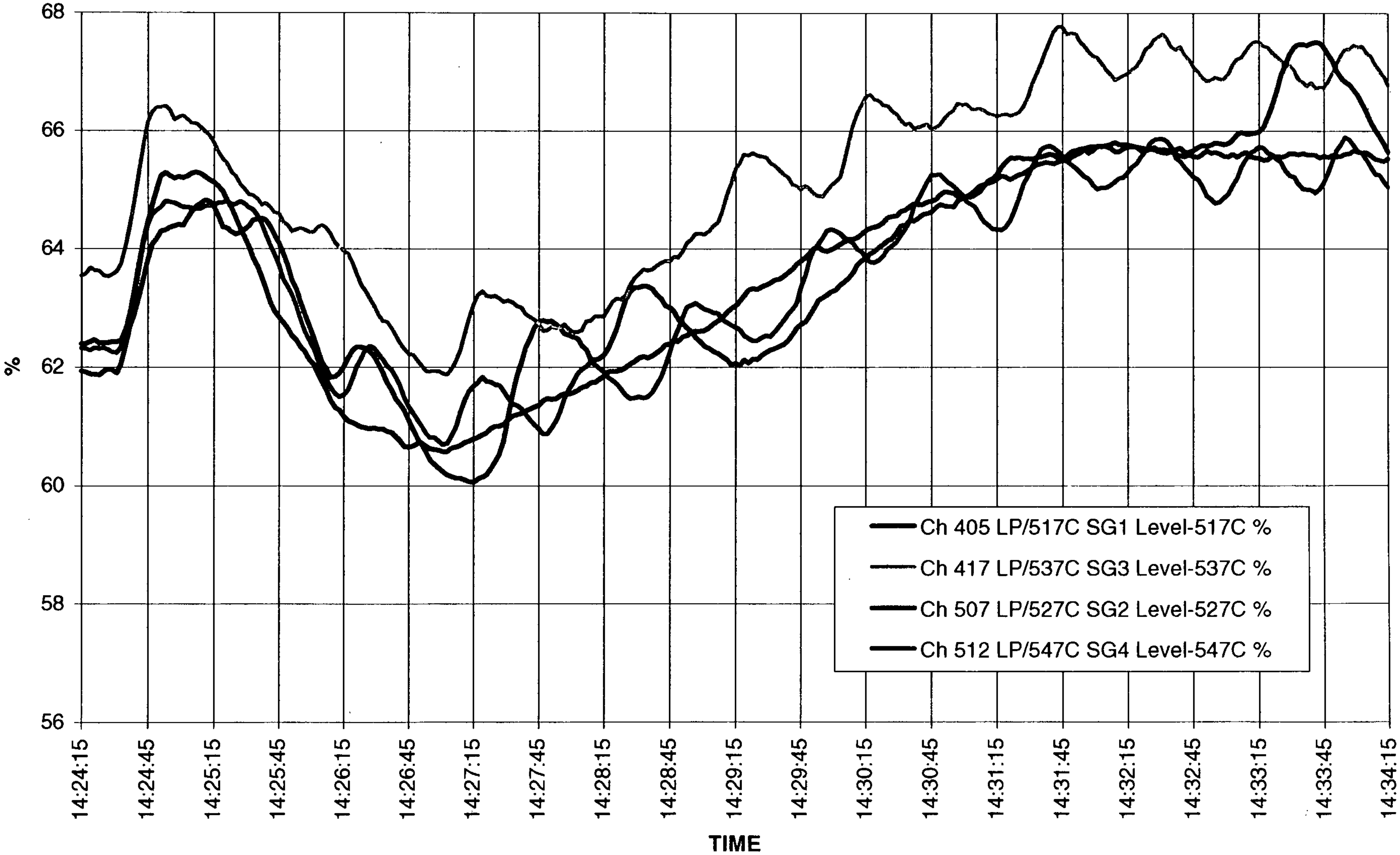


Figure 7.4.1-24
Steam Generator Levels vs. Time
(10% Increase, 100% Plateau)



7.4.2 Large Load Reduction Test (1-PAT-1.3)

This PAT was performed as part of test sequence 1-PAT-8.0, Test Sequence for 100% Plateau. This test was started and field completed on 5/12/96.

1.0 Objective

This test demonstrates the ability of primary and secondary side systems, including automatic control systems, to sustain a 50% step decrease in turbine generator load.

2.0 Test Method

Recorders were connected to monitor plant parameters (e.g., reactor power, RCS temperature and pressure, pressurizer level, feedwater and steam flows, steam generator levels, feedwater pump speed, and feedwater pressure) during the transient. Turbine governor valves were positioned to produce approximately a 50% step decrease in generator load. Parameters were allowed to stabilize.

3.0 Test Results

The acceptance criteria were met as delineated below:

3.1 Neither the reactor nor the turbine tripped. See Problem 1.

3.2 Safety injection was not initiated. See Problem 1.

3.3 Pressurizer and steam generator safety valves did not lift. See Problem 1.

3.4 Monitored plant parameters stabilized without manual intervention. See Problems 1 and 2.

Figures 7.4.2-1 through 7.4.2-12 depict the performance results of the automatic control systems.

7.4.2 Large Load Reduction Test (1-PAT-1.3) (continued)

4.0 Problems

[1] The decrease in load occurred in two steps instead of one step due to the response of the main turbine control system. TVA and Westinghouse review of the test data determined that the test demonstrated that the dynamic response of the plant is in accordance with design for the large load reduction. An evaluation concluded acceptance criteria would have been met had the test been performed as a single step decrease in turbine generator load.

Data for this test was submitted to the NRC for review.

[2] Manual action was taken by the unit operator to close 1-FCV-6-209A prior to being notified by the test director that normal plant operations could resume. The test director had already determined that stability had been achieved and was in the process of performing the steps leading to the notification of the Operations staff that normal plant operations could resume. Because the plant had already been declared stable by the test director, this manual action was determined not to violate the acceptance criteria. No retest nor corrective action was necessary.

Figure 7.4.2-1
Steam Header Pressure/Feedwater Header Pressure vs. Time

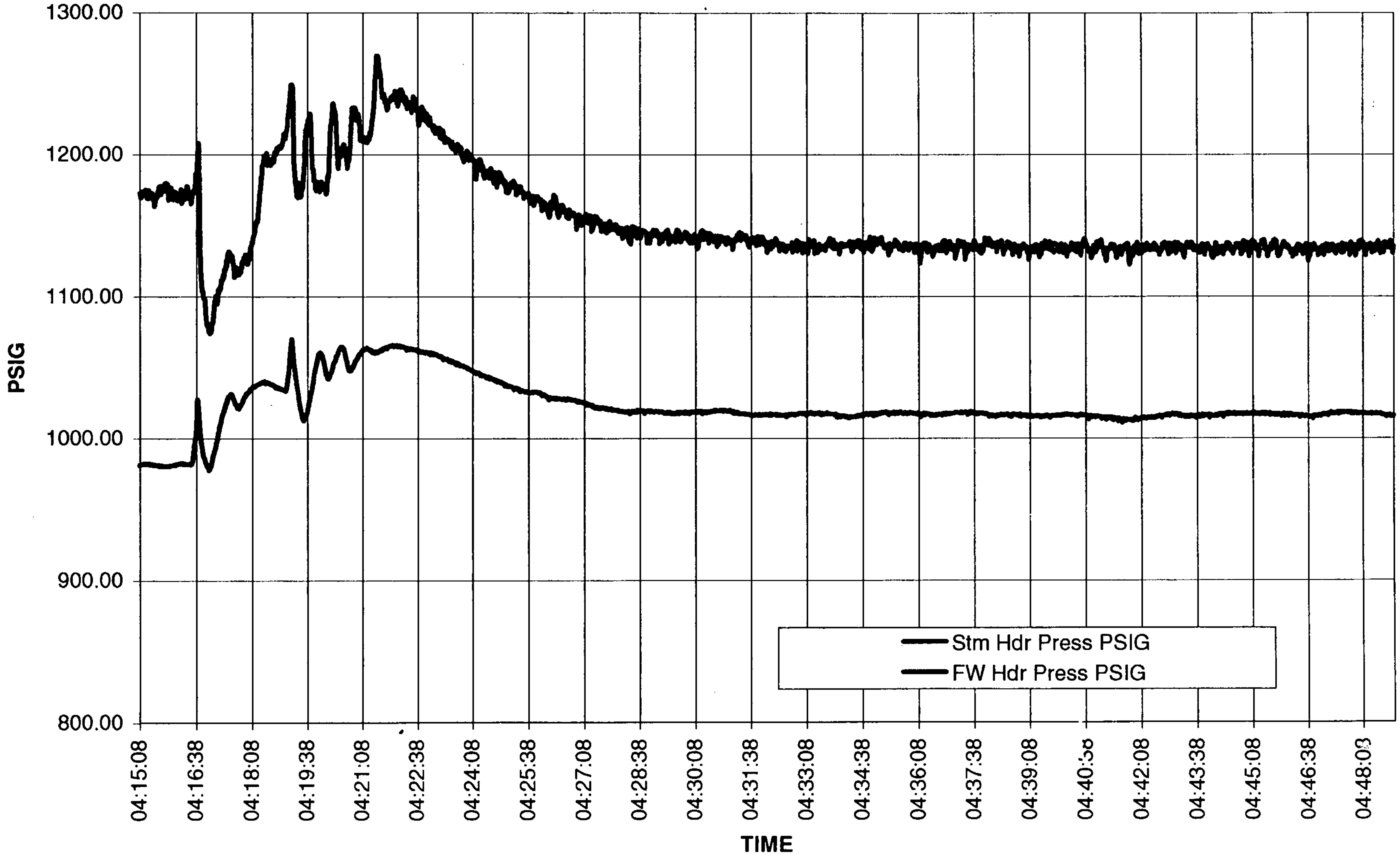


Figure 7.4.2-2
Loop Delta Temperatures in Percent Power vs. Time

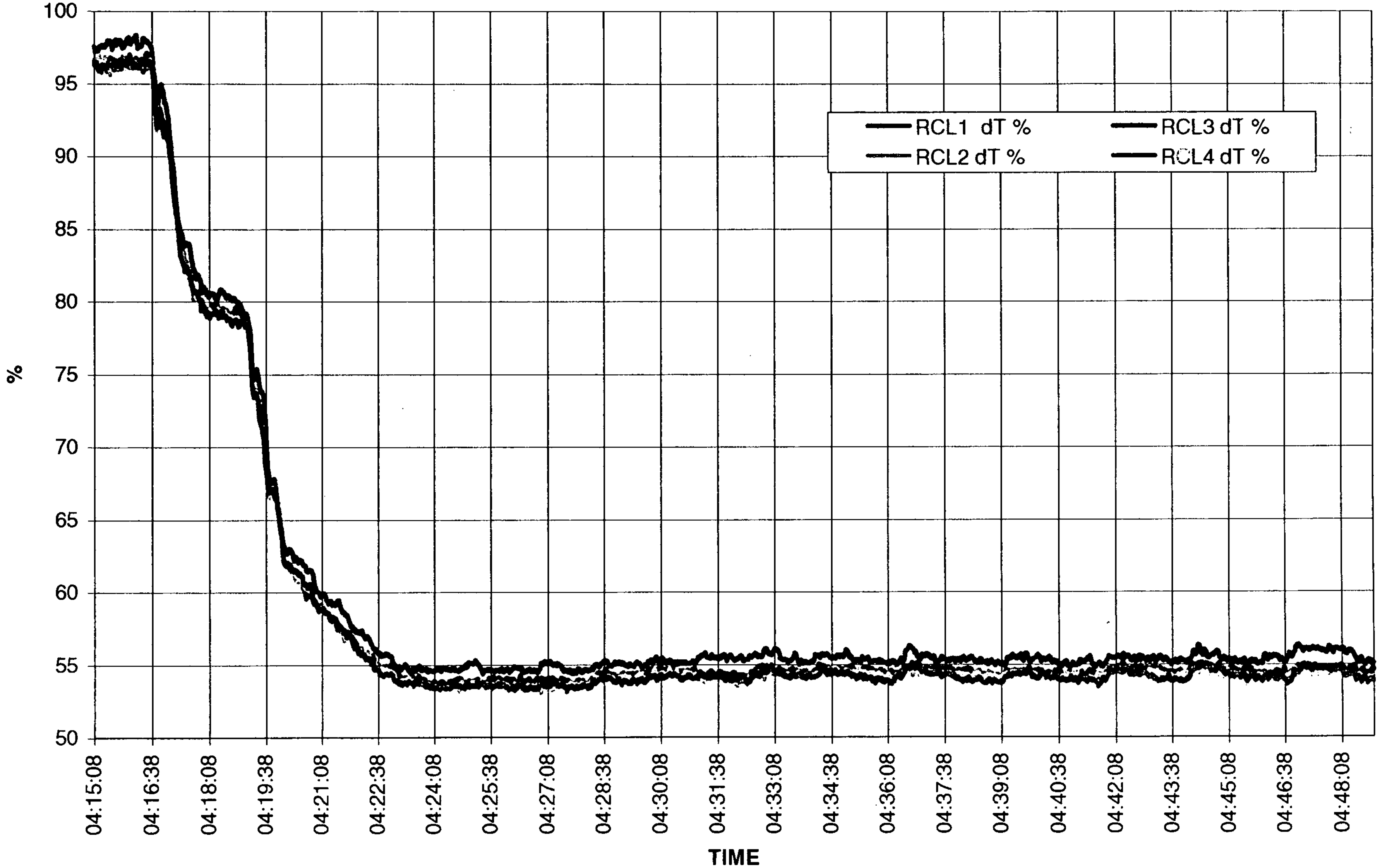


Figure 7.4.2-3
Generator MegaWatts vs. Time

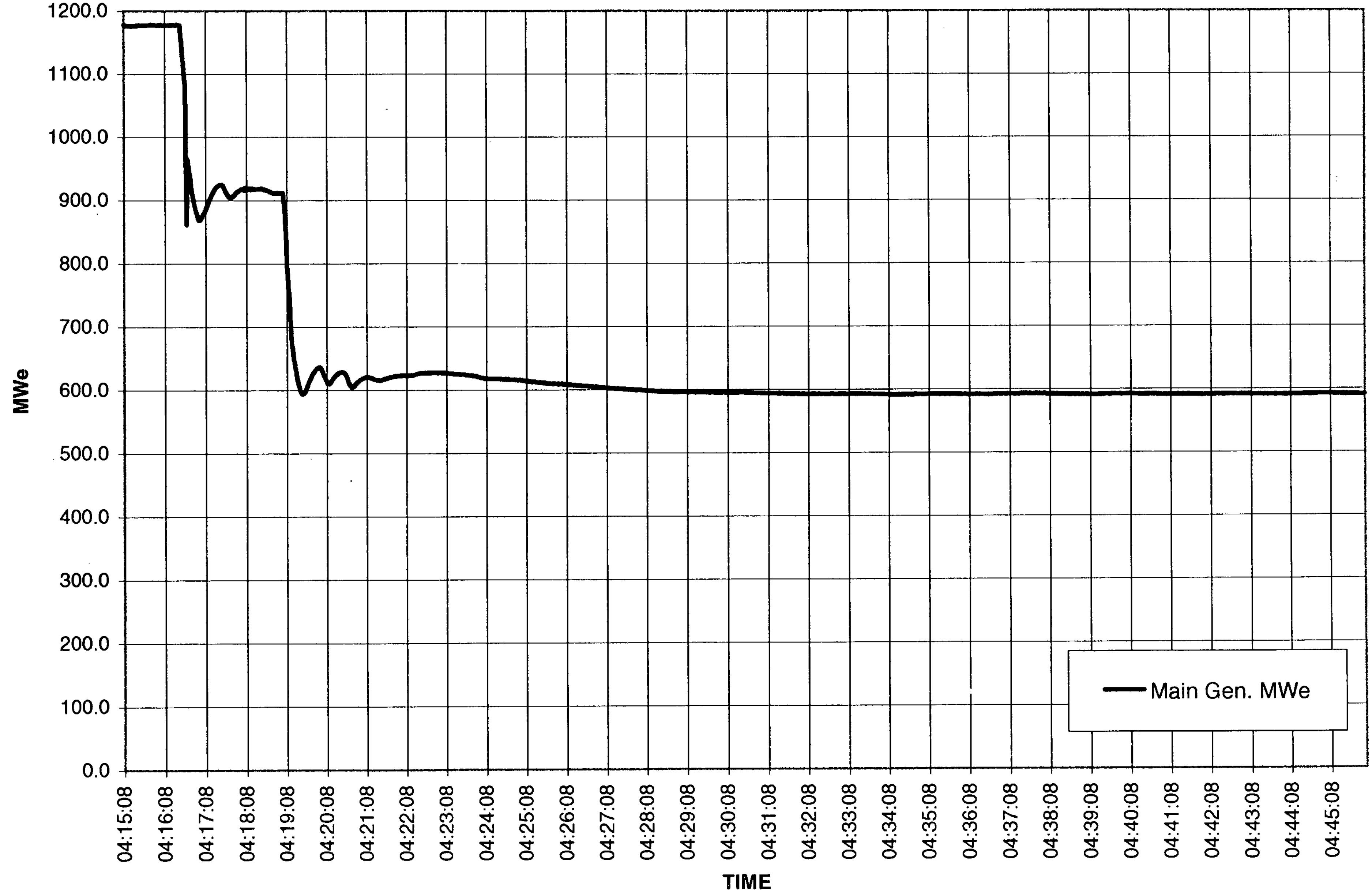


Figure 7.4.2-4
NIS Power vs. Time

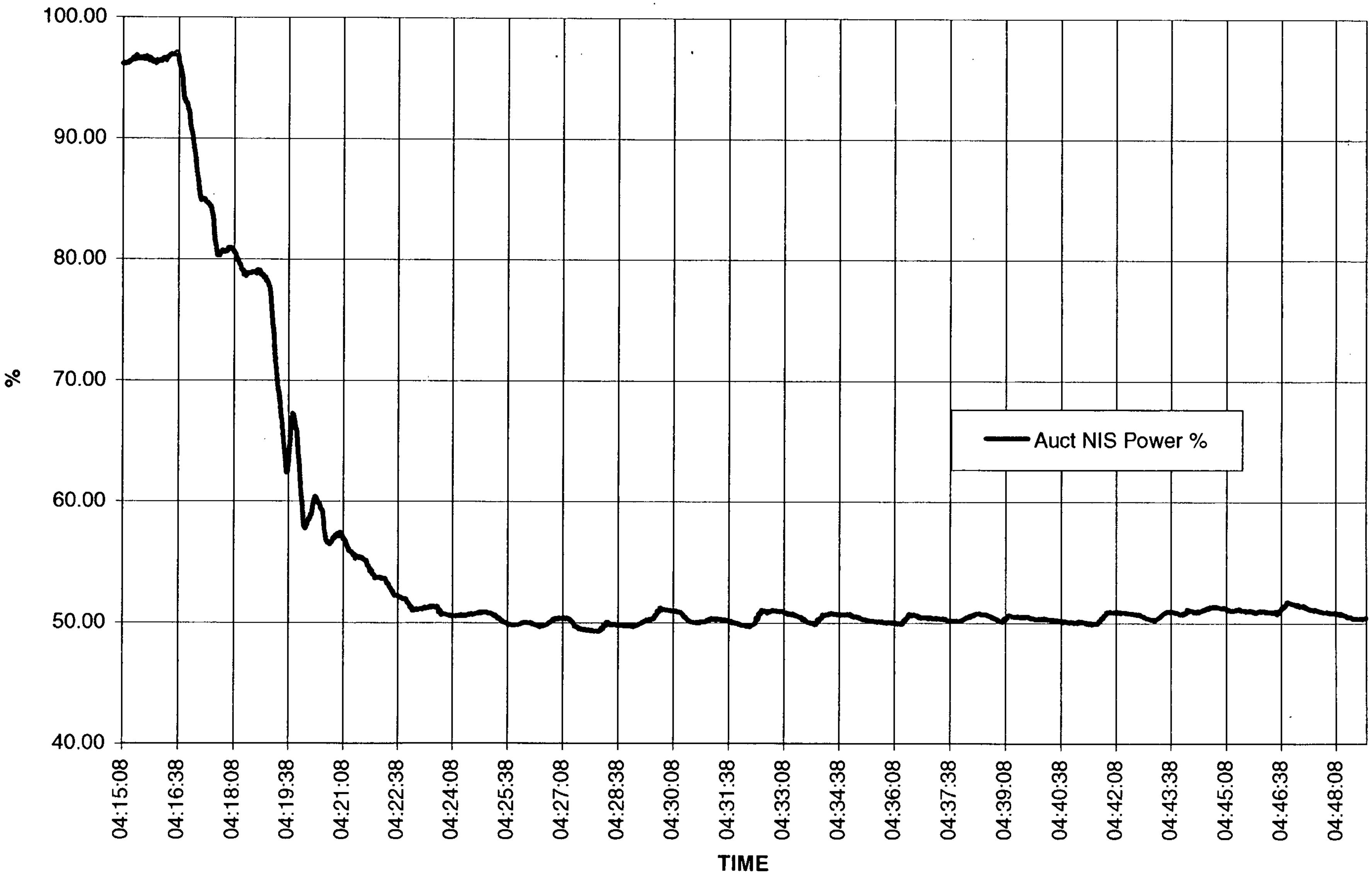


Figure 7.4.2-5
Steam Flow/Feedwater Flow vs. Time

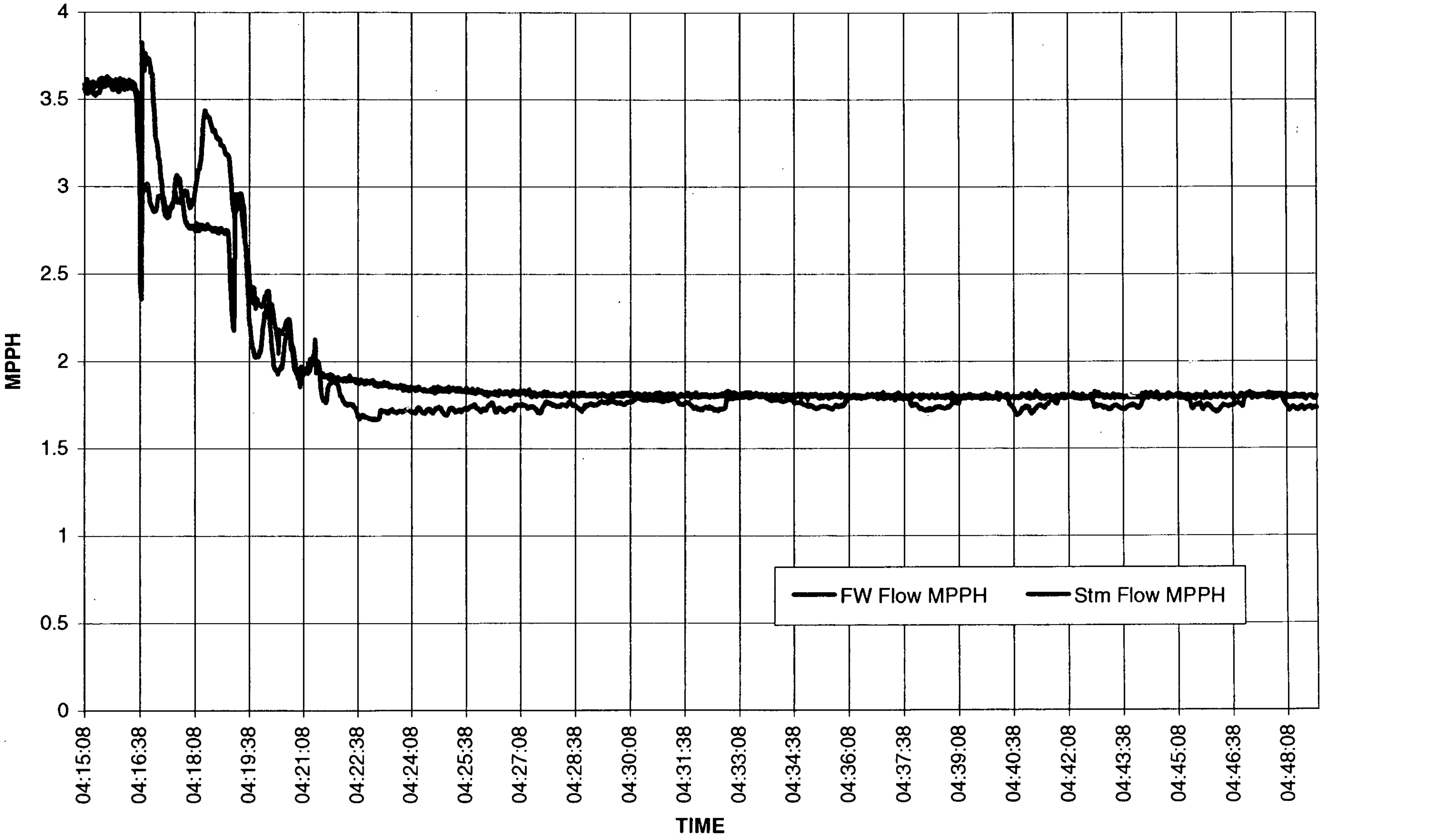


Figure 7.4.2-6
Pressurizer Pressure vs. Time

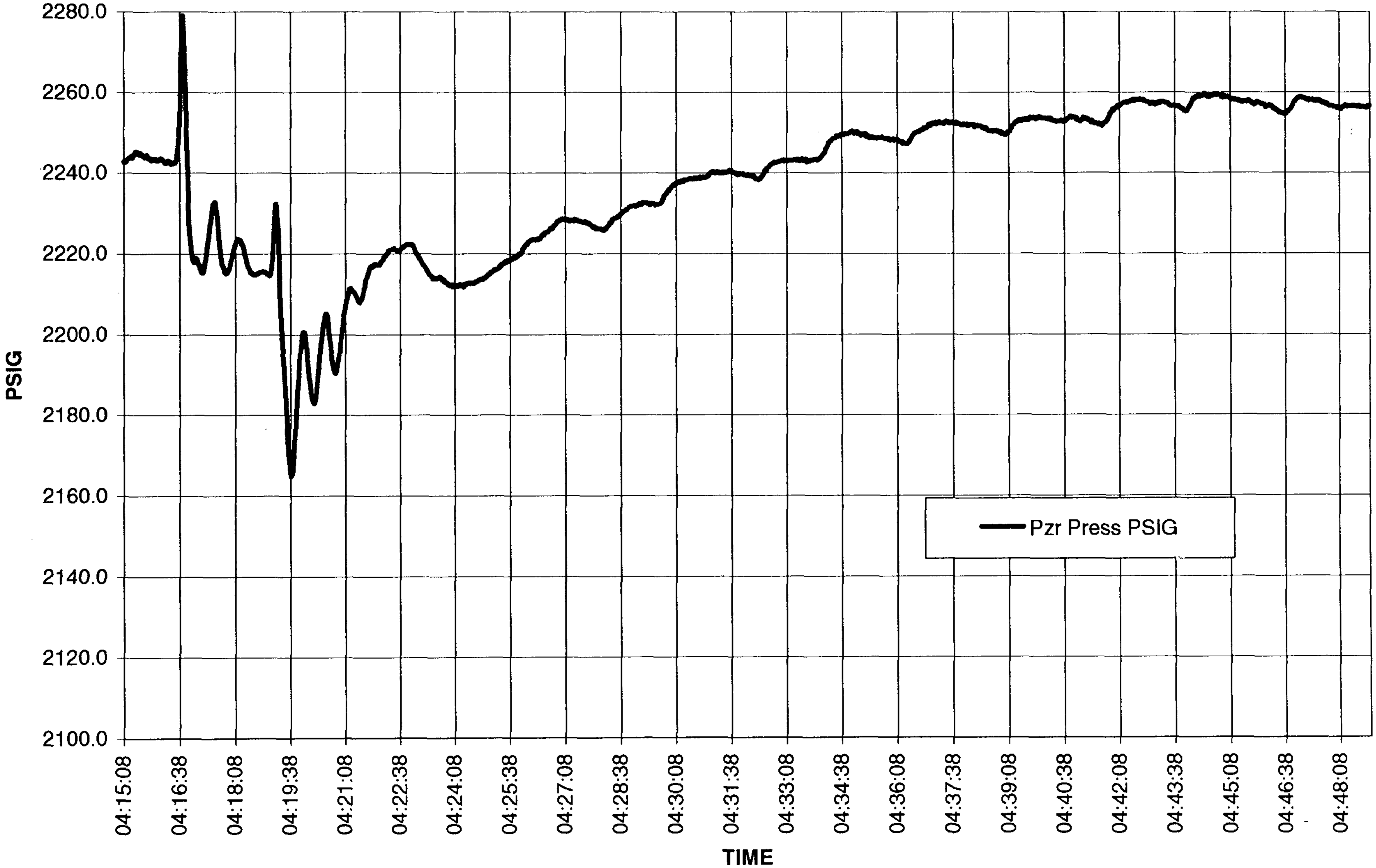


Figure 7.4.2-7
Steam Gernerator Levels vs. Time

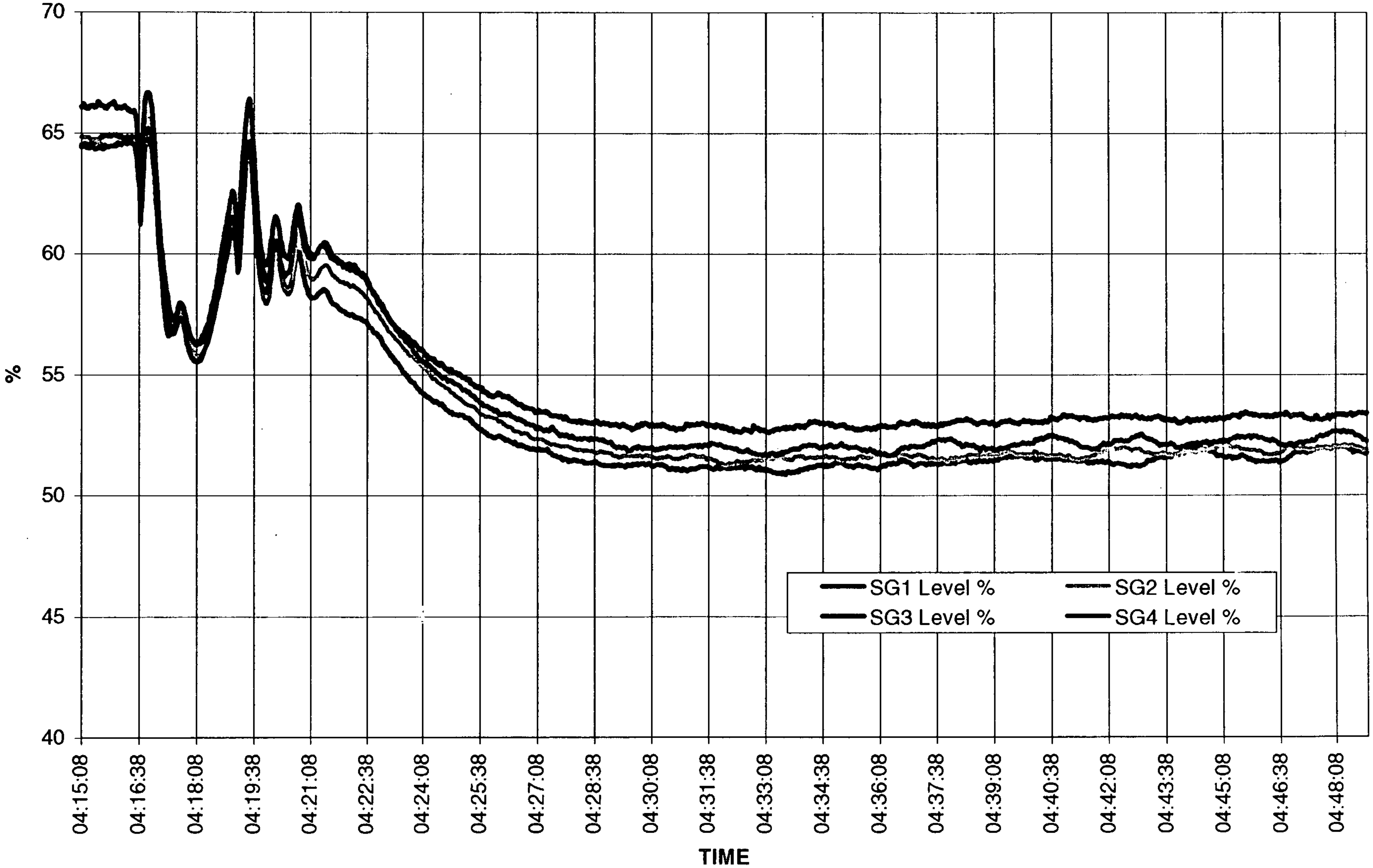
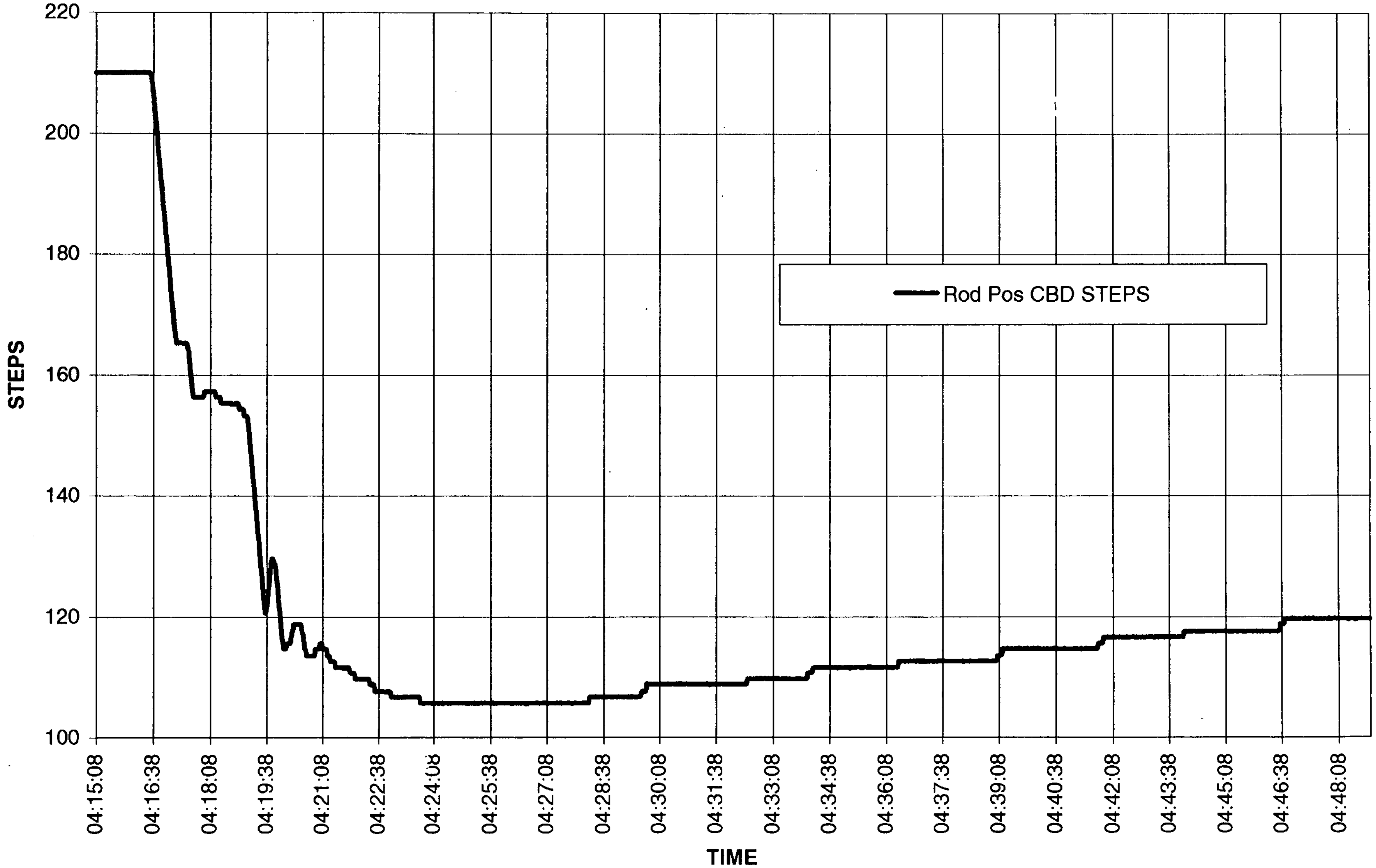


Figure 7.4.2-8
Control Bank D Position vs. Time



7.4.3 Pipe Vibration Monitoring (1-PAT-1.4)

This PAT was started on 11/21/95 and was field complete on 05/15/96. The purpose of this test was to verify that the vibration level of selected ASME Classes 1, 2, 3, and other high energy piping inside Category I structures and selected BOP piping outside Category I structures is acceptable under steady state and operational transient conditions. Steady state and transient testing is conducted on Main Steam, Condensate, Main Feedwater, Extraction Steam, Spent Fuel Pool Cooling, and Heater Drain and Vents Systems.

1.0 **Objectives**

This instruction provided verification that the vibration levels of selected ASME Class 1, 2, 3, other high energy piping inside Category I structures and selected BOP piping outside Category I structures was acceptable under steady-state and operational transient conditions.

2.0 **Test Method**

Selected locations at various flow modes and transients were observed to ensure that severe vibrations do not exist.

3.0 **Test Results**

All required acceptance criteria of this test were met as delineated below:

3.1 Visual observations (steady state vibration). See Problem 1.

3.1.1 Observed that no excessive vibrations existed, or

3.1.2 That measured velocities were less than 0.5 in/sec (peak), or

3.1.3 That the measured velocities or displacements were less than or equal to the allowable velocities or displacements per Engineering Specifications.

7.4.3 **Pipe Vibration Monitoring (1-PAT-1.4)** (continued)

3.2 Instrumented Measurements (Steady State Vibration).

3.2.1 The magnitude of steady state instrumented vibration was less than or equal to the velocity or displacement values specified by SE. See Problem 3.

3.3 Visual Observations (Transient Vibration). See Problem 2.

3.3.1 Observed that no excessive vibrations existed, and

3.3.2 Performed a posttransient visual inspection/walkdown of the transient test boundary.

3.4 Instrumented Measurements (Transient Vibration).

3.4.1 The magnitude of transient instrumented vibration was less than or equal to the velocity or displacement values specified by design. See Problem 4.

4.0 <u>Problems</u>

[1] Measured piping vibration velocity exceeded screening criteria on condensate piping during short cycle recirc mode of operation. Various supports required adjustment. The measured velocity was acceptable per SE evaluation. Supports were adjusted per the WO process.

[2] Excessive piping vibration observed on condensate piping from the MFPT condenser to SGBD 1st stage heat exchanger following loss of offsite power at 50% plateau. The condition was acceptable per evaluation by SE.

7.4.3 **Pipe Vibration Monitoring (1-PAT-1.4)** (continued)

[3] Pipe vibration data at instrumented location for FWV-3 exceeded allowable velocity and displacement criteria during steady state operation at 75% power. The condition was acceptable per evaluation by SE.

[4] Pipe vibration data at instrumented locations for FWV-5, FWV-6, FWV-7, and MSV-1 exceeded allowable velocity and displacement criteria following 100% turbine trip. The condition was acceptable per evaluation by SE.

[5] Test equipment and M&TE for this test have not been removed from the field because much of it is located inside containment or in areas inaccessible during operation. This equipment is identified under a TACF and will be removed by the WO process. The M&TE also requires a posttest calibration when removed.

7.4.4 Loose Parts Monitoring System (1-PAT-1.5)

This test was performed during the 0%, 30%, 50%, 75%, and 100% reactor power test plateaus.

1.0 Objectives

The objectives of this test were as follows:

1.1 To make tape recordings of the background noise from each of the twelve input channels.

1.2 To obtain frequency spectrums from each of the twelve input channels.

1.3 To document background and threshold signal levels of each of the twelve input channels.

1.4 To verify the adequacy of the system settings.

1.5 To document system sensitivity settings and any required changes.

2.0 Test Method

At each power plateau, the system settings were documented, tape recordings were made using the installed Loose Parts Monitoring System tape recorder, M&TE was used to obtain and produce the required frequency spectrums, and the adequacy of the system settings was verified by monitoring the system for spurious alarms.

3.0 Test Results

All required acceptance criteria for this test were met as delineated below:

3.1 The tape recordings were made.

3.2 The frequency spectrums were obtained.

3.3 The background and threshold signal levels were documented.

7.4.4 **Loose Parts Monitoring System (1-PAT-1.5)** (continued)

3.4 The system settings were verified to be adequate. The system sensitivity setting ("K") which defines the alert level as a function of background noise level did not require any change from the vendor-recommended initial setting of 2 which was established prior to the performance of the preoperational test of the Loose Parts Monitoring System.

4.0 Problems

There were no significant problems encountered during the performance of this teat.

7.4.5 Startup Adjustments of Reactor Control System (1-PAT-1.6)

This PAT was started on 01/02/96 and was field complete on 05/10/96.

1.0 Objectives

The objective of this test is to determine the T_{avg} program that results in the highest possible steam pressure and thus optimum plant efficiency without exceeding the pressure limitations of the turbine or the full load T_{avg} design limit.

2.0 Test Method

This test acquired steady-state data at the Mode 3, 30%, 50%, 75%, 90%, and 100% test plateaus to verify first stage turbine impulse pressure, steam generator pressure, and reactor coolant system average temperature are within limits. Data obtained at 75%, 90%, and 100% RTP was extrapolated to full load conditions and evaluated to determine if the full load T_{avg} design limit of 588.2°F is consistent with the design requirements of the reactor coolant system. The 90% and 100% power test data provide the basis for any adjustments necessary for the full load turbine impulse pressure value.

3.0 Test Results

All acceptance criteria were met as delineated below.

3.1 With the Rod Control System in automatic mode, the actual full load steam generator pressure was within ± 10 psi of the design full load steam generator pressure (1000 psia).

The test data demonstrated that with the Rod Control System in automatic mode and steady state plant operation at 98.36% RTP, the actual full load steam generator pressure extrapolated to 100% RTP was 996 psia. See Problems 1 and 3.

7.4.5 Startup Adjustments of Reactor Control System (1-PAT-1.6) (continued)

3.2 The full load T_{avg} value (i.e., calculated full load RCS auctioneered T_{avg} value corrected for measured RCS auctioneered T_{avg} and design T_{avg} mismatch error) does not exceed the design T_{avg} value of 588.2°F.

The calculated full load T_{avg} value was 588.7°F; however, the actual full load T_{avg} value remains 588.2°F so that the design limit will not be exceeded. See Problem 2.

4.0 Problems

[1] At the 100% test plateau, although the Rod Control System was in automatic when the test was performed, the rods were positioned against the rod stop at 220 steps.

This condition did not affect the test data, which is required to be obtained with the plant operating steady state such that there is no demand for automatic rod movement. The data obtained provided input to TACF 1-96-30-001 which rescaled 1-PT-1-72 and 1-PT-1-73. Test data from 1-PAT-1.2 demonstrated proper dynamic operation of the control rods in automatic mode.

[2] At the 100% test plateau the calculated full load T_{avg} value exceeded the design T_{avg} value of 588.2°F.

The calculation indicated that T_{avg} would have to be increased by 0.5°F in order to achieve the design value for steam pressure at 100% power. However, 588.2°F is a design limit and cannot be exceeded. 1-PT-1-72 and 1-PT-1-73 were rescaled by a TACF so that the actual first stage turbine pressure at 100% power will demand a T_{avg} of 588.2°F.

7.4.5 Startup Adjustments of Reactor Control System (1-PAT-1.6) (continued)

[3] During review of the test package, it was discovered that the corrective action section of Problem 1 did not address acceptance criteria 5.1.A which requires verification that the actual full load steam generator pressure is within ± 10 psi of the design full load steam generator pressure (1000 psia) with automatic rod control.

Data was obtained with the plant operating at steady state conditions such that there was no demand for automatic rod movement. The data shows that steam generator pressure met the ± 10 psi acceptance criteria.

7.4.6 Operational Alignment of Process Temperature Instrumentation (1-PAT-1.7)

This PAT was started on 12/31/95 and field completed on 05/09/96.

1.0 Objectives

The objectives of this PAT were to determine the full power temperature rise across the reactor vessel, to verify that the full power RCS average temperature did not exceed the maximum allowable, and to ensure that RCS temperature instrumentation is in alignment. This test was performed in Mode 3, and at approximately 30%, 50%, 75%, 90% and 100% RTP conditions.

2.0 Test Method

Section 6.1 of the test was performed prior to initial criticality with isothermal conditions established in the RCS. Temperature data was collected and reviewed to ensure that temperature instrumentation was aligned to acceptable limits.

Section 6.2 of the test was performed at each power test plateau. RCS hot and cold leg temperatures, RCS pressure, calorimetric power, and hot leg RTD streaming coefficients were measured. The RCS temperature and pressure were used to determine RCS hot and cold leg enthalpies. A curve fit was performed using these enthalpies and the associated calorimetric power from several test plateaus to extrapolate the enthalpies at full power. These extrapolated full power enthalpies were converted to the corresponding full power RCS hot and cold leg temperatures. These temperatures were used to determine the full power ΔT and T_{avg} for each RCS loop.

3.0 Test Results

All acceptance criteria were met as delineated below:

3.1 At zero power (Mode 3), core ΔT was approximately equal to 0.0% (-1.0% to +1.0%). The measured values ranged from -0.54823% to +0.42808%.

7.4.6 **Operational Alignment of Process Temperature Instrumentation (1-PAT-1.7)** (continued)

3.2 At zero power (Mode 3), steam generator level TTD ΔT was approximately equal to 0.0% (-1.0% to +1.0%). The measured values ranged from +0.00000% to +0.95789%.

3.3 At approximately 100% RTP, the highest value for the calculated T_{avg} at 100% power was less than or equal to 588.2°F. The highest value for the calculated T_{avg} was determined to be 588.15°F.

3.4 At approximately 100% RTP, the difference between reactor power and vessel ΔT was less than or equal to 1.0%. The reactor power difference ranged from +0.05% to +0.33% for the four RCS loops.

3.5 At approximately 100% RTP, the difference between reactor power and steam generator level TTD ΔT was less than or equal to 1.0%. The difference was determined to be 0.6%.

The RCS process temperature intercomparison results demonstrated that the temperature instrumentation is properly aligned.

4.0 <u>Problems</u>

[1] The initial test was performed with TE-411B NR cold leg RTD for Loop 1 out of scan in 1-R-2, thereby making performance at risk until evaluation was completed.

Evaluation showed possible error of up to 0.5% in ΔT, therefore, Retest 1 was written to collect data and perform calculations again. Retest 1 was performed successfully.

7.4.6 **Operational Alignment of Process Temperature Instrumentation (1-PAT-1.7)** (continued)

[2] There was error between the ΔT power indicated in S/G TTD rack R-5 and the calorimetric determined power level. This error is due to TE-420B NR cold leg RTD being removed from scan in R-5. A WR removed TE-420B from scan in R-5 to silence RTD failure alarms resulting from temperature differences between the two cold leg RTDs being at the redundant sensor algorithm cold leg (RSA C) limit of 2°F. When out of scan, the LCP does not use the RTD input for calculation purposes such as calculation of cold leg average temperature (TfCAve). This makes the calculated value for T_{avg} and ΔT different from the OTΔT rack R-6 which is measuring the same RTDs as R-5.

Corrective action was to manually calculate ΔT for R-5 using the analog input MMI printout obtained during Section 6.2 performance. Results showed acceptance criteria was met, no retest was required.

[3] The DAS data used for Loops 2 and 4 was from the time period ten minutes prior to data for Loops 1 and 3. Correct time period was data used for Loops 1 and 3.

Retest 2 was written to reperform data sheets and calculations (i.e., no field work required) using data from the same time as Loops 1 and 3. The new calculated data was transferred to 1-PAT-3.3 also to evaluate impact. The retest met the acceptance criteria.

7.4.7 Thermal Expansion of Piping Systems (1-PAT-1.8)

This procedure was performed during the performance of 1-PAT-3.0 through 1-PAT-8.0. This test was started on 11/21/95 and was field complete on 5/20/96. The purpose of this procedure was to confirm that piping system components and specified safety related systems designated as ASME Classes 1, 2, 3, and select BOP piping with operating temperatures greater than 200°F, experience thermal expansion consistent with design. Additionally, to verify that specific support components do not interfere with pipe thermal growth.

1.0 Objectives

This instruction demonstrates that the piping system components and specified safety related systems designated as ASME Classes 1, 2, 3, and selected BOP piping with operating temperatures greater than 200°F, experience thermal expansion consistent with design. This test verifies specific system support components do not interfere with the pipe thermal growth and satisfy the requirements of FSAR Table 14.2-2, Sheet 5.

2.0 Test Method

Selected systems, monitored at predetermined points, were verified to expand and then return without obstruction or interference. This was done for initial ambient conditions and at 30%, 50%, 75%, 100% power, and at final ambient conditions. Specified snubbers and spring hangers were inspected to ensure their movements remained within their working range.

3.0 Test Results

All required acceptance criteria of this test were met as delineated below: (See Problems 1 through 15)

3.1 Piping and components were free to expand and contract without restriction, other than by design, during power ascension heatup and cooldown of the specified systems.

3.2 The measured thermal movement was within ±1/4 inch or 10 percent of the analytical value, whichever was greater.

3.3 Spring hanger movements remained within the hot and cold working range, and snubbers did not become fully retracted or extended.

3.4 Pipe whip restraints did not interfere with the free thermal movement of the piping.

4.0 Problems

[1] There were insulation interferences on Systems 01, 02, 03, 05, 06, and 47.

In some cases, the insulation was notched per the WO process and in other cases the conditions were evaluated by SE as acceptable as is.

[2] The hanger settings were incorrect on System 05.

The hanger settings were corrected.

[3] Piping restraint J32U was in hard contact at 30%, 50%, 75%, and 100% RTP.

This was evaluated by SE as acceptable as is.

[4] Instrumented monitor points were out of tolerance at 30% 50%, 100% RTP, and return to ambient.

This was evaluated by SE as acceptable as is.

[5] A System 06 rod hanger support was broken.

The rod hanger was repaired.

7.4.7 **Thermal Expansion of Piping Systems (1-PAT-1.8)** (continued)

[6] A System 05 valve actuator was in contact with conduit.

This was evaluated by SE as acceptable as is.

[7] A System 06 rod hanger required adjustment.

The rod hanger was adjusted.

[8] System 01 support steel was in contact with a System 03 pipe.

The support was modified.

[9] Instrumented monitor points were out of tolerance at 75%.

Three System 03 supports were modified by DCN to allow for thermal movement. The remainder of the points were evaluated by SE as acceptable as is.

[10] Systems 01 and 03 piping was in contact with an HVAC duct.

The HVAC duct was removed by a DCN.

[11] A System 03 rod hanger required adjustment.

The rod was adjusted.

[12] The main steam valves were in contact with floor grating.

This was evaluated by SE as acceptable as is.

[13] There was interference between a pipe and a pipe clamp on Systems 03 and 32.

The clamp was moved.

[14] Instrumented monitor point temperature readings were greater than 100°F during the return to ambient measurement.

Readings were evaluated by SE as acceptable as is.

7.4.7 Thermal Expansion of Piping Systems (1-PAT-1.8) (continued)

[15] Test equipment and M&TE has not been removed from the field because much of it is located inside containment or in areas inaccessible during operation. This equipment is identified under a TACF and will be removed by the WO process. The M&TE also requires a posttest calibration when removed.

7.4.8 Automatic Steam Generator Level Control (1-PAT-1.9)

This test was performed as part of test sequence 1-PAT-8.0, Test Sequence for 100% Plateau. The test began on 5/8/96 and was field complete on 5/8/96.

1.0 Objective

The objective of this test was to demonstrate the proper operation and automatic response of the Steam Generator Level Control System for each steam generator during steady-state operation.

2.0 Test Method

This test collected data on Steam Generator Level Control System to verify proper system operation. Measured parameters (levels, flows, pressures, valve positions, etc.) were compared with predicted values and analyzed for stability.

This test was specified at 75% power in 1-PAT-7.0, Test Sequence For 75% Power, and at 100% power in 1-PAT-8.0, Test Sequence For 100% Power.

3.0 Test Results

3.1 At a nominal 100% power, the Main Feedwater Pump Speed Control System automatically maintained adequate feedwater header pressure such that the main feedwater control reg valves measured less than 100% open.

This criteria was successfully met by verifying that valves 1-FCV-3-35, 90, and 103 measured 80% open and 1-FCV-3-48 measured 82% open.

4.0 Problems

There were no significant problems encountered during the performance of this test.

7.4.9 Plant Process Computer (1-PAT-1.10)

This test was performed as part of test sequences 1-PAT-4.0, Initial Criticality and Low Power Test Sequence; 1-PAT-5.0, Test Sequence for 30% Plateau; 1-PAT-6.0, Test Sequence for 50% Plateau; 1-PAT-7.0, Test Sequence for 75% Plateau; and 1-PAT-8.0, Test Sequence for 100% Plateau. Testing was started on 1/20/96 and field completed on 5/14/96.

1.0 Objective

The objectives of this test were:

1.1 Obtain control room instrumentation readings to compare to plant process computer readings at steady-state power levels of 0%, 30%, 50%, 75%, and 100% of full power during power escalation to verify the accuracy of the plant process computer.

1.2 Complete a comparison of selected plant process computer calculations to other calculation methods at 100% power to verify the accuracy of the computer calculations.

2.0 Test Method

Plant performance data from selected control room indications were taken and compared to the corresponding P2500 computer points to verify that the plant computer is receiving correct inputs.

3.0 Test Results

All required acceptance criteria for this test were met as delineated below:

3.1 P2500 computer points agreed with the main control board indicators within the specified MCD values except for two cases. See Problems 1 and 2.

3.2 P2500 performance calculations agreed with alternate calculations within the specified MCD values.

4.0 <u>Problems</u>

[1] Main feedwater pump A flow and steam generator 1 feedwater flow main control board versus P2500 indication was not within the MCD acceptance criteria at the 0% power test plateau.

Neither of these indications were subject to process conditions during this performance. This condition was determined to be acceptable as is based on performance results at higher power levels where the identified channels showed response to positive process conditions.

[2] At the 100% test plateau, there was a difference in readings for 1-TR-74-14P001 and T0630A which exceeded the MCD limit (±13.2). The recorder was found to be reading approximately 20 degrees lower than the indicator and the computer log point. The recorder was calibrated.

7.4.10 RVLIS Performance Test (1-PAT-1.11)

Testing was started on 12/14/95 and field completed on 5/16/96.

1.0 Objective

To collect data during power ascension in order to determine the RVLIS scaling coefficients.

2.0 Test Method

Data was collected from each RVLIS input sensor and output from the control room plasma display as the plant progressed from Mode 4 to 100% power. The output level displays from RVLIS were reviewed at each plateau. The collected input and output data was used by SE to determine new RVLIS computer scaling coefficients and/or transmitter spans.

3.0 Test Results

All required acceptance criteria for this test were met as delineated below:

3.1 Acceptance criteria for RVLIS in Mode 3

3.1.1 RVLIS level indicated between 95.2% and 104.8% at each RCS temperature plateau with all RCPs running. See Problem 1.

3.1.2 RVLIS level indicated between 96.8% and 103.2% with no RCPs operating. Actual RVLIS level indication was 100% for both train A and train B.

3.1.3 RVLIS level indicated between 95.2% and 104.8% with all RCPs operating. See Problems 1 and 2.

3.1.4 RVLIS level indicated between 95.2% and 104.8% with at least one RCP operating. See Problems 1 and 2.

7.4.10 RVLIS Performance Test (1-PAT-1.11) (continued)

3.2 Acceptance criteria for RVLIS at Power

3.2.1 RVLIS level indicated between 95.2% and 104.8% for all power levels. Actual data is shown below:

Power	RVLIS Train A Level	RVLIS Train B Level
30%	97.96%	98.25%
50%	98.27%	99.09%
75%	99.78%	99.02%
100%	100%	100%

4.0 <u>Problems</u>

[1] At the 557°F plateau, the acceptance criteria was not met for RVLIS indication ($\geq$ 95.2%) with at least one and all RCPs running.

The test required the data be sent to SE / Westinghouse for evaluation. This test data was evaluated, and a TACF was implemented to change the dynamic range transmitters and software scaling coefficients. No retesting was required.

[2] A DN addressed acceptance criteria for multiple pump combinations. The data was forwarded to SE/Westinghouse as requested by the test, and new coefficients were generated but the test did not require multiple pump combinations to be reperformed.

A retest was performed at the 557°F plateau to verify acceptance criteria for multiple pump combinations. This retest was performed successfully.

7.4.11 RCS Flow Measurement (1-PAT-3.3)

This PAT was started on 01/01/96 and field complete on 05/09/96 based on the final 100% performance of 1-PAT-1.7, Operational Alignment of Process Temperature Instrumentation.

1.0 Test Objectives

The specific objective of this PAT is to determine the reactor coolant flow.

1.1 To determine the RCS flow rates (prior to initial criticality) via calculations using the three installed elbow tap differential pressure transmitters in each of the RCS loops.

1.2 To determine the RCS flow rates in Mode 1 during 1-PAT-6.0, 1-PAT-7.0, and 1-PAT-8.0 test plateaus.

2.0 Test Method

The performance of Section 6.1 was performed with the plant in Mode 3 at nominal hot zero power, temperature, and pressure prior to initial criticality as directed by 1-PAT-3.0, Post Core Loading Precritical Test Sequence. This section of the test measured the differential pressures across the elbow at the outlet of each steam generator, and from these values, RCS flow was calculated.

The performance of Sections 6.2, 6.3, and 6.4 were calculational only where RCS flow is determined from a secondary plant calorimetric and the RCS hot and cold leg enthalpy using Data Sheets 1 and 5 from 1-PAT-1.7. These performances were conducted at the 50%, 75%, and 100% testing plateaus respectively.

3.0 Test Results

All required acceptance criteria of this test were met as delineated below:

7.4.11 RCS Flow Measurement (1-PAT-3.3) (continued)

3.1 The RCS flow determined by calorimetric measurement at or above 90% power was equal to or greater than the Technical Specification limit of 397,000 gpm. The 100% power plateau test data was evaluated against this criterion.

At 98.35% power, the total RCS flow was 400,498 gpm.

3.2 The RCS flow determined by calorimetric measurement in Mode 1, 75% test sequence plateau was equal to or greater than the Technical Specification limit of 397,000 gpm.

At 71.58% power, the total RCS flow was 403,838 gpm.

All test objectives within the scope of this test were met; all acceptance criteria were satisfied.

4.0 Problems

There were no significant problems encountered during the performance of this test.

7.4.12 Calibration of Steam and Feedwater Flow Instrumentation at 100% Power (1-PAT-8.4)

This test was performed as part of test sequence 1-PAT-8.0, Test Sequence For 100% Plateau. The test began on 5/8/96 and was field complete on 5/8/96.

1.0 Objectives

The objectives of this test were to verify the calibration of feedwater flow and steam flow instrumentation by comparing indicated flows with calculated flows, and to collect data for determining the calibration spans for each steam flow transmitter.

2.0 Test Method

The test obtained data from other tests performed in Mode 3 at normal operating pressure and temperature, and at ascending power levels of 30%, 50%, 75%, and 100%. The tests utilized to obtain the data were 1-PAT-3.11, Adjustment of Steam Flow Transmitters at Minimal Steam Flow; 1-PAT-5.4, Calibration of Steam and Feedwater Flow Instrumentation at 30% Power; 1-PAT-6.3, Calibration of Steam and Feedwater Flow Instrumentation at 50% Power; 1-PAT-7.1, Calibration of Steam and Feedwater Flow Instrumentation at 75% Power; and 1-PAT-8.4, Calibration of Steam and Feedwater Flow Instrumentation at 100% Power. Secondary side parameters of pressure, temperature, and flows were collected. Feedwater flow to each steam generator was calculated using the collected data. This calculated feedwater flow was used as the basis for comparison with the permanent instrumentation. A curve fit using calculated feedwater flow and the measured differential pressure spans from each steam flow transmitter were used to determine the differential pressure spans for each steam flow transmitter.

3.0 Test Results

The span for each steam flow transmitter was normalized to feedwater flow as indicated by the following:

7.4.12 Calibration of Steam and Feedwater Flow Instrumentation at 100 % Power (1-PAT-8.4) (continued)

3.1 There are no steam flow/feedwater flow mismatch alarms.

This criteria was successfully met. All alarms were verified clear.

3.2 Steam generator water level control can remain in automatic.

This criteria was successfully met.

4.0 Problems

There were no significant problems encountered during the performance of this test.

7.4.13 Shutdown From Outside the Control Room (1-PAT-8.5)

This test was performed from approximately 30% reactor power during the testing in test sequence 1-PAT-8.0, Test Sequence For 100% Plateau. This test was started and completed on 5/15/96.

1.0 <u>Objectives</u>

1.1 This test satisfied the objectives of Regulatory Guide 1.68.2, Initial Startup Test Program To Demonstrate Remote Shutdown Capability For Water-Cooled Nuclear Power Plants, as follows:

- This test demonstrated the capability to safely shutdown the unit from outside the main control room.
- This test demonstrated the capability to maintain hot standby (Mode 3) conditions from outside the main control room for at least 30 minutes using the minimum shift crew.
- This test demonstrated the unit can be safely cooled from hot standby to cold shutdown conditions from outside the main control room. This objective is satisfied by a cooldown of approximately 50°F performed in this test and the cooldown demonstrated in preoperational test PTI-068-13, Shutdown From Outside The Main Control Room.

1.2 This test satisfied the requirements of FSAR Table 14.2-2, Sheet 32, Shutdown From Outside the Control Room Test Summary, Amendment 91. The objective statement for this test summary was "to demonstrate that the unit can be taken to and maintained in the hot standby condition from outside the control room. This test will be performed during the 100% power testing plateau and will be initiated from approximately 30% power."

7 4.13 **Shutdown From Outside the Control Room (1-PAT-8.5)** (continued)

2.0 Test Method

A reactor trip was initiated from a location outside the main control room. After confirmation of the reactor/turbine trip, operator actions were taken to abandon the main control room in accordance with appropriate operating instructions. Actions were taken to achieve and maintain hot standby conditions for at least thirty minutes from locations outside the main control room. Finally, the unit was cooled down approximately 50°F to show cooldown capability and control.

3.0 Test Results

All required acceptance criteria for this test were met as delineated below:

3.1 The unit was tripped from outside the main control room and was controlled at hot standby conditions from outside the main control room for at least 30 minutes using the Technical Specification's minimum shift crew. The unit was maintained at hot standby for 30 minutes.

3.2 The ability to cool the unit down approximately 50°F using the appropriate operating instructions was demonstrated. The unit was cooled down 55°F.

4.0 Problems

There were no significant problems encountered during the performance of this test.

7.4.14 Plant Trip From 100% Power (Turbine Trip) (1-PAT-8.6)

This PAT was performed as part of test sequence 1-PAT-8.0, Test Sequence for 100% Plateau. This test was started and field completed on 5/12/96.

1.0 Objectives

1.1 To demonstrate the ability of primary side systems to bring the unit to stable conditions following a plant trip resulting from opening of the generator output breaker.

1.2 To determine the overall response time of the RCS narrow range hot leg RTDs.

1.3 To satisfy the test requirements described in FSAR Table 14.2-2, Sheet 36, Plant Trip From 100% Power Test Summary.

2.0 Test Method

This test demonstrated the ability of primary and secondary plant systems, including automatic control systems, to sustain a plant trip from full power and determined the response time of the narrow range hot leg RTDs.

The plant was at steady-state full power conditions with control systems in automatic for this transient test. A full load rejection was initiated by the manual opening of the generator output breaker. The turbine tripped as a direct result of opening the generator output breaker, and a reactor trip followed the turbine trip. Primary and secondary plant parameters were monitored throughout the transient until stability was achieved. Operators took manual control of the plant systems as directed by the operating procedures and allowed by this test.

Test data was evaluated to determine if control system setpoint changes were required to improve the plant's transient response.

7.4.14 Plant Trip From 100% Power (Turbine Trip) (1-PAT-8.6) (continued)

3.0 Test Results

All required acceptance criteria of this test were met as delineated below:

3.1 A safety injection was not initiated as a result of the plant trip.

3.2 The steam generator safety valves did not lift as a result of the plant trip.

3.3 The pressurizer safety valves did not lift as a result of the plant trip.

3.4 The reactor tripped, and all RCCAs released and dropped as a result of the plant trip.

3.5 The overall response time for the RCS narrow range hot leg RTDs was less than or equal to 7.60 seconds. The actual measured response time was 6.0 seconds.

3.6 Nuclear flux decreased rapidly, as demonstrated by indicated NIS power decreasing to less than or equal to 15% within 2.0 seconds after the turbine trip. The actual measured time for NIS power to reduce to ≤ 15% was 1.6 seconds.

3.7 The main turbine did not trip as a result of overspeed.

Figures 7.4.14-1 through 7.4.14-5 depict the performance results.

4.0 Problems

There were no significant problems encountered during the performance of this test.

Figure 7.4.14-1
Pressurizer Pressure vs Time

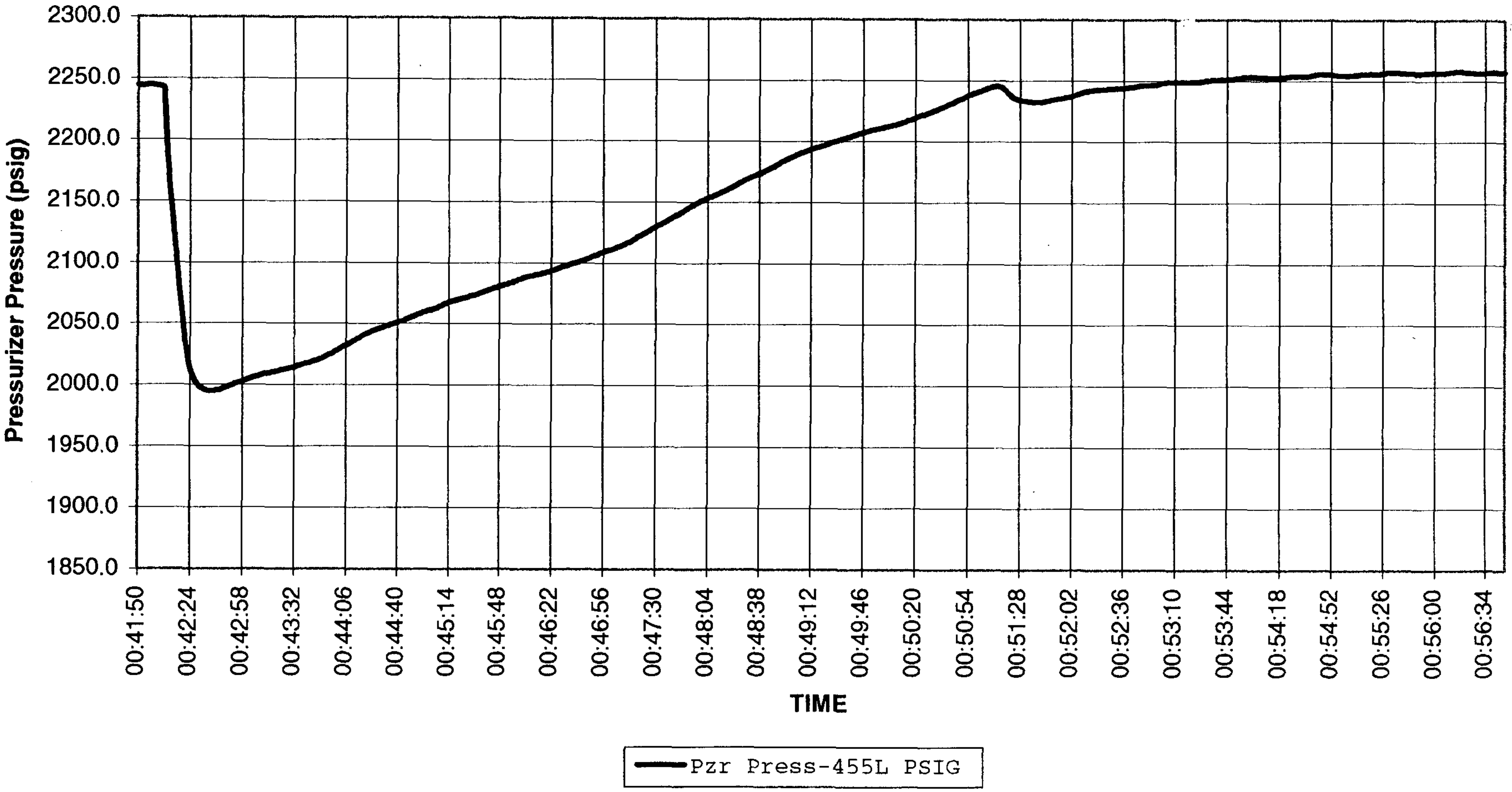


Figure 7.4.14-2
Pressurizer Level vs Time

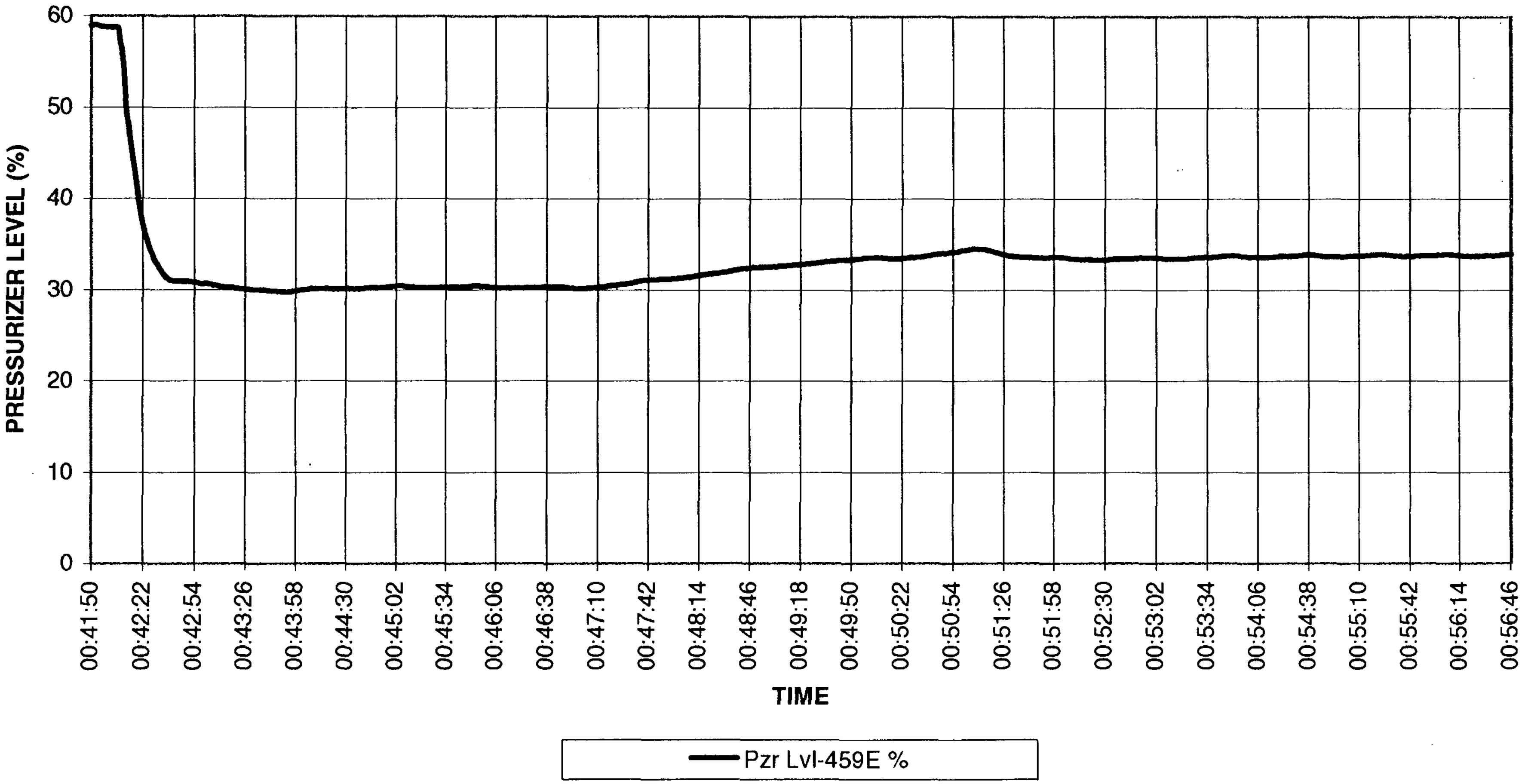


Figure 7.4.14-3
Steam Flow / Feedwater Flow vs Time

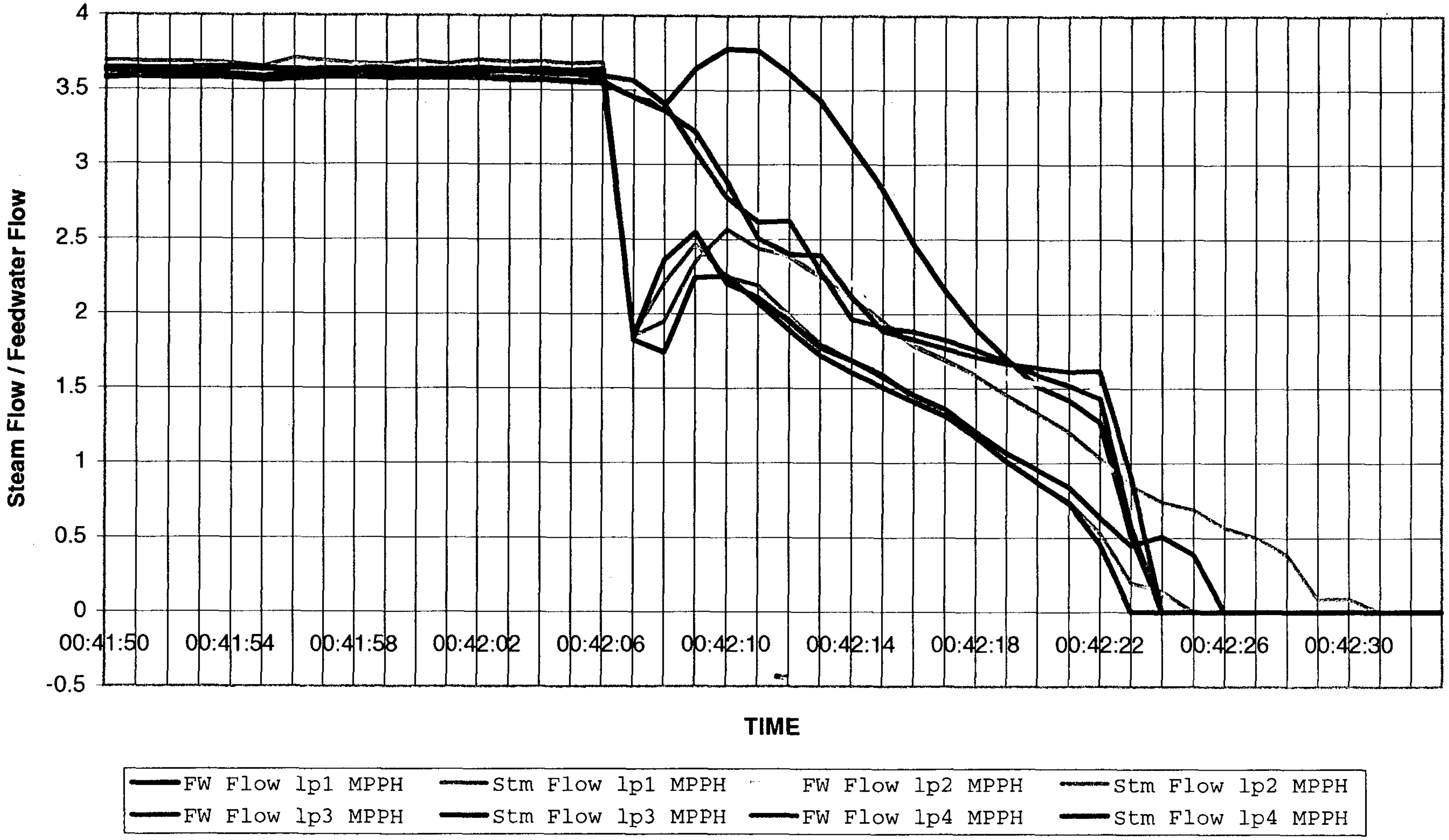


Figure 7.4.14-4
Steam Header Pressure / Feedwater Discharge Header Pressure vs Time

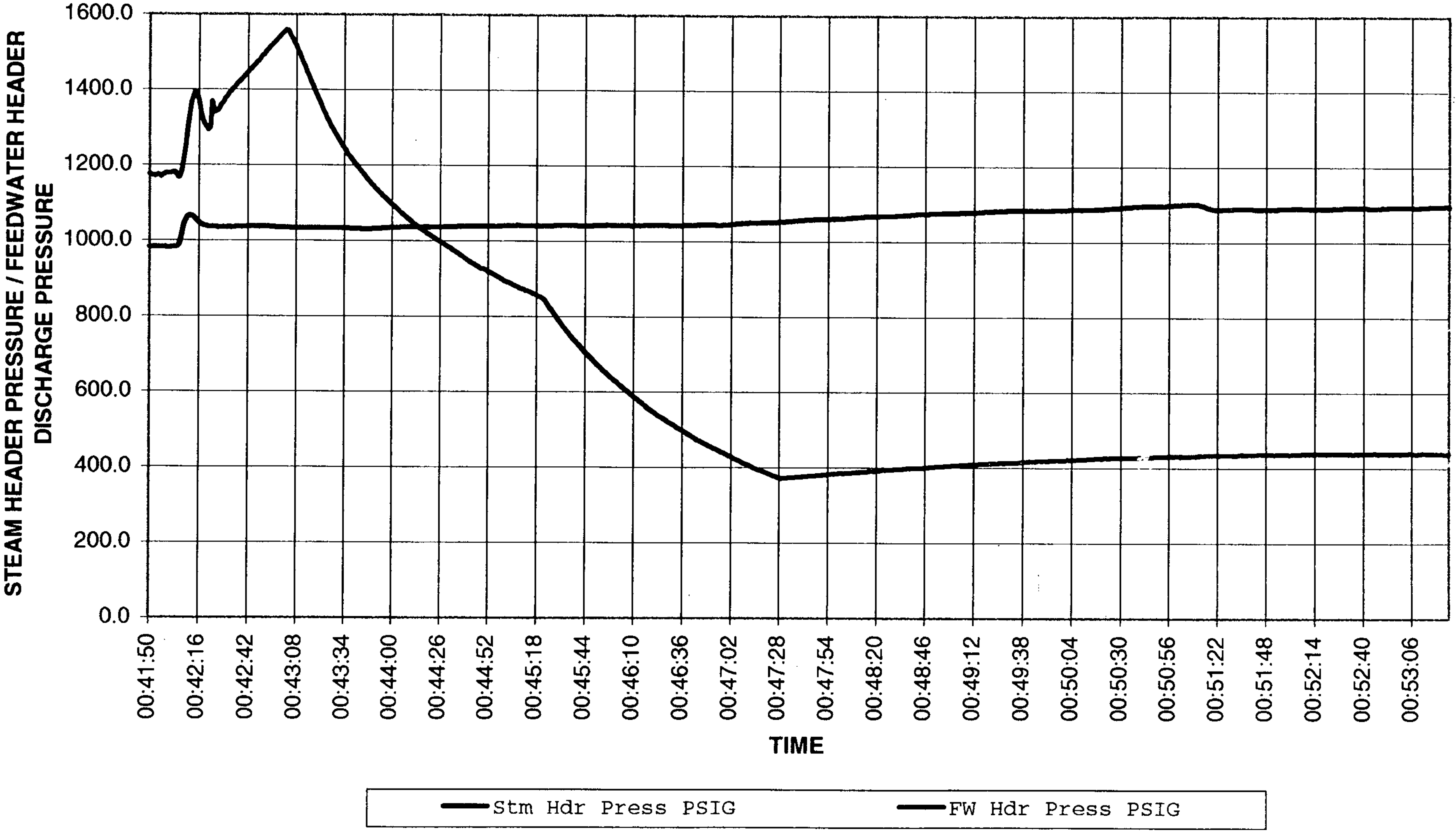


Figure 7.4.14-5
NIS power vs Time

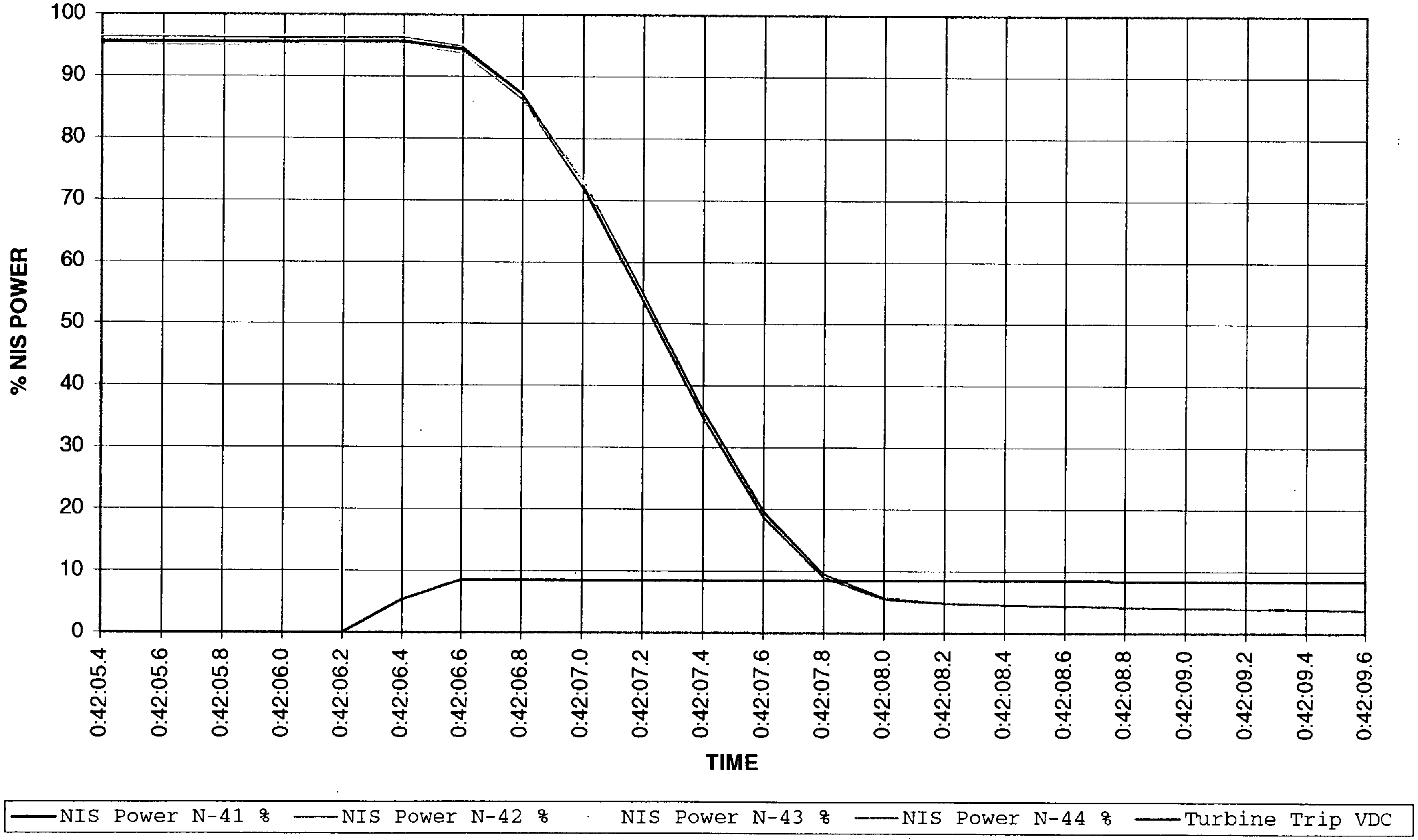
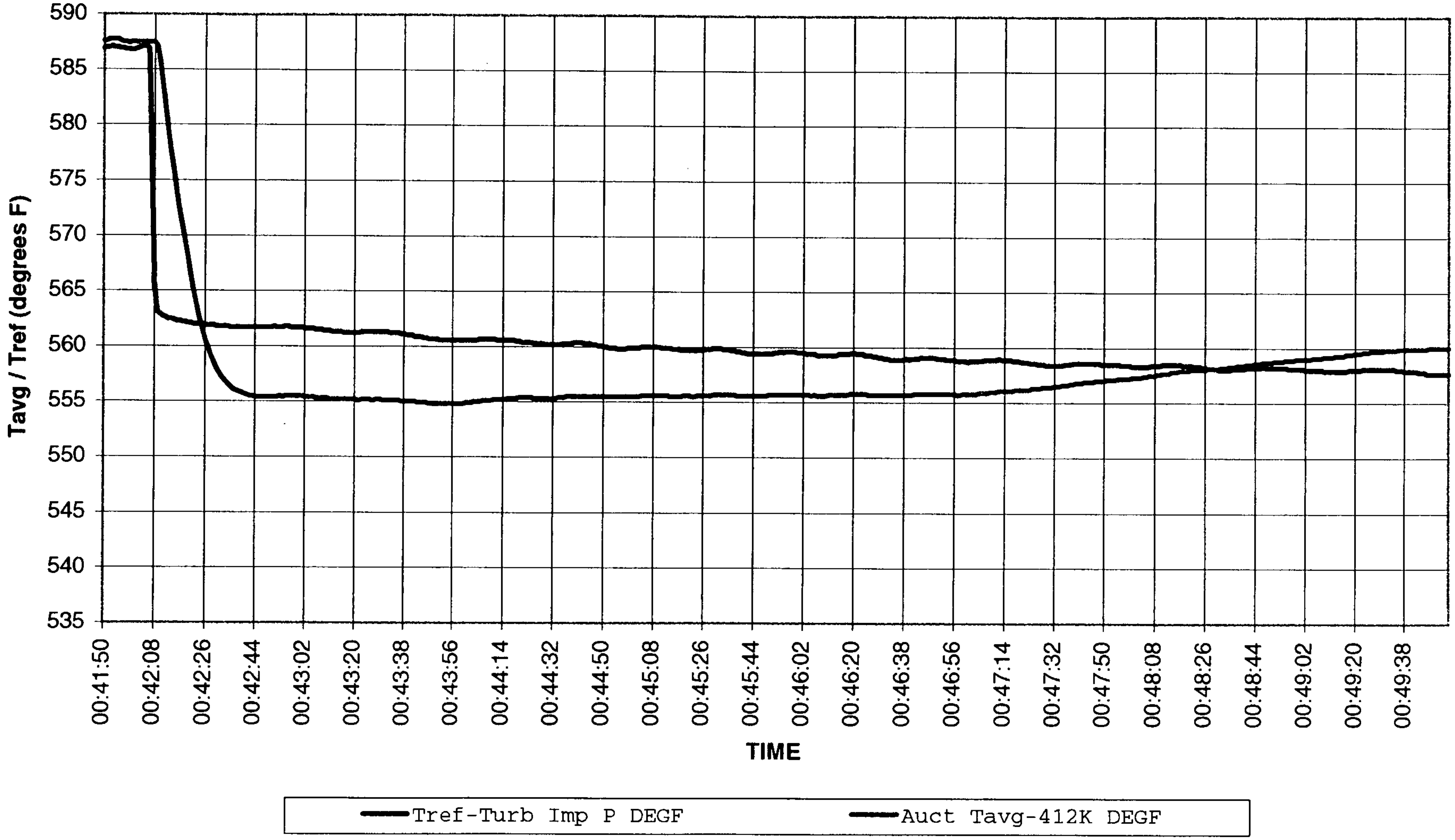


Figure 7.4.14-6
T_{avg} / T_{ref} vs Time



7.4.15 Core Power Distribution Factors (PET-301)

This PET was started on 03/08/96 and was field complete on 05/09/96.

This test was performed utilizing data from normally performed plant procedures under normal operating conditions to confirm core performance parameters.

1.0 Objectives

The specific objectives of this PET were as follows:

1.1 To confirm core performance parameters such as heat flux hot channel factor (F_Q^z), nuclear enthalpy rise hot channel factor ($F^N_{\Delta H}$), and QPTR are within specified limits.

1.2 Verify proper reactor core performance and provide assurance that the plant can be operated at design full power within the limits imposed by the plant Technical Specifications.

2.0 Test Method

This test was performed utilizing data from normally performed plant procedures under normal operating conditions to confirm core performance parameters. This test was performed at the 30%, 50%, 75%, 90%, and 100% test plateaus. Incore flux map data taken at each test plateau was reviewed to verify proper reactor core performance and provide assurance that power escalation to the next test plateau could proceed safely.

3.0 Test Results

All required acceptance criteria of this test were met as delineated below:

3.1 The measured incore quadrant tilt was ≤1.04. The actual measured results are shown below:

7.4.15 Core Power Distribution Factors (PET-301) (continued)

Test Plateau	30%	50%	75%	90%	100%
Measured Tilt	1.0147	1.0127	1.0111	1.007	1.0135

3.2 The measured hot channel factors (peaking factors) were within their respective T/S limits. The measured values for the limiting F^N_{DH} and the limiting $F^C_Q(Z)$ (Equil.) along with their associated T/S limits are shown below:

Test Plateau	30%	50%	75%	90%	100%
$F^N_{\Delta H}$ Limit	1.896	1.822	1.685	1.609	1.566
$F^N_{\Delta H}$ Measured	1.4871	1.4782	1.4510	1.432	1.431
$F^C_Q(Z)$ Limit	4.800	4.800	3.3850	2.7460	2.4870
$F^C_Q(Z)$ Measured	2.1140	2.0852	2.0880	2.0811	2.0597

3.3 The measured T/S QPTR is ≤1.02. The actual measured T/S QPTR results are shown below: (note that the T/S QPTR is not applicable below 50% RTP)

Test Plateau	75%	90%	100%
Measured QPTR	1.006	1.006	1.009

3.4 The high flux trip power level that the measured hot channel factors (peaking factors) can support was determined, and the impact to the 100% testing plateau was evaluated. There was no impact on the power plateau of 100% RTP. Hot channel factors supported operating at 100% RTP.

3.5 The absolute value of the difference between predicted and measured core reactivity (core reactivity balance) at HFP was less than 1000 pcm. The actual measured core reactivity difference was 159 pcm.

4.0 Problems

There were no significant problems encountered during the performance of this test.

7.4.16 Operational Alignment of NIS (PET-304)

This PET was started on 01/14/96 and was completed on 05/23/96.

1.0 Objectives

The specific objectives of this PET were as follows:

1.1 To ensure proper alignment or adjustment of the NIS.

1.2 To govern the conservative lowering of power range trip values in support of Power Ascension Testing.

1.3 To verify overlap between source range and intermediate range as well as between intermediate range and power range channels.

1.4 To verify the linearity of the power range channels in relation to reactor power.

2.0 Test Method

This test was performed utilizing data from normally performed plant procedures under normal operating conditions and utilized normally performed plant procedures to adjust/calibrate the NIS channels.

3.0 Test Results

All required acceptance criteria of this test were met as delineated below:

3.1 SR, IR, and PR channels were operable and calibrated to meet Technical Specifications and PR high flux trips were set less than or equal to 20% RTP above each power plateau prior to escalation to the plateau.

3.2 At least two decades of overlap existed between the SR and IR channels. Actual overlap was over four decades between the SR and IR channels.

3.3 At least 50% of RTP overlap existed between the IR and PR channels. Actual overlap was 100% of RTP between the IR and PR channels.

7.4.16 Operational Alignment of NIS (PET-304)

4.0 Problems

There were no significant problems encountered during the performance of this test.

7.4.17 Radiation Baseline Survey (RCI-126)

The baseline survey was started 11/06/96 and was field complete on 05/08/96.

1.0 Objective

To determine the effectiveness of the shielding by measuring radiation doses at preselected locations throughout the plant.

2.0 Test Method

Baseline gamma and neutron dose rates were monitored at preselected locations throughout the plant at ambient conditions after fuel load and at various power levels(<10%, 50%, 100%) during the PATP.

3.0 Test Results

All radiation levels were within design limits as specified in the FSAR as shown below.

Location	Maximum Criteria	Highest Result
Auxiliary Bldg	<1000.0 mRem/hr	0.100 mRem/hr
Control Bldg	<0.050 mRem/hr	0.007 mRem/hr
Environmental points	<0.050 mRem/hr	0.010 mRem/hr
	<5.000 mRem/hr(1 point)	0.012 mRem/hr
Reactor Bldg	100.0 REM/hr	2.060 REM/hr
Service Bldg	<0.050 mRem/h	0.008 mRem/hr
Turbine Bldg	<0.050 mRem/hr	0.008 mRem/hr

4.0 Problems

There were no significant problems encountered during the performance of this test.

8.0 SUMMARY

The Watts Bar Unit 1 Startup Test Program has shown that the plant operates as designed, will not endanger the health and safety of the public, and can withstand transients that can reasonably be expected during its lifetime.