CONTRACTOR REPORT

SAND84-8186
UC-62d
Unlimited Release

Thermal Storage Test Report TSU Bed Conditioning (1040A) Thermal Storage System Controls Test (1040B)

McDonnell Douglas
Huntington Beach, Ca

Prepared by Sandia National Laboratories, Albuquerque, New Mexico 87185 and Livermore, California 94550 for the United States Department of Energy under Contract DE-AC04-76DP00789.

Printed November 1984

When printing a copy of any digitized SAND Report, you are required to update the markings to current standards.

Issued by Sandia National Laboratories, operated for the United States Department of Energy by Sandia Corporation.
NOTICE: This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, nor any of the contractors, subcontractors, or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government, any agency thereof or any of their contractors or subconractors. The views and opinions expressed herein do not necessarily state or reflect those of the United States Government, any agency thereof or any of their contractors or subcontractors.

Printed in the United States of America
Available from
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161

NTIS price codes
Printed copy: A11
Microfiche copy: A01

10 MWe Solar Thermal
Central Receiver Pilot Plant

Thermal Storage Test Report
TSU Bed Conditioning (1040A)
Thermal Storage System Controls Test (1040B)

November 1983

DISCLAIMER

This report was prepared as an account of work sponsored by Sandia National Laboratories. Neither the United States nor Sandia National Laboratories, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed,or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, mark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

MCDONNELL DOUGLAS ASTRONAUTICS COMPANY
5301 BOLSA AVENUE
HUNTINGTON BEACH, CA 92647

PREPARED FOR
SANDIA NATIONAL LABORATORIES
UNDER CONTRACT 84-8173

ABSTRACT

This report which is provided by the McDonnell Douglas Astronautics Company (MDAC) documents work conducted Sandia National Laboratory Contracts No. 84-8173. The report documents the TSU Bed Conditioning (Test 1040A) and the TSS Controls Test (Test 1040B) preoperational test results for the 10 MWe Solar Thermal Central Receiver Pilot Plant System.

Questions concerning this document should be directed to R. G. Riedesel at (714) 896-3357.

ACKNOWLEDGEMENTS

The following people contributed to the Tests, Analyses and Documentation contained within this report:

1040A - E. C. Cady

1040B - E. J. Riel, A. B. Smee, R. M. Berry, D. Lenartz, T. McKeown J. Raetz, S. I. Ogawa, and J. Said

CONTENTS

FIGURES

TABLES

NOMENCLATURE

A/D	Analog to digital converter
A/F	Analog filter
AL	Analog line
A/M	Auto/manual transfer point
AMUX	Analog multiplexor
AOV	Air operated valve
CO	Controller output
CTU	Control transfer unit
Cv	Flow coefficient
D/A	Digital to analog converter
DARMS	Data acquisition remote multiplexing system
DAS	Data acquisition system
db	decibels
EPGS	Electrical power generation system
FC	Flow controller
FO	Fail open
FT	Flash tank
FV	Flow valve
Gm	Gain margin
GN_2	Gaseous nitrogen
ILS	Interlock logic system
KLBH	Thousands of pounds per hour
K_1	Proportional gain
K_2	Derivative gain
K_3	Integral grain
LC	Level controller
LCM	Level controller
LIC	Level indicating controller
LT	Level transmitter
LV	Level valve
LVDT	Linear voltage displacement transducer
MCC	Motor control center
MOV	Motor operated valve
MT	Mode transfer
MVCU	Multivariable control unit
MW	Megawatts
P	Pressure
P	Proportional controller (controller block diagrams)
PC	Pressure controller
PI	Pressure indicator
PI	Proportional and integral controller (controller block diagrams)
PID	Proportional, integral, and derivative controller (controller block diagrams)
PIH	Pressure indication high
ppb	parts per billion
psig	pounds per square inch gage
PV	Process variable (controller parameter)
PV	Pressure valve
Q	Volumetric flow
RS	Receiver system
SCU	Signal conditioning unit

SDPC	Subsystem distributed process control
SDS	Steam dump system
SNLL	Sandia National Laboratories Livermore
SOV	Solenoid operated valve
SP	Set point
T	Temperature
TC	Temperature controller
TFA	Transfer function analyzer
TSCH	Thermal storage charging system
TSSG	Thermal storage extraction (steam generation) system
TSS	Thermal storage system
TSU	Thermal storage unit
UMU	Ullage maintenance unit
TV	Temperature valve
UPS	Uninterruptable power supply
UV	Modulating control valve
V	Voltage
Vin	Input signal voltage
V	Output signal voltage
w/m^2	watts per square meter
$\dot{W}$	Mass flow
ZI	Position indicator
ΔP	Pressure difference
ΔT	Temperature difference
ρ	Density
τ	Time constant

<u>Subscripts</u>

C	Commanded
D	Delay
e	electrical
E	Edge
FB	Front to back
IN	Inlet
LP	Lateral panel
m	Metal
MAX	Maximum value
MIN	Minimum value
OUT	Outlet
REF	Reference condition
S	Steam

Section 1

INTRODUCTION

The Operational Test Program for the 10 MWe Central Receiver Solar Thermal Pilot Plant (Solar One) consists of four series of tests which are designed to fully demonstrate the plant operating capabilities and to develop operating/maintenance, performance, and related cost data which are applicable to future central receiver programs. The test series which are documented in Reference 1 (Appendix A) consists of:

I. Startup (1000 Series Tests)

II. Manual Control (1100 Series Tests)

III. Automatic Control (1200 Series Tests)

IV. Engineering (1300 Series Tests)

The 1000 Series Tests include the testing required to startup the receiver and thermal storage systems and to bring them into a fully operational status. Their specific goals are to

(i) demonstrate the integrated operation of the solar portion of the plant (receiver and thermal storage) with other plant systems and

(ii) verify satisfactory control system operation under actual operating conditions.

The major elements of the 1000 Series Tests are

(i) 1010 - Receiver "Cold Flow" (Controls) Preoperational Test

(ii) 1030 A & B - Receiver Steam Generation (Controls) Test

(iii) 1040 A - Thermal Storage Activation

(iv) 1040 B - Thermal Storage Charging and Extraction (Controls) Test

This report documents the combined test activities for the 1040A and 1040B TSS startup tests. It is divided into the following major sections:

- Section 1 - Introduction
- Sections 2 and 3 - 1040A Test Program and Results
- Sections 4 and 5 - 1040B Test Program and Results
- Section 6 - Special Studies
- Section 7 - Conclusions and Recommendations

The "Test Program and Results" sections describe the testing which was carried out in support of specific test objectives and special studies which are aimed at specific areas of concern.

Discussions related to the individual test objectives attempt to document the final equipment operating characteristics. In some cases, special studies are continuing beyond the publication date of this report utilizing receiver and TSS data gathered during on going plant operation. In those cases, "most current" information is used in this report and a study status is given.

The 1040 test series deals primarily with the Thermal Storage System (TSS) and includes the preoperational tests, initial test conditioning of the TSU tank, clean-up of the oil and steam sides of both charging and extraction trains and controls verification testing of all TSS control loops in their normal operating environment. The overall 1040 test program included Thermal Storage Activation (1040). In test 1040A the primary energy source was a rental boiler and the system was exercised at below normal operating conditions for the purpose of removing contamination and sediment from the oil. In test 1040B the primary energy source was receiver steam for charging loops, TSU stored energy for the extraction loops and the TSS system was operated throughout its normal operating range of conditions.

The systems of the Solar One generating station required for this test include:

- Condensate
- Feedwater
- Receiver
- Collector
- Circulating Water
- Cooling Tower
- Vacuum
- Sumps and Drains
- Auxiliary Steam
- Raw/Service Water
- Demineralized Water
- Gaseous Nitrogen
- Compressed Air
- Plant Control
- Plant Electrical
- Thermal Storage Charge
- Thermal Storage Extraction

Detailed description of each of these systems as well as other plant systems are contained in Reference 2 (Appendix A). In addition, the Data Acquisition System (DAS) was fully operational at the onset of this test program and as a result onsite DAS displays as well as data archiving were used to support the individual test activities.

It should also be noted that for selected sections of this report, the data presented were recorded after the actual test program was carried out as part of a retest activity. These retests were conducted to properly archive and document the final operating characteristics. Since most early testing was conducted over an extended period of time under changing operating conditions as well as some major modifications were made to existing control equipment as the testing progressed. These retests were for the most part carried out on a noninterference basis with the ongoing plant testing activities.

From an information presentation standpoint, this report makes wide use of two standard plot formats that were available through the onsite Data Acquisition System and the McDonnell Douglas data analysis system respectively. Information regarding the interpretation of these plots is contained in Appendix B of this report. Descriptive information is also contained in Appendix B pertaining to the format and understanding of Bode and Nyquist plots which are used in the body of the report to document hardware dynamic responses and controller stability. It is recommended that the generic plot information contained in this appendix be reviewed before attempting to interpret test data or analysis results contained in actual report plots.

1.1 TEST SCOPE

The principal activities of the 1040 test are summarized schematically in Figure 1.1-1. These activities include a verification of the following:

Test 1040A

(i) The TSU tank operation

(ii) TSS charge and extraction pumps

iii Auxiliary steam generation

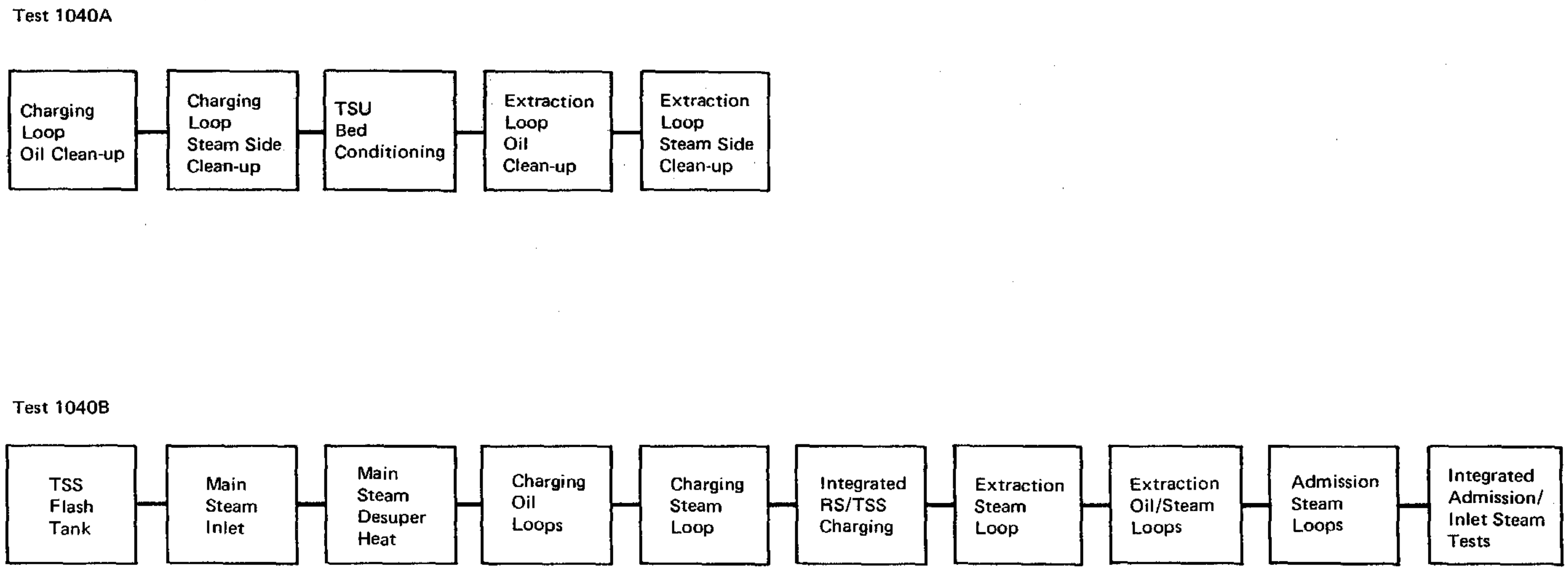


Figure 1.1-1. Top Level Thermal Storage Test 1040 Activities

The principal flow paths that were exercised for test 1040A are shown in Figure 1.1-2. It should be noted that control testing was excluded from 1040A although control valves were manually controlled from the control room and safety, alarm, and trip systems were active.

Test 1040B

The scope and activity flow of the 1040B test program is shown in Figure 1.1-1. The general objectives of the 1040B series preoperational tests were to:

(a) Verify the "process" operation of solar specific portions of the plant.

(b) Develop the control functions and/or field tune the individual plant controllers.

(c) Verify selected portions of the Plant Operating Procedures.

These activities included a verification of the following:

(i) Main steam change loop operation

(ii) TSS flash tank operation and steam/condensate distribution system

(iii) Charging condenser system operation including both steam and oil side operation

(iv) Extraction steam generator system including feedwater, steam and oil side operation

(v) Auxiliary steam equipment

(vi) Turbine admission steam operation

(vii) TSU thermocline

Test 1040B dealt primarily with operation and control loop tuning of the TSS control loops. These loops are summarized in Figure 1.1-3.

1.2 PREREQUISITE TESTING

As a prerequisite to the 1000 Series tests, 28 invididual system startup tests were carried out to verify construction completion. These tests included basic mechanical, electrical, and instrumentation and controls

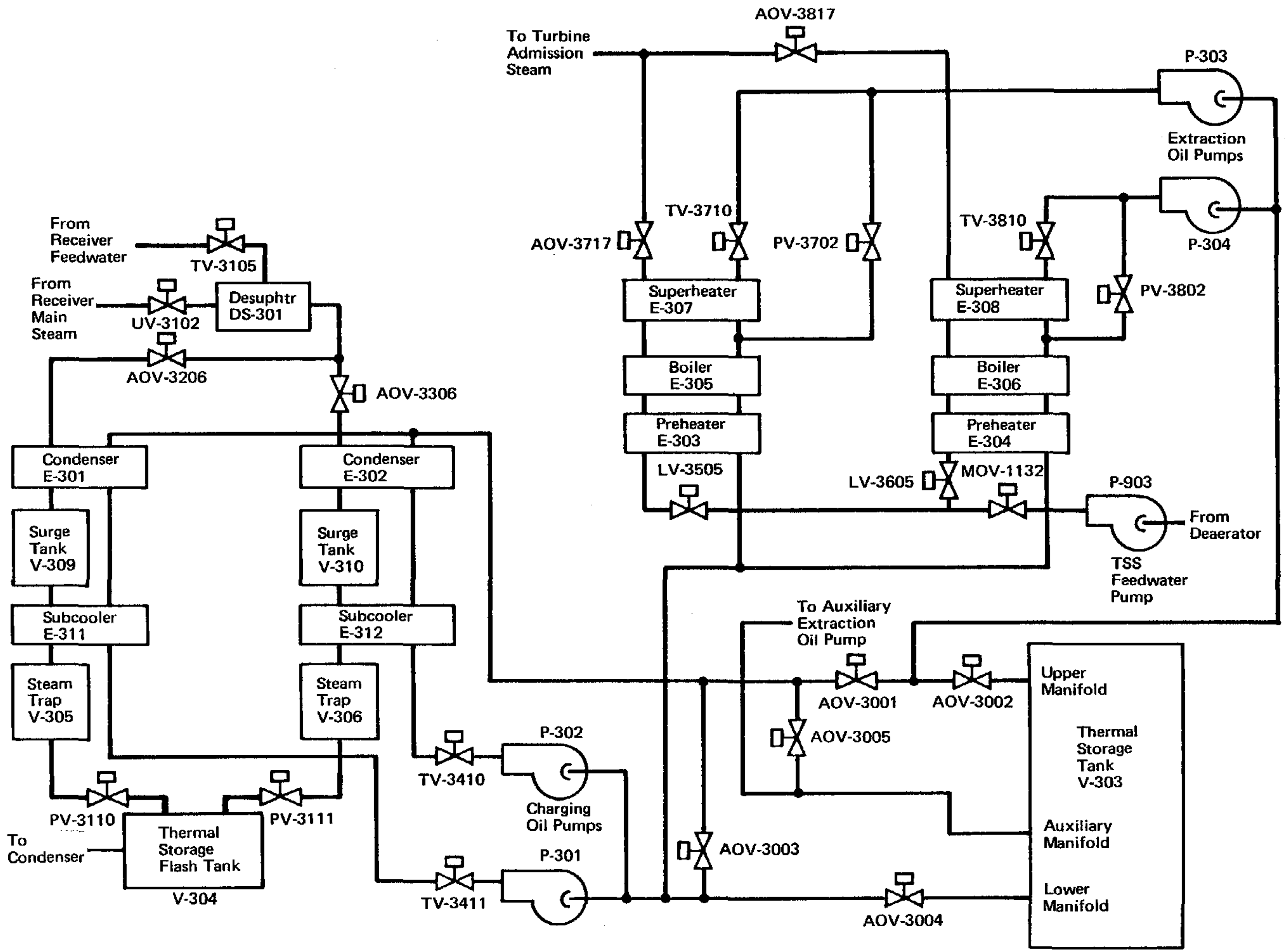


Figure 1.1-2 Test 1040 Principal Flow Paths

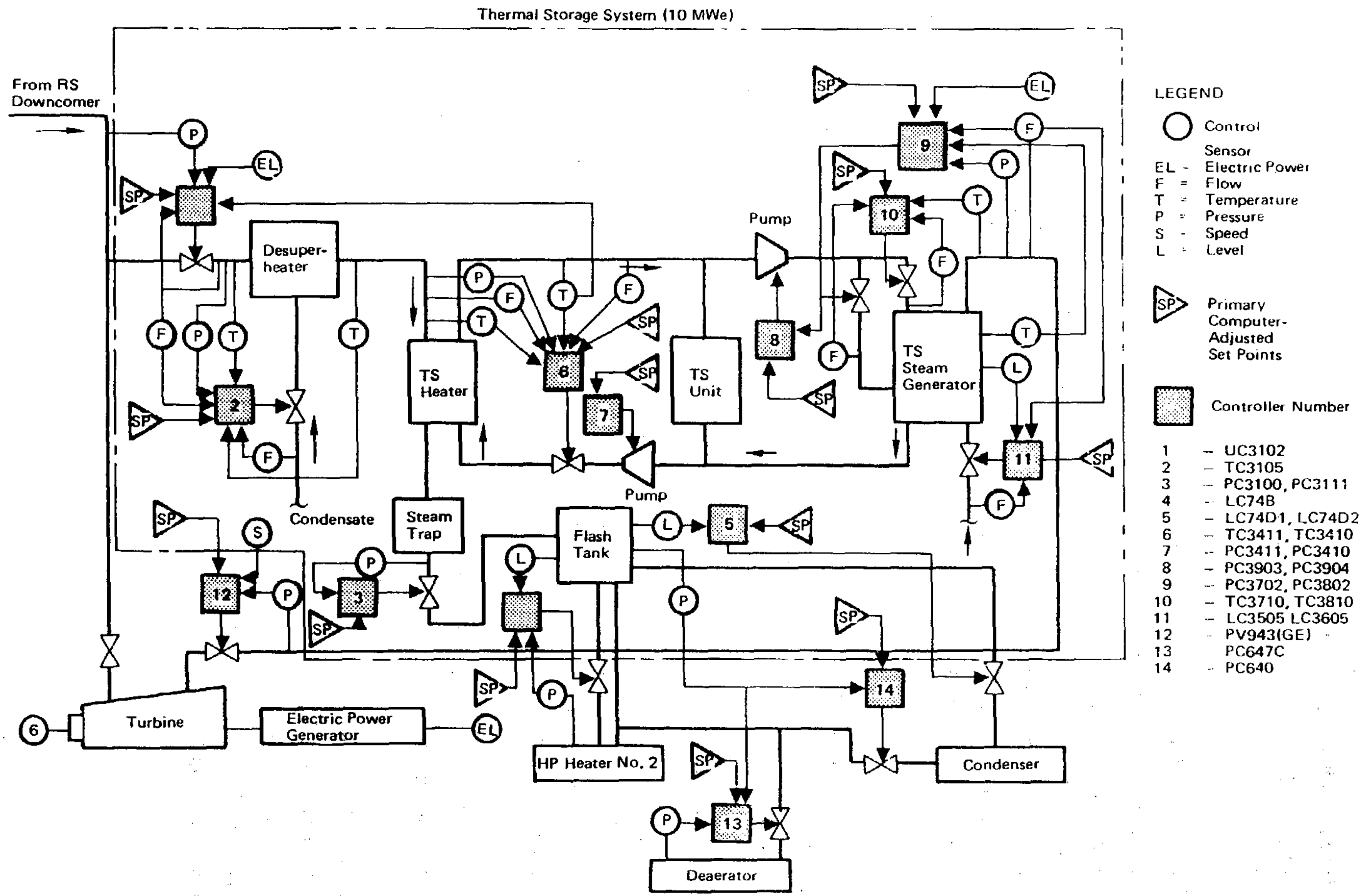


Figure 1.1-3. Thermal Storage Subsystem Control Loop Configurations

checks. In addition, all safety devices were verified and trip systems functionally checked to ensure safety operations once actual plant operations were initiated. The individual system startup tests are listed in Table 1.2-1 by system number.

The extent to which individual systems were ready for normal operation upon completion of these prerequisite tests varied from system to system. Tests involving standard utility systems e.g., water supply, cooling water, nitrogen resulted in totally operational systems. Tests involving the receiver and thermal storage on the other hand were carried out as "dry" tests in which normal process fluids (water, steam, or oil) were not flowing. Tests involving actual process flow conditions for these systems were deferred to the 1000 series tests.

Test 1040A was completed as a prerequisite to test 1040B. Also completion of test 1030 was also required prior to test 1040B in order to insure a stable source of steam for charging loop operational testing.

1.3 PLANT/EQUIPMENT STATUS

During the course of the 1040A test program, all required plant systems and support equipment listed in the test procedure except the Data Acquisition System (DAS) were fully operational and available to support the test activities. The DAS on the other hand was still undergoing checkout at the time Test 1010 was initiated. As a result, early data gathering was done using hand records. Subsequent portions of the test utilized the data scanning and hardcopy capabilities of the SDPC.

During the course of the 1040B test program, all required plant systems and supporting equipment listed in the test procedure were fully operational and available to support the test activities. This included the Data Acquisition System which was not available for most of the precursor test 1040A activities.

Table 1.2-1. Prerequisite Startup Tests

000	Receiver System
100	Collector System
150	Beam Characterization System
205	Thermal Storage Oil System
250	Thermal Storage Steam System
305	System Distributed Process Controllers (SDPC)
340	Operating Control System
360	Heliostat Array Controller
405	Main/Admission Steam System
420	Miscellaneous Steam Systems
505	Condensate
550	Feedwater
600	Circulating Water
705	Turbine Generator - Mechanical Systems
750	Turbine Generator - Electrical and Control Systems
805	Main/Auxiliary Power Transformers
820	Collector Power
830	Load Centers and MCCs
855	Low Voltage Systems
860	DC and UPS
871	Heat Tracing System
901	Instrumentation and Service Air Systems
905	Nitrogen
910	Water Supply Systems
940	Plant Drains and Sumps
951	Cooling Water System
956	Sampling System
960	Mechanical Support Systems

Significant test delays and work arounds were included during the 1040B testing due to short outages, flowmeter and level sensor anomalies, insufficient water quality, operational problems using admission steam for turbine roll, heat exchanger leaks, and other higher priority tests.

1.4 PRELIMINARY PLANT OPERATIONS

As a prerequisite to the charging loop operation certain feedwater chemistry limits had to be established since receiver operation was required. Certain chemistry limits were also improved for extraction operation. These limits are summarized in Table 1.4-1.

Table 1.4-1. Feedwater Chemistry Limits

	Flow to Boiler Panels	Receiver Steaming Operation	Extraction Steaming Operation
Fe	10 ppb	10 ppb	10 ppb
Silica	20 ppb	20 ppb	20 ppb*
Chloride	2 ppb	2 ppb	2 ppb
Copper	2 ppb	2 ppb	2 ppb
O_2	15 ppb	7 ppb	7 ppb
N_2H_4 (Hydrazine)	200 ppb	10-30 ppb	10-30 ppb
Conductivity	6-10 μmho	6-10 μmho	6-10 μmho
Cation Conductivity	0.6 μmho	0.3 μmho	0.3 μmho
Na	8 ppb	2 ppb	2 ppb
pH	9.0-9.6	9.45-9.6	9.45-9.6
Total Solids	60 ppb	50 ppb	50 ppb

ppb - Parts per Billion

* Silica content of the water in the boiler may be as high as 500 ppb. Steam out of the train must be 20 ppb or less.

A daily cleanup period through the water treatment loop was conducted prior to establishing flow to the receiver. The duration of this "daily" cleanup flow varied from a few hours to several days. The extended cleanup periods normally occurred following the activation of new piping networks or during periods of air inleakage to the condenser.

With no exception, as new system piping was opened to steam flow for the first time, the feedwater contamination increased sufficiently to cause the operating limits to be violated. This occurred despite the fact that extensive velocity flush, chemical cleaning, and steam blow activities had been carried out 4-6 months earlier, immediately following construction. In many cases, the contamination was in excess of the acceptable limits by several orders of magnitude, forcing the inline demineralizers to be bypassed and blowdown and draining operations to be initiated.

Whenever possible, steam line free blows were established prior to integrating new steam lines into the system. These blows would be carried out on an intermittent basis for several days prior to opening up the complete steam flow path. In addition, off shift use of the auxiliary electric boiler was made to accelerate the rate of system cleanup.

In all cases, the cleanup associated with activating new piping systems progressively improved following repeated steam flow and cleanup operations. Contamination was reduced to acceptable levels which would permit continuous daytime operation to support receiver and TSS testing. In most cases, acceptable water chemistry was maintained during the nightly shutdown cycle or rapid cleanup was accomplished with minimal feedwater circulation immediately prior to startup.

Section 2

TEST PROGRAM - 1040A

2.1 TEST OBJECTIVES AND ACCEPTANCE CRITERIA

The objective of the TSU bed conditioning test program (1040A) was to heat the thermal storage media (rock, sand and oil) in the TSU to 250°F - 300°F removing all water in the bed and enabling oil circulation at higher flows and temperatures for removal of contamination and sediment from the oil.

The acceptance criteria were considered satisfied when the bed was heated to a minimum of 250°F, and the filters in the oil charging loops had a pressure drop of less than 2 psid during two hours of oil flow at an oil flow rate of 500,000 lb/hr in each train at an oil temperature of 250°F. These criteria were scaled from nominal operating conditions.

2.2 TEST METHODOLOGY AND SPECIAL TEST EQUIPMENT

2.2.1 Test Methodology

The basic method for achieving TSU bed condition was to use the TSS charging train(s) together with, initially, a rental boiler and associated temporary piping (described below in Section 2.2.2) and later, receiver steam. The rental boiler was used to minimize interference with receiver testing and provide easily controllable low-temperature steam (approximately 300°F) for the initial TSU bed conditioning. The procedure used was to alternately send steam through the steam side of charging trains 1 and 2 heating the oil on the oil side of the trains. The hot oil so produced was then directed to the TSU establishing a thermocline. Water/steam leaving the charging heat exchangers were exhausted to the atmosphere since they were contaminated with impurities. The oil was continuously filtered to remove particulate contamination. The water/steam and oil flow paths are shown schematically in Figure 2.2-1. The following functions were provided simultaneously:

1. Steam blows cleaned out the steam/water side of the charging trains.
2. Oil was circulated, heated, and filtered, cleaning out the oil side of the charging trains.
3. The charging system heated up the oil, rock and sand in the TSU, boiling off and removing any entrained water in the TSU or charging trains.

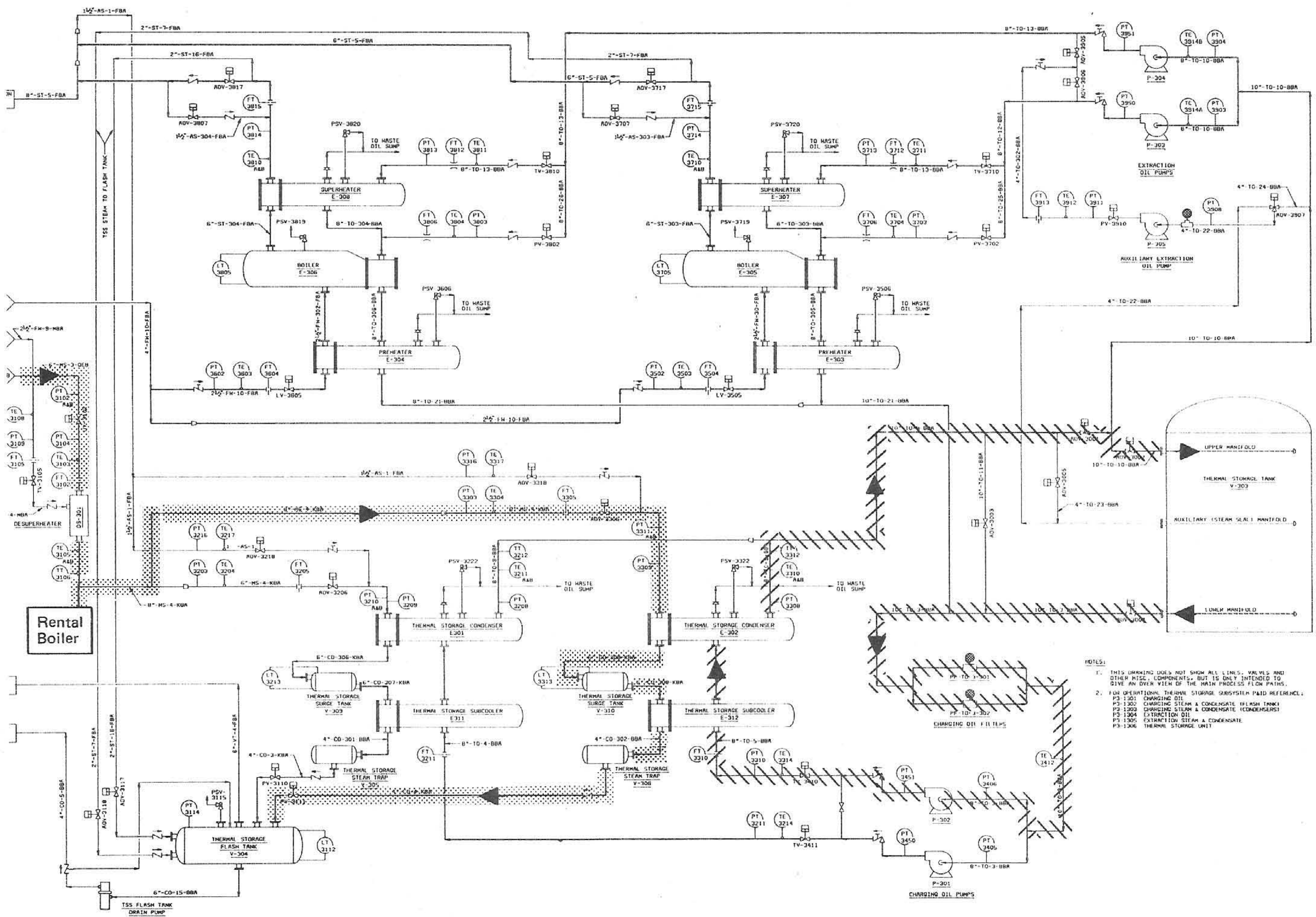


Figure 2.2-1. Flow Circuits for Heating Oil with Rental Boiler Steam

When the temperature throughout the TSU reached a minimum of $250^{O}F$ (the local water boiling point at the bottom), and steam generation and venting ceased, it was assumed that all water was removed from the oil piping, equipment, and TSU. Once the minimum temperature was reached and water condensate from the charging trains tested acceptably clean, the hot oil in the TSU was used to generate steam in the extraction trains, which was exhausted to the atmosphere through various pipe runs of the trains to clean the steam/water side of the extraction trains. The actual operating procedure was to run the charging train oil loops in series with the extraction train oil loops, bypassing the TSU, as shown in Figure 2.2-2. This directed the oil from the extraction trains through the permanent charging filters, assuring cleanup of the oil side of the extraction trains.

In general, steam was exhausted to the atmosphere from both charging and extraction trains, until the steam/water cleanliness was good enough to allow recovery of the water through the condenser system. The steam flow paths for cleaning were as follows: for charging trains, (1) free blows from condensers and preheaters, (2) free blow from TSS Flash Tank drain, and finally, (3) water circulation through the Flash Tank drain pump through temporary piping to the TSS Blowdown Tank, and then to the plant drains. For the extraction trains, (1) free blows from the boilers and superheaters, (2) blowdown to the condenser from the TSS Flash Tank through PV-640, LV74D1 and D2, and (3) flows through the turbine admission system and deaerator (PV-647C).

2.2.2 Special Test Equipment

The special test equipment in this test program included a rental boiler and associated temporary piping. The rental boiler was used to provide 20,000 lb/hr of saturated steam at 200 psig. The specifications for the rental boiler are shown in Table 2.2-1. The rental boiler was adjusted to burn Caloria HT-43. This was an economic decision designed to save both fuel costs and demurrage costs on a rail car of excess Caloria. The rental boiler and the temporary piping were located as shown in Figure 2.2-3. The temporary piping was as follows:

1. Rental boiler support piping: fuel supply and return to 8000-gallon temporary fuel tank; demineralized water supply; steam blowdown line to TSU berm.

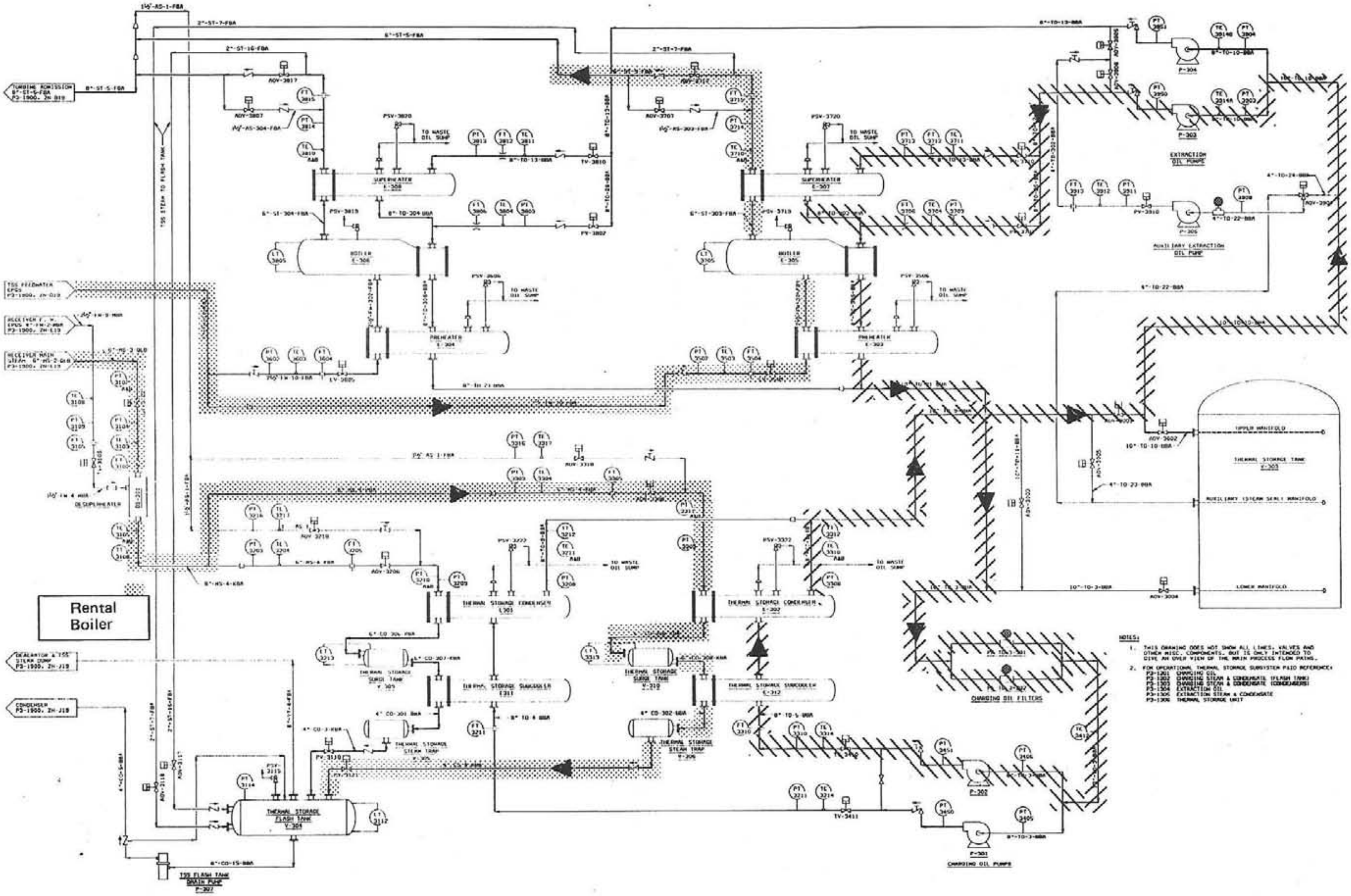


Figure 2.2-2. Flow Circuits for Combined Charging/Extraction with Rental Boiler Steam

Table 2.2-1
RENTAL BOILER SPECIFICATIONS

1970 Trailer-Mounted 20,000 lb/hr (600 HP) Erie City Package watertube boiler 250 psi design pressure with a special oil gun to burn excess Caloria as fuel, with the following equipment:

a. Bailey thermohydraulic single element feedwater regulator and three-valve bypass arrangement

b. Auxiliary on/off feedwater pump control

c. Two blowdown valves

d. Continuous surface blowdown metering valve

e. Two safety valves

f. Six-inch 250 psi main steam stop/check valve

g. Stub smokestack

h. Cleveland electric positioning controls

i. Oil pump set

j. Fireye flame safeguard system

k. Second low water cut-off

l. High and low water alarms

m. Factory Mutual Insurance Requirements

n. N.E.M.A. 4 electrical enclosures and seal tite conduit

o. Control circuit transformer

p. All TEFC motors

q. Fully weatherproof for outdoor installation

Also mounted on the trailer, a skid-mounted feedwater pump and 300 gallon tank system complete with the following equipment:

a. Pump and motor

b. Tank preheater and regulator

c. Stand and skid

d. Suction piping, valving and strainers

e. 230/460 volt, 3 phase operation

f. Neptune chemical treatment system--prepiped and wired on the feedwater skid.

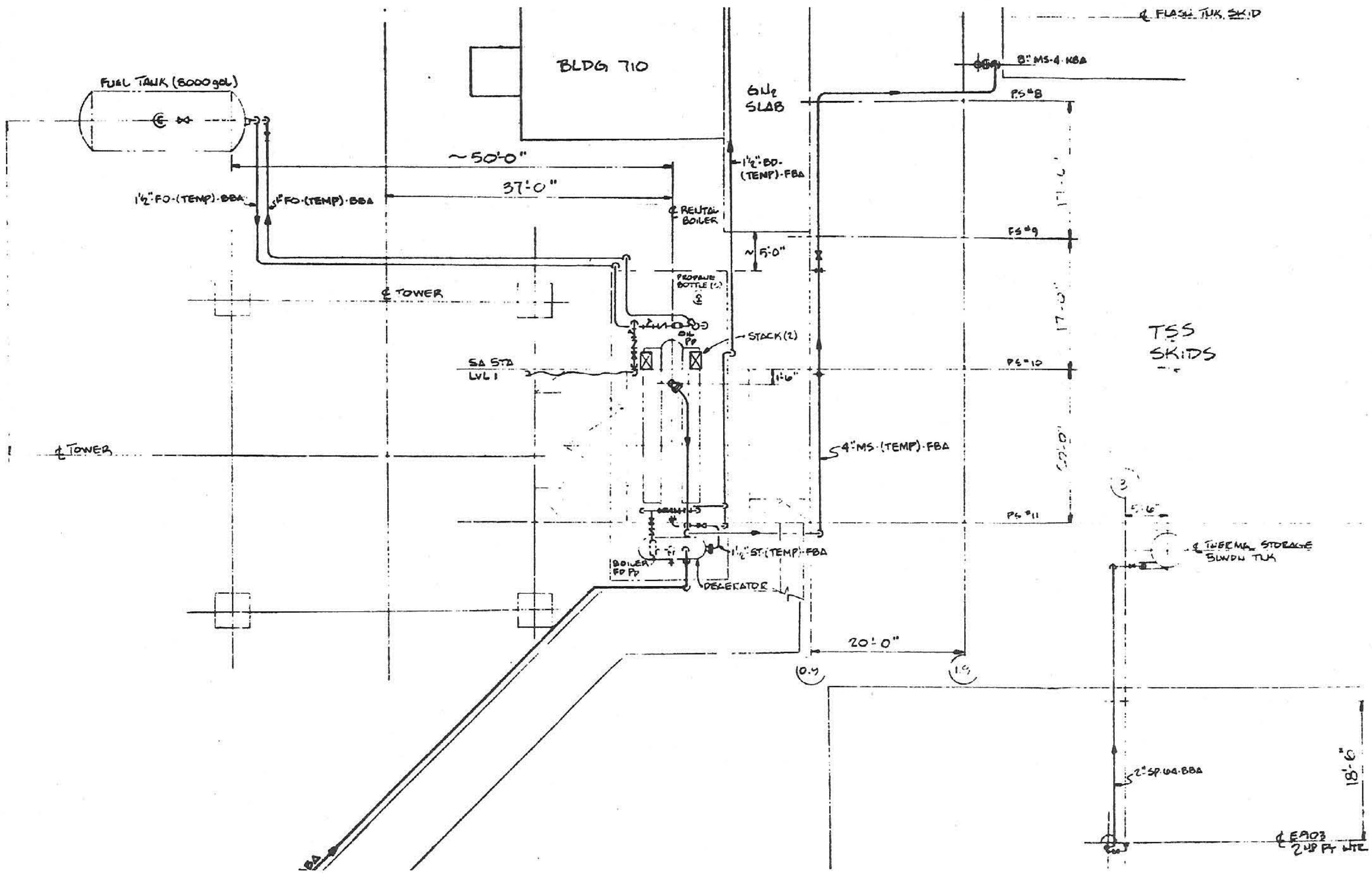


Figure 2.2-3. Rental Boiler Installation Layout

2. Main steam supply line (4"-MS-(TEMP)-FBA) from rental boiler to TSS Flash Tank desuperheater outlet line (8"-MS-4-KBA).

3. Blowdown line (2"-SP-64-BBA) from LV74B upstream block valve to TSS Blowdown Tank.

Temporary main steam piping (2, above) also included a drain valve and a block valve which was used during startup for TSS warmup and operating transient control.

2.3 TEST CHRONOLOGY

The test chronology for both the Procedure 240 Cold Flow tests and for the 1040A test (TSU Bed Conditioning) is shown below:

Event	Date
Thermal Storage System Flushing Test Procedure 240 Rev. 0 Released	3/15/82
Started Cold Flow Testing	3/15
Running Charging Trains 1 and 2 in Parallel	3/17
8" Plastic Pipe Cap Found in Oil Filter	3/18
Charging Train 2 Preliminary Cleanup	3/23
Charging Train 1 Preliminary Cleanup	3/24
Charging Train 1 and Extraction Train 1 in Series	3/24
Charging Train 1 and Extraction Train 1 Preliminary Cleanup	3/30
Charging Train 2 and Extraction Train 2 in Series	3/30
Charging Train 2 and Extraction Train 2 Preliminary Cleanup	4/28
Procedure 240 Complete	4/30
Engineering/Specifications/Procurement of Rental Boiler	3/22-4/21
Rental Boiler on Site	4/19
Installation of Rental Boiler and Temporary Piping	4/19-4/30
TSU Bed Conditioning Procedure 1040A Rev. 0 Released	4/30
1040A Orientation Meeting for SCE Operators	5/3
Oil Pump Trip Problems due to Fire Protection System	5/3-5/5
Started 1040A: Heated Oil in Charging Train 2	5/5
Charging Train 2 Initial Oil Cleanup Complete	5/12
Started Charging Train 1 Oil Heatup/Cleanup	5/13
Charging Train 1 Oil Cleanup Complete	5/25
Restarted Charging Train 2 Oil Heatup/Cleanup	5/26
Charging Train 2 Oil Cleanup Complete	6/9

UMU Pressure Switches Failed - Incorporated ILS Control of TSU Pressure	6/14-6/17
Dismantled Rental Boiler Installation	6/14-6/17
Rental Boiler Left Site	6/17
Started Train 2 Oil Heatup Using Receiver Steam	6/21
Started Train 1 Oil Heatup Using Receiver Steam	7/9
Steam Blows Through PV-640, LV74D1,-D2	7/15
Started Extraction Train 1 Steam Blowdown	7/22
Started Extraction Train 2 Steam Blowdown	7/26
Steam Blowdown of Both Extraction Trains 1 and 2	8/4
Steam Blow of Admission Steam Line (Turned Turbine) and LV74B	8/17
Extraction Trains 1 and 2 and Admission Steam System Clean	8/25
Generated 4.9 MW on Admission Steam from Extraction Train 2	8/25

Section 3
TEST RESULTS - 1040A

3.1 INITIAL OIL LOOP CLEANUP

3.1.1 Cold Flow Oil Cleanup

Cold Flow (Procedure 240) was used to provide the initial cleanup of the oil loops in both the charging and extraction trains. During the design phase, the concern was that during charging (suction from bottom of TSU), sand and/or fines from the TSU would find their way out through the oil piping to the charging trains; hence dual, large (10 in.) permanent filters were installed upstream of the charging pumps. These filters were set up with differential pressure (ΔP) instrumentation across them so that the degree of filter plugging could be determined. These instruments had a range of 0-100 in. H_2O (3.6 psid) with alarms to the operator at 90 in. H_2O (3.25 psid). The general procedure employed was to start the oil pump at a high commanded flowrate, observe the filter ΔP, and progressively reduce flow as the ΔP reached 90-100 in. H_2O, until the flowrate could be reduced no further, and a low flow trip of the oil pump occurred. This is shown in Figure 3.1-1 typically for charging train 2. The initial oil flow set (FI3310) was about 520,000 lb/hr, but the filter plugged (ΔP-reached 90 in. H_2O) in 2 minutes. The flow rate was progressively reduced to about 100,000 lb/hr but the filter ΔP remained at $\sim$100 in. H_2O requiring the pump to be shutdown and the filters cleaned. The procedure was then repeated.

Initially, with the oil flow circulated through the filters, oil pumps, train equipment, and returned to the top manifold of the TSU (see Figure 3.1-2) minimal filter plugging occurred. Because of the higher pressure drop through the TSU, the maximum oil flowrate was limited to about 140,000 lb/hr to maintain pump inlet pressure above approximately 13 psia and avoid cavitation (high viscous losses in the piping with cold oil were the cause of this restriction). At these flows, the pump ran for 20 hours with essentially no increase in ΔP across the filter (5 in. H_2O). It was apparent that no contaminants were coming out of the TSU, so the charging system was set up to bypass the TSU, as shown on Figure 3.1-3. With this arrangement, the oil

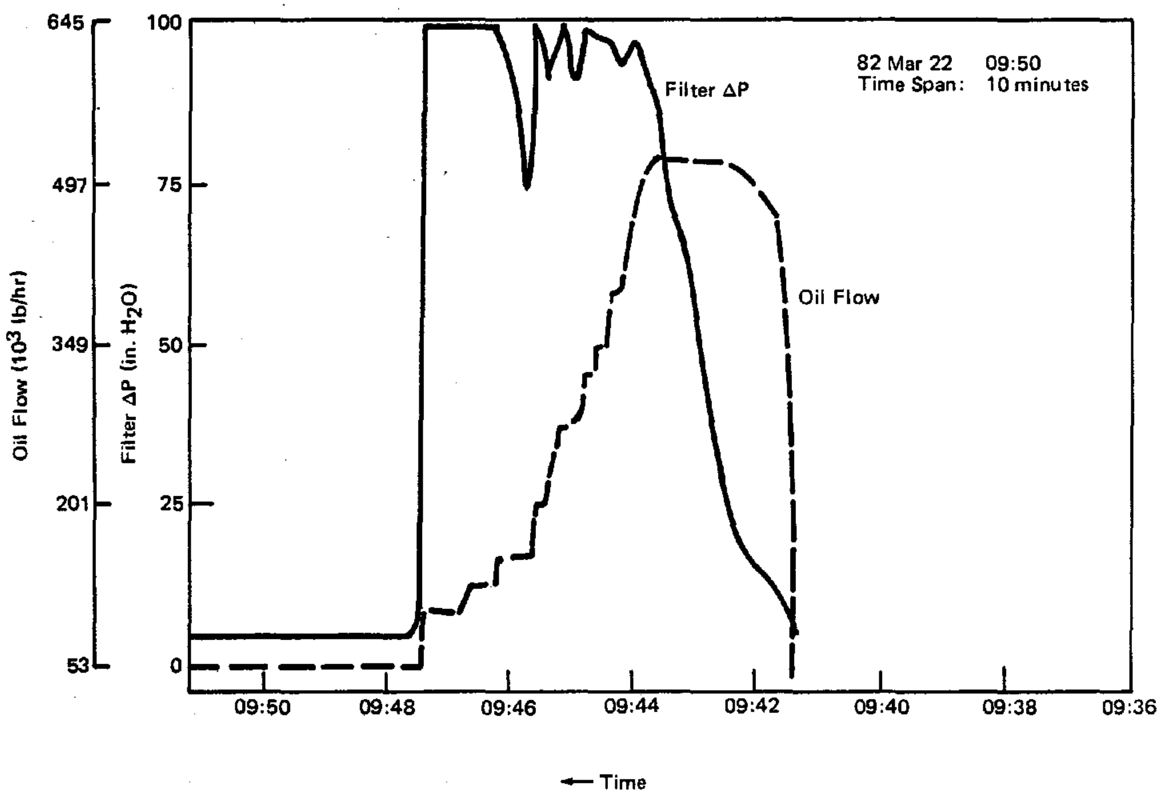


Figure 3.1-1. Charging Oil Train 2 Initial Filter ΔP

flows could be much larger (approximately 520,000 lb/hr - see Figure 3.1-1) resulting in more effective oil cleanup. After the filters plugged (both filters run in parallel) and low oil flow could no longer be maintained, the filters were cleaned. At first the filters were cleaned with trichloroethylene and steam at the nearby SCE Coolwater Power Plant. Later, trichloroethylene was available at the TSS pump area, and the filters were cleaned locally. The contamination found in the filters was identified as rust flakes and the black organic pipe coating used on steel pipes - all from the skid mounted equipment and plumbing. The only major solid debris found was an 8-in. plastic pipe cap, probably from charging train 2, found in the filter on 18 Mar 1982. The filters were cleaned as often as five times a day during the initial oil circulation through a train of heat exchangers and associated piping.

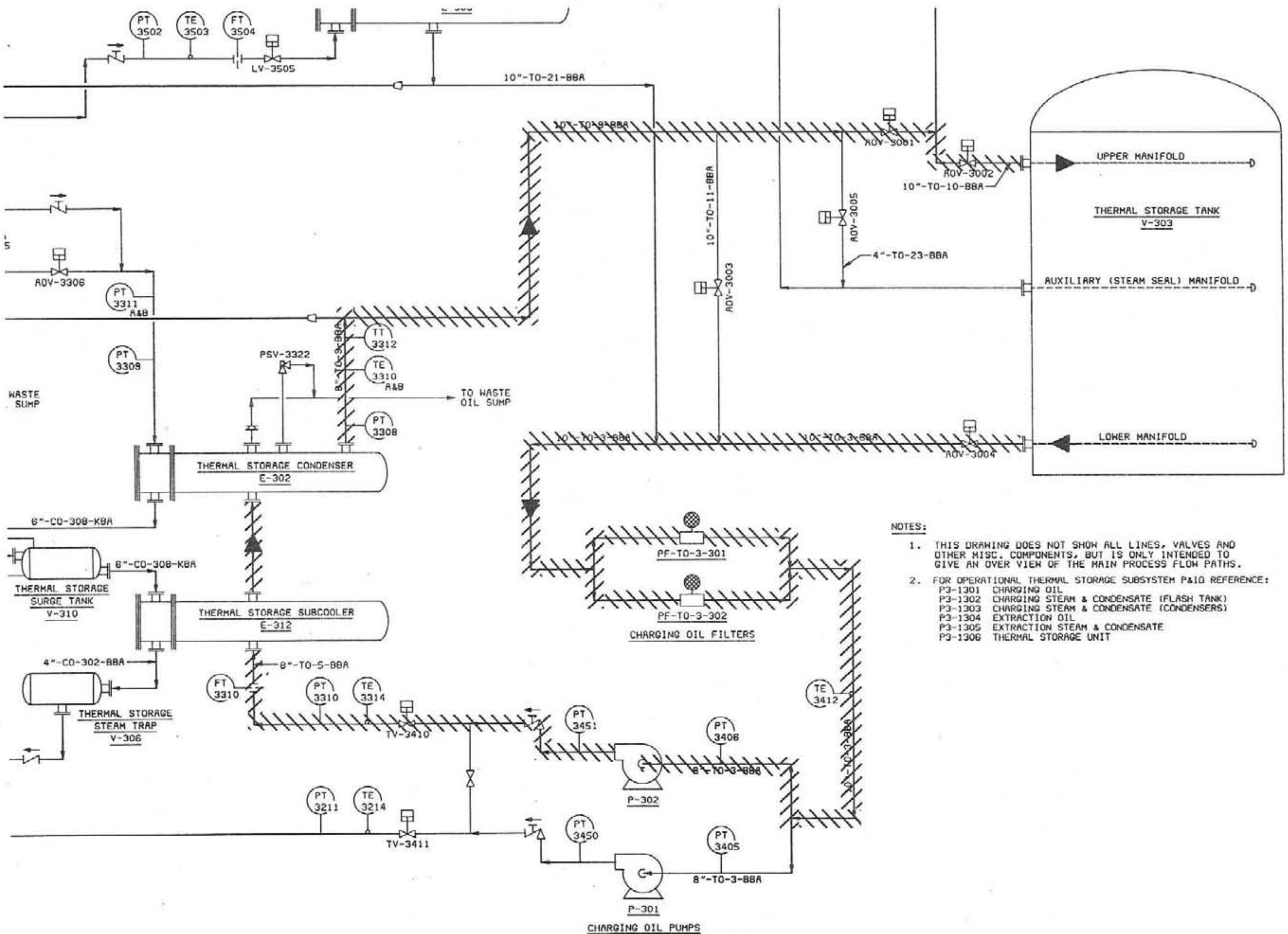


Figure 3.1-2. Flow Circuits for Oil Cold Flow Through TSU

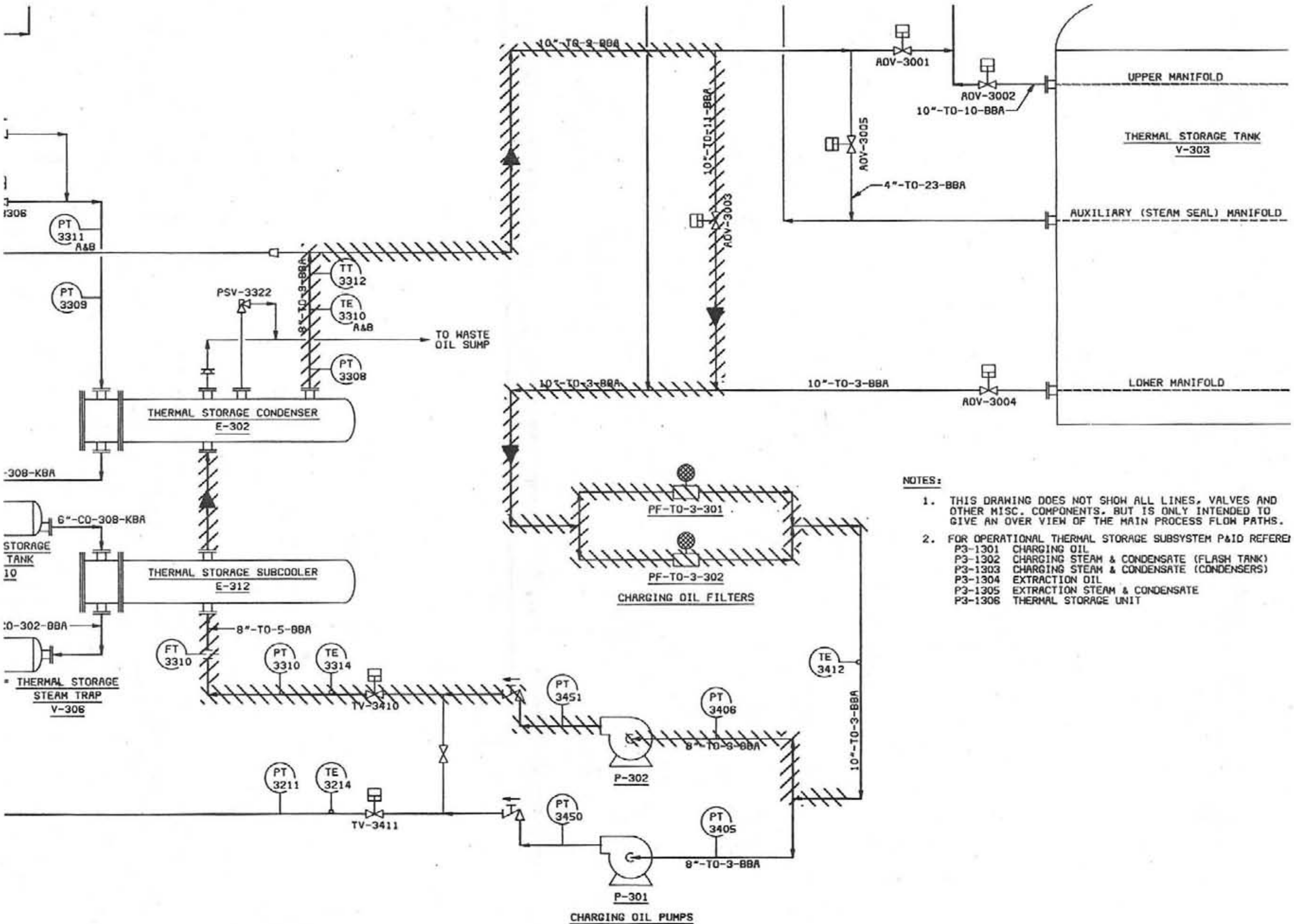


Figure 3.1-3. Flow Circuits for Oil Cold Flow Bypassing TSU

The result of the initial cleanup of train 2 is shown in Figure 3.1-4 (compare the rate of change of ΔP with Figure 3.1-1). Similarly, with charging train 1, the filters initially plugged quickly, (Figure 3.1-5), and later, plugged much more slowly, (Figure 3.1-6).

After the individual charging oil loops were cleaned, the extraction oil loops were set up in series with the charging oil loops, bypassing the TSU, (see Figure 2.2-2) allowing oil from the extraction trains to pass through the charging oil filters. Figure 3.1-7 shows the oil filter initial rapid plugging rate for extraction train 1 in series with charging train 1. Note that the oil flowrate is lower (approximately 300,000 lb/hr) because of the increased resistance of the two trains in series. The cleanup of extraction train 1 is shown in Figure 3.1-8. Extraction train 2 was set up in series with charging train 2 in a similar fashion, and the progression from dirty oil to clean is shown in Figures 3.1-9, 3.1-10 and 3.1-11. Note that Figure 3.1-11 is the same as Figure 3.1-10, but with a time interval of 100 minutes. The long time required to clean extraction train 2 (approximately 30 days) was due to prioritized receiver testing, culminating in turbine roll, which

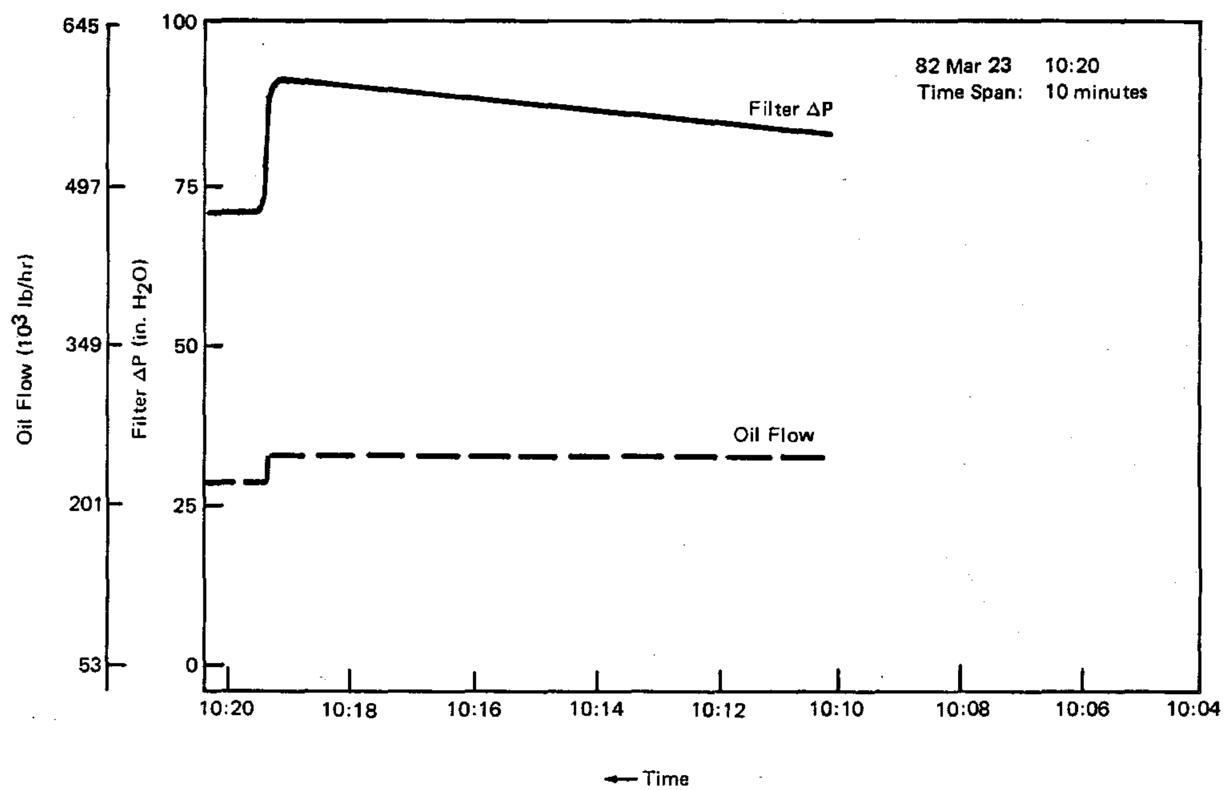


Figure 3.1-4. Charging Oil Train 2 Final Filter ΔP

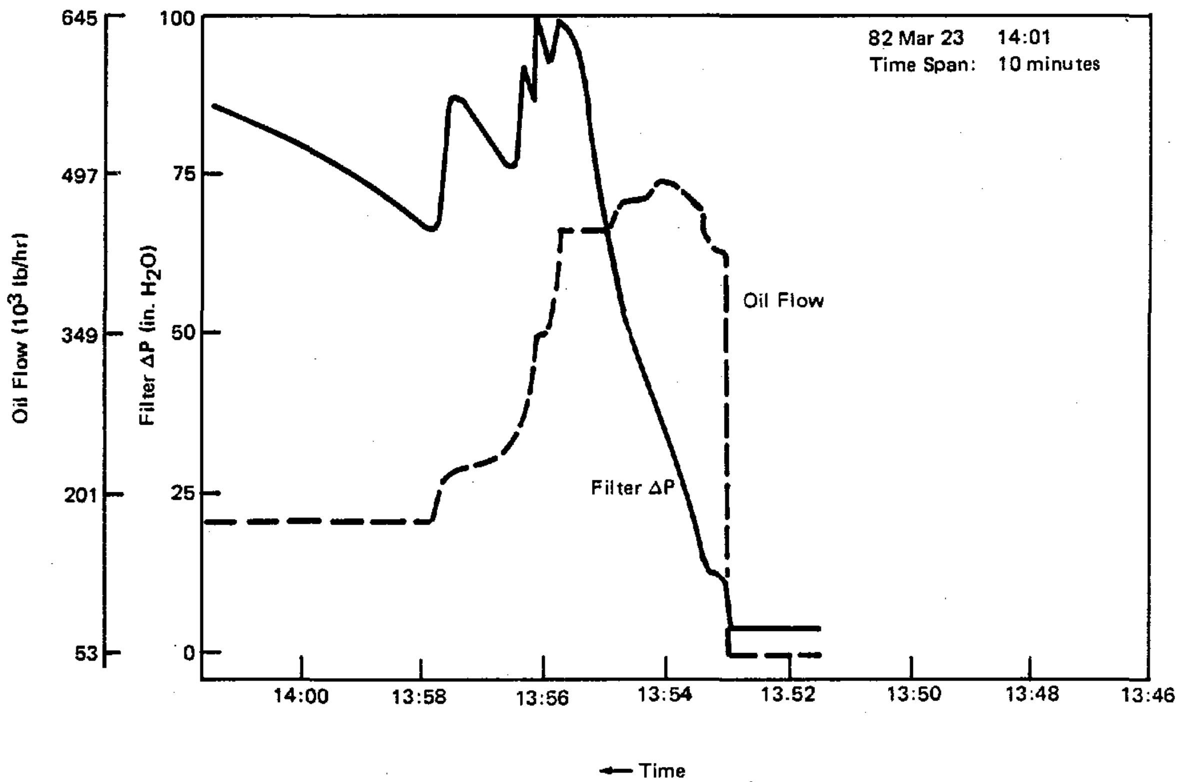


Figure 3.1-5. Charging Oil Train 1 Initial Filter ΔP

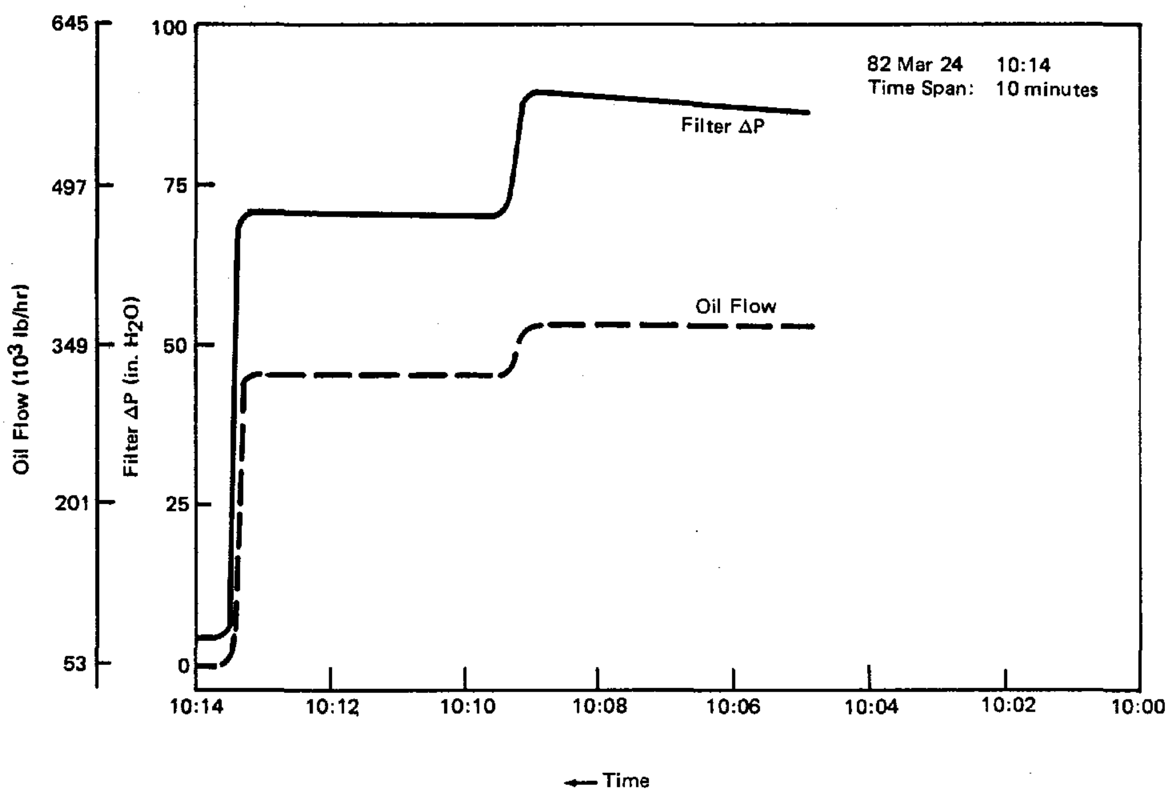


Figure 3.1-6. Charging Oil Train 1 Final Filter ΔP

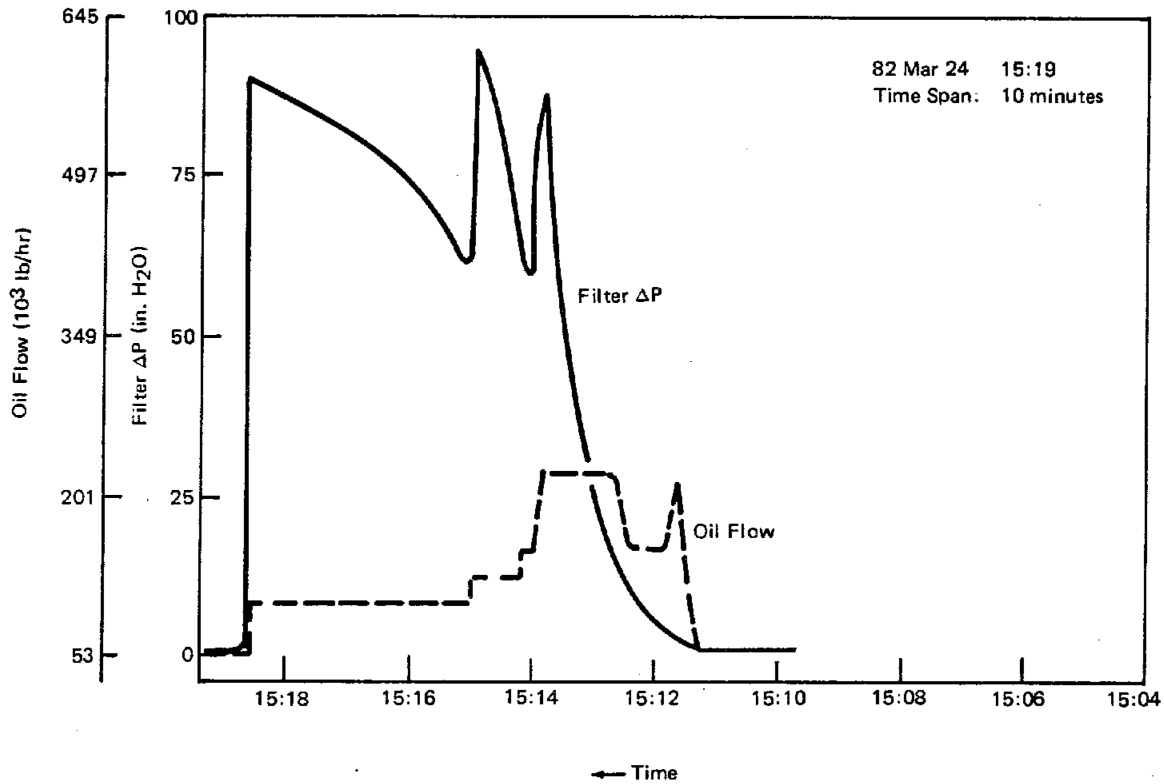


Figure 3.1-7. Extraction Oil Train 1 Initial Filter ΔP

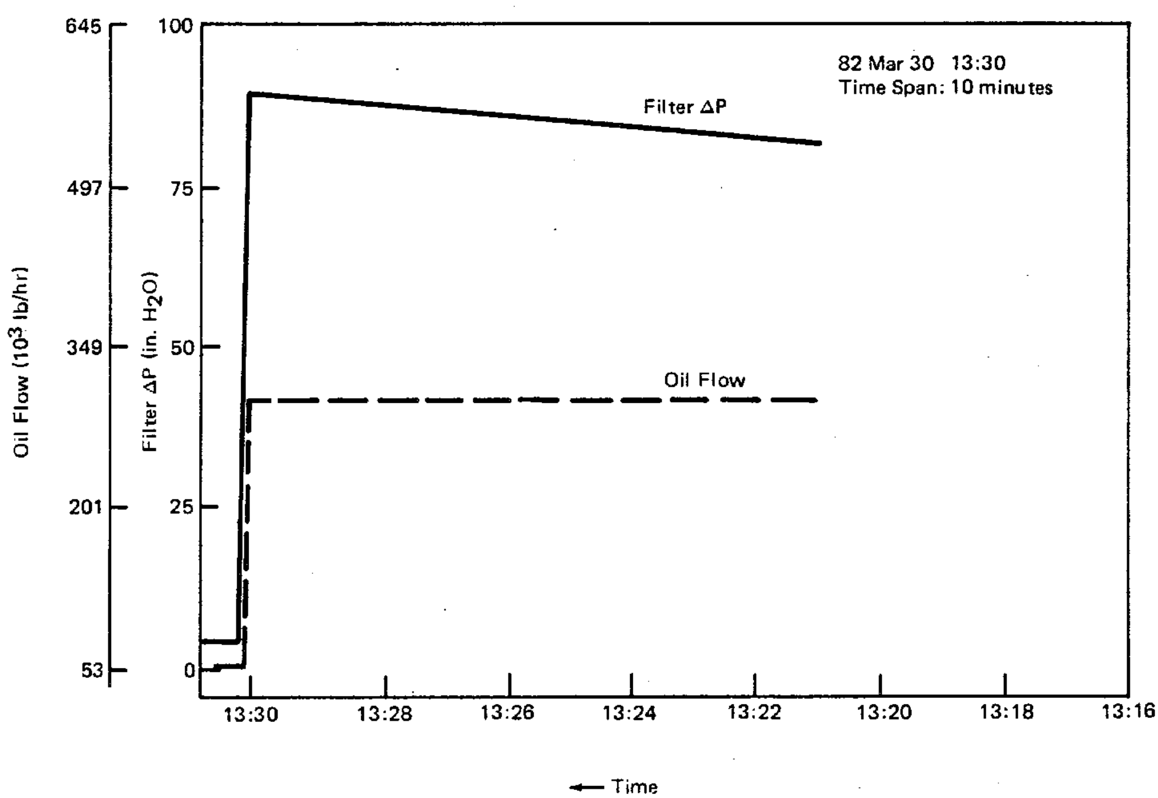


Figure 3.1-8. Extraction Oil Train 1 Final Filter ΔP

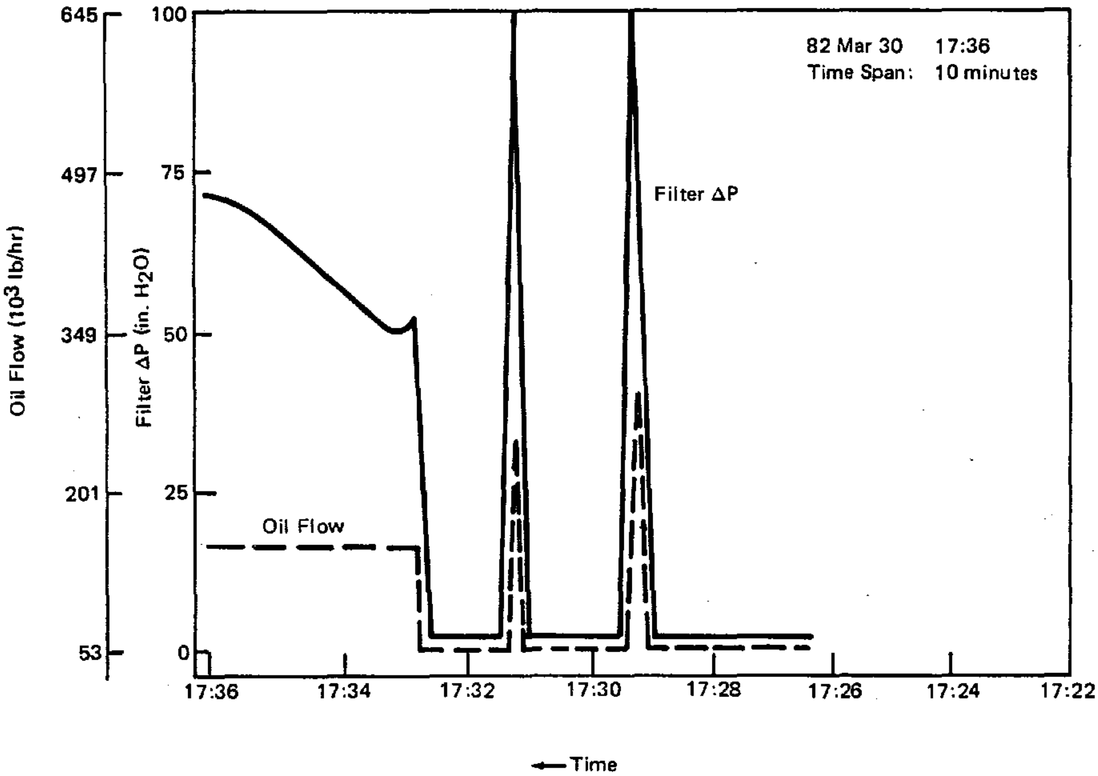


Figure 3.1-9. Extraction Oil Train 2 Initial Filter ΔP

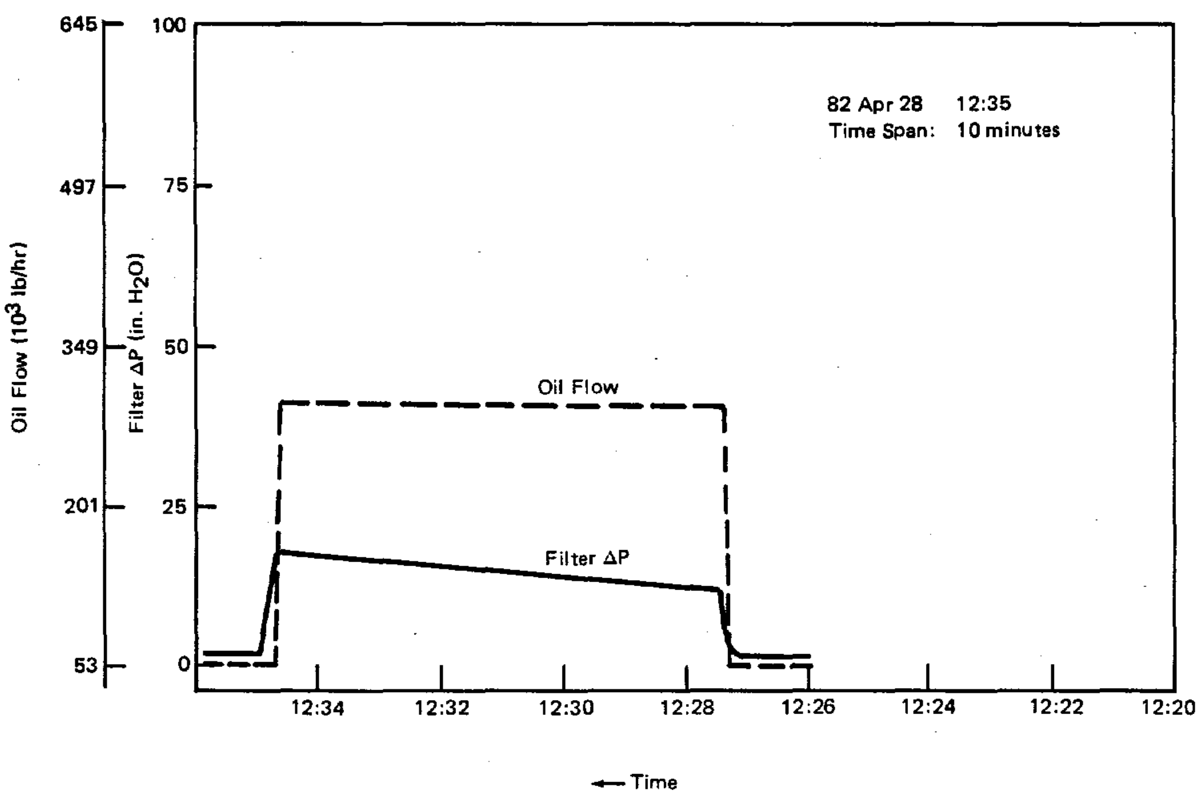


Figure 3.1-10. Extraction Oil Train 2 Final Filter ΔP

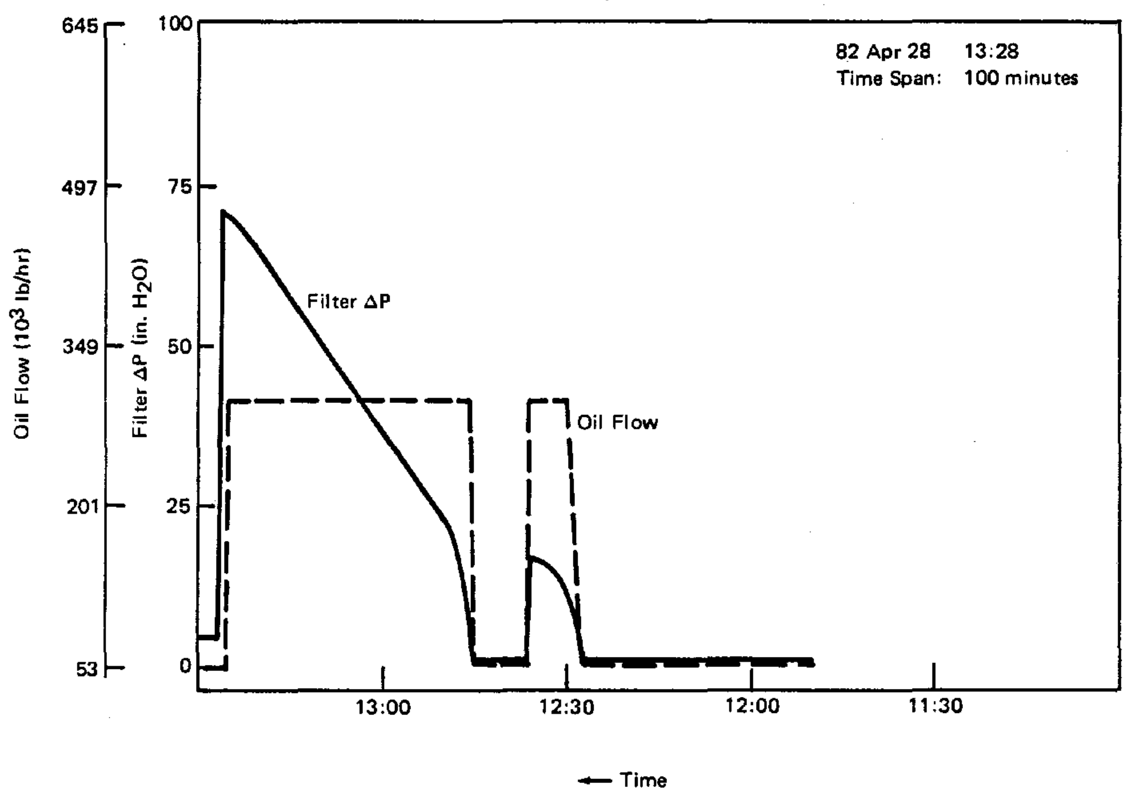


Figure 3.1-11. Extraction Oil Train 2 Final Filter ΔP (100-minute History)

impacted TSS testing. After the cold flow test 240 and prior to test 1040A, all of the temporary filters into the charging/extration skids were removed (e.g., TF-TO-4-1, TF-TO-5-2, TF-TO-25-3, TF-TO-36-4, TF-TO-12-5, TF-TO-13-6, and TF-TO-10-7). The filter screen was stripped from the perforated metal baskets, and the baskets were replaced to catch large solid debris, if any.

3.1.2 Hot Flow Oil Clean

The Procedure 1040A, TSU Bed Conditioning, was started by using steam from the rental boiler to heat oil in charging train 2. Prior to heating the oil, the TSU was vented to atmospheric pressure by removing the poppet assembly from the 8-in. Groth relief valve on top of the TSU. This was to provide high capacity venting of any steam which might be generated from water entrained in the oil, rocks and sand during heating of the TSU. The charging train was set to circulate oil through the TSU. All solid contaminants in the oil had apparently been filtered out during the 240 Cold Flow testing, since the filter ΔP was very low (maximum of 15.0 in H_2O at 165,000 lb/hr) and did not increase over several weeks of testing. The filters did not require cleaning again during these weeks.

The major system contaminant being removed during this testing phase was water, either in the oil piping/equipment on the skids or in the rock/sand in the TSU. The water saturation temperature varied from about 208°F at the top manifold of the TSU to about 245°F at the bottom manifold. Initially, the oil temperature out of the condenser was controlled to about 210°F, and was then increased over a period of several days to 250°F, while the condenser oil-side pressure and flow were monitored for evidence of surging caused by steam generation within the condenser or associated piping up to the TSU. No flow surges were ever noted. Steam was being generated continuously while the TSU was heated, venting from the TSU through the open 8-in. Relief Valve in a visible plume some 5 to 12 feet high. It was originally intended to measure the vent velocity from the 8-in. Relief Valve with a portable anemometer, but this proved to be impractical. Visual estimates of vent velocity indicated a typical vent rate of about 350 lb/hr. As the oil/rock/sand in the TSU were gradually heated up and the initial thermocline established (see section 3.7), the oil leaving the TSU and entering the charging pump rose to a temperature of approximately 250°F. This was above the water boiling temperature at the pump inlet pressure, and, as a result water in the oil flashed to steam at the pump inlet, choking the oil flow in the pump. As shown in Figure 3.1-12, the oil flow steadily dropped, (despite attempts to increase pump speed) until a low-oil-flow trip of the oil pump

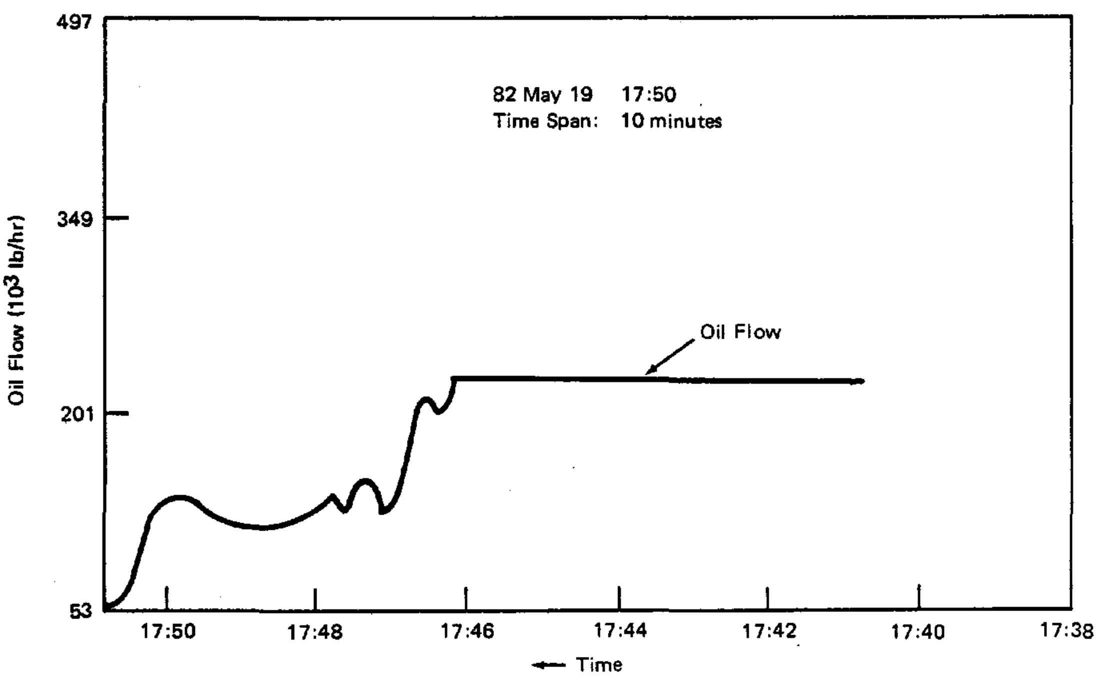


Figure 3.1-12. Oil Flow Decay Caused by Steam Choking of the Pump

occured. Fortunately, during these occurances, the oil pump was in manual speed control, and thus there was no tendency for the pump to overspeed, as is usually the case with vapor choking. Instead, the oil flow simply collapsed as shown in Figure 3.1-12. The extraction train was placed in series with charging train to solve this problem, as shown in Figure 3.1-13. With this arrangement, the extraction oil pump was run at about 420,000 lb/hr and the charging oil pump at about 200,000 lb/hr. The difference was extracted from the TSU upper manifold and injected back into the TSU lower manifold after being heated in the charging train and cooling only slightly from passing through the extraction train. This arrangement cured the problem, confirming that the water source (in the oil) was the rock/sand in the bottom of the TSU. The flow arrangement shown in Figure 3.1-13 allowed heating of the TSU from the bottom up, which encouraged water/steam in the TSU to rise and be vented, rather than being ingested into the pumps via the bottom manifold. The effect of this water on thermocline establishment is discussed below in section 3.7.

3.2 FINAL CHARGING OIL LOOP CLEANUP

After the oil had been heated to 300^0F - 350^0 using the rental boiler, the rental boiler was dismantled and returned to the supplier. The remaining oil heatup was accomplished using receiver steam. Since the oil would be heated above its flash point (400^0F) with receiver steam, the 8-in. Groth Relief Valve (used for venting the TSU) was restored to operating condition and further venting of steam and/or other ullage gases was handled using the Ullage Maintenance Unit (UMU). The UMU pressurizes the TSU to a nominal pressure of 9 in. H_2O, to exclude air from the TSU ullage for safety reasons, and details of the UMU operation are described in section 3.9.

Initially, all of the fluid collected in the UMU was water, which accumulated at about 10 gal/hr, and which was dumped. After the oil temperature in the TSU reached approximately 400^0F, lighter fractions (LF) in the oil began to distill, and were, in turn, collected in the UMU, along with water. The approximate quantities of LF and water accumulated are shown in Table 3.2-1. A surprising feature was that water was still generated in substantial quantities even after the TSU had been heated to above 400^0F in its entirety. The constituents of the ullage gas are shown in Table 3.2-2. The analysis of 10 Aug had a substantial quantity of water in it. The gaseous constituents were normalized to 1.0 percent water in order to compare them

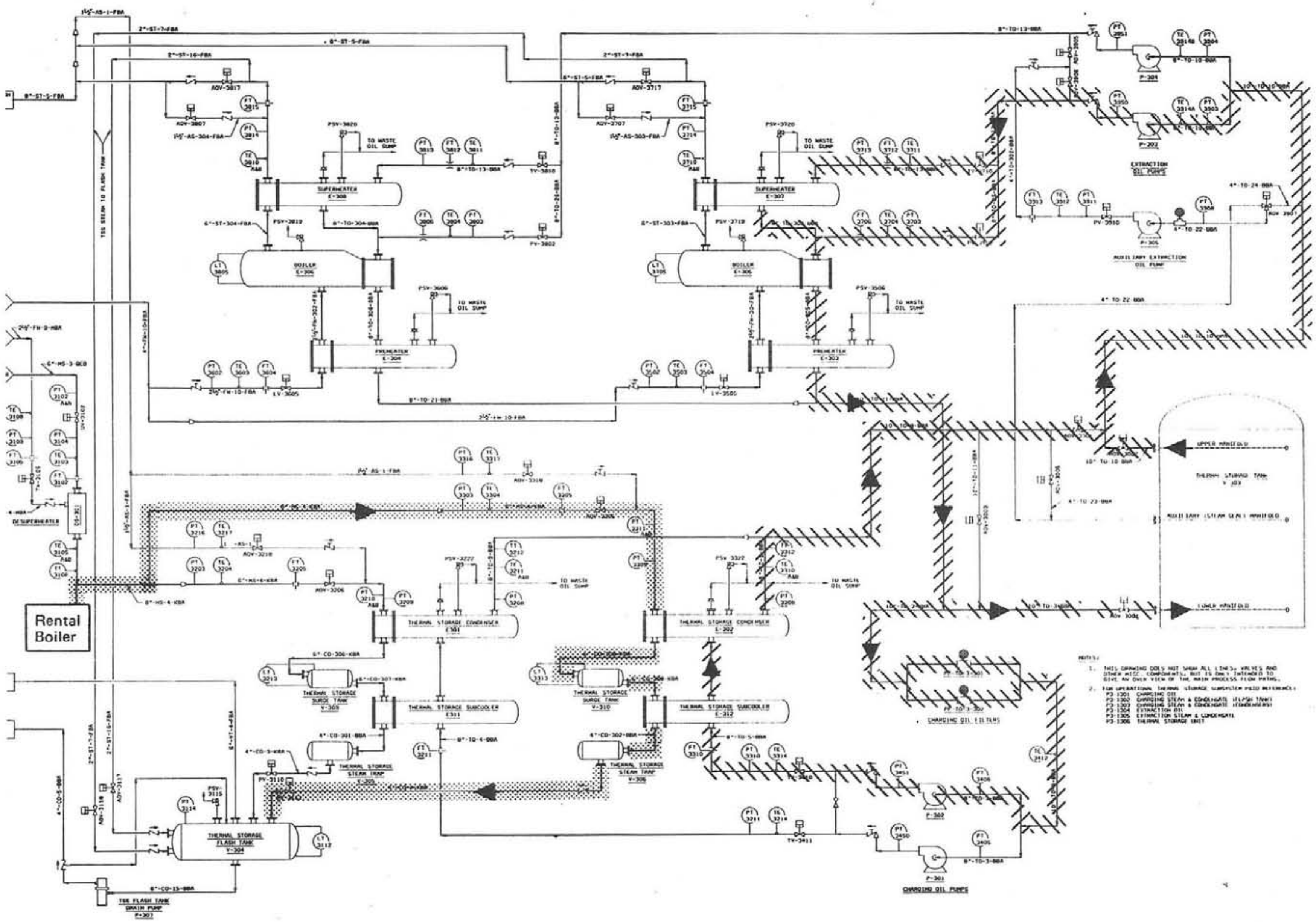


Figure 3.1-13. Flow Circuits for Heating Oil While Avoiding Steam Choking of Oil Pumps

Table 3.2-1
FLUID COLLECTION IN THE UMU

Date	Gallons Collected in the UMU				TSU Temperature – °F	
	Daily H_20	Cumulative H_20	Daily LF	Cumulative LF	Bed-Range	Bottom
6-30-82	100	100	—	—	320-330	280
7-1-82	220	320	—	—	330-390	280
7-2-82	200	520	—	—	330-390	290
7-9-82	250	770	—	—	395-415	295
7-13-82	200	970	150	150	425-445	325
7-14-82	25	995	50	200	435-470	360
7-15-82	150	1145	150	350	445-470	360
7-19-82	75	1220	300	650	440-465	370
7-20-82	25	1245	100	750	455-480	368
7-21-82	50	1295	250	1000	465-485	375
7-28-82	—	1295	350	1350	450-495	315
7-30-82	15	1310	50	1400	450-505	350
8-2-82	30	1340	170	1570	460-555	380
8-3-82	30	1370	170	1740	465-565	375
8-4-82	12	1382	100	1840	450-550	390
8-5-82	7	1389	70	1910	450-550	350
8-6-82	10	1399	100	2010	435-545	340
8-9-82	22	1421	260	2270	475-565	310
8-10-82	32	1453	350	2620	465-555	315
8-11-82	15	1468	100	2720	435-550	330
8-12-82	13	1481	150	2870	430-550	335
8-13-82	10	1491	50	2920	430-545	340
8-16-82	29	1520	250	3170	435-555	340
8-17-82	2	1522	25	3195	415-550	335
8-18-82	8	1530	125	3320	400-540	335
8-19-82	16	1546	125	3445	375-535	330
8-20-82	—	1546	100	3545	370-535	330
8-23-82	21	1567	200	3745	325-525	325
8-24-82	10	1577	200	3945	370-525	325
8-25-82	10	1587	200	4145	360-520	325

Table 3.2-2
ULLAGE GAS CONSTITUENTS

Constituent	Predicted at 575°F	Volume Percent Analysis 10 Aug @ 570°F	10 Aug Corrected for H_20	Analysis 2 Sept @ 570°F
Oxygen	0.2	ND* (<0.05)	0.0	ND* (<0.10)
Argon	—	—	—	—
Nitrogen	2.0	3.8	22.53	58.59
Carbon Monoxide	2.4	0.4	2.37	—
Carbon Dioxide	2.0	—	—	—
Hydrogen	20.8	8.9	52.77	17.45
Methane	20.5	0.24	1.42	2.43
Ethane	19.3	0.31	1.84	1.52
Ethylene	0.5	0.12	.71	—
Propane	12.3	0.50	2.96	2.43
Propylene	2.0	0.33	1.96	—
iso-Butane	2.4	0.38	2.25	5.23
n-Butane	8.1	0.28	1.66	—
Butene	—	0.26	1.54	—
iso-Pentane	0.4	0.23	1.36	3.40
n-Pentane	6.0	0.15	.89	—
Hexane	—	0.23	1.36	2.48
Heptane & Higher HC's	—	0.57	3.38	2.84
Water	1.0	83.3	(1.00)	*** 1.66
Other Condensibles	—	—	—	*** 1.97
Phenol		2000		
Methylphenols		1000		
Ethylphenols		200		
Dimethylphenols		60		
Ethylmethylphenols		70		
** Alkylphenol		20		
t-Butylphenols		10		
Dimethylbenzaldehyde		10		
$C_{12}H_{18}$ Alkylbenzene		10		
C_8HC's		Trace (<10)		
C_9HC's		Trace (<10)		
C_{10}HC's		Trace (<10)		

*ND – Not Detected
**Concentration in Water in μg/ml
***Percentages Inferred and Not Included in Gas Analysis

with predicted constituents in the first column of Table 3.2-2. The abnormally large quantities of nitrogen present (also present in the 2 Sept analysis) are due to the occasional use of nitrogen as a TSU pressurant during this period. It is interesting to note in both analyses the relatively small quantities of methane, ethane and propane being produced together with relatively larger quantities of butane and higher hydrocarbons. This may be due to the initial weathering process taking place in which the high boiling point fractions are being preferentially evaporated. The production of LF continued after charging even through no oil was being circulated and is apparently related to the "weathering" process known to occur for Caloria. Even though the cumulative quantities collected (approximately 4200 gal) are substantial, they represent less than 2% of the quantity of Caloria in the TSU.

During the entire period of operation with receiver steam, the TSU was being charged with hot oil flow into the top manifold of the TSU, while colder oil was being withdrawn from the bottom manifold of the TSU (see Figure 2.2-1). In this flow configuration, solid contaminants in the oil (if any) were "filtered" through the TSU bed, and no additional debris was collected in the charging oil filters.

3.3 FINAL EXTRACTION OIL LOOP CLEANUP

Final circulation and cleanup of the oil side of the extraction trains did not start until July 22 (a month afer the rental boiler was returned) because it was necessary to heat the TSU to a temperature above 425^{o}F, in addition to waiting until the charging trains were clean. The initial extraction used the auxiliary oil pump through the auxiliary manifold (with the TSU at 465-485^{o}F). This was the first time this circuit had been utilized, and as may be expected, both solid debris and water contamination were found. The solid debris plugged the inlet filter to the auxiliary oil pump (P-305). The filter was cleaned and a pressure gage was installed to indicate filter ΔP and future filter plugging. Again the debris was rust flakes and black organic material as found before - but this time there was considerable sand from the auxiliary manifold of the TSU. However, the next time this filter was cleaned, no sand was found. The flow arrangement during these tests was the extraction train and charging train in series (see Figure 2.2-2) so that the water-contamination oil in the auxiliary oil loop passed through the charging oil filters and pumps where the water flashed to steam, choked the charging pumps, (which tripped) and had to be vented from the charging oil piping on the pump skid. Once the steam had been vented twice from the lines, and the P-305 inlet filter cleaned, there was no further indication of contamination.

3.4 CHARGING TRAIN STEAM CLEANUP

3.4.1 Heat Exchanger Cleanup Using Rental Boiler Steam

In addition to preliminary heating of the oil, the rental boiler steam was used to flush and begin cleanup of the steam/water side of the charging train equipment. This was accomplished by exhausting steam and condensate to atmosphere (free blows) from selected drain/vent ports in the charging trains, as shown in Figure 3.4-1. The free blows upstream of the flow control valve to the Flash Tank (PV-3110 in Figure 3.4-1) were used first, and PV-3110 (Train 1) was put in pressure control. Pressure control accomplished two things: (1) flow was directed to the flash tank (which was cleaned) and then either drained or routed to the TSS blowdown tank, and (2) the pressure and temperature in the train steam side increased, which increased cleaning effectiveness. Water quality samples during cleanup are shown in Table 3.4-1. The principal concern in water quality was pH (basic - 9.0 to 9.6) and iron content (limited to approximately 10 ppb by spec for receiver operation). From Table 3.4-1 will be noted that although the steam from the rental boiler was quite clean, the train equipment was quite dirty (see 5-19-82) and took a long time to clean up. Even when apparently clean at low condenser steam pressures, cleanliness suffered when higher condenser pressures (and temperatures) were imposed (see 6-2-82 and 6-3-82). In addition, the trains tended to increase in iron content when left over the weekend (see 6-4-82 and 6-8-82) even when left on GN_2 purge. When water was directed to the flash tank through the condenser pressure control valves (e.g., PV-3110) it was found that even at maximum rental boiler steam flow (approximately 11,000 lb/hr) the leakage through the flash tank drain pump P-307 over to the TSS blowdown tank was adequate to keep up with the water flow. Pump P-307 never had to be operated. The TSS blowdown tank operated properly and conditioned the waste water to less than 160^{o}F before dumping the waste water to the sump. By the time the rental boiler was dismantled,

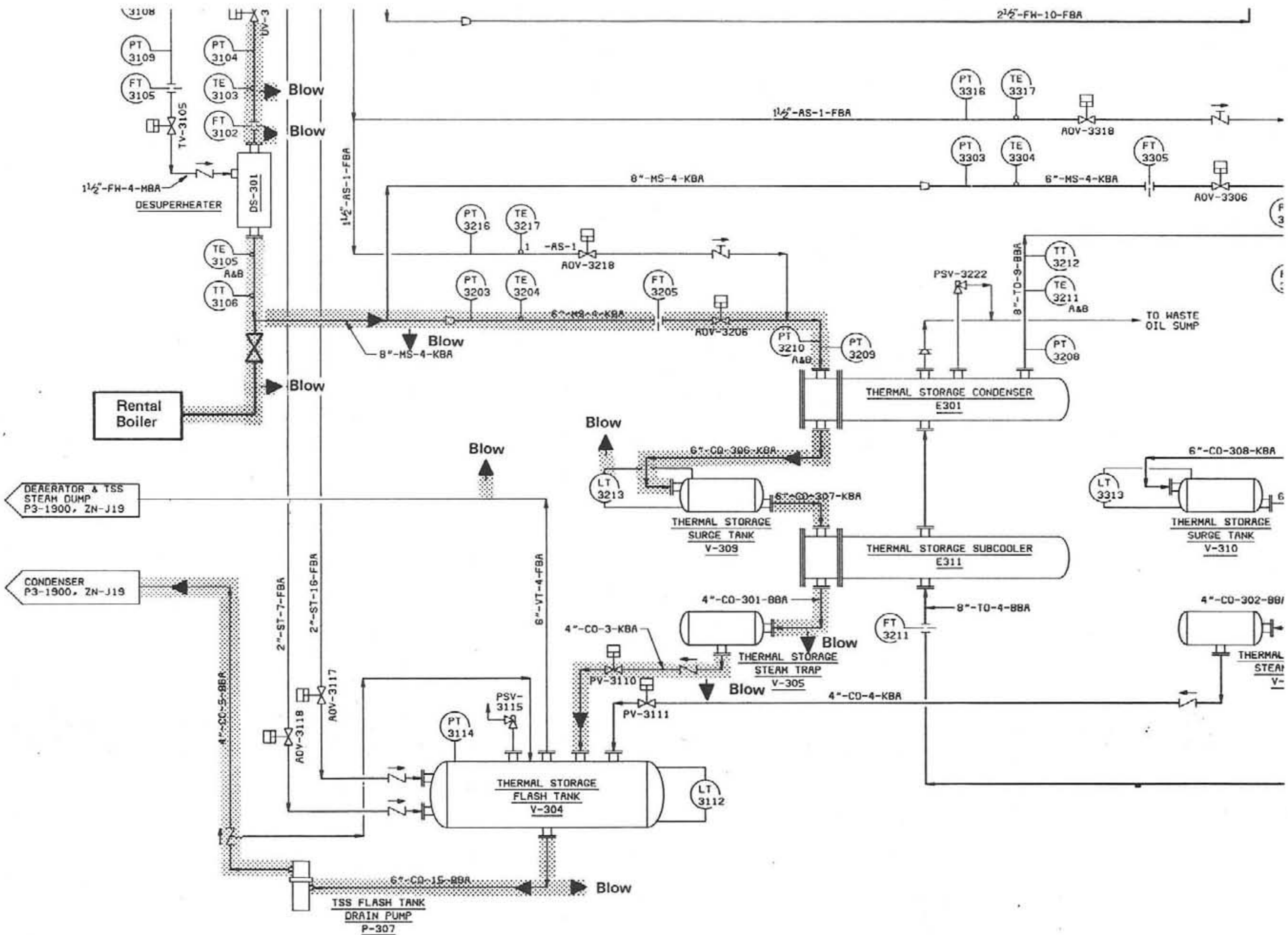


Figure 3.4-1. Charging Train Steam Side Cleanup with Free Blows

Table 3.4-1
STEAM SYSTEM CLEANLINESS

Date	Sample Point	pH	Fe ppb	Comments
5-10-82	TSS Drains		>1000	
5-12-82	Charging Train (CT) #1	6.01	>1000	
5-14-82	CT #1	9.83	>1000	
5-17-82	CT #1	9.27	>1000	Went to P = 180 psig on CT #1
5-18-82	Flash Tank (FT)	9.50	>1000	
5-19-82	Upstream of CT's	—	50	
	FT	9.61	>1000	
5-20-82	E301 Condenser	9.36	>1000	
5-25-82	E301 Condenser	9.53	10	CT #1 Clean
5-26-82	FT	9.67	>1000	Changed to CT #2
5-27-82	FT	7.15	500	
	CT #2	6.89	400	
6-1-82	FT	8.04	>1000	
	CT #2	8.25	150	
6-2-82	FT	9.52	>1000	
	CT #2	9.44	50	
6-3-82	FT	8.80	750	Went to P = 190 psig on CT #2
	CT #2	7.59	600	
6-4-82	FT	7.99	750	
	CT #2	7.07	600	
6-8-82	FT	9.62	>1000	Down Over Weekend
	CT #2	9.93	>1000	
6-9-82	FT	7.85	500	
	CT #2	7.15	100	
6-10-82	FT	8.83	500+	
	CT #2	9.09	125	
6-11-82	FT	—	500+	Last Day of Rental Boiler Operation
	CT #2	—	300	
6-22-82	Cond. Pump Dis. (CPD)	9.49	375	
6-29-82	CPD	9.39	15	
7-7-82	CPD	9.58	75	
	CT #2	9.53	—	
7-13-82	CT #2	8.30	50	
7-14-82	Hotwell (HW)	9.44	25 ➨>1000	TSS Vents to HW
7-15-82	HW	9.26	50 ➨>1000	TSS Vents to HW
7-16-82	CPD	9.41	10	
7-23-82	Extraction Train (ET) #1	—	150	
7-29-82	ET #1	9.28	75	
	FT	9.16	>1000	
7-30-82	FT	9.26	200	
	PV-640	9.47	125 ➨ 10	
8-2-82	FT	9.22	375	
	AS	7.04	250	
8-3-82	FT	9.23	50 ➨ 15	
8-17-82	ET #1	—	100	
8-20-82	PV-647A	6.72	100	
8-25-82	CPD	9.52	15	

the charging trains were reasonably clean (see Table 3.4-1) though the flash tank was still relatively dirty. The extraction trains had not yet been flushed/cleaned using the rental boiler, but cleaning was started after the transition to receiver steam, as described in section 3.5. The temporary piping from the condenser control valve LV74B block valve to the TSS blowdown tank was left in place to facilitate TSS cleanup after the rental boiler was removed.

3.4.2 Heat Exchanger Cleanup Using Receiver Steam

When the transition to receiver steam was made, the first activity was to use the bypass around MOV1030 and UV3102 to warm up the steam line and desuperheater. The desuperheater control loop was set up and tuned (see section 5.3) first, so that the steam temperature to the charging trains could be controlled to less than 650^{o}F as required to prevent potential overheating of the oil. During these proceedings MOV1030 was opened and UV3102 was manually opened 7-10%. Initially the receiver was controlled to 450 psi, and the pressure setpoint gradually increased to 750 psi, and then 1450 psi, with the charging train condenser setpoint (PV3110, PV3111) at 400 psi, 600 psi, 1050 psi, and 1400 psi, respectively. Each increase in steam side pressure increased the iron content in the water sample (see Table 3.4-1) but it only took about four days to clean up the charging train steam side through the flash tank. It was discovered during these tests that PV3110 and PV3111 were apparently undersized. The valve trim and poppets were eventually changed to increase the C_v from 4.7 to 7.4. During this time period there were a variety of UMU problems (see section 3.9) and some charging pump start problems which were resolved by General Electric. Following charging trains final cleanup, steam blows through PV640, LV74D1, and LV74D2 were accomplished (see section 3.6).

3.5 EXTRACTION TRAIN STEAM CLEANUP

Since the rental boiler was dismantled and removed before any steam was generated in the extraction trains, the steam side of these systems was found to be quite dirty. At first there were problems in the startup and control of the thermal storage feedwater pump, so the boiler(s) were filled with hoses, and the extraction was performed using only the auxiliary oil pump, P-305. The auxiliary oil pump was used for finer control of the steam generation process since the boiler level could not be controlled. As with the charging

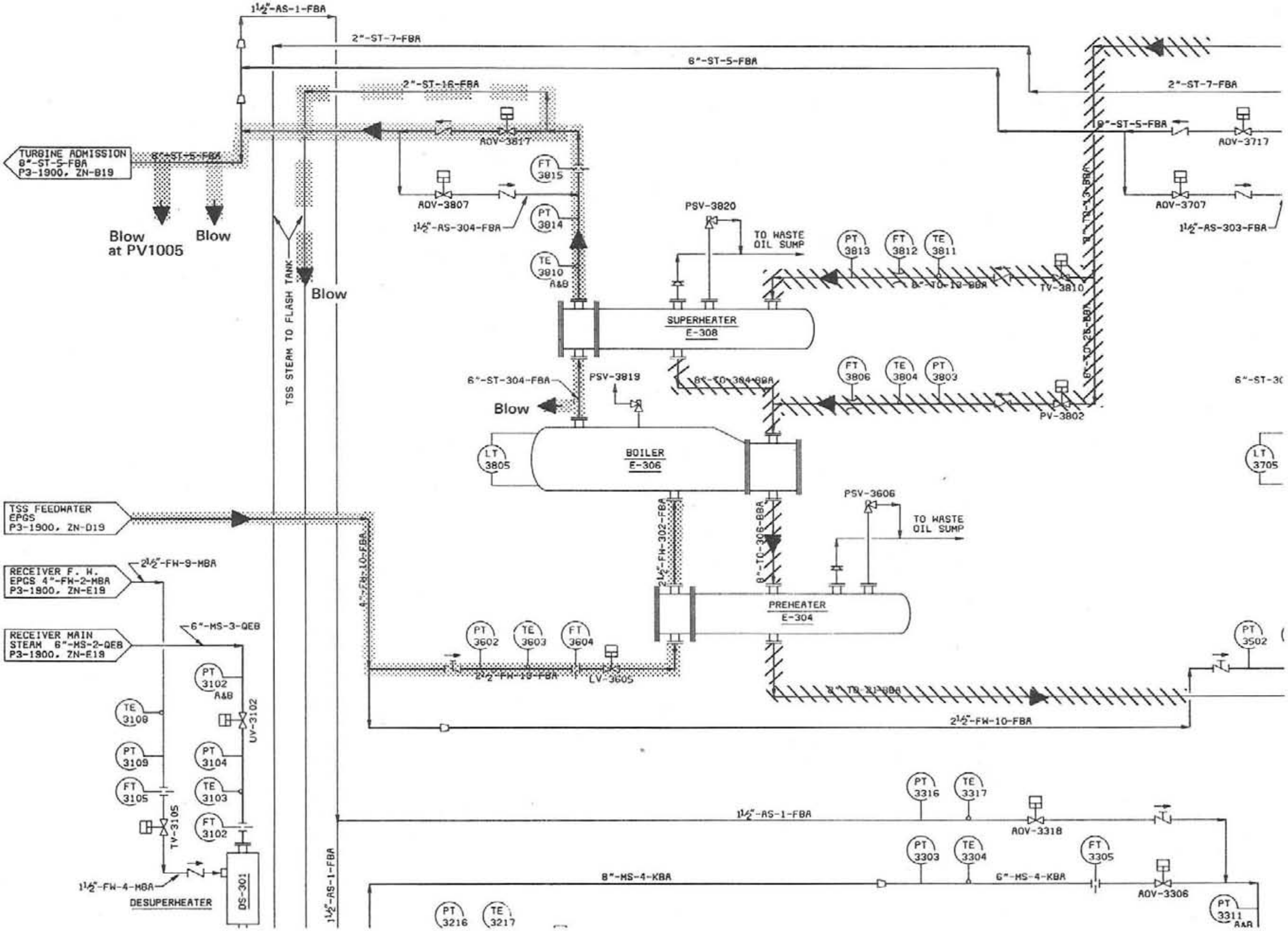


Figure 3.5-1. Extraction Train Steam Side Cleanup with Free Blows

trains, free blows from the extraction trains were made through selected vent/drain ports, as shown in Figure 3.5-1. Because the number of vent/drain ports was limited, it took a long time to clean up the extraction trains (7-22-82 to 8-25-82). Steam was also blown to the flash tank through AOV3118 and AOV3117, which again resulted in excessive iron in the flash tank (see Table 3.4-1). Finally, the extraction oil pumps P-303 and P-304 were used to generate extraction steam in both trains even though the TSS feedwater pump was not yet operational.

3.6 EPGS/PSS STEAM CLEANUP

During the extraction train steam blows described above, the control valves and associated piping from the Flash Tank to various equipment were blown down with steam. These were: PV640, LV74D1 and LV74D2 to the condenser, PV647C to the deaerator, and LV74B to the Second Point Heater. This usually contaminated the deaerator and/or condenser with excess iron at first (see Table 3.4-1), but these lines cleaned up quickly. The initial control loop tuning for all of these valves was accomplished during this phase (see section 5.0). The TSS feedwater pump was finally operational at about the time (8-17-82) the admission steam line to turbine was blown clean and the turbine was rolled on admission steam. Steam was blown through the turbine for 9 hours, resulting in sufficient cleanliness to run the turbine-generator (synchronized) on 8-25-82, when extraction train 2 was used to generate 4.9 MW_e gross during a rainstorm.

3.7 THERMOCLINE ESTABLISHMENT USING RENTAL BOILER STEAM

The goal of establishing a temperature of 250^{o}F - 300^{o}F in the oil/rock/sand bed of the TSU was achieved using steam from the rental boiler. The inital temperature distribution in the TSU (following the first 2 hours of charging) is shown in Figure 3.7-1).* The circles are temperatures measured by TSU thermocouples TE3009A through TE3010N (see Figure 3.7-2). The dashed

*The thermocline plots and energy balance tables were produced by Sandia National Laboratories-Livermore from SDPC data.

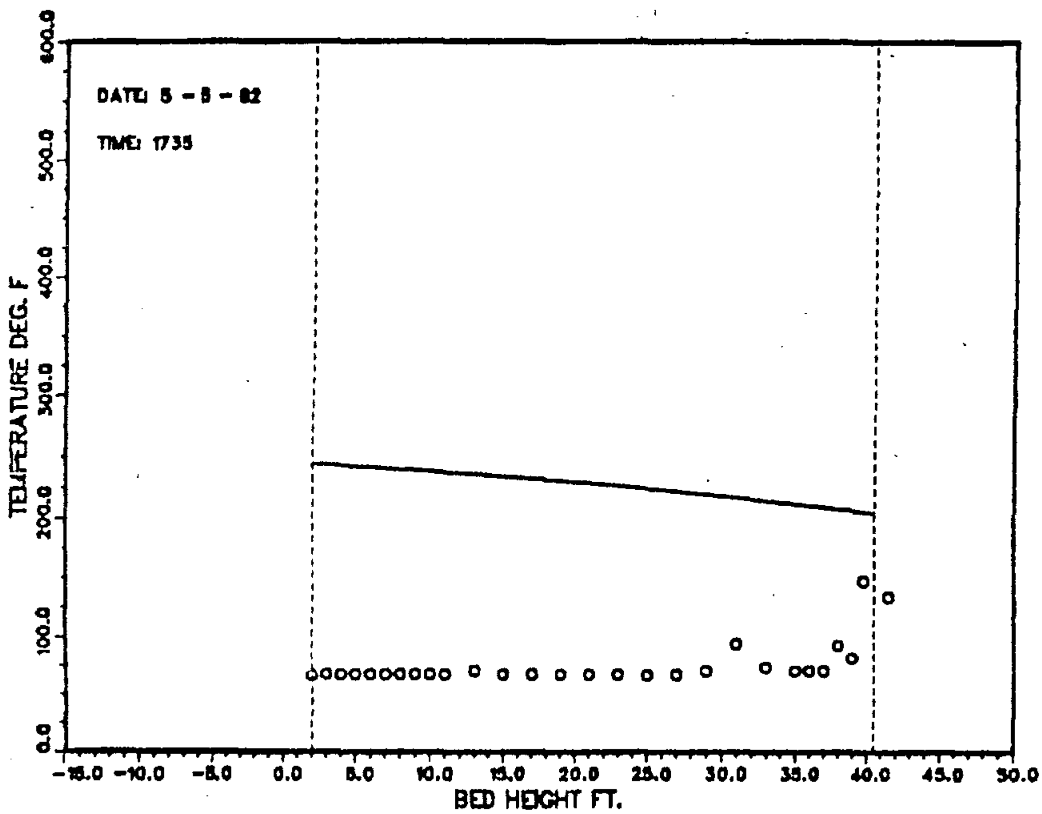


Figure 3.7-1. Thermocline Profile

lines are the positions of the upper manifold and lower manifold (TI3007-measured outside the TSU-is shown as representing the temperature at the 2 ft level), and the solid line is the calculated water saturation temperature at the pressure of the local (cold) oil head. In Figure 3.7-1 the temperature values at 39 ft 9 in. and 31 ft are incorrect. These thermocouples gave incorrect readings due to loose wires until they were repaired on 7-6-82. The values shown were interpolated from adjoining values. The temperature dip shown in Figure 3.7-3 between 5 ft and 17 ft was an artifact left over from 5-5-82 and 5-6-82 when the oil pump was inadvertantly allowed to run all night with cold oil (renter boiler off) which pushed the hot spot at the top of the tank in Figure 3.7-1 down to the 12 ft level. It then migrated to the 5 ft level over the next couple of days of testing. However, in Figure 3.7-3, note the sharp gradient at the water saturation line at 31 ft. The same sharp gradient is also shown in Figure 3.7-4 at 19 ft, while the temperatures above the 21 ft level follow the saturation line. This clearly shows the presence of free water in the rock/sand bed, which was being boiled off at the location of the sharp gradient.

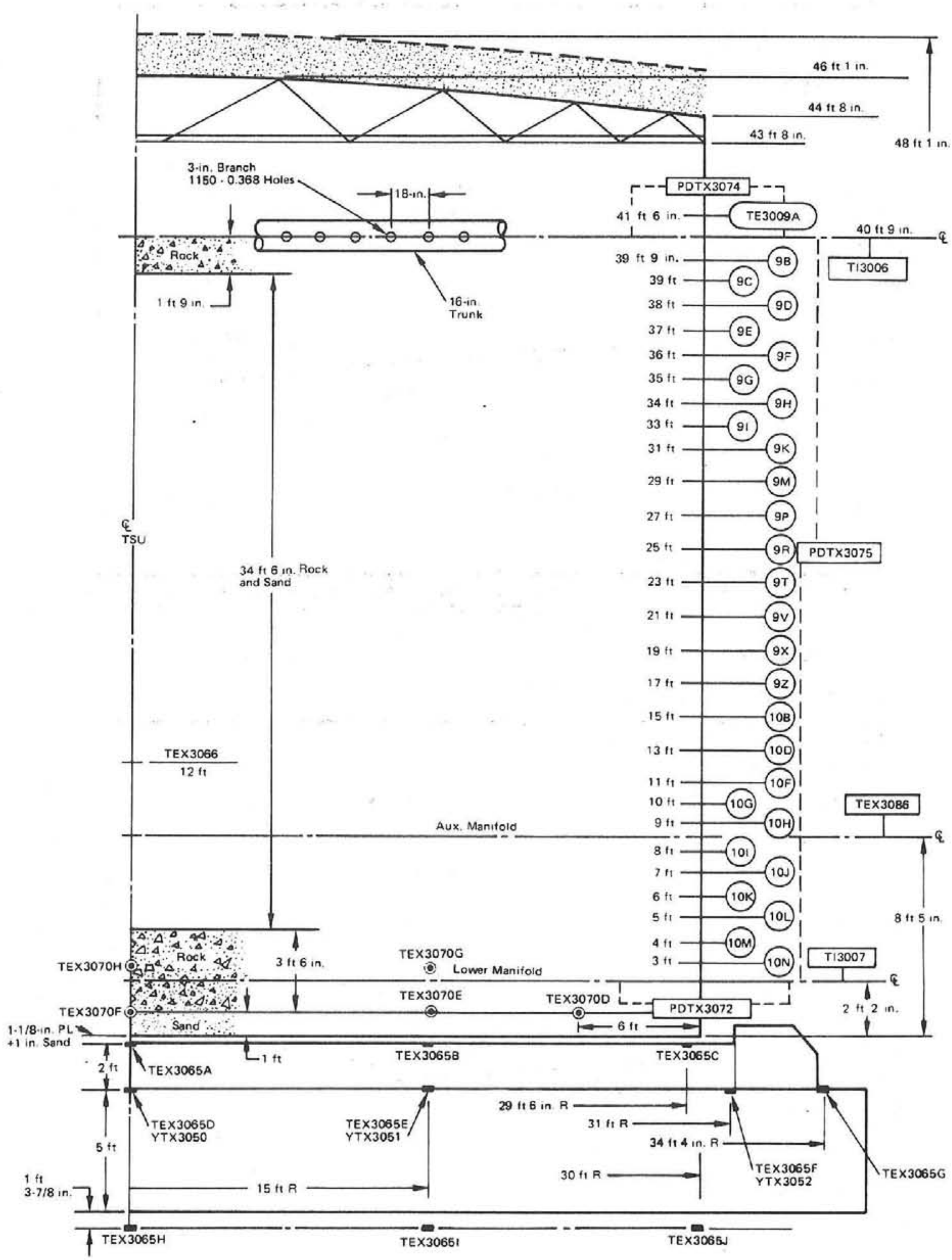


Figure 3.7-2. Thermocouple Location in TSU

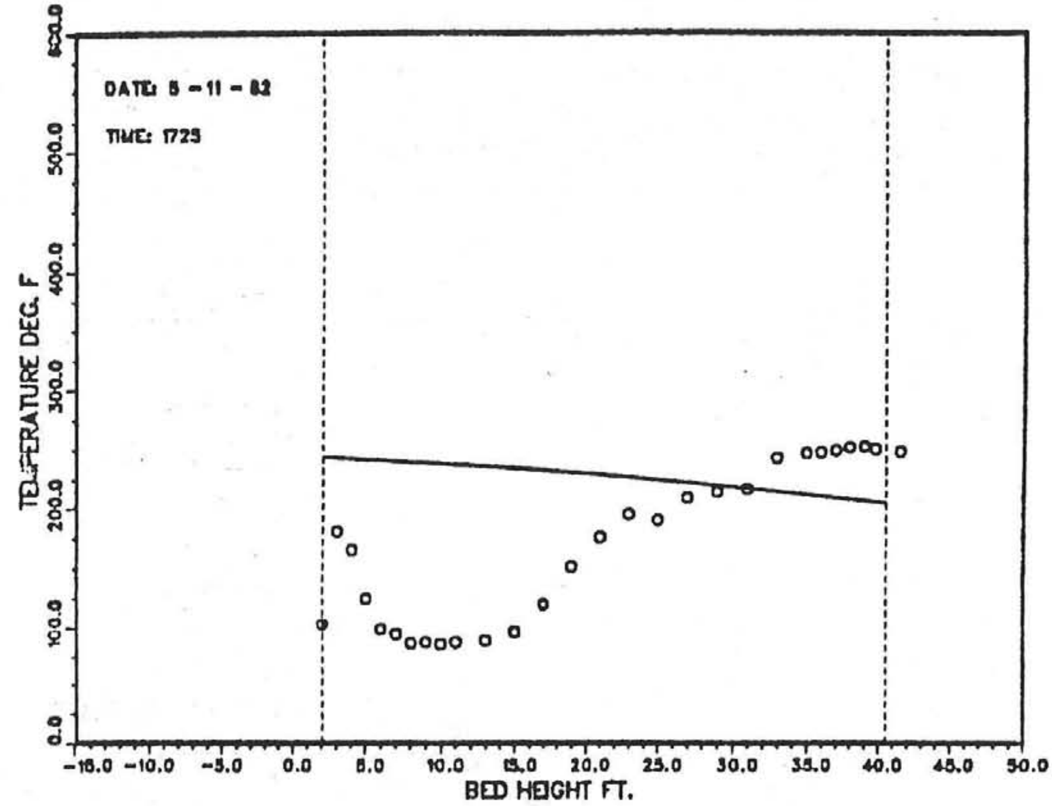


Figure 3.7-3. Thermocline Profile

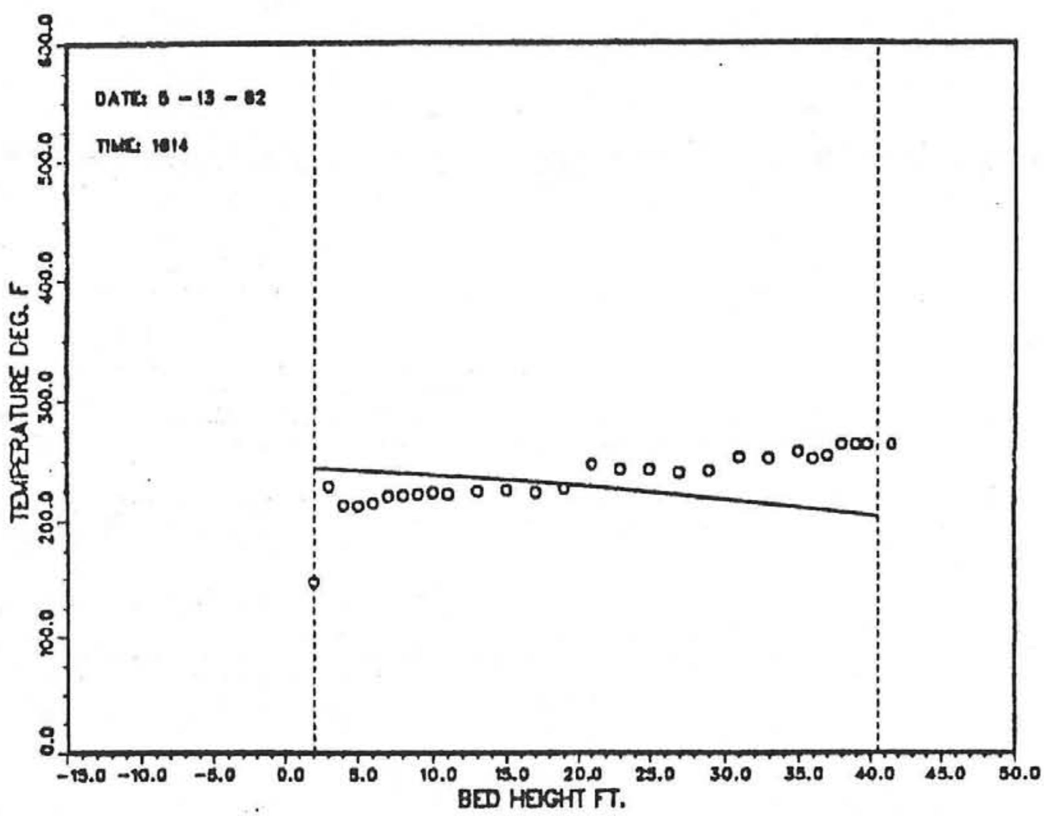


Figure 3.7-4. Thermocline Profile

Similarly, continued high temperature charging in Figure 3.7-5 has dropped the saturation point to 9 ft and elevated the bed from 11 ft up to a nearly uniform temperature. Figure 3.7-6 clearly shows the heat loss to the insulating concrete. Temperatures immediately below the TSU are also shown for reference (note that the temperature at the 2 ft level is measured by a thermocouple just outside the TSU in the oil piping). Also on 5-17-82 (see Figure 3.7-7) after charging for 7 hours, the thermocline has been pushed down to the 6 ft level, and again the thermocline gradient is on the water saturation line. The maximum temperature difference from 7 ft to the top of the TSU is only 15^{o}F. Figure 3.7-8 shows that the thermocline has been dropped below the bottom manifold; the maximum temperature difference over the entire TSU is only 10^{o}F. The heat loss to the insulating concrete over 11 hours (overnight) is shown in Figure 3.7-9. The uniform temperature above the 6 ft level is undisturbed (and differs from the previous night, Figure 3.7-8, by an average of 0.3^{o}F). The small temperature change allows evaluation of the heat loss from the TSU sidewalls (above the 6 ft level) and top, and comparison with predicted values. The total sidewall and top heat loss rate

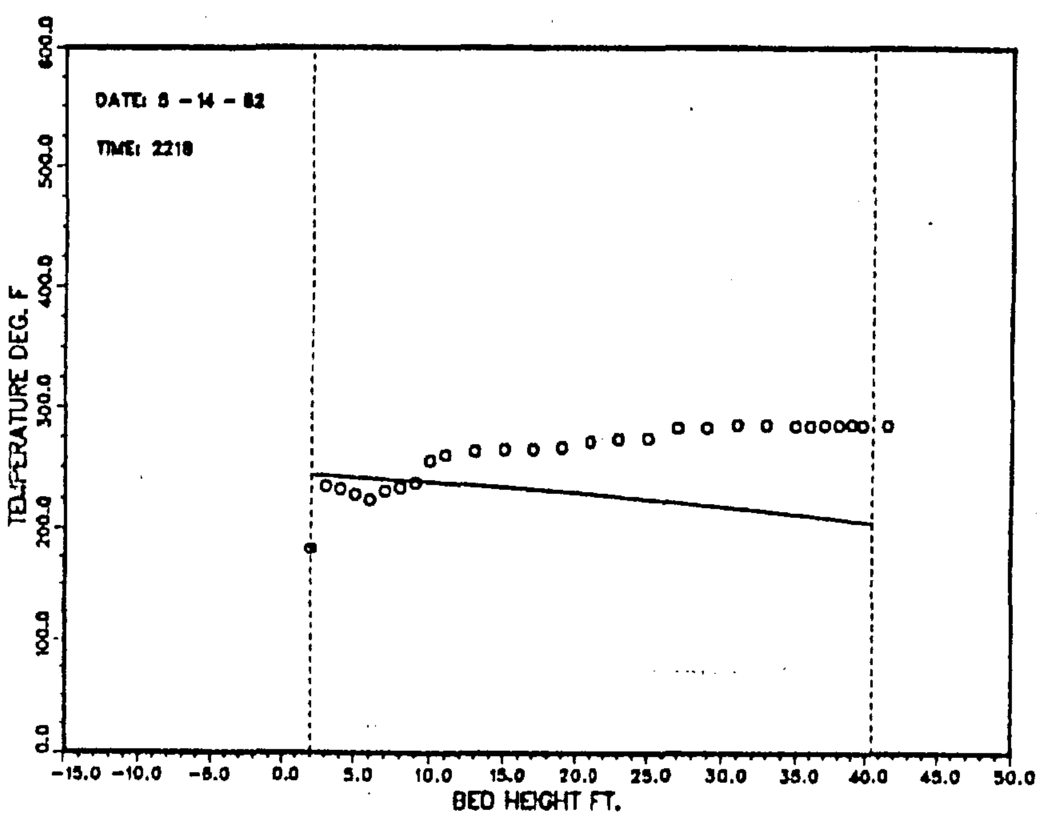


Figure 3.7-5. Thermocline Profile

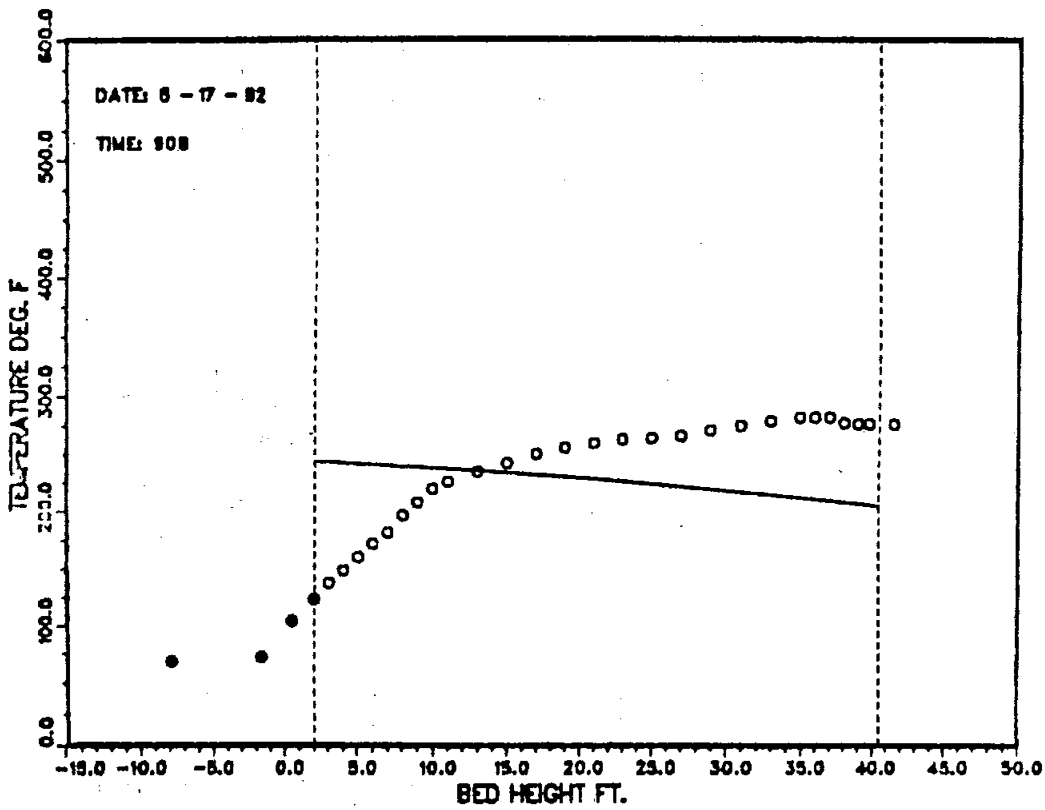


Figure 3.7-6. Thermocline Profile

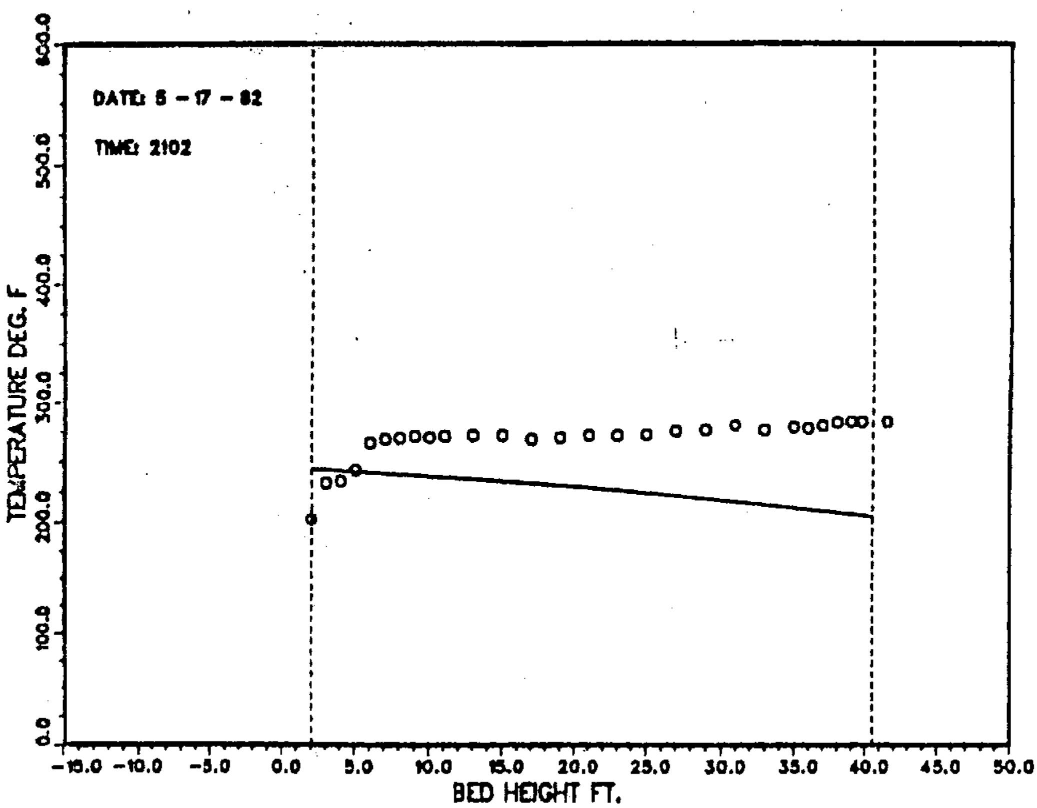


Figure 3.7-7. Thermocline Profile

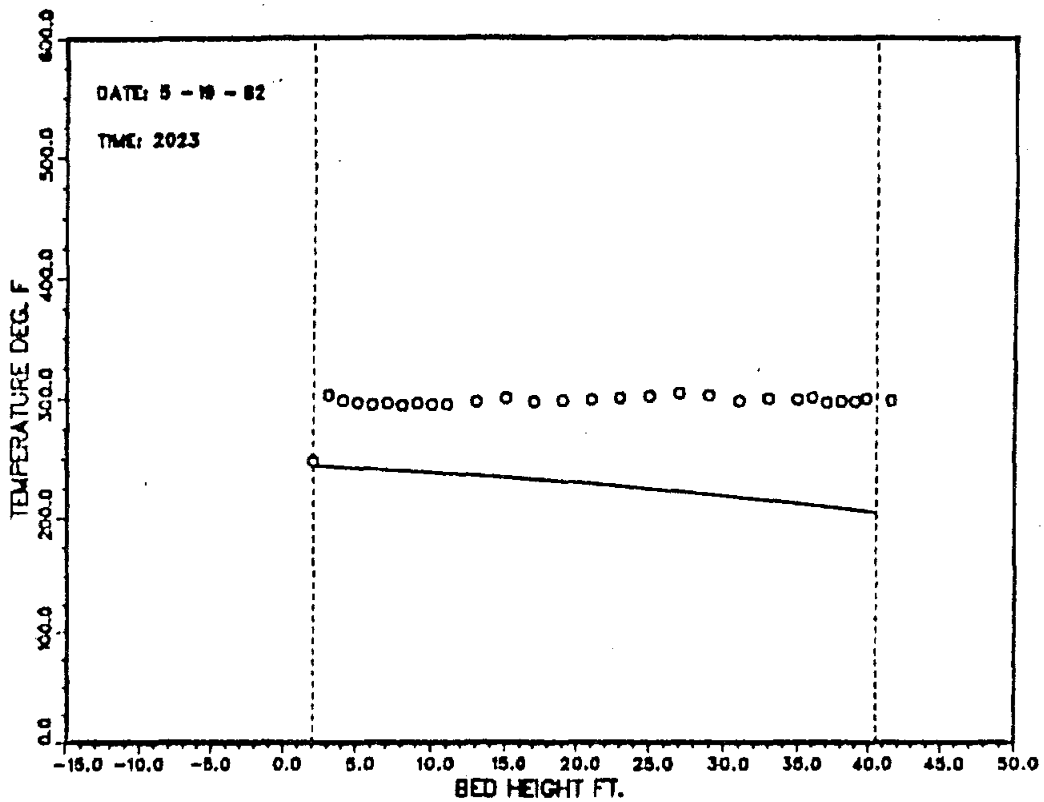


Figure 3.7-8. Thermocline Profile

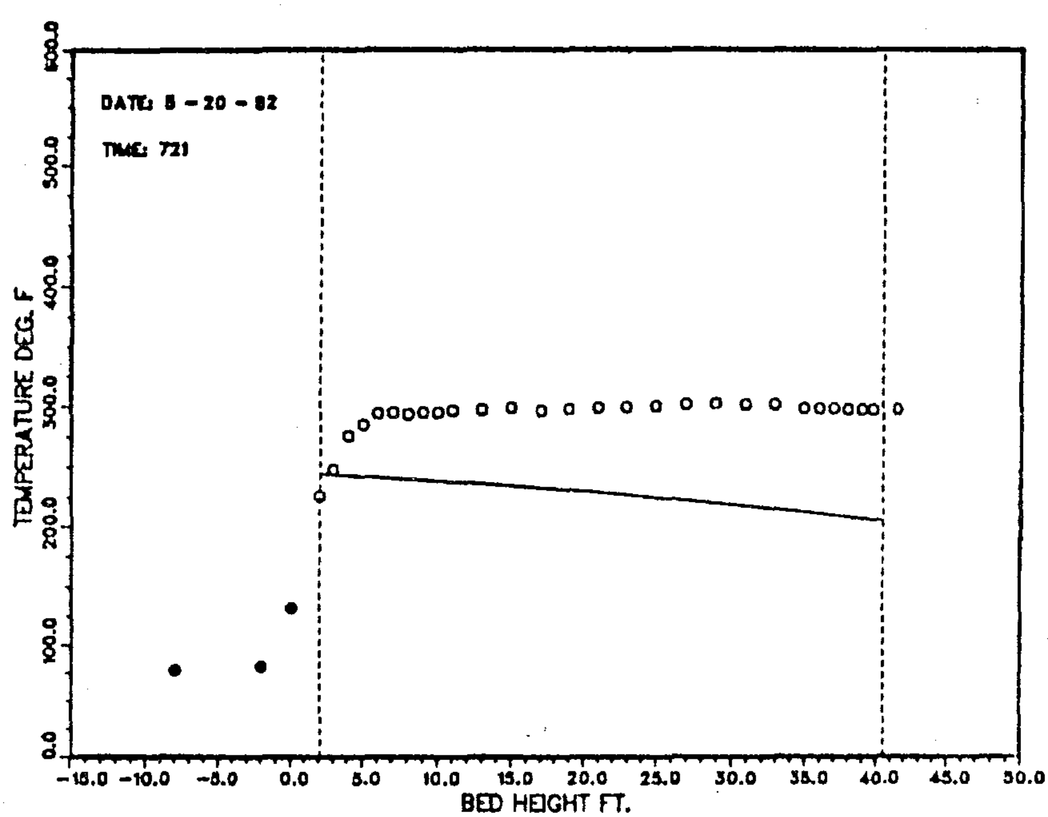


Figure 3.7-9. Thermocline Profile

at 300^{O}F was .035MW, which is about twice that predicted from insulation properties. The difference may be due to losses through insulation penetrations and heat shorts and/or small energy equalizations within the TSU during this initial transient phase. From 5-20-82 to 5-25-82 there was no significant charging activity because the oil pump kept tripping on low flow due to water in the oil flashing to steam at the pump inlet (see section 3.1.2). Figure 3.7-10 shows an interesting phenomenon wherein the oil temperature parallels the water saturation line but at an average 47^{O}F above it over the range of 6 ft to 33 ft. This temperature difference is equivalent to a water saturation pressure of 22 to 31 psi above the local hydrostatic head. It was speculated that this may represent the additional pressure required to force the steam/water from interstitial cracks in the rock.

In order to heat the oil to the highest temperature possible using the rental boiler, the charging train condenser setpoint pressure was raised to 190 psig (the maximum rental boiler outlet pressure was about 215 psig), which raised the oil outlet temperature from the charging trains to about 365^{O}F. The start of the higher temperature charging is shown in Figure 3.7-11 and the

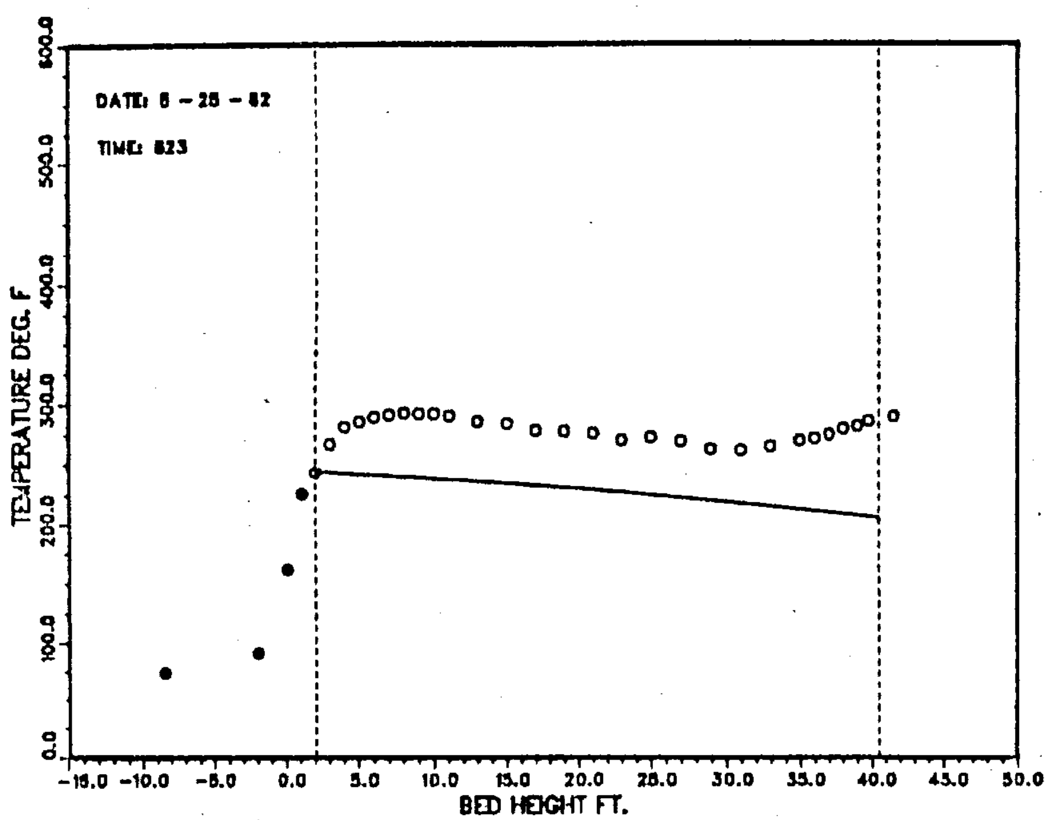


Figure 3.7-10. Thermocline Profile

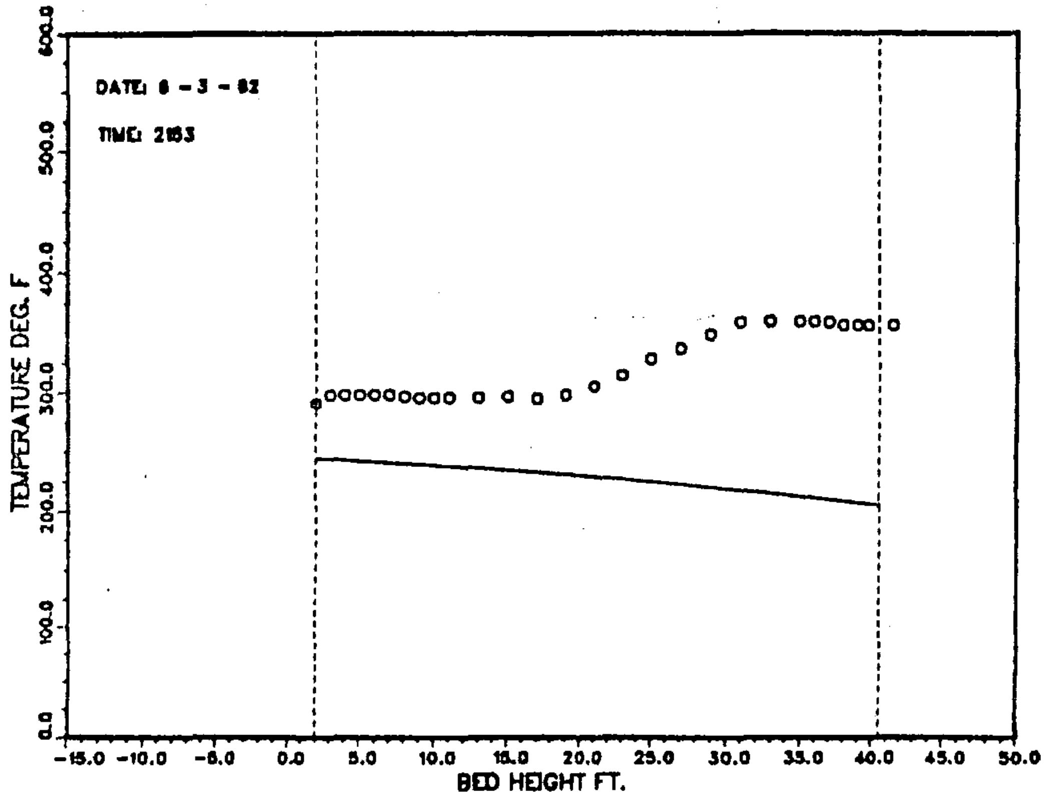


Figure 3.7-11. Thermocline Profile

completed charging using the rental boiler is shown in Figure 3.7-12. The temperature varies from 344°F to 366°F over the length of the TSU. Again, the heat loss overnight (15-1/2 hours) to the insulating concrete is shown in Figure 3.7-13.

Calculations of heat balances and flows through the insulating concrete during this initial transient phase were unrewarding because large quantities of energy were being consumed in boiling water in the oil/rock/sand bed of the TSU. Approximate calculations of steam generation rates matched with reasonable accuracy the steam quantities observed being discharged from the TSU relief valve (see section 3.1.2). TSU heat flows after the TSU, insulating concrete, structural concrete, and earth temperatures have essentially stabilized are discussed in more detail below.

It was found that the temperature in the sand layer on the bottom of the TSU (below the bottom manifold at the 1 ft level) remained below the water saturation temperature long after the entire TSU bed above the bottom manifold

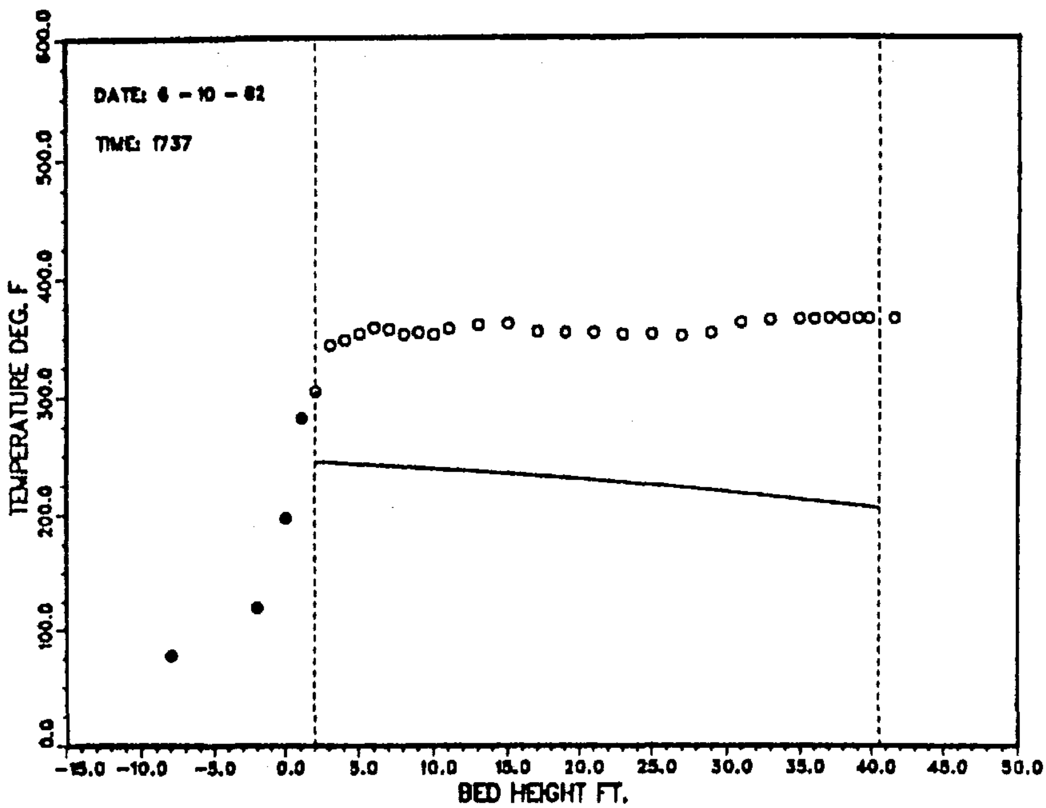


Figure 3.7-12. Thermocline Profile

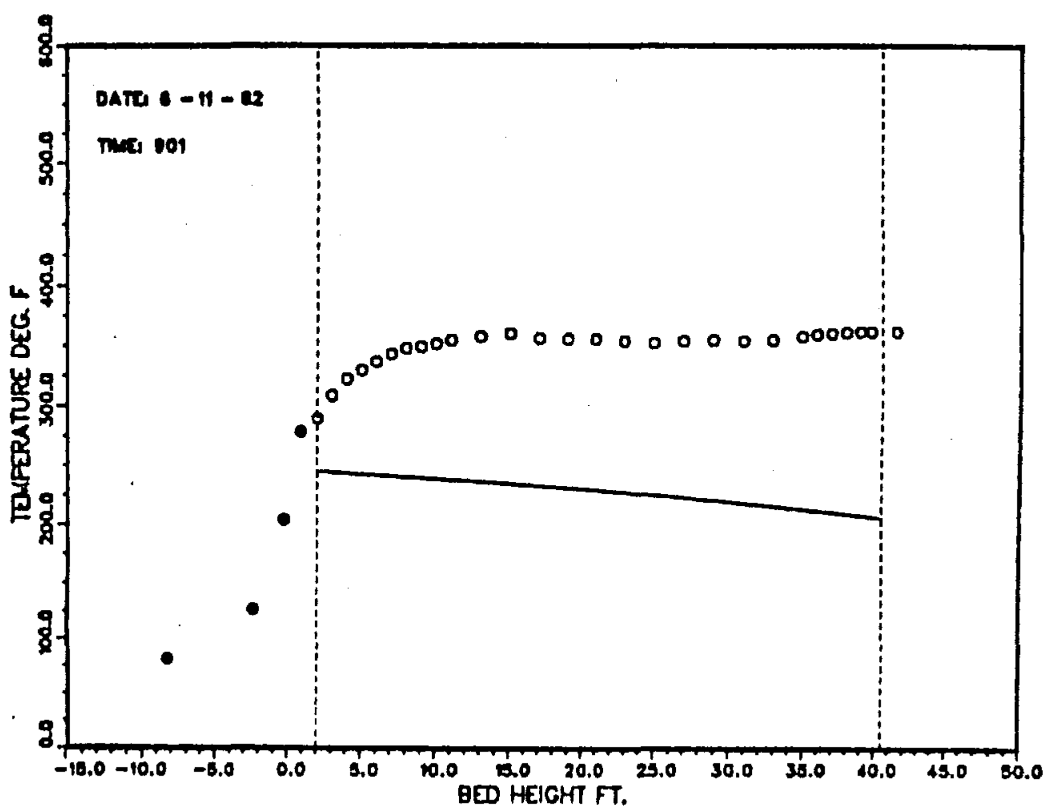


Figure 3.7-13. Thermocline Profile

was heated up. This difference is shown in Figure 3.7-14 which compares the temperature from TEX3070F (TSU C_L) and TEX3070D (6 ft in from wall) which are both at the 1 ft level, with TE3010N, which is at the wall at the 3 ft level (just above the bottom manifold). The open circles show the TE3010N temperature early in the morning, after cooling down all night, while the shaded circles show the TE3010N temperature late in the afternoon, after charging during the day. Note that the temperature above the manifold stayed above saturation from 5-20-82 on while the temperature at the TSU C_L did not exceed the saturation temperature until 6-11-82. It is believed that the water in the sand layer below the manifold may have resulted from a brief rain shower while the TSU was being filled with rock and sand, and may have persisted because there was essentially no oil circulation in that region, and the water had to be boiled off by heat conducted rather than convected from the hotter bed above the region. The temperature in the sand stayed above saturation after the 6-11-82 date shown in Figure 3.7-14, which was the last day of operation for the renter boiler.

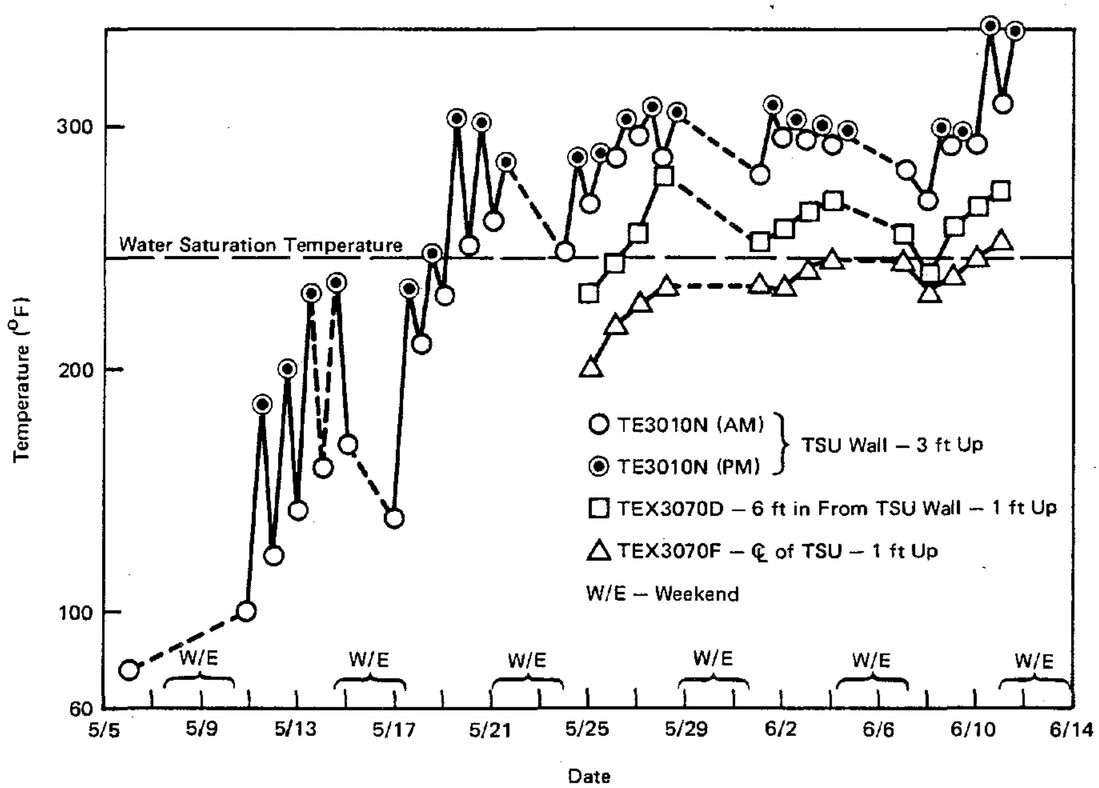


Figure 3.7-14. TSU Temperatures

3.8 THERMOCLINE ESTABLISHMENT USING RECEIVER STEAM

Following the establishment of the initial thermocline in the TSU, the goal was to establish the nominal charged thermocline position in the TSU (425°F minimum to 575°F maximum). Initially, the receiver steam was controlled to about 450 psi and 430°F and charging proceeded as shown in Figure 3.8-1 (before charging) and Figure 3.8-2 (after charging). The dip at the 38 ft level in Figure 3.8-2 was due to an oil temperature setpoint change incurred during some control valve tuning.

In time, the receiver pressure was increased to 1450 psi with charging steam desuperheated to about 650°F, which allowed an oil temperature setpoint of 570°F. Figure 3.8-3 shows the profile prior to high temperature charging and clearly shows the insulating concrete heat loss which occurred over the weekend. Figure 3.8-4 shows the result of the higher temperature charging. The result of overnight heat loss to the insulating concrete after high temperature charging is shown in Figure 3.8-5. Between 8-10-82 and 8-20-82 only a couple of hours of charging but many hours of extraction (blowing the turbine admission steam system and condenser system) were

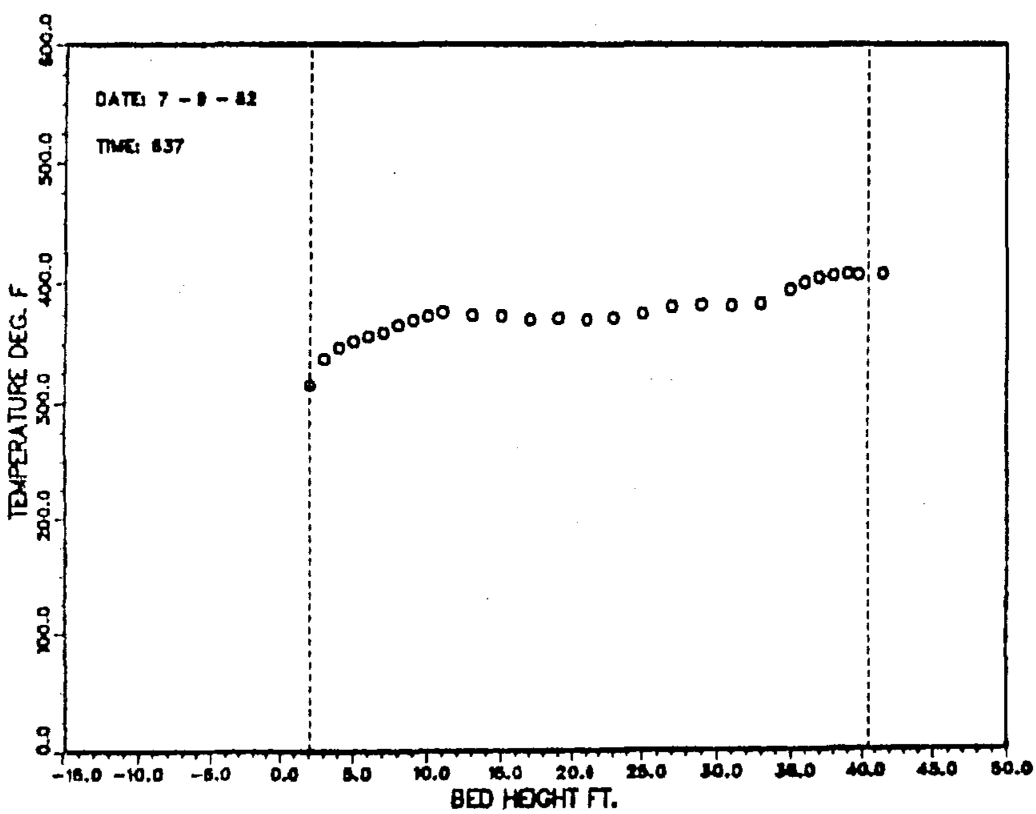


Figure 3.8-1. Thermocline Profile

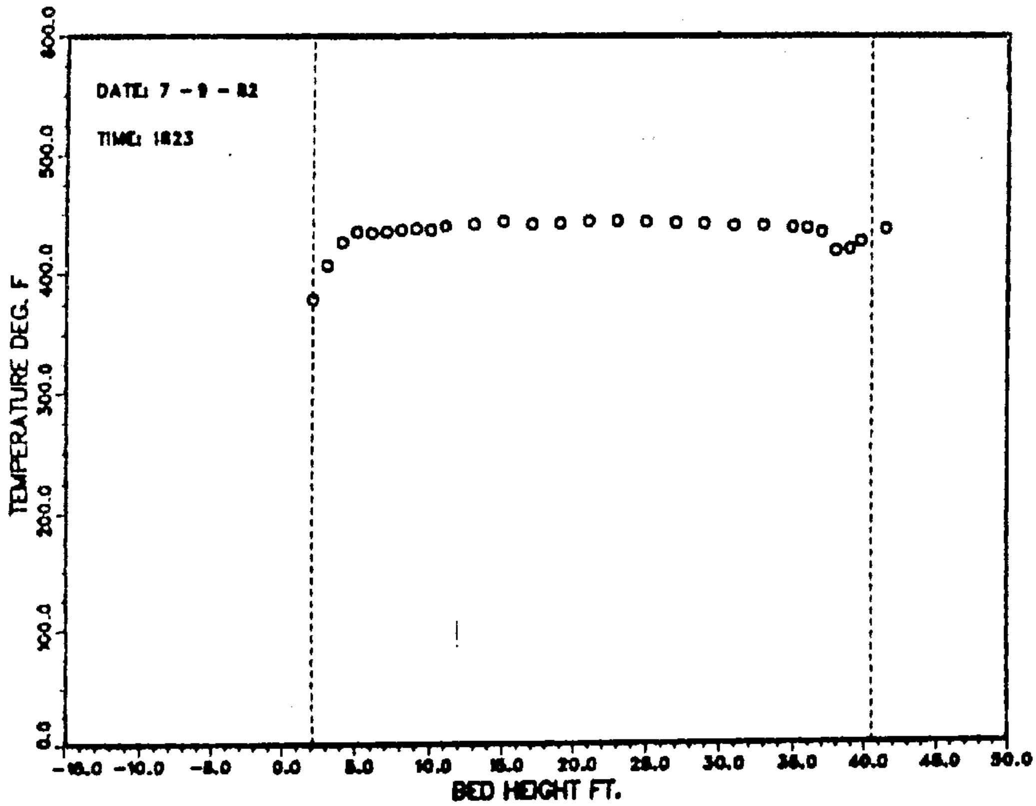


Figure 3.8-2. Thermocline Profile

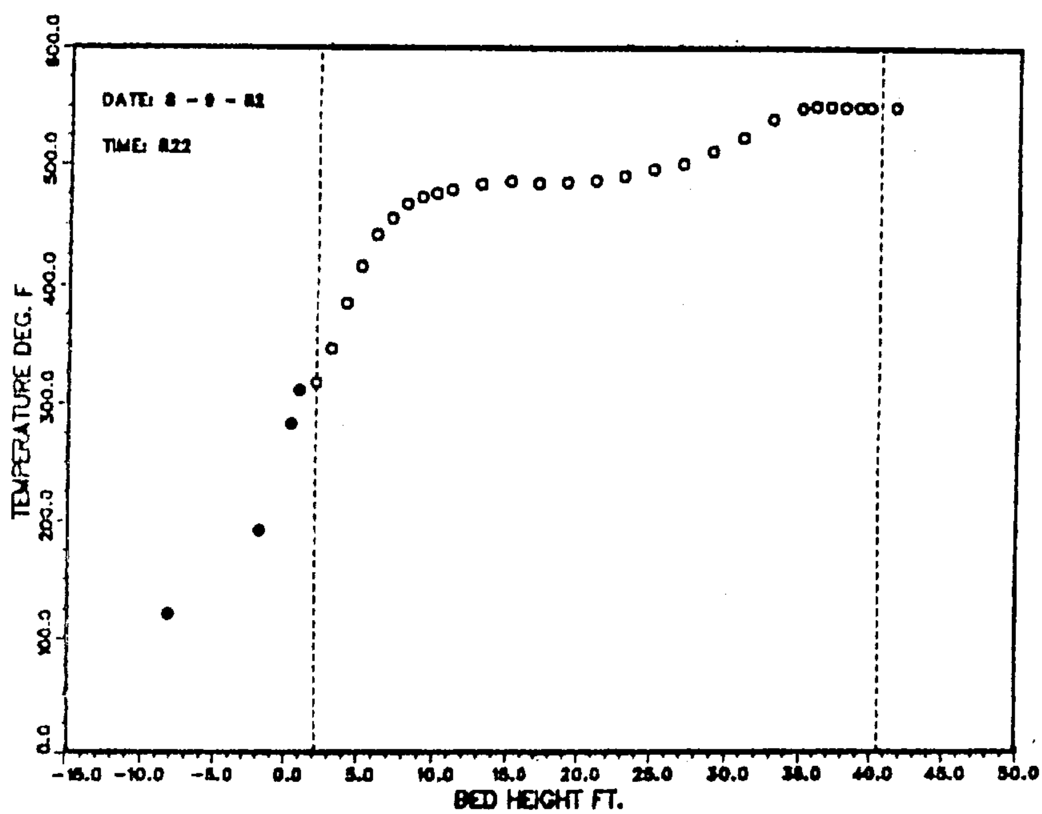


Figure 3.8-3. Thermocline Profile

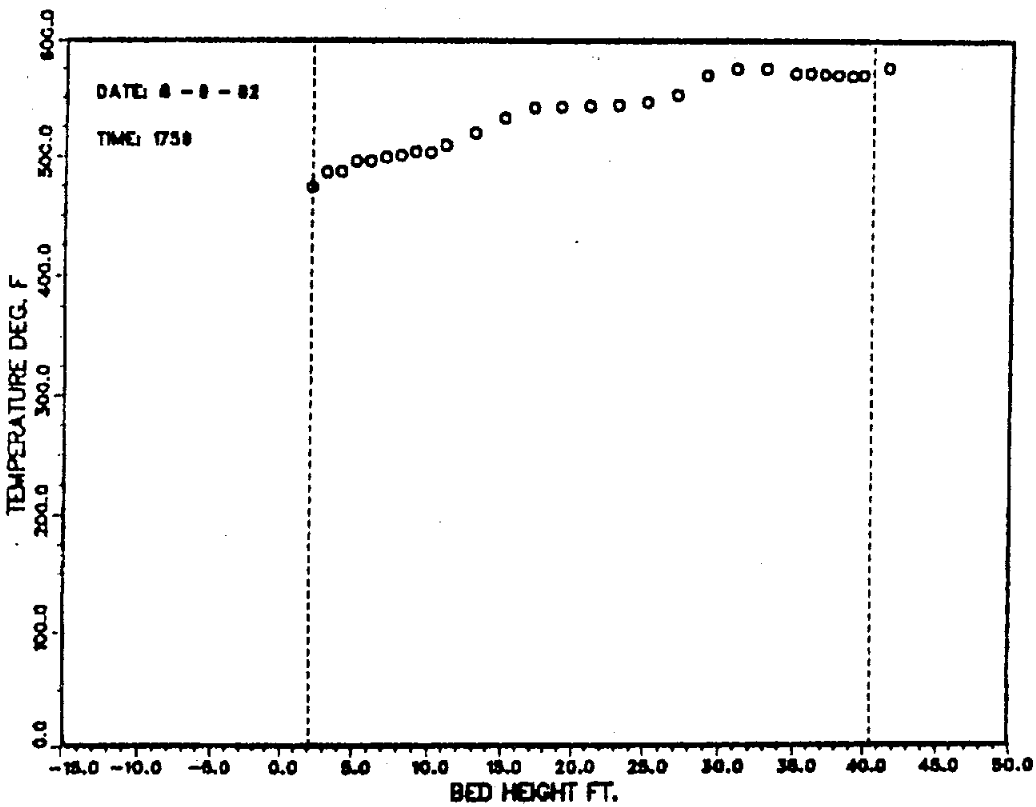


Figure 3.8-4. Thermocline Profile

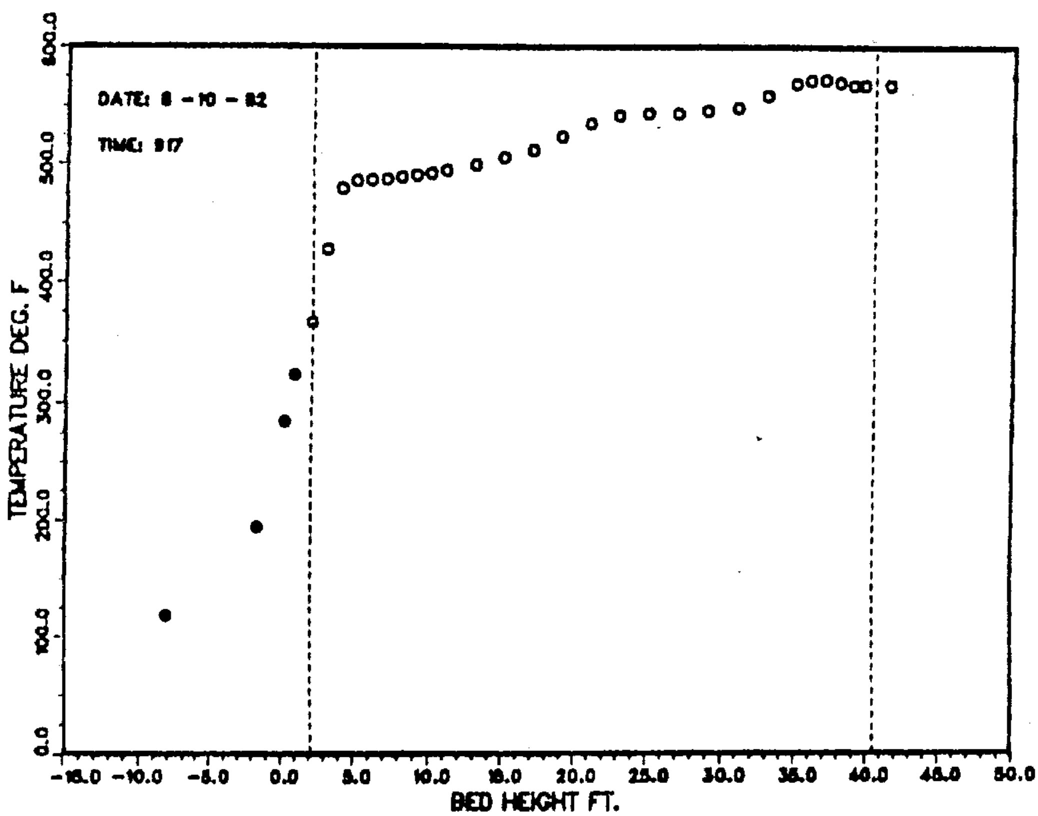


Figure 3.8-5. Thermocline Profile

performed. A combination of extraction and weekend heat loss to the insulating concrete, resulted in the sharp thermocline situation shown in Figure 3.8-6 (142°F drop over 4 ft). Temperatures in the bottom of the TSU, on the top and bottom of the insulating concrete, and in the soil below the TSU foundation (see Figure 3.7-2) were monitored over a period of several months, as shown in Figure 3.8-7. The circles (○) shown represent the readings of the thermocouple TEX3070H (at the 3 ft level in the TSU). The squares (□) shown represent the readings of thermocouple TEX3070F (at the 1 ft level in the TSU). The triangles (△) represent the readings of thermocouple TEX3065A (on top of the insulating concrete). The (⊙) symbols represent the readings of thermocouple TEX3065D (at the bottom of the insulating concrete-also the top of the structural concrete). Finally, the (◇) symbols represent the readings of the thermocouple TEX3065H (in the earth 1 ft 3-7/8 in. below the structural concrete). These temperatures are all on the TSU centerline, and were thus less likely to be distorted by radial heat flow effects. The temperature in the TSU (○ and □) increased steadily as the TSU was initially charged until about 7-20-82, and then varied over a wide range

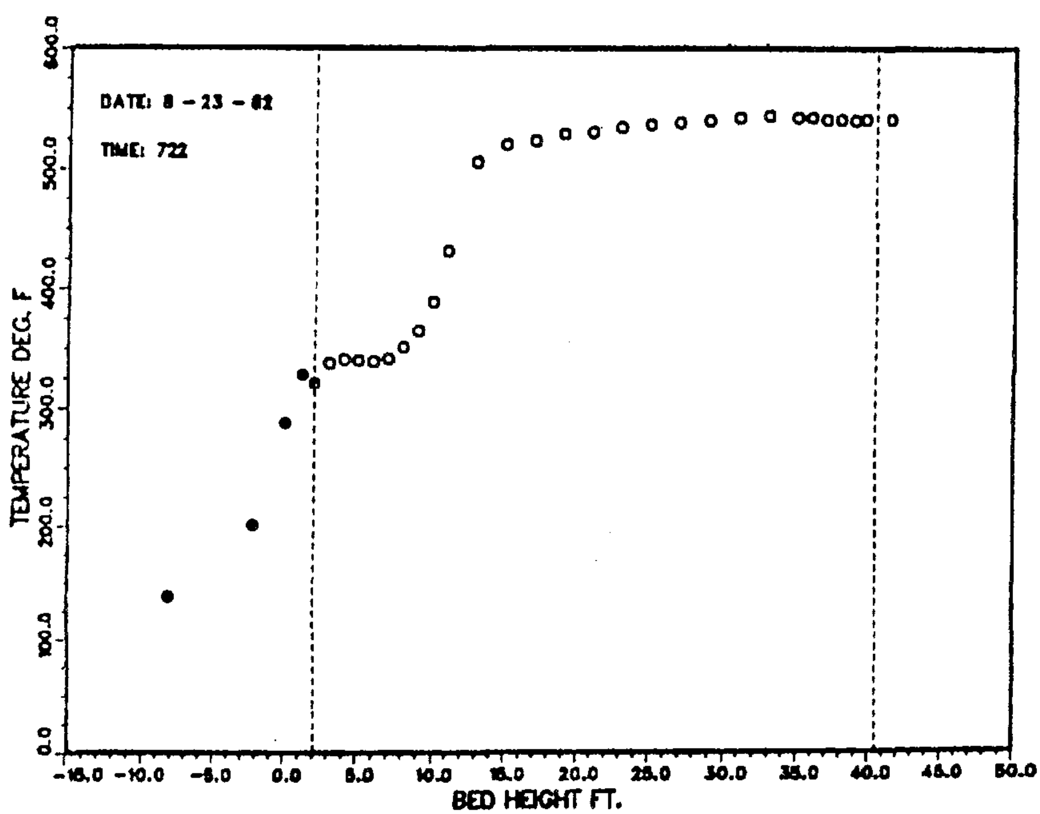


Figure 3.8-6. Thermocline Profile

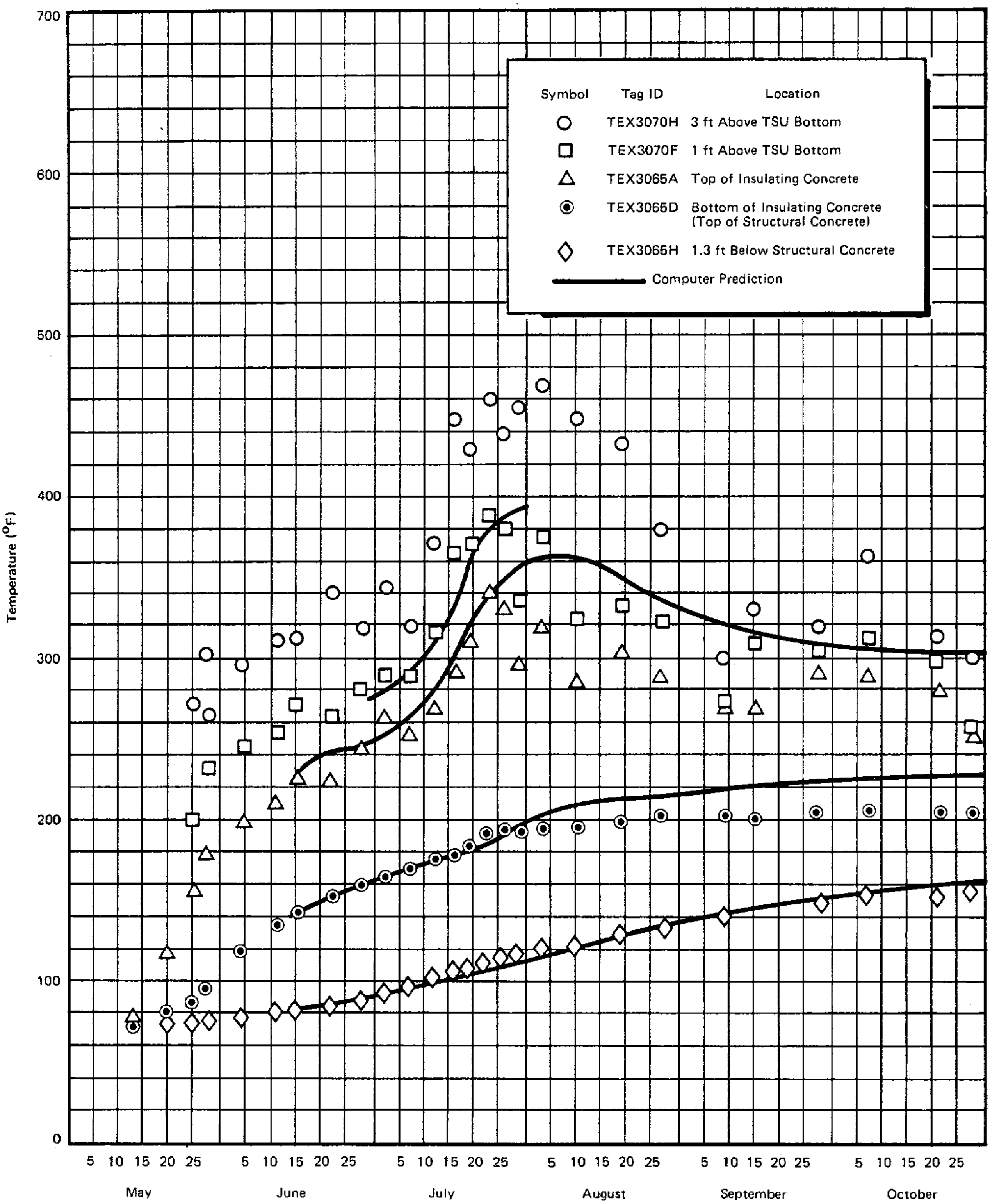


Figure 3.8-7. TSU Foundation Temperature History

as the TSU was charged and discharged during the 1040B testing. The temperature at the top of the insulating concrete (Δ) also increased steadily and tended to follow the TSU temperatures until it stabilized at about 285°F under normal operating conditions (e.g., 8-1-82 through 10-15-82). The sharp drop in this temperature at the end of October was due to several days of inactivity caused by a variety of mechanical problems, and once TSU charging recommenced, this temperature started upward again (e.g., 11-3-82). The temperature at the bottom of the insulating concrete (⊙) followed and lagged slightly the top temperature until it reached a temperature of about 205°F, which happens to be the boiling point of water. Apparently, the conduit enclosing this thermocouple contains water, which is boiling and creating a false reading. A one-dimensional heat flow model of the TSU calculated temperatures in the concrete and earth based on observed temperatures in the TSU (TEX3070H), and with calculations starting on 6-14-82 (after the water had been boiled out of the TSU). The results of this analysis are shown as the lines in Figure 3.8-7 and in Table 3.8-1 The agreement is excellent, after slight variations were made in the thermal conductivity of the insulating concrete from nominal values (as shown in Table 3.8-1). These variations may be due to a slight increase in concrete density or water content. The "stabilized" heat flow and expected future temperatures in the insulating concrete and earth are also shown in Table 3.8-1

On 8-25-82, there was an extended extraction period, which culminated in operation of the turbine-generator and production of 4.9 MW of power from extraction train 2. The result of this extraction was that the TSU was nearly completely discharged, as shown in Figure 3.8-8. The thermocline is at the 29 ft to 35 ft level with 132°F drop over this distance. After 2-1/4 hours of charging (Figure 3.8-9) the thermocline has been lowered to the 21 ft to 27 ft level, and after completion of charging for the day (Figure 3.8-10) the thermocline has been lowered to the 2 ft to 5 ft level. The temperature difference across the thermocline is 140°F, which is essentially indistinguishable from the thermocline shown in Figure 3.8-8, illustrating the stability of the thermocline is passing from a discharged to fully charged condition.

Table 3.8-1

TSU FOUNDATION TEMPERATURE ANALYSIS

- Parameters Assumed for TSU Model

Component	Conductivity (BTU/HR-FT-°F)	Density (LB/FT^3)	Heat Capacity (BTU/LB-°F)
TSU Rock Layer and Oil (Around Bottom Manifold)	0.6	*	*
TSU Sand Layer and Oil (+ TSU plate and 1" sand base)	0.4	*	*
Insulating Concrete	(T<210°F) 0.21 (T>260°F) 0.12	40	0.21
Structural Concrete	(T<210°F) 0.568 (T>260°F) 0.4	105	0.21
Earth	0.55	100	0.20

*Functions of Temperature

- Driving Temperatures at 3 ft above TSU bottom were actual temperatures TE 3010N and TEX 3070H
- Initial Conditions were actual temperatures on 14 June 1982

Date	Temperatures (Predicted) Actual: Top of Insulating Concrete	Bottom of Insulating Concrete (Top of Structural Concrete)	Earth 1.3 ft Below Structural Concrete
24 June 1982	(245) 232	(154) 155	(88) 91
18 July 1982	(311) 309	(177) 179	(104) 107
17 Aug 1982	(355) 302	(211) 199	(125) 129
16 Sept 1982	(316) 269	(219) 201	(145) 145
26 Oct 1982	(304) 250	(226) 204	(161) 154
19 Nov 1982	(354) 324	(232) 206	(167) 159
2 Dec 1982	(350) 321	(243) 209	(171) 162

- "Stabilized" Heat Flow Through Insulating Concrete ≐ 20,000 BTU/HR

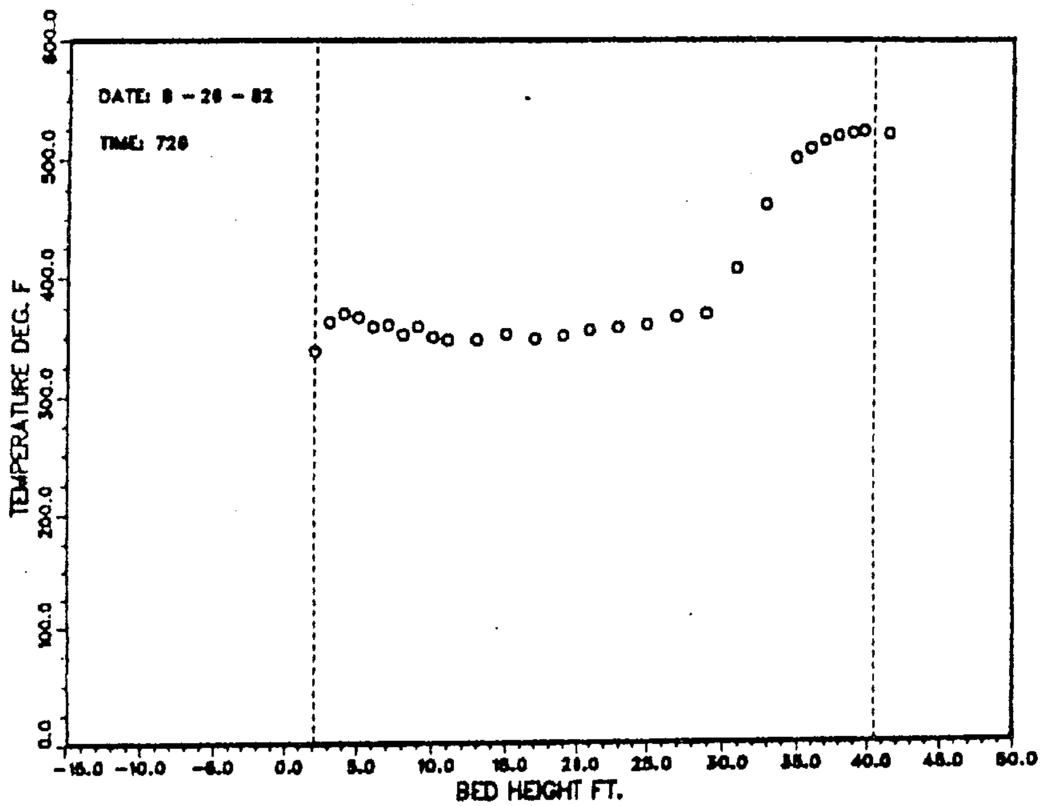


Figure 3.8-8. Thermocline Profile

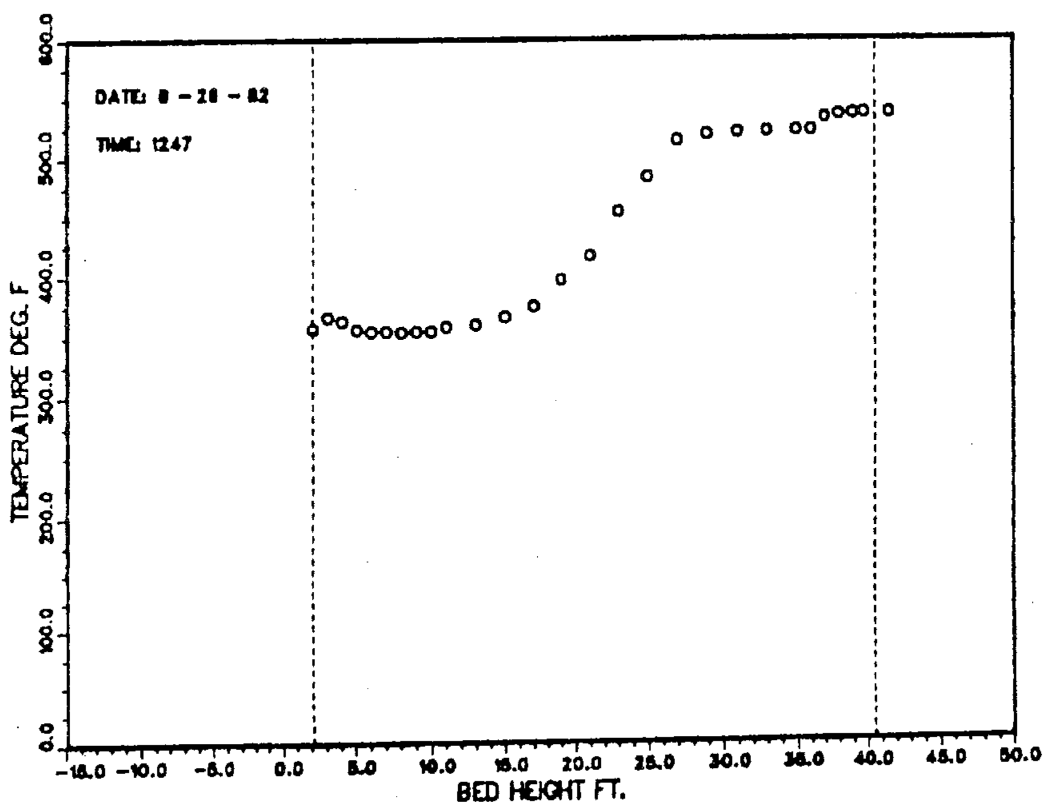


Figure 3.8-9. Thermocline Profile

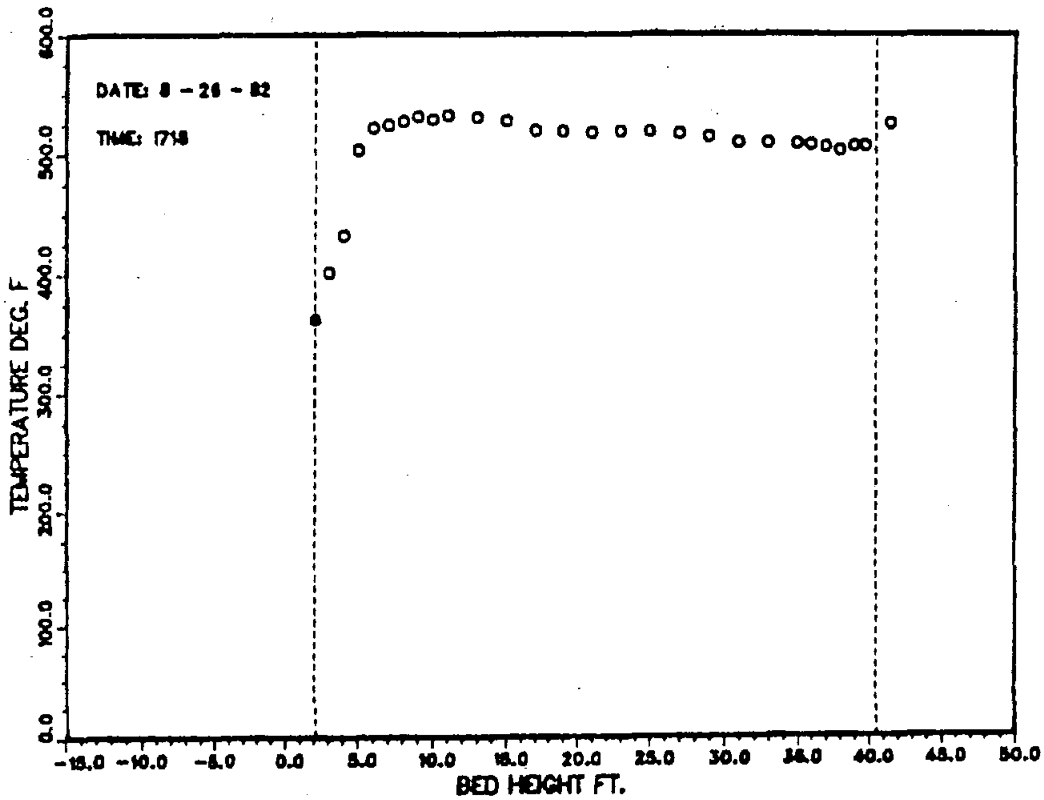


Figure 3.8-10. Thermocline Profile

3.9 UMU OPERATIONS

The function of the Ullage Maintenance Unit (UMU) is twofold: (1) to maintain the TSU at a positive pressure at all times to exclude air from the TSU protecting the oil from oxidizing into a tarry sludge and obviate the hazard of a Caloria oil fire, and (2) to safely dispose of oil decomposition (cracking) products which occur due to oil heating. Initially the TSU nominal pressure was set at 9 in. H_2O, and was regulated by two mechanical pressure switches located on top of the TSU. The pressure range of the TSU is shown in Figure 3.9-1. Typically, the TSU venting cycle was initiated at 11 in. H_2O (nominal) and stopped when the TSU pressure dropped to 9 in. H_2O (nominal), while the TSU pressurization cycle was initiated at 7 in. H_2O (nominal) and stopped when the TSU pressure rose to 9 in. H_2O (nominal). The pressure in the TSU was measured by PI4008, also located on top of the TSU, which indicated the TSU pressure was intially well-controlled by the pressure switches, as shown in Figure 3.9-2 for venting cycles while charging with the rental boiler. On 10 June, the venting pressure switch (PS4011) failed to

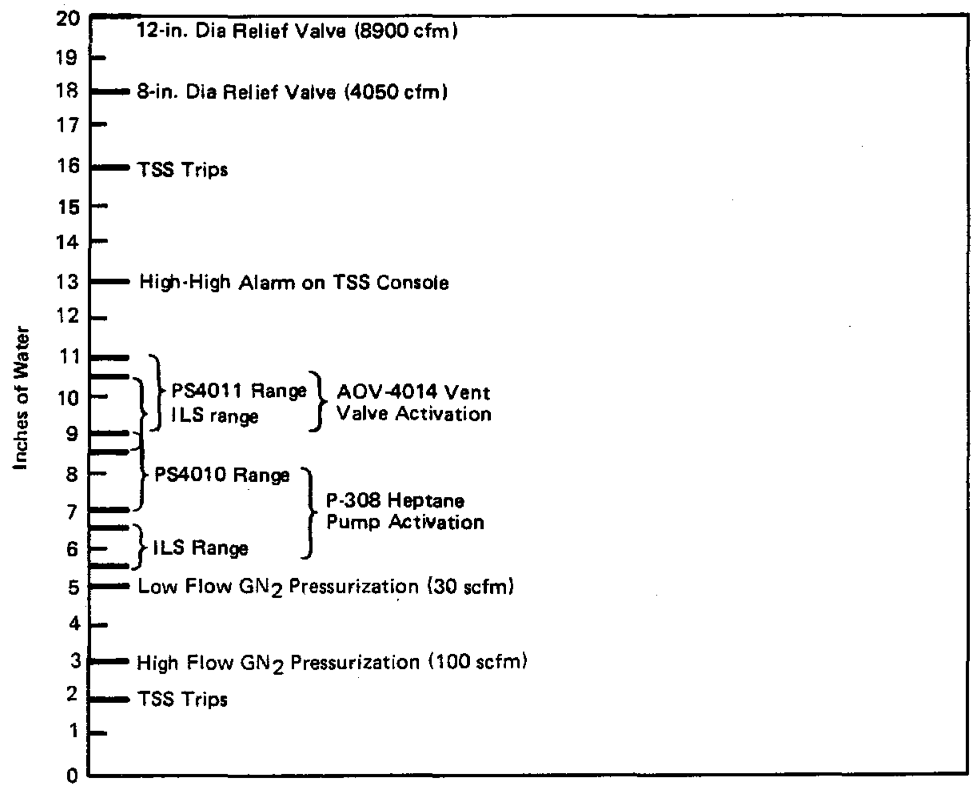


Figure 3.9-1. TSU Pressure Control Settings

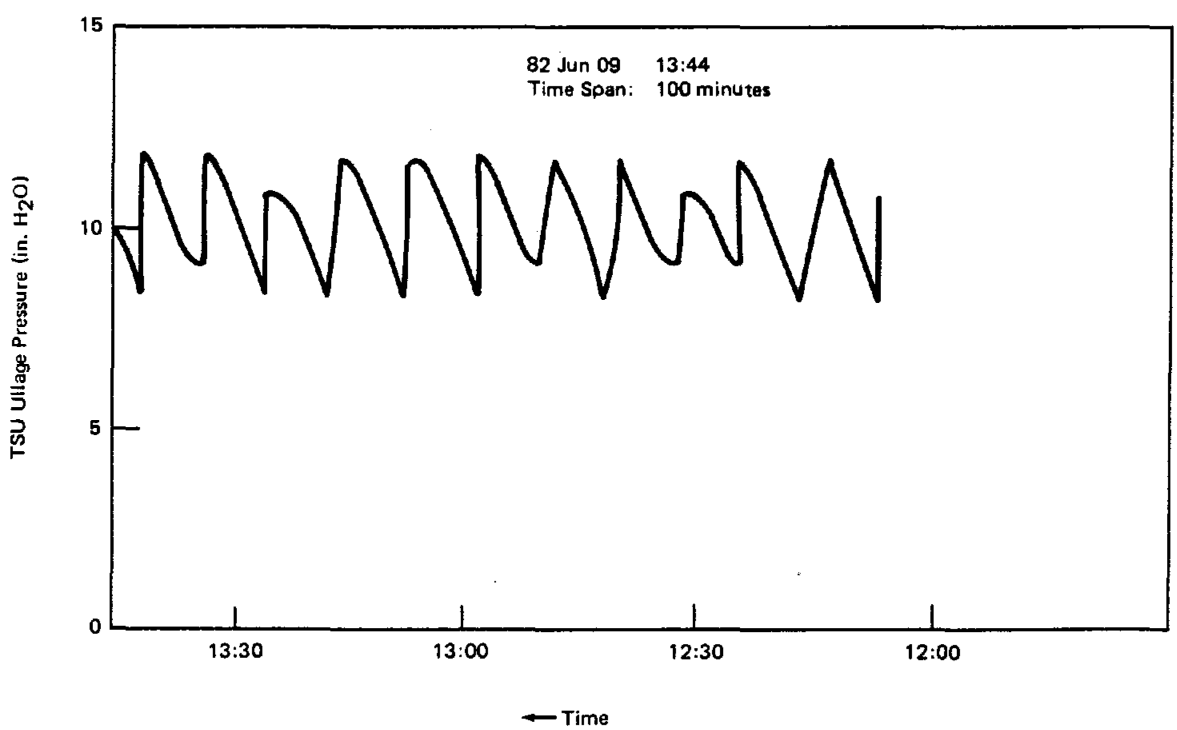


Figure 3.9-2. TSU Pressure Control Using Pressure Switches

actuate, resulting in TSU overpressure, and an inadvertent check of the TSU Relief Valve, as shown in Figure 3.9-3. It was found that the pressure switch diaphragm, made of brass, had corroded through from the effects of the ullage gas (and water) rendering it useless for TSU pressure control. Stainless steel replacement diaphragms were ordered, and it was decided to modify the TSU pressure control system to use the TSU pressure, as sensed by PI4008, (which used a stainless steel sensing element) to control the TSU venting and pressurization cycles through the Interlock Logic System (ILS). Wiring changes were installed and the ILS control of the TSU pressure was demonstrated on 14-15 June, as shown in Figure 3.9-4. Originally, it was intended to retain the pressure switches (with stainless steel diaphragms) as mechanical backups to the ILS control. However, it was found that the pressure switches remained somewhat erratic and occasionally interfered with the ILS operation. Since mechanical backups, in the form of Relief Valves on the high-pressure side, and GN_2 pressurization on the low-pressure side, already exist, the pressure switches were disconnected, and the ILS control is used exclusively.

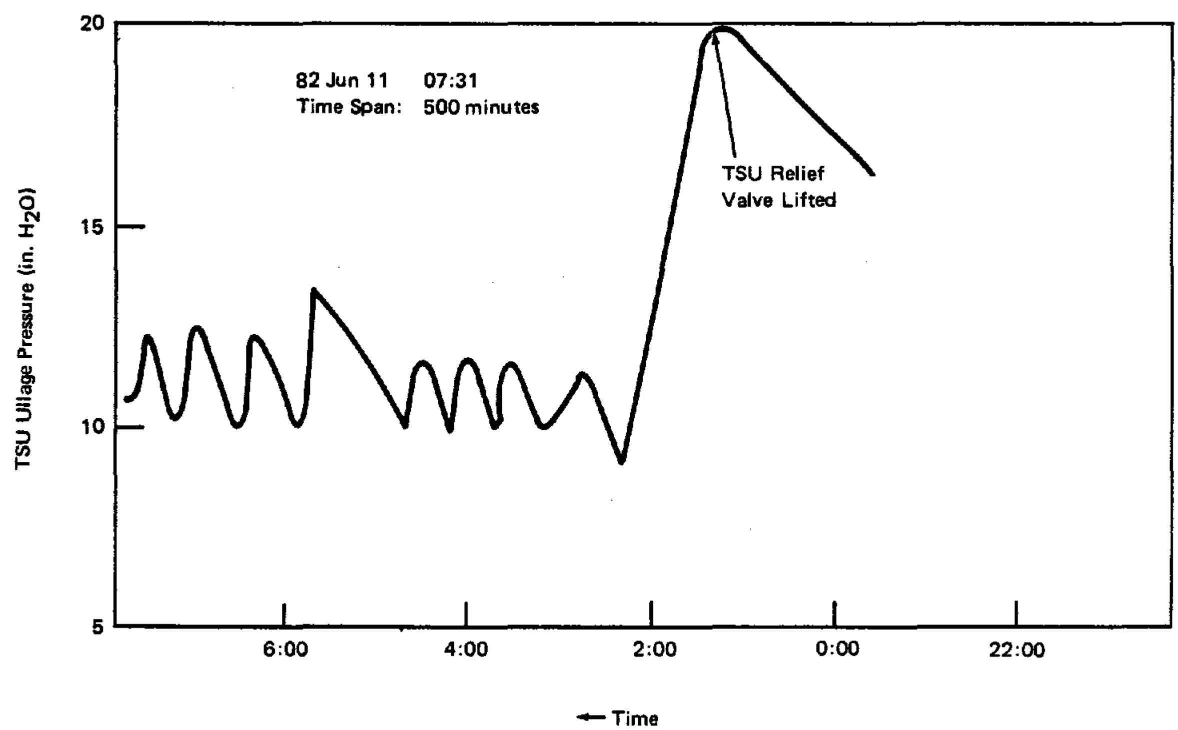


Figure 3.9-3. TSU Pressure Switch Failure

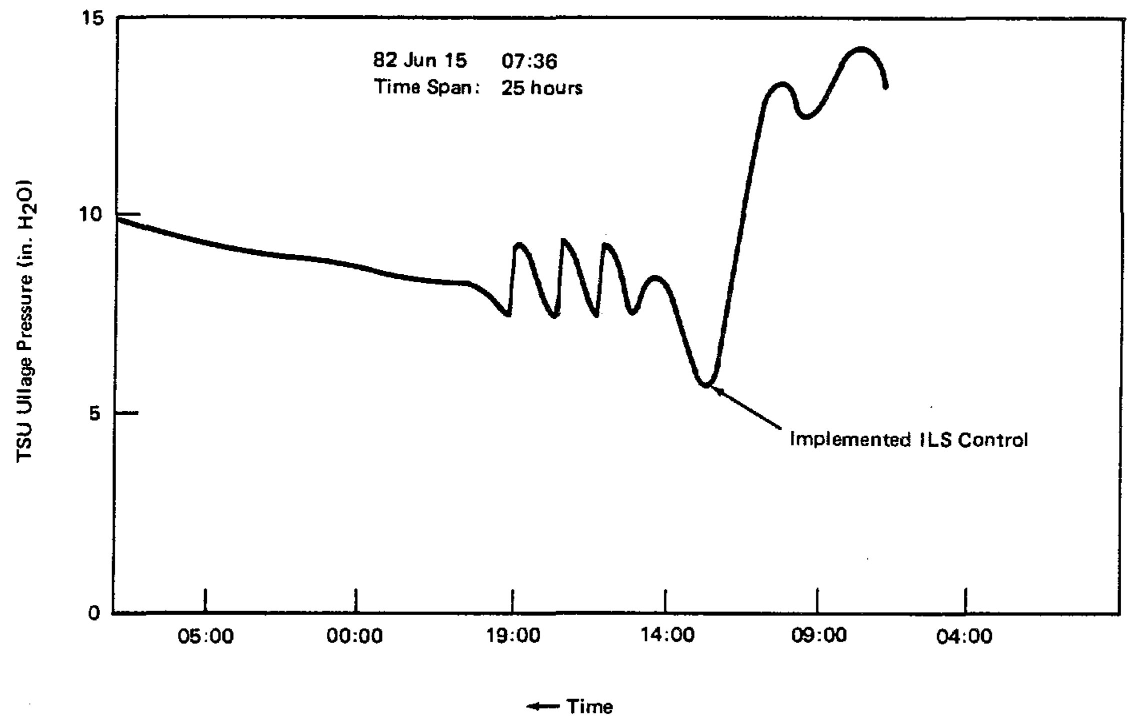


Figure 3.9-4. ILS Control of TSU Pressure

The fume blower FA-302 on the UMU began to trip occasionally during charging operations. It was theorized that the hot ullage gases were overheating the motor in FA-302, so a thermocouple was installed upstream of FA-302, and the temperatures were measured during the operation on 1 July as follows:

Time	Temperature ^{o}F
9:00	86
10:30	105
13:00	176
14:00	189 (maximum)

Inasmuch as these temperatures were below the nominal design operating temperature of 200^{o}F for FA-302, the motor overload links were checked and found to be undersized. The FA-302 trip problem was solved by: (1) installing a heat reflective cover on FA-302, and (2) installing the proper size overload links in the motor.

Early in the operation of the UMU, the propane supply to the burner pilot light was erratic, which resulted in occasional failure to vent the TSU since the burner system only allows venting when the pilot light is sensed. The propane supply regulator and permissive propane pressure switches were adjusted to eliminate this problem. In addition, condensate from the TSU (mostly water) was collecting in the pilot light well below the UMU burn stack and interfering with proper pilot light ignition: a small drain line was added to the bottom of the pilot light well which solved this problem.

It was found that fairly large quantities of inert ullage gases, which would not burn in the UMU, were being vented from the TSU. Often this was GN_2 which was used as back-up pressurization for the TSU. The original control setup in the UMU was arranged so that in the event of no flame in the burn stack, MOV4015 (the burn stack admission valve downstream of the fume blower) would close, and an alarm would sound and be indicated on the operator console in the control room. When this happened, the TSU could not be vented (because MOV4015 was closed) and an operator had to be dispatched to the UMU to silence the alarm and manually open MOV4015 to vent the TSU. The UMU control setup was modified by adding a timer relay to automatically open MOV4015 (and silence the alarm) 30 seconds after a "no-flame" indication had closed MOV4015. This change allowed safe operation of the TSU venting cycle without the need of operator intervention.

The normal method of TSU pressurization is by ullage injection of heptane, using the heptane pump on the UMU. Heptane is used because it vaporizes at $209^{o}F$ upon injection into the TSU ullage, and condenses and is recovered in the heptane tank on the UMU during TSU venting. After the TSU reached operational temperatures ($400^{o}F$), light fractions cracked from the Caloria were condensed and collected in the heptane tank (rather than heptane). These light fractions are now used to effectively pressurize the TSU by being returned to the TSU ullage with the heptane pump. During extensive extraction from the TSU, it was found that the heptane pump could pump the heptane tank dry, which could damage the pump. The UMU control setup was modified to use the ILS to protect the heptane pump from being run dry. If the heptane flow switch, FI4024, downstream of the heptane pumps did not pick up, showing flow, within 30 seconds after starting the pump, the pump would turn off and an alarm would show at the operator console.

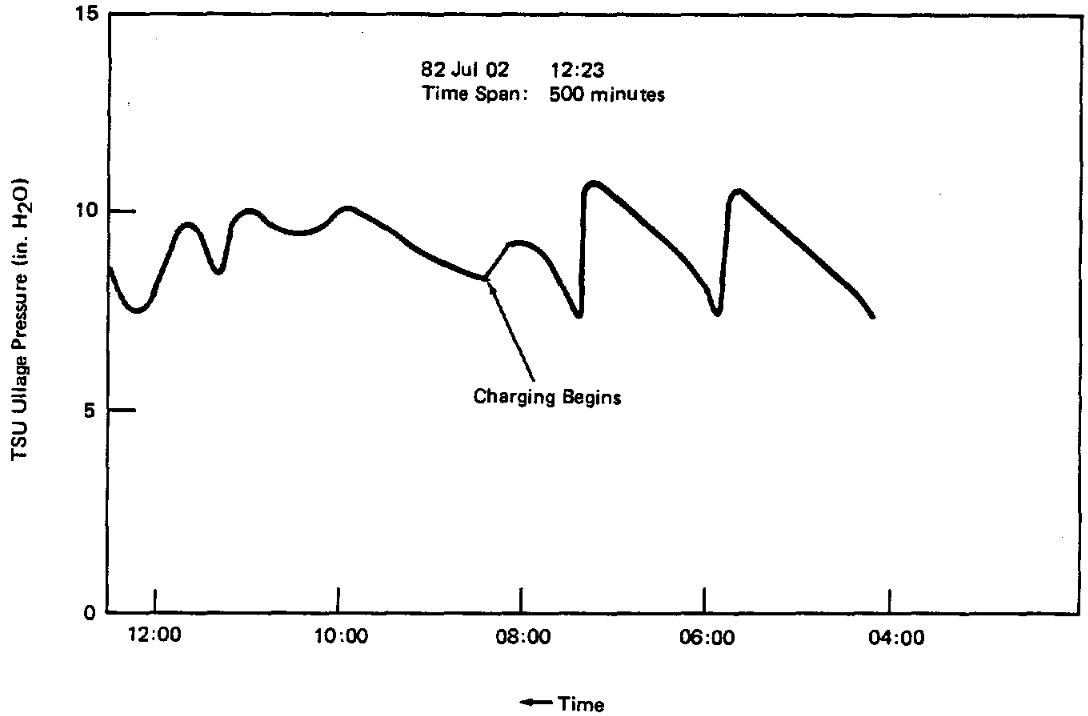


Figure 3.9-5. TSU Pressure Control While Dormant and While Charging

After all of these modifications to the UMU, it performed properly and reliably, with no further trips or malfunctions attributable to the UMU. As previously shown in Figure 3.9-1, the venting limits were changed to 8.5 to 10.5 in H_2O, and the heptane pressurization limits changed to 5.5 to 6.5 in. H_2O. The additional dead band (6.5 to 8.5 in H_2O) serves to limit cycling of the heptane pump and helps stabilize system operation. The proper operation of the UMU is shown in Figure 3.9-5, which shows the venting frequency overnight (prior to 0800) as well as during charging operations (after 0900). Similarly, continuous venting of the TSU, with the top oil temperature at about 480^{o}F, over a weekend, is shown in Figure 3.9-6. It appears that weathering of the oil above about 400^{o}F is a continuous process initially, which requires TSU venting whether or not the TSU is being actively charged. Finally, Figure 3.9-7 shows that the TSU continues to vent due to cracking (weathering) of oil at about 560^{o}F, even when extraction is occurring, as it was during the period shown in Figure 3.9-7. Clearly, if extraction were to continue for a significant period of time, venting due to initial oil weathering would diminish, and eventually the TSU would require pressurization through the heptane pump.

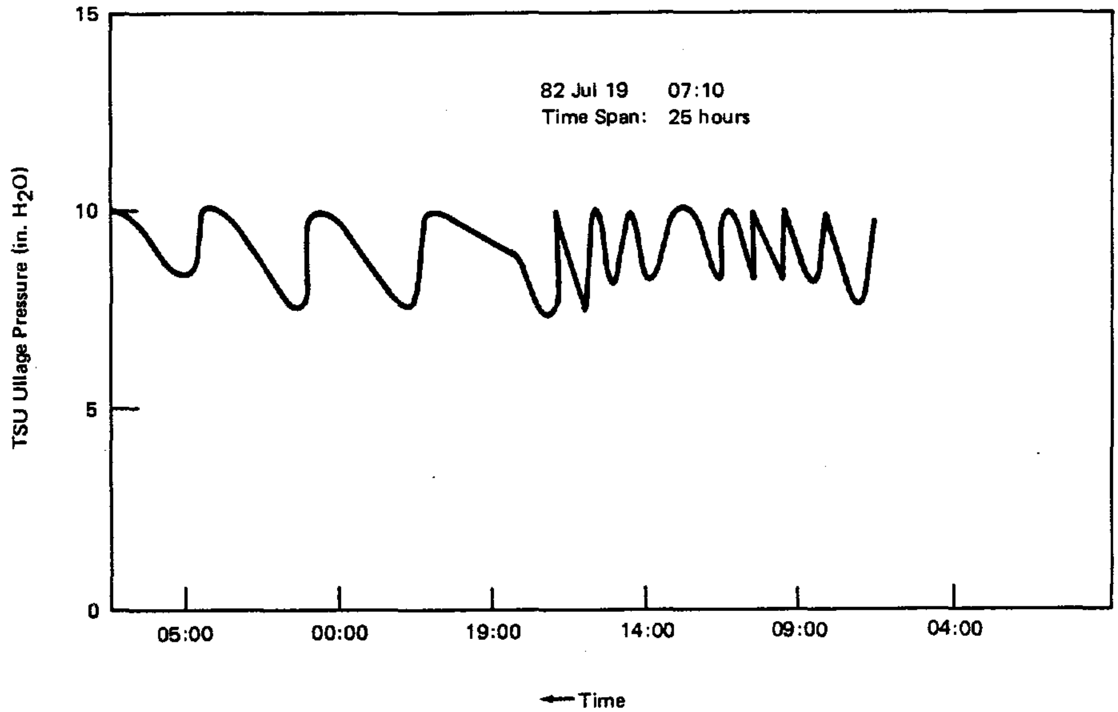


Figure 3.9-6. TSU Venting Cycles While Dormant

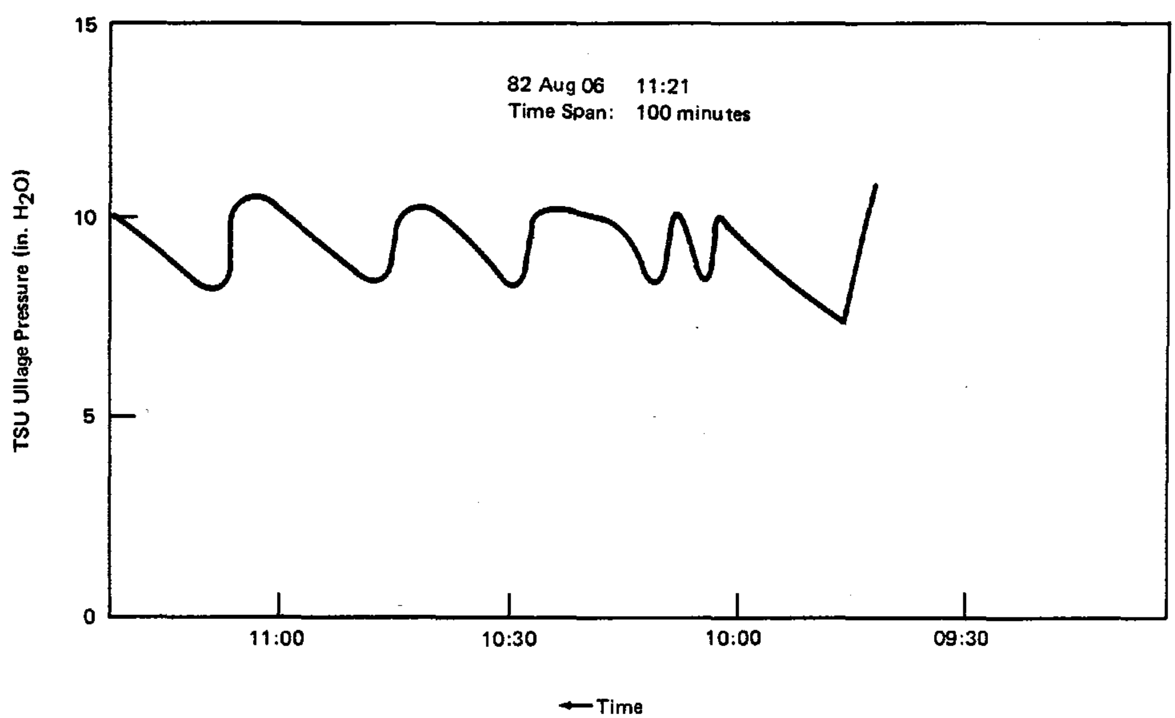


Figure 3.9-7. TSU Venting Cycles During Extraction

Section 4
TEST PROGRAM 1040B

The scope and activity flow of the 1040B test program is shown in Figure 4-1. The general objectives of the 1040B series preoperational tests were to:

(a) Verify the "process" operation of solar specific portions of the plant.

(b) Develop the control functions and/or field tune the individual plant controllers.

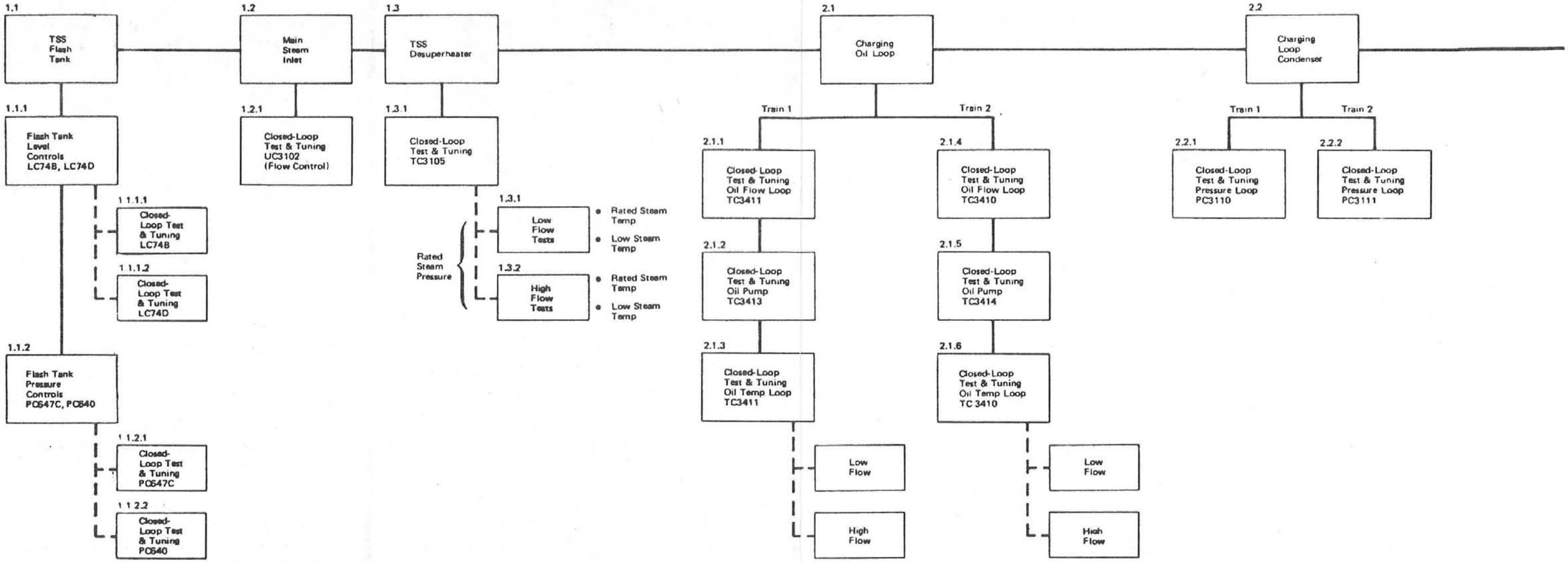
(c) Verify selected portions of the Plant Operating Procedures

As a result, in addition to satisfying the stated Acceptance Criteria (Section 4.1), portions of this procedure were designed to gather basic data required to develop and refine the basic control functions. Also, the actual procedures themselves (step-by-step activities) were evaluated against currently published operating procedures. In the event selected steps of the procedure did not produce the desired condition or better ways of achieving the desired conditions were identified, the operating procedures were revised to support subsequent testing.

Preoperational test 1040A involves low temperature bed conditioning activities using steam from the rental boiler. Preoperational test 1040B involves control activities using receiver steam at nominal conditions.

The first portion of the 1040B test involved bringing the TSS flash tank loops into service as well as the main inlet steam and desuperheater loops. Included in these tests were functional testing of control loops at off-nominal pressure and temperature conditions as well as normal operating conditions.

The second portion of the 1040B test program involved the charging loop subsystem. This included bringing both oil and steam loops in both condenser


1.1
TSS Flash Tank
1.2
Main Steam Inlet
1.3
TSS Desuperheater
2.1
Charging Oil Loop
2.2
Charging Loop Condenser
1.1.1
Flash Tank Level Controls LC74B, LC74D
1.1.1.1
Closed-Loop Test & Tuning LC74B
1.1.1.2
Closed-Loop Test & Tuning LC74D
1.1.2
Flash Tank Pressure Controls PC647C, PC640
1.1.2.1
Closed-Loop Test & Tuning PC647C
1.1.2.2
Closed-Loop Test & Tuning PC640
1.2.1
Closed-Loop Test & Tuning UC3102 (Flow Control)
1.3.1
Closed-Loop Test & Tuning TC3105
Rated Steam Pressure
1.3.1
Low Flow Tests
Rated Steam Temp
Low Steam Temp
1.3.2
High Flow Tests
Rated Steam Temp
Low Steam Temp
Train 1
Train 2
2.1.1
Closed-Loop Test & Tuning Oil Flow Loop TC3411
2.1.2
Closed-Loop Test & Tuning Oil Pump TC3413
2.1.3
Closed-Loop Test & Tuning Oil Temp Loop TC3411
Low Flow
High Flow
2.1.4
Closed-Loop Test & Tuning Oil Flow Loop TC3410
2.1.5
Closed-Loop Test & Tuning Oil Pump TC3414
2.1.6
Closed-Loop Test & Tuning Oil Temp Loop TC 3410
Low Flow
High Flow
Train 1
Train 2
2.2.1
Closed-Loop Test & Tuning Pressure Loop PC3110
2.2.2
Closed-Loop Test & Tuning Pressure Loop PC3111

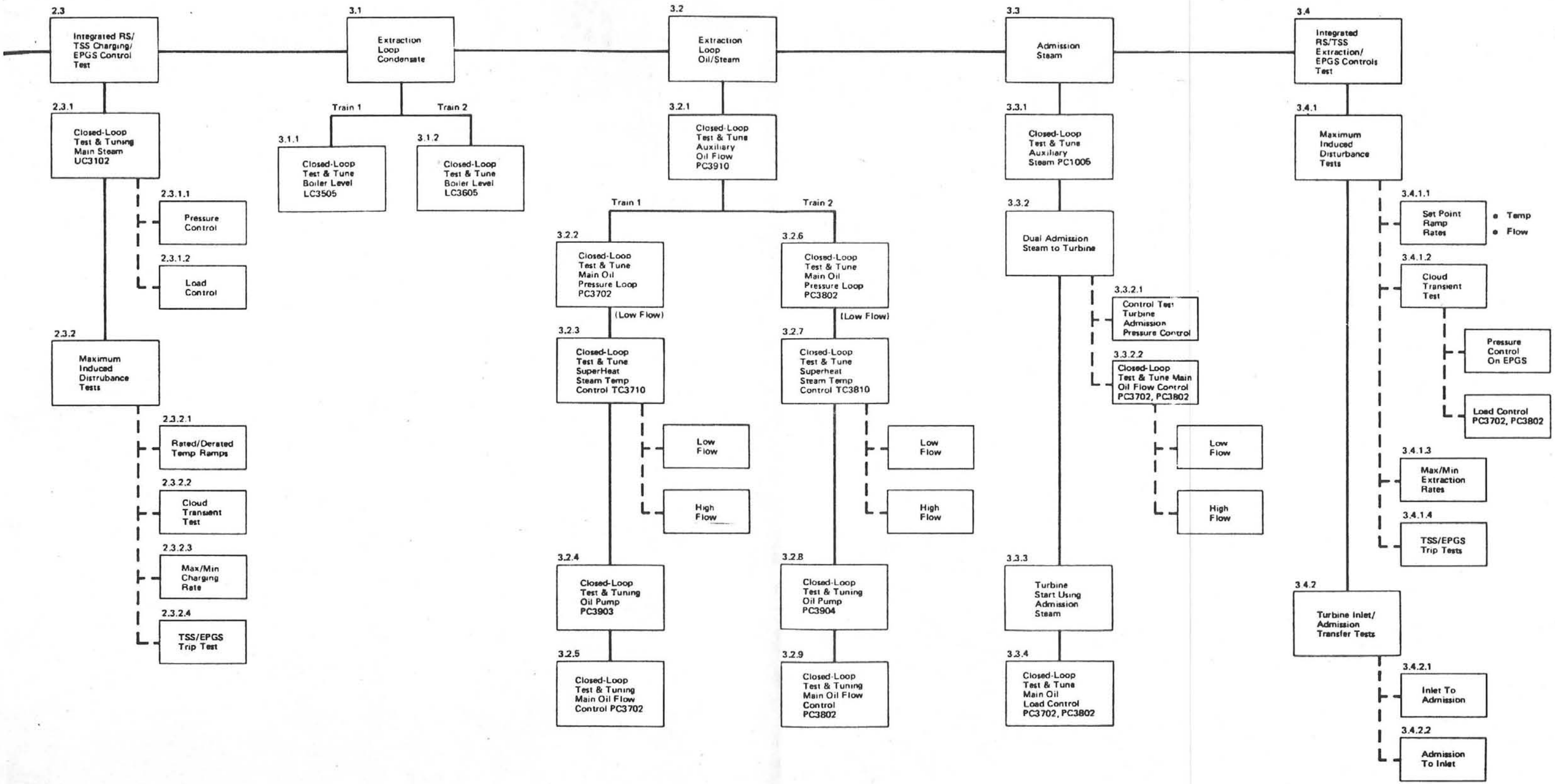


Figure 4-1 Thermal Storage Control/Operations Test (1040B) Detailed Test Flowchart

trains into service. Tests were performed initially at off-nominal conditions later followed by tests at normal operating temperatures and pressures. After the control loops were tuned, integrated RS/TSS charge testing at maximum induced disturbances, were performed. Dual charging train tests were delayed due to unavailability of critical hardware.

The third portion of the 1040B test program involved the extraction loop subsystem. This included bringing both oil and steam loops in both extraction trains into service. Tests were performed initially at off-nominal conditions later followed by tests at normal operating temperatures and pressures. After the control loops were tuned, dual train tests and integrated RS/TSS extraction testing at maximum induced disturbances were performed. Turbine admission steam start up tests as well as transition from main inlet to admission back to main inlet turbine steam transfer tests were also accomplished.

From a test activity standpoint, the 1040B test program can be divided into two phases. Phase I dealt primarily with functional tests of control loops and limited control loop tuning. Emphasis was placed on achieving steam conditions necessry for rolling and synchronizing the turbine/generator on admission steam. The second phase dealt primarily with tuning of control loops and performing closed loop testing over full operating ranges of temperature, pressure, and flow.

4.1 TEST OBJECTIVES AND ACCEPTANCE CRITERIA

The test objectives and acceptance criteria for the TSS controls test program (1040B) are contained in the following listing. The number assigned to each objective correspond to the numbers contained in the test procedure and is consistent with the overall test flow as shown in Figure 4-1. (Reference Thermal Storage System Controls Test Procedure 1040, June 1982).

OBJECTIVES

4.1.1 Main Inlet Steam/Condensate System

The general objective is to put the TSS flash tank, main steam inlet, and desuperheater into service with its associated control loops.

4.1.1.1 TSS Flash Tank. The general objective is to put the TSS flash tank steam and condensate loops into service.

4.1.1.1.1 Objective: Conduct closed loop tests on flash tank level loops LC74B, LC74D.

4.1.1.1.2 Objective: Conduct closed loop tests on flash tank steam pressure controllers PC647C, PC640.

4.1.1.2 Main Steam Inlet. The general objective is to confirm control and operation of the main steam inlet valve.

4.1.1.3 TSS Desuperheater. The general objective is to confirm control and operation of the TSS desuperheater.

4.1.1.3.1 Objective: Conduct closed loop control test on TC3105 at low flow conditions. Tune loop as required. Confirm response to inlet steam flow disturbances. Increase steam inlet temperature to 960^{o}F and confirm control response is satisfactory.

4.1.1.3.2 Objective: Conduct closed loop control tests on TC3105 at high flow rated temperature conditions. Tune loop as required.

4.1.2.1 Charging Oil Loop System. The general objective is to put the TSS charging oil and steam/condensate loops into service with their associated control loops.

4.1.2.1.1 Objective: Confirm control and operation of the oil flow control loops in Train 1, TC3411, TC3413.

4.1.2.1.2 Objective: For the flow loop gains established in 4.1.2.1.1 perform closed loop control test on Train 1 oil pump loop PC3413.

4.1.2.1.3 Objective: Establish a steam flow in Train 1 to approximately 20% of rated flow in order to support oil temperature control tests on TC3411.

- Conduct closed loop control tests on TC3411. Tune loop as required.
- Conduct closed loop temperature control tests on TC3411 at high flow. Tune loops as required.

4.1.2.1.4 Objective: Establish steam flow at rated pressure, low flow conditions to Train 2 for the purpose of conducting closed loop test on the oil loops. Conduct closed loop control test on FCM3410. Tune loop as required.

4.1.2.1.5 Objective: For the flow loop gains established in 4.1.2.1.4 perform closed loop control test on Train 2 pump loop PCM3414.

4.1.2.1.6 Objective: Establish a steam flow in Train 2 to approximately 20% of rated flow in order to support oil temperature control tests on TC3410.

- Conduct closed loop control tests on TC3410. Tune loop as required.
- Conduct closed loop temperture control tests on TC3410 at high flow. Tune loop as required.

4.1.2.2 Charging Loop Condenser. The general objective is to confirm control and operation of the TSS charging loop condenser controls, PC3110, PC3111.

4.1.2.2.1 Objective: Conduct closed loop control test on PCM3111. Tune loop as required. Both setpoint and flow disturbance tests are required.

4.1.2.2.2 Objective: Conduct closed loop control test on PCM3111. Tune loop as required. Both setpoint and flow disturbance tests are required.

4.1.2.3 Integrated Receiver, TSS Charge and EPGS. The general objective is to confirm control and operation of the integrated RS, TSS and EPGS subsystems using main steam inlet control (UC3102) in pressure and load control modes. Confirm integrated system performance under maximum induced disturbance conditions.

4.1.2.3.1 Objective: Establish steam flow to the charging loop at rated pressure, low to moderate flow for the purpose of conducting closed loop control tests on UC3102.

- Conduct closed loop control tests on PC3102. Tune loop as required.
- Verify response for both setpoint and receiver flow transient disturbances.
- Conduct closed loop control tests on JC3102. Tune loop as required.

4.1.2.3.2 Establish flow at rated pressure, rated temperature, and moderate flow to TSS charging loop for the purpose to verifying response at maximum disturbance conditions. Turbine not in service (Train 1 or Train 2 or both active).

4.1.2.3.2.1 Objective: Ramp the receiver temperature from 960^{O}F to 660^{O}F and back to 960^{O}F at design ramp rates and verify response primarily on TC3105.

4.1.2.3.2.2 Objective: With UC3102 in a pressure control mode verify response of PC3102 using an induced receiver power transient of 20%, 50%, 80% of rated power.

4.1.2.3.2.3 Objective: Confirm max/min charging rates on TSS charging loop.

4.1.2.3.2.4 Objective: Establish flow to the TSS charging loop in combination with power generation from the EPGS for the purpose of verifying TSS/EPGS trip transient response.

- Initiate turbine trip and verify response on TSS and steam dump systems.
- Initiate TSS trip and verify response on TSS and steam dump systems.

4.1.3 Extraction Loop System. The general objective is to put the TSS extraction oil and steam/condensate loops into service with their associated control loops.

4.1.3.1 Extraction Loop Condensate - The general objective is to confirm control and operation of the condensate control loops in Train 1 and 2 for level controller LC3505, LC3605.

4.1.3.1.1 Objective: Conduct closed loop flow control test on LCM3505. Tune loop as required. Also, conduct closed loop control test on boiler level controller LC3505. Tune loop as required.

4.1.3.1.2 Objective: Establish flow through Train 2 of the extraction boiler.

- Conduct closed loop flow control test on LCM3605. Tune loop as required.

- Conduct closed loop control test on boiler level controller LC3605. Tune loop as required.

4.1.3.2. Extraction Loop Oil/Steam. The general objective is to confirm control and operation of the extraction loop oil/steam control loops.

4.1.3.2.1 Objective: Establish flow through the TSS oil loop using the auxiliary extraction oil pump. Conduct closed loop control test on PCM3910. Tune loop as required.

4.1.3.2.2 Objective: Confirm control and operation of the extraction oil/steam control loops for Train 1, PC3702. Conduct closed loop control tests on PC3702. Tune loop as required.

4.1.3.2.3 Objective: Confirm control and operation of the extraction superheater steam temperature controller on Train 1 (TC3710).

- Establish steaming operation in Train 1 to support initiation of extraction superheater control.
- Conduct closed loop control test on FCM3710. Tune flow loop as required.
- Conduct closed loop control tests on TC3710 at low flow. Tune loop as required. Subject loop to both temperature setpoint and flow disturbances.
- Conduct closed loop control test on TC3710 at high flow. Tune loop as required. Subject loop to both temperature setpoint and flow disturbances.

4.1.3.2.4 Objective: Conduct closed loop control tests on PCM3903 at low flow. Tune loop as required. Also, conduct closed loop control test on PCM3903 at high flow. Tune loop as required.

4.1.3.2.5 Objective: Establish steam operation in Train 1 to support controls tests on steam/oil flow controller PC3702.

- Conduct closed loop control test on FC3702. Tune loop as required.
- Conduct closed loop control tests on PC3702. Tune loop as required.

4.1.3.2.6 Objective: Confirm control and operation of the extraction oil/steam control loops for Train 2, PC3802. Conduct closed loop control tests on PC3802. Tune loop as required.

4.1.3.2.7 Objective: Confirm control and operation of the extraction superheater steam temperature controller on Train 2 (TC3810).

- Establish steaming operation in Train 2 to support initiation of extraction superheater control.
- Conduct closed loop control test on FCM3810. Tune flow loop as required.
- Conduct closed loop control tests on TC3810 at low flow. Tune loop as required. Subject loop to both temperature setpoint and flow disturbances.
- Conduct closed loop control test on TC3810 at high flow. Tune loop as required. Subject loop to both temperature setpoint and flow disturbances.

4.1.3.2.8 Objective: Conduct closed loop control tests on PCM3904 at low flow. Tune loop as required. Also, conduct closed loop control test on PCM3904 at high flow. Tune as required.

4.1.3.2.9 Objective: Establish steam operation in Train 2 to support controls tests on steam/oil flow controller PC3802.

- Conduct closed loop control test on FC3802. Tune loop as required.
- Conduct closed loop control tests on PC3802. Tune loop as required.

4.1.3.3 Admission Steam. The general objective is to confirm control and operation of the extraction loop system in combination with admission steam operation of the turbine.

4.1.3.3.1 Establish steam flow to the admission steam system for the purpose of putting the auxiliary steam system into service. Conduct closed loop control test on PCM1005. Tune loop as required.

4.1.3.3.2 Objective: Confirm control and operation of the TSS extraction system in a dual admission mode.

4.1.3.3.2.1 Objective: Transition pressure control from PC3702/PC3802 to turbine inlet pressure control. Confirm stable operation.

4.1.3.3.2.2 Objective: Confirm control and operation of the main oil flow control loop.

- Conduct closed loop control tests at low flow on FC3702/FC3802. Tune loops as required.
- Conduct closed loop control at high flow on FC3702/FC3802. Tune loops as required.

4.1.3.3.3 Objective: Confirm control and operation of the extraction loops and turbine during a turbine start-up on admission steam. Conduct control tests on turbine admission pressure control loop by ramping FC3702 setpoint to induce a flow disturbance into the turbine. G.E. loops should be tuned if required.

4.1.3.3.4 Objective: Confirm control and operation of the main oil valve in the load control mode JC3702, JC3802. Conduct closed loop control tests on JC3702/JC3802. Tune loops as required.

4.1.3.4 Integrated Receiver, TSS and EPGS. The general objective is to confirm control and operation of the integrated RS TSS, and EPGS subsystems using main steam and admission steam in pressure and load control modes. Confirm integrated system performance under maximum induced disturbance conditions.

4.1.3.4.1 Establish flow at rated pressure, rated temperature, moderate flow to TSS extraction loops for the purpose of verifying response at maximum distrubance conditions. (Perform test on Train 1 and Train 2 separately and then simultaneously.)

- Verify system response to maximum induced flow setpoints and temperature setpoint changes
- Verify system response to maximum induced cloud conditions with the TSS extraction train in Load Control
- Verify system response to disturbances via turbine pressure control setpoint changes

- Confirm maximum/minimum extraction rates on TSS extraction loops
- Confirm system operation under conditions of TSS extraction/EPGS trip

4.1.3.4.2 Establish extraction loop flow to turbine in addition to main steam inlet flow to confirm the transfer operation from admission to main inlet flow and from main inlet to admission flow on the turbine.

4.1.3.5 Acceptance Criteria. For the most part, the test acceptance criteria involved completing the required actions or demonstrating the plant operations as called for in the objectives in a reasonable manner. For those objectives involving open loop and closed loop controls testing, the following explicit acceptance criteria exist:

Open Loop Test - All appropriate monitored and recorded data are valid (or valid alternates exist and are being recorded). The data meet the evaluation requirements of having proper tag identifiers, adequate data scan rate, proper calibration, and measurable output values over the specified range of test conditions. Tests are performed under quasi-steady state conditions.

Closed Loop Test - Closed loop response is stable and well behaved in the presence of set point changes and process disturbances.

Mode switching transients do not significantly degrade plant operation or cause conditions to exceed design requirements.

All alarms and limits are acceptable for safe, controlled operation.

Control logic for initialization, mode transfers, and shutdown is satisfactory.

Monitored, displayed, and recorded data is satisfactory for evaluating the closed loop test performance.

Adequate control loop stability margins are maintained and verified for the desired range of operation.

4.2 TEST METHODOLOGY AND SPECIAL TEST EQUIPMENT

The detailed 1040B test activities were designed to be compatible with the logical controls activation of both the TSS charging and extraction loops. The five major process activation activities to which testing was applied were in sequence of execution:

- (I) TSS flash tank and condensate system
- (II) TSS charge main steam system
- (III) TSS charging loops (oil and steam side for both trains 1 & 2)
- (IV) TSS extraction loop (oil and steam side for both trains 1 & 2)
- (V) Admission steam system

Closed loop control tests were for the most part conducted on all major control loops at near both maximum and minimum operating conditions (refer to Figure 4-1). Loop gains were tuned to give satisfactory response characteristics over the full range of operating conditions. As a result of initial closed loop testing some control loops were redesigned and reconfigured to compensate for either process dynamic characteristics or inoperable process instrumentation.

Open loop pulse tests were conducted on the TSS charging loop to characterize the process dynamic characteristics and support control loop tuning activities. Open loop tests required sustained quiescent operating conditions (no disturbances) for 10-30 minute intervals. Test data was recorded on the DAS system and post processed through Fourier Analysis Programs to provide data for analysis purposes. No special test equipment was required for the 1040B tests.

4.3 TEST CHRONOLOGY

The 1040B test program covered the period from June 16, 1982 to May 18, 1983. Interspersed throughout the duration of the test program were other activities involving plant power production (Mode 1 Operation) on weekends and assigned week days, special turbine admission steam testing, and operator training. In addition, partial and complete plant outages were carried out as required to maintain and/or repair equipment. As equipment was restored to a fully operational state, additional testing beyond the scope of the original 1040B test program was required to verify proper operation or to gather necessary control-related data in response to the equipment modifications.

The major test activities and problem areas which impacted operation during the 1040B test program are summarized in Table 4.3-1. The problem areas include receiver and turbine (admission steam) considerations as well as those involving thermal storage directly since problems in any of these areas adversely impacted the conduct of the 1040B test program. The fact that the available insolation for receiver operation was 20-30% below the design values during this period also impacted the progress of the test program and is so reflected in Table 4.3-1.

The major plant-related factors which impacted the test program were:

(i) Initial cleanup of steam and feedwater piping and vessels as new equipment was placed into service for the first time

(ii) Thermal storage heat exchanger flange leaks

(iii) Thermal storage heat exchanger tube-to-shell leaks

(iv) Malfunctions of steam side flowmeters in thermal storage

(v) Erratic level indications in the thermal storage steam generators

(vi) Miscellaneous oil leaks

(vii) Improper turbine operation during startup using thermal storage-generated (admission) steam

Initial cleanup of steam and feedwater piping and vessels - Cleanup of the water/steam portions of the thermal storage system was an ongoing activity during the activation and initial operation of each new thermal storage element. The principal contaminates were magnetite (Fe_3O_4), ferric oxide (Fe_2O_3), and silica. The magnetite was residual material that remained in the system following the chemical cleaning activities carried out in late fall of 1981. The ferric oxide was due to naturally occuring rust. The silica probably resulted from site sand which could have blown into vessels and pipes during construction.

Table 4.3-1. Thermal Storage Controls Test Chronology* (Page 1 of 10)

Date	Test 1040 Activities	Problems or Activities Impacting Testing
6/17/82		• Outage - move receiver flowmeter electronics
6/18/82		• Bad feedwater chemistry (high silica)
6/21/82	• First TS charge from receiver steam	• Charge rate limited by tank vapor generation rate • Partly cloudy
6/22/82 6/23/83	• Activate charging train 2	• TS trips (2) • Ullage maintenance unit over pressure problems
6/24/82 6/25/82		• Partly cloudy • Oil leak in charging train 2
6/28/82 6/30/82		• Cloudy • Steam dump valve operating problems • Condenser tube leaks
7/1/82 7/2/82	• Continue initial tank conditioning	• TS desuperheater control not functioning • Steam dump valve broken and out of service
7/6/82 7/9/82 7/12/82	• Continue initial tank conditioning • Activate TS desuperheater control	• Cloudy • Receiver leaks (flowmeter body) • Reactivate steam dump valve (controlled heatup)
7/13/82 7/19/82	• Initial activation of TS flash tank (route steam and condensate to the condenser) • Fill and drain TS steam generator	• Bad feedwater chemistry (high Fe) • Extended steam dump valve warmup • TS feedwater pump overheated (out of service)

*Excludes consideration of weekend power production operation

Table 4.3-1. Thermal Storage Controls Test Chronology* (Page 2 of 10)

Date	Test 1040 Activities	Problems or Activities Impacting Testing
7/20/82 7/21/82	• Initiate control testing on TS flash tank valves PV640, LV74DI, and LV74D2	• Receiver panel flowmeter problems • Marginal feedwater chemistry
7/22/82 7/23/82	• Intermittent charging operation • Fill and drain TS steam generators	• Cloudy • Marginal feedwater chemistry • Receiver outage (remove debris from flowmeters 4 and 12)
7/26/82 7/27/82	• Initial TS steam generator operation (steam freeblows)	• Plant shutdown due to severe electrical storm • Partial loss of computer memories • Cooling tower basin drained for leak repair
7/28/82 7/30/82	• TS charging for extraction operation • TS steam generator free blows feedwater pump • Attempt reactivation of TS feedwater pump	• TS charging system trips • TS oil pump starting • TS feedwater pump internal leak (cooling water to condensate)
8/2/82 8/3/82	• Initial TS charging to 575°F oil temp • Control testing on valves PV640, LV74D1, and LV74D2	• Receiver panel 17 flowmeter problems (large bias shift)
8/4/82 8/6/82	• TS steam generator free blow	• Receiver panel flowmeter problems (water in electrical conduit) • Partly cloudy
8/9/82 8/10/82	• TS flash tank control testing • Reactivate and test TS feedwater pump • Charging oil control tests	
8/11/82 8/13/82		• Collector field beam safety tests • Leak in plant fire protection system

*Excludes consideration of weekend power production operation

Table 4.3-1. Thermal Storage Controls Test Chronology* (Page 3 of 10)

Date	Test 1040 Activities	Problems or Activities Impacting Testing
8/16/82	• Initial activation of TS flash tank heat recovery control valves (PV647C and LV74B)	• Bad feedwater chemistry due to activation of new lines
8/17/82	• First turbine roll on admission steam	• Turbine runaway problem (excessive steam leakage) • Bad feedwater chemistry due to activation of admission steam line
8/18/82	• Charge storage	• Bad feedwater chemistry
8/20/82	• Admission steam line free blow	• Extended warmup of steam dump valve • Cloudy
8/23/82	• Free blow auxiliary steam lines from TS steam generator	
8/24/82	• Roll turbine on admission steam • First power production from admission steam	
8/25/82	• Control tests on charging, tion, and auxiliary oil system	
8/28/82		• Partly cloudy • Oscillations in deaerator • Partial loss of computer (MVCU) data base • Loss of receiver "red line unit (RLU)" power
8/30/82	• Charge storage	• Partly cloudy
9/3/82	• Extraction and charging controls tests • Deaerator (NPSH) control tests	• Feedwater pump trips (NPSH) • Computer data base problems
9/6/82 9/7/82		• Collector field operational problems (computer related) • Receiver trips • Steam generator level sensor calibration problems • Partly cloudy

*Excludes consideration of weekend power production operation

Table 4.3-1. Thermal Storage Controls Test Chronology* (Page 4 of 10)

Date	Test 1040 Activities	Problems or Activities Impacting Testing
9/8/82 9/10/82	• Charging oil and steam loop control tests	• Cloudy
9/13/82 9/15/82	• Charging oil and extraction water/steam control tests	• Oil pump casing leak • Steam generator head leak
9/16/82 9/17/82	• Intermittent charging tests	• Cloudy
9/20/82 9/2/82	• Charging steam control tests • Extraction testing with turbine operation	• TS steam generator flow-meter problems
9/23/82 9/24/82		• Plant outage • Receiver inspection • Trace heat steam valve
9/27/82 10/1/82	• Charging and extraction controls testing	• Steam dump valve preheat/warmup tests • TS charging trip • Receiver trip • Oil pump startup problems
10/4/82 10/5/82		• Marginal water chemistry • Power production
10/6/82 10/8/82	• Charging control test	• Problems with charging flowmeter FE3102 • TS desuperheater spray water valve leak thru • Control console operational problems • Marginal water chemistry (high cation)
10/11/82 10/12/82		• Feedwater cleanup
10/13/82	• Charging for turbine admission steam startup testing • Auxiliary steam controls testing • Free blow TS steam generator	• Marginal water chemistry (high silica) • TS charging heat exchanger leak (water side)
10/14/82	• Turbine admission steam startup test (gather startup data for GE)	• Marginal water chemistry

*Excludes consideration of weekend power production operation

Table 4.3-1. Thermal Storage Controls Test Chronology* (Page 5 of 10)

Date	Test 1040 Activities	Problems or Activities Impacting Testing
10/15/82 10/29/82		• Plant outage (repair of turbine gland steam exhauster)
11/1/82		• Plant dedication
11/2/82 11/5/82	• Charging control tests	• Partly cloudy • Receiver feedwater pump testing • TS charging trips

11/8/82
11/23/82
		• Plant outage
		  • Misc. plant repairs
		  • TS heat exchanger leak repairs
		  • Manufacturer restoration of TS feedwater pump

11/29/82 12/1/82	• Reinstall and test TS feedwater pump	• Clouds, rain, and high winds
12/2/82 12/3/82		• TS heat exchanger warmup (charging and extraction systems) for bolt torquing tests
12/6/82 12/10/82		• TS water and steamside cleanup (steam blow) • Clouds, rain, and high winds
12/13/82 12/16/82	• Limited charging controls testing	• Charging steam flowmeter problems • TS desuperheater spray water valve leak thru • Boiler level sensor problems • Failure of thermocouple reference junction oven
12/20/82 12/23/82		• Cloudy with high winds

*Excludes consideration of weekend power production operation

Table 4.3-1. Thermal Storage Controls Test Chronology* (Page 6 of 10)

Date	Test 1040 Activities	Problems or Activities Impacting Testing
12/24/82 1/2/83		• Holiday power production period • Receiver feedwater pump controller problems
1/3/83 1/7/83	• Recharge thermal storage tank (totally discharged) • Controls tests on charging inlet steam valve-UV3102	• TS charging trips (excessive tank pressure) • TS charging heat exchanger flange leak (waterside) • Bad water chemistry • Charging train oscillations
1/10/83		• Mode 1 (receiver-to-turbine) performance testing
1/11/83 1/13/83	• TS charging system controls	• Charging train oscillations • Partly cloudy
1/14/83		• Turbine transition testing between main (receiver) and admission steam supplies
1/17/83 1/19/83	• TS open loop charging control	• Cloudy and high winds
1/21/83 1/29/83		• Clouds and rain • Intermittent Mode 1 power production
1/31/83 2/3/83		• Troubleshoot receiver panel 11 trips • Lack of makeup condensate prevented TS operation • Wind, rain, and snow
2/4/83	• Open loop charging tests	
2/7/83 2/11/83	• Limited charging control tests	• Cloudy and windy • TS control computer problems • Receiver panel 19 flowmeter bias problem

*Excludes consideration of weekend power production operation

Table 4.3-1. Thermal Storage Controls Test Chronology* (Page 7 of 10)

Date	Test 1040 Activities	Problems or Activities Impacting Testing
2/14/83		• Mode 1 (receiver-to-turbine) performance tests
2/15/83		• Cloudy • TS control console not functioning properly
2/16/83	• Limited charging control tests	• Automation testing • Test new receiver panel (8) control valve trim • TS charging train oscillations
2/17/83		• Control computer malfunction in operating charging steam valve UV3102 • Reinstalled and checked out flowmeter FE3102
2/18/83		• Cloudy and windy (67 mph)
2/21/83	• Test flowmeter FE3102 • Limited charging control tests	• Charging train 2 out of service due to heat exchanger gasket leak (oil side) • Partly cloudy
2/22/83	• Charge storage for extraction testing	• Automation testing • Adjust flowmeter FE3102
2/23/83 2/24/83		• Cloudy
2/25/83	• Turbine admission steam maximum power test (test 8.2 mw gross)	• TS oil pump inverter problems • Turbine admission steam startup testing (per GE)
2/28/83 3/4/83		• Cloudy and rain
3/7/83		• Mode 1 (receiver-to-turbine) performance testing

*Excludes consideration of weekend power production operation

Table 4.3-1. Thermal Storage Controls Test Chronology* (Page 8 of 10)

Date	Test 1040 Activities	Problems or Activities Impacting Testing
3/8/83 3/10/83	• Charging oil loop controls	• Control computer malfunction in operating charging steam valve UV3102 • Heliostat computer failover and loss of collector field control from control room • Partly cloudy
3/11/83		• Cloudy
3/14/83 3/18/83		• Broken TS flash tank burst disk • Interlock logic system hardware problems • Broken waste water line • Cloudy

3/21/83
3/25/83
		• Plant outage
		  • Piping modifications
		  • Control computer hardware and software modifications
		  • Wiring modifications
		  • Replace leaking desuperheater spray water valve (TV3105)

3/28/83 3/29/83	• Checkout operation of new spray water valve (TV3105)	• Plant startup after outage
3/30/83 4/1/83	• TS charging loop pulse tests	• High winds • Reset charging train steam side safety valve • Charging heat exchanger oil flange leak
4/4/83 4/5/83		• Broken TS flash tank burst disk • Changeout valve trim on PV3110

*Excludes consideration of weekend power production operation

Table 4.3-1. Thermal Storage Controls Test Chronology* (Page 9 of 10)

Date	Test 1040 Activities	Problems or Activities Impacting Testing
4/6/83 4/7/83	• Test new control valve trim for PV3110 • Change storage for extraction testing • TS extraction controls testing	
4/8/83		• Low power receiver testing
4/11/83 4/12/83	• Charge storage on intermittent	• Partly cloudy and windy
4/13/83 4/14/83	• TS charging control tests • Plant mode transition tests • TS extraction control tests	• Partly cloudy
4/15/83	• High charging rate tests	
4/18/83		• Receiver power step tests
4/19/83 4/21/83		• Cloudy
4/22/83	• TS charging and extraction controls testing	
4/25/83	• TS charging for extraction testing	
4/26/83 4/29/83		• Cloudy and rain • Interlock logic system hardware problems • Receiver flowmeter replacement (panel 5)
5/2/83 5/3/83	• TS charging for extraction testing	• Receiver flowmeter replacement (panel 5) • Test startup automation
5/4/83 5/5/83	• TS extraction testing • Turbine operation until 3:18 a.m. (5/5)	• Cloudy
5/6/83	• TS "max disturbance" charging tests	

*Excludes consideration of weekend power production operation

Table 4.3-1. Thermal Storage Controls Test Chronology* (Page 10 of 10)

Date	Test 1040 Activities	Problems or Activities Impacting Testing
5/9/83 5/10/83		• Mode 1 (receiver-to-turbine) operation • Control valve UV3102 trim changeout • High winds limited plant operation
5/11/83 5/13/83	• Test new valve trim (UV3102) • TS charging control tests • All night turbine operation (5/11)	
5/16/83 5/17/83	• TS charging for maximum extraction test	
5/18/83	• Maximum TS extraction test MWHe gross, 43.4 MWHe net)	• TS trip on high tank pressure

---------- TEST 1040 COMPLETED -----------

Where possible, steam side components and pipes were cleaned up by means of steam free blows to the atmosphere. Water side cleanup employed diverting flows through low point drains and on to the plant sump and drain system. Steam generator shells (water side) were flushed out as much as possible by means of repeated fill and drain cycles. Once steady state water chemistry conditions were reached in the boiler effluents, the steaming process was initiated. Initial steam free blows were employed to further cleanup the superheated stage and the downstream piping. Blowdown of the steam generator water continued throughout this period.

Once the contamination levels reached acceptable or steady state levels as a result of the initial flushing and steam blowing efforts, the elements were valved into service. In some cases, this resulted in contamination conditions moving throughout the feedwater system. However, after repeated operation of the thermal storage equipment, system contamination was reduced to acceptable levels although some recurring problem with high silica levels was experienced. This suggests that initial activation activities did not completely remove the sources of silica contamination.

Thermal Storage Heat Exchanger Flange Leaks - Heat exchanger flange leaks occured on both water/steam and oil side of many of the heat exchangers. These resulted from a combination of inadequate flange bolt torquing and improper flange seals and were accentuated by the cyclic temperature duty experienced during normal operation. Water/steam leaks which developed through the steam generator flanges (both vessels) resulted in erosion of the flange surfaces. On both vessels, weld material was added and the flange surface refinished prior to reassembly. One of the vessels (E-305) utilized a new convoluted seal as opposed to the previously used wire wound gasket. The second vessel (E-306) was reassembled with a exfoliated graphite wrap around the original wire wound gasket. In both cases, no additional boiler leak problems were experienced once the retorquing activities were complete.

Oil side flange leaks also occurred with some degree of regularity on many of the vessels. Charging Train 2 (heat exchanger grouping) was lost from service early in 1983 due to a severe oil flange leak that could not be stopped by simply retorquing the flange bolts. Charging Train 1 was maintained in an operational condition throughout the 1040B test program by retorquing the bolts as required. Leaks that occurred in the Train 1 heat exchangers also tended to be self sealing once the heat exchangers began to heat up as part of their daily duty cycle. Starting June 6, 1983, all charging heat exchangers (oil flanges) were opened and new convoluted seals incorporating exfoliated graphite were installed in the anticipation of minimizing future oil leaks. New flange bolts were used during reassembly and a careful bolt torquing program was carried out.

(iii) Thermal Storage Heat Exchanger Tube-to-Tubesheet Leaks - In an effort to minimize the possibility of oil to water leakage, all thermal storage heat exchangerswere designed with a double tube sheet and an atmospheric drain mounted in the annulus between the tube sheets. Tubes in turn were rolled into the tube sheets. Due to the temperature cycling which occurred during startup and shutdown and the resulting differential expansion between the tubes and the shell which restrained the tube sheet, some deflection of the tube sheets occurred and tube sheet leaks formed. In all cases, the leaking fluid was removed from the annular zone through the atmospheric drain.

In an attempt to correct this problem, the subcooler tube bundle was removed and returned to the manufacturer where tube-to-tube sheet welds could be made to strengthen the joints. The annular shells were also cut so that the differential expansion problem between the tubes and shell would no longer cause deformation of the tube sheets. Convoluted gasket seals (grafoil) were also used during heat exchanger reassembly and a careful retorquing program was also employed.

(iv) Malfunction of Thermal Storage Steam Side Flowmeters - Flowmeter malfunctions (strain gauge type meters) involved the debonding of the strain gauges from the target arm and the failure of internal seals allowing moisture to enter the electronic portion of the meter. The original strain gauge attachments involved the use of a ceramic bond which tended to crack. The strain on the highest temperature meter (FE3102-rated for 950^{O}F) was reduced by changing the mounting while an epoxy bonding material was used on the two lower temperature meters (FE3205 and FE3305-rated for 650^{O}F).

The internal seal problem and subsequent moisture leakage which was experienced by all 5 thermal storage steam flowmeters was eliminated by removing the seal and welding the meter assemblies into an integrated meter. By doing so however, no further field maintenance could be performed on meter elements without cutting the meter housing open.

From an engineering evaluation stand point, the flowmeters also exhibited a zero and span shift with temperature. Information regarding strain gauge temperature and its relationship to process fluid temperatures was gathered from a thermocouple mounted on the strain gauge of flowmeter FE3102. These temperature data were used for data reduction purposes to correct the indicated flow values for the temperature dependent zero and span parameters.

(v) Erratic Level Indications In The Thermal Storage Steam Generators - Boiler water level indications which are primary inputs to the boiler level controller exhibited erratic response during initial steam generator operation. Problems arose primarily from fouled sense lines that attached to the lower portion of the boiler vessel and an occasional boil out of the steam side sense line. Sight glasses were added to each boiler to give a more positive indication of actual level. Since these glasses were attached to the same ports as the level sensor, erratic sensor behavior was also experienced due to the natural circulation flow that exists continually through the sight glass. The problem was ultimately corrected by increasing the size of the root valves and allowing for the draining of deposits that accumulate in the bottom sense line from the bottom of the boiler.

(vi) Miscellaneous Oil Leaks - In addition to the heat exchanger oil flange leaks, other leaks were experienced in the oil system. One of the main thermal storage oil pumps experienced a leak through a fine crack which developed in the pump case. The crack was ground out and welded in place with no further leakage observed.

Valve packing and other flanged joints also exhibited a tendency to leak. In all cases, these leaks were maintained at insignificant levels by retorquing bolts and making adjustments to valve packings.

(vii) Improper Turbine Operation During Startup On Admission Steam - The turbine is designed to be started and brought up to synchronous speed while operation on either main (receiver) or admission (thermal storge) steam. When starting the turbine on admission steam, the initial high pressure stages are pressurized to the full admission steam pressure. However, due to shaft seal leakage between the high and low pressure stages, sufficient steam flow passed from the high pressure to low pressure sections (admission control valves closed) to cause a rapid acceleration of the turbine.

In order to alleviate this situation, the startup procedure was temporarily modified to roll the turbine with the control valves open while throttling flow with the variable position stop valve. At the same time, interstage packing leak thru was diverted directly to the condenser through the packing steam dump valve. Startup in this manner results in a severe steam generator duty cycle and a waste of stored thermal energy while the packing dump valve is maintained in the open position.

The ultimate correction as proposed by General Electric (turbine supplier) is to modify the admission steam stop valve by including a bypass pilot valve which can give the degree of flow controllability necessary to roll and synchronizing the turbine in a controlled manner without overspeed or the need for diverting excess steam to the condenser. Installation of this modified valve configuration is currently scheduled for mid June 1983.

Section 5
TEST RESULTS - 1040B

The primary purpose of the TSS control system testing (1040B) was to verify control system operation and perform the required control loop tuning to achieve the desired control response characteristics. Since an understanding of the control loops themselves is fundamental to the interpretation of the test results a description of each control loop is included in addition to the control loop verification test results. The results section is organized in the same general order in which the tests were performed, i.e.

5.1 TSS Control System Description
5.2 TSS Steam Inlet
5.3 Main Steam Inlet
5.4 TSS Desuperheater
5.5 Charging Oil Loops
5.6 Charging Condenser Loops
5.7 Extraction Condensate Loops
5.8 Extraction Oil Loops
5.9 Extraction Steam Loops
5.10 TSS Auxiliary Steam Loops
5.11 Turbine Admission Steam Loop
5.12 Integrated System Tests (Charging)
5.13 Integrated System Start-up Tests
5.14 Charging System Start-up Tests
5.15 Extraction System Start-up Tests

In general control loop verification testing consisted of closed loop tests where specific loops were subjected to both setpoint changes and typical process disturbances at normal operating conditions. These test results verify that the loop operates properly and can meet its design requirements. Where significant, test results are presented at maximum and minimum operating conditions to demonstate controllability at critical operating conditions. Open loop tests for the charging condenser loops were performed to characterize the process dynamics and to support rework on the charging control loop design. This is discussed in detail in Section 5.5. In general open loop tests were limited to only those loops where additional analysis and rework was considered necessary.

In order to aid the reader the format and general types of figures used in this report section are described in Appendix B. A general procedure that was used during the control loop testing process is also presented for reference in Appendix C.

In the following section a general overview of the TSS system and the control and process loops used for each portion of the 1040B test is presented. A detailed description of each loop, test and the test results are then presented in the ensuing subsections.

5.1 TSS CONTROL SYSTEM DESCRIPTION

The thermal storage system (TSS) incorporates different control configurations to satisfy the functional requirements imposed by the plant operation. These requirements are stated in terms of various operating modes. The TSS is logically broken into two main parts: the charging subsystem and the extraction subsystem. Figure 5.1-1 shows the major TSS control loop coinfigurations of the 10 MWe pilot plant. Enclosed by the phantom lines are the elements of the TSS. Also shown are the elements of the electrical power generation subystem (EPGS) with which the TSS interfaces.

As shown in Figure 5.1-1 the charging subsystem (TSCH) takes steam from the receiver, desuperheats it (if required), and heats circulating oil, which heats the Thermal Storage Unit (TSU). The extraction subsystem (TSSG) circulates heated oil from the TSU through the TS steam generator to develop superheated steam.

5.1.1 TSS Charging Subsystem (TSCH)

The TSCH is designed to absorb thermal energy by circulating low temperature oil (nominally 425^{O}F) oil through charging heat exchangers, which condenses receiver steam, and exits from the heat exchangers at an elevated temperature (580^{O}F). The high temperature oil is routed either

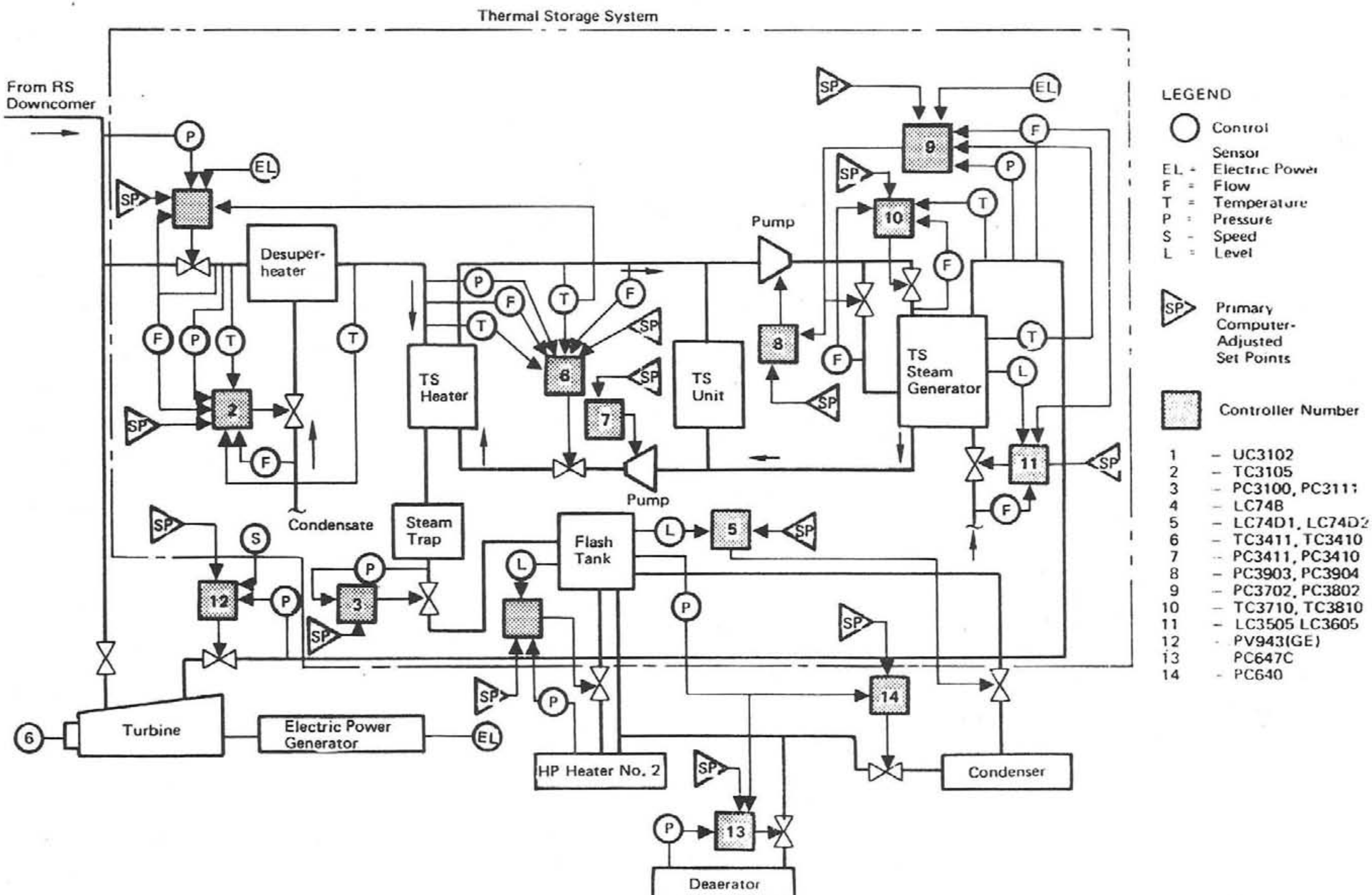


Figure 5.1-1. Thermal Storage Subsystem Control Loop Configurations

into the top of the TSU for storage or directly to the extraction heat exchangers. While performing these functions the TSCH controllers must perform as follows:

- A. Main inlet steam flow
  - Flow control, $\pm$ 10%
  - Load control, $\pm$ 5%
  - Pressure control, $\pm$ 5%
- B. Desuperheater steam outlet, 650, $\pm$ 15^{o}F
- C. Heater oil outlet temperature, 575 $\pm$ 15^{o}F
- D. TSS flash tank level, 25 inch, $\pm$ 2 inch
- E. Control stability margins, all controllers
  - Gain margin, greater than 6 db
  - Phase margin, greater than 30 deg.

The TSCH main inlet steam can be controlled by one of three different control schemes: flow control, receiver pressure control, and electrical generator load control. Steam temperature is regulated by a desuperheater using condensate from the receiver feedwater pump. Two separate trains are required to provide the required turndown ratio over the expected operating range. Associated with each train are pressure controllers to control the pressure within the condenser, oil fluid pumps and flow control valves to control outlet oil temperature, and controls for the flash tank outlet steam and condensate flows. Table 5.1-1 lists the 13 controllers (9 controller types) associated with TSS charge control and defines the control function of each.

The following sections describe the logic which drives specific valves for the charging subsystem control. With the exception of the desuperheater control, each control loop is duplicated since two trains of heat exchangers operate in parallel.

5.1.2 TSS Extraction Subsystem (TSSG)

The TSSG is designed to produce steam at 410 psig and 540^{o}F by flowing hot oil (at a nominal inlet temperature of 575^{o}F) directly from the outlet of the charging system (TSCH) or from the top manifold of the TSU through the extraction steam generators (TSSG). The oil leaves the TSSG at a nominal

Table 5.1-1. Thermal Storage Charging Loop Control

System/Controller	Controller Tag Number(s)	Control Function
NOTE: Functional block diagrams may be found in Appendix I (index) under the respective tag number.		
1. TSS main inlet	UC3102	Controls turbine inlet pressure, TSS flow rate, or turbine load by controlling TSS main inlet flow valve.
2. Desuperheater outlet	TC3105	Reduces steam temperature to TSS by regulating inlet spray water.
3. Charging steam	PCM3110, PCM3111	Controls charging steam condenser pressure by controlling condesnate flow to the TSS flash tank.
4. Charging fluid pump	PCM3413, PCM3414	Controls the charging fluid pump speed to maintain a differential pressure across the charging fluid temperature control valve such that the maximum commanded valve position is 80% open.
5. Charging fluid	TC3411, TC3410	Controls charging oil outlet temperature by controlling oil flow circulation.
6. Flash tank level	LC74B	Controls flash tank level by dumping condensate to No. 2 HP heater.
7. Flash tank level - high	LC74D1, D2	Diverts excess TSS flash tank condensate from No. 2 HP heater to condenser.
8. Deaerator pressure - (Flash tank steam)	PCM647C	Controls deaerator pressure by venting flash tank steam to the aeaerator (has deaerator pressure override).
9. TSS Flash Tank Steam Pressure	PC640	Vents excess TSS flash tank steam to the condenser to control the flash tank pressure.

temperature of 425°F and flows to either the TSU bottom manifold where it is reintroduced into the tank or directly into the TSCH where it absorbs additional charging energy.

While performing these functions the TSSG controllers must perform as follows:

A. Extraction steam
   - Flow control, ± 10%
   - Load control, ± 5%
   - Pressure control, 410 psig ± 5%
   - Temperature, 540 ± 15°F

B. Boiler level, 44 inch, ± 1 inch

C. Auxiliary steam
   - Pressure, 150 psig, ± 5 psia
   - Temperature, 360°F (approximately saturation temp)
   - Flow, ± 15%

D. Control stability margins
   - Gain margin, greater than 6 db
   - Phase margin, greater than 30 deg.

The TSS extraction subsystem is controlled by one of these different control schemes: flow control, pressure control, or gross electrical generator load control. In addition, auxiliary blanket steam can be provided by using the auxiliary extraction oil pump loop. The amount of steam generated is regulated by the amount of oil circulated through the boiler. Temperature control is maintained by the amount of oil circulated through the superheater section of the TSSG. Two separate trains are required to provide the turndown ratio over the operating range. Associated with each train are oil fluid pumps to control the oil circulation, controls for the steam flow or pressure and temperature, controls for the boiler condensate level, and controls for generating auxiliary blanket steam. Table 5.1-2 lists 9 controllers (5 controller types) and defines the functions of each.

The following sections describe the controllers that drive specific components for the extraction subsystem. With the exceptions of the auxiliary extraction oil flow valve, each control loop is duplicated since two trains of steam generators operate in parallel.

Table 5.1-2. Thermal Storage Extraction Loop Control

System/Controller	Controller Tag Number(s)	Control Function
NOTE: Functional block diagrams may be found in Appendix I (index) under the respective tag number.		
1. Boiler water level	LC3505, LC3605	Maintains boiler water level within specified limits.
2. Extraction steam flow	PC3702, PC3802	Accommodates extraction steam flow, pressure, or turbine load following demand by controlling corresponding extraction oil flow circulation.
3. Extraction steam	TC3710, TC3810	Controls steam temperature at TSS outlet by controlling superheater bypass oil flow.
4. Extraction oil pumps	PC3903, PC3904	Controls extraction oil pump speed to regulate the differential pressure across the extraction oil flow valve such that the valve position is 80% open.
5. Auxiliary extraction	PC3910	Controls auxiliary extraction oil flow through boilers to control steam header pressure thereby providing auxiliary blanket steam.

Both trains are operated independently of each other enabling the operator choices on how to manipulate the system. Each train has a rated capability of 55 KLBH of steam flow and when both are in operation there is as total maximum output of approximately 110 KLBH of steam flow.

5.2 TSS FLASH TANK CONTROLS TESTS

5.2.1 TSS Flash Tank Level (LC74B, LC74D)

The condensate level within the flash tank is controlled by two controllers through a condensate drain pump. The functional block diagrams for these controllers are shown in Figures 5.2-1 and 5.2-2, Flash Tank Level (low, high).

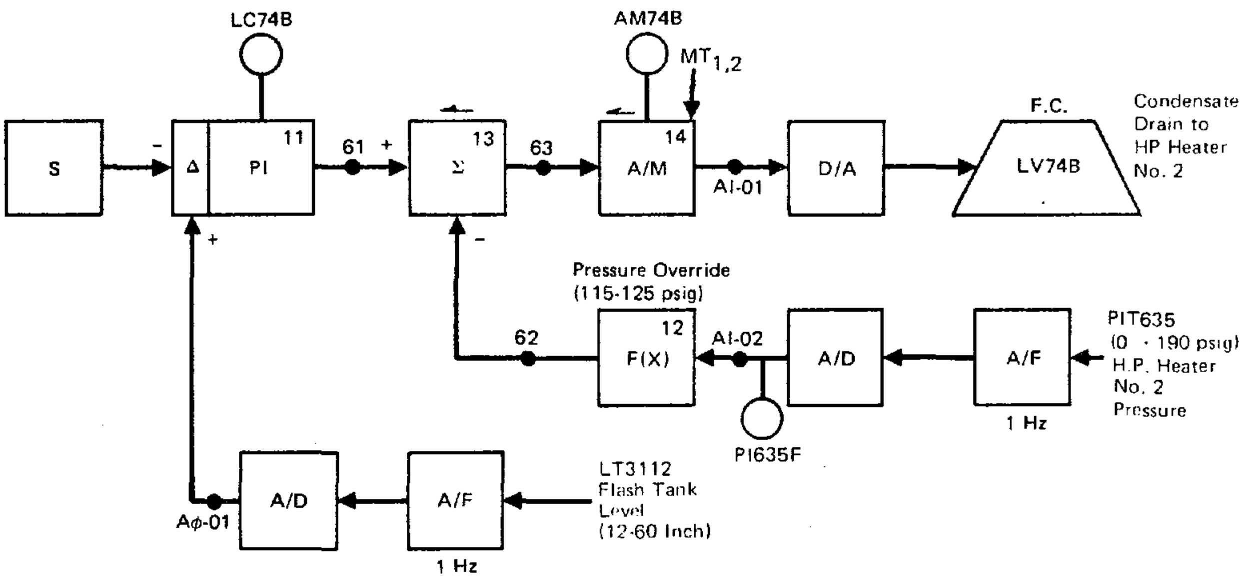


Figure 5.2-1. TSS Flash Tank Low Level Controller Block Diagram — LC74B

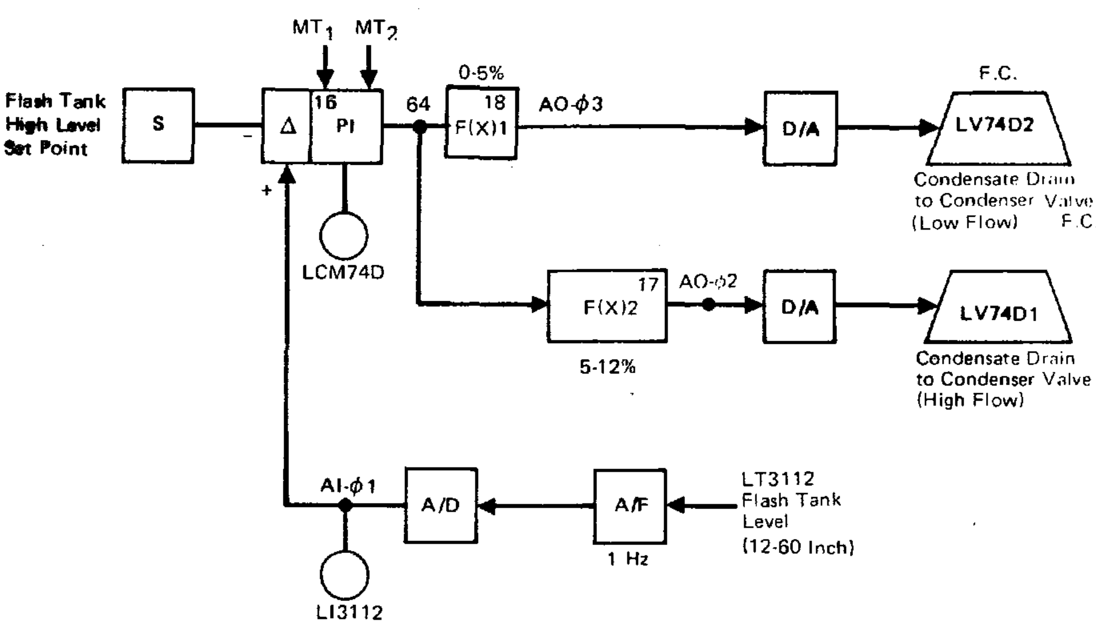


Figure 5.2-2. TSS Flash Tank High-Level Controller Functional Block Diagram — LCM74D

LC74B controls the low level of the flash tank by draining off condensate to the second point heater. This controller also has a pressure override so that when the pressure of the 2nd point heater reaches 115 - 125 psig the valve will start closing down.

LC74D works with LC74B by draining excess condensate that accumulates in the flash tank to the condenser. The valve LV74D2 is smaller than LV74D1 to allow level control over a wide range of flowrates. Valve LV74D2 operates full stroke at low error signals. A function generator for LV74D1 will open the valve at any increased demand from the controller to maintain the level at nominal conditions.

The purpose of the TSS flash tank controllers LC74B and LC74D are to maintain flash tank level during TSS operation. The TSS flash tank is in service continually during charging loop operation and also used to support startup operation of the extraction system. The stressing condition for the flash tank occurs during a process upset due to cloud disturbances in the charging system. A response to a cloud disturbance is shown and discussed in paragraph 5.3 and demonstrates the capability of the level loop to control during system disturbances. The flash tank level control has proven adequate for TSS startup and shutdown in all plant operation to this date. Because of mechanical difficulties with valve LV74B, closed loop response data on level control was not available for this report.

5.2.2 TSS Flash Tank Pressure Control (PC647C, PC640)

The steam in the flash tank is vented to both the deaerator and/or the condenser. PC647C controls the pressure within the deaerator using flash tank steam to maintain a desired setpoint pressure. During startup PC647C is also used to vent to the deaerator the nitrogen that had been pressurizing the flash tank.

PC640 diverts excess steam flow from the flash tank to the condenser by controller the TSS flash tank pressure. This valve controller also has a pressure override such that if the pressure within the condenser becomes too high, the valve PC640 is closed. The functional block diagrams for these controllers are shown in Figures 5.2-3 and 5.2-4.

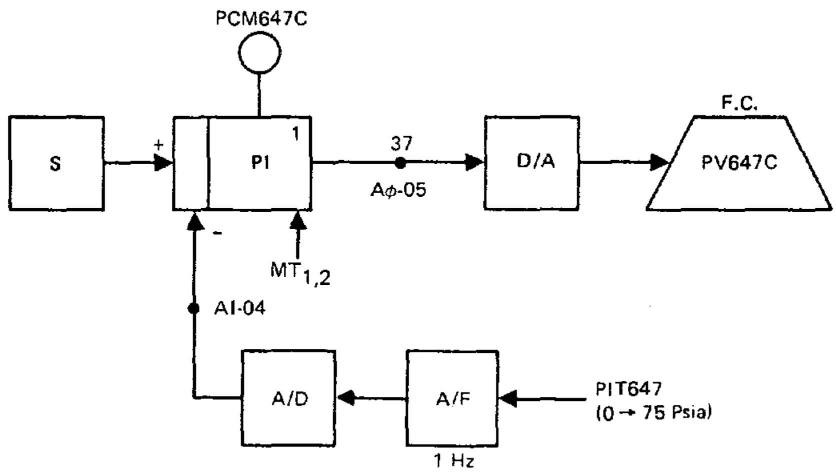


Figure 5.2-3. Deaerator Pressure (TSS Flash Tank Steam) Controller Block Diagram – PCM647C

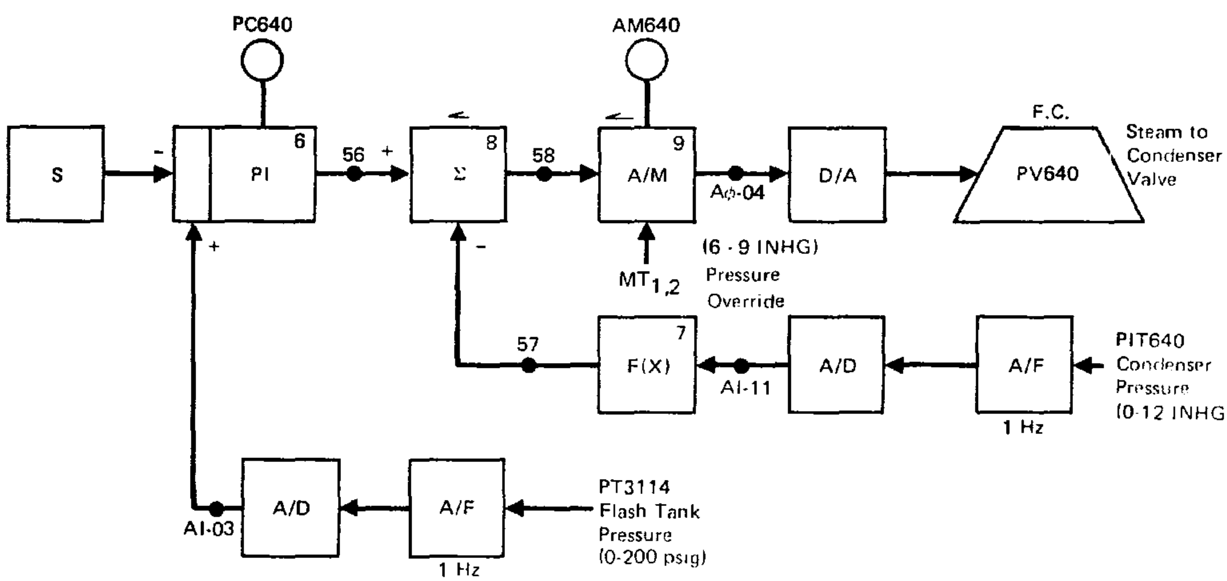


Figure 5.2-4 TSS Flash Tank Pressure Controller Block Diagram – PC640

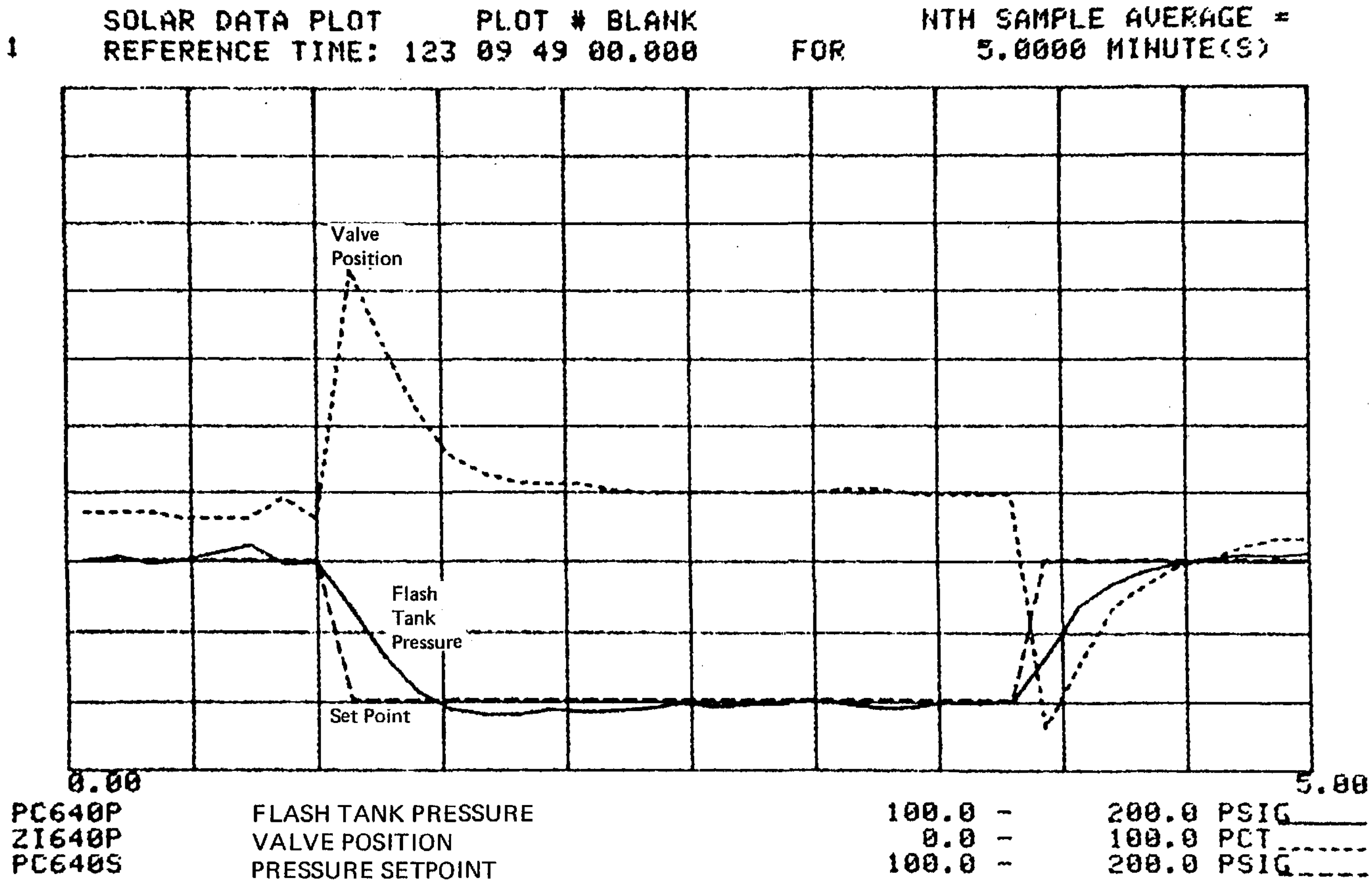
The purpose of the TSS flash tank controllers PC640 and PC647C are to maintain flash tank pressure during TSS operation. The TSS flash tank is in service continually during charging loop operation and also used to support startup operation of the extraction system. The stressing condition for the flash tank occurs during a process upset due to cloud disturbances in the charging system. A response to a cloud disturbance is shown and discussed in paragraph 5.3 and demonstrates the capability of the level loop to control during system disturbances. The stability and control characteristics of the pressure loops are demonstrated by subjecting the control loops to small signal pressure setpoint changes.

During typical operation of the TSS flash tank all of the steam from the flash tank is used to peg the deaerator pressure (i.e., valve PV647C is wide open) and the flash tank pressure is regulated with PC640. For this reason the proportional controller PC647C in reality operates in an on/off manner and a controller response is of little interest and is not included. The response of the TSS flash tank pressure controller PC640 is shown in Figure 5.2-5. This response to a small signal pressure setpoint change (20 psi step) is stable and well behaved and meets its desired response requirements with an equivalent 30 sec response time.

5.3 TSS MAIN STEAM INLET (VALVE CONTROL TESTS)

The main steam inlet valve controller has 3 basic modes of operation; flow control, pressure control, and electrical load control. In the source of 1040B testing this controller was tested in all three modes and the results are presented in the following paragraphs. Switching between these three modes of operation is also important and was tested and consequently has been automated to a single command from the operator. This provides for a very smooth transition between modes and ensures a minimum of operator intervention. The functional block diagram for this controller is shown in Figure 5.3-1.

During the 1040B test phase of the plant problems were encountered with operating this valve at low stroke. Due to its CV characteristic the high gain on the valve at low stroke would cause the steam flow to peak from 0-80 KLBH for very small changes in the valve position. These disturbances had an



*

Figure 5.2-5. TSS Flash Tank Pressure Response Set Point Disturbance

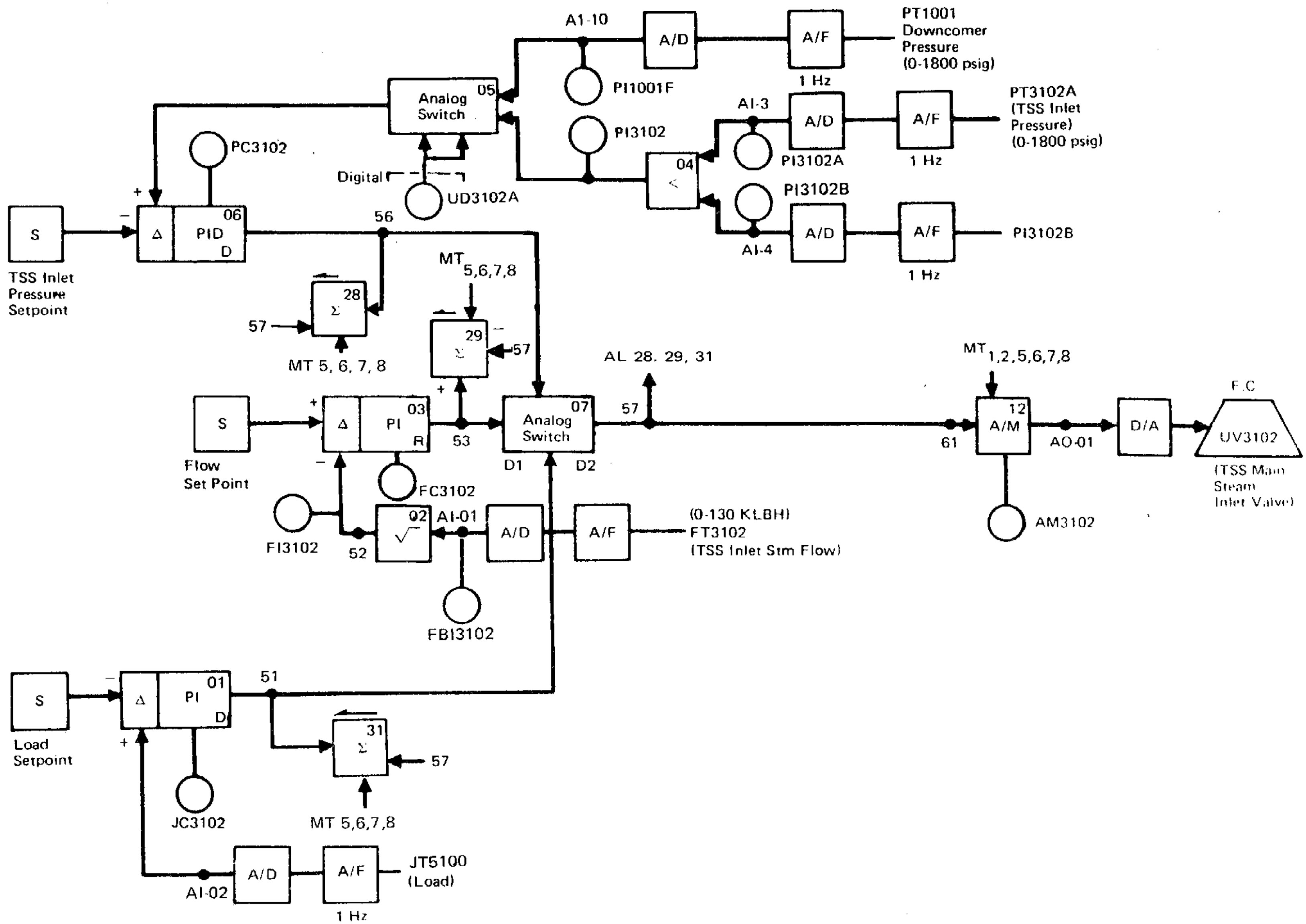


Figure 5.3-1. TSS — Main Steam Inlet Controller Functional Block Diagram UC-3102

adverse effect on the entire plant. The linear trim was replaced with a spare equal percentage and the control gains retuned. This trim resulted in improved control loop response characteristics at low valve stroke.

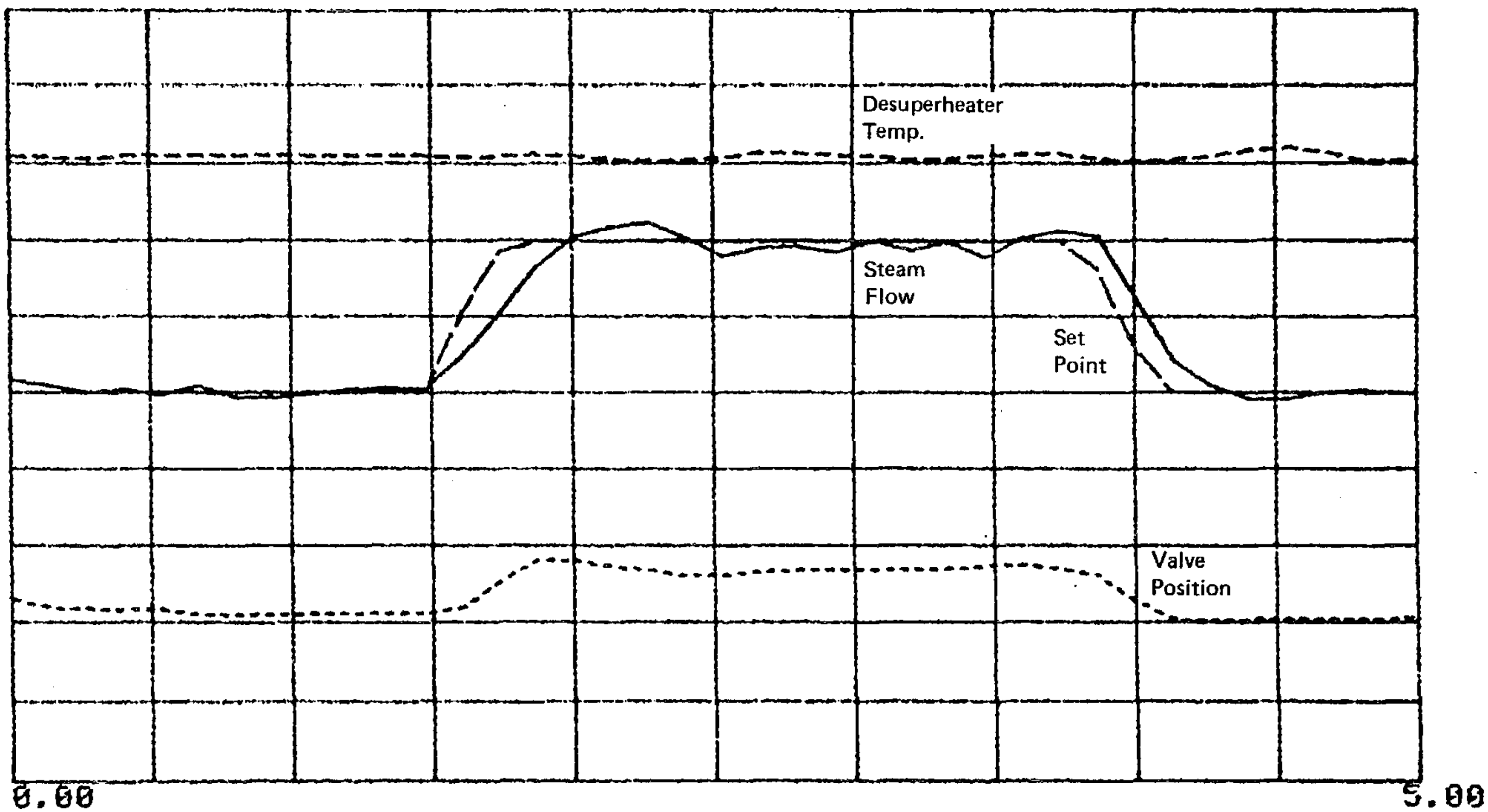
5.3.1 Flow Control Mode

In flow control the main inlet valve can be used to control a desired flow rate into the charging system. This mode of operation is advantageous on a clear day when the operator must charge the tank while operating with the turbine. This controller has a setpoint ramp of 5% per minute built into it to avoid unnecesssry transients to the turbine. The flow response is given for two different flow conditions. At a low flow condition the flow setpoint is increased to 35 KLB/HR, held for approximately 2 minutes and then reduced back to 25 KLB/HR. Both the flow setpoint, flow response and valve position response history for this test are shown in Figure 5.3-2. The response is stable and well behaved and demonstrates excellent control of steam flow. A similar type of response test is shown in Figure 5.3-3 only at a moderate flowrate of 65 KLB/HR. The response exhibits excellent steam flow control characteristics also at this flow condition and demonstrates the control capability over an extended range of flows. Also included in these figures is the response of the downstream desuperheater temperature controller (TC3105). These flow changes represent significant flow disturbances into the desuperheater. Temperature excursions of less than $\pm$ 7^{0}F about a nominal operating setpoint of 650^{0}F demonstrate the capability of the desuperheater temperature controller (TC3105) to reject disturbances and meet its design requirements of $\pm$ 15^{0}F.

5.3.2 Pressure Control Mode

In the pressure control mode the pressure in the downcomer line is sensed and the control valve UV3102 regulated by means of the pressure controller (PC3102) to maintain the desired setpoint value. During typical plant operation the pressure loop must be capable of responding to both pressure setpoint changes as well as input flow disturbances. Both conditions were tested during 1040B and the results are presented below. The most stressing test condition for pressure control results when the charging loop system is subjected to receiver cloud disturbances (either actual or simulated clouds).

1 SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE =
REFERENCE TIME: 131 09 18 00.000 FOR 5.0000 MINUTE(S)



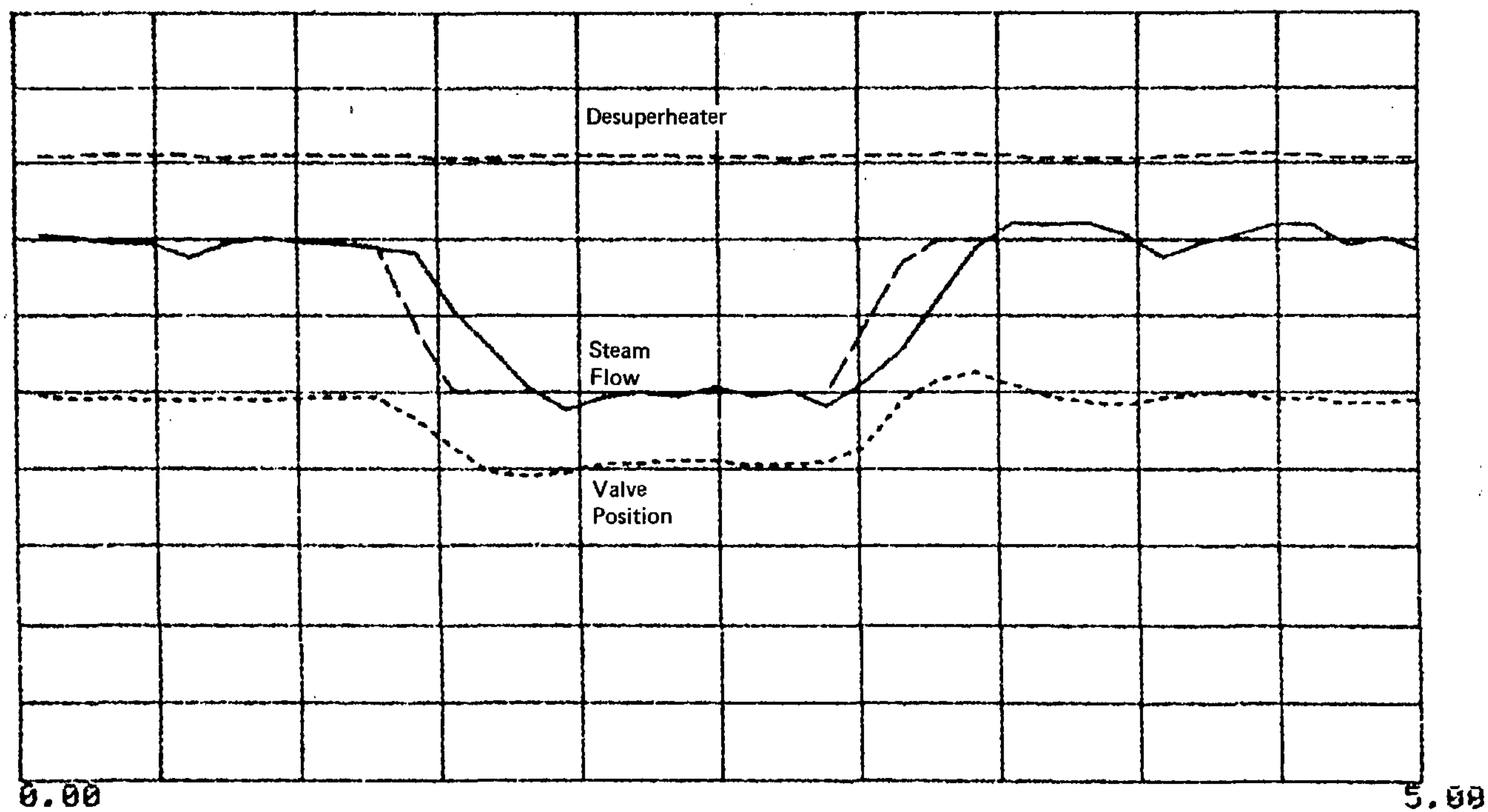
FC3102P	STEAM FLOW	0.0 -	50.0	KLBH ______
ZI3102P	VALVE POSITION	0.0 -	100.0	PCT ....
TC3105P	DESUPERHEATER TEMPERATURE	0.0 -	800.0	DEGE - - - -
FC3102S	STEAM FLOW SETPOINT	0.0 -	50.0	KLBH _ . _ .

*

Figure 5.3-2. Steam Flow Response to a Flow Setpoint Change (FC3102) — Low Flow Conditions

SOLAR DATA PLOT   PLOT # BLANK   NTH SAMPLE AVERAGE =

1   REFERENCE TIME: 131 13 05 00.000   FOR   5.0000 MINUTE(S)



FC3102P	STEAM FLOW	25.0 -	75.0 KLBH
ZI3102P	VALVE POSITION	0.0 -	100.0 PCT
TC3105P	DESUPERHEATER TEMPERATURE	0.0 -	800.0 DEGF
FC3102S	STEAM FLOW SETPOINT	25.0 -	75.0 KLBH

*

Figure 5.3-3. Steam Flow Response to a Flow Setpoint Change (FC3102) — Moderate Flow Conditions

The capability of the pressure controller to respond to a setpoint change is demonstrated in Figure 5.3-4. The system was subjected to a 20 psi decrease in the setpoint for approximately 2 minutes and then returned to its normal operating condition of 1445 psi. The pressure response as shown exhibits excellent control stability and response to characteristics with a response time of approximately 1 minute.

The response of the pressure control loop to large input flow disturbances is shown in Figures 5.3-5 through 5.3-7. The system was subjected to a simulated cloud by removing two complete rings of heliostats from the receiver. This resulted in power-flow reduction in excess of 50% of the operating condition in less than 30 seconds. The removed heliostats were then reapplied 2 minutes later. The resultant flow disturbance from the receiver (F12233) and into the charging system is shown in Figure 5.3-5. As the receiver flow output decreases the control valve UV3102 closes in response to the pressure controller PC3102 in order to maintain steam pressure.

The TSS pressure response and equivalent flow regulation for this simulated cloud transient is shown in Figure 5.3-6. Pressure excursions are less than 8 psi even in the midst of this very severe flow disturbance. This clearly demonstrate the control loops ability to meet the design requirements of $\pm$ 75 psi. Also shown in Figure 5.3-7 is the response of the oil temperature controller TC3411 to this severe disturbance. Oil temperature excursion are within the design requirements limits. Oil temperature control is discussed in detail in paragraph 5.4. It should also be noted in Figure 5.3-6 that steam temperature control excursion of the desuperheater (TC3105) during this severe transient is less than 8^{0}F further verifying excellent desuperheater temperature control.

The capability of the TSS pressure control to respond to actual cloudy day conditions is demonstrated in Figure 5.3-8. During this test the receiver was driving the charging system directly (Mode 5) and the intermittant clouds resulted in flow disturbances into the TSS system. Over a one hour test period a wide variety of disturbances occurred and pressure control was maintained within $\pm$ 20 psia. This clearly demonstrates the excellent pressure control characteristics and the capability of the charging system to maintain control during cloudy day operations.

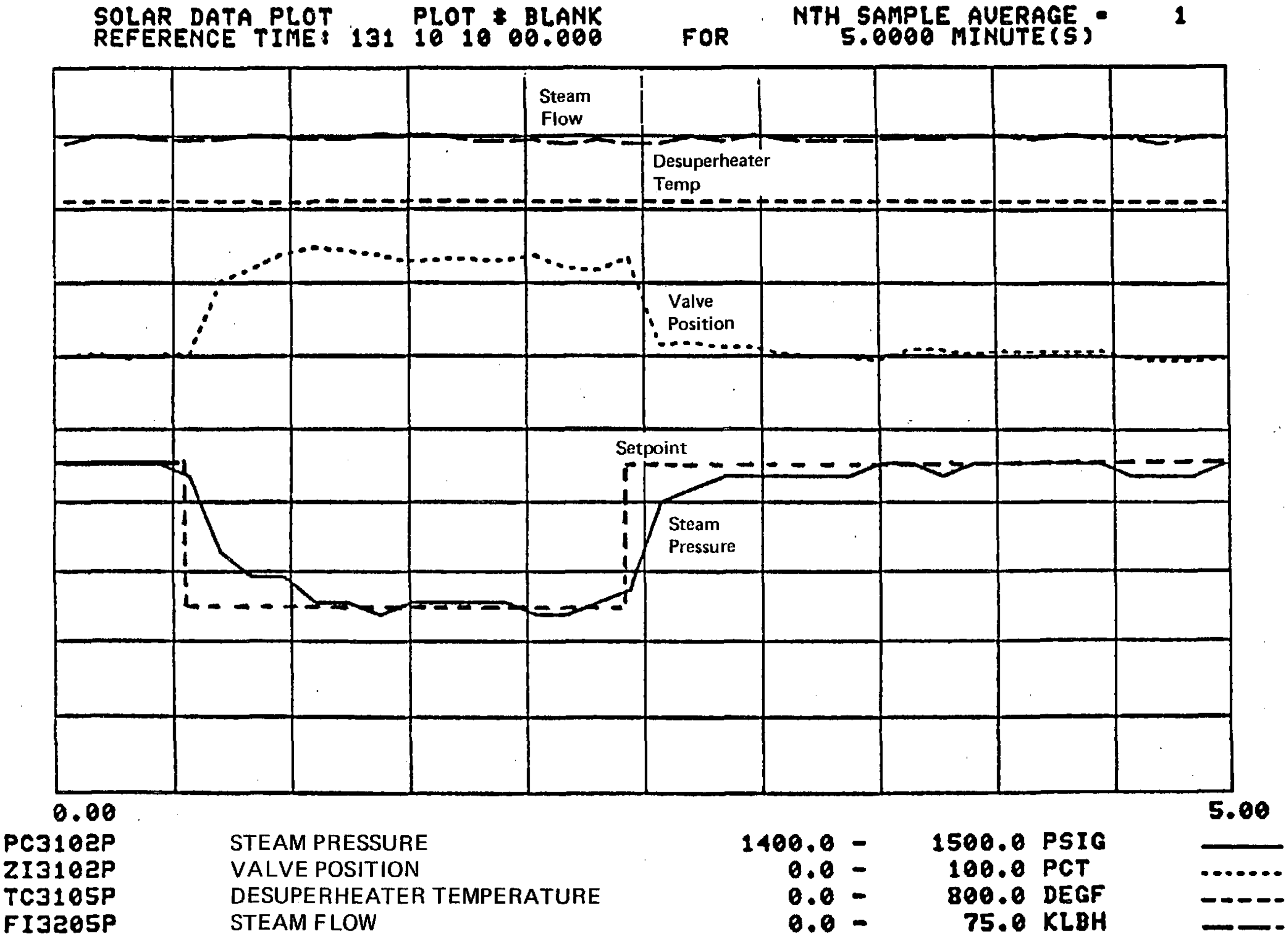
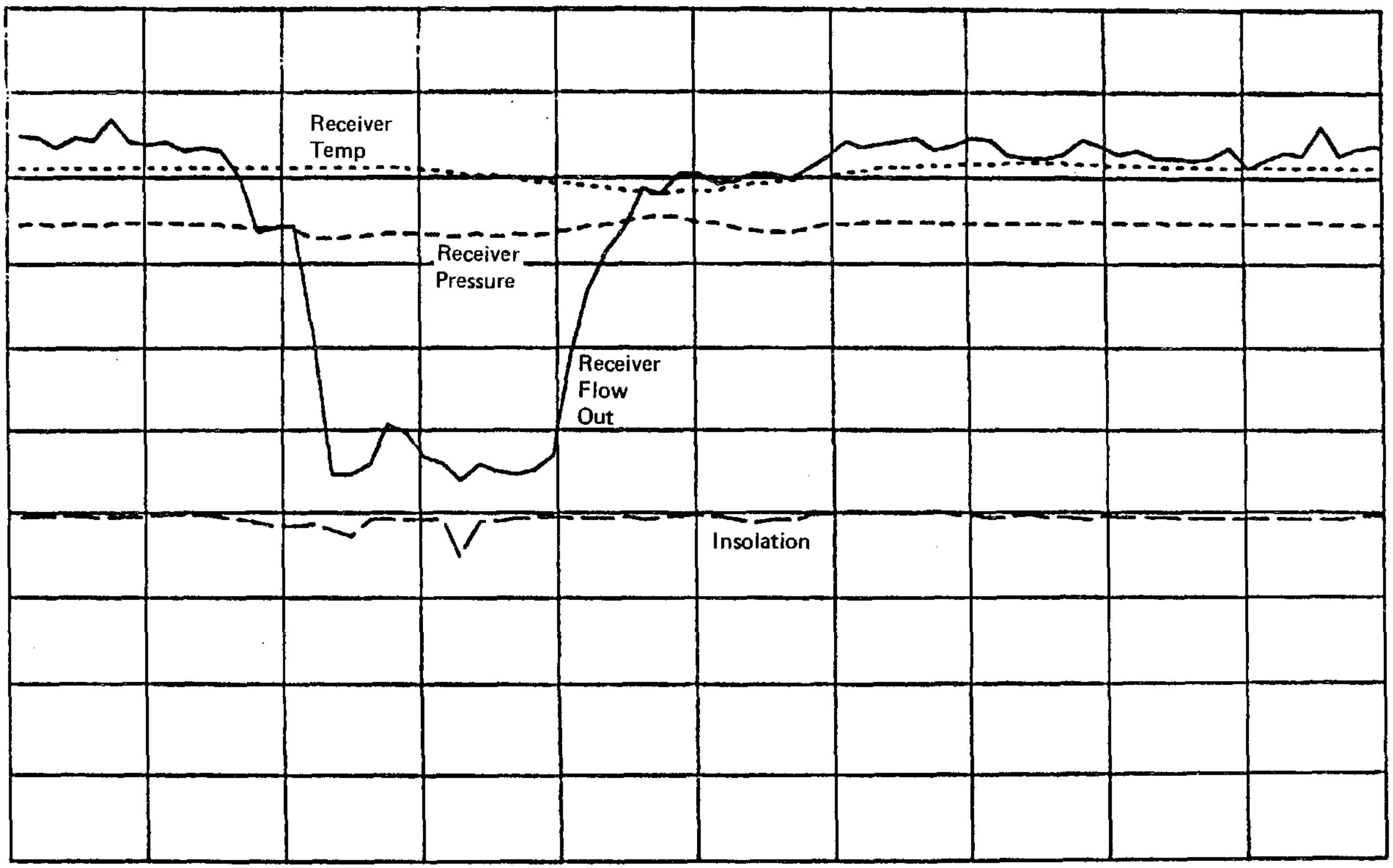


Figure 5.3-4. Pressure Control Response to a Pressure Setpoint Change (PC3102)

SOLAR DATA PLOT   PLOT $ BLANK   NTH SAMPLE AVERAGE =   1
REFERENCE TIME: 125 11 06 00.000   FOR   10.0000 MINUTE(S)



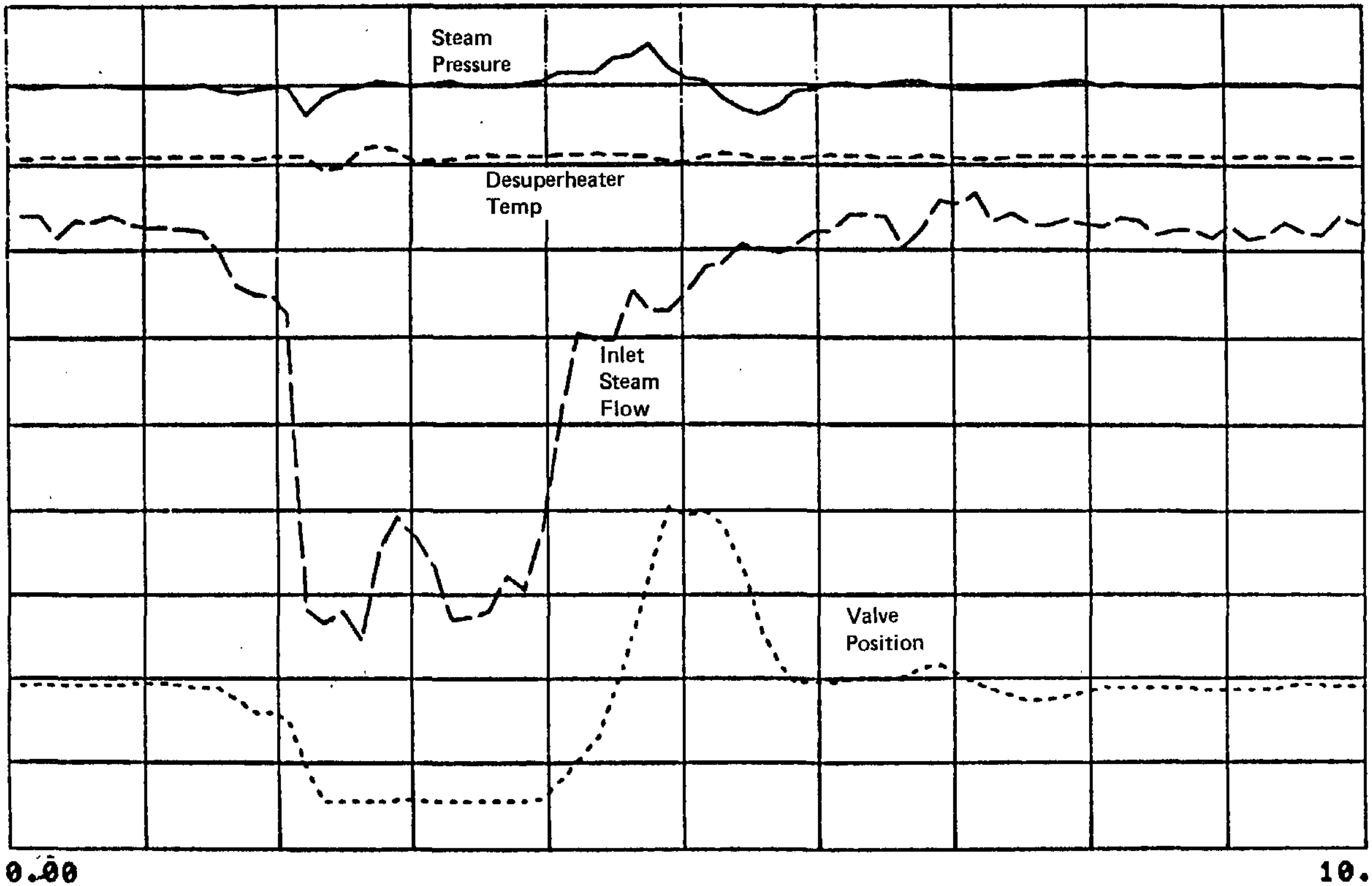
0.00 — 10.00

FI2233P	RECEIVER FLOW	0.0 -	100.0 KLBH	———
TI2903P	STEAM TEMPERATURE	0.0 -	1000.0 DEGF	-------
PI2902P	STEAM PRESSURE	0.0 -	2000.0 PSIG	-----
NIP1000P	SOLAR INSOLATION	0.0 -	2000.0 W/SM	—-—-

*

Figure 5.3-5. Receiver Response — Simulated Cloud Disturbance

SOLAR DATA PLOT   PLOT * BLANK   NTH SAMPLE AVERAGE =   1
REFERENCE TIME: 125 11 06 00.000   FOR   10.0000 MINUTE(S)

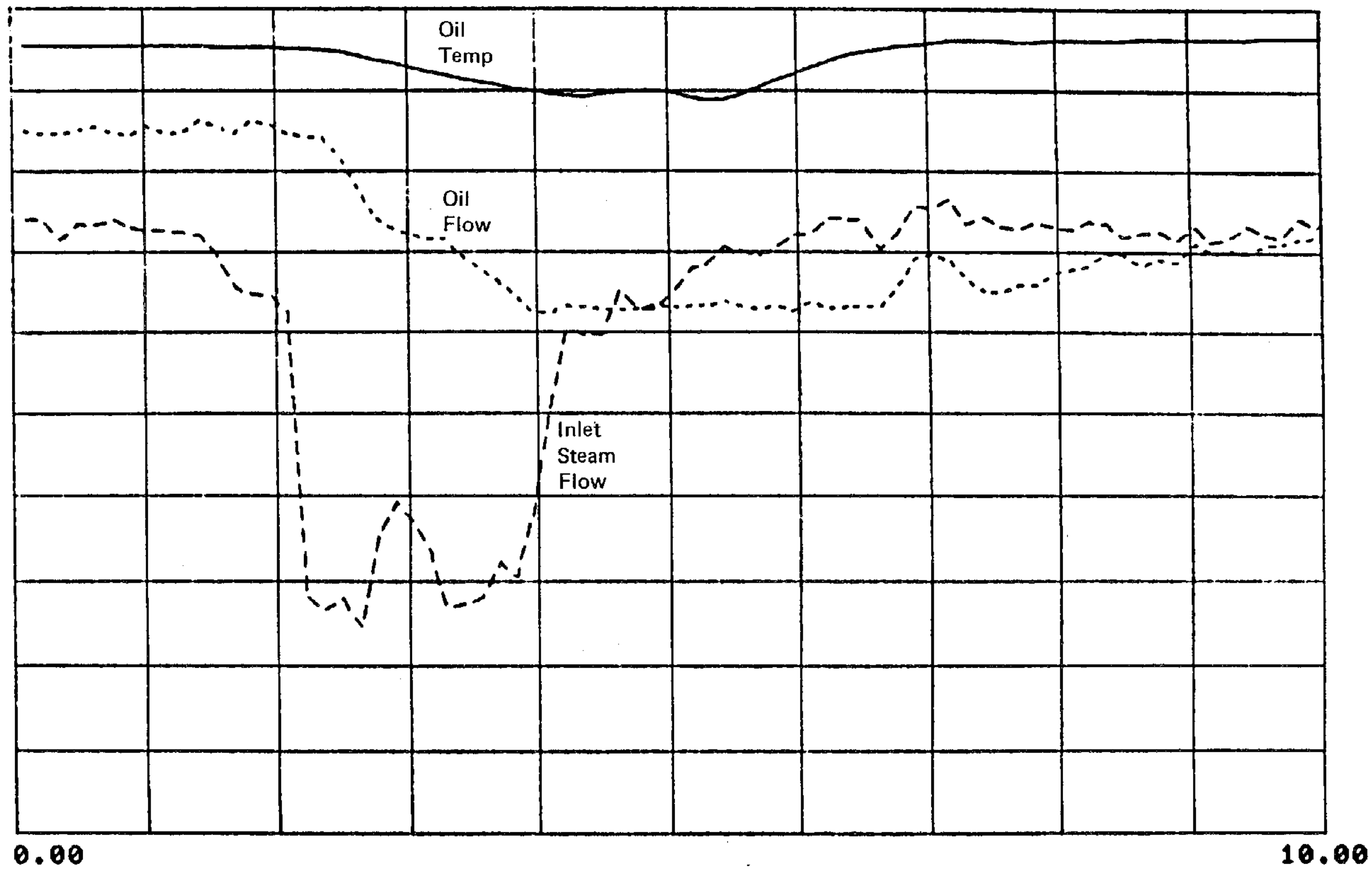


PC3102P	STEAM PRESSURE	1000.0 -	1500.0 PSIG	———
ZI3102P	VALVE POSITION	0.0 -	100.0 PCT	-------
TC3105P	DESUPERHEATER TEMPERATURE	0.0 -	800.0 DEGF	-----
FI3205P	STEAM FLOW	0.0 -	75.0 KLBH	—— —.

*

Figure 5.3-6. TSS Pressure Control Response – Simulator Cloud Disturbance

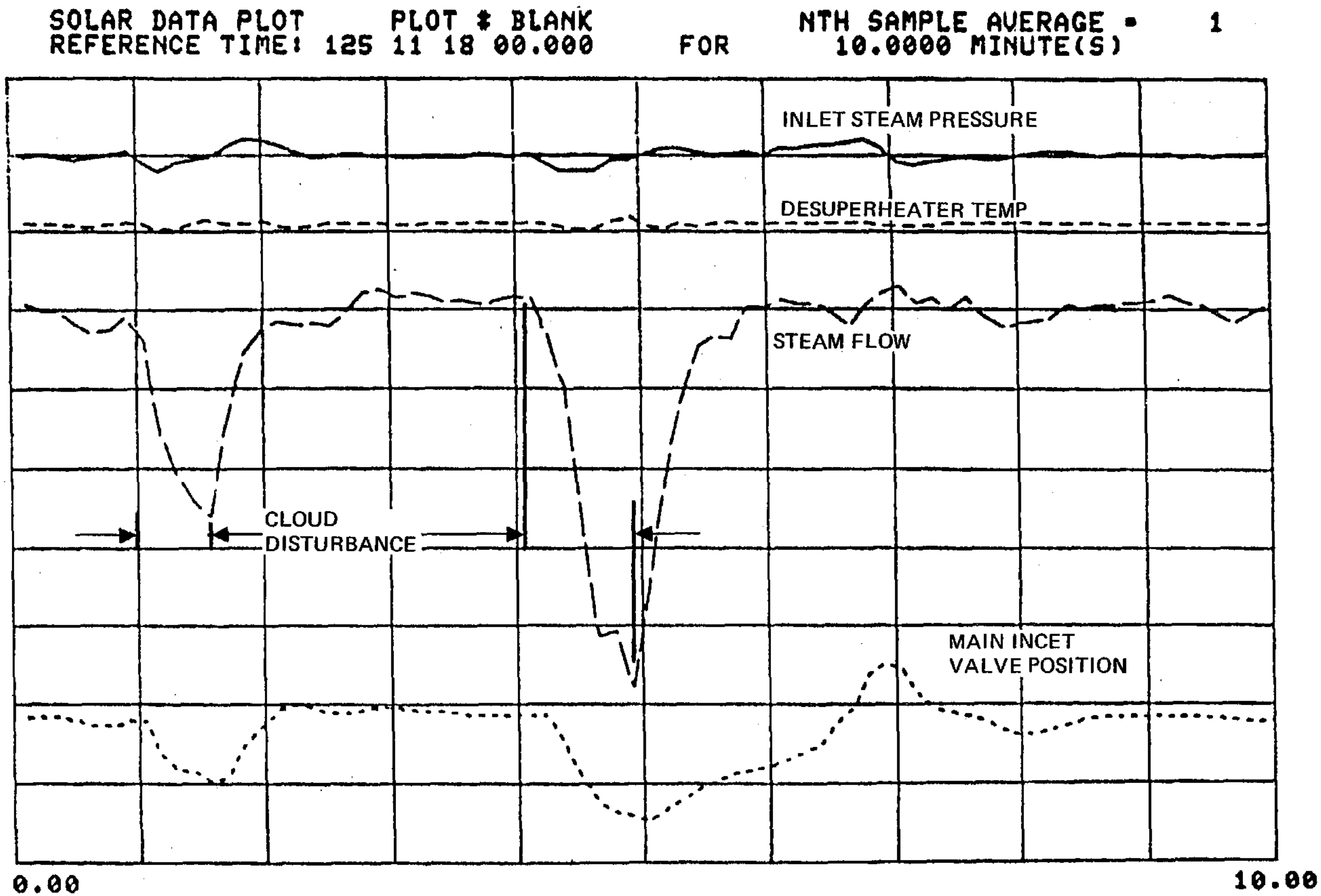
SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE = 1
REFERENCE TIME: 125 11 06 00.000 FOR 10.0000 MINUTE(S)



TC3411P	OUTLET OIL TEMPERATURE	0.0 - 600.0 DEGF	———
FCM3411P	OIL FLOW	0.0 - 700.0 KLBH	....
FI3205P	INLET STEAM FLOW	0.0 - 75.0 KLBH	-----

*

Figure 5.3-7. TSS Oil Temperature Control Response — Simulated Cloud Transient



PC3102P	INLET STEAM PRESSURE	1000.0 -	1500.0 PSIG	———
ZI3102P	VALVE POSITION	0.0 -	100.0 PCT	....
TC3105P	DESUPERHEATER TEMPERATURE	0.0 -	800.0 DEGF	-----
FI3205P	STEAM FLOW	0.0 -	75.0 KLBH	—— —-

Figure 5.3-8. TSS Charging Pressure Control — Cloud Disturbance

5.3.3 Load Control

In load control the main inlet valve is used in conjunction with the turbine. If there are any variations in the receiver output the controller adjusts the UC3102 to keep the turbine electrical output equal to the setpoint. This mode of operation is best for power generation during a cloudy day. Priority is given to the turbine so that when a disturbance occurs every effort is made to keep it on line.

The load control loop was tested in response to both load setpoint changes and induced flow disturbances by modulating the collector field.

The plant was configured to operate in mode 2 with load control on TSS charge at rated temperature and pressure conditions. Initially the turbine load setpoint was 4.2 MW, reduced to 3.2 MW, held for 6 minutes and then returned to its nominal condition. This load setpoint response history is shown in Figure 5.3-9. This same configuration was subjected to a simulated cloud disturbance (modulated collector field) with a load setpoint of 5.2 MW. The response to this 2 minute disturbance pulse is shown in Figures 5.3-10 and 5.3-11. The disturbance transient reduced the TSS inlet steam flow to near zero. However resultant excursion in the design load were less than 1.0 MW and oil temperature excursion were less than 10^{o}F. These typical responses demonstrate that the control stability and performance characteristics of the TSS in load control (JC3102) meet plant operating requirements under both setpoint and cloud disturbance conditions.

5.4 TSS DESUPERHEATER CONTROL TESTS

The desuperheater controls steam temperature to the two charging trains by spraying condensate into the main steam line.

The flow rate needed to maintain a steady state outlet temperature is calculated by enthalpy relationships of the inlet steam flow and temperature. This feedforward command is trimmed by an outer temperature loop TC3105 as shown in Figure 5.4-1. This type of feedforward calculation provides for fast response of the loop and maintains accurate steam temperature during inlet steam flow disturbances.

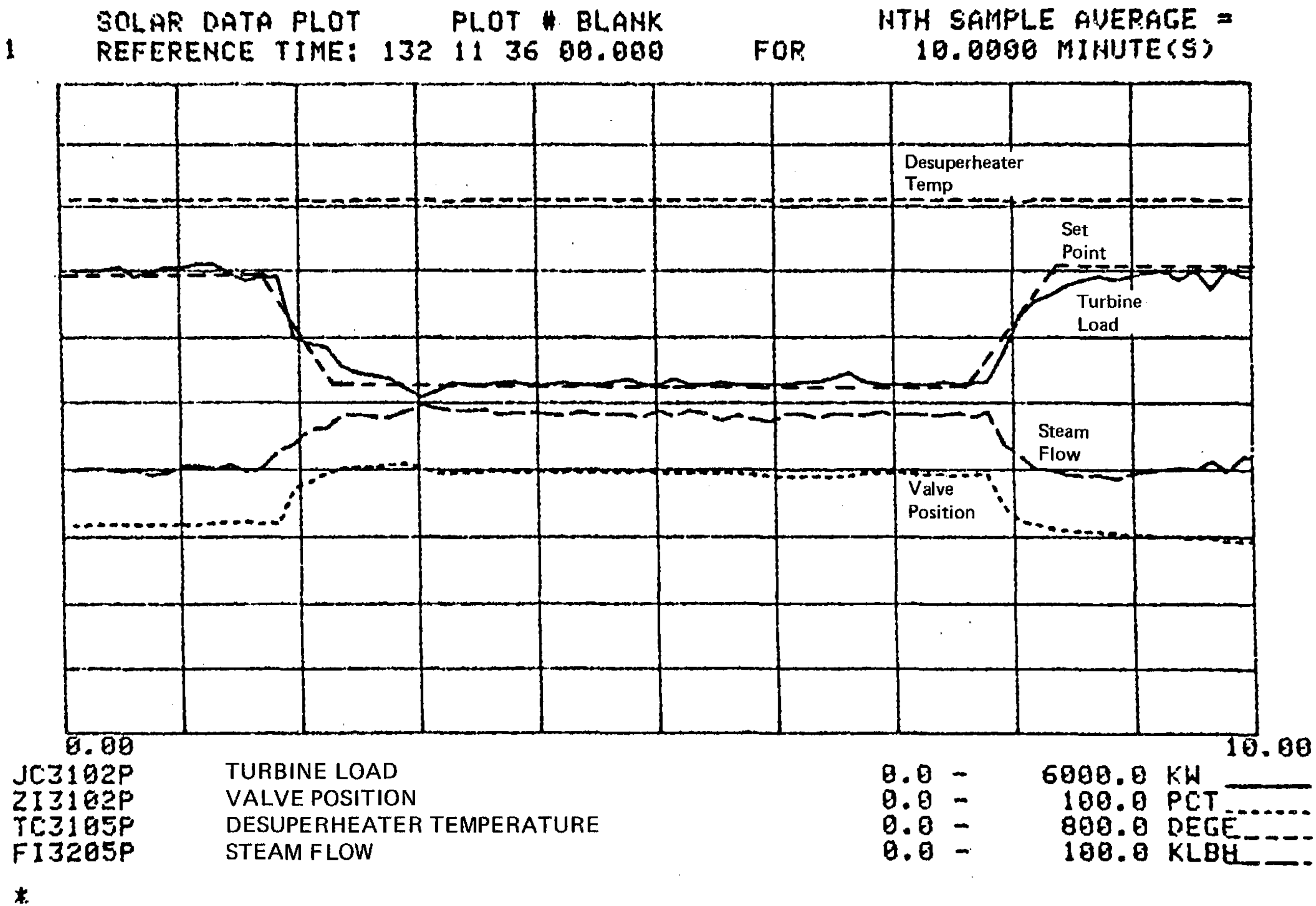


Figure 5.3-9. Load Control Response to a Load Setpoint Change (JC3102)

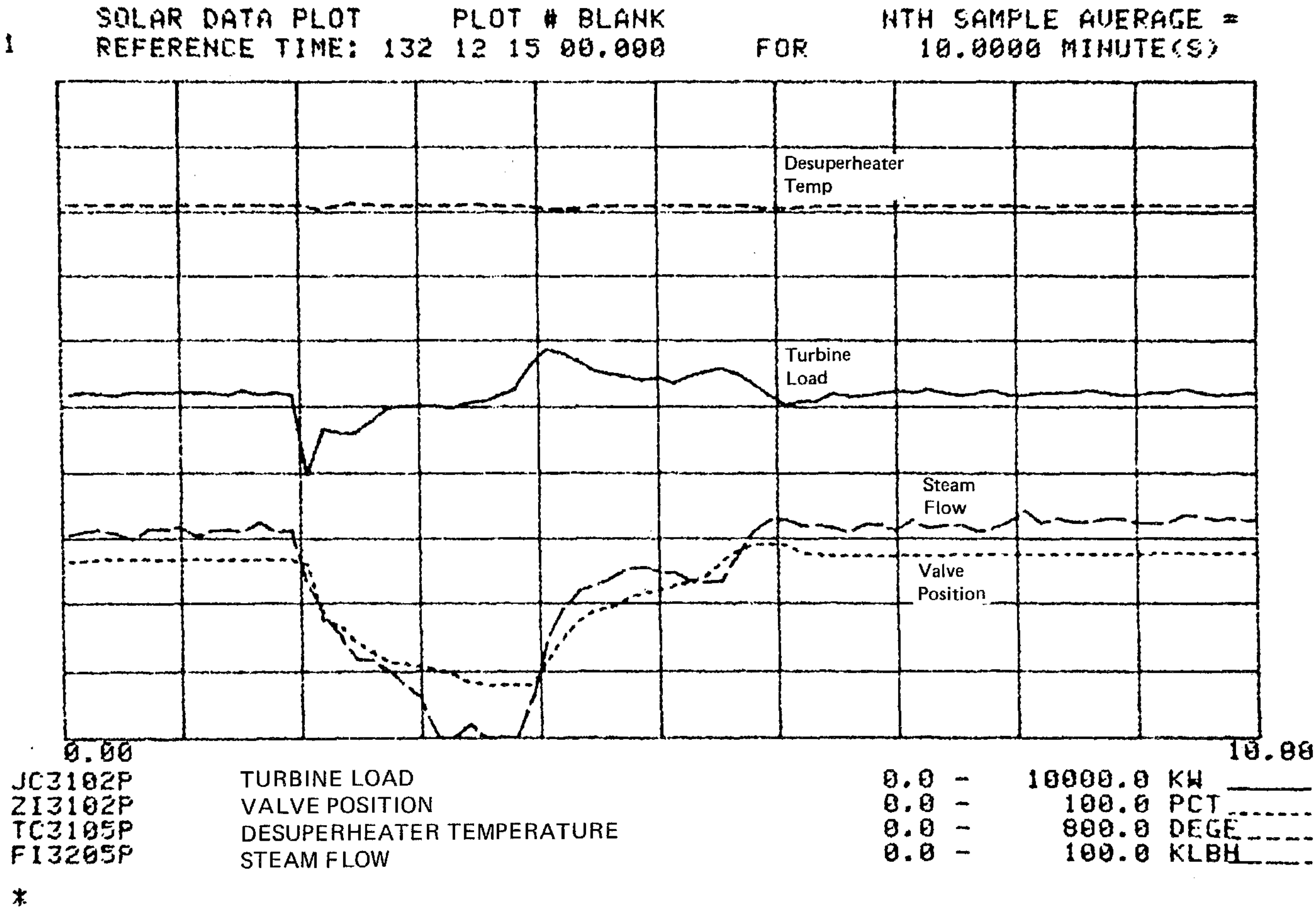


Figure 5.3-10. Load Control Response to a Simulated Cloud Condition (JC3102)

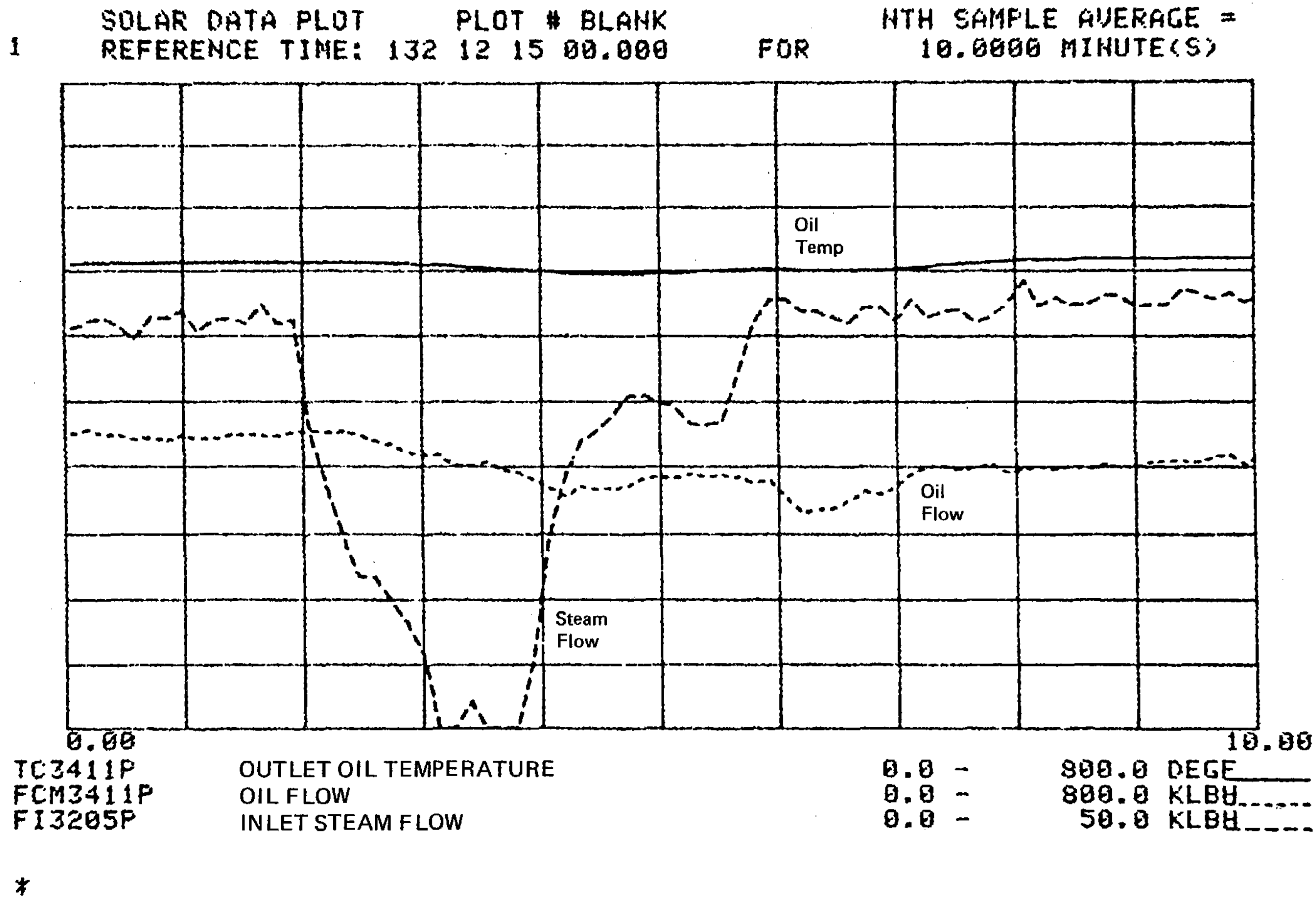


Figure 5.3-11. Load Control Response to a Simulated Cloud Condition (JC3102)

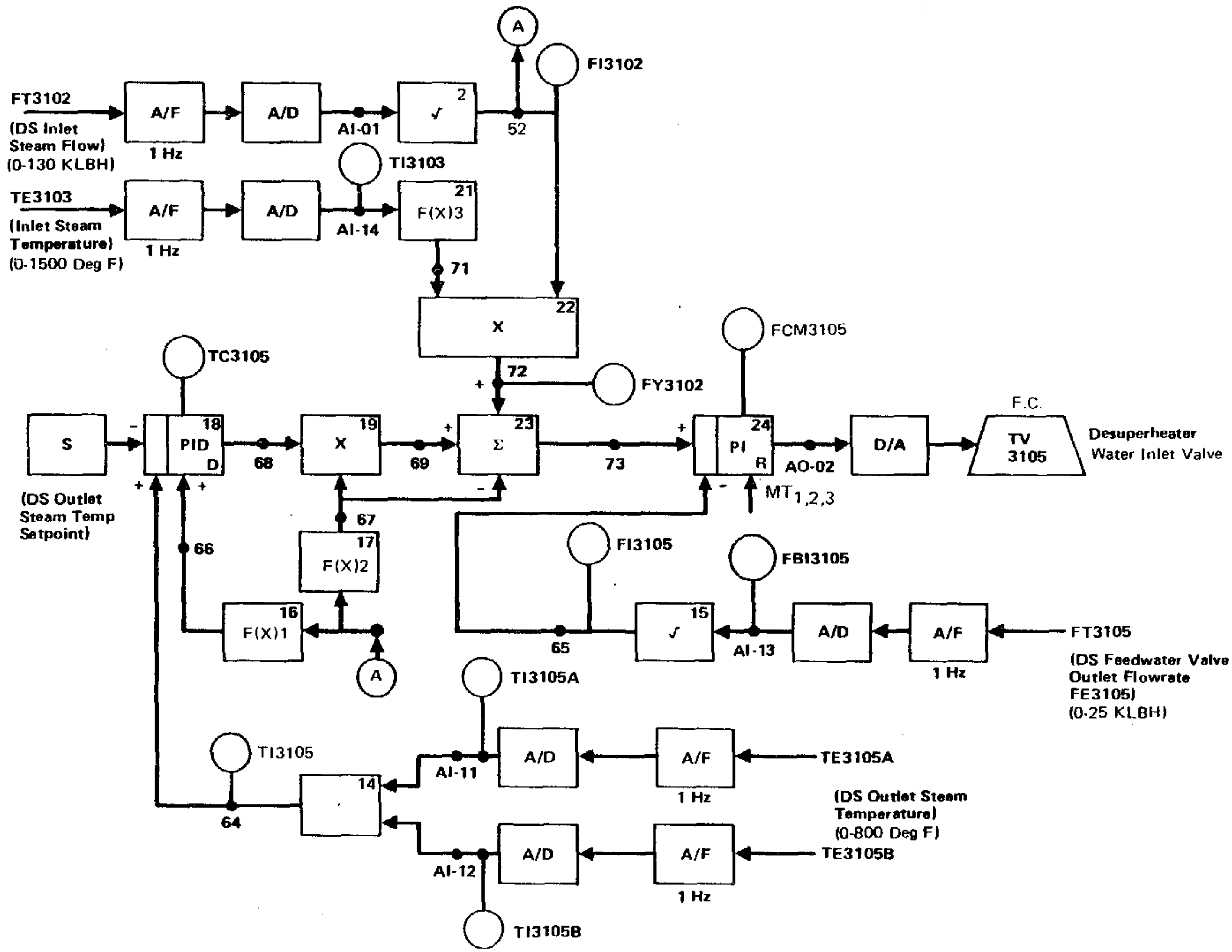


Figure 5.4-1. TSS Desuperheater Outlet Steam Temperature Controller Functional Block Diagram TC 3105

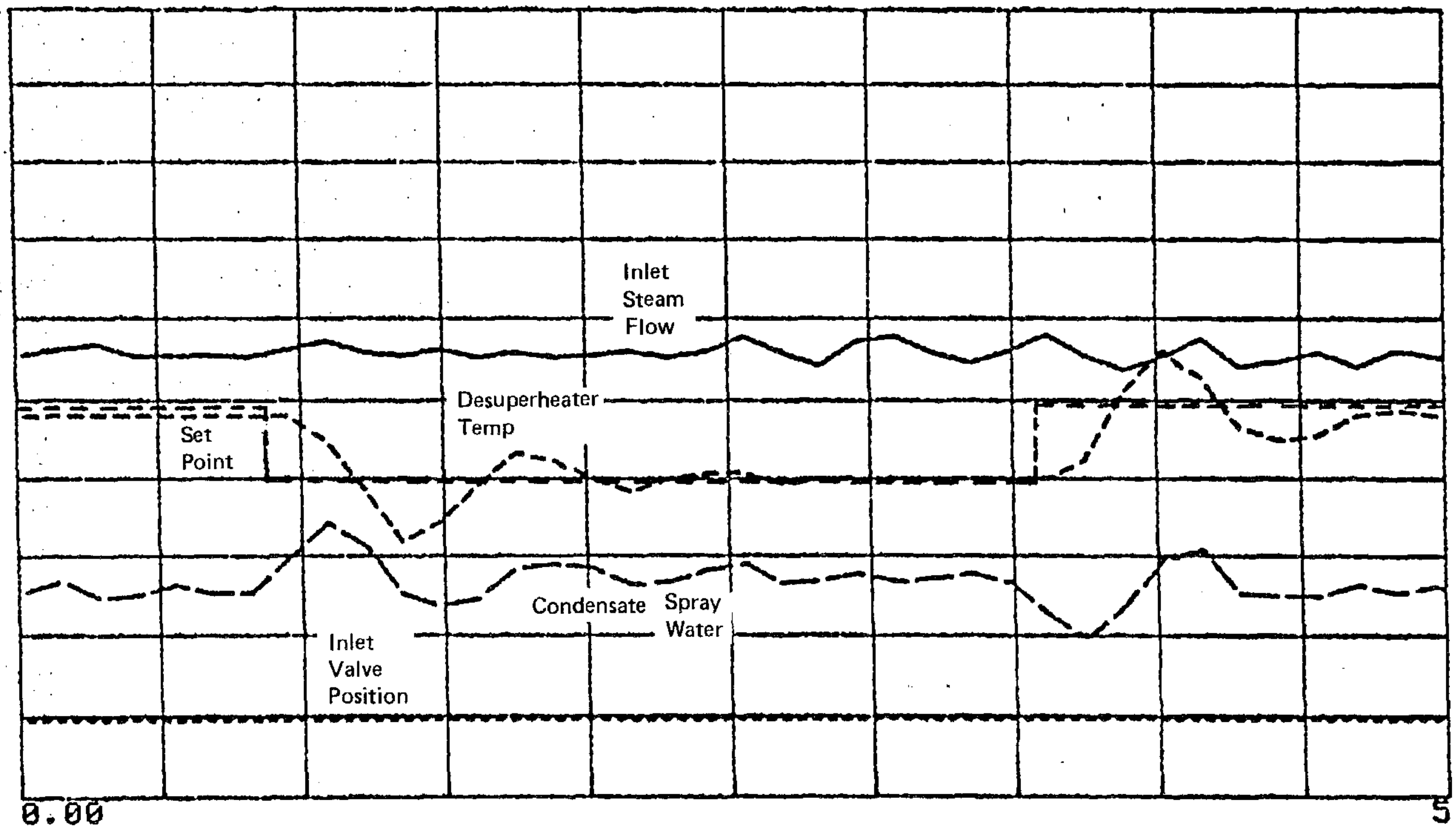
The purpose of the desuperheater temperature controller (TC3105) is to maintain the inlet steam to the charging trains within a $\pm$ 15°F tolerance of the setpoint. This controller must be able to maintain this type of control when subjected to setpoint charges, inlet temperature disturbances and inlet steam flow disturbances. A typical response to a small signal (10°F) step change in the temperature setpoint is shown in Figure 5.4-2. The control loop has been tuned to be slightly underdamped in order to have good disturbance rejection characteristics. In general the desuperheater setpoint is fixed at 650°F and is not manipulated during plant operation so an underdamped response to setpoint changes is satisfactory.

The desuperheater controller must also maintain temperature control charging inlet steam temperature changes as a result of ramping the receiver outlet temperature from rated to derated type conditions. The temperature controller must also be able to respond to inlet flow disturbances as a result of power changes in the receiver whether due to either clouds or a modulating collector field.

The response of the desuperheater to the receiver outlet temperature design ramps rates from 940°F to 860°F is shown in Figure 5.4-3. The desuperheater outlet steam temperature is maintained within 2°F of the setpoint during the disturbance.

The response of the TSS desuperheater to severe flow disturbances has been shown and discussed previously in paragraph 5.3 (refer to Figures 5.3-3, 5.3-3, 5.3-4, 5.3-6 and 5.3-8). These flow disturbance tests cover the full range of expected TSS desuperheater operating conditions. In all of the above, the outlet steam temperature control is stable, well behaved and the maximum excursion due to all disturbances is less than $\pm$ 8°F compared to a design requirement of $\pm$ 15°F. These test results confirm the excellent control characteristics of the temperature loop TC3105.

1 SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE =
REFERENCE TIME: 126 09 40 30.000 FOR 5.0000 MINUTE(S)

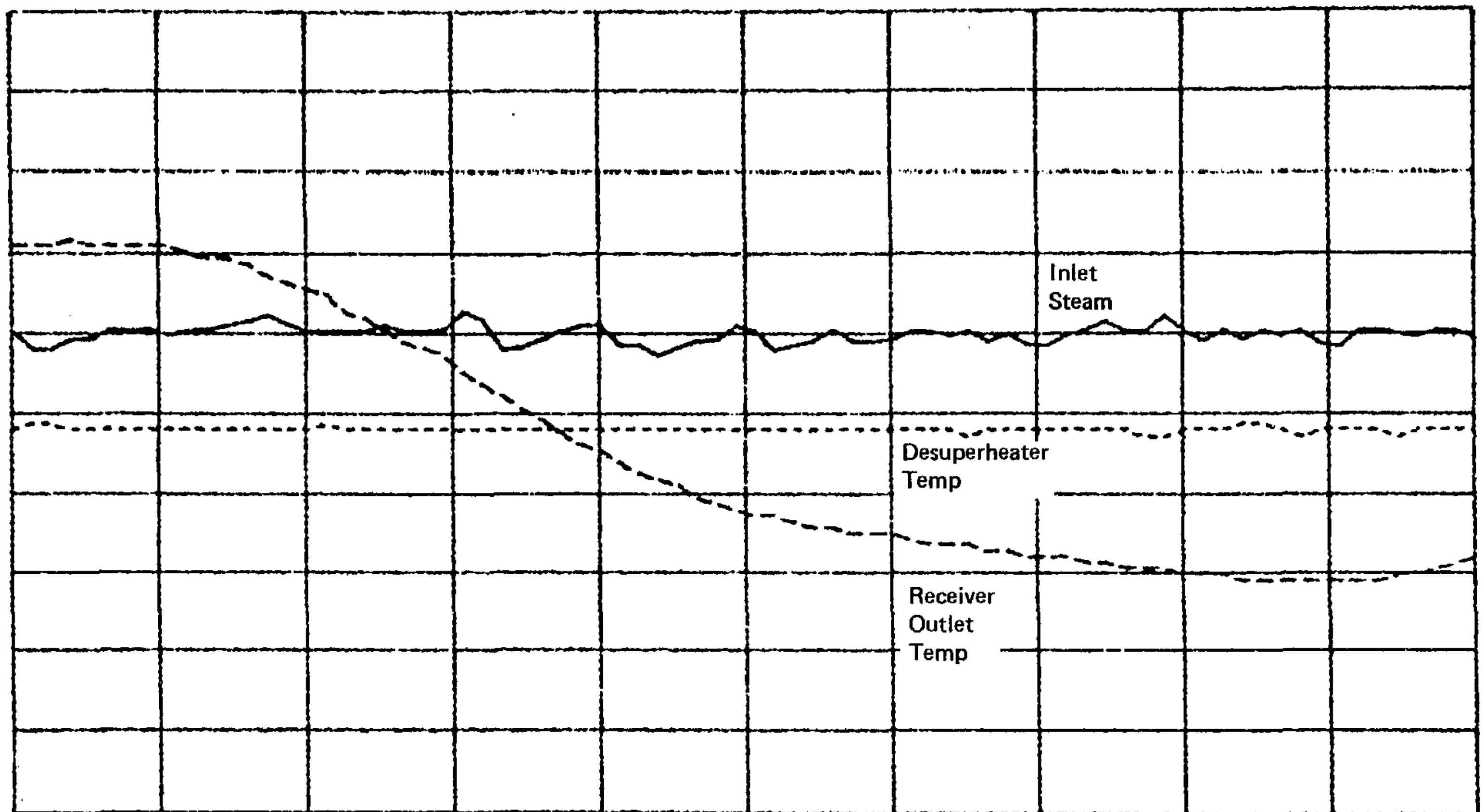


FC3102P	INLET STEAM FLOW	0.0 -	50.0 KLBH
ZI3102P	VALVE POSITION	0.0 -	100.0 PCT
TC3105P	DESUPERHEATER TEMPERATURE	600.0 -	700.0 DEGF
FCM3105P	SPRAY WATER FLOW	0.0 -	20.0 KLBH

*

Figure 5.4-2. TSS Desuperheater Temperature Control Response to a Setpoint Change (TC3105)

1 SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE =
REFERENCE TIME: 126 11 04 00.000 FOR 10.0000 MINUTE(S)

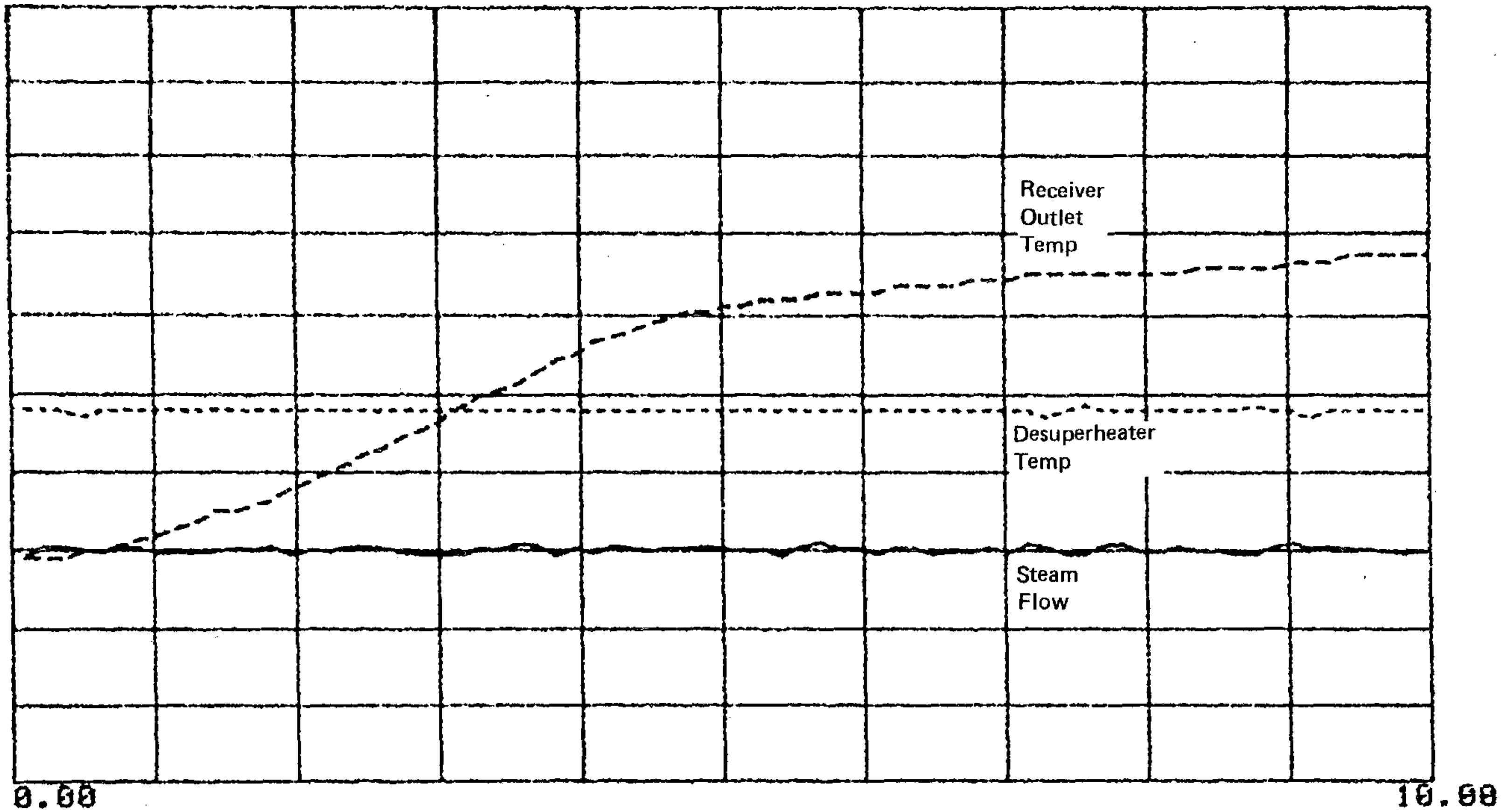


FC3102P	INLET STEAM FLOW	0.0 -	50.0	KLBH ____
TC3105P	DESUPERHEATER TEMPERATURE	600.0 -	700.0	DEGF......
TI2903P	RECEIVER OUTLET TEMPERATURE	800.0 -	1000.0	DEGF_ _ _ _

*

Figure 5.4-3. TSS Desuperheater Temperature Control Response to an Inlet Steam Temperature Disturbance

SOLAR DATA PLOT   PLOT # BLANK   NTH SAMPLE AVERAGE =
1   REFERENCE TIME: 126 11 13 00.000   FOR   10.0000 MINUTE(S)



FC3102P	INLET STEAM FLOW	0.0 -	100.0 KLBH____
TC3105P	DESUPERHEATER TEMPERATURE	600.0 -	700.0 DEGE......
TI2903P	RECEIVER OUTLET TEMPERATURE	800.0 -	1000.0 DEGE_ _ _ _

*

Figure 5.4-3. TSS Desuperheater Temperature Control Response to an Inlet Steam Temperature Disturbance (Cont'd)

5.5 CHARGING OIL LOOP CONTROL TESTS

The oil temperature of each of the two charging trains is controlled by varying the oil flow rate through each charging condenser via modulating control valves TV3411 (TRAIN 1) and TV3412 (TRAIN 2). Since the two trains are essentially identical, only Train 1 will be discussed here. The functional block diagram of the charging oil temperature controller, TC3411, for Train 1 is shown in Figure 5.5-1. The final controller configuration consists of an oil flow rate and an oil temperature feedback loop. During TSS control testing, the steam flow feedforward loop, which was part of the original design, was removed when it was found to behave as a positive feedback loop due to coupling between the steam flow and oil flow in the condensation process. With the current two-loop control configuration, the flow rate setpoint with the temperature loop in auto is provided by the temperature loop. The steady state oil flow rate is that required to reduce the oil temperature error to zero for a given steam flow rate condition.

The multiplier in the temperature loop provides a variable proportional gain as a function of the difference between the charging condenser outlet oil temperature, TE3211, and the TSS subcooler inlet temperature, TE3214. For this application, the outlet oil temperature was assumed to be fixed at a value equal to the oil temperature setpoint of 580°F. As the differential temperature across the condenser increases, the gain decreases to maintain adequate stability gain margin. A 6 db gain variation is provided over the range of inlet oil temperatures from 260 to 425°F.

During startup and shutdown of the charging oil trains, the oil temperature controller is automatically sequenced through its various control modes by the digital logic shown in Figures 5.5-2 and 5.5-3. The controller is started up with the temperature control valve TV3411, in Manual, 70% open, until the oil flow increases to approximately 135KLBH. Two minutes after reaching this flow rate the flow loop PID, FCM3411, is switched to Auto with the flow setpoint equal to 200KLBH. The flow setpoint is provided by the Auto/Manual station FCY3411 which is in Manual. When the oil temperature increases to 570°F, the controller is switched to temperature control by switching FCY3411 to Auto. If the oil temperature should decrease to 540°F, for example due to a cloud transient, the controller is returned to the flow

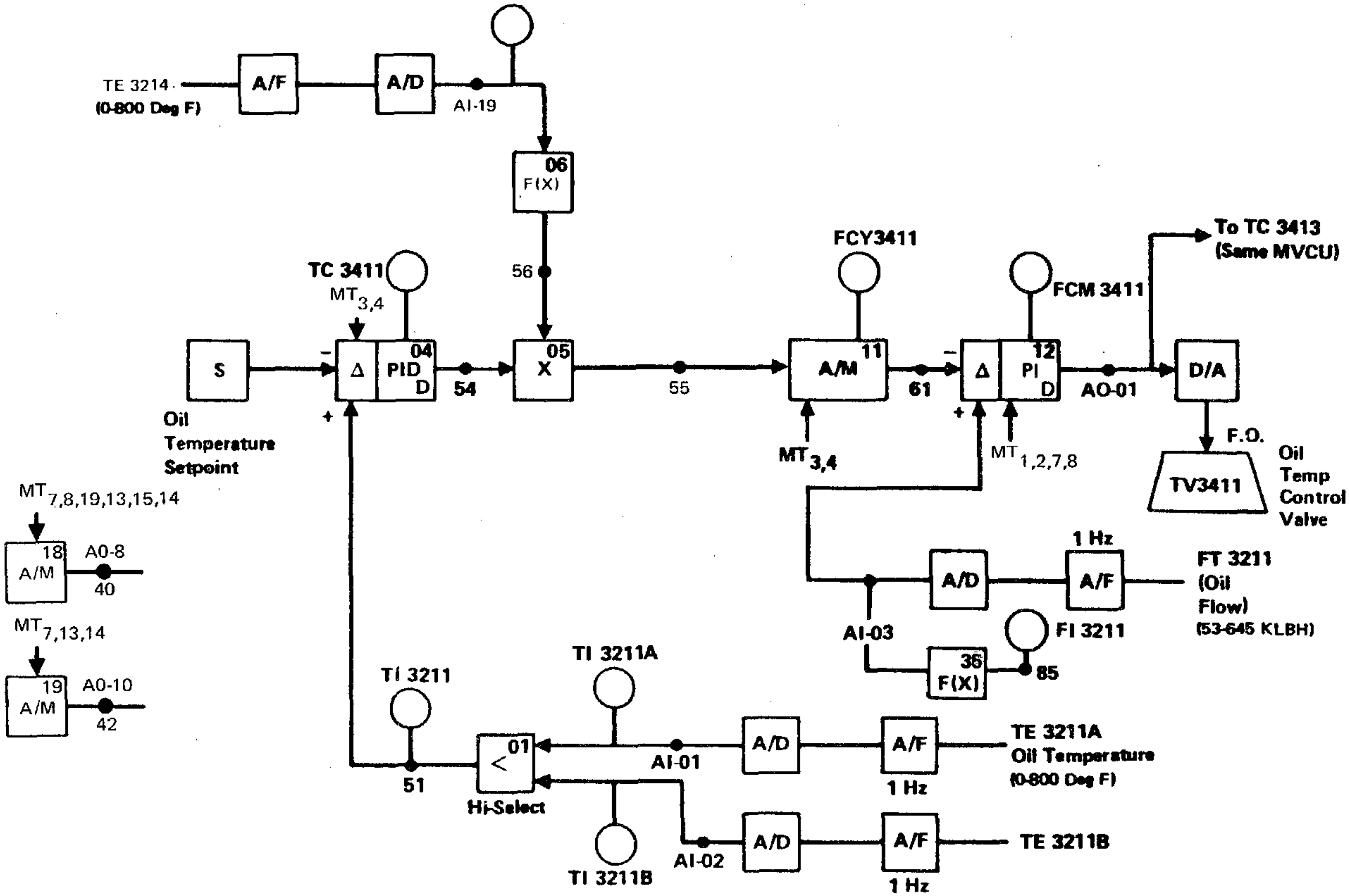


Figure 5.5-1. TSS Charging Oil Loop Temperature Controller Functional Block Diagram TC 3411 (Train 1)

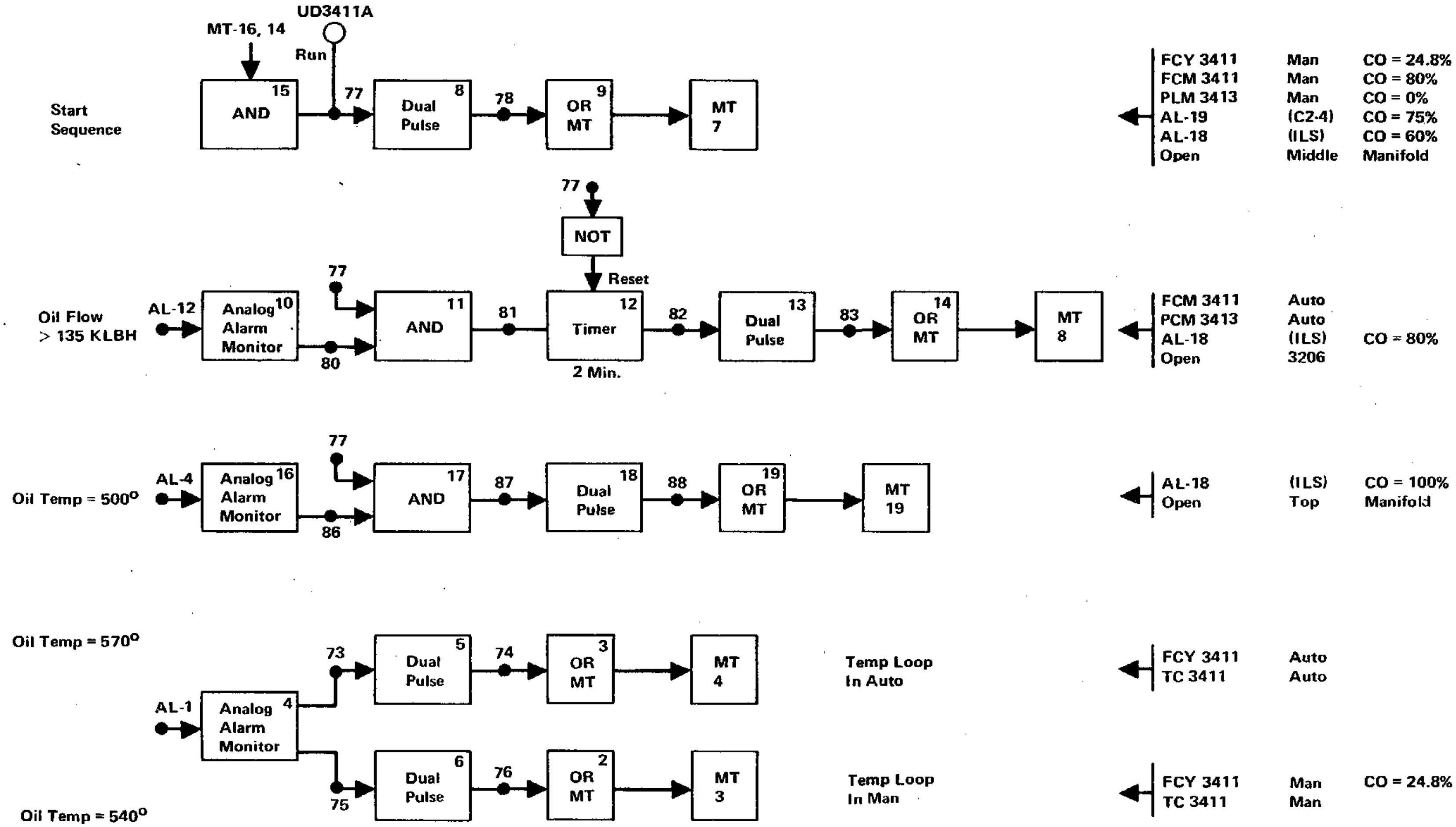


Figure 5.5-2. Charge Train One Start Sequence

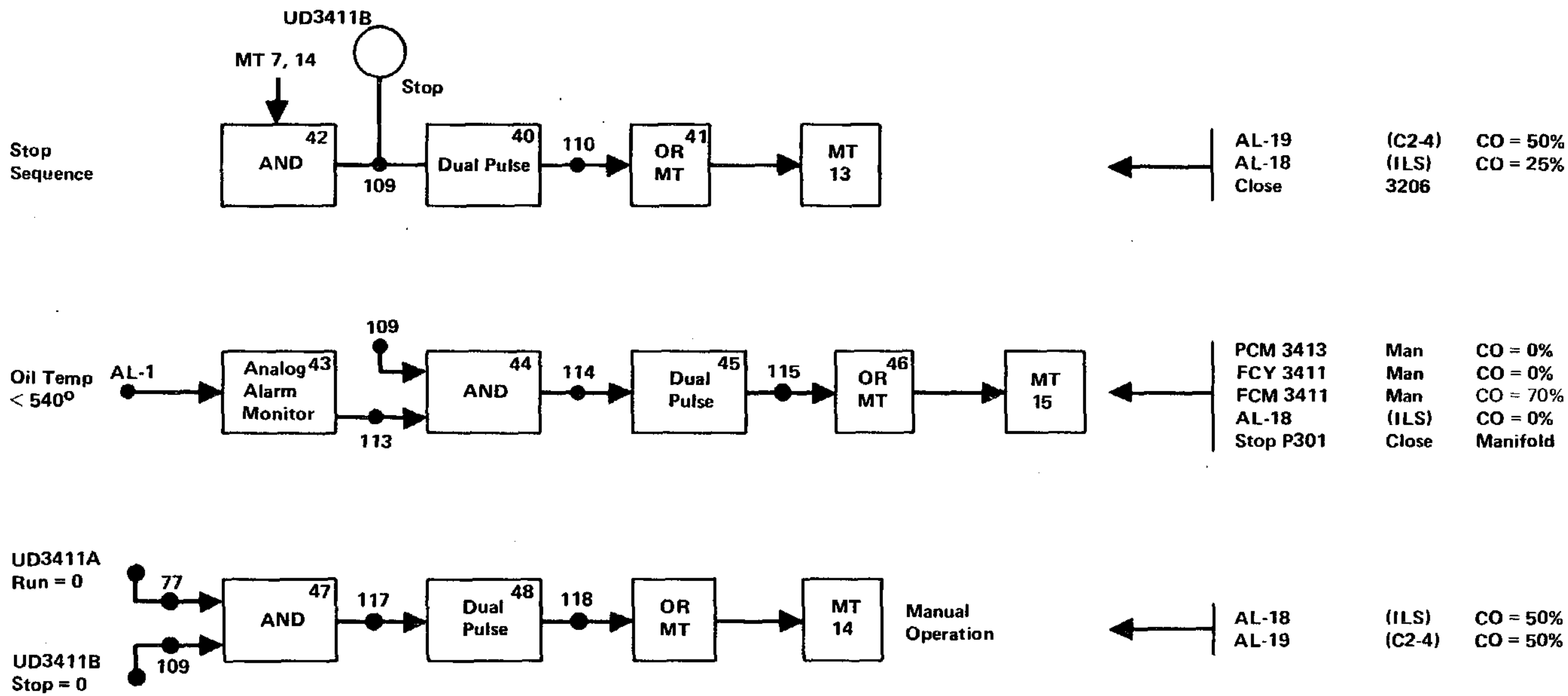


Figure 5.5-3. Charge Train One Stop Sequence

control mode with a flow setpoint of 200KLBH until the oil temperature again increases to 570°F. The shutdown sequence is initiated by switch UD3411B, which will sequence the controller back to manual valve control with the valve set at 70% open when the oil temperature drops to 540°F.

The majority of the required turndown in the oil flow rate over the range of expected steam flow rate operating conditions is provided by the charging oil pump. This is accomplished by slaving the oil temperature commanded valve position to the oil pump speed control so as to maintain the valve 70% open. The functional block diagram of the charging oil pump controller PCM3413 (Train 1) is shown in Figure 5.5-4. Over the required 3:1 turndown ratio in oil flow rate from approximately 600KLBH to approximately 200KLBH, the oil pump provides a 2:1 turndown ratio with the oil temperature control valve providing the balance. This requires that the valve operate only over a range of 45% to 70% open where the valve linearity is best.

Three types of tests were conducted on the charging oil temperature controller during 1040B testing: 1) open loop pulse tests, 2) field tuning of control loop PIDs, including stability margin tests, and 3) closed loop tests including setpoint changes and system disturbances. During the initial testing of this system, considerable difficulty was encountered due to coupling between the condensation process and the main steam flow and condenser pressure controllers. A block diagram illustrating the major coupling loops is shown in Figure 5.5-5. In attempting to perform open or closed loop tests which required changes in oil flow rates, changes induced in steam flow through the condensation process would cause upsets in the condenser pressure, PI3210. At that time, the condenser pressure control setpoint was only 50 psi below the upstream pressure at the main steam inlet valve, UV3102. Consequently, changes in condenser pressures resulted in large changes in the differential pressure across the main steam inlet valve. This produced large steam flow rate transients which further reinforced the coupling process. Steps were taken to tighten control of the steam flow rate and condenser pressure and to reduce the sensitivity to condenser pressure variations. During the 1040B test program, the following changes were made: 1) the condenser pressure control setpoint was decreased to 1350 psia or 100 psia below the main steam inlet valve pressure in order to double the ΔP

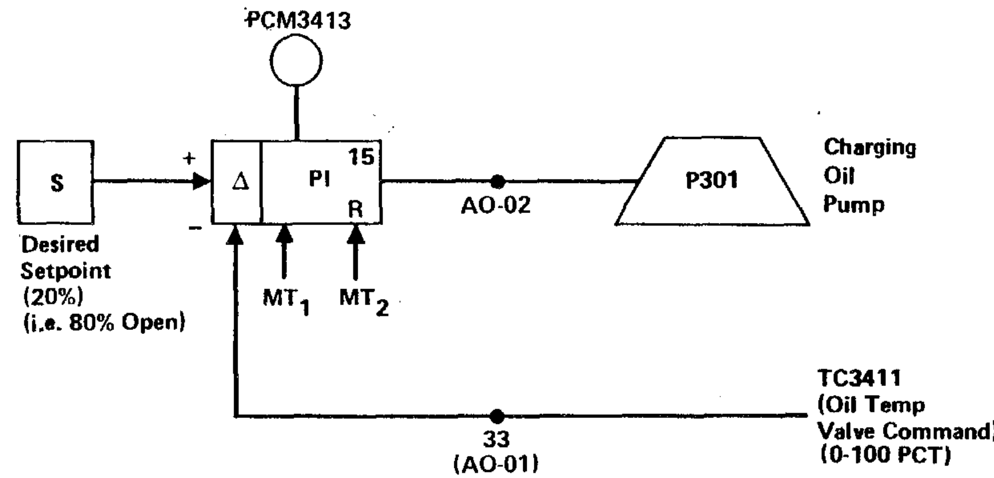


Figure 5.5-4. TSS Charging Oil Pump Speed Controller Functional Block Diagram — PCM3413 (Train 1)

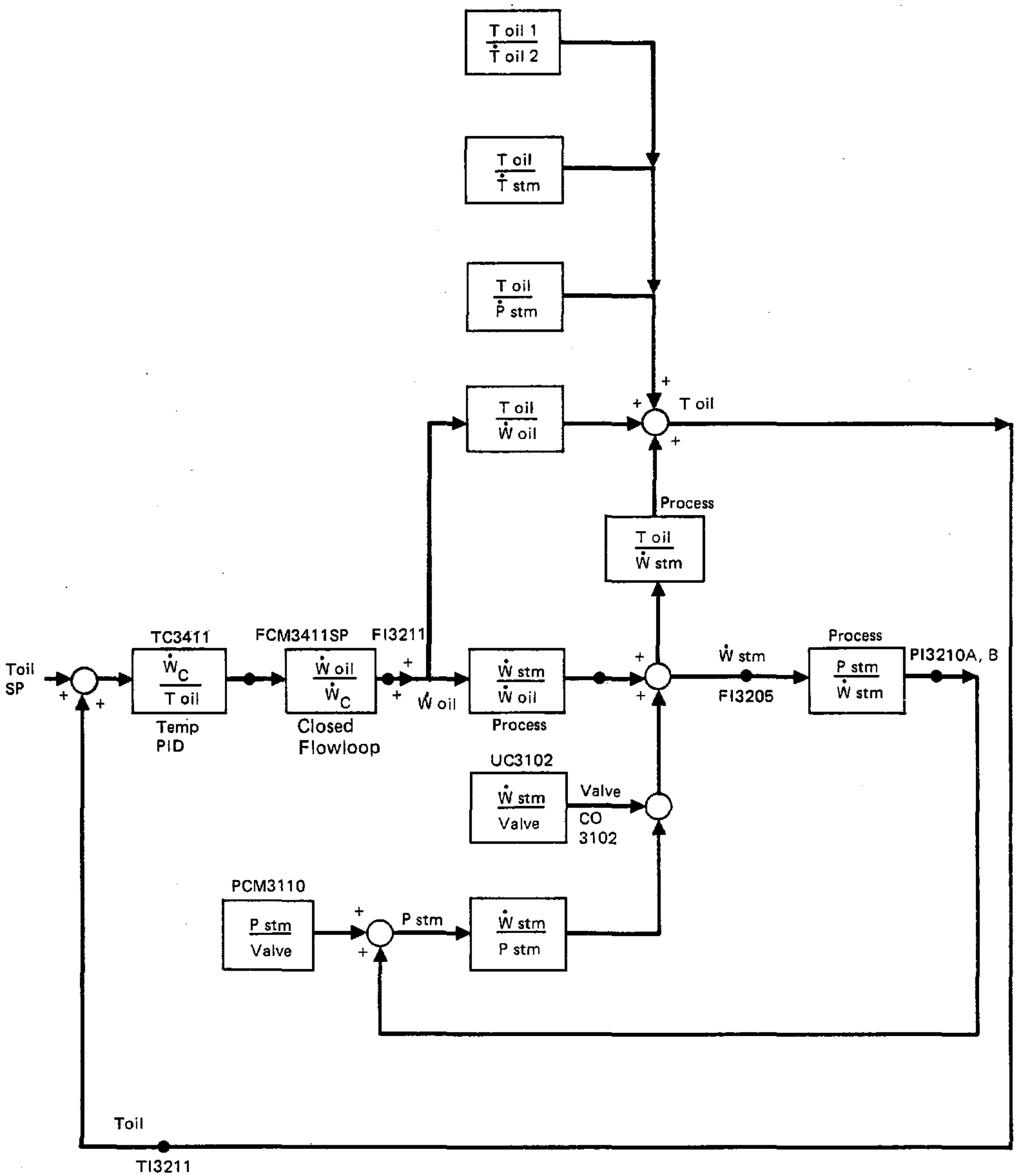


Figure 5.5-5. Charging Oil Subsystem Coupling Diagram

across the UV3102 control valve, 2) the trim on the PV3110 condensate drain valve that controls the condenser pressure was increased from 4.7 to 7.4 to improve the response of the PCM3110 control loop, 3) problems with the FT3102 flow sensor which forced operating the main steam inlet valve in manual were temporarily resolved by using the downstream flow sensor FT3205, and 4) control problems at low stroke with the UV3102 valve were resolved by replacing the linear trim with an equal percentage trim.

Testing of the charging oil temperature controller proceeded with field tuning of the TC3411 inner control loops. The oil flow loop PI controller gains were determined by the following procedure: With the oil flow loop in auto and the oil pump controller and oil temperature loop in manual, the pump speed was set to achieve a 70% open oil temperature control valve at the maximum oil flow rate required. The integral gain was set very low and the proportional gain increased until the flow loop oscillated. The proportional gain was then decreased by a factor of 2 to assure a minimum 6 db of gain margin at the maximum gain condition (maximum flow). With this proportional gain, the integral gain was increased until a flow oscillation occurred. The integral gain was then reduced by a factor of 3. This same procedure was followed to tune the oil pump PID with the oil flow loop in auto. In tuning the oil pump loop PID, it was found that the derivative gain required was less than the minimum capability of the Beckman PID algorithm. Consequently, the derivative action was disabled for the oil pump loop controller. The controller response without derivative control was tested and found to be satisfactory.

The final configuration for the oil temperature loop PID TC3411 was determined from a linear stability analysis based on a model of the oil charging process. The model was derived from a Fourier analysis of open loop pulse test data in which the oil temperature response to a commanded oil flow rate triangular pulse was obtained. A typical pulse test conducted on day 104 at an oil flow rate of approximately 280KLBH is shown in Figure 5.5-6. The Fourier analysis produced an open loop frequency response from which the poles and zeros or a transfer function of the process was derived using a least squares curve fitting program. The Nyquist stability criterion was then applied to derive the oil temperature loop PID characteristics to provide as

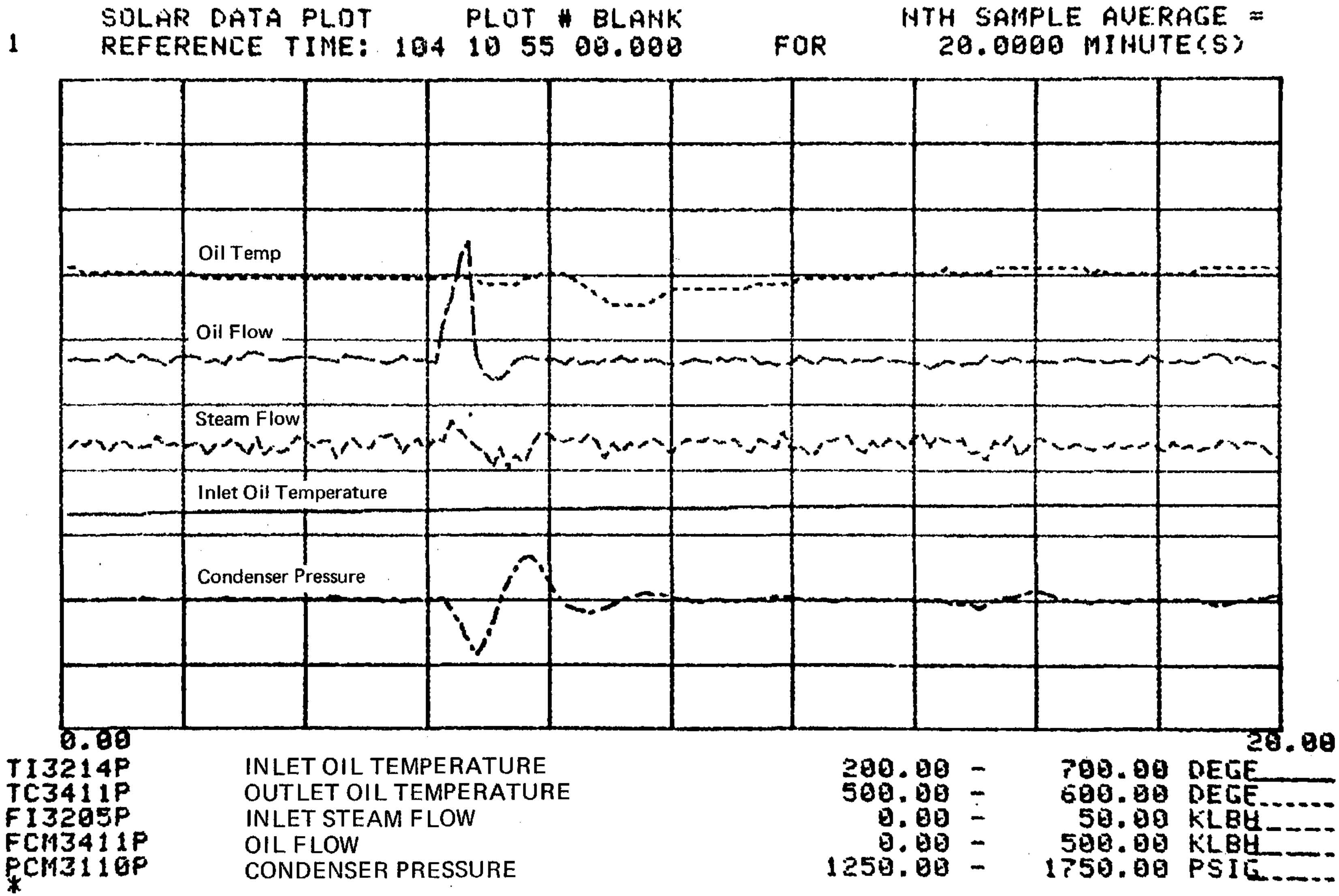


Figure 5.5-6. Open Loop Oil Flow Rate Pulse Test (Oil Flow = 280 KLB)

fast a loop response as possible while maintaining adequate gain and phase stability margins. The resulting single loop Nyquist stability plot is shown in Figure 5.5-7 at a low oil flow rate condition of 280KLBH and a condenser oil inlet temperature of 380°F. The gain and phase margins for this condition are approximately 9 db and 60 degrees, respectively, which satisfies design requirements for acceptable stability margins.

An open loop pulse test at a higher oil flow rate of approximately 500 KLBH was also conducted and is shown in Figure 5.5-8. The Fourier analysis model for this test condition results in a charging oil temperature process response which is faster than the previous low flow condition. Consequently, the Nyquist stability plot which is shown in Figure 5.5-9 exhibits increased phase margin and a higher crossover frequency compared to the low flow condition. Based on this model, the closed loop response of the charging oil temperature to oil flow rate changes would then be expected to respond faster with less overshoot at the high oil flow rate condition. The closed loop response tests which are discussed in the following paragraph confirm these expected characteristics.

Closed loop response tests of the Charging Oil Temperature controller to oil temperature setpoint steps were conducted over the range of expected steam/oil flow rate operating conditions. During these tests, the steam flow rate and condenser pressure were held relatively constant to minimize the effects of coupling on the oil temperature response. Test conditions for six representative closed loop temperature setpoint step tests are summarized in Table 5.5-1. For these tests, steam flow rates ranged from a high of 53 KLBH to a low of 21 KLBH with the corresponding oil flow rates ranging from a high of 600 KLBH to a low of 280 KLBH.

The charging oil temperature step responses are shown in Figures 5.5-10 through 5.5-15 for the six conditions given in Table 5.5-1. The oil temperature responses exhibit more overshoot when the oil temperature setpoint is decreased from 570°F to 560°F than when it is increased from 560°F to 570°F. This occurs at all flow rate conditions and is probably due to changes in the heat transfer between the metal and oil due to two effects: 1) the non-linear behavior of the oil side heat transfer coefficient with changes

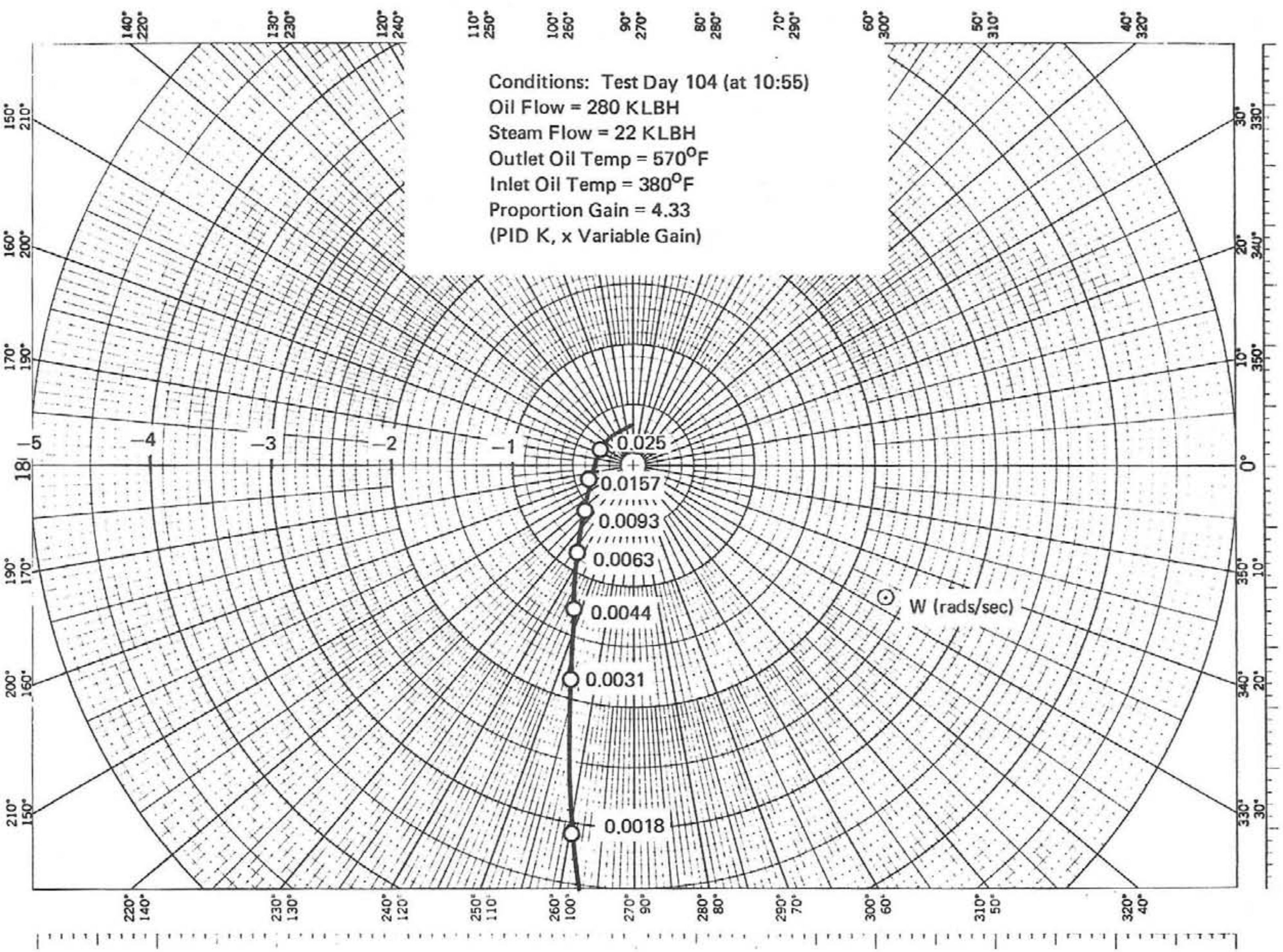
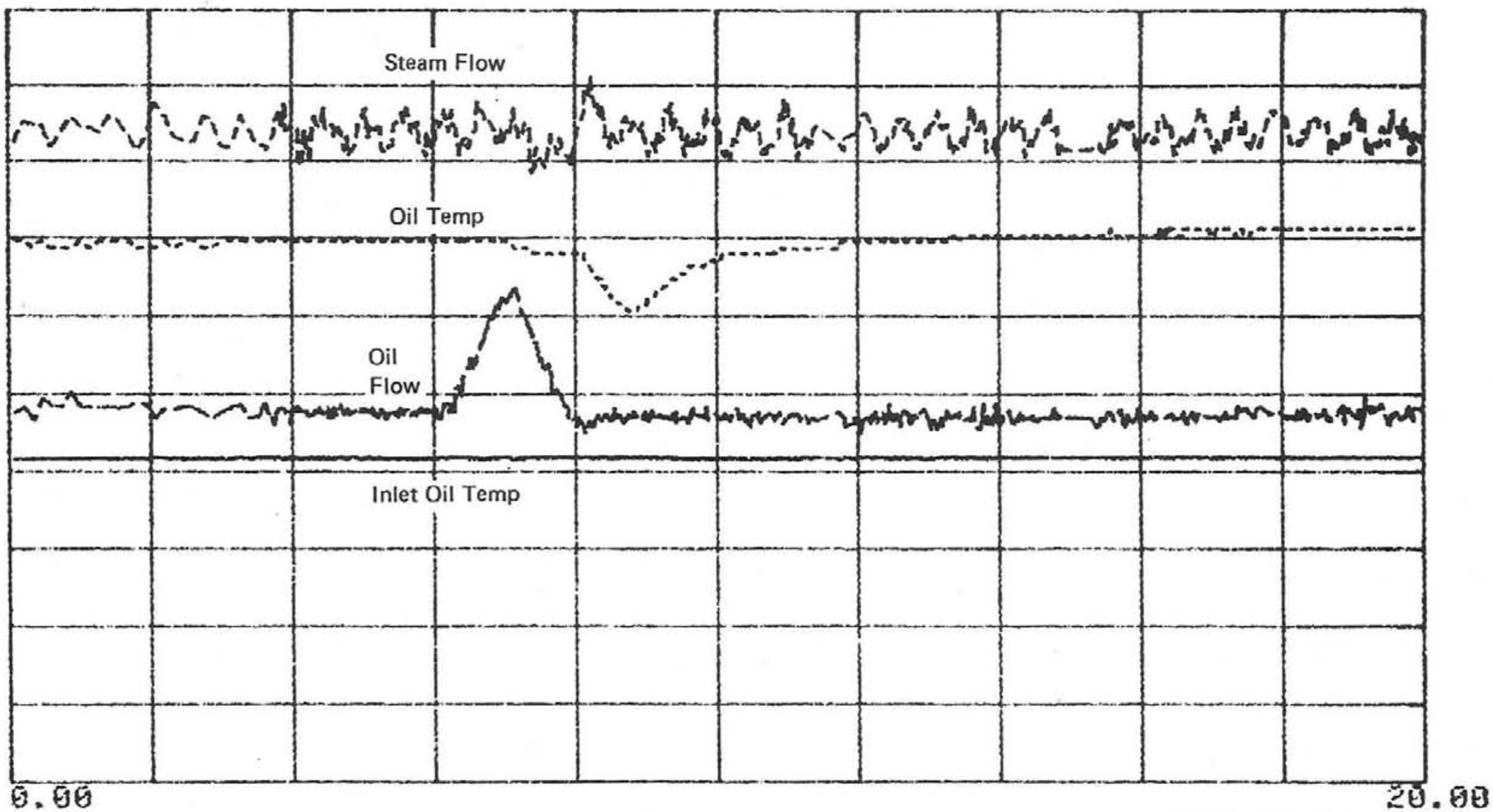


Figure 5.5-7. One-Loop Nyquist (Charging Oil Temperature Controller, TC3411 – Low Flow)

1 SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE =
REFERENCE TIME: 105 10 40 00.000 FOR 20.0000 MINUTE(S)



TI3214P	INLET OIL TEMPERATURE	200.00 -	700.00	DEGF____
TC3411P	OUTLET OIL TEMPERATURE	500.00 -	600.00	DEGF......
FI3205P	INLET STEAM FLOW	0.00 -	50.00	KLBH----
FCM3411P	OIL FLOW	250.00 -	750.00	KLBH_.__.

*

Figure 5.5-8. Open Loop Oil Flowrate Pulse Test (Oil Flow = 500 KLBH)

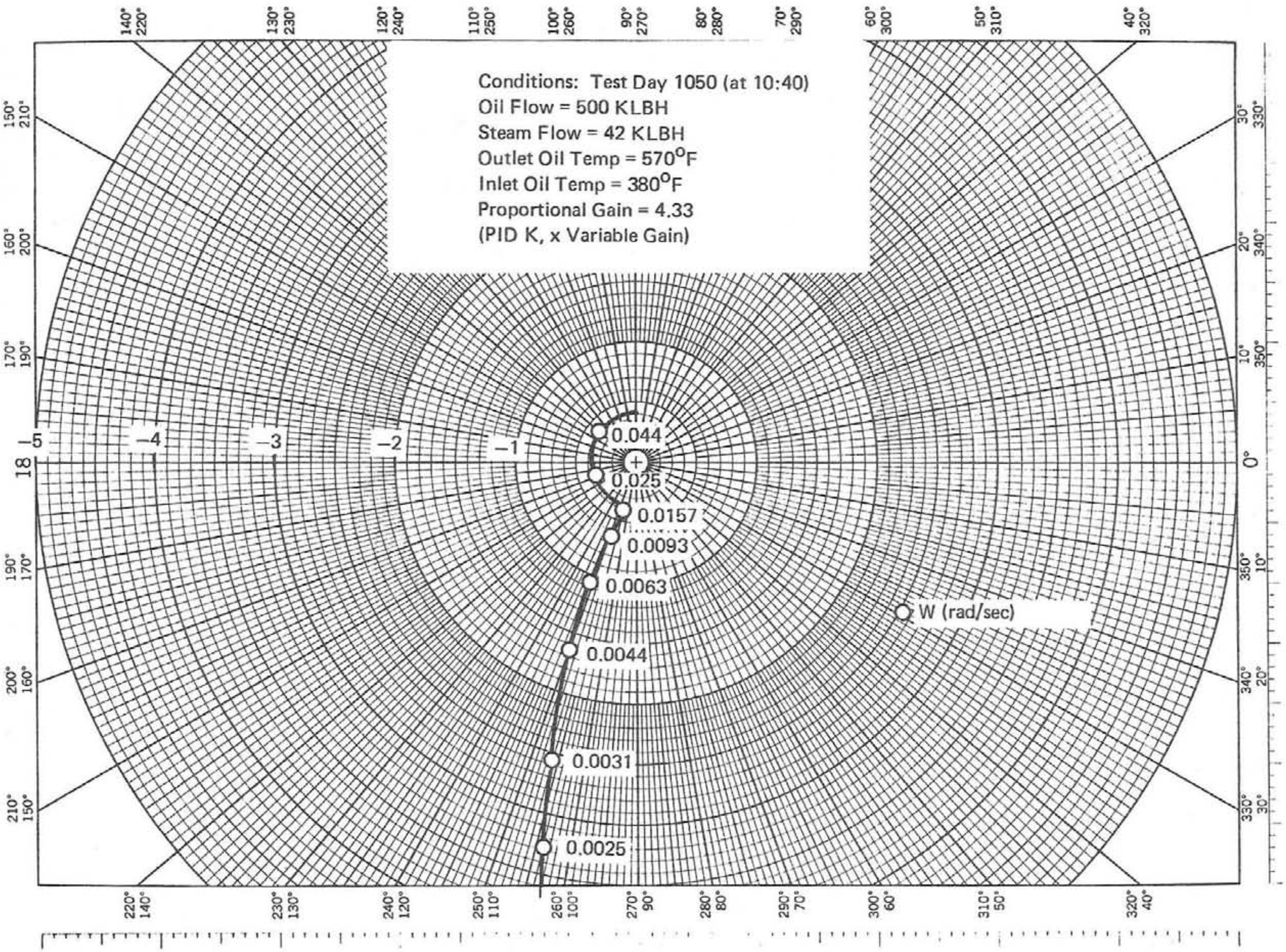


Figure 5.5-9. One-Loop Nyquist (Charging Oil Temperature Controller, TC3411 – High Flow)

Table 5.5-1. Closed Loop Test Summary - Temperature Setpoint Steps
Charging Oil Temperature Controller - TC3411

Oil/Steam Flow Condition	Test Day	Time Slice Start	(°F) Setpoint			(LBH) Oil Flow			(LBH) Steam Flow	Figure
High	104	14:40	570	560	570	500K			48K	5.4-9
High	105	11:15	570	560		520K	575K		45K	5.4-10
High	105	11:30	560	570		550K	520K		45K	5.4-11
Medium	105	12:55	570 560	560 570	570	400K 400K	450K 450K	 400K	31K	5.4-12
Low	125	09:25	570	560°	570	280K	350K		21K	5.4-13
High	125	10:35	570	560	570	550K	600K		53K	5.4-14

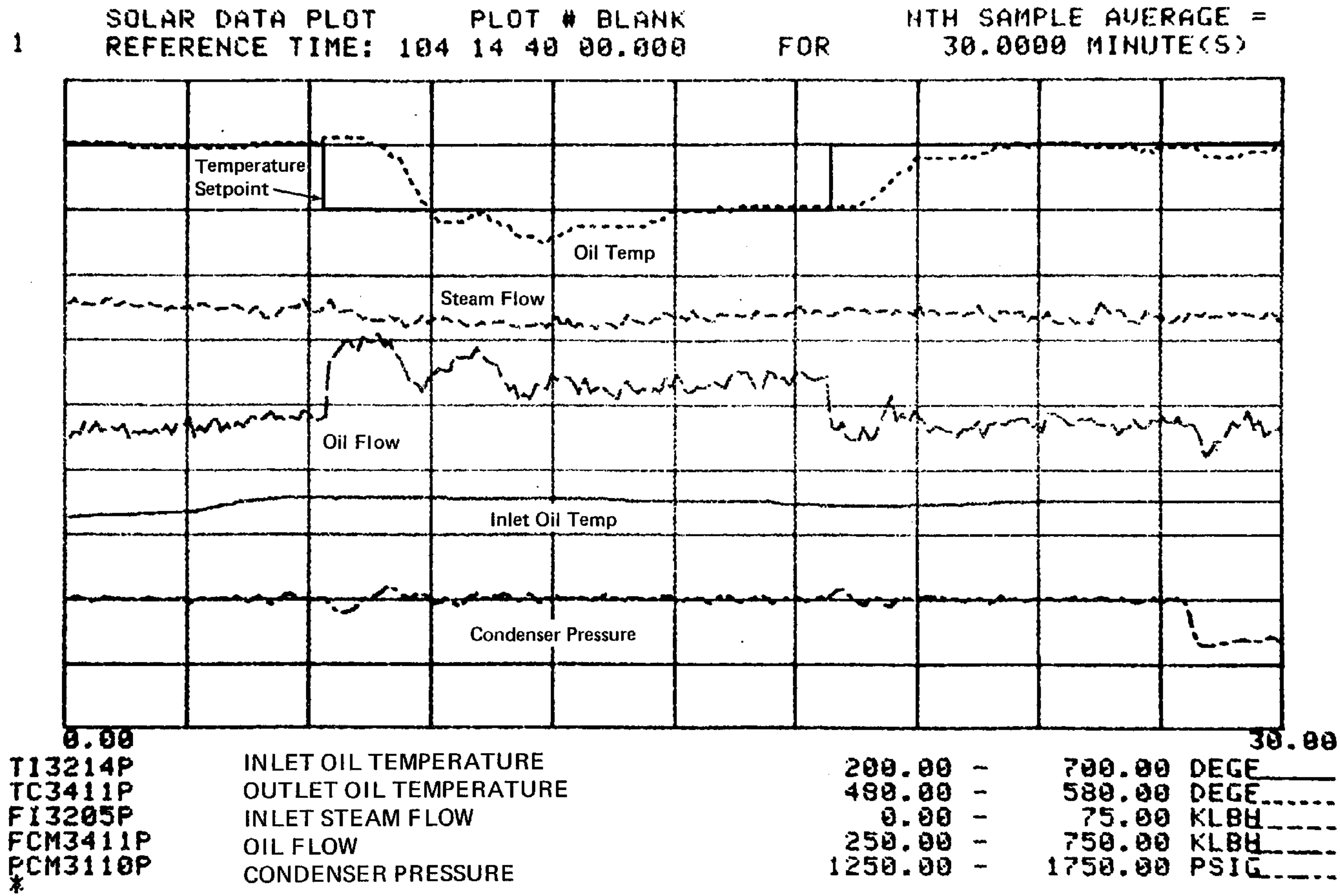


Figure 5.5-10. Charging Oil Temperature Step Response — High Flow Rate (Day 104/Setpoint 570→560→570°F)

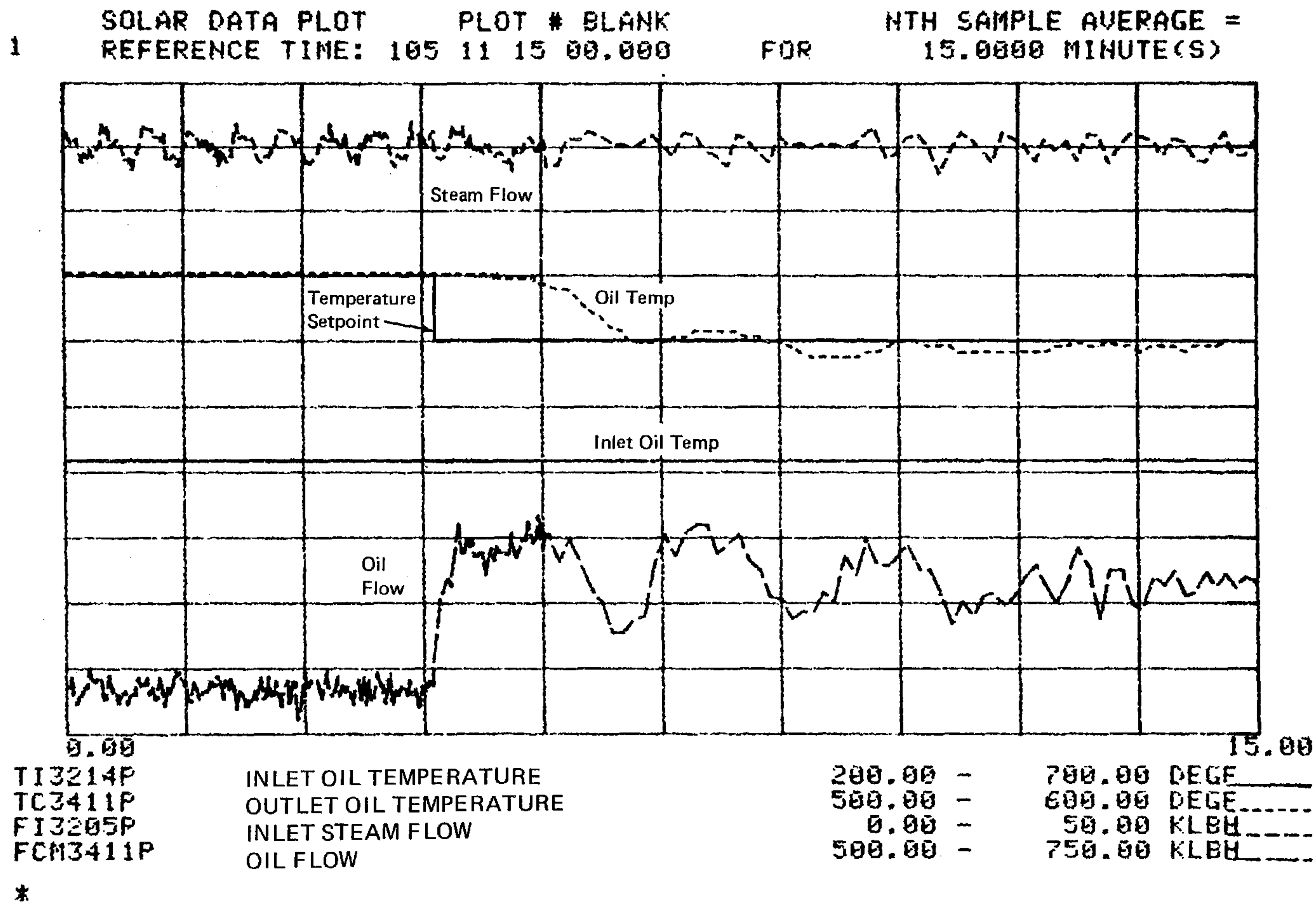


Figure 5.5-11. Charging Oil Temperature Step Response — High Flow Rate (Day 105/Setpoint 570→560°F)

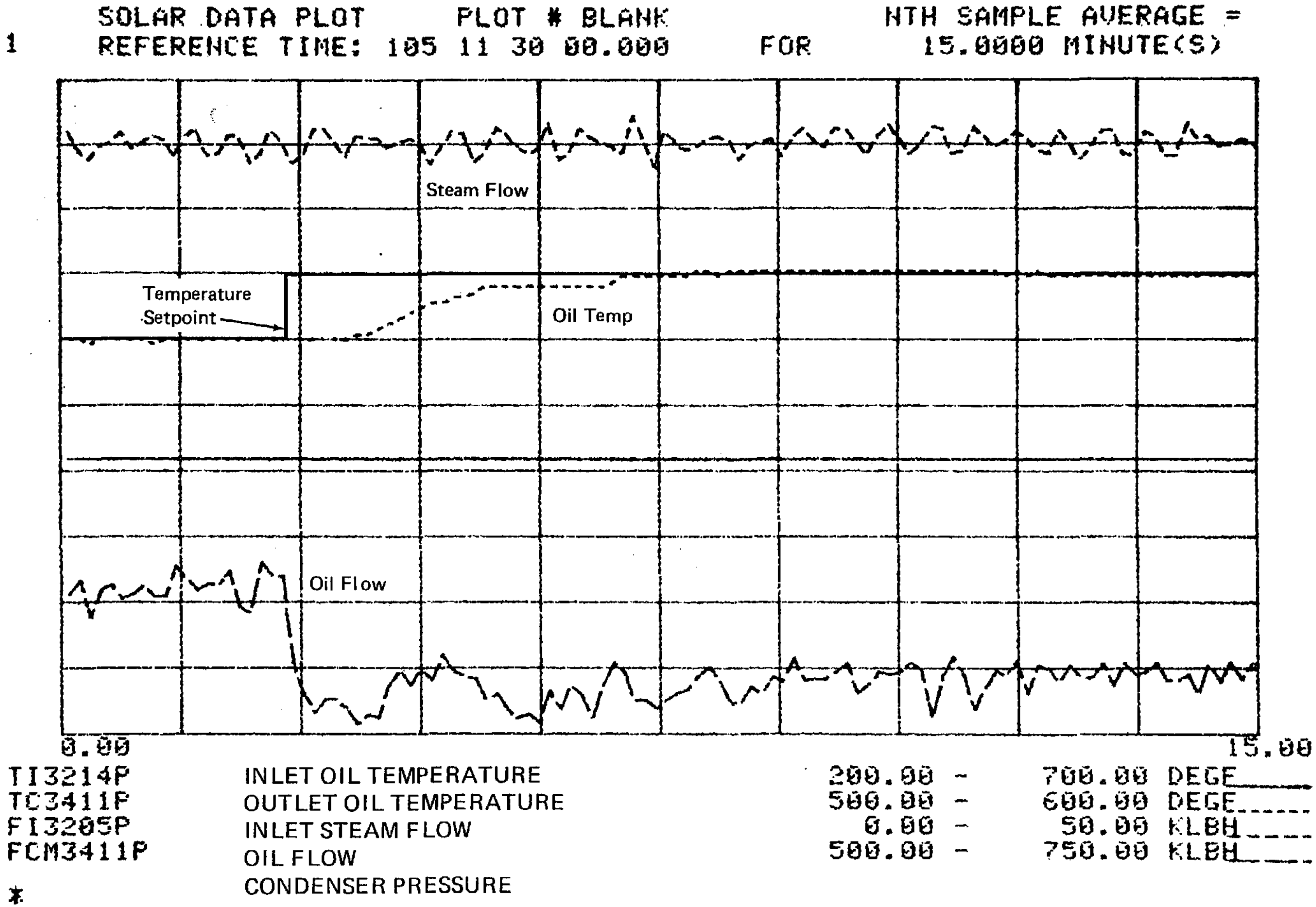


Figure 5.5-12. Charging Oil Temperature Step Response — High Flow Rate (Day 105/Setpoint 560→570°F)

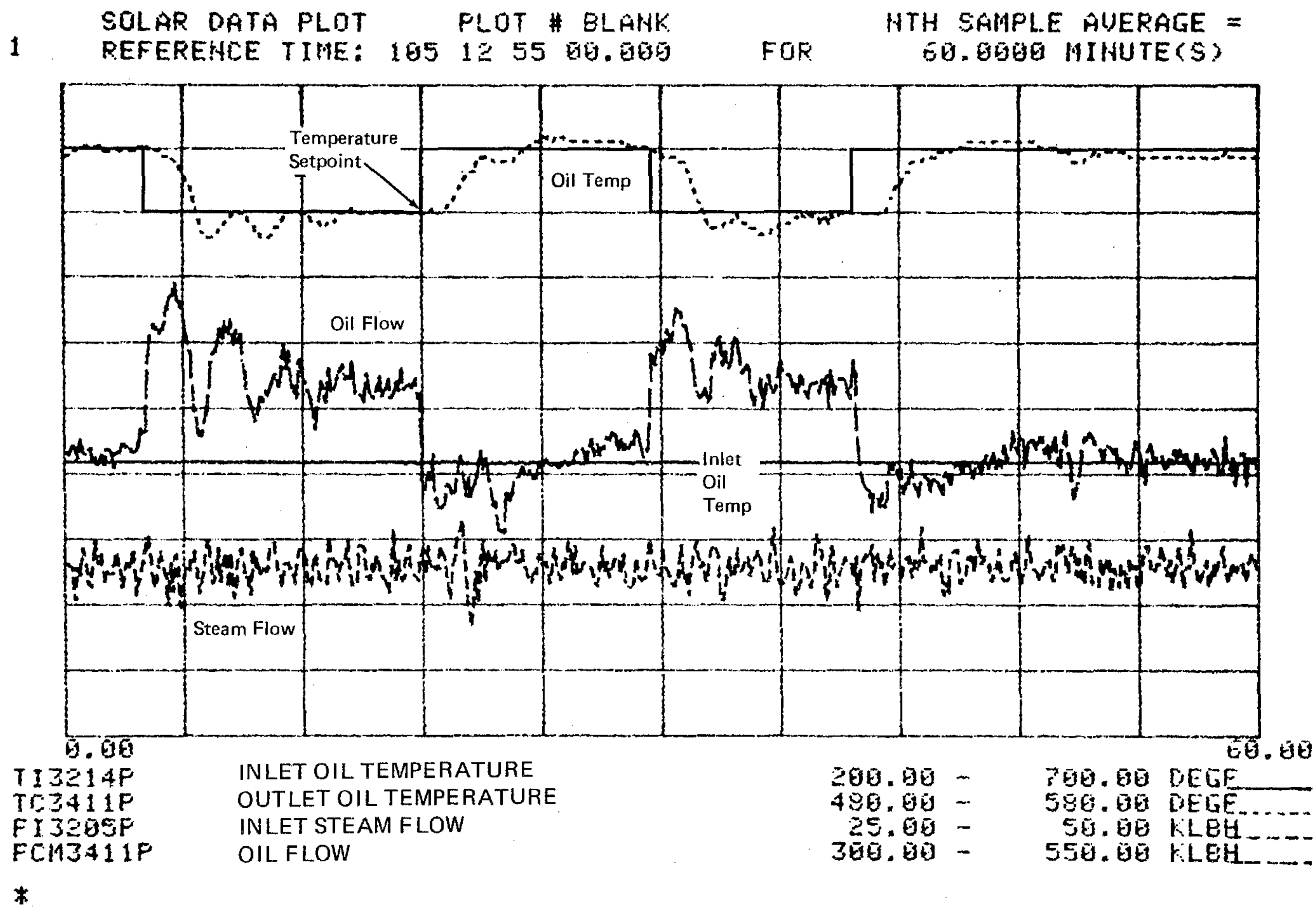
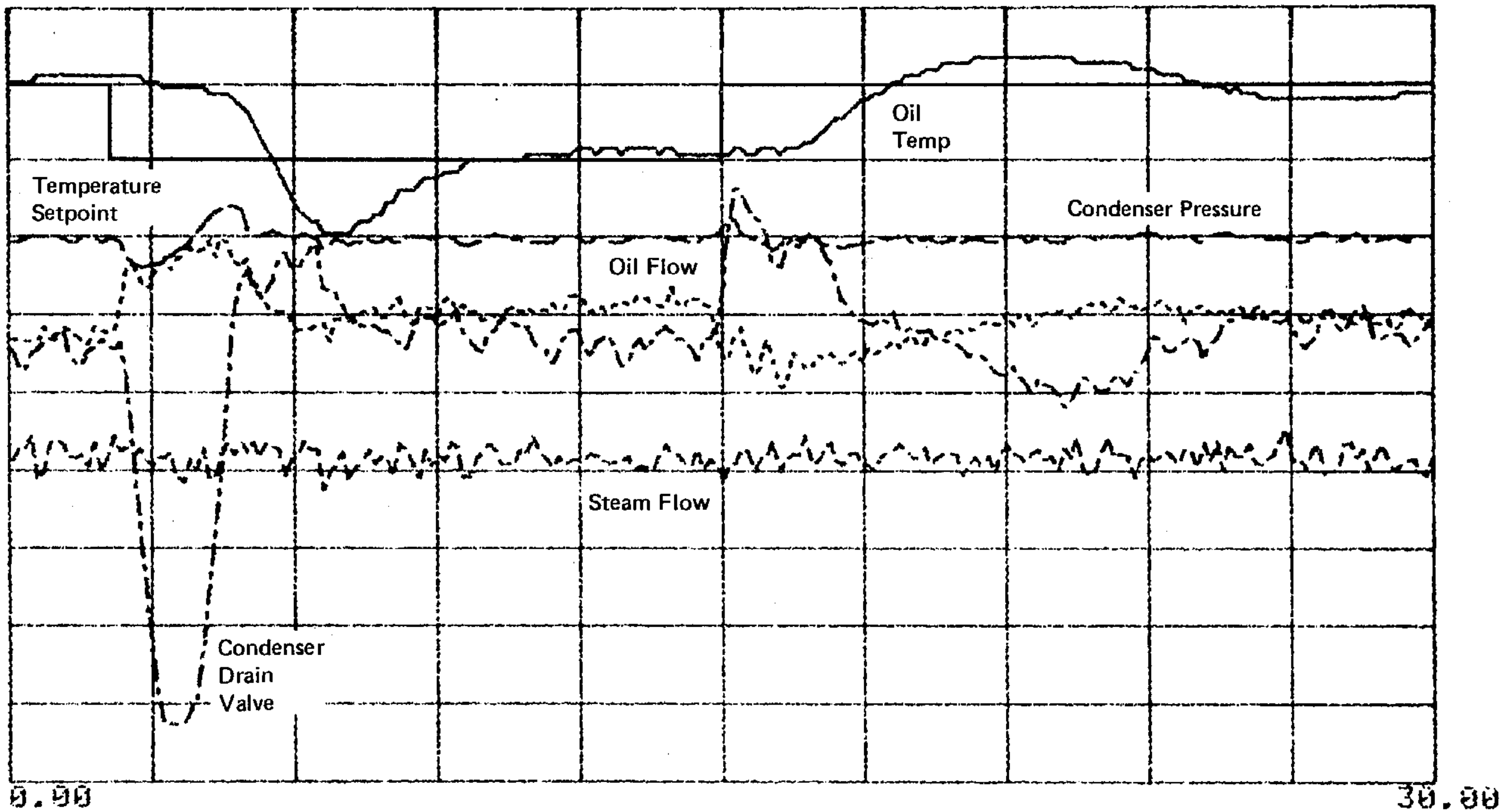


Figure 5.5-13. Charging Oil Temperature Step Response — Medium Flow Rate (Day 105/Setpoint 570→560→570→560→570°F)

SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE =

1 REFERENCE TIME: 125 09 25 00.000 FOR 30.0000 MINUTE(S)



TC3411P	OUTLET OIL TEMPERATURE	480.00	-	580.00	DEGF
FCM3411P	OIL FLOW	0.00	-	500.00	KLBH
FI3205P	INLET STEAM FLOW	0.00	-	50.00	KLBH
PCM3110P	CONDENSER PRESSURE	1000.00	-	1500.00	PSIG
ZI3110P	VALVE POSITION	0.00	-	100.00	PCT

*

Figure 5.5-14. Charging Oil Temperature Step Response — Low Flow Rate (Day 125/Setpoint 570→560→570°F)

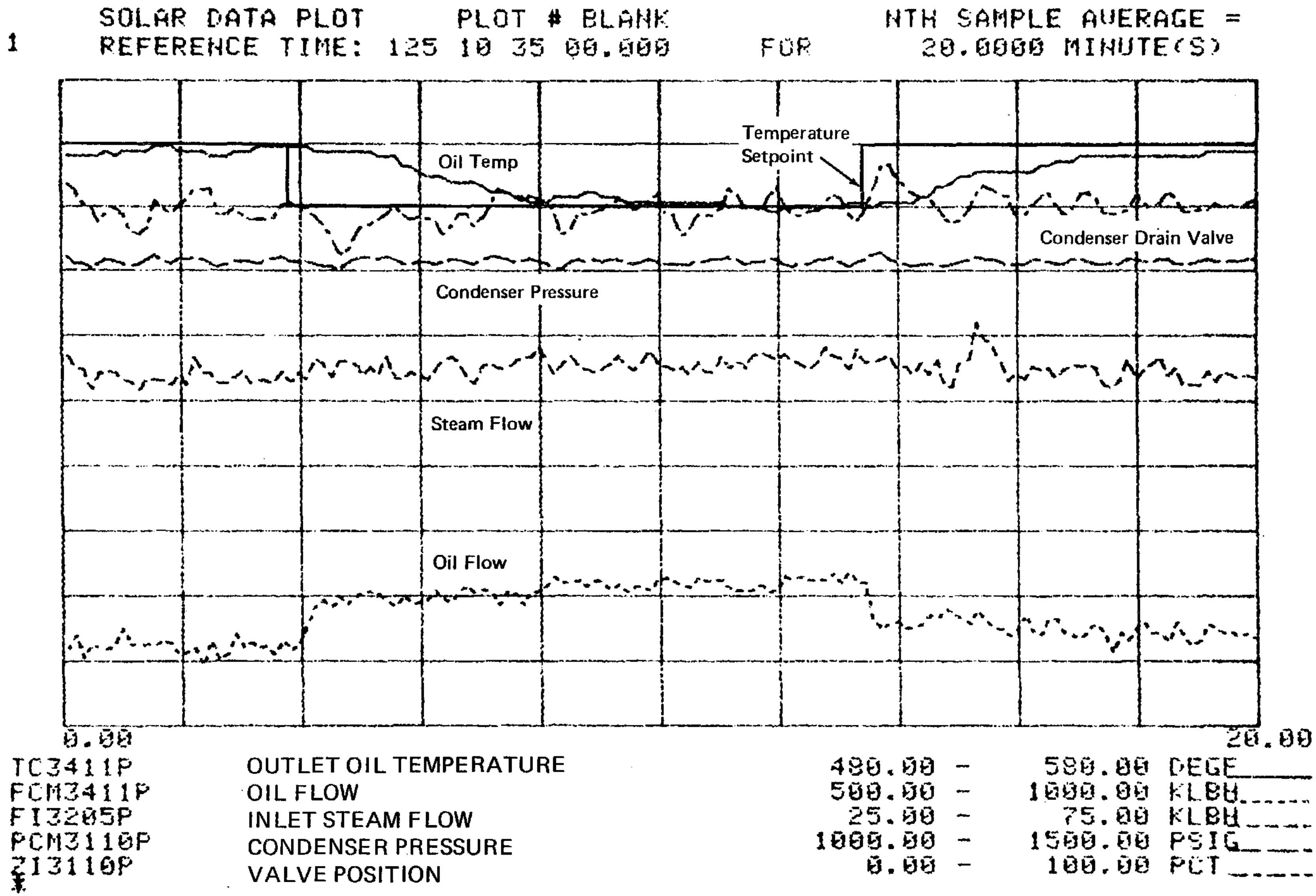


Figure 5.5-15. Charging Oil Temperature Step Response — High Flow Rate (Day 125/Setpoint 570→560→570°F)

in oil flow rate, and 2) the increase or decrease in the temperature differential between the oil and metal as the setpoint changes.

Another characteristic of the oil temperature response to setpoint changes is the increase in overshoot as the oil/steam flow rates decrease. The overshoot at the lowest oil flow rate tested (Figure 5.5-14) is 10°F on the step down from 570°F to 560°F, and is approximately 4°F on the step up to 570°F. At the high flow rate condition (Figure 5.5-15), the temperature response is well damped and does not overshoot in either direction. This difference in response, as mentioned in the linear stability analysis discussion, is due to the faster process response (less phase lag) at the higher flow rates which results in improved stability margins and higher bandwidth. Reduction of the loop gain as the flow decreases (variable gain) was implemented in an attempt to compensate for the process variation with flow. However, this resulted in a positive feedback loop in which any increase in oil flow rate resulted in a gain increase which further increased the flow. Consequently, the variable gain as a function of oil flow rate was eliminated. Ramping instead of stepping the oil temperature setpoint will minimize the overshoot for setpoint changes, but will still be present in response to disturbances as discussed in the following paragraphs.

Closed loop tests to determine the capability of the Charging Oil Temperature controller to reject disturbances were conducted for both simulated clouds (power off/on or flow setpoint changes) and actual clouds. Table 5.5-2 summarizes all of the disturbance tests conducted including the test day, type of control of the TSS main steam inlet valve (UV3102) and, in some cases, the steam/oil flow rate conditions. Representative response data for tests conducted on Days 105 and 125 are shown in Figures 5.5-16 through 5.5-23. On Day 105, a cloud was simulated twice by ramping the steam flow setpoint on the main inlet valve controller, FC3102, from 48 KLBH to 24 KLBH and back to 48 KLBH. The oil temperature and condenser pressure responses are shown in Figure 5.5-16 for two 50% simulated clouds with a 30-second ramp, 10 minutes apart. The oil temperature deviation from the 570°F setpoint is approximately -15°F and +5°F for both clouds, which is within acceptable bounds. The disturbance response to a series of actual clouds lasting approximately 1 hour 45 minutes is shown in Figures 5.5-17 through 5.5-23 with

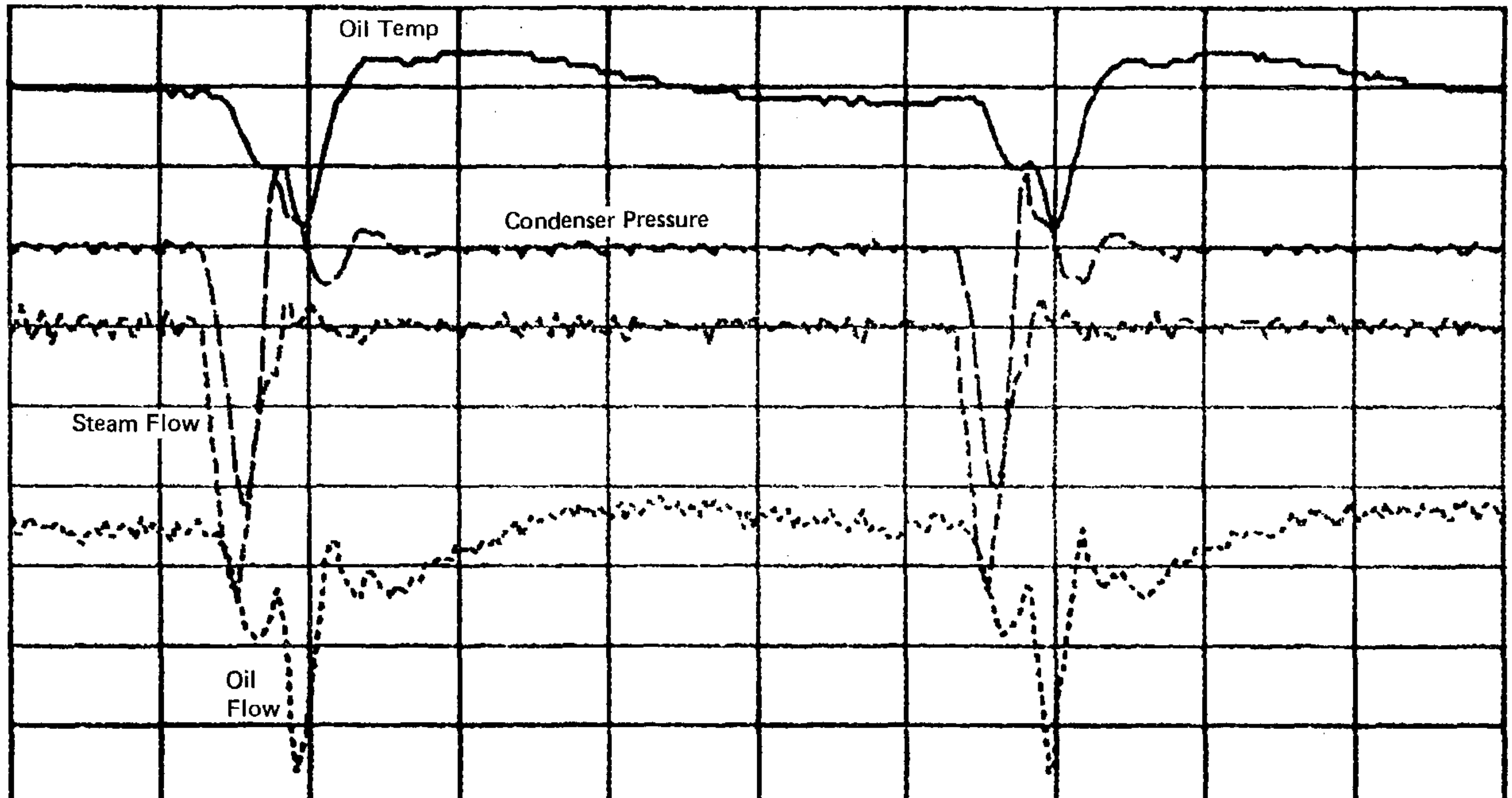
Table 5.5-2. Closed Loop Disturbance Response Tests
Charging Oil Temperature Controller - TC3411 (Page 1 of 2)

Test Day	Time Slice Begins	UV3102 Control	(LBH) Steam Flow	(LBH) Oil Flow	Disturbance
103	14:19	Flow	26K	275K	60% simulated cloud (FC3102SP ramp 26K → 11K → 26K)
105	12:06	Flow	48K	500K	50% simulated cloud (FC3102SP ramp 48K → 24K → 48K)
105	12:26	Flow	48K	500K	50% simulated cloud (FC3102SP ramp 48K → 24K → 48K)
105	14:08	Flow	35K	400K	50% simulated cloud (FC3102SP ramp 35K → 17K → 35K)
105	14:21	Flow	35K	400K	50% simulated cloud (FC31025P ramp 35K → 17K → 35K)
123	12:05	Flow	58K	500K	Simulated Cloud (FC3102SP 50K → 30K → 58K)
125	10:58	Pressure	55K	550K	Small cloud
125	11:08	Pressure	55K	550K	50% simulated cloud (Rings 2 & 4 off)
125	11:19	Pressure	55K	550K	Actual cloud
125	11:22	Pressure	55K	550K	Actual cloud
125	11:38	Pressure	55K	550K	Small clouds
125	13:25 to	Load	30K	350K	Series of clouds
125	15:10	Load	30K	350K	Series of clouds

Table 5.5-2. Closed Loop Disturbance Response Tests
Charging Oil Temperature Controller - TC3411 (Page 2 of 2)

Test Day	Time Slice Begins	UV3102 Control	(LBH) Steam Flow	(LBH) Oil Flow	Disturbance
131	11:16	Pressure	65K	Unknown	Simulated cloud (Ring 2 off/on)
131	11:53	Pressure	65K	Unknown	Simulated cloud (2 rings off/on)
131	13:06	Flow	60K	Unknown	FC3102SP step 60K → 50K → 60K
131	16:27	Pressure	60K	Unknown	Simulated cloud (1 ring off/on)
131	16:36	Pressure	50K	Unknown	Simulated cloud (2 rings off/on)
132	11:52	Load (SP=4.2 MWT)	Unknown	Unknown	Simulated cloud (Ring 2 off/on)
	12:16	Load (SP=5.2 MWT)	Unknown	Unknown	Simulated cloud (Ring 2 off/on)

1 SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE =
REFERENCE TIME: 105 12 00 00.000 FOR 40.0000 MINUTE(S)



0.00 40.00

TC3411P	OUTLET OIL TEMPERATURE	480.00	-	580.00	DEGF
FCM3411P	OIL FLOW	350.00	-	850.00	KLBH
FI3205P	INLET STEAM FLOW	0.00	-	75.00	KLBH
PCM3110P	CONDENSER PRESSURE	1000.00	-	1500.00	PSIG

*

Figure 5.5-16. Charging Oil Subsystem Disturbance Response — Simulated Cloud — High Flow

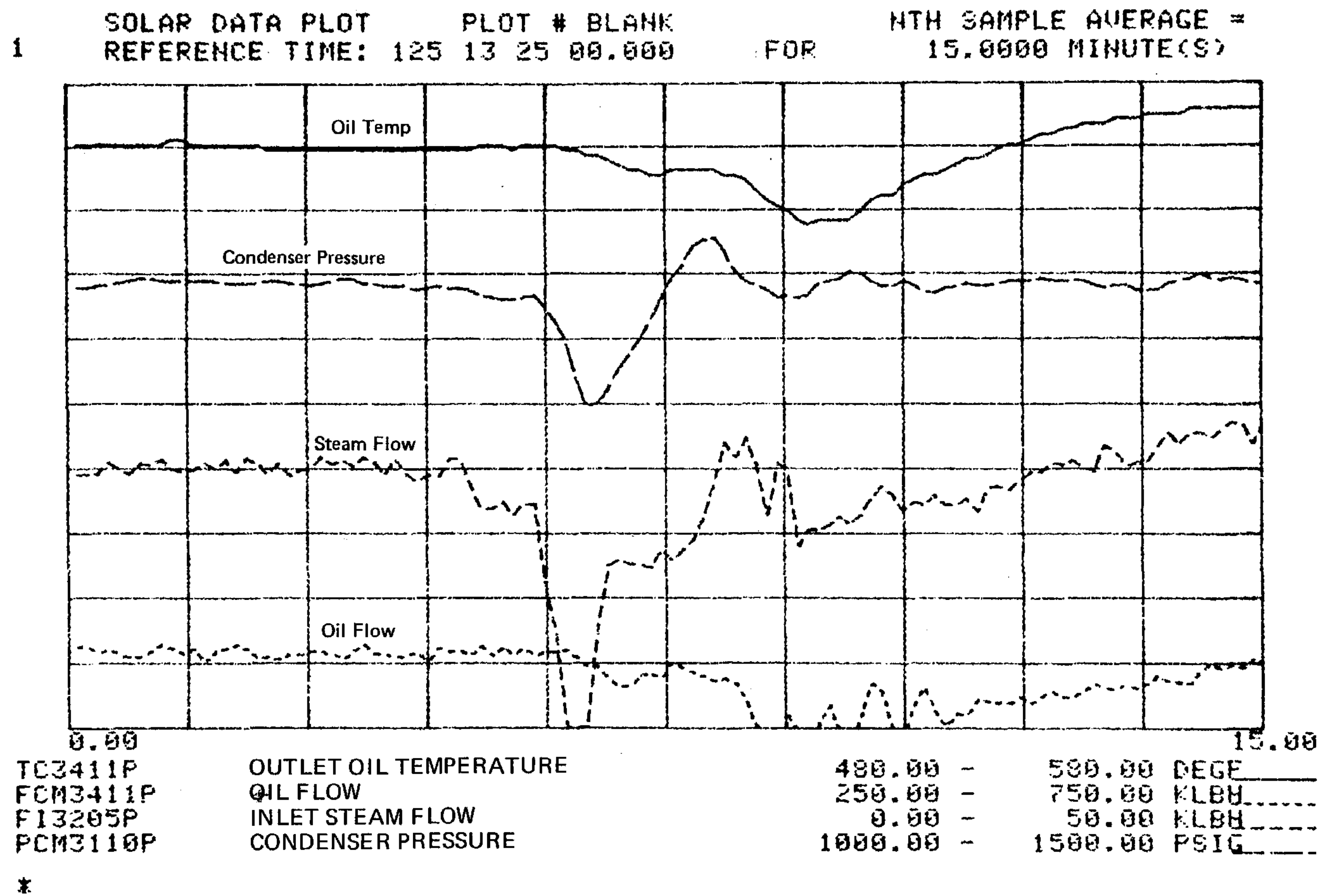
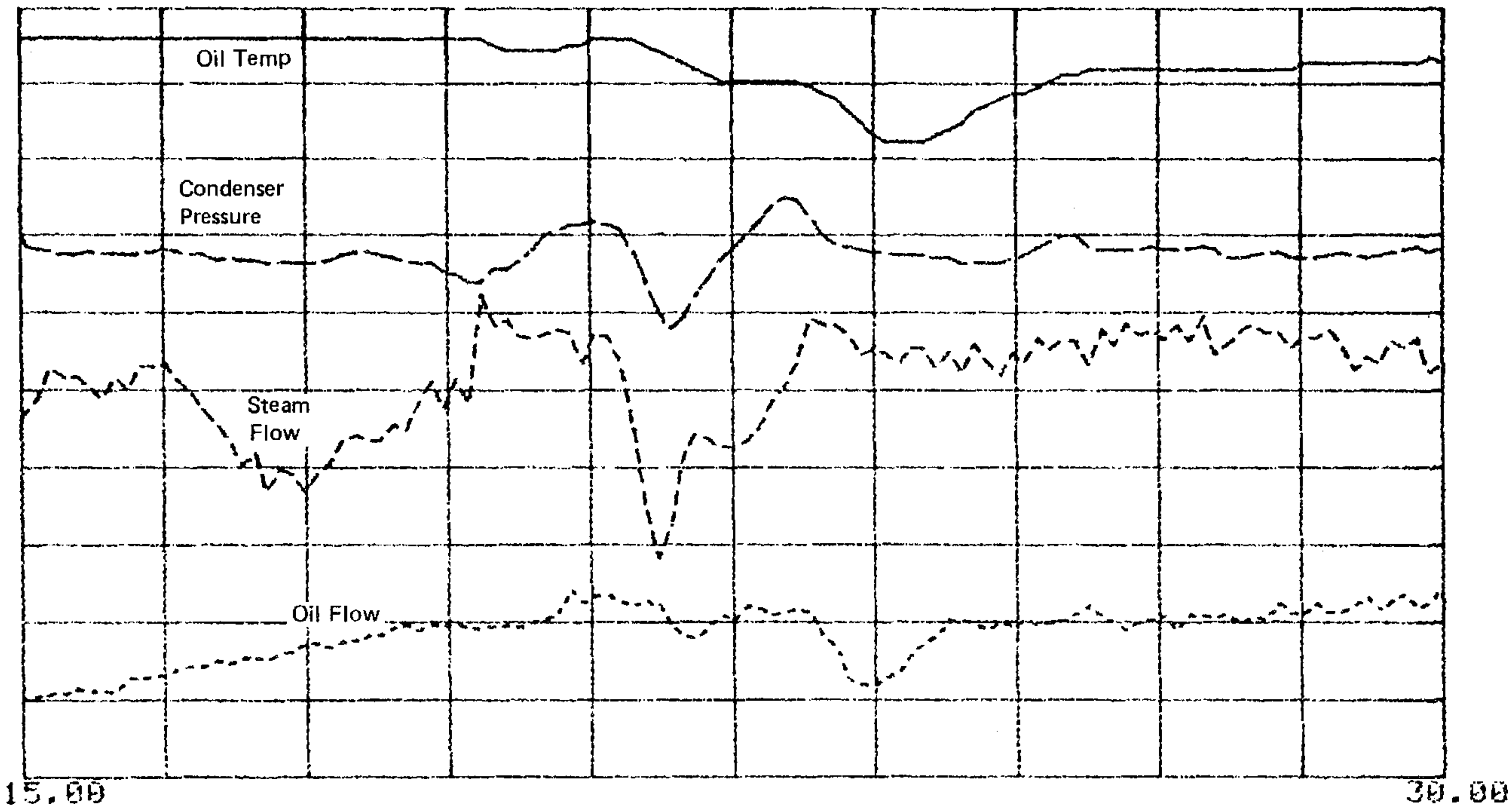


Figure 5.5-17. Charging Oil Subsystem Disturbance Response to Clouds — 1st Time Segment

SOLAR DATA PLOT   PLOT # BLANK   NTH SAMPLE AVERAGE =
REFERENCE TIME: 125 13 25 00.000   FOR   15.0000 MINUTE(S)

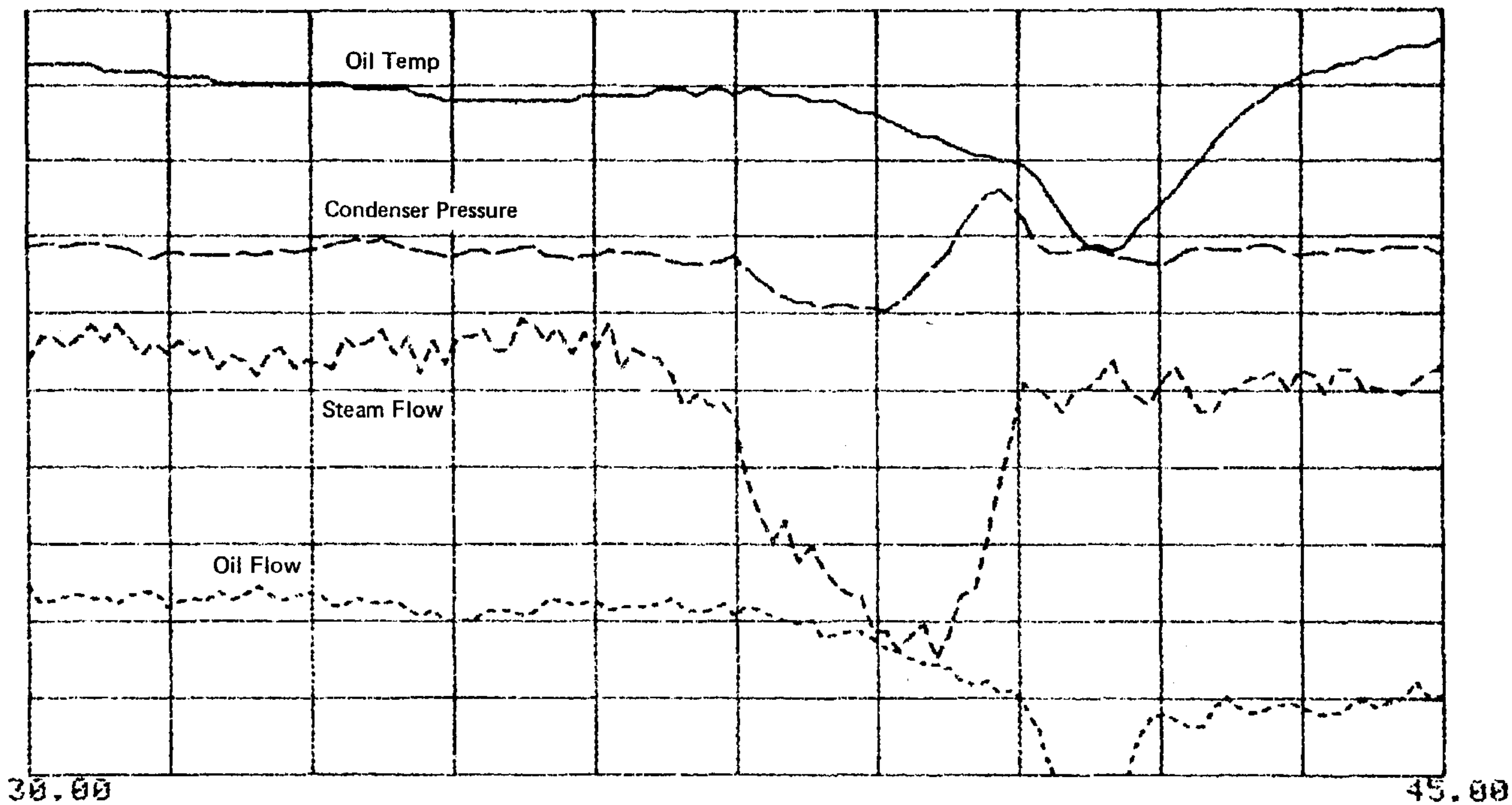


TC3411P	OUTLET OIL TEMPERATURE	480.00 –	580.00	DEGF _____
FCM3411P	OIL FLOW	250.00 –	750.00	KLBH .....
FI3205P	INLET STEAM FLOW	0.00 –	50.00	KLBH _ _ _ _
PCM3110P	CONDENSER PRESSURE	1000.00 –	1500.00	PSIG _._._.

*

Figure 5.5-18. Charging Oil Subsystem Disturbance Response to Clouds — 2nd Time Segment

SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE =
REFERENCE TIME: 125 13 25 00.000 FOR 15.0000 MINUTE(S)

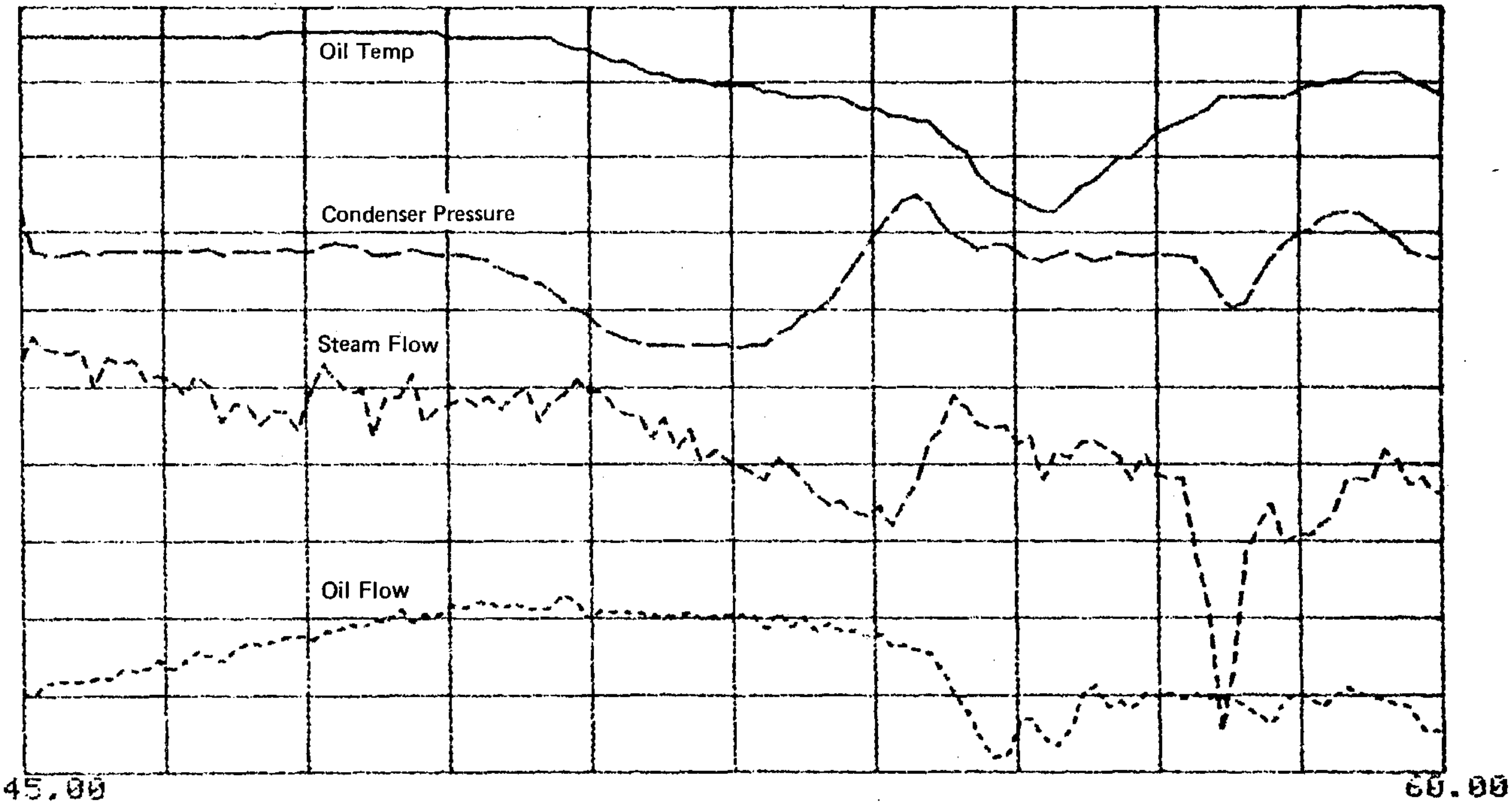


TC3411P	OUTLET OIL TEMPERATURE	480.00 -	580.00 DEGF
FCM3411P	OIL FLOW	250.00 -	750.00 KLBH
FI3205P	INLET STEAM FLOW	0.00 -	50.00 KLBH
PCM3110P	CONDENSER PRESSURE	1000.00 -	1500.00 PSIG

*

Figure 5.5-19. Charging Oil Subsystem Disturbance Response to Clouds — 3rd Time Segment

SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE =
REFERENCE TIME: 125 13 25 00.000 FOR 15.0000 MINUTE(S)



TC3411P	OUTLET OIL TEMPERATURE	480.00 -	580.00	DEGF ____
FCM3411P	OIL FLOW	250.00 -	750.00	KLBH ......
FI3205P	INLET STEAM FLOW	0.00 -	50.00	KLBH _ _ _ _
PCM3110P	CONDENSER PRESSURE	1000.00 -	1500.00	PSIG _ __ _

*

Figure 5.5-20. Charging Oil Subsystem Disturbance Response to Clouds — 4th Time Segment

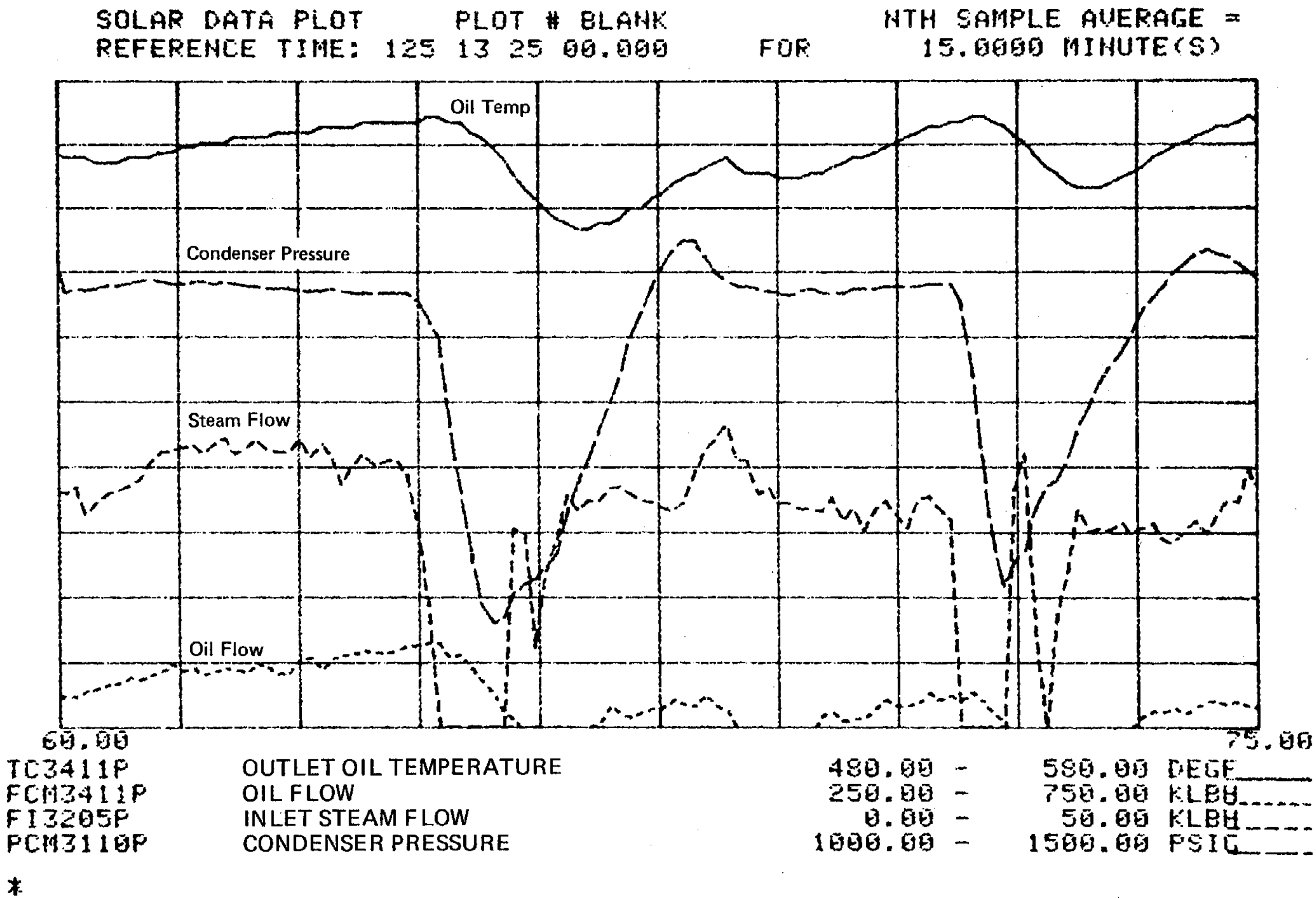
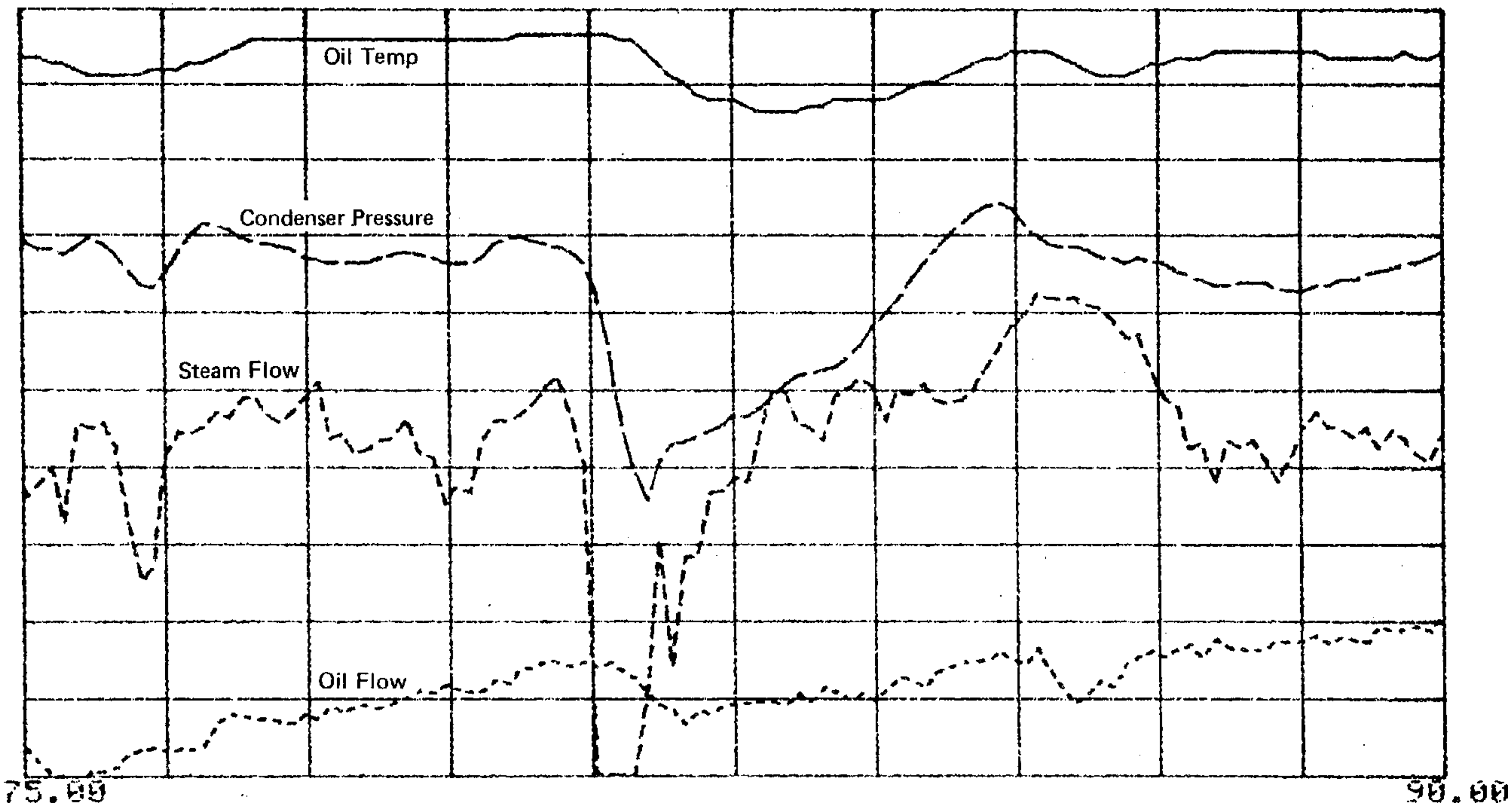


Figure 5.5-21. Charging Oil Subsystem Disturbance Response to Clouds — 5th Time Segment

SOLAR DATA PLOT   PLOT # BLANK   NTH SAMPLE AVERAGE =
REFERENCE TIME: 125 13 25 00.000   FOR   15.0000 MINUTE(S)

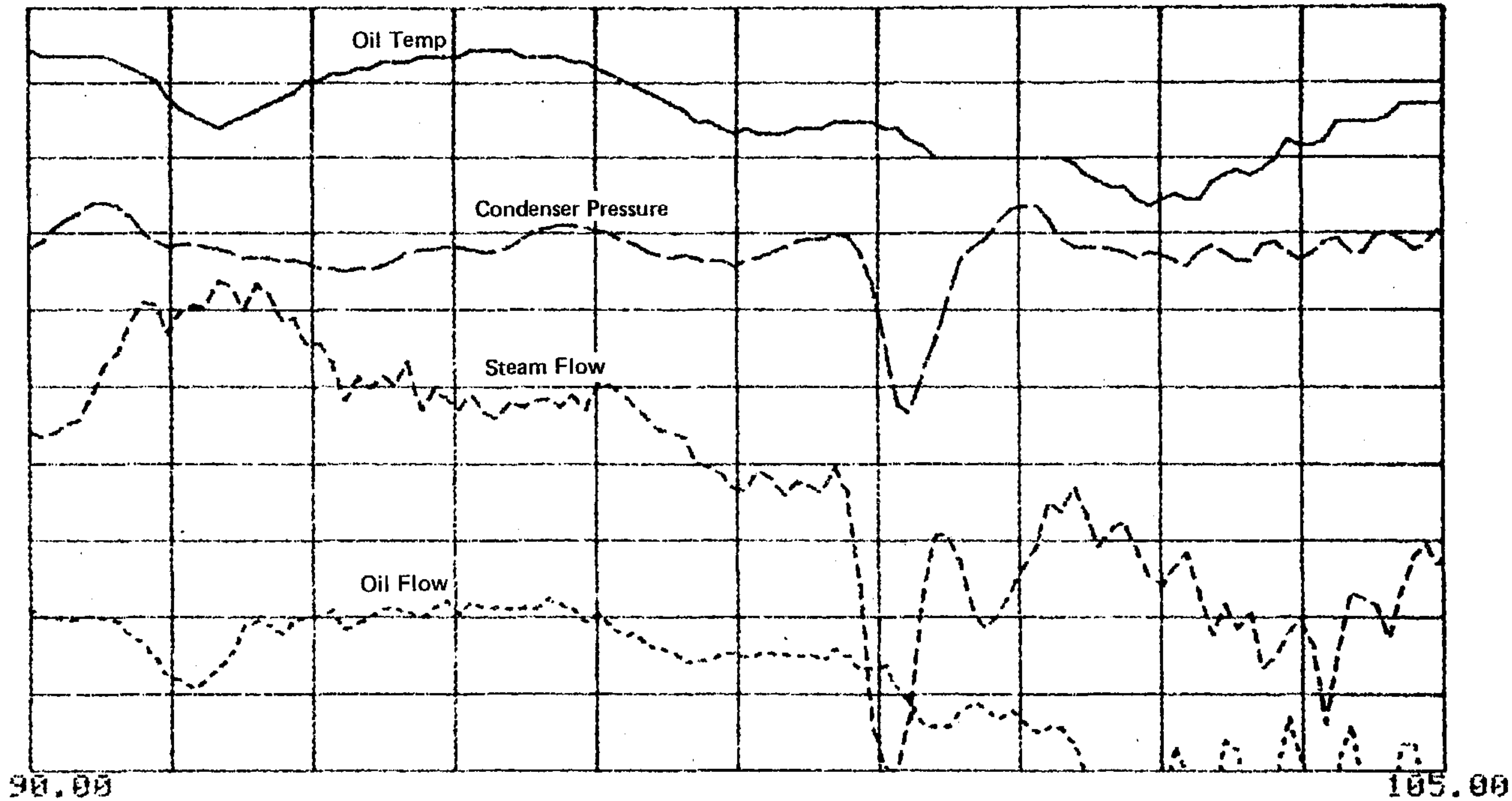


TC3411P	OUTLET OIL TEMPERATURE	480.00 -	580.00	DEGF
FCM3411P	OIL FLOW	250.00 -	750.00	KLBH
FI3205P	INLET STEAM FLOW	0.00 -	50.00	KLBH
PCM3110P	CONDENSER PRESSURE	1000.00 -	1500.00	PSIG

*

Figure 5.5-22. Charging Oil Subsystem Disturbance Response to Clouds — 6th Time Segment

SOLAR DATA PLOT   PLOT # BLANK   NTH SAMPLE AVERAGE =
REFERENCE TIME: 125 13 25 00.000   FOR   15.0000 MINUTE(S)



TC3411P	OUTLET OIL TEMPERATURE	480.00 -	580.00	DEGF
FCM3411P	OIL FLOW	250.00 -	750.00	KLBH
FI3205P	INLET STEAM FLOW	0.00 -	50.00	KLBH
PCM3110P	CONDENSER PRESSURE	1000.00 -	1500.00	PSIG

*

Figure 5.5-23. Charging Oil Subsystem Disturbance Response to Clouds – 7th Time Segment

UV3102 in load control. In this mode, the load is maintained constant if possible by reducing the charging steam flow as the total flow is reduced due to cloud induced insolation loss. For these tests, the load setpoint ranged from 4.3 to 3.8 MWT. The oil temperature deviation for these repeated disturbances, including some in which the charging steam flow is reduced to zero, is maintained within a range of approximately -22°F to +7°F about the 570°F setpoint. These excursions are also considered to be within acceptable bounds.

5.6 CHARGING LOOP CONDENSER CONTROL TESTS

The condenser inlet pressure of each of the two charging trains is controlled by modulating the condensate drain valves, PV3110 and PV3111, between the TSS subcoolers and the TSS flash tank. For purposes of this discussion, only Train 1 will be described here. Redundant measurements of the Train 1 condenser inlet pressure PI3210A and PI3210B are high selected for reliability and compared to the pressure setpoint, as shown in the functional block diagram, Figure 5.6-1. The condenser pressure setpoint, PY1001 into MVCU 2-4, is derived from the commanded steam dump system pressure PC1001 which is biased down by 100 psi in MVCU 2-5. As the receiver outlet pressure is ramped up or down, the condenser pressure setpoint will automatically track it to maintain a differential pressure across the main steam inlet valve, UV3102, of 100 psi. At rated RS pressure of 1450 psi, the condenser pressure setpoint is 1350 psi. As discussed previously, the differential pressure was increased during 1040B testing from 50 psi to 100 psi to reduce the TSS steam flow sensitivity to condenser pressure variations.

Difficulty in controlling condenser pressure with the original installed drain valve trims was also encountered. The maximum C_V trims of the PV3110 and PV3111 drain valves, were changed from 4.7 to 7.4 during the 1040B test program. This 50% increase in condensate flow capability along with the increase in differential pressure across the TSS main inlet valve reduced the coupling between the steam flow and condenser pressure significantly, allowing tighter control of the condenser pressure.

Closed loop response tests of the PCM3110 condenser pressure controller were conducted with the higher valve trim for steam flow rates ranging from

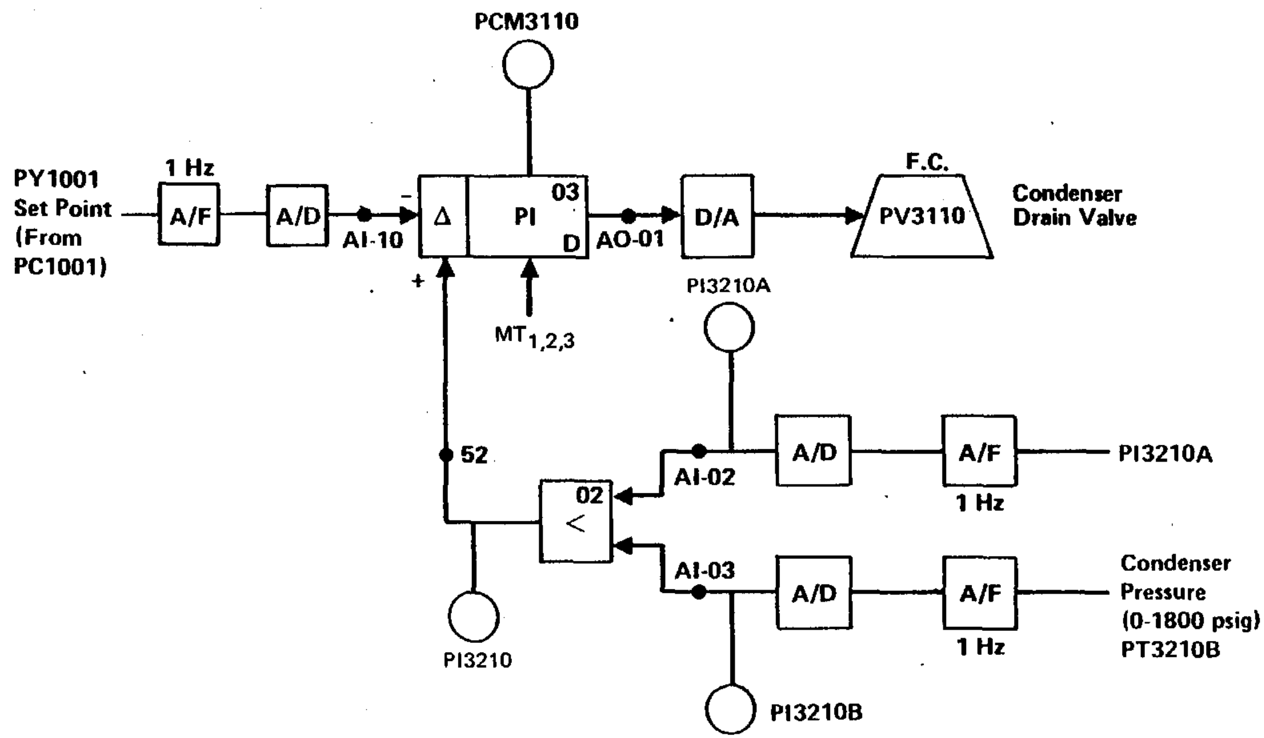


Figure 5.6-1. TSS Charging Loop Condenser Level/Pressure Controller Functional Block Diagram – PCM3110 (Train 1)

approximately 20 KLBH to almost 50 KLBH, the maximum flow expected through a single train. Figures 5.6-2 and 5.6-3 show the closed loop response to a +30 psi pressure setpoint step at high steam flow rate. The condensate drain valve position at this high steam flow rate is approximately 80% open. The large amount of valve authority required to produce a level change in the condenser to control pressure, even with the larger valve trim, is evident from the valve transients. The drain valve swings +20%, -25% in response to the +30 psi pressure step. The pressure response is well damped with no overshoot on the step down and is underdamped with approximately 15 psi overshoot on the setpoint step back up to 1350 psi. The 90% response time is approximately 20 seconds. Figures 5.6-4 and 5.6-5 show the closed loop pressure response at steam flows of 32 KLBH and 20 KLBH, respectively. At the low steam flow rate (Figure 5.6-5) the steady state drain valve position is approximtely 55% and swings +20%, -30% in response to the +30 psi step inputs. The pressure response damping at the lower flow rate is similar to the high flow rate condition, but the 90% response time is significantly slower at approximately 40 seconds. The capability of the pressure controller to adequately suppress disturbances with these response characteristics has been demonstrated and is included in Section 5.5, Figure 5.5-16 through 5.5-23.

5.7 EXTRACTION LOOP CONDENSATE CONTROL TESTS

The condensate level in each of the extraction boilers is maintained by three element controllers via modulating control valves LV3505 (Train 1) and LV3605 (Train 2). Since the two trains are essentially identical only Train 1 will be discussed here. The functional block diagram for the level controller, LC3505, for Train 1 is shown in Figure 5.7-1. This is a standard three element boiler water level controller. The feedwater control valve responds not only to the actual level of water in the boiler (water inventory), but to the demand of steam flow from the boiler and the inflow of feedwater. This makes the boiler level control less susceptible to changes in water level caused by false level due to pressure changes and quick demands for more or less steam flow.

The boiler water level controller outer loop (level sensor) is tuned to react slowly to level disturbances. Figure 5.7-2 shows a level set point step from 44.5 inches to 45.0 inches and back to 44.5 inches; the level response is not rapid. The slow loop response and level overshoot to the set point changes were as expected.

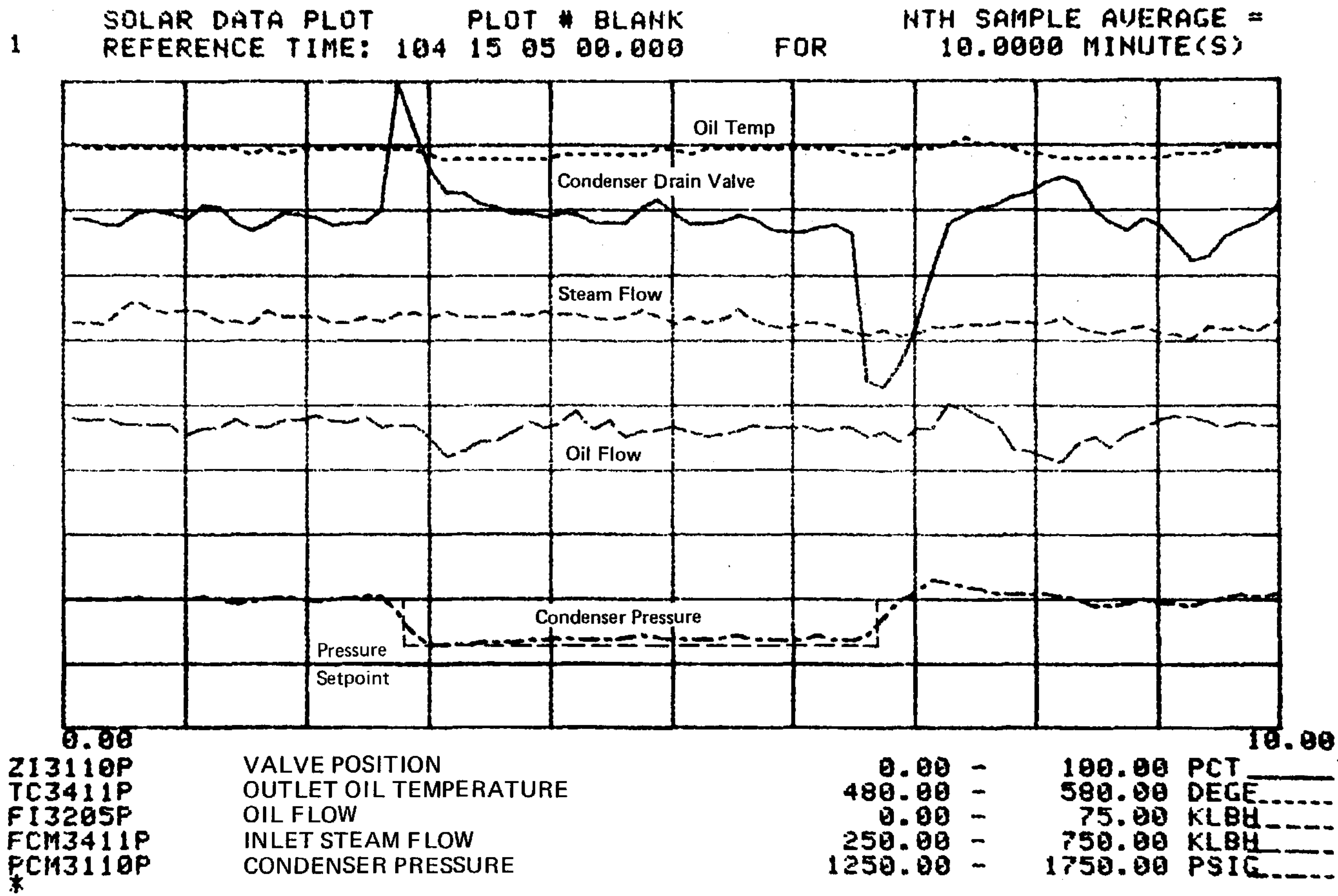


Figure 5.6-2. Condenser Pressure Controller (PCM3110) Setpoint Step Response (Steam Flow = 50 KLBH)

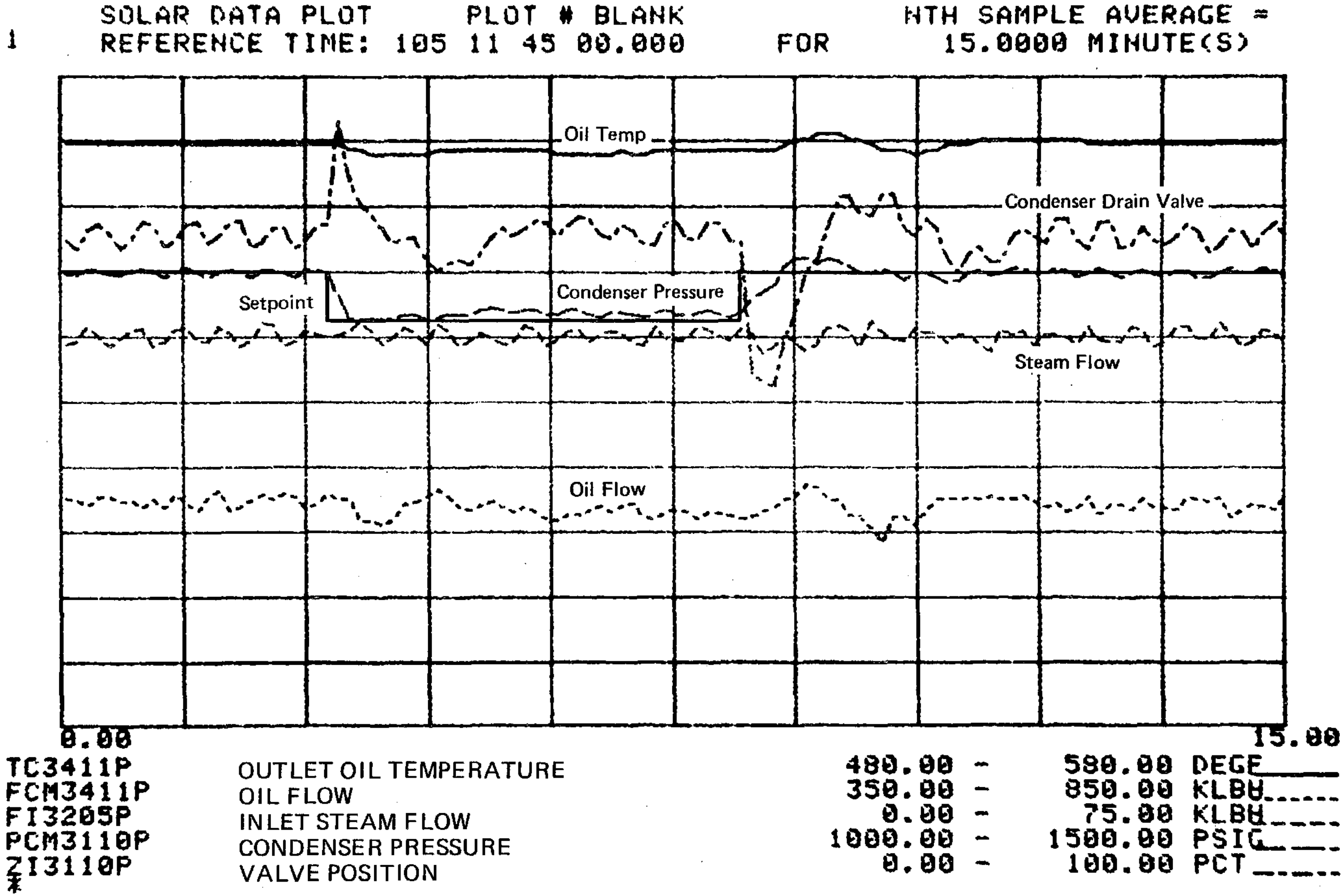
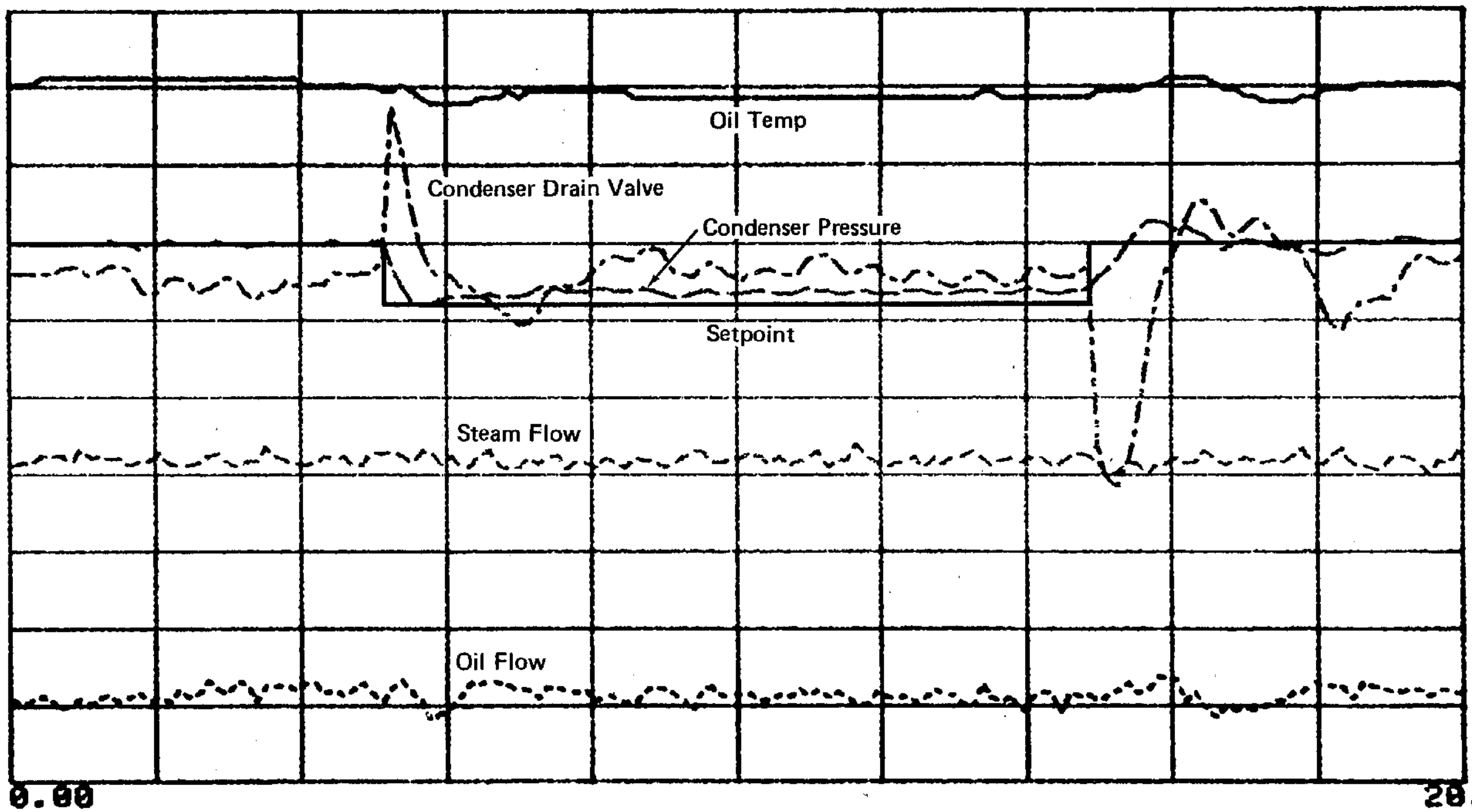


Figure 5.6-3. Condenser Pressure Controller (PCM3110) Setpoint Step Response (Steam Flow = 45 KLBH)

SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE =

1 REFERENCE TIME: 105 13 40 00.000 FOR 20.0000 MINUTE(S)



TC3411P	OUTLET OIL TEMPERATURE	480.00 -	590.00	DEGF
FCM3411P	OIL FLOW	350.00 -	850.00	KLBH
FI3205P	INLET STEAM FLOW	0.00 -	75.00	KLBH
PCM3110P	CONDENSER PRESSURE	1000.00 -	1500.00	PSIG
ZI3110P	VALVE POSITION	0.00 -	100.00	PCT

*

Figure 5.6-4. Condenser Pressure Controller (PCM3110) Setpoint Step Response (Steam Flow = 32 KLBH)

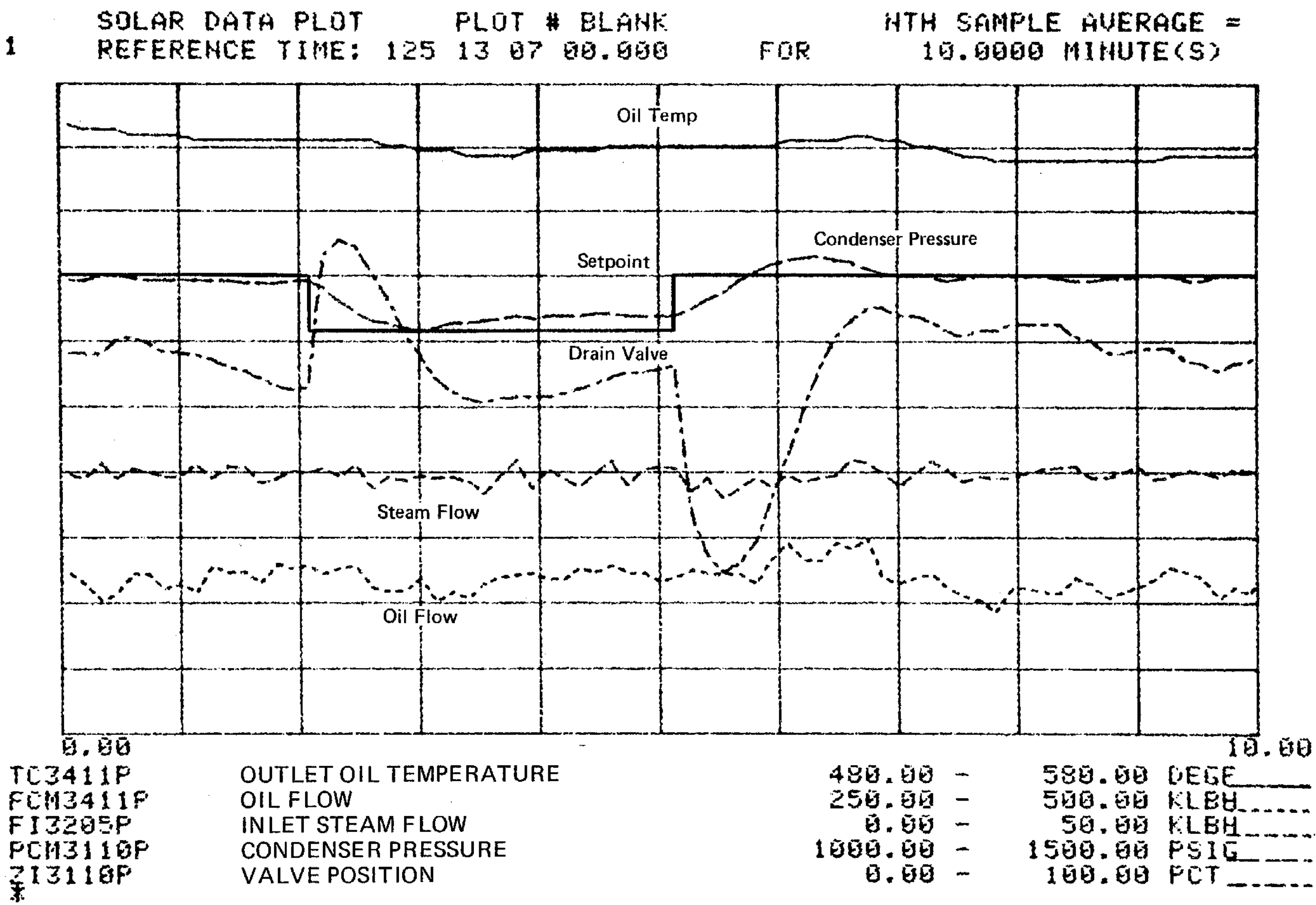


Figure 5.6-5. Condenser Pressure Controller (PCM3110) Setpoint Step Response (Steam Flow = 20 KLBH)

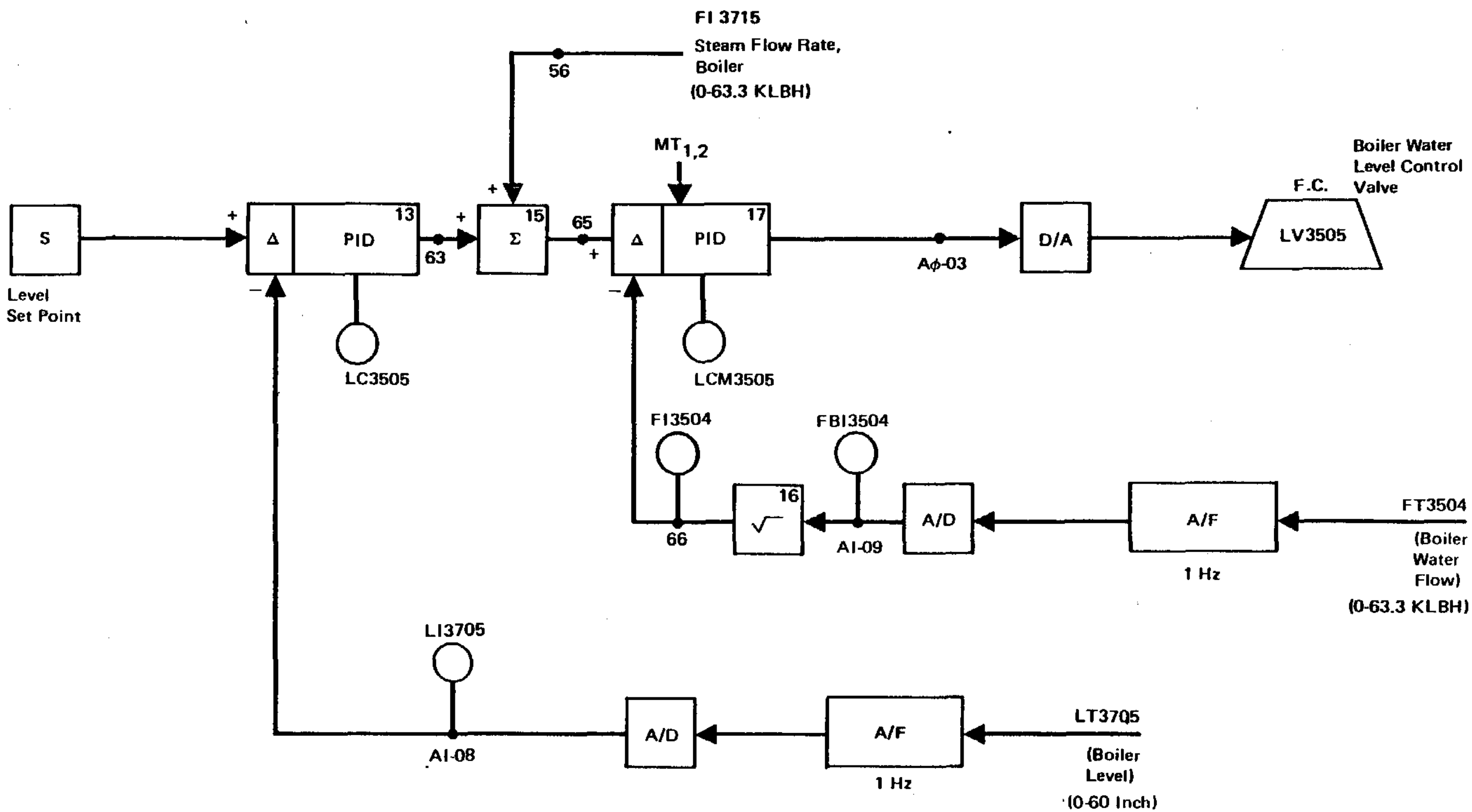


Figure 5.7-1. TSS Extraction Boiler Water Level Controller Functional Block Diagram LC 3505 (Train 1)

MVCU 2-2
Primary Highway 1
Device Address 2

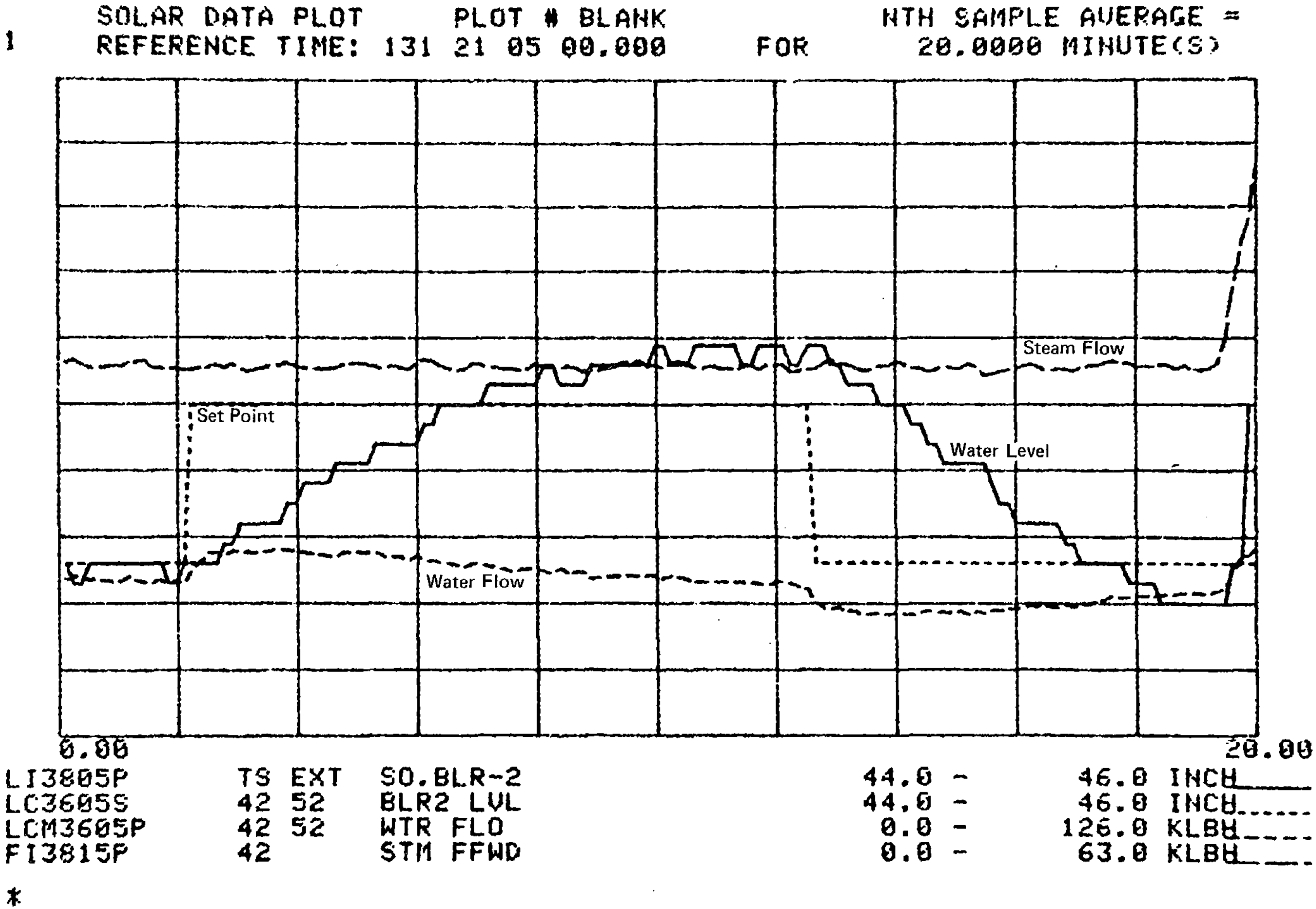


Figure 5.7-2. Extraction Boiler Water Level Set Point Step

5.8 EXTRACTION OIL LOOP CONTROL TESTS

The TSS extraction system is made up of two steam generator trains, each having a boiler, superheater, variable speed oil pump and oil control valves. Since both trains are essentially identical, only train 1 will be discussed here but it should be noted that some of the data presented was gathered during train 2 operation.

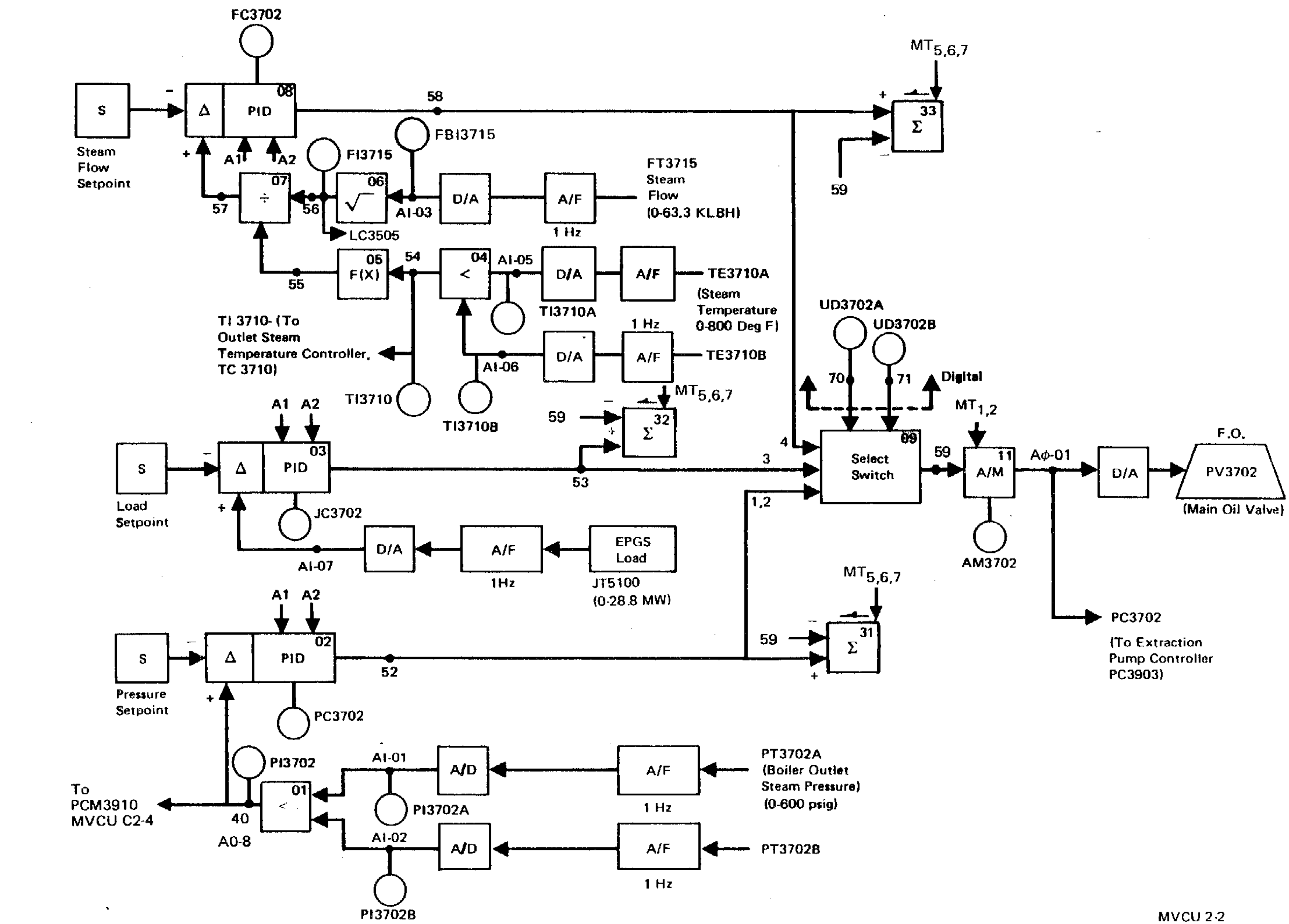
5.8.1 Boiler Oil Control Valve

The functional block diagram for the boiler oil control valve, PC3702, is shown in Figure 5.8-1. The controller, PC3702, has three modes of operation: flow, pressure and load control. In flow control the controller monitors steam mass flow rate which is calculated using steam flow and steam temperature. Any error between the setpoint and the process flowrate will result in a correction of the main oil valve position. In pressure control a single control loop regulates this valve to maintain the boiler outlet steam pressure; in load control the loop regulates the same valve to control the gross electrical output of the turbine generator.

The transfer between control modes is made by selecting digital switches. The switching arrangement of UD3702A/B and UD3802A/B provides for bumpless transfer from one mode to the next (pressure, flow, load). By selecting the correct mode the respective PID controller will switch to auto and the other two will go to manual. A unique feature of this configuration is that the two controllers out of service will have their outputs track the output of the active controller (auto), providing a quick and smooth transition to the next mode whenever it occurs.

Since the extraction system dynamics are less coupled than the charging loops it was determined that closed loop testing would be sufficient for tuning these loops. The following paragraphs present the final data gathered during the test program using set point changes and system disturbances.

Tests incorporating steam flow set point changes were used for tuning gains for flow controller FC3702. A typical response is shown in Figures 5.8-2 and 5.8-3. As can be seen the set point was ramped from 35 KLBH-to-55 KLBH in 30 sec with the system response lagging approximately by 15 sec. The



MVCU 2-2
Primary Highway 1
Device Address 2

Figure 5.8-1. TSS Extraction Main Oil VAlve Controller Functional Block Diagram PC 3702 (Train 1)

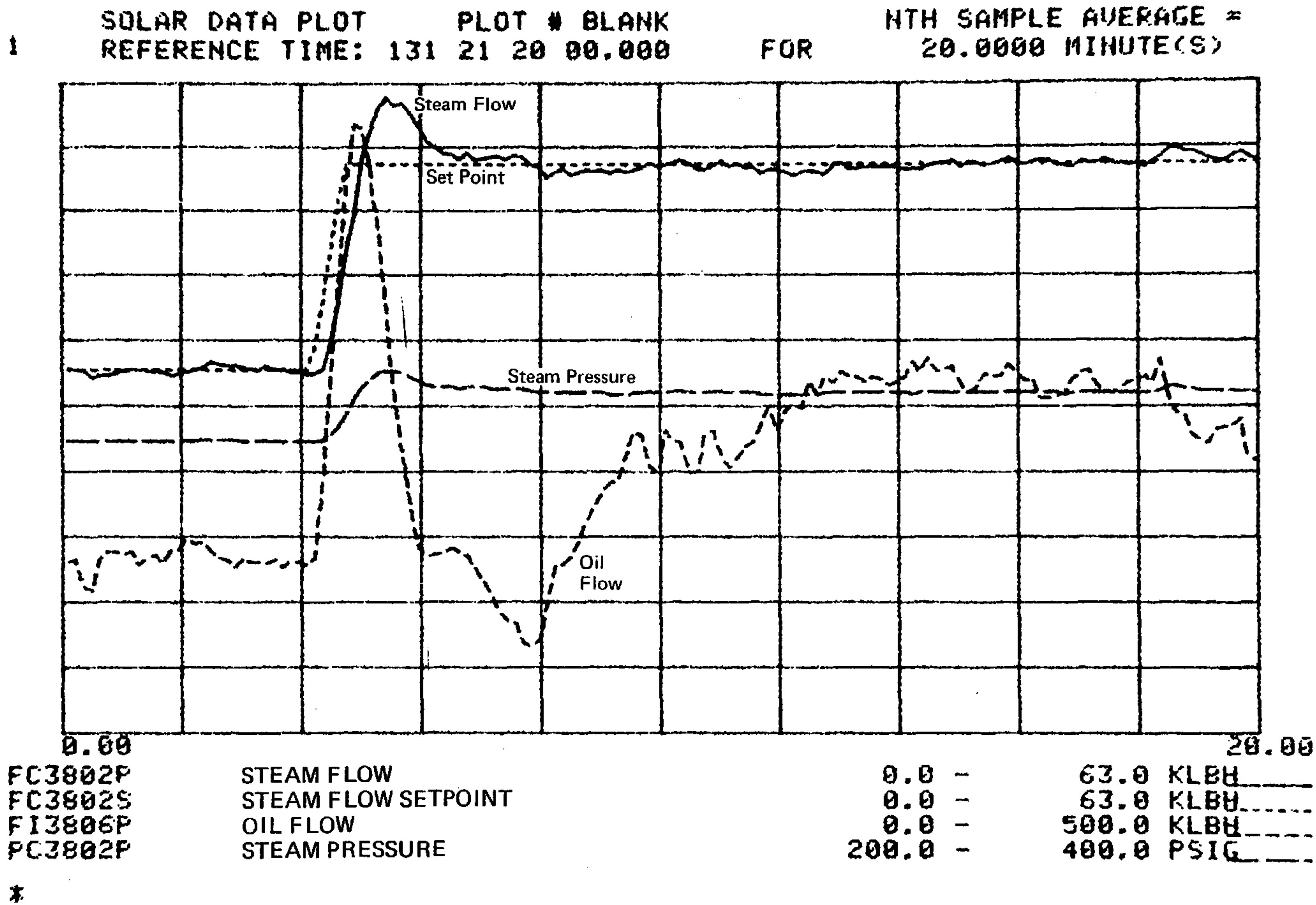
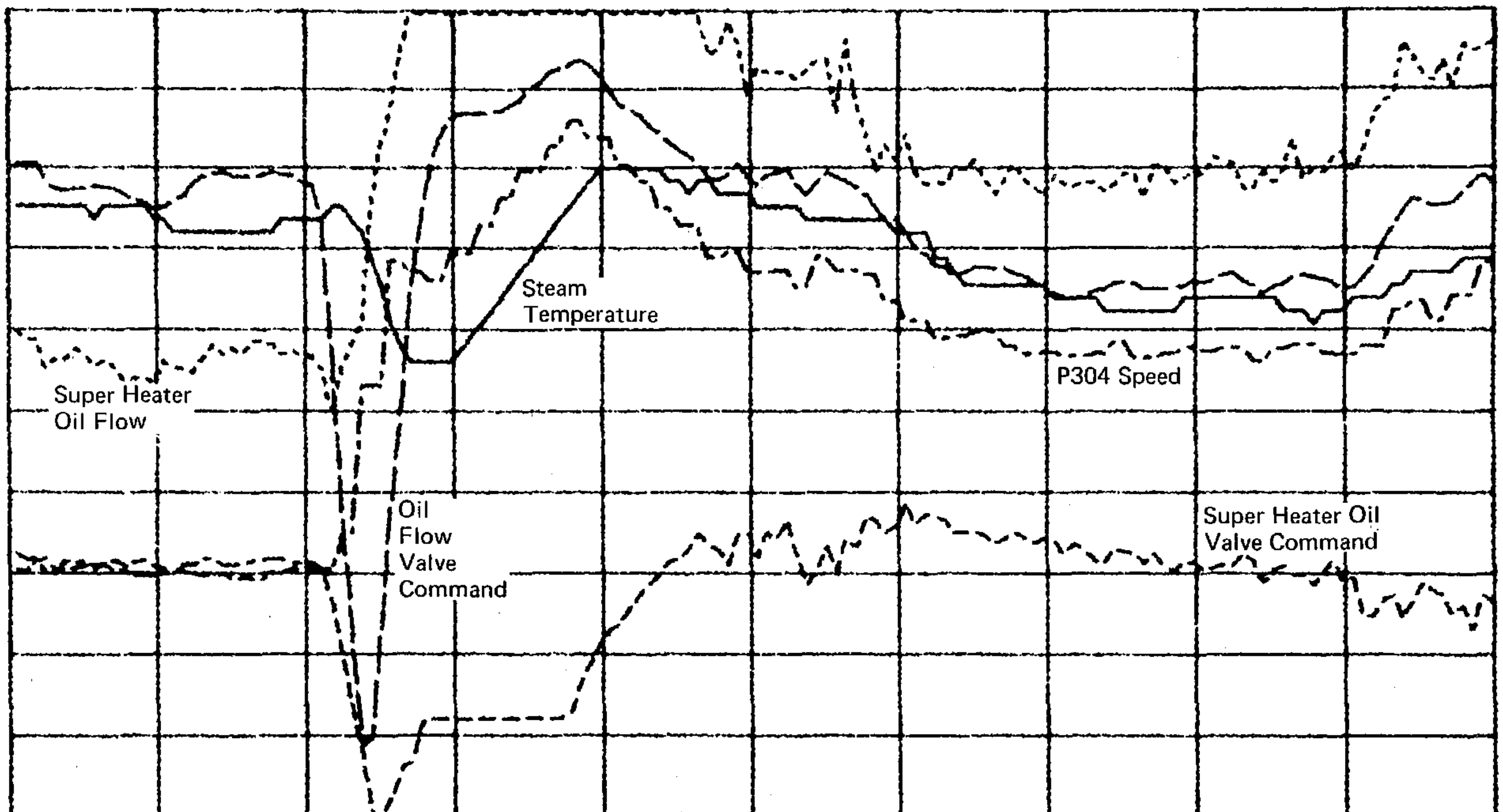


Figure 5.8-2. Extraction Flow Control Loop Response — Step Set Point Change

SOLAR DATA PLOT   PLOT # BLANK   HTH SAMPLE AVERAGE =

1 REFERENCE TIME: 131 21 20 00.000   FOR   20.0000 MINUTE(S)



TC3810P	OUTLET STEAM TEMPERATURE	500.0 -	550.0 DEGF
FI3812P	SUPERHEATER OIL FLOW	0.0 -	300.0 KLBH
FCM3810C	SUPERHEATER VALVE COMMAND	0.0 -	100.0 PCT
FC3802C	BOILER OIL VALVE COMMAND	0.0 -	100.0 PCT
ŞI3904P	OIL PUMP SPEED	450.0 -	2200.0 RPM

*

Figure 5.8-3. Extraction Flow Control Loop Step Set Point Change

process variable (flow) experienced an overshoot of 6 KLBH and returned to within 10% of the desired flow within 2 minutes. The superheater outlet steam temperature, Figure 5.8-3, was also affected, due to an increase steam flow rate. Steam temperature excursions were less than $\pm 6^{o}F$ during this disturbance.

The system is quite sensitive to abrupt setpoint changes and thus set point ramp rate limits were incorporated. A setpoint ramp rate limit of 1.0%/sec was selected. Figures 5.8-4 and 5.8-5 show the results of a simulated cloud test which includes this ramp rate limit. As can be seen, the set point was ramped up and down at the fixed rate with good control of the steam flow.

Another simulated cloud test is shown in Figures 5.8-6 and 5.8-7. In this test, the flow setpoint was ramped from 35 KLBH-to-55 KLBH in 30 sec, held there for about 3.5 min and then ramped down to 35 KLBH in 30 sec. The different ramp overshoot responses are due to the system nonlinear characteristics. The superheater outlet steam temperature was also affected, but was controlled within $\pm 10^{o}F$.

Pressure control responses to pressure setpoint changes are shown in Figures 5.8-8 and 5.8-9. The system responses compares with the other two modes of the main oil flow control valve, and, as shown, the system reacts quickly and is well controlled.

Load control simulated clouds were generated by ramping the load control setpoint from 2 M_{we}-to-4 M_{we} in approximately 30 sec. Then after approximately 3.5 min ramped from 4 M_{we}-to-2 M_{we} at the same ramprate. The responses are shown in Figures 5.8-10 and 5.8-11. As can be seen in Figure 5.8-10 afer 1.5 min the load was within 10% of the set point. The system response was as expected. Note in Figure 5.8-11 that the superheater outlet steam temperature is also affected, due to the increase steam flow. The temperature upset was minimized (less than $10^{o}F$) by cross feed of the main oil flow into the superheater outlet steam temperature controller, this will be more fully explained in that controllers section later in this report. As can be seen the main oil flow was modulated to produce the

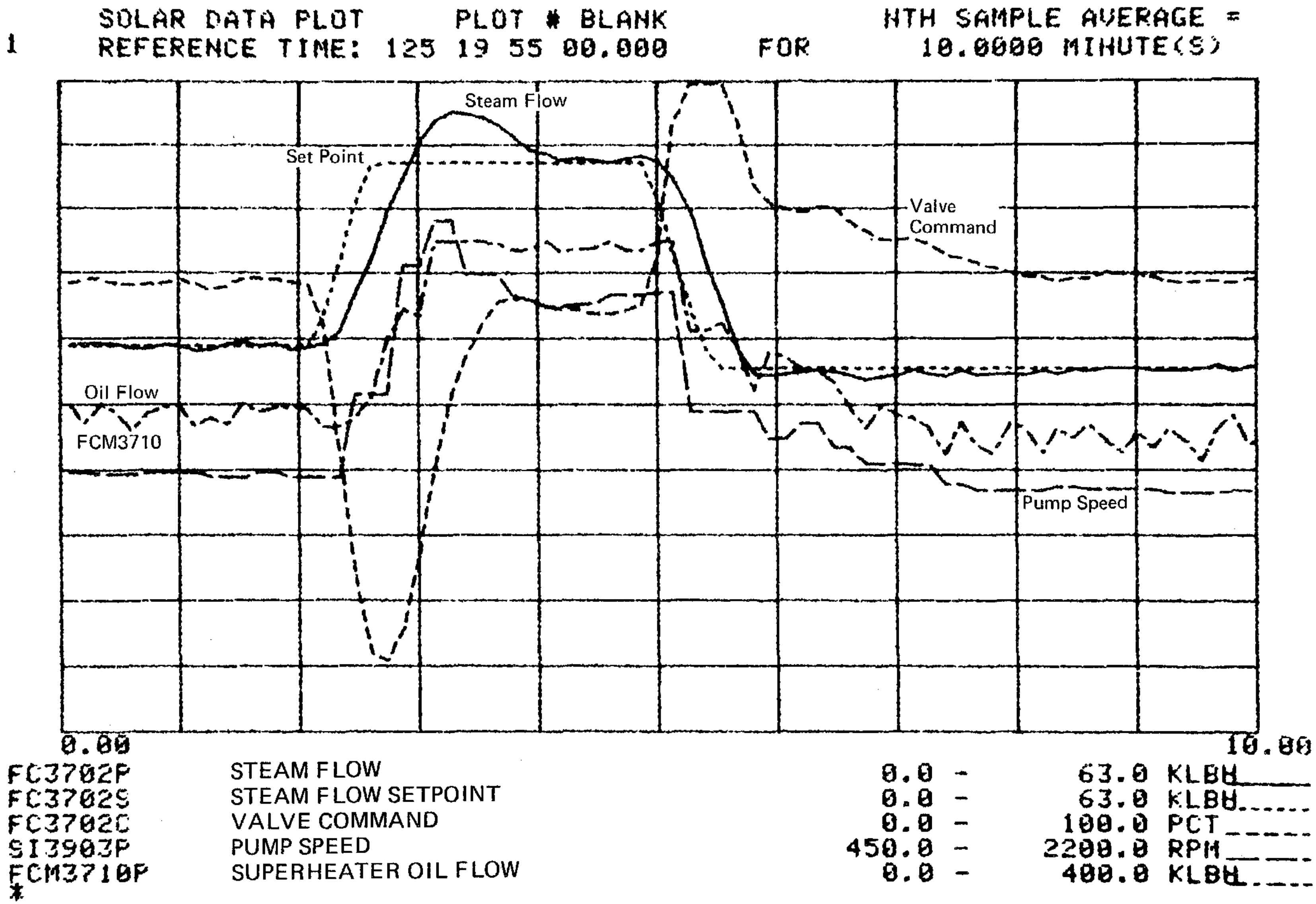
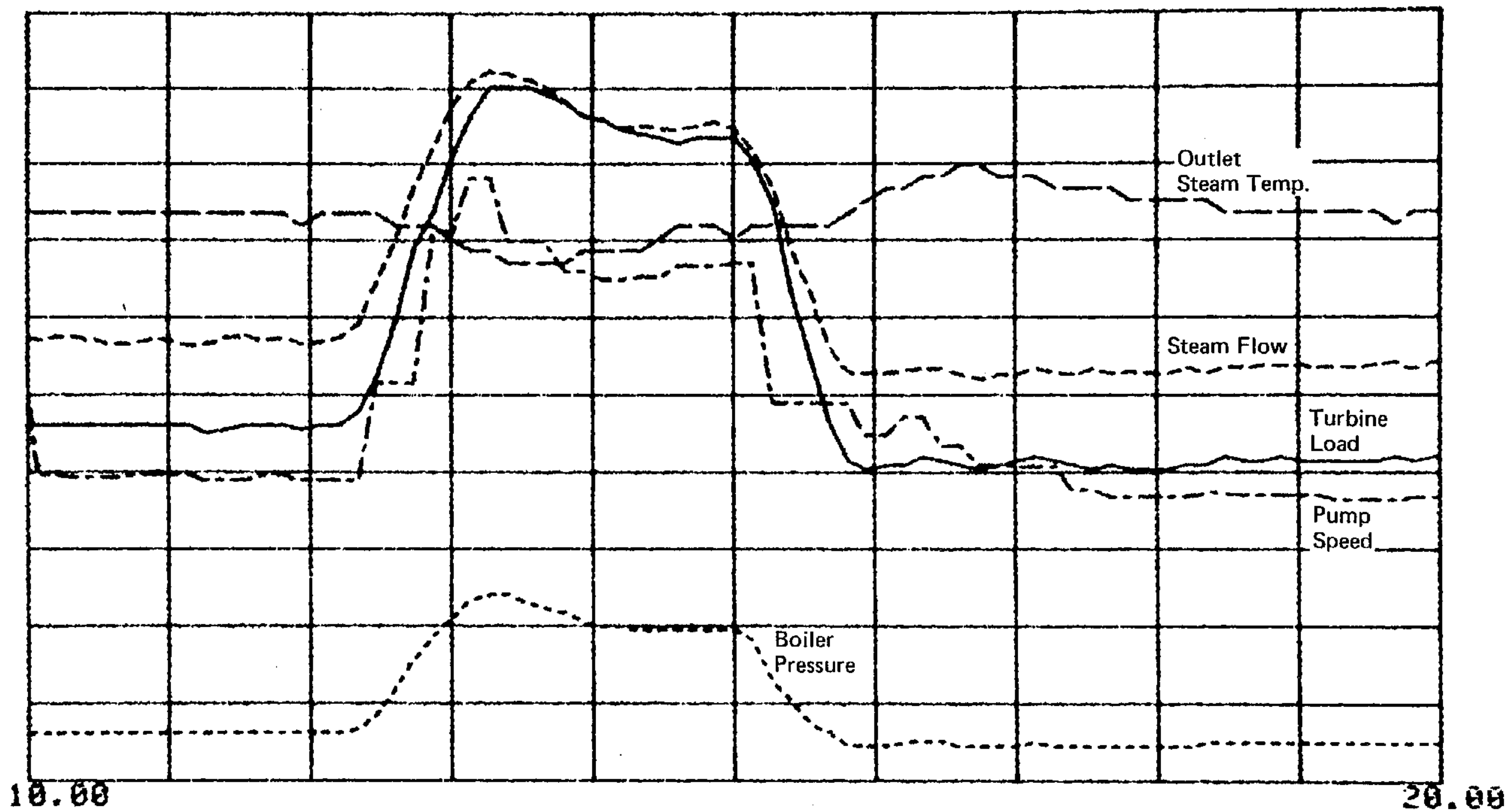


Figure 5.8-4. Extraction Flow Control Loop — Set Point Ramp Rate Response

SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE =
REFERENCE TIME: 125 19 45 00.000 FOR 10.0000 MINUTE(S)



JC3702P	TURBINE LOAD	0.0 -	5.0 MW	______
PC3702P	BOILER PRESSURE	300.0 -	400.0 PSIG	.....
FC3702P	STEAM FLOW	0.0 -	65.0 KLBH	----
TC3710P	STEAM TEMPERATURE	500.0 -	550.0 DEGF	__ __
SI3903P	PUMP SPEED	450.0 -	2200.0 RPM	_._..

*

Figure 5.8-5. Extraction Flow Control Loop — Set Point Ramp Rate Response

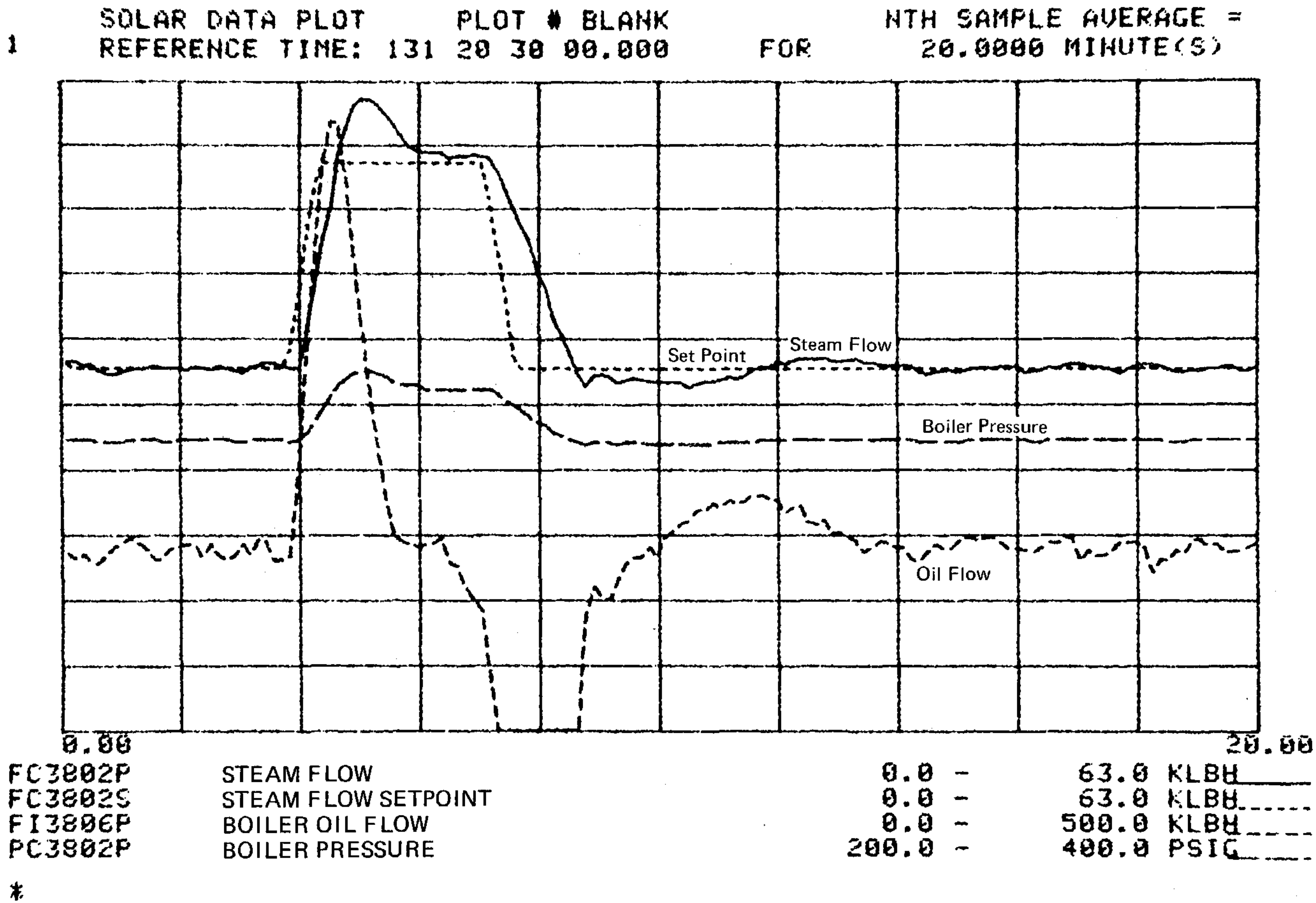


Figure 5.8-6. Extraction Flow Control Loop — Simulated Cloud Transient

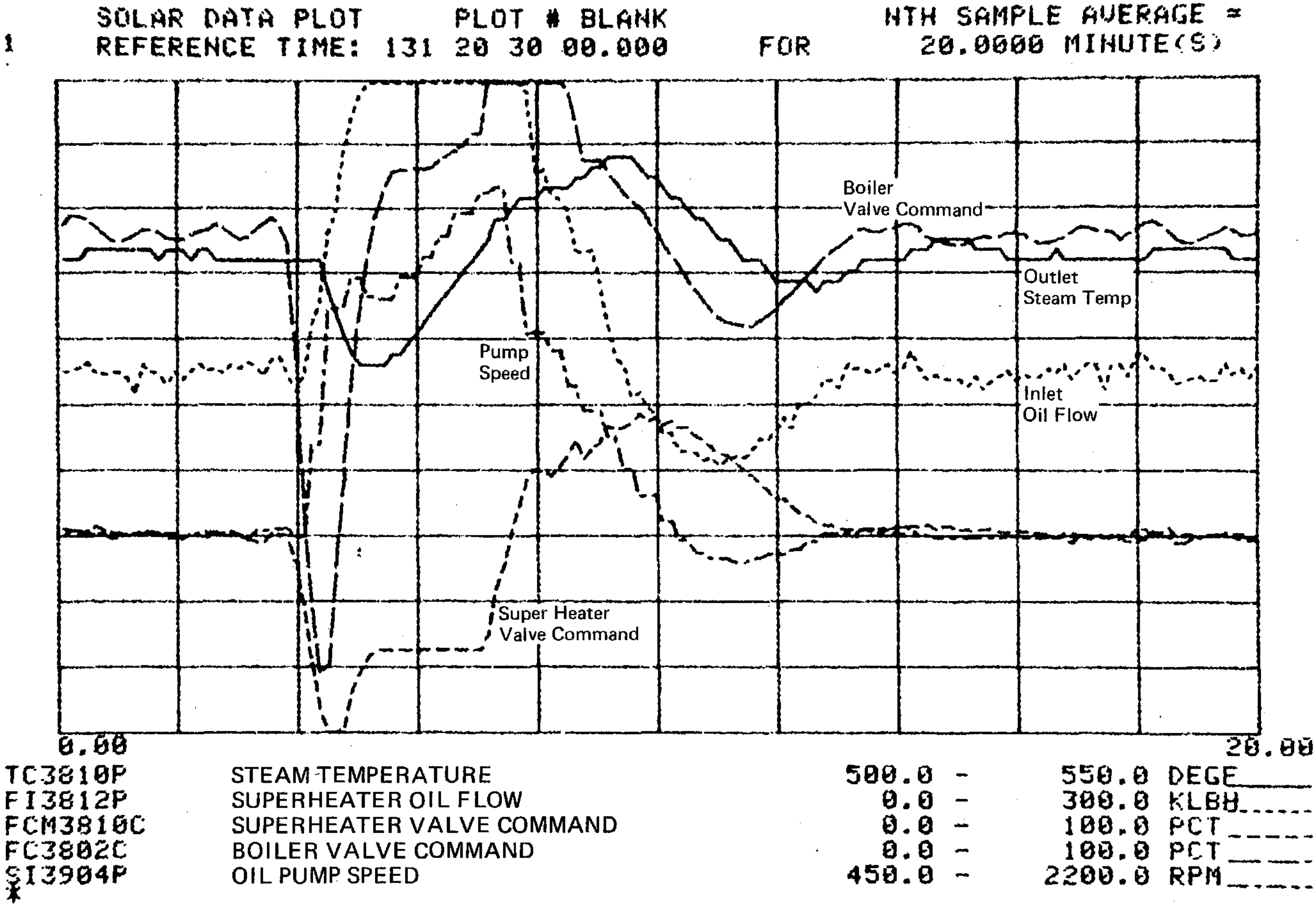


Figure 5.8-7. Extraction Flow Control Loop — Simulated Cloud Transient

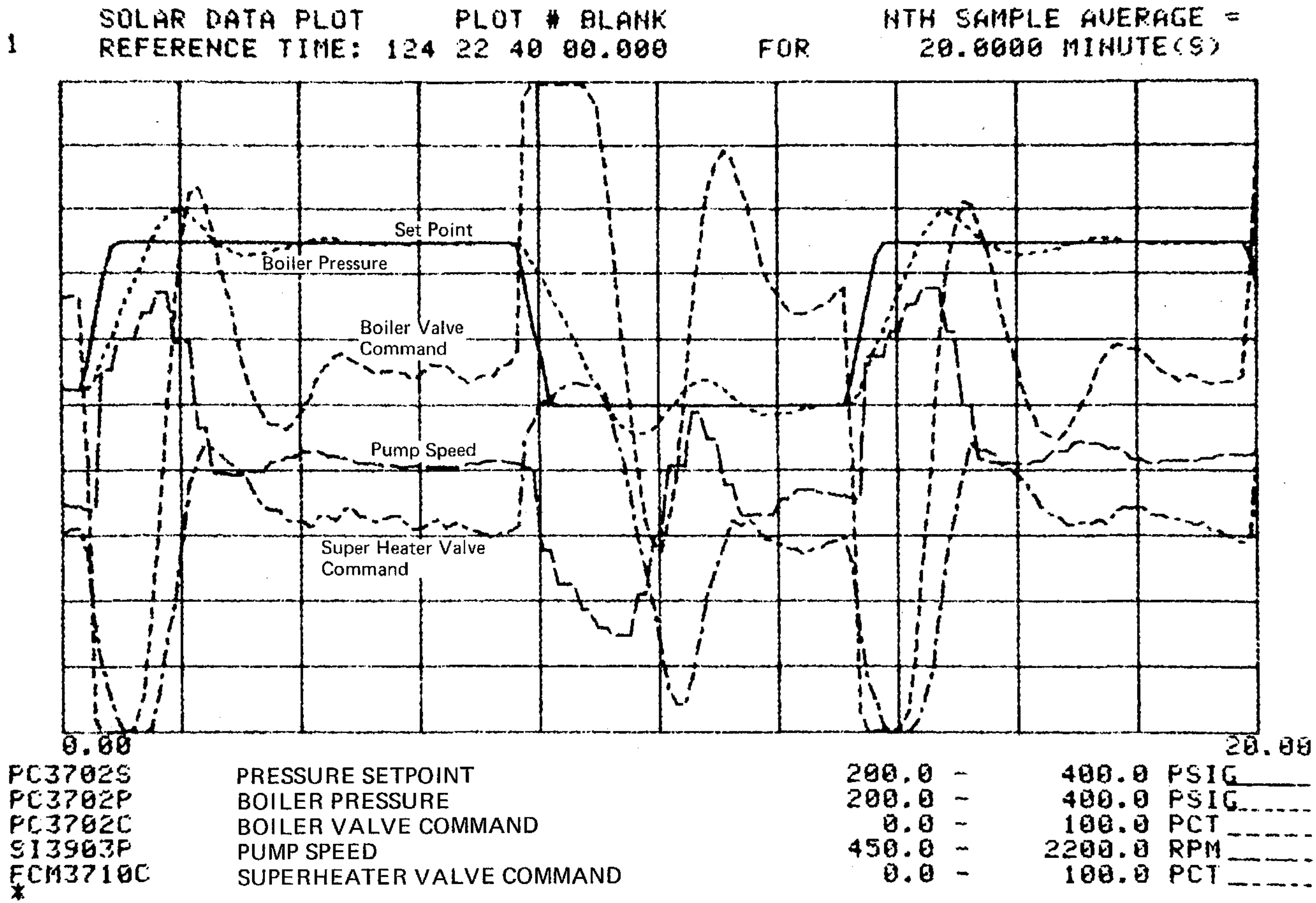
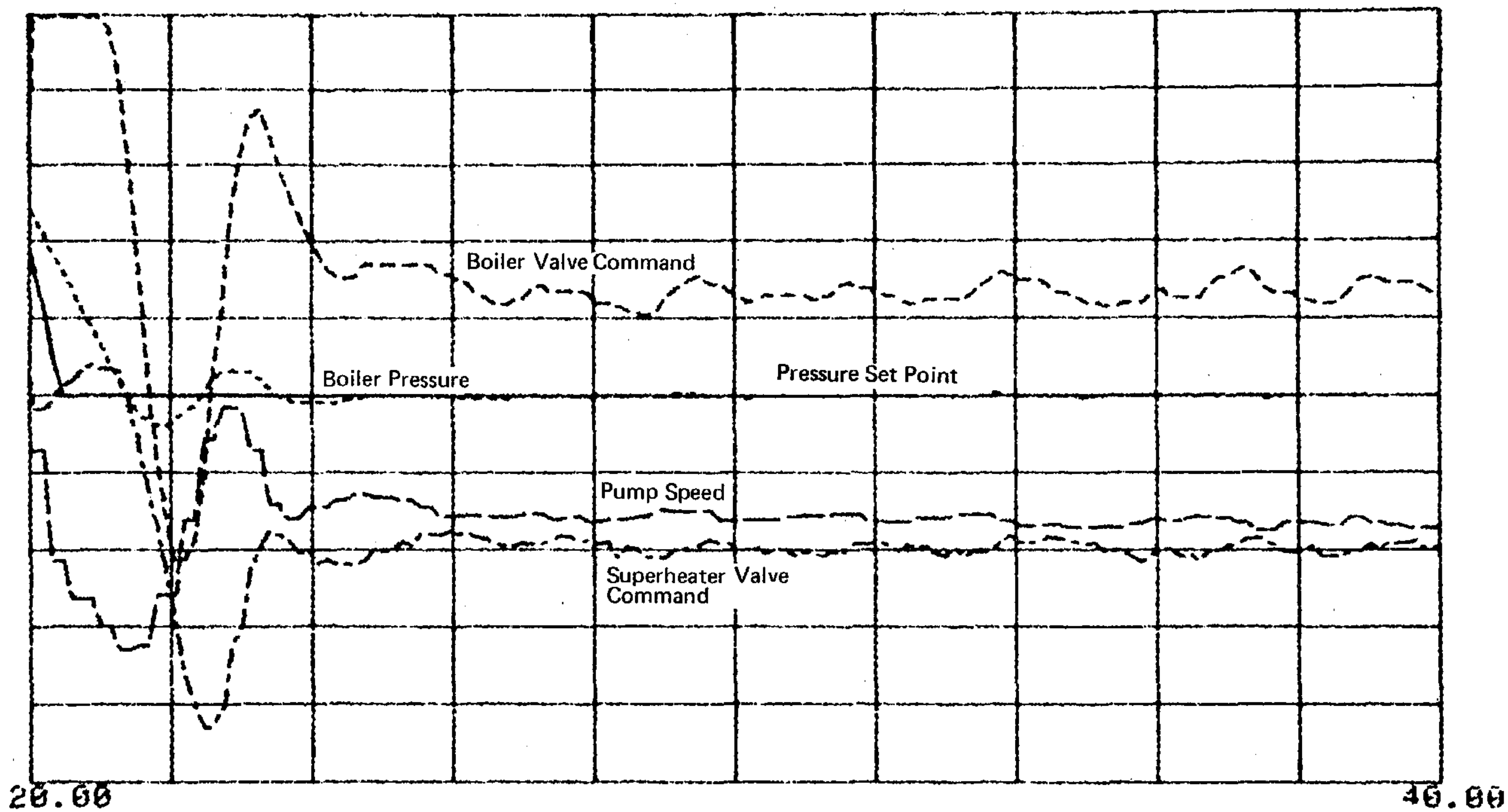


Figure 5.8-8. (Page 1) Extraction Pressure Control Loop — Set Point Change

SOLAR DATA PLOT   PLOT # BLANK   NTH SAMPLE AVERAGE =
REFERENCE TIME: 124 22 40 00.000   FOR   20.0000 MINUTE(S)

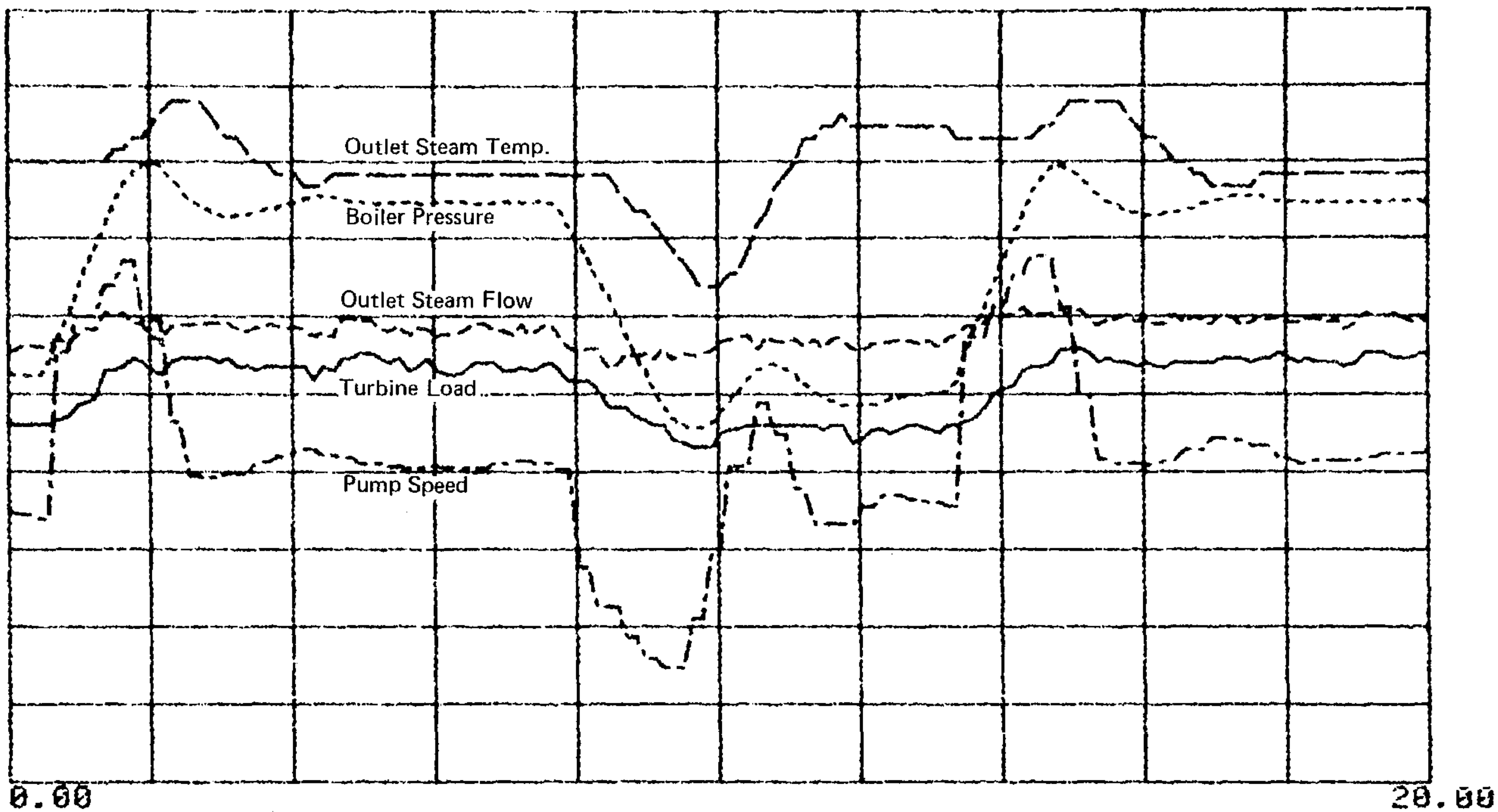


PC3702S   PRESSURE SETPOINT   200.0 - 400.0 PSIG
PC3702P   BOILER PRESSURE   200.0 - 400.0 PSIG
PC3702C   BOILER VALVE COMMAND   0.0 - 100.0 PCT
SI3903P   PUMP SPEED   450.0 - 2200.0 RPM
FCM3710C   SUPERHEATER VALVE COMMAND   0.0 - 100.0 PCT
*

Figure 5.8-8. (Page 2) Extraction Pressure Control Loop — Set Point Change

SOLAR DATA PLOT   PLOT # BLANK   NTH SAMPLE AVERAGE =

1   REFERENCE TIME: 124 22 40 00.000   FOR   20.0000 MINUTE(S)



JC3702P	TURBINE LOAD	0.0	-	5.0	MW
PC3702P	BOILER PRESSURE	200.0	-	400.0	PSIG
FC3702P	OUTLET STEAM FLOW	0.0	-	65.0	KLBH
TC3710P	OUTLET STEAM TEMPERATURE	500.0	-	550.0	DEGF
SI3903P	PUMP SPEED	450.0	-	2200.0	RPM

*

Figure 5.8-9. (Page 1) Extraction Pressure Control Loop — Set Point Change

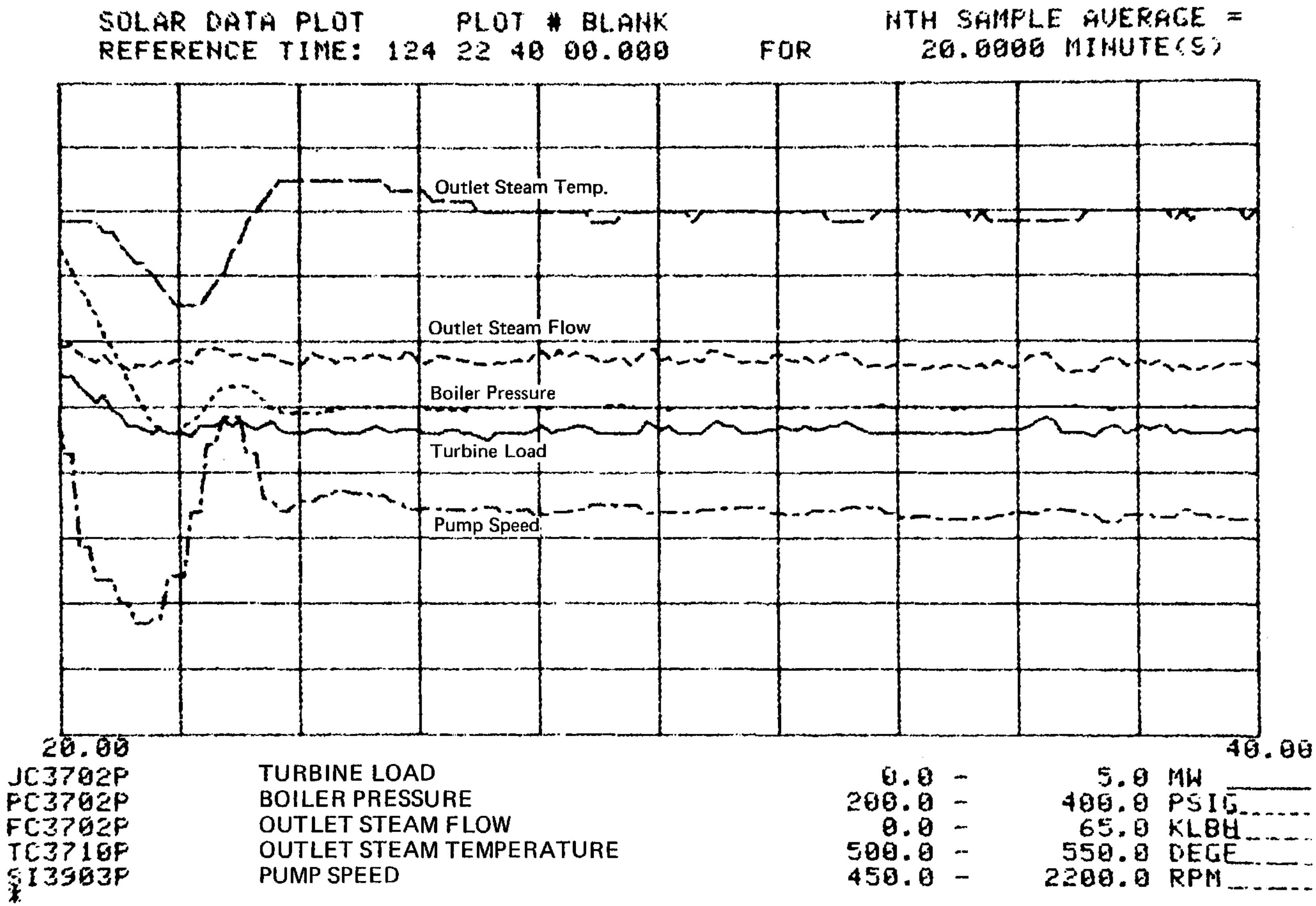
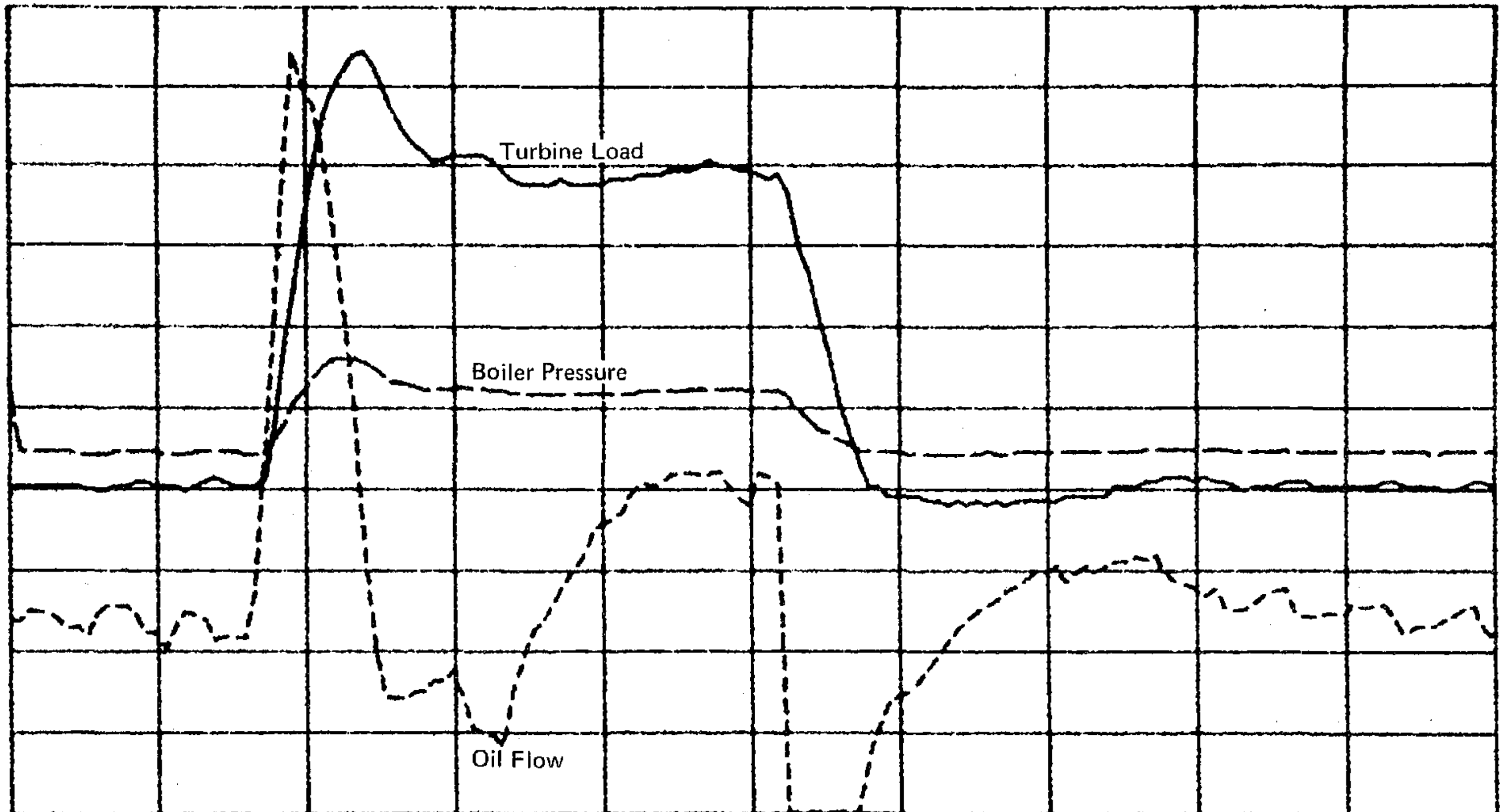


Figure 5.8-9. (Page 2) Extraction Pressure Control Loop — Set Point Change

SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE =
REFERENCE TIME: 131 19 10 00.000 FOR 20.0000 MINUTE(S)

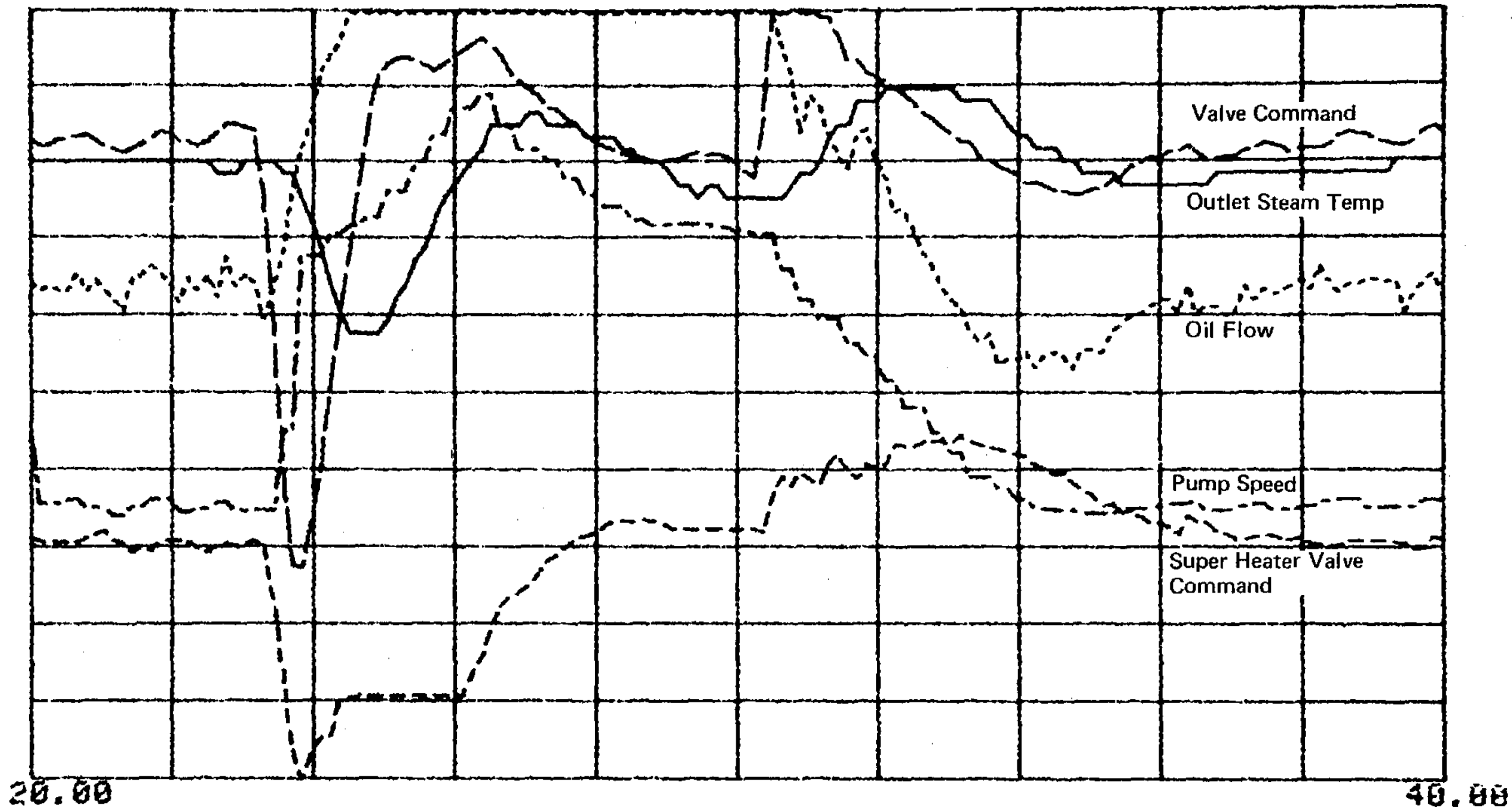


JC3802P	TURBINE LOAD	0.0 -	5.0 MW	————
JC3802S	LOAD SETPOINT			
FI3806P	BOILER OIL FLOW	0.0 -	500.0 KLBH	----
PC3802P	BOILER PRESSURE	200.0 -	400.0 PSIG	— —

*

Figure 5.8-10. Extraction Load Control Loop — Load Set Point Change

SOLAR DATA PLOT   PLOT # BLANK   NTH SAMPLE AVERAGE =
REFERENCE TIME: 131 19 10 00.000   FOR   20.0000 MINUTE(S)



TC3810P	OUTLET STEAM TEMPERATURE	500.0 -	550.0	DEGF
FI3812P	SUPERHEATER OIL FLOW	0.0 -	300.0	KLBH
FCM3810C	VALVE COMMAND	0.0 -	100.0	PCT
JC3802C	TURBINE LOAD	0.0 -	100.0	PCT
SI3904P	PUMP SPEED	450.0 -	2200.0	RPM

Figure 5.8-11. Extraction Load Control Loop — Load Set Point Change

necessary system response to bring the controlling process load to match the new setpoint in a rapid and controlled manner.

Another test was conducted where the boiler oil inlet valve was in load control (JC3702) and the turbine was in pressure control. The admission steam turbine inlet pressure was ramped up 30 psi, held there for about 3 min and then stepped down to the original pressure. As shown in Figures 5.8-12 and 5.8-13 the steam generators response was quick and well within operational limits.

5.8.2 Oil Pump Controllers

The controller PCM3903 controls the extraction oil pump speed (total oil flow). Figure 5.8-14 shows a functional block diagram of this controller. The speed control is accomplished by using a selector that compares the main oil valve and superheater oil valve commanded positions to find the most open valve. this command either increases or decreases the pump speed to bring the most open valve into the 70% open position. This reduces pump pressure losses and parasitic loads.

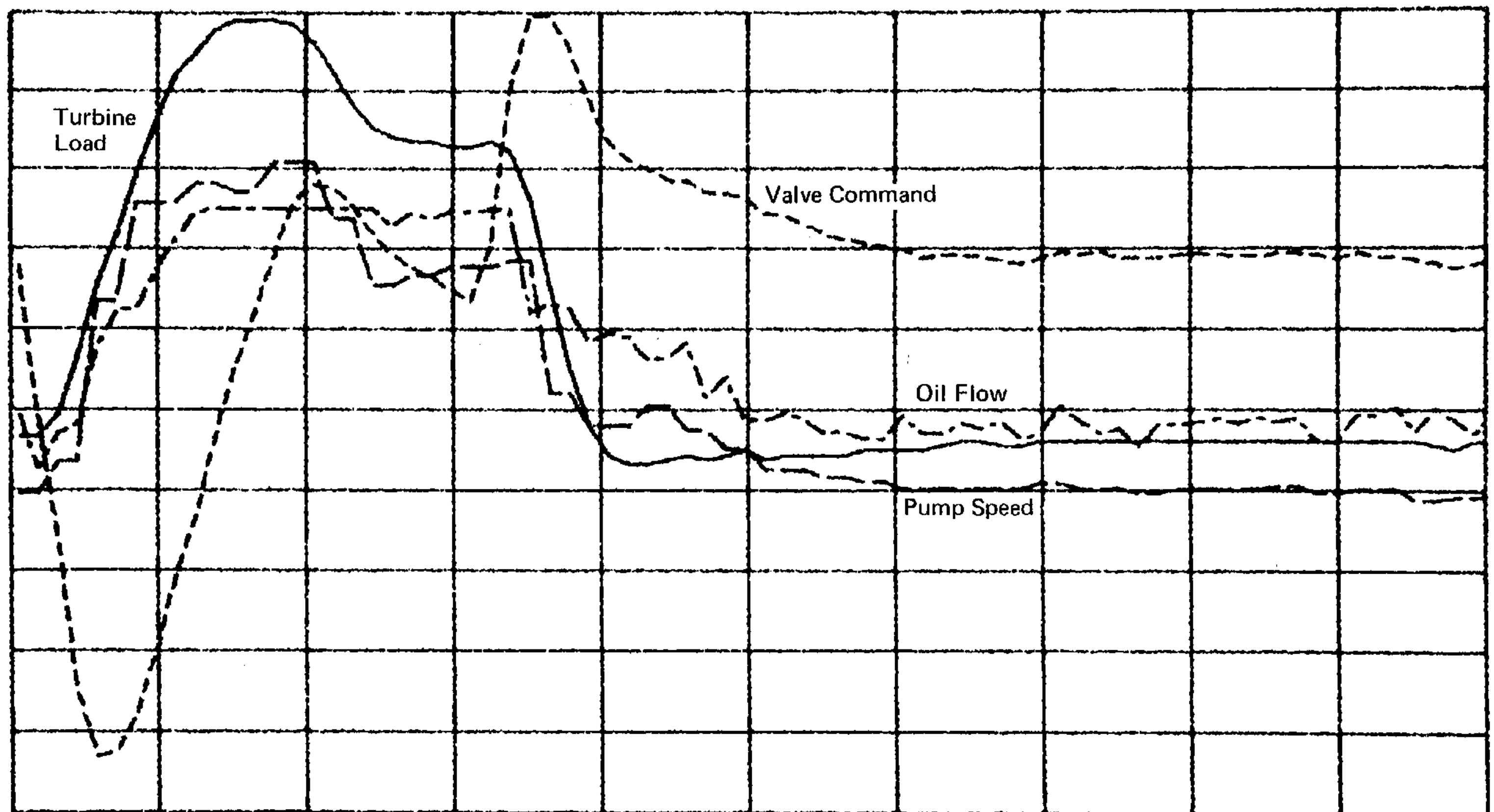
During either the main oil valve controllers or the superheater oil valve controllers tests the pump speed controller was in the automatic mode. While the other controllers were being disturbed, by set point changes, the control of the pump speed transferred from one valve to the other and back without any problems. This can be seen in Figures 5.8-3, 5.8-4, 5.8-5, 5.8-7, 5.8-8, 5.8-9, 5.8-11, 5.8-12 and 5.8-13.

5.9 EXTRACTION STEAM TEMPERATURE CONTROL LOOP TESTS

The functional block diagram for the outlet steam temperature controller is shown in Figure 5.9-1 (train 1). The steam temperature is controlled by regulating the amount of oil circulating through the superheater. Since the the boiler flow response affects the temperature some means of decoupling this action from the main oil valve was necessary. This decoupling was accomplished by cross feeding the commanded position of main oil valve to the temperature control value. This produced a faster temperature response to disturbances caused by the balance of plant upsets. Since the heat exchanger is a nonlinear system, a variable gain as a function of oil flowrate was implemented in the temperature loop.

SOLAR DATA PLOT   PLOT # BLANK   NTH SAMPLE AVERAGE =

1 REFERENCE TIME: 125 19 45 00.000   FOR   10.0000 MINUTE(S)



JC3702P	TURBINE LOAD	0.0 -	5.0 MW
JC3702S	LOAD SETPOINT		
JC3702C	BOILER OIL VALVE COMMAND	0.0 -	100.0 PCT
SI3903P	PUMP SPEED	450.0 -	2200.0 RPM
FCM3710P	OIL FLOW	0.0 -	400.0 KLBH

*

Figure 5.8-12. Extraction Load Control Loop — Turbine Inlet Pressure Disturbance

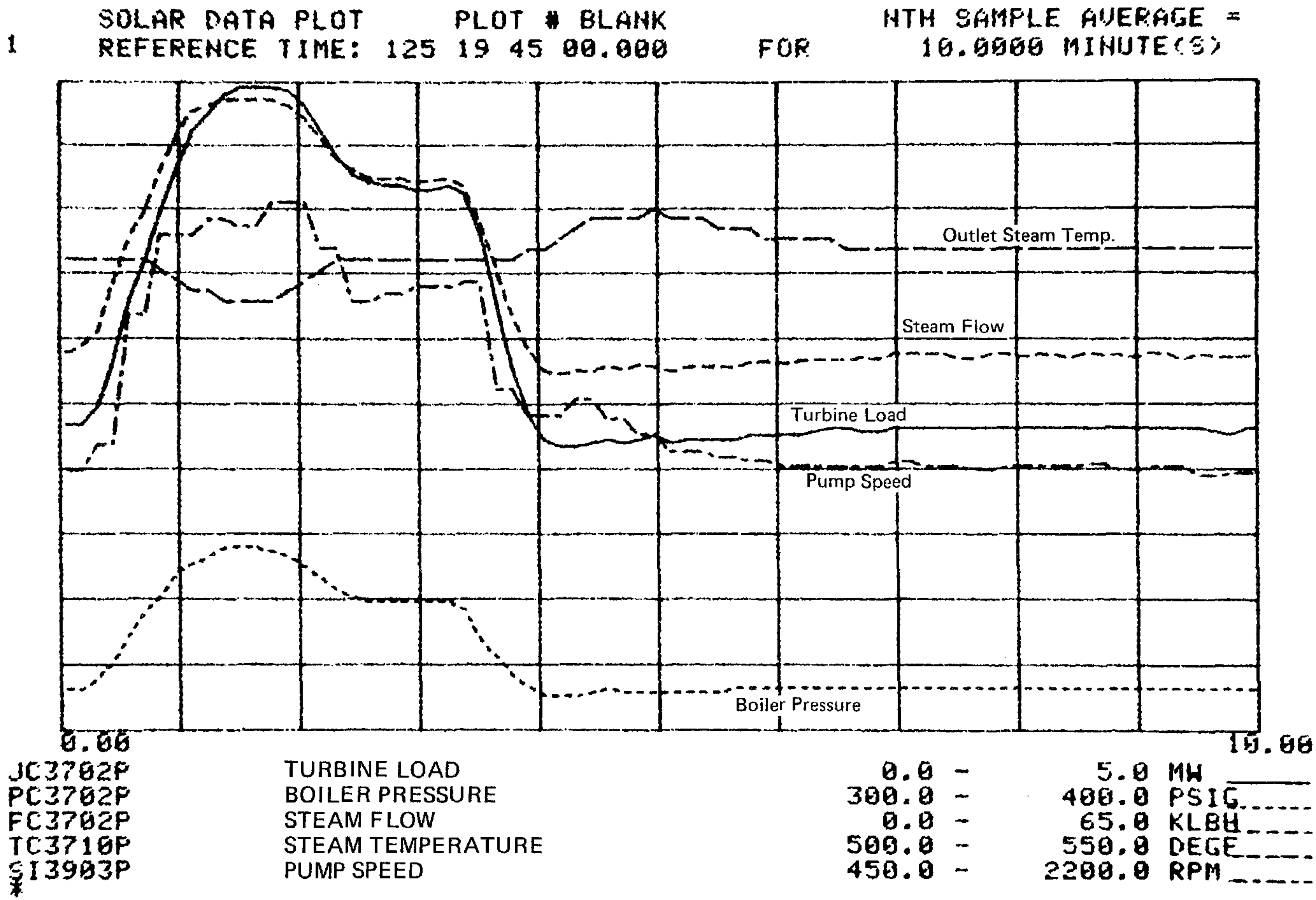


Figure 5.8-13. Extraction Load Control Loop – Turbine Inlet Pressure Disturbance

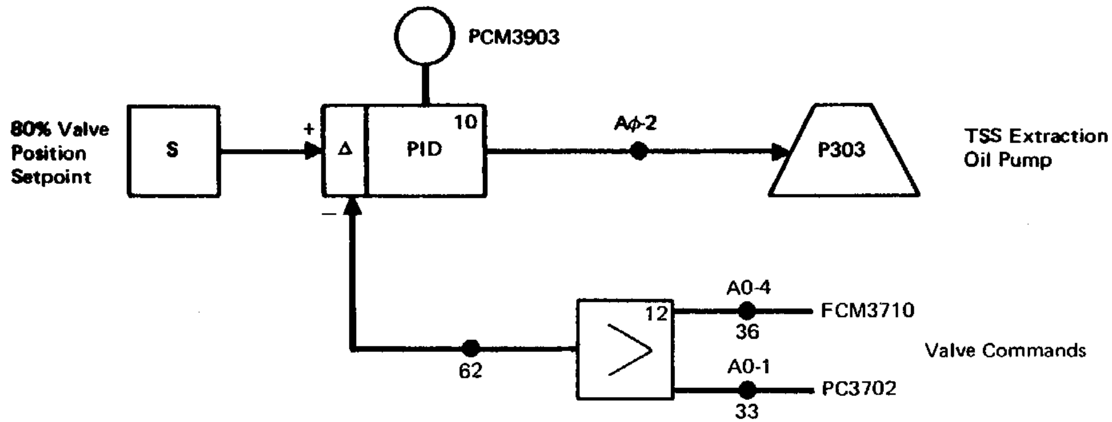


Figure 5.8-14. TSS Extraction Pump P303 (Train 1) PCM 3903

MVCU 2-2
Highway 1
Device 2

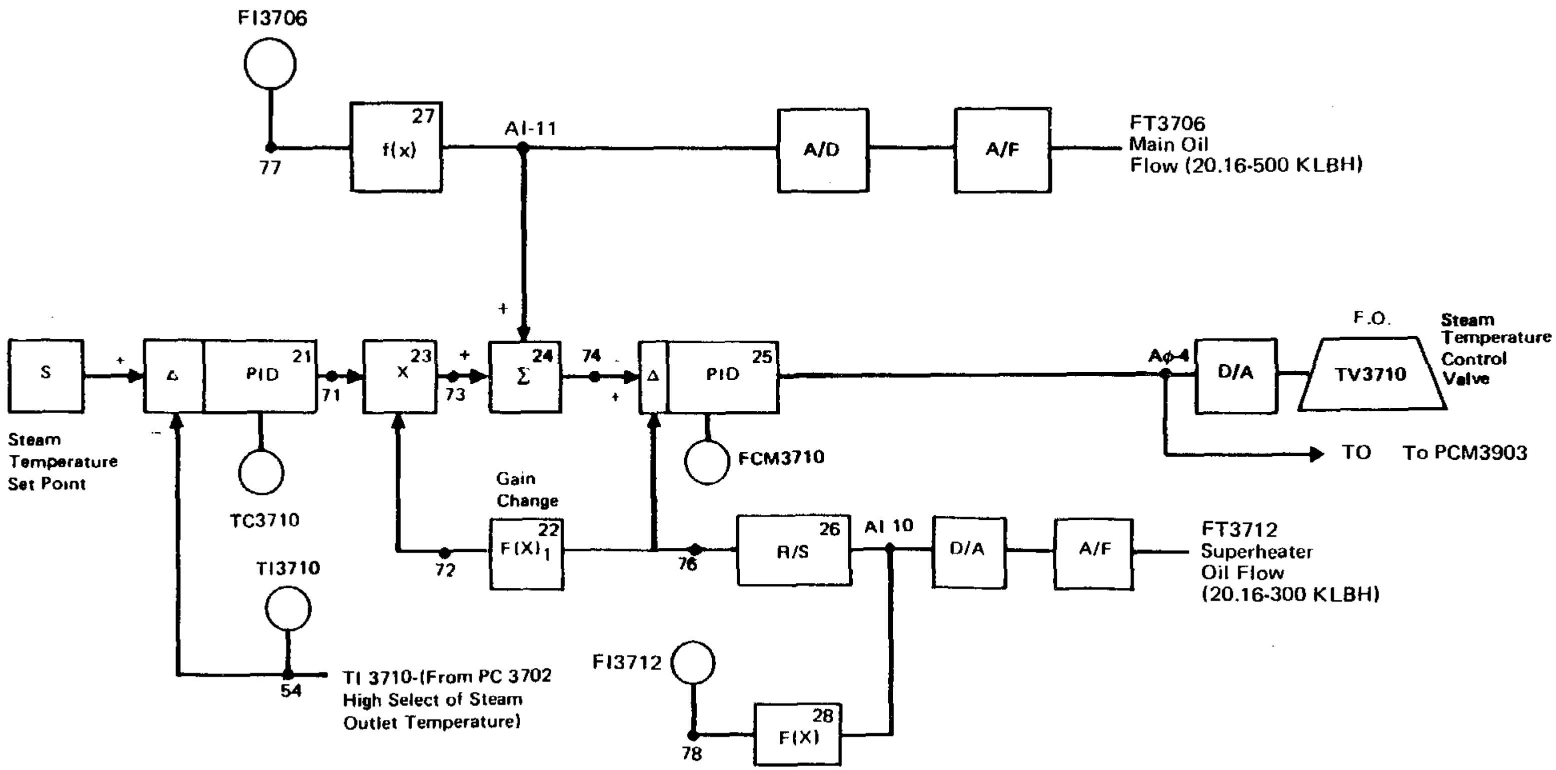


Figure 5.9-1. TSS Superheater Outlet Steam Temperature Controller Functional Block Diagram TC 3710 (Train 1)

MVCU 2-2
Primary Highway 1
Device Address 2

The superheater response to setpoint changes from 537°F to 532°F and back, at two different steam flows (35 KLBM and 55 KLBH) are shown in Figures 5.9-2 through 5.9-5. The responses are stable and well behaved maintaining the temperature within 1°F of the desired value.

Since the hot oil that flows through the superheater is combined with the oil that flows through the main oil valve before it enters the boilers, the boiler is affected by the superheater oil flow response. This can be seen in Figures 5.9-6 through 5.9-8 as increases and decreases in the steam flow rate are induced by the temperature setpoint disturbance and are rejected by the main oil valve controller in a well behaved manner.

5.10 AUXILIARY STEAM CONTROL TESTS

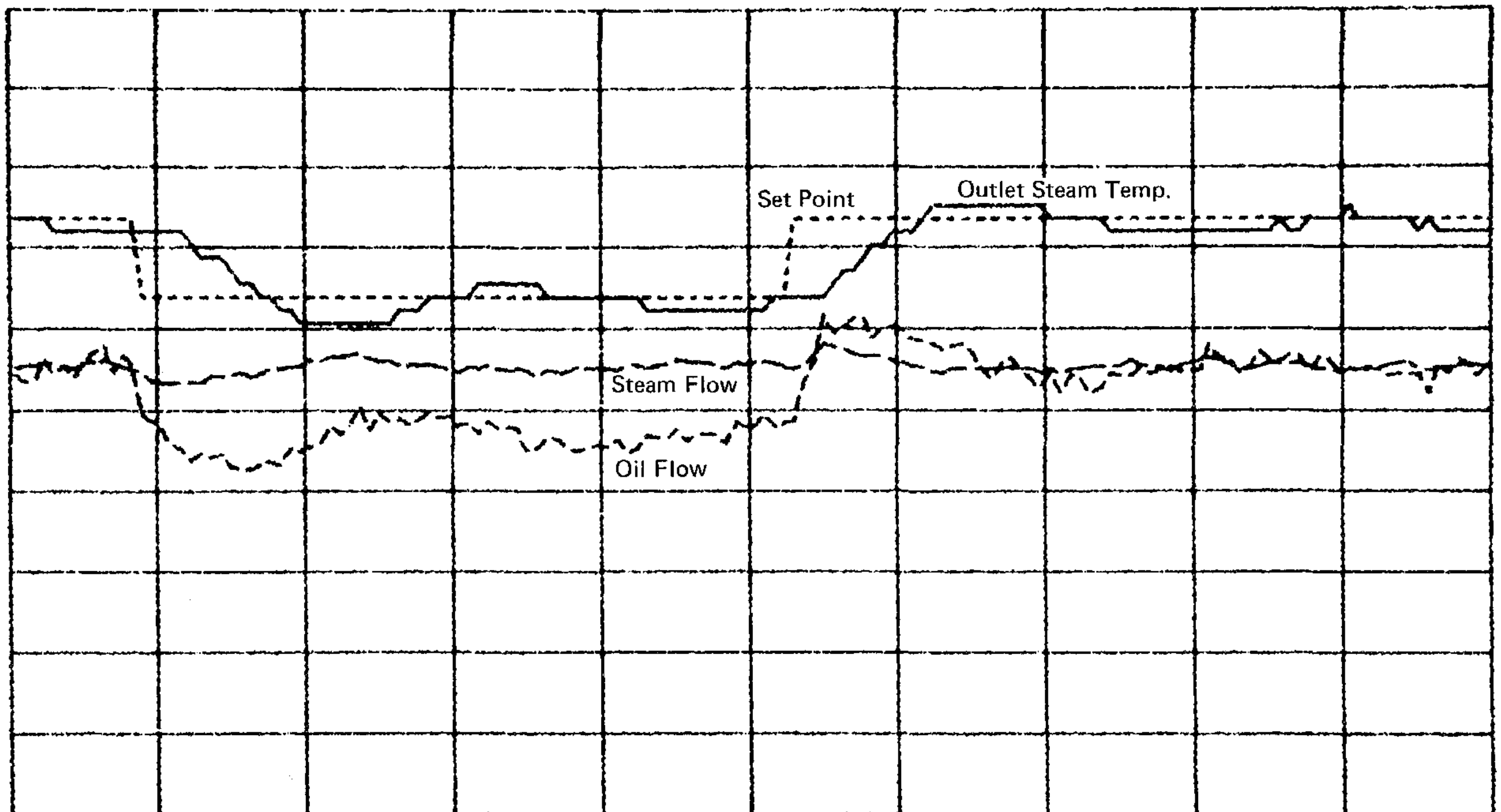
The TSS extraction system may be used as a source of auxiliary steam (8-10 KLBH) by using the auxiliary oil pump (P305 - a low power constant speed pump) and a pressure control valve, PV3910. This auxiliary steam is used either during receiver down periods or to warm the steam generators during extraction startup.

Figure 5.10-1 is a functional block diagram of the auxiliary steam pressure controller PCM 3910. It is a simple one loop controller which regulates the flow of oil to the boiler oil flow valve (PV3702) and the temperature control valve (TV3710). These valves are set at 20% and 80% open respectively for the desired ratio of oil flow to the boiler and superheater. The response of this controller to a step pressure setpoint change can be seen in Figure 5.10-2. As shown, the response is slow but well behaved.

5.11 ADMISSION STEAM LOOP CONTROL TESTS

The turbine admission inlet pressure is controlled by the turbine admission valve controller furnished by General Electric. This controller is not a part of the TSS extraction system but acts as an external disturbance to the system when pressure set point changes are made. Figure 5.11-1 shows the extraction system reaction to a 24 psig ramp up in turbine inlet pressure. The load setpoint was 8.8 MW and the excursions in load on the step up were approximately ±0.8 MW with the transient damping out in 3 minutes. On the pressure step down the excursion was approximately ±0.9 MW. The response is considered adequate for the Solar One application.

SOLAR DATA PLOT   PLOT # BLANK   NTH SAMPLE AVERAGE =
1 REFERENCE TIME: 131 20 49 00.000   FOR   20.0000 MINUTE(S)



TC3810P	OUTLET STEAM TEMPERATURE	500.0 -	550.0 DEGF
TC3810S	TEMPERATURE SETPOINT	500.0 -	550.0 DEGF
FI3812P	SUPERHEATER OIL FLOW	0.0 -	300.0 KLBH
FC3802P	STEAM FLOW	0.0 -	63.0 KLBH

Figure 5.9-2. Extraction Temperature Controller Step Set Point Change — 35 KLBH Steam Flow

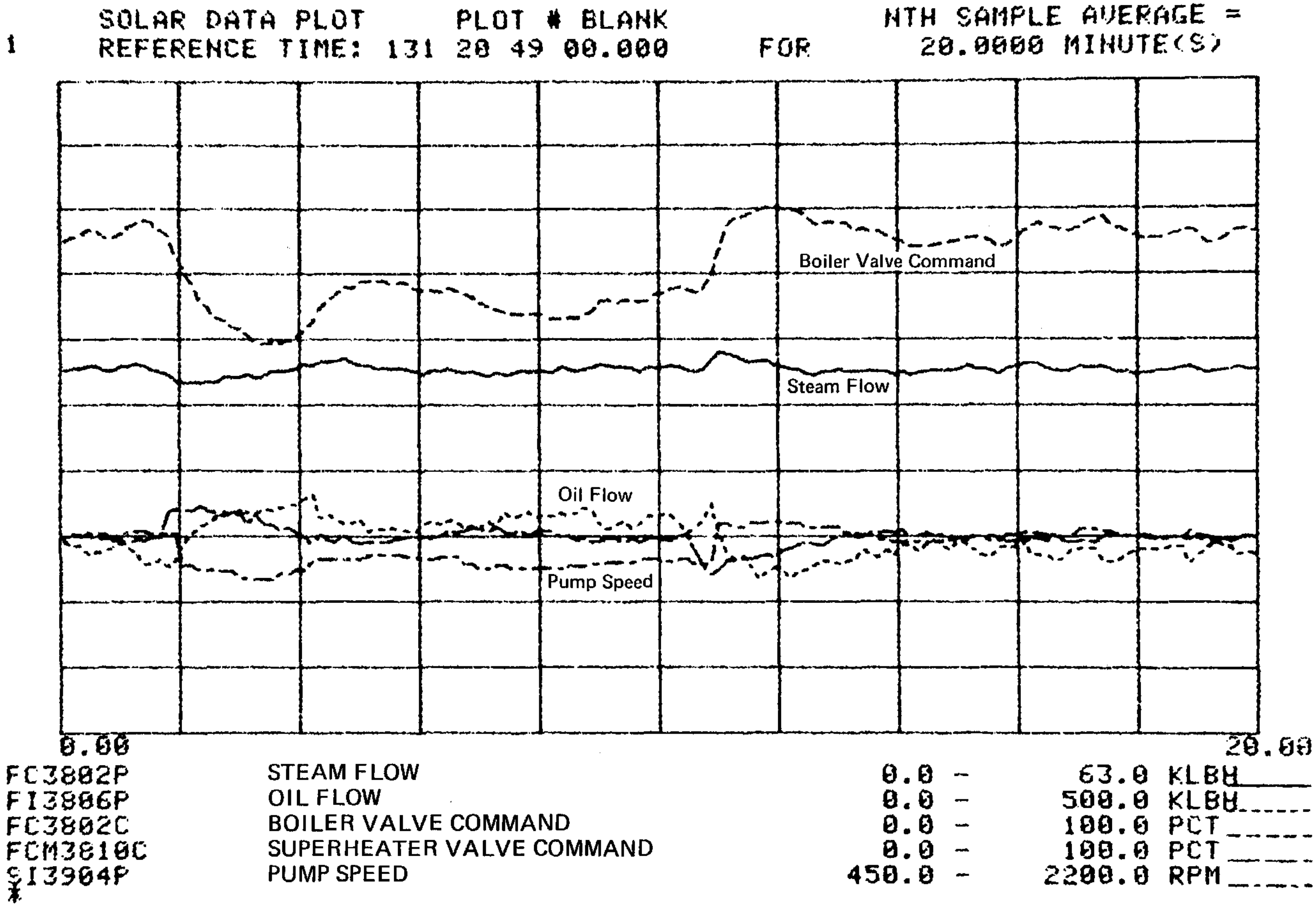


Figure 5.9-3. Extraction Temperature Controller Step Set Point Change — 35 KLBH Steam Flow

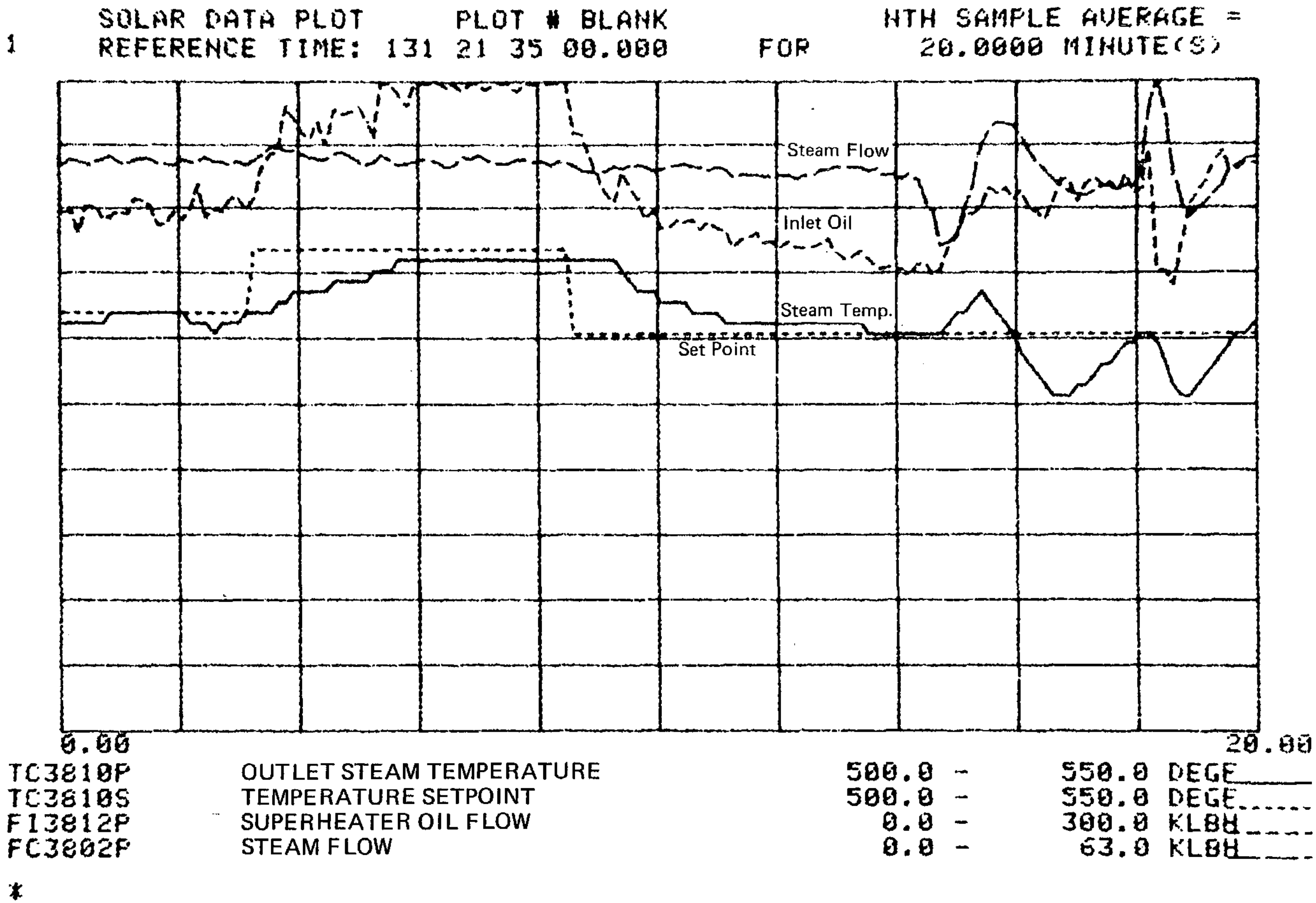
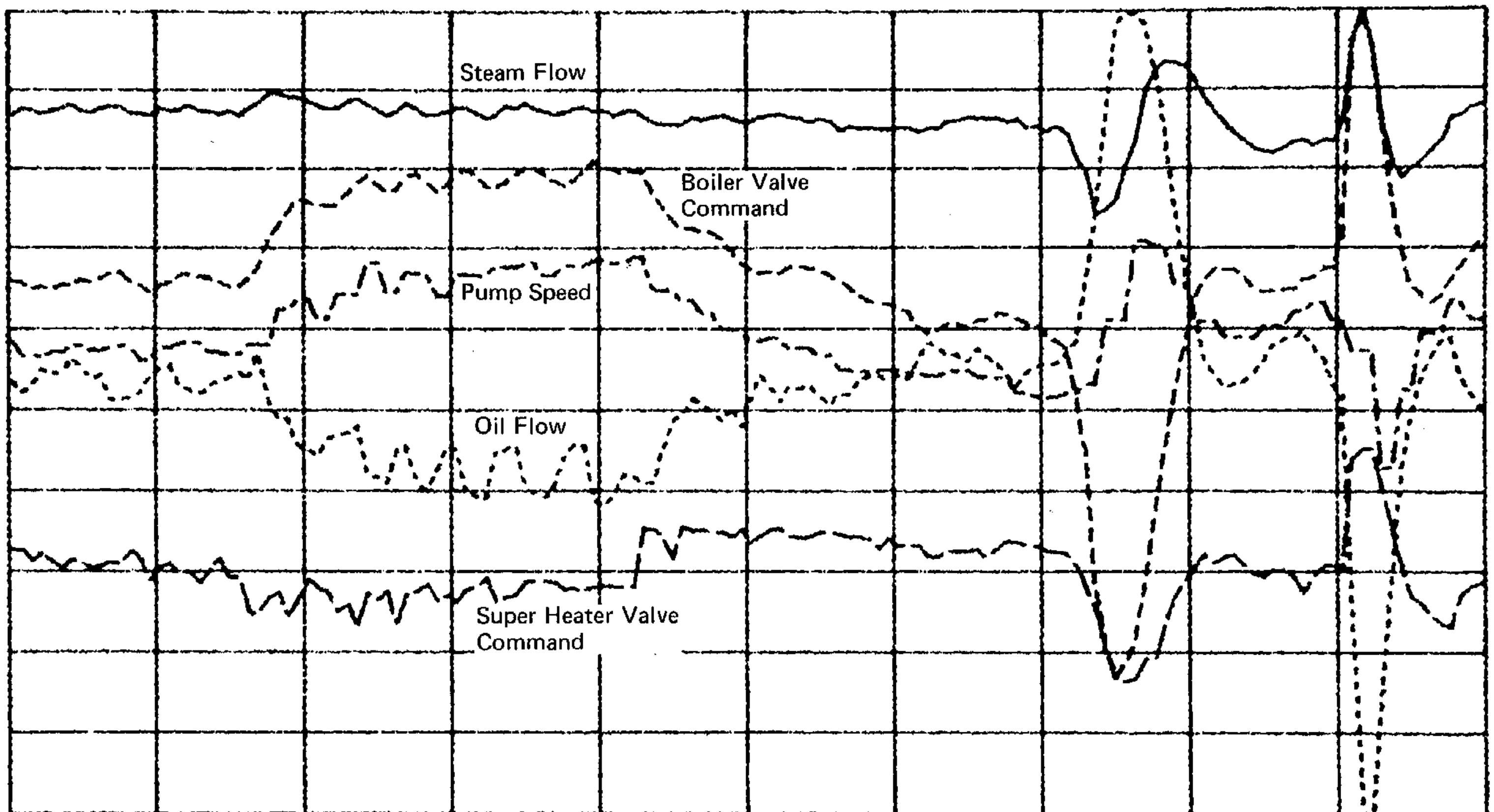


Figure 5.9-4. Extraction Temperature Controller Step Set Point Change — 55 KLBH Steam Flow

SOLAR DATA PLOT   PLOT # BLANK   NTH SAMPLE AVERAGE =

1   REFERENCE TIME: 131 21 35 00.000   FOR   20.0000 MINUTE(S)



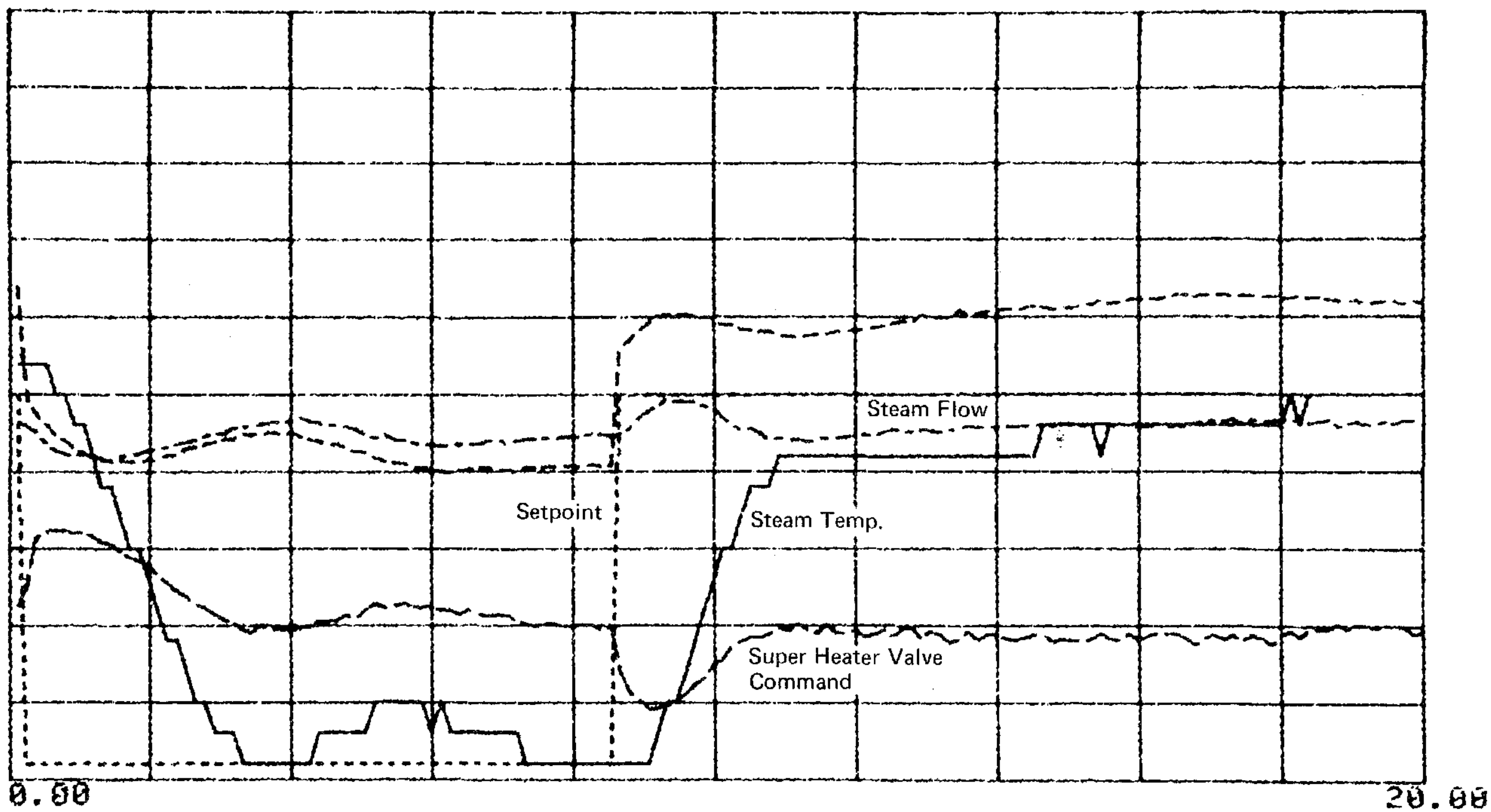
0.00 — 20.00

FC3802P	STEAM FLOW	0.0 -	63.0 KLBH	____
FI3806P	BOILER OIL FLOW	0.0 -	500.0 KLBH	.....
FC3802C	VALVE COMMAND	0.0 -	100.0 PCT	-----
FCM3810C	OIL FLOW	0.0 -	100.0 PCT	-- --
SI3904P	PUMP SPEED	450.0 -	2200.0 RPM	-.-.-

*

Figure 5.9-5. Extraction Temperature Controller Step Set Point Change

1 SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE =
REFERENCE TIME: 124 20 50 00.000 FOR 20.0000 MINUTE(S)

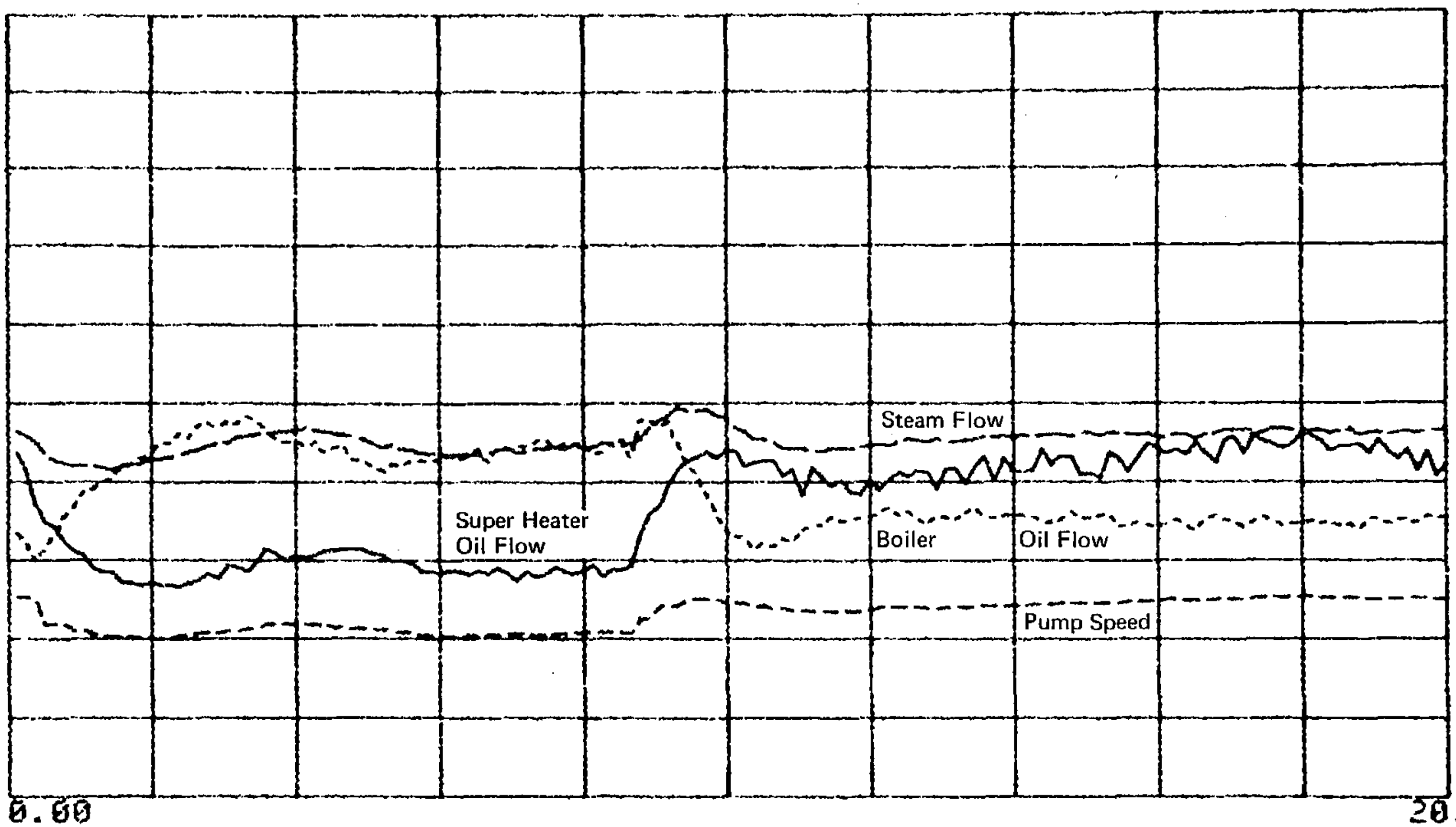


TC3710P	OUTLET STEAM TEMPERATURE	530.0	-	550.0 DEGF
TC3710S	TEMPERATURE SETPOINT	530.0	-	550.0 DEGF
TC3710C	OIL FLOW COMMAND	0.0	-	100.0 PCT
FCM3710C	SUPERHEATER VALVE COMMAND	0.0	-	100.0 PCT
FC3702P	STEAM FLOW	0.0	-	80.0 KLBH

*

Figure 5.9-6. Extraction Boiler Response to Temperature Controller Step Set Point Change

1 SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE =
REFERENCE TIME: 124 20 50 00.000 FOR 20.0000 MINUTE(S)



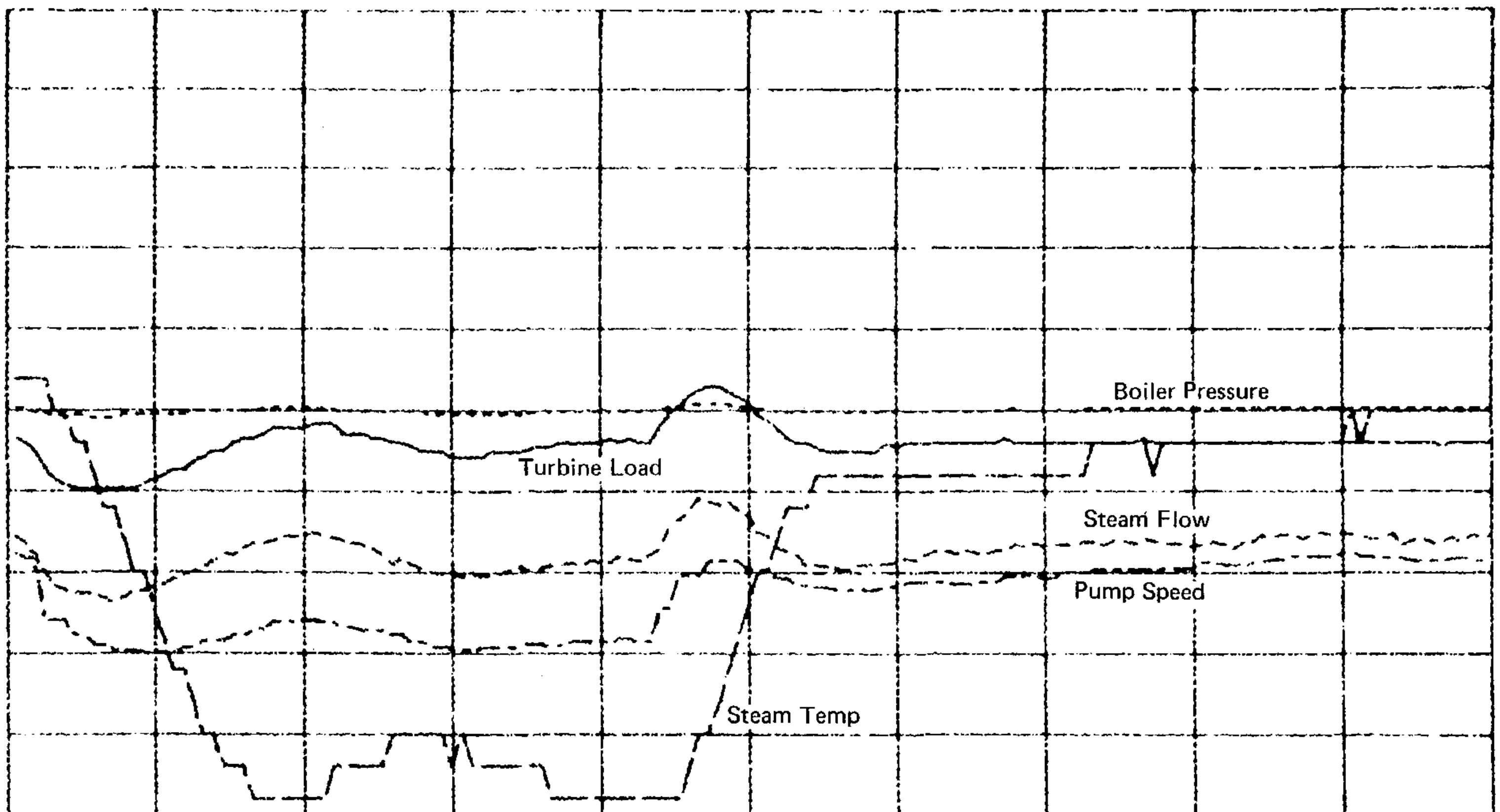
FI3712P	SUPERHEATER OIL FLOW	0.0 -	400.0 KLBH
FI3706P	BOILER OIL FLOW	0.0 -	500.0 KLBH
SI3903P	PUMP SPEED	0.0 -	4000.0 RPM
FC3702P	STEAM FLOW	0.0 -	80.0 KLBH

*

Figure 5.9-7. Extraction Boiler Response to Temperature Controller Step Set Point Change

SOLAR DATA PLOT　　PLOT # BLANK　　NTH SAMPLE AVERAGE =

1　REFERENCE TIME: 124 20 50 00.000　　FOR　　20.0000 MINUTE(S)



0.00　　30.00

JC3702P	TURBINE LOAD	0.0	-	5.0	MW
PC3702P	BOILER PRESSURE	200.0	-	400.0	PSIG
FC3702P	STEAM FLOW	20.0	-	70.0	KLBH
TC3710P	STEAM TEMPERATURE	530.0	-	550.0	DEGF
SI3903P	PUMP SPEED	450.0	-	2200.0	RPM

Figure 5.9-8. Extraction Boiler Response to Temperature Controller Step Set Point Change

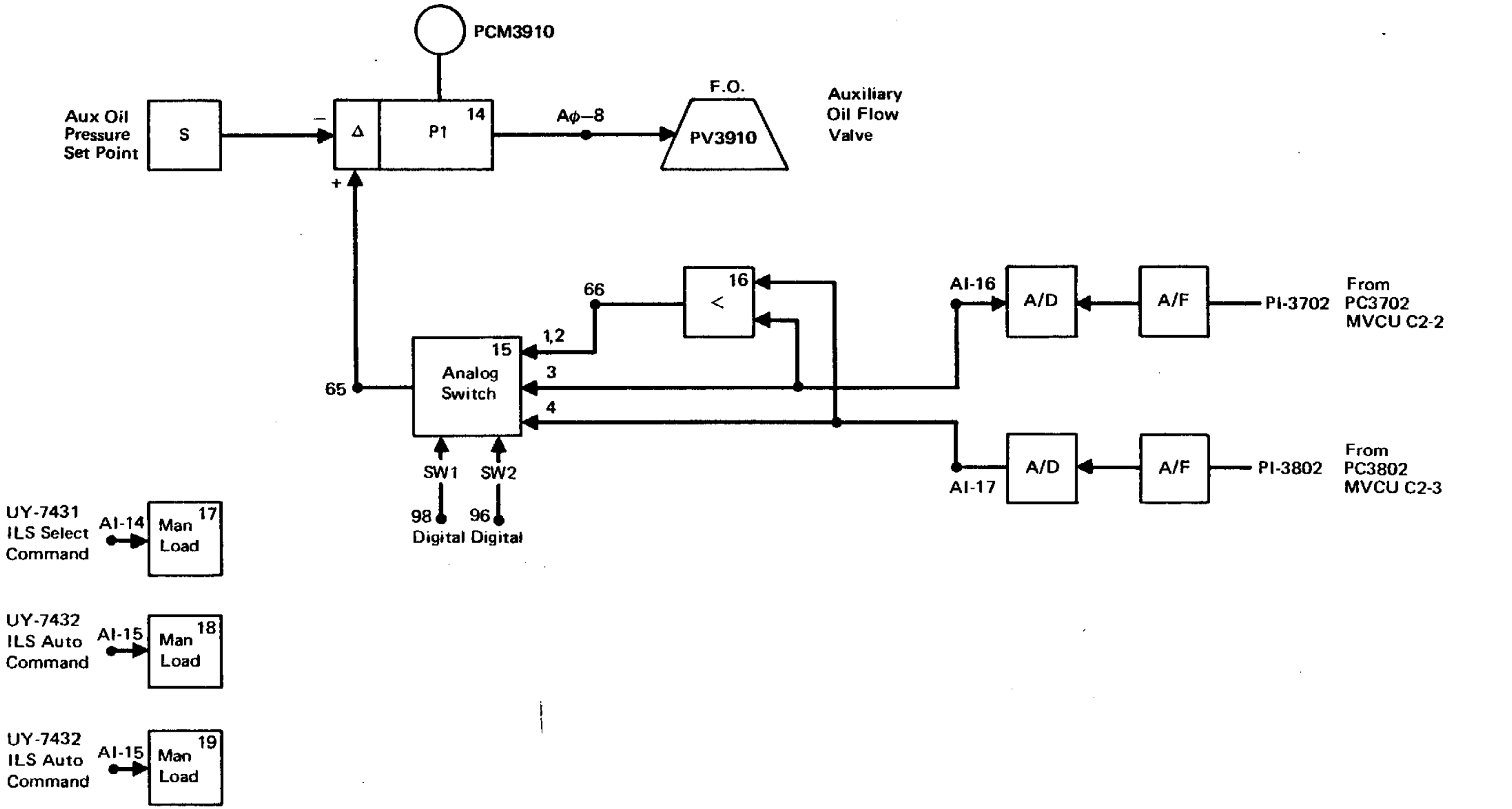


Figure 5.10-1 TSS Auxiliary Oil Flow – Steam Pressure Contoller – PCM3910

MVCU 2-4
Highway 2
Device 2

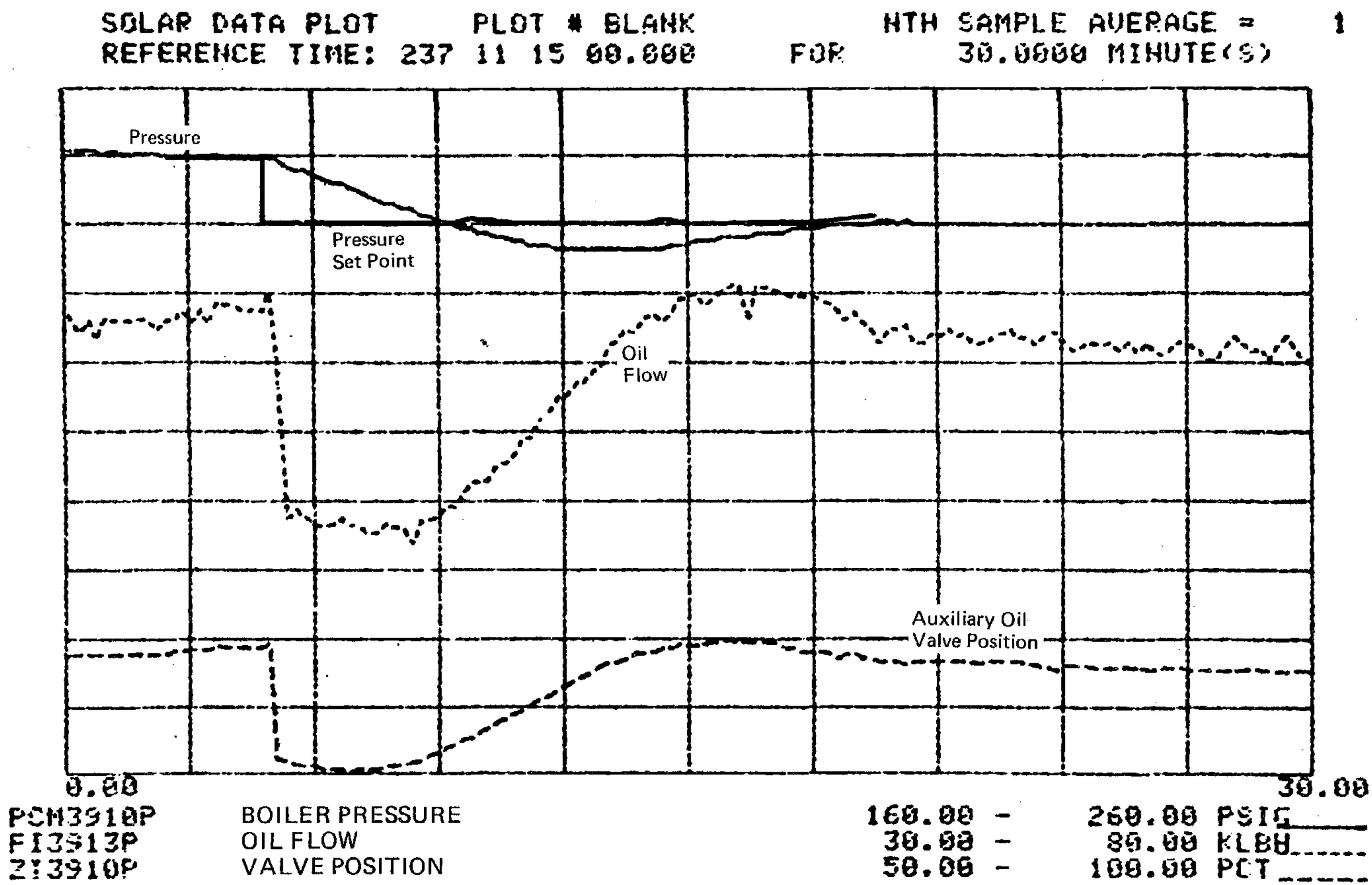


Figure 5.10-2. Auxiliary Steam Pressure Controller, PCM3910 — Step Response

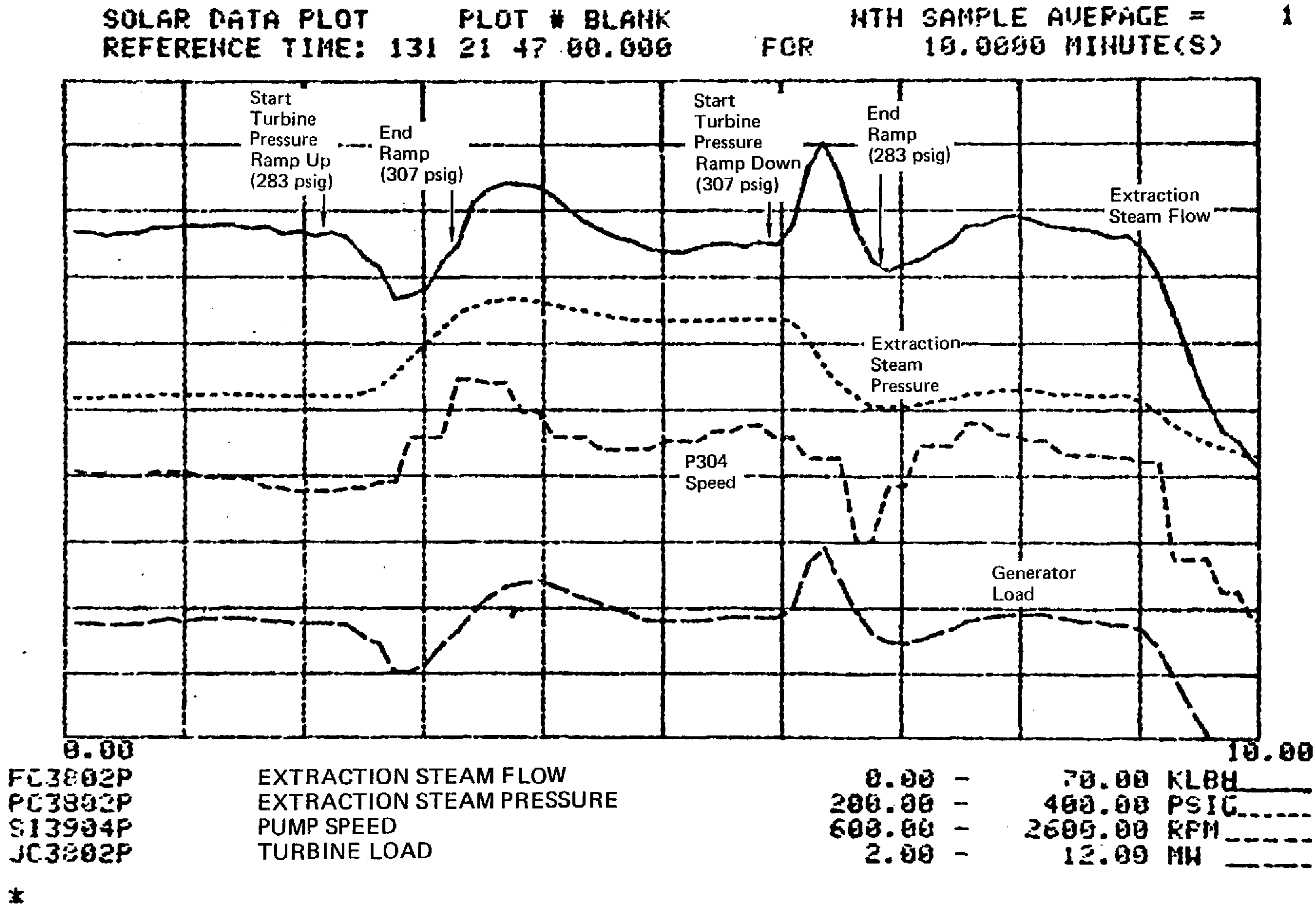


Figure 5.11-1. Extraction Load Controller Disturbance — Turbine Inlet Pressure Step Change

5.12 INTEGRATED RS/TSS CHARGE/EPGS TESTS

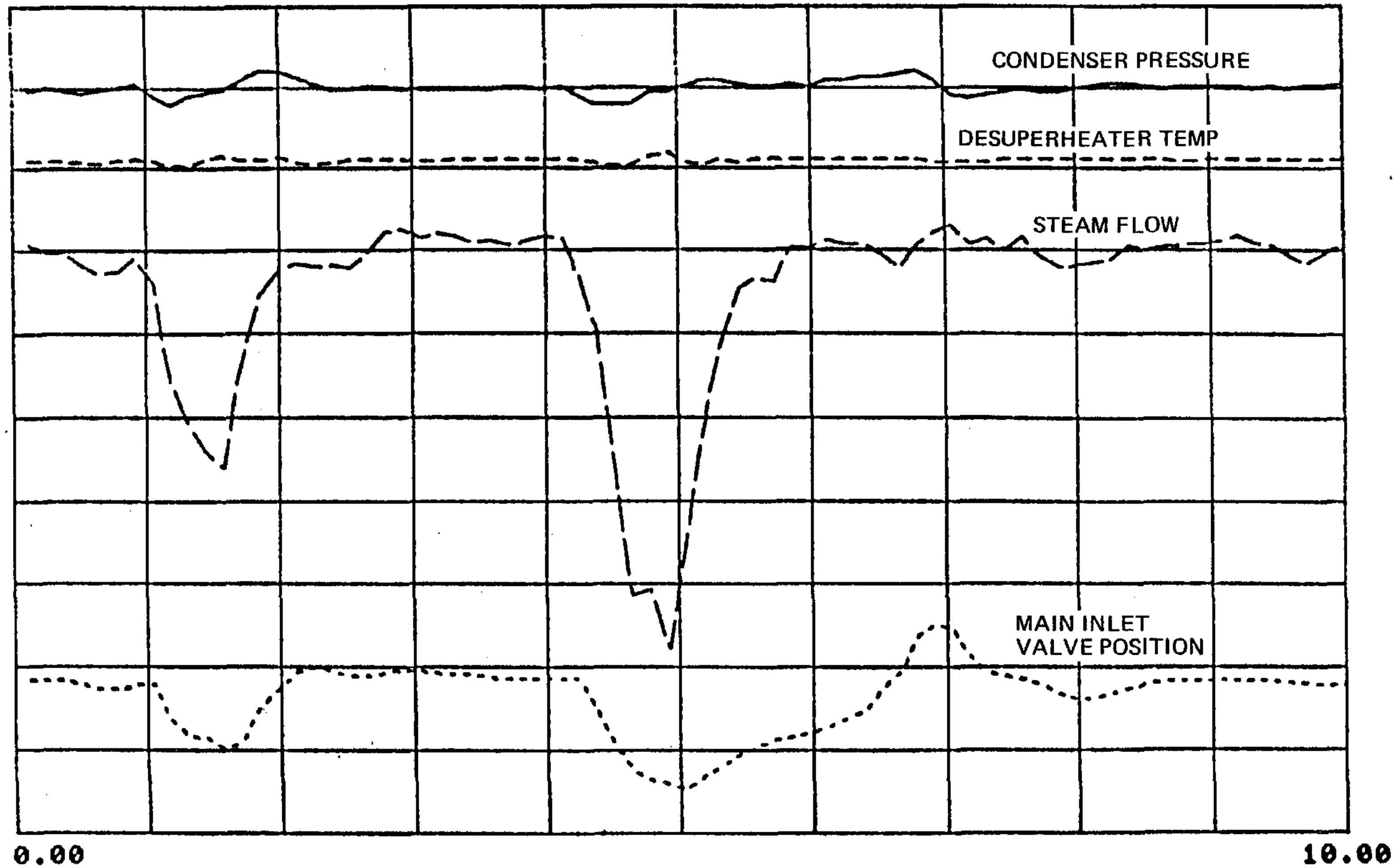
The primary operating modes tested during the 1040B test program which involved integrated receiver/TSS charge/EPGS systems were Modes 5 and 2. Typically during a cloudy day operation the plant was operated in Mode 5 with the TSS charge system in pressure control (steam dump system nominally closed). During intermittent clouds conditions when it was desirable to both generate electrical power and charge storage, operating mode 2 was selected. If clouds were severe enough in mode 2 the plant would be transitioned to Mode 5 when the turbine could not maintain minimum load. Typical cloudy day responses in these modes are discussed in the following paragraphs.

The Mode 5 system response to short duration clouds for a typical 10 minute period is shown in Figure 5.12-1 through 5.12-6. Two clouds are experienced approximately 3 minutes apart with the steam inlet valve (UV3102) in pressure control. The first noticeable effect is the receiver outlet flow decreases causing a flow disturbance into the charging train. The main inlet steam pressure controller, desuperheater temperature controller and the charging heat exchanger pressure and oil temperature controllers respond to this disturbance. Main inlet pressure variations are less than ± 10 psi and the desuperheated steam temperature excursions are less than $\pm 5^{O}F$ as shown in Figure 5.12-1. Oil temperature excursions during this cloud disturbance are less than $\pm 10^{O}F$ for a flow disturbance of approximately 40 KLBH as shown in Figure 5.12-2. Receiver temperature and pressure excursions (refer to Figure 5.12-3) during these disturbances were less than $5^{O}F$ and 20 psi respectively even though the recorded local insolation (NIP1000) changed by 700 w/m^2 due to the clouds.

Similar responses to the same cloudy day conditions but for an expanded 30 minute period are shown in Figure 5.12-4 through 5.12-6. These response demonstrated excellent temperature and pressure control on both the main inlet steam and condenseroutlet oil conditions.

The Mode 2 system responses to a major cloud disturbance leading to an operator transition from Mode 2 to Mode 5 is shown in Figures 5.12-7 and 5.12-8. In Mode 2 the main inlet steam to the charging train is in flow control (UV3102). System pressure is maintained by the turbine which is in pressure control. As the cloud reduces the receiver outlet flow (refer to

SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE = 1
REFERENCE TIME: 125 11 18 00.000 FOR 10.0000 MINUTE(S)



PC3102P	DOWNCOMER PRESSURE	1000.0 -	1500.0 PSIG	————
ZI3102P	VALVE POSITION	0.0 -	100.0 PCT	....
TC3105P	DESUPERHEATER TEMPERATURE	0.0 -	800.0 DEGF	-----
FI3205P	INLET STEAM FLOW	0.0 -	75.0 KLBH	—— —-

Figure 5.12-1. TS Charge System, Mode 5 — Cloud disturbance — Steam Conditions

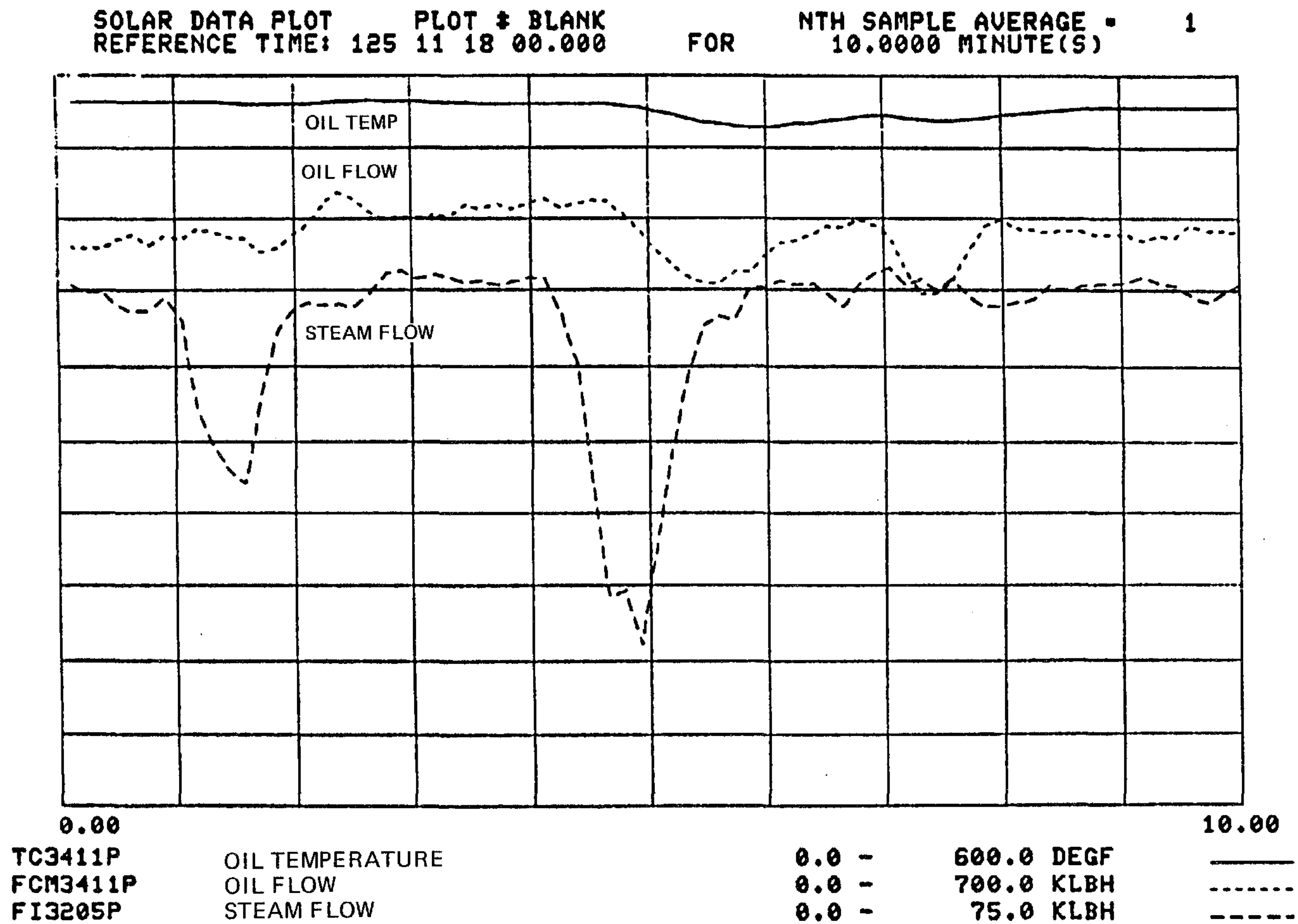
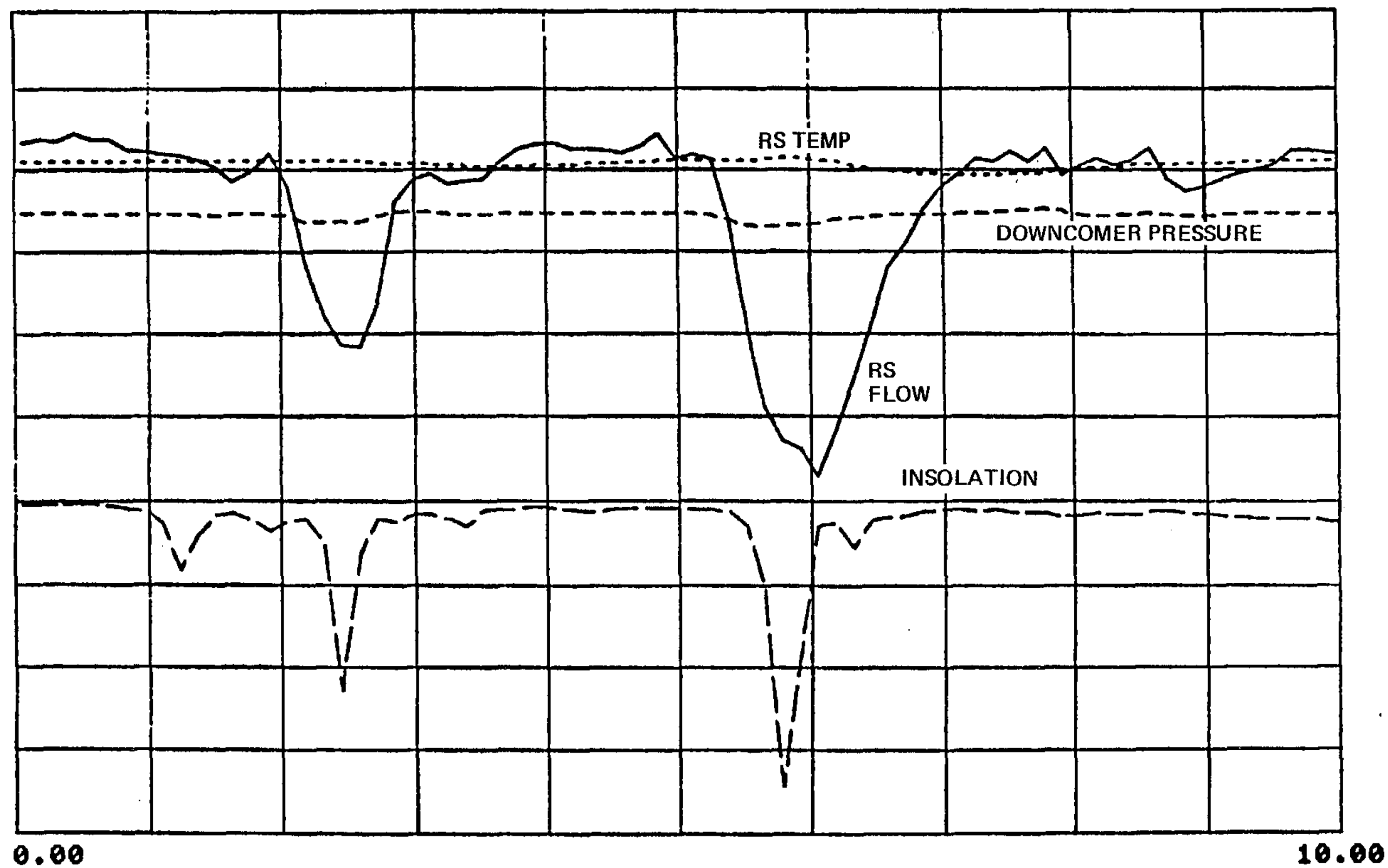


Figure 5.12-2 TS Charge System, Mode 5-Cloud Disturbance - Oil Conditions

SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE = 1
REFERENCE TIME: 125 11 17 00.000 FOR 10.0000 MINUTE(S)



FI2233P	RECEIVER OUTLET FLOW	0.0 -	100.0	KLBH	————
TI2903P	RECEIVER OUTLET TEMPERATURE	0.0 -	1000.0	DEGF	-------
PI2902P	DOWNCOMER PRESSURE	0.0 -	2000.0	PSIG	-----
NIP1000P	INSOLATION	0.0 -	2000.0	W/SM	———

Figure 5.12-3 TS Charge System, Mode 5-Cloud Disturbance - Receives Outlet Conditions

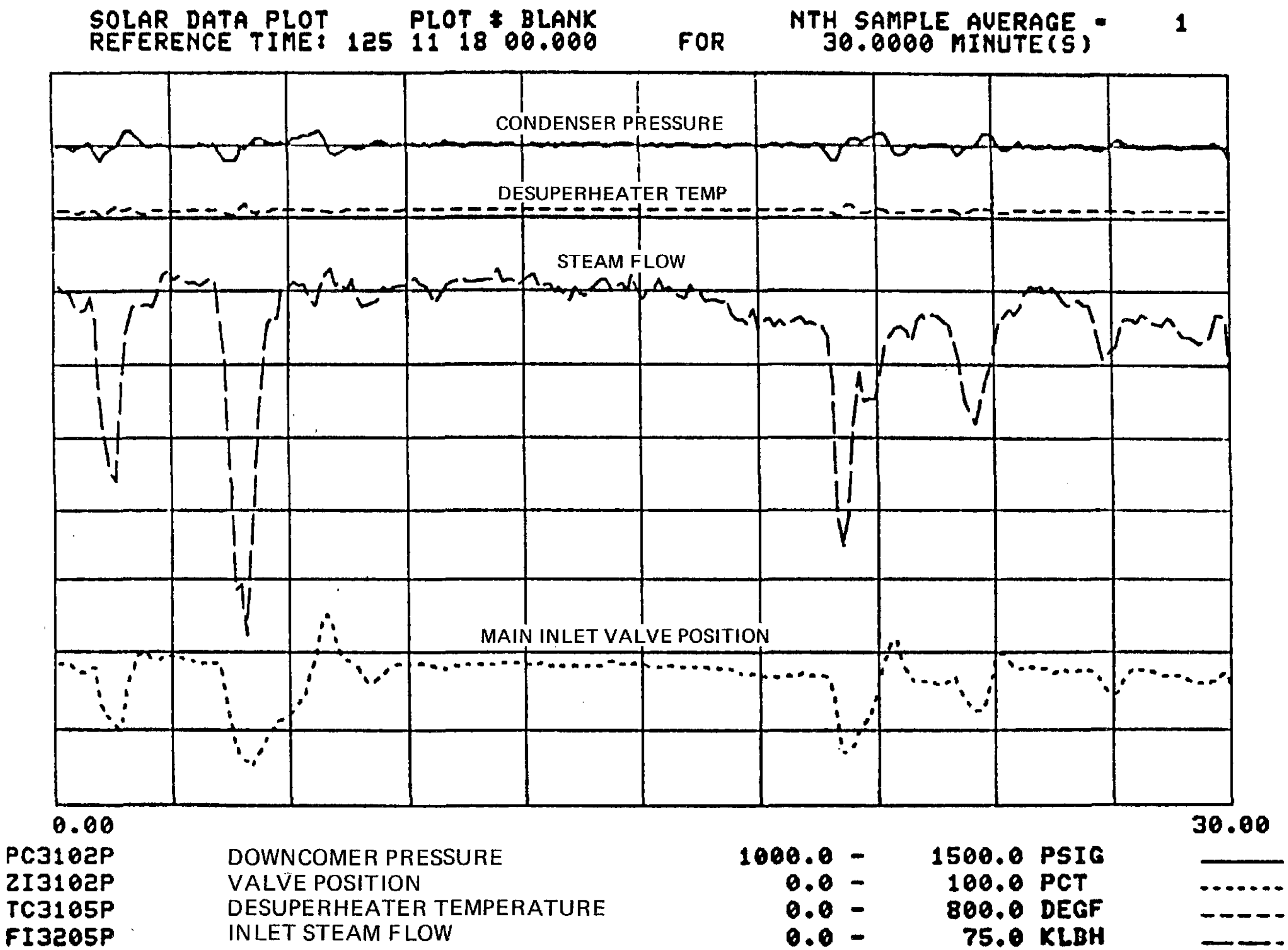
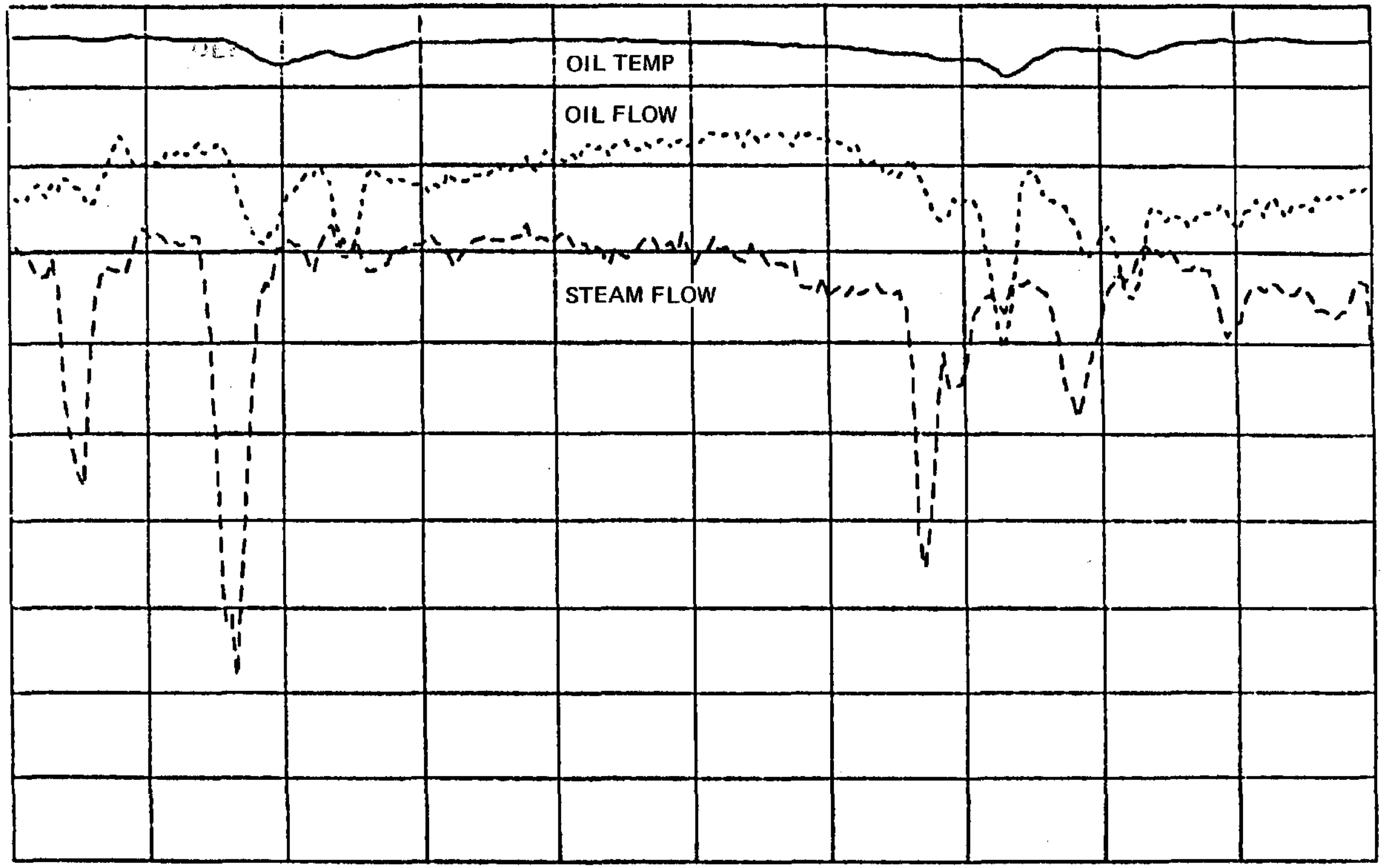


Figure 5.12-4 TS Charge System, Mode 5-Cloud Disturbances - Steam Conditions

SOLAR DATA PLOT   PLOT # BLANK   NTH SAMPLE AVERAGE = 1
REFERENCE TIME: 125 11 18 00.000   FOR   30.0000 MINUTE(S)



0.00 … 30.00

TC3411P	OIL TEMPERATURE	0.0 -	600.0 DEGF	————
FCM3411P	OIL FLOW	0.0 -	700.0 KLBH	-------
FI3205P	STEAM FLOW	0.0 -	75.0 KLBH	-----

Figure 5.12-5 TS Charge System, Mode 5-Cloud Disturbance - Oil Conditions

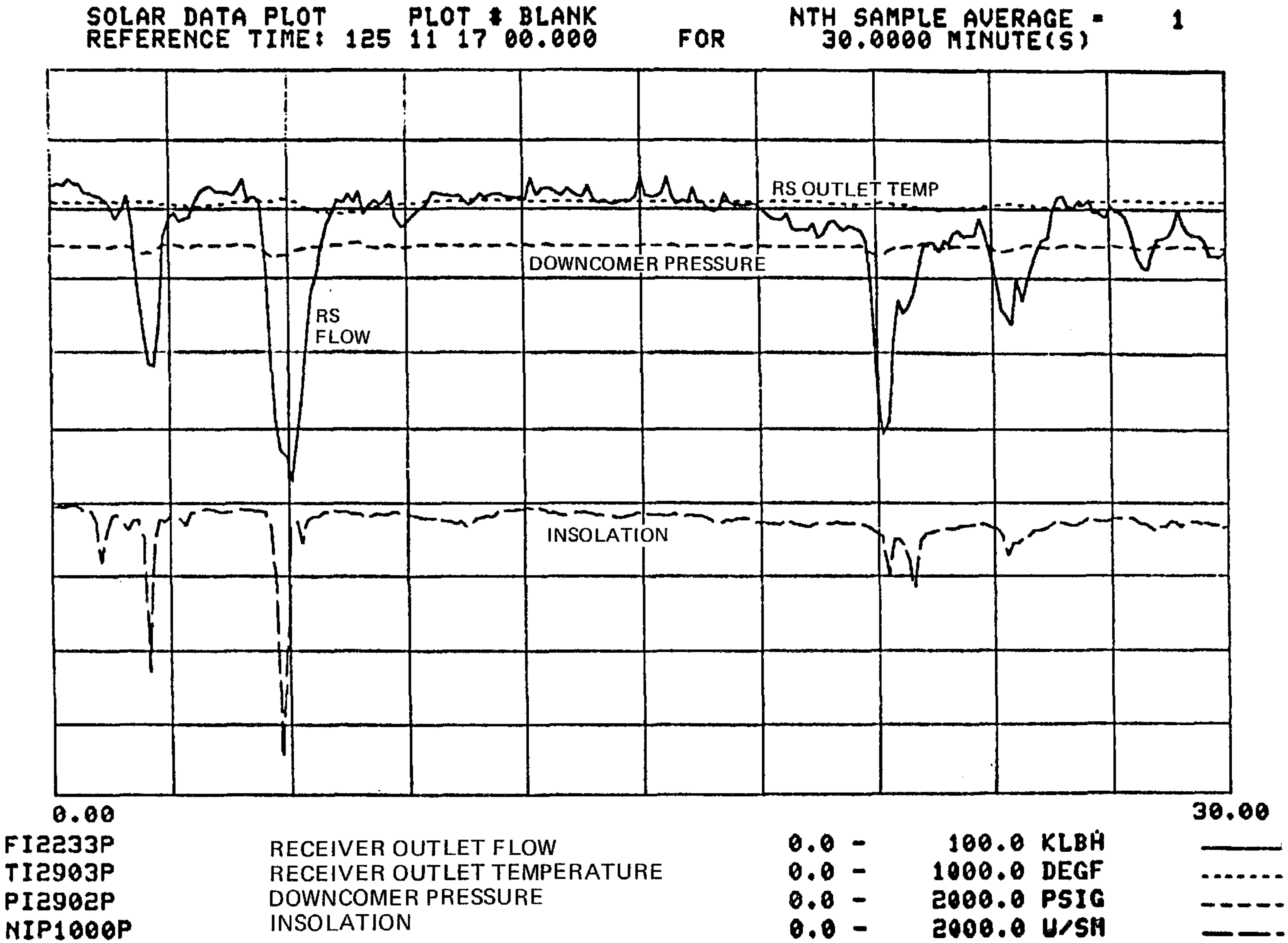


Figure 5.12-6 TS Charge System, Mode 5-Cloud Disturbance - Receives Outlet Conditions

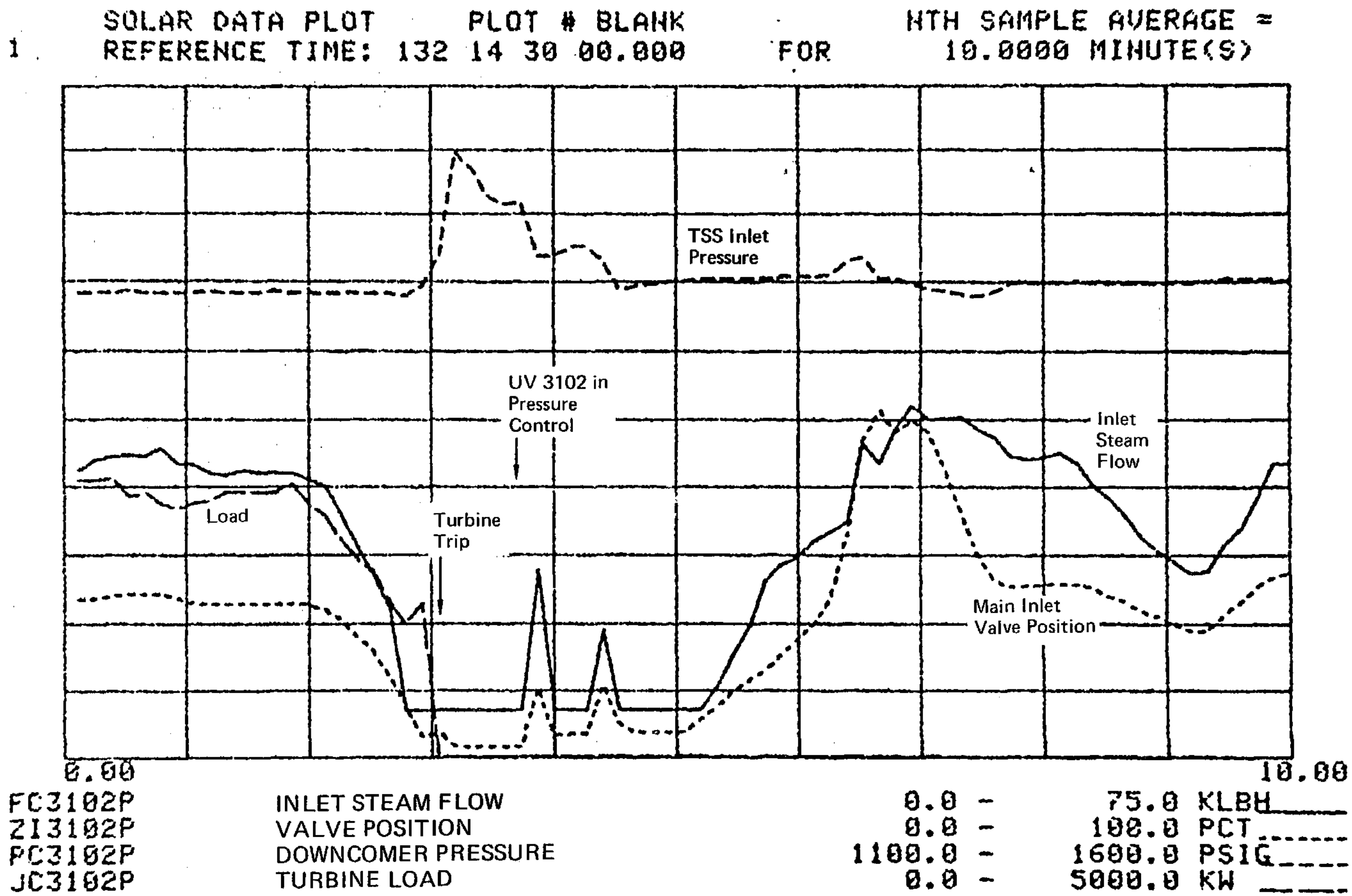


Figure 5.12-7. Mode 2 to Mode 5 Transition — Cloud Disturbance

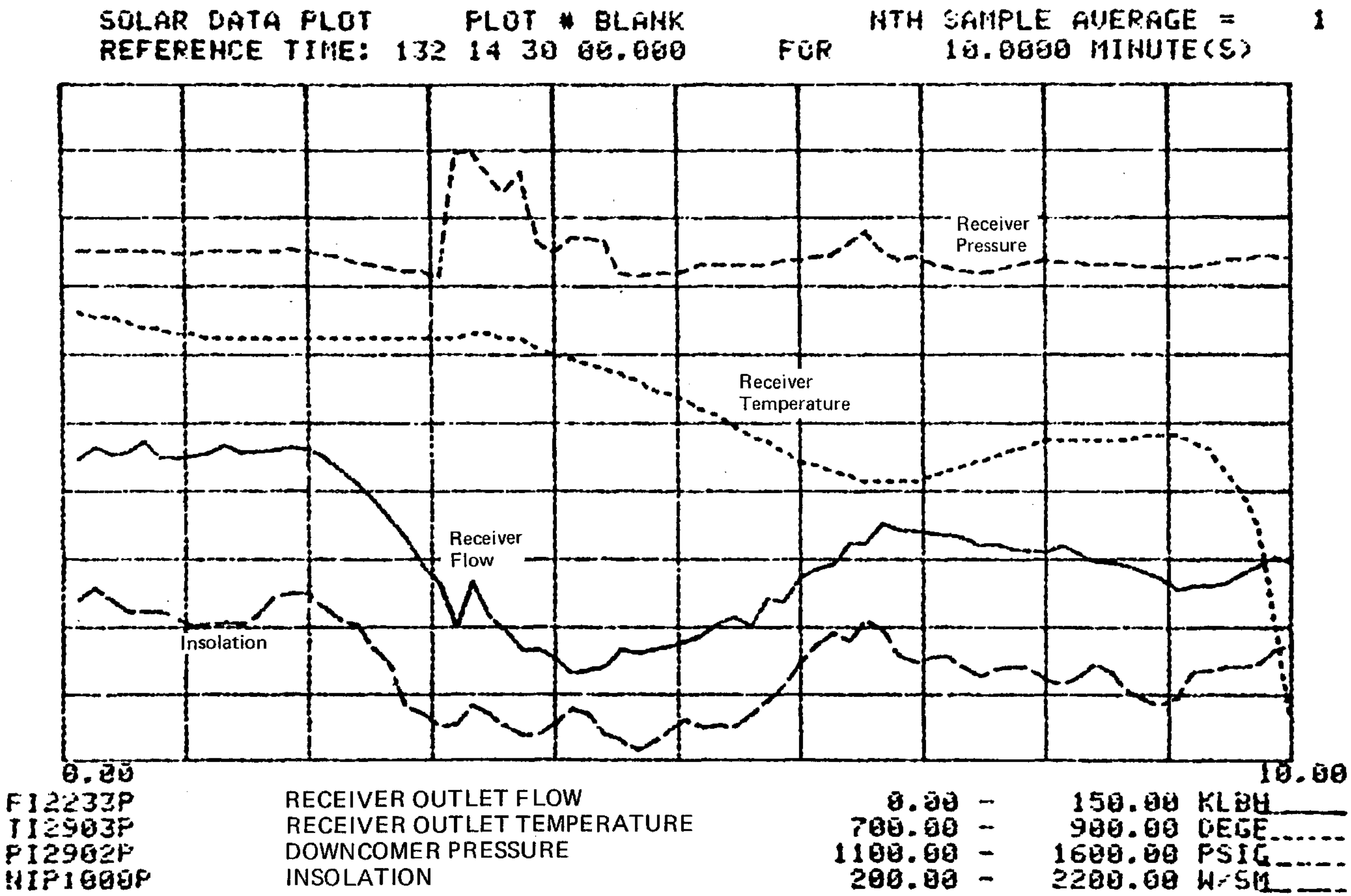


Figure 5.12-8. Mode 2 to Mode 5 Transition — Cloud Disturbance

Figure 5.12-8) pressure and flow control are maintained until the turbine shuts down at a low load of 0.5 MW. With the turbine stop valve closed, residual receiver flow increases system pressure until the steam dump system overrides at 1525 psi. The operator manually transfers the main inlet valve (UV3102) from flow control to pressure control and the system completely recovers within 1 minute. The charging system continues to maintain the desired pressure in the midst of continuing cloud disturbances. This demonstrates the ability of the integrated Receiver/TSS Charge System to respond to clouds and forced mode transitions due to extreme system upsets.

5.13 INTEGRATED RS/TSS EXTRACTION/EPGS TESTS

The primary operating modes tested during the 1040B test program which involved the Receiver TSS Extraction and the EPGS systems were Modes 5, 4 and 6. During a cloudy day operation the system was set in a Mode 5 (charge only mode). If heavy intermittent clouds existed and power was to be generated Mode 4 was used until full cloud coverage forced a transition to Mode 6 (extraction only). Typical responses for these conditions are discussed in the following paragraphs.

The RS was supplying steam to the TS charge system (Mode 5) when the TS extraction train 2 was started up and the turbine rolled and brought on-line at approximately 1643 hrs. At that time the plant was in Mode 4 (see Figures 5.13-1 through 5.13-2). At approximately 1824 hrs pressure control was moved to the admission inlet valve and at 1826 hrs the extraction boiler inlet valve, PV3802 was put in flow control. The insolation (NIP1000) slowly decreased until steam flow to the charging train was very low. At approximately 1850 hrs the heliostats were defocused, charging operation was shutdown and the plant was then in Mode 6. Figures 5.13-3 through 5.13-5 show the important plant parameters during this time. Very little disturbance is noticed when going from one mode to another.

At approximately 1915 hrs the extraction system was put into load control with a set point of 2 MW. Figures 5.13-4 and 5.13-5 show the response to this configuration change. At 1915 hrs the load SP was stepped from 2 MW to 4 MW. At 1922 hrs the SP was stepped back to 2 MW. Figures 5.13-6 and 5.13-7 show the responses. A slight load overshoot is seen on a step up but the step down is nicely damped. Both steps show quick response to a steady state value.

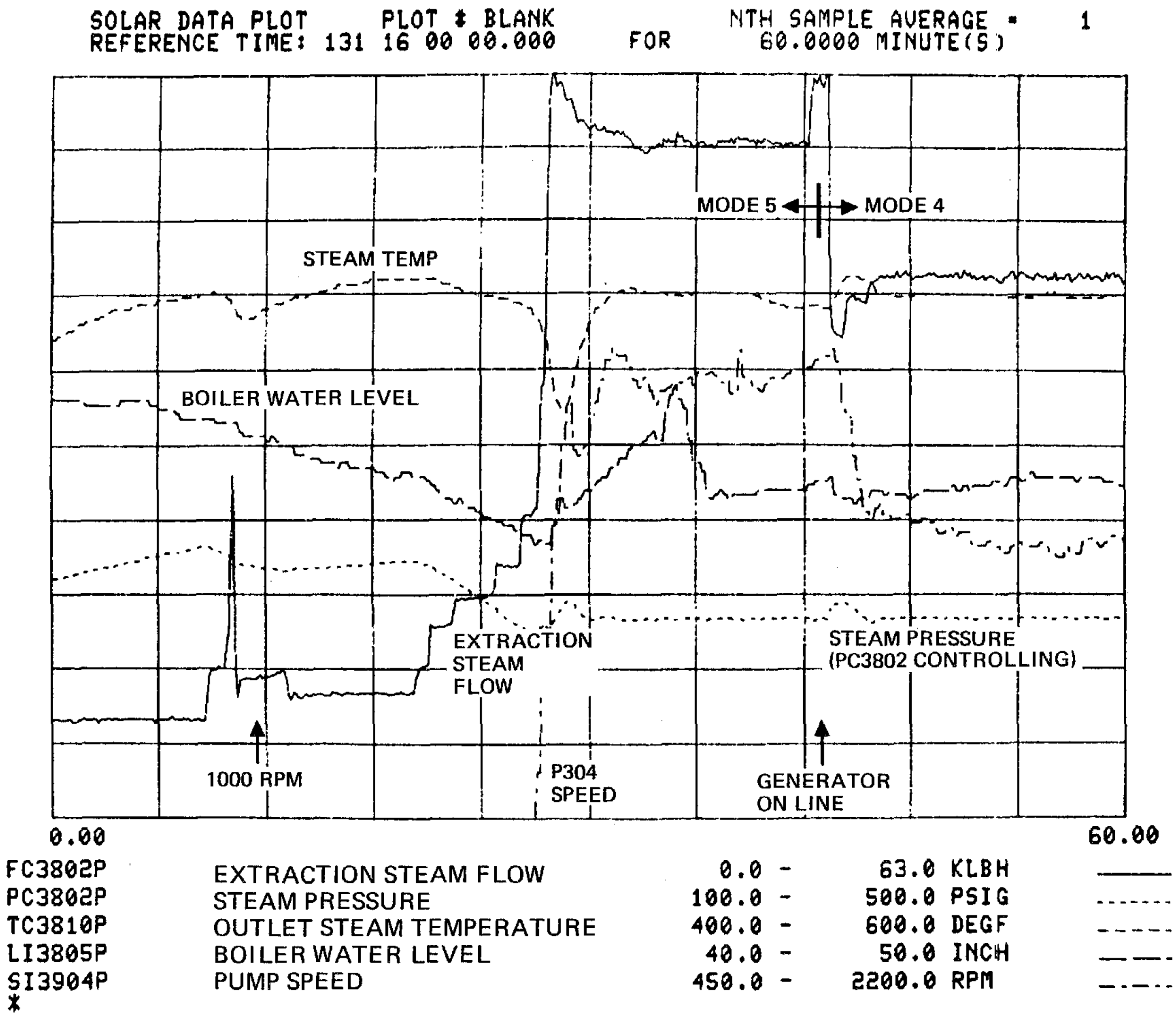


Figure 5.13-1 Integrated RS/TSS Extraction/EPGS Tests - Mode 5 to Mode 4

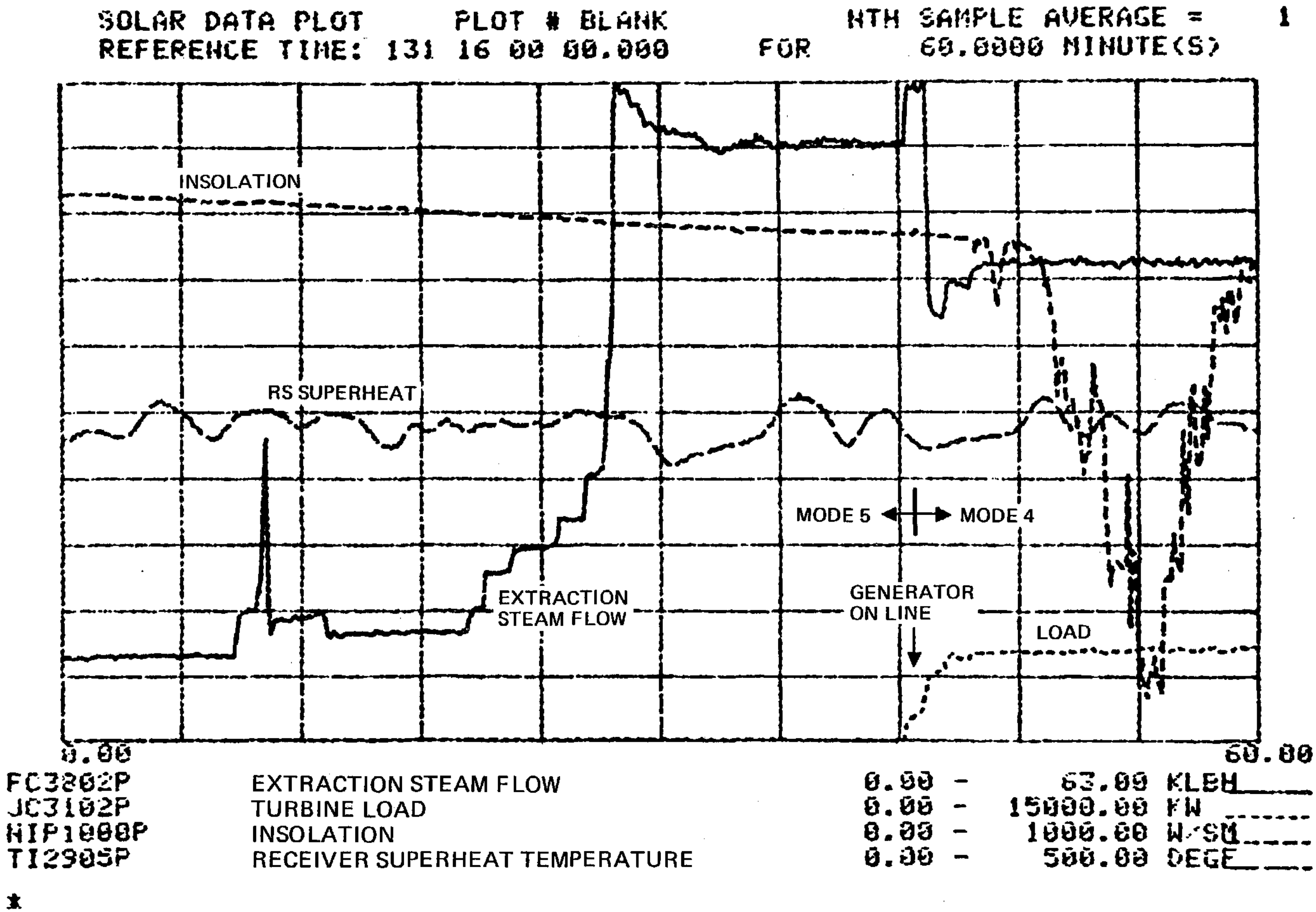


Figure 5.13-2 - Integrated RS/TSS Extraction/EPGS Tests - Mode 5 to Mode 4

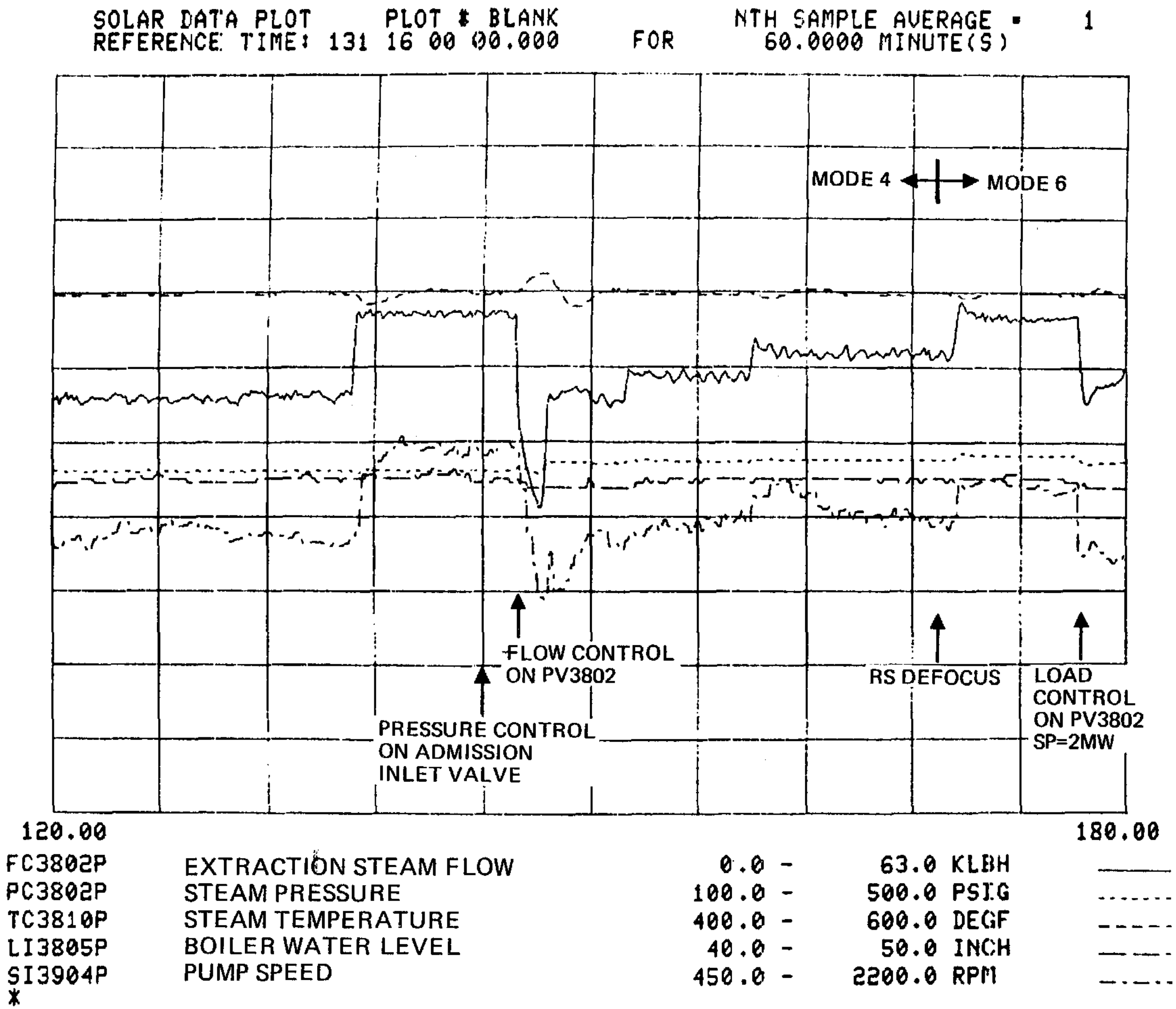
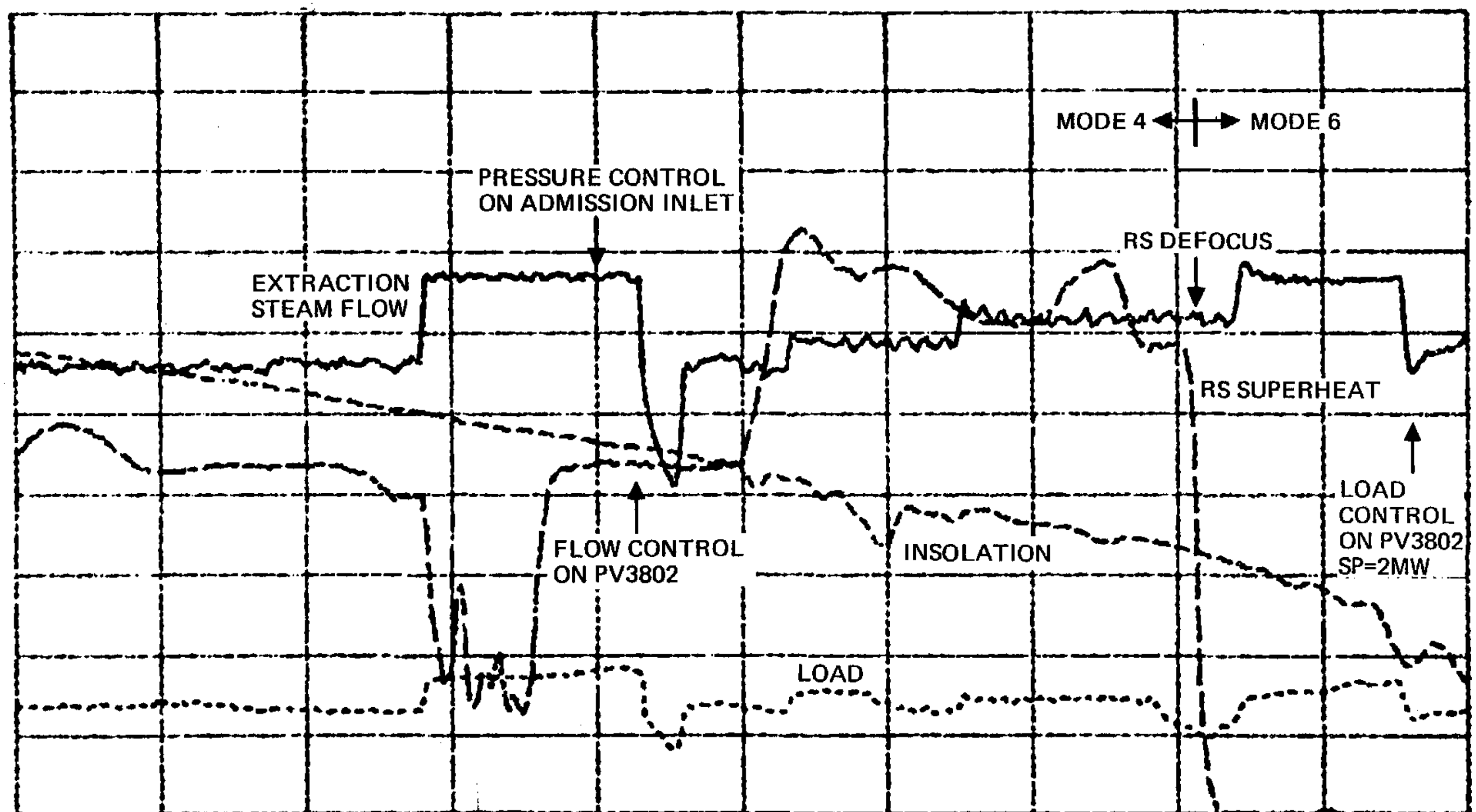


Figure 5.13-3 - Integrated RS/TSS Extraction/EPGS Tests - Mode 4 to Mode 6

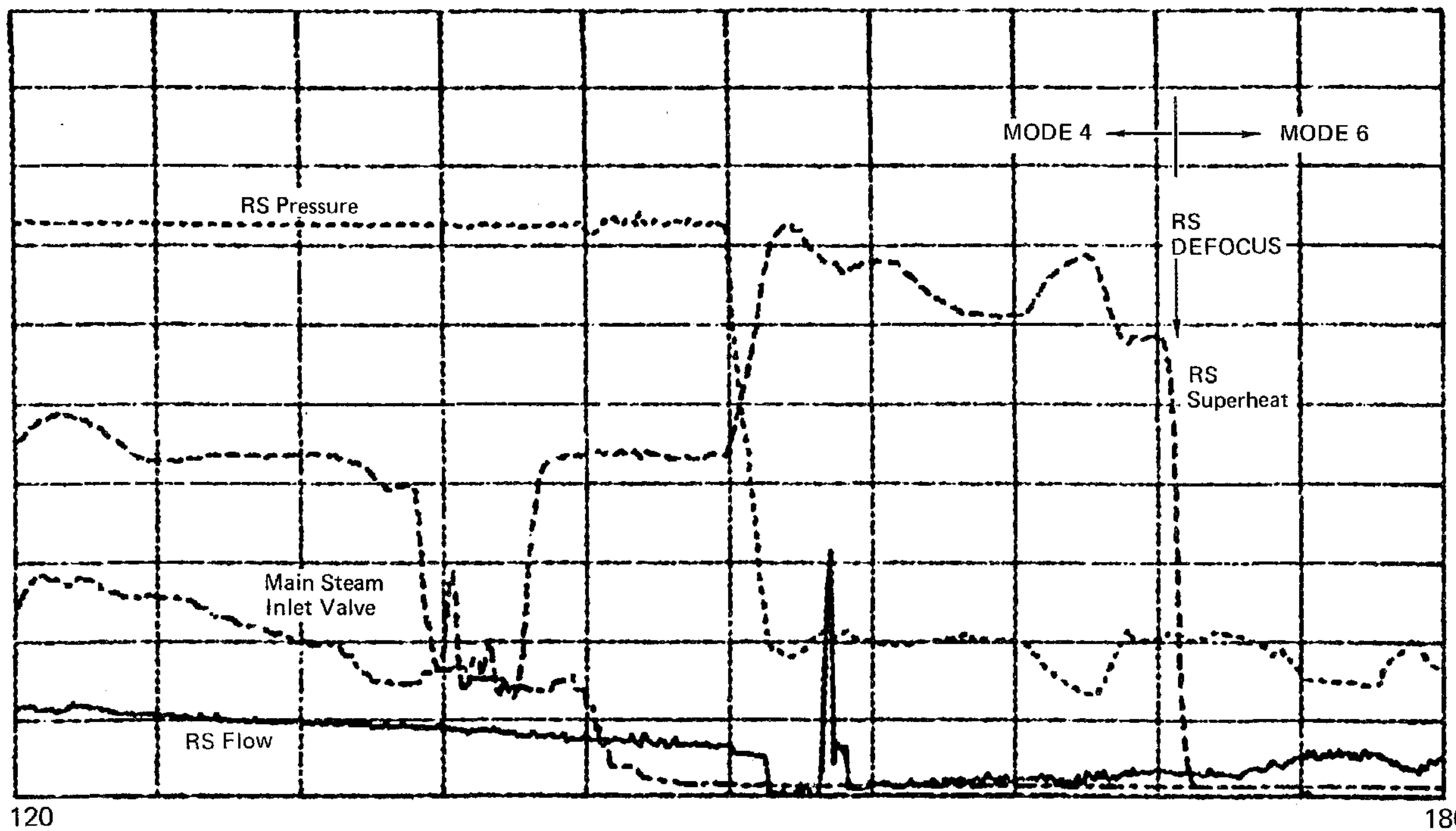
SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE = 1
REFERENCE TIME: 131 16 00 00.000 FOP 60.0000 MINUTE(S)



FC3802P	STEAM FLOW	0.00 -	63.00 KLBH
JC3102P	TURBINE LOAD	0.00 -	15000.00 KW
NIP1000P	INSOLATION	0.00 -	1000.00 W/SM
TI2505P	RECEIVER SUPERHEAT TEMPERATURE	0.00 -	500.00 DEGF

Figure 5.13-4 Integrated RS/TSS Extraction/EPGS Tests—Mode 4 to Mode 6

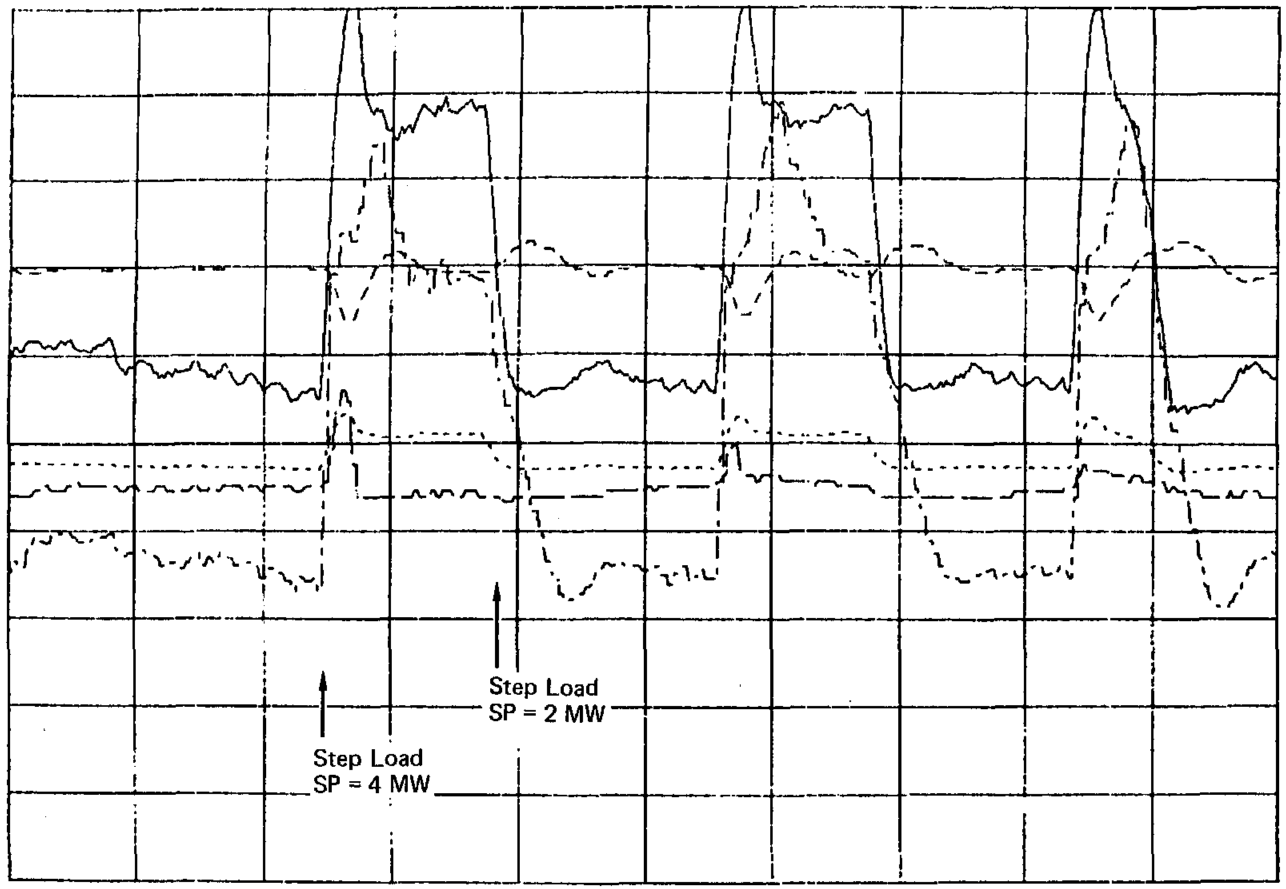
SOLAR DATA PLOT PLOT # BLANK NTH SAMPLE AVERAGE = 1
REFERENCE TIME: 131 16 00 00.000 FOR 60.0000 MINUTE(S)



FI2233P	RECEIVER OUTLET FLOW	0.00 -	400.00 KLBH
PI2902P	DOWNCOMER PRESSURE	0.00 -	2000.00 PSIG
TI2905P	RECEIVER SUPERHEAT TEMPERATURE	0.00 -	500.00 DEGF
ZI3102P	TSS MAIN STEAM INLET VALVE POSITION	0.00 -	100.00 PCT

Figure 5.13-5. Integrated RS/TSS Extraction/EPGS Tests — Mode 4 to Mode 6

SOLAR DATA PLOT   PLOT # BLANK   NTH SAMPLE AVERAGE =   1
REFERENCE TIME: 131 16 00 00.000   FOR   60.0000 MINUTE(S)



180.00 240.00

FC3802P	STEAM FLOW	0.0 -	63.0 KLBH	————
PC3802P	STEAM PRESSURE	100.0 -	500.0 PSIG	-------
TC3810P	STEAM TEMPERATURE	400.0 -	600.0 DEGF	– – – –
LI3805P	BOILER WATER LEVEL	40.0 -	50.0 INCH	—— —— .
SI3904P	PUMP SPEED	450.0 -	2200.0 RPM	— . — . .

*

Figure 5.13-6. Integrated RS/TSS Extraction/EPGS Tests — Load Control Step SP

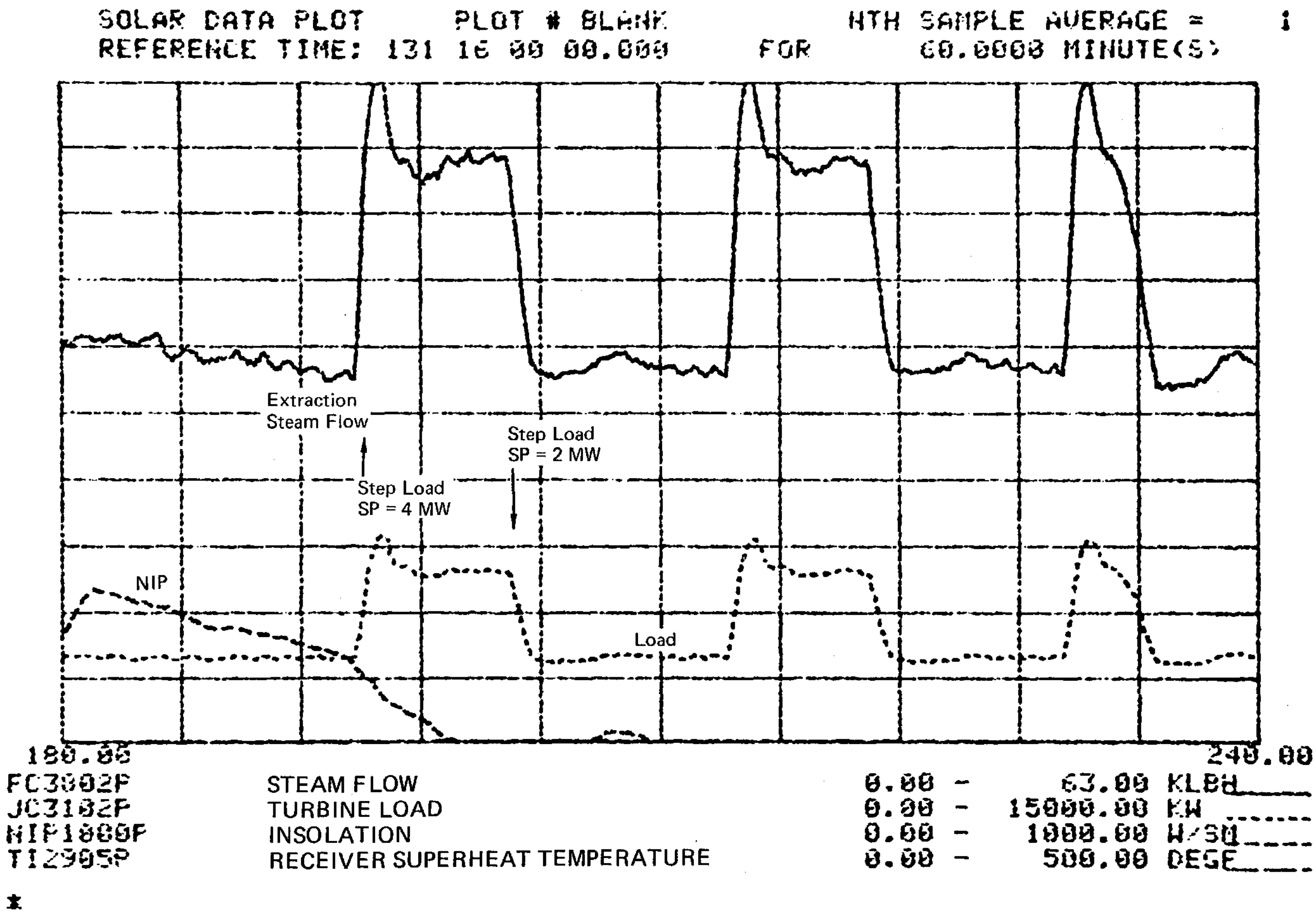


Figure 5.13-7. Integrated RS/TSS Extraction/EPGS Tests — Load Control Step SP

5.14 TSS CHARGING LOOP STARTUP TESTS

In the course of daily operation with startup of the TSS charging system procedures were developed to provide a startup which was both efficient from an energy standpoint and simple from an operators viewpoint. Figures 5.14-1 and 5.14-2 shows a sequence of events for an early morning startup of charging train 1 which are summarized below.

Beginning with the start of the charging oil pump the condenser is allowed to establish an oil flow rate before pressurizing the steam side of the condenser. This pressurizing must be done slowly to protect the condenser from any harsh temperature cycles. A large differential pressure exists across the steam inlet valve UV3102 which will result in a few steam flow peaks until the pressure equalizes. Startup criteria dictates that there must be at least 1200-1300 psi steam pressure available out of the receiver. As the receiver outlet pressure is ramped from 750 to 1450 psi, the oil temperature will follow. At operating oil temperature conditions (570^{0}F) the oil loop switches into auto to accommodate the increase in steam flow from the receiver.

5.15 TSS EXTRACTION LOOP STARTUP TESTS

Experience has dictated that the extractions trains be warmed and pressurized using the TSS auxiliary oil pump. In general, the boiler level will be checked and filled if required, the aux oil pump will be started with the pressure control valve, PV3910, in manual and 40% open. The pressure in the boiler gradually rises and at 100 psig the pressure control valve is put into auto. Figure 5.15-1 shows a typical pressurization sequence. In this example the valve had been opened in several steps by the operator to 100% open. Shortly after the pressure control valve was put into auto the pressure climbed above setpoint value and the valve closed down to control to 120 psig. This is a slow acting process because the pump is small compared to the boiler size. However speed is not important and as can be seen, the process is controlled very well in steady state.

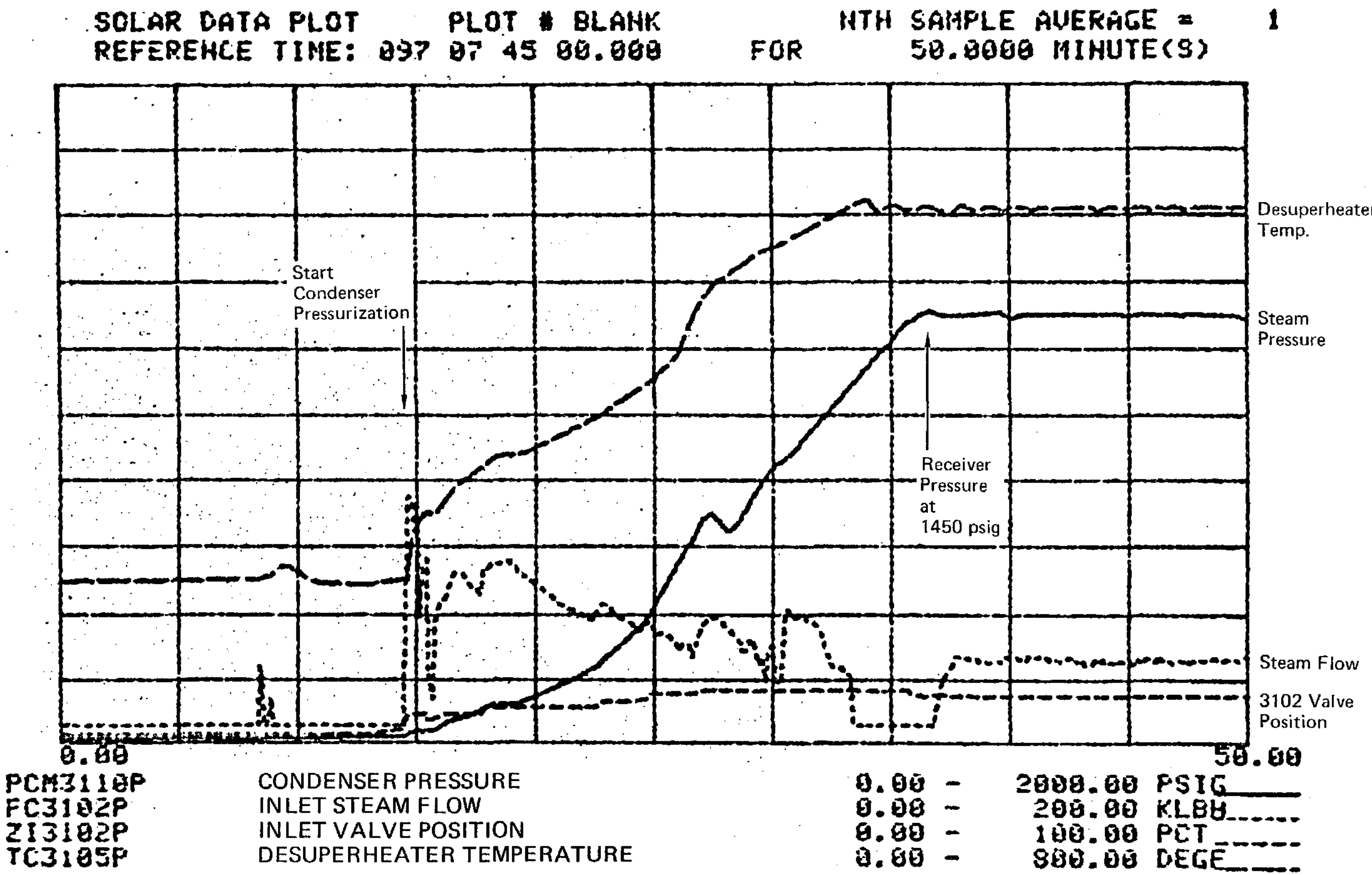


Figure 5.14-1. Charge Train 1 Startup — Steam Side

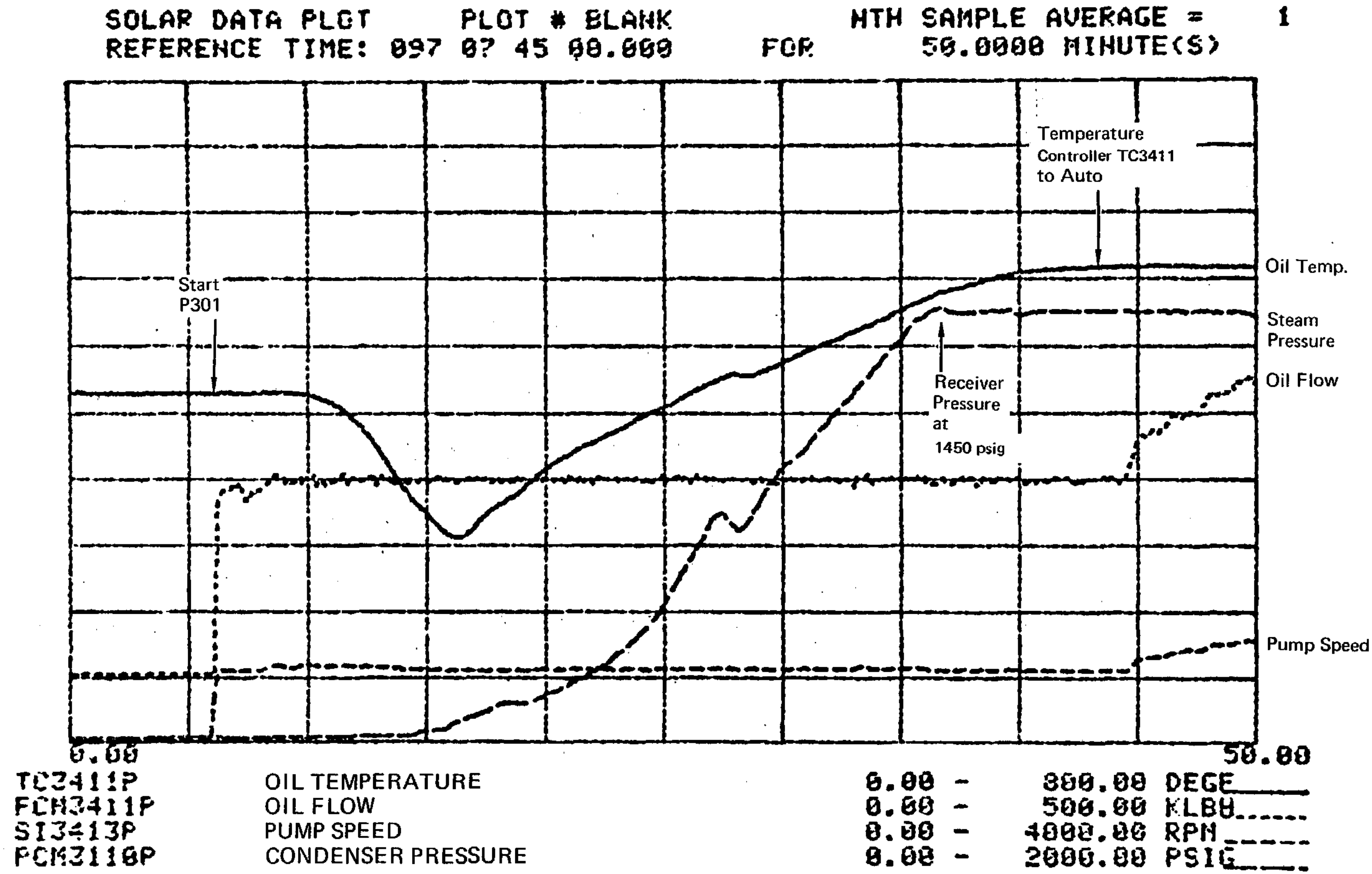
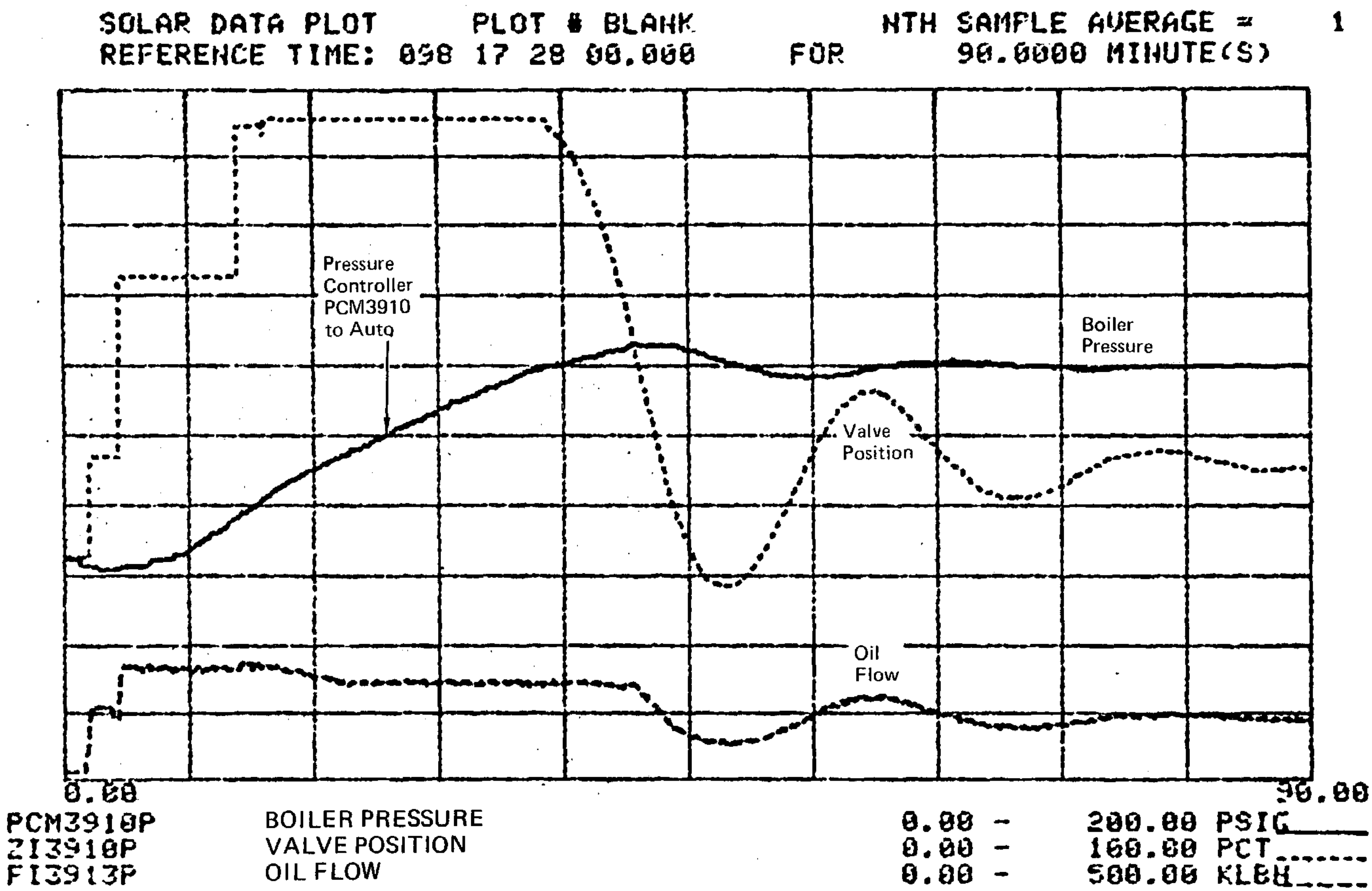


Figure 5.14-2. Charge Team 1 Startup — Oil Side



*

Figure 5.15-1. TSS Extraction Loop Startup — Aux Oil Pump

Section 6

SPECIAL STUDIES

6.1 TSU EXTERNAL HEAT LOSS ANALYSIS

In order to properly evaluate the energy storage performance of the TSU, the energy losses from the TSU to the environment must be known. During the period from 5 November 1982 to 24 November 1982 there was a planned outage of Solar One during which the fully-charged TSU was allowed to lose heat to its surroundings without operational interference. The energy decay from the TSU was monitored during this time by observing the TSU temperatures (as described previously in Section 3.0), as well as observing the temperatures in the foundation under the TSU (as described previously in Section 3.0). In the TSU, the energy is computed using the temperatures TE3009A through TE3010N (see Figure 3.7-2) and the equations

$$T_m = (T_{n-1} + T_n)/2.0$$

$$\text{Energy} = \sum_{n=1}^{26} A\, L_n \left[(f_{o_n}\, \rho_{o_n}\, cp_{o_n} + f_{R_n}\, \rho_{R_n}\, cp_{R_n} + f_{s_n}\, \rho_{s_n}\, cp_{s_n}) T_m\right] - E_{ref}$$

where E_{ref} is the energy evaluated at a temperature of 67^{o}F or 425^{o}F as appropriate, and

A	=	cross sectional area of the TSU
L_n	=	TSU horizontal element thickness
f_{o_n}, f_{R_n}, f_{s_n}	=	fraction of oil, rock/sand, steel in the nth element
ρ_{o_n}, ρ_{R_n}, ρ_{s_n}	=	density of oil, rock/sand, steel in the nth element
cp_{o_n}, cp_{e_n}, cp_{s_n}	=	specific heat of oil, rock/sand, steel in the nth element
T_m	=	mean temperature of nth element (see above equation)

The TSU temperature-dependent and physical properties are shown in Table 6.1-1. A typical energy summation for 5 November 1982 is shown in Figure 6.1-1. The total energy content of the TSU, calculated at specific times during this

Table 6.1-1. TSU Bed Thermophysical Properties

Caloria HT-43		
ρ	$= 55.0 - 0.0241T$	lb/ft^3
cp	$= 0.4 + 5 \times 10^{-4}T$	$B/lb\text{-}^oF$
k	$= 0.074 - 4.5 \times 10^{-5}T$	$B/h\text{-}ft\text{-}^oF$
μ	$= 10^{6.559 - 1.027 \ln T}$	lbm/h-ft
Gravel and Sand		
ρ	$= 165.0$	lb/ft^3
cp	$= 0.19 + 0.0001T$	$B/lb\text{-}^oF$

Mass of Granite Gravel in TSU = 4532 tons
Mass of Sand in TSU = 2266 tons
Mass of Caloria in TSU @ 425^{o}F = 637 tons
Void fraction of rock alone or sand alone = 0.40
Void fraction of rock and sand mixture = 0.22

outage period, is shown in Figure 6.1-2. The data show that as the contents cooled, the heat loss rate decreased. Since the TSU average temperature only drops from 559^{o}F to 529^o during this time (Reference 11) the heat loss rate would be expected to be nearly constant (the ΔT to ambient only changes by about 7%--this is probably much less than the ambient temperature and wind variability). Therefore, the initial sharp heat loss rate over the first 100 hours shown in Figure 6.1-2 may not be real, but many reflect equilibration processes occurring in the TSU. If a constant heat loss rate is assumed, the average loss rate is .095 MW or 1.25% of the TSU energy per day. It is of interest to determine the proportion of the total lost through the TSU foundation, top and sides. A one-dimensional axial thermal model of the TSU, foundation, and underlying earth was used to determine the transient warmup and stabilization of the TSU foundation. This was shown previously in Figure 3.8-7 and Table 3.8-1, and discussed in Section 3.0. This computer model calculated the losses through the foundation, as shown in Table 6.1-2; the

INPUT

```
ENTER TEMPS. TE3009A,TE3009B,TE3009C,TE3009D,TE3009E
.575.,576.,576.,575.,574.

ENTER TEMPS. TE3009F,TE3009G,TE3009I,TE3009K,TE3009M
?574.,574.,573.,572.,570.

ENTER TEMPS. TE3009P,TE3009R,TE3009T,TE3009V,TE3009X
?570.,566.,563.,560.,559.

ENTER TEMPS. TE3009Z,TE3010B,TE3010D,TE3010F,TE3010G
?557.,555.,553.,551.,549.

ENTER TEMPS. TE3010H,TE3010I,TE3010J,TE3010K,TE3010L
?549.,549.,547.,546.,546.

ENTER TEMPS. TE3010M AND TE3010N
?514.,477.
```

OUTPUT

```
INDIVIDUAL SLICE HEAT CONTENT
L = THE INDIVIDUAL SLICE THICKNESS
 T( 1)=575.0  L= 1.750  Q=  2.28916+007BTU
 T( 2)=576.0  L= 1.375  Q=  2.13150+007BTU
 T( 3)=576.0  L=  .875  Q=  1.52433+007BTU
 T( 4)=575.0  L= 1.000  Q=  1.85738+007BTU
 T( 5)=574.0  L= 1.000  Q=  1.84451+007BTU
 T( 6)=574.0  L= 1.000  Q=  1.84451+007BTU
 T( 7)=574.0  L= 1.500  Q=  2.76676+007BTU
 T( 8)=573.0  L= 2.000  Q=  3.66327+007BTU
 T( 9)=572.0  L= 2.000  Q=  3.63754+007BTU
 T(10)=570.0  L= 2.000  Q=  3.58612+007BTU
 T(11)=570.0  L= 2.000  Q=  3.58612+007BTU
 T(12)=566.0  L= 2.000  Q=  3.48344+007BTU
 T(13)=563.0  L= 2.000  Q=  3.40657+007BTU
 T(14)=560.0  L= 2.000  Q=  3.32982+007BTU
 T(15)=559.0  L= 2.000  Q=  3.30426+007BTU
 T(16)=557.0  L= 2.000  Q=  3.25318+007BTU
 T(17)=555.0  L= 2.000  Q=  3.20216+007BTU
 T(18)=553.0  L= 2.000  Q=  3.15118+007BTU
 T(19)=551.0  L= 1.500  Q=  2.32520+007BTU
 T(20)=549.0  L= 1.000  Q=  1.52470+007BTU
 T(21)=549.0  L= 1.000  Q=  1.52470+007BTU
 T(22)=549.0  L= 1.000  Q=  1.52470+007BTU
 T(23)=547.0  L= 1.000  Q=  1.49929+007BTU
 T(24)=546.0  L= 1.000  Q=  1.48660+007BTU
 T(25)=546.0  L= 1.000  Q=  1.48660+007BTU
 T(26)=514.0  L= 1.000  Q=  1.04910+007BTU
 T(27)=477.0  L= 1.333  Q=  7.93535+006BTU


 DATE - 110582  TIME - 1208
 TOTAL ENERGY  =  6.50762+008BTU( 1.90725+002MW-HR)
```

Figure 6.1-1. Total Energy Content for 5 November 1982

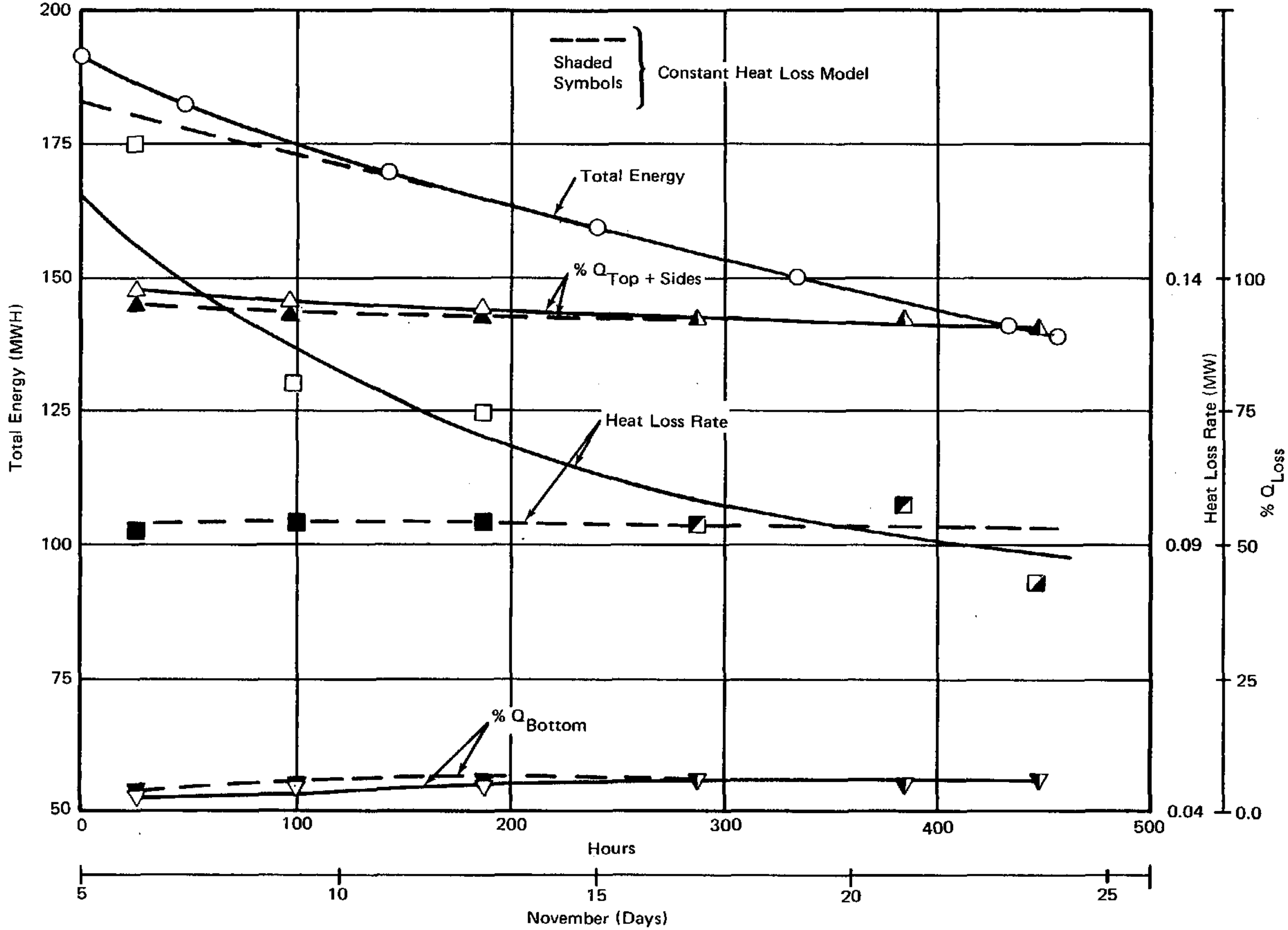


Figure 6.1-2. TSU Fully Charged Heat Loss Parameters

difference between the total heat loss and the foundation loss was charged to the top and sides, also shown in Table 6.1-2. For the constant heat loss rate assumption, the foundation loss was about 6.8% of the total and the loss through the top and sides about 93.2% of the total. These losses are about two-thirds of those originally predicted (Reference 12).

6.2 TSU PRELIMINARY PERFORMANCE EVALUATION

This preliminary performance evaluation attempts to reconcile the change in energy in the TSU with that passed through the charging and and extraction heat exchangers. This procedure is complicated by the operational constraints which occurred as the charging and extraction control loops were being tuned, and carefully controlled test conditions were not present. Further, some instrumentation was not functioning and/or was erroneous (this will be discussed further below).

The two tests selected for evaluation were:

1. 2 September 1982, where from 1300-1600 hours high power charging of the TSU was accomplished, and from 1700-2000 hrs low power extraction from the TSU was done to perform extraction controls testing.
2. 28 September 1982/2200 hrs to 29 September 1982/0500 hrs where long low power extraction occurred.

The charging/extraction performance comparison for 2 September 1982 is shown in Figure 6.2-1. The TSU charging rate from 1300 hrs to 1600 hrs (calculated from the TSU energy balance) is shown by the dashed line. The energy change in the oil flow through the charging heat exchangers (shown by the open circles) was calculated from the SDPC data at the times shown. During this charging period, extraction train 2 was also in operation and the energy extraction from the TSU oil flow is shown by the shaded area: thus the net oil energy flow to the TSU is shown by the shaded circles. The general agreement is excellent. The high TSU energy at the start of the charging operation may again be due to nonequilibration of the temperatures in the layers of the TSU, leading to calculation of excessive thermal content. The difference between the TSU energy and oil flow energy between 1500 hrs and 1630 hrs may be due to thermal losses from the oil heat exchangers and

Table 6.1-2. TSU Heat Loss Summary

			Constant Heat Loss Model			
Day/Time	Energy MWH	Total Losses MW	Energy MWH	Total Losses MW	Foundation Losses 10^{-3} MW	Top & Side Losses MW
110582/1208	190.7		182.5			
		.1648		.0933	4.05	.0893
110782/1534	182.2		177.8			
		.1211		.0942	5.46	.0887
111182/1919	170.1		168.4			
		.115		.0946	6.35	.0883
111582/0754	160.4		160.4			
		.0944		.0944	6.518	.0879
111982/0823	151.3		151.3			
		.0979		.0979	6.434	.0915
112382/0640	142.0		142.0			
		.0843		.0843	6.29	.078
112482/0802	139.9		139.9			
				Average 111182 to 112482	6.398×10^{-3} MW	.0879 MW

piping. The energy change in the steam flow through the charging heat exchangers, shown by the squares, averages only 75% of the oil flow energy. Ths discrepancy was found to be due to calibration errors in the steam flowmeters.

A similar trend was found in the extraction data from 1700 hrs to 2000 hrs in Figure 6.2-1. The energy calculated from the steam and water flowmeters gave qualitative agreement with the energy calculated from the oil flowmeters, but gave consistently lower values--again traced to calibration errors in these flowmeters.

For the long extraction on 28 September 1982/2200 hrs to 29 September 1982/0500 hrs, the agreement between the energy calculated from the oil flow and the calculated TSU energy is excellent, as shown in Figure 6.2-2. Again the energy calculated from the steam/water flow is about 75% of the oil flow energy, due to calibration errors.

6.3 THERMOCLINE STABILITY AND SHARPNESS

The temperature profiles in the TSU during the long extraction of 28 September 1982/2200 hrs to 29 September 1982/0500 hrs are shown in Figure 6.3-1. The extraction actually started at 2019 hrs and continued to 1002 hrs on 29 September 1982. The initial profile at 2019 hrs closely matches that predicted in Reference 13 for five full charge/discharge (extraction) cycles. The maximum predicted thermocline slope is about $36^{o}F/ft$, and the maximum slope during the entire 14-hr extraction varies between $30^{o}F/ft$ and $36^{o}F/ft$. Note also from Figure 6.3-1 that the minimum TSU temperature quickly approaches $415^{o}F$ and only varies by less than $10^{o}F$ over the lower 35 ft of the TSU. Similarly, the maximum temperature of the TSU at the start of extraction only varies by $\pm$ $5^{o}F$ from $575^{o}F$ over the top 20 ft of the TSU. Figure 6.3-1 clearly shows the stability of the thermocline during extraction.

For the high-rate charging of the TSU on 2 September 82 discussed previously, the TSU temperature profiles at the start and end of charging are shown in Figure 6.3-2. The thermocline extends over 19 ft at $11.9^{o}F/ft$ at

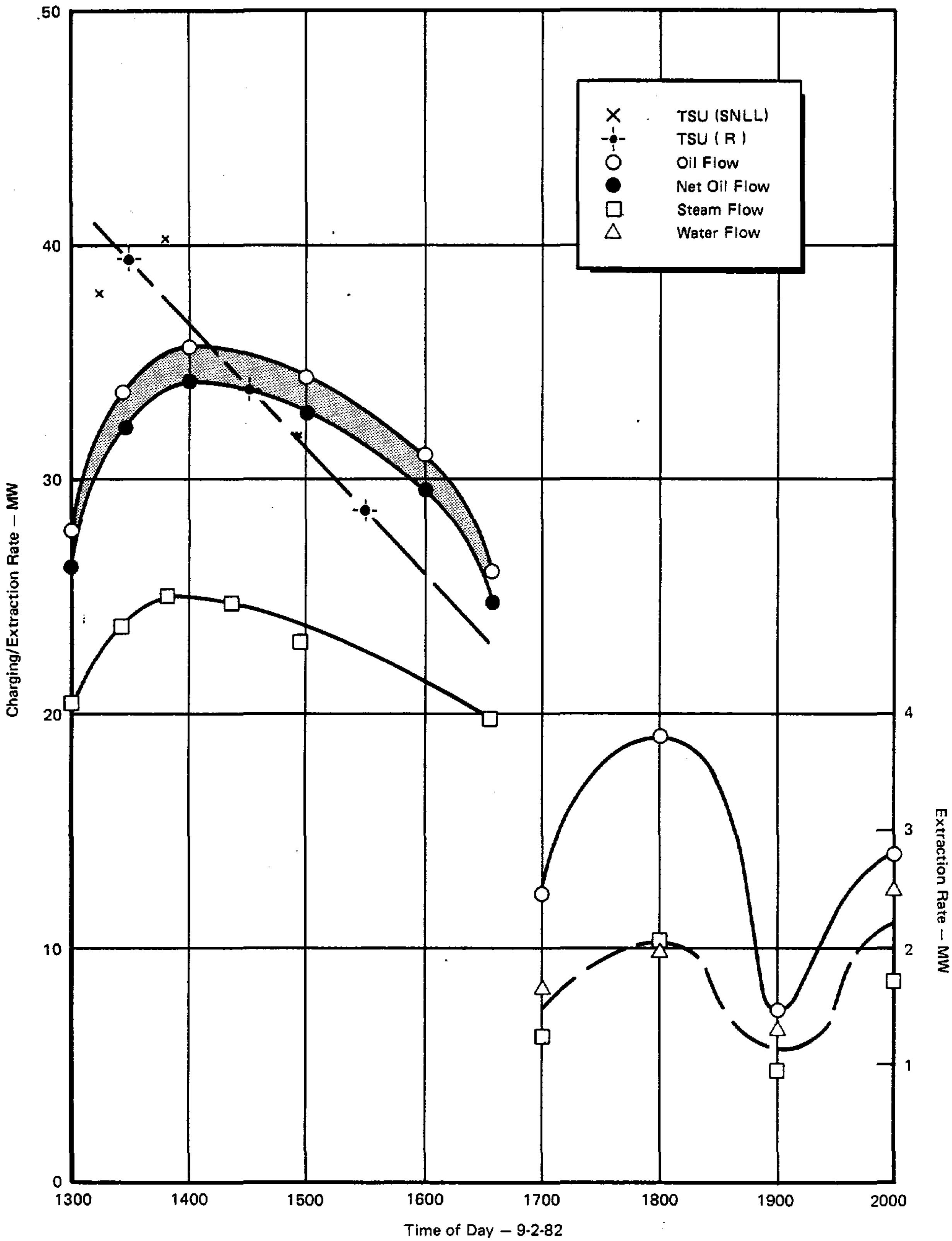


Figure 6.2-1. TSU/HEX Performance Comparison

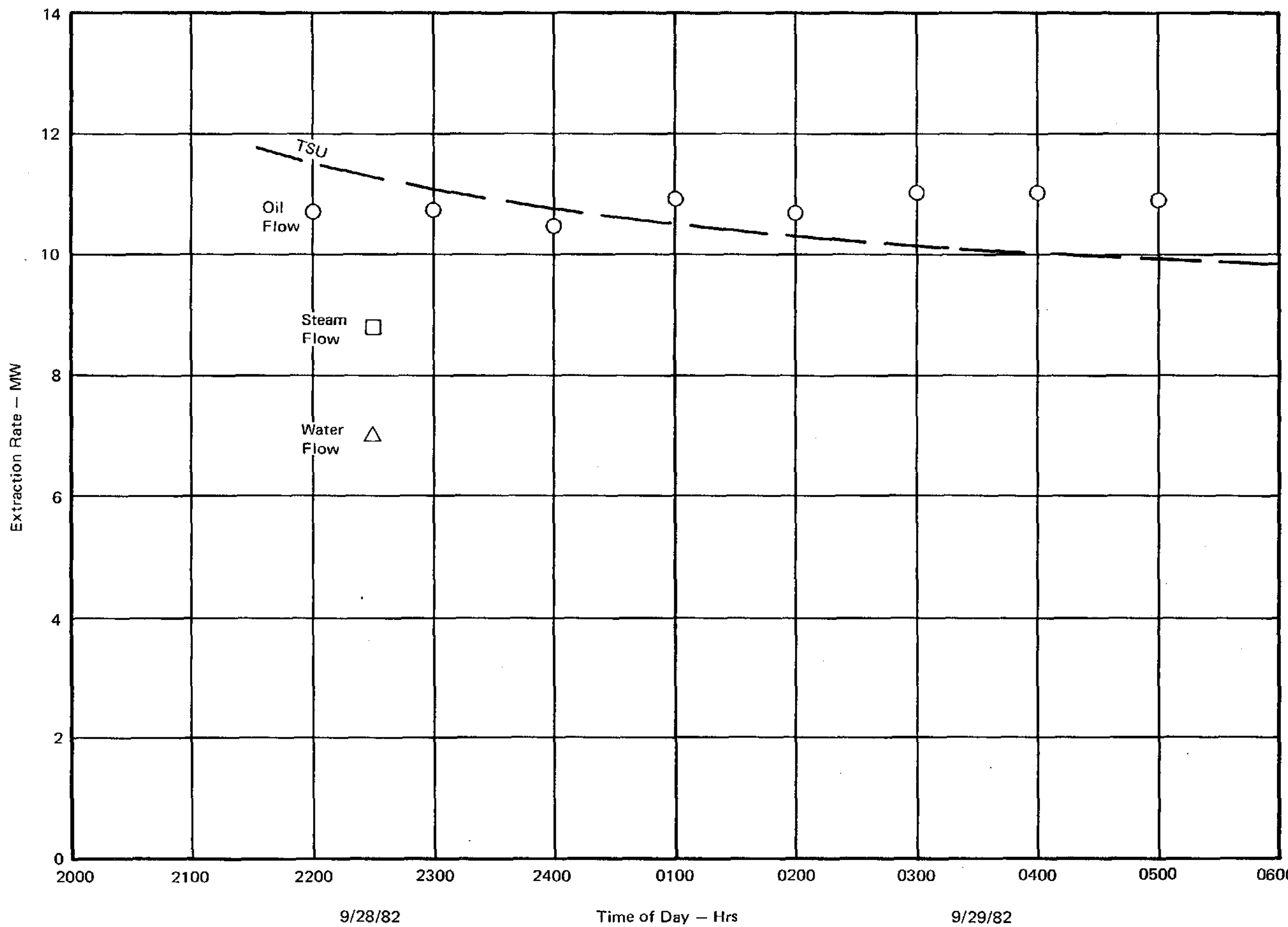


Figure 6.2-2. Extraction Performance Comparison

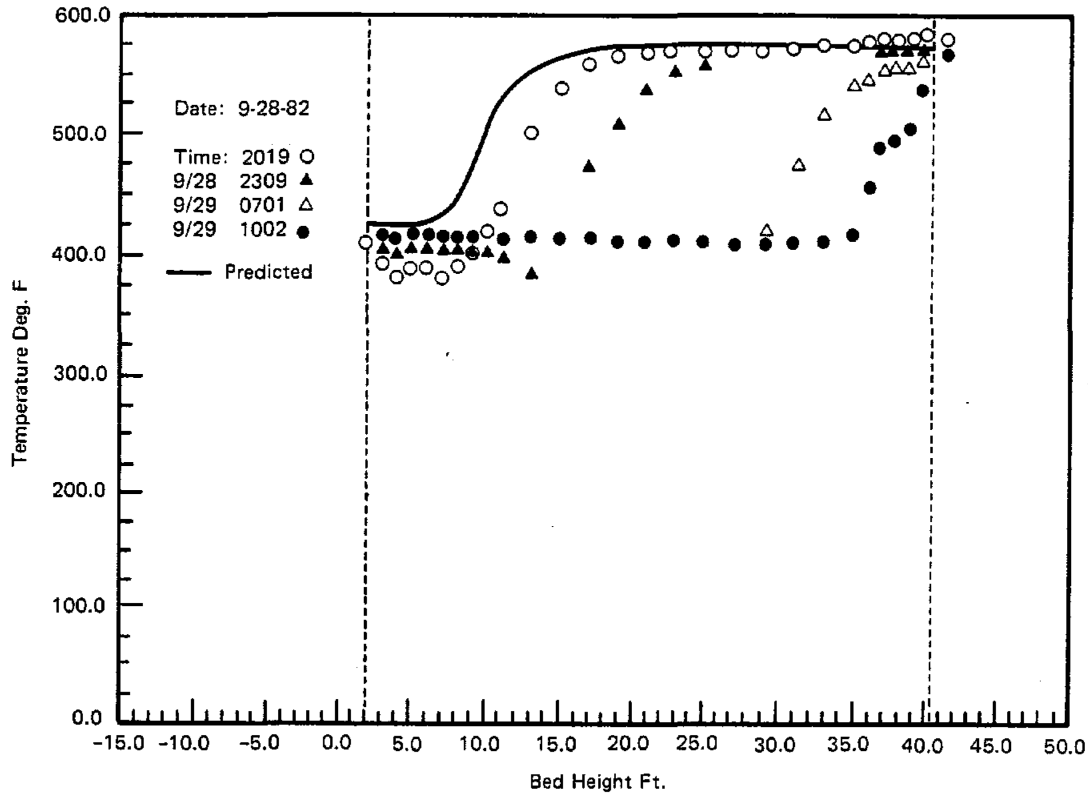


Figure 6.3-1. Thermocline Profile During Extraction

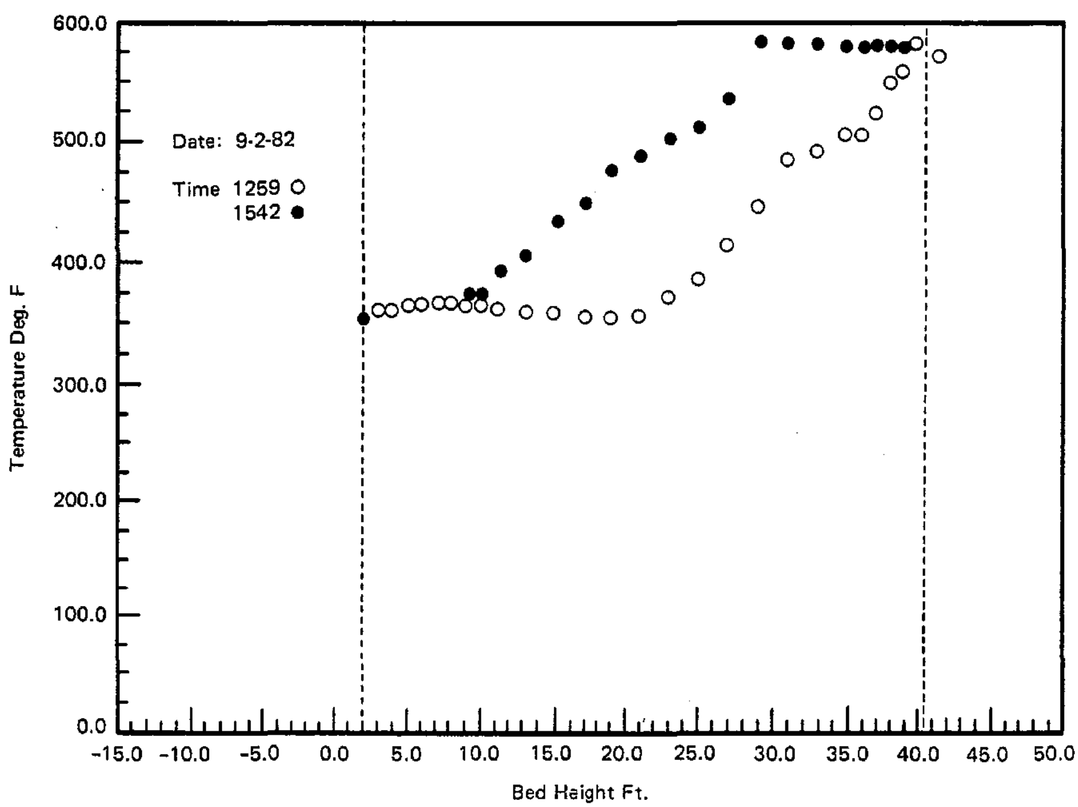


Figure 6.3-2. Thermocline Profile During Charging

the start of charging, and still extends over 19 ft at 11.0°F/ft at the end of charging 3 hours later. Again, the stability of the thermocline during charging is remarkable.

Finally, for nearly full charging which occurred on 26 August 1982, and which was previously discussed in Section 3.0 (see Figures 3.8-8 through 3.8-10), the TSU temperature profiles are shown in Figure 6.3-3. The initial thermocline is 132°F over 6 ft, grows slightly to 140°F over 10 ft, and then compresses sharply at the end of charging to 141°F over 3 ft (or 47°F/ft). Again the stability and sharpness of the TSU thermocline during charging is clearly shown.

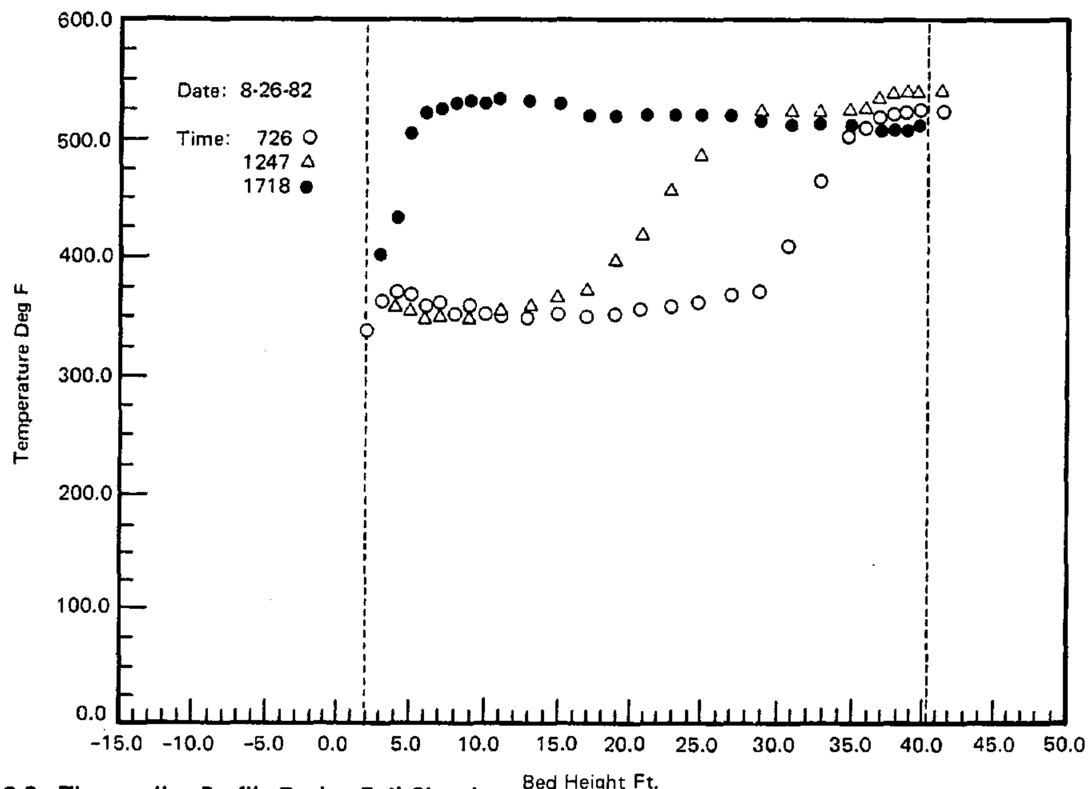


Figure 6.3-3. Thermocline Profile During Full Charging

Section 7

CONCLUSIONS AND RECOMMENDATIONS

With the completion of the 1040 test program the Thermal Storage System (TSS) is considered fully operational. In general, all parts of the TSS (charge, extraction and TSU) perform as expected and are controllable. Some changes were made to the charge system during the test program, but the extraction system and TSU remain as built. It must be said however that the 101 test series was not able to fully evaluate dual train operation due to charging train two being out of commission in the latter part of the series. Data that has been compiled was not presented since more analysis has yet to performed.

The charging system originally responded slower than expected during transient periods and it was a focal point of the test program to develop an insight into the actual process of the system being controlled. Redesigning for a faster response time compounded the coupling problems between all of the controllers. Modifications to the basic control law were made and the system now exhibits good steady state control accuracy as well as transient response, enabling charging operation during both clear and cloudy day operations as well as mode transitions.

In general both TSS charging and extraction system have exceeded expectations in their demonstrated control accuracies of steam temperature within $\pm 5^{o}F$, oil temperature within $\pm 10^{o}F$ and steam pressure within ± 20 psi even in the presence of severe cloud induced disturbances. The TSS system has demonstrated that it can control and maintain the desired operating conditions both during all start-up, normal operation, induced disturbances and shutdown scenarios experienced at Solar One.

Some design deficiencies in the selection of valve trims limited plant operation and charging loop controllability. The valve trim on the steam inlet valve, UV3102, exhibited an undesirable quick opening CV characteristics at low stroke. This was replaced with an equal percentage trim and satisfactory performance was achieved. Undersized valve trims on the condenser drain valves limited performance and controllability. A new trim was procurred for each valve increasing the flow capability by a factor of 2 providing better control of condenser pressure during transient periods.

Control system tuning was significantly effected by various flowmeter problems ranging from intermittent operation to erratic drift behavior. Control loops were redesigned to minimize the reliance on flow signals for control and was successful on the charging oil temperature loops. Relocation of the flowmeters to a less severe temperature environment also improved accuracy and reliability of the measurement.

Dual train testing of the extraction loops controls was successfully completed and no major problems were incurred. Dual train charging tests were not completed due to unavailability of 2 trains during the test period.

Pressure control strategy on the charging train condenser drain valves was demonstrated to be the desirable method of control and was used exclusively in lieu of level control in the surge tank.

Both TSS charge and extraction train controls were designed to be fully automated and this was demonstrated to be an effective control and operational method for accomplishing startup, transfer to normal operation and shutdown of both trains. The system was complemented with essentially pushbutton operation significantly reducing startup time and temperature excursions and cycling during typical daily operation.

The TSU performance appears to be better than expected in three areas. (1) The heat loses from the tank are about 2/3 of those originally predicted, (2) energy values calculated from energy in to energy out are in excellent agreement with predictions, and (3) the TSU thermocline is stable and sharp during both charging and extraction.

Appendix A
REFERENCES

1. 10mW$_e$ Central Receiver Solar Thermal Pilot Plant Test Operations Plan, Sandia National Laboratories/Livermore, Draft Release, July 1982.

2. Pilot Plant System Description (RADL 2-1), SAN/0499-57, September 1982.

3. Thermal Storage TSU Bed Conditioning Test Procedure, 1040A.

4. Thermal Storage System Controls Test Procedure, 1040B.

5. Thermal Storage System SDPC Data Base, McDonnell Douglas Drawing 1D44186.

6. Electrical Power Generation System SDPC Data Base, McDonnell Douglas Drawing 1D44187.

7. Receiver System SDPC Data Base, McDonnell Douglas Drawing 1D44188.

8. Solar One Plant Control System Design Requirements, McDonnell Douglas Drawing 1D44755.

9. SDPC Interlock Logic Subsystem Configuration Data Base, McDonnell Douglas Drawing 1D44789.

10. TSS RLU Configuration Data Base, McDonnell Douglas Drawing 1D44772.

11. S. E. Faas, "Thermal Storage Unit Transient Cooldown Test Results", inhouse memo 11 February 1983, Sandia Natonal Laboratoroes.

12. N. Batton, "10 MW Pilot Plant TSU Thermocline Degradation and External Heat Losses", Rocketdyne Memo ATU-80-5010, 5 February 1980.

13. G. R. Morgan, "Thermal Storage Subsystem Analysis Report (RADL Item 5-1)", Dept. of Energy Report SAN/0499-28, February 1980.

Appendix B
DATA PRESENTATION

Throughout this report, use is made of standard plot format which were available through the onsite Data Acquisition System and the McDonnell Douglas data system respectively. In addition, extensive use has been made of Bode and Nyquist plots in describing hardware transfer functions and control system responses

The purpose of this appendix is to familiarize the reader with the format and content of these plots in order to aid in the understanding of the report material.

Data Acquisition System Plot

Figure B-1 shows a typical Data Acquisition System plot that was developed real time as receiver testing proceeded. The plot is a 10 minute trace of 4 parameters associated with receiver boiler panel 11. The plot was generated (real time) on 5/5/82 (top right hand corner) starting at 13:16:10 (hours:minutes:seconds - lower left hand corner). The tag identifiers for each of the 4 numbers traces and vertical scales are listed in the top left hand corner of the plot. These tags are contained in the overall tag listing contained in Appendix B. The indicated "current value" numerical data located in the lower left hand corner correspond to the data values that existed at the end of the 10 minute plot interval.

McDonnell Douglas Data System Plot

Figure B-2 shows a typical McDonnell Douglas data system plot. The plot header information can be interpreted as follows: the "Solar Data Plot" number (A4B) is one of a predefined set of plots which can be called up through the data system. The "Reference Time" information (284 16 55 30.000) refers to day 284 (Oct 11) at time 16:55:30 (hours:minutes:seconds). The plot interval is for 1.5 minutes. The three parameters plotted in this figure correspond to the three tag identifiers shown at the bottom of the plot. The vertical scale for each of the parameters as well as the units and plotting identification symbols are shown in the lower right hand side of the figure.

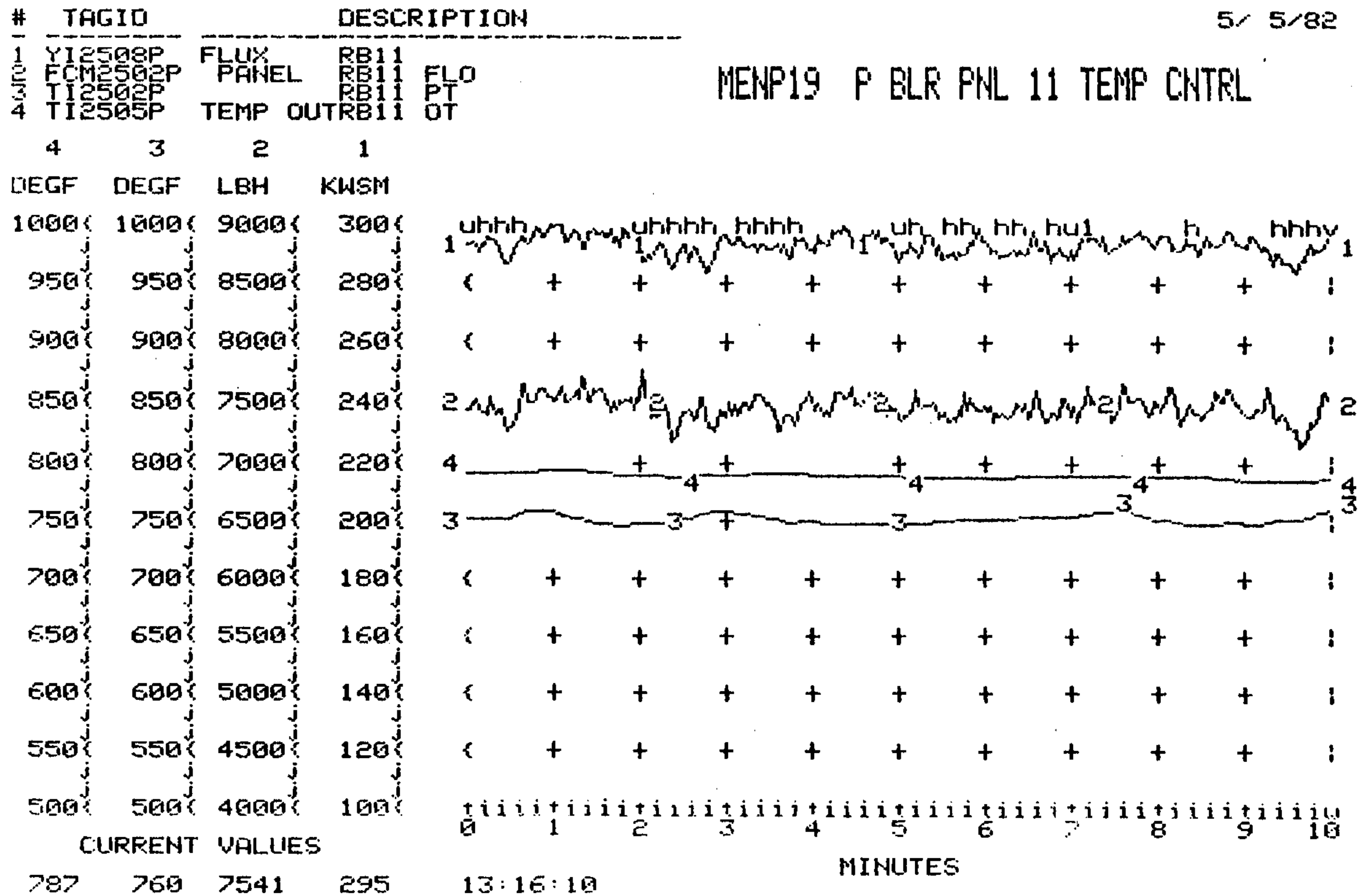
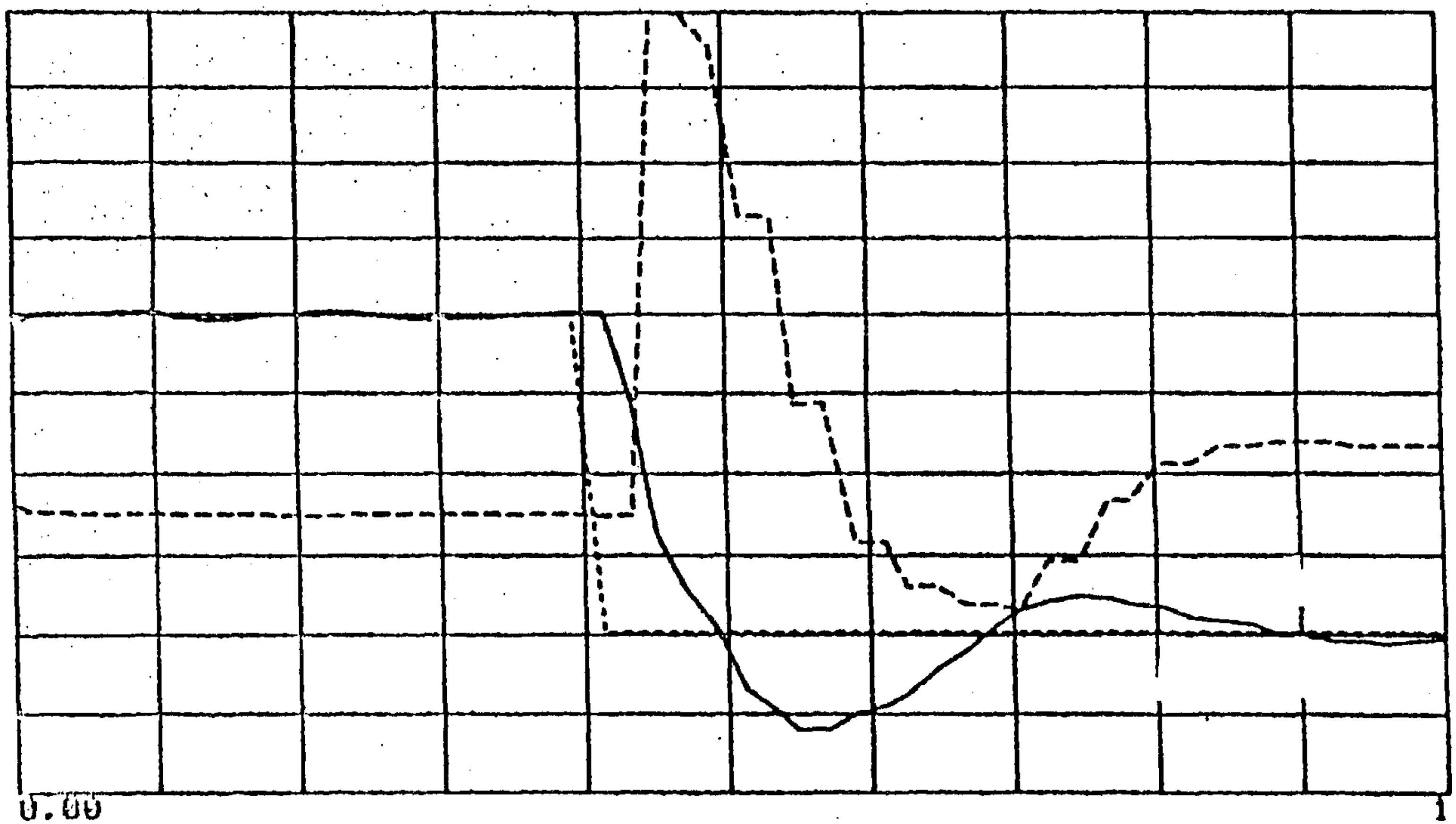


Figure B-1. Data Acquisition System Plot

SOLAR DATA PLOT PLOT # A4B
REFERENCE TIME: 284 16 55 30.000 FOR 1.5000 MINUTE(S)



PC1001P	DOWNCOMER PRESSURE	1100.0 -	1600.0 PSIG____
PC1001S	CONTROLLER SETPOINT	1100.0 -	1600.0 PSIG......
ZI1001P	VALVE POSITION	0.0 -	50.0 PCT_ _ _ _ _

Figure B-2. Typical McDonnell Douglas Data System Plot

Bode Plot

A Bode plot is a frequency domain plot of a transfer function. It represents their gain and phase of a transfer function as a function of frequency. It is used to represent the dynamic characteristics of processes, actuators, sensors, or control loops in the frequency domain. Typically Bode plot are used to characterize, represent or compare analytical models, empirical models or actual test data of specific hardware, processes or control loops. For example a Bode plot could present the open loop frequency response of a valve (see Figure 3.4-24 - 1010 Test Results) or the temperature response of a boiler panel to valve commands (see Figure 3.4-7 - 1030 Test Results). If the open loop control transfer function (GH) is represented on a Bode plot then it can be used to determine control loop stability margins.

Nyquist Plot - General Description

The Nyquist plot is a polar of the open loop transfer function (GH) of a control loop. From this plot the relative stability of a control loop can be determined in terms of the phase margin (m) and gain mar g in (Gm) of the system (refer to Figure B-3). These stability margins are direct measure of how much a loop can degrade and still maintain marginal stability. Stability margins must be maintained in order to compensate for variations or degradation in either process, actuator or sensor gains as well as to assure good transient response characteristics. In general gain marains of 6 9 db and phase margins of 40 60 degrees are desirable.

Given a simple control loop in Figure B-4 where G is the transfer function (gain) of the combined actuator and process and H is the transfer function of the controller (e.g., PID), then the closed loop response of the loop is expressed by G/1+GH. The characteristic equation or critical condition for the system exists when GH* -1. The Nyquist plot is nothing more than a polar plot of GH as a function of frequency and the stability margins are nothing more than a measure of how close GH comes to the -1 point. A typical Nyquist plot for the feedwater pump controller is shown in Figure 3.4-33 in the Test 1010 - Test Program and Results section of this report.

*Note - GH is a complex number and can be represented by a vector having a magnitude and a phase angle.

Frequency (rad/sec)	GH: Gain	GH: Phase (degrees)
0.01	1.7	−110
0.02	1.4	−125
0.05	1.05	−145
0.10	0.6	−160
0.5	0.1	−230

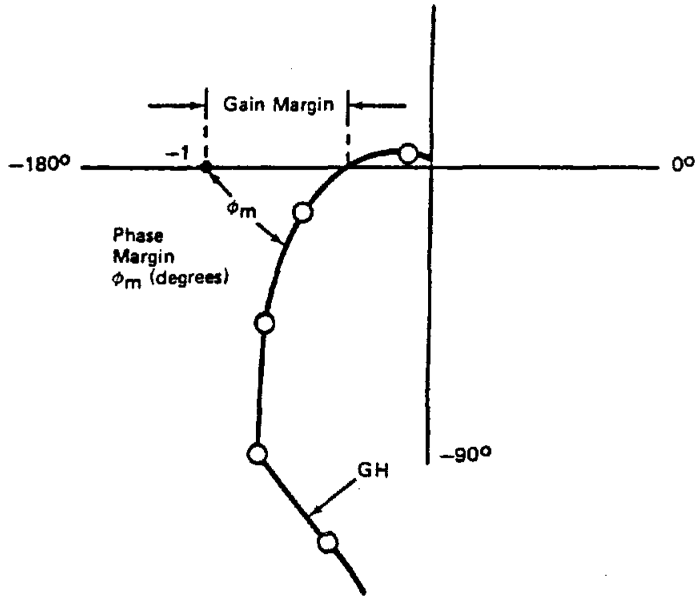
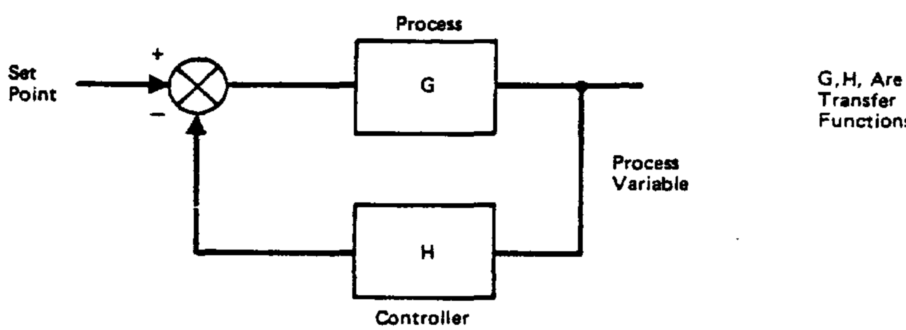


Figure B-3. Typical Nyquist Plot



	Closed Loop	Open Loop
Key Transfer Functions	$\frac{G}{1 + GH}$	GH (Control Loop) G (Process)

Figure B-4. Typical Control Loop Block Diagram

Appendix C

CONTROL TEST AND LOOP TUNING PROCEDURE

The general methods for performing the control system tests are described in the following paragraphs. These test methods include the following:

1) Loop Static Tests
2) Loop Initialization
3) Stop Response Test
4) Control Loop Tuning
5) Open Loop Test

Attachment C - Typical Closed Loop Control Test Procedure
(Refer to Figure C-1)

1) Loop Static Checks (one time)

a) Confirm loop is configured properly (coding and gains, etc).

b) Verify process variables are correct and operating (PV1000, PV1001).

c) Verify control valve motion and polarity is correct by stroking valve with AM1000 C.O.

2) Loop Initialization

a) Confirm AM1000 is in manual mode.

b) Verify TC1000 is in manual mode.

c) Adjust AM1000 C.O. to achieve the desired operating conditions on PV1000.

d) Set TC1000 setpoint to current value of PV1000.

e) Adjust TC1000 C.O. such that the P.V. of AM1000 balances and C.O. of AM1000 (note - If backcalculation is used this step is not required).

f) Set AM1000 to auto.

g) Set TC1000 to auto (Note - This step not required if backcalculation is used).

h) If loop response is not acceptable set AM1000 to manual and investigate.

3) Step Response Test (closed loop)

a) Confirm loop is in steady state conditions.

b) Vary setpoint on TC1000 by ± 10% (step change) and allow loop to steady out.

c) Return setpoint to normal value (step change) and allow loop to steady out.

d) Vary process input (i.e., flux, flow, etc.) by ± 10% (step change) and allow loop to steady out.

e) Return disturbance input to normal value (step change) and allow loop to steady out.

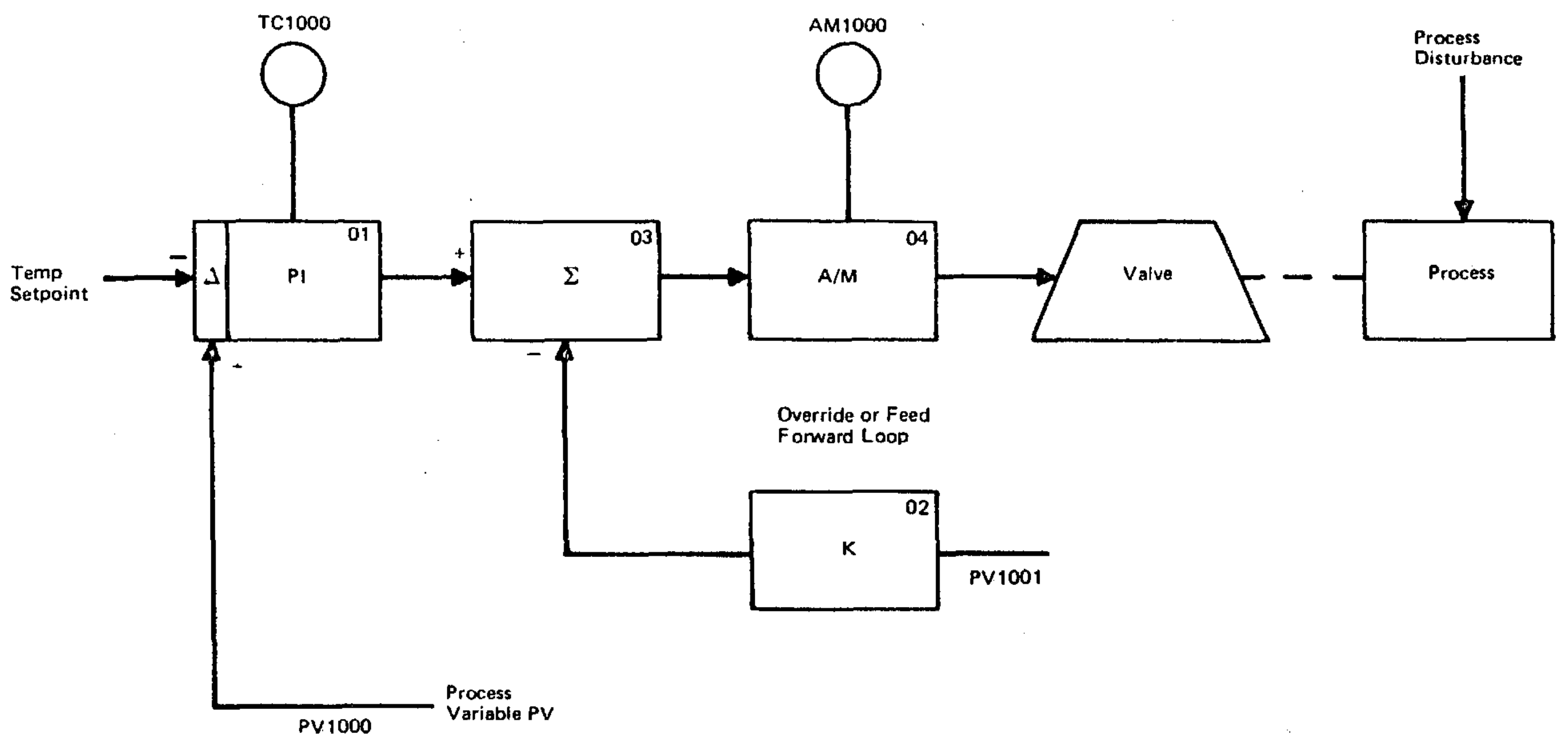


Figure C-1. Typical Control Loop Functional Block Diagram

4) Control Loop Tuning

Tune TC1000, temperature controller (see Figure A-1) by carrying out the following steps using the loop tuning form.

a) Set console to configure mode and call up loop detail on TC1000.

b) Decrease temperature setpoint of TC1000 by 10% and observe the response on the strip chart.

c) Increase TC1000 setpoint back to nominal value and observe the response on the strip chart.

d) Increase/decrease proportional gain K1 (C1-1, AL-01).

e) Repeat steps b -- d as required until response is satisfactory.

f) Decrease TC1000 setpoint 10% and observe response on strip chart.

g) Increase TC1000 setpoint to nominal value and observe temperature response on strip chart.

h) Increase/decrease reset gain, K2 (C1-1, AL-01), in $\pm$ 30% increments.

i) Repeat steps f -- h as required until response is satisfactory.

j) Establish preliminary TC1000 controller gains in temperature control mode and record.

k) Adjust setpoints, alarms, and limits if required.

5) Open Loop Test

a) Set AM1000 to manual

b) Perform open loop step response by adjusting AM1000 C.O. to the desired valves and monitor response to a new steady state condition.

c) Perform open loop disturbance response by subjecting the pressure, power etc. ... Monitor the response until a new steady state condition is reached.

11/6/84

UNLIMITED RELEASE
INITIAL DISTRIBUTION

U.S. Department of Energy (4)
Forrestal Building, Room 5H021
Code CE-314
1000 Independence Avenue, S.W.
Washington, D.C. 20585
Attn: C. Carwile
       H. Coleman
       F. Morse
       M. Scheve

U. S. Department of Energy (2)
P.O. Box 5400
Albuquerque, NM 87115
Attn: D. Graves
       J. Weisiger

U.S. Department of Energy (2)
1333 Broadway
Oakland, CA 94612
Attn: T. Vaeth
       R. Hughey

University of California
Environmental Science and Engineering
Los Angeles, CA 90024
Attn: R. G. Lindberg

University of Houston
Solar Energy Laboratory
4800 Calhoun
Houston, TX 77704
Attn: A. F. Hildebrandt

AMFAC
P.O. Box 3230
Honolulu, HI 96801
Attn: G. E. St. John

ARCO Power Systems
7061 S. University, Suite 300
Littleton, CO 80122
Attn: F. A. Blake

ARCO Power Systems
302 Nichols Drive
Hutchins, TX 75141
Attn: R. L. Henry

Arizona Public Service Company
P.O. Box 21666
Phoenix, AZ 85036
Attn: E. Weber

Babcock and Wilcox (3)
91 Stirling Avenue
Barberton, OH 44203
Attn: G. Grant
M. Seale
D. C. Smith

Bechtel Group, Inc.
P. O. Box 3965
San Francisco, CA 94119
Attn: S. Fleming

Black & Veatch Consulting Engineers (2)
P.O. Box 8405
Kansas City, MO 64114
Attn: J. C. Grosskreutz
S. L. Levy

Boeing Engineering and Construction Company
P.O. Box 3707
Seattle, WA 98124
Attn: R. L. Campbell

California Energy Commission
1516 Ninth St., M/S 40
Sacramento, CA 95814
Attn: A. Jenkins

California Public Utilities Com.
Resource Branch, Room 5198
455 Golden Gate Ave.
San Francisco, CA 94102
Attn: T. Thompson

Combustion Engineering, Inc.
1000 Prospect Hill Road
Winsor, CT 06095
Attn: C. R. Buzzuto

El Paso Electric Company
P.O. Box 982
El Paso, TX 79946
Attn: J. E. Brown

Electric Power Research Institute (2)
P.O. Box 10412
Palo Alto, CA 94303
Attn: J. Bigger
E. DeMeo

Elliott, S. D.
1801 Highway 128
Star Route 7550
Philo, CA 95466

Exxon Enterprises, Inc.
P.O. Box 592
Florham Park, NJ 07932
Attn: T. L. Guckes

Foster Wheeler Development Co.
12 Peach Tree Hill Road
Livingston, NJ 07039
Attn: R. J. Zoschak

Georgia Institute of Technology
Atlanta, GA 30332
Attn: C. T. Brown

Jet Propulsion Laboratory
4800 Oak Grove Drive
Pasadena, CA 91103
Attn: M. Alper

Los Angeles Department of Water and Power
Alternate Energy Systems
P.O. Box 111
111 North Hope St.
Los Angeles, CA 90051
Attn: D. Chu

Meridian Corporation
5113 Leesburg Pike
Falls Church, VA 22041
Attn: R. King

Martin Marietta Aerospace
P.O. Box 179, MS L0450
Denver, CO 80201
Attn: H. Wroton

McDonnell Douglas Astronautics Company (2)
5301 Bolsa Avenue
Huntington Beach, CA 92647
Attn: R. L. Gervais
H. H. Dixon

Olin Chemicals Group (2)
120 Long Ridge Road
Stamford, CT 06904
Attn: F. N. Christopher
L. C. Fiorucci

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Attn: R. E. Price

Pacific Gas and Electric Company (2)
3400 Crow Canyon Road
San Ramon, CA 94526
Attn: G. Braun
C. Weinberg

Pioneer Mill Company (AMFAC)
P.O. Box 727
Lahaina, HI 96761
Attn: R. K. MacMillan

Rockwell International
Energy Systems Group
8900 De Soto Avenue
Canoga Park, CA 91304
Attn: T. Springer

Rockwell International
Rocketdyne Division
6633 Canoga Avenue
Canoga Park, CA 91304
Attn: J. Friefeld

Solar Energy Industries Association
1140 19th St. N.W.
Suite 600
Washington, D.C. 20036
Attn: C. LaPorta

Solar Energy Research Institute (2)
1617 Cole Boulevard
Golden, CO 80401
Attn: B. Gupta
R. Hulstram

Southern California Edison
P.O. Box 325
Daggett, CA 92327
Attn: C. Lopez

Southern California Edison
P.O. Box 800
Rosemead, CA 92807
Attn: J. N. Reeves
P. Skvarna (25)

Stearns-Roger
P.O. Box 5888
Denver, CO 80217
Attn: W. R. Lang

Stone and Webster Engineering Corporation
P.O. Box 1214
Boston, MA 02107
Attn: R. W. Kuhr

Westinghouse Electric Corporation
Advanced Energy Systems Division
P.O. Box 10864
Pittsbugh, PA 15236
Attn: J. R. Maxwell

E. H. Beckner, 6000; Attn: V. Dugan, 6200
D. G. Schueler, 6220
J. V. Otts, 6222
R. S. Claassen, 8000; Attn: D. M. Olson, 8100
A. N. Blackwell, 8200
D. L. Hartley, 8300
C. S. Selvage, 8000A
C. Hartwig, 8244
M. E. John, 8245
R. C. Wayne, 8400; Attn: L. D. Bertholf, 8430
H. Hanser, 8440
R. L. Rinne, 8470
J. B. Wright, 8450
A. C. Skinrood, 8452 (25)
D. N. Tanner, 8452
Sandia Solar One Office, 8452
J. C. Swearengen, 8453
J. B. Wright, 8454 (Actg.)

Publications Division 8265, for TIC (27)
Publications Division 8265/Technical Library Processes Division, 3141
Technical Library Processes Division, 3141 (3)
M. A. Pound, 8024, for Central Technical Files (3)