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RELAP5 Thermal Hydraulic Analysis to Support PTS Evaluations for the Oconee-1, Beaver Valley-1, and Palisades Nuclear Power Plants

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ABSTRACT

As part of the Pressurized Thermal Shock Rebaseline Program, thermal hydraulic calculations were performed for the Oconee-1, Beaver Valley-1, and Palisades Nuclear Power Plants using the RELAP5/MOD3.2.2gamma computer program. Transient sequences that are important to the risk due to a PTS event were defined as part of a risk assessment by Sandia National Laboratories. These sequences include loss of coolant accidents (LOCA) of various sizes with and without secondary side failures and also non-break transients with primary and secondary side failure. Operator actions are considered in many of the sequences analyzed. The results of these thermal hydraulic calculations are used as boundary conditions to the fracture mechanics analysis performed by Oak Ridge National Laboratory.

FOREWORD

The reactor pressure vessel is exposed to neutron radiation during normal operation. Over time, the vessel steel becomes progressively more brittle in the region adjacent to the core. If a vessel had a preexisting flaw of critical size *and* certain severe system transients occurred, this flaw could propagate rapidly through the vessel, resulting in a through-wall crack. The severe transients of concern, known as pressurized thermal shock (PTS), are characterized by rapid cooling (i.e., thermal shock) of the internal reactor pressure vessel surface that may be combined with repressurization. The simultaneous occurrence of critical-size flaws, embrittled vessel, and a severe PTS transient is a very low probability event. The current study shows that U.S. pressurized-water reactors do not approach the levels of embrittlement to make them susceptible to PTS failure, even during extended operation well beyond the original 40-year design life.

Advancements in our understanding and knowledge of materials behavior, our ability to realistically model plant systems and operational characteristics, and our ability to better evaluate PTS transients to estimate loads on vessel walls have shown that earlier analyses, performed some 20 years ago as part of the development of the PTS rule, were overly conservative, based on the tools available at the time. Consistent with the NRC's Strategic Plan to use best-estimate analyses combined with uncertainty assessments to resolve safety-related issues, the NRC's Office of Nuclear Regulatory Research undertook a project in 1999 to develop a technical basis to support a risk-informed revision of the existing PTS Rule, set forth in Title 10, Section 50.61, of the *Code of Federal Regulations* (10 CFR 50.61).

Two central features of the current research approach were a focus on the use of realistic input values and models and an *explicit* treatment of uncertainties (using currently available uncertainty analysis tools and techniques). This approach improved significantly upon that employed in the past to establish the existing 10 CFR 50.61 embrittlement limits. The previous approach included unquantified conservatisms in many aspects of the analysis, and uncertainties were treated *implicitly* by incorporating them into the models.

This report is one of a series of 21 reports that provide the technical basis that the staff will consider in a potential revision of 10 CFR 50.61. The risk from PTS was determined from the integrated results of the Fifth Version of the Reactor Excursion and Leak Analysis Program (RELAP5) thermal-hydraulic analyses, fracture mechanics analyses, and probabilistic risk assessment. This report documents the application of the RELAP5 code to calculate the thermal-hydraulic response of a reactor pressure vessel for a wide spectrum of transients and accidents of possible PTS significance. The results of those calculations were used as boundary conditions in fracture mechanics analyses.

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EXECUTIVE SUMMARY

In 1978, the occurrence of a non-LOCA overcooling event at Rancho Seco showed the possibility of rapid cooldown of the reactor coolant system followed by repressurization, leading to increased stress on the reactor vessel. This situation, referred to as Pressurized Thermal Shock (PTS), could lead to crack propagation in a reactor vessel where material fracture toughness has been reduced by neutron irradiation over long periods of operation. Crack propagation could lead to through-wall cracking with vessel failure and core damage in extreme cases.

Since the time of the Rancho Seco event, risk analyses have been performed to evaluate the risk of vessel failure due to pressurized thermal shock under the sponsorship of the U.S. Nuclear Regulatory Commission (USNRC). During the 1980's, a PTS study was performed for the Oconee-1, Calvert Cliffs-1, and H.B. Robinson-2 nuclear power plants. The specific objective of these evaluations was to provide a best-estimate of the probability of through-wall cracking of the reactor pressure vessel due to a transient event. As part of this effort, event sequences were evaluated and consideration was given to plant features and operator actions that could influence primary system temperature and pressure and the risk of through-wall cracking. This work was undertaken in response to the PTS unresolved safety issue (A49).

The purpose of the current investigation is to determine whether through-wall cracking of the reactor vessel is credible for all classes of cooldown transients and accidents. Since completion of the earlier work, new information has resulted in improved analytical capability to evaluate PTS events. This capability includes improved embrittlement correlations, greatly improved knowledge to estimate original flaw density, size, orientation, and distribution, refinement of the probabilistic fracture mechanics code, improved understanding of flow interruption, flow stagnation, and fluid mixing behavior. Also, improvements in computing capabilities since the 1980's study means that more variations of PTS events can be considered, resulting in a better understanding of the types of transients that are significant contributors to risk.

The purpose of the thermal hydraulics analysis discussed in this report is to provide the downcomer boundary conditions for the probabilistic fracture mechanics analysis. The boundary conditions of interest are time dependent primary system pressure, fluid temperature in the downcomer, and the convective heat transfer coefficient between the downcomer fluid and the vessel wall. These thermal hydraulic calculations are performed for the Oconee-1, Beaver Valley-1, and Palisades Nuclear Power Plants using the RELAP5/MOD3.2.2gamma computer program for specific transient sequences. The sequences were defined as part of a risk assessment to identify sequences that are important to the risk due to a PTS event by Sandia National Laboratories. These sequences include LOCAs of various sizes with and without secondary side failures and also non-LOCA transients with primary and secondary side failures. Operator actions are considered in many of the sequences analyzed. The calculated primary system pressure, downcomer temperature and heat transfer coefficient at the vessel wall are used as boundary conditions to the probabilistic fracture mechanics analysis performed by Oak Ridge National Laboratory.

Detailed results for the transients sequences that contribute more than 1 percent of the total risk for each plant are provided in Sections 3 and 4. A summary of the results for all transients that were included in the risk evaluation are presented in Appendices A through C.

ACKNOWLEDGMENTS

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ABBREVIATIONS

AFW	Auxiliary Feedwater
B&W	Babcock and Wilcox
CSAU	Code Scaling Assessment and Uncertainty
ECCS	Emergency Core Cooling System
EFW	Emergency Feedwater System
HPI	High Pressure Injection System
INEEL	Idaho National Engineering and Environmental Laboratory
ICS	Integrated Control System
LANL	Los Alamos National Laboratory
LOCA	Loss of Coolant Accident
LPI	Low Pressure Injection System
MFW	Main Feedwater System
MSIV	Main Steam Isolation Valve
MSLB	Main Steam Line Break
ORNL	Oak Ridge National Laboratory
OTSG	Once-through Steam Generator
PORV	Power Operated Relief Valve
PTS	Pressurized Thermal Shock
PWR	Pressurized Water Reactor
RCP	Reactor Coolant Pump
RWST	Reactor Water Storage Tank
SIAS	Safety Injection Actuation Signal
SBLOCA	Small Break Loss of Coolant Accident
SG	Steam Generator
SRV	Safety Relief Valve
TBV	Turbine Bypass Valve
USNRC	U.S. Nuclear Regulatory Commission

1.0 INTRODUCTION

1.1 Previous PTS Analysis

In 1978, the occurrence of a non-LOCA overcooling event at Rancho Seco showed the possibility of rapid cooldown of the reactor coolant system followed by repressurization, leading to increased stress on the reactor vessel. This situation, referred to as Pressurized Thermal Shock (PTS), could lead to crack propagation in a reactor vessel where material fracture toughness has been reduced by neutron irradiation over long periods of operation. Crack propagation could lead to through-wall cracking in the reactor vessel with vessel failure and core damage in extreme cases.

A series of thermal hydraulic and risk analyses were performed in the early to mid 1980's to evaluate the risk of vessel failure due to pressurized thermal shock under the sponsorship of the U.S. Nuclear Regulatory Commission (USNRC). Three pressurized water reactor plants were evaluated at that time: Oconee-1, Calvert Cliffs-1, and H.B. Robinson-2. The specific objective of these evaluations was to provide a best-estimate of the probability of through-wall cracking of the reactor pressure vessel due to a transient event. As part of this effort, event sequences were evaluated and consideration was given to plant features and operator actions that could affect reactor coolant system pressure and temperature and ultimately influence the risk of through-wall cracking. This work was undertaken in response to the PTS unresolved safety issue (A49).

Oak Ridge National Laboratory (ORNL) was responsible for the overall coordination of the PTS effort and published the results of their work for Oconee-1 in NUREG/CR-3770 [Ref. 1-1]. In their report, ORNL discussed the development of a PTS risk analysis approach that incorporates elements of risk assessment, thermal hydraulics and fracture mechanics. ORNL provided estimates of the probability of a through-wall crack due to PTS. Main steam line breaks were identified as the most significant contributors to the risk of through-wall cracks by ORNL. Downcomer temperature uncertainty was identified as the most significant contributor to overall uncertainty.

After the initial work on PTS was completed in the mid 1980's, the NRC revised Section 50.61 of 10CFR Part 50 to address PTS. This regulation establishes screening criteria on the reference temperature for nil-ductility transition, requires licensees to accomplish practical neutron flux reductions to avoid exceeding the screening criterion, and requires plants that exceed the screening criterion to submit an analysis of the modifications that are necessary if continued operation beyond the screening criterion is to be allowed.

The issue of pressurized thermal shock was further discussed in NUREG/CR-5452 published in 1999 [Ref. 1-2]. The objective of this report was to investigate recent improvements in the PTS thermal hydraulic methodology. Both the RELAP5 and TRAC-P codes were used to analyze the H.B. Robinson plant. The thrust of this effort was a general demonstration of PTS methods which focused on the quantification of uncertainty rather than the thermal hydraulic analyses pertinent to plant-specific PTS evaluations.

1.2 PTS Rebaseline Program

The purpose of the current investigation is to determine whether brittle fracture of the reactor vessel is credible for all classes of cooldown transients and accidents. Since completion of the earlier work discussed in Section 1.1, new information has resulted in improved analytical capability to evaluate PTS events. This capability includes improved embrittlement correlations, greatly improved knowledge to estimate original flaw density, size, orientation, and distribution, refinement of the probabilistic fracture mechanics code, and improved understanding of flow interruption, flow stagnation, and fluid mixing behavior. Also, improvements in computing capabilities since the 1980's study means that more variations of PTS events can be considered, resulting in a better understanding of the types of transients that are significant contributors to risk.

The purpose of the thermal hydraulics analysis discussed in this report is to provide the downcomer boundary conditions for the fracture mechanics analysis. The boundary conditions of interest are time dependent primary system pressure, fluid temperature in the downcomer, and the convective heat transfer coefficient between the downcomer fluid and the vessel wall.

1.3 References

1-1 Burns, T. J., et. al., Preliminary Development of an Integrated Approach to the Evaluation of Pressurized Thermal Shock As Applied to the Oconee Unit 1 Nuclear Power Plant, NUREG/CR-3770, ORNL/TM-9176, May 1986.

1-2 Palmrose, D., Demonstration of Pressurized Thermal Shock Thermal Hydraulic Analysis with Uncertainty, NUREG/CR-5452, SCIE-NRC-350, March 1999.

2.0 RELAP5 MODELS FOR THE OCONEE, BEAVER VALLEY AND PALISADES NUCLEAR POWER PLANTS

This section describes the RELAP5 models developed for the Oconee-1, Beaver Valley Unit 1 and the Palisades plants. The thermal-hydraulic analysis methodology is similar for the three plants. In each case, the best available RELAP5 input model was used as the starting point to expedite the model development process. For Oconee, the base model was that used in the code scaling, applicability and uncertainty (CSAU) study. For Beaver Valley, the base model was the H.B. Robinson-2 model used in the original PTS study in the mid 1980s. This model was revised by Westinghouse to reflect the Beaver Valley plant configuration. For Palisades, the base model was obtained from Nuclear Management Corporation, the operators of the Palisades plant. This model was originally developed and documented by Siemens Power Corporation to support analysis of the loss of electrical load event for Palisades.

The RELAP5 models for the Oconee, Beaver Valley and Palisades plants are detailed representations of the power plants and include all major components for both the primary and secondary plant systems. RELAP5 heat structures are used throughout the models to represent structures such as the fuel, vessel wall, vessel internals and steam generator tubes. The reactor vessel nodalization includes the downcomer, lower plenum, core inlet, core, core bypass, upper plenum and upper head regions. Plant-specific features, such as the reactor vessel vent valves, are included as appropriate.

The downcomer model used in each plant utilizes a two-dimensional nodalization. This approach was used to capture the possible temperature variation in the downcomer due to the injection of cold ECCS water into each of the cold legs. Capturing this temperature variation in the downcomer is not possible with the original one-dimensional downcomer. In the revised models, the downcomer is divided into six azimuthal regions for each plant.

The safety injection systems modeled for the Oconee, Palisades, and Beaver Valley plants include high pressure injection (HPI), low pressure injection (LPI), other ECCS components (e.g. accumulators, core flood tanks (CFTs), safety injection tanks (SITs) depending on the plant designation), and makeup/letdown as appropriate.

The secondary coolant system models include steam generators, main and auxiliary/emergency feedwater, steam lines, safety valves, main steam isolation valves (as appropriate) and turbine bypass and stop valves.

Each of the models was updated to reflect the current plant configuration including updating system setpoints (to best estimate values) and modifying control logic to reflect current operating procedures. Other changes to the models include the addition of control blocks to calculate parameters for convenience or information only (e.g., items such as minimum downcomer temperature). The Oconee, Beaver Valley and Palisades models were then initialized to simulate hot full power and hot zero power steady plant operation for the purpose of establishing satisfactory steady state conditions from which the PTS transient event sequence calculations are started.

In RELAP5 simulations of LOCA event sequences for the Oconee and Palisades plants during which all of the reactor coolant pumps are tripped and the loss of primary coolant system inventory is sufficient to interrupt coolant loop natural circulation flow, a circulating flow was observed between the two cold legs on the same coolant loop. The circulations mix coolant in the reactor vessel downcomer, cold leg and SG outlet plenum regions. These RELAP5 cold-leg circulations were originally reported during the first PTS evaluation study (Reference 2.0.1) and are significant for the PTS application. When the circulation is present the calculated reactor vessel downcomer fluid temperature benefits from the warming effects created by mixing the cold HPI fluid with the warm steam generator outlet plenum fluid. When the circulation is not present the calculated reactor vessel downcomer fluid temperature more directly feels the influence of the cold HPI fluid. Note that both the Oconee and Palisades plants have a “2x4" configuration with two cold legs and one hot leg in each coolant loop. In contrast, the Beaver Valley plant has a single hot and cold leg per coolant loop and this type of circulating flow is not seen.

The cold leg circulation issue is also addressed in Section 3.9 of the current RELAP5 PTS assessment report (Reference 2.0.2). Certain of the experiments used in the assessment exhibited apparent indications of cold leg circulations very similar to those simulated with RELAP5. However, the experimental evidence was not judged to be conclusive and concerns (related to circulation initiation and the scalability of the behavior from the sub-scale experiment to full-scale plant configurations) remain regarding the veracity of these circulations. Because of these concerns and because the effect of including cold leg circulations in the RELAP5 simulations is non-conservative for PTS (i.e., it results in warmer reactor vessel downcomer temperatures), same-loop cold leg circulations were prevented in the RELAP5 PTS plant simulations for LOCA events. The cold leg circulations were prevented by implementing large reverse flow loss coefficients (1.0E5, based on the cold leg pipe flow area) in the reactor coolant pump regions of the RELAP5 model. The model change is implemented at the time during the event sequence when the reactor coolant pump coast-down is complete.

In the following sections, plant specific RELAP5 modeling features important to the Oconee, Beaver Valley and Palisades plants are discussed. A tabulation of the key parameters for these plants relevant to PTS is presented in Table 2.0-1.

Table 2.0-1 Summary of Plant Parameters Relevant to the PTS Evaluation

Description	Oconee	Beaver Valley	Palisades
Reactor thermal power	2568 MWt	2660 MWt	2530 MWt
Primary code safety valve opening pressure	17.34 MPa [2515 psia]	17.27 MPa [2505 psia]	Three valves with staggered opening setpoints of 17.24, 17.51 and 17.79 MPa [2500, 2540 and 2580 psia].
Primary code safety valve capacity	Two valves each with a capacity of 43.47 kg/s [345,000 lbm/hr] at 16.89 MPa [2450 psia].	Three valves each with a capacity of 62.77 kg/s [498,206 lbm/hr] at 17.24 MPa [2500 psia].	Three valves each with a capacity of 28.98 kg/s [230,000 lbm/hr] at 17.75 MPa [2575 psia]

Description	Oconee	Beaver Valley	Palisades
Pressurizer PORV opening pressure	17.0 MPa [2465 psia]	The first PORV is controlled by a compensated error signal. The error [pressurizer pressure – 15.51 MPa [2250 psia] is processed with a proportional plus integral controller. This PORV begins to open when the compensated error is ≥ 0.69 MPa [100 psi] and closes when the compensated pressure error < 0.62 MPa [90 psi]. The second and third PORVs open when the pressurizer pressure is ≥ 16.2 MPa [2350 psia] and close when pressure < 16.1 MPa [2340 psia].	Two valves, both with an opening setpoint pressure of 16.55 MPa [2400 psia]. Note that closed block valves prevent the function of pressure relief through these valves during normal plant operation.
PORV capacity	Estimated flow rate is 16.03 kg/s [127,000 lbm/hr] at 16.9 MPa [2450 psia].	Three valves each with a capacity of 26.46 kg/s [210,000 lbm/hr] at 16.2 MPa [2350 psia]	Two valves each with a capacity of 61.46 kg/s [487,800 lbm/hr] at 16.55 MPa [2400 psia].
LPI injection actuation setpoint	3.89 MPa [550 psig].	SIAS signal: pressurizer pressure ≤ 12.72 MPa [1845 psia], high steamline DP (steamline pressure < header pressure by 0.69 MPa [100 psi] or more), or steamline pressure ≤ 3.47 MPa [503 psia].	Pressurizer pressure less than 10.98 MPa [1593 psia] with a 27 second time delay.
LPI pump shutoff head	1.48 MPa [214 psia]	1.48 MPa [214.7 psia]	1.501 MPa [217.7 psia].
LPI pump runout flow	504.5 kg/s [1110 lbm/s] total for two pumps.	313.4 kg/s [690.84 lbm/s] total for the three loops.	433.5 kg/s [955.7 lbm/s] total for the four loops.

Description	Oconee	Beaver Valley	Palisades
HPI injection actuation setpoint	11.07 MPa [1605 psia]	SIAS signal: pressurizer pressure ≤ 12.72 MPa [1845 psia], high steamline DP (steamline pressure < header pressure by 0.69 MPa [100 psi] or more), or steamline pressure ≤ 3.47 MPa [503 psia].	Pressurizer pressure less than 10.98 MPa [1593 psia] with a 27 second time delay.
HPI pump shutoff head	> 18.61 MPa [2700 psia]	> 17.93 MPa [2600 psia]	8.906 MPa [1291.7 psia].
HPI pump runout flow	80.9 kg/s [178.2 lbm/s] total for the four loops.	61.12 kg/s [134.7 lbm/s] total for the three loops.	86.49 kg/s [190.7 lbm/s] total for the four loops.
Reactor coolant pump trip setpoint	No automatic trips on the reactor coolant pump. Operator is assumed to trip RCPs at 0.28 K [0.5°F] subcooling.	No automatic trips on the reactor coolant pumps. Operator is assumed to trip RCPs when the differential pressure between the RCS and the highest SG pressure was less than 2.59 MPa [375 psid].	No automatic pump trips. Procedures instruct the operators to trip two RCPs (one in each loop) if pressurizer pressure falls below 8.96 MPa [1300 psia] and to trip all pumps if RCS subcooling falls below 13.9 K [25°F] or if containment pressure exceeds 0.127 MPa [18.4 psia].
SG safety valve bank opening pressure	The lowest relief valve setpoint is 6.76 MPa [980 psia].	The lowest relief valve setpoint is 7.51 MPa [1090 psig].	The lowest MSSV opening setpoint pressure is 7.097 MPa [1029.3 psia].
SG atmospheric steam dumps opening criteria	Not included in the RELAP5 model.	Opening pressure of 7.24 MPa [1050 psia].	Open to control the RCS average temperature to 551 K (532°F)
Number of main steam isolation valves	None.	One per steam line.	One per steam line.
Location of steamline flow restrictors	None.	Located in SG outlet nozzles.	Located in SG outlet nozzles.
Isolation of turbine-driven EFW/AFW pump during MSLB	Isolated during MSLB by isolation circuitry	Requires manual operator action and would be done if needed to maintain SG level	Requires manual operator action and would be done if needed to maintain SG level.

Description	Oconee	Beaver Valley	Palisades
Analyzed range of SI water temperature	Base case model assumptions for HPI and LPI nominal feed temperature is 294.3 K [70°F]. CFT temperature is 299.8 K [80°F] Sensitivity cases for ECCS temperature due to seasonal variation: Summer Conditions HPI, LPI - 302.6 K [85°F] CFT - 310.9 K [100°F] Winter Conditions HPI, LPI - 277.6 K [40°F] CFT - 294.3 K [70°F]	Base case model assumptions for HPI and LPI nominal feed temperature is 283.1 K [50°F]. CFT temperature is 305.4 K [90°F] Sensitivity cases for ECCS temperature due to seasonal variation: Summer Conditions HPI, LPI – 285.9 K [55°F] CFT – 313.7 K [105°F]	Base case model assumptions for HPI and LPI nominal feed temperature is 304.2 K [87.9°F]. SIT temperature is 310.9 K [100°F] Sensitivity cases for ECCS temperature due to seasonal variation: Summer Conditions HPI, LPI - 310.9 K [100°F] SIT - 305.4 K [90°F] Winter Conditions HPI, LPI - 277.6 K [40°F] SIT - 288.7 K [60°F]
Refueling water storage tank water volume	Borated water storage tank water volume is 327,000 gallons	Tank's useable volume is between 1627.7 and 1669.4 m^3 [430,000 and 441,000 gallons].	889.5 m^3 [235,000 gallons]
Containment spray actuation setpoint and flowrate	Total containment spray flow rate is 3000 gpm [1500 gpm/pump]	Total containment spray flow is 334.4 liter/s [5300 gpm]	Containment spray is activated on high containment pressure at 0.127 MPa [18.4 psia]. Total containment spray rate is 229.8 liters/s [3643 gpm].
CFT/accumulator water volume	2 tanks each with a water volume of 28,579 liters [7550 gallons]	3 accumulators each with a liquid volume of 29,299 liters [7740 gallons]	4 SITs each with a water volume of 29450 liters [7780 gallons].
CFT/SIT/ accumulator discharge pressure	4.07 MPa [590 psia]	4.47 MPa [648 psia]	1.48 MPa [214.7 psia]

2.0.1 References

2.0.1 Fletcher, C. D., et. al., RELAP5 Thermal Hydraulic Analyses of Pressurized Thermal Shock Sequences for the Oconee-1 Pressurized Water Reactor, NUREG/CR-3761, June 1984.

2.0.2 Fletcher, C. D., Prelewicz, D.A. and Arcieri, W. C., RELAP5/MOD3.2.2 Gamma Assessment for Pressurized Thermal Shock Applications, NUREG/CR-6857, Draft, October 2004.

2.1 Oconee Model

2.1.1 Oconee Model Description

The Oconee-1 Nuclear Power Station is a Babcock and Wilcox (B&W) designed pressurized water reactor with a rated power of 2568 MWt. The reactor coolant system for Oconee-1 consists of the reactor vessel with two cooling loops connected in parallel and designated as loops ‘A’ and ‘B’. Each cooling loop consists of a hot leg, a once-through steam generator, and two parallel cold legs each with a reactor coolant pump. The pressurizer and pressurizer surge line are connected to the hot leg in loop A. Water flow in the reactor coolant system is from the reactor core through the hot legs to the once-through steam generator. From the steam generator, the primary system water flows to the reactor coolant pump suction and then back to the reactor vessel. The pressurizer, which is electrically heated, provides overall pressure control to the reactor coolant system. The Oconee station is a lowered-loop design with the lowest part of the cold leg about six feet lower than the bottom of the reactor vessel. The reactor coolant pumps are located such that the center line of the discharge is about 1 meter [3.5 feet] above the center line of the cold leg nozzle. A section of the cold leg is sloped at 45 degrees to compensate for the difference in elevation.

The Oconee-1 RELAP model is a detailed representation of the Oconee-1 Nuclear Power Plant and includes all major components for both the primary and secondary systems. The noding diagram for the Oconee RELAP5 model is illustrated in Figures 2.1-1 to 2.1-5. RELAP5 heat structures are used throughout the model to represent structures such as the fuel, vessel wall, vessel internals and steam generators.

The reactor vessel nodalization includes the downcomer, lower plenum, core inlet, core, core bypass, and the upper plenum and upper head region as shown in Figure 2.1-1. Because of the need for more detailed temperature information in the downcomer for PTS evaluations, a two-dimensional renodalization of the reactor vessel downcomer region in the reactor vessel is used. In the revised model, the downcomer adjacent to the core is divided into five axial and six azimuthal regions as shown in Figure 2.1-1. The reason for choosing six azimuthal regions is so that each of the four cold legs, and the two core flood tank/LPI injection points inject into separate nodes to preclude artificial mixing of these two temperature streams. This noding is carried down for the axial length of the downcomer. Because of problems with non-physical numerically-driven flow circulation among the six azimuthal regions in the downcomer, application of the momentum flux model was disabled. This approach reduced the magnitude of these flows to a realistic level.

The vent valve modeling was revised as part of the downcomer nodalization. The vent valves connect the upper plenum to the vessel annulus above the hot and cold leg nozzles. Each valve consists of a hinged disk and valve body that remains closed during normal operation. The valves open if the pressure drop across the core barrel reverses, a situation that can exist when natural circulation and/or flow stagnation occurs. The vent valves allow steam flow from the upper plenum of the reactor vessel through the downcomer to the break in the event of a cold leg break. The vent valves allow hot water to flow into the downcomer region during PTS transients when natural circulation flow may be limited. Flow from the vent valves will enhance mixing of the ECCS flow in the downcomer. The eight reactor vessel vent valves are represented by six RELAP5 servo valves which connect from the upper plenum to each of the six sectors in the upper portion of the downcomer annulus as shown in Figure 2.1-1. Adjustments were made to the valve flow area to compensate for the difference between the actual number of vent valves and the number modeled.

Reactor loop nodalization includes the hot legs (one per loop) and cold legs (two per loop), the reactor coolant pumps (two per loop), and the OTSG tubes (primary side) as shown in Figure 2.1-2. Loop A components are numbered with 100 series numbers while loop B components are numbered with 200-series numbers. For the reactor coolant pumps, the default pump flow curves included in RELAP5 are used. The rated flow of each reactor coolant pump is 4147.0 kg/s [88,000 gpm].

The high pressure injection system for Oconee connects to each cold leg and is modeled as a time dependent volume-junction combination. The HPI system actuates if the reactor coolant system pressure decreases to 11.1 MPa [1605 psia] as listed in Table 2.0-1. The low pressure injection (LPI) system and the core flood tanks (CFT) inject directly into the vessel downcomer and hence are part of the reactor vessel nodalization. There are two injection nozzles for both the LPI and CFT on opposite sides of the vessel. The low pressure injection system is modeled as a time-dependent volume-junction pair. Each of the core flood tanks is modeled as a RELAP5 accumulator injecting to the same point as the LPI.

The pressurizer is connected to the riser section of the Loop A hot leg as shown in Figure 2.1-2. The pressurizer system nodalization includes the pressurizer, pressurizer spray line, power operated relief valve (PORV) and primary system safety relief valve as shown in Figure 2.1-3. The pressurizer spray system connects to the cold leg downstream of the reactor coolant pump in Loop A2. The primary system safety relief valve and the power operated relief valve (PORV) are included in the model as RELAP5 trip valves. The discharge of these valves is connected to time-dependent volumes representing the quench tanks in the containment. The pressurizer spray system is also represented in the Oconee-1 model. The spray valve is included as a RELAP5 trip valve.

Secondary side components included in the RELAP5 model are the hotwell pump, condensate booster pump, two main feedwater pumps, startup and main feed regulation valves, steam generator secondary side and the connecting piping. The steam generator secondary side nodalization is shown in Figures 2.1-4 and 2.1-5. The boiler section of the steam generator is modeled as a parallel stack of nodes. The emergency feedwater system is connected to the topmost node of the stack of nodes with the smaller flow area. This noding approach is used to avoid problems with liquid entrainment during counter-current flow situations when emergency feedwater injection is activated and steam is exiting the steam generator.

The turbine bypass valve, safety valves and turbine stop valves are modeled as servo valve-time dependent volume pairs, where the time dependent volumes represent the condenser, atmosphere, and turbine-generator, respectively. These valves are connected to the main steam line at various locations as shown in Figure 2.1-4.

Modeling of the feedwater train from the high pressure feedwater header to the steam generator downcomers is shown in Figure 2.1-4. This figure also shows the modeling of the turbine-driven and motor-driven emergency feedwater systems. The startup and main feedwater control valves for each steam generator are modeled as a pair of RELAP5 servo valves. The main feedwater crossover to the emergency feedwater lines is shown as components 850 to 852 on the 'A' side and components 950 to 952 on the 'B' side. The turbine- and motor-driven emergency feedwater systems are modeled as time-dependent junction volume pairs. Valve components 775 and 777 are the feedwater isolation valves for the 'A' and 'B' trains, respectively. Modeling of the main feedwater train from the hotwell to the startup and main feed valves is shown in Figure 2.1-5. The main feedwater pumps (components 754 and 760) discharge to the main feedwater pump header (component 763). From this header, flow is through nodes representing high pressure feedwater heater trains (components 764 and 766) to the high pressure feedwater header (component 768).

Control system models are included in the RELAP5 model for the emergency feedwater control, turbine bypass valve control, and main feedwater control. The models used were originally developed for the PTS study performed by the INEEL discussed in Section 1.1. The once-through steam generator has two ranges of level indication that are used during plant operation: the startup range and the operating range. The startup range indication is used to monitor steam generator level during plant startup at power levels $\leq$ 15 percent of full power. The range of indication is 0-635 cm [0-250 in] measured from the upper surface of the lower tube sheet. Normal startup level is 76.2 cm [30 in] above the tube sheet when the reactor coolant pumps are operating and 610 cm [240 in] when they are tripped. The operating range indication is used during normal plant operation and is an input to the Integrated Control System (ICS). The operating range indication is monitored by the ICS for the purpose of limiting feedwater flow to prevent flooding of the aspirating ports.

The Main Steam Line Break (MSLB) detection and feedwater isolation circuitry is designed to mitigate containment overpressurization by isolating feedwater to both steam generators during a main steam line break event. This circuitry is designed to trip the main feedwater pumps, to inhibit/stop the turbine-driven emergency feedwater pump, and to isolate main feedwater and startup feedwater systems. The MSLB circuitry was added in response to I&E bulletin 80-04 to prevent overfeed and rapid reactor cooldown and return to power. Section 7.9 of the Oconee FSAR provides additional details on the MSLB circuitry.

2.1.2 Oconee Steady State Initialization

Steady-state calculations simulating hot full power and hot zero power plant operation were performed with the Oconee RELAP5 model in order to establish model initial conditions from which to begin transient calculations. For this purpose, long (8000 s) steady state runs were made to assure that steady conditions had been achieved in the fluid and heat structures in the RELAP5 model. Figures 2.1-6 and 2.1-7, respectively, show the cold leg pressure and fluid temperature responses from the hot full power and hot zero power RELAP5 calculations. The figures demonstrate that the RELAP5 solutions have reached a steady state at the end of the calculation. Tables 2.1-1 and 2.1-2, respectively, compare the RELAP5-calculated steady-state results for key parameters (at the 8,000 s end points of the calculations) with the desired plant values for the parameters for hot full power and hot zero power plant operation. The tables indicate that the

RELAP5 calculated steady-state solutions are in excellent agreement with the desired steady plant conditions for both cases.

2.1.3 References

2.1-1 Duke Power Company, Oconee Nuclear Station Final Safety Analysis Report, Revision dated December 31, 1999.

Table 2.1-1 Comparison of Key Oconee Plant Design Parameters to RELAP5 Steady-State Results for Hot Full Power Conditions

	Desired Plant Value	RELAP5-Calculated Value
Reactor Thermal Power	2,568 MWt	2,568 MWt
Cold Leg Temperature	565.3 K [557.8°F]	568.3 K [563.2°F]
Hot Leg Temperature	590.0 K [602.4°F]	593.4 K [608.5°F]
Hot Leg Pressure	14.96 MPa [2,169.8 psia]	14.85 MPa [2,153.3 psia]
Reactor Coolant Flow Rate at Core Inlet	16580 kg/s [36,477 lbm/s]	16393 kg/s [36,066 lbm/s]
Pressurizer Level	5.59 m [220 in]	5.72 m [225 in]
Main Feedwater Temperature at SG Inlet	508 K [455°F]	508.7 K [455.9°F]
Main Steam Flow Rate (per SG)	669.3 kg/s [1,472.5 lbm/s]	682.4 kg/s [1,501.2 lbm/s]
Main Steam Pressure	6.38 MPa [925 psia]	6.29 MPa [912.6 psia]
Note: Desired plant data in this table taken from Tables 4-1 and 5-20 of the Oconee FSAR and Table 1 of NUREG/CR-3791.		

Table 2.1-2 Comparison of Key Oconee Plant Design Parameters to RELAP5 Steady-State Results for Hot Zero Power Conditions

	Desired Plant Value	RELAP5 Calculated Value
Reactor Thermal Power	---	5.136 MW
Cold Leg Temperature	550.9 K [532.0°F]	551.2 K [532.6°F]
Hot Leg Temperature	550.9 K [532.0°F]	551.2 K [532.6°F]
Hot Leg Pressure	14.82 MPa [2,150.0 psia]	14.82 MPa [2,150.1 psia]
Reactor Coolant Flow Rate at Core Inlet	---	17,640 kg/s [38,090 lbm/s]
Pressurizer Level	---	5.70 m [224.5 in]
Main Feedwater Temperature at SG Inlet	305.4 K [90°F]	305.4 K [90°F]
Main Steam Flow Rate (per SG)	---	5 kg/s [11 lbm/s]
Main Steam Pressure	6.21 MPa [900 psia]	5.99 MPa [869 psia]
SG Startup Level	91.44 [36 in]	92.58 cm [36.45 in]
Note: Desired plant data in this table taken from Tables 4-1 and 5-20 of the Oconee FSAR and Table 16 of NUREG/CR-3791.		

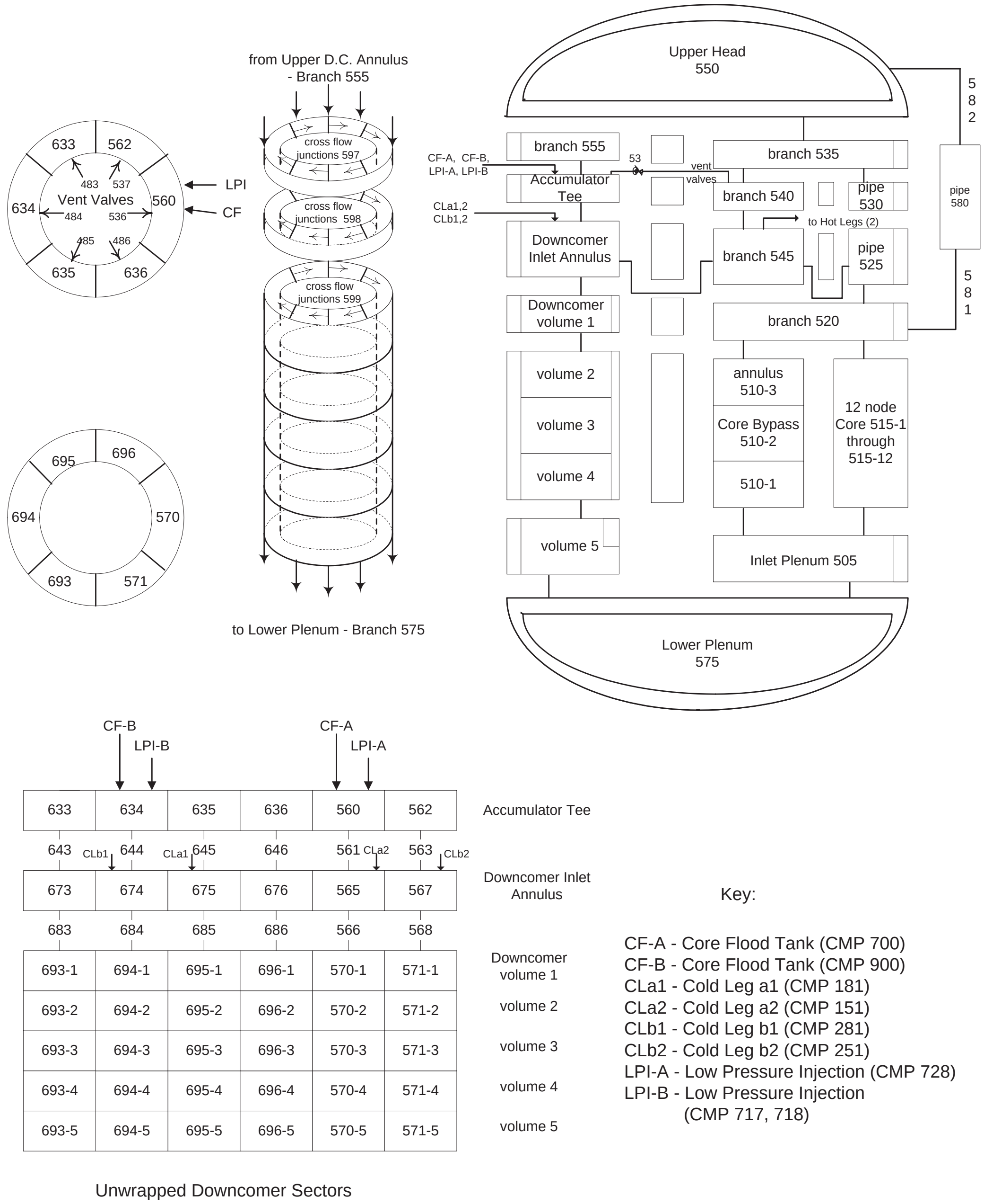


Figure 2.1-1 Oconee Reactor Vessel RELAP5 Nodalization

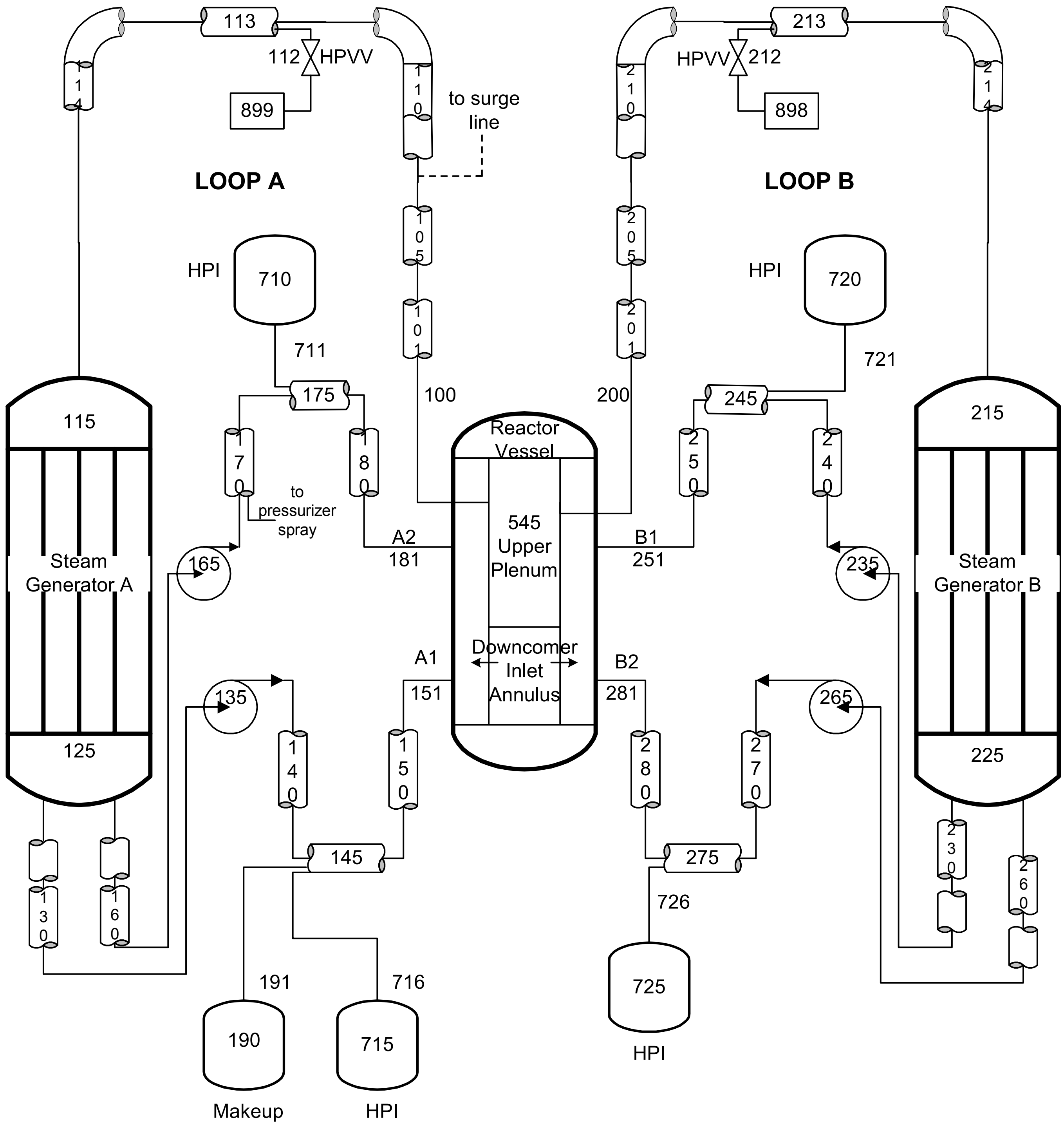


Figure 2.1-2 Oconee Reactor Coolant System RELAP5 Nodalization

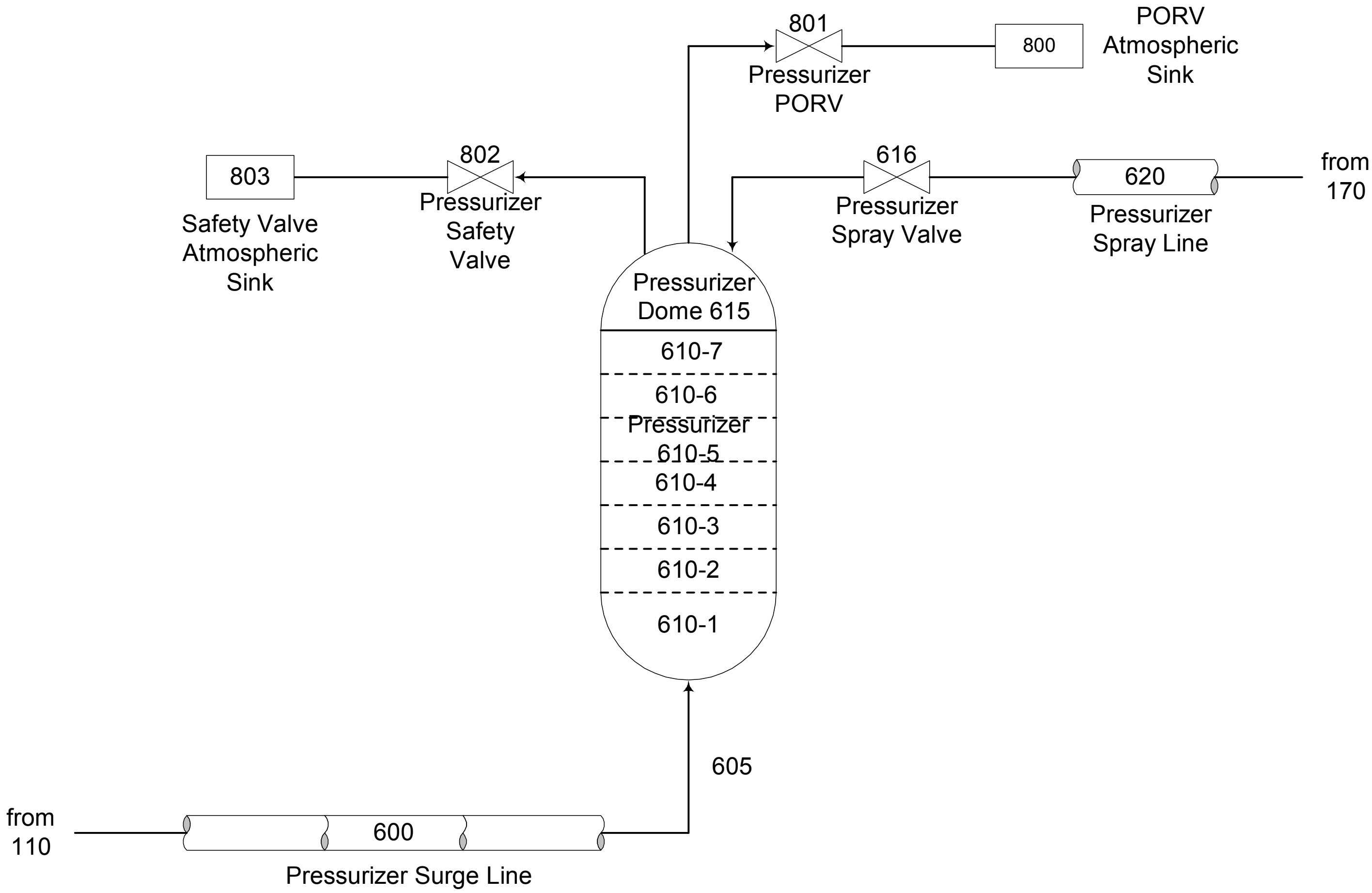


Figure 2.1-3 Oconee Pressurizer System Nodalization

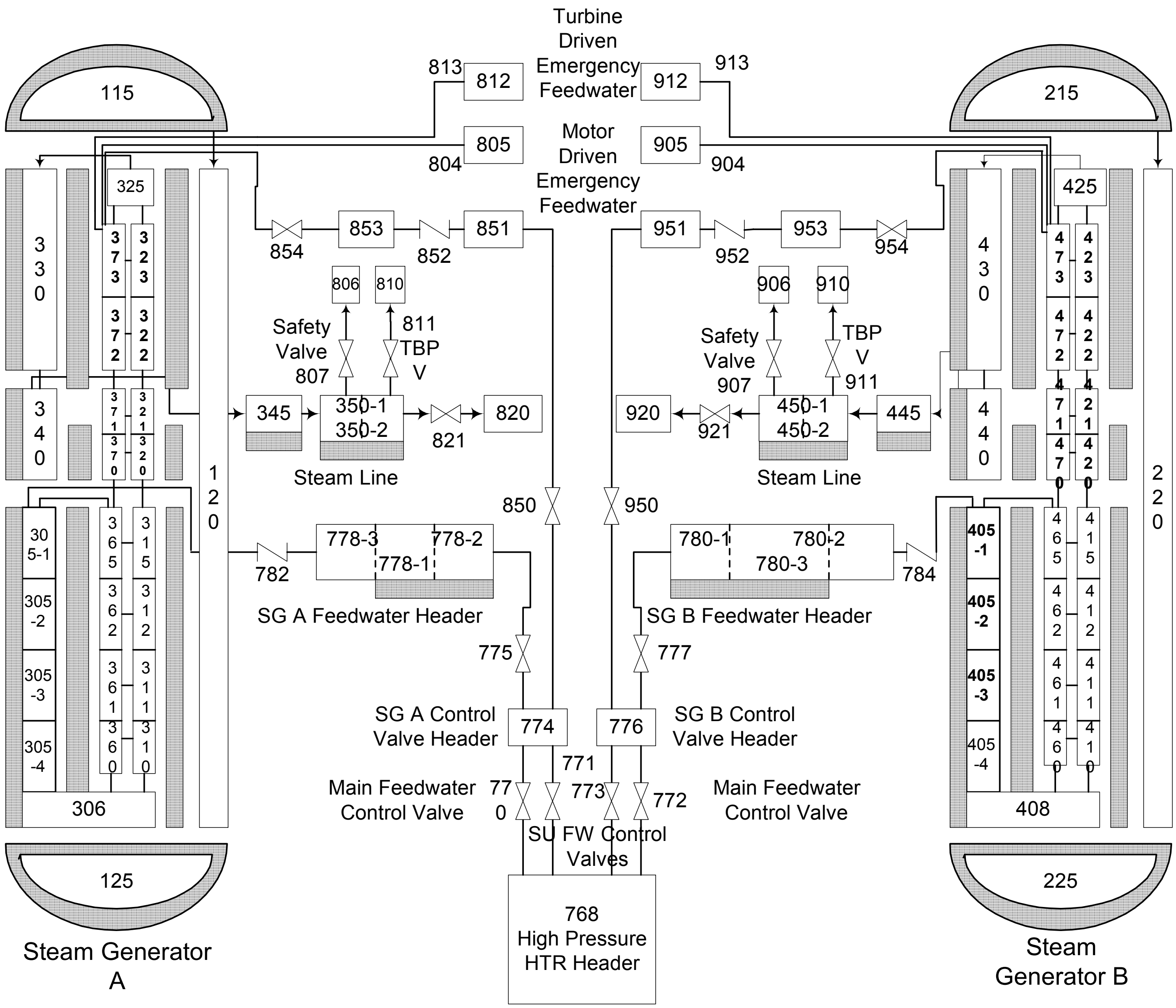


Figure 2.1-4 Oconee Steam Generator Secondary Side Nodalization

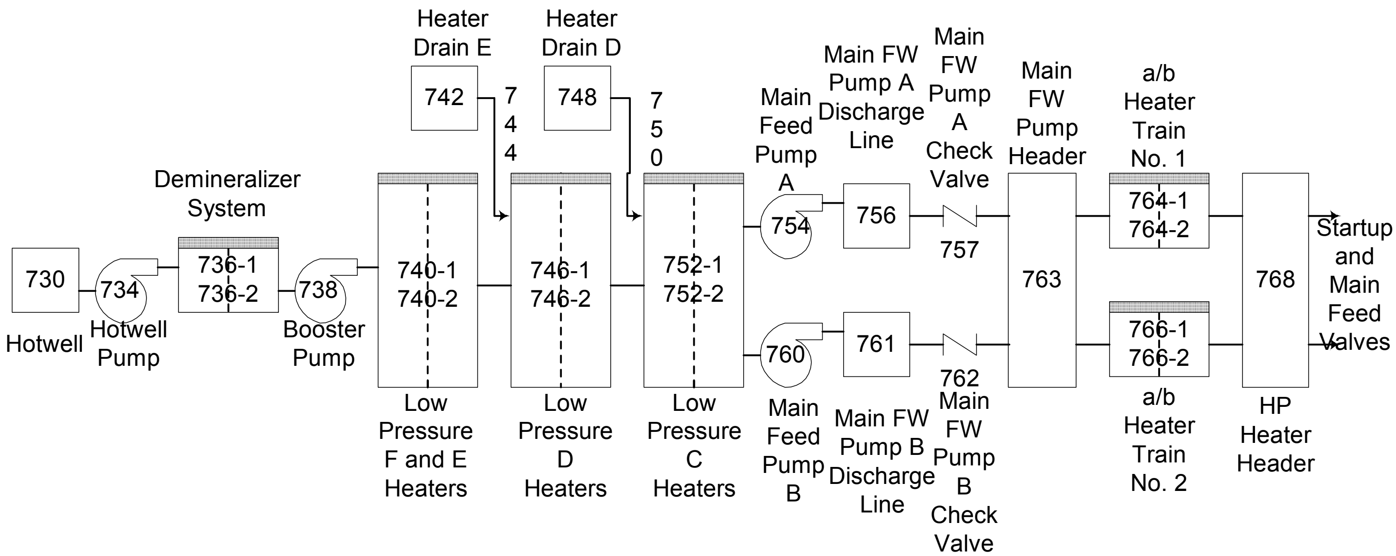


Figure 2.1-5 Oconee Main Feedwater Train RELAP5 Nodalization

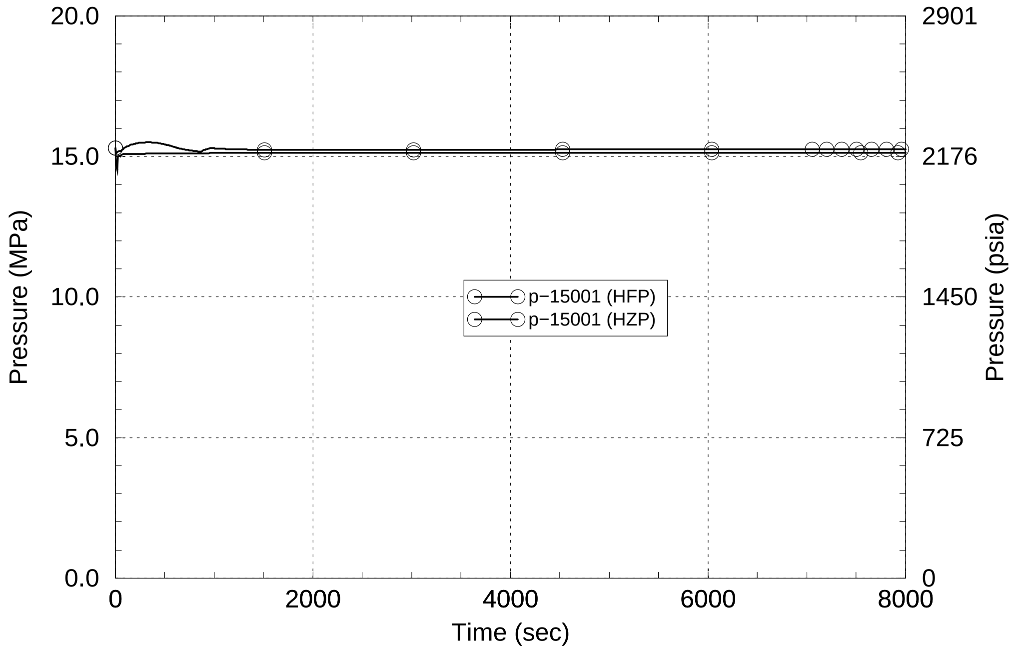


Figure 2.1-6 Oconee Hot Leg Pressure Response - Steady State

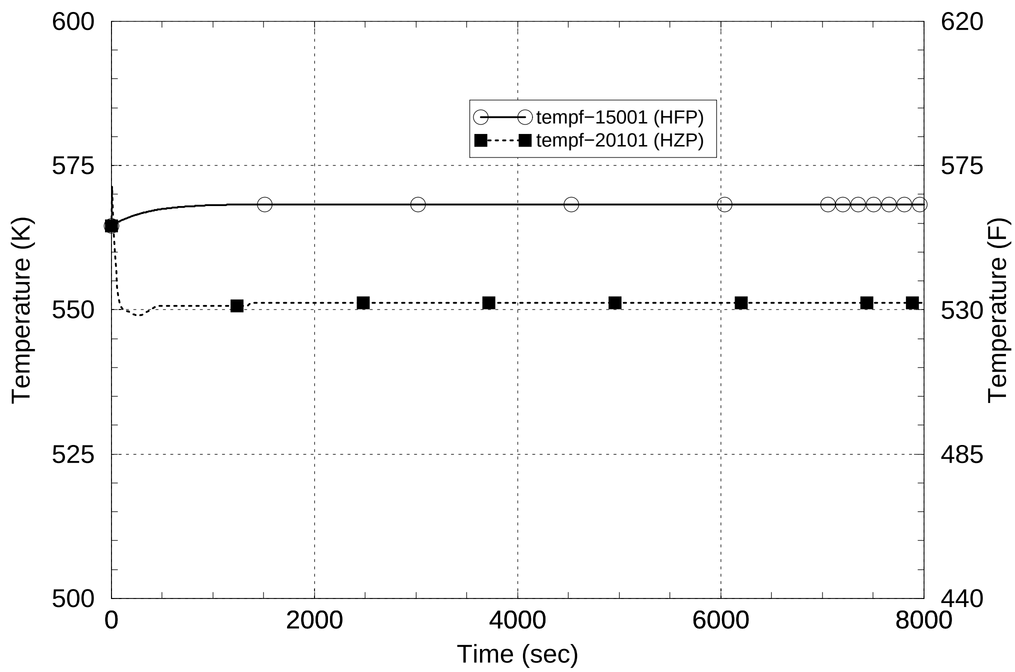


Figure 2.1-7 Oconee Hot Leg Temperature Response - Steady State

2.2 Beaver Valley Model

2.2.1 Beaver Valley Model Description

The Beaver Valley Unit 1 (BV-1) nuclear power plant is a Westinghouse three loop pressurized water reactor, operated by FirstEnergy Nuclear Operating Co., with a rated thermal power of 2660 MW (821 MWe). In early 2001, Westinghouse Electric Company created a RELAP5 input model of the Beaver Valley plant (Ref. 2.2-1) which was based on the H.B. Robinson RELAP5 model. This model was used as the starting point for this analysis. The Westinghouse model was revised for several reasons, including setpoint changes, additional control/trip logic changes and other changes including corrections to the original model. These changes include the addition of control blocks to calculate parameters for information only (i.e., items such as minimum downcomer temperature, etc.).

The RELAP5 model used is a detailed representation of the Beaver Valley Unit 1 power plant, describing all the major flow paths for both primary and secondary systems including the main steam and feed systems. Also modeled are primary and secondary side relief/safety valves as well as the emergency core cooling systems (high pressure injection, low pressure injection, accumulators) in the primary and auxiliary feedwater on the secondary. The model contains 281 volumes, 377 junctions and 353 heat structures. A noding diagram of the model is included as Figures 2.2-1 through 2.2-7.

The BV-1 plant has three primary coolant loops and each loop is represented in the RELAP5 model. The loops are designated as A, B, and C. Each coolant loop contains a hot leg, U-tube steam generator, pump suction, reactor coolant pump (RCP) and cold leg as shown in Figure 2.2-1. The pressurizer is attached to the C loop and the pressurizer spray lines are connected to the A and B loops. Attached to each cold leg are low pressure safety injection, high pressure safety injection and accumulators. The low and high pressure injection systems are set to deliver one third of the total LPI and HPI flow to each loop and are modeled using a time dependent volume/junction pairs in RELAP5. Also attached to the B loop is the chemical and volume control system (CVCS). The CVCS was modeled with a single time dependent volume-junction pair. Heat structures were connected to primary loop volumes to represent the metal mass of the piping and steam generator tubes. Heat structures were also used to represent the pressurizer heaters.

The reactor vessel noding is shown in Figures 2.2-2 and 2.2-3. The downcomer, downcomer bypass, lower plenum, core, upper plenum, and upper head were represented in the RELAP5 model. The downcomer was divided into six azimuthal sectors to obtain a more detailed downcomer temperature distribution. The following leakage paths were represented in the model: downcomer to upper plenum, downcomer to downcomer bypass, downcomer bypass to lower plenum, cold leg inlet annulus to upper plenum, and upper plenum to the upper head by way of the guide tubes. Heat structures represent both external and internal metal mass of the vessel as well as the core (fuel rods). Decay heat was assumed to be at the ANS standard rate.

The secondary side of the BV-1 RELAP5 model is shown in Figures 2.2-4 through 2.2-7. The steam generator secondary model (Figures 2.2-4 through 2.2-6) represents the major flow paths in the secondary and includes the downcomer, boiler region, separator and dryer region, and the steam dome. The major flow paths from the steam generator to the turbine control valves were modeled and are shown in Figure 2.2-7. Each steam line from the steam generators to the common header was modeled individually and include a main steam isolation valve, a check valve, atmospheric steam dump and safety relief valves. From the common header to the turbine control valve was modeled as a single volume. The steam dump valves were modeled with a single RELAP5 valve component with appropriate control logic capable of opening individual valves as required.

The major flowpaths of the main feedwater system were modeled and are shown in Figure 2.2-7. The feedwater model begins at the main feedwater header just upstream of the main feedwater pumps. The conditions in the main feedwater header were held at a constant temperature. Downstream of the pumps, the high pressure heaters were modeled as well as the MFW pump bypass. The control valves which regulate main feedwater flow were also modeled. The auxiliary feedwater system was modeled included both the motor and steam driven systems.

Heat structures were used in the secondary side to include both internal and external metal mass of the steam generators as well as the metal mass of the piping for both the steam and feedwater systems.

2.2.2 Beaver Valley Steady State Initialization

Steady-state calculations simulating hot full power and hot zero power plant operation were performed with the Beaver Valley RELAP5 model in order to establish model initial conditions from which to begin transient calculations. For this purpose, long (8000 s) steady state runs were made to assure that steady conditions had been achieved in the fluid and heat structures in the RELAP5 model. Figures 2.2-8 and 2.2-9, respectively, show the cold leg pressure and fluid temperature responses from the hot full power and hot zero power RELAP5 calculations. The figures demonstrate that the RELAP5 solutions have reached a steady state at the end of the calculation. Tables 2.2-1 and 2.2-2, respectively, compare the RELAP5 calculated steady-state results for key parameters (at the 8,000 s end points of the calculations) with the desired plant values for the parameters for hot full power and hot zero power plant operation. The tables indicate that the RELAP5-calculated steady-state solutions are in excellent agreement with the desired steady plant conditions for both cases.

2.2.3 References

2.2-1 Janke, Mark, Beaver Valley Unit 1 RELAP Input Deck for PTS Analysis, Westinghouse Calculation CN-LIS-00-180, Rev. 0, March 2001.

Table 2.2-1 Comparison of Key Beaver Valley Plant Design Parameters to RELAP5 Steady-State Results for Hot Full Power Conditions

	Plant Data[1]	RELAP5
Reactor Thermal Power	2660 MW	2660 MW
Reactor Coolant Temperature at Vessel Inlet	556.5 K [542°F]	558.0 K [544.8°F][2]
Reactor Coolant Temperature at Vessel Outlet	594.8 K [610.9°F]	594.5 K [610.4°F][2]
Reactor Core Operating Pressure	15.51 MPa [2250 psia]	15.51 MPa [2249.8 psia]
Reactor Coolant Flow at Core Inlet	12,688 kg/s [27,972 lbm/s]	12,849 kg/s [28,328 lbm/s]
Pressurizer Level	48%	47.8%
Main Feedwater Temperature at SG Inlet	495.7 K [432.5°F]	500.0 K [440.4°F][3]
Main Steam Flow Rate (per SG)	485.1 kg/s [1069 lbm/s]	491.7 kg/s [1084 lbm/s]
Main Steam Pressure	5.65 MPa [820 psia]	5.72 MPa [829.7 psia][3]

Note:

(1) Plant data from References: Janke, Mark, "Beaver Valley Unit 1 RELAP Input Deck for PTS Analysis", Westinghouse Calculation CN-LIS-00-180, Rev. 0, March 2001 AND BV FSAR.

(2) RELAP5 value is the average of all three loops

(3) RELAP5 value is the average of all three steam generator values

Table 2.2-2 Comparison of Key Beaver Valley Plant Design Parameters to RELAP5 Steady-State Results for Hot Zero Power Conditions

	Plant Data[1]	RELAP5
Reactor Thermal Power	5.32 MW[2]	5.32 MW
Reactor Coolant System Average Temperature	559.3 K [547.0°F]	559.3 K [547.0°F]
Reactor Core Operating Pressure	15.51 MPa [2250.0 psia]	15.51 MPa [2249.8 psia]
Reactor Coolant Flow at Core Inlet	Unknown	12,918 kg/s [28,480 lbm/s][3]
Pressurizer Level	22.4%	22.2%
Main Feedwater Temperature at SG Inlet	Unknown	300 K [80.0°F][4]
Main Steam Flow Rate (per SG)	Unknown	[3.34 lbm/s]
Main Steam Pressure	7.03 MPa [1020.0 psia]	6.93 MPa [1005.0 psia]

Note:

(1) Plant data from References: BV FSAR

(2) This value is the assumed heat load at 1 month after shutdown (0.2%).

(3) The reactor coolant pumps are assumed to operate at the same constant speed as during HFP operation. The RCS loop flow rate at HZP is that attained based on the pump head-flow-speed homologous curves and fluid conditions that are slightly different at HZP operation than at HFP operation

(4) This temperature was assumed to represent the water in the condenser under no load conditions.

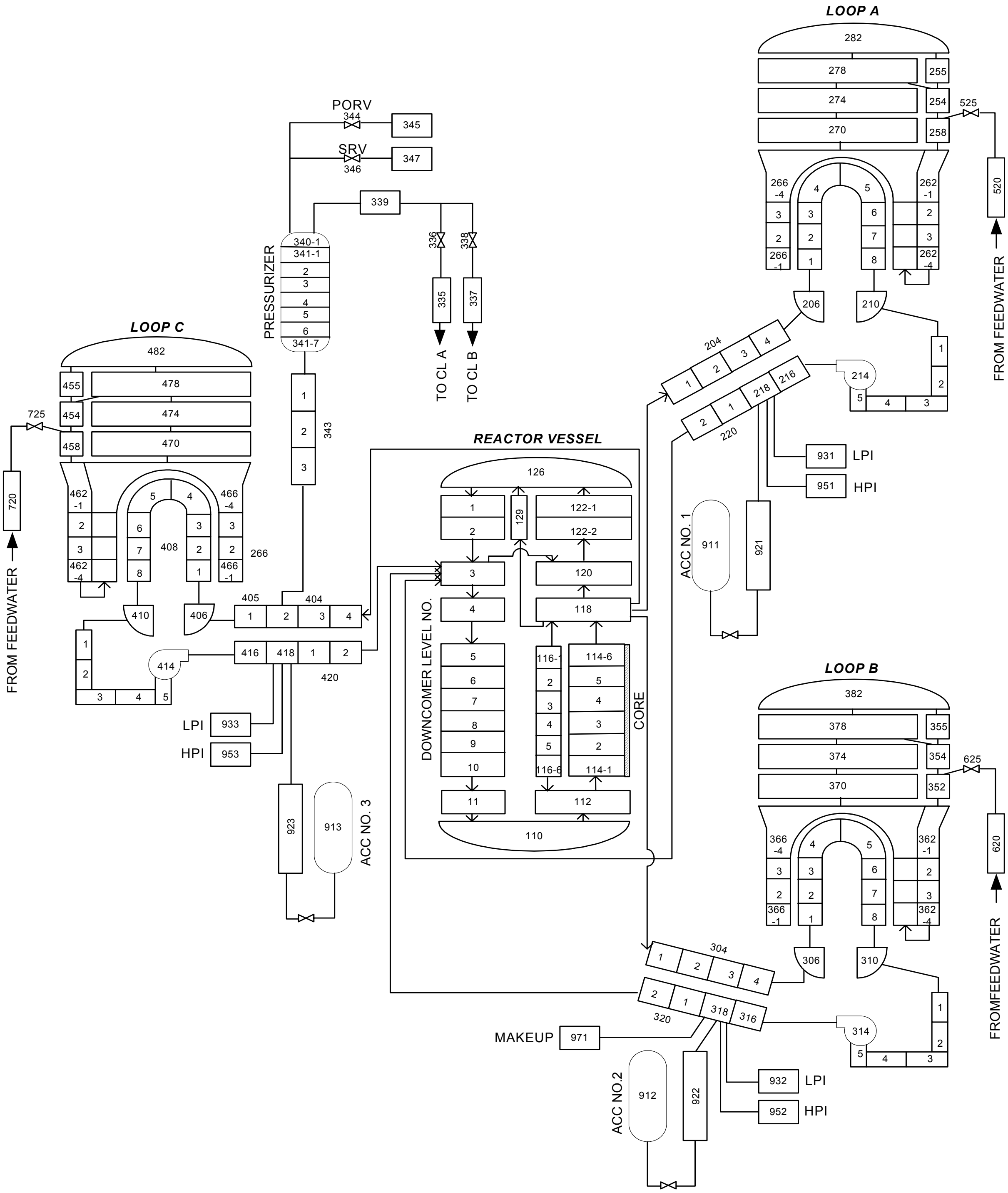
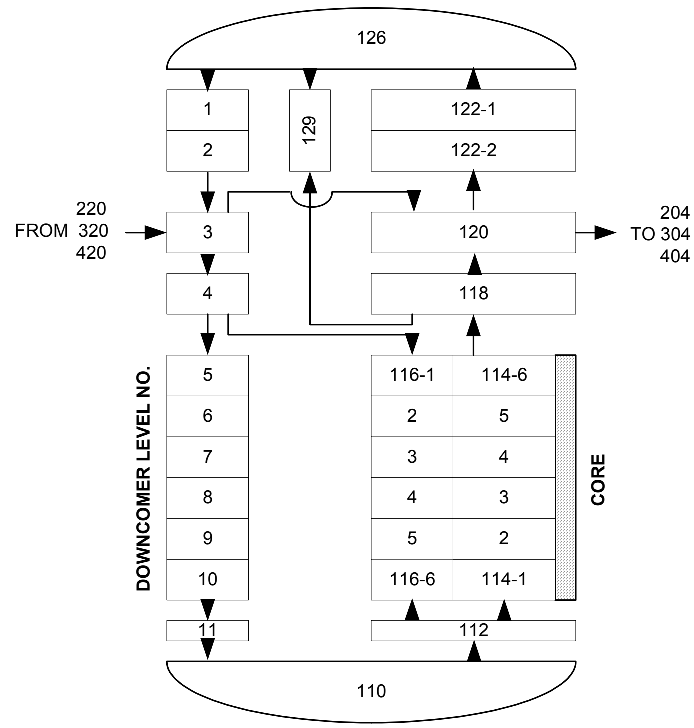
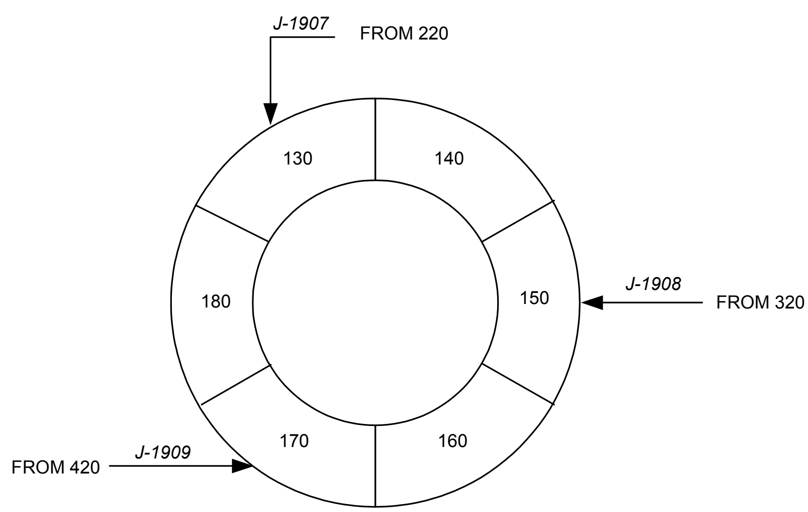


Figure 2.2-1   Beaver Valley Reactor System Nodalization





TOP VIEW OF DOWNCOMER

Figure 2.2-2 Beaver Valley Reactor Vessel Nodalization

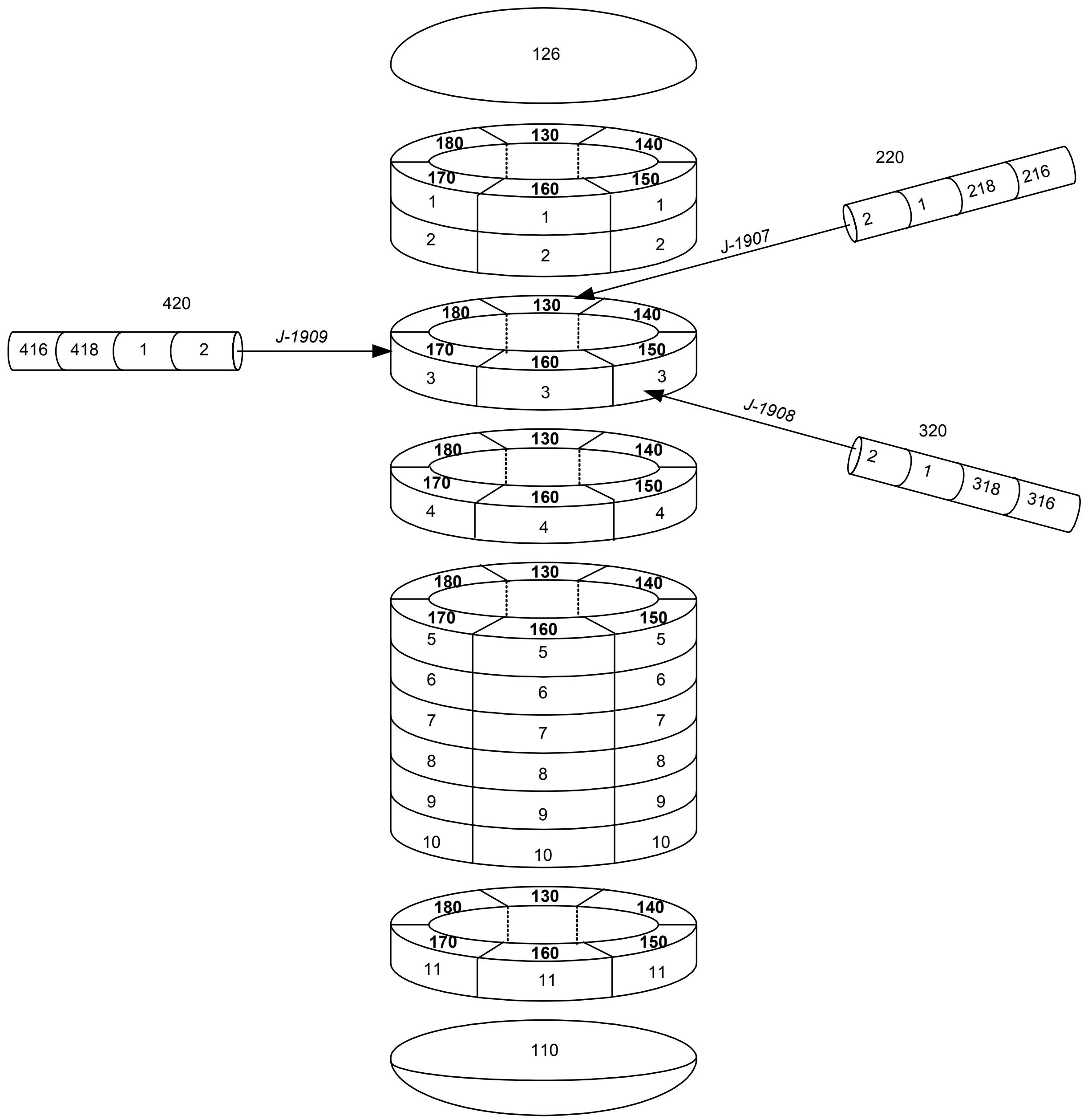


Figure 2.2-3 Beaver Valley 2-Dimensional Downcomer Nodalization

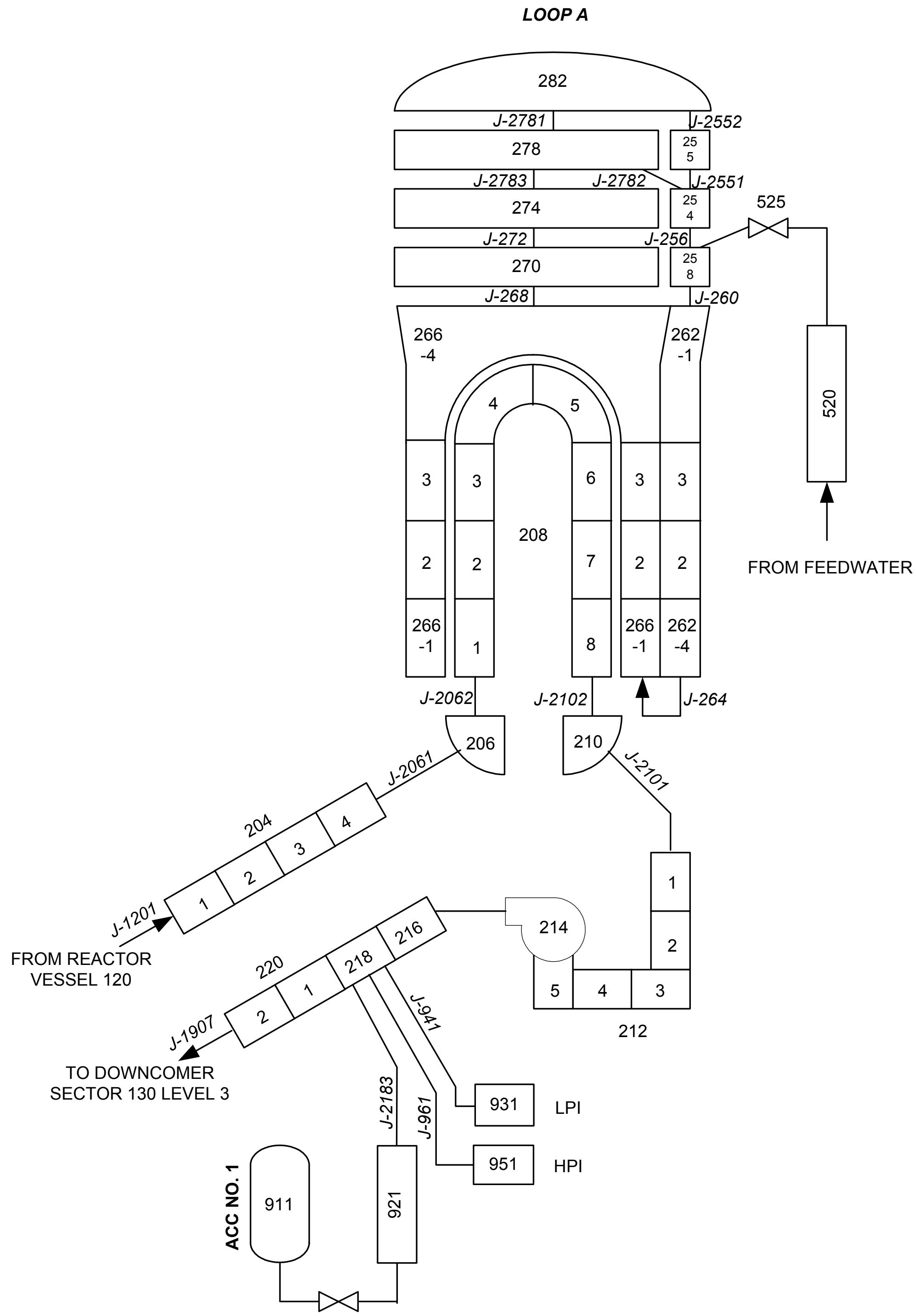


Figure 2.2-4 Beaver Valley Loop A Nodalization

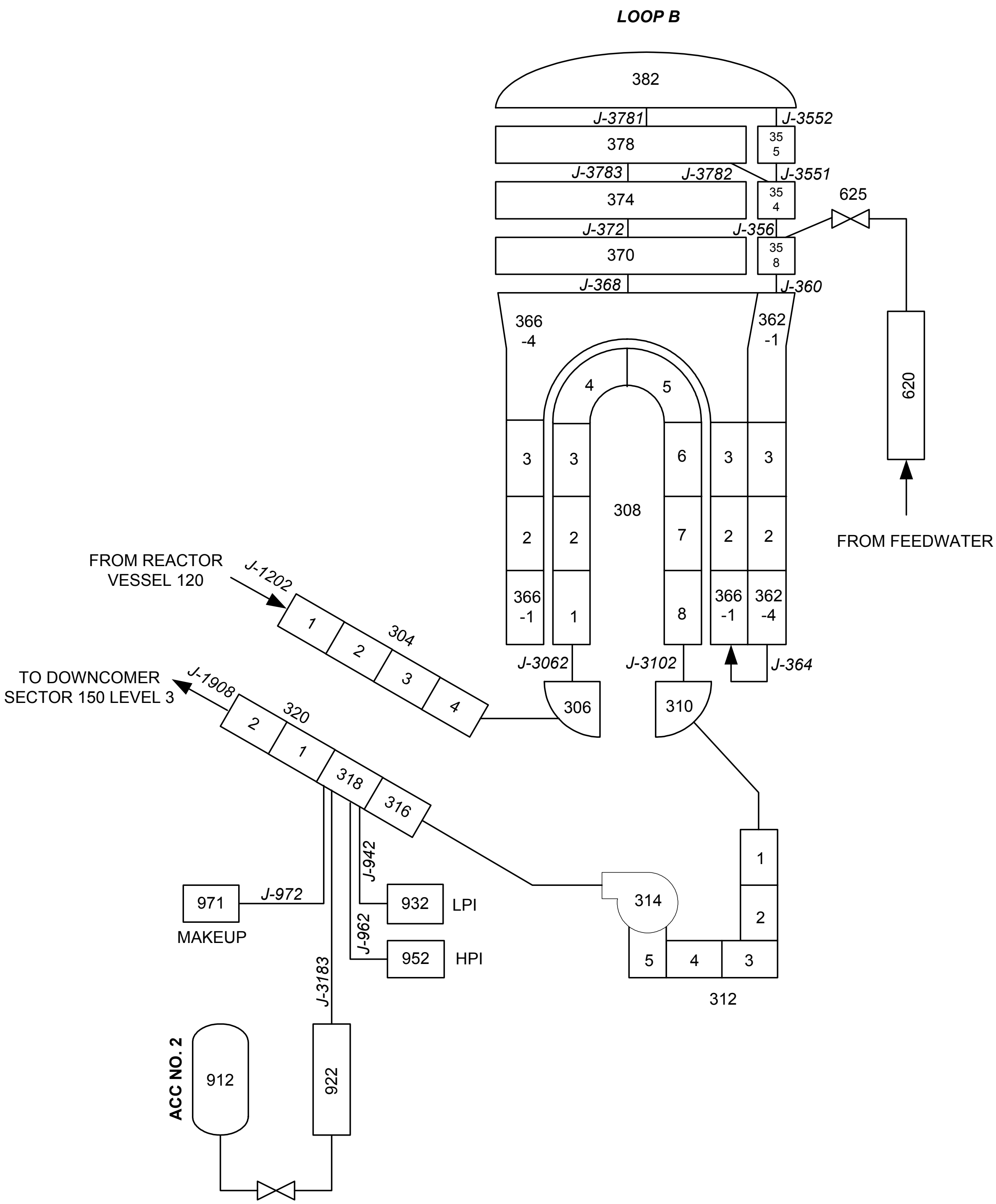


Figure 2.2-5 Beaver Valley Loop B Nodalization

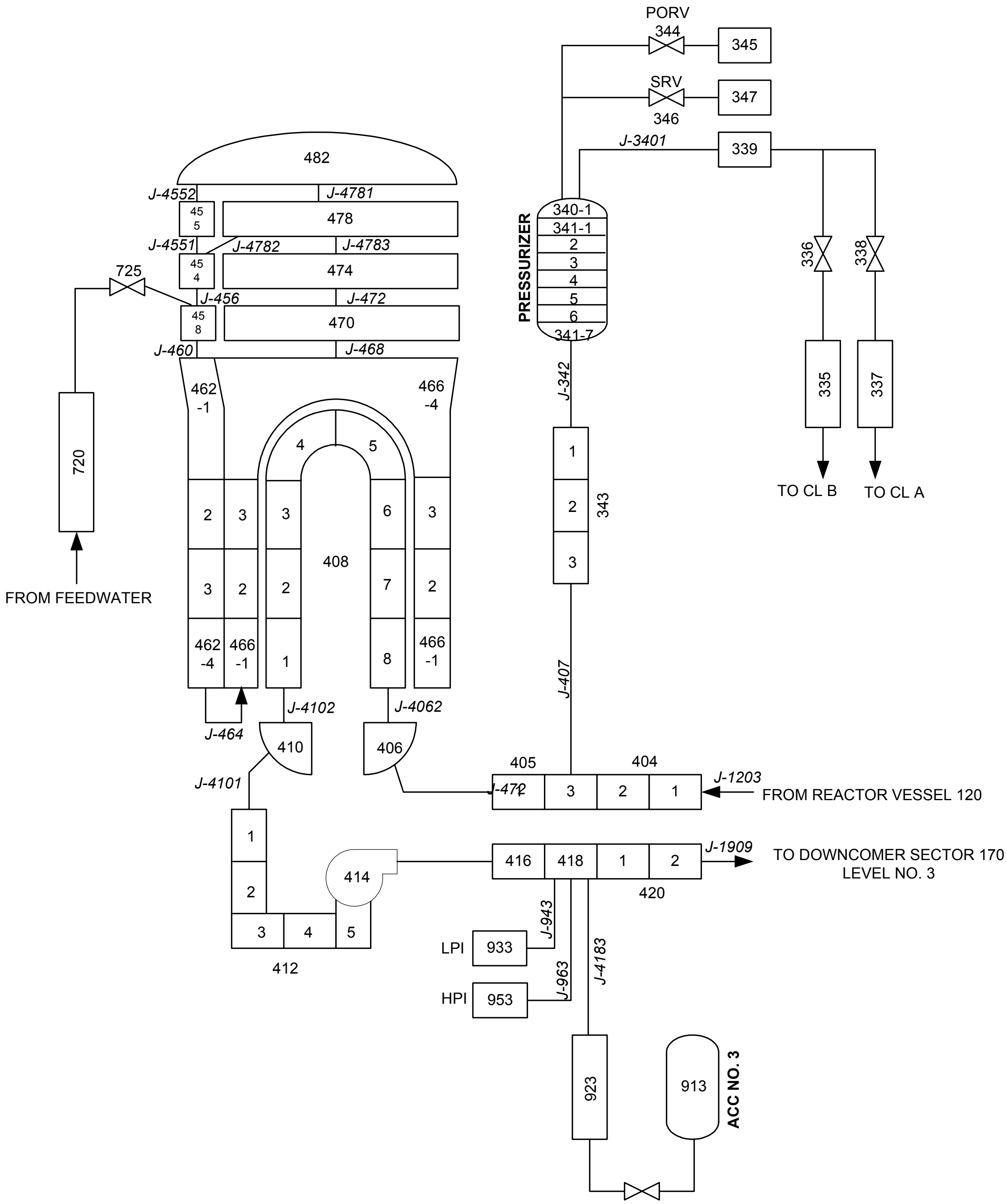


Figure 2.2-6 Beaver Valley Loop C Nodalization

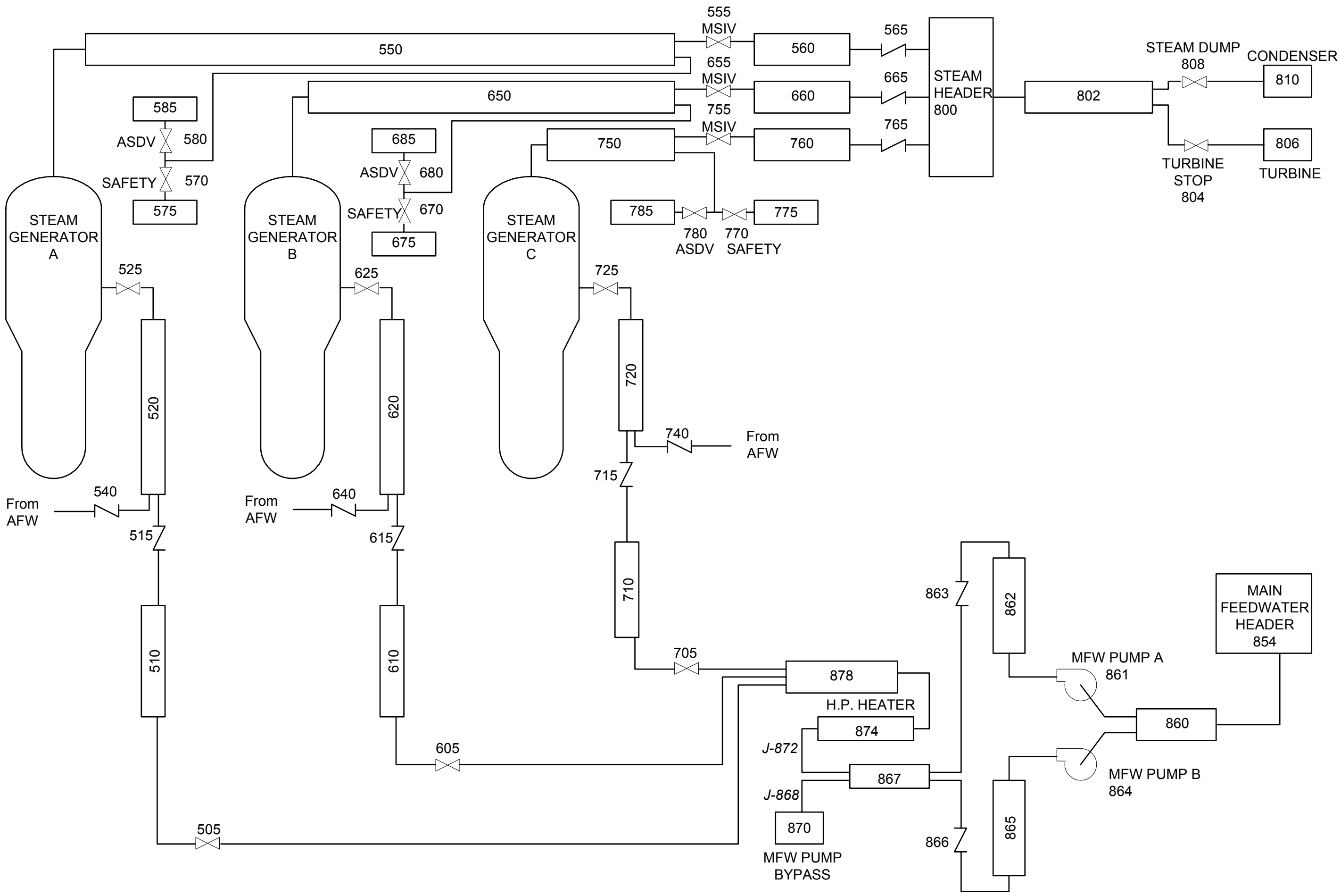


Figure 2.2-7 Beaver Valley Secondary Side Nodalization

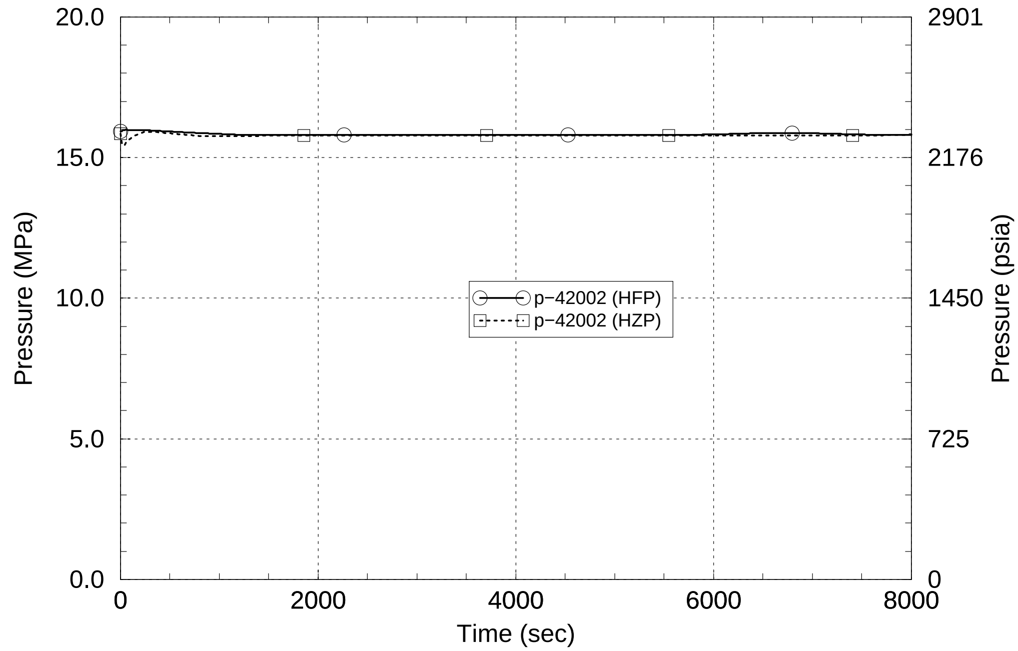


Figure 2.2-8 Beaver Valley Cold Leg Pressure Response - Steady State

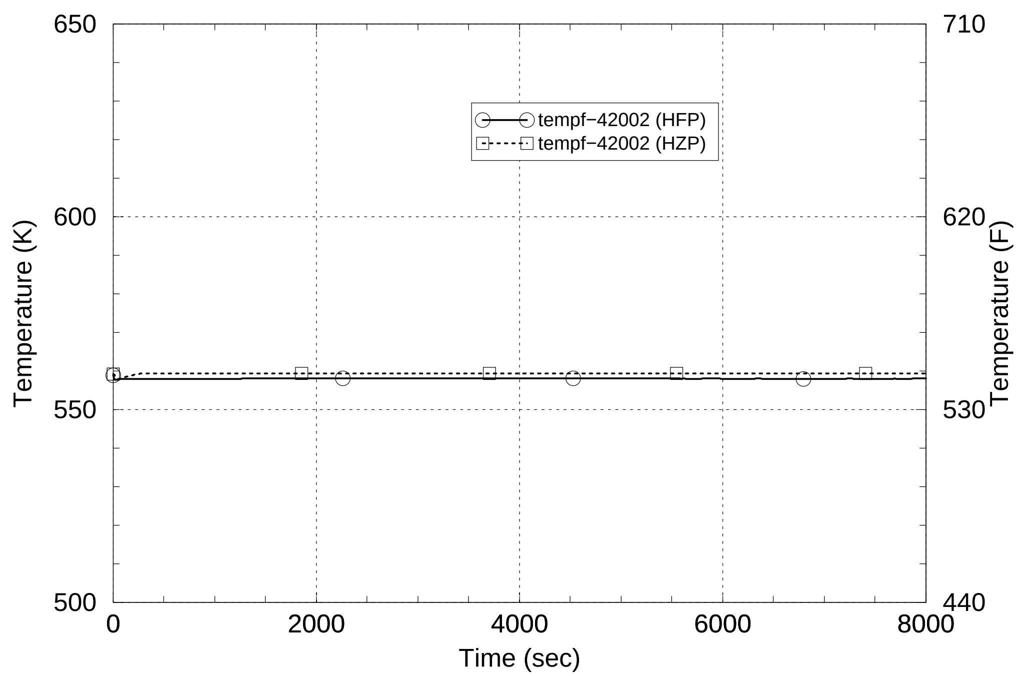


Figure 2.2-9 Beaver Valley Cold Leg Temperature Response - Steady State

2.3 Palisades Model Description

2.3.1 Palisades RELAP5 Model Description

The Palisades Nuclear Power Plant is a pressurized water reactor of Combustion Engineering design with a rated thermal power of 2530 MW. The Palisades reactor coolant system consists of a reactor vessel and two coolant loops connected in parallel and designated as Loops 1 and 2. Each coolant loop includes hot leg piping, an inverted U-tube type steam generator, and two sets of reactor coolant pumps and cold leg piping. The cold legs and reactor coolant pumps on each loop are designated as A and B. The normal coolant flow on each loop is from the reactor vessel outlet nozzle, through the hot leg, steam generator, reactor coolant pumps and cold legs to the reactor vessel inlet nozzle. A pressurizer is connected via a surge line to the hot leg on Loop 1. The electrically-heated pressurizer provides pressure control for the reactor coolant system. Two pressurizer spray lines are routed from one of the pump-discharge cold legs on each loop through control valves to a spray nozzle in the pressurizer upper dome. Reactor coolant system overpressure protection is provided by safety relief valves atop the pressurizer (the plant also employs power operated safety relief valves, but they are blocked closed during normal plant operation). Emergency core cooling functions are provided by high and low pressure injection systems and safety injection tanks, which are connected to each of the four pump-discharge cold legs. A charging/letdown system performs the functions of reactor coolant system water chemistry control and pressurizer level control. Decay heat removal capability is provided by motor-driven and turbine-driven auxiliary feedwater systems that discharge into the steam generator downcomers. The maximum auxiliary feedwater flow that may be delivered to each steam generator is automatically limited. Steam generator secondary system overpressure protection is provided by safety relief valves, atmospheric dump valves and turbine bypass valves located on the main steam lines. Main steam isolation valves are located in each of the two steam lines, limiting the influence that a break in one of the steam generator secondary systems would have on the other.

The Palisades RELAP5 model is a detailed thermal-hydraulic representation of the Palisades Nuclear Power Plant that includes all major components of the primary and secondary coolant systems and the plant control systems pertinent for simulating the PTS transient event sequences. Nodalization diagrams for the Palisades RELAP5 model are illustrated in Figures 2.3-1 through 2.3-3.

The reactor vessel model nodalization is shown in Figure 2.3-1. Because of the need for detailed information on reactor vessel downcomer temperature for evaluating PTS, a two-dimensional nodalization scheme with seven axial and six azimuthal nodes is used in the downcomer region.

During preliminary RELAP5 calculations of LOCA sequences with break diameters of 10.16-cm [4-in] diameter and larger, non-physical numerically-driven circulations among the six reactor vessel downcomer internal channels of the model (Components 500 through 505 in Figure 2.3-1) were observed. A variety of methods were tried in an attempt to suppress or remove these circulations from the calculations. However, the only modeling approach which successfully eliminated them was to disable momentum flux in all internal reactor vessel downcomer junctions. Since the downcomer flow pattern can be of significance for the PTS analysis, the Palisades transient LOCA cases with break diameters of 10.16 cm [4 in] and larger were run with momentum flux disabled in all internal downcomer junctions.

The reactor core region is modeled using six axial nodes. Other nodes are used to represent the lower plenum, upper plenum, core bypass, control rod guide tube and upper head regions of the reactor vessel.

A constant reactor power is modeled until the reactor trip time using a table; afterward a reactor power decay is specified as a function of time after trip. The model includes control system logic that monitors various plant parameters during transient calculations and trips the reactor based on any of the following conditions: high containment pressure, low pressure in either steam generator, high pressurizer pressure, or exceeding the thermal margin/low pressure trip limit (the criterion varies as a function of several plant variables).

The reactor coolant loop region nodalization is shown in Figure 2.3-2. The speed of the reactor coolant pump models is held constant to deliver the normal-operation flow rate unless the pumps are tripped by operator action (based on indications of low reactor coolant system pressure or low subcooling). Once tripped, the reactor coolant pump speed coasts down based on rotational inertia effects.

Charging flow is injected into the Loop 1A and 2A pump-discharge cold leg piping and letdown flow is withdrawn from the Loop 2B pump-suction cold leg piping. The charging flow is controlled so as to maintain a desired pressurizer setpoint level, which is specified as a function of average reactor coolant system temperature. The letdown flow is isolated upon receipt of a safety injection actuation signal, which results from a low pressurizer pressure condition. The operation of the pressurizer heater power and spray valve flow area are specified so as to maintain the pressurizer pressure within the desired range.

The safety injection tanks are modeled on each of the four pump-discharge cold legs using RELAP5 accumulator components. Safety injection tank flow occurs whenever the cold leg pressure is below the tank pressure. The high and low pressure injection systems are represented using RELAP5 time dependent volume and junction component pairs on each of the four pump-discharge cold legs. The injection characteristics of these centrifugal pump systems are modeled with the flow delivered specified as a function of the cold leg pressure; flow is initiated after a time delay following the occurrence of a safety injection actuation signal. Control logic is included such that operator throttling of high pressure injection (based on pressurizer level and subcooling criteria) can be represented for event sequences specified to include that operator function. Control logic also is included to monitor the inventory status of the refueling water storage tank (that is first used as the source of emergency core coolant). This tank supplies water for the charging, high pressure injection, low pressure injection and containment spray systems. When the inventory of the tank has been expended, the model includes features that represent the actions taken in the plant (termination of the charging and low pressure injections and switching the suction of the high pressure injection system to the containment sump). Following this switch, the high pressure injection system flow characteristics are changed and the injected water temperature increases.

The main feedwater flow is adjusted so as to control the steam generator levels at the setpoint level and to match the feedwater and steam flow rates in each steam generator. After turbine trip, the main feedwater flow stops and the auxiliary feedwater flow is delivered to control steam generator levels within a specified range.

The main steam system nodalization is shown in Figure 2.3-3. The model represents the steam line from each steam generator to the common turbine inlet header. A valve component is used to represent the turbine stop valves, which close upon receipt of a turbine trip signal. Overpressure protection is modeled by the main steam safety relief valve components on each steam line. Steam pressure control for post-turbine trip operating conditions is provided by a turbine bypass valve component located on the turbine inlet header. Primary coolant system average temperature control is provided by an atmospheric dump valve component on each of the steam lines. Main steam isolation valves connect each steam line to the turbine inlet header. These valves close if a low pressure condition is sensed in either steam generator or if a containment high pressure condition is sensed.

2.3.2 Steady-State Initializations for the Palisades RELAP5 Model

Steady-state calculations simulating hot full power and hot zero power plant operation were performed with the Palisades RELAP5 model in order to establish model initial conditions from which to begin transient accident calculations. For this purpose, long (8000 s) steady state runs were made to assure that steady conditions had been achieved in the fluids and heat structures represented by the Palisades RELAP5 model. Figures 2.3-4 and 2.3-5, respectively, show the cold leg pressure and fluid temperature responses from the hot full power and hot zero power RELAP5 calculations. The figures demonstrate that the RELAP5 solutions are steady at the ends of the calculations. Tables 2.3-1 and 2.3-2, respectively, compare the RELAP5-calculated steady-state results for key parameters (at the 8,000 s end points of the calculations) with the desired Palisades plant values for hot full power and hot zero power plant operation. The tables indicate that the RELAP5-calculated steady-state solutions are in excellent agreement with the desired steady plant conditions for both cases.

2.3.3 References

2.3-1 Consumers Energy Company, Palisades Cycle 16 Principal Plant Parameters, EA-PPD-00-01, Revision 0, November 2000.

2.3-2 Final Safety Analysis Report, Palisades Nuclear Power Plant, Revision 22.

Table 2.3-1 Comparison of Key Palisades Plant Design Parameters to RELAP5 Steady-State Results for Hot Full Power Conditions

	Plant Data	RELAP5
Reactor Thermal Power	2530 MWt	2530 MWt
Reactor Coolant Temperature at Vessel Inlet	553.8 K [537.3°F]	553.94 K [537.42°F]
Reactor Coolant Temperature at Vessel Outlet	579.1 K [582.7°F]	579.12 K [582.75°F]
Reactor Core Operating Pressure	14.20 MPa [2060 psia]	14.20 MPa [2060.2 psia]
Reactor Coolant Flow at Core Inlet	17388 kg/s [38335 lbm/s]	18315 kg/s [40377 lbm/s]
Pressurizer Level	57 %	56.99 %
Main Feedwater Temperature at SG Inlet	497.0 K [435.0°F]	497.0 K [435.0b°F]
Main Steam Flow Rate (per SG)	693.1 kg/s [1528.1 lbm/s]	695.9 kg/s [1534.1 lbm/s]
Main Steam Pressure	5.309 MPa [770 psia]	5.220 MPa [757.03 psia]
Note: The plant data presented in this table is taken from the Palisades Principal Plant Parameters Document [Ref. 2.3-1] and the Palisades FSAR [Ref. 2.3-2].		

Table 2.3-2 Comparison of Key Palisades Plant Design Parameters to RELAP5 Steady-State Results for Hot Zero Power Conditions

	Plant Data	RELAP5
Reactor Thermal Power	5.06 MWt	5.06 MWt
Reactor Coolant Temperature at Vessel Inlet	550.9 K [532.0°F]	551.02 K [532.16°F]
Reactor Coolant Temperature at Vessel Outlet	551.0 K [532.1°F]	551.07 K [532.25°F]
Reactor Core Operating Pressure	14.20 MPa [2060 psia]	14.20 MPa [2060.2 psia]
Reactor Coolant Flow at Core Inlet	16647 kg/s [36700 lbm/s]	18535 kg/s [40863 lbm/s]
Pressurizer Level	42 %	42.11 %
Main Feedwater Temperature at SG Inlet	294.3 K [70.0°F]	294.3 K [70.0°F]
Main Steam Flow Rate (per SG)	4.202 kg/s [9.264 lbm/s]	4.202 kg/s [9.264 lbm/s]
Main Steam Pressure	6.205 MPa [900.0 psia]	6.109 MPa [886.01 psia]
Note: The plant data presented in this table is taken from the Palisades Principal Plant Parameters Document [Ref. 2.3-1] and the Palisades FSAR [Ref. 2.3-2].		

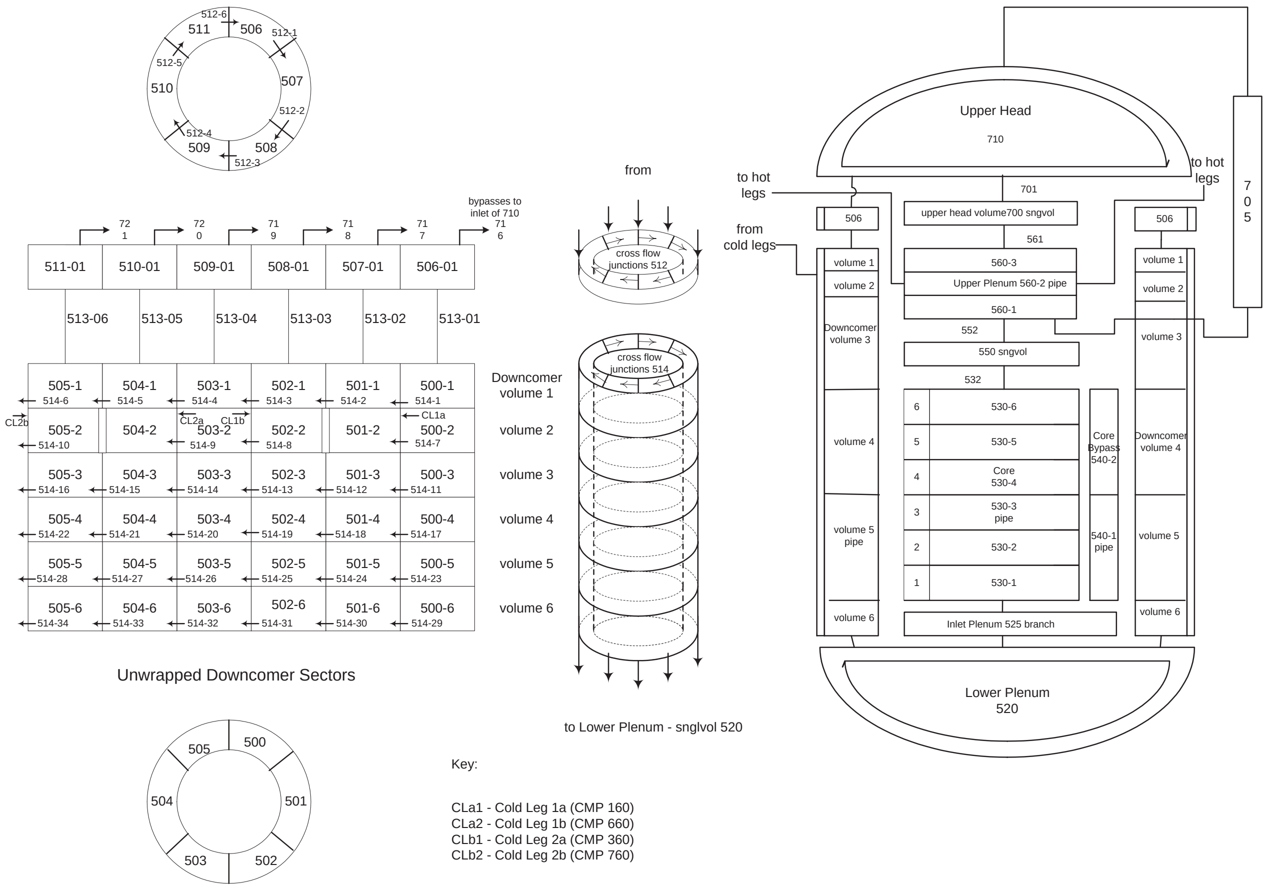


Figure 2.3-1   Palisades Reactor Vessel Nodalization

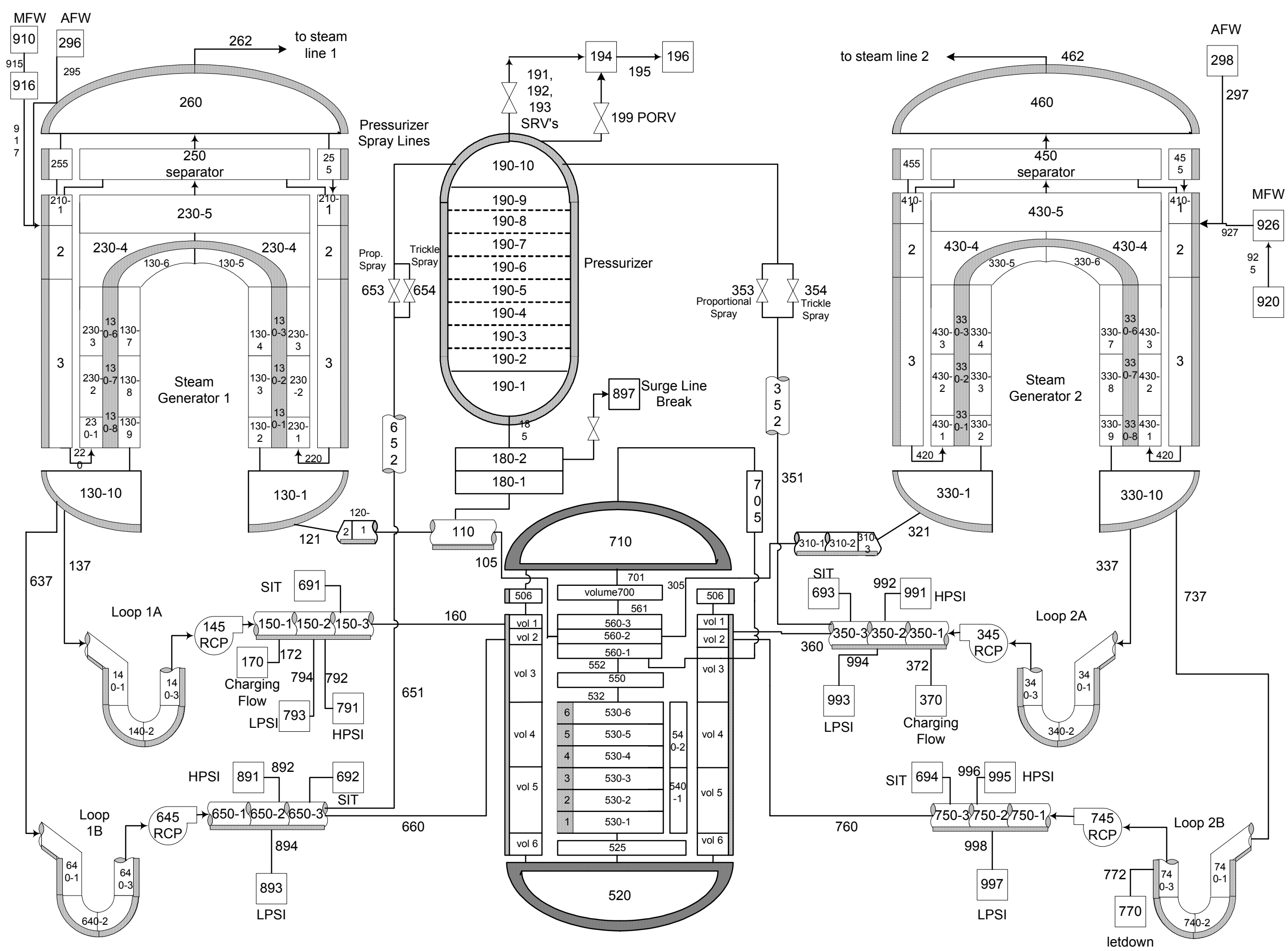


Figure 2.3-2 Palisades Coolant Loops Nodalization

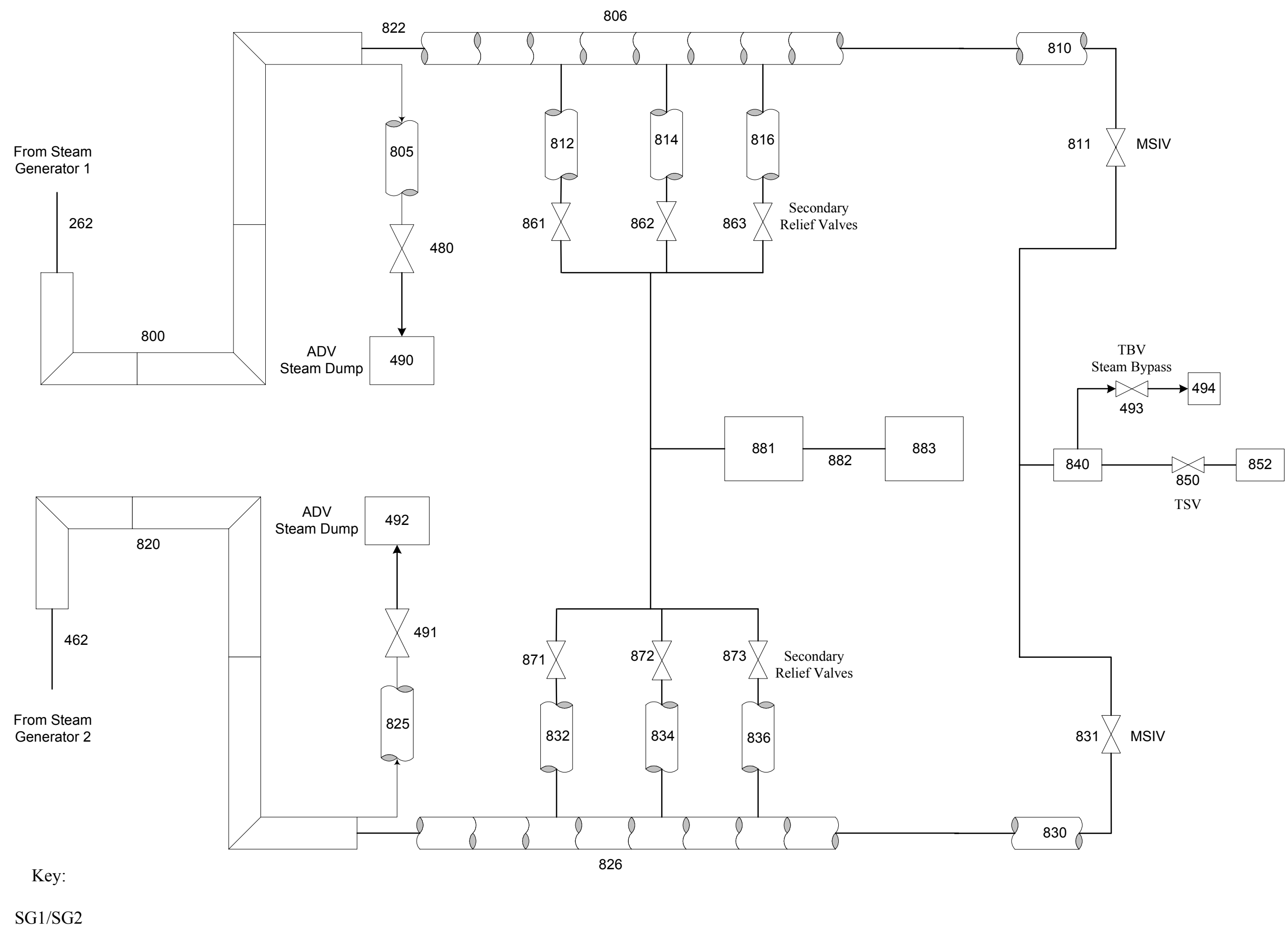


Figure 2.3-3 Palisades Main Steam System Nodalization

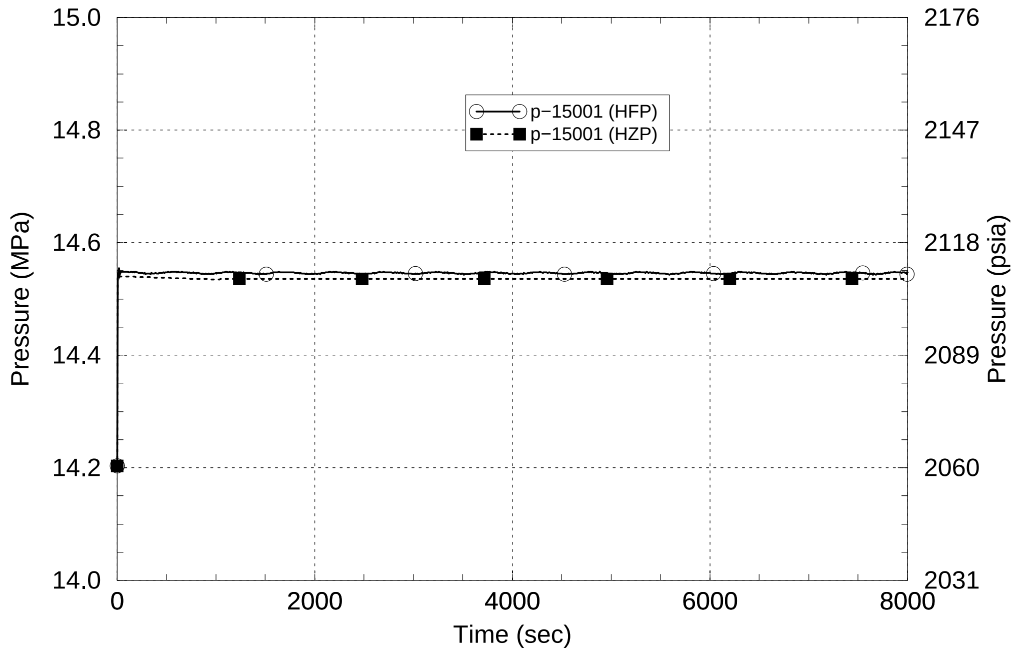


Figure 2.3-4 Palisades Cold Leg Pressure Response - Steady State

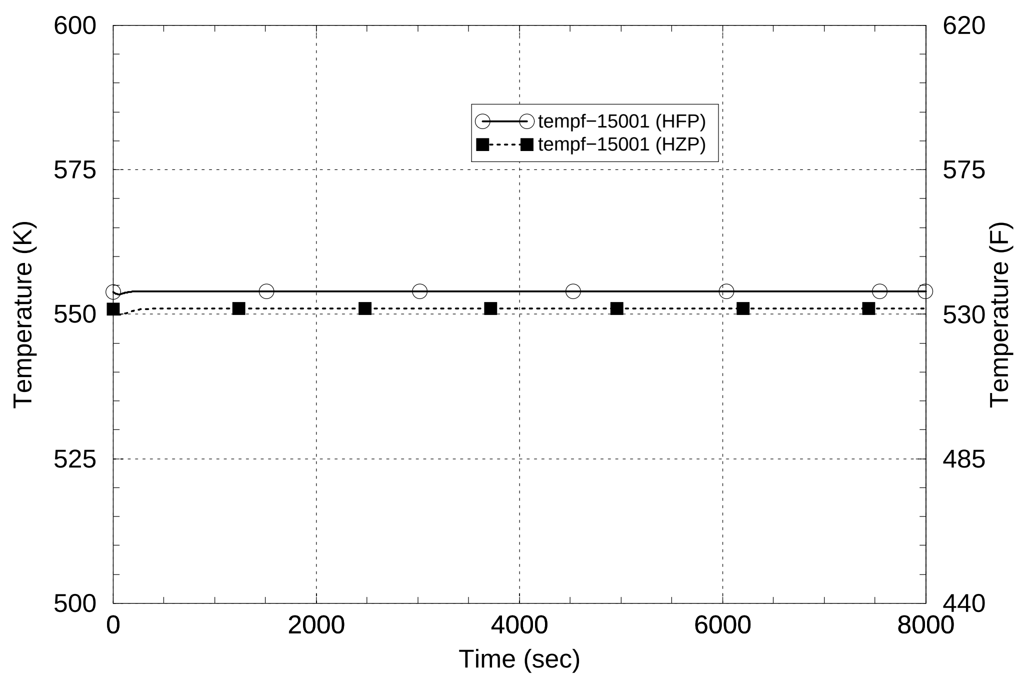


Figure 2.3-5 Palisades Cold Leg Temperature Response - Steady State

3.0 RELAP5/MOD3 ANALYSIS OF TRANSIENTS FOR PTS EVALUATION

The thermal-hydraulic responses for various PTS transient event sequences are calculated with the RELAP5 code and the plant models described in Section 2. The event sequences analyzed were defined through a risk assessment performed by the Sandia National Laboratories to identify sequences that may be important for risk due to PTS. The sequences analyzed were initiated by LOCAs in the pressurizer surge line, hot and cold leg piping, stuck-open pressurizer relief valves, reactor and turbine trips with stuck-open steam line valves, main steam line breaks and feedwater overfill events. A total of 177 cases were run for Oconee, 130 for Beaver Valley, and 67 for Palisades. Of these sequences analyzed, 55 Oconee cases, 62 Beaver Valley cases, and 30 Palisades cases are identified as having the highest PTS concern and are the subject of reactor vessel wall fracture mechanics analyses performed by Oak Ridge National Laboratory. These sequences, which are referred to as "base cases" are listed in Appendices A to C for Oconee, Beaver Valley and Palisades, respectively. These tabulations present the case numbers, initiating events and plant system failures and operator actions for the event sequences undergoing the fracture mechanics analyses and identify the dominant-risk sequences as determined through those analyses.

The fracture mechanics analysis performed by Oak Ridge identifies the sequences that are dominant contributors to the risk for rupture of the reactor vessel due to PTS for the Oconee, Beaver, and Palisades plants. Dominant contributors are those sequences that contribute more than 1 percent to the total risk of vessel failure due to a PTS event. Those sequences that are dominant based on the Oak Ridge results are identified in Appendices A to C.

From the PTS perspective, the principal thermal-hydraulic results of interest are the pressure and temperature in the reactor vessel downcomer along with the heat transfer coefficient on the inside surface of the reactor vessel wall at elevations corresponding to the span of the reactor core. These thermal-hydraulic results are used as boundary conditions for vessel wall probabilistic fracture mechanics analyses. Figures showing the time-history response of these parameters for the dominant PTS-risk event scenarios are provided in this section, along with descriptions of the event sequences, the modeling changes implemented and brief analyses of the RELAP5-calculated plant transient responses.

3.1 Thermal Hydraulic Results for the Dominant Oconee Transients

The Oconee sequences that were dominant contributors to the risk of vessel failure are primary coolant system LOCAs. However, cases involving stuck open pressurizer safety valves that reclose and main steam line breaks selected from the base case list in Appendix A are discussed to allow comparison with the Beaver Valley and Palisades plants. Also, these cases are included because, in some cases, they were important risk contributors in the 1980's PTS studies.

All RELAP5 transient case calculations were restarted from the end points of the steady state runs representing hot full power and hot zero power operation of the Oconee plant, as described in Section 2.1.2. All RELAP5 base case calculations were run for 10,000 s following the occurrence of the sequence initiating event. On the accompanying plots, the data shown prior to time zero represents the calculated steady-state condition prior to the transient initiation.

3.1.1 Primary Side Loss of Coolant Accidents from Hot Full Power

Four risk dominant sequences have been identified for Oconee and all involve primary side loss of coolant accidents. These LOCA sequences are: 1) Case 156 which is a 40.64 cm [16 in] break in the hot leg, 2) Case 160 which is a 14.37 cm [5.656 in] surge line break, 3) Case 164 which is a 20.32 cm [8 in] surge line break, and 4) Case 172 which is a 10.16 cm [4 in] cold leg break. All of these LOCA cases are initiated while the reactor is operating at full power. All systems are assumed to operate as designed. The surge line break is assumed to be located in the bottom of the surge line along the horizontal length (Component 600-02 in Figure 2.1-3). The hot leg break is assumed to be located in the bottom of the hot leg adjacent to the surge line connection (Component 105-01 in Figure 2.1-2). The cold leg break is assumed to be located in the bottom of the reactor coolant pump discharge pipe (Component 140-01 in Figure 2.1-2). The Henry Fauske critical flow model is activated in the break junction in all cases. Flow loss coefficients used for the break are based on the AP-600 derived flow loss coefficients [Ref 3.1.1] and scaled for the specific break size and location. No special operator action to control the primary system cooldown rate is assumed in these cases. Also note that no HPI or LPI throttling strategy is considered in these cases. In these analyses, the operator is assumed to trip the reactor coolant pumps when primary system subcooling is lost (a trip criteria of 0.27 K [0.5°F] is assumed). Large reverse flow loss coefficients were implemented in the cold legs to inhibit same-loop flow circulation as described in Section 2.0.

In the primary side loss of coolant accident cases, the breaks modeled are sufficiently large to start the containment (reactor building) sprays due to high containment pressure. As a result, the time that the HPI and LPI system suction switches to the containment sump is determined in RELAP5 by computing the integrated flow of the containment sprays, HPI and LPI systems compared to the total volume of water in the borated water storage tank. When the tank volume is depleted, switchover is assumed to occur. The temperature used for the sump water temperature is based on data for a 0.0046 m^2 [0.05 ft^2] break. The temperature used, 322 K [120°F] at switchover, increases to 325 K [125°F] by 3,000 s after switchover and then decreases to 313 K [105°F] by the end of the transient.

A tabulation of the timing of key events for the surge line and hot leg break transients is presented in Table 3.1-1.

Table 3.1-1 Comparison of Event Timing for LOCA Sequences

	Event Time (seconds)			
	Case 156 - 40.64 cm [16 in] break in the hot leg	Case 160 - 14.37 cm [5.656 in] surge line break	Case 164 - 20.32 cm [8 in] surge line break	Case 172 - 10.16 cm [4 in] cold leg break
Reactor power level	HFP	HFP	HFP	HFP
Reactor scram	1	1	1	1
HPI actuates	1	5	2	8
RCP trip time on loss of subcooling margin	1	10	2	31
Time that vent valves open	60	75	54	90
Core flood tank discharge start time	60	310	220	600
Low pressure injection starts	90	1190	610	2195
Core flood tank empties	150	1565	840	2720
Pressurizer starts to refill	does not refill	1910	1390	does not refill
ECCS Switchover time	1740	2890	2310	3760

3.1.1.1 Case 156 - 40.64 cm [16 in] Diameter Hot Leg Break from HFP Conditions

Case 156 is a 40.64 cm [16 in] diameter break in the hot leg from hot full power conditions. The equivalent break flow area is 0.13 m^2 [1.39 ft^2]. The parameters of interest for the fracture mechanics analysis: primary system pressure, average downcomer fluid temperature, and downcomer fluid-wall heat transfer coefficient are provided in Figures 3.1.1-1 through 3.1.1-3.

As a result of the break, rapid primary system depressurization occurs as shown in Figure 3.1.1-1. The primary system pressure falls to 0.23 MPa [33 psia] by 300 s after initiation and continues down to a equilibrium pressure of about 0.15 MPa [21 psia] by about 1,000 s after initiation. The downcomer temperature also falls rapidly as a result of the break, dropping to a temperature of 300 K [80°F] within 300 s and remaining at that temperature for the rest of the transient. The pressurizer level, shown in Figure 3.1.1-4, decreases rapidly and empties from the loss of coolant inventory as the reactor coolant system depressurizes. The pressurizer generally remains empty throughout the transient. Reactor trip occurs within 1 s, followed by actuation of the HPI system which runs for the duration of the event. The operators are assumed to trip the reactor coolant pumps as a result of the loss of subcooling immediately upon accident initiation when the trip criteria of 0.27 K [0.5°F] is reached. The trip of the reactor coolant pumps causes loss of forced convection in the downcomer which causes the drop in the downcomer wall heat transfer coefficient from a steady state value of about 24,110 w/m^2 K [1.18 Btu/s-ft^2-°F] to the values shown in

Figure 3.1.1-3. The break flow is presented in Figure 3.1.1-5 and consists of a liquid-steam mixture for most of the event. The total HPI flow is shown in Figure 3.1.1-6.

Because of the size of the break, the core flood tanks start to discharge by 60 s after initiation and are completely discharged by 150 s as shown in Figure 3.1.1-7. Low pressure injection flow, shown in Figure 3.1.1-8, starts within 90 s after initiation and remains on for the rest of the transient.

Hot leg flow is shown in Figure 3.1.1-9. The hot leg flow in the A loop is approximately equal to the break flow and is due to the continued operation of the HPI and LPI systems. There is little or no flow in the B loop. The system energy balance is shown in Figure 3.1.1-10 which shows that the break energy is much larger than the core decay heat load, which causes the system temperature to decrease. This plot also shows that the steam generators have a minor effect on the downcomer temperature. Heat is transferred from the steam generator into the primary system as the system depressurizes, but the size of the break is sufficiently large to remove this heat from the primary system along with the decay heat energy which is substantially larger.

Because of the size of the break and the continued operation of the HPI and LPI systems, the borated water storage tank inventory is depleted and HPI and LPI pump suction is switched to the containment sump. This switchover occurs at about 1,740 s as shown in Figure 3.1.1-11 and results in an increase in the HPI and LPI injection temperature, which directly impacts the downcomer temperature as seen from Figure 3.1.1-2.

The steam generator secondary side pressures are shown in Figure 3.1.1-12. The initial drop in secondary side pressure is due to the transfer of heat into the primary system from the steam generators. Actuation of feedwater flow, which is initiated by trip of the reactor coolant pumps, causes the steam generator to fill. This feedwater flow is reflected by the increase in steam generator startup level shown in Figure 3.1.1-13.

The minimum downcomer temperature of about 300 K [80°F] was reached by about 600 s after initiation. The corresponding system pressure is about 0.18 MPa [26 psia] and remains at about that pressure for the rest of the transient. The downcomer temperature increased to about 325 K [125°F] by about 1,900 s after initiation as a result of ECCS switchover to the containment sump.

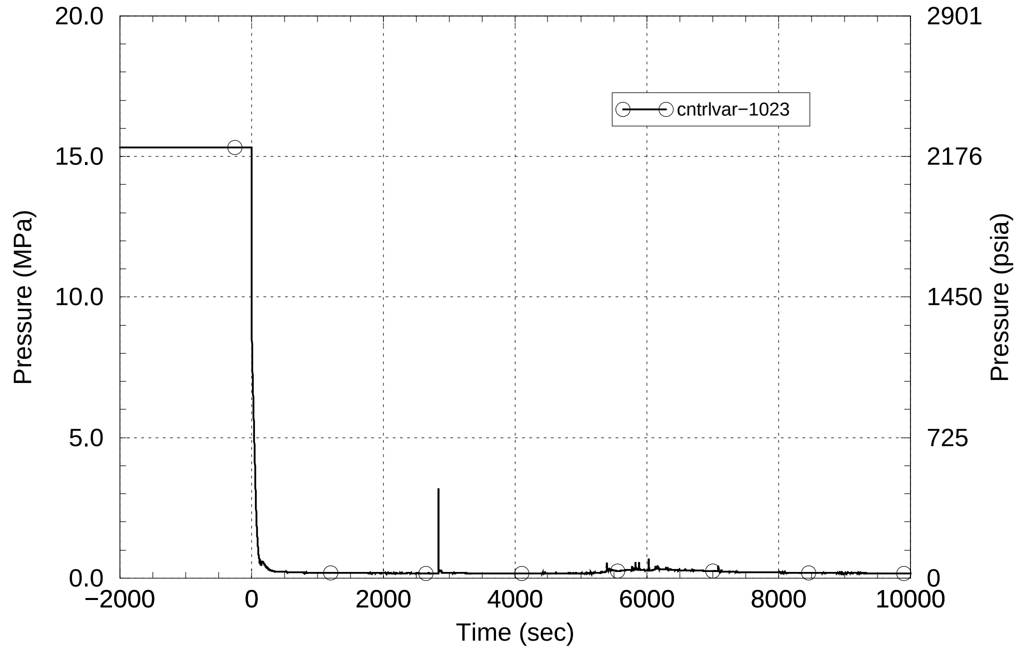


Figure 3.1.1-1 Reactor Coolant System Pressure - Oconee Case 156

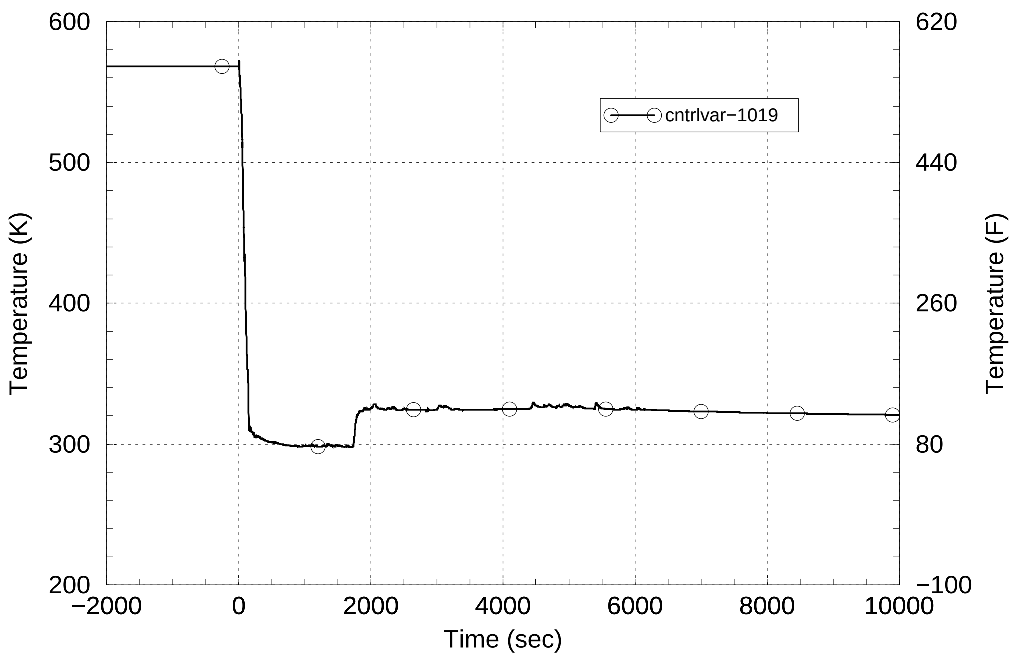


Figure 3.1.1-2 Avg Reactor Vessel Downcomer Temperature - Oconee Case 156

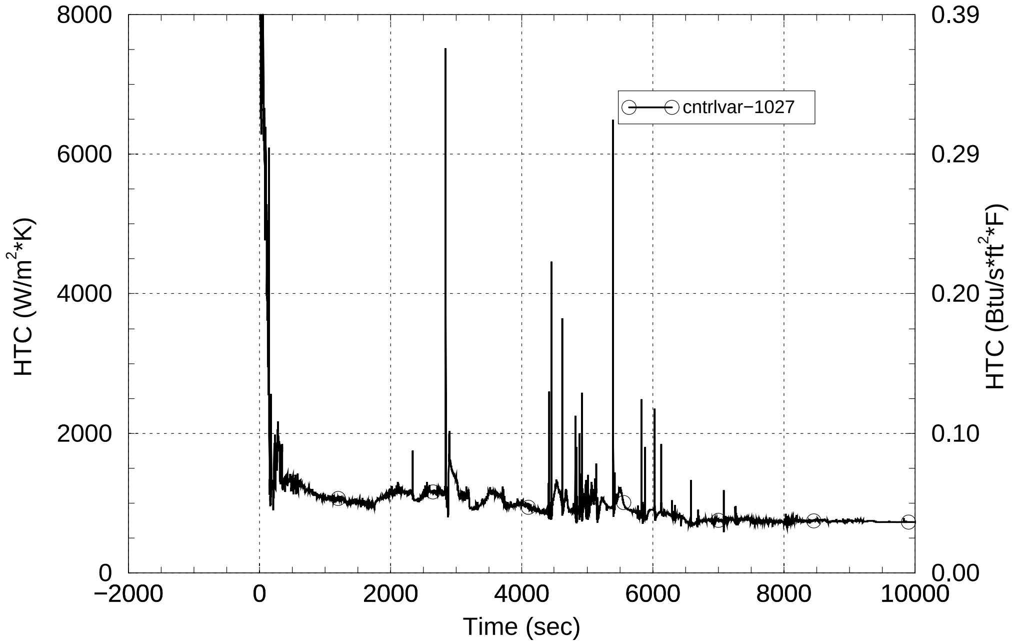


Figure 3.1.1-3 Avg Reactor Vessel Inner Wall Heat Transfer Coefficient - Oconee Case 156

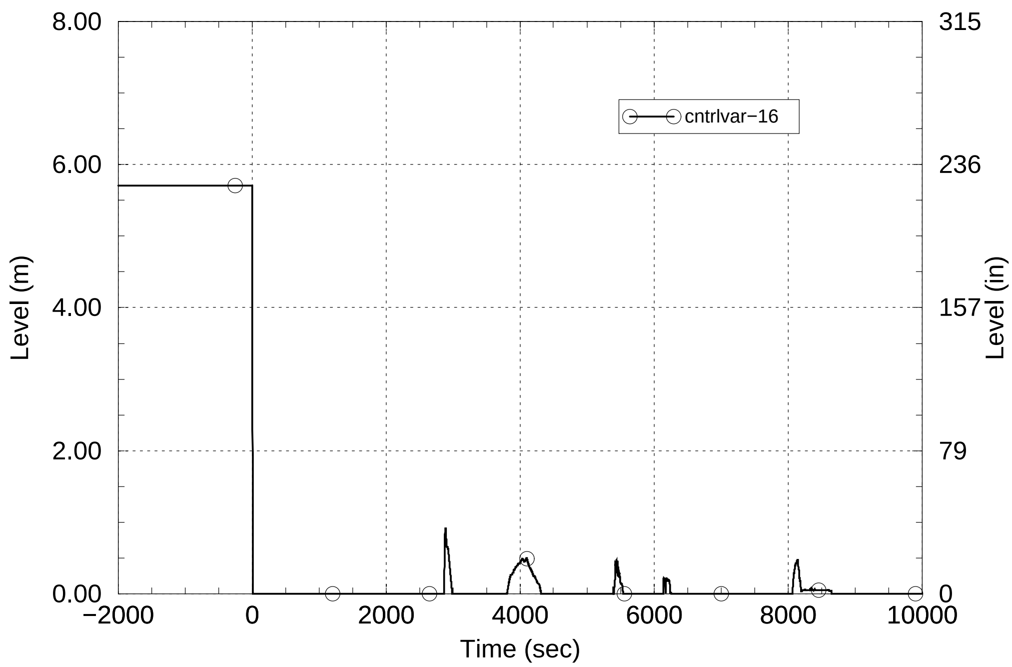


Figure 3.1.1-4 Pressurizer Level - Oconee Case 156

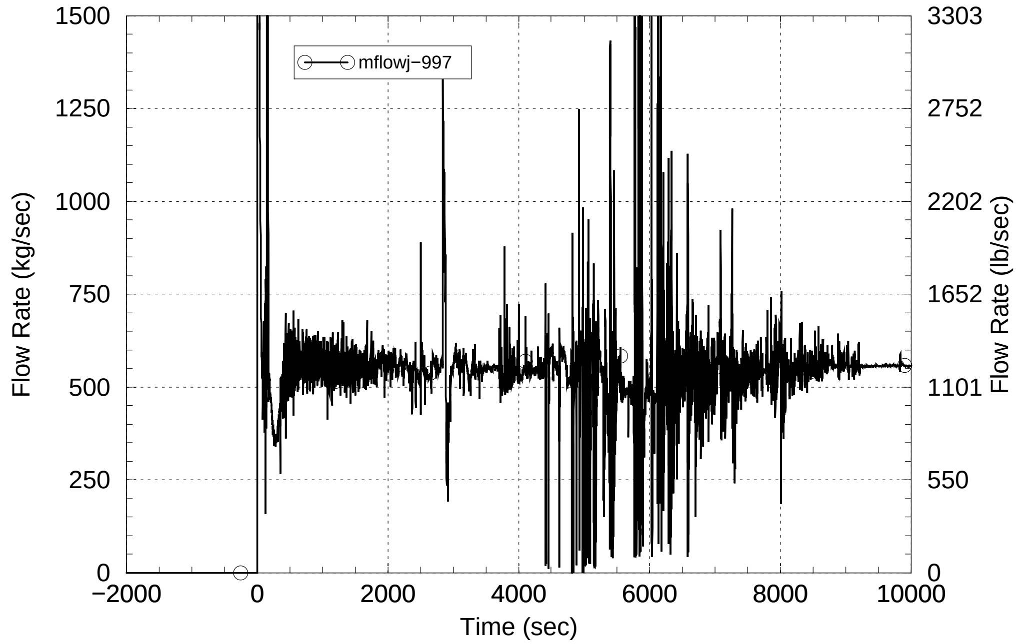


Figure 3.1.1-5 Break Flowrate - Oconee Case 156

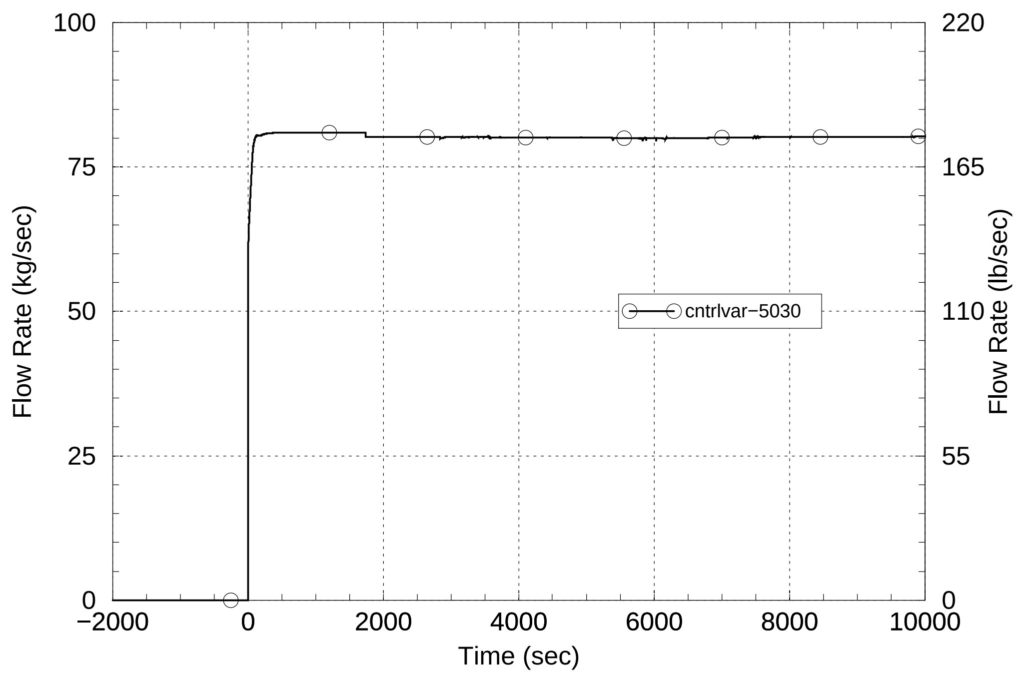


Figure 3.1.1-6 Total High Pressure Injection Flowrate - Oconee Case 156

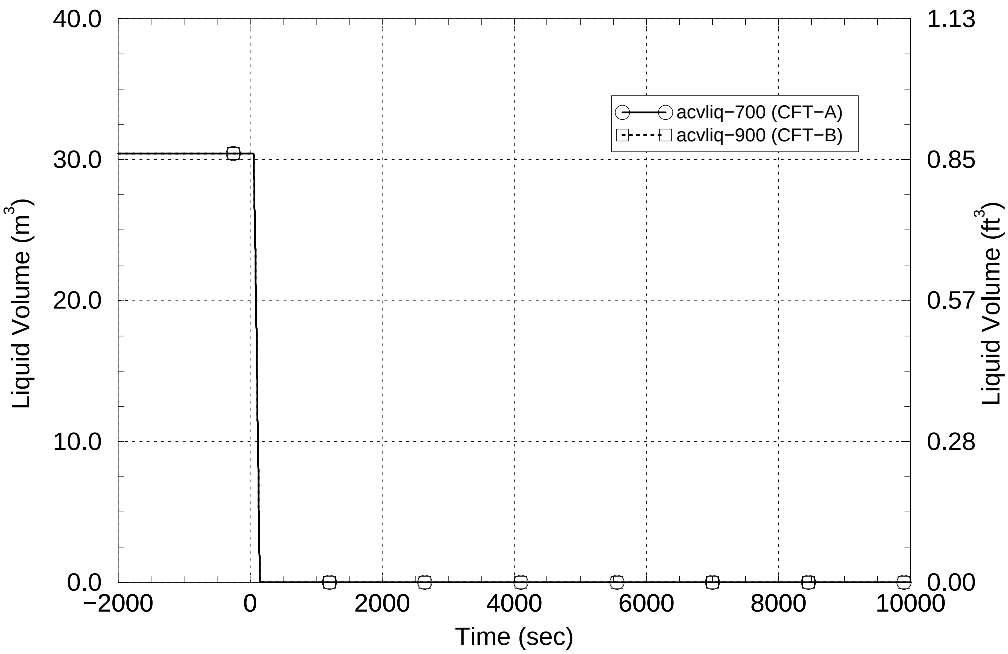


Figure 3.1.1-7 Core Flood Tank Discharge - Oconee Case 156

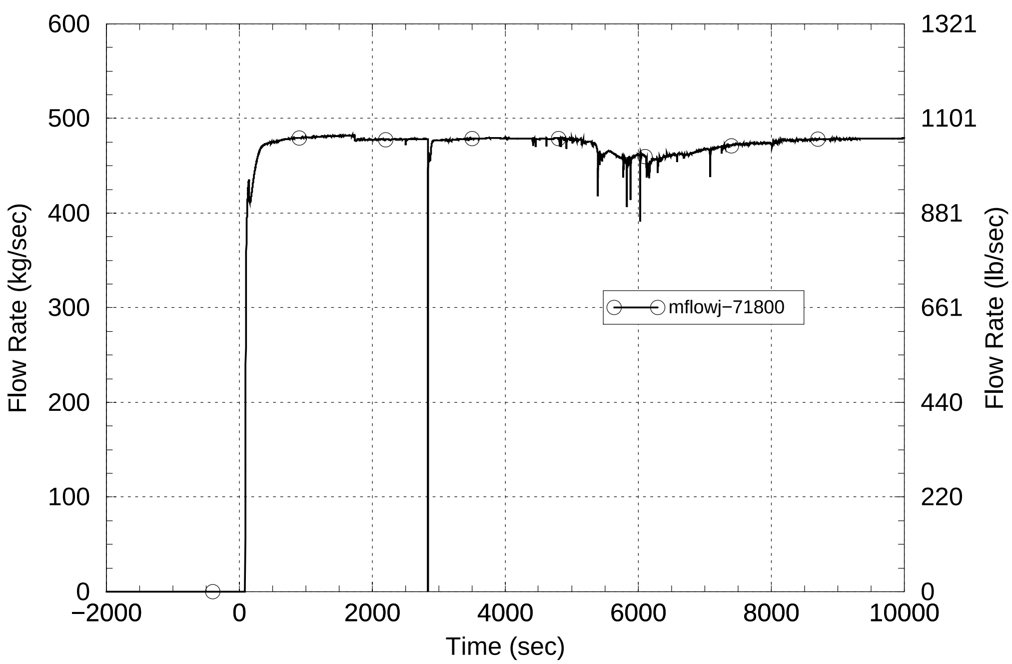


Figure 3.1.1-8 Total Low Pressure Injection Flowrate - Oconee Case 156

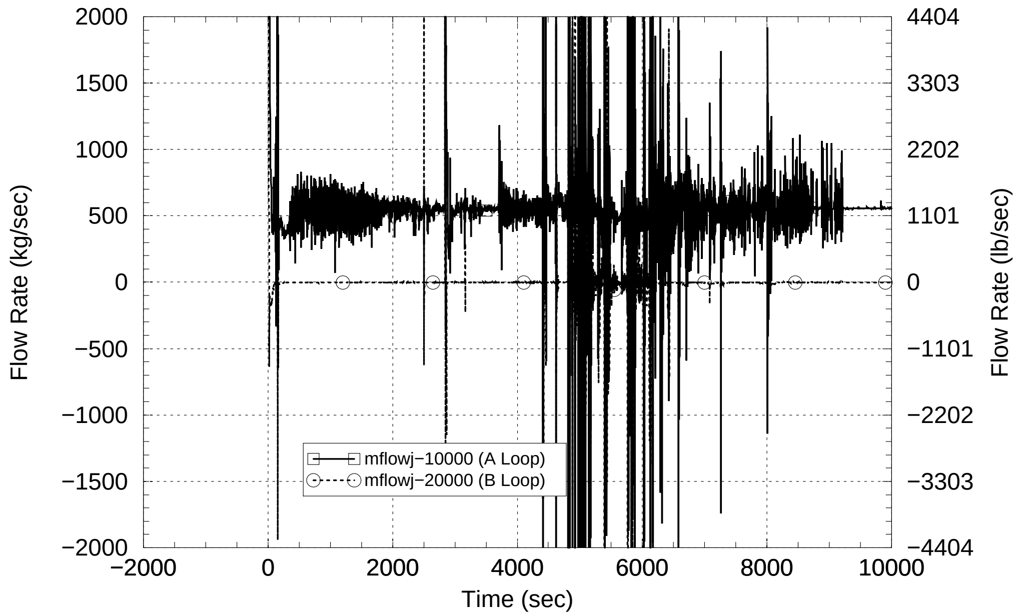


Figure 3.1.1-9   Hot Leg Flow in the A and B Loops - Oconee Case 156

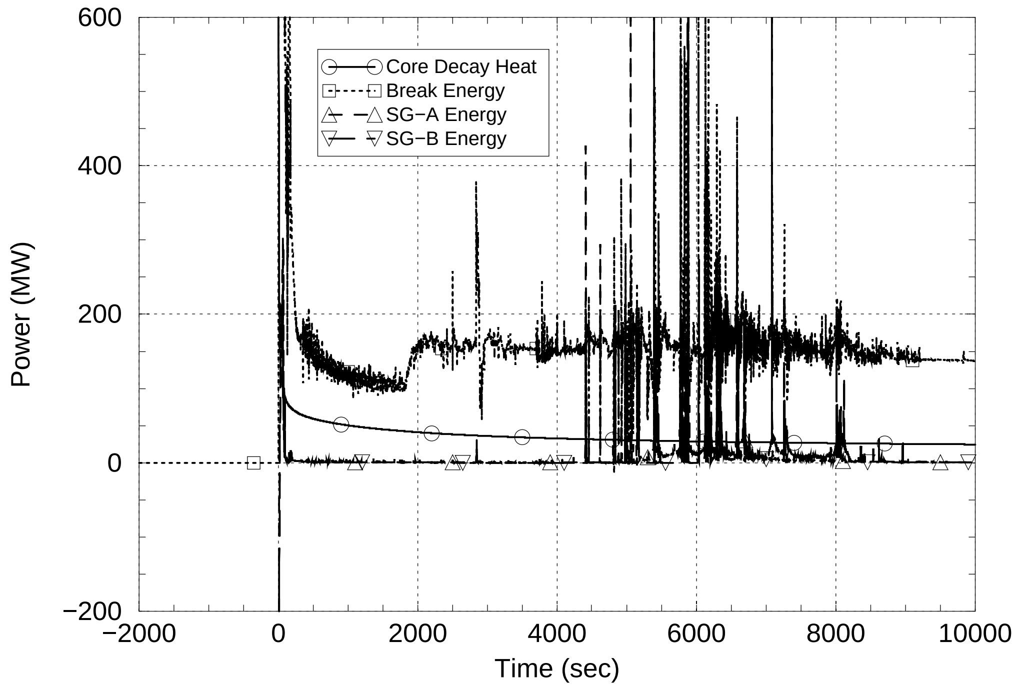


Figure 3.1.1-10   System Energy Balance - Oconee Case 156

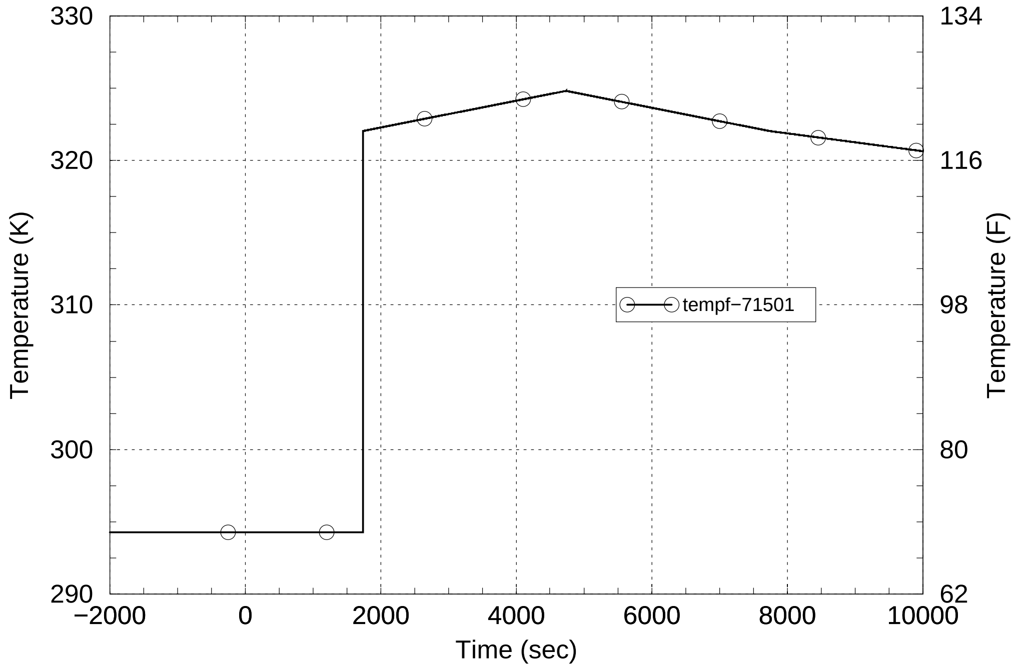


Figure 3.1.1-11   HPI and LPI Injection Temperature - Oconee Case 156

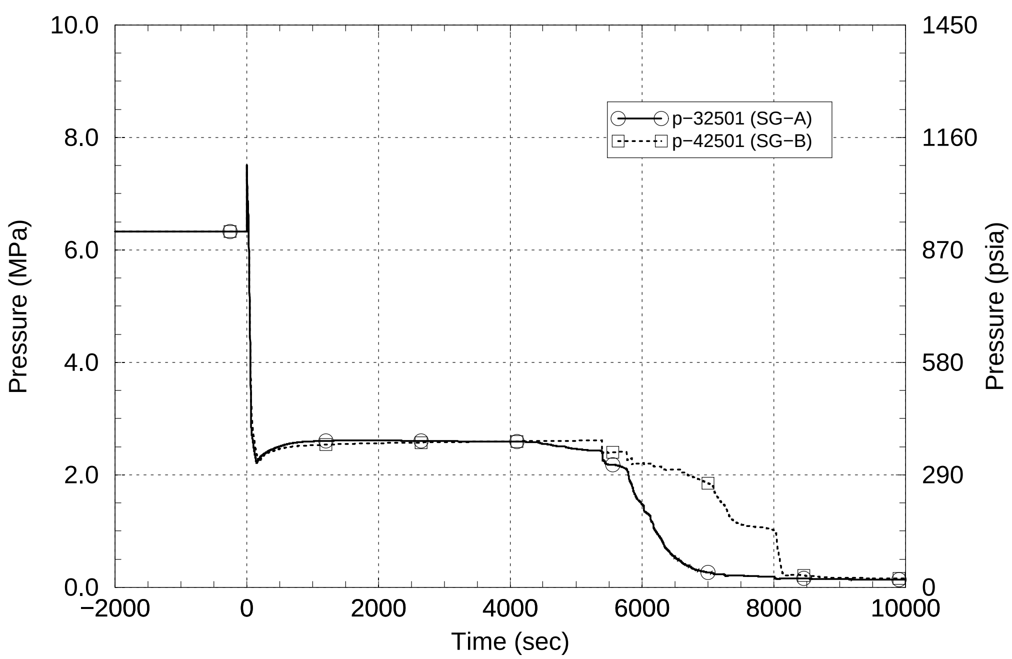


Figure 3.1.1-12   Steam Generator Secondary Pressure - Oconee Case 156

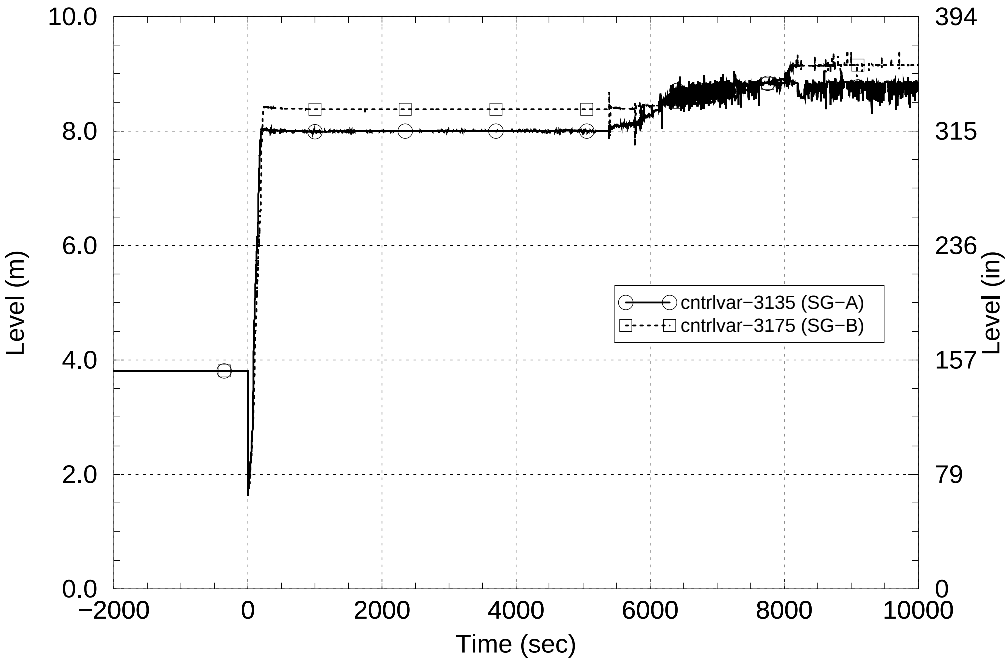


Figure 3.1.1-13 Steam Generator Secondary Startup Level - Oconee Case 156

3.1.1.2 Case 160 - 14.37 cm [5.656 in] Diameter Surge Line Break from HFP Conditions

Case 160 is a 14.37 cm [5.656 in] diameter break in the surge line from hot full power conditions. The equivalent break flow area is 0.016 m^2 [0.175 ft^2]. The parameters of interest for the fracture mechanics analysis: primary system pressure, average downcomer fluid temperature, and downcomer fluid-wall heat transfer coefficient are provided in Figures 3.1.1-14 through 3.1.1-16.

As a result of the break, system depressurization occurs as shown in Figure 3.1.1-14. The primary system pressure falls to 4.0 MPa [580 psia] by 300 s and continues decreasing to an equilibrium pressure of about 0.80 MPa [115 psia] by about 2,000 s after initiation. The downcomer temperature decreases to 518 K [472°F] by 300 s and to 300 K [80°F] by 2,000 s. The pressurizer level, shown in Figure 3.1.1-17, decreases rapidly and empties from the loss of coolant inventory as the reactor coolant system depressurizes. Reactor trip occurs within 1 s, followed by actuation of the HPI system which runs for the duration of the event. The operators are assumed to trip the reactor coolant pumps as a result of the loss of subcooling within 10 s after accident initiation. The trip of the reactor coolant pumps causes loss of forced convection which causes the drop in the downcomer wall heat transfer coefficient from a steady state value of about 24,110 W/m^2-K [1.18 Btu/s-ft^2-°F] to the values shown in Figure 3.1.1-16.

The break flow is presented in Figure 3.1.1-18. After the initial flow spike, the break flow drops as flashing occurs in the system and the break flow consists mostly of steam. As the system cools and ECCS injection starts, the break flow becomes principally liquid. The changeover to liquid driven by ECCS flow is the reason for the increase in break flow. The total HPI flow is shown in Figure 3.1.1-19.

The core flood tanks start to discharge by 310 s and are completely discharged by 1,565 s as shown in Figure 3.1.1-20. Low pressure injection flow, shown in Figure 3.1.1-21, starts at about 1,190 s and remains on for the rest of the transient. The combined effect of the HPI, LPI and core flood tank flow causes the pressurizer to refill at 1,910 s as seen from Figure 3.1.1-17. Pressurizer level equalizes at about 6.6 m [260 in] by about 6,000 s after initiation.

Hot leg flow is shown in Figure 3.1.1-22. The hot leg flow in the A loop is approximately equal to the break flow and is due to the continued operation of the HPI and LPI systems. There is little or no flow in the B loop. The system energy balance is shown in Figure 3.1.1-23 which shows that the break energy is much larger than the core decay heat load, which causes the system temperature to decrease. This plot also shows that the steam generators have a minor effect on the downcomer temperature. Heat is transferred from the steam generator into the primary system as the system depressurizes, but the size of the break is sufficient to remove this heat from the primary system along with the decay heat energy which is substantially larger.
Because of the size of the break and the continued operation of the HPI and LPI systems, the borated water storage tank inventory is depleted and HPI and LPI pump suction is switched to the containment sump. This switchover occurs at about 2,890 s as shown in Figure 3.1.1-24 and results in an increase in the HPI and LPI injection temperature, which directly impacts the downcomer temperature as seen from Figure 3.1.1-15.

The steam generator secondary side pressures are shown in Figure 3.1.1-25. The decrease in secondary side pressure is due to the transfer of heat into the primary system from the steam generators. Actuation of feedwater flow, which is initiated by trip of the reactor coolant pumps and which causes the steam generators to fill, also contributes to the decline in secondary side pressure. This feedwater flow is reflected by the increase in steam generator startup levels shown in Figure 3.1.1-26.

The minimum downcomer temperature of about 299 K [78°F] was reached by about 2,300 s after initiation. The corresponding system pressure is about 0.90 MPa [130 psia] and remains at about that pressure for the rest of the transient. The downcomer temperature increased to about 325 K [125°F] by about 3,500 s after initiation as a result of ECCS switchover to the containment sump.

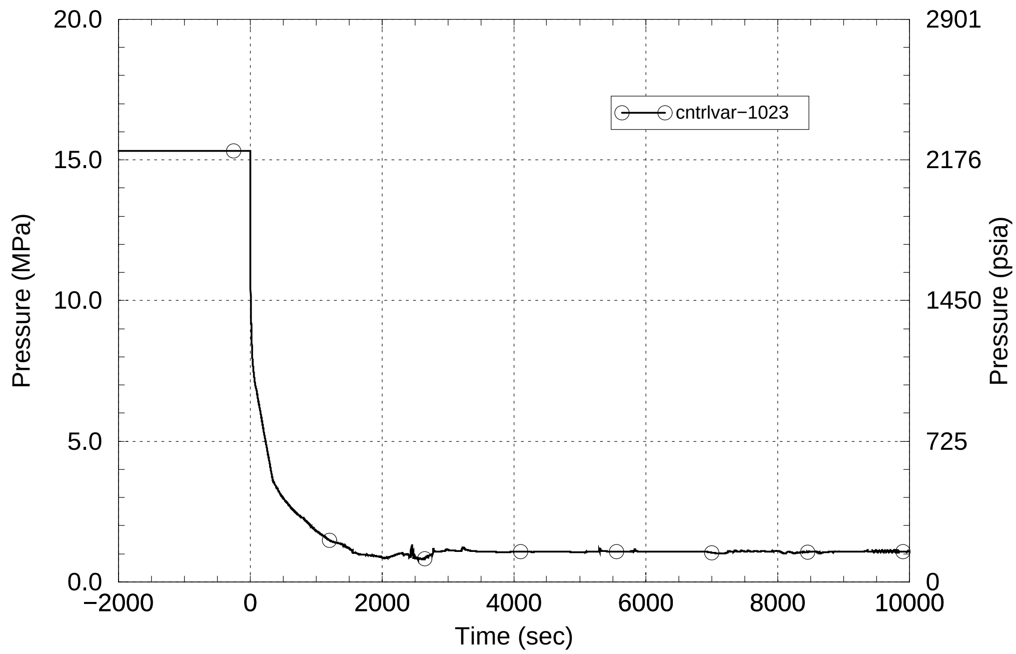


Figure 3.1.1-14 Reactor Coolant System Pressure - Oconee Case 160

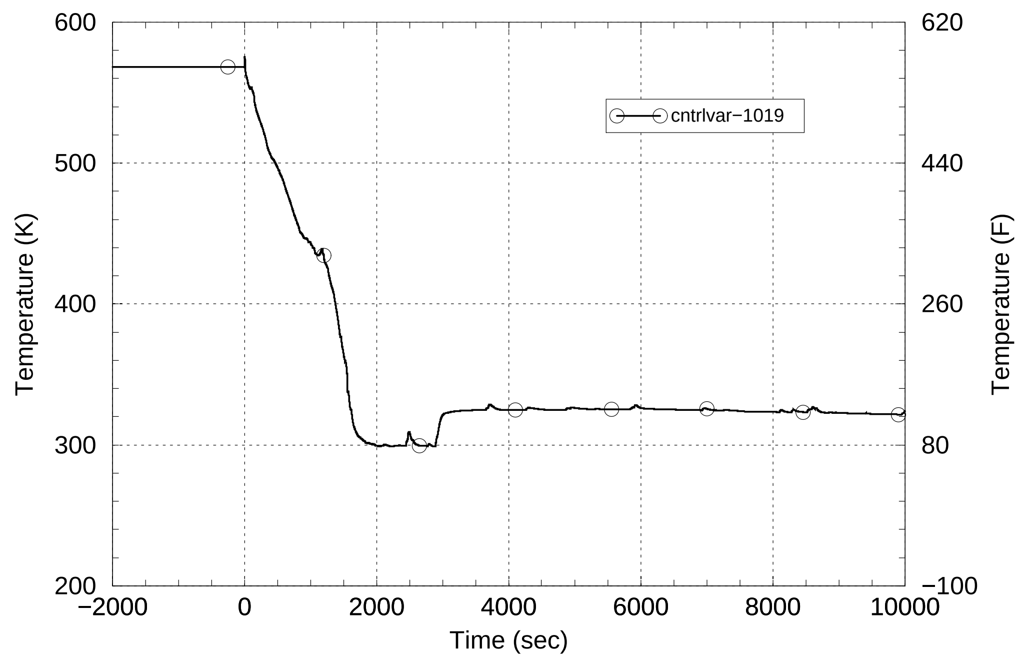


Figure 3.1.1-15 Avg Reactor Vessel Downcomer Temperature - Oconee Case 160

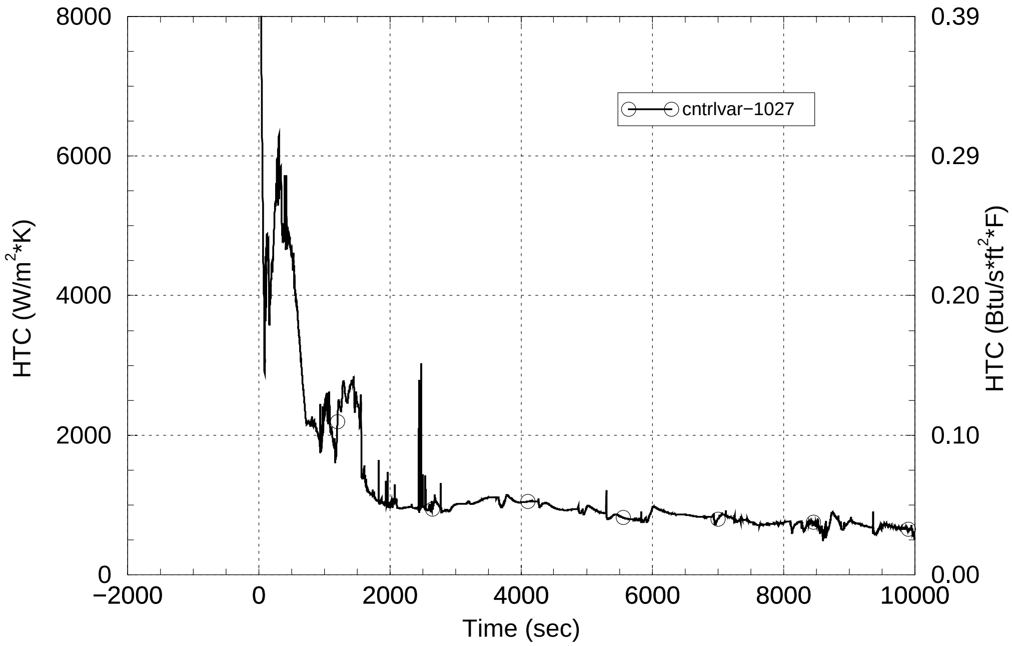


Figure 3.1.1-16 Avg Reactor Vessel Inner Wall Heat Transfer Coefficient - Oconee Case 160

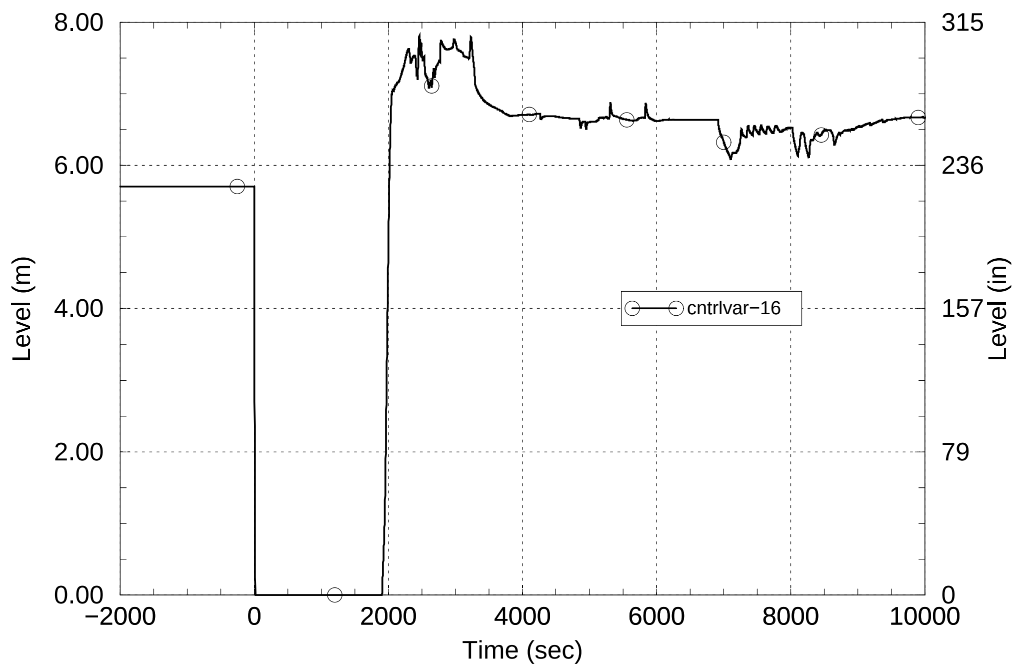


Figure 3.1.1-17 Pressurizer Level - Oconee Case 160

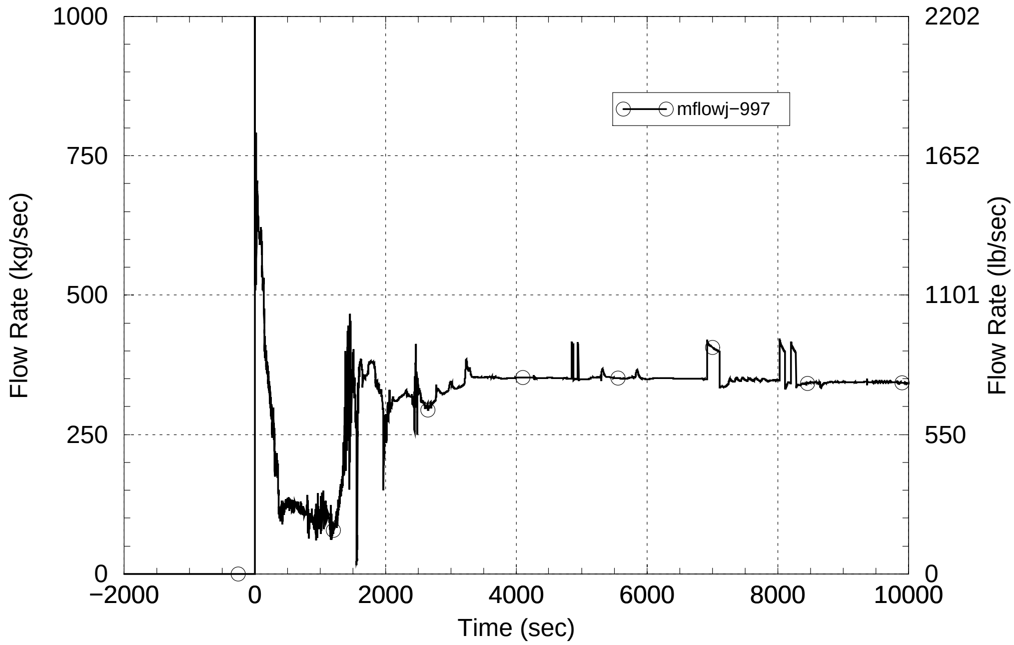


Figure 3.1.1-18   Break Flowrate - Oconee Case 160

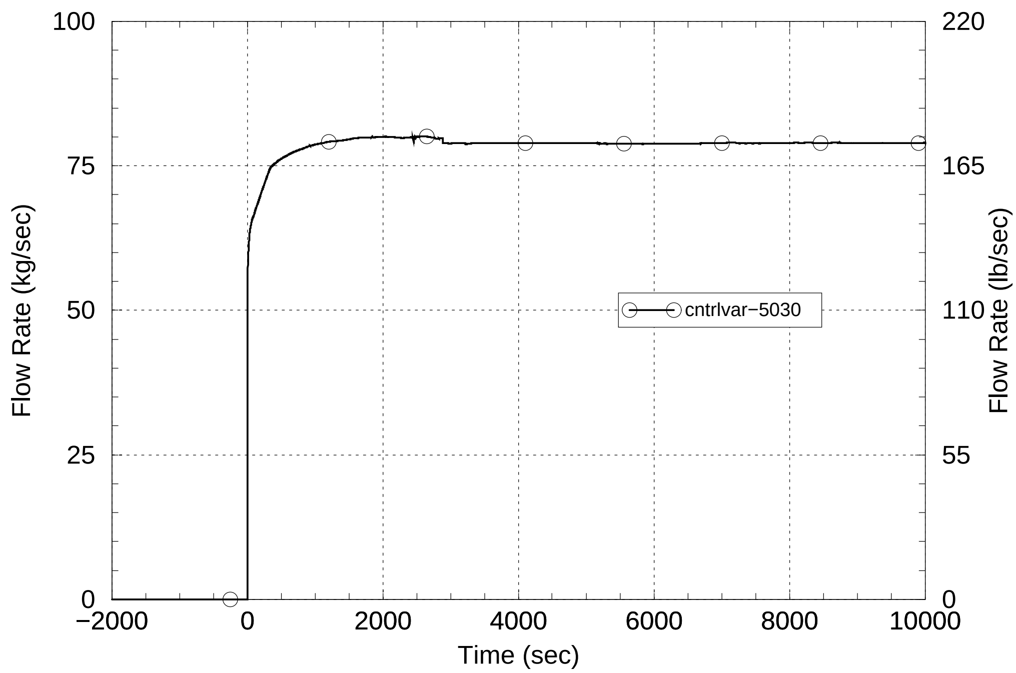


Figure 3.1.1-19   Total High Pressure Injection Flowrate - Oconee Case 160

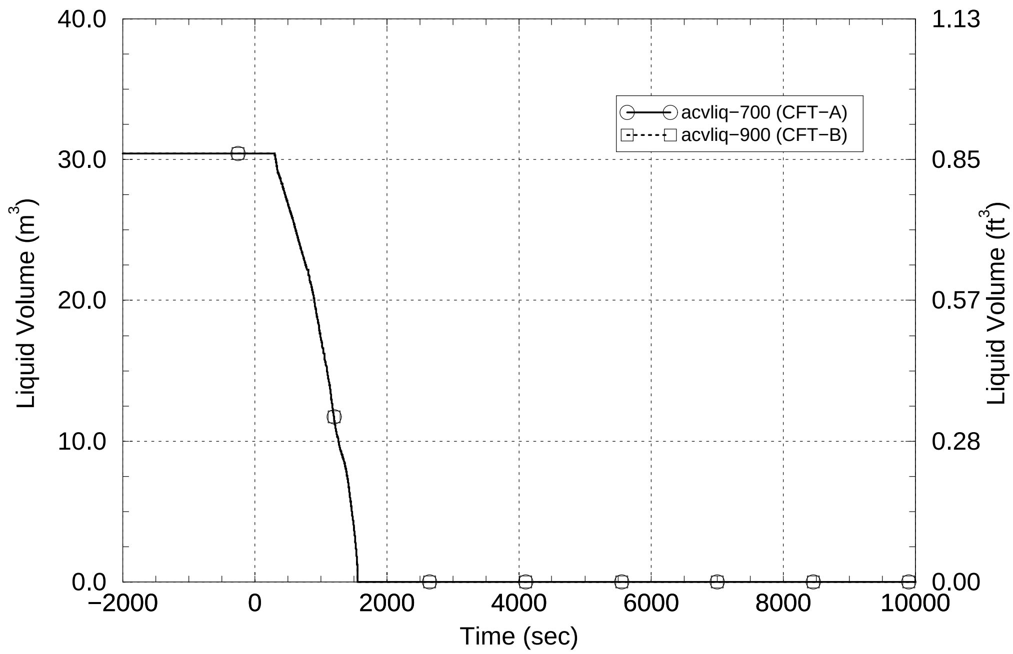


Figure 3.1.1-20 Core Flood Tank Discharge - Oconee Case 160

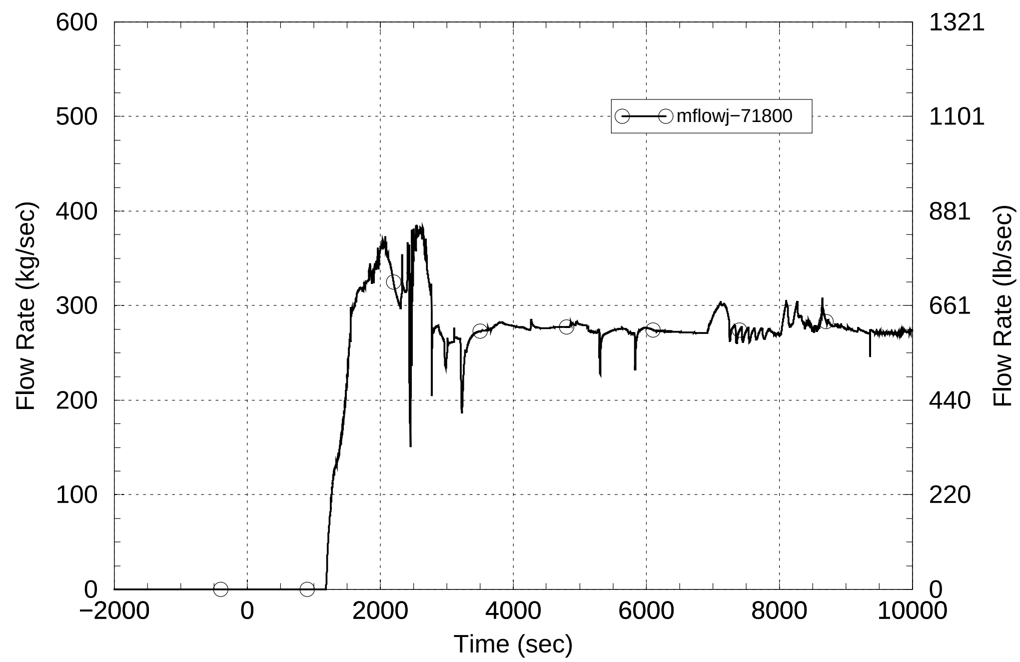


Figure 3.1.1-21 Total Low Pressure Injection Flowrate - Oconee Case 160

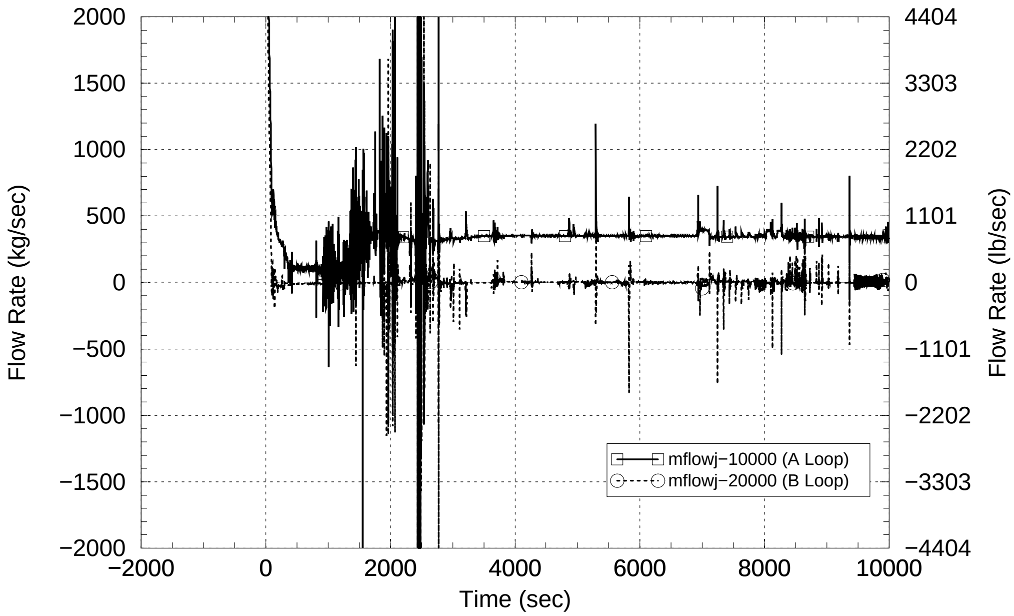


Figure 3.1.1-22 Hot Leg Flow in the A and B Loops - Oconee Case 160

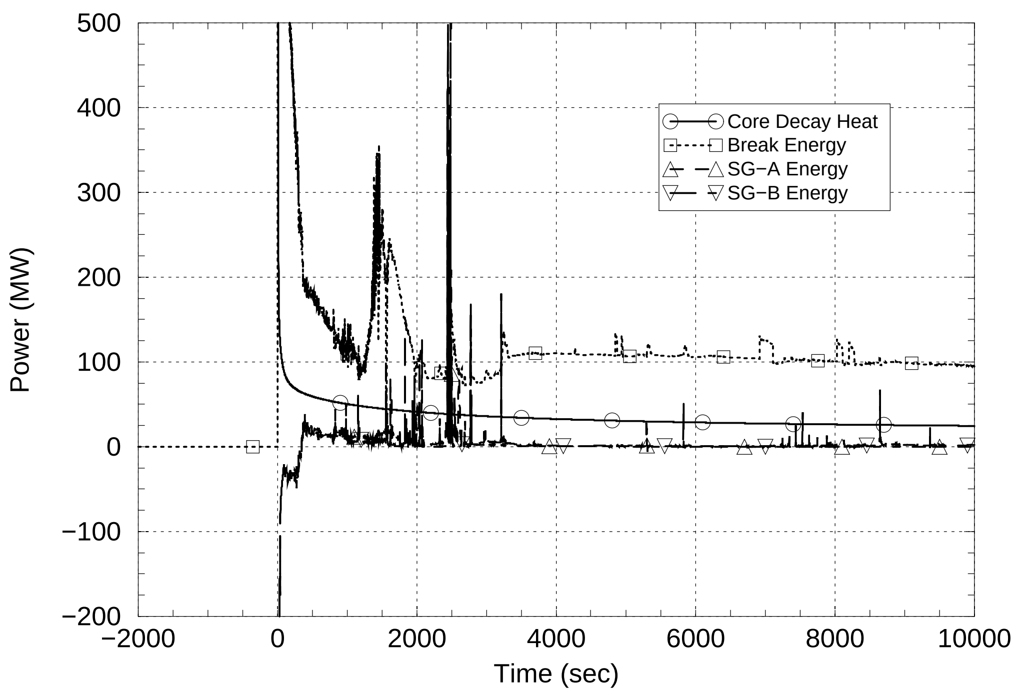


Figure 3.1.1-23 System Energy Balance - Oconee Case 160

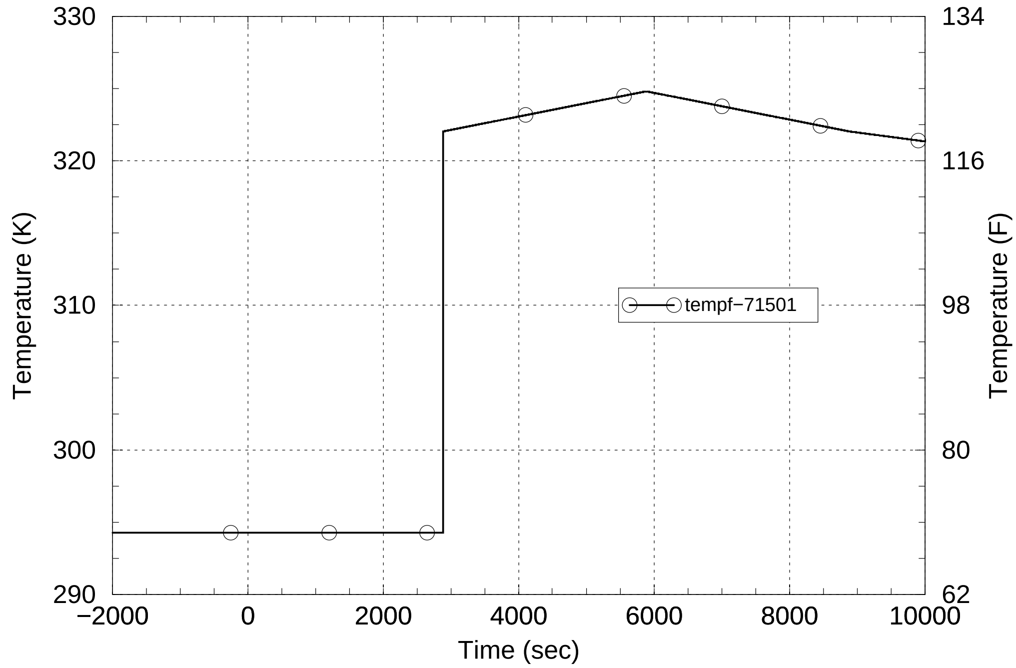


Figure 3.1.1-24 HPI and LPI Injection Temperature - Oconee Case 160

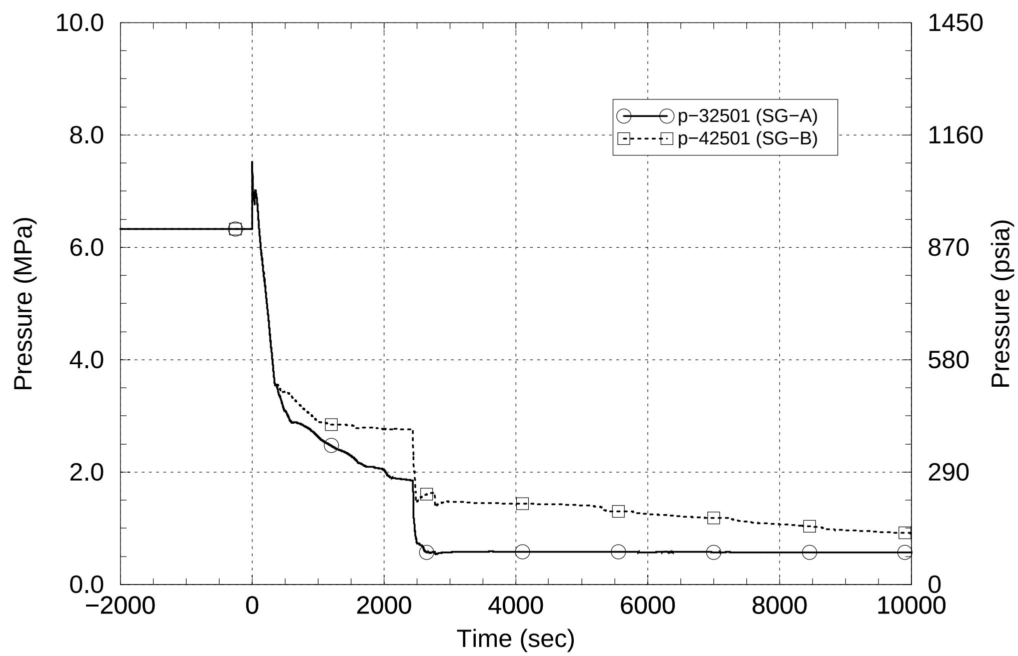


Figure 3.1.1-25 Steam Generator Secondary Pressure - Oconee Case 160

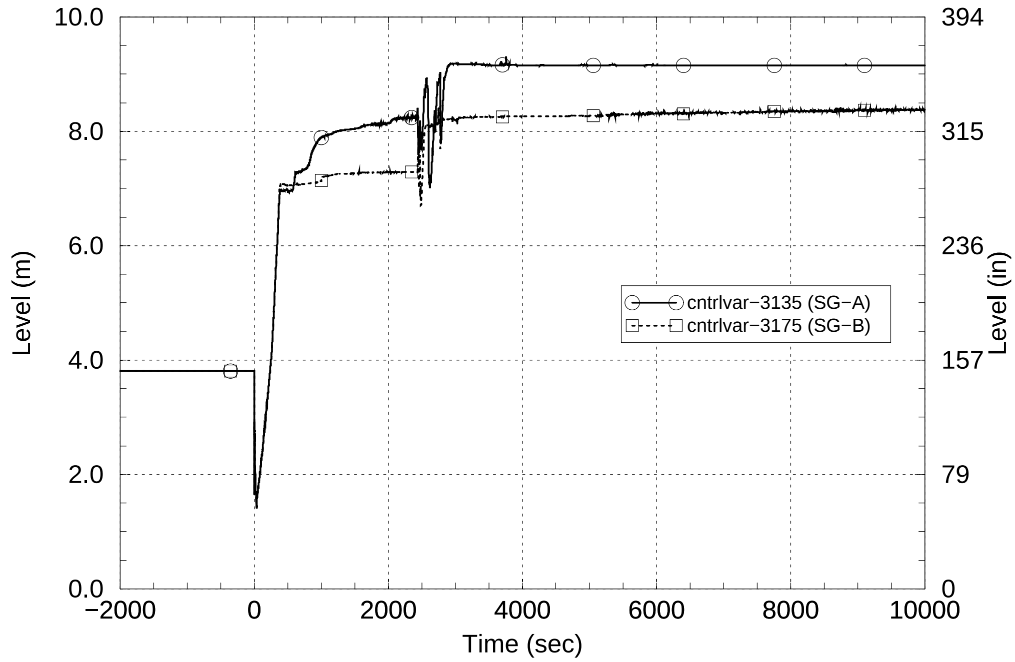


Figure 3.1.1-26 Steam Generator Secondary Startup Level - Oconee Case 160

3.1.1.3 Case 164 - 20.32 cm [8 in] Diameter Surge Line Break from HFP Conditions

Case 164 is a 20.32 cm [8 in] diameter break in the surge line from hot full power conditions. The equivalent break flow area is 0.032 m^2 [0.349 ft^2]. The parameters of interest for the fracture mechanics analysis: primary system pressure, average downcomer fluid temperature, and downcomer fluid-wall heat transfer coefficient are provided in Figures 3.1.1-27 through 3.1.1-29.

As a result of the break, rapid system depressurization occurs as shown in Figure 3.1.1-27. The primary system pressure falls to 2.4 MPa [350 psia] by 300 s and continues decreasing to an equilibrium pressure of about 0.43 MPa [62 psia] by about 2,000 s after initiation. The downcomer temperature decreases to 495 K [430°F] by 300 s and to about 298 K [76°F] by 2,000 s. The pressurizer level, shown in Figure 3.1.1-30, also decreases rapidly and empties from the loss of coolant inventory as the reactor coolant system depressurizes. Reactor trip occurs within 1 s, followed by actuation of the HPI system which runs for the duration of the event. The operators are assumed to trip the reactor coolant pumps as a result of the loss of subcooling within about 2 s after accident initiation. The trip of the reactor coolant pumps causes loss of forced convection in the downcomer which causes the drop in the downcomer wall heat transfer coefficient from a steady state value of 24,112 W/m^2-K [1.18 Btu/s-ft^2-°F] to the values shown in Figure 3.1.1-29.

The break flow is presented in Figure 3.1.1-31. After the initial flow spike, the break flow drops as flashing occurs in the system and the break flow consists mostly of steam. As the system cools and ECCS injection starts, the break flow becomes principally liquid. The changeover to liquid driven by ECCS flow is the reason for the increase in break flow. The total HPI flow is shown in Figure 3.1.1-32.

The core flood tanks start to discharge by 220 s and are completely discharged by 840 s as shown in Figure 3.1.1-33. Low pressure injection flow, shown in Figure 3.1.1-34, starts at about 610 s and remains on for the rest of the transient. The combined effect of the HPI, LPI and core flood tank flow causes the pressurizer to refill at about 1,500 s.

Hot leg flow is shown in Figure 3.1.1-35. The hot leg flow in the A loop is approximately equal to the break flow and is due to the continued operation of the HPI and LPI systems. There is little or no flow in the B loop. The system energy balance is shown in Figure 3.1.1-36 which shows that the break energy is much larger than the core decay heat load, which causes the system temperature to decrease. This plot also shows that the steam generators have a minor effect on the downcomer temperature. Heat is transferred from the steam generator into the primary system as the system depressurizes, but the size of the break is sufficient to remove this heat from the primary system along with the decay heat energy which is substantially larger.
Because of the size of the break and the continued operation of the HPI and LPI systems, the borated water storage tank inventory is depleted and HPI and LPI pump suction is switched to the containment sump. This switchover occurs at about 2,310 s as shown in Figure 3.1.1-37 and results in an increase in the HPI and LPI injection temperature, which directly impacts the downcomer temperature as seen from Figure 3.1.1-28.

The steam generator secondary side pressures is shown in Figure 3.1.1-38. The decrease in secondary side pressure is due to the transfer of heat into the primary system from the steam generators. Actuation of feedwater flow, which is initiated by trip of the reactor coolant pumps and which causes the steam generators to fill, also contributes to the decline in secondary side pressure. This flow is reflected by the increase in steam generator startup levels shown in Figure 3.1.1-39.

The minimum downcomer temperature of about 300 K [80°F] was reached by about 1,200 s after initiation. The corresponding system pressure is about 0.56 MPa [80 psia] and remains at about that pressure for the rest of the transient. The downcomer temperature increased to about 325 K [125°F] by about 2,600 s after initiation as a result of ECCS switchover to the containment sump.

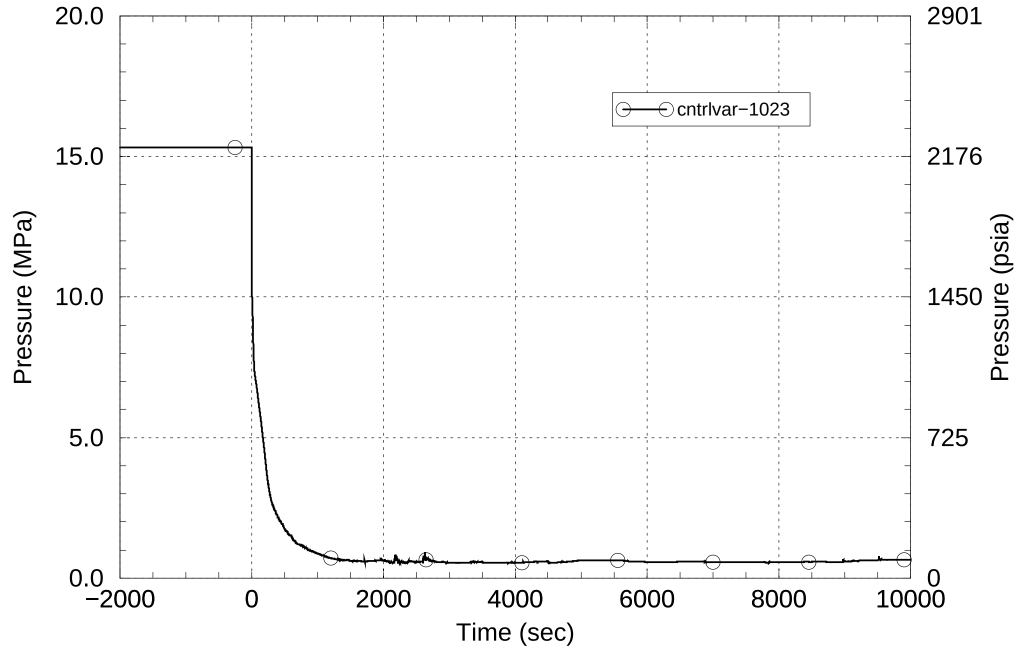


Figure 3.1.1-27 Reactor Coolant System Pressure - Oconee Case 164

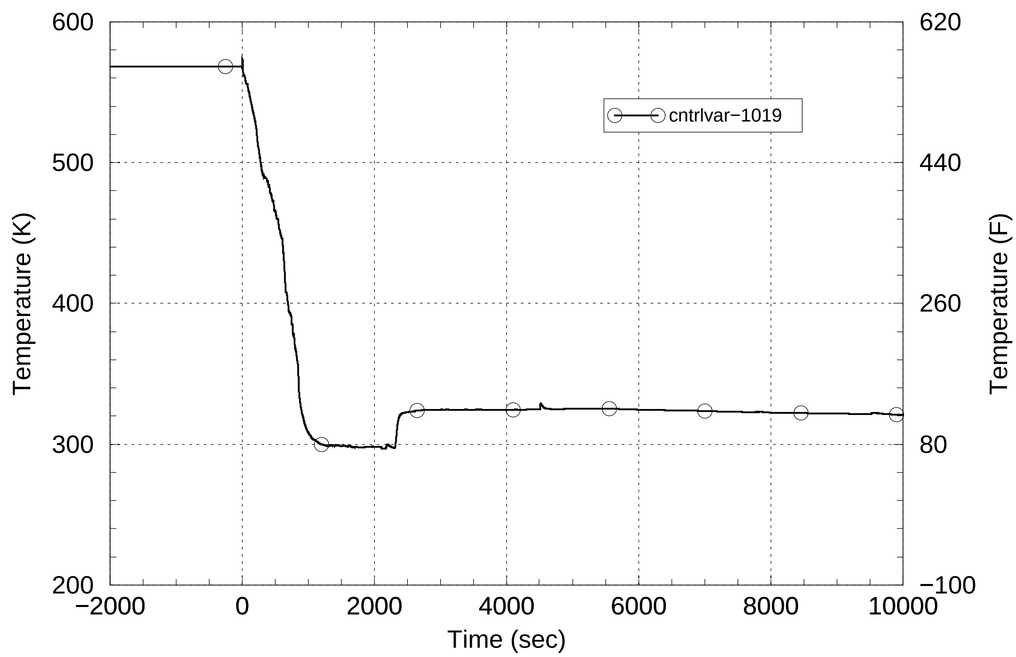


Figure 3.1.1-28 Avg Reactor Vessel Downcomer Temperature - Oconee Case 164

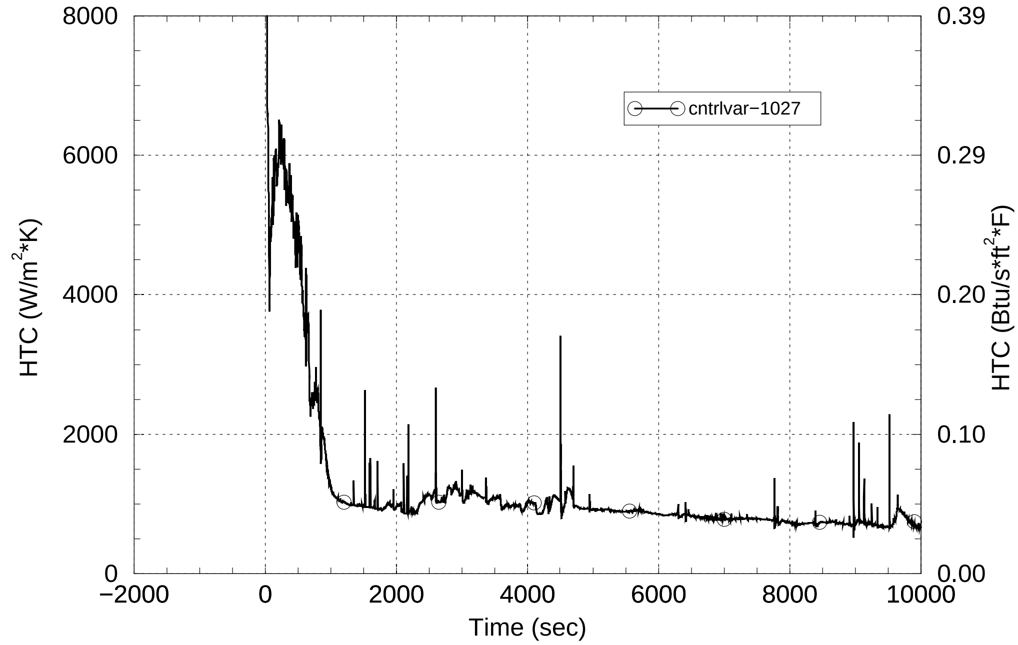


Figure 3.1.1-29 Avg Reactor Vessel Inner Wall Heat Transfer Coefficient - Oconee Case 164

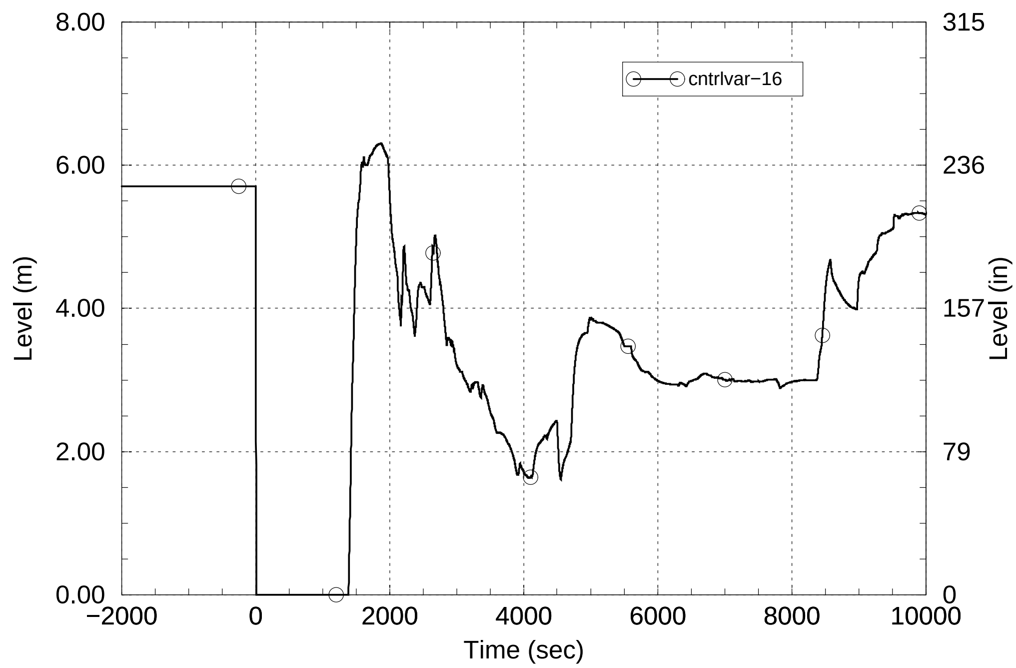


Figure 3.1.1-30 Pressurizer Level - Oconee Case 164

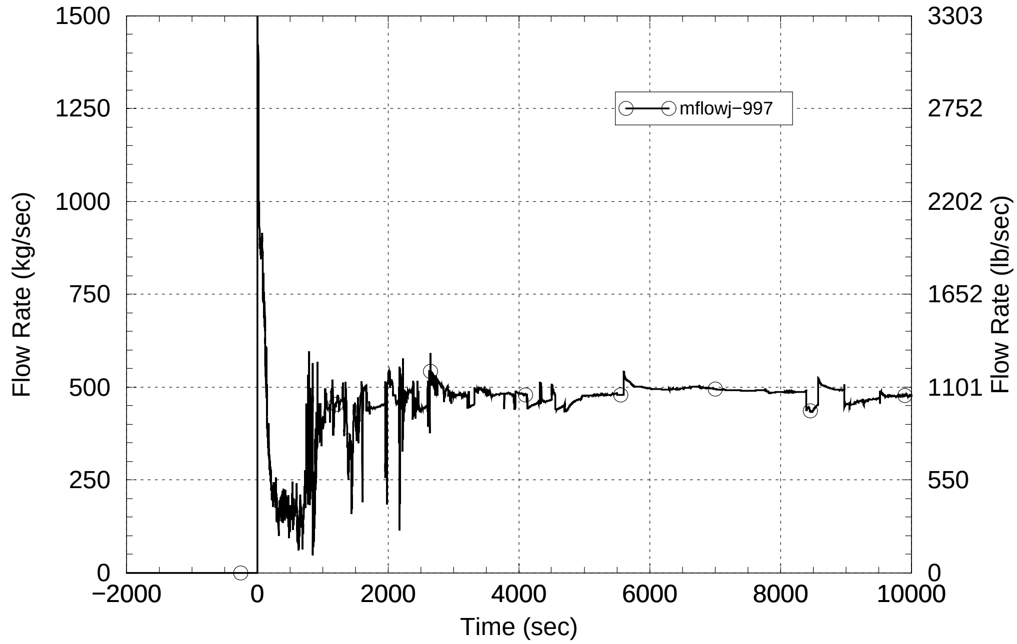


Figure 3.1.1-31 Break Flowrate - Oconee Case 164

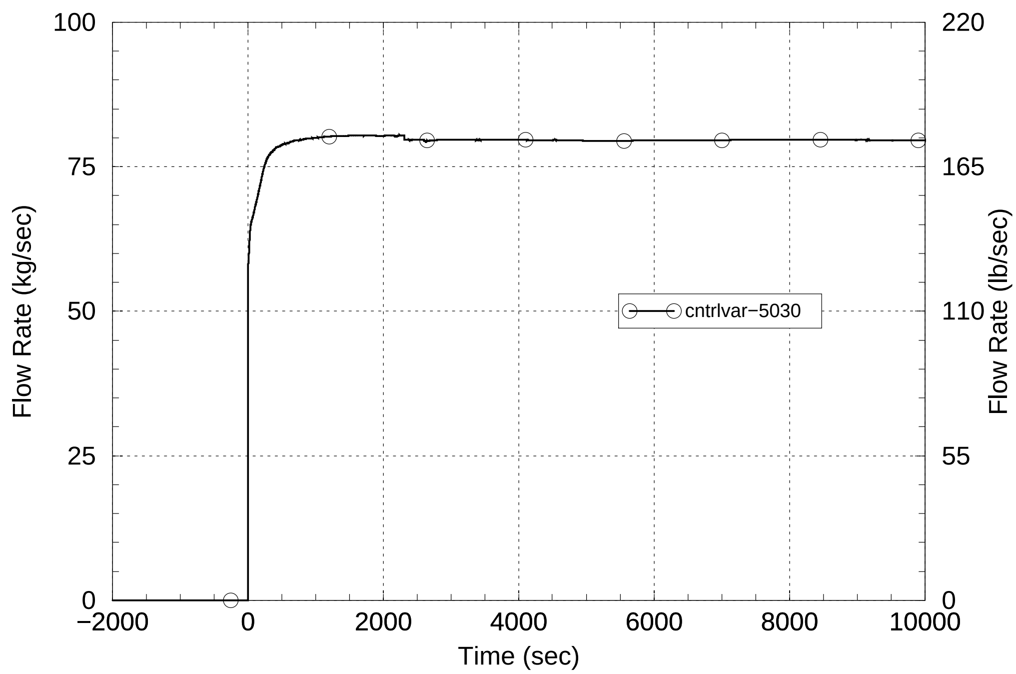


Figure 3.1.1-32 Total High Pressure Injection Flowrate - Oconee Case 164

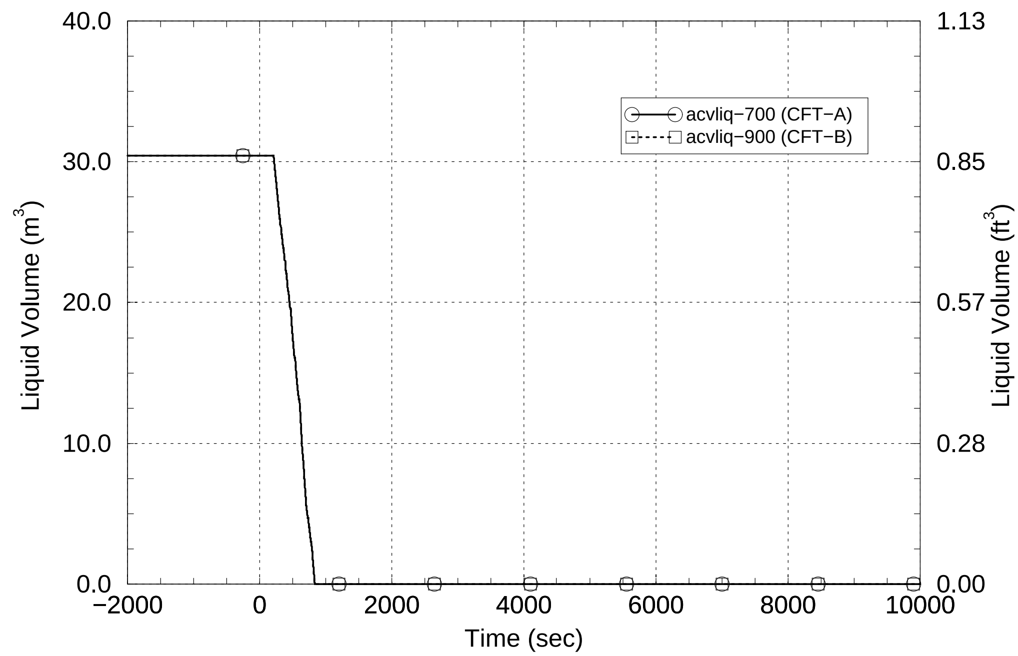


Figure 3.1.1-33   Core Flood Tank Discharge - Oconee Case 164

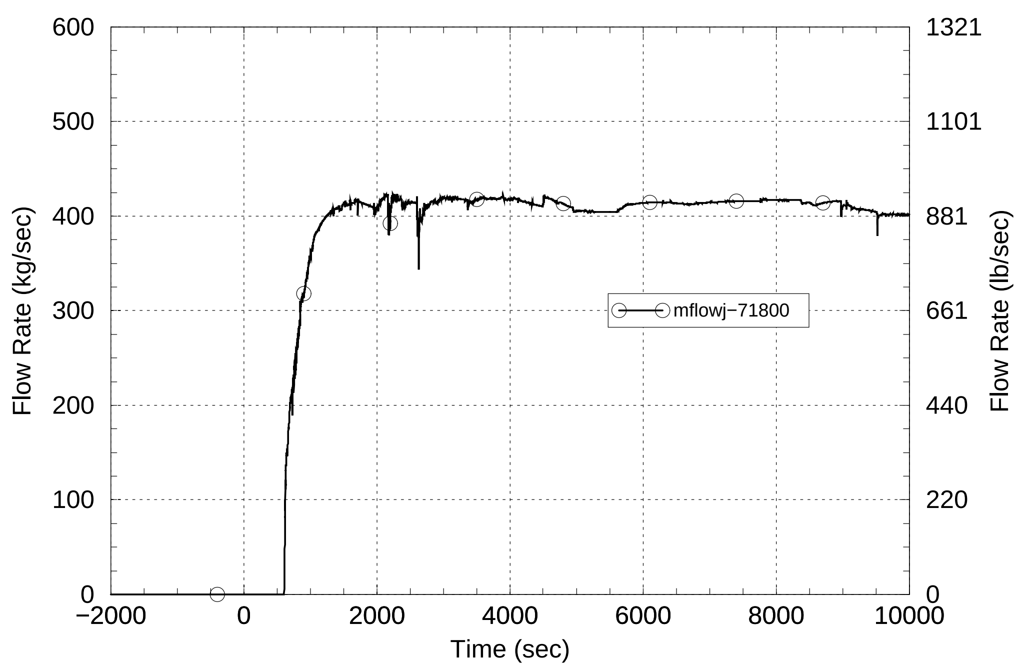


Figure 3.1.1-34   Total Low Pressure Injection Flowrate - Oconee Case 164

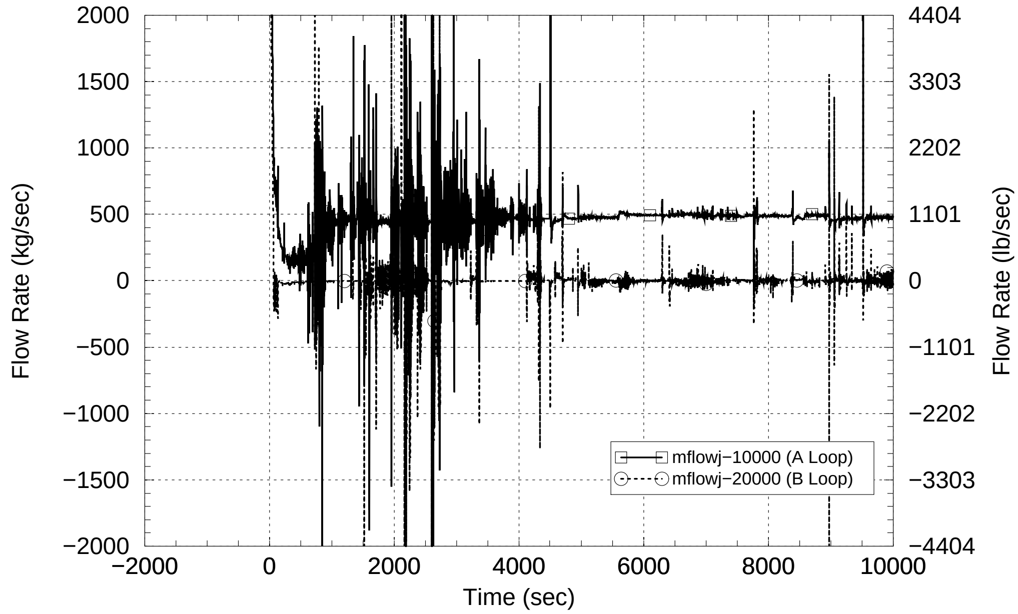


Figure 3.1.1-35 Hot Leg Flow in the A and B Loops - Oconee Case 164

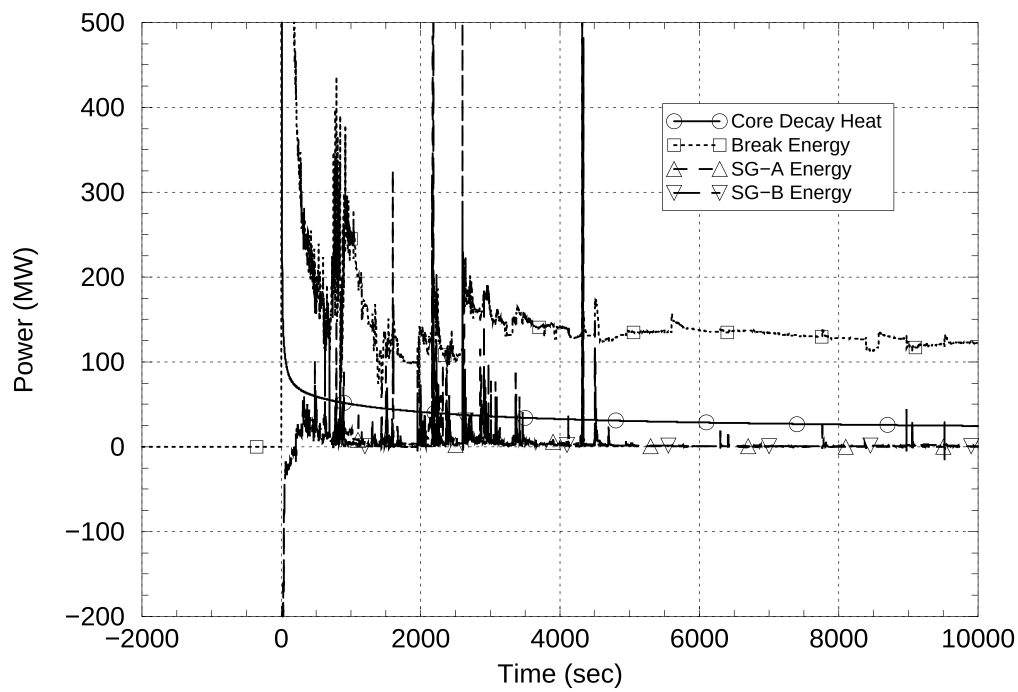


Figure 3.1.1-36 System Energy Balance - Oconee Case 164

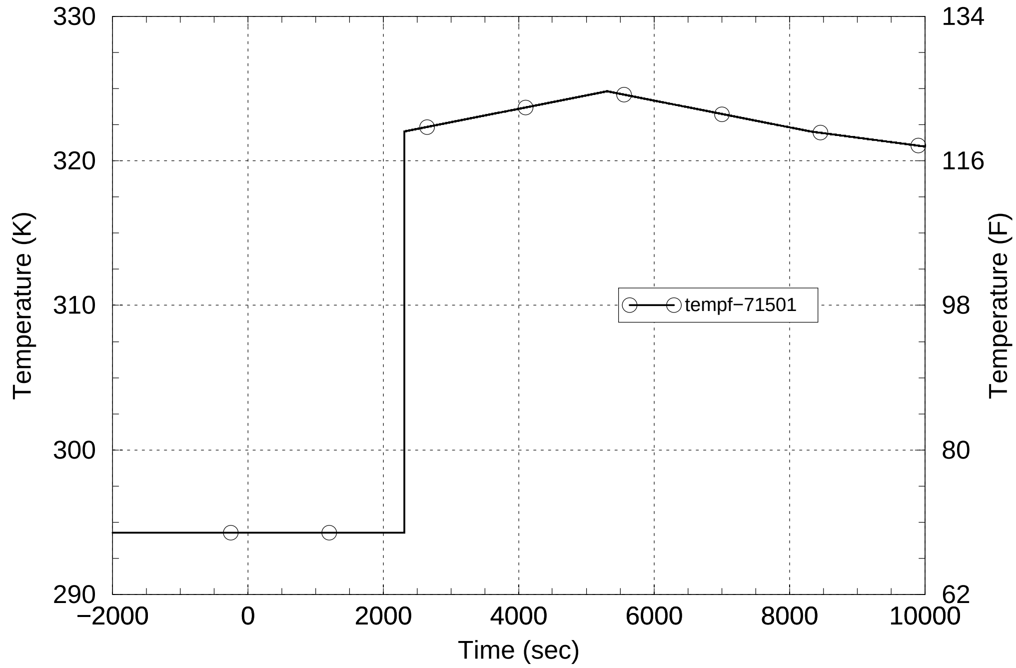


Figure 3.1.1-37 HPI and LPI Injection Temperature - Oconee Case 164

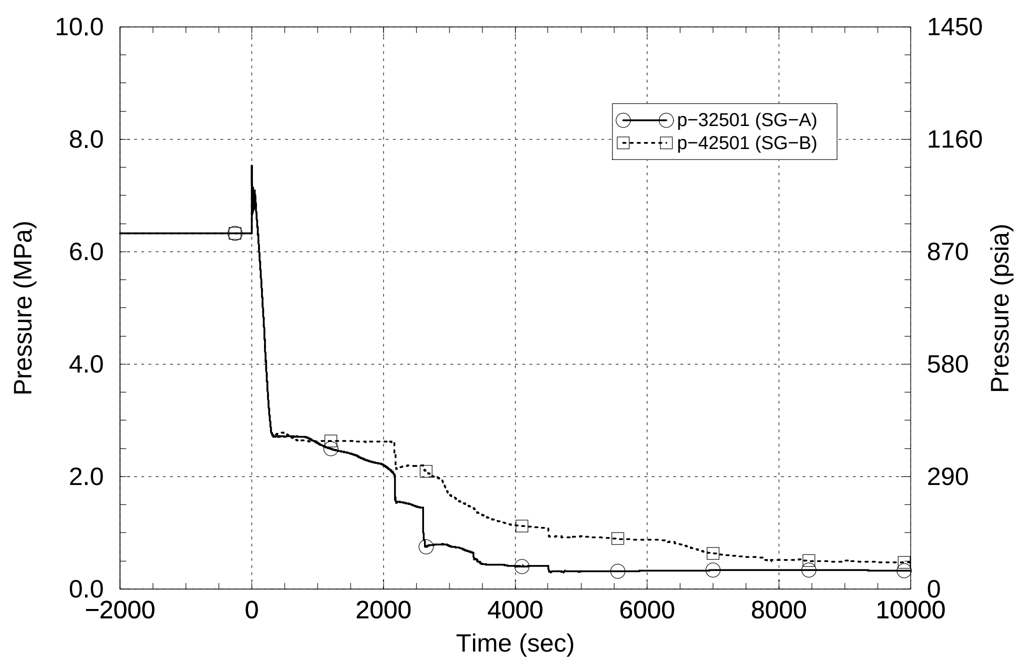


Figure 3.1.1-38 Steam Generator Secondary Pressure - Oconee Case 164

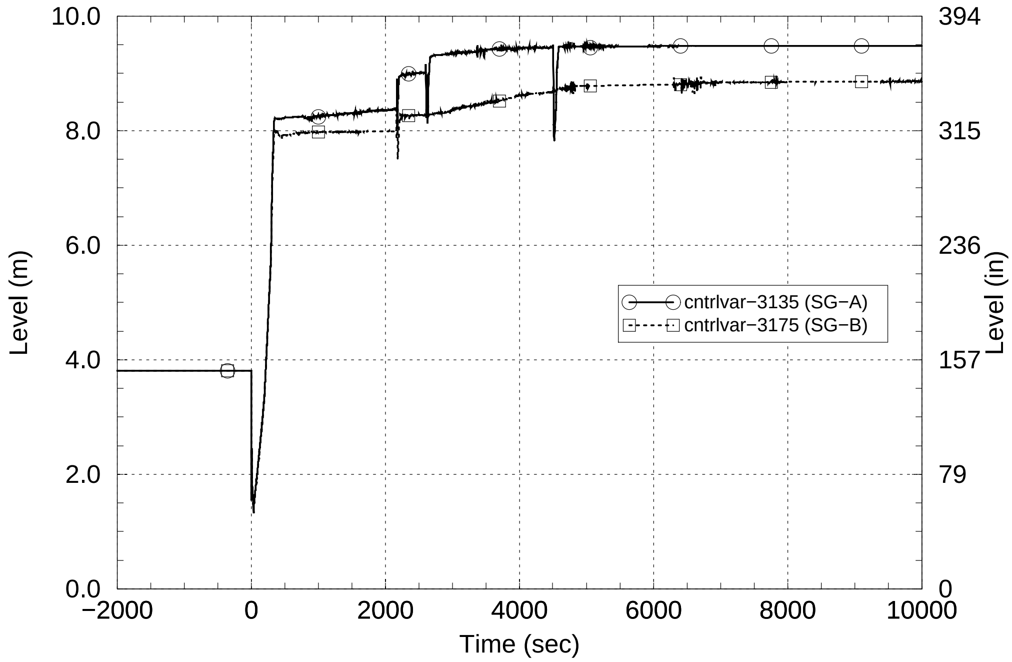


Figure 3.1.1-39 Steam Generator Secondary Startup Level - Oconee Case 164

3.1.1.4 Case 172 - 10.16 cm [4 in] Diameter Cold Leg Break from HFP Conditions

Case 172 is a 10.32 cm [4 in] diameter break in the cold leg from hot full power conditions. The equivalent break flow area is 0.008 m^2 [0.087 ft^2]. The parameters of interest for the fracture mechanics analysis: primary system pressure, average downcomer fluid temperature, and downcomer fluid-wall heat transfer coefficient are provided in Figures 3.1.1-40 through 3.1.1-42.

As a result of the break, system depressurization occurs as shown in Figure 3.1.1-40. The primary system pressure falls to 4.9 MPa [710 psia] by 300 s and continues decreasing to an equilibrium pressure of about 1.2 MPa [180 psia] by about 3,000 s after initiation. The downcomer temperature decreases to 525 K [485°F] by 300 s and to about 360 K [190°F] by 3,000 s. The pressurizer level, shown in Figure 3.1.1-43, decreases rapidly and empties from the loss of coolant inventory as the reactor coolant system depressurizes. Reactor trip occurs within 1 s, followed by actuation of the HPI system which runs for the duration of the event. The operators are assumed to trip the reactor coolant pumps as a result of the loss of subcooling within 31 s after accident initiation. The trip of the reactor coolant pumps causes loss of forced convection which causes the drop in the downcomer wall heat transfer coefficient from a steady state value of about 24,112 W/m^2-K [1.18 Btu/s-ft^2-°F] to the values shown in Figure 3.1.1-42.

The break flow is presented in Figure 3.1.1-44. After the initial flow spike, the break flow drops as flashing occurs in the system and the break flow consists mostly of steam. As the system cools and ECCS injection starts, the break flow becomes principally liquid. At the point when LPI starts, the break flow consists mostly of liquid. The changeover to liquid driven by ECCS flow is the reason for the increase in break flow. The total HPI flow is shown in Figure 3.1.1-45.

The core flood tanks start to discharge by 600 s and are completely discharged by 2,720 s as shown in Figure 3.1.1-46. Low pressure injection flow, shown in Figure 3.1.1-47, starts at about 2,195 s and remains on for the rest of the transient.

Hot leg flow is shown in Figure 3.1.1-48. There is little or no flow in either hot leg since the break is located in the cold leg. The system energy balance is shown in Figure 3.1.1-49 which shows that the break energy is larger than the core decay heat load, which causes the system temperature to decrease. This plot also shows that the steam generators have a minor effect on the downcomer temperature. Heat is transferred from the steam generator into the primary system as the system depressurizes, but the size of the break is sufficient to remove this heat from the primary system along with the decay heat energy which is substantially larger.

Because of the size of the break and the continued operation of the HPI and LPI systems, the borated water storage tank inventory is depleted and HPI and LPI pump suction is switched to the containment sump. This switchover occurs at about 3,760 s as shown in Figure 3.1.1-50 and results in an increase in the HPI and LPI injection temperature, which directly impacts the downcomer temperature as seen from Figure 3.1.1-41.

The steam generator secondary side pressures are shown in Figure 3.1.1-51. The decrease in secondary side pressure is due to the transfer of heat into the primary system from the steam generators. Actuation of feedwater flow, which is initiated by trip of the reactor coolant pumps and which cause the steam generator to fill, also contributes to the decline in secondary side pressure. This feedwater flow is reflected by the increase in steam generator startup levels shown in Figure 3.1.1-52.

The minimum downcomer temperature of about 355 K [180°F] was reached by about 2,700 s after initiation. The corresponding system pressure is about 1.1 MPa [160 psia] and remains at about that pressure for the rest of the transient. The downcomer temperature increased to about 325 K [125°F] by about 4,000 s after initiation as a result of ECCS switchover to the containment sump.

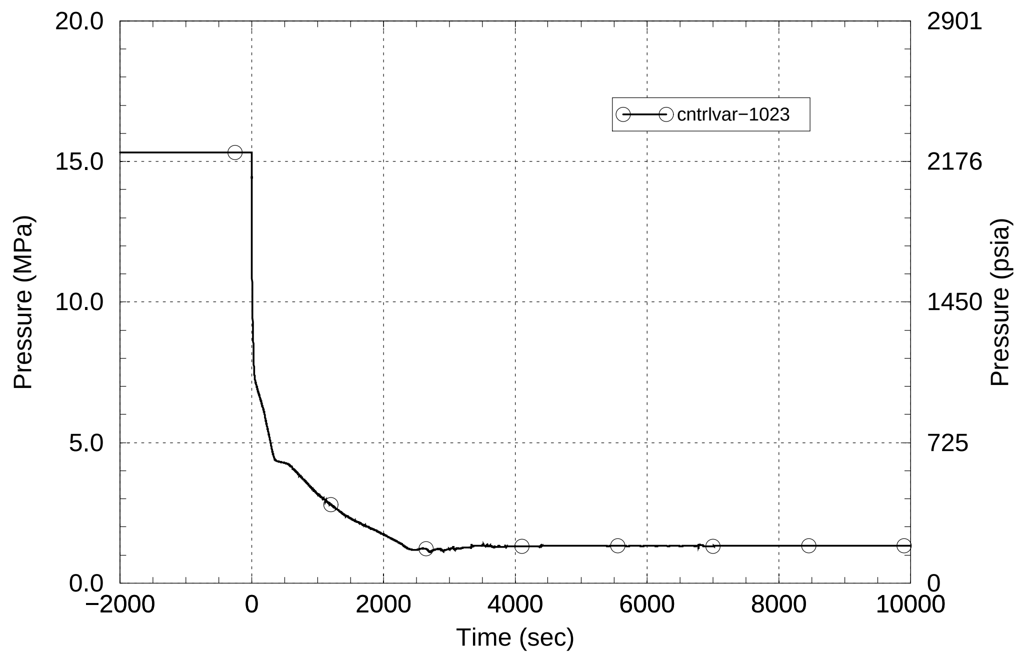


Figure 3.1.1-40 Reactor Coolant System Pressure - Oconee Case 172

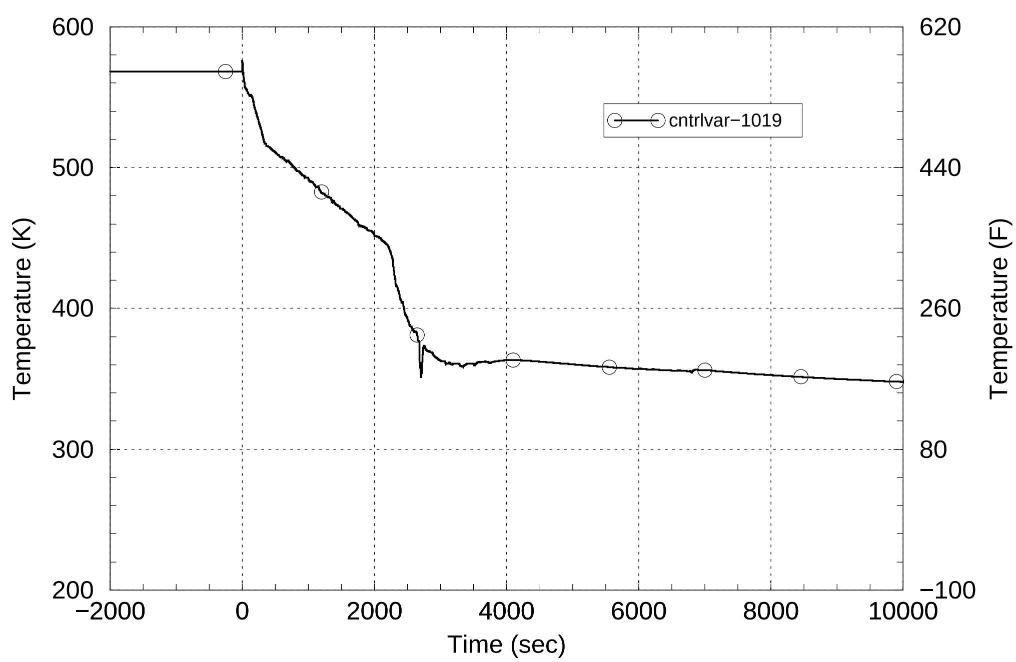


Figure 3.1.1-41 Avg Reactor Vessel Downcomer Temperature - Oconee Case 172

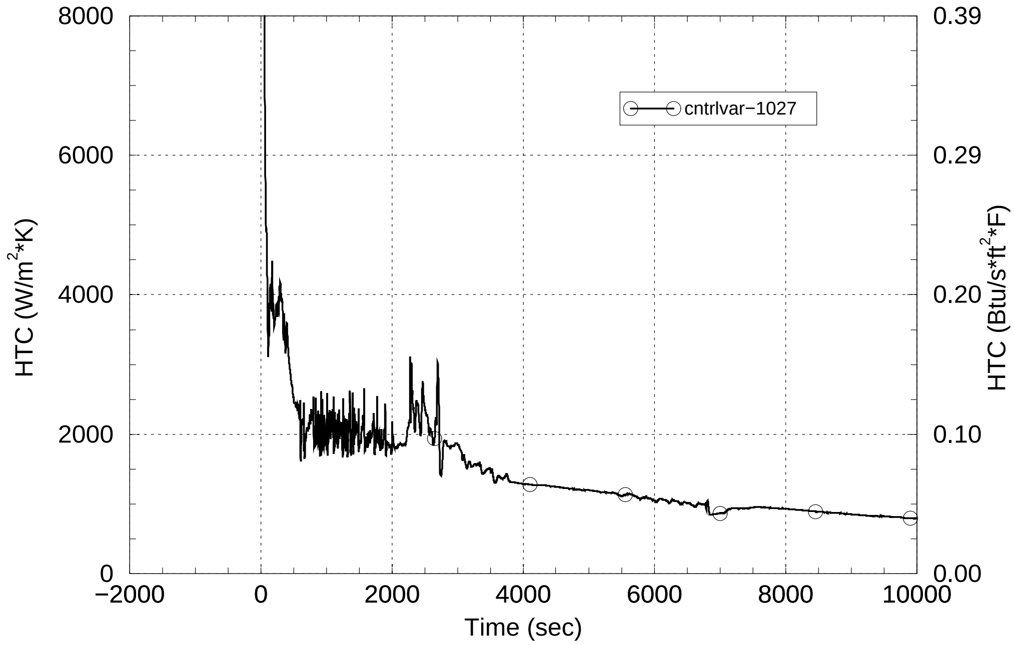


Figure 3.1.1-42 Avg Reactor Vessel Inner Wall Heat Transfer Coefficient - Oconee Case 172

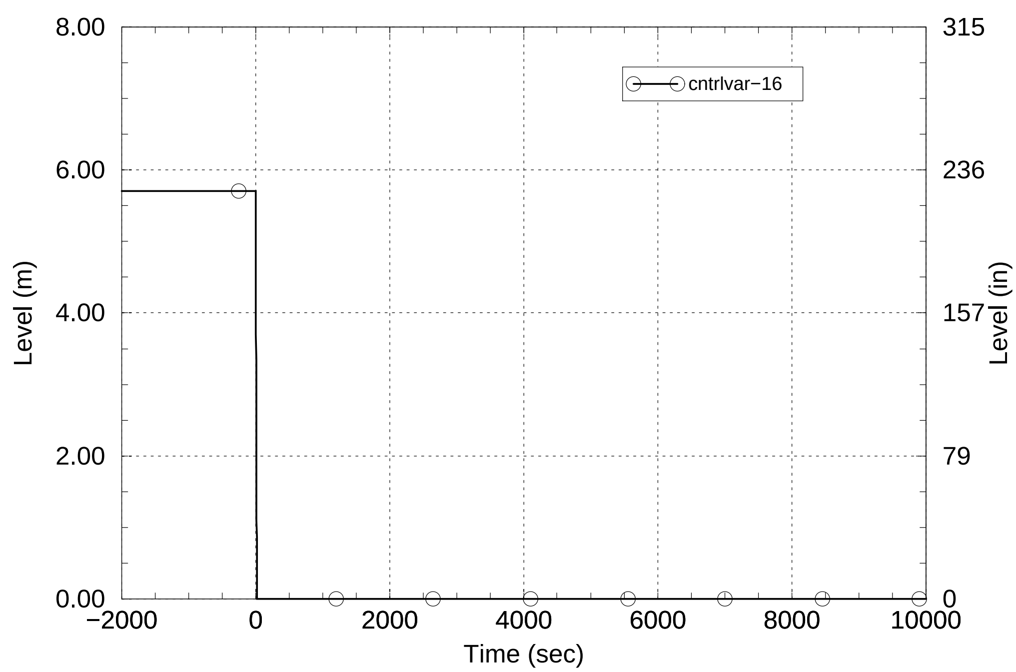


Figure 3.1.1-43 Pressurizer Level - Oconee Case 172

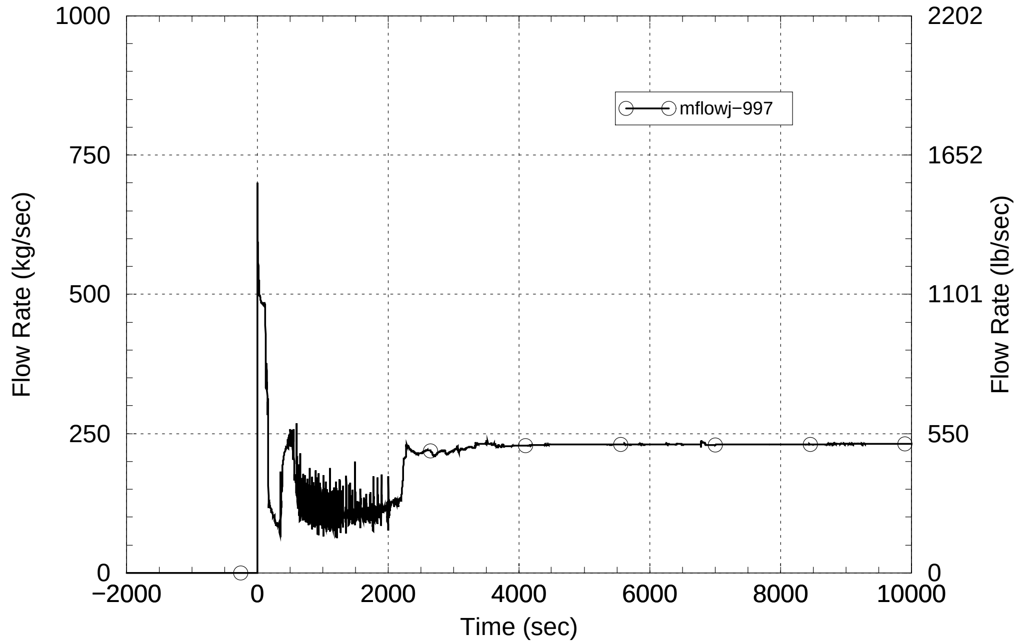


Figure 3.1.1-44 Break Flowrate - Oconee Case 172

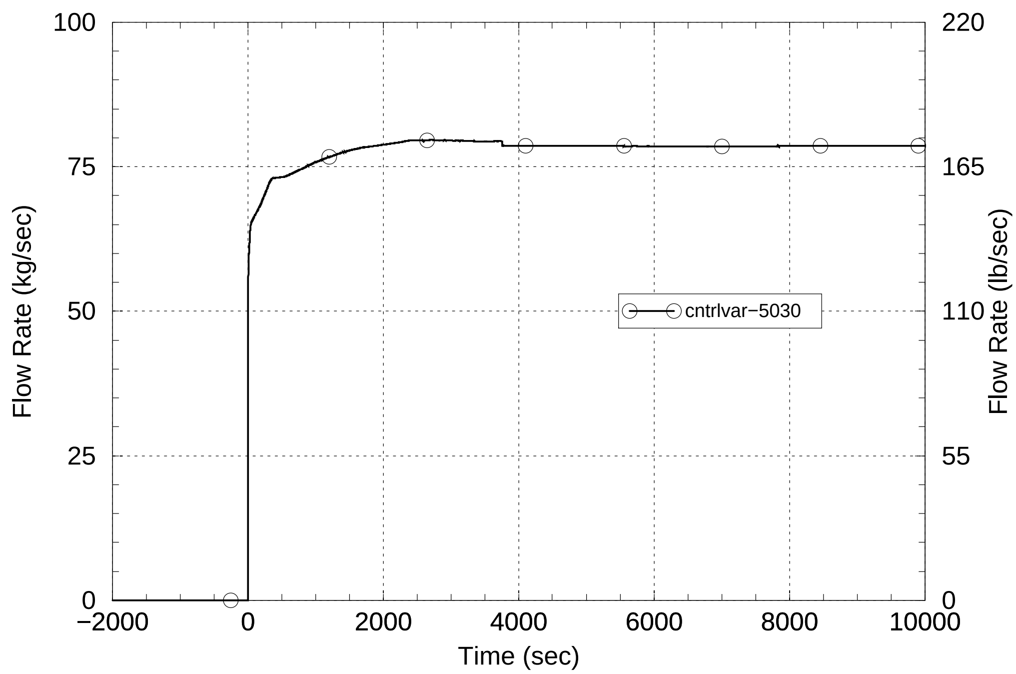


Figure 3.1.1-45 Total High Pressure Injection Flowrate - Oconee Case 172

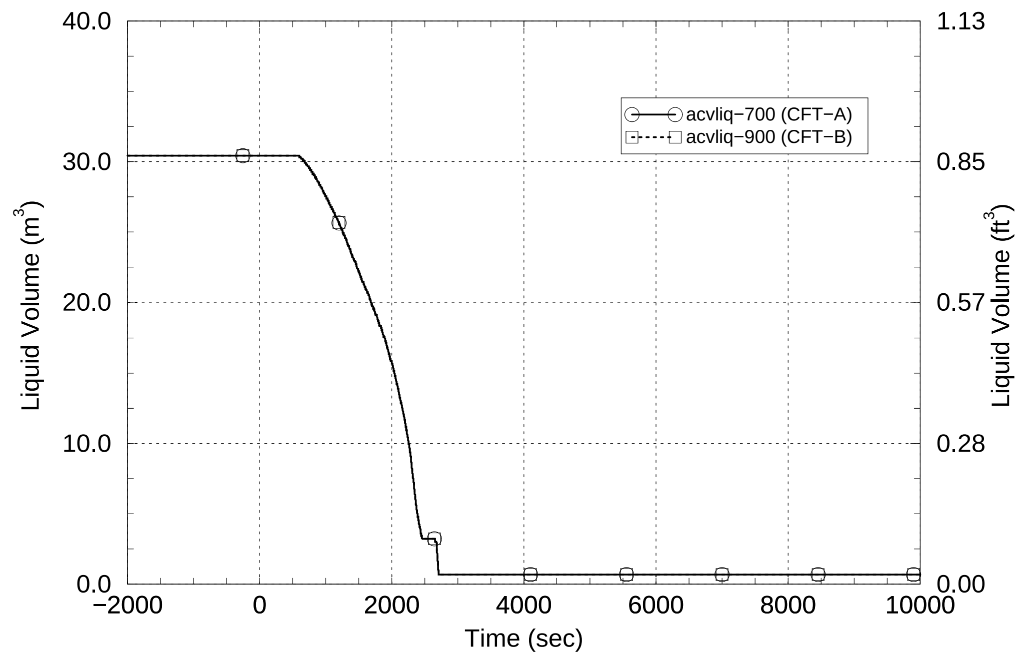


Figure 3.1.1-46 Core Flood Tank Discharge - Oconee Case 172

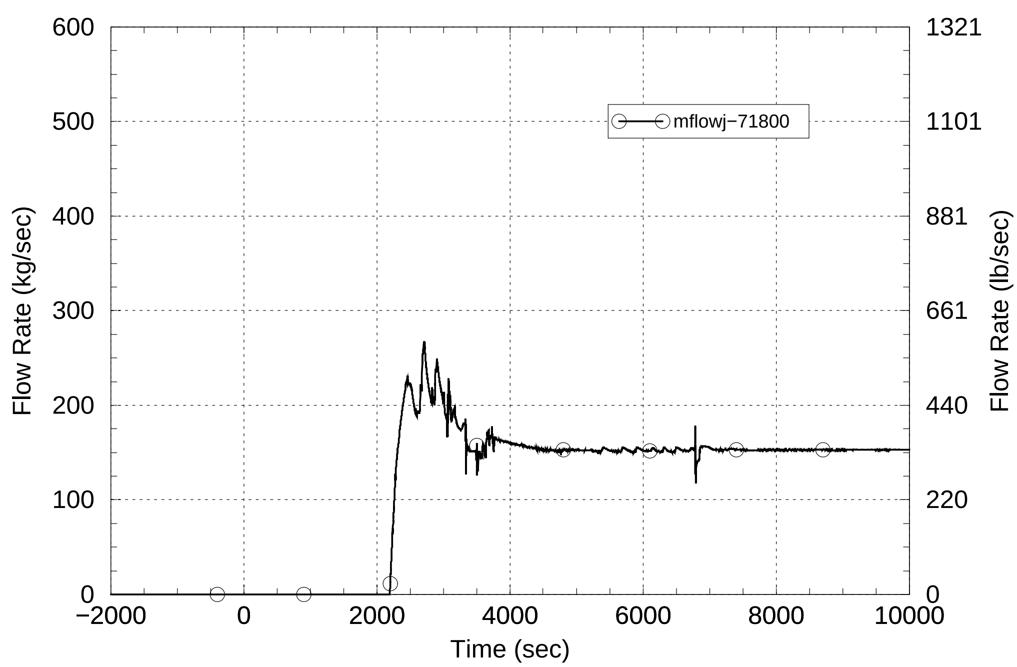


Figure 3.1.1-47 Total Low Pressure Injection Flowrate - Oconee Case 172

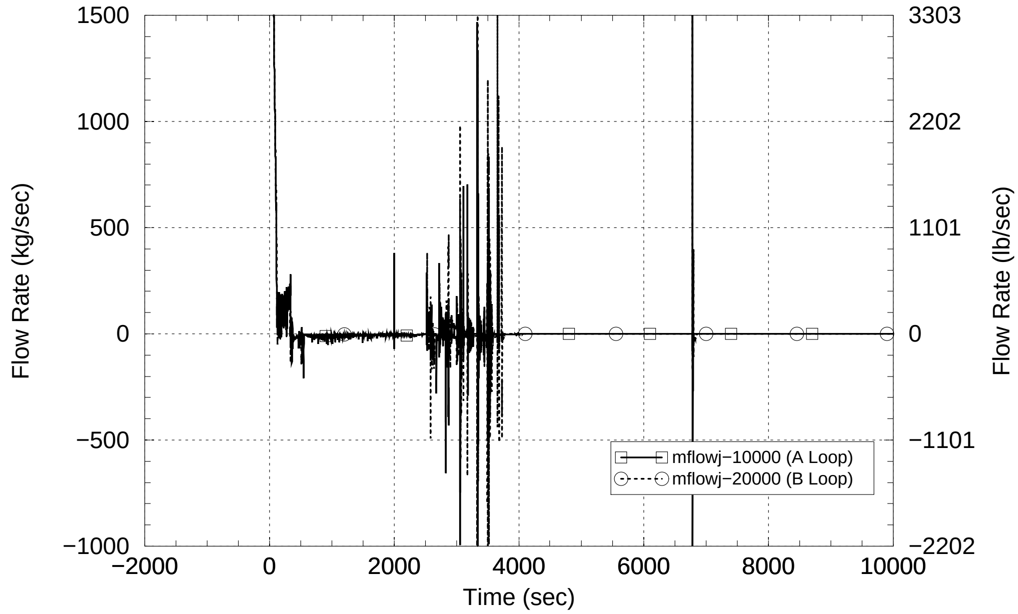


Figure 3.1.1-48 Hot Leg Flow in the A and B Loops - Oconee Case 172

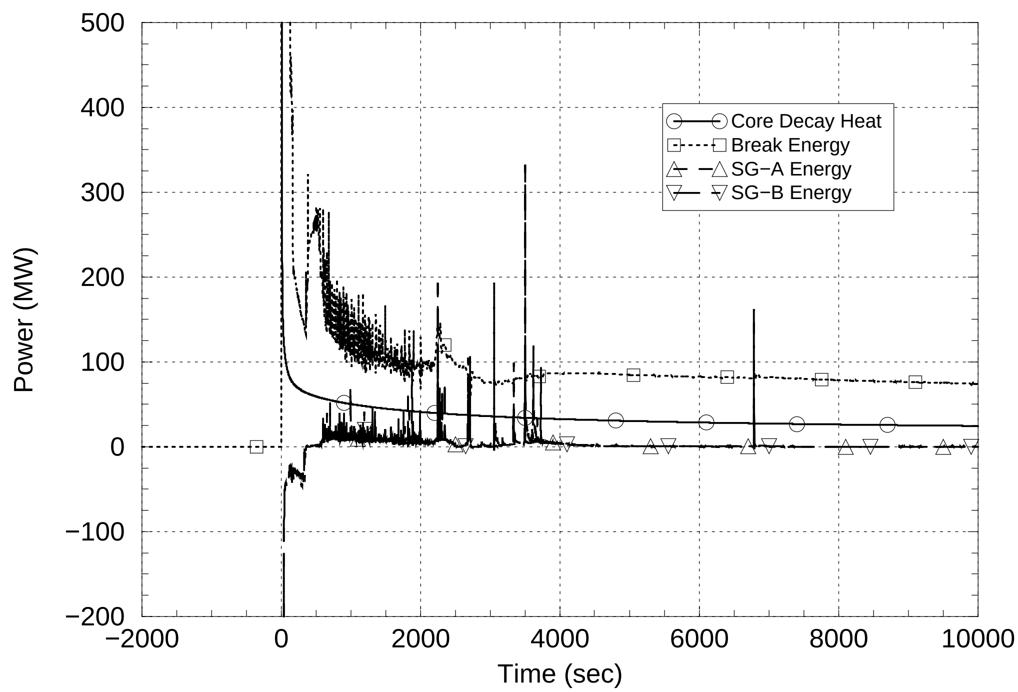


Figure 3.1.1-49 System Energy Balance - Oconee Case 172

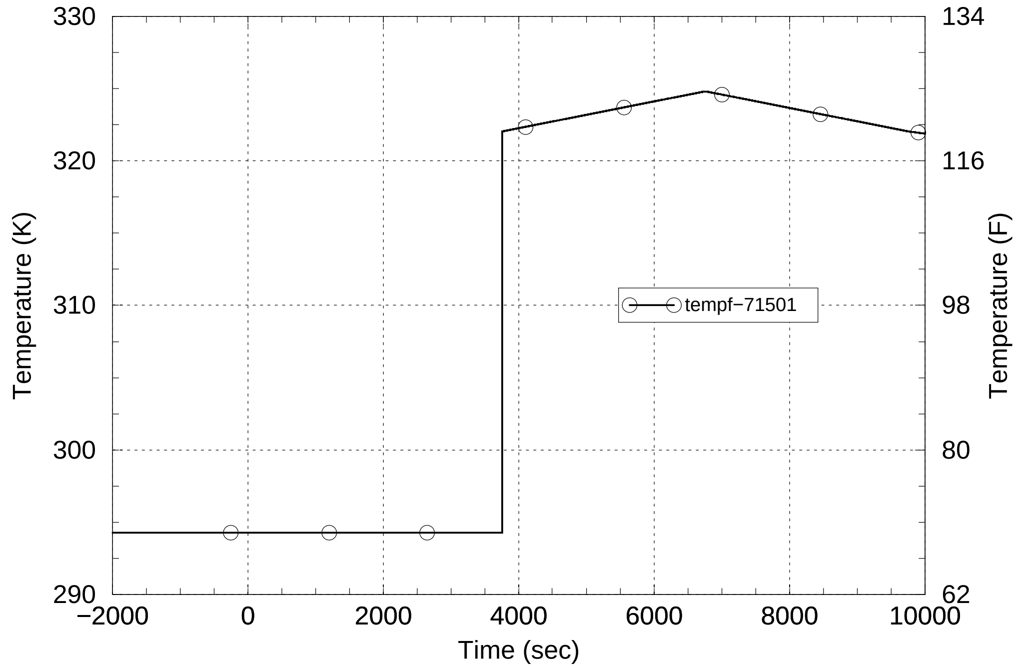


Figure 3.1.1-50 HPI and LPI Injection Temperature - Oconee Case 172

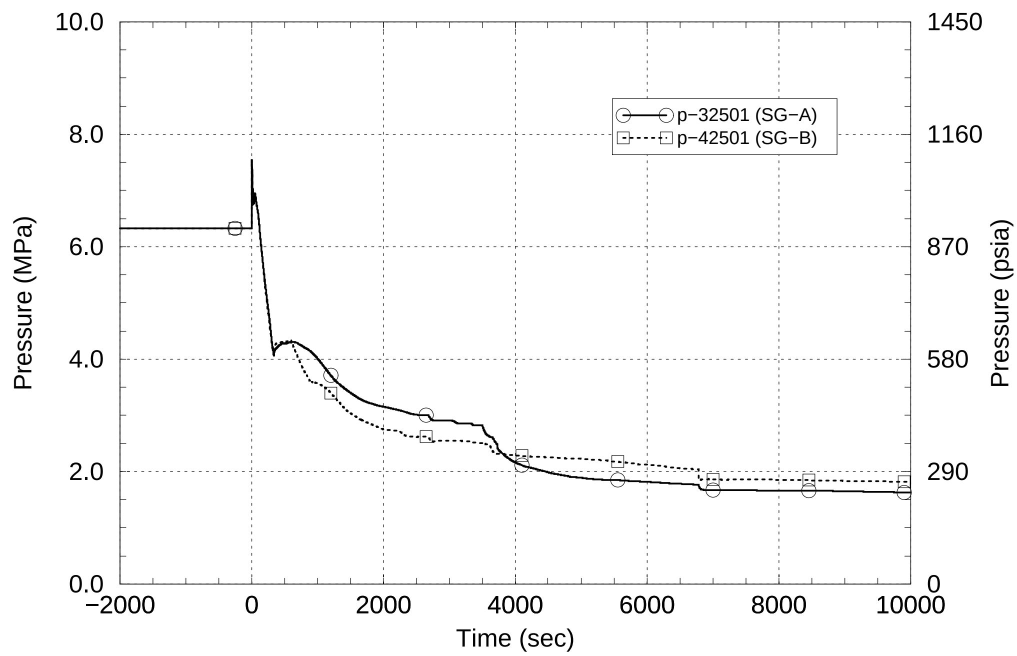


Figure 3.1.1-51 Steam Generator Secondary Pressure - Oconee Case 172

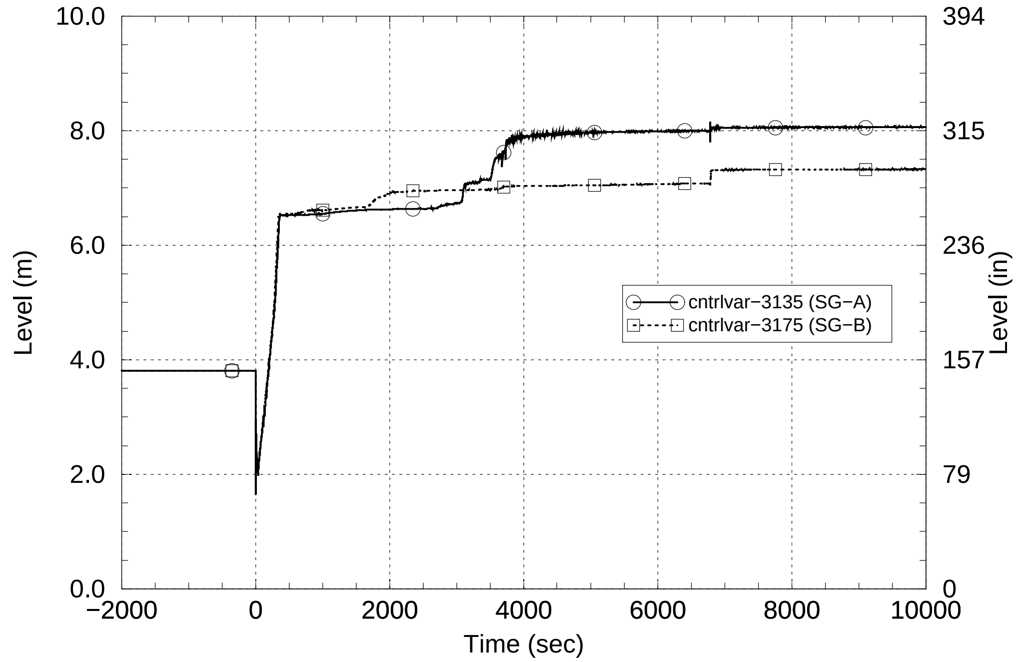


Figure 3.1.1-52 Steam Generator Secondary Startup Level - Oconee Case 172

3.1.2 Sequences with Stuck Open Pressurizer Safety Valve that Reclose at 6,000 Seconds

Sequences involving stuck open primary safety valves that subsequently reclose after 6,000 s are presented in this section. The sequences selected for discussion are Case 109, Case 113, and Case 122. These cases are described below:

- Case 109 involves a stuck open pressurizer safety valve that recloses at 6,000 s from hot full power conditions. No operator actions regarding HPI throttling are performed.
- Case 113 involves a stuck open pressurizer safety valve that recloses at 6,000 s from hot full power conditions. After the valve recloses, the operator throttles HPI 10 minutes after 2.7 K [5°F] subcooling and 254 cm [100 in] pressurizer level is reached. The throttling criteria is 27.8 K [50°F] subcooling.
- Case 122 involves a stuck open pressurizer safety valve that recloses at 6,000 s from hot zero power conditions. After the valve recloses, the operator throttles HPI 10 minutes after 2.7 K [5°F] subcooling and 254 cm [100 in] pressurizer level is reached. The throttling criteria is 27.8 K [50°F] subcooling.
- Case 165 involves a stuck open pressurizer safety valve that recloses at 6,000 s from hot zero power conditions. There are no operator actions assumed.

The pressurizer safety valve is assumed to open at sequence initiation due to a spontaneous failure and recloses at 6,000 s after initiation. The equivalent flow area of the stuck open valve is 0.0016 m^2 [0.0176 ft^2]. The operator is assumed to trip the reactor coolant pumps when primary system subcooling is lost. A trip criteria of 0.27 K [0.5°F] is assumed for the hot full power cases. For the hot zero power case, the trip criteria was raised to 3.9 K [7°F] to cause a reactor coolant pump trip. Note that the stuck open pressurizer safety valve is assumed to not sufficiently pressurize the containment to reach the setpoint at which containment sprays start. As a result, the HPI injection temperature remains constant for the duration of the event. A tabulation of the timing of key events for these transients are listed in Table 3.1-2.

Table 3.1-2 Comparison of Event Timing for Sequences with a Stuck Open PSV that Recloses at 6000 Seconds

	Event Time (seconds)			
	Case 109 - stuck open PZR SRV that recloses at 6000 seconds. No operator actions.	Case 113 - stuck open PZR SRV that recloses at 6000 seconds. Operator throttles HPI.	Case 122 - stuck open PZR SRV that recloses at 6000 seconds. Operator throttles HPI.	Case 165 - stuck open PZR SRV that recloses at 6000 seconds. No operator action.
Reactor Power Level	HFP	HFP	HZP	HZP
Reactor scram	1	1	N/A	N/A
HPI actuates	18	18	17	17
Time that vent valves open	238	238	454	454
RCP trip time on loss of subcooling margin	141	141	110	110
Time that operator throttles HPI	N/A	7355	7375	N/A
Core flood tank discharge start time	2750	2750	875	875
Low pressure injection starts	does not start	does not start	does not start	does not start
Core flood tank discharge stops	6010	6010	6550	6550
ECCS Switchover time	does not occur	does not occur	does not occur	does not occur

3.1.2.1 Case 109 - Stuck Open PSV that Recloses at 6,000 s from HFP and No Operator Actions

Case 109 is a stuck open pressurizer safety valve that recloses at 6,000 s from hot full power conditions. The parameters of interest for the fracture mechanics analysis: primary system pressure, average downcomer fluid temperature, and downcomer fluid-wall heat transfer coefficient are provided in Figures 3.1.2-1 through 3.1.2-3.

As a result of the stuck open pressurizer safety valve, the primary system pressure decreases to about 7.2 MPa [1045 psia] in the first 300 s and continues to depressurize to about 2.3 MPa [335 psia] at 6,000 s. The downcomer temperature decreases to 545 K [521°F] by 300 s and to about

386 K [235°F] by 6,000 s. Reactor trip occurs within 1 s, followed by actuation of the HPI system at about 18 s. The operators are assumed to trip the reactor coolant pumps as a result of loss of primary system subcooling at about 141 s. The trip of the reactor coolant pumps causes loss of forced convection in the downcomer which causes the drop in the downcomer wall heat transfer coefficient from a steady state value of 24,112 W/m^2-K [1.18 Btu/s-ft^2-°F] to the values shown in Figure 3.1.2-3.

The pressurizer level is shown in Figure 3.1.2-4. The pressurizer level increases because of level swell due to the stuck open pressurizer safety valve, which is located at the top of the pressurizer. Also, the HPI system is actuated and is filling the pressurizer. As a result, the pressurizer remains filled for the duration of the event.

At 6000 s, the pressurizer safety valve recloses and the system pressure increases to the PORV opening setpoint of 17.0 MPa [2465 psia] by about 7,120 s. Because of the continued operation of the HPI system, the primary system remains at that pressure with system fluid discharging through the PORV for the remainder of the event. The flowrate through the stuck open pressurizer safety valve and the PORV is shown in Figure 3.1.2-5. Note that the PORV cycles open and closed as necessary to limit the RCS pressurization. The total HPI flowrate is shown in Figure 3.1.2-6. The closure of the pressurizer safety valve at 6,000 s causes a corresponding drop in HPI flow due to increased system pressure, especially once the system repressurizes to the PORV setpoint.

The core flood tanks discharge about 30 percent of the total water volume as seen in Figure 3.1.2-7. At 6000 s, the discharge stops because the pressurizer safety valve reclosed and the system repressurized. Note that there is no LPI flow in this case because the primary system pressure never drops below the LPI pump shutoff head of 1.48 MPa [214 psia].

The flow in the hot leg is shown in Figure 3.1.2.8. The flow in the A loop hot leg is initially due to the stuck open pressurizer safety valve. When the valve recloses, the hot leg flow is interrupted until the PORV opens. The oscillatory flow pattern after about 7,000 s in the hot leg flow is induced by the continued opening and closing of the PORV.

Figure 3.1.2-9 shows the system energy balance. The core decay heat energy is removed initially by the stuck open pressurizer safety valve. When the valve recloses, energy is removed through the PORV after the system pressurizes to the PORV setpoint from continued HPI operation. This plot also shows that the steam generators have a minor effect on the primary system energy and hence the downcomer temperature. Heat is transferred from the steam generator into the primary system as the system depressurizes, but the capacity of the stuck open valve or the PORV is sufficient to remove this heat from the primary system along with the decay heat energy which is substantially larger.

The steam generator secondary side pressure is shown in Figure 3.1.2-10. The decrease in secondary side pressure is due to the transfer of heat into the primary system from the steam generators. Actuation of feedwater flow, which is initiated by trip of the reactor coolant pumps and which cause the steam generator to fill, also contributes to the decline in secondary side pressure. This flow is reflected by the increase in steam generator startup level shown in Figure 3.1.2-11.

The minimum downcomer temperature of about 350 K [170°F] was reached by 6,010 s after initiation when the pressurizer safety valve recloses. The corresponding system pressure is about 2.3 MPa [330 psia]. However, the system repressurized to the PORV opening pressure because of continued HPI operation and remains at about that pressure for the rest of the transient as shown in Figure 3.1.2-1. Note that a momentary discharge of water from the core flood tanks occurred at the time the valve reclosed, causing the downward temperature spike seen in Figure 3.1.2-2.

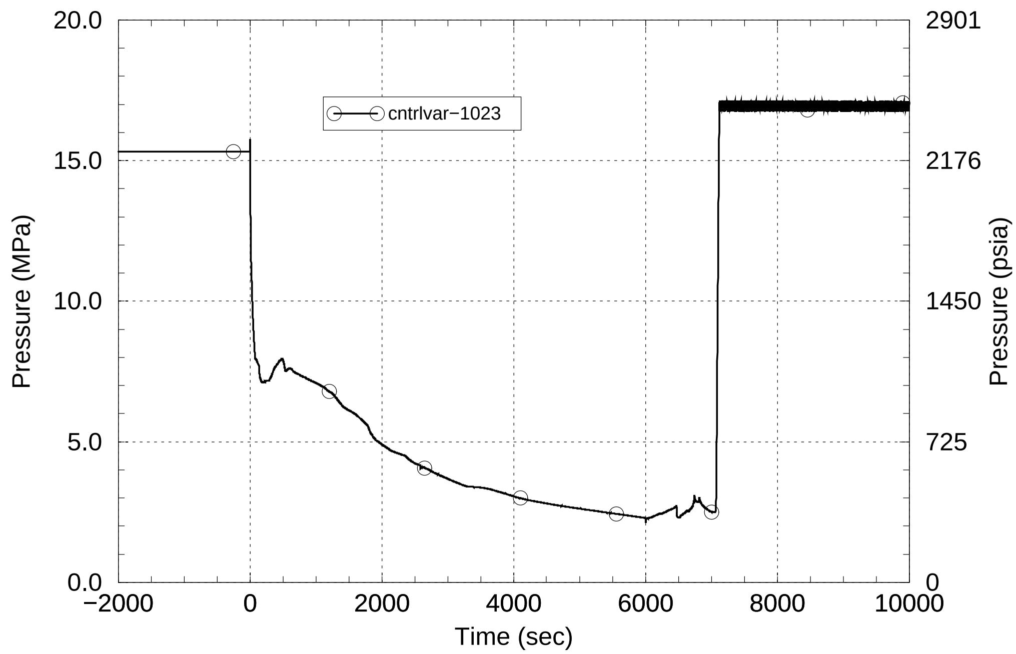


Figure 3.1.2-1 Reactor Coolant System Pressure - Oconee Case 109

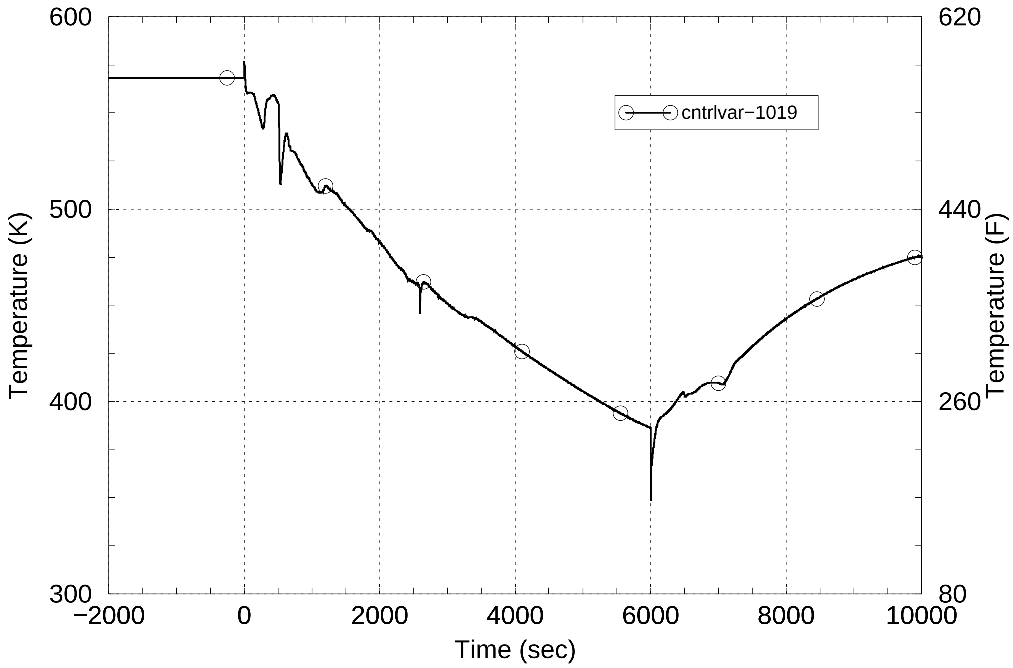


Figure 3.1.2-2 Avg Reactor Vessel Downcomer Temperature - Oconee Case 109

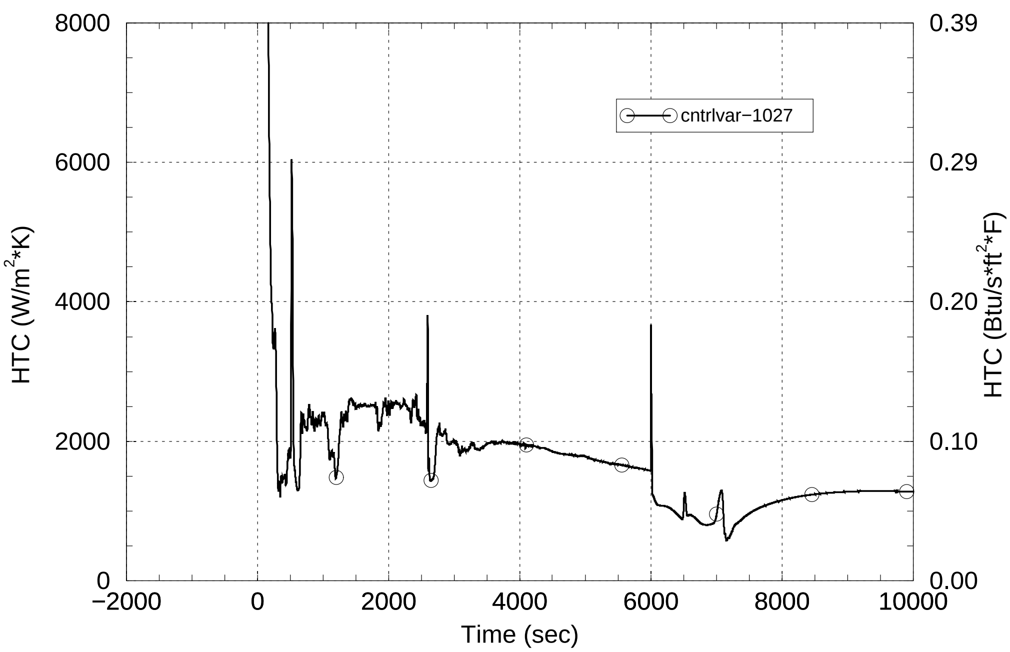


Figure 3.1.2-3 Avg Reactor Vessel Inner Wall Heat Transfer Coefficient - Oconee Case 109

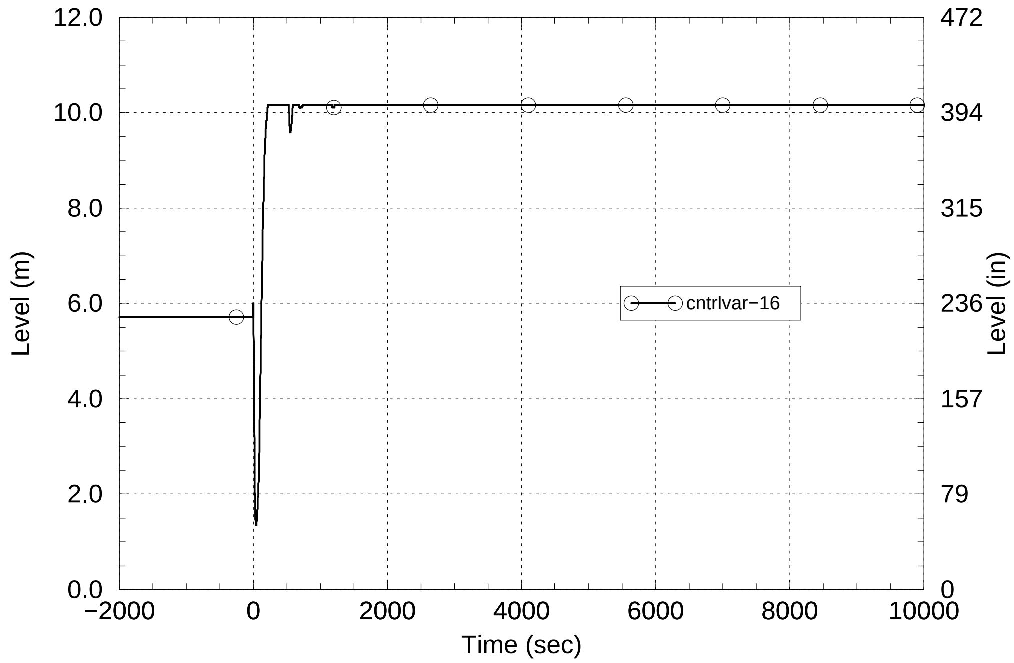


Figure 3.1.2-4 Pressurizer Level - Oconee Case 109

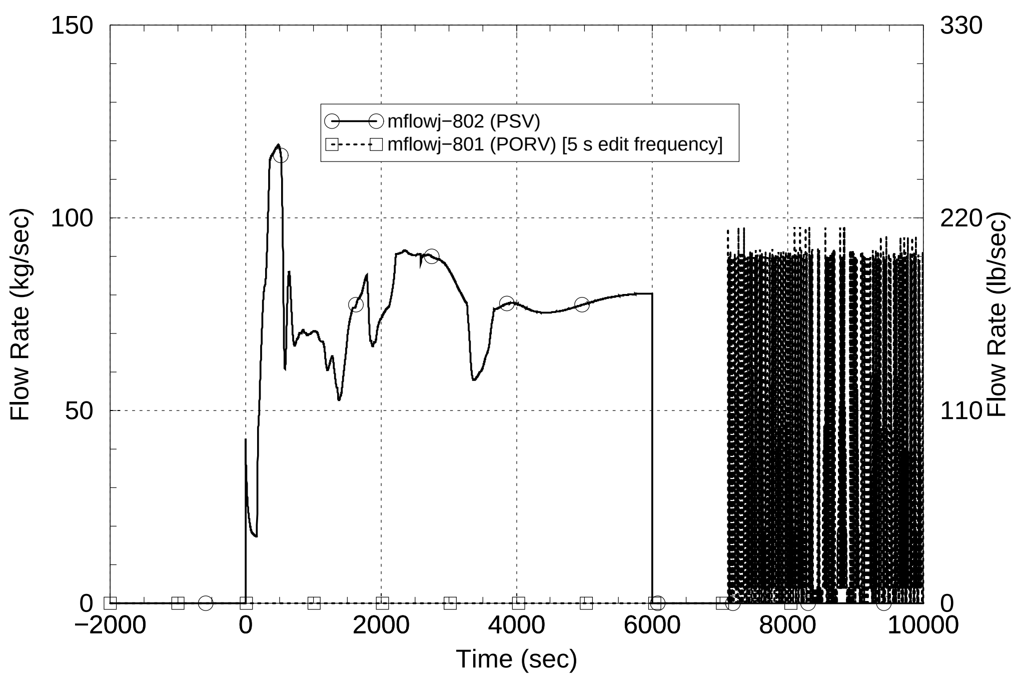


Figure 3.1.2-5 Flowrate through the Stuck Open PSV and PORV - Oconee Case 109

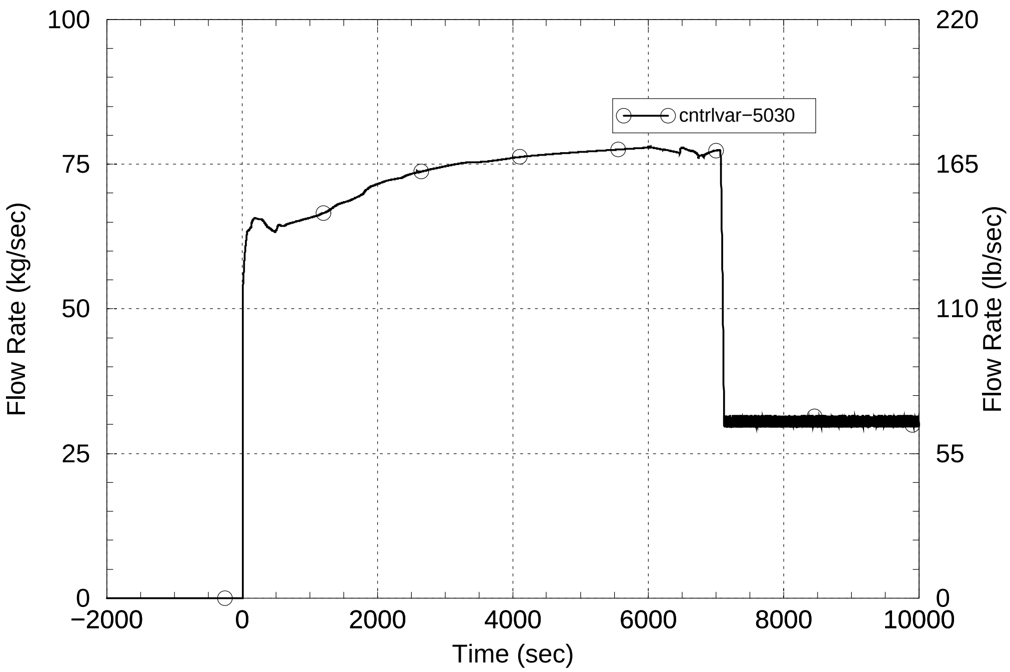


Figure 3.1.2-6   Total High Pressure Injection Flowrate - Oconee Case 109

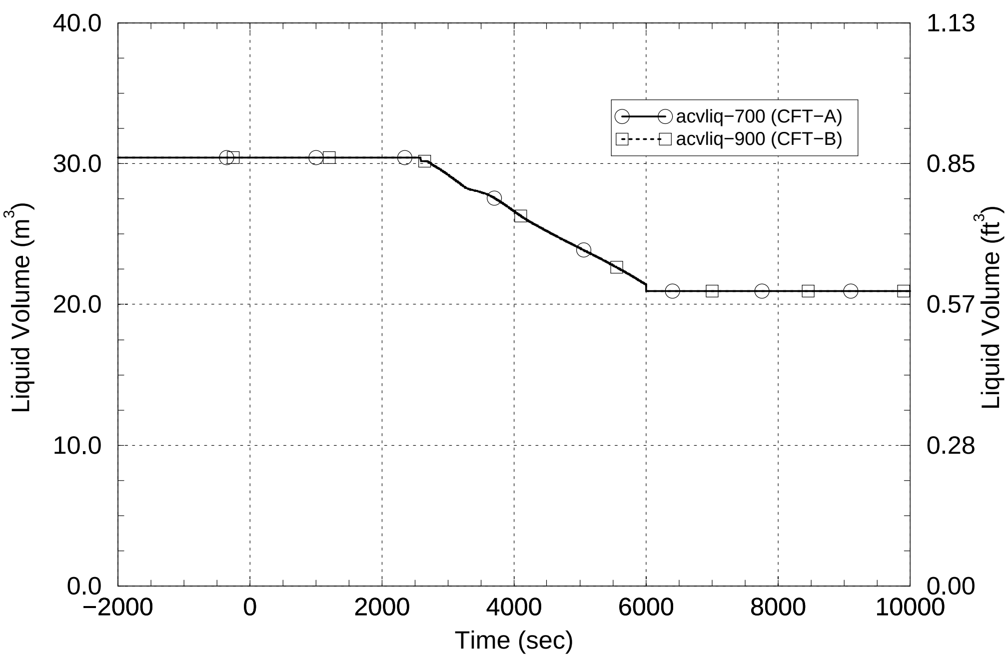


Figure 3.1.2-7   Core Flood Tank Discharge - Oconee Case 109

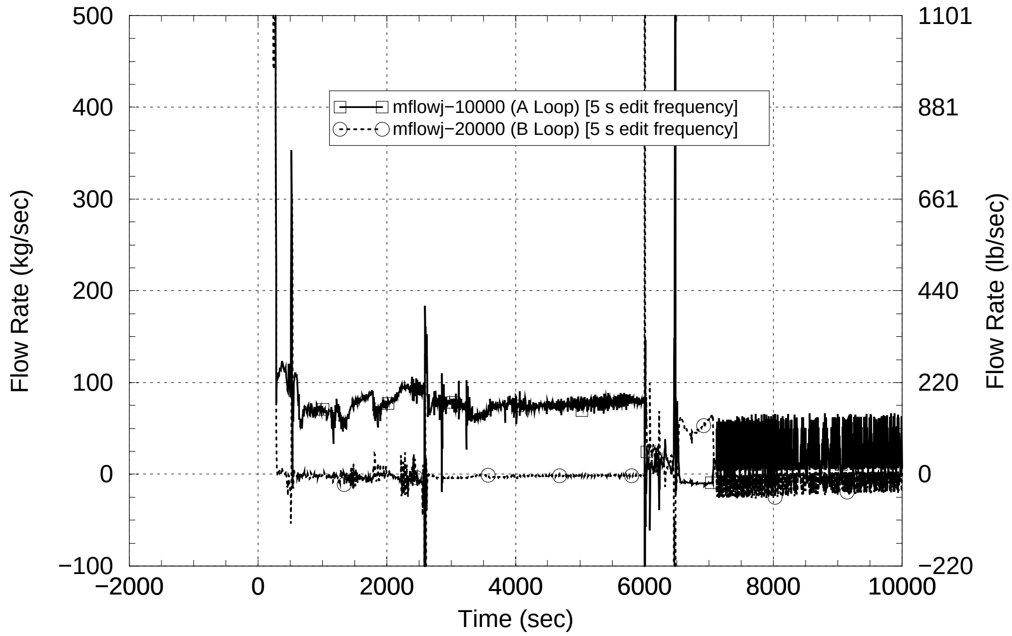


Figure 3.1.2-8 Hot Leg Flow in the A and B Loops - Oconee Case 109

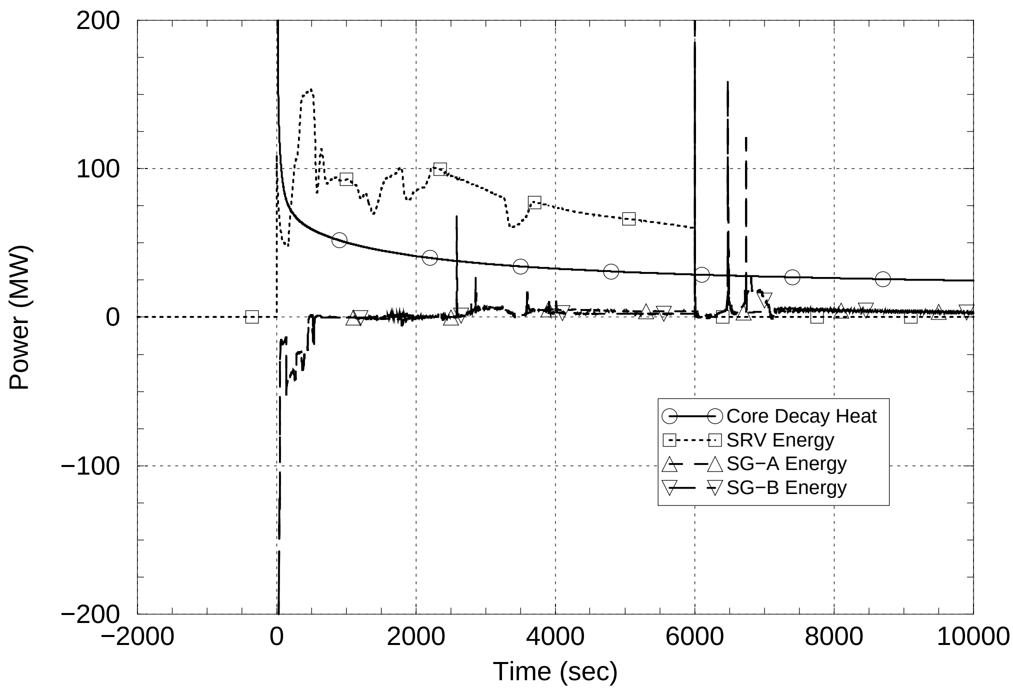


Figure 3.1.2-9 System Energy Balance - Oconee Case 109

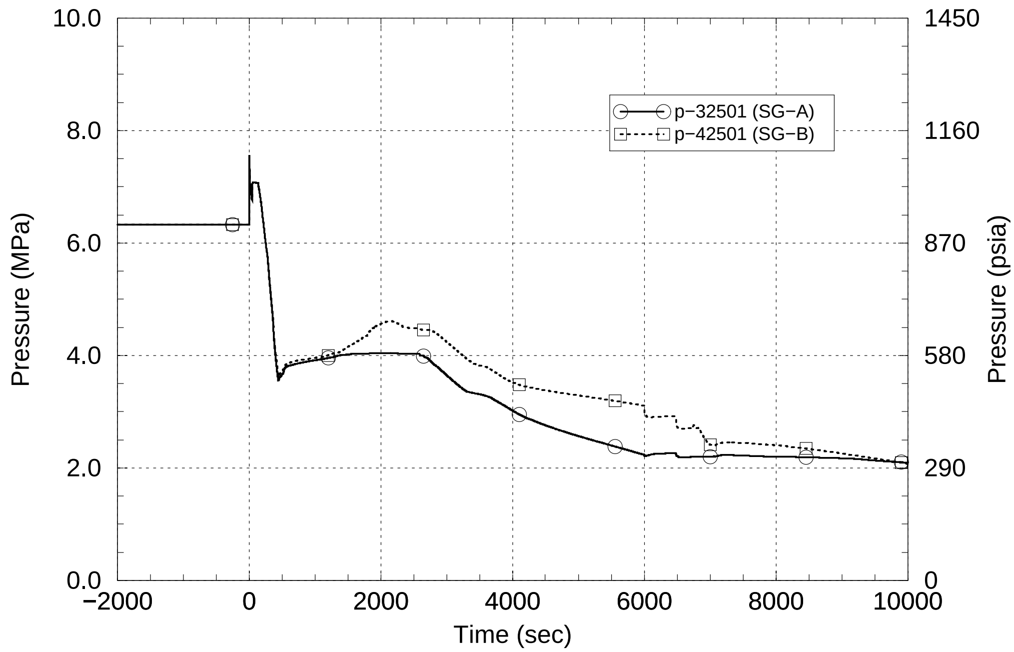


Figure 3.1.2-10 Steam Generator Secondary Pressure - Oconee Case 109

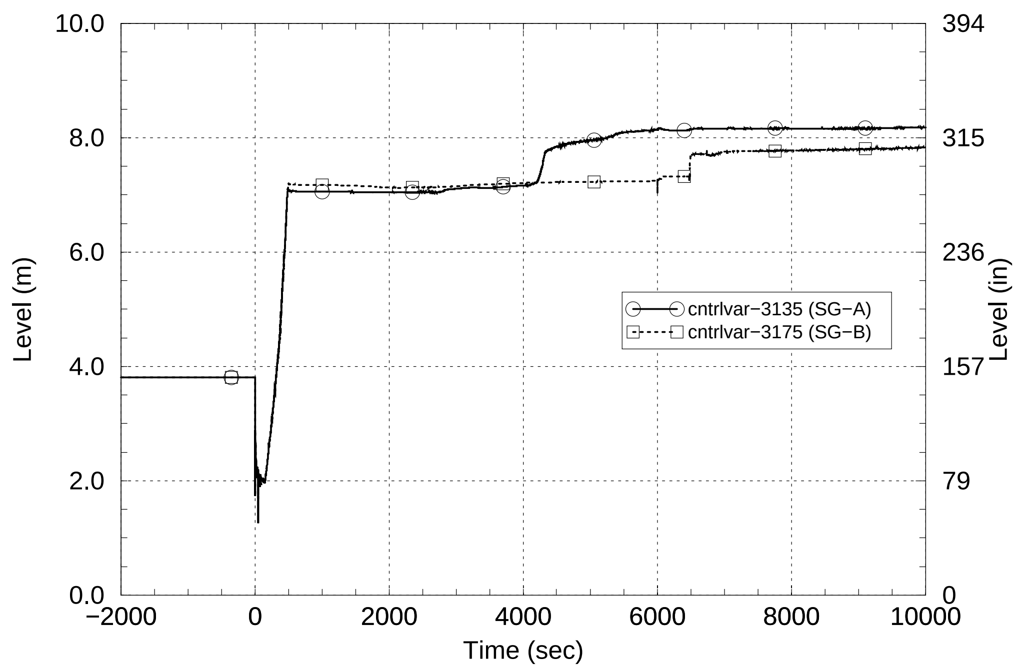


Figure 3.1.2-11 Steam Generator Secondary Startup Level - Oconee Case 109

3.1.2.2 Case 113 - Stuck Open PSV that Recloses at 6,000 s from HFP with Operator Actions

Case 113 is a stuck open pressurizer safety valve that recloses at 6,000 s from hot full power conditions. In this case, the operator is assumed to throttle HPI at 10 minutes after 2.7 K [5°F] primary system subcooling and when the pressurizer level is over 2.54 m [100 in]. The throttling criteria is 27.8 K [50°F] subcooling. The parameters of interest for the fracture mechanics analysis: primary system pressure, average downcomer fluid temperature, and downcomer fluid-wall heat transfer coefficient are provided in Figures 3.1.2-12 through 3.1.2-14.

As a result of the stuck open pressurizer safety valve, the primary system pressure decreases to about 7.2 MPa [1045 psia] in the first 300 s and continues to depressurize to about 2.3 MPa [335 psia] at 6,000 s. The downcomer temperature decreases to 545 K [521°F] by 300 s and to about 386 K [235°F] by 6,000 s. Reactor trip occurs within 1 s, followed by actuation of the HPI system at about 18 s. The operators are assumed to trip the reactor coolant pumps as a result of loss of primary system subcooling at about 141 s. The trip of the reactor coolant pumps causes loss of forced convection in the downcomer which causes the drop in the downcomer wall heat transfer coefficient from a steady state value of 24,112 W/m^2-K [1.18 Btu/s-ft^2-°F] to the values shown in Figure 3.1.2-14.

The pressurizer level is shown in Figure 3.1.2-15. The pressurizer level increases because of level swell due to the stuck open pressurizer safety valve, which is located at the top of the pressurizer. Also, the HPI system is running and filling the pressurizer. The flowrate through the stuck open pressurizer safety valve and the PORV is shown in Figure 3.1.2-16. The total HPI flowrate is shown in Figure 3.1.2-17.

At 6000 s, the pressurizer safety valve recloses and the system pressure starts to increase. The operator starts to throttle HPI at about 7355 s, just after the PORV opening setpoint is reached. When the throttling criteria of 27.8 K [50°F] is exceeded, the HPI is throttled back to regain control of subcooling.

The core flood tank discharge about 30 percent of the total water volume as seen in Figure 3.1.2-18. At 6000 s, the discharge stops because the pressurizer safety valve reclosed and the system repressurized. Note that there is no LPI flow in this case because the primary system pressure never drops below the LPI pump shutoff head of 1.48 MPa [214 psia].

The flow in the hot leg is shown in Figure 3.1.2.19. The flow in the A loop hot leg is initially due to the stuck open pressurizer safety valve. When that valve recloses, the hot leg flow generally stops, with occasional flow restarting because the PORV opens.

Figure 3.1.2-20 shows the system energy balance. The core decay heat energy is removed initially by the stuck open pressurizer safety valve. When the valve recloses, energy is removed through the PORV after the system repressurizes to the PORV setpoint. Some heat is transferred out of the primary when the PORV opens. The primary system pressure stays at the PORV setpoint and the valve continues to cycle due to decay heat. Steam generators have a minor impact on the primary system energy as seen from the figure.

The steam generator secondary side pressures are shown in Figure 3.1.2-21. The decrease in secondary side pressure is due to the transfer of heat into the primary system from the steam generators. Actuation of feedwater flow, which is initiated by trip of the reactor coolant pumps and which cause the steam generator to fill, also contribute to the decline in secondary side pressure. This flow is reflected by the increase in steam generator startup level shown in Figure 3.1.2-22.

The minimum downcomer temperature of about 350 K [170°F] was reached by 6,030 s after initiation when the pressurizer safety valve recloses. The corresponding system pressure is about 2.3 MPa [330 psia] at that time, but the system repressurized to about the opening pressure of the PORV and remains at that level due to decay heat. Note that a momentary discharge of water from the core flood tank occurred at the time the valve reclosed causing the downward temperature spike seen in Figure 3.1.2-13.

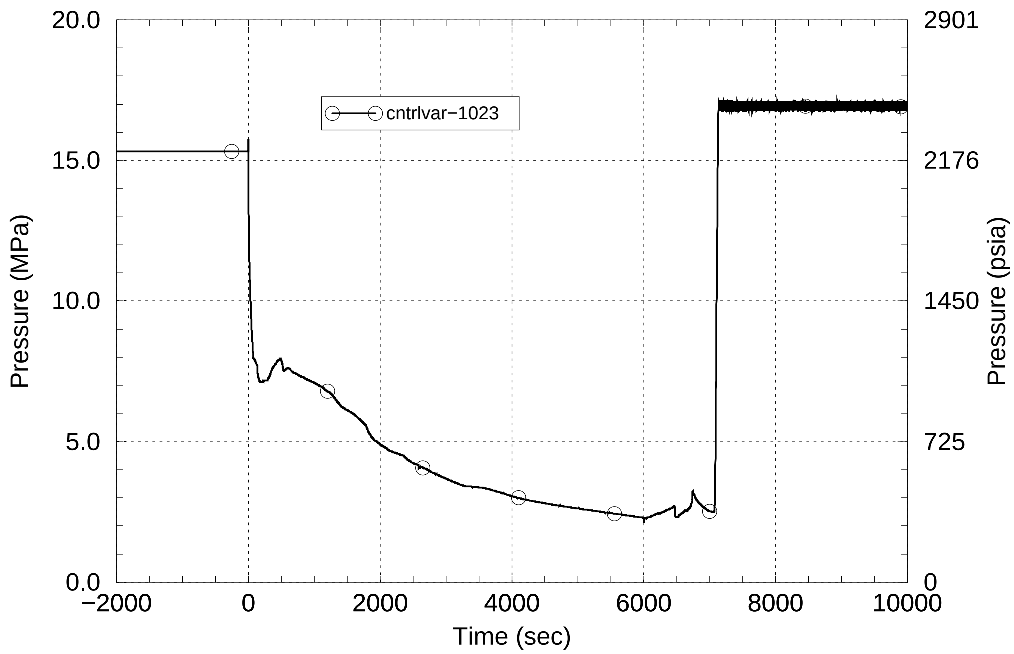


Figure 3.1.2-12   Reactor Coolant System Pressure - Oconee Case 113

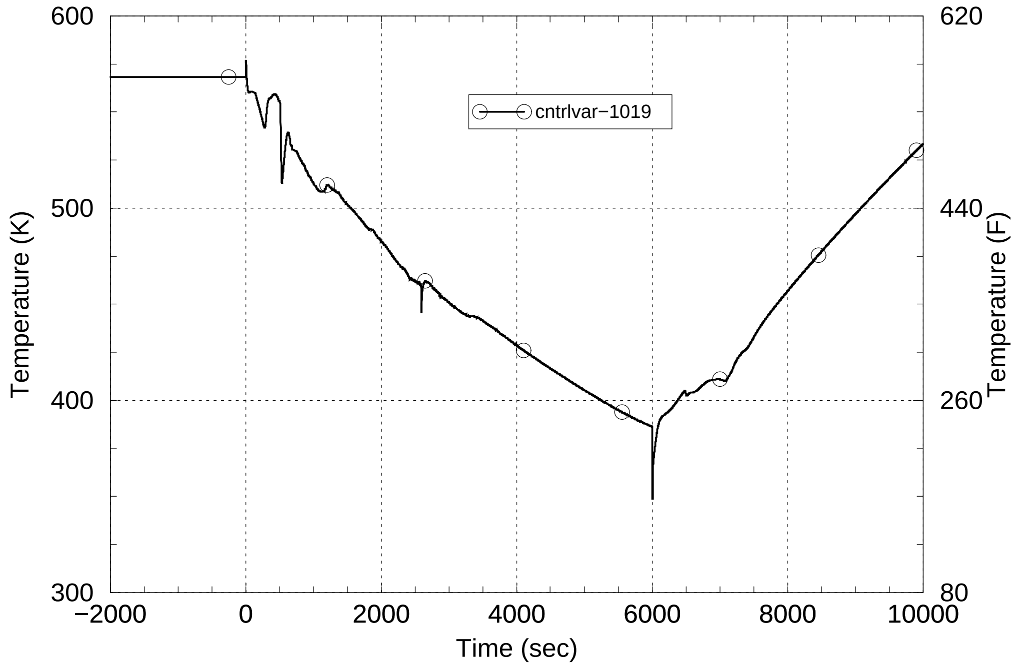


Figure 3.1.2-13 Avg Reactor Vessel Downcomer Temperature - Oconee Case 113

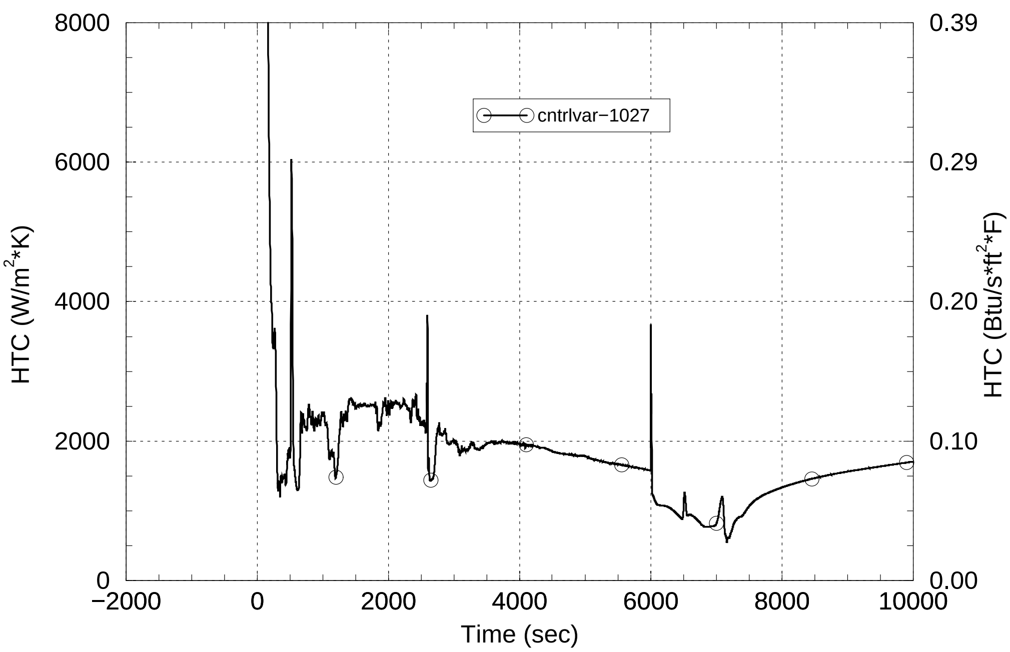


Figure 3.1.2-14 Avg Reactor Vessel Inner Wall Heat Transfer Coefficient - Oconee Case 113

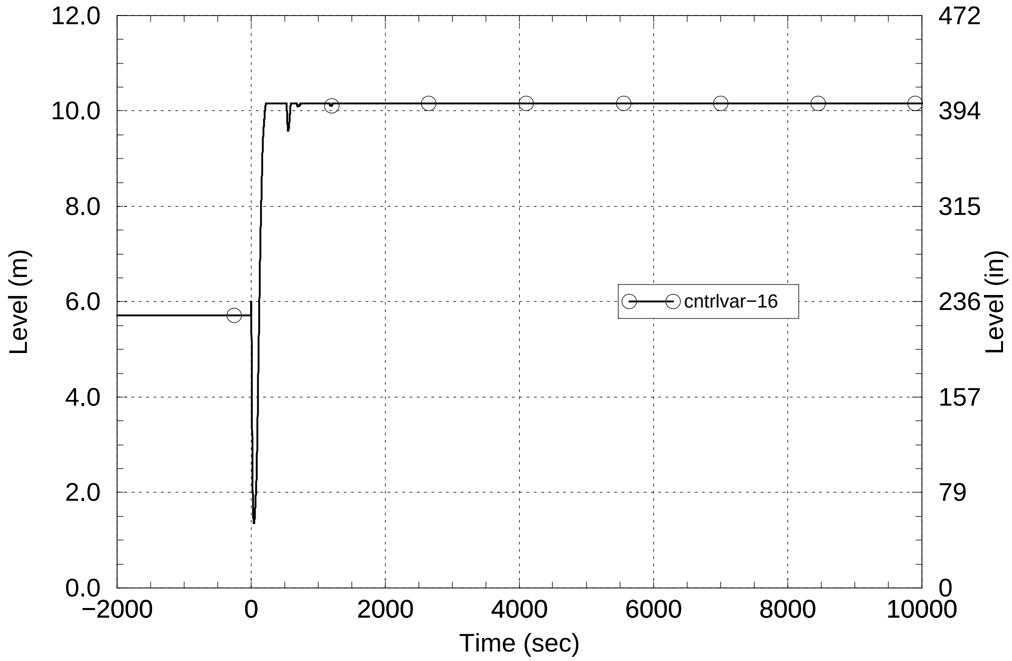


Figure 3.1.2-15 Pressurizer Level - Oconee Case 113

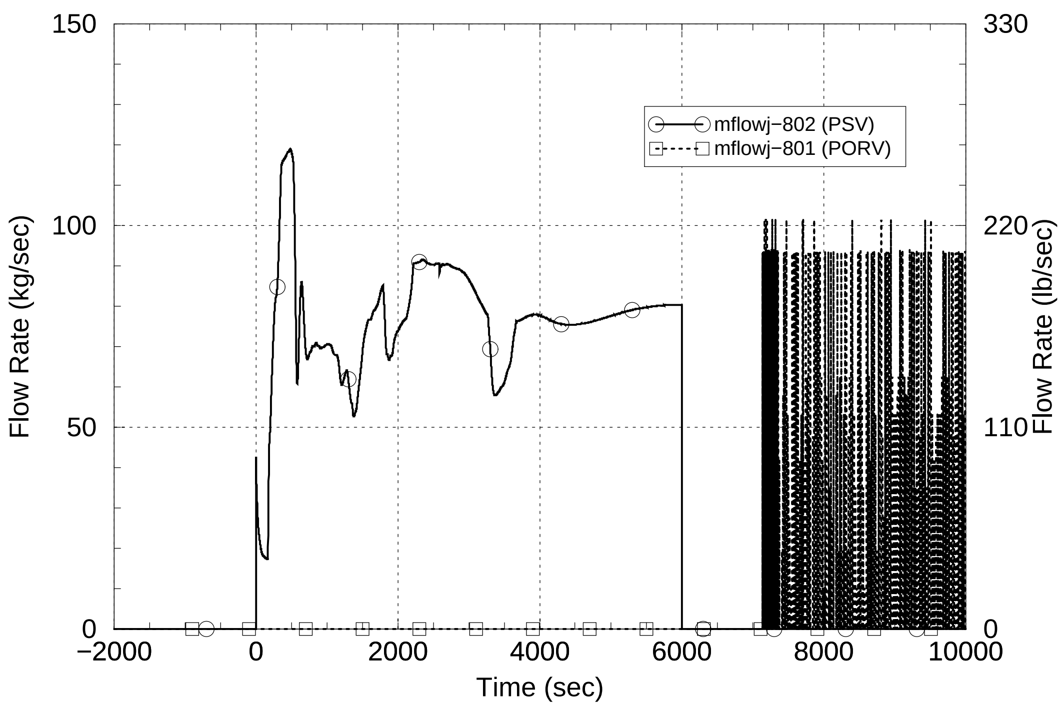


Figure 3.1.2-16 Flowrate through the Stuck Open PSV and PORV - Oconee Case 113

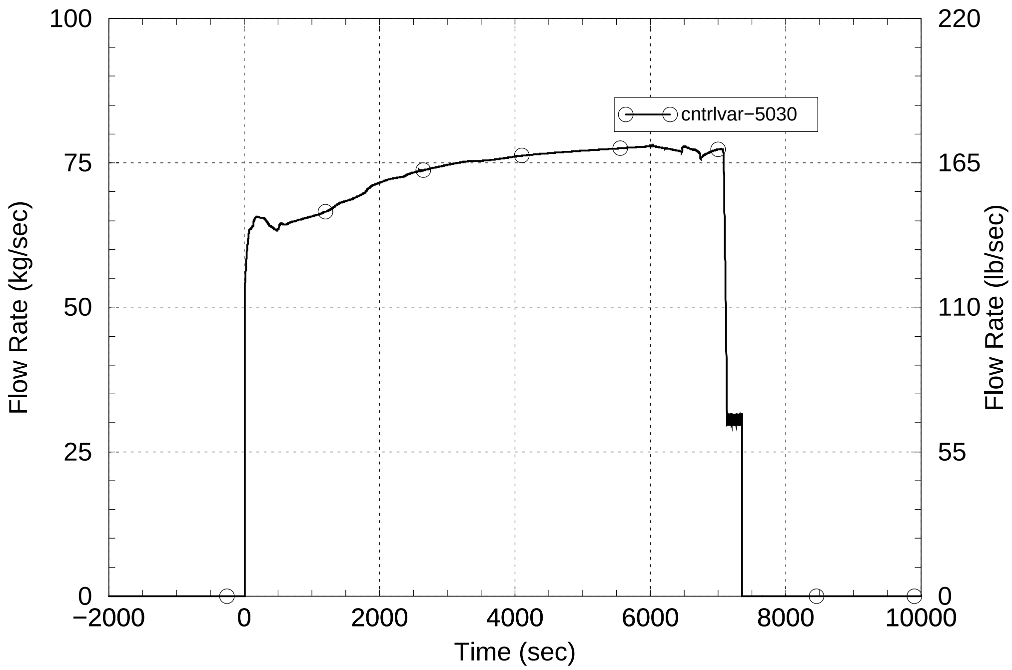


Figure 3.1.2-17 Total High Pressure Injection Flowrate - Oconee Case 113

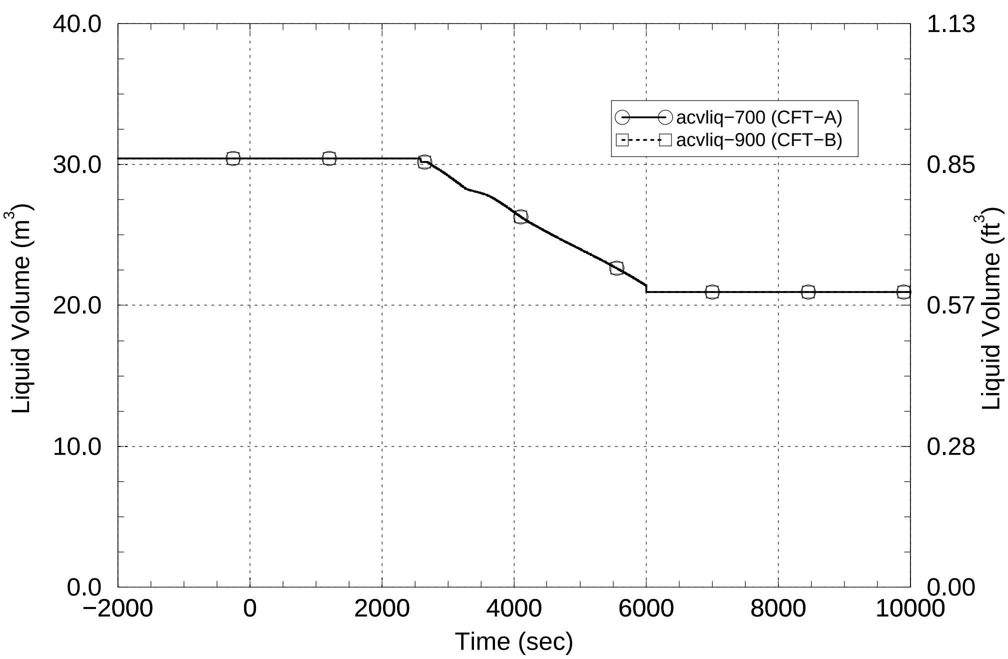


Figure 3.1.2-18 Core Flood Tank Discharge - Oconee Case 113

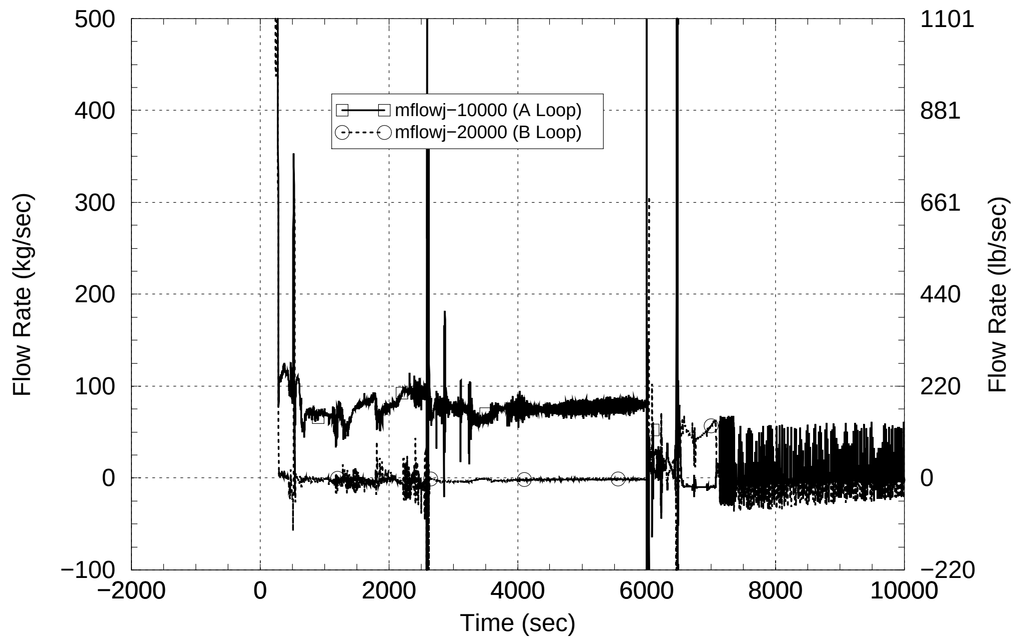


Figure 3.1.2-19 Hot Leg Flow in the A and B Loops - Oconee Case 113

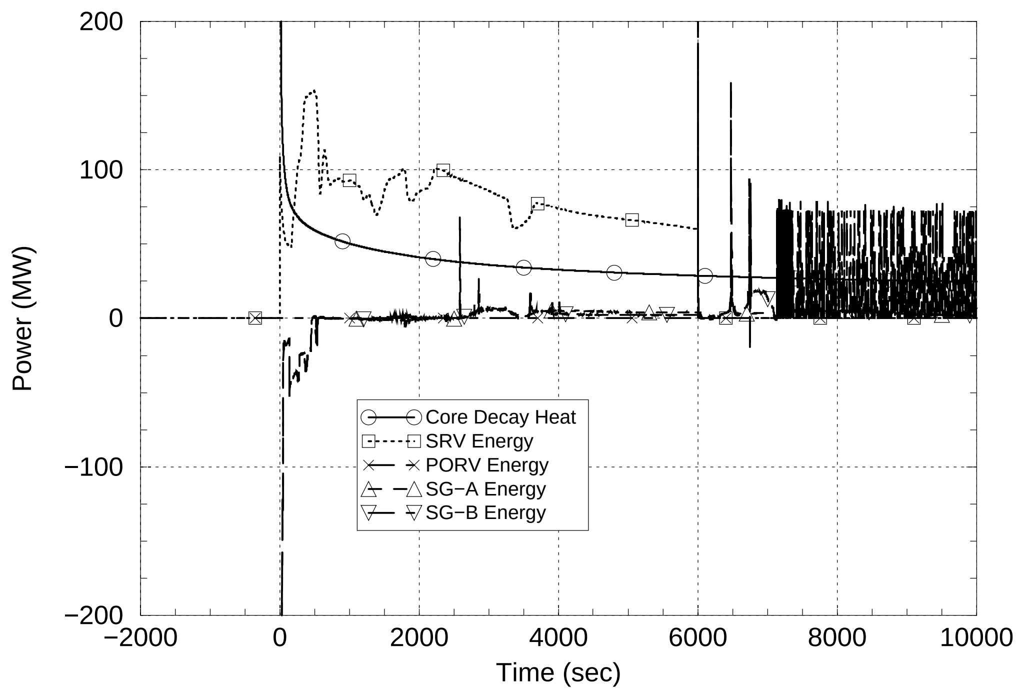


Figure 3.1.2-20 System Energy Balance - Oconee Case 113

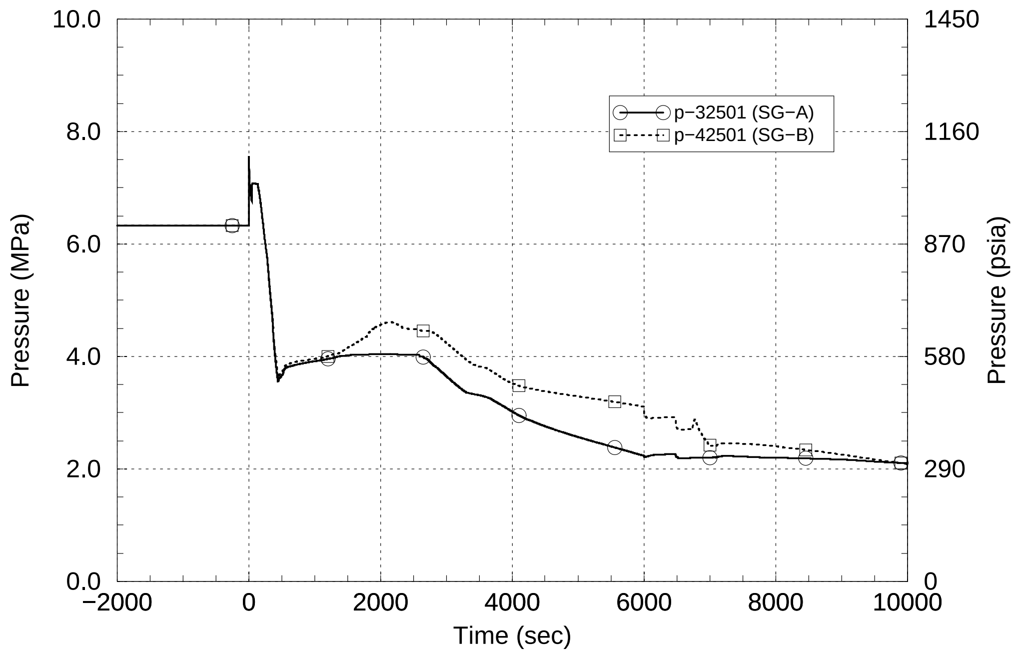


Figure 3.1.2-21 Steam Generator Secondary Pressure - Oconee Case 113

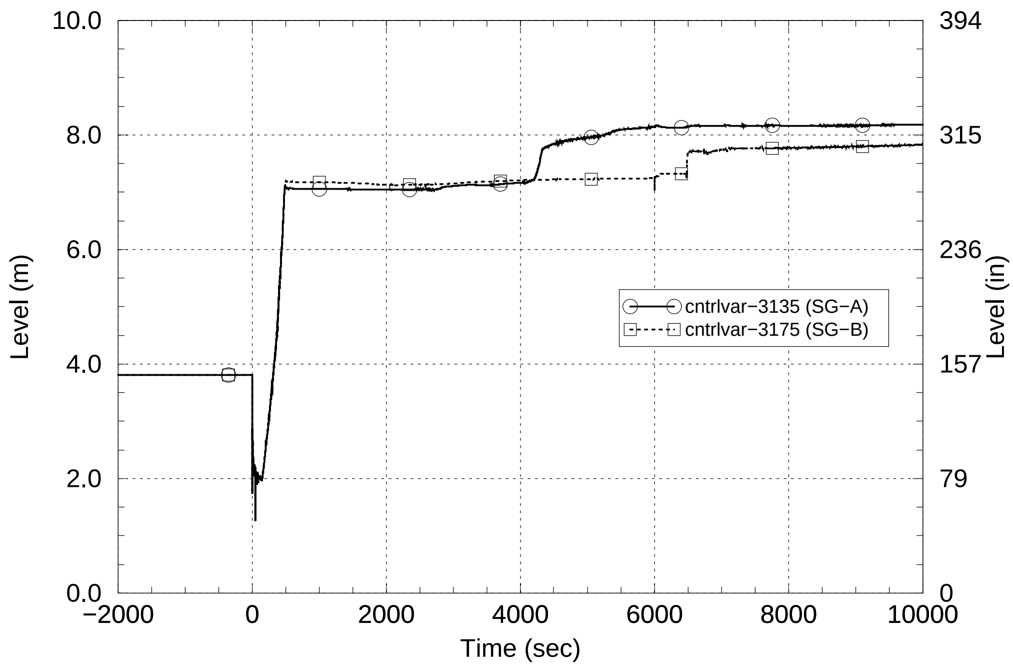


Figure 3.1.2-22 Steam Generator Secondary Startup Level - Oconee Case 113

3.1.2.3 Case 122 - Stuck Open PSV that Recloses at 6,000 s from HZP with Operator Actions

Case 122 is a stuck open pressurizer safety valve that recloses at 6,000 s from hot zero power conditions. In this case, the operator is assumed to throttle HPI at 10 minutes after 2.7 K [5°F] primary system subcooling and when the pressurizer level is over 2.54 m [100 in]. The throttling criteria is 27.8 K [50°F] subcooling. The parameters of interest for the fracture mechanics analysis: primary system pressure, average downcomer fluid temperature, and downcomer fluid-wall heat transfer coefficient are provided in Figures 3.1.2-23 through 3.1.2-25.

As a result of the stuck open pressurizer safety valve, the primary system pressure decreases to about 4.9 MPa [710 psia] in about the first 300 s followed by a continued slower depressurization to about 1.7 MPa [247 psia] at 6,000 s. The downcomer temperature decreases to 516 K [469°F] by 300 s and to about 307 K [92°F] by 6,000 s. Actuation of the HPI system occurs at about 17 s. The operators are assumed to trip the reactor coolant pumps as a result of loss of primary system subcooling at about 110 s. The trip of the reactor coolant pumps causes loss of forced convection in the downcomer which causes the drop in the downcomer wall heat transfer coefficient from a steady state value of 24,713 W/m^2-K [1.21 Btu/s-ft^2-°F] to the values shown in Figure 3.1.2-25.

The pressurizer level is shown in Figure 3.1.2-26. The pressurizer level increases because of level swell due to the stuck open pressurizer safety valve, which is located at the top of the pressurizer. Also, the HPI system is running and filling the pressurizer. The flowrate through the stuck open pressurizer safety valve and the PORV is shown in Figure 3.1.2-27. The total HPI flowrate is shown in Figure 3.1.2-28.

At 6000 s, the pressurizer safety valve recloses and the system pressure starts to increase. The operator starts to throttle HPI at about 7375 s, just after the PORV opening setpoint is reached. After the system pressure peaks, a slow pressure decline occurs and is due to continued operation of the charging/letdown system. About 2.8 kg/s [6.2 lbm/s] is removed while the pressurizer level is above 9.53 m [375 in] and 2.7 K [5°F] subcooling. HPI flow resumes at a low level of about 2.27 kg/s [5 lbm/s] at about 9,430 s and continues for the remainder of the transient. The system pressure stabilizes at about 2.5 MPa [363 psia] at this point.

The core flood tank discharge about 60 percent of the total water volume as seen in Figure 3.1.2-29. It is interesting to note that the core flood tanks do not continue to discharge after about 9,300 s even though the system pressure is below the tank discharge pressure. The reason is that the vessel is filled solid with water at this point, which stops the core flood tank discharge.

The flow in the hot leg is shown in Figure 3.1.2.30. The flow in the A loop hot leg is initially due to the stuck open pressurizer safety valve. When that valve recloses, the hot leg flow generally stops, with occasional flow restarting because the PORV opens or because HPI is restarted.

Figure 3.1.2-31 shows the system energy balance. The capacity of the pressurizer safety valve is more than adequate to remove the system energy in the first 6,000 s. After the valve recloses, the primary system temperature slowly reheats. A small amount of heat is transferred into the primary system from the steam generators after the valves reclose.

The steam generator secondary side pressures are shown in Figure 3.1.2-32. The secondary side pressure decreases due to flow to the steam generator secondary from the feedwater system, which is initiated by the reactor coolant pump trip. This flow is reflected by the increase in steam generator startup level shown in Figure 3.1.2-33.

The minimum downcomer temperature of about 307 K [93°F] was reached by 6,010 s after initiation when the pressurizer safety valve recloses. The corresponding system pressure is about 1.7 MPa [249 psia] at that time, but the system repressurized and then depressurized to a stable pressure of about 2.5 MPa [363 psia] as described above.

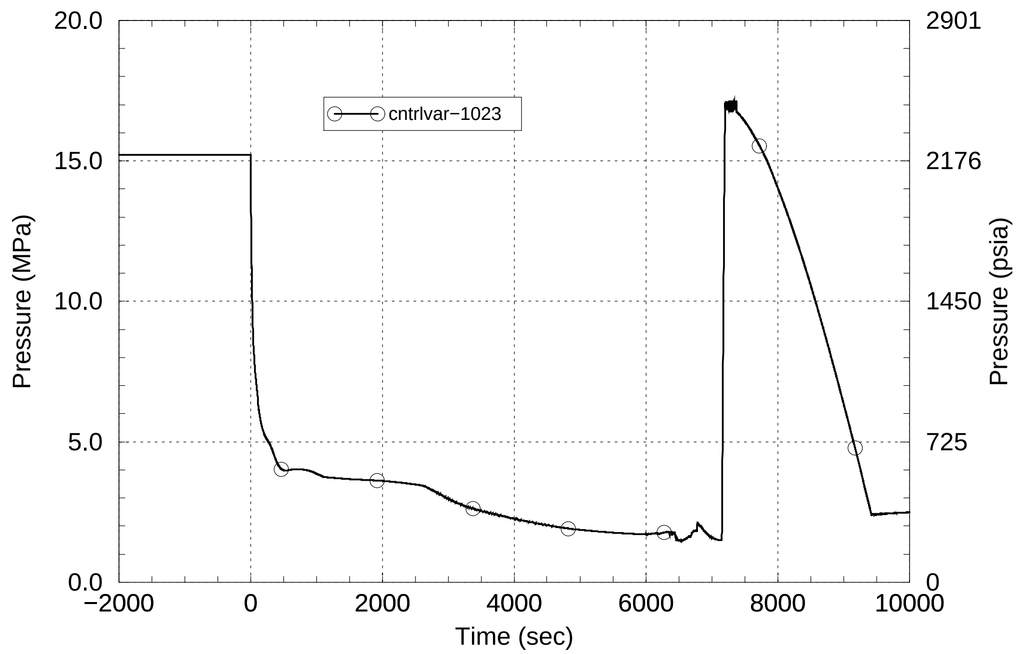


Figure 3.1.2-23 Reactor Coolant System Pressure - Oconee Case 122

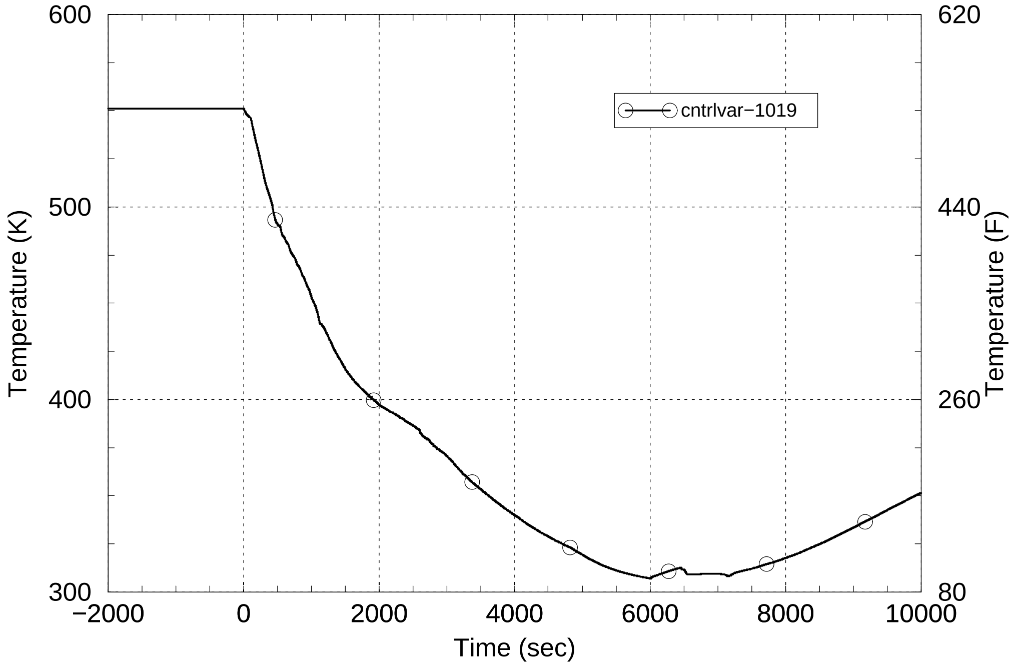


Figure 3.1.2-24   Avg Reactor Vessel Downcomer Temperature - Oconee Case 122

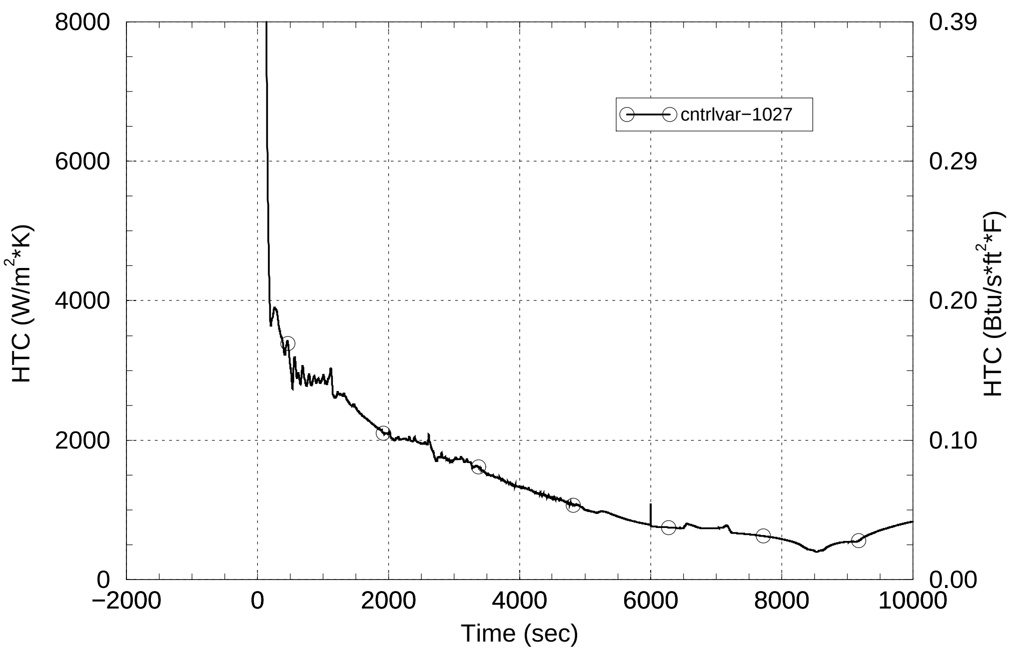


Figure 3.1.2-25   Avg Reactor Vessel Inner Wall Heat Transfer Coefficient - Oconee Case 122

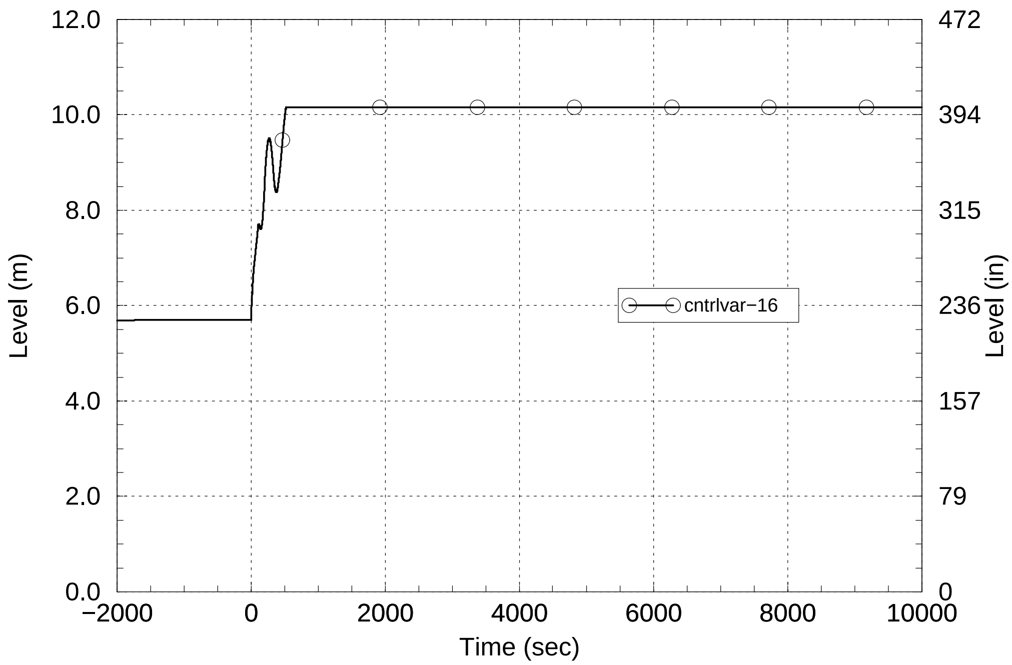


Figure 3.1.2-26 Pressurizer Level - Oconee Case 122

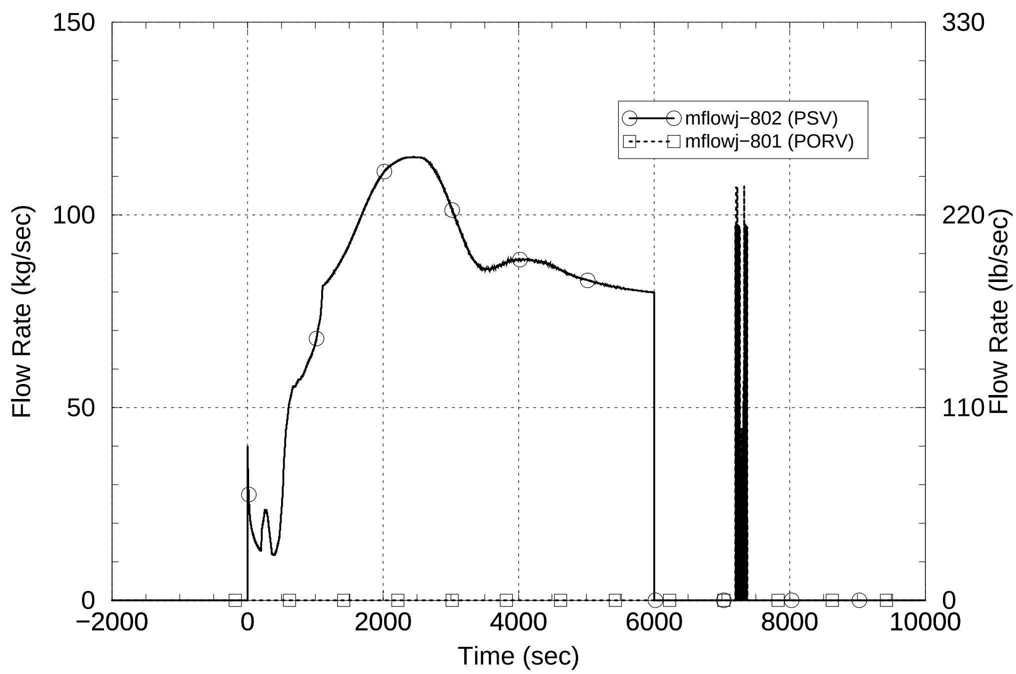


Figure 3.1.2-27 Flowrate through the Stuck Open PSV and PORV - Oconee Case 122

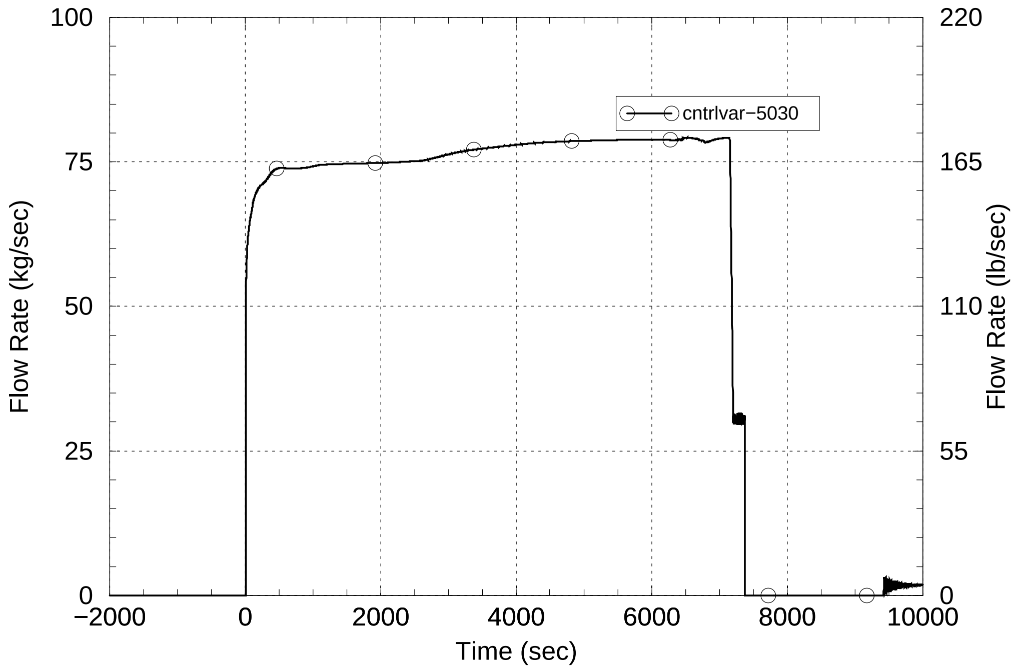


Figure 3.1.2-28 Total High Pressure Injection Flowrate - Oconee Case 122

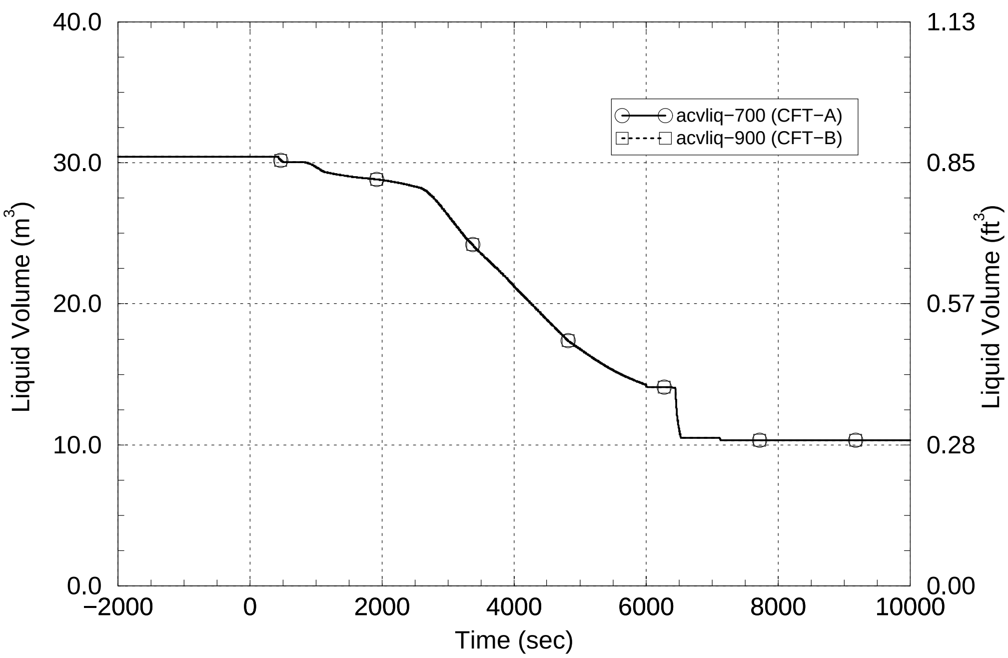


Figure 3.1.2-29 Core Flood Tank Discharge - Oconee Case 122

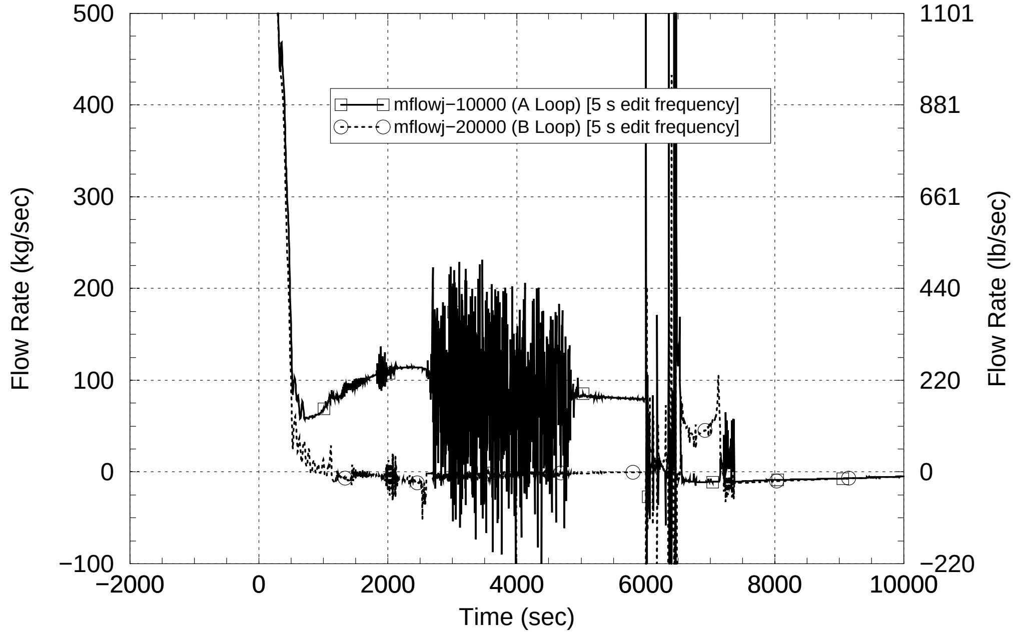


Figure 3.1.2-30 Hot Leg Flow in the A and B Loops - Oconee Case 122

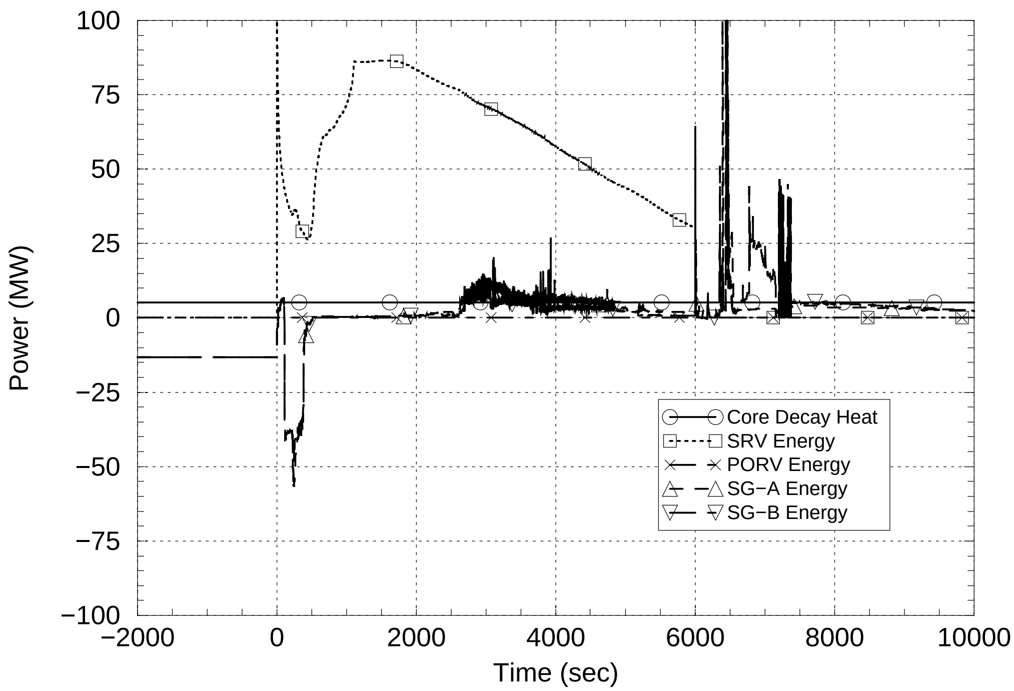


Figure 3.1.2-31 System Energy Balance - Oconee Case 122

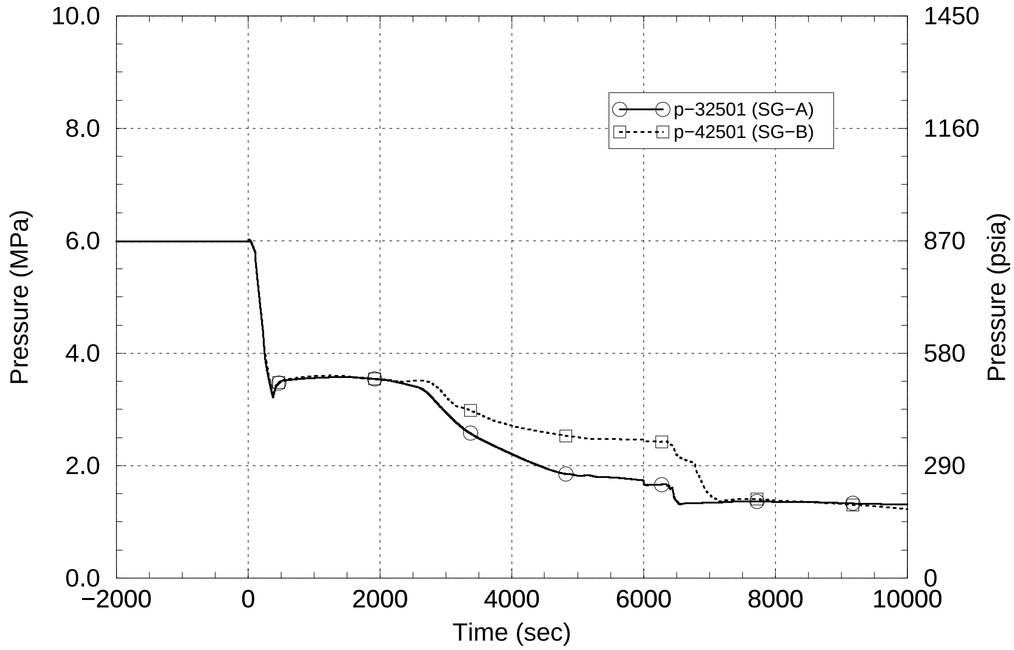


Figure 3.1.2-32 Steam Generator Secondary Pressure - Oconee Case 122

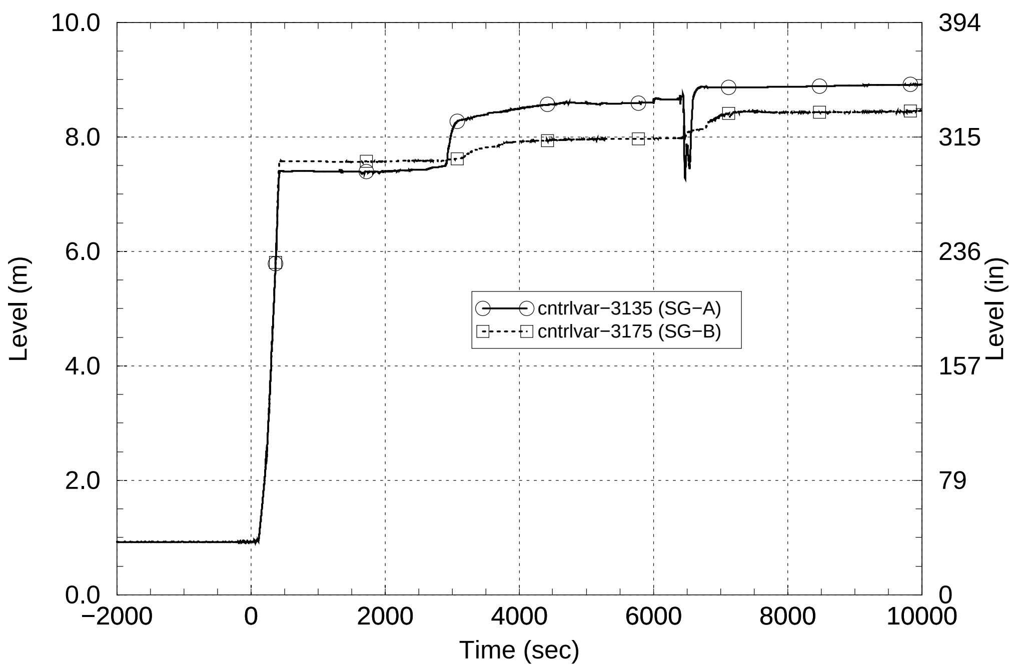


Figure 3.1.2-33 Steam Generator Secondary Startup Level - Oconee Case 122

3.1.2.4 Case 165 - Stuck Open PSV that Recloses at 6,000 s from HZP and No Operator Actions

Case 165 is a stuck open pressurizer safety valve that recloses at 6,000 s from hot zero power conditions. No operator actions are considered in this case. The parameters of interest for the fracture mechanics analysis: primary system pressure, average downcomer fluid temperature, and downcomer fluid-wall heat transfer coefficient are provided in Figures 3.1.2-34 through 3.1.2-36.

As a result of the stuck open pressurizer safety valve, the primary system pressure decreases to about 4.9 MPa [710 psia] in about the first 300 s followed by a continued slower depressurization to about 1.7 MPa [247 psia] at 6,000 s. The downcomer temperature decreases to 516 K [469°F] by 300 s and to about 306 K [91°F] by 6,000 s. Actuation of the HPI system occurs at about 17 s. The operators are assumed to trip the reactor coolant pumps as a result of loss of primary system subcooling at about 110 s. The trip of the reactor coolant pumps causes loss of forced convection in the downcomer which causes the drop in the downcomer wall heat transfer coefficient from the steady state value of 24,112 W/m^2-K [1.18 Btu/s-ft^2-F] to the values shown in Figure 3.1.2-36.

The pressurizer level is shown in Figure 3.1.2-37. The pressurizer level increases because of level swell due to the stuck open pressurizer safety valve, which is located at the top of the pressurizer. Also, the HPI system is running and filling the pressurizer. The flowrate through the stuck open pressurizer safety valve and the PORV is shown in Figure 3.1.2-38. The total HPI flowrate is shown in Figure 3.1.2-39.

At 6000 s, the pressurizer safety valve recloses and the system pressure starts to increase. The PORV opening setpoint is reached at about 7,180 s. System pressure remains relatively stable after that point which causes a reduction in the HPI flow as seen in Figure 3.1.2-39. The system pressure stabilizes at about 17.0 MPa [2,465 psia].

The core flood tank discharge about 60 percent of the total water volume as seen in Figure 3.1.2-40. The flow in the hot leg is shown in Figure 3.1.2.41. The flow in the A loop hot leg is due to the stuck open pressurizer safety valve. When that valve recloses, the hot leg flow stops and then restarts due to system repressurization resulting in flow through the PORV due to continued HPI operation.

Figure 3.1.2-42 shows the system energy balance. The capacity of the pressurizer safety valve is more than adequate to remove the system energy in the first 6,000 s. After the valve recloses, the primary system temperature slowly reheats. A small amount of heat is transferred into the primary system from the steam generators after the valves reclose.

The steam generator secondary side pressures are shown in Figure 3.1.2-43. The secondary side pressure decreases due to flow to the steam generator secondary from the feedwater system, which is initiated by the reactor coolant pump trip. This flow is reflected by the increase in steam generator startup level shown in Figure 3.1.2-44.

The minimum downcomer temperature of about 306 K [91 °F] was reached by 6,010 s after initiation when the pressurizer safety valve recloses. The corresponding system pressure is about 1.8 MPa [261 psia] at that time, but the system repressurized to a stable pressure of about 17.0 MPa [2465 psia] as described above.

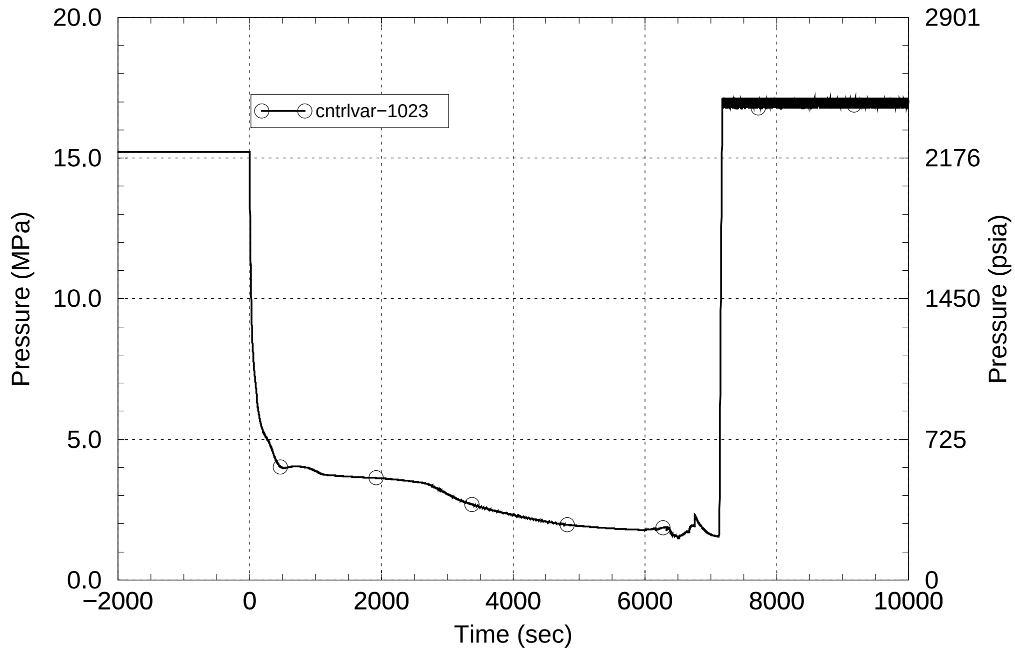


Figure 3.1.2-34 Reactor Coolant System Pressure - Oconee Case 165

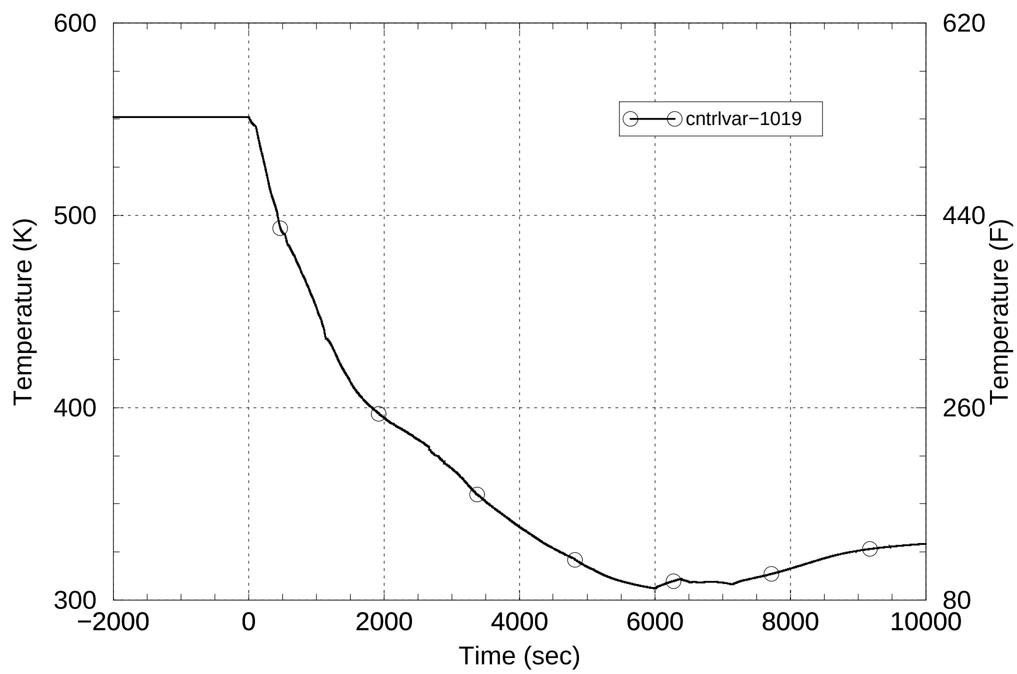


Figure 3.1.2-35 Avg Reactor Vessel Downcomer Temperature - Oconee Case 165

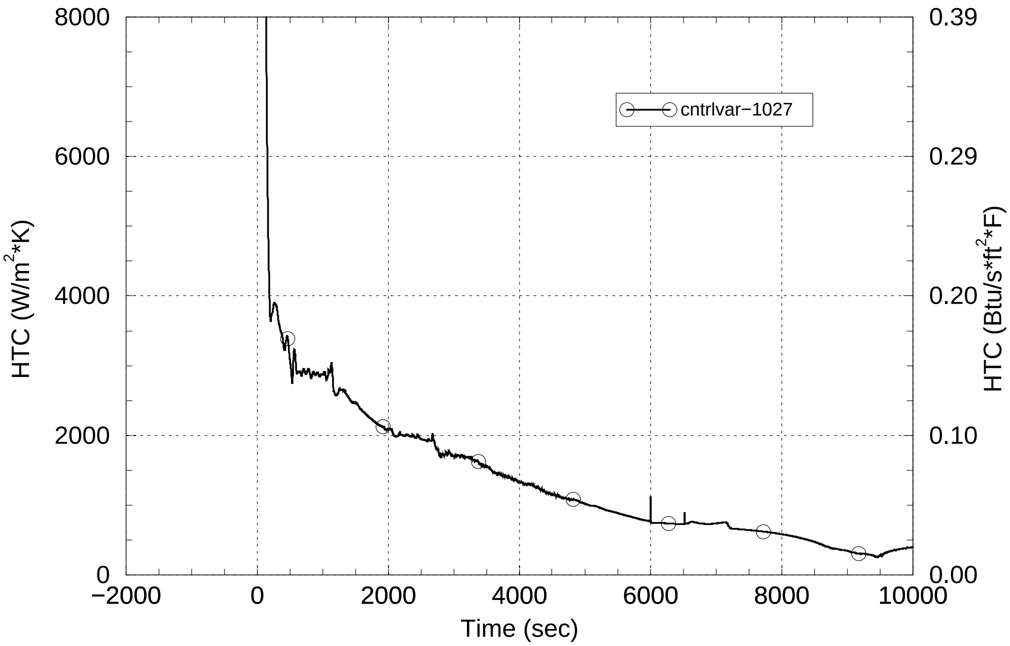


Figure 3.1.2-36 Avg Reactor Vessel Inner Wall Heat Transfer Coefficient - Oconee Case 165

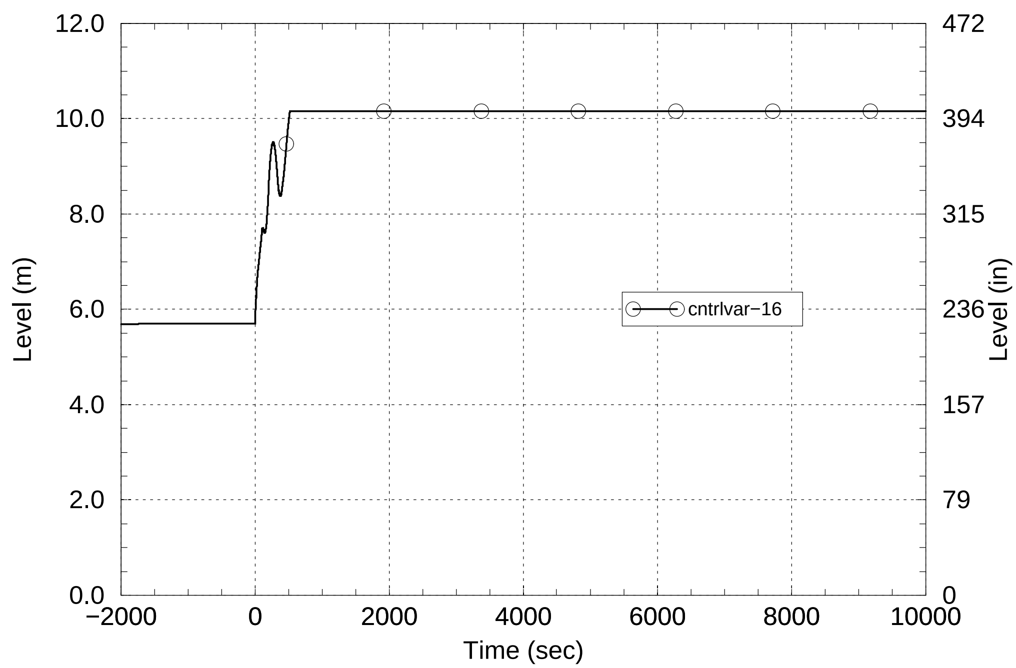


Figure 3.1.2-37 Pressurizer Level - Oconee Case 165

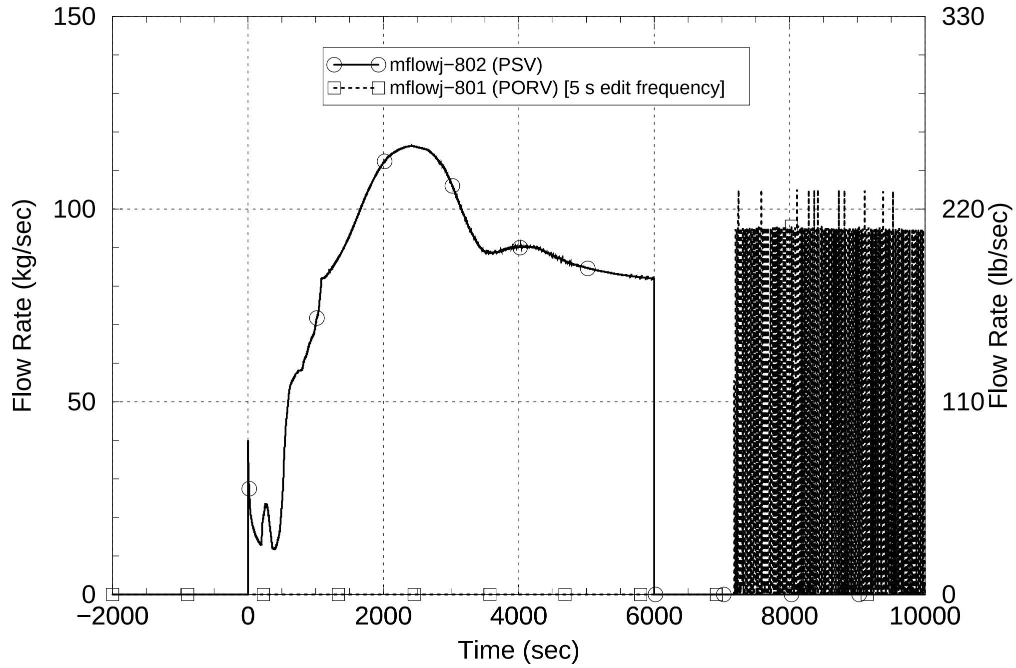


Figure 3.1.2-38 Flowrate through the Stuck Open PSV and PORV - Oconee Case 165

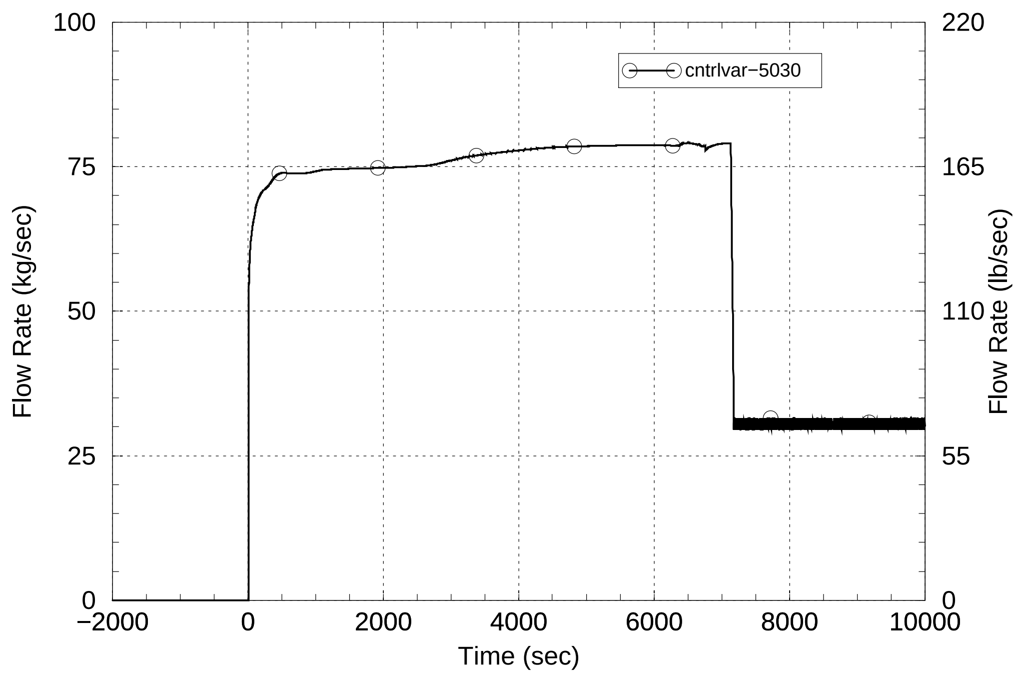


Figure 3.1.2-39 Total High Pressure Injection Flowrate - Oconee Case 165

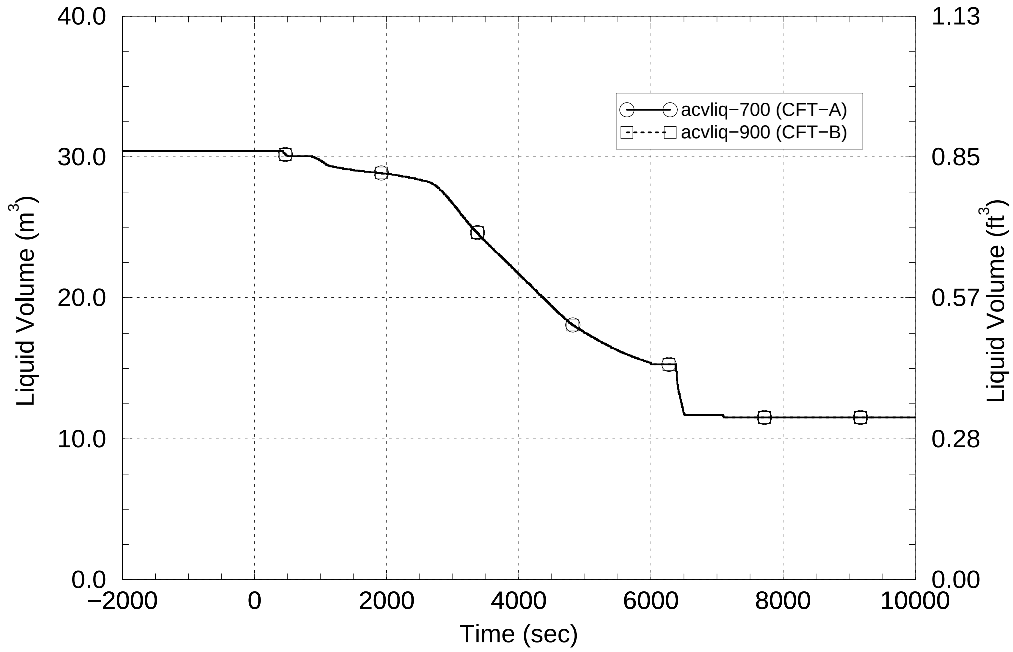


Figure 3.1.2-40 Core Flood Tank Discharge - Oconee Case 165

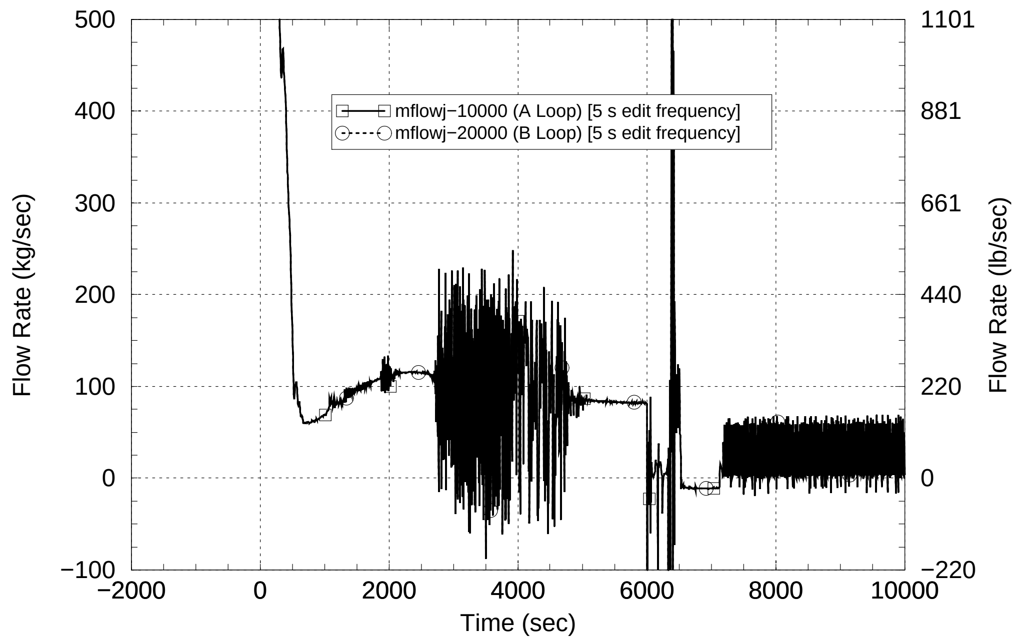


Figure 3.1.2-41 Hot Leg Flow in the A and B Loops - Oconee Case 165

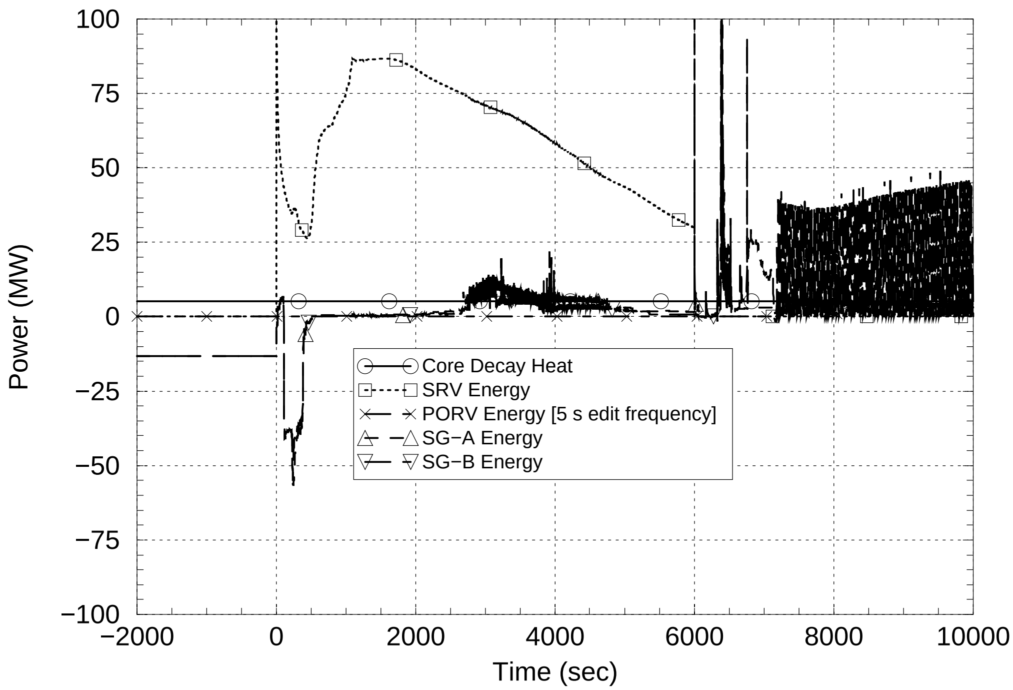


Figure 3.1.2-42 System Energy Balance - Oconee Case 165

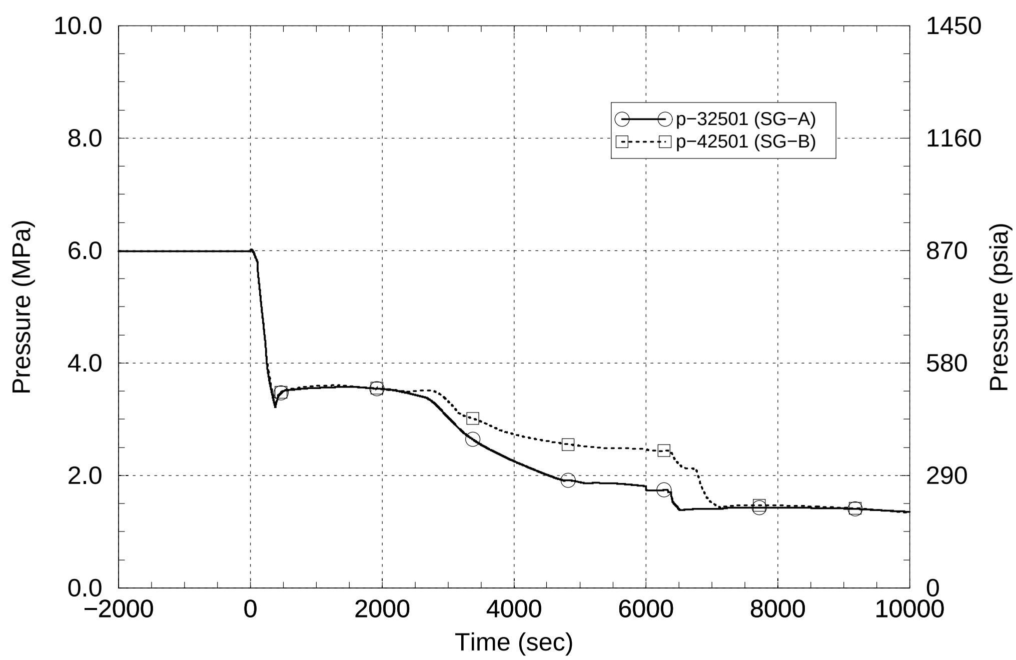


Figure 3.1.2-43 Steam Generator Secondary Pressure - Oconee Case 165

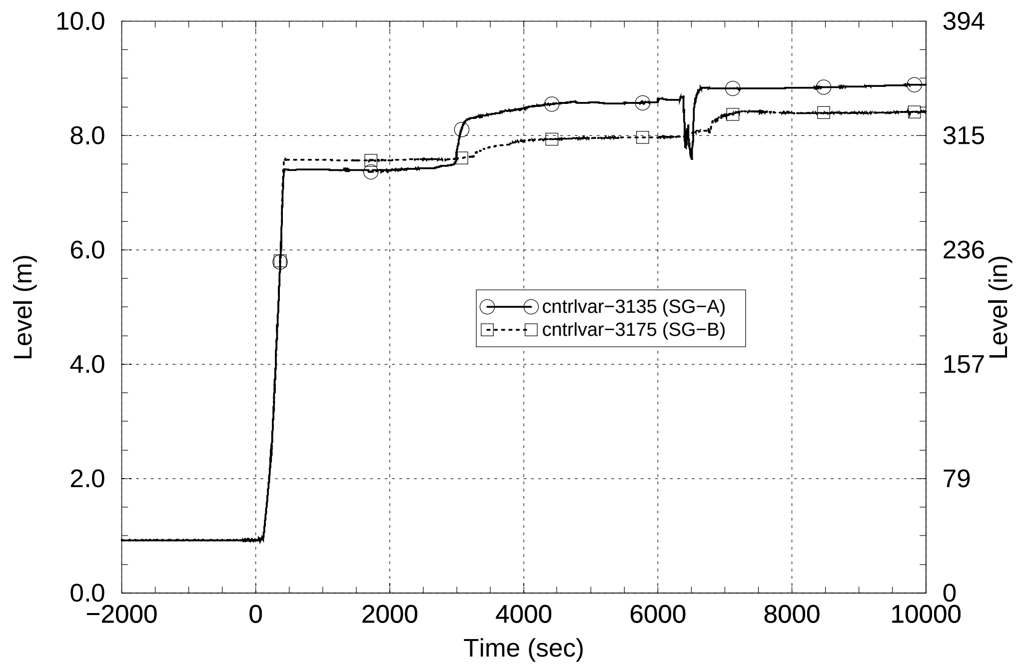


Figure 3.1.2-44 Steam Generator Secondary Startup Level - Oconee Case 165

3.1.3 Sequences with Stuck Open Pressurizer Safety Valve that Reclose at 3,000 Seconds

Sequences involving stuck open primary safety valves that subsequently reclose after 3,000 s are presented in this section. The sequences selected for discussion are Case 115 and Case 124. These cases are described below:

- Case 115 involves a stuck open pressurizer safety valve that recloses at 3,000 s from hot full power conditions. After the valve recloses, the operator throttles HPI 10 minutes after 2.7 K [5°F] subcooling and 254 cm [100 in] pressurizer level is reached. The throttling criteria is 27.8 K [50°F] subcooling.
- Case 124 involves a stuck open pressurizer safety valve that recloses at 3,000 s from hot zero power conditions. After the valve recloses, the operator throttles HPI 10 minutes after 2.7 K [5°F] subcooling and 254 cm [100 in] pressurizer level is reached. The throttling criteria is 27.8 K [50°F] subcooling.

The pressurizer safety valve is assumed to open at sequence initiation due to a spontaneous failure and recloses at 3,000 s after initiation. The operator is assumed to trip the reactor coolant pumps when primary system subcooling is lost. A trip criteria of 0.27 K [0.5°F] is assumed for the hot full power cases. For the hot zero power case, the trip criteria was raised to 3.9 K [7°F] to cause a reactor coolant pump trip. Note that the stuck open pressurizer safety valve is assumed to not sufficiently pressurize the containment to reach the setpoint at which containment sprays start. As a result, the HPI injection temperature remains constant for the duration of the event. A tabulation of the timing of key events for these transients are listed in Table 3.1-3.

Table 3.1-3 Comparison of Event Timing for Sequences with a Stuck Open PSV that Recloses in 3000 Seconds

	Event Timing (seconds)	
	Case 115 stuck open PZR SRV that recloses at 3000 seconds. Operator throttles HPI.	Case 124 stuck open PZR SRV that recloses at 3000 seconds. Operator throttles HPI.
Reactor Power Level	HFP	HZP
Reactor scram	14	N/A
RCP trip time on loss of subcooling margin	141	110
HPI actuates	18	17
Time that operator throttles HPI	4690	4430
Core flood tank discharge start time	2750	875
Low pressure injection starts	does not start	does not start
Core flood tank discharge stops	3020	4030
Time that vent valves open	240	455
ECCS Switchover time	does not occur	does not occur

3.1.3.1 Case 115 - Stuck Open PSV that Recloses at 3,000 s from HFP and No Operator Actions

Case 115 is a stuck open pressurizer safety valve that recloses at 3,000 s from hot full power conditions. In this case, the operator is assumed to throttle HPI at 10 minutes after 2.7 K [5°F] primary system subcooling and when the pressurizer level is over 2.54 m [100 in]. The throttling criteria is 27.8 K [50°F] subcooling. The parameters of interest for the fracture mechanics analysis: primary system pressure, average downcomer fluid temperature, and downcomer fluid-wall heat transfer coefficient are provided in Figures 3.1.3-1 through 3.1.3-3.

As a result of the stuck open pressurizer safety valve, primary system pressure decreases to about 7.2 MPa [1044 psia] in the first 300 s followed by a continued slower depressurization to about 3.7 MPa [537 psia] at 3,000 s. The downcomer temperature decreases to 545 K [521°F] by 300 s and to about 450 K [350°F] by 3,000 s. Reactor trip occurs within 1 s, followed by actuation of the HPI system at about 18 s. The operators are assumed to trip the reactor coolant pumps as a result of loss of primary system subcooling at about 141 s. The trip of the reactor coolant pumps causes loss of forced convection in the downcomer which causes the drop in the downcomer wall heat transfer coefficient from a steady state value of 24,112 W/m^2-K [1.18 Btu/s-ft^2-°F] to the values shown in Figure 3.1.3-3.

The pressurizer level is shown in Figure 3.1.3-4. The pressurizer level increases because of level swell due to the stuck open pressurizer safety valve, which is located at the top of the pressurizer.

Also, the HPI system is running and filling the pressurizer. The flowrate through the stuck open pressurizer safety valve and the PORV is shown in Figure 3.1.3-5. The total HPI flowrate is shown in Figure 3.1.3-6.

At 3000 s, the pressurizer safety valve recloses and the system pressure starts to increase. The operator starts to throttle HPI at about 4690 s, which is 10 minutes after the time that the above mentioned throttling criteria are met and just before the PORV opening setpoint is reached. If the throttling criteria of 27.8 K [50°F] is exceeded, the HPI is throttled back in order to regain control of subcooling.

The pressure and temperature excursions that occur after about 6,600 s after sequence initiation is due to the momentary startup and decay of natural circulation flow in the primary loops. This startup and decay of loop circulation is caused by the slow heatup of the primary system. The primary system is at high pressure and relatively low temperature because of the cooldown during the period when the pressurizer safety valve is stuck open. As the primary system heats up in the section of the hot leg near the vessel, the temperature increases in that section to 310 K [100°F] or more above the temperature of the liquid in the candy cane section of the hot leg. This temperature creates enough buoyancy to start the loop flow, which cools the primary system and interrupts the flow. Then, the heatup cycle is repeated. This behavior likely occurs in SG-A more than SG-B because the pressurizer with the PORV that opens intermittently is on this loop.

The core flood tanks discharge a small fraction of the total water volume as seen in Figure 3.1.3-7. Basically, there is a small time window of about 240 s between the time that the tanks start to discharge and the pressurizer safety valve recloses and repressurizes the system. Note that there is no LPI flow in this case because the primary system pressure never falls below the LPI pump shutoff head of 1.48 MPa [214 psia].

The flow in the hot leg is shown in Figure 3.1.3.8. The flow in the A loop hot leg is initially due to the stuck open pressurizer safety valve. When that valve recloses, hot leg flow spikes occur due to the opening of the PORV up to about 6,600 s. At that point, the first cycle of the momentary startup of natural circulation flow occurs followed by hot leg flow spikes as the PORV cycles. A second cycle of momentary natural circulation occurs at about 8,000 s followed by a third cycle at about 9,000 s. A fourth cycle is starting at the end of the transient. Note that the HPI flow is throttled back to near zero up to the point where natural circulation flow starts, except for three injection cycles corresponding to the times when momentary natural circulation occurs.

Figure 3.1.3-9 shows the system energy balance. The core decay heat energy is removed initially by the stuck open pressurizer safety valve. When the valve recloses, energy is removed through the PORV after the system repressurizes to the PORV setpoint. Some heat is transferred out of the primary when the PORV opens. When the HPI flow restarts, some heat is transferred out of the primary system to the steam generator (negative values) due to the periodic natural circulation situation described above. Once natural circulation starts at about 10,000 s, energy is transferred to the secondary of the Loop A steam generator.

The steam generator secondary side pressures are shown in Figure 3.1.3-10. The pressure spike at the beginning of the simulation is due to the closure of the turbine stop valves. The secondary side pressure decreases due to flow to the steam generator secondary from the feedwater system, which is initiated by the reactor coolant pump trip. This flow is reflected by the increase in steam generator startup levels shown in Figure 3.1.3-11. Note that the pressure increases in the secondary of SG-A to about 7.0 MPa [1015 psia] due to the transfer of heat from the primary due to the periodic natural circulation situation described above.

The minimum downcomer temperature of about 433 K [320°F] was reached by 3,010 s after initiation when the pressurizer safety valve recloses. The corresponding system pressure is about 3.7 MPa [537 psia] at that time, but the system repressurized to about the opening pressure of the PORV and remains at that level except during periods where pressure dips occur due to natural circulation startup and decay.

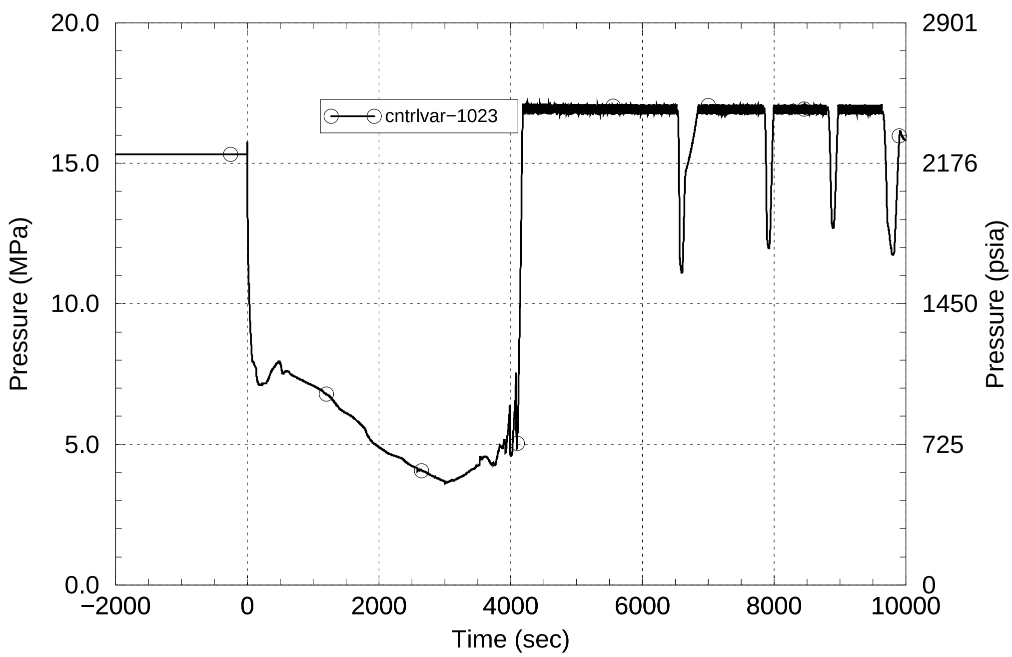


Figure 3.1.3-1 Reactor Coolant System Pressure - Oconee Case 115

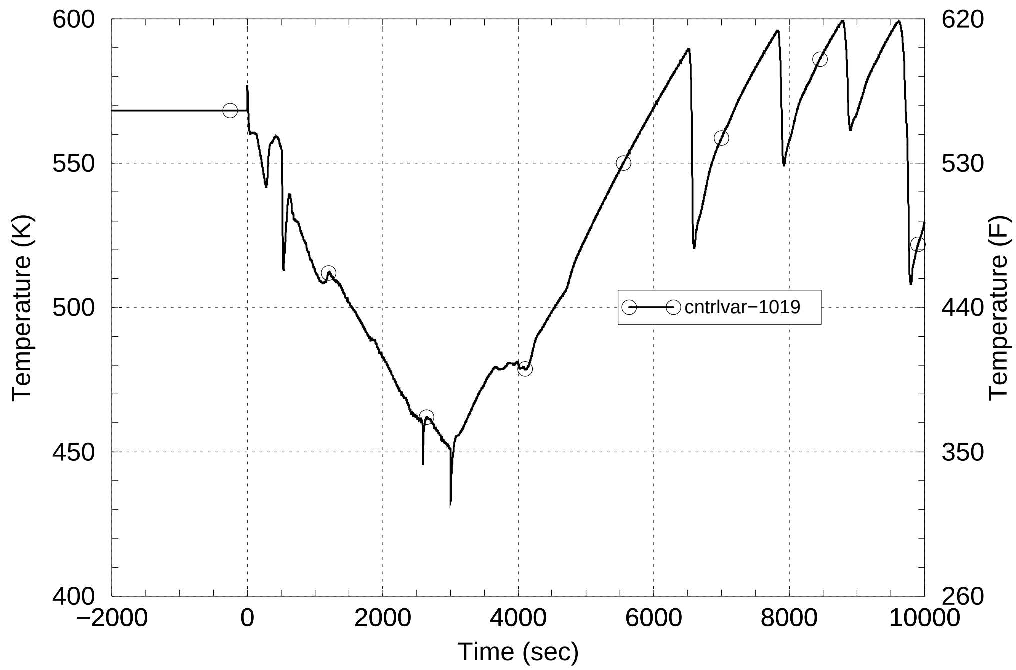


Figure 3.1.3-2 Avg Reactor Vessel Downcomer Temperature - Oconee Case 115

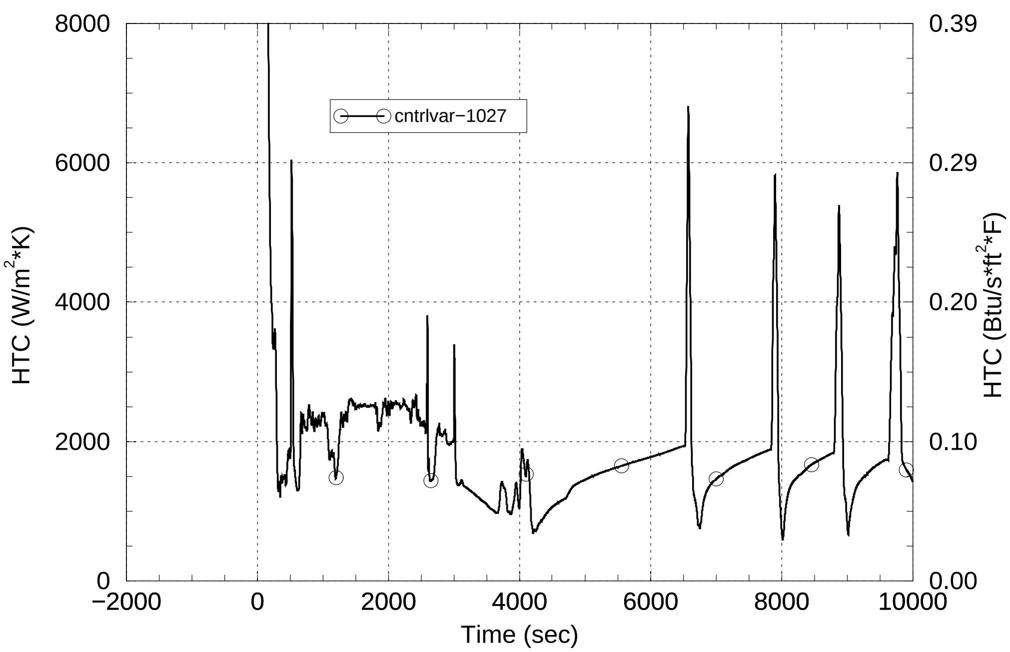


Figure 3.1.3-3 Avg Reactor Vessel Inner Wall Heat Transfer Coefficient - Oconee Case 115

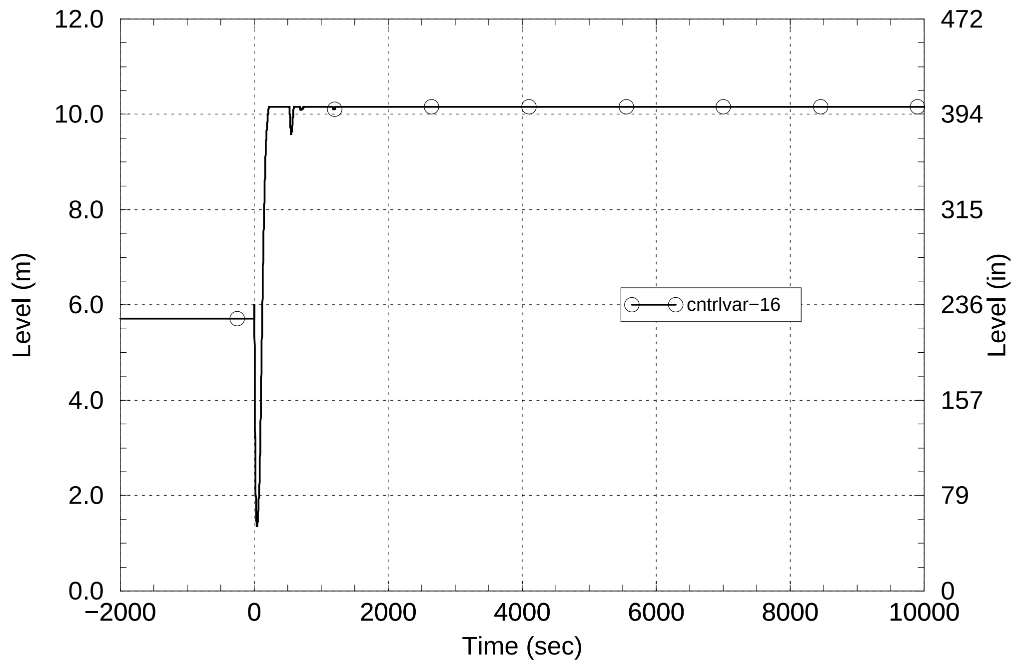


Figure 3.1.3-4   Pressurizer Level - Oconee Case 115

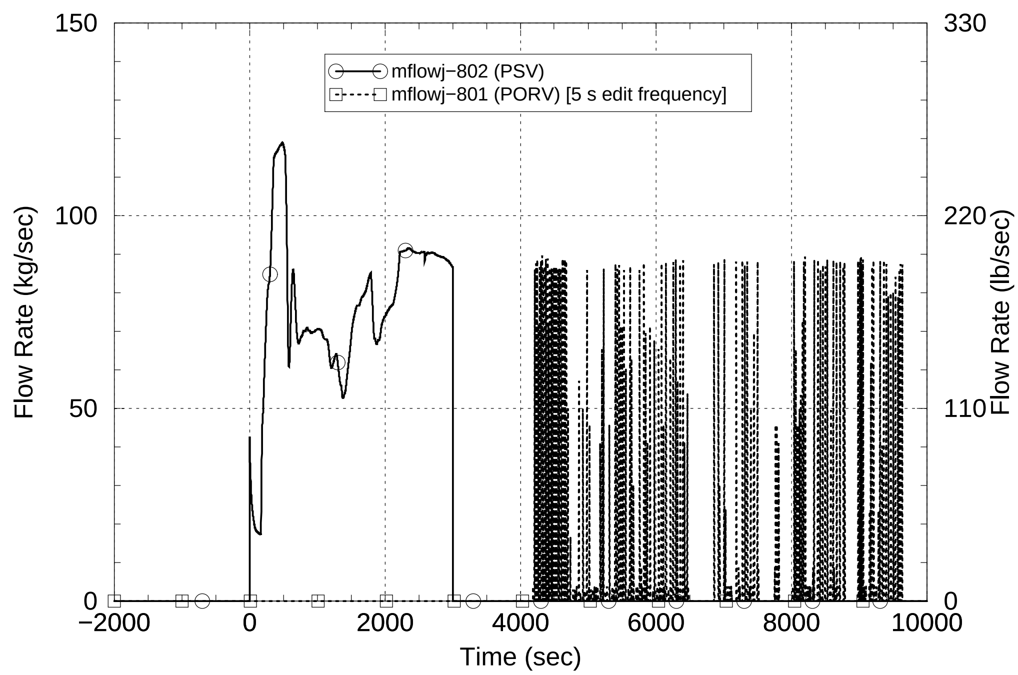


Figure 3.1.3-5   Flowrate through the Stuck Open PSV and PORV - Oconee Case 115

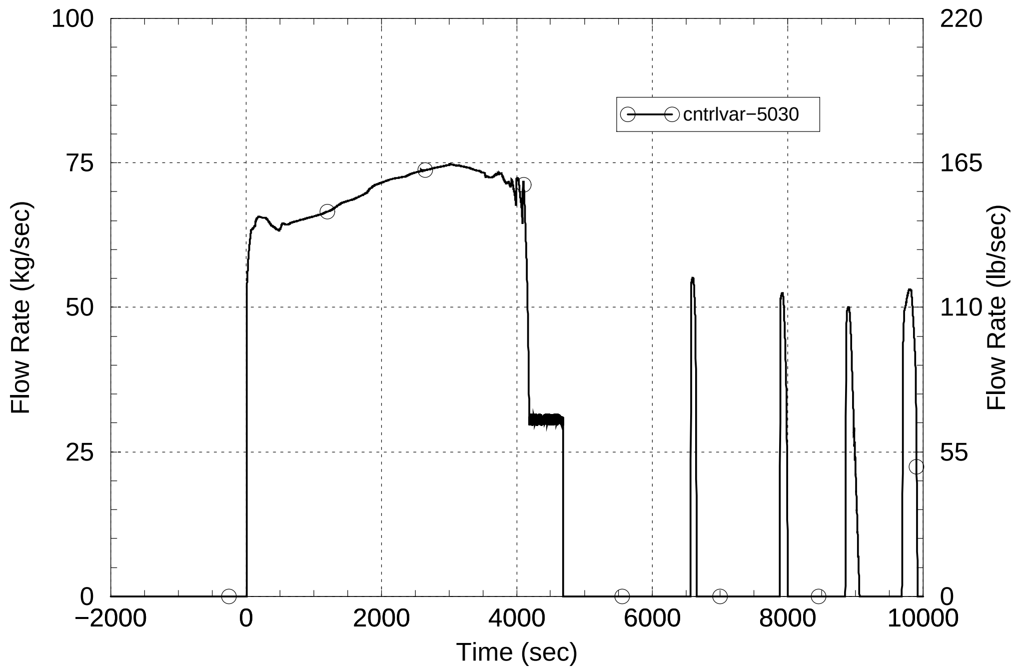


Figure 3.1.3-6 Total High Pressure Injection Flowrate - Oconee Case 115

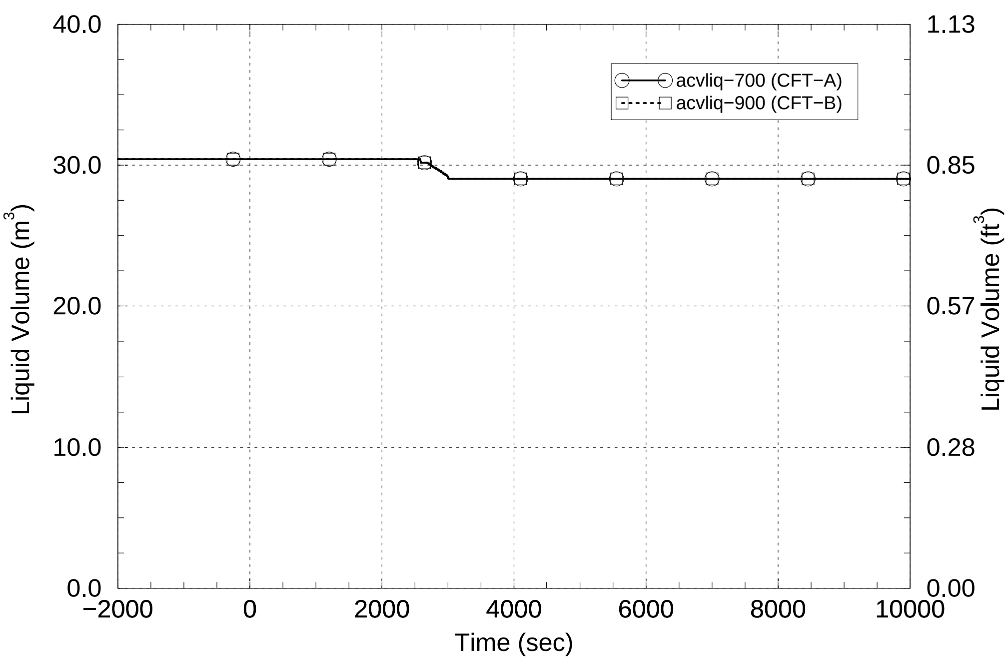


Figure 3.1.3-7 Core Flood Tank Discharge - Oconee Case 115

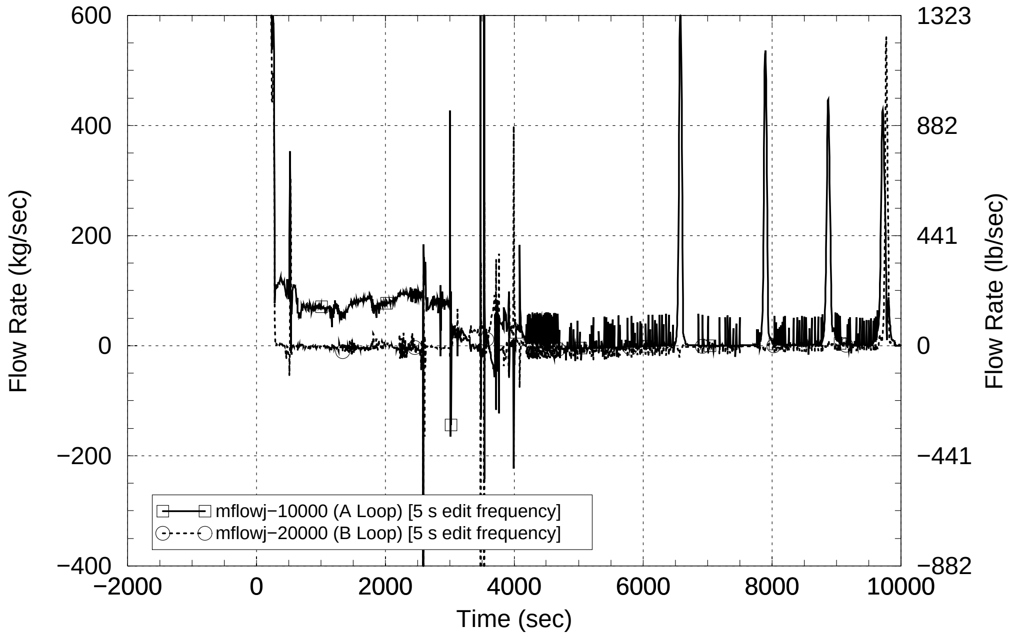


Figure 3.1.3-8   Hot Leg Flow in the A and B Loops - Oconee Case 115

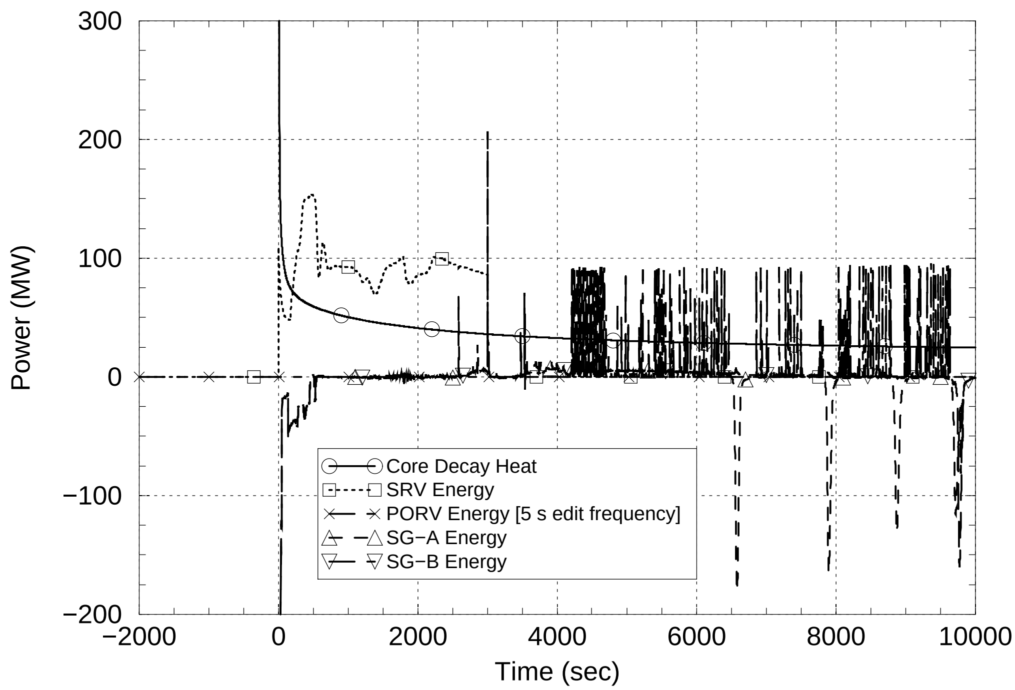


Figure 3.1.3-9   System Energy Balance - Oconee Case 115

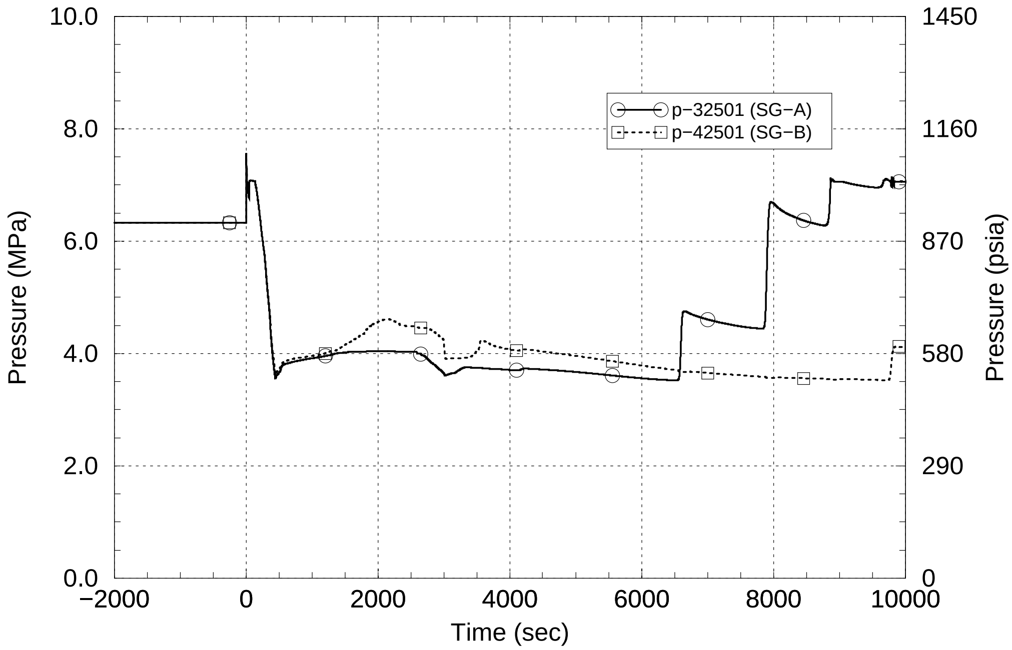


Figure 3.1.3-10 Steam Generator Secondary Pressure - Oconee Case 115

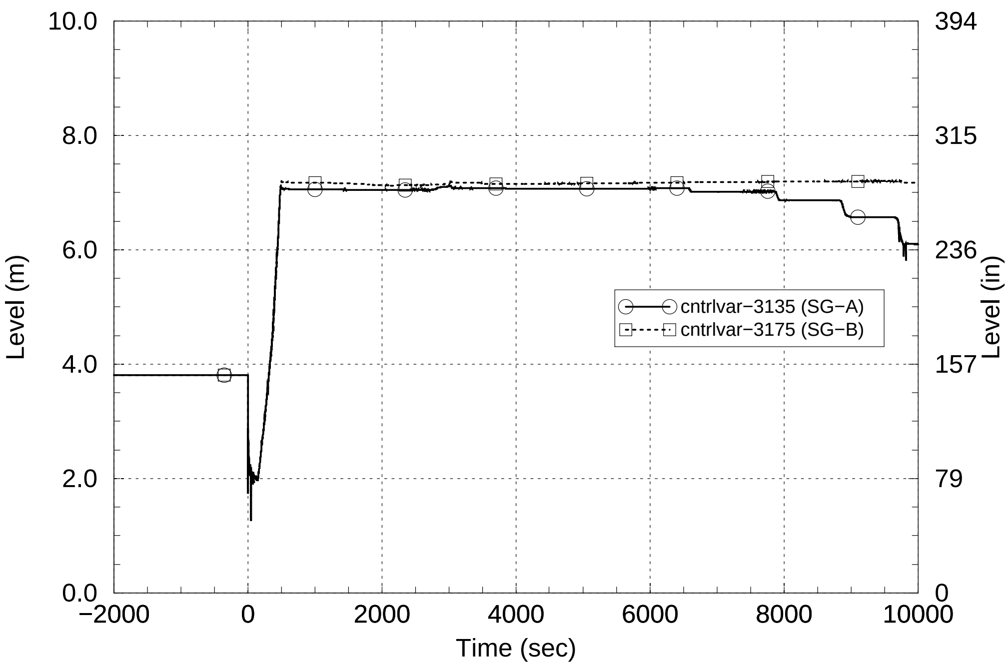


Figure 3.1.3-11 Steam Generator Secondary Startup Level - Oconee Case 115

3.1.3.2 Case 124 - Stuck Open PSV that Recloses at 3,000 s from HZP with Operator Actions

Case 124 is a stuck open pressurizer safety valve that recloses at 3,000 s from hot zero power conditions. In this case, the operator is assumed to throttle HPI at 10 minutes after 2.7 K [5°F] primary system subcooling and when the pressurizer level is over 2.54 m [100 in]. The throttling criteria is 27.8 K [50°F] subcooling. The parameters of interest for the fracture mechanics analysis: primary system pressure, average downcomer fluid temperature, and downcomer fluid-wall heat transfer coefficient are provided in Figures 3.1.3-12 through 3.1.3-14.

As a result of the stuck open pressurizer safety valve, primary system pressure decreases to about 4.8 MPa [700 psia] in about the first 300 s followed by a continued slower depressurization to about 3.0 MPa [435 psia] at 3,000 s. The downcomer temperature decreases to 516 K [468°F] by 300 s and to about 371 K [208°F] by 3,000 s. Actuation of the HPI system occurs at about 17 s. The operators are assumed to trip the reactor coolant pumps as a result of loss of primary system subcooling at about 110 s. The trip of the reactor coolant pumps causes loss of forced convection in the downcomer which causes the drop in the downcomer wall heat transfer coefficient from the steady state value of 24,713 W/m^2-K [1.21 Btu/s-ft^2-°F] to the values shown in Figure 3.1.3-14.

The pressurizer level is shown in Figure 3.1.3-15. The pressurizer level increases because of level swell due to the stuck open pressurizer safety valve, which is located at the top of the pressurizer. Also, the HPI system is running and filling the pressurizer. The flowrate through the stuck open pressurizer safety valve and the PORV is shown in Figure 3.1.3-16. The total HPI flowrate is shown in Figure 3.1.3-17.

At 3000 s, the pressurizer safety valve recloses and continued HPI operation causes the system pressure to start to increase at about 4,100 s to the PORV setpoint. The operator starts to throttle HPI at about 4430 s, which is 10 minutes after the time that the above mentioned throttling criteria are met and just after the PORV opening setpoint is reached. The PORV opens for a short duration at about 4,100 s as shown in Figure 3.1.3-16. After the system pressure peaks, a slow pressure decline occurs and is due to continued operation of the charging/letdown system. About 2.8 kg/s [6.2 lbm/s] is removed while the pressurizer level is above 9.53 m [375 in] and 2.7 K [5°F] subcooling. HPI flow resumes at a low level of about 2.27 kg/s [5 lbm/s] at about 7,300 s and continues for the remainder of the transient. The system pressure stabilizes at about 4.6 MPa [667 psia] at this point.

The core flood tanks discharge about 15 percent of the total water volume as seen in Figure 3.1.3-18. At about 4000 s, the discharge stops because the pressurizer safety valve reclosed and the system repressurized. Note that there is no LPI flow in this case because the system pressure never dropped below the shutoff head of the LPI pumps.

The flow in the hot leg is shown in Figure 3.1.3.19. The flow in the A loop hot leg is initially due to the stuck open pressurizer safety valve. When that valve recloses, the hot leg flow generally stops, with flow restarting when the PORV opens.

Figure 3.1.3-20 shows the system energy balance. The capacity of the pressurizer safety valve is more than adequate to remove the system energy during the first 3,000 s. After the valve recloses, the system slowly reheats. A small amount of heat is transferred into the primary system from the steam generators after the valves reclose.

The steam generator secondary side pressures are shown in Figure 3.1.3-21. The secondary side pressure decreases due to flow to the steam generator secondary from the feedwater system, which is initiated by the reactor coolant pump trip. This flow is reflected by the increase in steam generator startup level shown in Figure 3.1.3-22.

The minimum downcomer temperature of about 360 K [188°F] was reached by 4,000 s after the pressurizer safety valve recloses. The corresponding system pressure is about 2.8 MPa [406 psia] at that time, but the system repressurized and then depressurized to a stable pressure of about 4.6 MPa [667 psia].

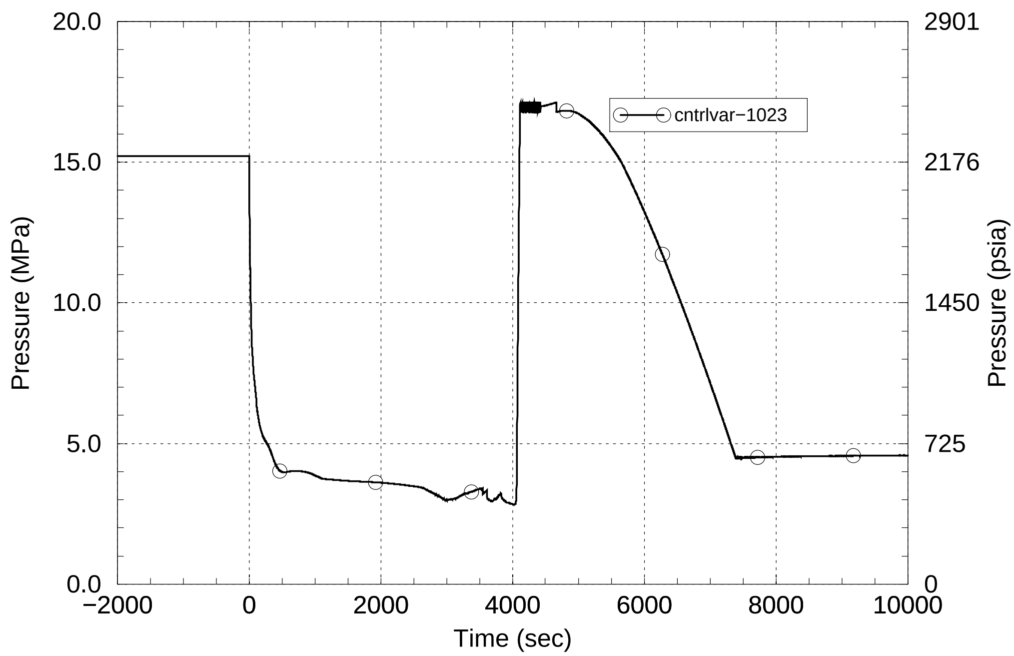


Figure 3.1.3-12 Reactor Coolant System Pressure - Oconee Case 124

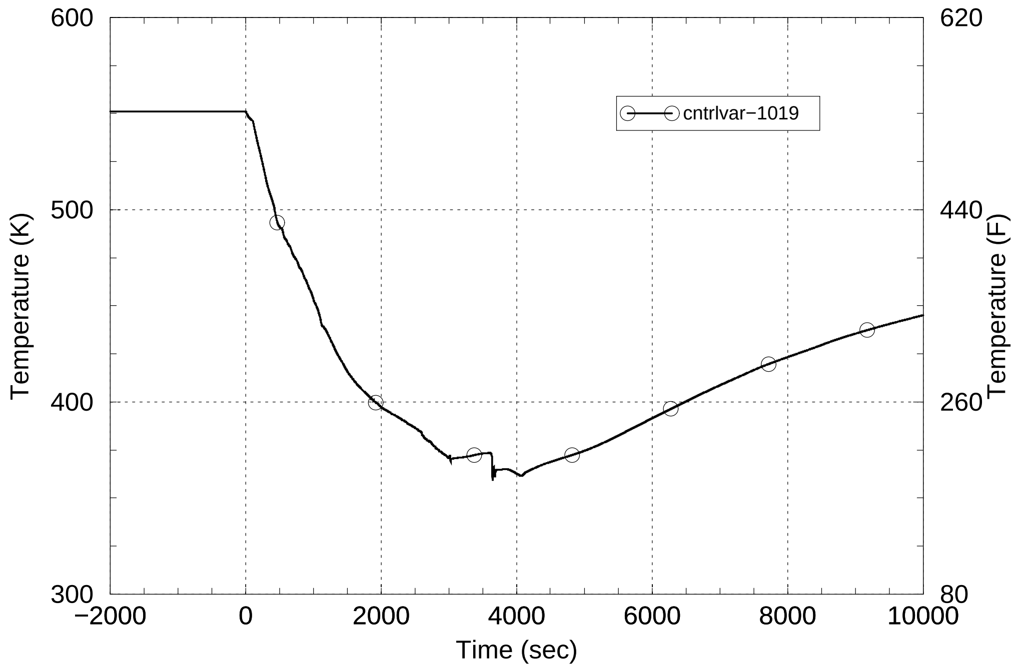


Figure 3.1.3-13 Avg Reactor Vessel Downcomer Temperature - Oconee Case 124

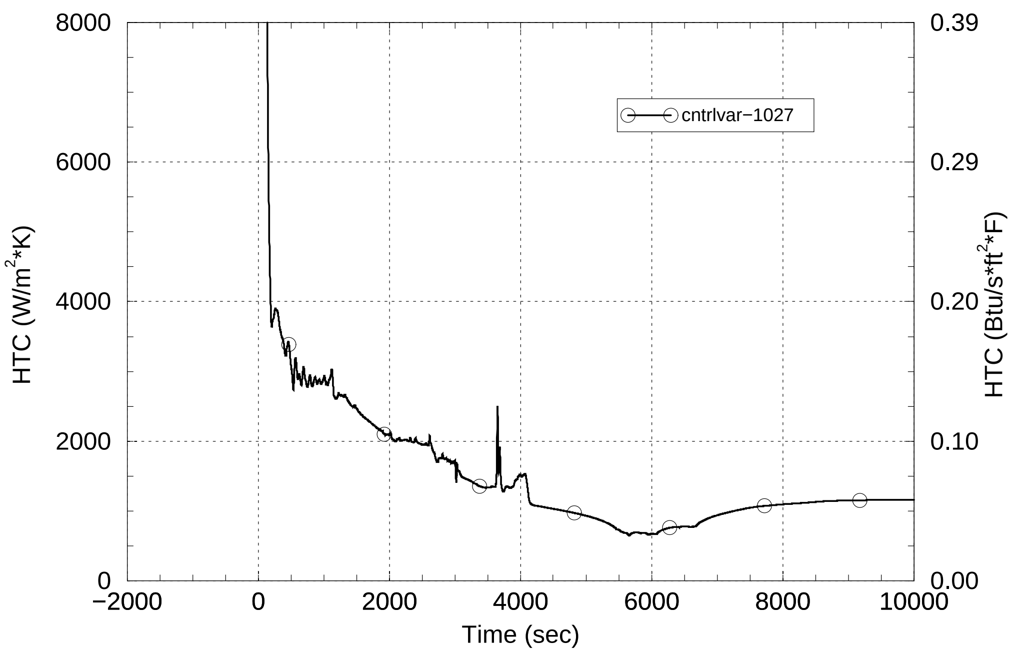


Figure 3.1.3-14 Avg Reactor Vessel Inner Wall Heat Transfer Coefficient - Oconee Case 124

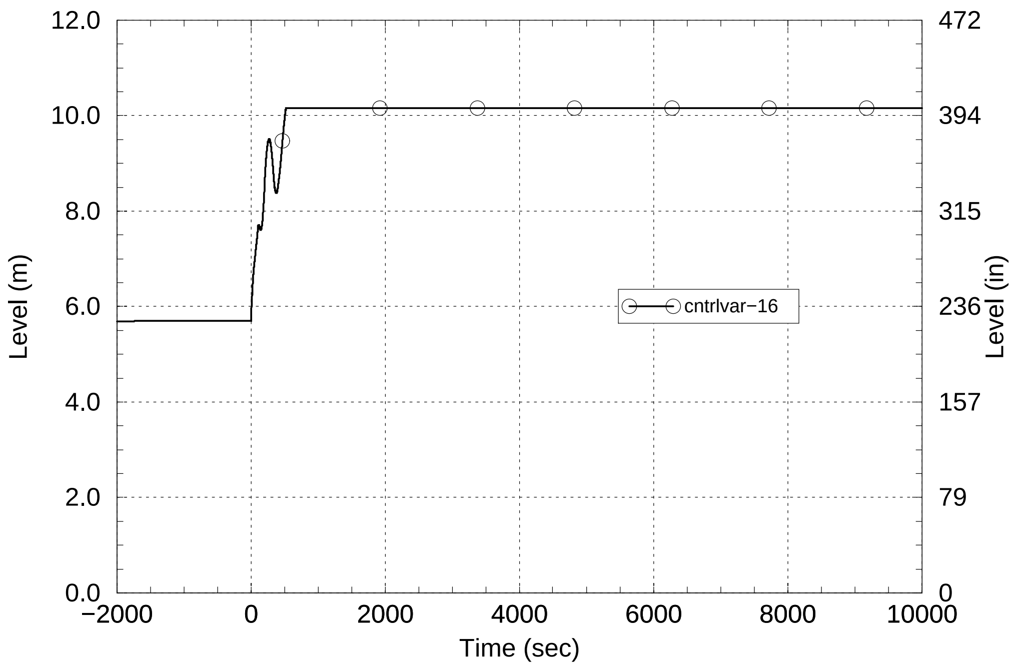


Figure 3.1.3-15 Pressurizer Level - Oconee Case 124

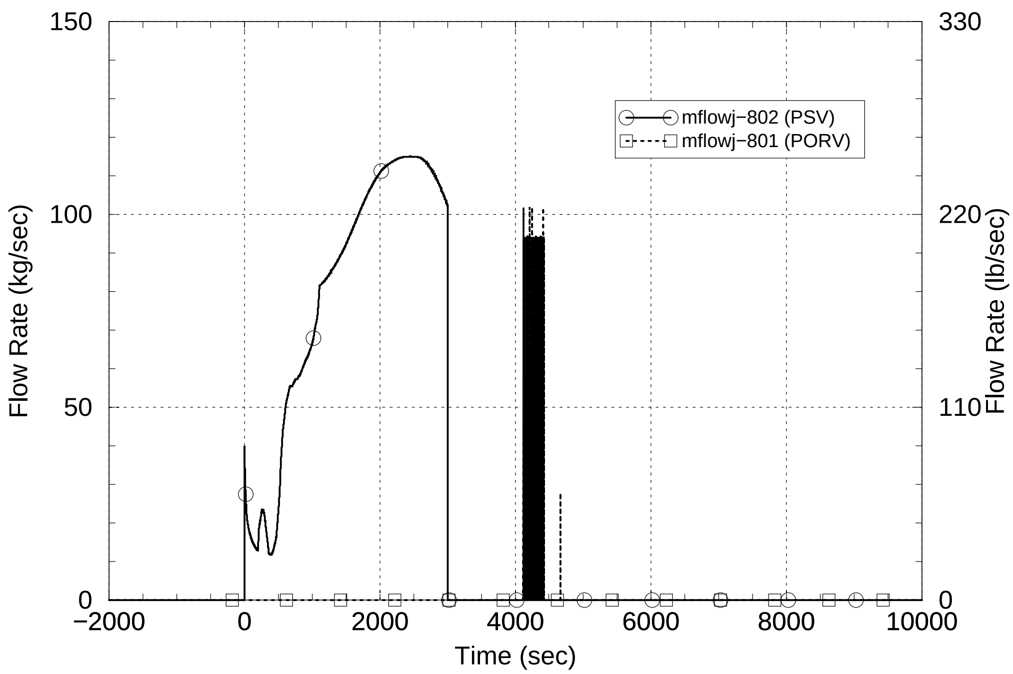


Figure 3.1.3-16 Flowrate through the Stuck Open PSV and PORV - Oconee Case 124

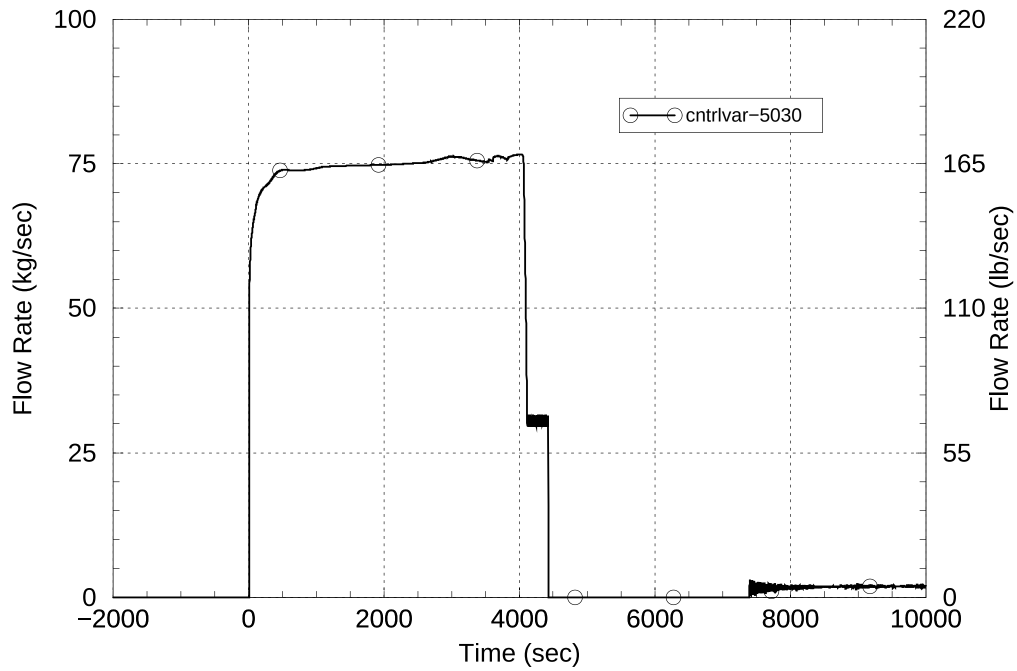


Figure 3.1.3-17 Total High Pressure Injection Flowrate - Oconee Case 124

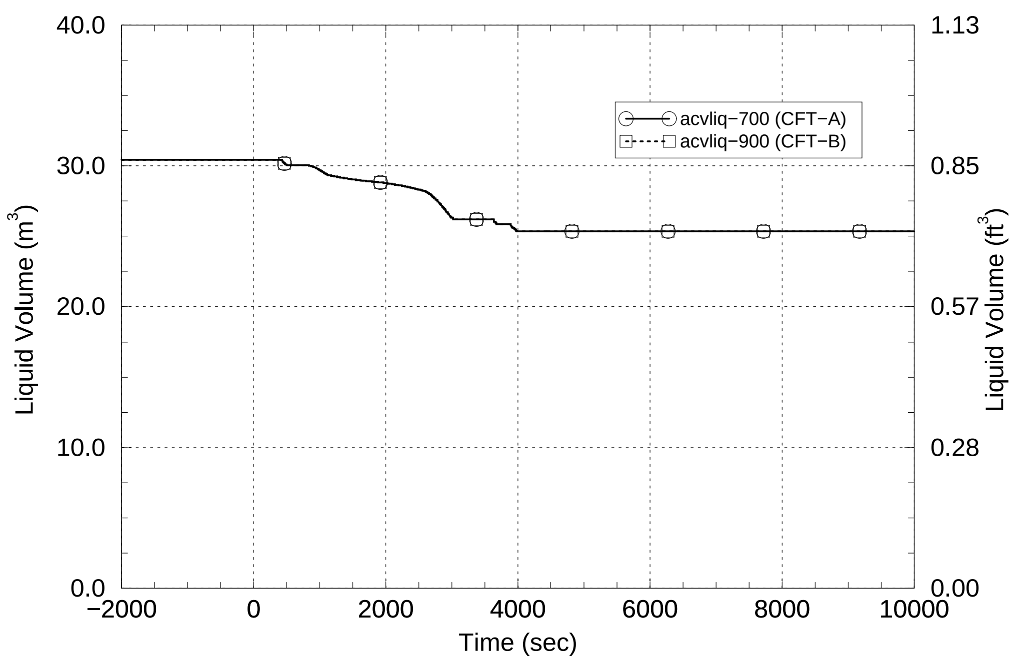


Figure 3.1.3-18 Core Flood Tank Discharge - Oconee Case 124

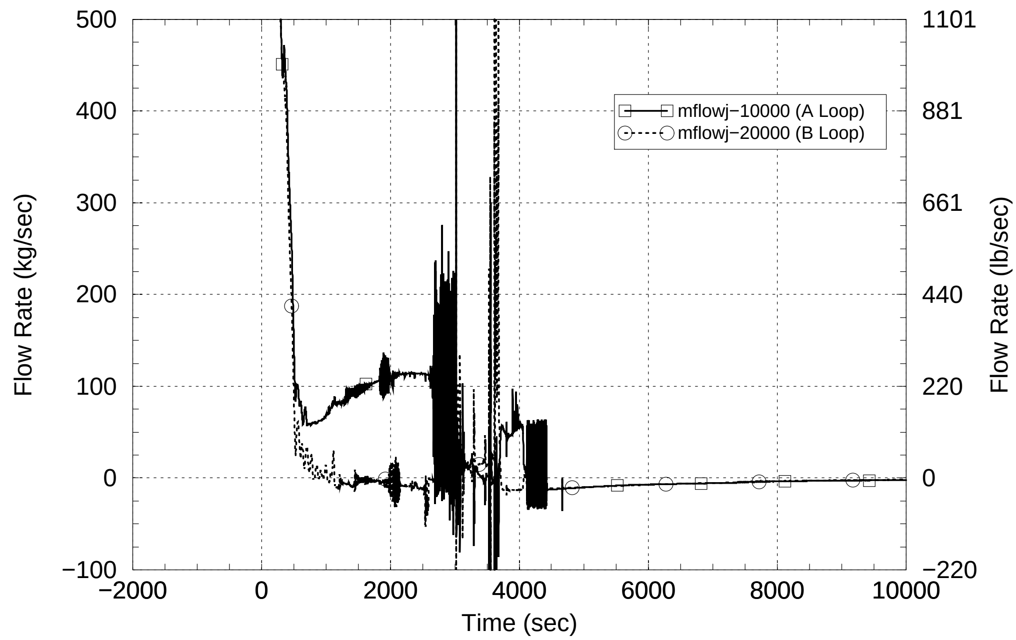


Figure 3.1.3-19   Hot Leg Flow in the A and B Loops - Oconee Case 124

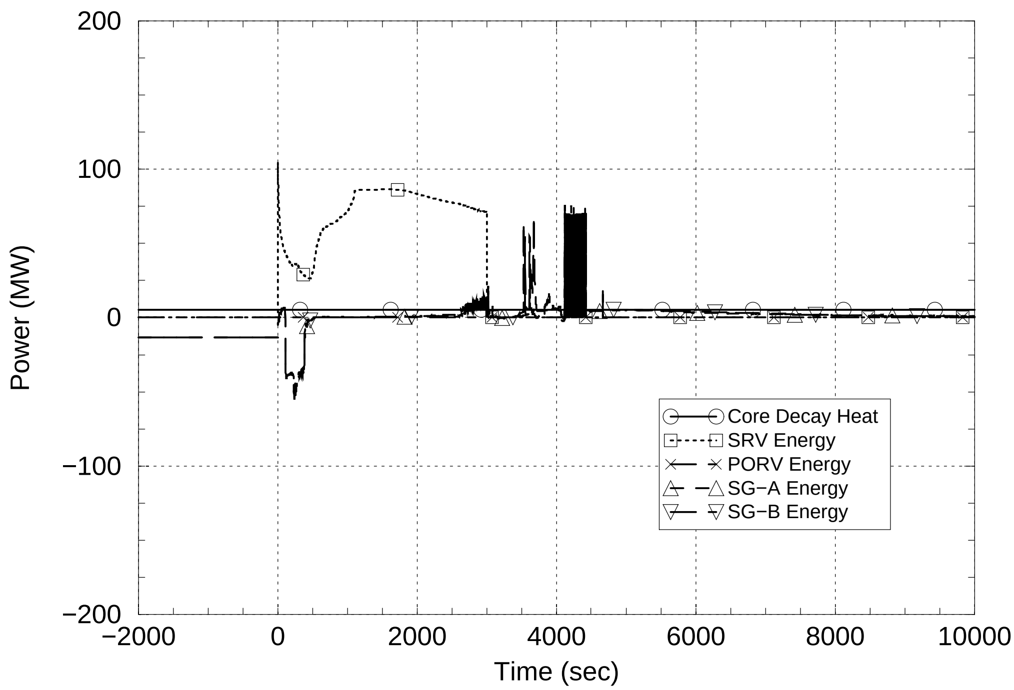


Figure 3.1.3-20   System Energy Balance - Oconee Case 124

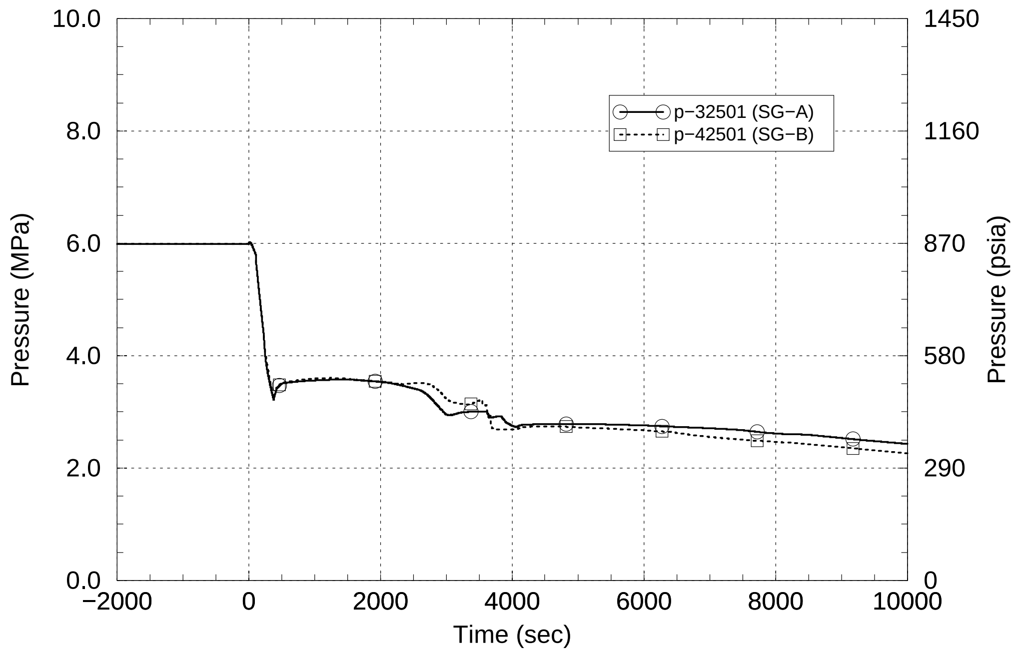


Figure 3.1.3-21 Steam Generator Secondary Pressure - Oconee Case 124

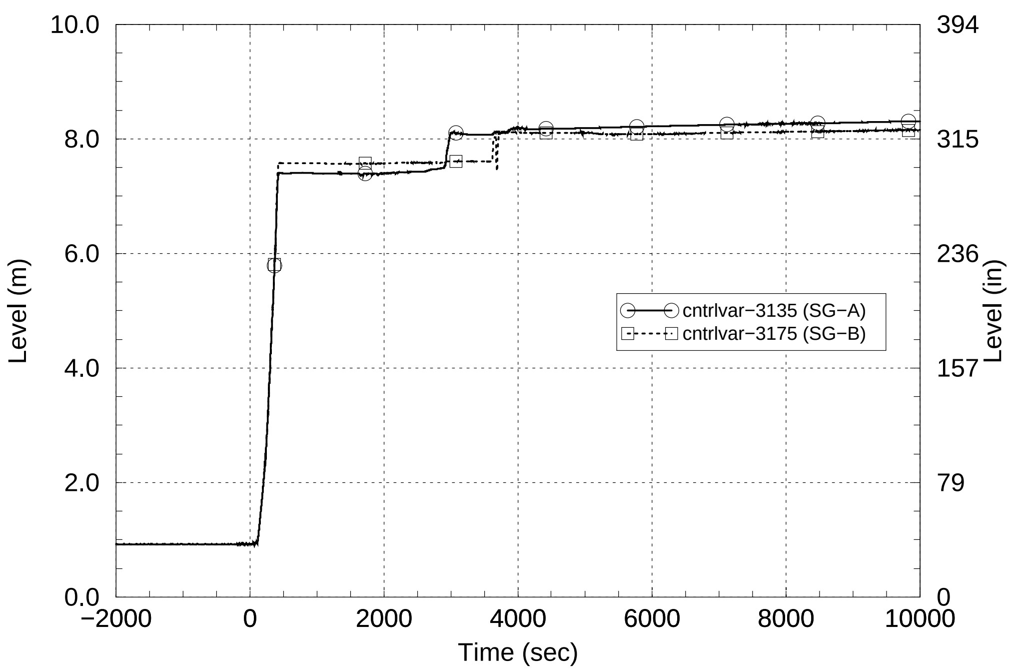


Figure 3.1.3-22 Steam Generator Secondary Startup Level - Oconee Case 124

3.1.4 Main Steam Line Breaks with Operator Actions

This section of the report discusses two double-ended main steam line break (MSLB) analyses that are analyzed in the list of base cases, but are not dominant sequences. These cases are included since main steam line breaks are among the dominant sequences in the Palisades and Beaver Valley plants. The sequences discussed in this section are listed below:

- Case 27 is a main steam line break from hot full power conditions. Both turbine driven and auxiliary driven feedwater are assumed to be operating. The operator is assumed to throttle HPI to maintain 27.8 K [50°F] subcooling.
- Case 101 is a main steam line break from hot zero power conditions. Both turbine driven and auxiliary driven feedwater are assumed to be operating. The operator is assumes to throttle HPI to maintain 27.8 K [50°F] subcooling.

The break in the steam line is assumed to be located in the main steam line section just downstream of the Steam Generator A nozzle (Component 345 in Figure 2.1-4). A tabulation of the timing of key events for the surge line and hot leg break transients is presented in Table 3.1-4.

Table 3.1-4 Comparison of Event Timing for MSLB Sequences

	Event Timing (seconds)	
	Case 27 - main steam line break. Operator throttles HPI.	Case 101 - main steam line break. Operator throttles HPI.
Reactor power level	HFP	HZP
Reactor scram	1	N/A
RCP trip time on loss of subcooling margin	does not trip	does not trip
Main Feedwater Pump Trip	1	N/A
HPI actuates	18	17
Emergency feedwater starts	260	55
Core flood tank discharge start time	2280	875
Low pressure injection starts	does not start	does not start
Core flood tank discharge stops	8500	5100
Time that vent valves open	do not open	do not open
Pressurizer starts to refill	6430	does not refill

3.1.4.1 Case 27 - Main Steam Line Break from HFP Conditions and with Operator Actions

Case 27 is a double-ended main steam line break from hot full power conditions. The break area is 0.586 m^2 [6.305 ft^2]. Both turbine driven and motor driven emergency feedwater are assumed to be available for the duration of the event. The operator is assumed to throttle HPI to maintain 27.8 K [50°F] subcooling. The parameters of interest for the fracture mechanics analysis: primary system pressure, average downcomer fluid temperature, and downcomer fluid-wall heat transfer coefficient are provided in Figures 3.1.4-1 through 3.1.4-3.

As a result of the steam line break, primary system depressurization occurs as shown in Figure 3.1.4-1. The system pressure falls to about 2.4 MPa [348 psia] by 3,000 s and about 1.9 MPa [275 psia] about 1,000 s later. The downcomer temperature decreases to 435 K [323°F] by 3,000 s and to about 387 K [237°F] by 4,000 s. The pressurizer level, shown in Figure 3.1.4-4, decreases rapidly and empties due to the cooldown of the system as the reactor coolant system cools and depressurizes. The steam line break flow is presented in Figure 3.1.4-5. Reactor trip occurs within 1 s, followed by trip of the main feedwater pumps. The HPI system also starts and is assumed to be throttled by the operator to the 27.8 K [50°F] subcooling criteria when HPI starts. The total HPI flow is shown in Figure 3.1.4-6. The reactor coolant pumps remain running for the duration of the event as subcooling is never lost. As a result, the value of the downcomer wall heat transfer coefficient shown in Figure 3.1.4-3 is higher compared to the LOCA and stuck open pressurizer safety valve cases discussed in the previous sections.

Because of the system depressurization, the core flood tanks start to discharge by 2,280 s as shown in Figure 3.1.4-7. About 60 percent of the total core flood tank volume is discharged by about 7,000 s. Note that there is no LPI flow in this case because the vessel pressure never dropped below the shutoff head of the LPI pumps.

Hot leg flow is shown in Figure 3.1.4-8. The hot leg flow in both loops is the same due to the continued operation of the reactor coolant pumps. The hot leg mass flow rates increase because reactor coolant system water becomes colder and more dense. The system energy balance is shown in Figure 3.1.4-9 which shows that the primary system energy is being transferred to Steam Generator A. The emergency feedwater flow, shown in Figure 3.1.4-10, provides feedwater to Steam Generator A for the duration of the event which allows this energy transfer to continue.

The steam generator secondary side pressures are shown in Figure 3.1.4-11. Steam Generator A depressurizes rapidly due to the break. Steam Generator B depressurizes slowly due to flow to the steam generator secondary from the feedwater system and due to reverse steam generator heat transfer. The feedwater system flow is reflected by the increase in steam generator startup level shown in Figure 3.1.4-12.

The minimum downcomer temperature of about 380 K [224°F] was reached by about 4,400 s after initiation and remained at that temperature for the rest of the transient. The corresponding system pressure is about 1.8 MPa [261 psia].

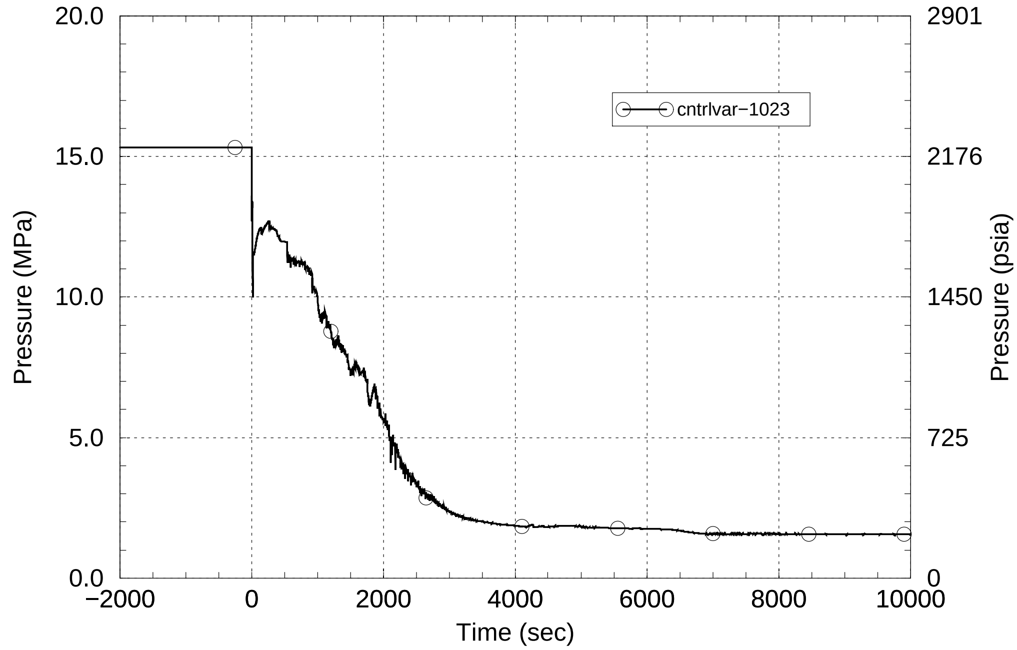


Figure 3.1.4-1 Reactor Coolant System Pressure - Oconee Case 27

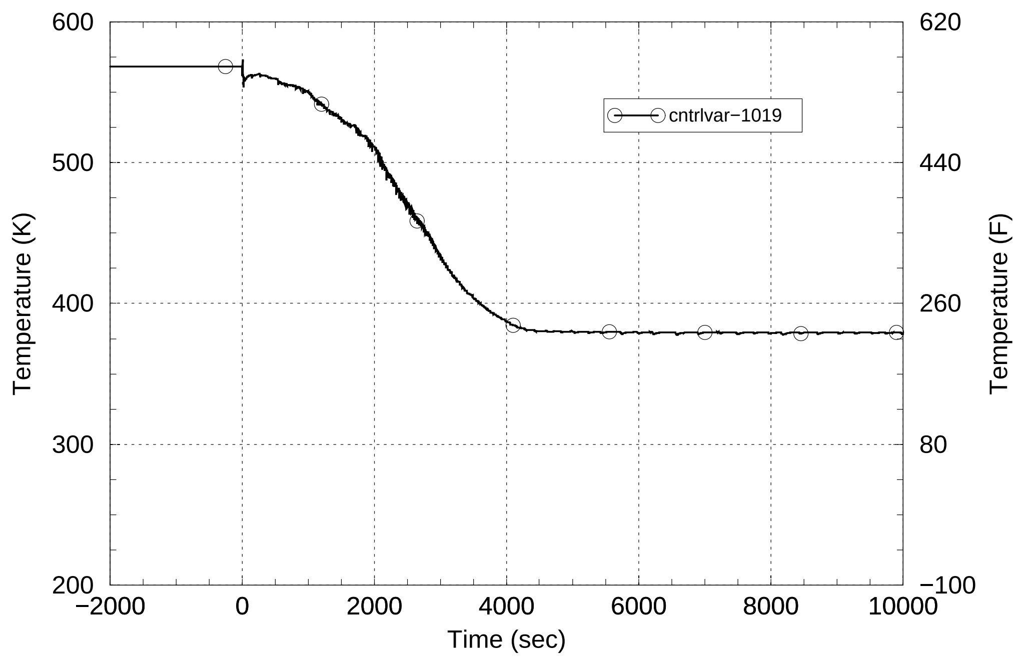


Figure 3.1.4-2 Avg Reactor Vessel Downcomer Temperature - Oconee Case 27

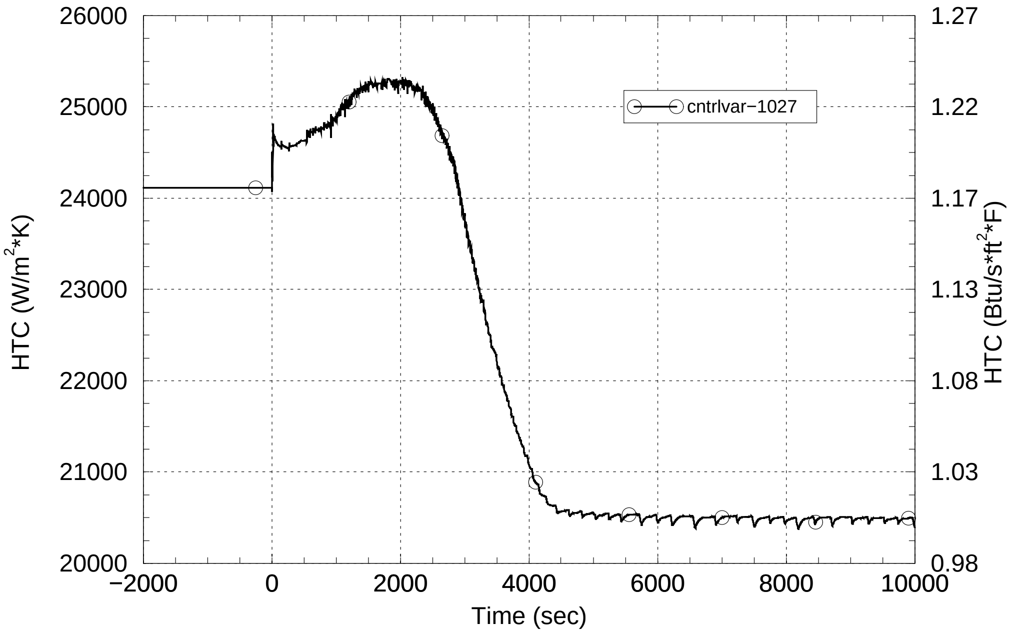


Figure 3.1.4-3 Avg Reactor Vessel Inner Wall Heat Transfer Coefficient - Oconee Case 27

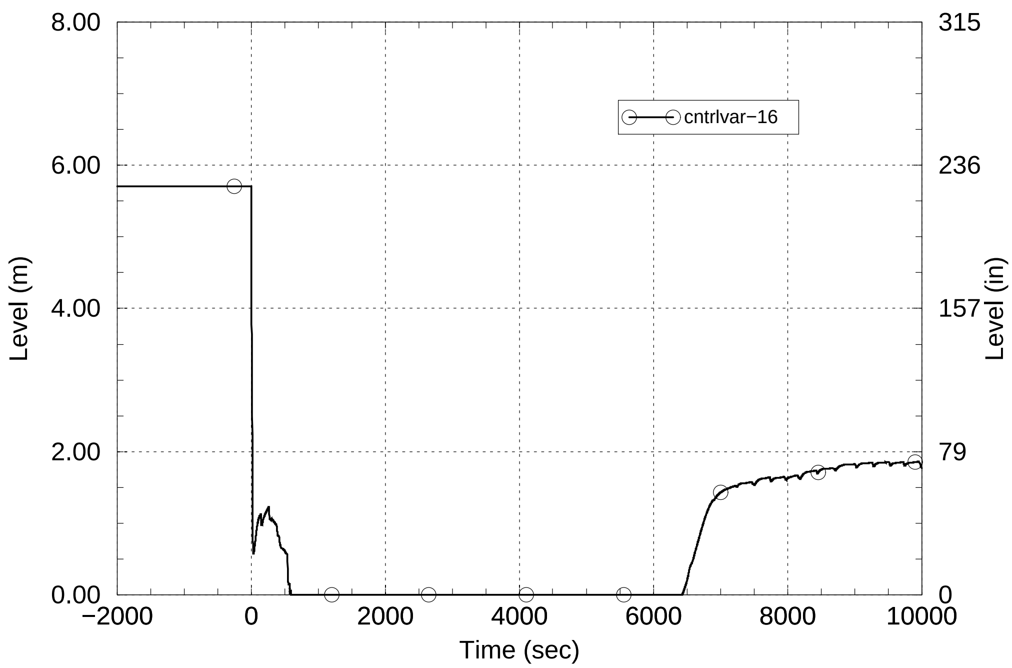


Figure 3.1.4-4 Pressurizer Level - Oconee Case 27

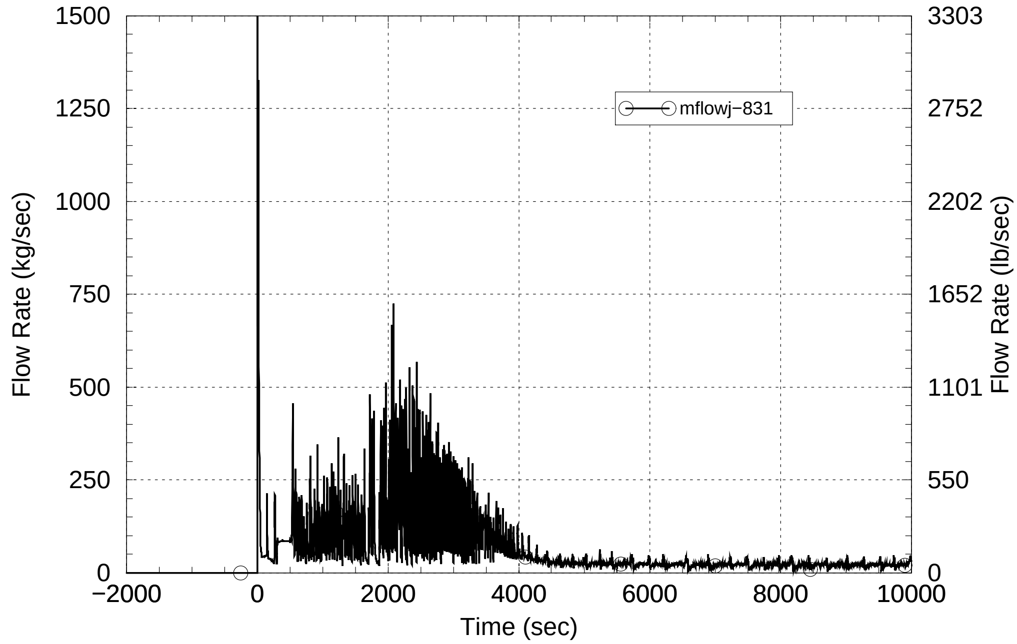


Figure 3.1.4-5 Steam Line Break Flowrate - Oconee Case 27

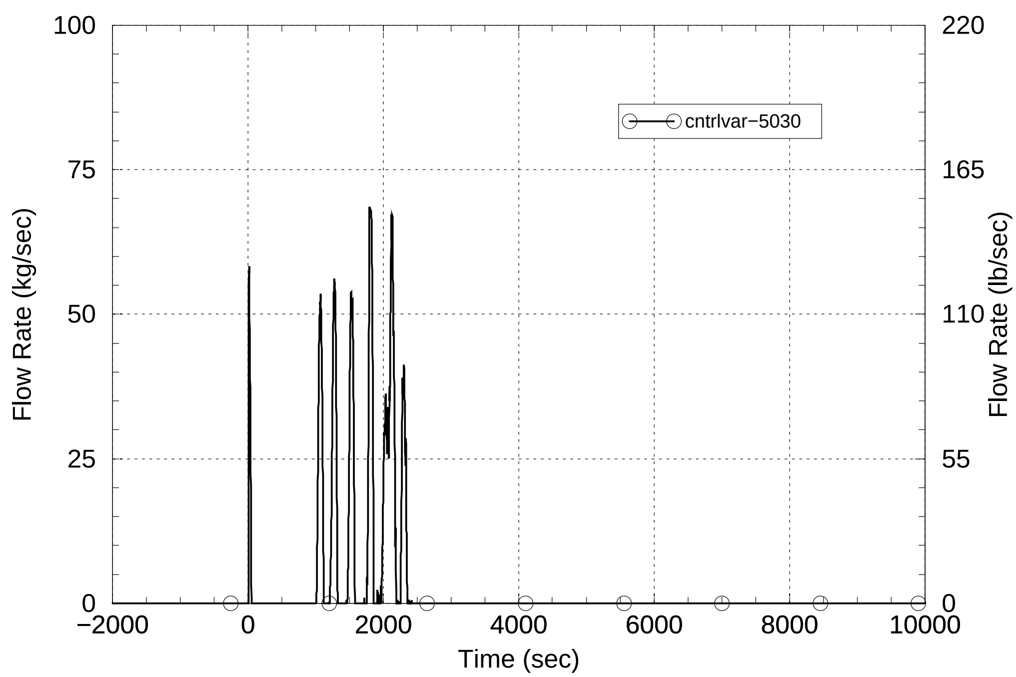


Figure 3.1.4-6 Total High Pressure Injection Flowrate - Oconee Case 27

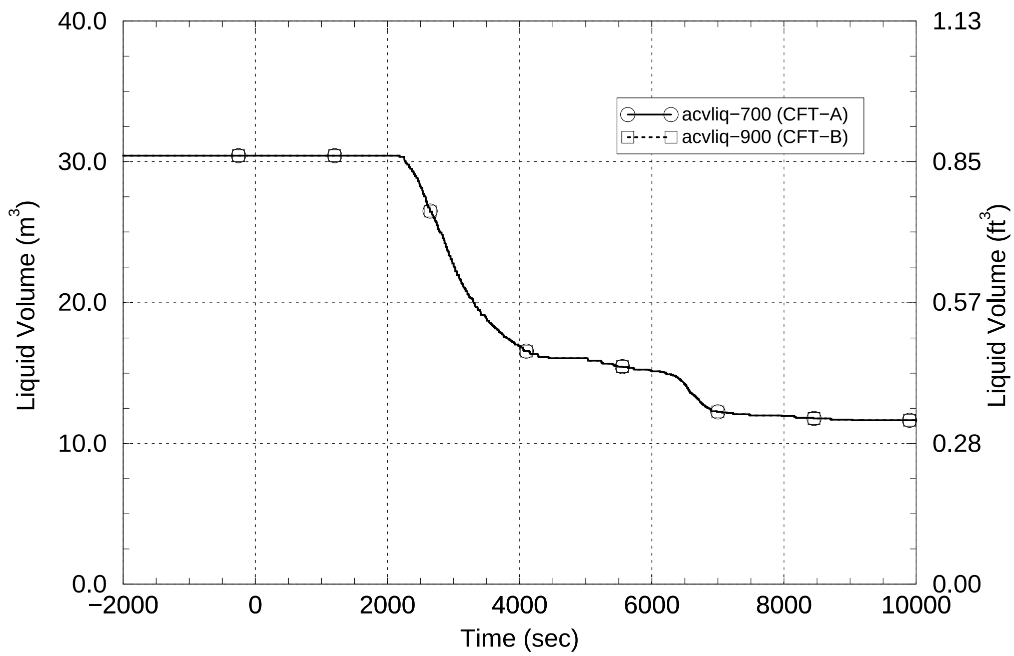


Figure 3.1.4-7 Core Flood Tank Discharge - Oconee Case 27

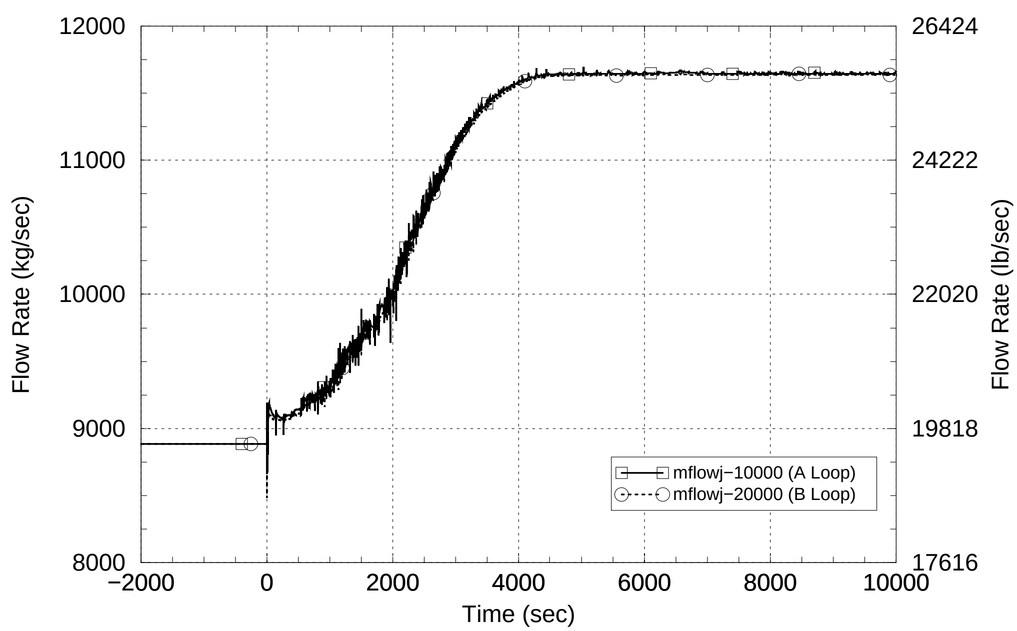


Figure 3.1.4-8 Hot Leg Flow in the A and B Loops - Oconee Case 27

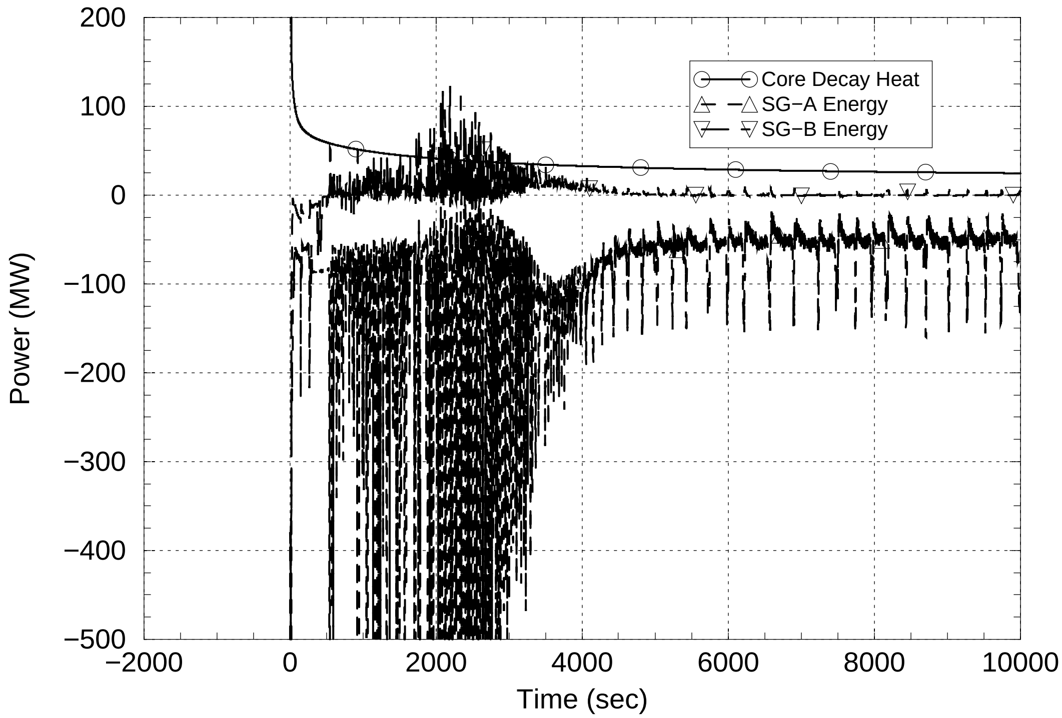


Figure 3.1.4-9 System Energy Balance - Oconee Case 27

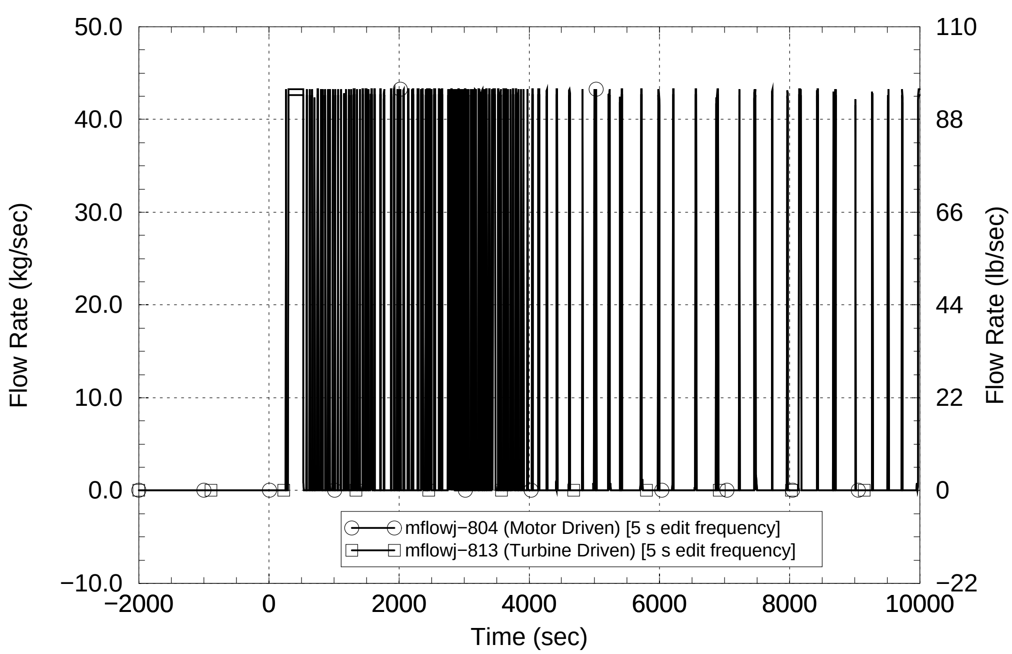


Figure 3.1.4-10 Emergency Feedwater Flow to Steam Generator A - Oconee Case 27

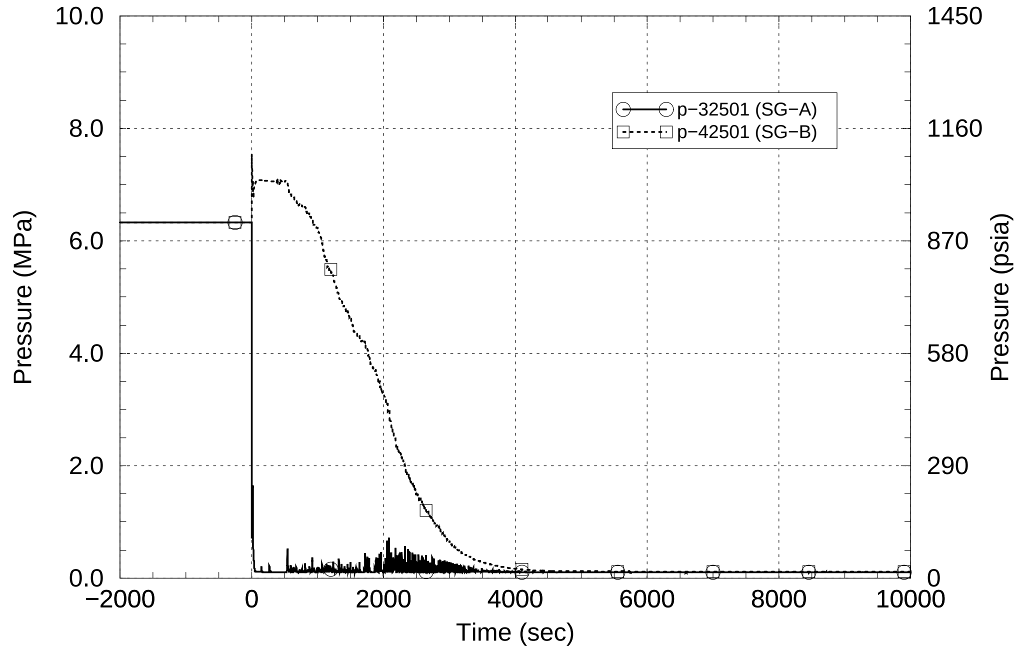


Figure 3.1.4-11 Steam Generator Secondary Pressure - Oconee Case 27

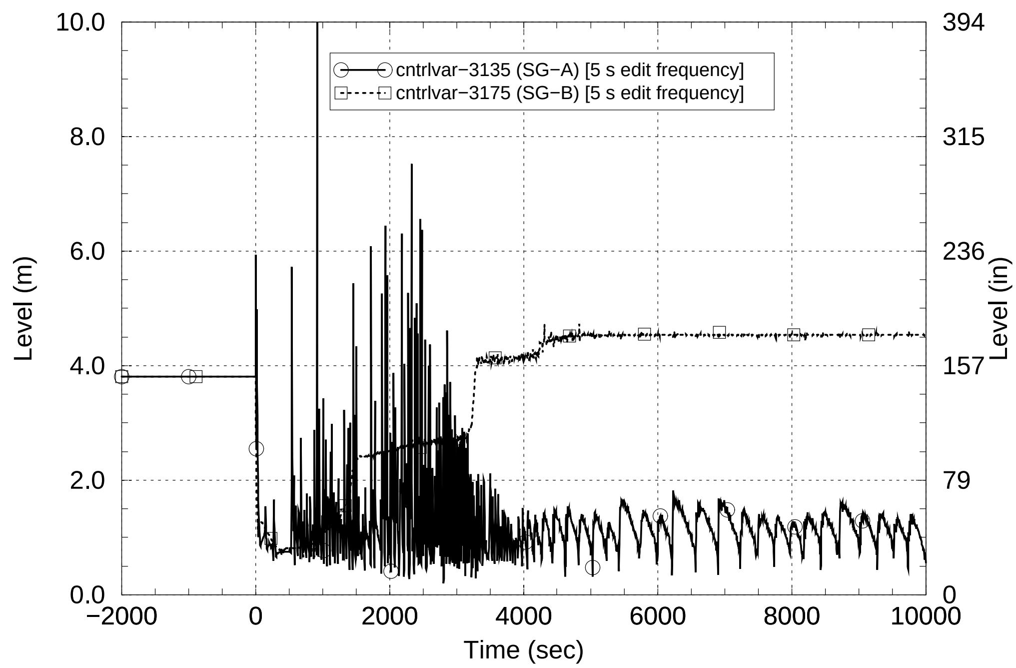


Figure 3.1.4-12 Steam Generator Secondary Startup Level - Oconee Case 27

3.1.4.2 Case 101 - Main Steam Line Break from HZP Conditions and with Operator Actions

Case 101 is a double-ended main steam line break from hot zero power conditions. The break area is 0.586 m^2 [6.305 ft^2]. Both turbine driven and motor driven emergency feedwater are assumed to be available. The operator is assumed to throttle HPI to maintain 27.8 K [50°F] subcooling. The parameters of interest for the fracture mechanics analysis: primary system pressure, average downcomer fluid temperature, and downcomer fluid-wall heat transfer coefficient are provided in Figures 3.1.4-13 through 3.1.4-15.

As a result of the steam line break, primary system depressurization occurs as shown in Figure 3.1.4-13. The system pressure decreases to about 1.8 MPa [261 psia] by 3,000 s. The downcomer temperature decreases to about 378 K [220°F] by 2,600 s and remained at that temperature for the rest of the transient. The pressurizer level, shown in Figure 3.1.4-16, also decreases rapidly and empties due to the cooldown of the system as the reactor coolant system cools and depressurizes. The steam line break flow is presented in Figure 3.1.4-17. Reactor trip occurs within 1 s, followed by trip of the main feedwater pumps. The HPI system also starts and is assumed to be throttled by the operator to the 27.8 K [50°F] subcooling criteria when HPI starts. The total HPI flow is shown in Figure 3.1.4-18. Because the system remains above 27.8 K [50°F] subcooling, HPI flow is throttled to zero flow for most of the event. The reactor coolant pumps remain running for the duration of the event as subcooling is never lost. As a result, the value of the downcomer wall heat transfer coefficient shown in Figure 3.1.4-15 is higher compared to the LOCA and stuck open pressurizer safety valve cases discussed in the previous sections.

Because of the system depressurization, the core flood tanks start to discharge by about 875 s as shown in Figure 3.1.4-19. About 50 percent of the total core flood tank volume is discharged by about 2,500 s. Note that there is no LPI flow in this case because the vessel pressure never dropped below the shutoff head of the LPI pumps.

Hot leg flow is shown in Figure 3.1.4-20. The hot leg flow in both loops is driven by the continued operation of the reactor coolant pumps. The system energy balance is shown in Figure 3.1.4-21 which shows that the primary system energy is being transferred to Steam Generator A. The emergency feedwater flow, shown in Figure 3.1.4-22, provides feedwater to the Steam Generator A for the duration of the event which allows this energy transfer to continue.

The steam generator secondary side pressures are shown in Figure 3.1.4-23. Steam Generator A depressurizes rapidly due to the break. Steam Generator B depressurizes slowly due to flow to the steam generator secondary from the feedwater system. This flow is reflected by the increase in steam generator startup level shown in Figure 3.1.1-24.

The minimum downcomer temperature of about 377 K [219°F] was reached by about 2,600 s after initiation and remained at that temperature for the rest of the transient. The corresponding system pressure is about 1.8 MPa [272 psia].

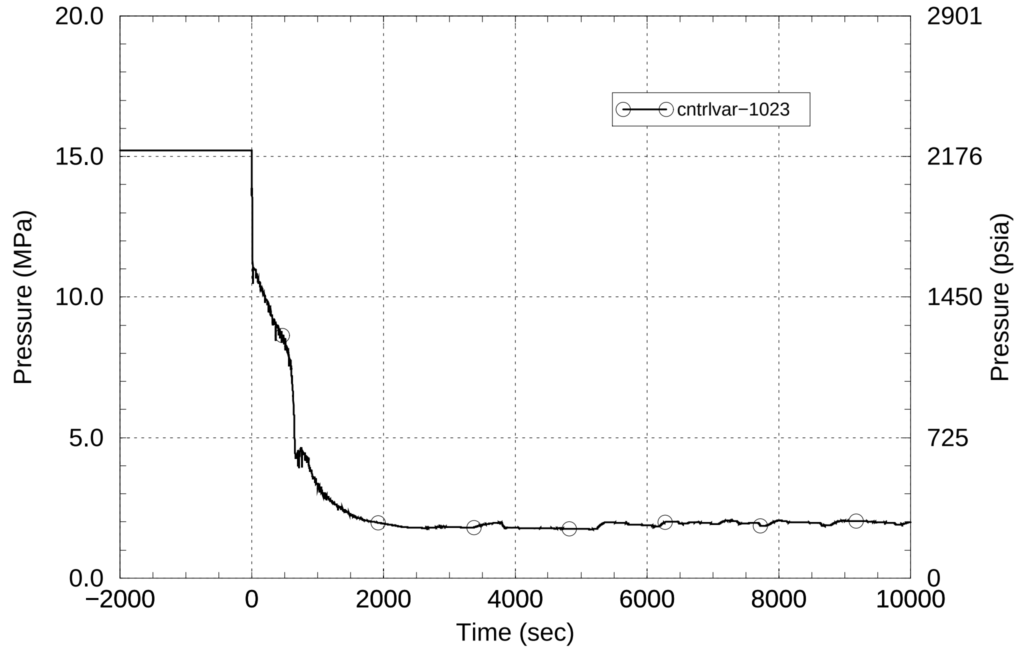


Figure 3.1.4-13 Reactor Coolant System Pressure - Oconee Case 101

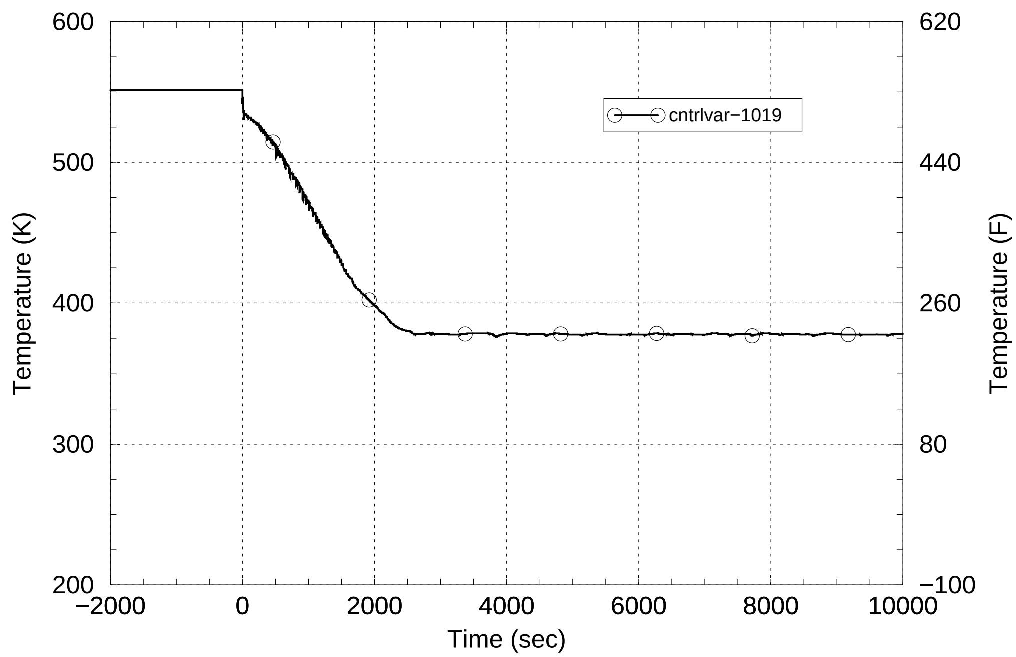


Figure 3.1.4-14 Avg Reactor Vessel Downcomer Temperature - Oconee Case 101

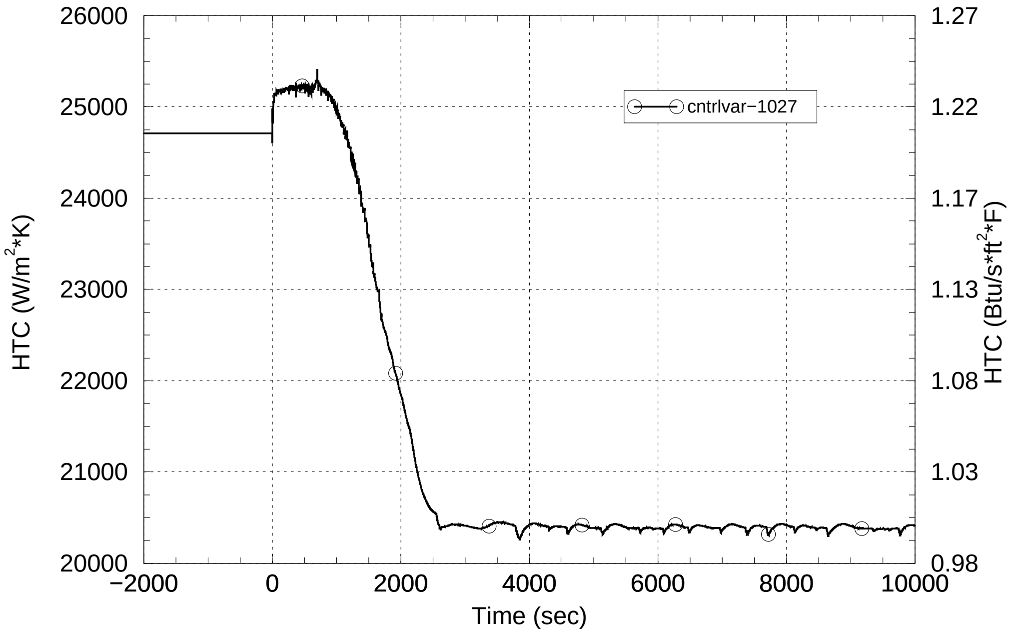


Figure 3.1.4-15 Avg Reactor Vessel Inner Wall Heat Transfer Coefficient - Oconee Case 101

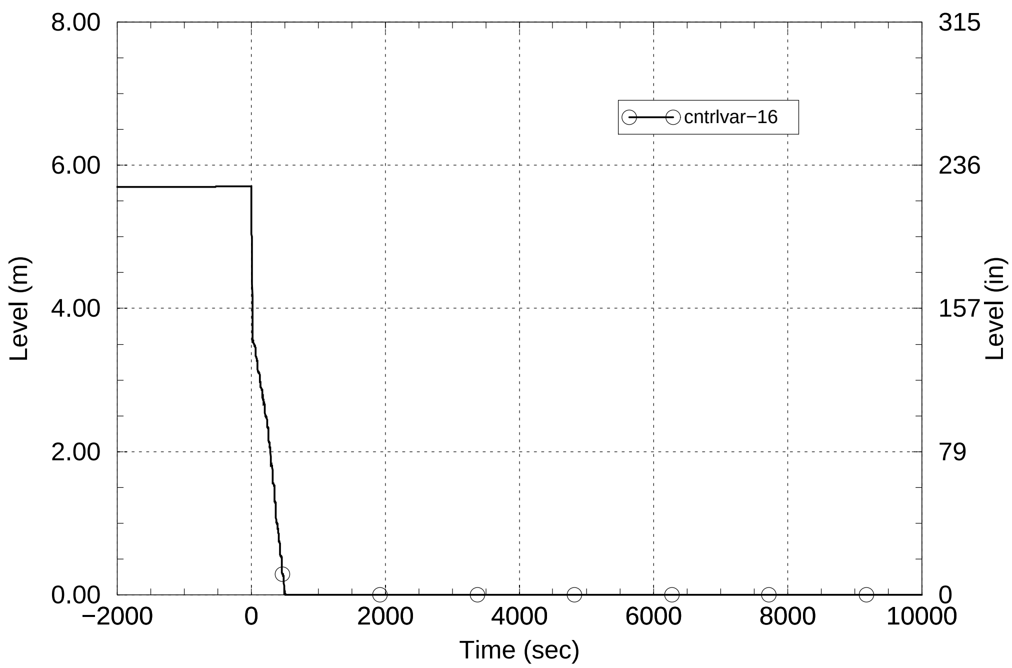


Figure 3.1.4-16 Pressurizer Level - Oconee Case 101

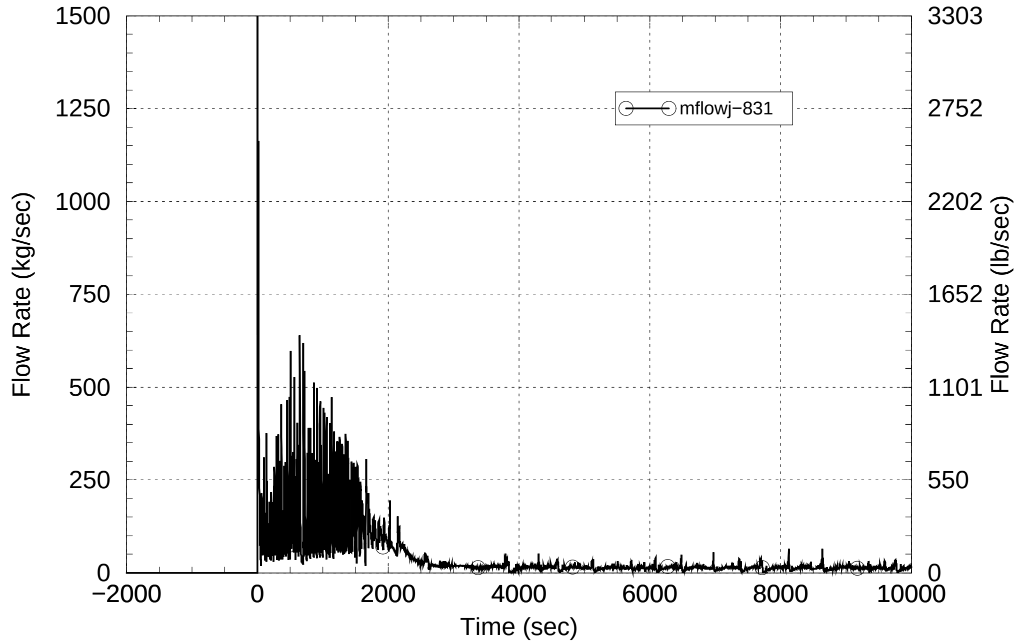


Figure 3.1.4-17 Steam Line Break Flowrate - Oconee Case 101

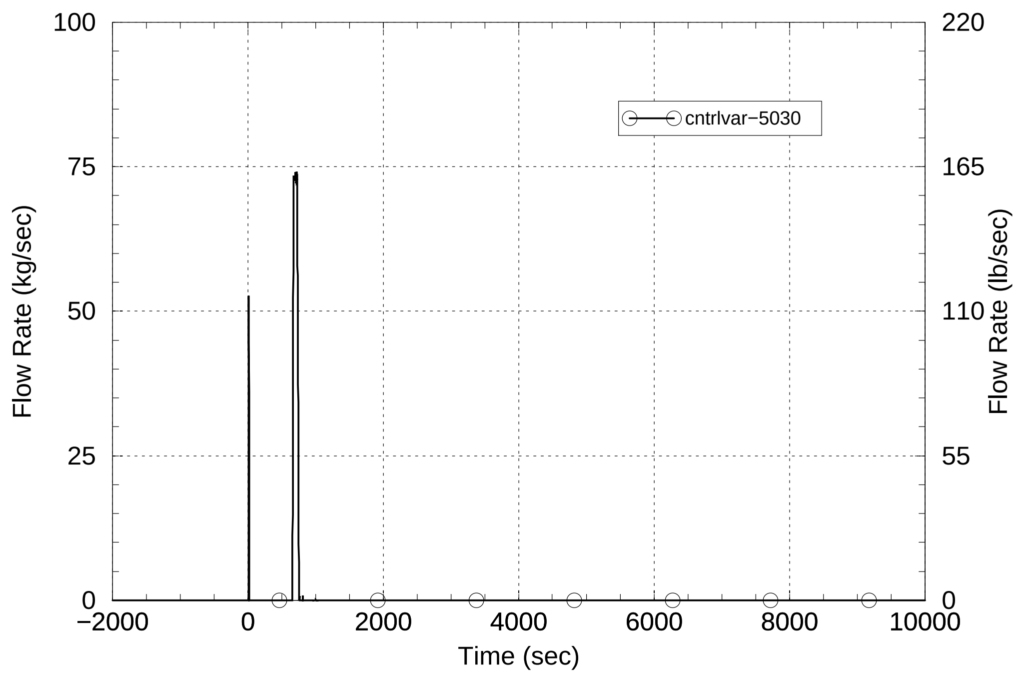


Figure 3.1.4-18 Total High Pressure Injection Flowrate - Oconee Case 101

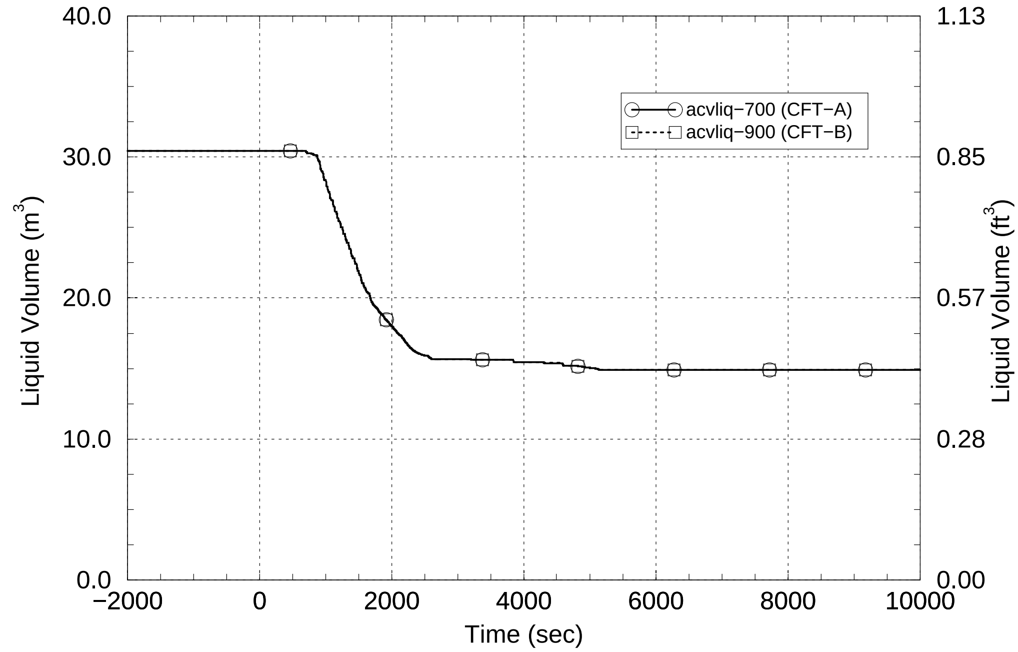


Figure 3.1.4-19 Core Flood Tank Discharge - Oconee Case 101

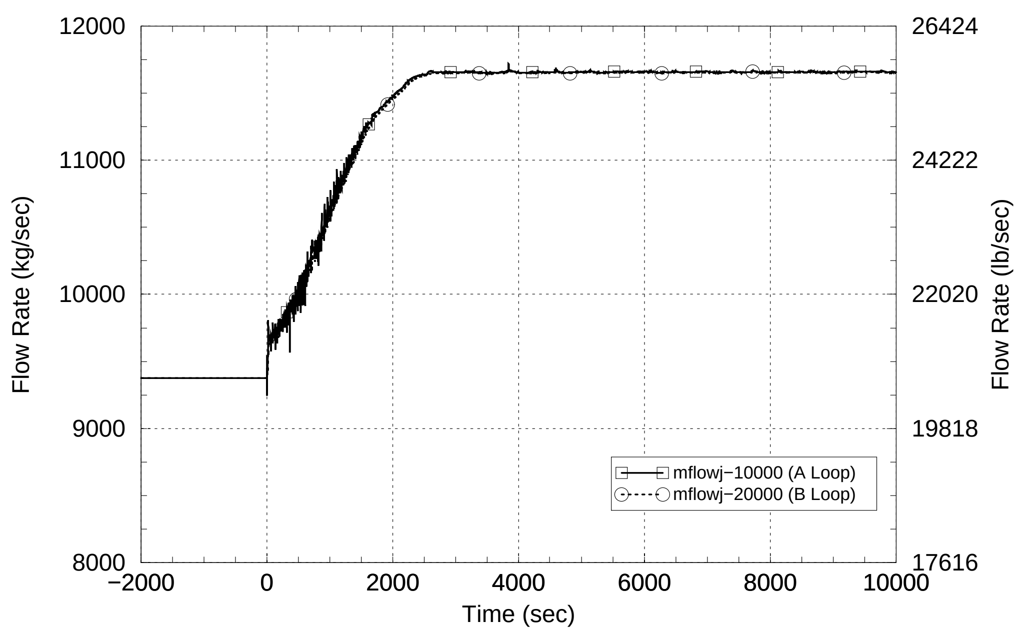


Figure 3.1.4-20 Hot Leg Flow in the A and B Loops - Oconee Case 101

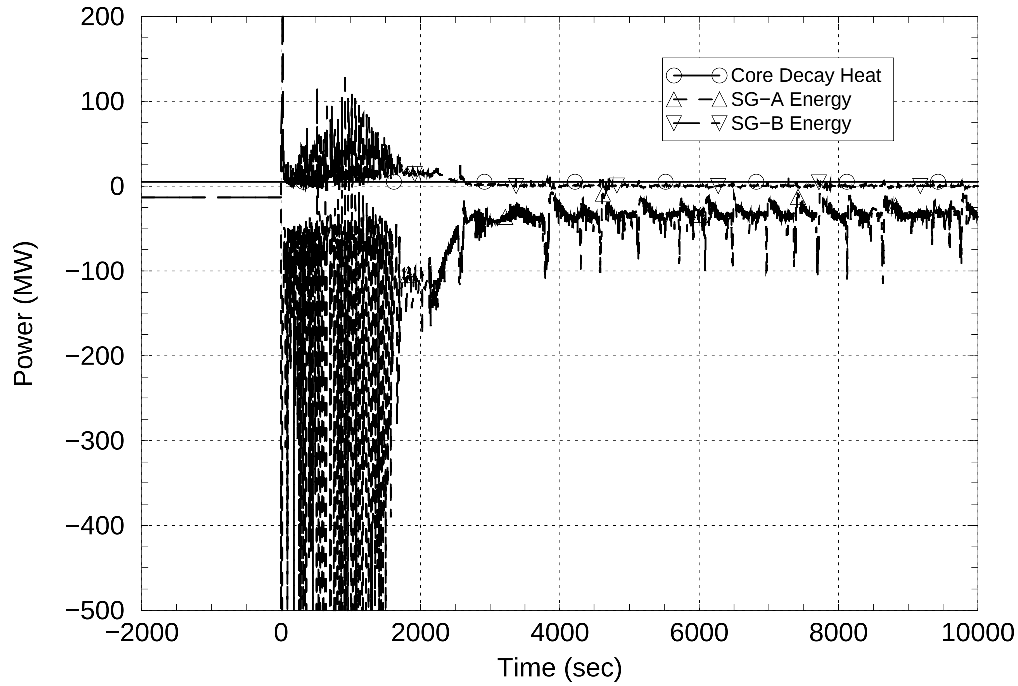


Figure 3.1.4-21 System Energy Balance - Oconee Case 101

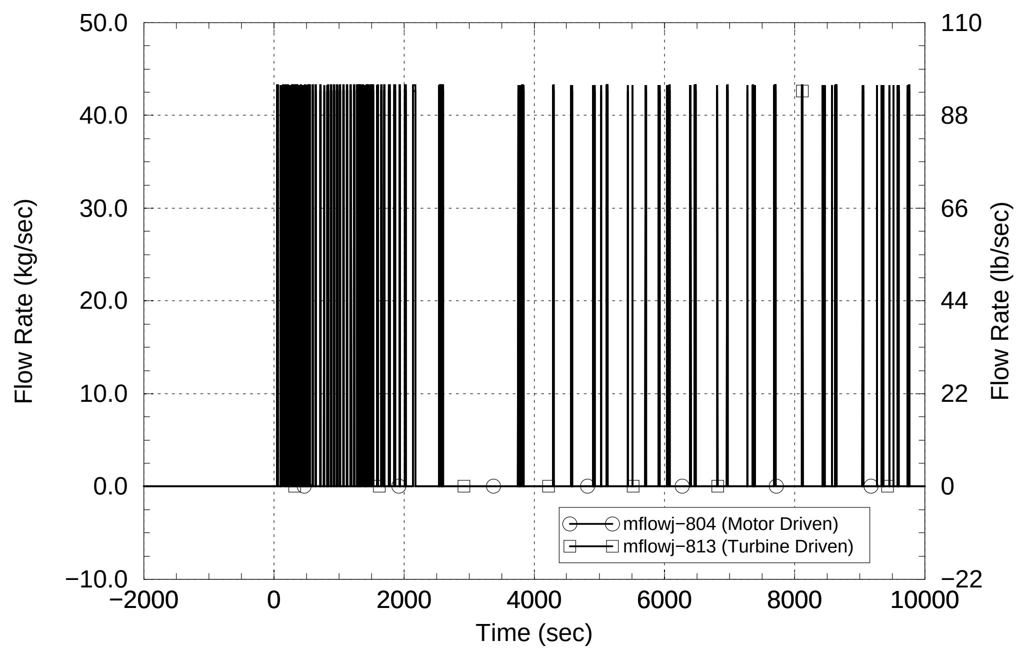


Figure 3.1.4-22 Emergency Feedwater Flow to Steam Generator A - Oconee Case 101

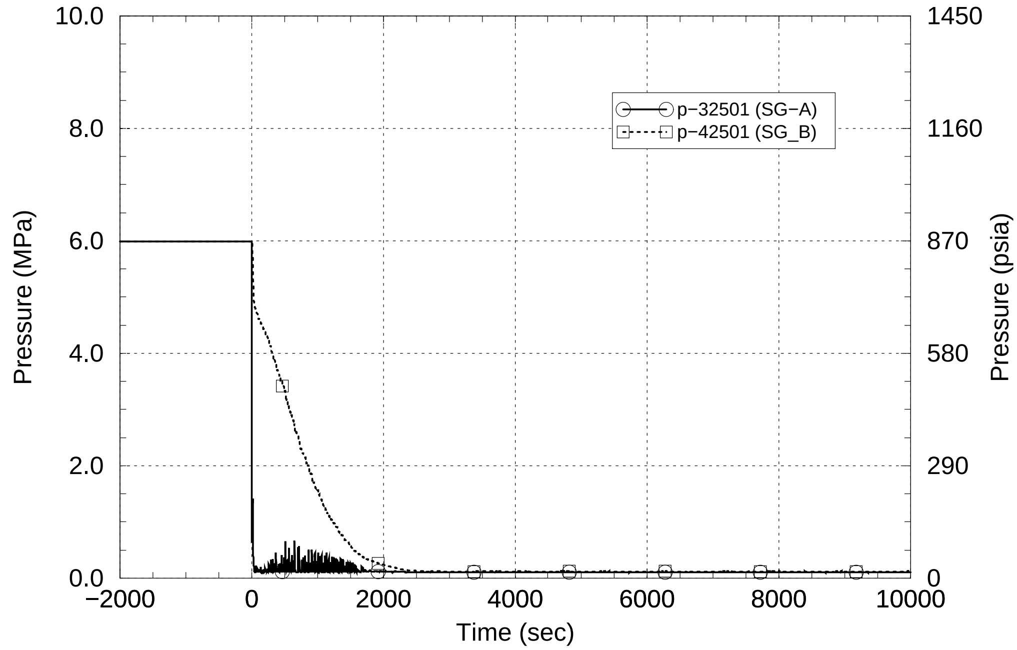


Figure 3.1.4-23   Steam Generator Secondary Pressure - Oconee Case 101

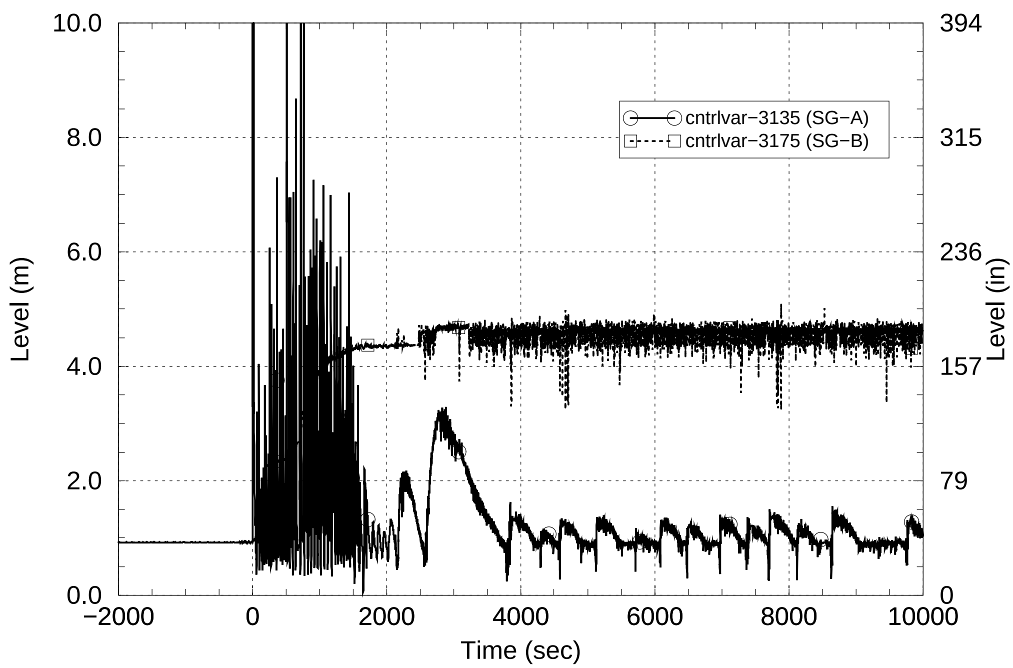


Figure 3.1.4-24   Steam Generator Secondary Startup Level - Oconee Case 101

3.1.5 References

3.1.1 SCIENTECH, Inc., RELAP5.Mod 3 Code Manual, Volume IV: Models and Correlations, Formally NUREG/CR-5535, Volume IV, June 1999 (Section 7.3).

3.2 Beaver Valley Transient Results of Dominant Sequences

Several groups of transients were analyzed for the PTS evaluation as listed in Appendix B, Table B-1. Transient sequences analyzed were defined as part of a risk assessment by the Sandia National Laboratory to identify sequences that may be important to risk due to a PTS event. The transients analyzed include small break LOCAs with various break areas in the surge line, hot and cold legs, main steam line breaks, steam generator overfeeds, stuck open valves which reclose and other types of transients initiated by a reactor or turbine trip. Note that in the RELAP5 model, there is no difference between a turbine trip and a reactor trip as both occur at the same time.

The principal results of interest from a PTS perspective are the fluid temperature and pressure in the reactor vessel downcomer along with the heat transfer coefficient at the vessel wall-downcomer fluid interface. These results will be used as boundary conditions to the fracture mechanics analysis performed by Oak Ridge National Laboratory. Plots for these parameters are presented in the sections that follow along with other plots of interest needed to explain the results.

The following subsections (3.2.1 through 3.2.6) present the thermal hydraulic results for transients which were determined to be the dominant sequences (> 1% of the total risk) for PTS risk. For each transient which was considered dominant, the following is provided; transient description, modeling changes made to perform the calculation, detailed analysis of the transient results and conclusions drawn from the analysis. All RELAP5 cases were restarted from the 8,000 s null transient (steady state) calculations described above in Section 2.2.2 using the RELAP5 restart feature. All transients were run for 15,000 s. Note that data presented prior to time zero on the time axis show the null transient (steady state) conditions prior to transient initiation.

3.2.1 Beaver Valley Primary Side Loss of Coolant Accidents From Hot Full Power

The transients in this group were initiated from full power steady state operating conditions (nominal temperature and pressure) and all control systems were in automatic control. The transients are as follows; 20.32 cm [8.0 in] diameter surge line break, 40.64 cm [16.0 in] diameter hot leg break, and 7.184 cm [2.828 in] diameter surge line break with summer ECCS temperatures and increased heat transfer. In order to model these breaks, two additional components were added to the RELAP5 model (in the transient restart input file). These components were a time dependent volume to model the break downstream conditions and a break valve. The time dependent volume was set to atmospheric conditions. The break valve for the surge line break was connected to the middle node of the surge line (volume 343, cell 2, see Figure 2.2-1). The break valve for the hot leg break was connected to hot leg A (volume 204, cell 3). The loss coefficients for the breaks were based on AP600 derived loss coefficients (Ref. 3.2.1) and scaled for the appropriate break sizes. In all transients, the break valve was set to open at time 0.0 s. Due to the 8,000 s null transient, the valve opening time was actually set to 8,000 s in the RELAP5 transient input model. Note that when times are quoted in this report they will refer to the time from the start of the event. When plots are made, the 8,000 s null transient was subtracted off so the events start at time 0.0 s. A sequence of events table for these transients is provided as Table 3.2-1.

Table 3.2-1 Sequence of Events for Loss of Coolant Accidents from Hot Full Power

	Case 007 - 20.32 cm [8.0 in] surge line break	Case 009 - 40.64 cm [16.0 in] diameter hot leg break	Case 114 - 7.184 cm [2.828 in] diameter surge line break with summer ECCS temperatures and increased heat transfer
	Event Time (s)		
Break valve opened	0	0	0
Reactor/turbine trip	2.006	0.036	13.805
SIAS generated	3.5	3.04	17.7
HHSI flow initiated	3.5	3.04	17.7
MFW stopped	3.5	3.04	17.7
AFW started	3.5	3.04	17.7
RCPs trip	9.5	7.5	49.5
Pressurizer empties	<15	<15	<30
Accumulators begin injecting	180	30	1,050
LHSI flow initiated	285	45	3,030
Accumulators empty	435	90	3,540
MSIV closure	585	540	540
Containment spray pumps start	642	386	3,022
Switchover to sump recirculation	2,025	1,693	4,872

3.2.1.1 Beaver Valley Surge Line Break from Hot Full Power – 20.32 cm [8.0 in] diameter (BV Case 007)

This case is a 20.32 cm [8.0 in] diameter surge line break from hot full power. This case is identified as Beaver Valley Case 007 in Appendix B, Table B-1. The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.1-1 through 3.2.1-3, respectively.

As a result of the break, the primary system rapidly depressurizes as shown in Figure 3.2.1-1 and remains near 0.19 MPa [28 psia] for the remainder of the transient. In addition, the pressurizer level (shown in Figure 3.2.1-4) also decreased rapidly due to loss of inventory and was completely empty by 15 s. At 2.006 s, a reactor/turbine trip occurred due to low primary pressure. At approximately 3.5 s, a safety injection actuation signal (SIAS) was generated. The SIAS results in actuation of both the high head safety injection (HHSI), and low head safety injection (LHSI). Note that actuation does not necessarily mean that a system begins working immediately. In this case, while LHSI is actuated, it will not begin flow until the primary pressure falls below the pump shutoff head. In addition, the SIAS also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated.

A plot of break flow versus total safety injection (SI) flow is provided as Figure 3.2.1-5. Total SI flow includes high pressure injection, low pressure injection, accumulators and charging/letdown. High pressure injection flow is shown in Figure 3.2.1-6. Initially, break flow is much larger than safety injection flow. By 180 s the primary pressure has decreased to below the accumulator pressure, resulting in accumulator injection as shown in Figure 3.2.1-7. With this additional flow, the total SI flow is now greater than the break flow. At 285 s primary pressure is below the low head safety injection (LHSI) shutoff head, and LHSI flow begins as shown in Figure 3.2.1-8. At 435 s, the accumulators have emptied and injection stops. Note that the accumulators were isolated when the liquid level was near the bottom of the tank. This was done to stop non-condensible gases from entering the system. These non-condensible gases frequently cause numerical problems in RELAP5 which lead to code failures. By 2,500 s, the safety injection flow and break flow are equal for the remainder of the transient.

At approximately 9.5 s, the reactor coolant pumps were tripped due to an operator action. This causes the flow in the loops to decrease to near zero. Figure 3.2.1-9 presents the hot leg mass flow for all three loops at the exit of the vessel. At around 1,050 s there are significant flow oscillations which last until about 2,000 s. These oscillations appear to be due to condensation effects in the primary tubes of the steam generators. The code is predicting that the steam generator primary tubes void completely by about 100 s. When they begin to refill around 1,000 s, some nodes in the primary tubes are condensing liquid while others are boiling. The condensation/vaporization causes pressure waves which drive the oscillatory flow behavior. By 3,000 s, the large oscillations have stopped and the only loop which has flow is the C loop, which contains the break. Figure 3.2.1-3 shows the downcomer fluid-wall heat transfer coefficient. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops rapidly from an initial value of approximately 23,950 $W/m^2{\cdot}K$ [1.171 $Btu/s{\cdot}ft^2{\cdot}{}^\circ F$]. The heat transfer coefficient then gradually decreases to a value of around 750 $W/m^2{\cdot}K$ [0.037 $Btu/s{\cdot}ft^2{\cdot}{}^\circ F$] by the end of the transient.

Figure 3.2.1-10 shows the core power versus the energy lost through the break. As seen in this figure, the break energy is larger than the core decay heat, thus, heat is being removed from the system causing the temperature to decrease. The average downcomer fluid temperature is shown in Figure 3.2.1-2. In addition to the heat lost through the break and core decay heat considerations, the safety injection water temperature plays a role in the downcomer fluid temperature. Initially, the high pressure injection and low pressure injection are at 283 K [50°F], however, after the reactor water storage tank (RWST) has depleted, the source of injection water becomes the containment sump. After switchover to sump recirculation at 2,025 s, the injection temperature is increased to 341 K [155°F] as shown in Figure 3.2.1-11. Looking at Figure 3.2.1-2 shows that the sump temperature significantly affects the downcomer fluid temperature.

Figure 3.2.1-12 shows the steam generator narrow range water level. Upon the SIAS being generated, the MFW is isolated and the steam generator level immediately drops. AFW is started, and begins refilling the generators to the desired post-trip setpoint of 33% NRL (120.7 cm [47.52 in]). Figure 3.2.1-13 shows the auxiliary feedwater flow. The auxiliary feedwater system provides flow from the steam driven pump and one motor driven pump to a common header which then splits to each steam generator feedwater line. Flow from the other motor driven pump is delivered to a common header which then splits to each steam generator feedwater line. Flow losses were entered between the pumps and common headers as well as between the header and generators. Due to the use of a common header, the differential pressures between the header and steam generator determine the auxiliary feedwater flow. For about the first 100 s, all three generators have similar pressures and receive equal amounts of feedwater. After 100 s, the A loop steam generator has a slightly higher pressure (Figure 3.2.1-14) than the B and C loop generators. This results in more feedwater going to steam generators B and C and at times no feedwater going to steam generator A even though the level is well below the setpoint. Once generators B and C have refilled to the level setpoint, steam generator A receives all the auxiliary feedwater flow until it is refilled to the level setpoint.

Upon the reactor/turbine trip, the turbine stop valve closes, and the steam dump valve begins controlling to 7.03 MPa [1,020 psia]. Since the secondary side pressure is below 7.03 MPa [1,020 psia], as seen in Figure 3.2.1-14, the steam dump valve remains closed. In addition, none of the safety relief or atmospheric dump valves open. As a result, the feedwater and steam systems remain isolated for the duration of the transient. Up until about 3,000 s the steam generators are putting heat into the primary, resulting in a decrease in steam generator pressure. The pressure in steam generator C continues to fall gradually during the remainder of the event due to retaining some primary loop flow. Loop C retains some loop flow due to the break being in the surge line, which is connected to loop C.

As a consequence of the size of the surge line break it is shown that the break is capable of removing more than core decay heat. This leads to the downcomer fluid temperature decreasing to a minimum of 291 K [64.1°F] at approximately 1,000 s and again at approximately 2,000 s. Between 1,000 and 2,000 s, where the hot leg flow oscillations were observed, increased mixing in the downcomer occurred, thus moderately increasing the downcomer fluid temperature. The pressure during this time was approximately 0.21 MPa [30 psia]. There is no mechanism which would allow the primary system to repressurize.

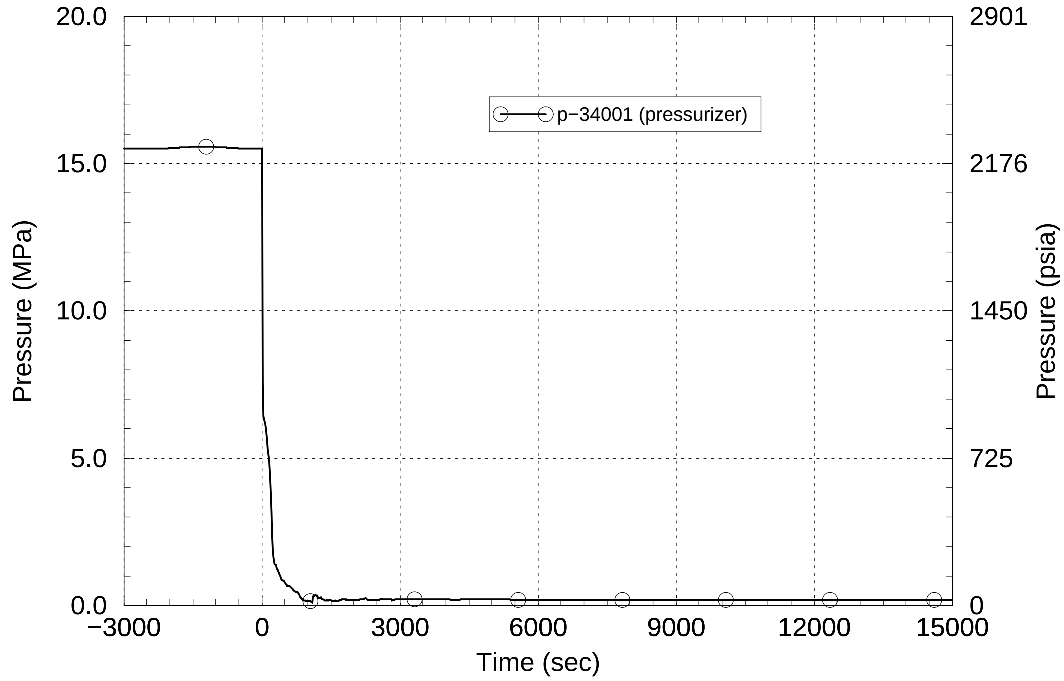


Figure 3.2.1-1   Primary System Pressure – BV Case 007

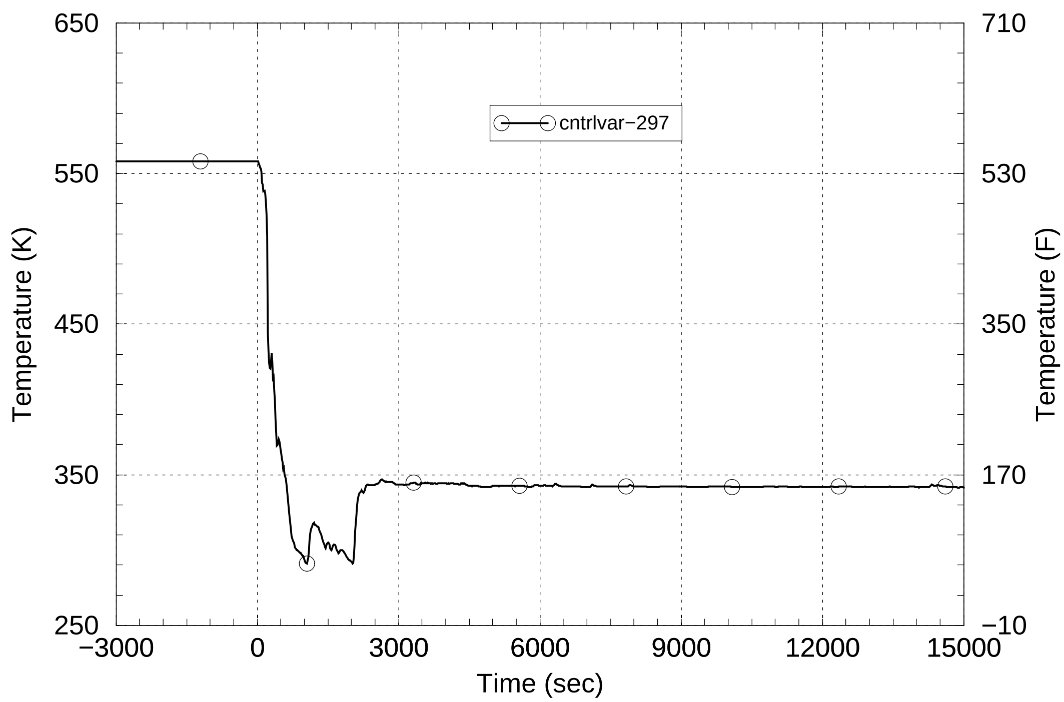


Figure 3.2.1-2   Average Downcomer Fluid Temperature – BV Case 007

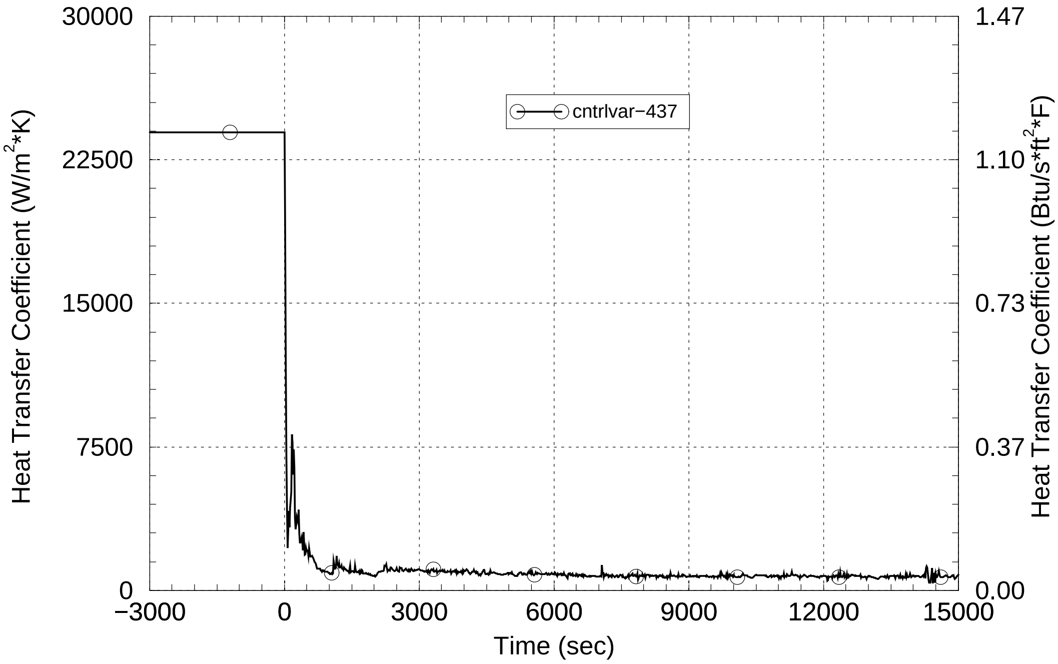


Figure 3.2.1-3   Downcomer Wall Heat Transfer Coefficient – BV Case 007

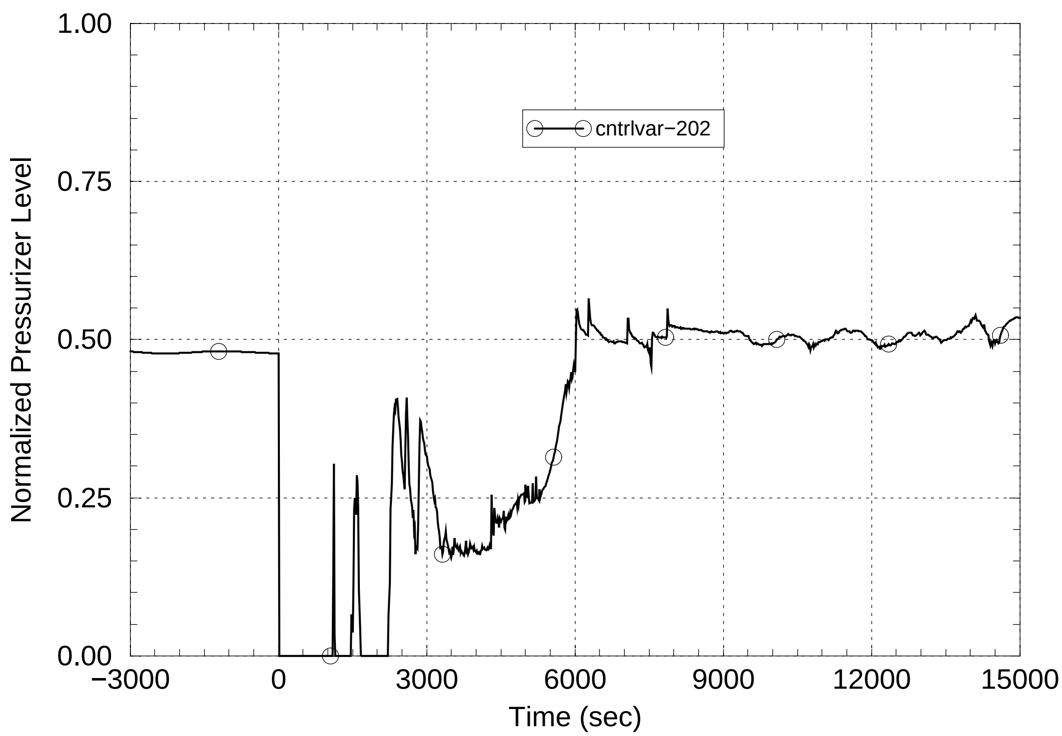


Figure 3.2.1-4   Pressurizer Water Level – BV Case 007

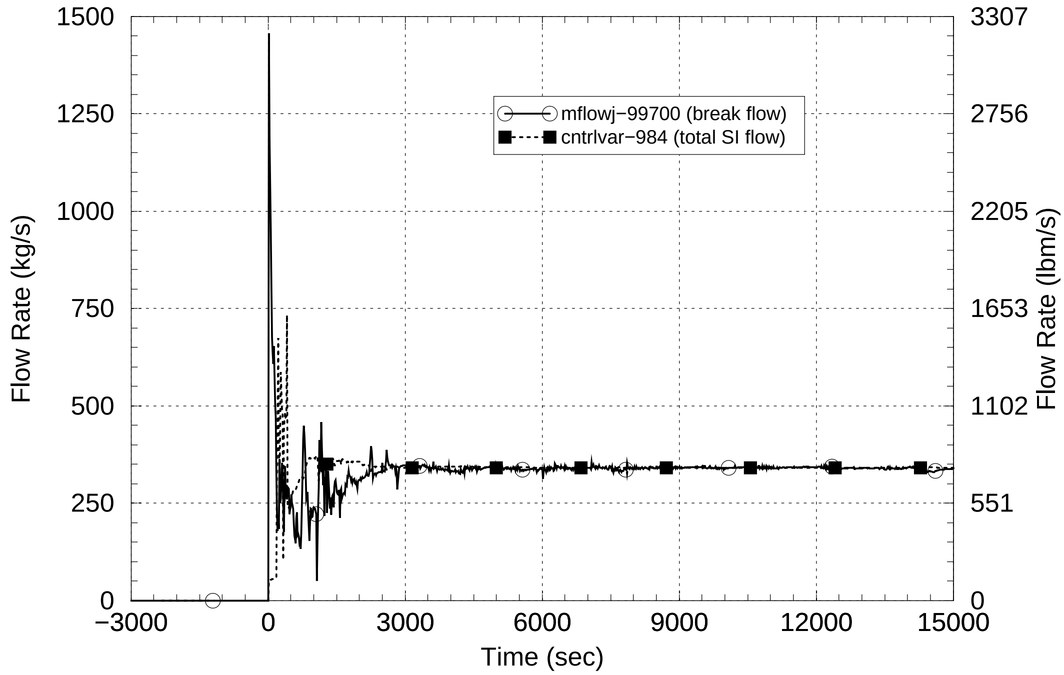


Figure 3.2.1-5   Break Flow and Total Safety Injection Flow – BV Case 007

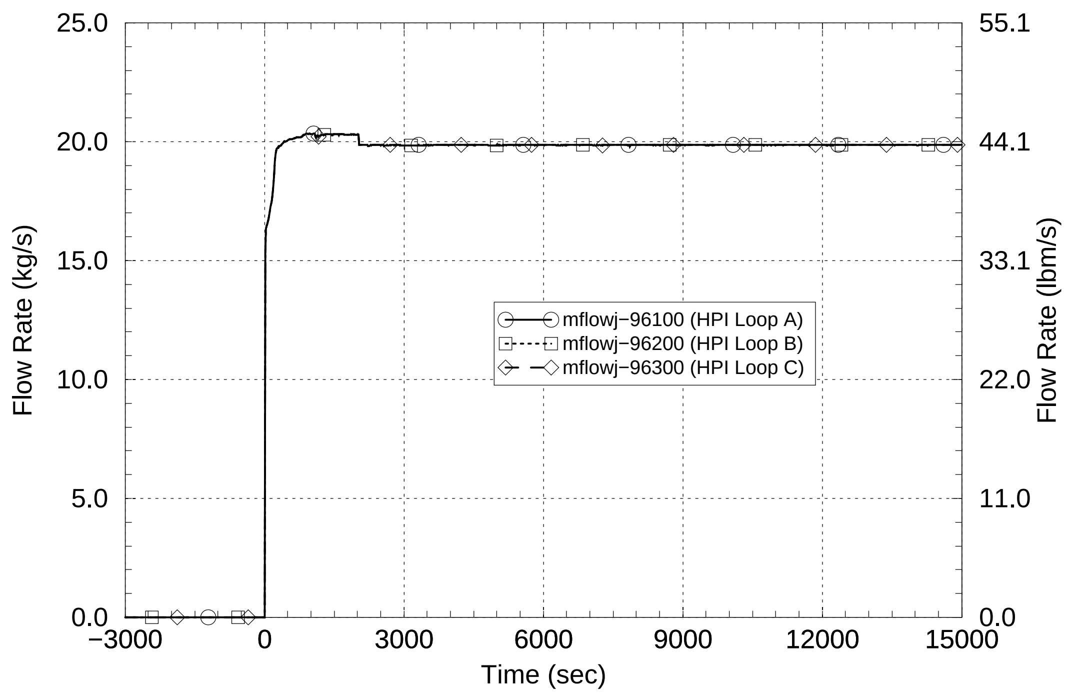


Figure 3.2.1-6   High Pressure Injection Flow Rate – BV Case 007

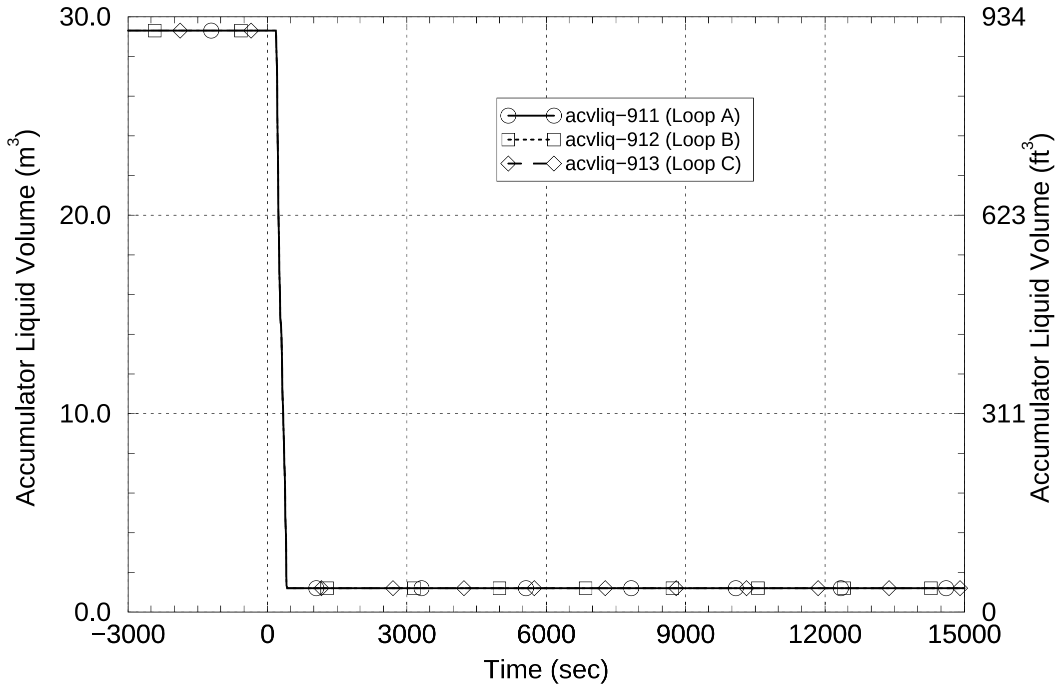


Figure 3.2.1-7 Accumulator Liquid Volume for – BV Case 007

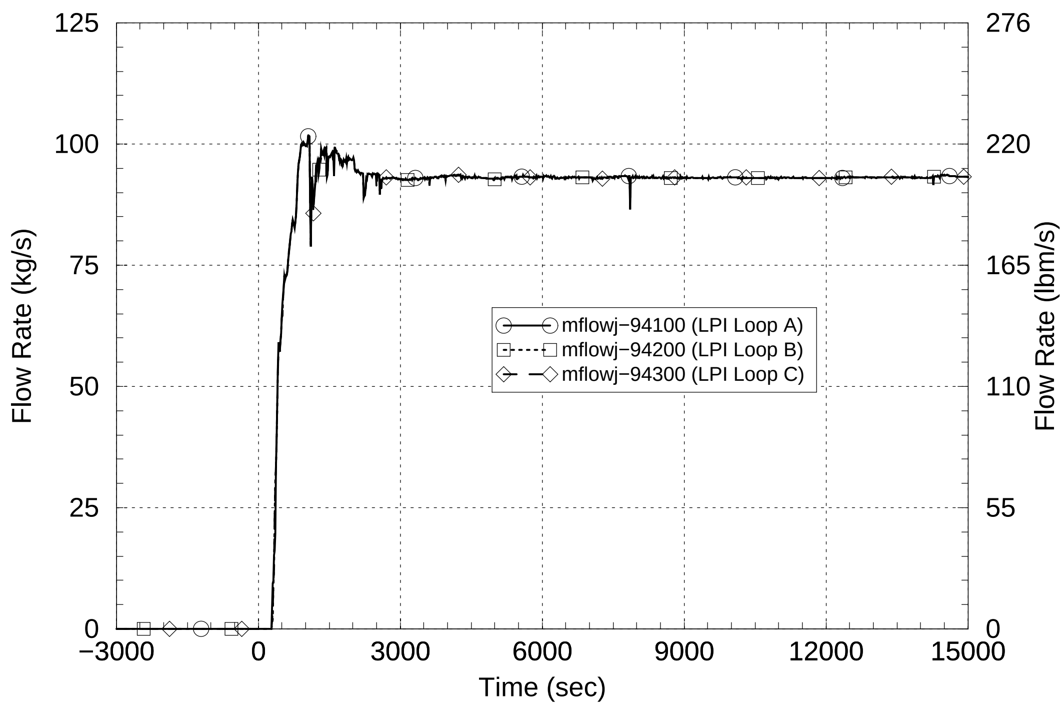


Figure 3.2.1-8 Low Pressure Injection Flow Rate – BV Case 007

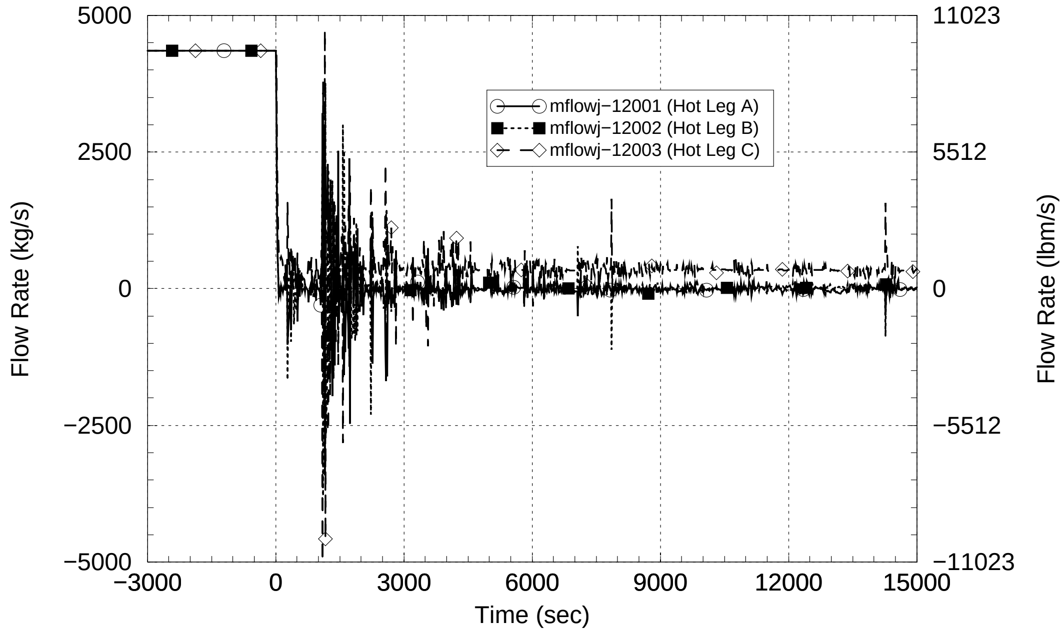


Figure 3.2.1-9   Hot Leg Mass Flow Rate – BV Case 007

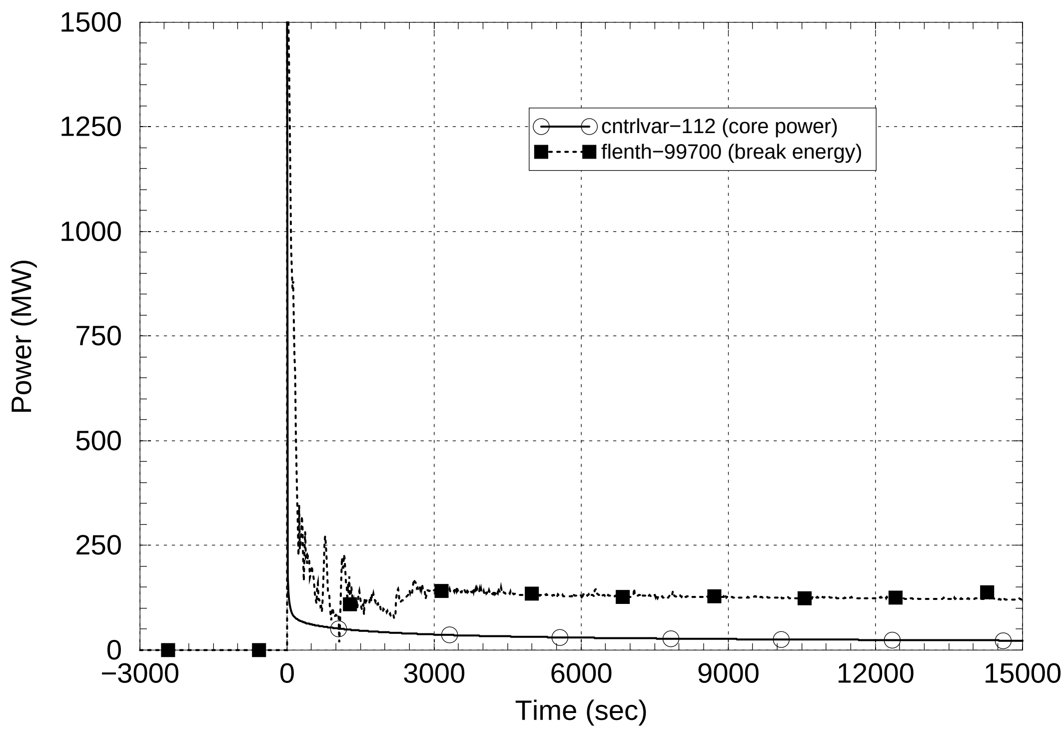


Figure 3.2.1-10   Core Power and Break Energy – BV Case 007

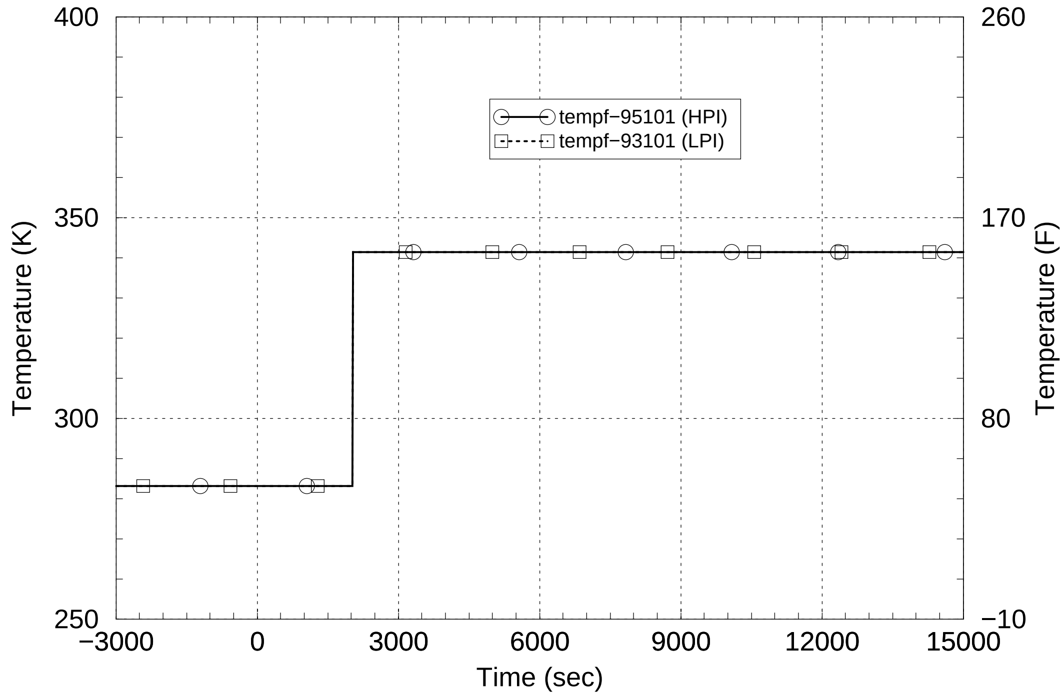


Figure 3.2.1-11   Safety Injection Fluid Temperature – BV Case 007

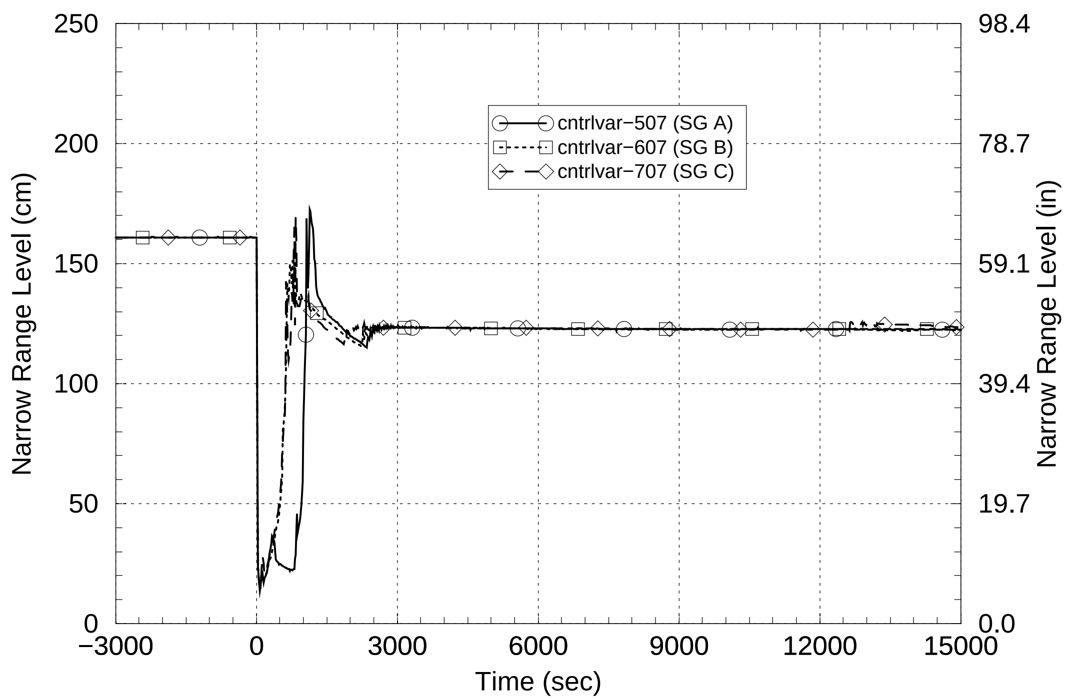


Figure 3.2.1-12   Steam Generator Narrow Range Water Level – BV Case 007

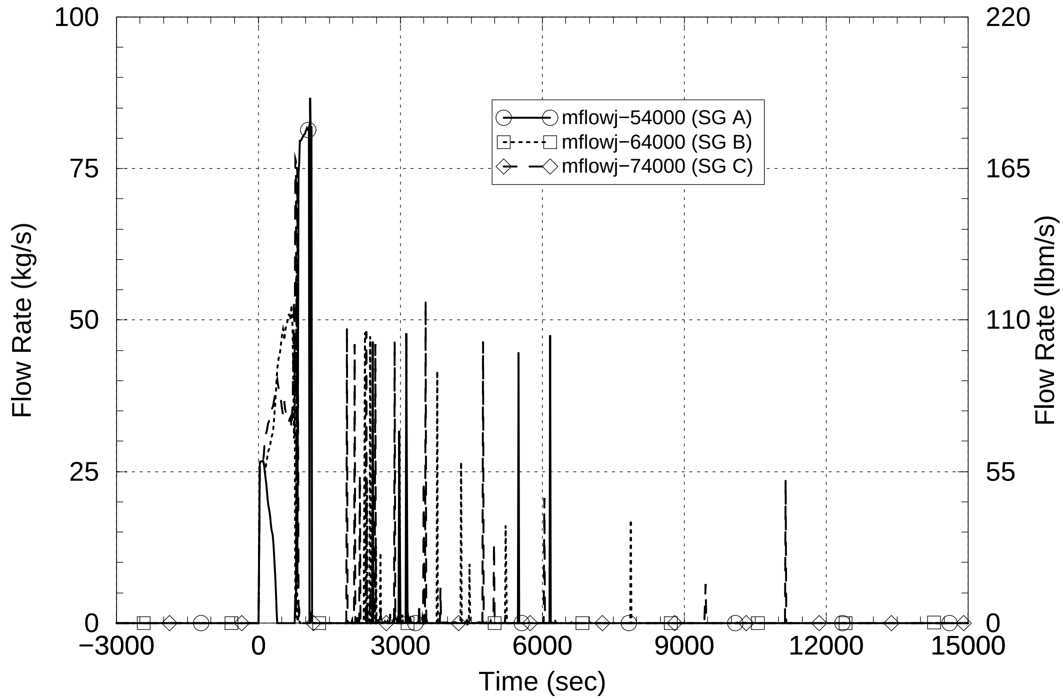


Figure 3.2.1-13 Auxiliary Feedwater Flow Rate – BV Case 007

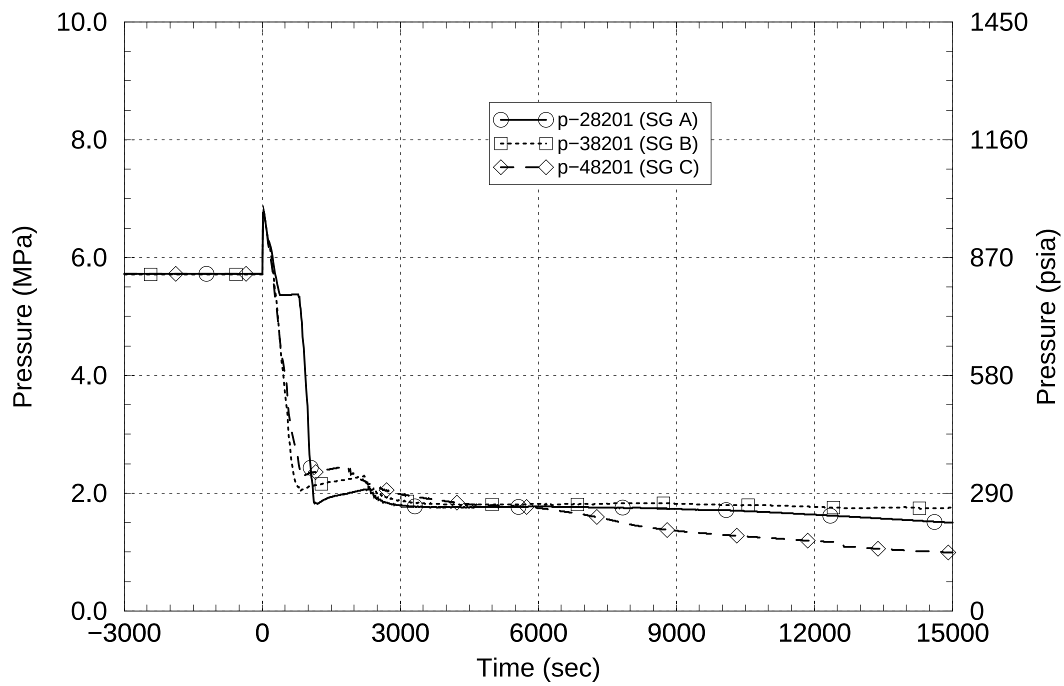


Figure 3.2.1-14 Steam Generator Pressure – BV Case 007

3.2.1.2 Beaver Valley Hot Leg Break from Hot Full Power – 40.64 cm [16.0 in] diameter (BV Case 009)

This case is a 40.64 cm [16.0 in] diameter surge line break from hot full power. This case is identified as Beaver Valley Case 009 in Appendix B, Table B-1. The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.1-15 through 3.2.1-17, respectively.

As a result of the break, the primary system rapidly depressurizes as shown in Figure 3.2.1-15 and remains near atmospheric for the remainder of the transient. In addition, the pressurizer level (shown in Figure 3.2.1-18) also decreased rapidly due to inventory loss and was completely empty by 15 s. The pressurizer never refilled during the 15,000 s transient.

At 0.036 s, a reactor/turbine trip occurred due to low primary pressure. At approximately 3.04 s, a SIAS was generated. The SIAS results in actuation of both the HHSI, and LHSI. In addition, it also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated.

A plot of break flow versus total safety injection flow is provided as Figure 3.2.1-19. Total SI flow includes high pressure injection, low pressure injection, accumulators and charging/letdown. High pressure injection flow is shown in Figure 3.2.1-20. Initially, break flow is much larger than safety injection flow. By 30 s the primary pressure has decreased to below the accumulator pressure, resulting in accumulator injection as shown in Figure 3.2.1-21. With this additional flow, the total SI flow is now greater than the break flow. At 45 s, the low pressure injection begins as shown in Figure 3.2.1-22. At 90 s, the accumulators have emptied and injection stops. Note that the accumulators were isolated when the liquid level was near the bottom. This was done to stop non-condensible gases from entering the system. These non-condensible gases frequently cause numerical problems in RELAP5 which lead to code failures.

From about 1,000 s to 2,000 s, the break quality is oscillating between zero and one. This results in the oscillatory break flow behavior shown in Figure 3.2.1-19. By 2,000 s the hot leg has refilled, however, some voiding occurs until 6,500 s. By 2,500 s, the safety injection flow and break flow are equal for the remainder of the transient.

At approximately 7.5 s, the reactor coolant pumps were tripped due to an operator action. This causes the flow in the loops to decrease to near zero. Figure 3.2.1-23 presents the hot leg mass flow for all three loops at the exit of the vessel. At around 1,000 s there are significant flow oscillations which last until about 2,000 s. These oscillations appear to be due to condensation effects in the primary tubes of the steam generators. The code is predicting that the steam generator primary tubes void completely by about 100 s. Around 1,000 s, some liquid begins to fill the bottom of the primary tubes on the hot leg side. At this time, some nodes in the primary tubes are condensing liquid while the bottom-most node is boiling. This condensation/vaporization causes pressure waves which drive the oscillatory flow behavior. By 2,000 s, the large oscillations have stopped and the only loop which has flow is the A loop, which contains the break. From 2,000 s on, the primary steam generator tubes remain completely voided.

Figure 3.2.1-17 shows the downcomer fluid-wall heat transfer coefficient. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops quickly from an initial value of approximately 23,950 $W/m^2 \cdot K$ [1.171 $Btu/s \cdot ft^2 \cdot {}^\circ F$]. The heat transfer coefficient then gradually decreases to a value of around 750 $W/m^2 \cdot K$ [0.037 $Btu/s \cdot ft^2 \cdot {}^\circ F$] by the end of the transient.

Figure 3.2.1-24 shows the core power versus the energy lost through the break. As seen in this figure, the break energy is larger than the core decay heat, thus, heat is being removed from the system causing the temperature to decrease. The average downcomer fluid temperature is shown in Figure 3.2.1-16. In addition to the heat lost through the break and core decay heat considerations, the safety injection water temperature plays a role in the downcomer fluid temperature. Initially, the high pressure injection and low pressure injection are at 283 K [50°F], however, after the reactor water storage tank (RWST) has depleted, the source of injection water becomes the containment sump. After switchover to sump recirculation at 1,693 s, the injection temperature is increased to 341 K [155°F] as shown in Figure 3.2.1-25. Looking at Figure 3.2.1-16 shows that the sump temperature significantly affects the downcomer fluid temperature.

Figure 3.2.1-26 shows the steam generator narrow range water level. Upon the SIAS being generated, the MFW is isolated and the steam generator level immediately drops. AFW is started, and begins refilling the generators to the desired post-trip setpoint of 33% NRL (120.7 cm [47.52 in]). Figure 3.2.1-27 shows the auxiliary feedwater flow. For about the first 30 s, all three generators have similar pressures and receive equal amounts of feedwater. After 30 s, the C loop steam generator has a slightly higher pressure (Figure 3.2.1-28) than the A and B loop generators. This results in more feedwater going to steam generators A and B and at times no flow going to steam generator C even though the level is well below the setpoint. Once generators A and B have refilled to the level setpoint, steam generator C receives all the auxiliary feedwater flow until it is refilled to the level setpoint.

Upon the reactor/turbine trip, the turbine stop valve closes, and the steam dump valve begins controlling to 7.03 MPa [1020 psia]. Since the secondary side pressure is below 7.03 MPa [1020 psia] as seen in Figure 3.2.1-28, the steam dump valve remain closed. In addition, none of the safety relief or atmospheric dump valves open. As a result, the feedwater and steam systems remain isolated for the duration of the transient. Up until about 2,000 s the steam generators are putting heat into the primary, resulting in a decrease in steam generator pressure.

As a consequence of the size of the hot leg break it is shown that the break is capable of removing more than core decay heat. This leads to the downcomer fluid temperature decreasing to a minimum of 291 K [64.1°F] at approximately 1,000 s and again at approximately 1,650 s. Between 1,000 and 2,000 s were the hot leg flow oscillations which resulted in greater mixing in the downcomer thus moderately increasing the fluid temperature. The pressure during this time was approximately 0.097 MPa [14.0 psia]. There is no mechanism which would allow the primary to repressurize.

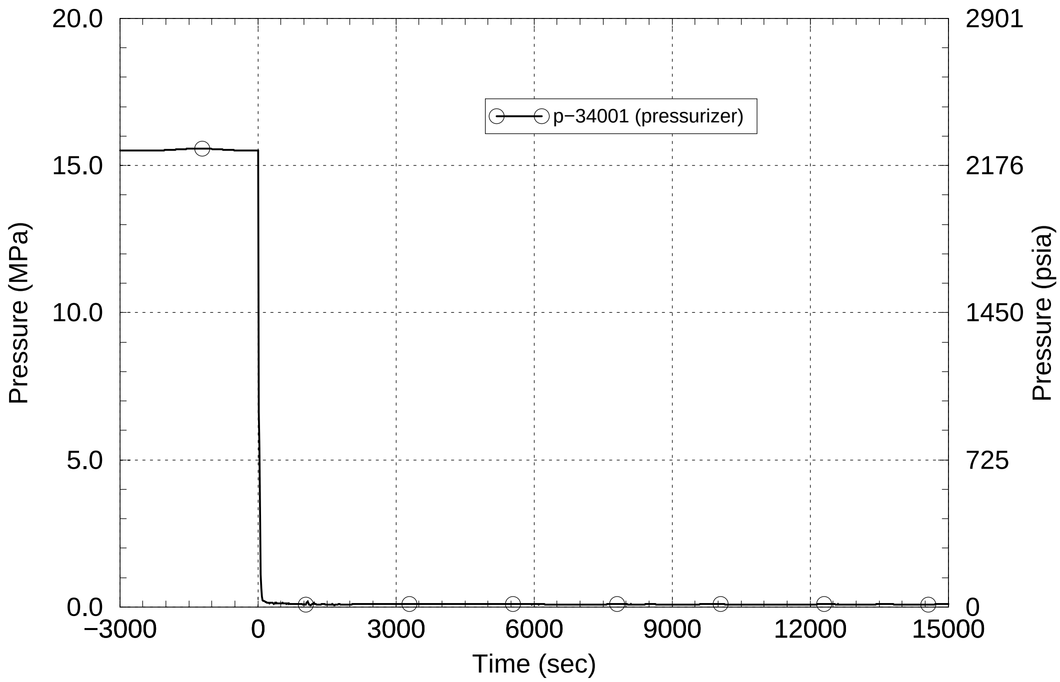


Figure 3.2.1-15 Primary System Pressure for – BV Case 009

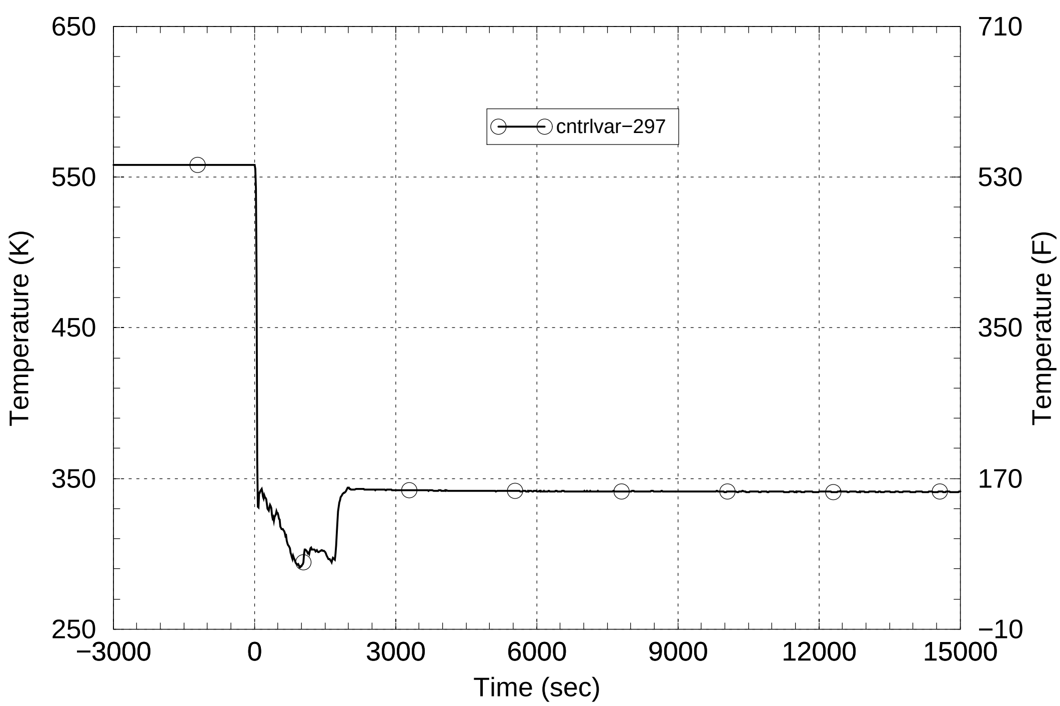


Figure 3.2.1-16 Average Downcomer Fluid Temperature – BV Case 009

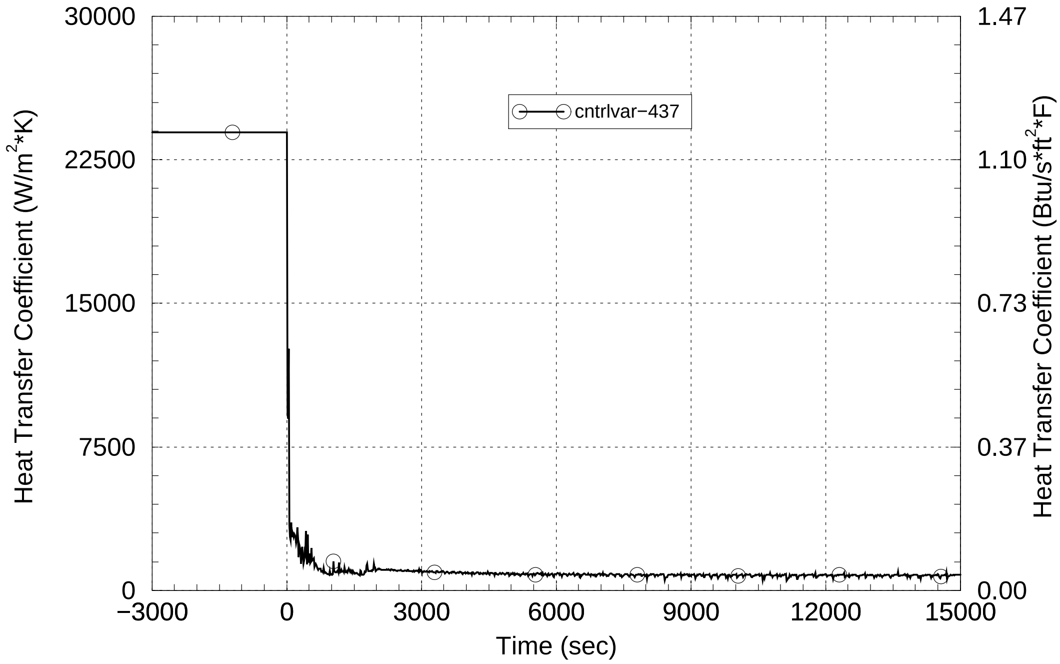


Figure 3.2.1-17 Downcomer Wall Heat Transfer Coefficient – BV Case 009

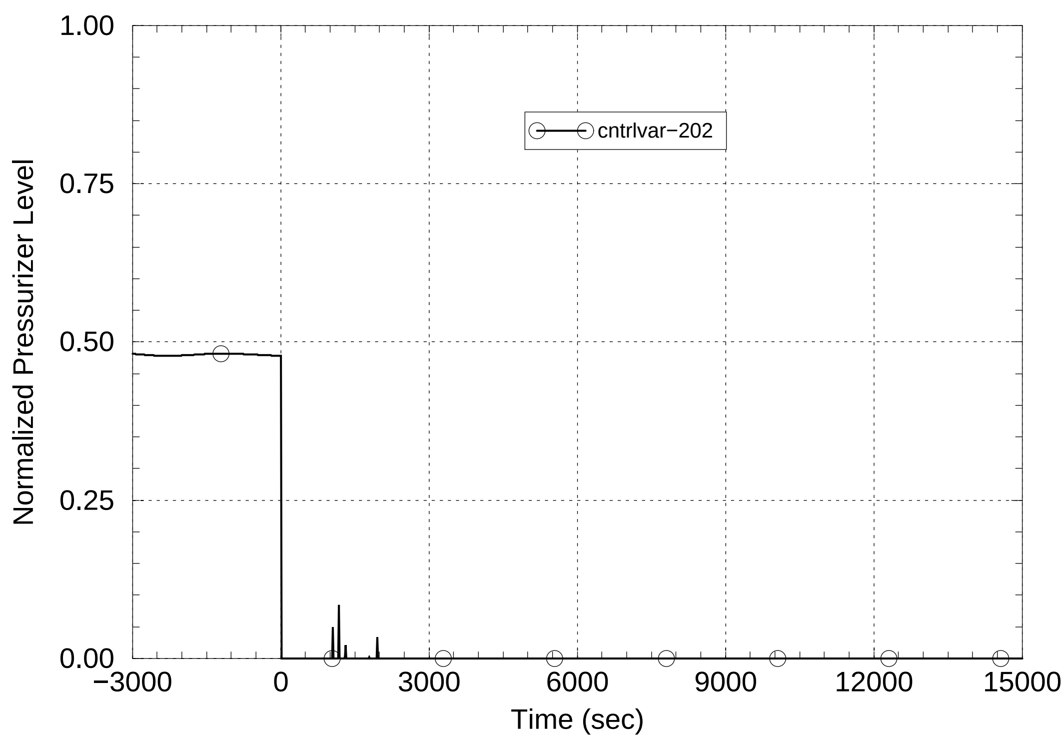


Figure 3.2.1-18 Pressurizer Water Level – BV Case 009

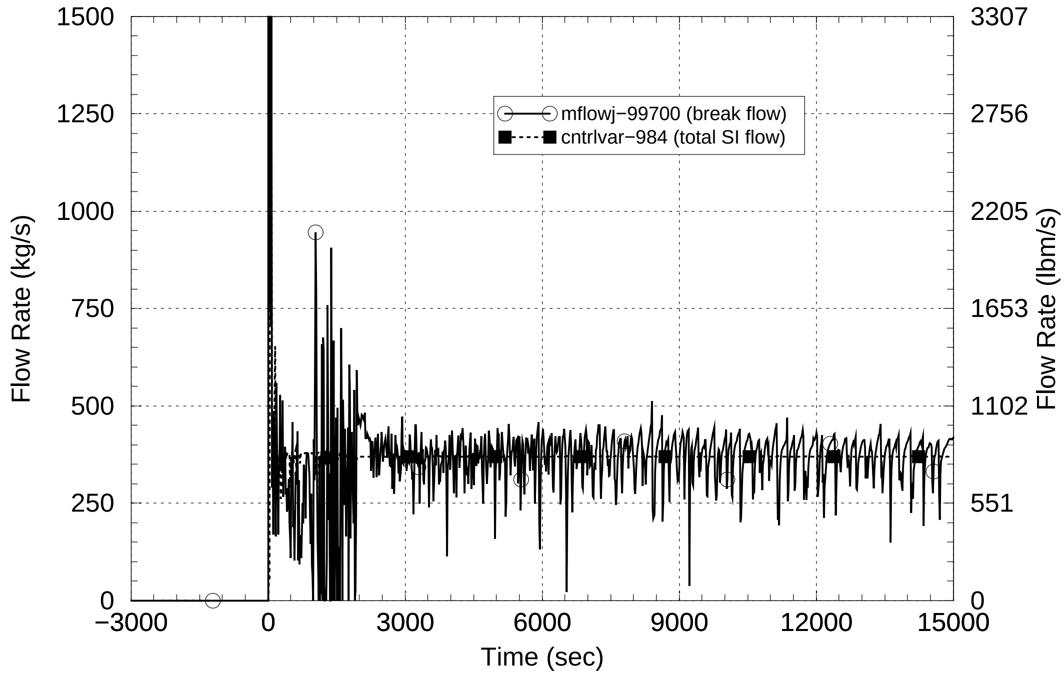


Figure 3.2.1-19 Break Flow and Total Safety Injection Flow – BV Case 009

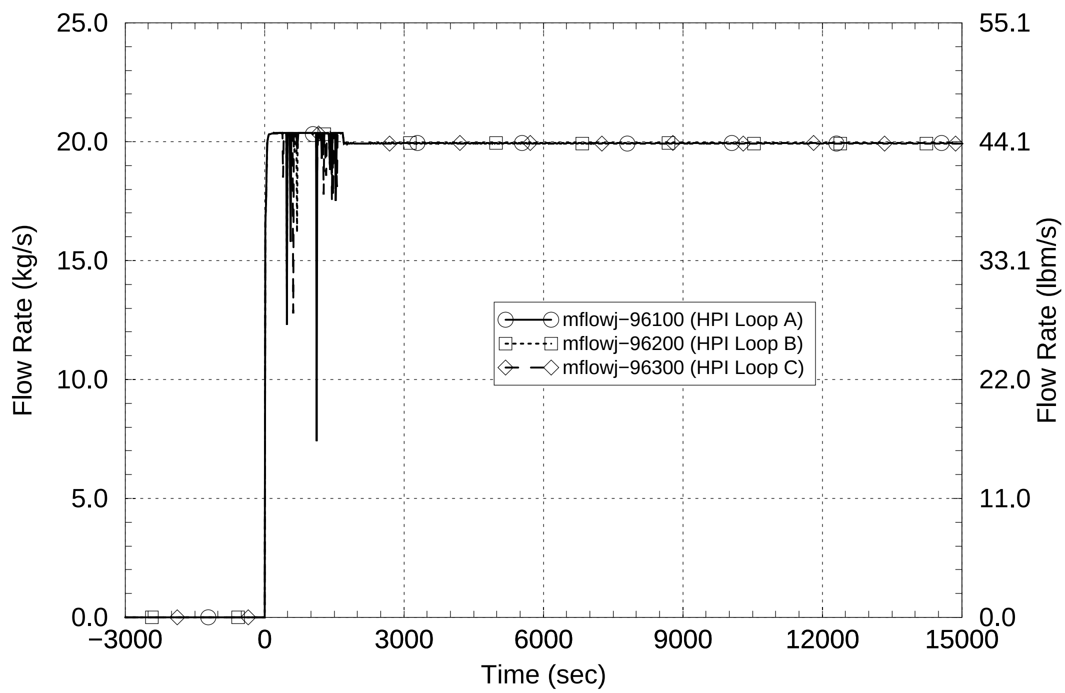


Figure 3.2.1-20 High Pressure Injection Flow Rate – BV Case 009

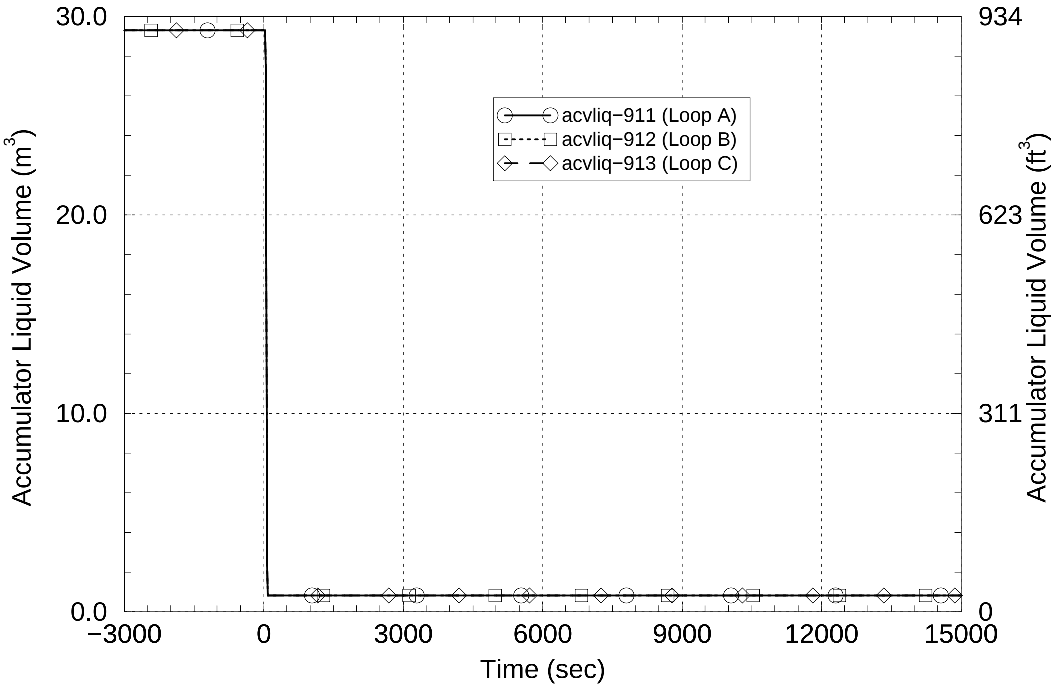


Figure 3.2.1-21 Accumulator Liquid Volume – BV Case 009

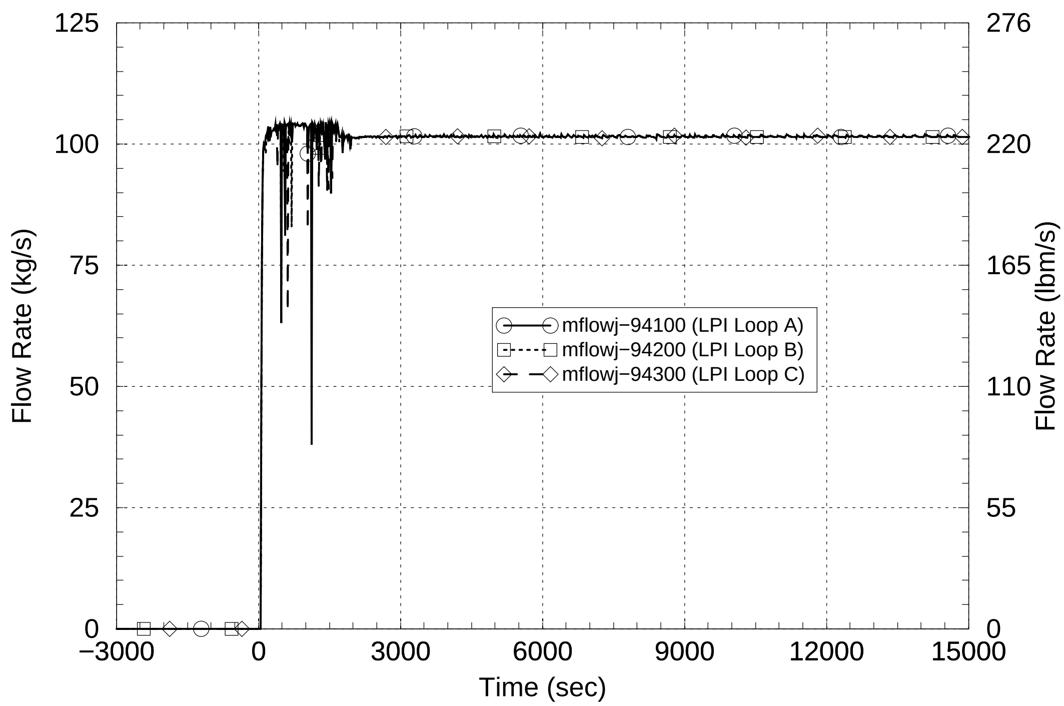


Figure 3.2.1-22 Low Pressure Injection Flow Rate – BV Case 009

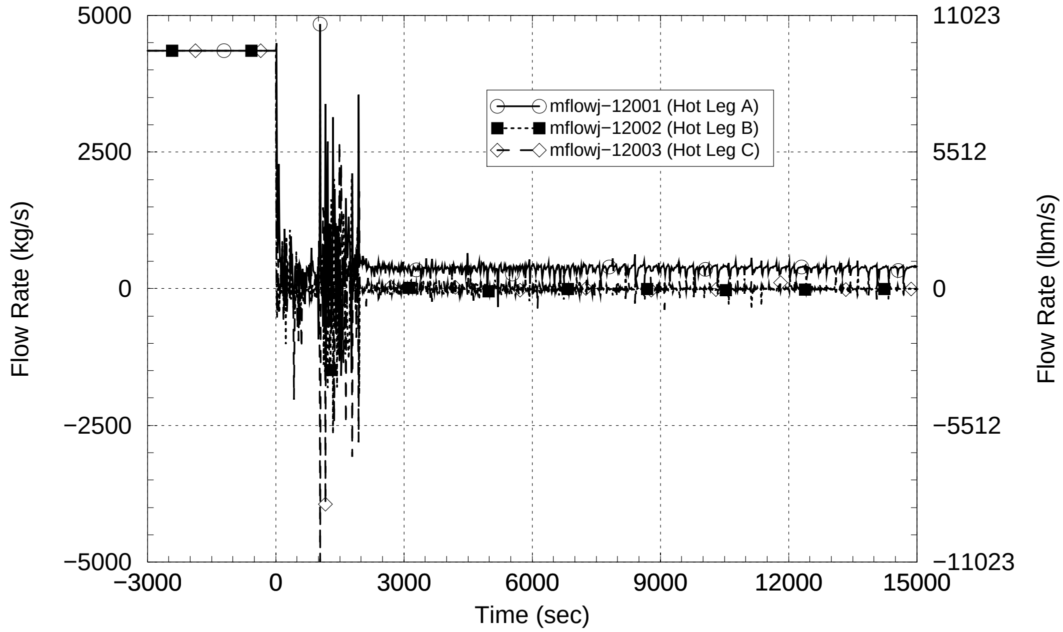


Figure 3.2.1-23 Hot Leg Mass Flow Rate – BV Case 009

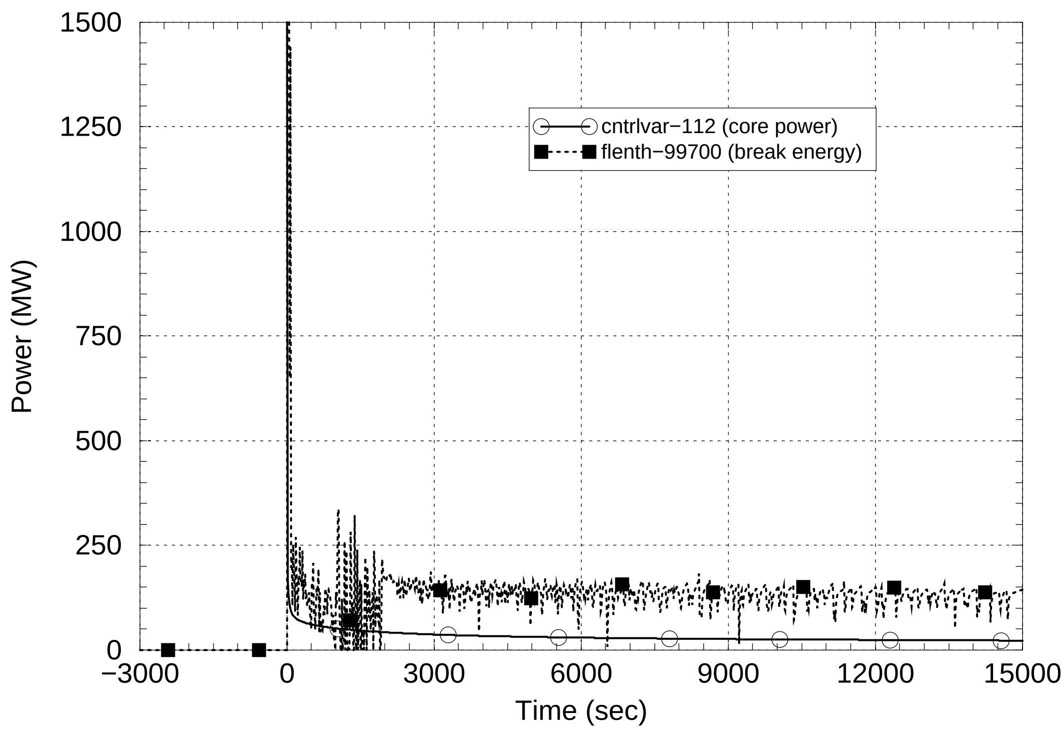


Figure 3.2.1-24 Core Power and Break Energy – BV Case 009

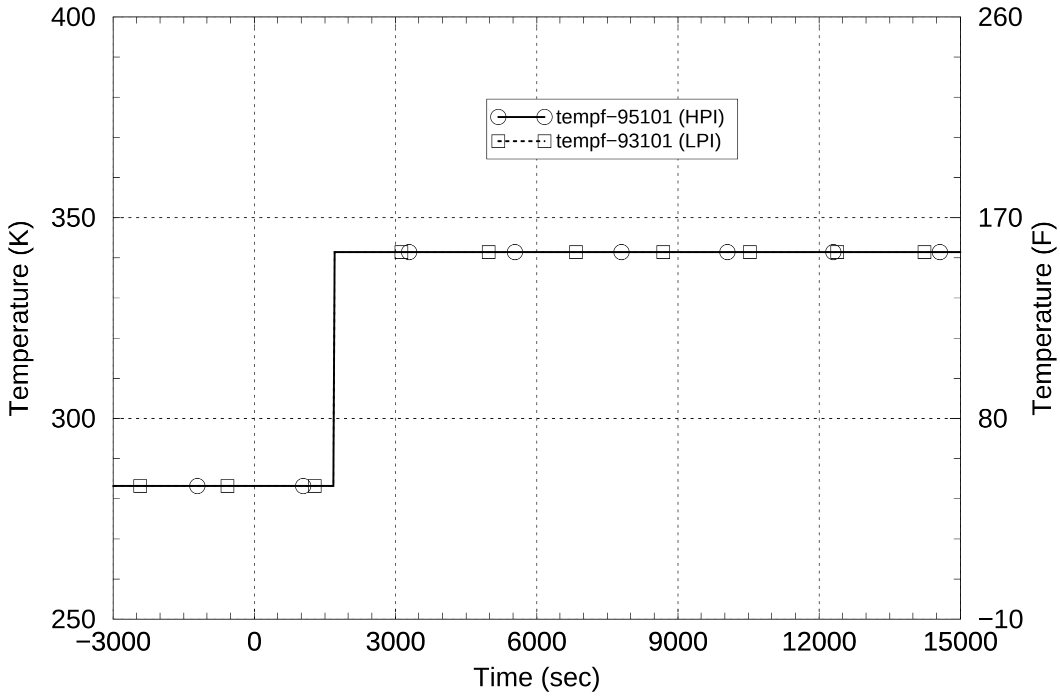


Figure 3.2.1-25 Safety Injection Fluid Temperature – BV Case 009

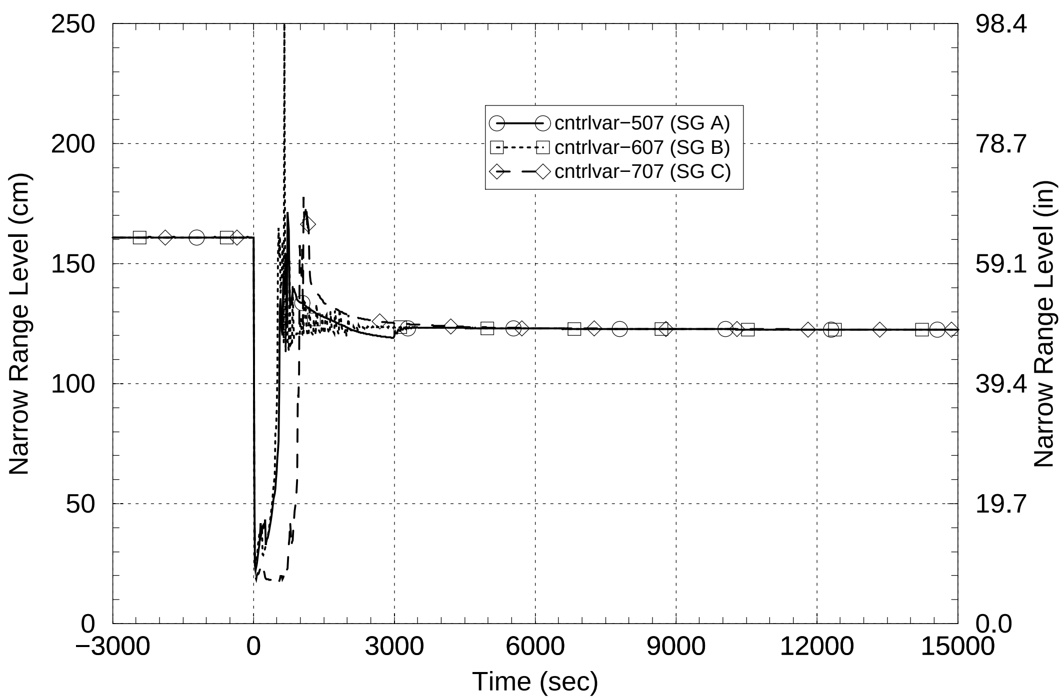


Figure 3.2.1-26 Steam Generator Narrow Range Water Level – BV Case 009

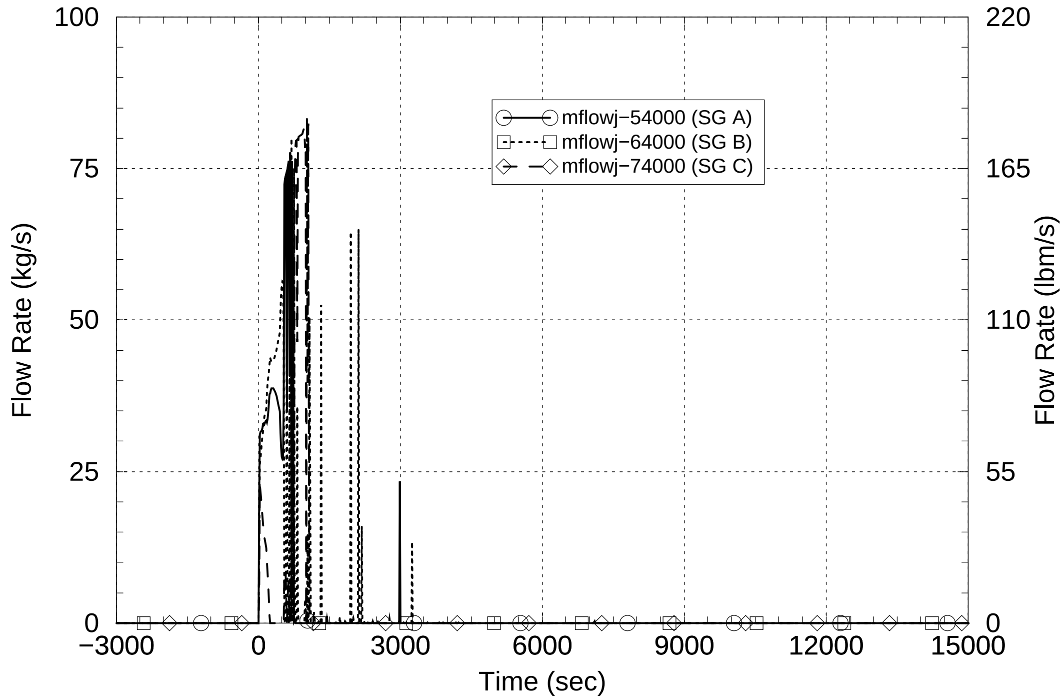


Figure 3.2.1-27   Auxiliary Feedwater Flow Rate – BV Case 009

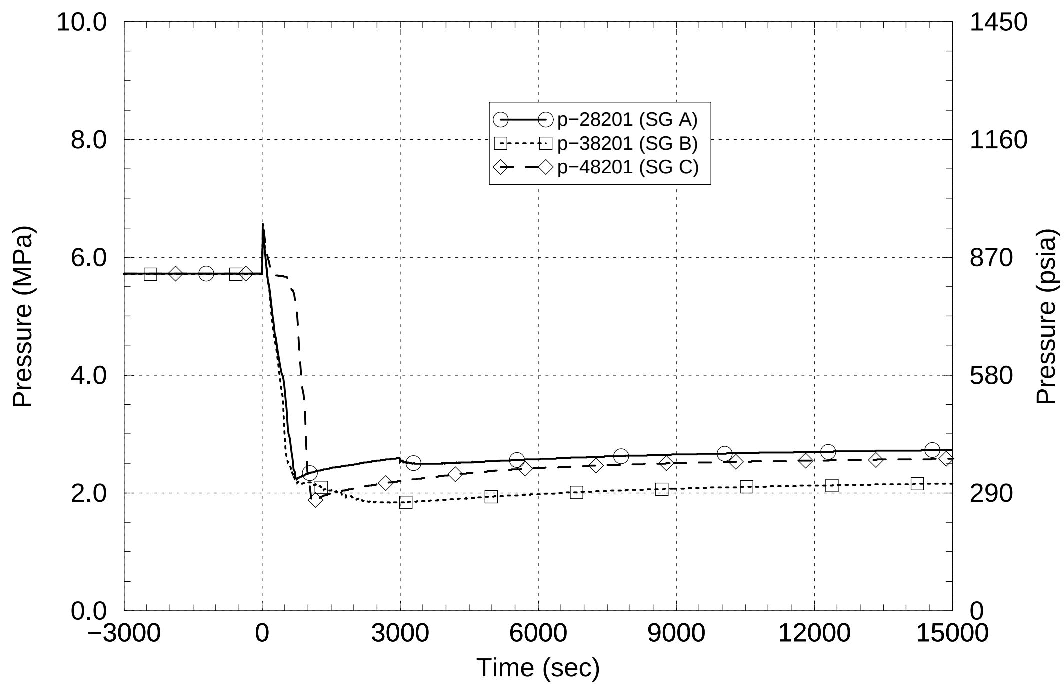


Figure 3.2.1-28   Steam Generator Pressure – BV Case 009

3.2.1.3 Beaver Valley Surge Line Break from Hot Full Power - 7.184 cm [2.828 in] diameter, with summer ECCS temperature and increased heat transfer (BV Case 114)

This case is a 7.184 cm [2.828 in] diameter surge line break from hot full power with summer ECCS temperatures and increased heat transfer. This case is identified as Beaver Valley Case 114 in Appendix B, Table B-1. For the assumed summer ECCS conditions, the HHSI and LHSI fluid temperatures are increased from 283.1 K [50°F] to 285.9 K [55°F] (maximum allowed by technical specifications). The accumulator fluid temperature was increased from 305.4 K [90°F] to 313.7 K [105°F]. In addition this case assumed that heat transfer to passive structures was increased by 30%. This change was made in the RELAP5 model by increasing the heat structure surface area by 30% on all heat structures with the following exceptions; core, steam generator tubes and pressurizer heaters.

The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.1-29 through 3.2.1-31, respectively.

As a result of the break, the primary system rapidly depressurizes as shown in Figure 3.2.1-29. In addition, the pressurizer level (shown in Figure 3.2.1-32) also decreased rapidly due to loss of inventory and was completely empty by 30 s. At 13.8 s, a reactor/turbine trip occurred due to low primary pressure. At 17.7 s, a safety injection actuation signal (SIAS) was generated. The SIAS results in actuation of both the high head safety injection (HHSI), and low head safety injection (LHSI). Note that actuation does not necessarily mean that a system begins working immediately. In this case, while LHSI is actuated, it will not begin flow until the primary pressure falls below the pump shutoff head. In addition, the SIAS also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated.

A plot of break flow versus total safety injection (SI) flow is provided as Figure 3.2.1-33. Total SI flow includes high pressure injection, low pressure injection, accumulators and charging/letdown. High pressure injection flow is shown in Figure 3.2.1-34. Initially, break flow is much larger than safety injection flow. By 1,050 s the primary pressure has decreased to below the accumulator pressure, resulting in accumulator injection as shown in Figure 3.2.1-35. With this additional flow, the total SI flow is now equal to or greater than the break flow. At 3,030 s primary pressure is below the low head safety injection (LHSI) shutoff head, and LHSI flow begins as shown in Figure 3.2.1-36. At 3,540 s, the accumulators have emptied and injection stops. Note that the accumulators were isolated when the liquid level was near the bottom of the tank. This was done to stop non-condensible gases from entering the system. These non-condensible gases frequently cause numerical problems in RELAP5 which lead to code failures. By 5,000 s, the safety injection flow and break flow are equal for the remainder of the transient.

At 49.5 s, the reactor coolant pumps were tripped due to an operator action. This causes the flow in the loops to decrease to near zero. Figure 3.2.1-37 presents the hot leg mass flow for all three loops at the exit of the vessel. At around 3,500 s there are significant flow oscillations which last until about 4,500 s. These oscillations appear to be due to condensation effects in the primary tubes of the steam generators. The code is predicting that the steam generator primary tubes void completely by about 600 s. When they begin to refill around 3,500 s, some nodes in the primary tubes are condensing liquid while others are boiling. The condensation/vaporization causes pressure waves which drive the oscillatory flow behavior. By 4,500 s, the large oscillations have stopped and the only loop which has flow is the C loop, which contains the break. Figure 3.2.1-31 shows the downcomer fluid-wall heat transfer coefficient. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops rapidly from an initial value of approximately 23,950 $W/m^2 \cdot K$ [1.171 $Btu/s \cdot ft^2 \cdot F$]. The heat transfer coefficient then gradually decreases to a value of around 600 $W/m^2 \cdot K$ [0.029 $Btu/s \cdot ft^2 \cdot F$] by the end of the transient.

Figure 3.2.1-38 shows the core power versus the energy lost through the break. As seen in this figure, the break energy is larger than the core decay heat, thus, heat is being removed from the system causing the temperature to decrease. The average downcomer fluid temperature is shown in Figure 3.2.1-30. In addition to the heat lost through the break and core decay heat considerations, the safety injection water temperature plays a role in the downcomer fluid temperature. Initially, the high pressure injection and low pressure injection are at 286 K [55°F], however, after the reactor water storage tank (RWST) has depleted, the source of injection water becomes the containment sump. After switchover to sump recirculation at 4,872 s, the injection temperature is increased to 341 K [155°F] as shown in Figure 3.2.1-39. Looking at Figure 3.2.1-30 shows that the sump temperature significantly affects the downcomer fluid temperature.

Figure 3.2.1-40 shows the steam generator narrow range water level. Upon the SIAS being generated, the MFW is isolated and the steam generator level immediately drops. AFW is started, and begins refilling the generators to the desired post-trip setpoint of 33% NRL (120.7 cm [47.52 in]). Figure 3.2.1-41 shows the auxiliary feedwater flow. The auxiliary feedwater system provides flow from the steam driven pump and one motor driven pump to a common header which then splits to each steam generator feedwater line. Flow from the other motor driven pump is delivered to a common header which then splits to each steam generator feedwater line. Flow losses were entered between the pumps and common headers as well as between the header and generators. Due to the use of a common header, the differential pressures between the header and steam generator determine the auxiliary feedwater flow. For about the first 100 s, all three generators have similar pressures and receive equal amounts of feedwater. After 100 s, the A loop steam generator has a slightly higher pressure (Figure 3.2.1-42) than the B and C loop generators. This results in more feedwater going to steam generators B and C and at times no feedwater going to steam generator A even though the level is well below the setpoint. Once generators B and C have refilled to the level setpoint, steam generator A receives all the auxiliary feedwater flow until it is refilled to the level setpoint.

Upon the reactor/turbine trip, the turbine stop valve closes, and the steam dump valve begins controlling to 7.03 MPa [1,020 psia]. Since the secondary side pressure is below 7.03 MPa [1,020 psia], as seen in Figure 3.2.1-42, the steam dump valve remains closed. In addition, none of the safety relief or atmospheric dump valves open. As a result, the feedwater and steam systems remain isolated for the duration of the transient. Up until about 1,600 s the steam generators are putting heat into the primary, resulting in a decrease in steam generator pressure. The pressure in steam generator C continues to fall gradually during the remainder of the event due to retaining some primary loop flow. Loop C retains some loop flow due to the break being in the surge line, which is connected to loop C.

As a consequence of the size of the surge line break it is shown that the break is capable of removing more than core decay heat. This leads to the downcomer fluid temperature decreasing to a minimum of 304 K [87.5°F] at approximately 4,890 s. Between 3,500 and 4,500 s, where the hot leg flow oscillations were observed, increased mixing in the downcomer occurred, thus moderately increasing the downcomer fluid temperature. The pressure during this time was approximately 1.15 MPa [167 psia]. There is no mechanism which would allow the primary system to repressurize.

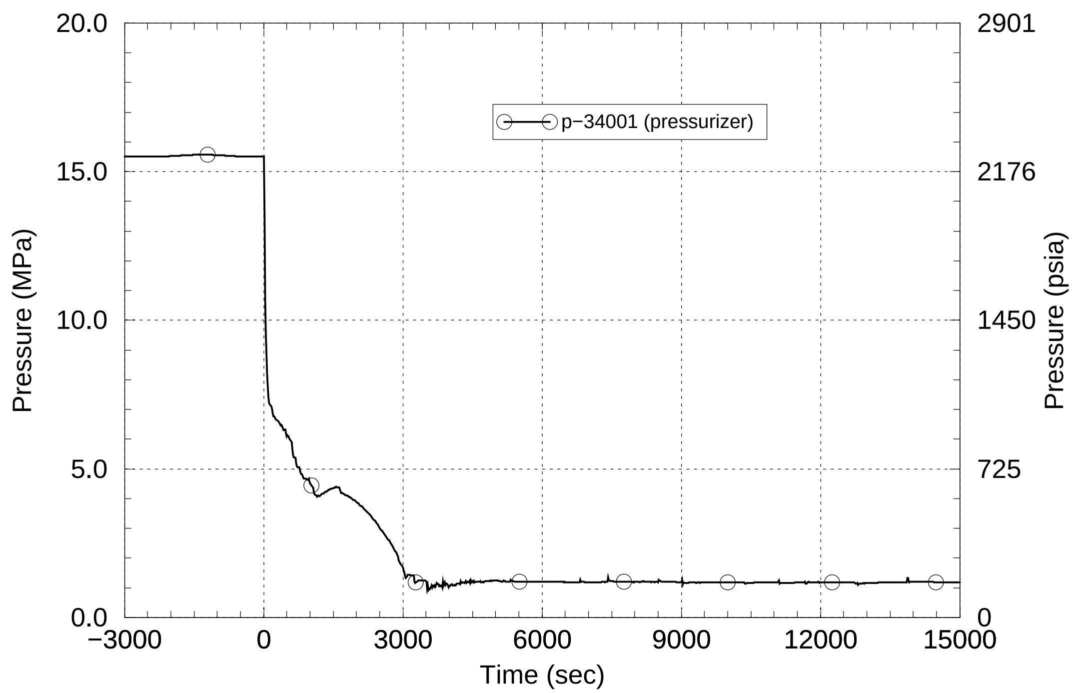


Figure 3.2.1-29   Primary System Pressure - BV Case 114

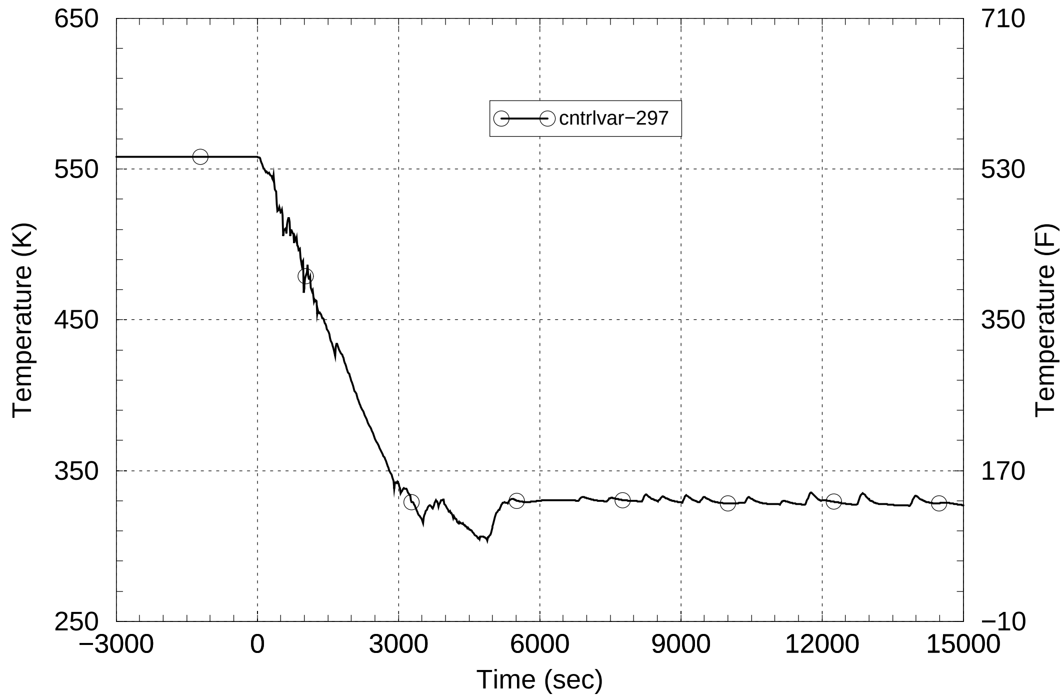


Figure 3.2.1-30 Average Downcomer Fluid Temperature - BV Case 114

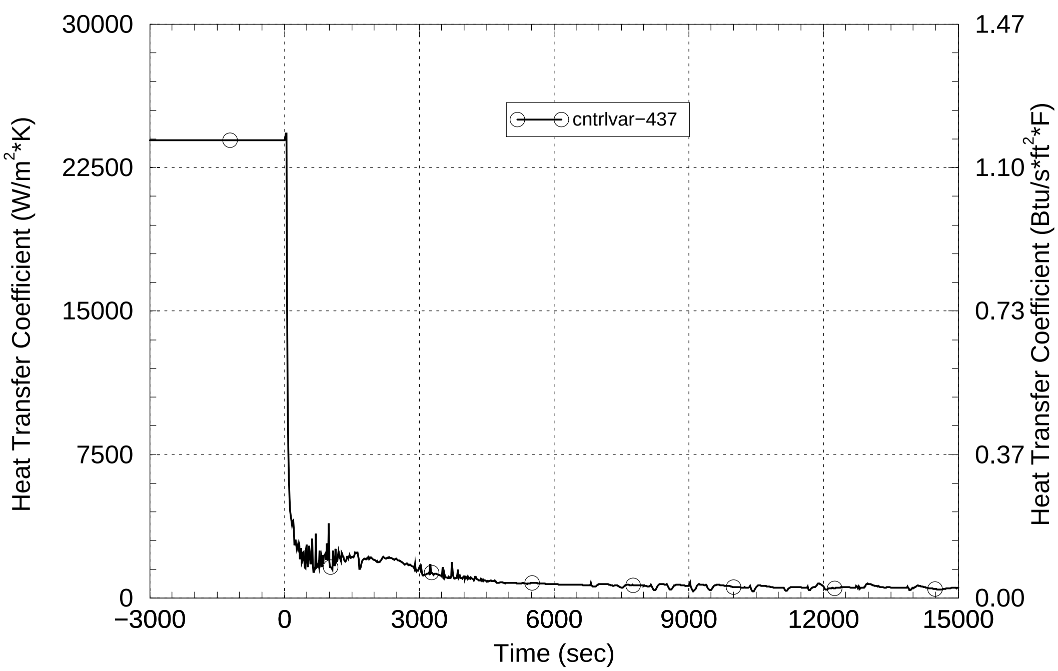


Figure 3.2.1-31 Downcomer Wall Heat Transfer Coefficient - BV Case 114

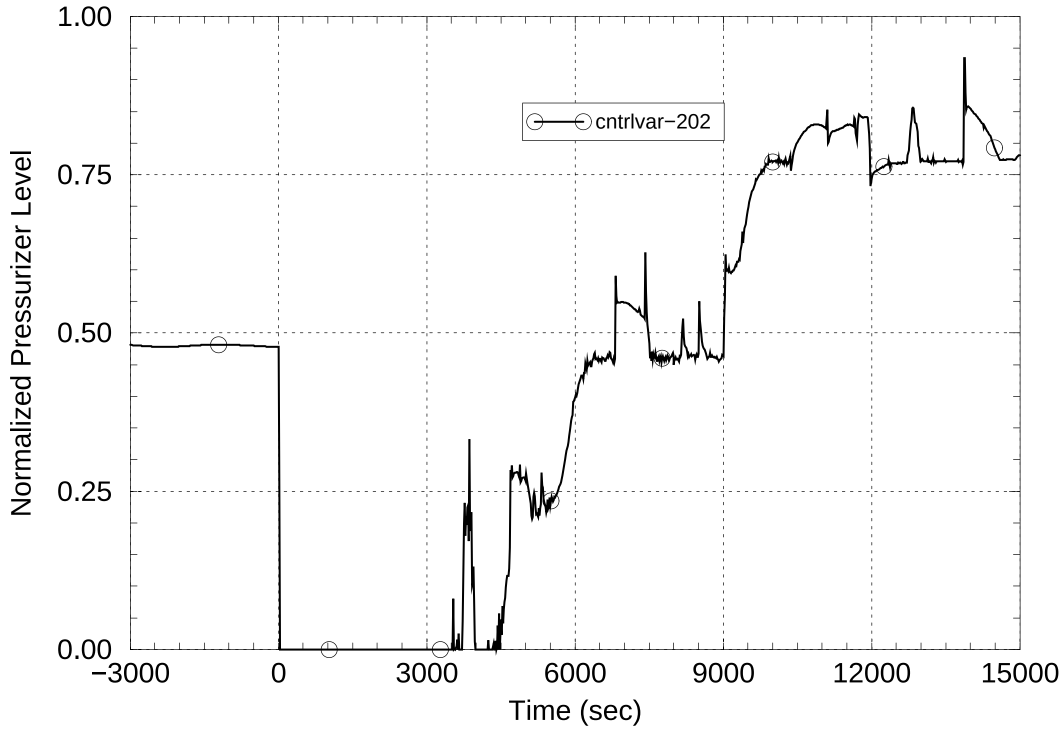


Figure 3.2.1-32 Pressurizer Water Level - BV Case 114

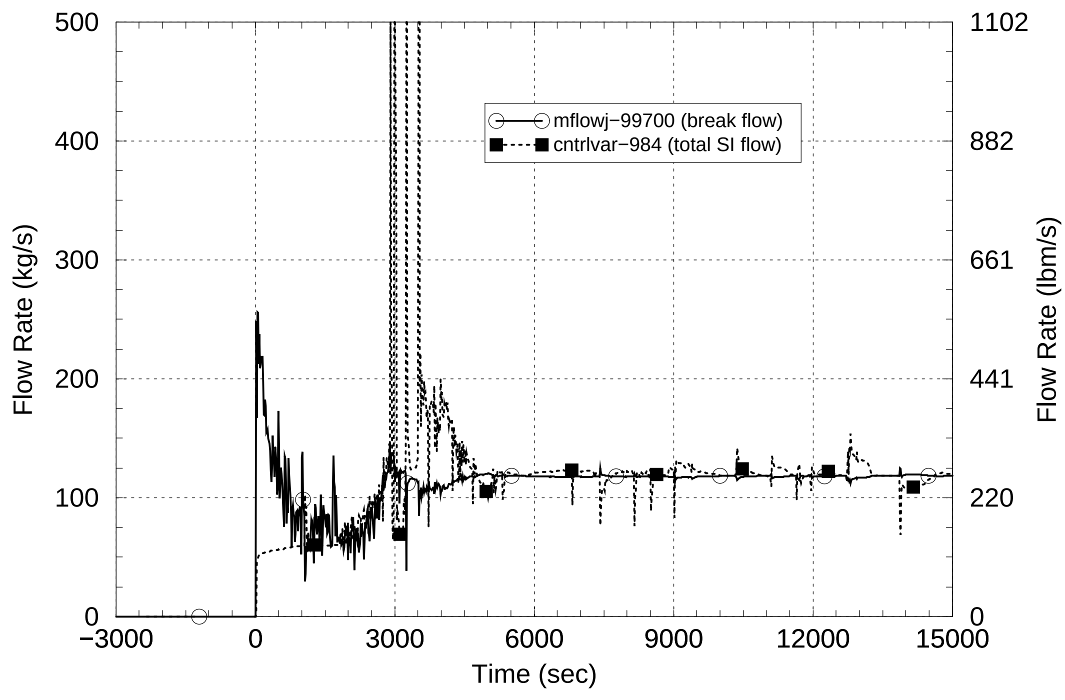


Figure 3.2.1-33 Break Flow and Total Safety Injection Flow - BV Case 114

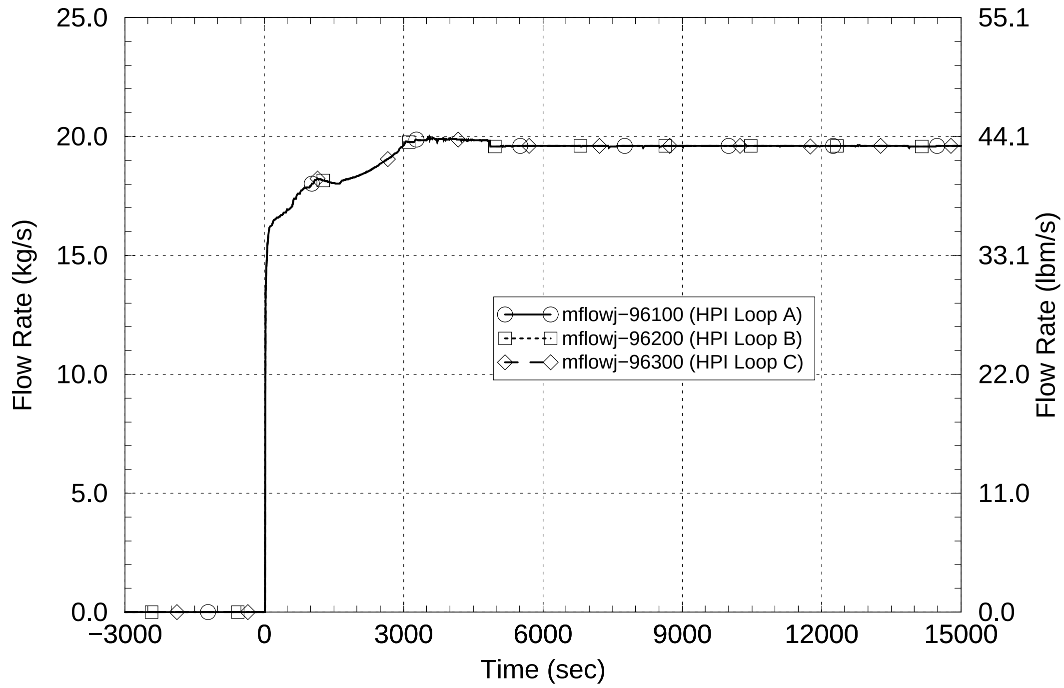


Figure 3.2.1-34 High Pressure Injection Flow Rate - BV Case 114

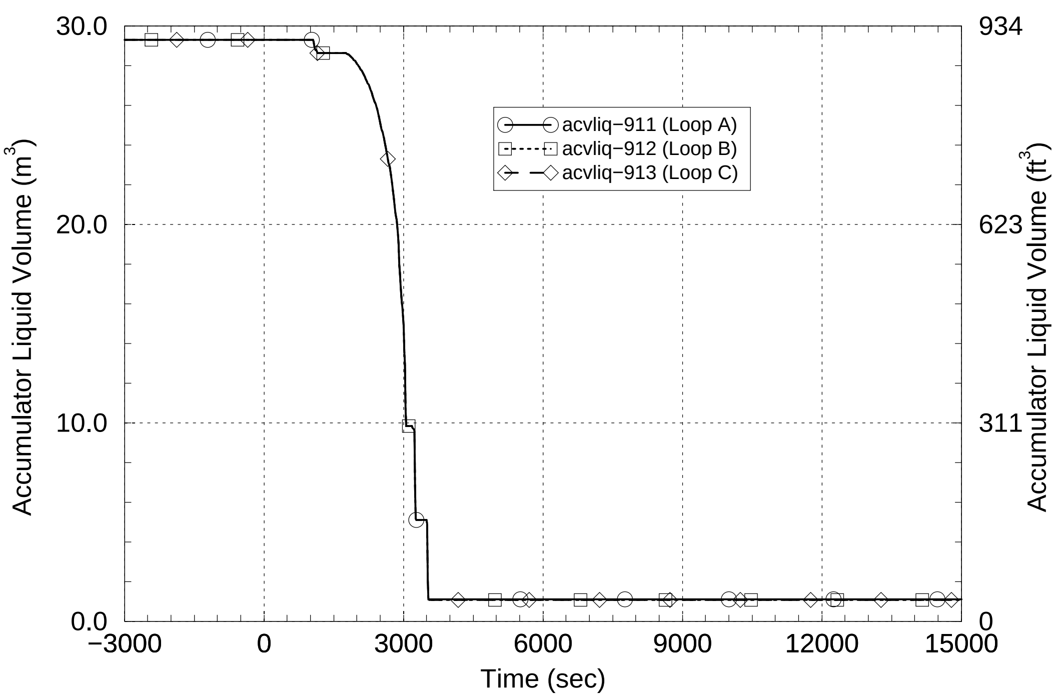


Figure 3.2.1-35 Accumulator Liquid Volume for - BV Case 114

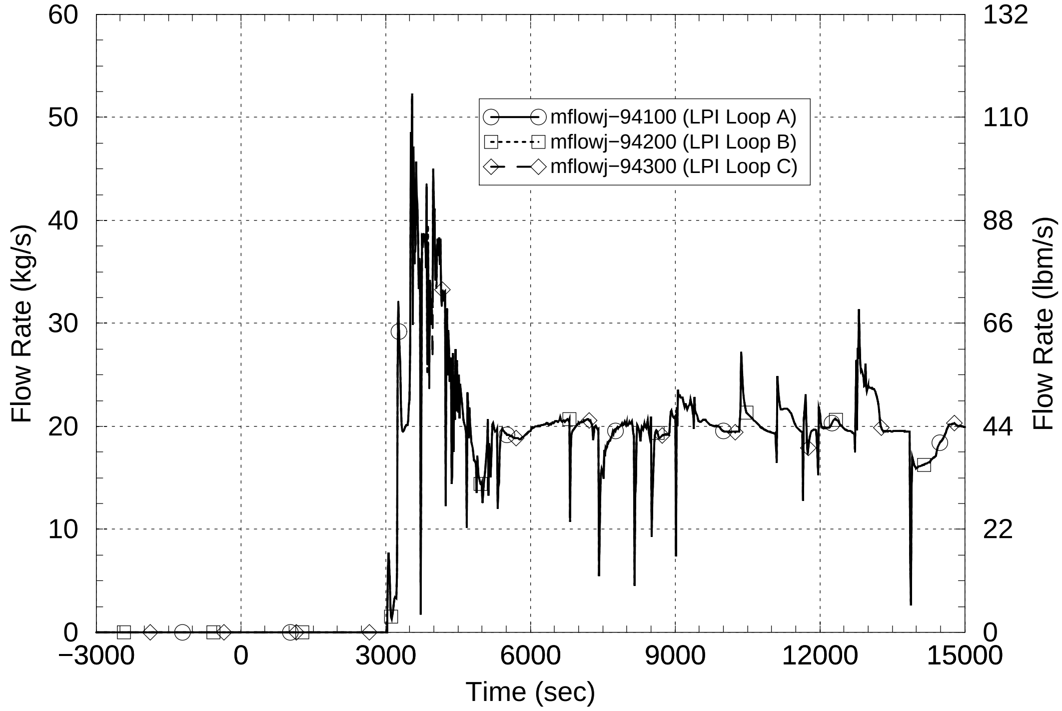


Figure 3.2.1-36   Low Pressure Injection Flow Rate - BV Case 114

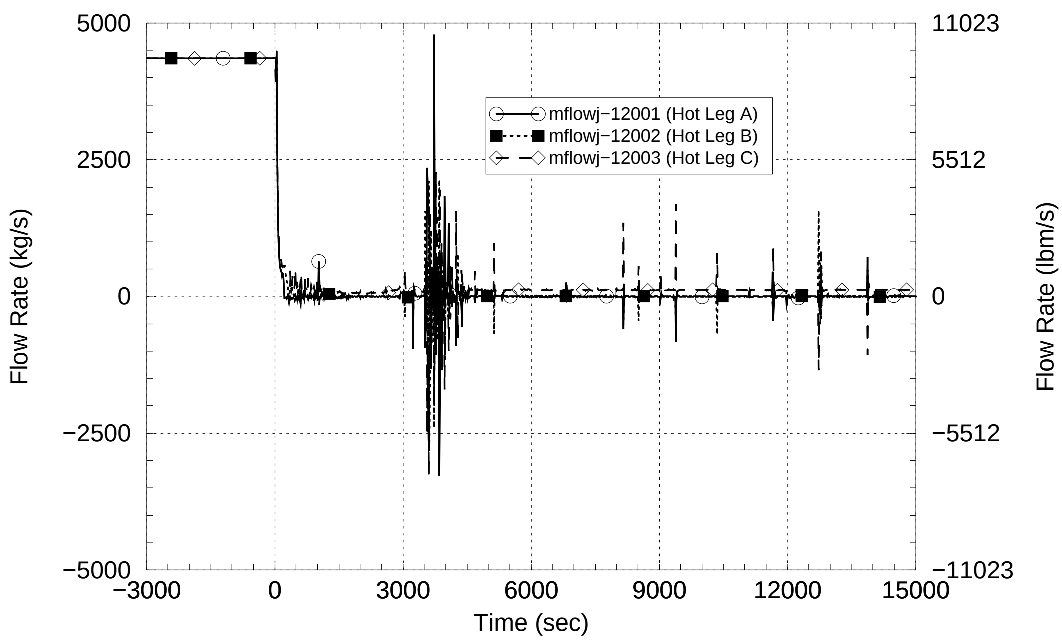


Figure 3.2.1-37   Hot Leg Mass Flow Rate - BV Case 114

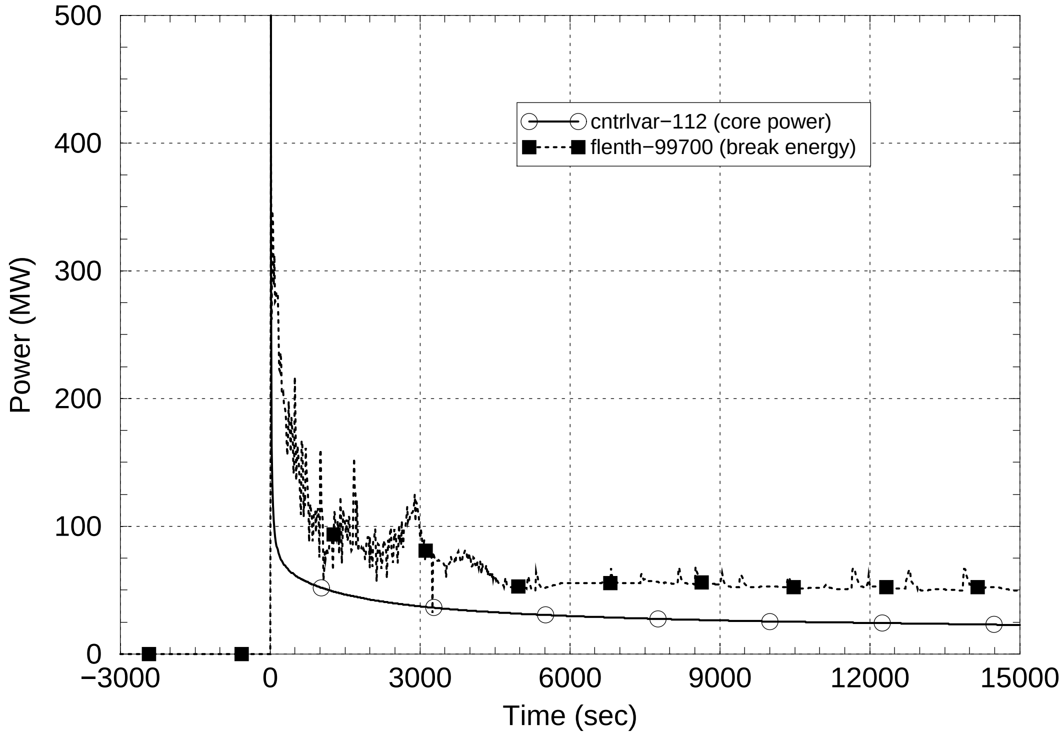


Figure 3.2.1-38 Core Power and Break Energy - BV Case 114

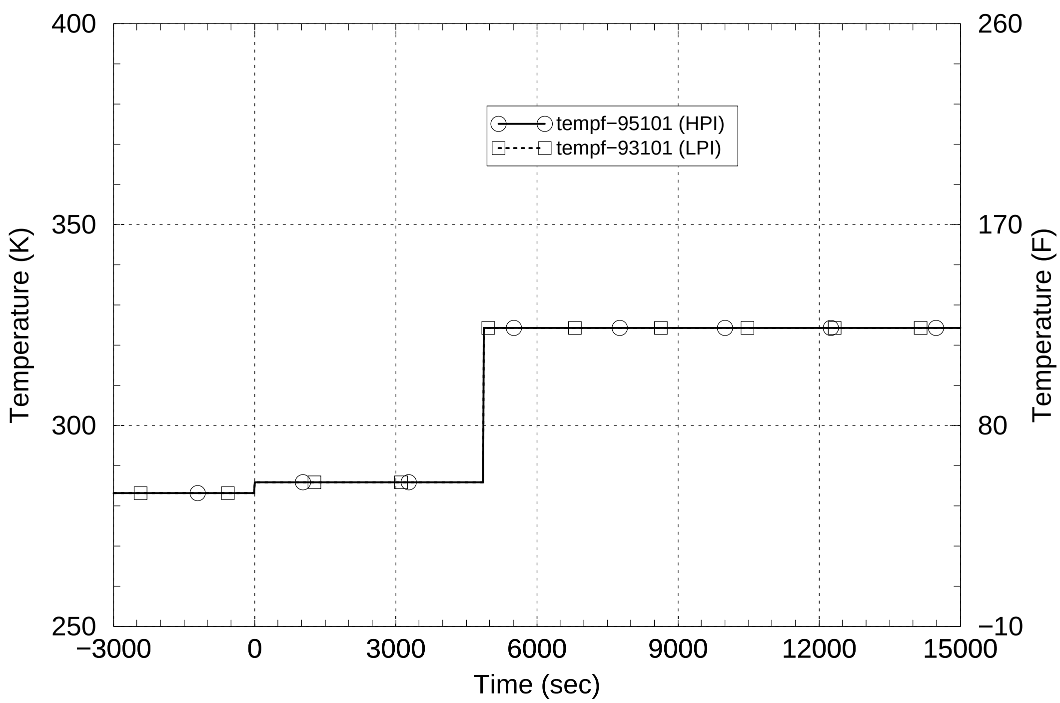


Figure 3.2.1-39 Safety Injection Fluid Temperature - BV Case 114

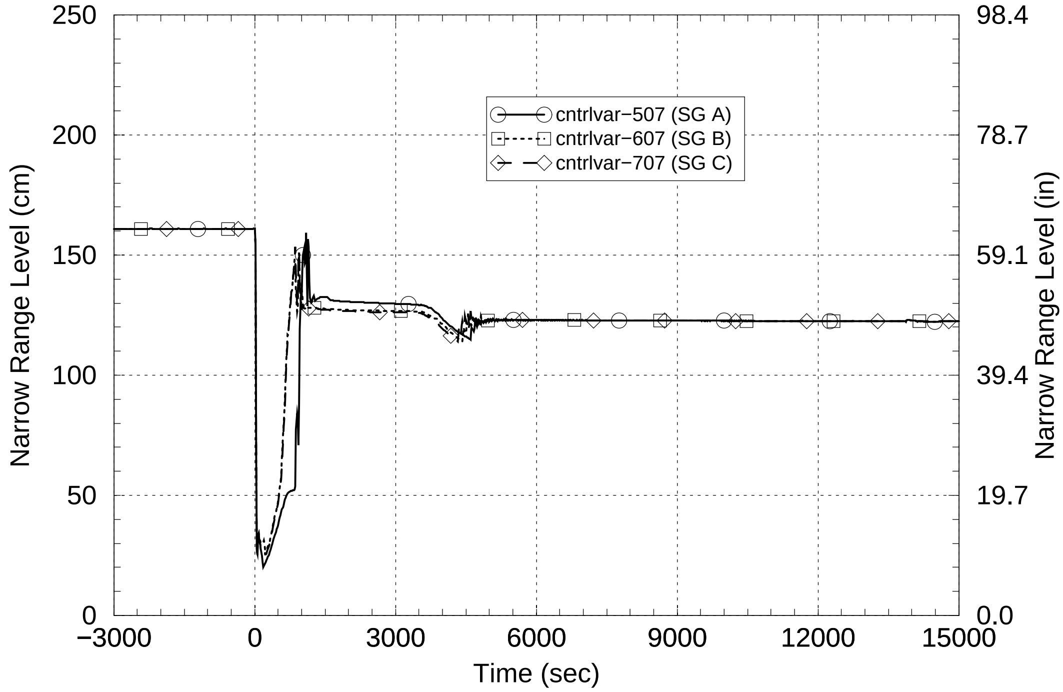


Figure 3.2.1-40 Steam Generator Narrow Range Water Level - BV Case 114

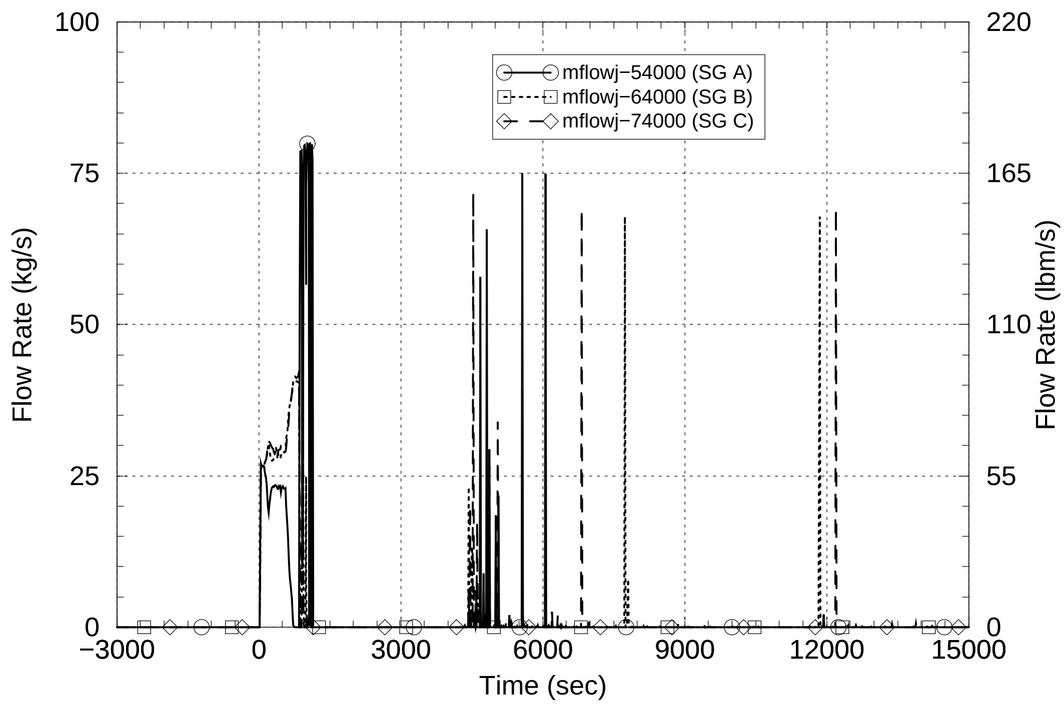


Figure 3.2.1-41 Auxiliary Feedwater Flow Rate - BV Case 114

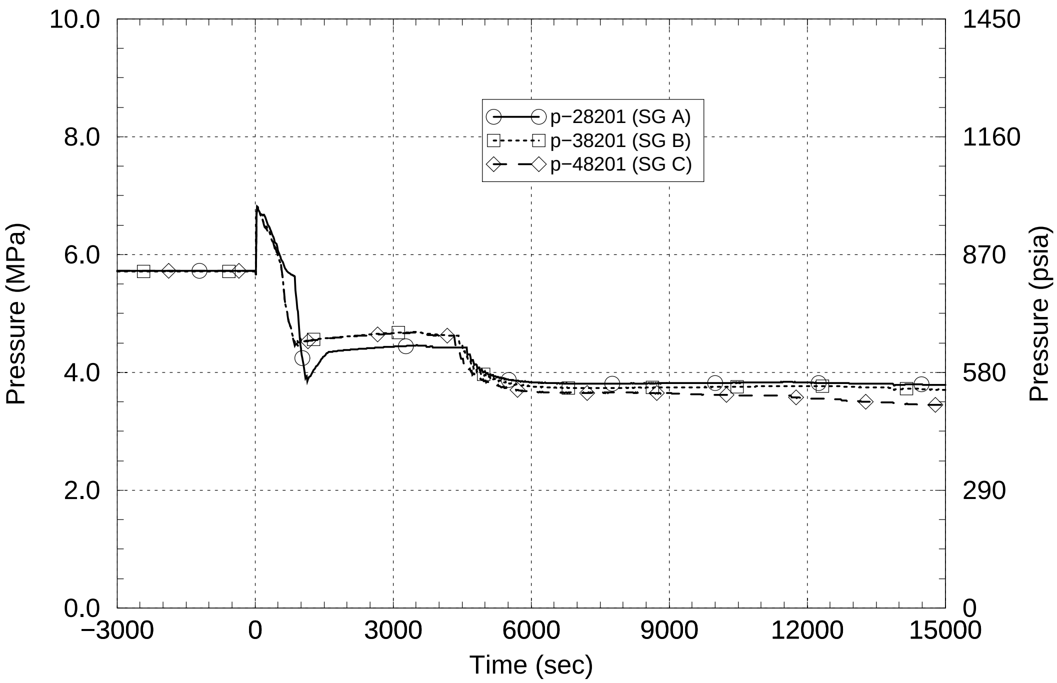


Figure 3.2.1-42 Steam Generator Pressure - BV Case 114

3.2.2 Beaver Valley Primary Side Loss of Coolant Accident at Hot Zero Power

The transient in this group was initiated from hot zero power steady state operating conditions. At hot zero power, the core power is nearly zero and the reactor coolant pumps are operating at normal speed, adding heat to the reactor coolant system (RCS). Because the RCS heat load is small, the fluid temperatures in all portions of the RCS (cold legs, hot legs and reactor vessel) and the steam generator (SG) secondary system are virtually the same. This temperature defines the HZP secondary system pressure (the secondary is at the saturation pressure corresponding to the RCS temperature). The steam dump valve controllers in the plant and model modulate the steam dump valve to attain this SG pressure and RCS average temperature.

On the SG secondary side, the turbine is tripped at HZP and therefore the turbine stop valves are closed. Main feedwater is delivered at a very low rate, consistent with the low RCS heat load. Because the feedwater train heaters depend on turbine extraction steam for operation, feedwater is delivered to the SGs at the low condenser temperature, rather than the elevated temperature associated with main feedwater at HFP operation.

The reduced steam generator heat load at HZP results in much less steam production and voiding in the SG boiler sections than is present at full power. Therefore, SG water mass is significantly higher for HZP operation than for HFP operation.

In the hot full power steady state model, core power is input using a table. Power is held constant until the time of reactor trip and it decays afterward on the basis of ANS standard decay heat. In the HZP condition, the reactor is critical with control element assemblies withdrawn. From a modeling view, it is difficult to initialize a plant model with zero core power because of the plant system's long thermal time constants. For these reasons, the Beaver Valley Unit 1 hot zero power RELAP5 model assumes a constant 5.32 MW core power, both at steady state and during transients. This value represents the heat load at 1 month after shutdown and is 0.2% of the rated thermal power. The core power table was revised to reflect this assumption.

The only transient in this group is a 10.16 cm [4.0 in] diameter surge line break. This transient is restarted from the hot zero power null transient described in Section 2.2.

In order to model the surge line break, two additional components were added to the RELAP5 model transient restart input file. These components were a time dependent volume to model the break downstream conditions and a break valve. The time dependent volume was set to atmospheric conditions. The break valve for the surge line break was connected to the middle node of the surge line (volume 343, cell 2, see Figure 2.2-1). The loss coefficients for the break were based on AP600 derived loss coefficients (Ref. 3.2.1) and scaled for the appropriate break size. The break valve was set to open at time zero.

A sequence of events table for the surge line break is provided as Table 3.2-2.

Table 3.2-2 Sequence of Events for Loss of Coolant Accidents from Hot Zero Power

	Case 056 - 10.16 cm [4.0 in] surge line break at HZP
	Event Time (s)
Break valve opened	0
Reactor/turbine trip	6.72
SIAS generated	9.716
HHSI flow initiated	9.716
MFW stopped	9.716
AFW started	9.716
Pressurizer empties	<15
RCPs trip	21.717
Accumulators begin injecting	375
LHSI flow initiated	960
Accumulators stop injecting	1,080
3ontainment spray pumps start	1,663

	Case 056 - 10.16 cm [4.0 in] surge line break at HZP
	Event Time (s)
Pressurizer begins to refill	1,920
MSIV closure	2,385
Switchover to sump recirculation	3,121

3.2.2.1 Beaver Valley Surge Line Break from Hot Zero Power – 10.16 cm [4.0 in] diameter (BV Case 056)

This case is a 10.16 cm [4.0 in] diameter surge line break from hot zero power. This case is identified as Beaver Valley Case 056 in Appendix B, Table B-1. The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.2-1 through 3.2.2-3, respectively.

As a result of the break, the primary system rapidly depressurizes as shown in Figure 3.2.2-1 and remains near 0.86 MPa [125 psia] for the duration of the transient. In addition, the pressurizer level (shown in Figure 3.2.2-4) also decreased rapidly due to loss of inventory and was completely empty by 15 s. At 6.72 s, a reactor trip occurred due to low primary pressure. At approximately 9.7 s, a safety injection actuation signal (SIAS) was generated. The SIAS results in actuation of both the HHSI, and LHSI. In addition, it also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated.

A plot of break flow versus total safety injection flow is provided as Figure 3.2.2-5. Total SI flow includes high pressure injection, low pressure injection, accumulators and charging/letdown. High pressure injection flow is shown in Figure 3.2.2-6. Initially, break flow is much larger than safety injection flow. By 375 s the primary pressure has decreased to below the accumulator pressure, resulting in accumulator injection as shown in Figure 3.2.2-7. With this additional flow, the total SI is now greater than the break flow. At 960 s, the low pressure injection begins as shown in Figure 3.2.2-8. By 3,000 s, the safety injection flow and break flow are equal and remain equal for the remainder of the transient.

At approximately 22 s, the reactor coolant pumps were tripped due to an operator action. This causes the flow in the loops to decrease to near zero. Figure 3.2.2-9 presents the hot leg mass flow for all three loops at the exit of the vessel. As in the cases at full power, there are hot leg flow oscillations. These oscillations begin around 1,100 s and last until about 2,000 s. Again, these are due to condensation effects in the primary tubes of the steam generators. By 2,000 s, the large oscillations have stopped and the only loop which has flow is the C loop, which contains the break. Figure 3.2.2-3 shows the downcomer fluid-wall heat transfer coefficient. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops quickly from an initial value of approximately 24,073 $W/m^2 \cdot K$ [1.178 $Btu/s \cdot ft^2 \cdot {}^\circ F$] to 2,000 $W/m^2 \cdot K$ [0.098 $Btu/s \cdot ft^2 \cdot {}^\circ F$]. During the remainder of the transient, this drops gradually to 500 $W/m^2 \cdot K$ [0.024 $Btu/s \cdot ft^2 \cdot {}^\circ F$].

At 1,080 s, the accumulators have emptied and injection stops. Note that the accumulators were isolated when the liquid level was near the bottom. This was done to stop non-condensible gases from entering the system. These non-condensible gases frequently cause numerical problems in RELAP5 which lead to code failures. By 2,000 s, the pressurizer begins to refill, and is filled solid by 2,000 s. Note that there is no operator action to control pressurizer level.

Figure 3.2.2-10 shows the core power versus the energy lost through the break. As seen in this figure, the break energy is larger than the core decay heat, thus, heat is being removed from the system causing the temperature to decrease. Note that in the hot zero power cases, the power is held constant at 5.32 MW. The average downcomer fluid temperature is shown in Figure 3.2.2-2. In addition to the heat lost through the break and core power considerations, the safety injection water temperature plays a role in the downcomer fluid temperature. Initially, the high pressure injection and low pressure injection are at 283 K [50°F], however, after the reactor water storage tank (RWST) has depleted, the source of injection water becomes the containment sump. After switchover to sump recirculation at 3,121 s, the injection temperature is increased to 324 K [124°F] as shown in Figure 3.2.2-11. Looking at Figure 3.2.2-2 shows that the sump temperature significantly affects the downcomer fluid temperature.

Figure 3.2.2-12 shows the steam generator narrow range water level. Upon the SIAS being generated, the MFW is isolated. Since the MFW at hot zero power is very small (approximately 2 kg/s [4.4 lbm/s]), the isolation of MFW does not have a significant effect on steam generator water level. Upon SIAS, the AFW is started and begins controlling the generators to the level setpoint of 33% NRL (120.7 cm [47.52 in]). Note that the hot zero power pre/post reactor trip level setpoints are the same. Figure 3.2.2-13 shows the auxiliary feedwater flow which comes on occasionally for short periods of time to maintain steam generator water level.

The steam generator secondary side pressure is shown in Figure 3.2.2-14. The pressure in the steam generators decreases as a result of the primary side decrease in temperature.

As a consequence of the size of the surge line break it is shown that the break is capable of removing more than the assumed core decay heat at hot zero power. This leads to the downcomer fluid temperature decreasing to a minimum of 288.5 K [59.6°F] at approximately 2,975 s. The pressure during this time was approximately 0.917 MPa [133 psia]. There was no mechanism which would allow the primary to repressurize.

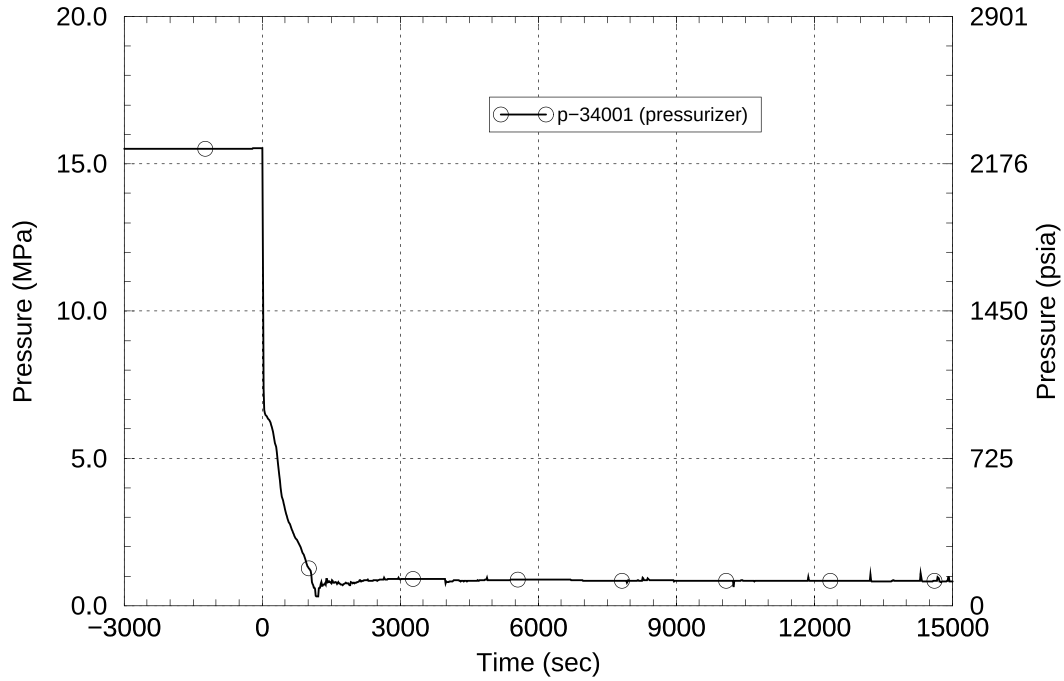


Figure 3.2.2-1 Primary System Pressure – BV Case 056

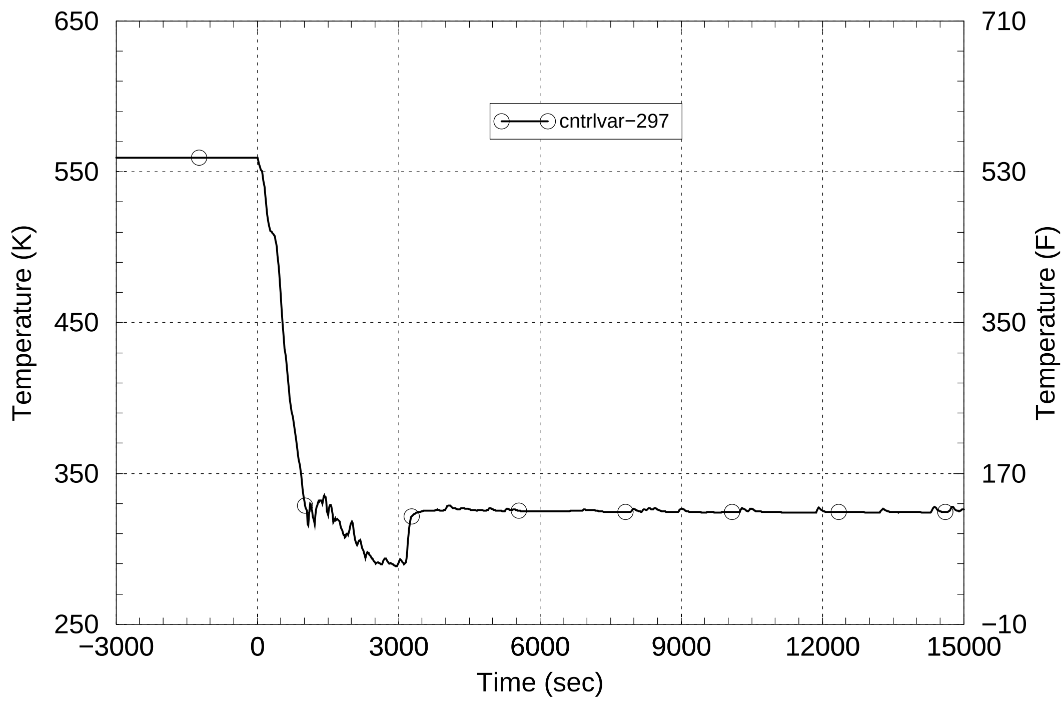


Figure 3.2.2-2 Average Downcomer Fluid Temperature – BV Case 056

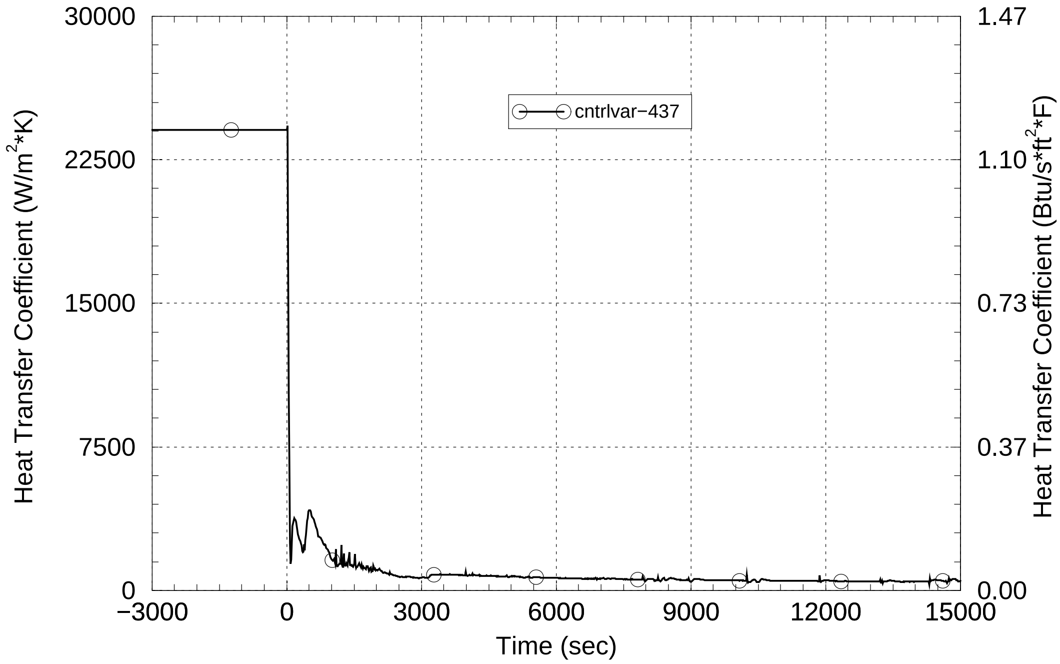


Figure 3.2.2-3 Downcomer Heat Transfer Coefficient – BV Case 056

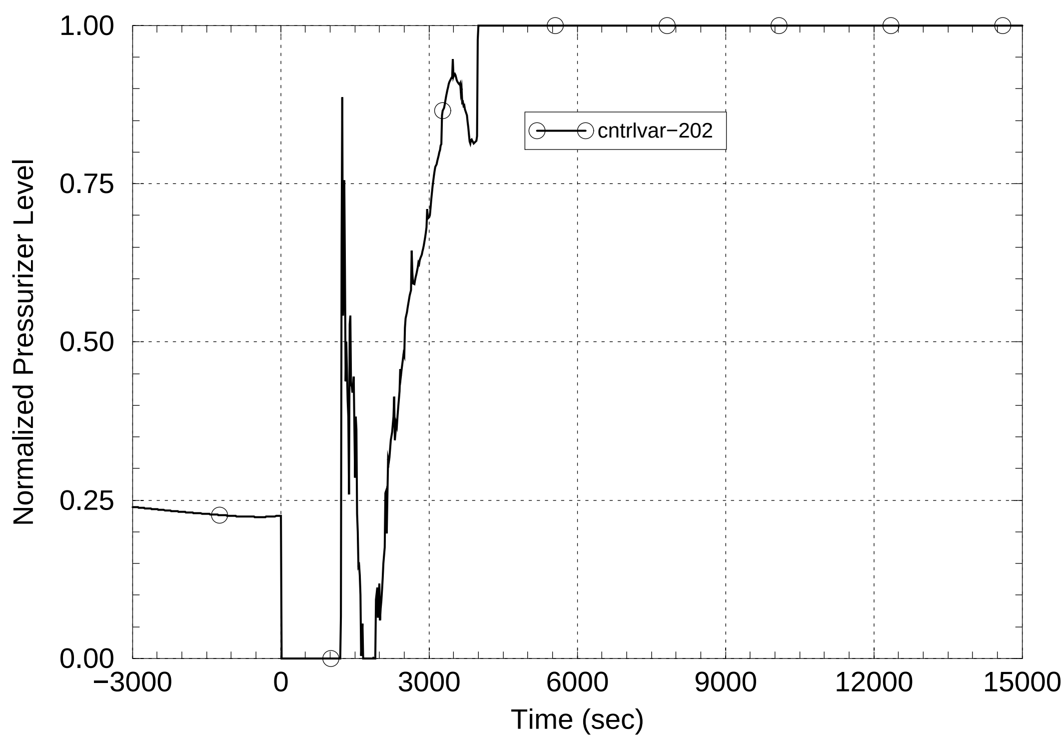


Figure 3.2.2-4 Pressurizer Water Level – BV Case 056

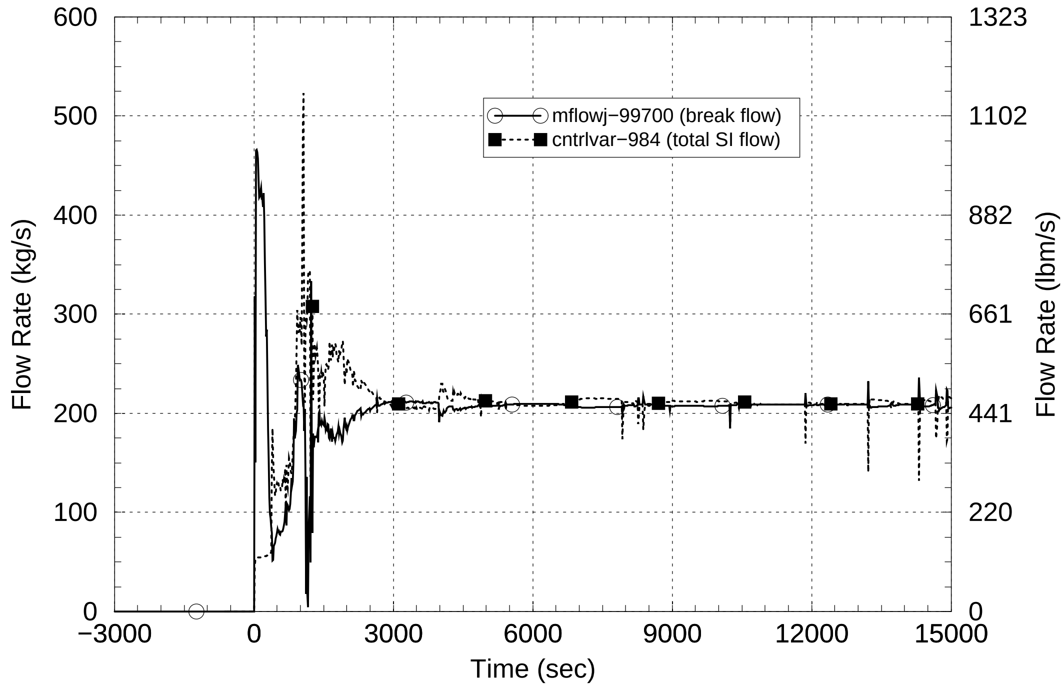


Figure 3.2.2-5 Break Flow and Total Safety Injection Flow – BV Case 056

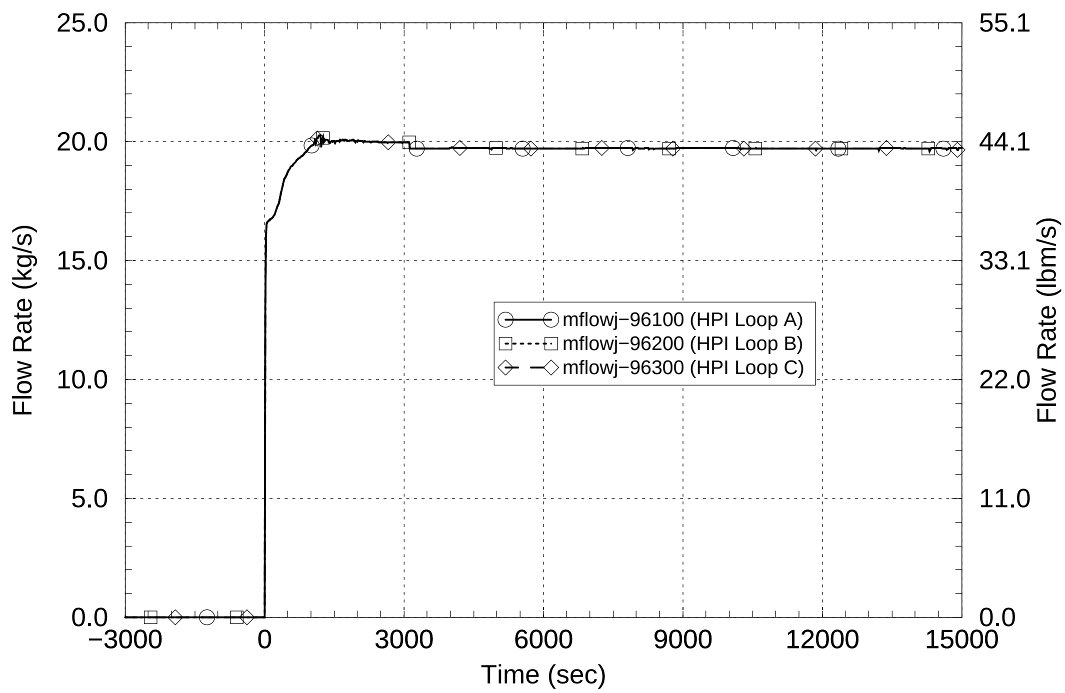


Figure 3.2.2-6 High Pressure Injection Flow Rate – BV Case 056

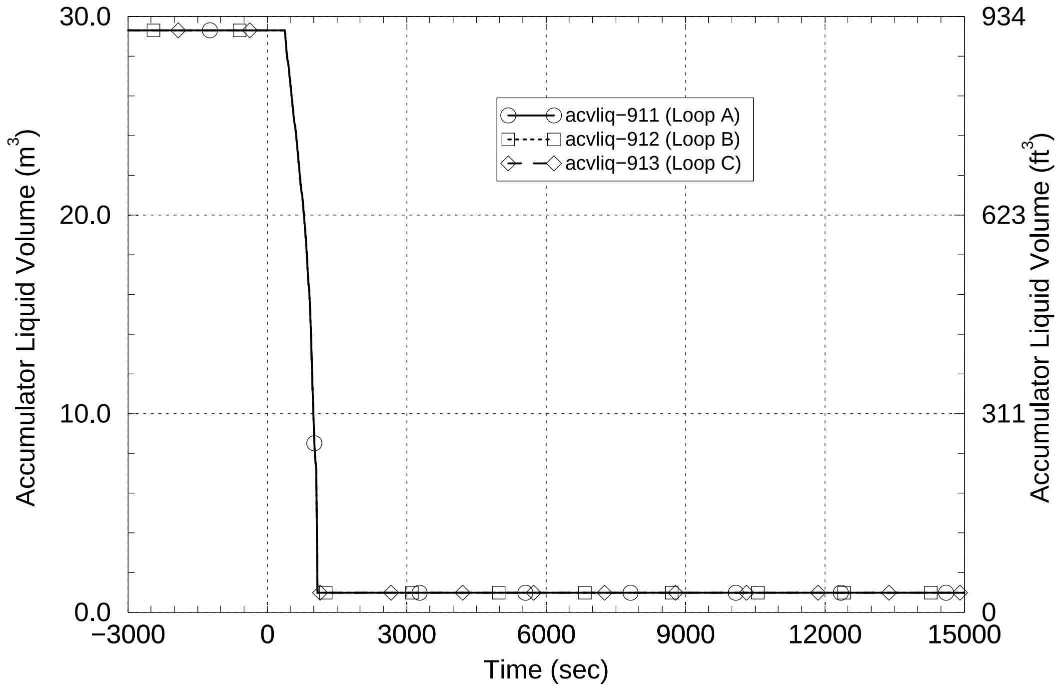


Figure 3.2.2-7 Accumulator Liquid Volume – BV Case 056

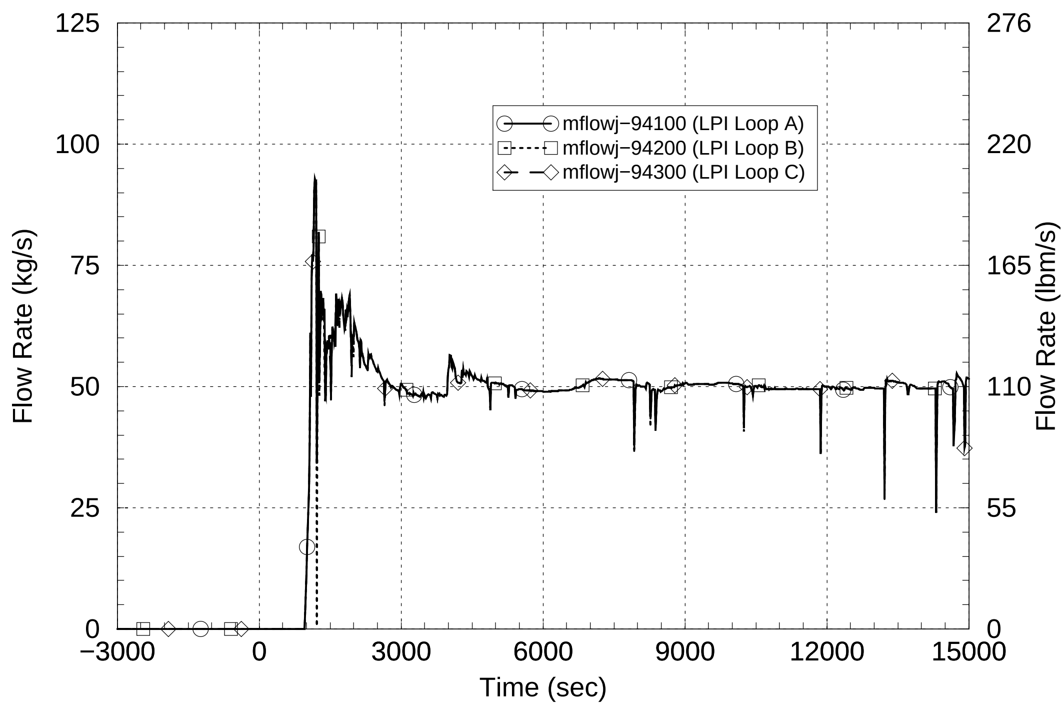


Figure 3.2.2-8 Low Pressure Injection Flow Rate – BV Case 056

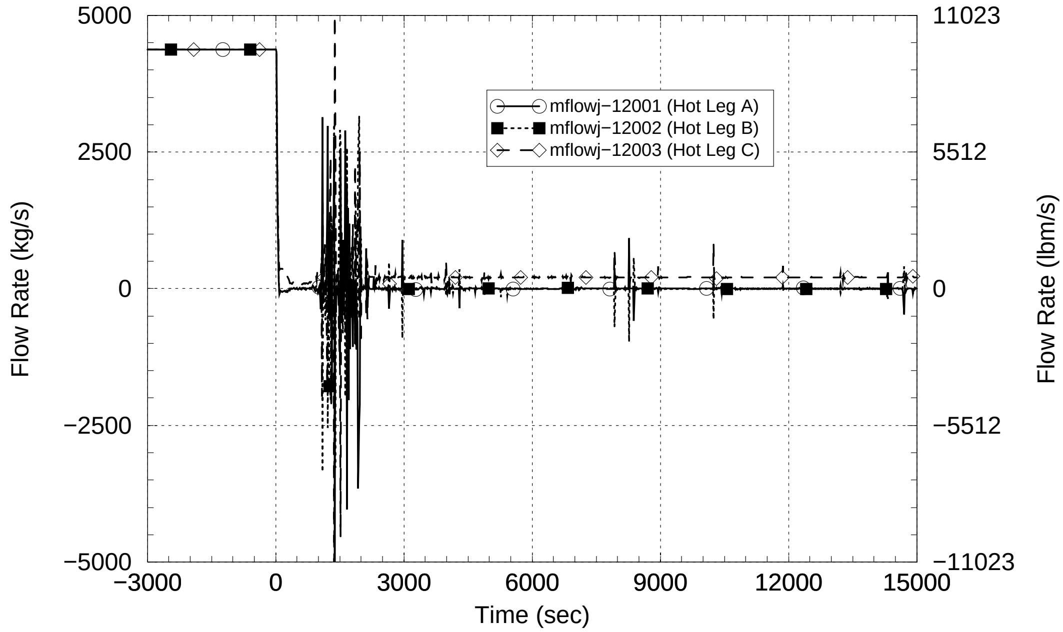


Figure 3.2.2-9 Hot Leg Mass Flow Rate – BV Case 056

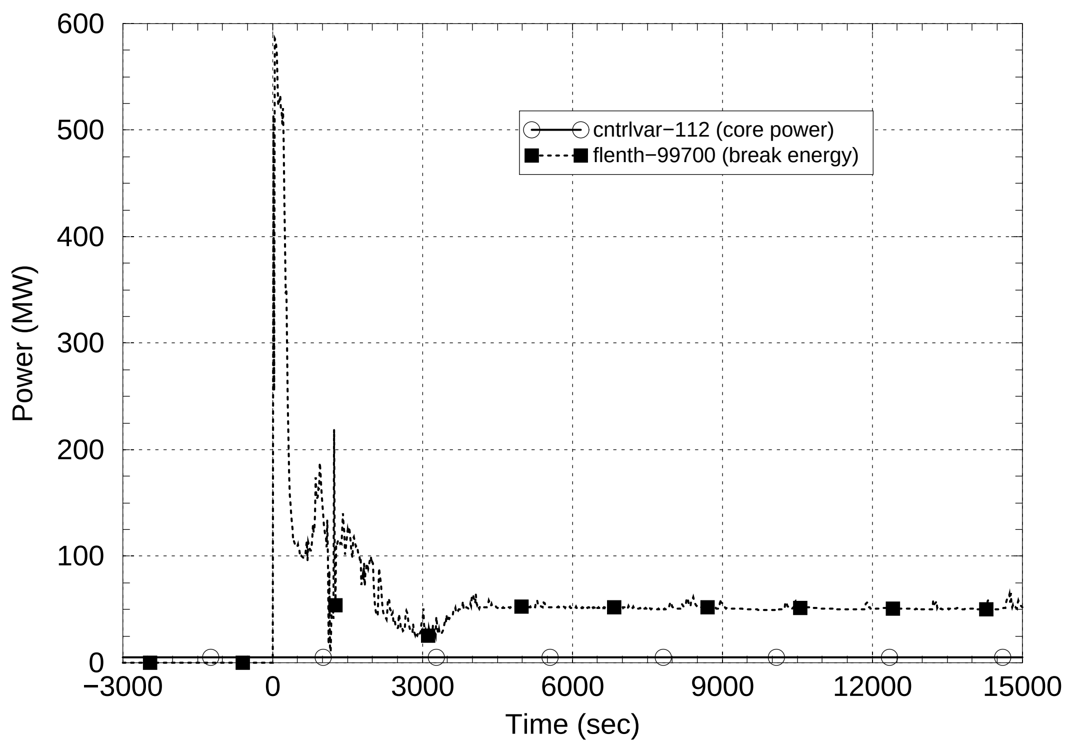


Figure 3.2.2-10 Core Power and Break Energy – BV Case 056

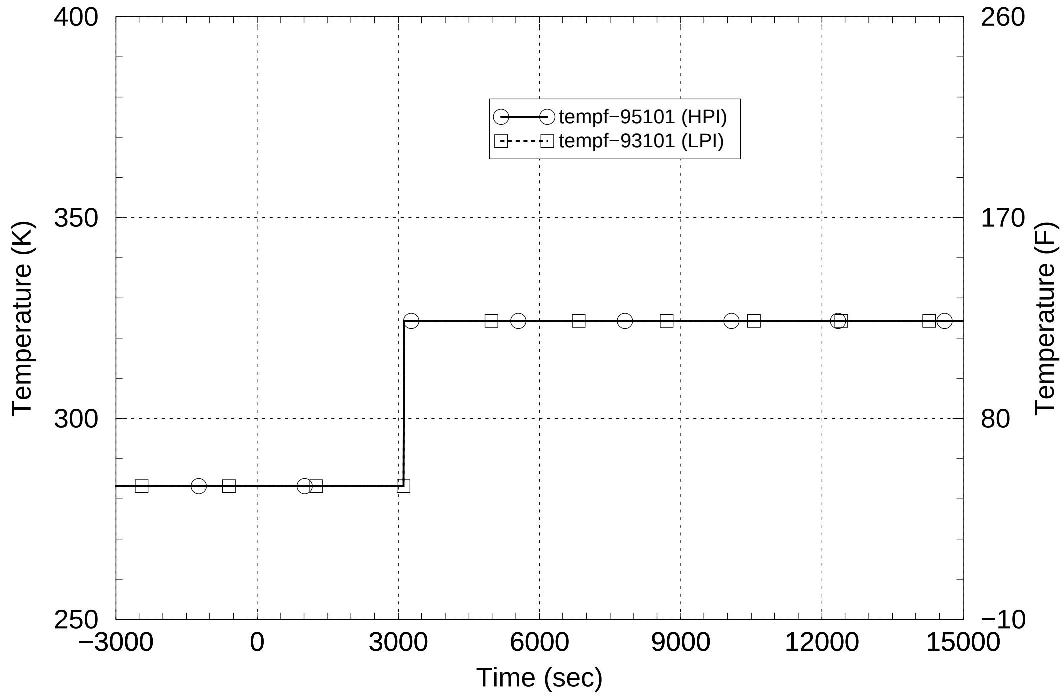


Figure 3.2.2-11 Safety Injection Fluid Temperature – BV Case 056

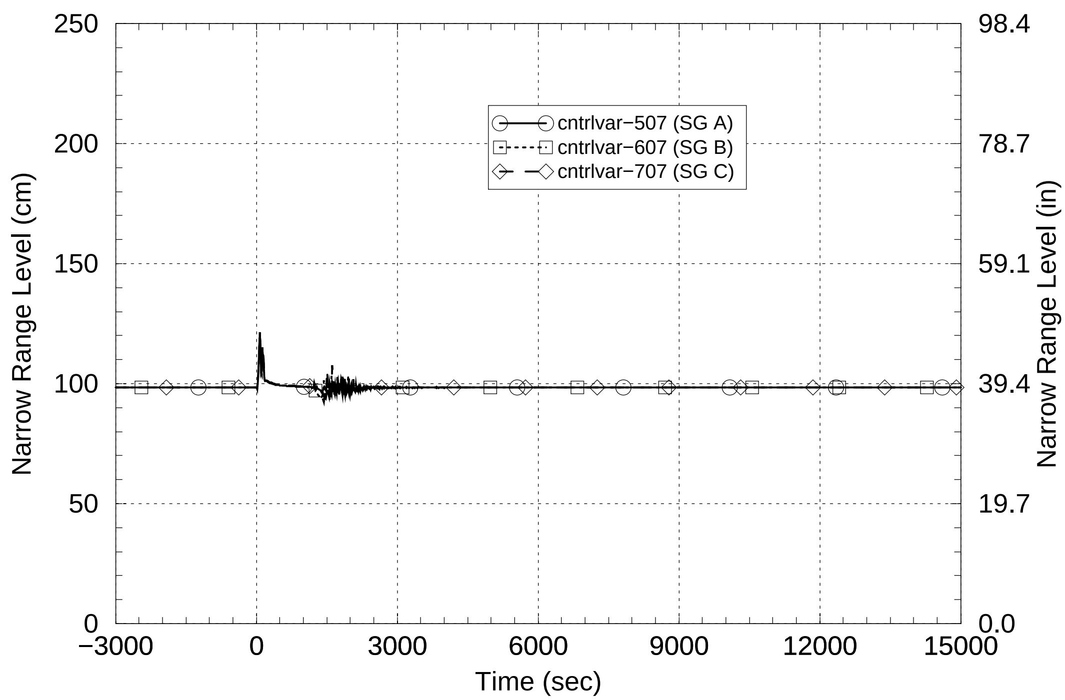


Figure 3.2.2-12 Steam Generator Narrow Range Water Level – BV Case 056

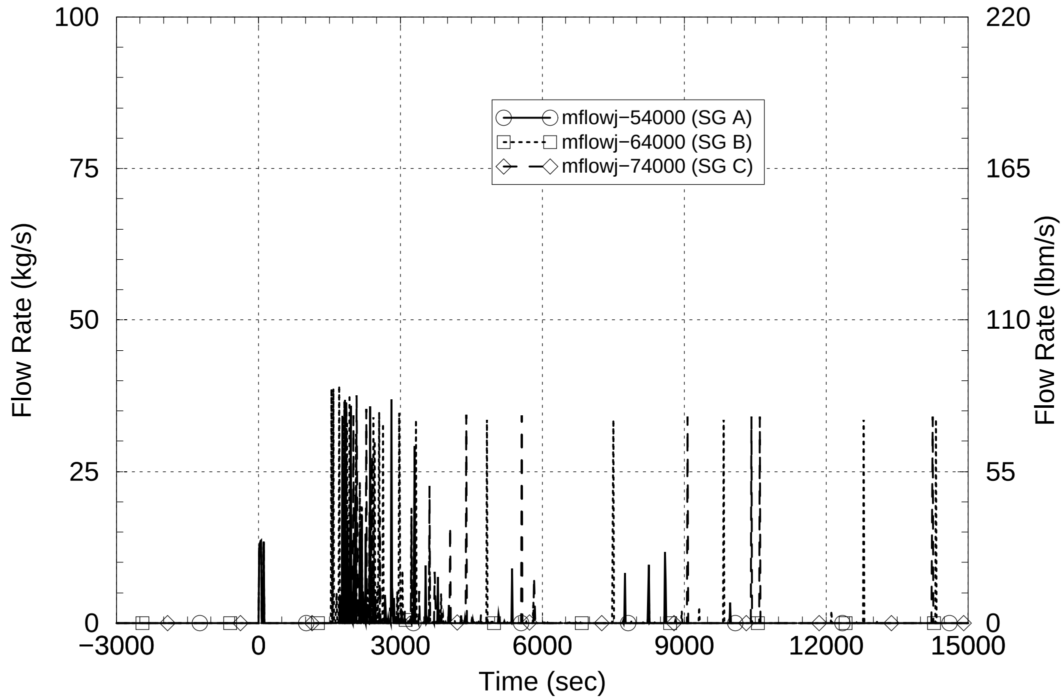


Figure 3.2.2-13   Auxiliary Feedwater Flow Rate – BV Case 056

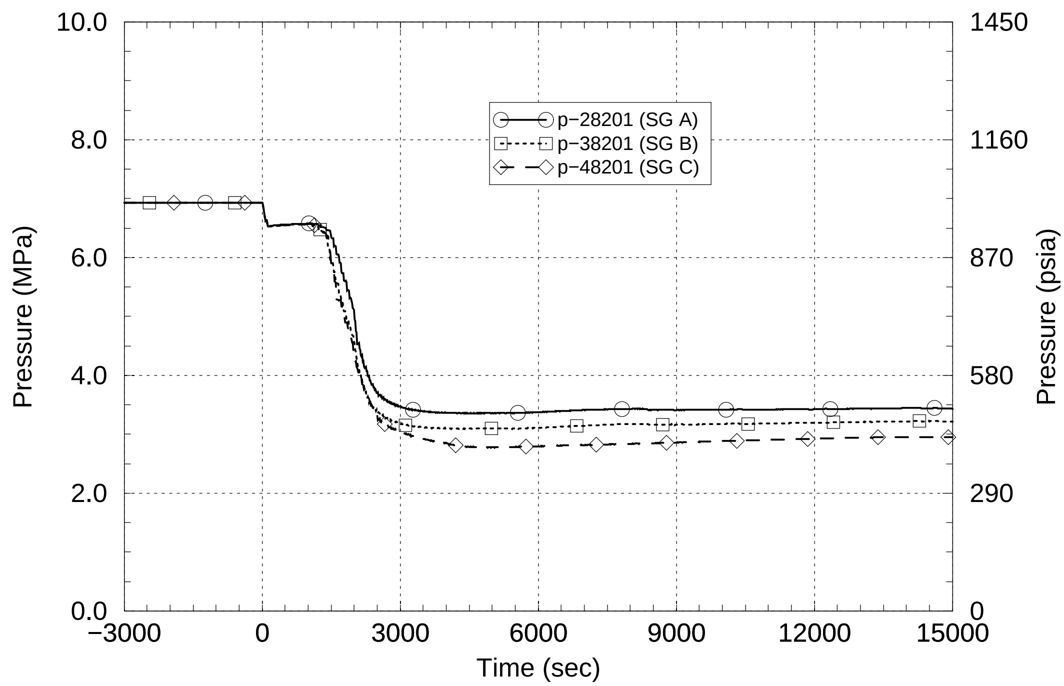


Figure 3.2.2-14   Steam Generator Pressure – BV Case 056

3.2.3 Beaver Valley Main Steam Line Breaks From Hot Full Power

The transients in this group were initiated from hot full power steady state operating conditions (nominal temperature and pressure). The large steam line breaks are assumed to be double ended guillotine breaks just downstream of the flow restrictor in steam generator A. The breaks are assumed to occur inside containment, thus leading to "adverse" containment conditions. This results in a trip of the reactor coolant pumps. The small steam line breaks are simulated by sticking open the steam generator safety relief valves. In all cases, the auxiliary feedwater flow is assumed to continue to the broken loop generator for 30 minutes, at which point it is isolated by the operator. These cases also have operator control of the high head safety injection (HHSI).

The RELAP5 transient restart input was modified to add the following: steam line break, RCP trip, AFW isolation at 30 minutes, control of HHSI and allow letdown after both HHSI pumps are stopped.

The break downstream conditions were modeled with time dependent volumes which were set at atmospheric conditions. In the double ended break cases, both the steam generator side and the steam line side were connected to time dependent volumes. In all transients, the breaks were set to occur at time zero.

The AFW was isolated at 30 minutes by multiplying the original control valve position by zero using RELAP5 trips and controls.

The HHSI in Beaver Valley is controlled by turning HHSI pumps on or off, rather than throttling to a desired flow rate. Conditions for turning pumps off are as follows: core exit subcooling greater than 22.2 K [40°F], any steam generator NRL greater than 32%, pressurizer water level greater than 32% and primary pressure stable or increasing. If the conditions listed are met, the operator is allowed to turn off one HHSI pump. If conditions are still met five minutes later the second HHSI pump can be turned off. If the above conditions are no longer met at any time, HHSI pumps must be turned back on. In both cases, the operator is assumed to turn off HHSI pumps after the above conditions are met plus a time delay (30 minutes in some cases and 60 minutes in the others). A sequence of events table for the main steam line break transients is provided as Table 3.2-3.

Table 3.2-3 Sequence of Events for Main Steam Line Breaks from Hot Full Power

	Case 102 - MSLB with AFW continuing to feed affected generator for 30 minutes and operator controls HHSI 30 minutes after allowed	Case 104- MSLB with AFW continuing to feed affected generator for 30 minutes and operator controls HHSI 60 minutes after allowed	Case 108 - Small steam line break (simulated by sticking open all SG-A SRVs) with AFW continuing to feed affected generator for 30 minutes and operator controls HHSI 30 minutes after allowed.
	Event Time (s)		
Break	0	0	0
RCP trip	0	0	0
SIAS generated	0.089	0.089	6.693
HHSI flow initiated	0.089	0.089	6.693
MFW stopped	0.089	0.089	6.693
AFW started	0.089	0.089	6.693
Reactor/turbine trip	2.554	2.554	0
Pressurizer pressure exceeds PORV setpoint	735	735	600
Pressurizer fills	1,260	1,260	1,260
AFW stopped to broken loop	1,800	1,800	1,800
MSIV closure	2,020	2,020	1,575
1st HHSI pump stopped	4,020	5,820	3,570
2nd HHSI pump stopped	4,320	6,120	3,870
Accumulators begin injecting	6,555	N/A	N/A
Accumulators stop injecting	6,915	N/A	N/A

3.2.3.1 Beaver Valley Main Steam Line Break From Hot Full Power (BV Case 102)

This case is a double ended main steam line break (in steam generator A) from hot full power with auxiliary feedwater continuing to feed the affected loop generator for 30 minutes and operator control of high head safety injection. This case is identified as Beaver Valley Case 102 in Appendix B, Table B-1. The steam line break is assumed to occur downstream of the flow restrictor and inside of containment, so the RCPs are tripped due to adverse containment conditions. The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.3-1 through 3.2.3-3 respectively. A sequence of events table for this event is shown as Table 3.2-3.

When the steam line break occurs, the secondary side pressure in steam generator A drops rapidly as shown in Figure 3.2.3-4. Steam line break flow is shown in Figure 3.2.3-5. An MSIV closure signal should be generated upon high containment pressure, however, the containment is not modeled. In the model, the MSIV did not receive a close signal until 2,020 s on two out of three steam line pressures less than 3.47 MPa [503 psia]. While the MSIV should have closed much sooner, there are check valves in the lines to prevent backflow from one steam generator to another. At 2.5 s, a reactor/turbine trip was generated (based on two of three loop delta temperature) which closes the turbine stop valve. In addition, since the secondary side pressure was less than the steam dump valve setpoint, there was no flow through any of the MSIVs. Therefore, it is acceptable for the calculation to simulate that the MSIVs did not close upon high containment pressure.

At 0.1 s a safety injection actuation signal was generated due to high steamline pressure differential. The SIAS results in actuation of both the HHSI, and LHSI. In addition, it also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated. Because of the break and main feedwater being stopped, the steam generator water levels drop rapidly as shown in Figure 3.2.3-6.

AFW flow begins almost immediately, as shown in Figure 3.2.3-7, and all flow goes to the broken loop generator (SG A). As the pressure in steam generator A decreases, the flow through the break decreases and becomes smaller than the AFW flow, allowing the water level to recover. At 1,800 s, the operator is assumed to stop AFW flow to the broken loop generator. At this time, AFW begins flowing to steam generators B and C. With no feedwater, steam generator A begins to boil dry.

Heat transfer from the primary to the depressurizing steam generator resulted in a rapid cooldown of the primary system as shown in Figure 3.2.3-2. This cooling also causes the primary fluid volume to shrink which slightly depressurizes the primary as shown in Figure 3.2.3-1 as well as causes the pressurizer water level to decrease as shown in Figure 3.2.3-8. Because the SIAS signal was generated, HHSI flow (Figure 3.2.3-9) is started and repressurizes the primary to the pressurizer PORV setpoint by 735 s.

As a boundary condition to this case, the RCPs were tripped (based on adverse containment conditions). Upon RCP trip, the loop flow decreases rapidly as shown in Figure 3.2.3-10. Loop natural circulation flow for steam generator A continues after the RCP trip as a result of the continual heat removal of the steam generator. Figure 3.2.1-3 shows the downcomer fluid-wall heat transfer coefficient. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops rapidly from an initial value of approximately 23,950 $W/m^2{\cdot}K$

[1.171 Btu/s·ft^{2}·°F]. The heat transfer coefficient then remains around a value of 1,500 W/m^{2}·K [0.073 Btu/s·ft^{2}·°F] for the duration of the transient.

By 2,220 s the system has met all of the conditions for stopping an HHSI pump. These conditions include: core exit subcooling greater than 22.2 K [40°F] (Figure 3.2.3-11), any steam generator NRL greater than 32% (Figure 3.2.3-6), pressurizer water level greater than 32% (Figure 3.2.3-8) and pressure stable or increasing (Figure 3.2.3-1). After waiting an additional 30 minutes (as given in the case description), the operator is assumed to stop a single HHSI pump (at 4,020 s). Then, after waiting five more minutes, the above conditions are still met so the second HHSI pump is stopped (at 4,320 s).

Upon stopping the second HHSI pump, letdown flow was re-established. Between the loss of the HHSI pumps and letdown flow, the primary pressure drops rapidly. At 6,555 s, the primary pressure has dropped below the accumulator pressure and the accumulators begin injecting as shown in Figure 3.2.3-12. At 6,855 s steam generator A has boiled dry, and can no longer remove heat. Since there is no longer any ECCS water entering the system, the primary begins to heatup and repressurize. By 6,915 s the primary pressure has increased and the accumulator injection stops.

When steam generator A has boiled dry, its heat removal effectiveness drops as shown in Figure 3.2.3-13. At this time the primary system temperature is much colder than the temperature of steam generator B and C secondaries as shown in Figure 3.2.3-14. So, between 6,855 s and 10,050 s the primary system does not have a heat sink and the primary system heats up. The loop A natural circulation during this period is being driven by the transient heatup of the loop.

By 8,500 s, the primary system temperature becomes hotter than steam generator B and C temperatures and by 10,050 s enough hot primary water finds its way into the steam generator B and C primaries that natural circulation through these loops starts up. The burst of heat removal (as well as associated pressure/temperature drop) and rapid natural circulation flow in loops B and C results because in order to start the flow the primary system had to become much hotter than could be sustained by steady natural circulation flow. So the flow starts up, but the cooling it affords at first is at a much greater rate than needed and this reduces the flow to the sustainable rate.

By 13,000 s, the system has reached a stable point where all of the loops are circulating but with loop A a little slower than loops B and C. For the remainder of the transient, both loops B and C remove some heat from the primary, however this, in addition to the heat lost through the pressurizer PORV, is not enough to remove the core decay heat. Therefore, the primary system continues to heat up.

The double ended main steam line break results in a continuous cooldown of the primary side while auxiliary feedwater flow is allowed to the broken steam generator. The minimum downcomer fluid temperature is 373 K [212°F] at 3,990 s. Due to continuous HHSI flow, the primary pressure at 3,500 s is 16.2 MPa [2,350 psia]. Once the HHSI flow is controlled/stopped, the primary pressure decreases, however, core heat and the lack of ECCS flow causes the system to heatup/repressurize.

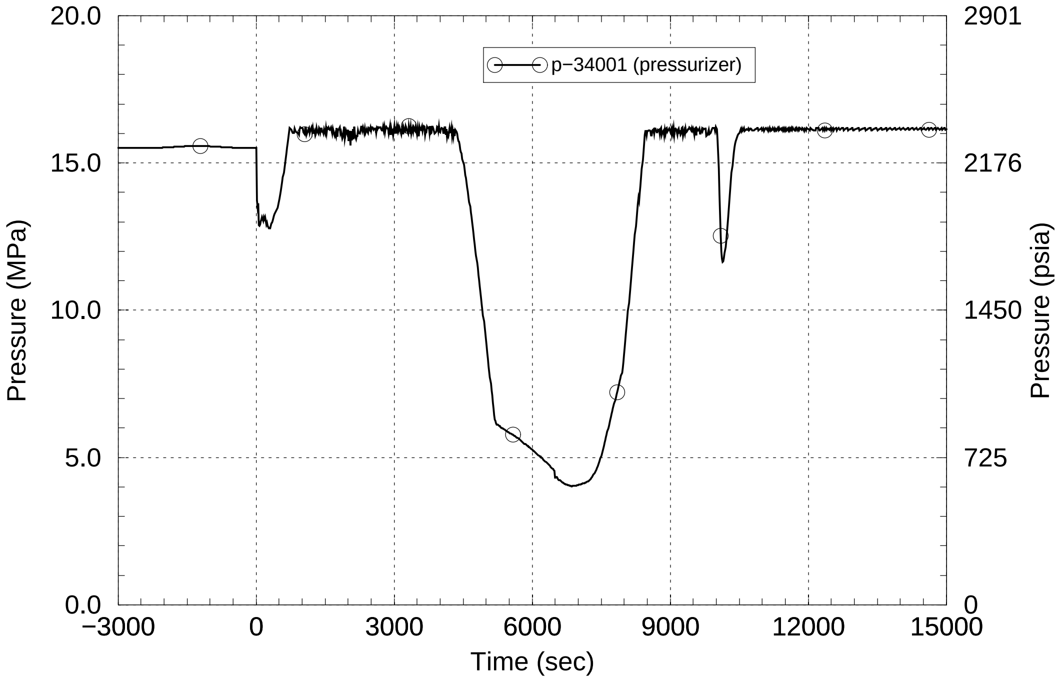


Figure 3.2.3-1 Primary System Pressure – BV Case 102

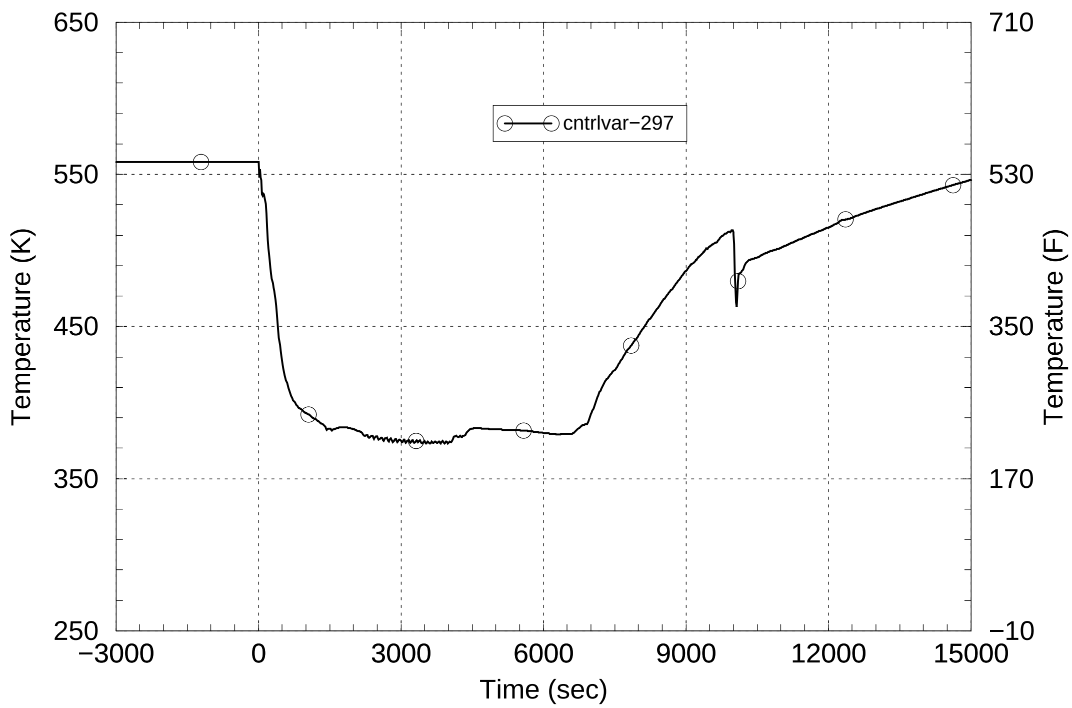


Figure 3.2.3-2 Average Downcomer Fluid Temperature – BV Case 102

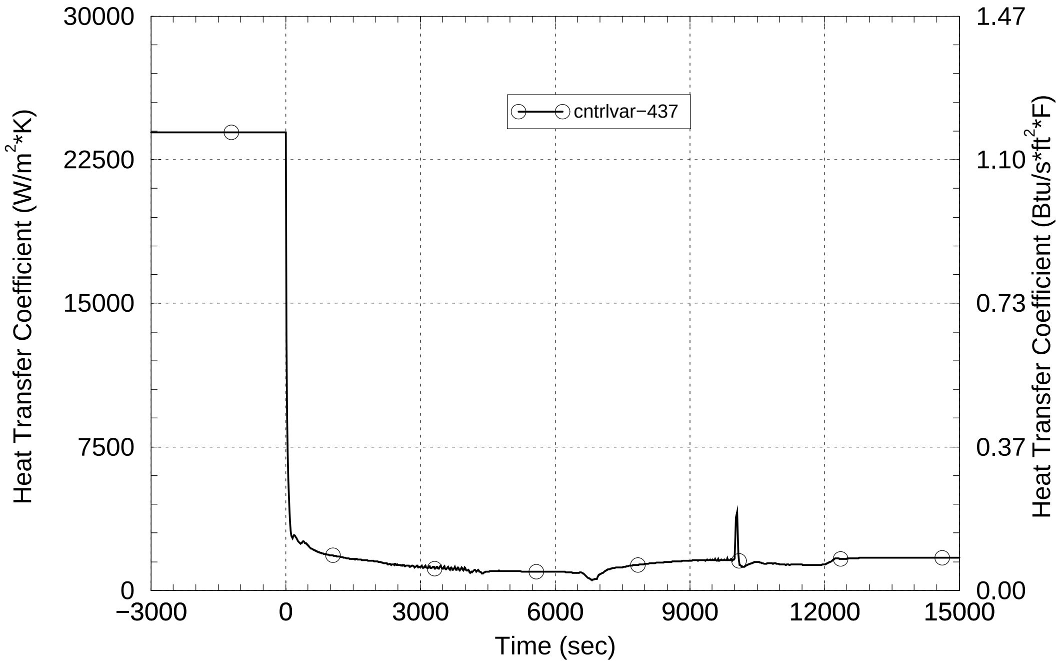


Figure 3.2.3-3 Downcomer Wall Heat Transfer Coefficient – BV Case 102

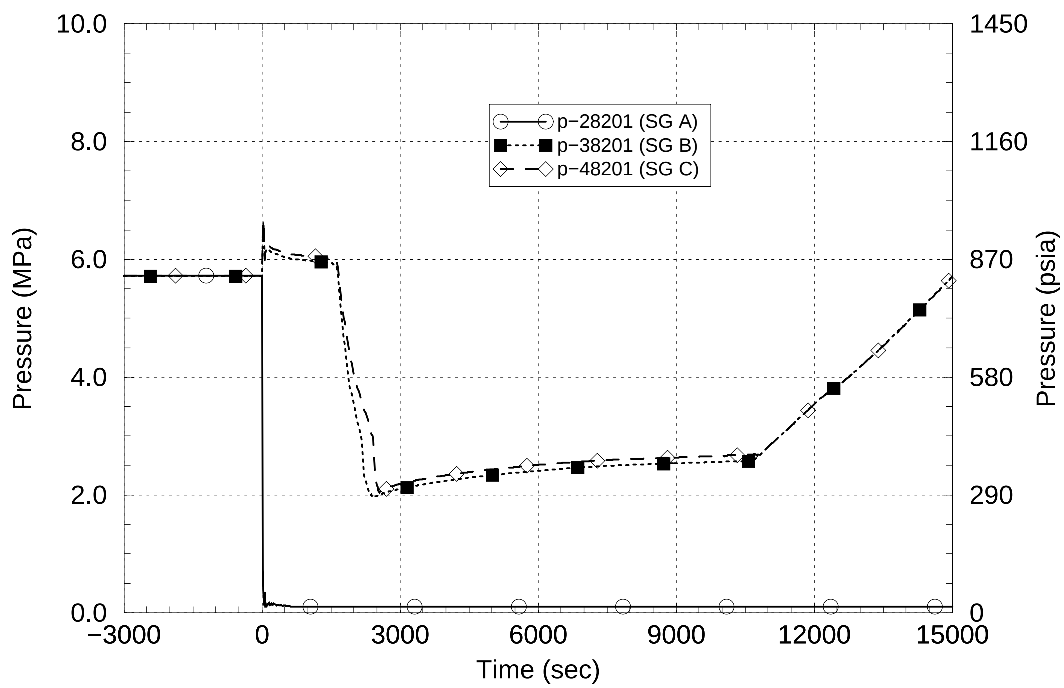


Figure 3.2.3-4 Steam Generator Pressure – BV Case 102

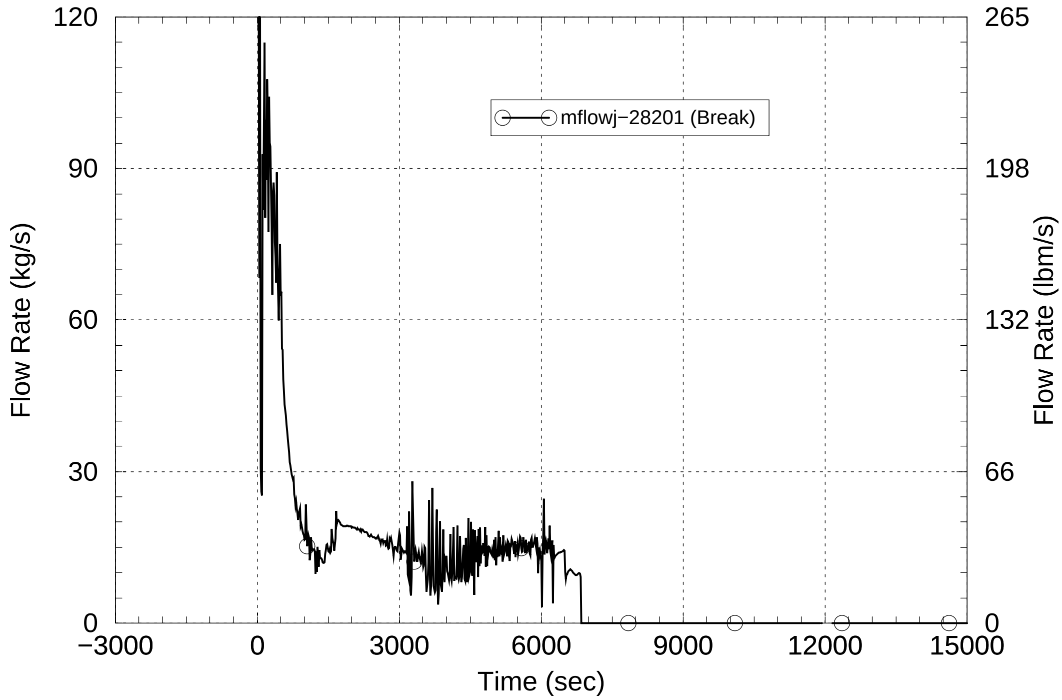


Figure 3.2.3-5 Break Flow – BV Case 102

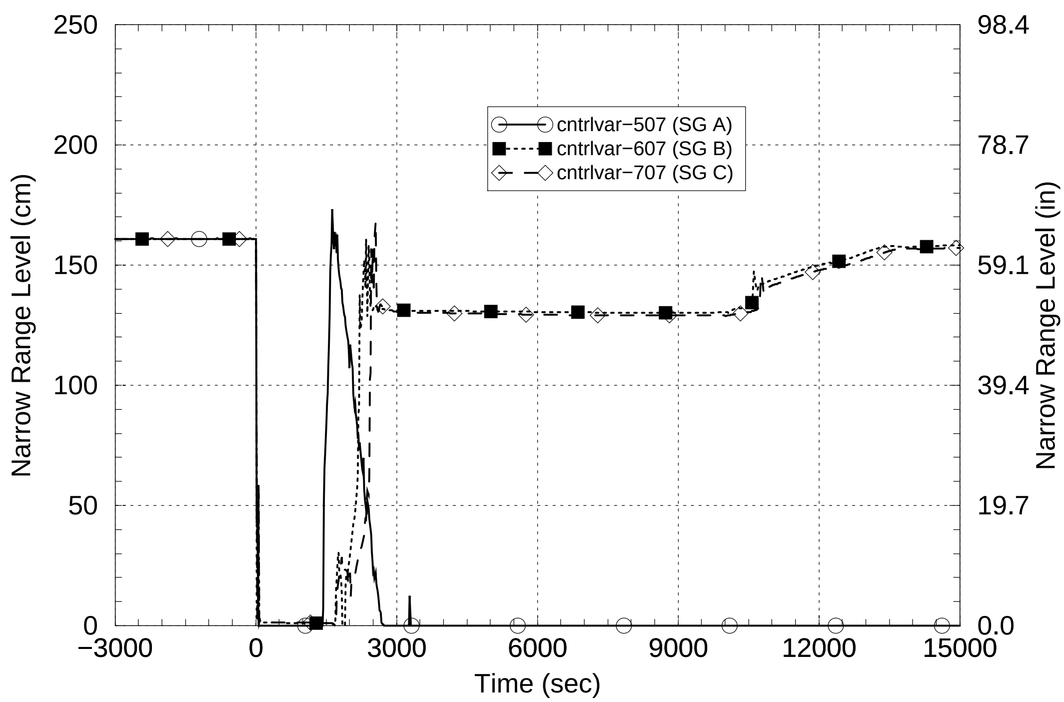


Figure 3.2.3-6 Steam Generator Narrow Range Level – BV Case 102

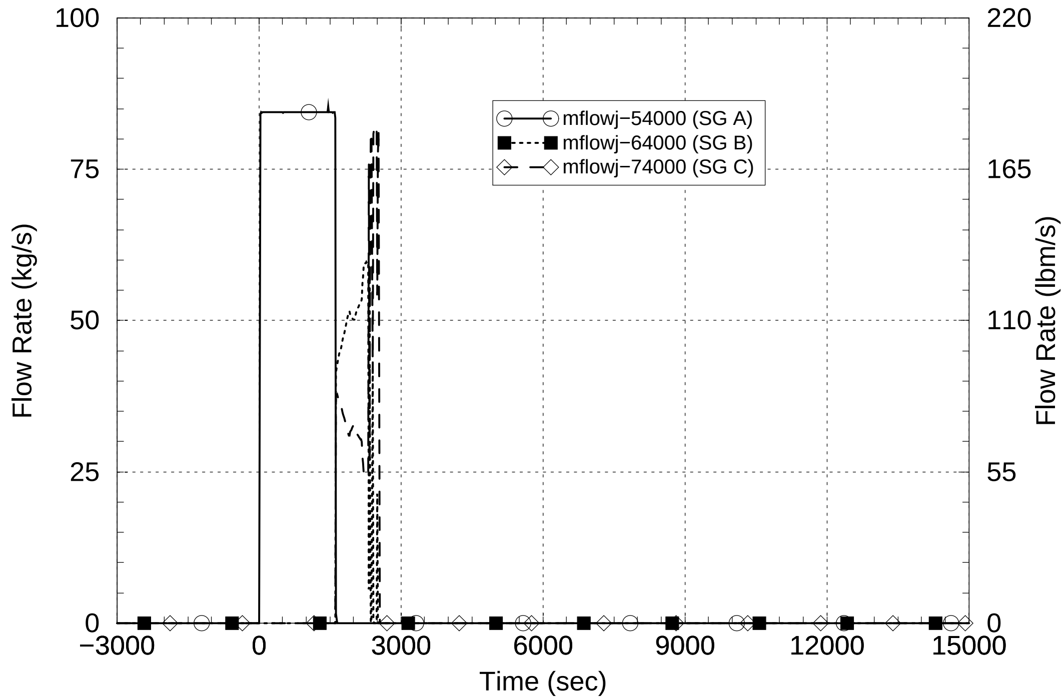


Figure 3.2.3-7 Auxiliary Feedwater Flow Rate – BV Case 102

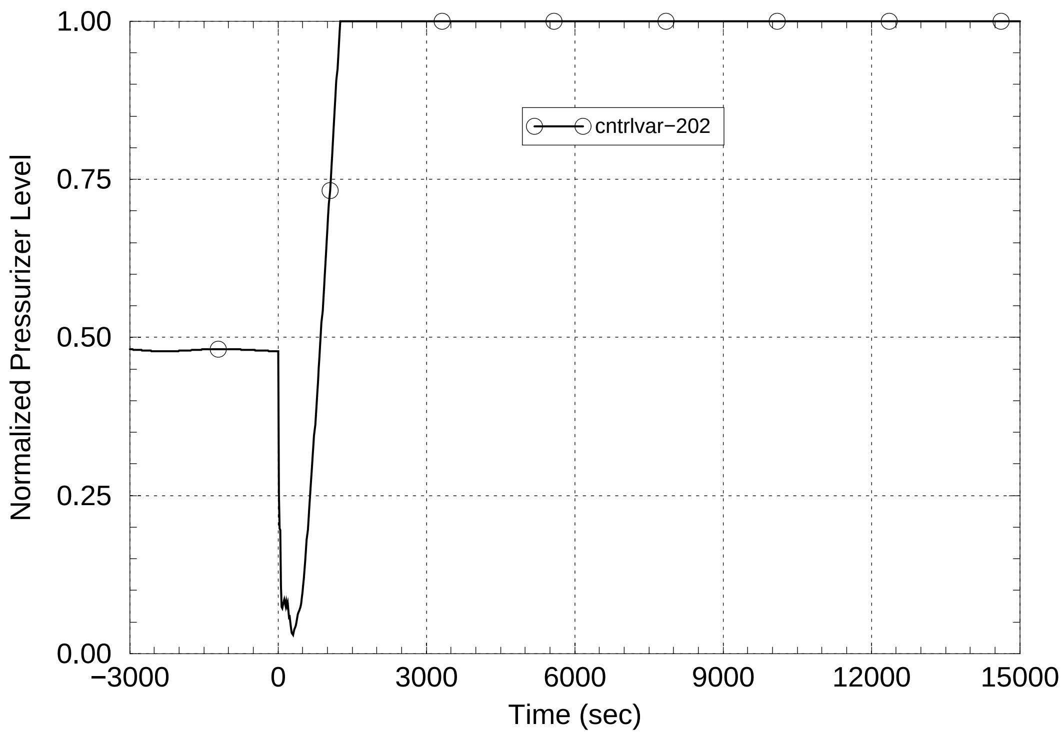


Figure 3.2.3-8 Normalized Pressurizer Water Level – BV Case 102

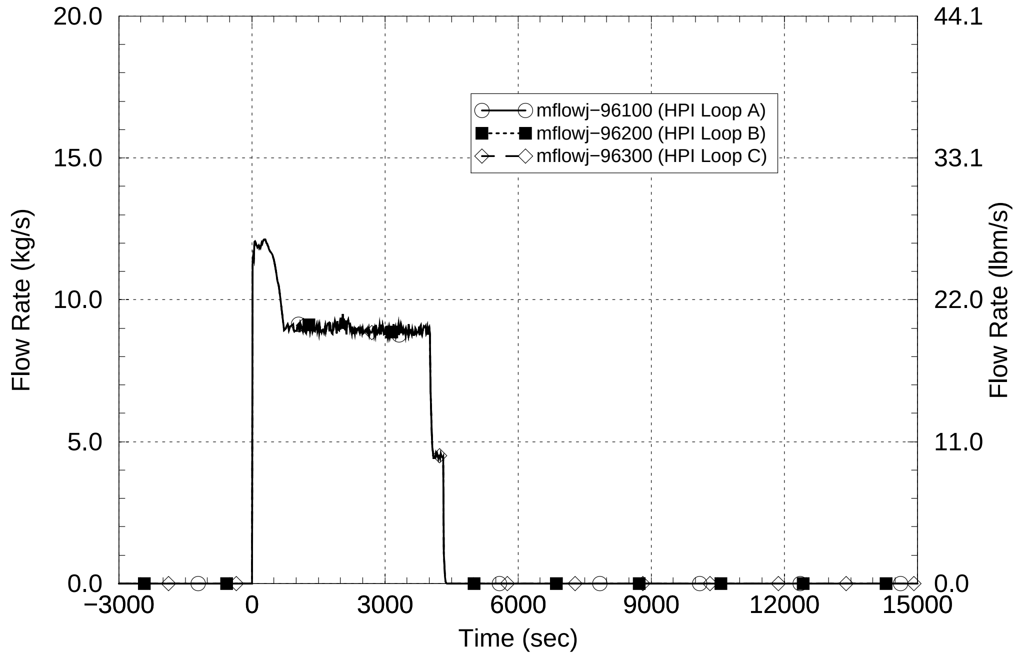


Figure 3.2.3-9 HHSI Flow Rate – BV Case 102

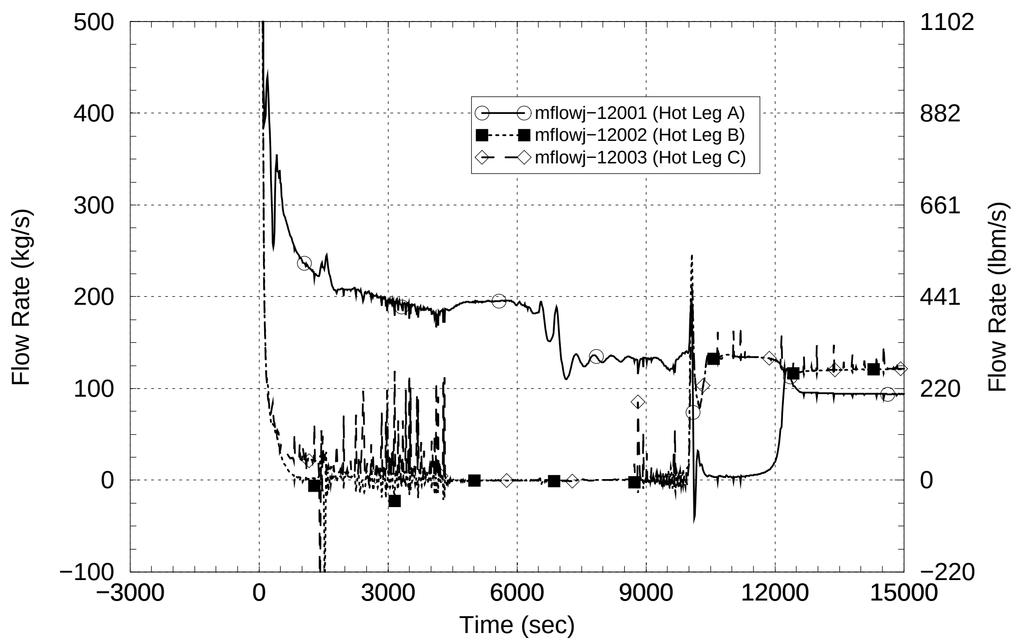


Figure 3.2.3-10 Hot Leg Mass Flow Rate – BV Case 102

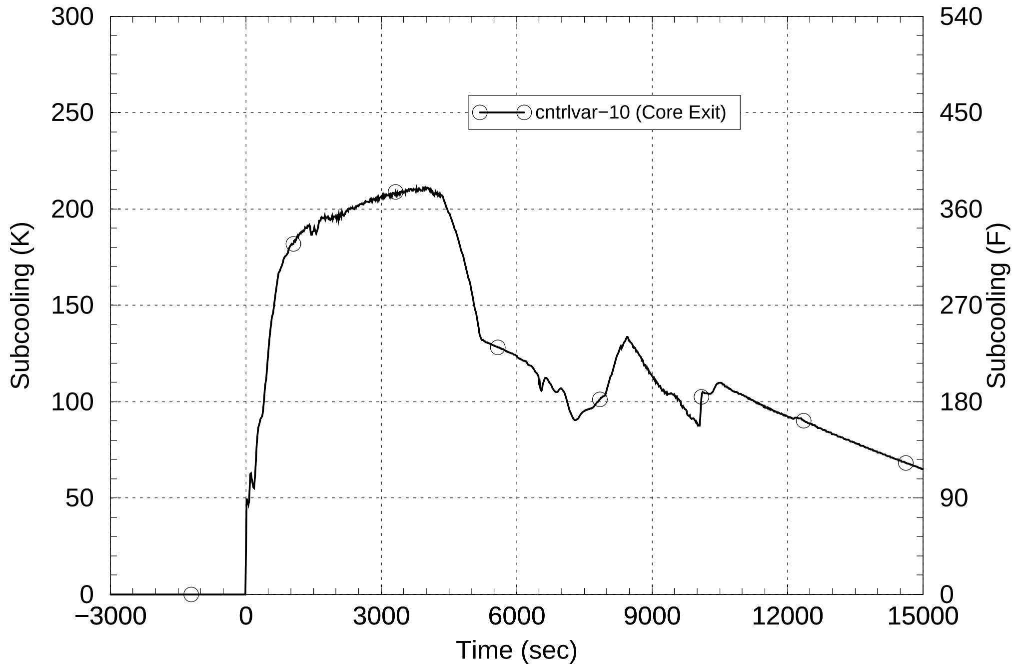


Figure 3.2.3-11 Core Exit Subcooling – BV Case 102

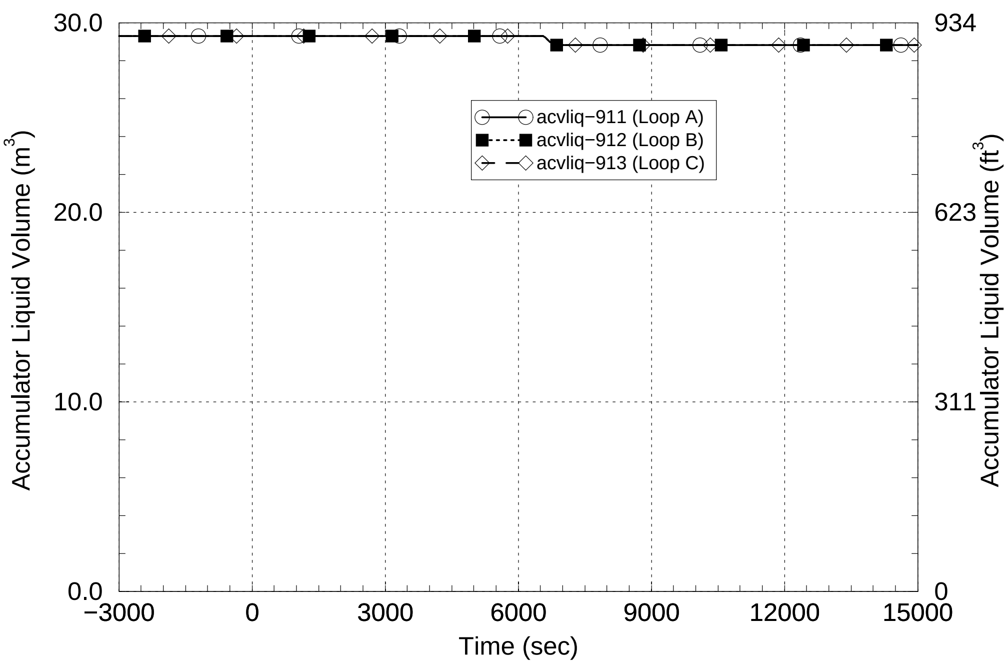


Figure 3.2.3-12 Accumulator Liquid Volume – BV Case 102

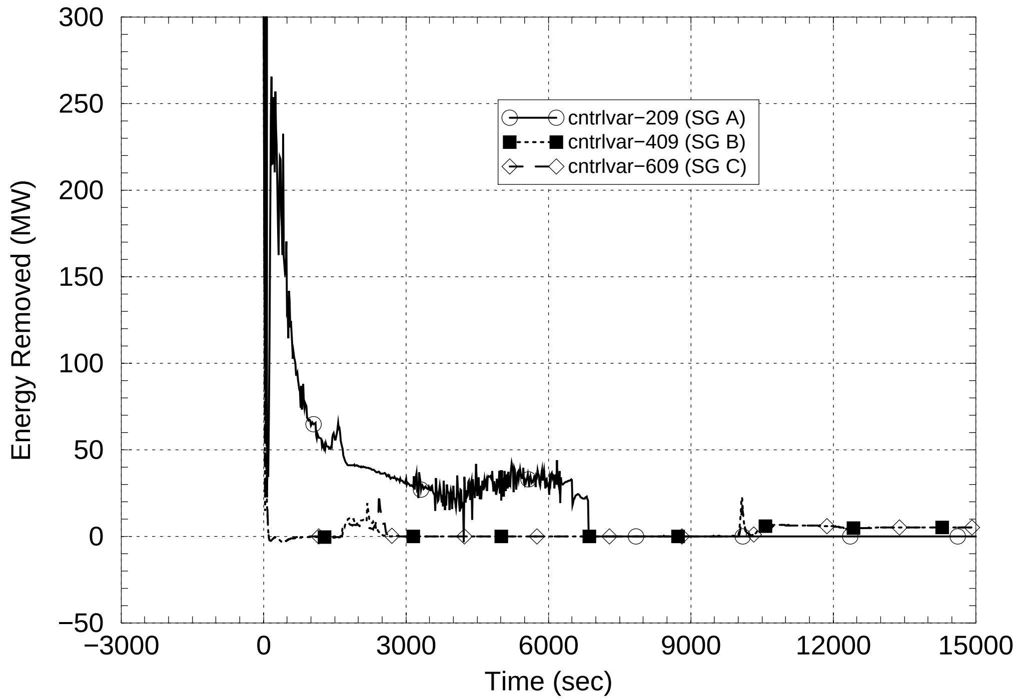


Figure 3.2.3-13 Steam Generator Energy Removal Rate – BV Case 102

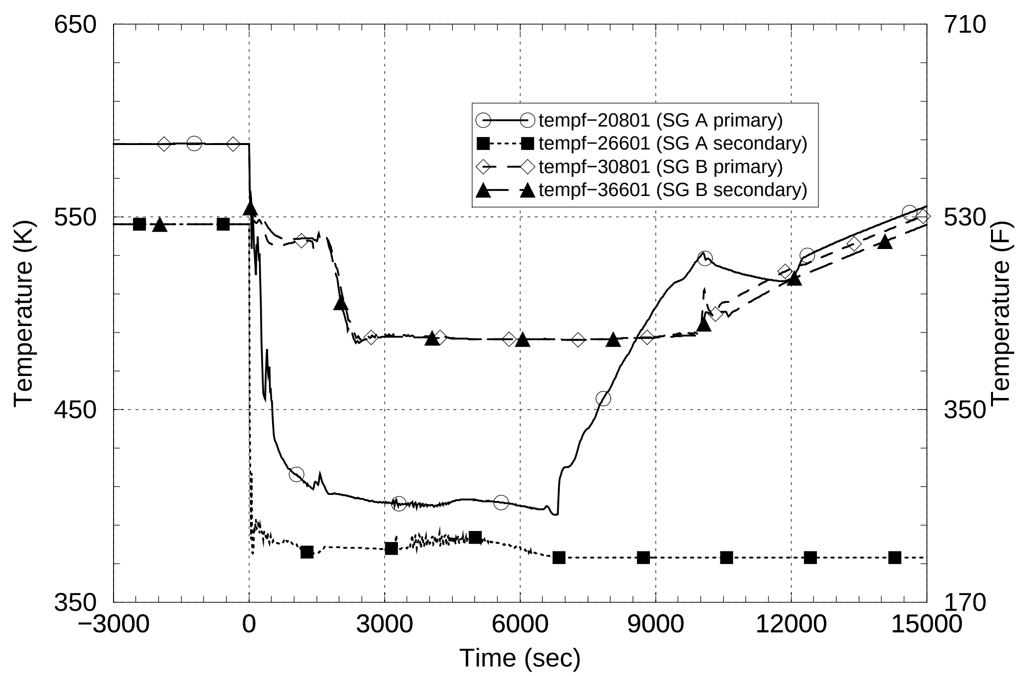


Figure 3.2.3-14 System Fluid Temperatures – BV Case 102

3.2.3.2 Beaver Valley Main Steam Line Break From Hot Full Power (BV Case 104)

This case is identical to the steam line break case described in Section 3.2.3.1, except the operator is assumed to wait 60 minutes prior to stopping HHSI pumps upon meeting all of the required conditions. It is a double ended main steam line break (in steam generator A) from hot full power with auxiliary feedwater continuing to feed the affected loop generator for 30 minutes and operator control of high head safety injection. This case is identified as Beaver Valley Case 104 in Appendix B, Table B-1. The steam line break is assumed to occur downstream of the flow restrictor and inside of containment, so the RCPs are tripped due to adverse containment conditions. The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.3-15 through 3.2.3-17 respectively. A sequence of events table for this event is shown as Table 3.2-3.

When the steam line break occurs, the secondary side pressure in steam generator A drops rapidly as shown in Figure 3.2.3-18. Steam line break flow is shown in Figure 3.2.3-19. An MSIV closure signal should be generated upon high containment pressure, however, the containment is not modeled. In the model, the MSIV did not receive a close signal until 2,020 s on two out of three steam line pressures less than 3.47 MPa [503 psia]. While the MSIV should have closed much sooner, there are check valves in the lines to prevent backflow from one steam generator to another. At 2.5 s, a reactor/turbine trip was generated (based on two of three loop delta temperature) which closes the turbine stop valve. In addition, since the secondary side pressure was less than the steam dump valve setpoint, there was no flow through any of the MSIVs. Therefore, it is acceptable for the calculation to simulate that the MSIVs did not close upon high containment pressure.

At 0.1 s a safety injection actuation signal was generated due to high steamline pressure differential. The SIAS results in actuation of both the HHSI, and LHSI. In addition, it also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated. Because of the break and main feedwater being stopped, the steam generator water levels drop rapidly as shown in Figure 3.2.3-20.

AFW flow begins almost immediately, as shown in Figure 3.2.3-21, and all flow goes to the broken loop generator (SG A). As the pressure in steam generator A decreases, the flow through the break decreases and becomes smaller than the AFW flow, allowing the water level to recover. At 1,800 s, the operator is assumed to stop AFW flow to the broken loop generator. At this time, AFW begins flowing to steam generators B and C. With no feedwater, steam generator A begins to boil dry.

Heat transfer from the primary to the depressurizing steam generator resulted in a rapid cooldown of the primary system as shown in Figure 3.2.3-16. This cooling also causes the primary fluid volume to shrink which slightly depressurizes the primary as shown in Figure 3.2.3-15 as well as causes the pressurizer water level to decrease as shown in Figure 3.2.3-22. Because the SIAS signal was generated, HHSI flow (Figure 3.2.3-23) is started and repressurizes the primary to the pressurizer PORV setpoint by 735 s.

As a boundary condition to this case, the RCPs were tripped (based on adverse containment conditions). Upon RCP trip, the loop flow decreases rapidly as shown in Figure 3.2.3-24. Loop natural circulation flow for steam generator A continues after the RCP trip as a result of the continual heat removal of the steam generator. Figure 3.2.1-17 shows the downcomer fluid-wall heat transfer coefficient. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops rapidly from an initial value of approximately 23,950 $W/m^2{\cdot}K$ [1.171 $Btu/s{\cdot}ft^2{\cdot}{}^{\circ}F$]. The heat transfer coefficient then remains around a value of 1,500 $W/m^2{\cdot}K$ [0.073 $Btu/s{\cdot}ft^2{\cdot}{}^{\circ}F$] for the duration of the transient.

By 2,220 s the system has met all of the conditions for stopping an HHSI pump. These conditions include: core exit subcooling greater than 22.2 K [40°F] (Figure 3.2.3-25), any steam generator NRL greater than 32% (Figure 3.2.3-20), pressurizer water level greater than 32% (Figure 3.2.3-22) and pressure stable or increasing (Figure 3.2.3-15). After waiting an additional 60 minutes (as given in the case description), the operator is assumed to stop a single HHSI pump (at 5,820 s). Then, after waiting five more minutes, the above conditions are still met so the second HHSI pump is stopped (at 6,120 s).

Upon stopping the second HHSI pump, letdown flow was re-established. Between the loss of the HHSI pumps and letdown flow, the primary pressure drops rapidly. At 7,680 s steam generator A has boiled dry, and can no longer remove heat. Since there is no longer any ECCS water entering the system, the primary begins to heatup and repressurize.

When steam generator A has boiled dry, its heat removal effectiveness drops as shown in Figure 3.2.3-26. At this time the primary system temperature is much colder than the temperature of steam generator B and C secondaries as shown in Figure 3.2.3-27. So, between 7,680 s and 11,250 s the primary system does not have a heat sink and the primary system heats up. The loop A natural circulation during this period is being driven by the transient heatup of the loop.

By 9,490 s, the primary system becomes hotter than steam generator B and C temperatures and by 11,250 s enough of that hot primary water finds its way into the steam generator B and C primaries that natural circulation through those loops starts up. The burst of heat removal (as well as associated pressure/temperature drop) and rapid natural circulation flow in loops B and C results because in order to start the flow the primary system had to become much hotter than could be sustained by steady natural circulation flow. So the flow starts up, but the cooling it affords at first is at a much greater rate than needed and this reduces the flow to the sustainable rate.

By 14,500 s, the system has reached a stable point where all of the loops are circulating but with loop A a little slower than loops B and C. For the remainder of the transient, both loops B and C remove some heat from the primary, however this, in addition to the heat lost through the pressurizer PORV, is not enough to remove the core decay heat. Therefore, the primary system continues to heat up.

The double ended main steam line break results in a continuous cooldown of the primary side while auxiliary feedwater flow is allowed to the broken steam generator. The minimum downcomer fluid temperature is 370 K [206°F] at 5,820 s. Due to continuous HHSI flow, the primary pressure at 5,820 s is 16.2 MPa [2,350 psia]. Once the HHSI flow is controlled/stopped, the primary pressure decreases, however core heat and the lack of ECCS flow causes the system to heatup/repressurize.

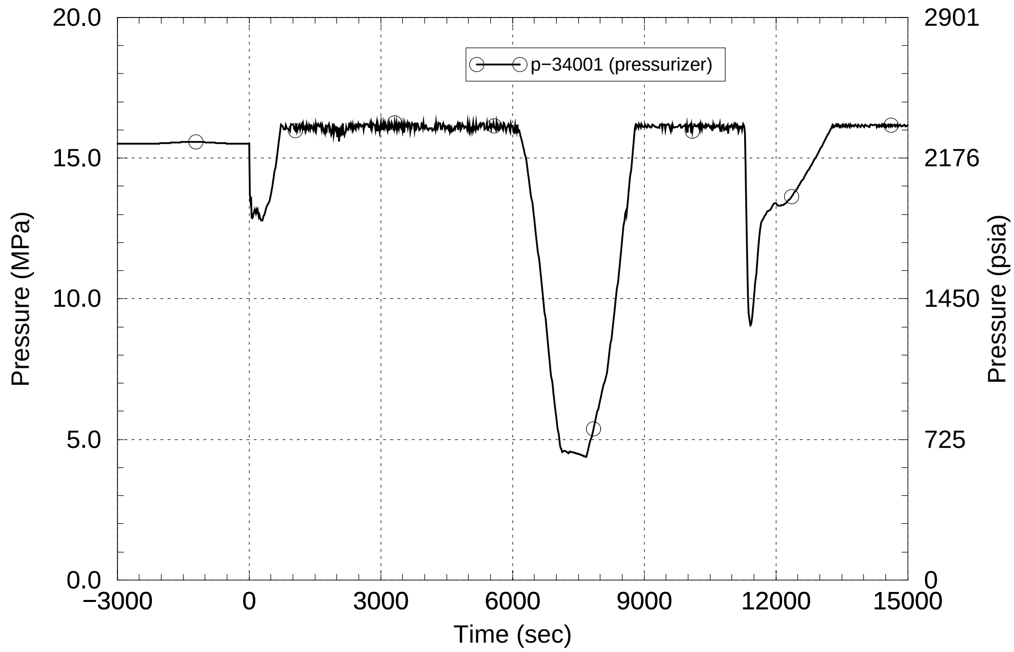


Figure 3.2.3-15 Primary System Pressure – BV Case 104

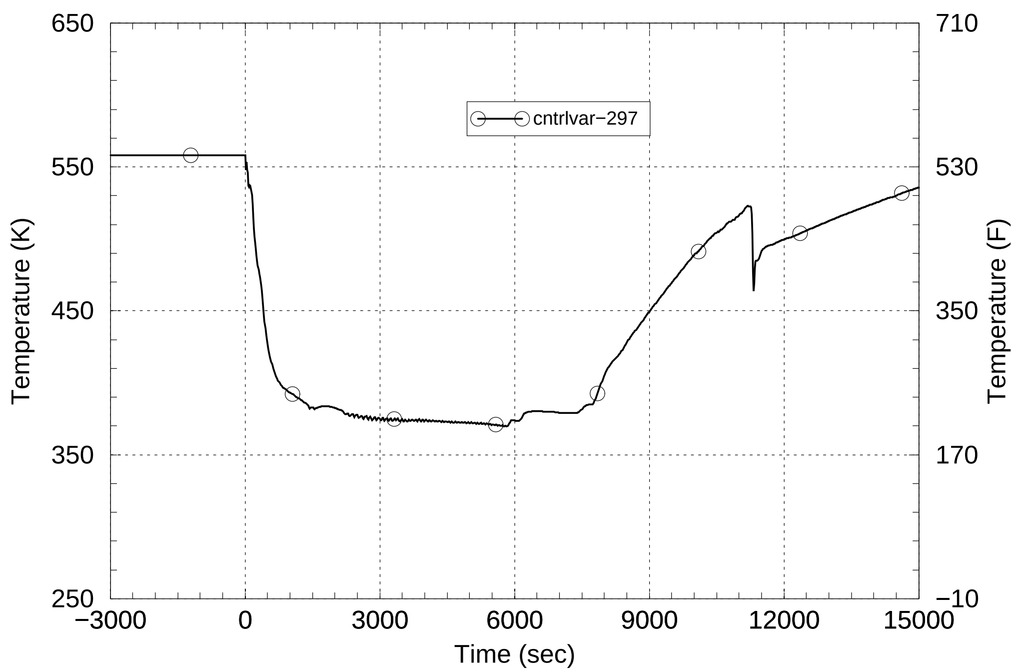


Figure 3.2.3-16 Average Downcomer Fluid Temperature – BV Case 104

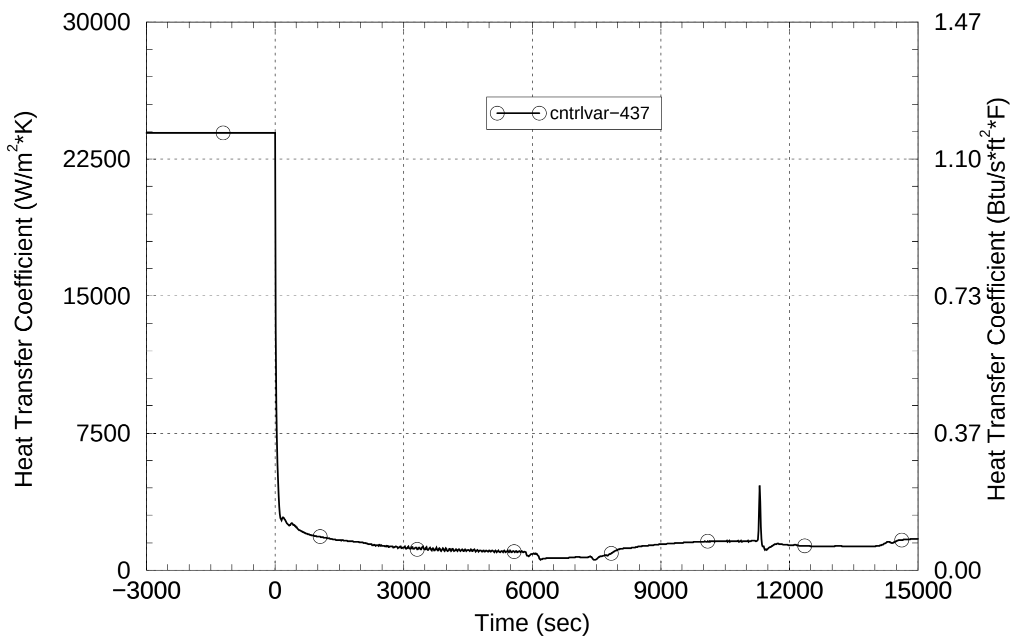


Figure 3.2.3-17 Heat Transfer Coefficient – BV Case 104

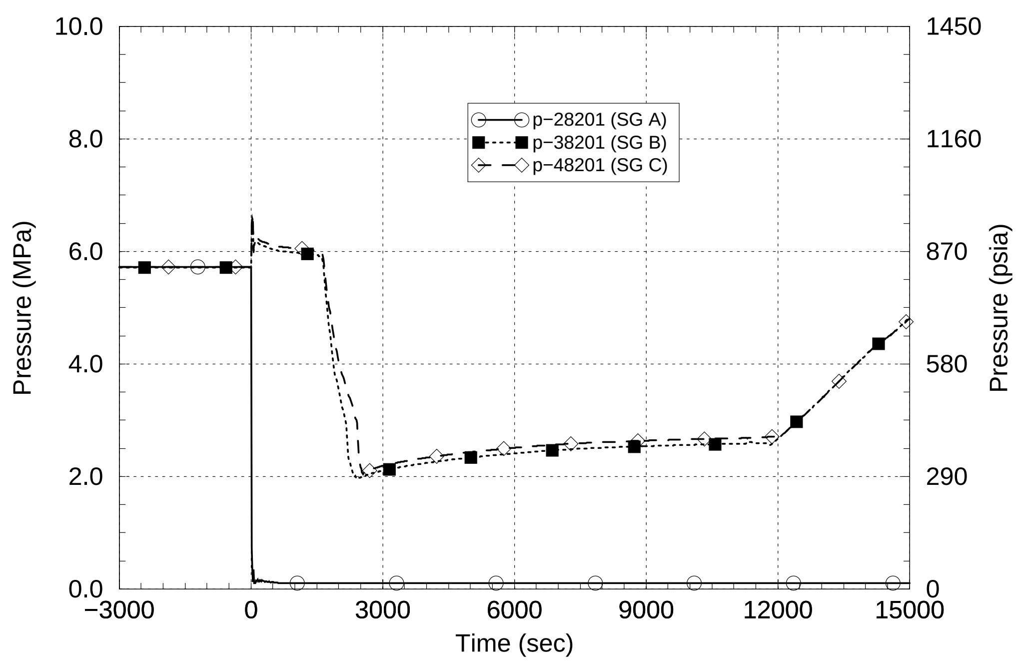


Figure 3.2.3-18 Steam Generator Pressure – BV Case 104

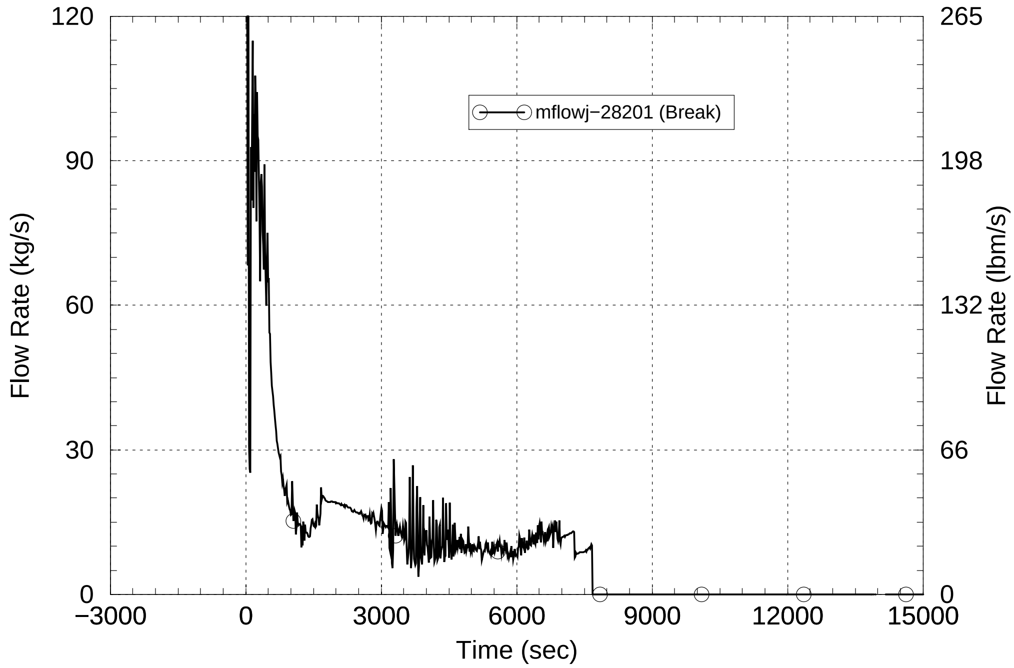


Figure 3.2.3-19   Break Flow – BV Case 104

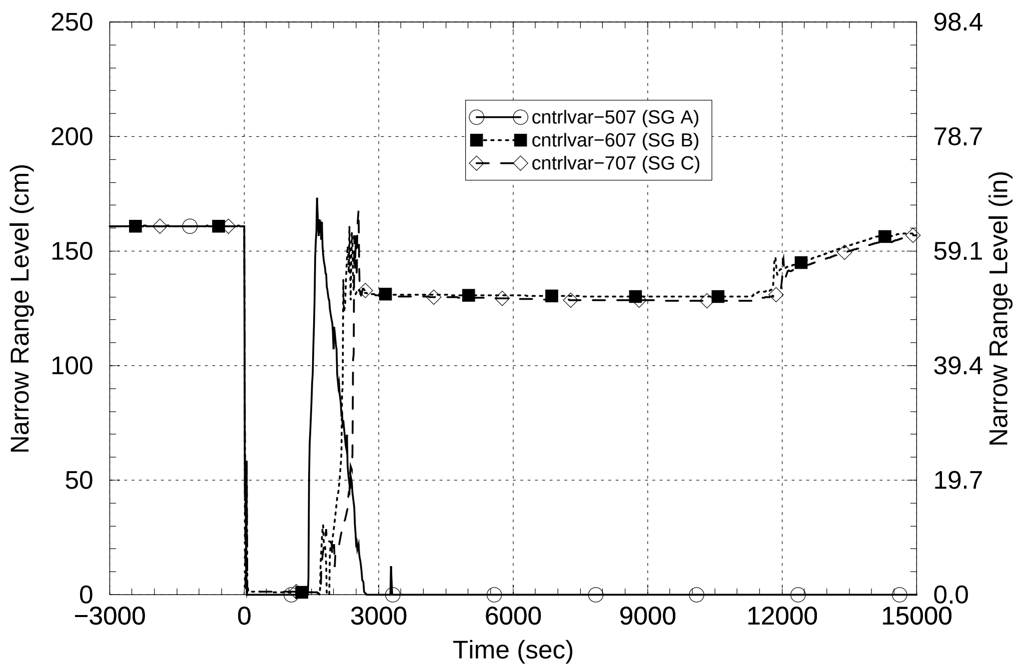


Figure 3.2.3-20   Steam Generator Narrow Range Level – BV Case 104

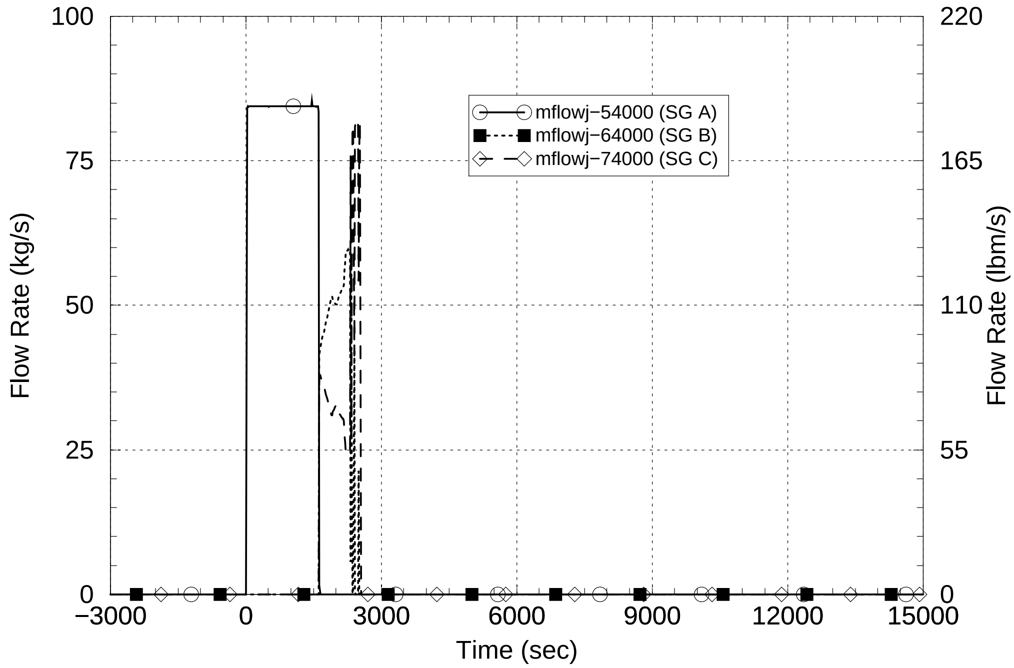


Figure 3.2.3-21 Auxiliary Feedwater Flow Rate – BV Case 104

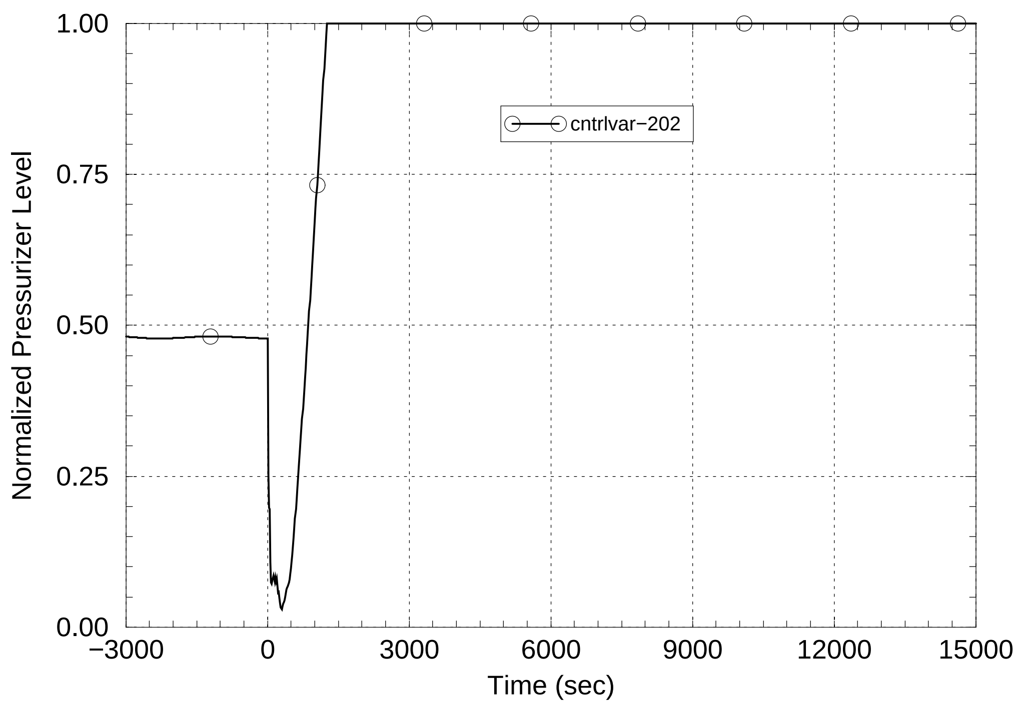


Figure 3.2.3-22 Normalized Pressurizer Water Level – BV Case 104

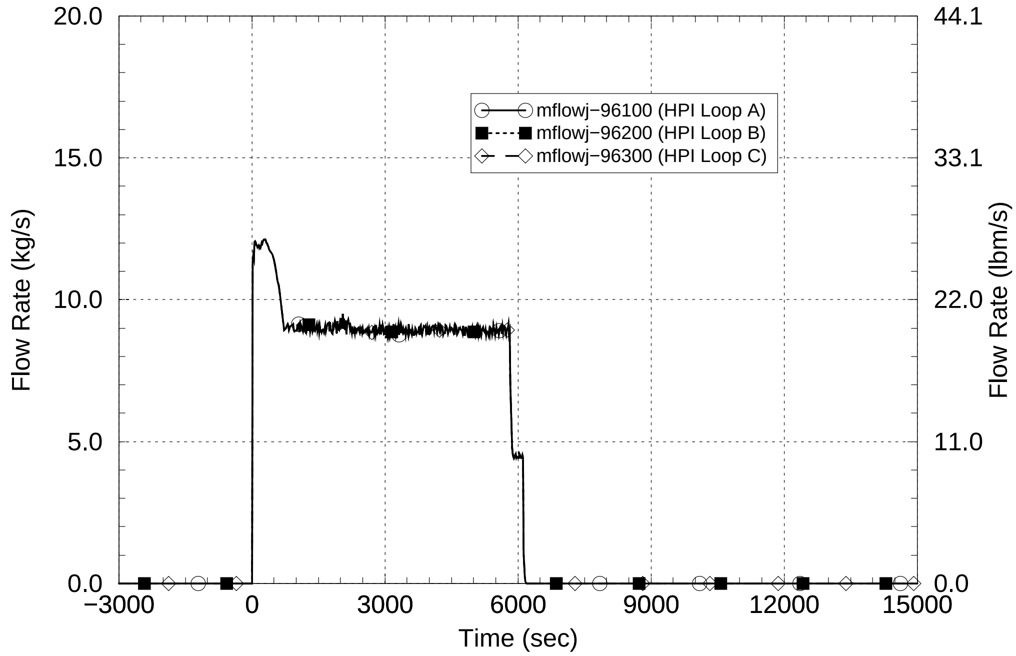


Figure 3.2.3-23 HHSI Flow Rate – BV Case 104

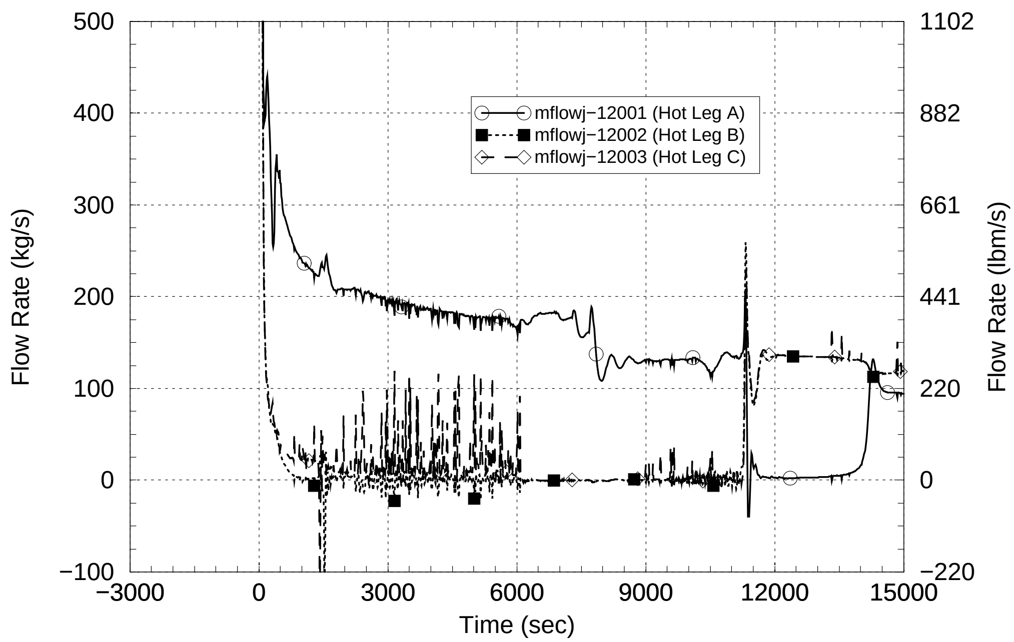


Figure 3.2.3-24 Hot Leg Mass Flow Rate – BV Case 104

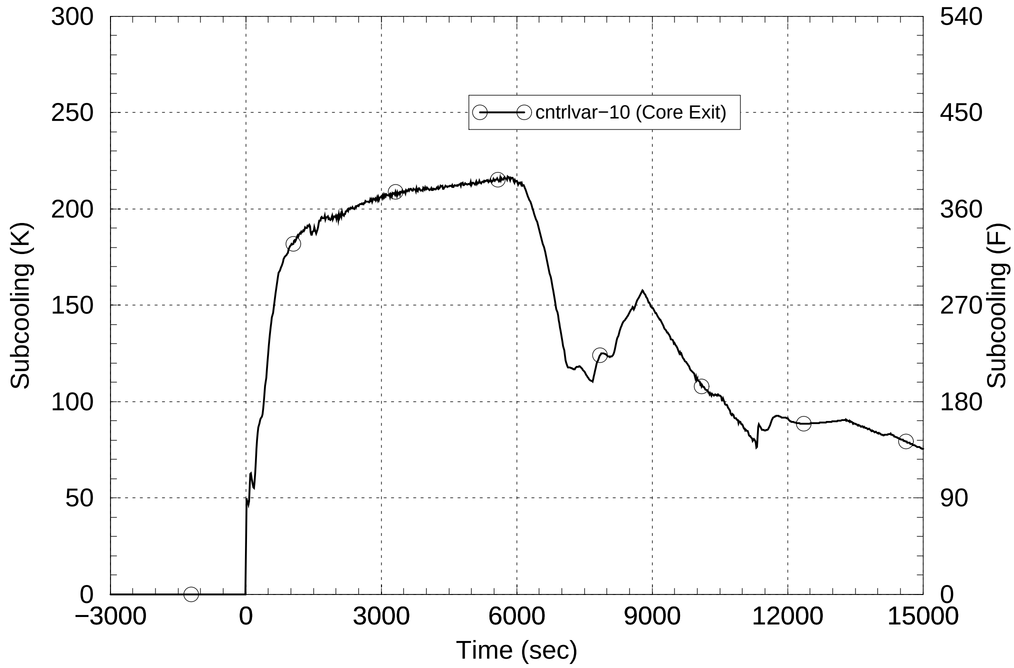


Figure 3.2.3-25 Core Exit Subcooling – BV Case 104

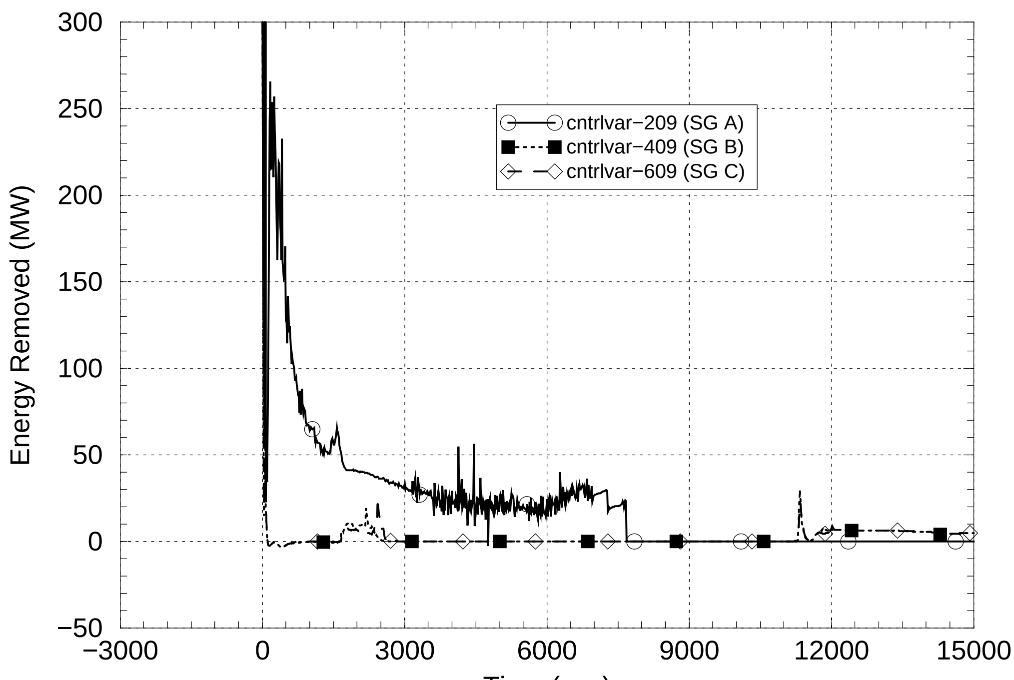


Figure 3.2.3-26 Steam Generator Energy Removal Rate – BV Case 104

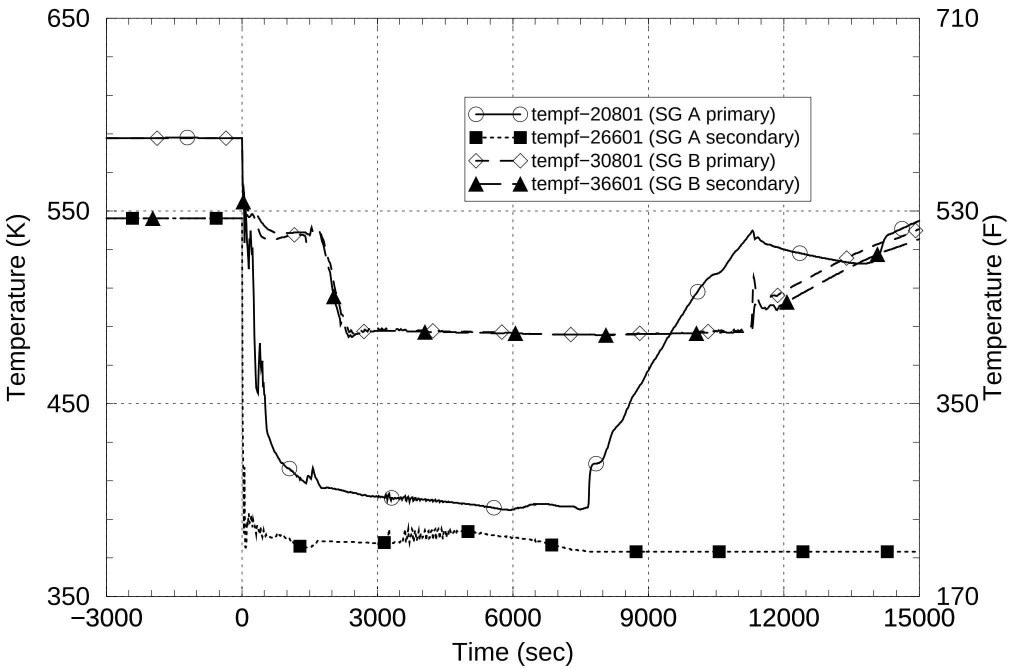


Figure 3.2.3-27 System Fluid Temperatures – BV Case 104

3.2.3.3 Beaver Valley Main Steam Line Break From Hot Full Power (BV Case 108)

This case is a small steam line break in steam generator A from hot full power with auxiliary feedwater continuing to feed the broken loop generator for 30 minutes and operator control of high head safety injection. This case is identified as Beaver Valley Case 108 in Appendix B, Table B-1. This case is simulated by sticking open all steam generator A safety relief valves. This results in a total break flow area of 0.0505 m^2 [0.54325 ft^2]. The break is assumed to occur downstream of the flow restrictor and inside of containment, so the RCPs are tripped due to adverse containment conditions. The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.3-28 through 3.2.3-30 respectively. A sequence of events table for this event is shown as Table 3.2-3.

When the steam line break occurs, the secondary side pressure in steam generator A drops rapidly as shown in Figure 3.2.3-31. Steam line break flow is shown in Figure 3.2.3-32. An MSIV closure signal should be generated upon high containment pressure, however, the containment is not modeled. In the model, the MSIV did not receive a close signal until 1,575 s on two out of three steam line pressures less than 3.47 MPa [503 psia]. While the MSIV should have closed much sooner, there are check valves in the lines to prevent backflow from one steam generator to another. At 0.0 s the turbine stop valves were closed. In addition, since the secondary side pressure was less than the steam dump valve setpoint, there was no flow through any of the

MSIVs. Therefore, it is acceptable for the calculation to simulate that the MSIVs did not close upon high containment pressure.

At approximately seven seconds a safety injection actuation signal was generated due to high steamline pressure differential. The SIAS results in actuation of both the HHSI, and LHSI. In addition, it also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated. Because of the break and main feedwater being stopped, the steam generator water levels drop rapidly as shown in Figure 3.2.3-33.

AFW flow begins almost immediately, as shown in Figure 3.2.3-34, and all flow goes to the broken loop generator (SG A). As the pressure in steam generator A decreases, the flow through the break decreases and becomes smaller than the AFW flow, allowing the water level to recover. At 1,800 s, the operator is assumed to stop AFW flow to the broken loop generator. At this time, AFW begins flowing to steam generators B and C. With no feedwater, steam generator A begins to boil dry.

Heat transfer from the primary to the depressurizing steam generator resulted in a rapid cooldown of the primary system as shown in Figure 3.2.3-29. This cooling also causes the primary fluid volume to shrink which slightly depressurizes the primary as shown in Figure 3.2.3-28 as well as causes the pressurizer water level to decrease as shown in Figure 3.2.3-35. Because the SIAS signal was generated, HHSI flow (Figure 3.2.3-36) is started and repressurizes the primary to the pressurizer PORV setpoint by 600 s.

As a boundary condition to this case, the RCPs were tripped (based on adverse containment conditions). Upon RCP trip, the loop flow decreases rapidly as shown in Figure 3.2.3-37. Loop natural circulation flow for steam generator A continues after the RCP trip as a result of the continual heat removal of the steam generator. Figure 3.2.1-30 shows the downcomer fluid-wall heat transfer coefficient. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops rapidly from an initial value of approximately 23,950 $W/m^2{\cdot}K$ [1.171 $Btu/s{\cdot}ft^2{\cdot}{}^\circ F$]. The heat transfer coefficient then remains around a value of 1,500 $W/m^2{\cdot}K$ [0.073 $Btu/s{\cdot}ft^2{\cdot}{}^\circ F$] for the duration of the transient.

By 1,770 s the system has met all of the conditions for stopping an HHSI pump. These conditions include: core exit subcooling greater than 22.2 K [40°F] (Figure 3.2.3-38), any steam generator NRL greater than 32% (Figure 3.2.3-33), pressurizer water level greater than 32% (Figure 3.2.3-35) and pressure stable or increasing (Figure 3.2.3-28). After waiting an additional 30 minutes (as given in the case description), the operator is assumed to stop a single HHSI pump (at 3,570 s). Then, after waiting five more minutes, the above conditions are still met so the second HHSI pump is stopped (at 3,870 s).

Upon stopping the second HHSI pump, letdown flow was re-established. Between the loss of the HHSI pumps and letdown flow, the primary pressure drops rapidly. At 6,075 s steam generator A has boiled dry, and can no longer remove heat. Since there is no longer any ECCS water entering the system, the primary begins to heatup and repressurize.

When steam generator A has boiled dry, its heat removal effectiveness drops as shown in Figure 3.2.3-39. At this time the primary system is much colder than the steam generator B and C secondaries as shown in Figure 3.2.3-40. So, after 6,075 s the primary system does not have a heat sink and the primary system heats up. The loop A natural circulation during this period is being driven by the transient heatup of the loop.

By 7,185 s, the primary system becomes hotter than steam generator B and C temperatures and by 7,500 s enough of that hot primary water finds its way into steam generator B primary that natural circulation starts up. The burst of heat removal (as well as associated pressure/temperature drop) and rapid natural circulation flow in loop B results because in order to start the flow the primary system had to become much hotter than could be sustained by steady natural circulation flow. So the flow starts up, but the cooling it affords at first is at a much greater rate than needed and this causes the flow reduction down to the sustainable rate. Around 11,500 s, natural circulation begins in loop C.

The small main steam line break results in a continuous cooldown of the primary side while auxiliary feedwater flow is allowed to the broken steam generator. The minimum downcomer fluid temperature is 395 K [252°F] at 3,600 s. Due to continuous HHSI flow, the primary pressure at 3,600 s is 16.2 MPa [2,350 psia]. Once the HHSI flow is controlled/stopped, the primary pressure decreases, however, between core heat, the lack of ECCS flow, and the loss of a heat sink (steam generator A boiling dry) causes the system to heatup/repressurize.

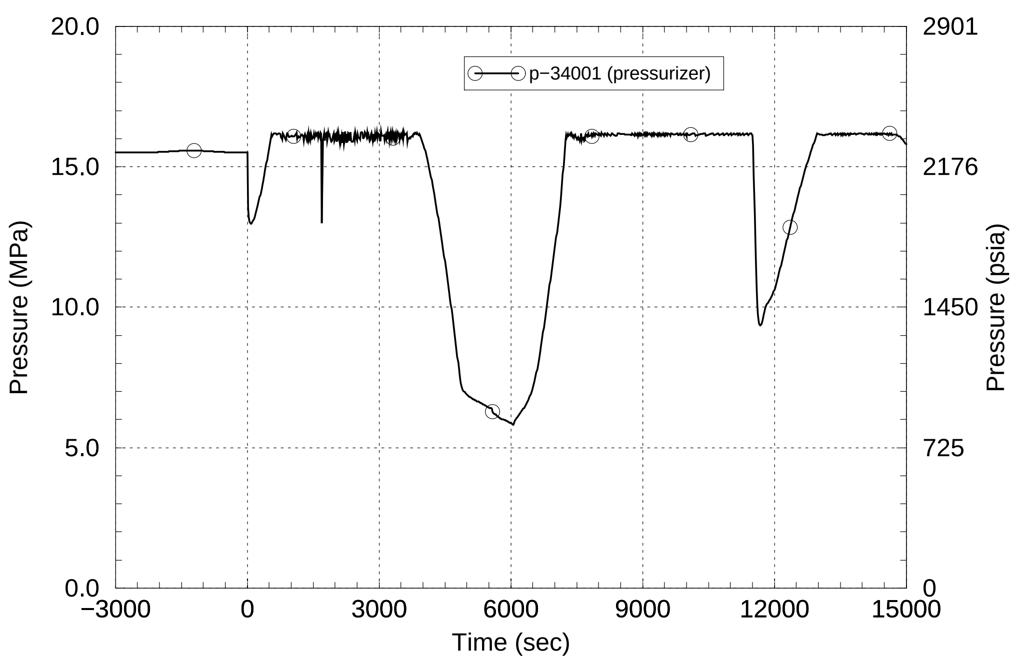


Figure 3.2.3-28 Primary System Pressure - BV Case 108

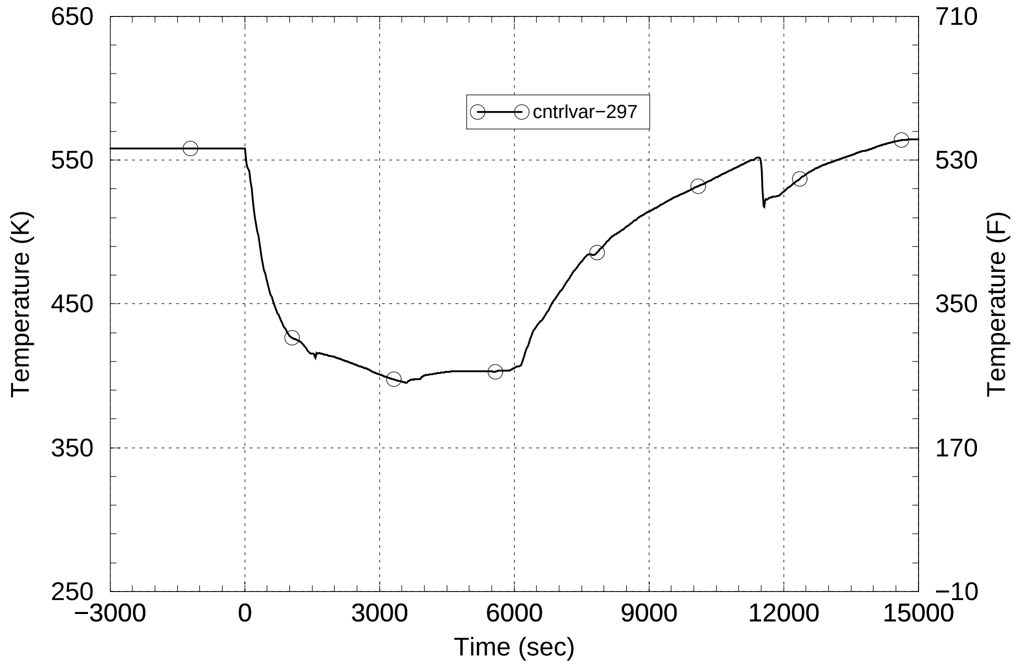


Figure 3.2.3-29 Average Downcomer Fluid Temperature - BV Case 108

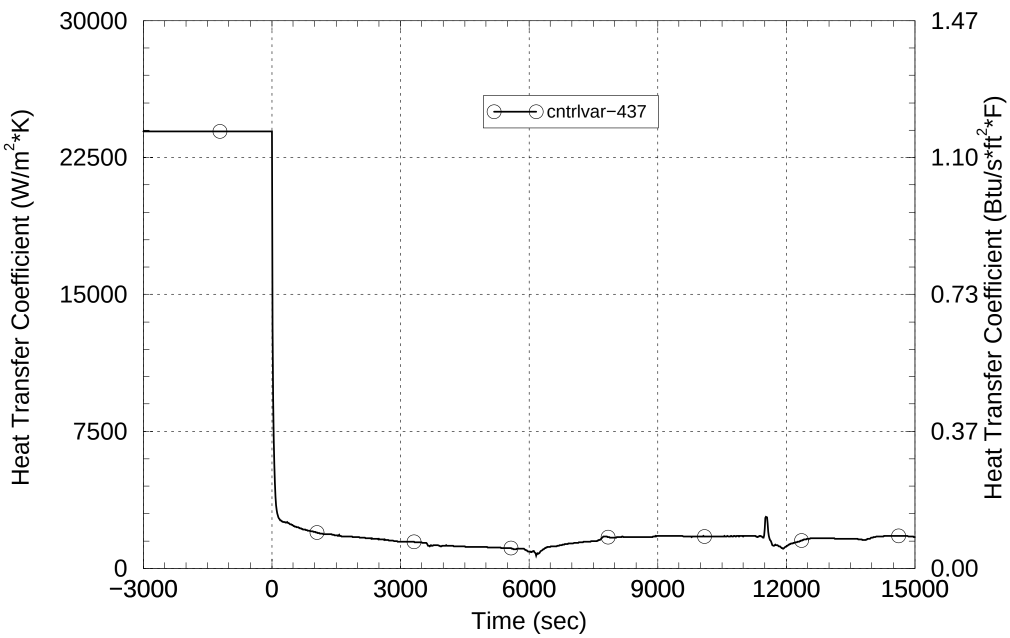


Figure 3.2.3-30 Heat Transfer Coefficient - BV Case 108

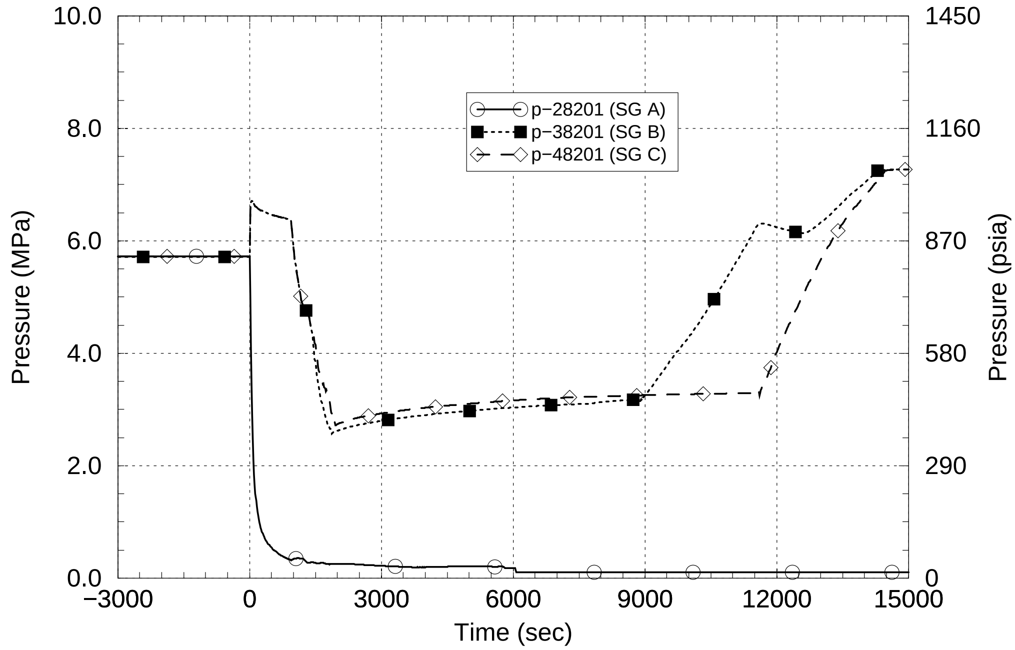


Figure 3.2.3-31 Steam Generator Pressure - BV Case 108

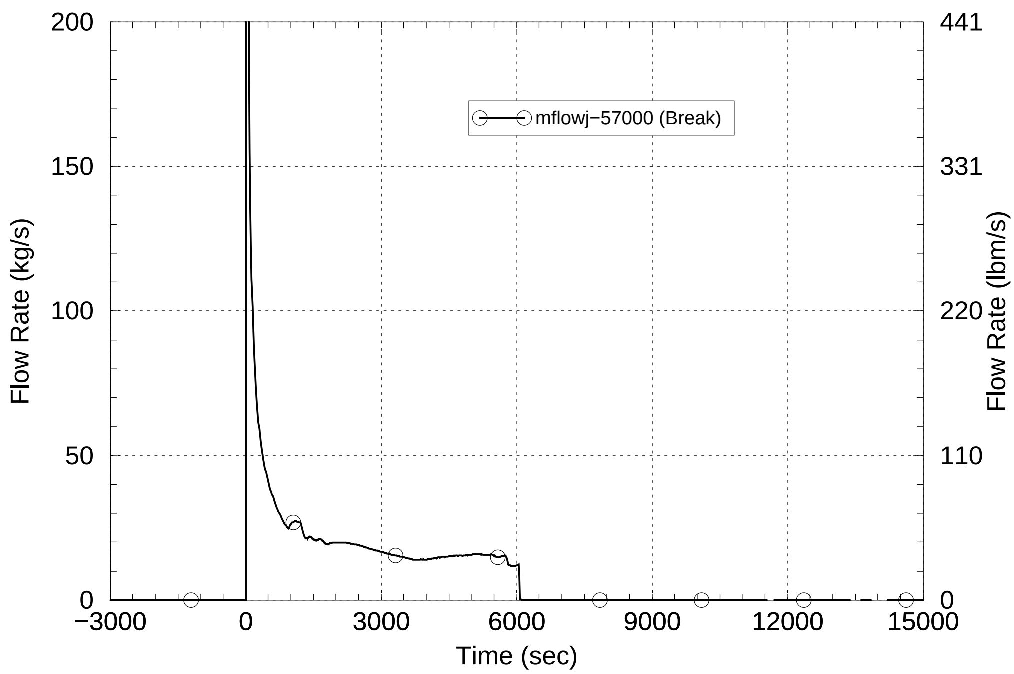


Figure 3.2.3-32 Break Flow - BV Case 108

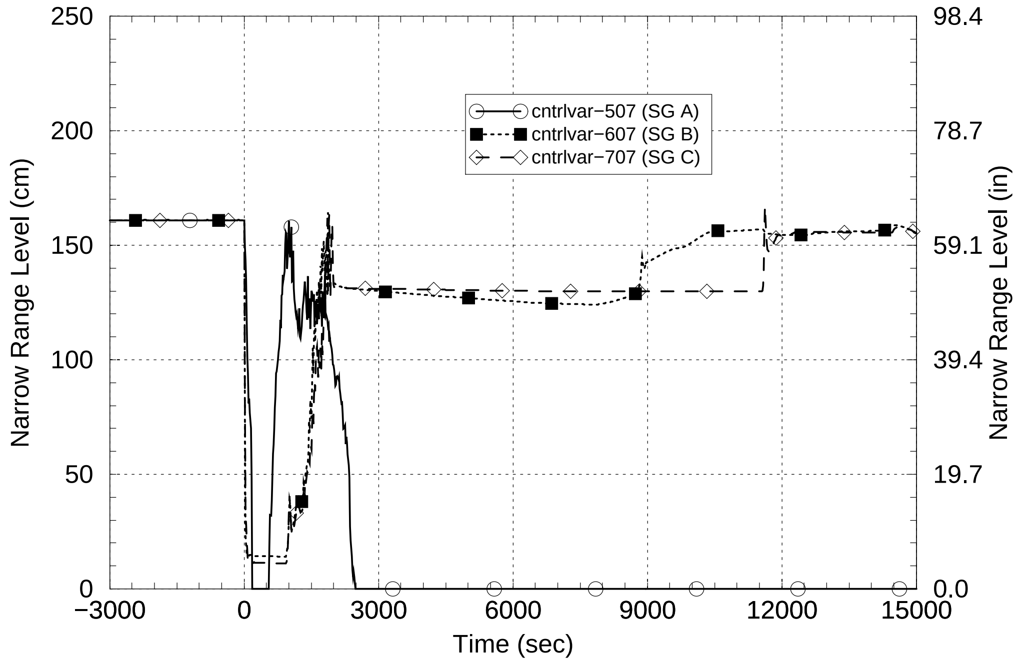


Figure 3.2.3-33 Steam Generator Narrow Range Level - BV Case 108

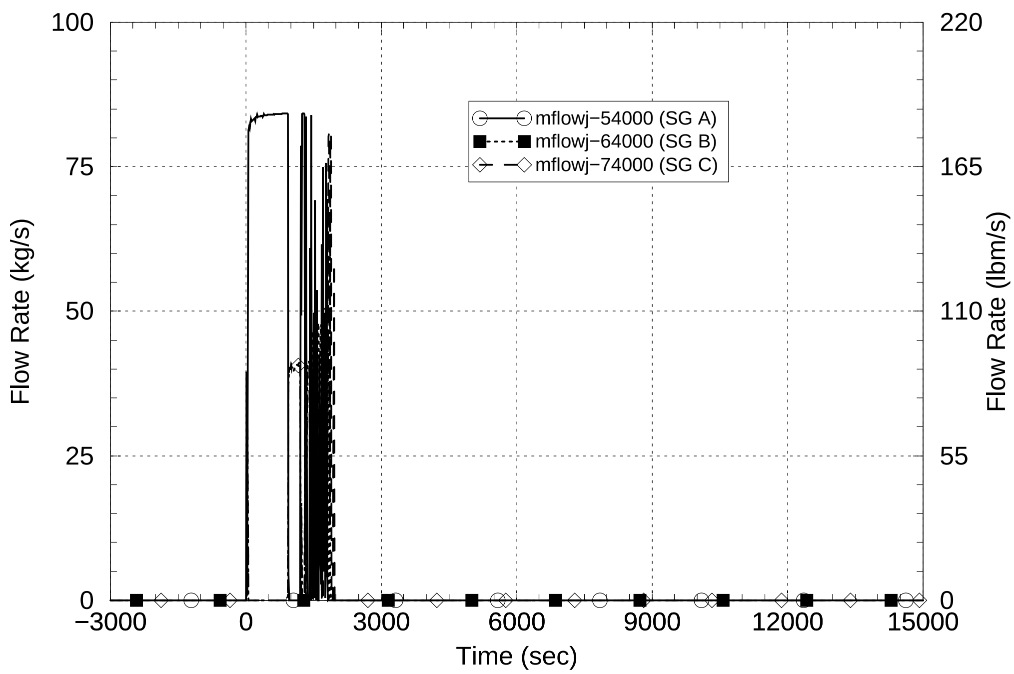


Figure 3.2.3-34 Auxiliary Feedwater Flow Rate - BV Case 108

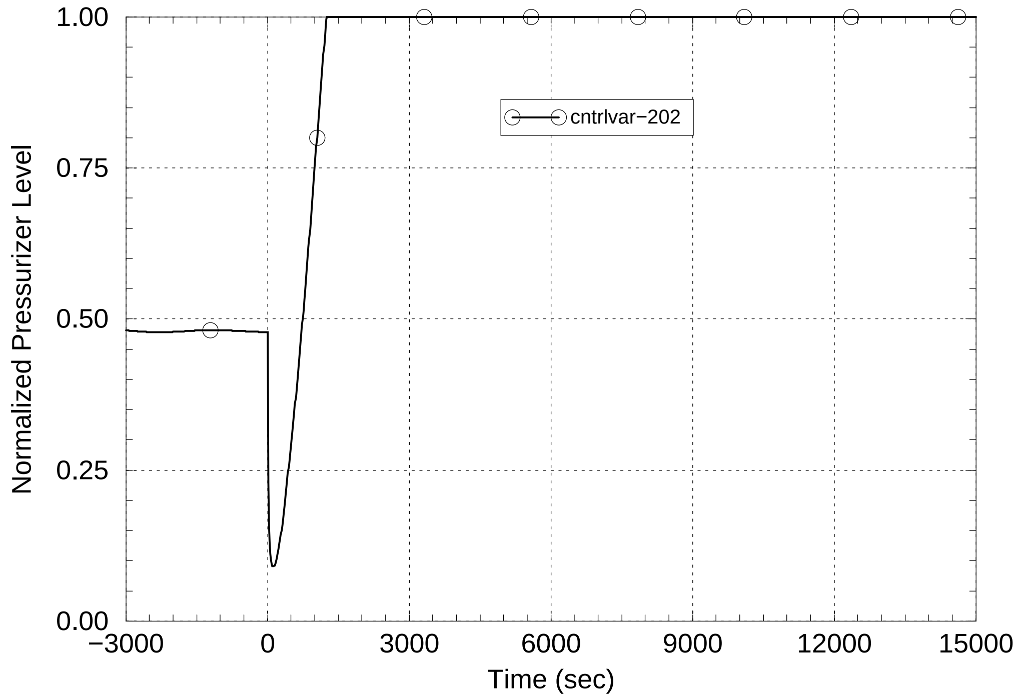


Figure 3.2.3-35   Normalized Pressurizer Water Level - BV Case 108

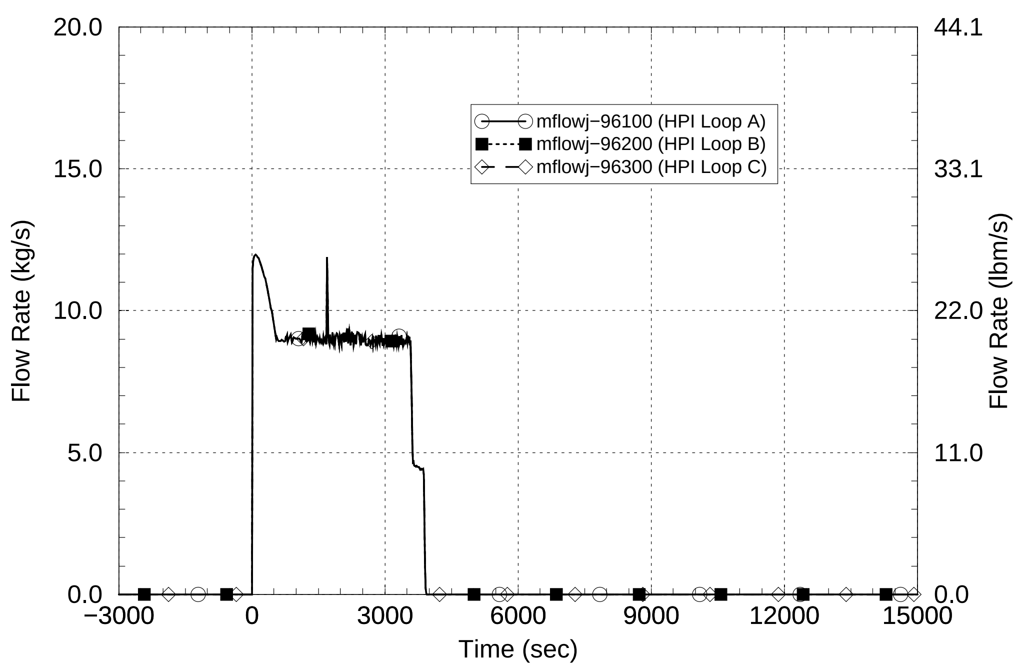


Figure 3.2.3-36   HHSI Flow Rate - BV Case 108

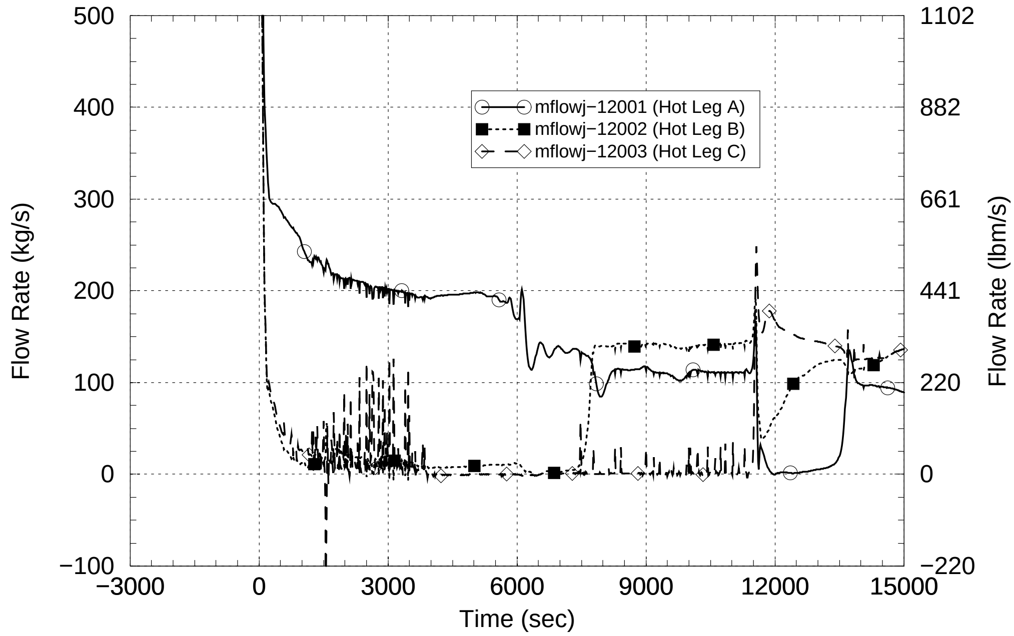


Figure 3.2.3-37 Hot Leg Mass Flow Rate - BV Case 108

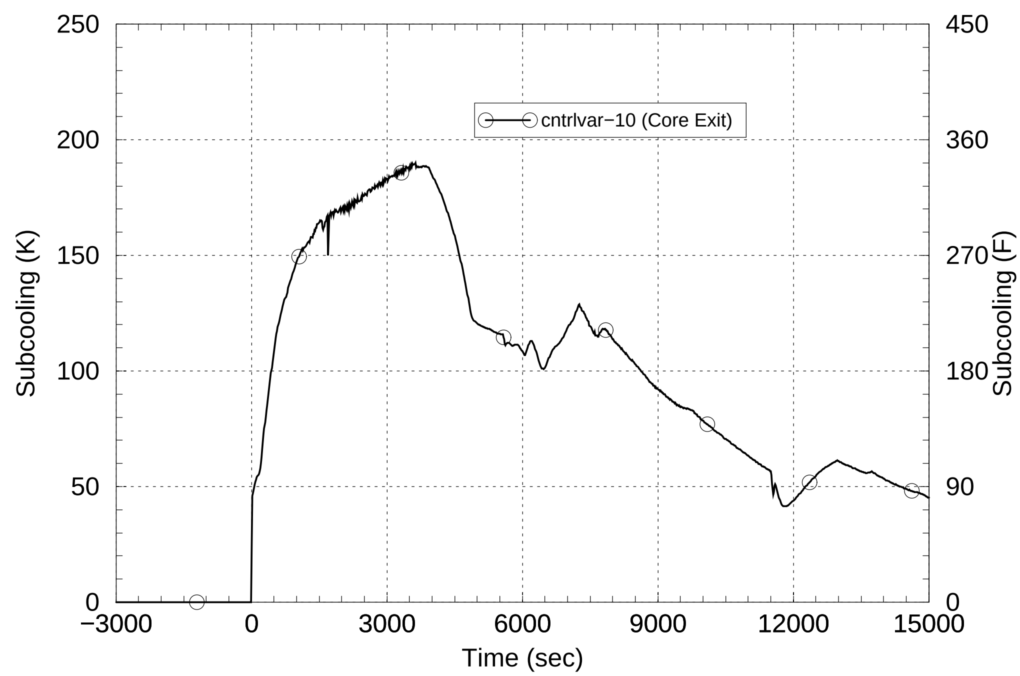


Figure 3.2.3-38 Core Exit Subcooling - BV Case 108

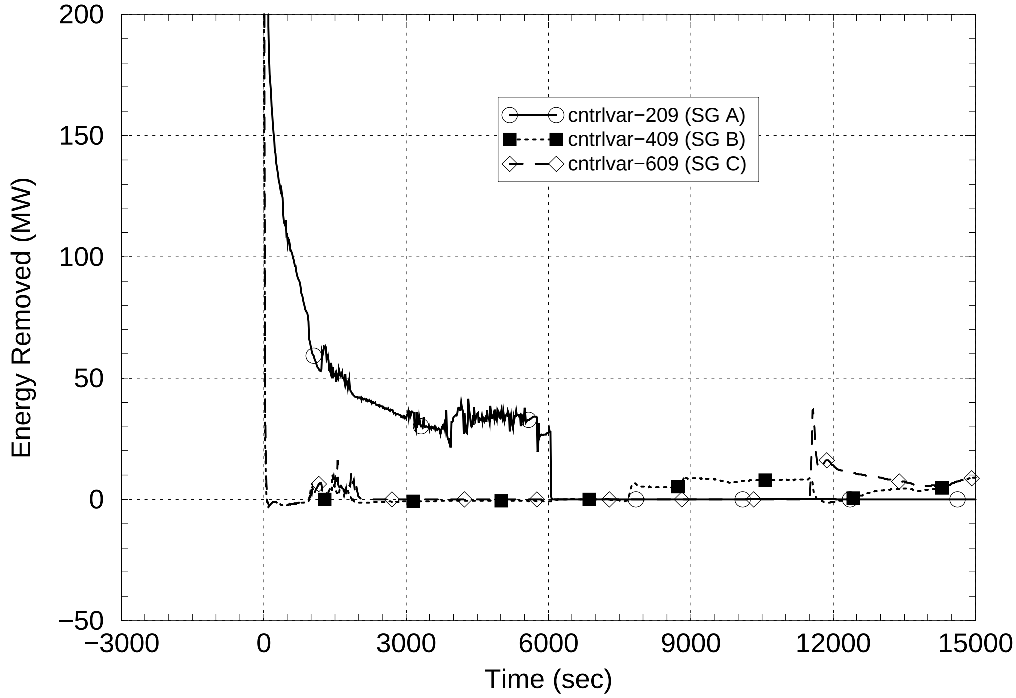


Figure 3.2.3-39 Steam Generator Energy Removal Rate - BV Case 108

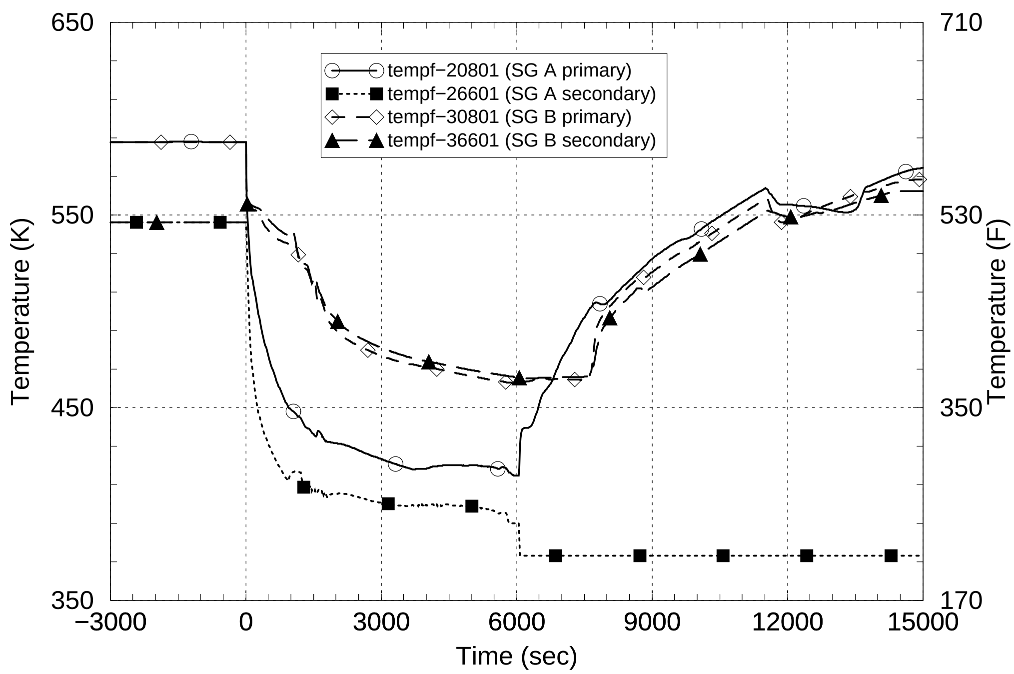


Figure 3.2.3-40 System Fluid Temperatures for Main Steam Line Break - BV Case 108

3.2.4 Beaver Valley Main Steam Line Breaks at Hot Zero Power

This group of transients is identical to the large steam line breaks discussed in Section 3.2.3 above, however, they are initiated from hot zero power. The large steam line breaks were assumed to be double ended guillotine breaks just downstream of the flow restrictor in steam generator A. The breaks are assumed to occur inside containment, thus leading to "adverse" containment conditions. This results in a trip of the reactor coolant pumps. In both cases, the auxiliary feedwater flow is assumed to continue to the broken loop generator for 30 minutes, at which point it is isolated by the operator. These cases also have operator control of the high head safety injection (HHSI).

The RELAP5 transient restart input was modified to add the following: steam line break, RCP trip, AFW isolation at 30 minutes, control of HHSI and allow letdown after both HHSI pumps are stopped.

The break downstream conditions were modeled with time dependent volumes which were set at atmospheric conditions. Since this was a double ended break, both the steam generator side and the steam line side were connected to time dependent volumes. In both transients, the break was set to occur at time zero.

The AFW was isolated at 30 minutes by multiplying the original control valve position by zero using RELAP5 trips and controls.

The HHSI in Beaver Valley is controlled by turning HHSI pumps on or off, rather than throttling to a desired flow rate. Conditions for turning pumps off are as follows: core exit subcooling greater than 22.2 K [40°F], any steam generator NRL greater than 32%, pressurizer water level greater than 32% and primary pressure stable or increasing. If the conditions listed are met, the operator is allowed to turn off one HHSI pump. If conditions are still met five minutes later the second HHSI pump can be turned off. If the above conditions are no longer met at any time, HHSI pumps must be turned back on. In both cases, the operator is assumed to turn off HHSI pumps after the above conditions are met plus a time delay (30 minutes in one case and 60 minutes in the other).

A sequence of events table for both main steam line break transients is provided as Table 3.2-4.

Table 3.2-4 Sequence of Events for Main Steam Line Breaks from Hot Zero Power

	Case 103 - MSLB with AFW continuing to feed affected generator for 30 minutes and operator controls HHSI 30 minutes after allowed	Case 105 - MSLB with AFW continuing to feed affected generator for 30 minutes and operator controls HHSI 60 minutes after allowed
	Event Time (s)	
Break	0	0
RCP trip	0	0
SIAS generated	0	0
HHSI flow initiated	0	0
MFW stopped	0	0
AFW started	0	0
Reactor trip	24.96	24.96
Pressurizer pressure exceeds PORV setpoint	930	930
Pressurizer fills	1,050	1,050
AFW stopped to broken loop	1,800	1,800
1st HHSI pump stopped	3,405	5,205
2nd HHSI pump stopped	3,705	5,505

3.2.4.1 Beaver Valley Main Steam Line Break From Hot Zero Power (BV Case 103)

This case is a main steam line break in steam generator A from hot zero power with auxiliary feedwater continuing to feed the broken loop generator for 30 minutes and operator control of high head safety injection. This case is identified as Beaver Valley Case 103 in Appendix B, Table B-1. The steam line break is assumed to occur downstream of the flow restrictor and inside of containment, so the RCPs are tripped due to adverse containment conditions. The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.4-1 through 3.2.4-3 respectively. A sequence of events table for this event is shown as Table 3.2-4.

When the steam line break occurs, the secondary side pressure in steam generator A drops rapidly as shown in Figure 3.2.4-4. Steam line break flow is shown in Figure 3.2.4-5. An MSIV closure signal should be generated upon high containment pressure, however, the containment is not modeled. In the model, the MSIV never received an MSIV closure signal and remained open the entire transient. While the MSIV should have closed, there are check valves in the lines to prevent backflow from one steam generator to another. At 25 s, a reactor/turbine trip was generated (based on two of three loop delta temperature) which closes the turbine stop valve. In addition, since the secondary side pressure was less than the steam dump valve setpoint, there was no flow through any of the MSIVs. Therefore, it is acceptable for the calculation to simulate that the MSIVs did not close upon high containment pressure.

Immediately after the break occurs a safety injection actuation signal was generated due to high steamline pressure differential. The SIAS results in actuation of both the HHSI and LHSI. In addition, it also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated. Because of the break and main feedwater being stopped, the steam generator water level drops rapidly as shown in Figure 3.2.4-6.

AFW flow begins almost immediately, as shown in Figure 3.2.4-7, and all flow goes to the broken loop generator (SG A). As the pressure in steam generator A decreases, the flow through the break decreases and becomes smaller than the AFW flow, allowing the water level to recover. By 420 s, the steam generator A water level has recovered and auxiliary feedwater then goes to maintain level in steam generators B and C. Between 555 and 825 s all AFW goes to steam generator A. By 825 s the water level in steam generator A has recovered well above the level setpoint so AFW stops. At 1,800 s, the operator is assumed to stop AFW to steam generator A. Note that at 1,800 s there is currently no flow, however, when flow is demanded near 3,000 s, it is no longer available to steam generator A and it begins to boil dry.

Heat transfer from the primary to the depressurizing steam generator resulted in a rapid cooldown of the primary system as shown in Figure 3.2.4-2. This cooling also causes the primary fluid volume to shrink which slightly depressurizes the primary as shown in Figure 3.2.4-1 as well as causes the pressurizer water level to decrease as shown in Figure 3.2.4-8. Because the SIAS signal was generated, HHSI flow (Figure 3.2.4-9) is started and repressurizes the primary to the pressurizer PORV setpoint by 930 s.

As a boundary condition to this case, the RCPs were tripped (based on adverse containment conditions). Upon RCP trip, the loop flow decreases rapidly as shown in Figure 3.2.4-10. Loop natural circulation flow for steam generator A continues after the RCP trip as a result of the continual heat removal of the steam generator. Figure 3.2.1-3 shows the downcomer fluid-wall heat transfer coefficient. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops rapidly from an initial value of approximately 24,075 $W/m^2 \cdot K$ [1.178 $Btu/s \cdot ft^2 \cdot {}^\circ F$]. The heat transfer coefficient then remains around a value of 650 $W/m^2 \cdot K$ [0.032 $Btu/s \cdot ft^2 \cdot {}^\circ F$] for the duration of the transient.

By 1,605 s the system has met all of the conditions for stopping an HHSI pump. These conditions include: core exit subcooling greater than 22.2 K [40°F] (Figure 3.2.4-11), any steam generator NRL greater than 32% (Figure 3.2.4-6), pressurizer water level greater than 32% (Figure 3.2.4-8) and pressure stable or increasing (Figure 3.2.4-1). After waiting an additional 30 minutes (as given in the case description), the operator is assumed to stop a single HHSI pump (at 3,405 s). Then, after waiting five more minutes, the above conditions are still met so the second HHSI pump is stopped (at 3,705 s).

Upon stopping the second HHSI pump, letdown flow was re-established. Between the loss of the HHSI pumps and letdown flow, the primary pressure drops rapidly.

Figure 3.2.4-12 shows the energy removed by the steam generators. By 4,850 s, steam generator A is removing all of the decay heat, and the downcomer fluid temperature remains about 380 K [224°F] for the duration of the transient.

The double ended main steam line break results in a continuous cooldown of the primary side while auxiliary feedwater flow is allowed to the broken steam generator. The minimum downcomer fluid temperature is 362 K [192°F] at 3,420 s. Due to continuous HHSI flow, the primary pressure at 3,420 s is 16.2 MPa [2,350 psia]. Once the HHSI flow is controlled/stopped, the primary pressure decreases. By 4,850 s, core decay heat is being removed through steam generator A and the downcomer fluid temperature remains nearly constant.

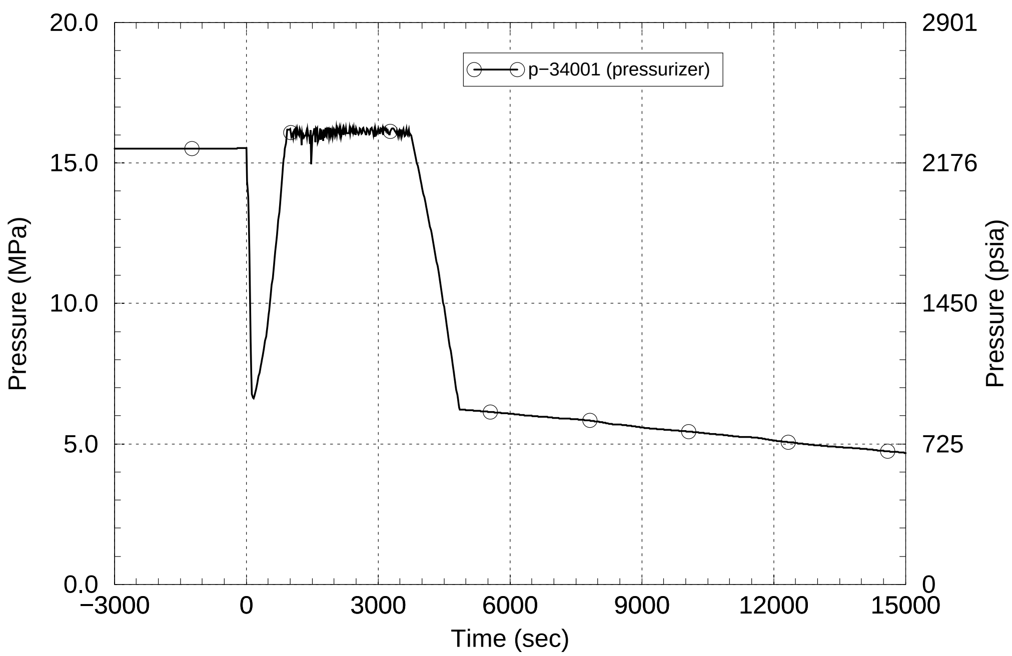


Figure 3.2.4-1 Primary System Pressure – BV Case 103

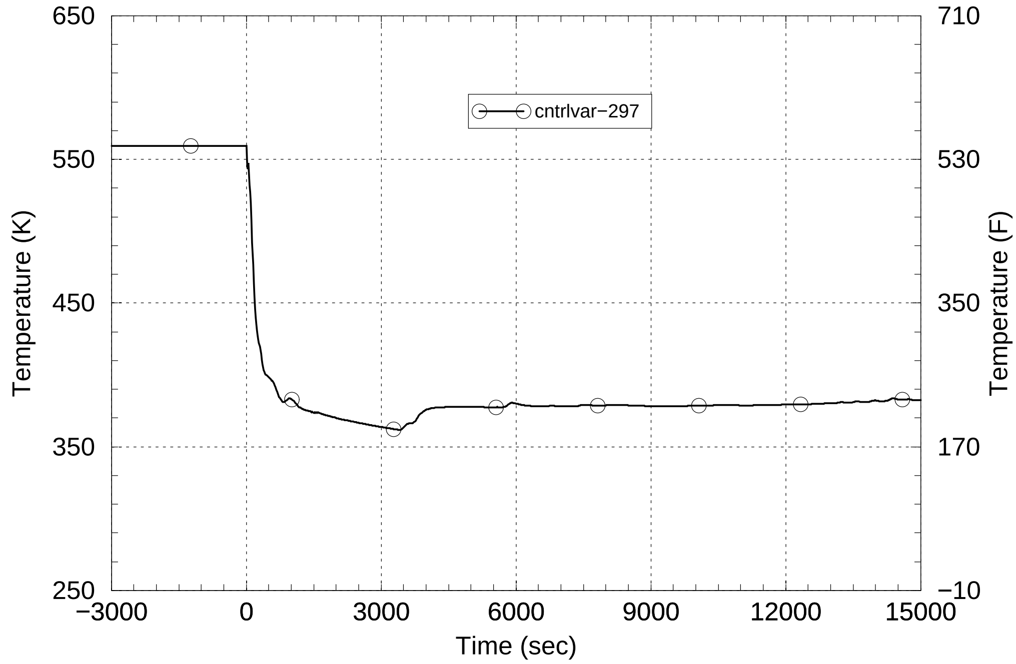


Figure 3.2.4-2 Average Downcomer Fluid Temperature – BV Case 103

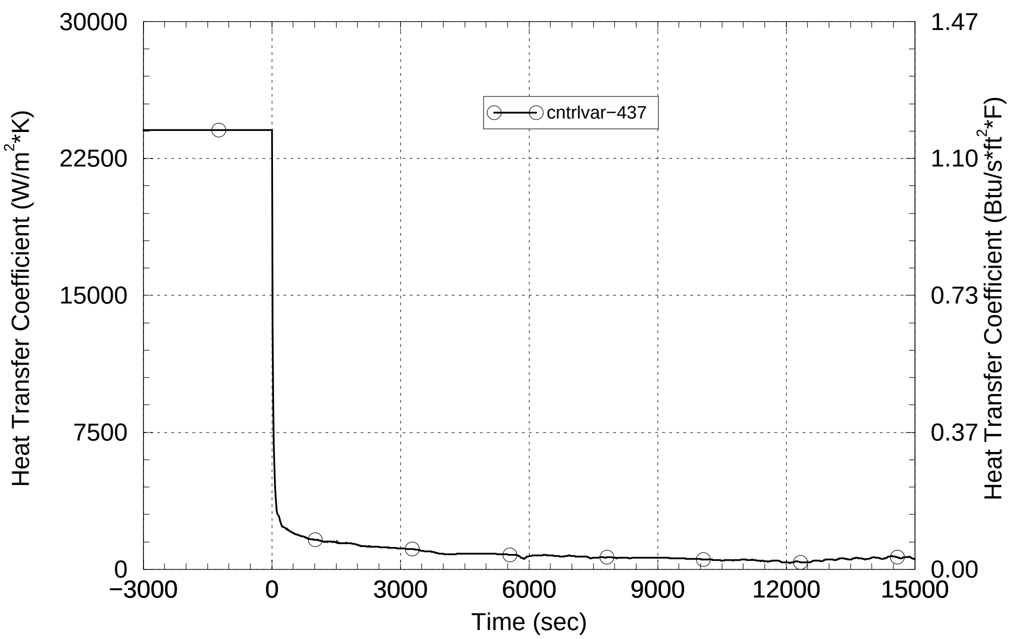


Figure 3.2.4-3 Downcomer Wall Heat Transfer Coefficient – BV Case 103

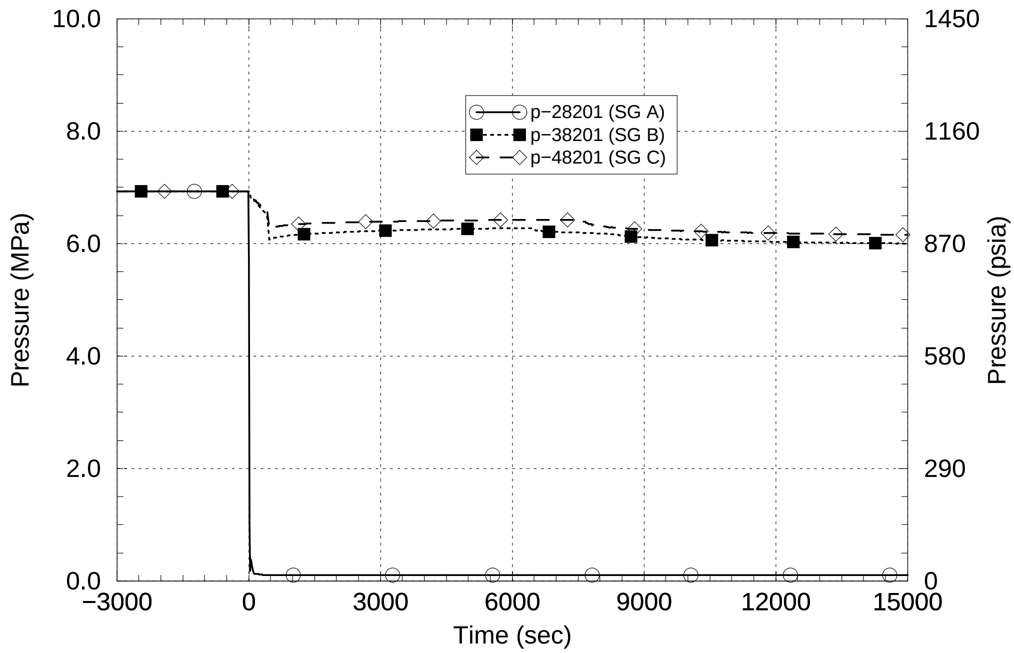


Figure 3.2.4-4 Steam Generator Pressure – BV Case 103

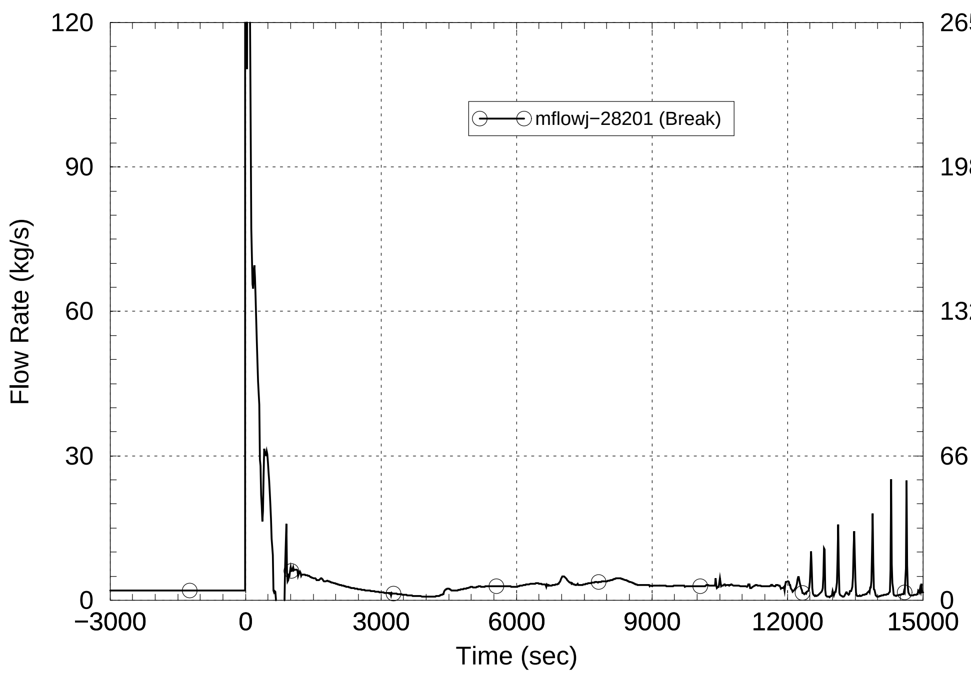


Figure 3.2.4-5 Break Flow Rate – BV Case 103

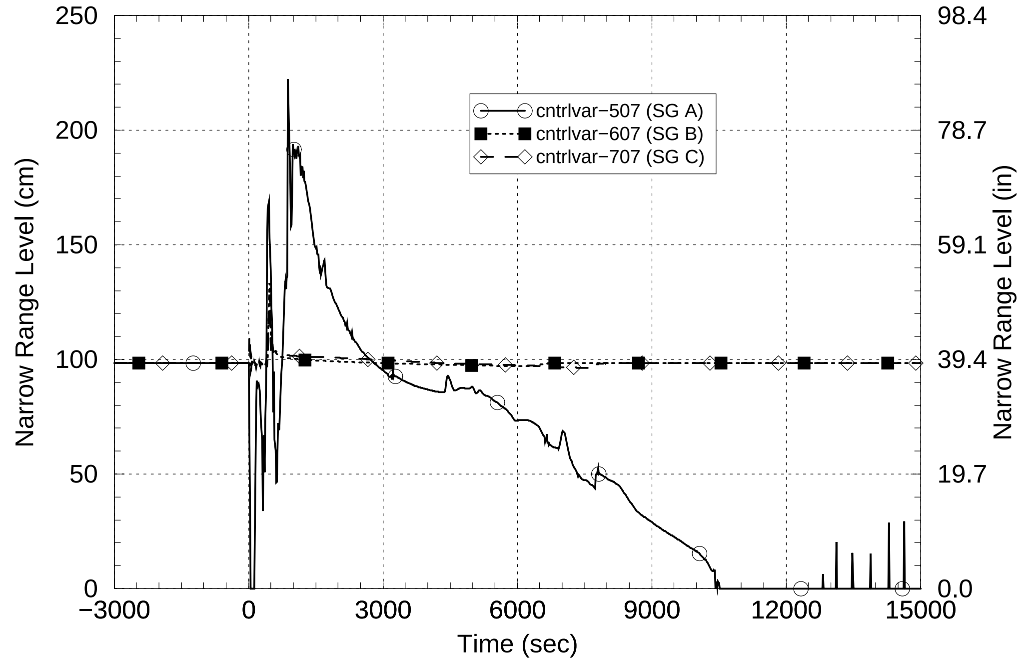


Figure 3.2.4-6 Steam Generator Narrow Range Level – BV Case 103

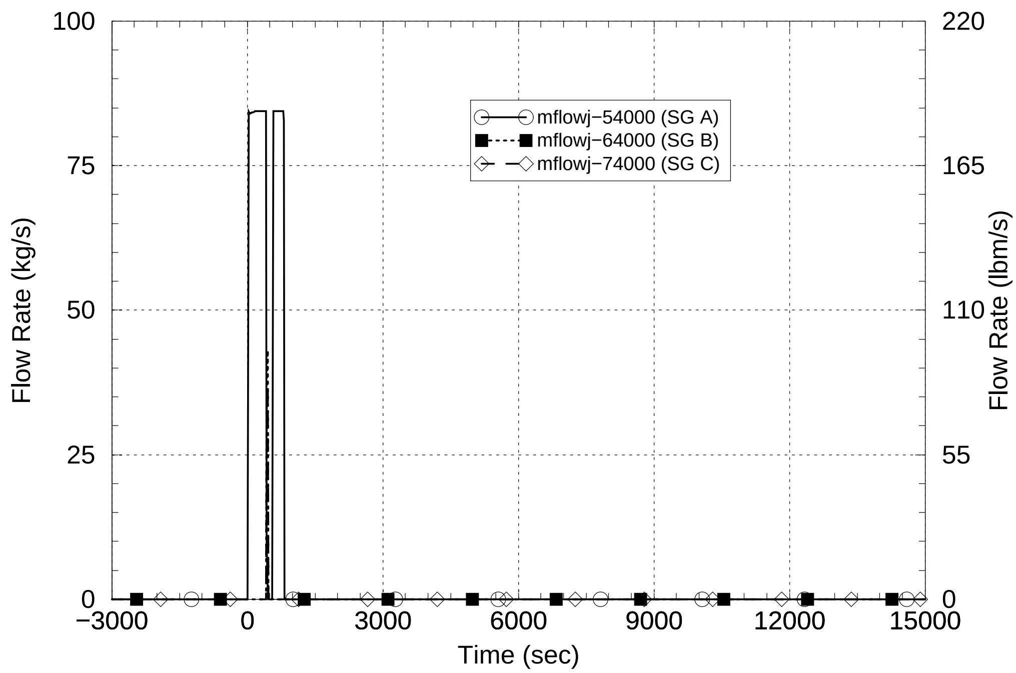


Figure 3.2.4-7 Auxiliary Feedwater Flow Rate – BV Case 103

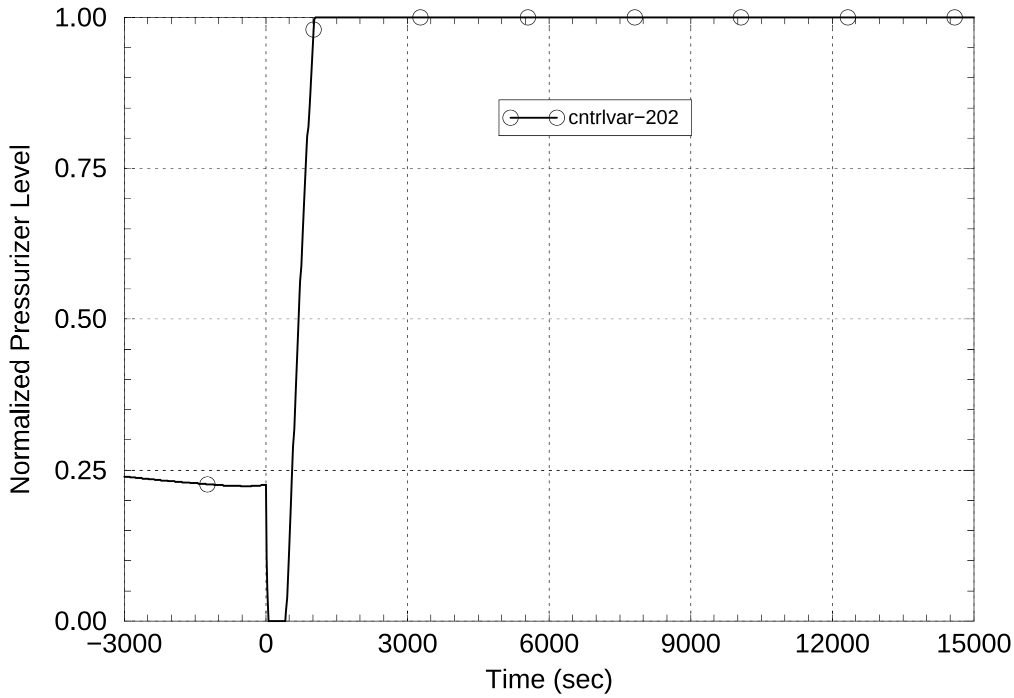


Figure 3.2.4-8 Pressurizer Water Level – BV Case 103

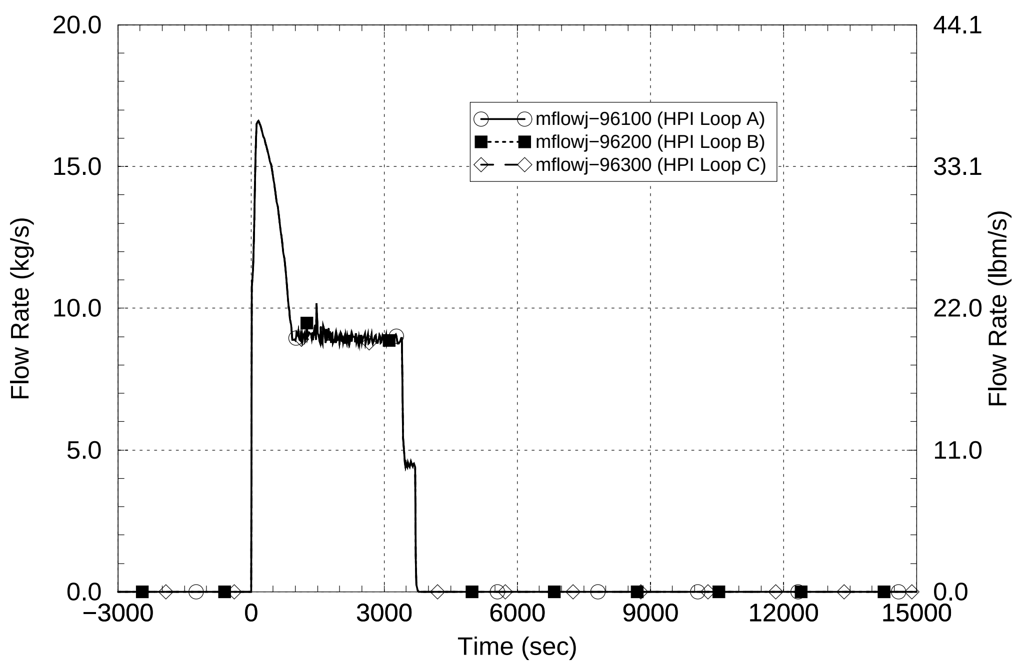


Figure 3.2.4-9 HHSI Flow Rate – BV Case 103

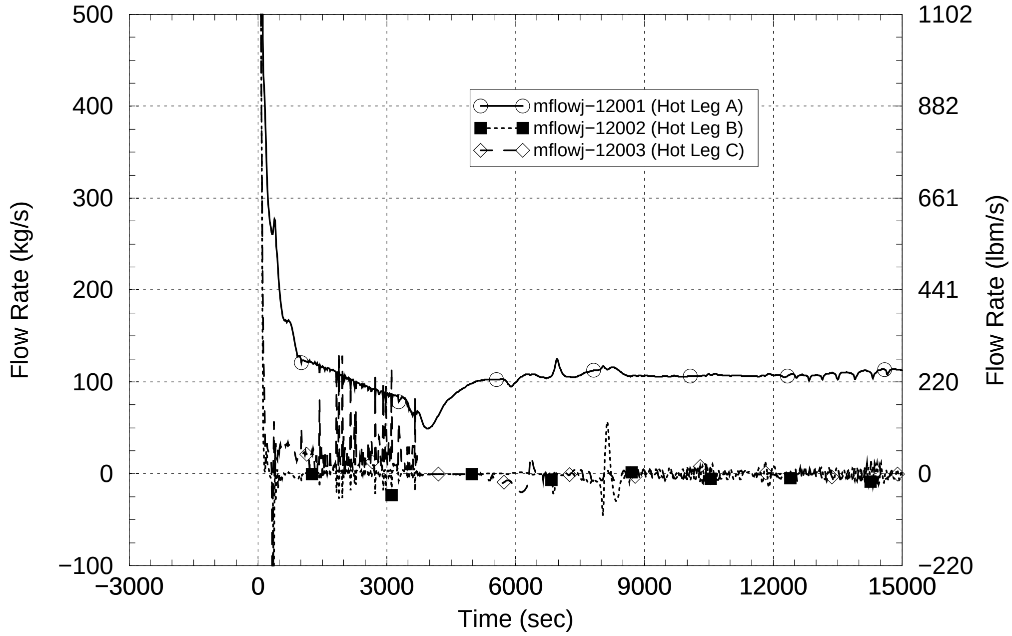


Figure 3.2.4-10 Hot Leg Flow Rate – BV Case 103

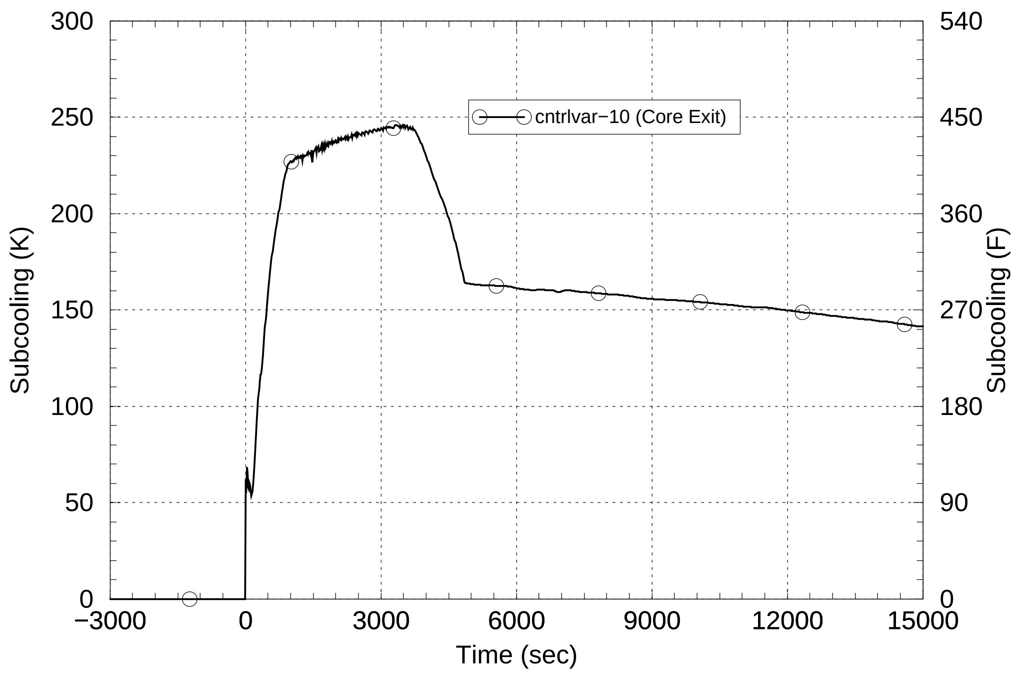


Figure 3.2.4-11 Core Exit Subcooling – BV Case 103

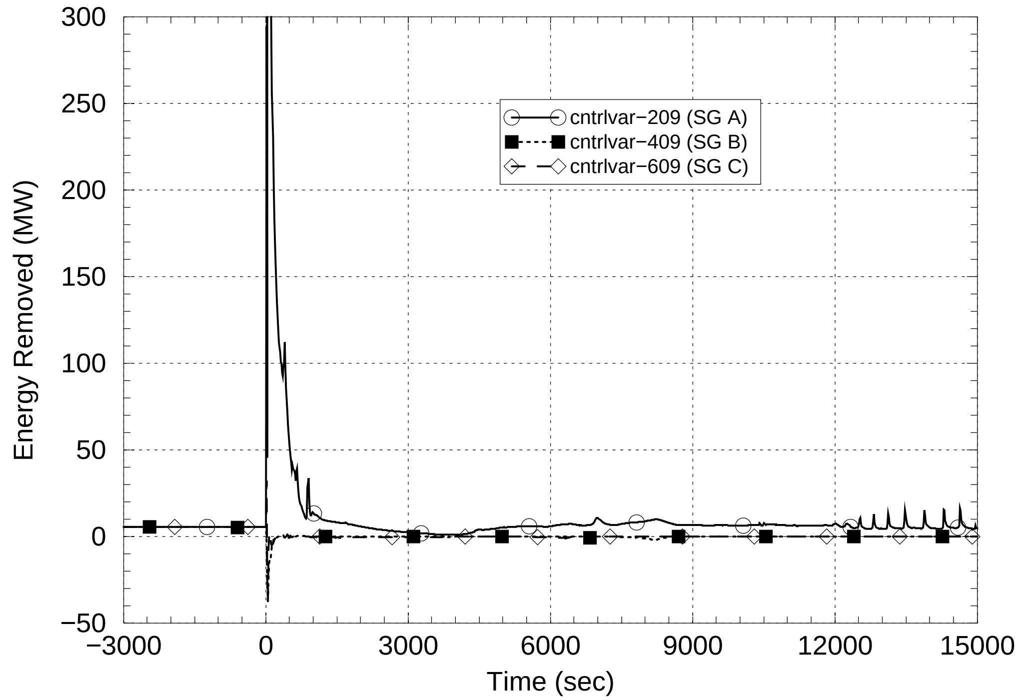


Figure 3.2.4-12 Steam Generator Energy Removal Rate – BV Case 103

3.2.4.2 Beaver Valley Main Steam Line Break From Hot Zero Power (BV Case 105)

This case is a main steam line break in steam generator A from hot zero power with auxiliary feedwater continuing to feed the broken loop generator for 30 minutes and operator control of high head safety injection. This case is identified as Beaver Valley Case 105 in Appendix B, Table B-1. The steam line break is assumed to occur downstream of the flow restrictor and inside of containment, so the RCPs are tripped due to adverse containment conditions. The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.4-13 through 3.2.4-15 respectively. A sequence of events table for this event is shown as Table 3.2-4.

When the steam line break occurs, the secondary side pressure in steam generator A drops rapidly as shown in Figure 3.2.4-16. Steam line break flow is shown in Figure 3.2.4-17. An MSIV closure signal should be generated upon high containment pressure, however, the containment is not modeled. In the model, the MSIV never received an MSIV closure signal and remained open the entire transient. While the MSIV should have closed, there are check valves in the lines to prevent backflow from one steam generator to another. At 25 s, a reactor/turbine trip was generated (based on two of three loop delta temperature) which closes the turbine stop valve. In addition, since the secondary side pressure was less than the steam dump valve setpoint, there was no flow through any of the MSIVs. Therefore, it is acceptable that the MSIVs did not close upon high containment pressure.

Immediately after the break occurs a safety injection actuation signal was generated due to high steamline pressure differential. The SIAS results in actuation of both the HHSI and LHSI. In addition, it also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated. Because of the break and main feedwater being stopped, the steam generator water level drops rapidly as shown in Figure 3.2.4-18.

AFW flow begins almost immediately, as shown in Figure 3.2.4-19, and all flow goes to the broken loop generator (SG A). As the pressure in steam generator A decreases, the flow through the break decreases and becomes smaller than the AFW flow, allowing the water level to recover. By 420 s, the steam generator A water level has recovered and auxiliary feedwater then goes to maintain level in steam generators B and C. Between 555 and 825 s all AFW goes to steam generator A. By 825 s the water level in steam generator A has recovered well above the level setpoint so AFW stops. At 1,800 s, the operator is assumed to stop AFW to steam generator A. Note that at 1,800 s there is currently no flow, however, when flow is demanded near 3,000 s, it is no longer available to steam generator A and it begins to boil dry.

Heat transfer from the primary to the depressurizing steam generator resulted in a rapid cooldown of the primary system as shown in Figure 3.2.4-14. This cooling also causes the primary fluid volume to shrink which slightly depressurizes the primary as shown in Figure 3.2.4-13 as well as causes the pressurizer water level to decrease as shown in Figure 3.2.4-20. Because the SIAS signal was generated, HHSI flow (Figure 3.2.4-21) is started and repressurizes the primary to the pressurizer PORV setpoint by 930 s.

As a boundary condition to this case, the RCPs were tripped (based on adverse containment conditions). Upon RCP trip, the loop flow decreases rapidly as shown in Figure 3.2.4-22. Loop natural circulation flow for steam generator A continues after the RCP trip as a result of the continual heat removal of the steam generator. Figure 3.2.1-15 shows the downcomer fluid-wall heat transfer coefficient. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops rapidly from an initial value of approximately 24,075 $W/m^2{\cdot}K$ [1.178 $Btu/s{\cdot}ft^2{\cdot}{}^\circ F$]. The heat transfer coefficient then remains around a value of 650 $W/m^2{\cdot}K$ [0.032 $Btu/s{\cdot}ft^2{\cdot}{}^\circ F$] for the duration of the transient.

By 1,605 s the system has met all of the conditions for stopping an HHSI pump. These conditions include: core exit subcooling greater than 22.2 K [40°F] (Figure 3.2.4-23), any steam generator NRL greater than 32% (Figure 3.2.4-18), pressurizer water level greater than 32% (Figure 3.2.4-20) and pressure stable or increasing (Figure 3.2.4-13). After waiting an additional 60 minutes (as given in the case description), the operator is assumed to stop a single HHSI pump (at 5,205 s). Then, after waiting five more minutes, the above conditions are still met so the second HHSI pump is stopped (at 5,505 s).

Upon stopping the second HHSI pump, letdown flow was re-established. Between the loss of the HHSI pumps and letdown flow, the primary pressure drops rapidly.

By 8,000 s, steam generator A is removing all of the decay heat, and the downcomer fluid temperature remains about 380 K [224°F] for the duration of the transient.

The double ended main steam line break results in a continuous cooldown of the primary side while auxiliary feedwater flow is allowed to the broken steam generator. The minimum downcomer fluid temperature is 355 K [179°F] at 5,220 s. Due to continuous HHSI flow, the primary pressure at 5,220 s is 16.2 MPa [2,350 psia]. Once the HHSI flow is controlled/stopped, the primary pressure decreases. By 8,000 s, core decay heat is being removed through steam generator A and the downcomer fluid temperature remains nearly constant.

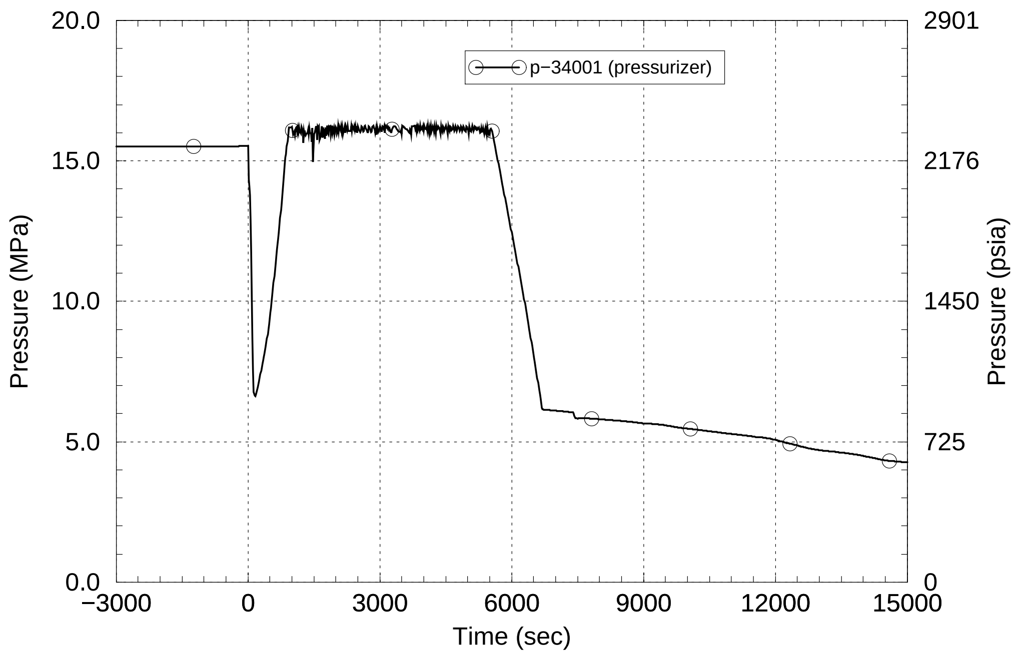


Figure 3.2.4-13   Primary System Pressure – BV Case 105

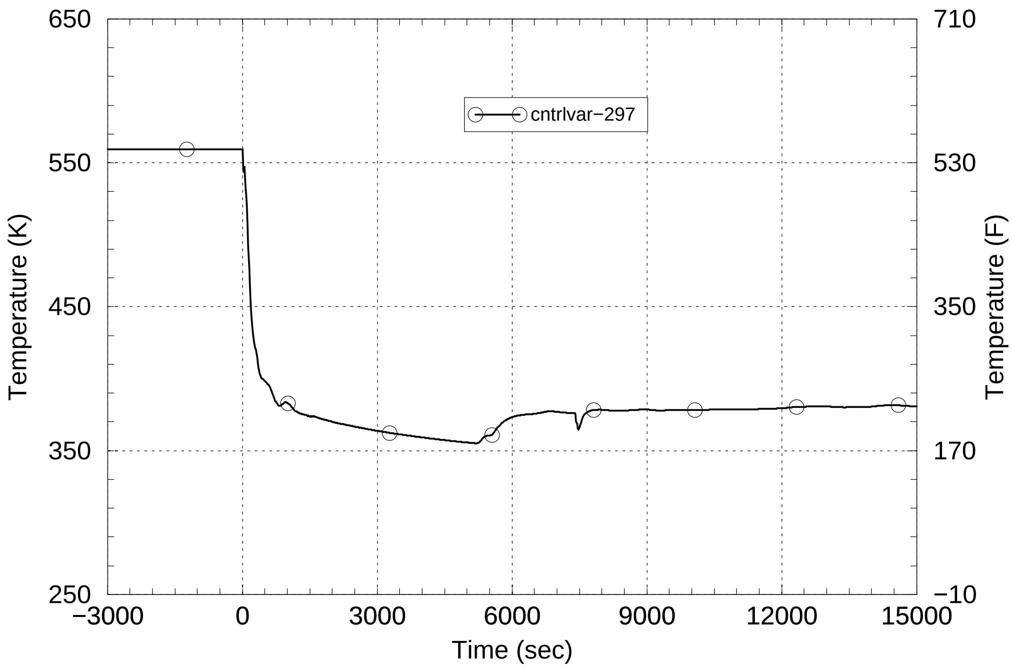


Figure 3.2.4-14 Average Downcomer Fluid Temperature – BV Case 105

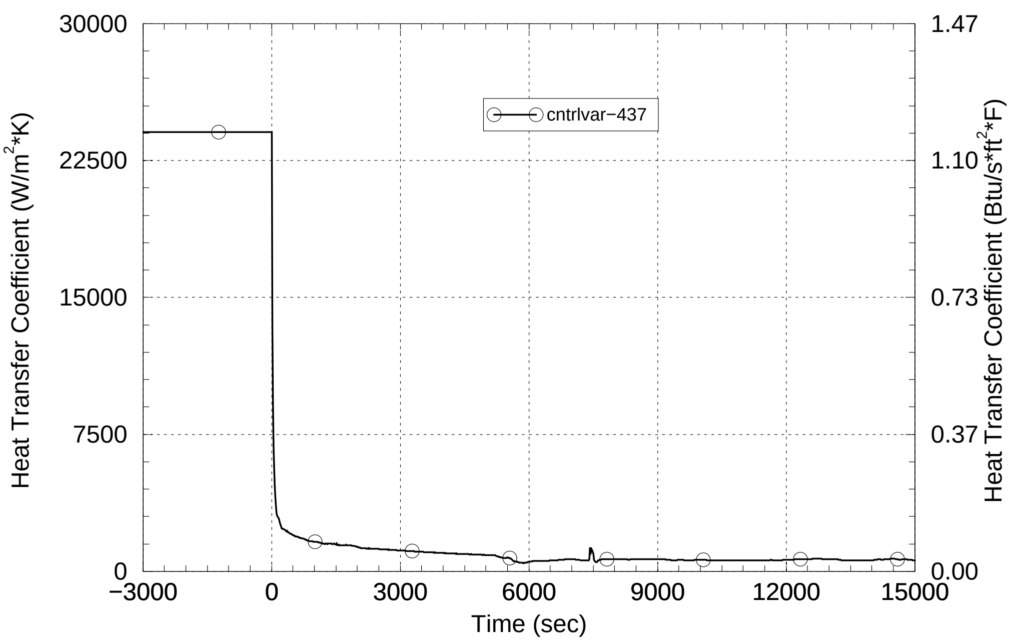


Figure 3.2.4-15 Downcomer Wall Heat Transfer Coefficient – BV Case 105

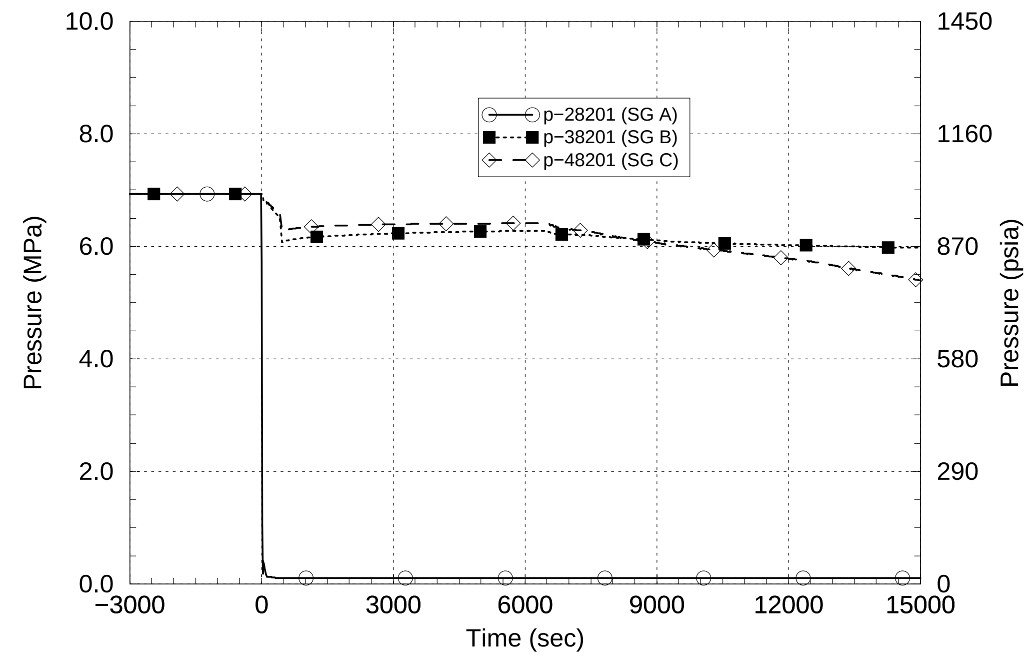


Figure 3.2.4-16 Steam Generator Pressure – BV Case 105

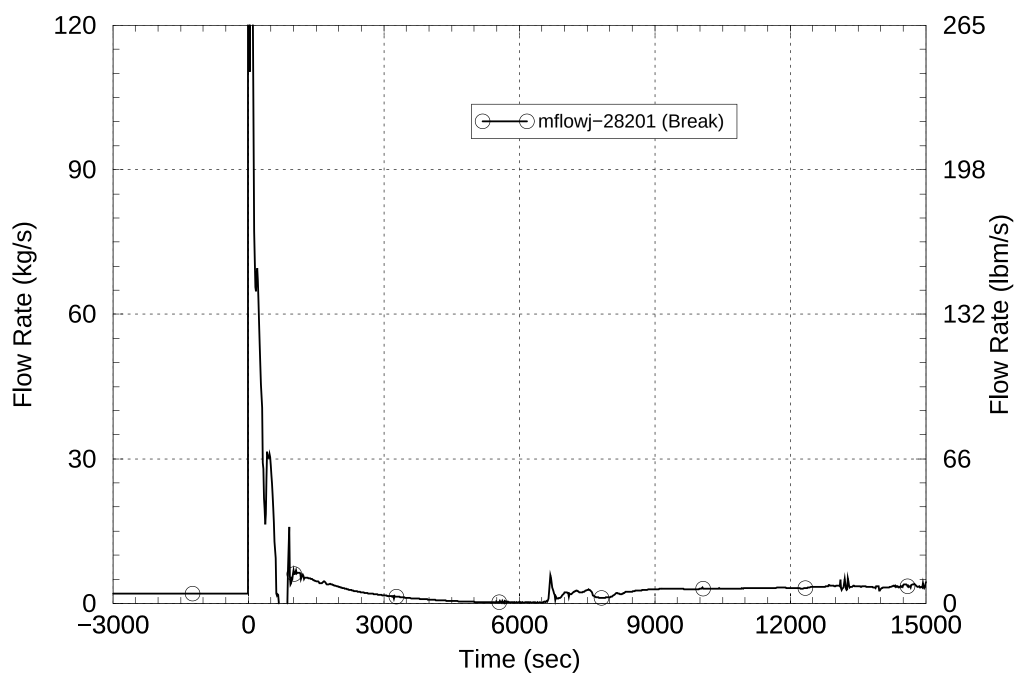


Figure 3.2.4-17 Break Flow Rate – BV Case 105

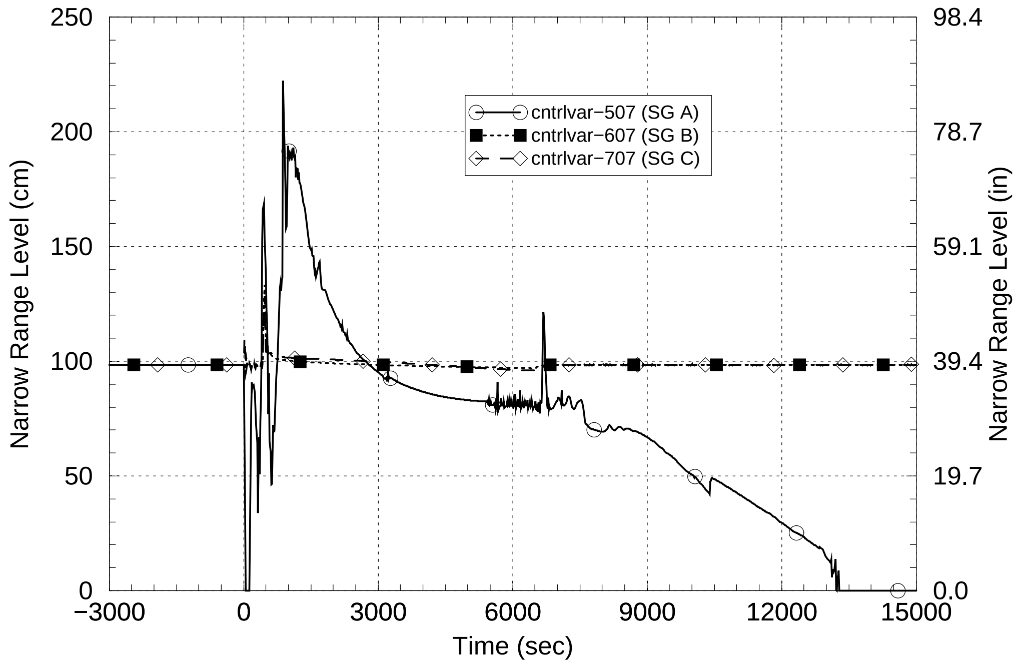


Figure 3.2.4-18 Steam Generator Narrow Range Level – BV Case 105

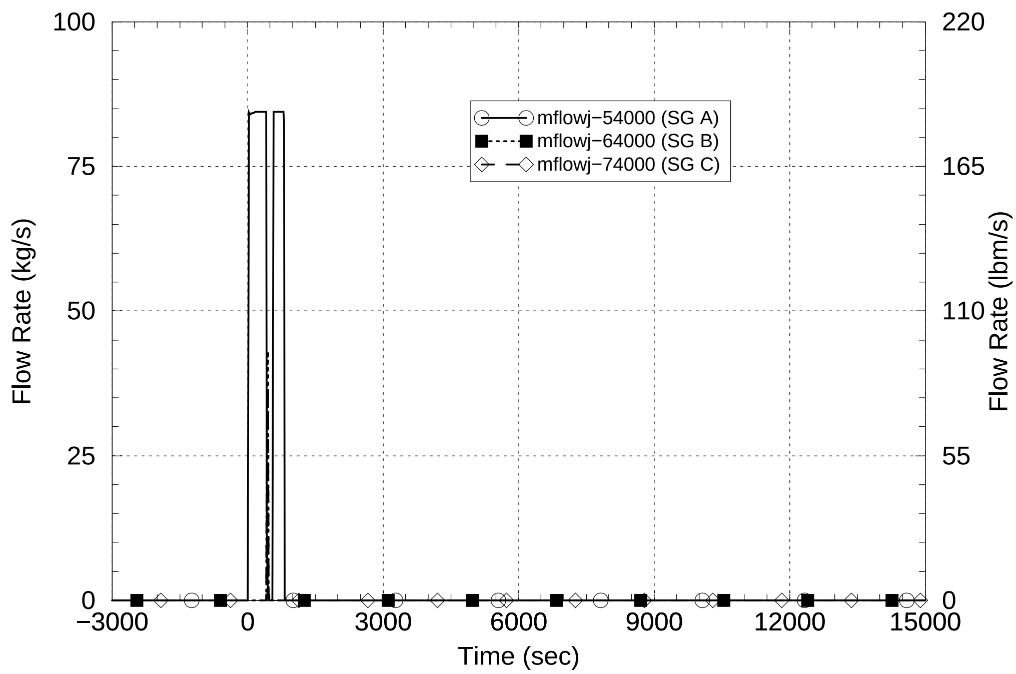


Figure 3.2.4-19 Auxiliary Feedwater Flow Rate – BV Case 105

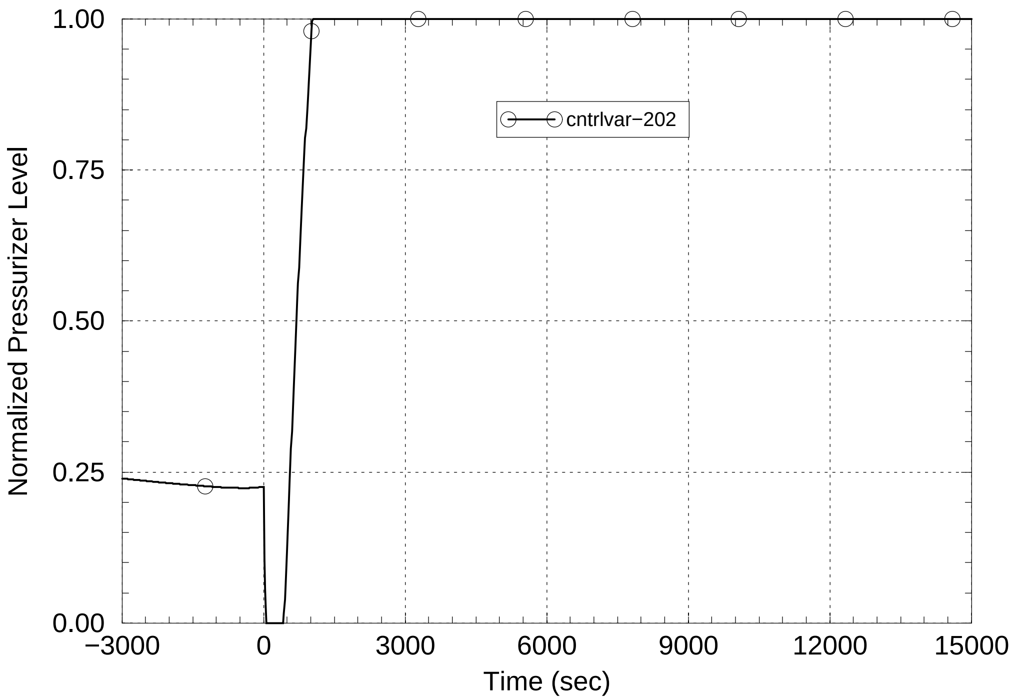


Figure 3.2.4-20 Pressurizer Water Level – BV Case 105

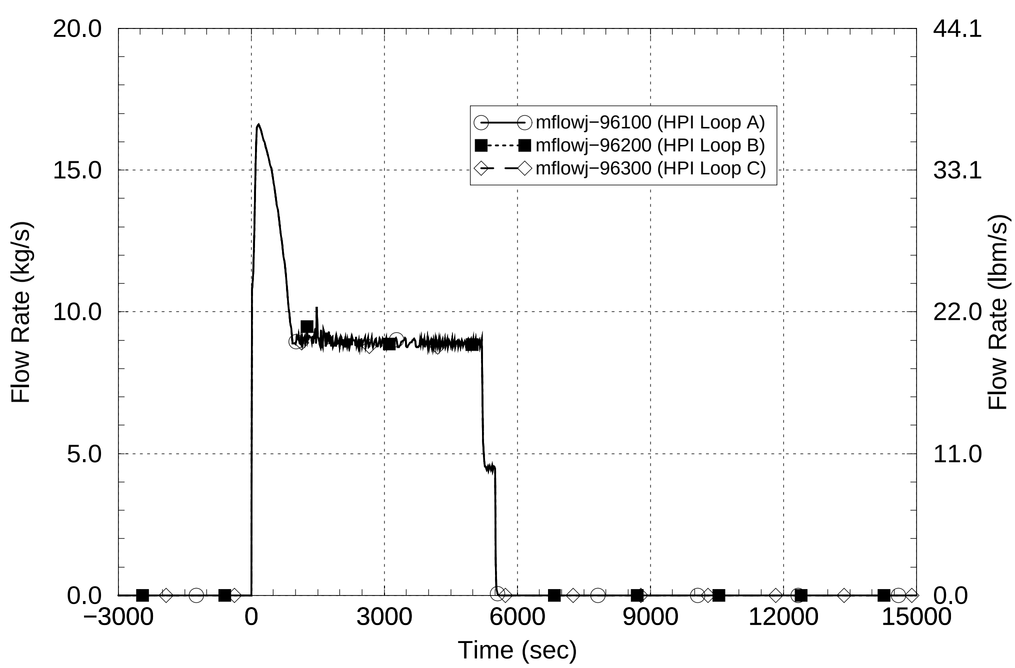


Figure 3.2.4-21 HHSI Flow Rate – BV Case 105

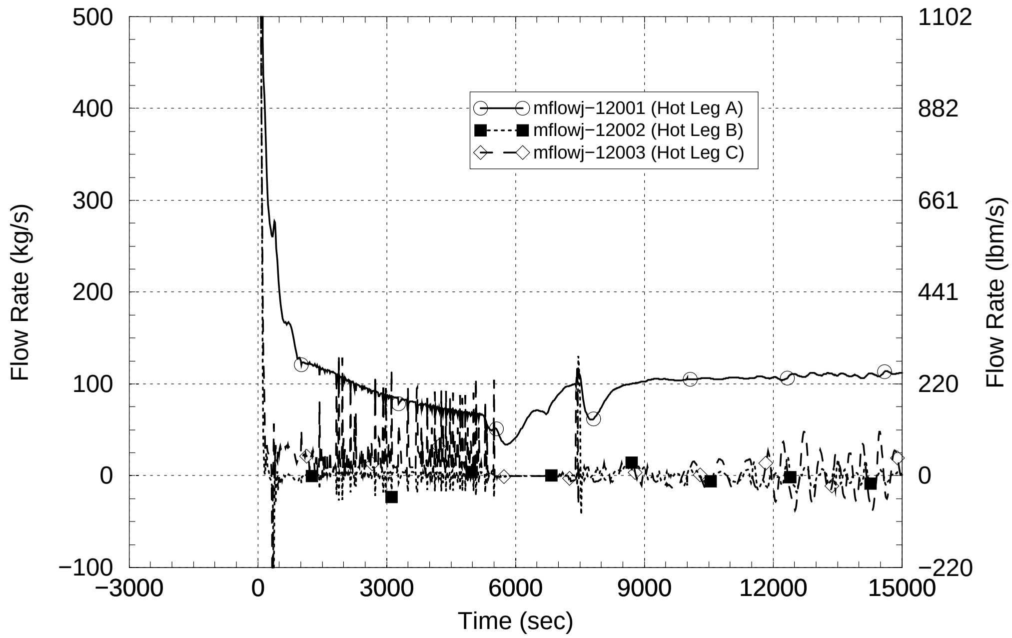


Figure 3.2.4-22 Hot Leg Flow Rate – BV Case 105

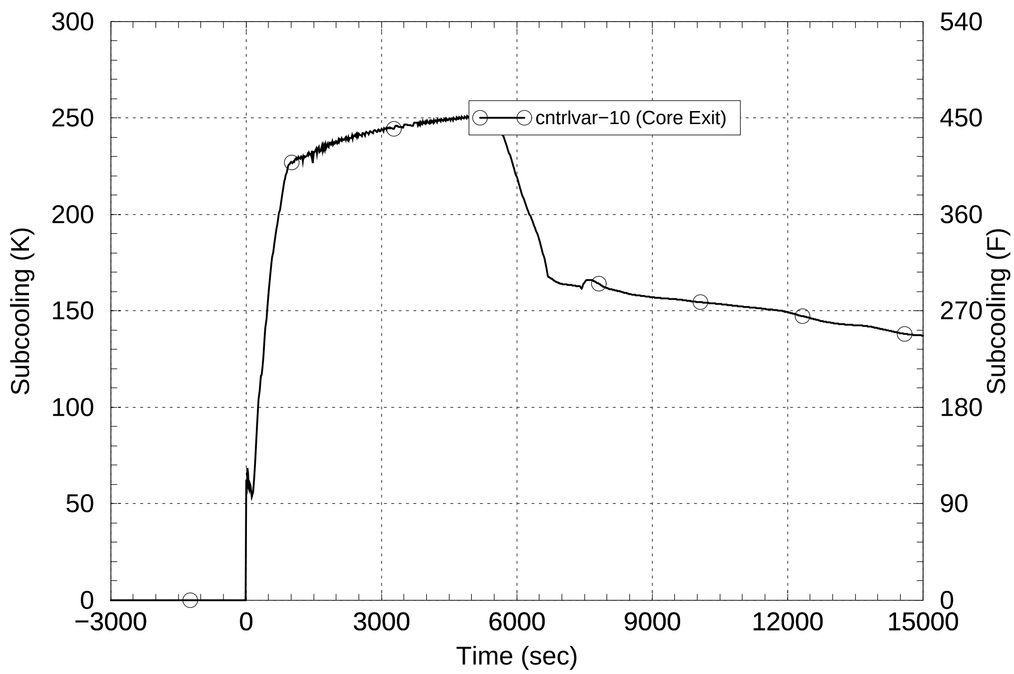


Figure 3.2.4-23 Core Exit Subcooling – BV Case 105

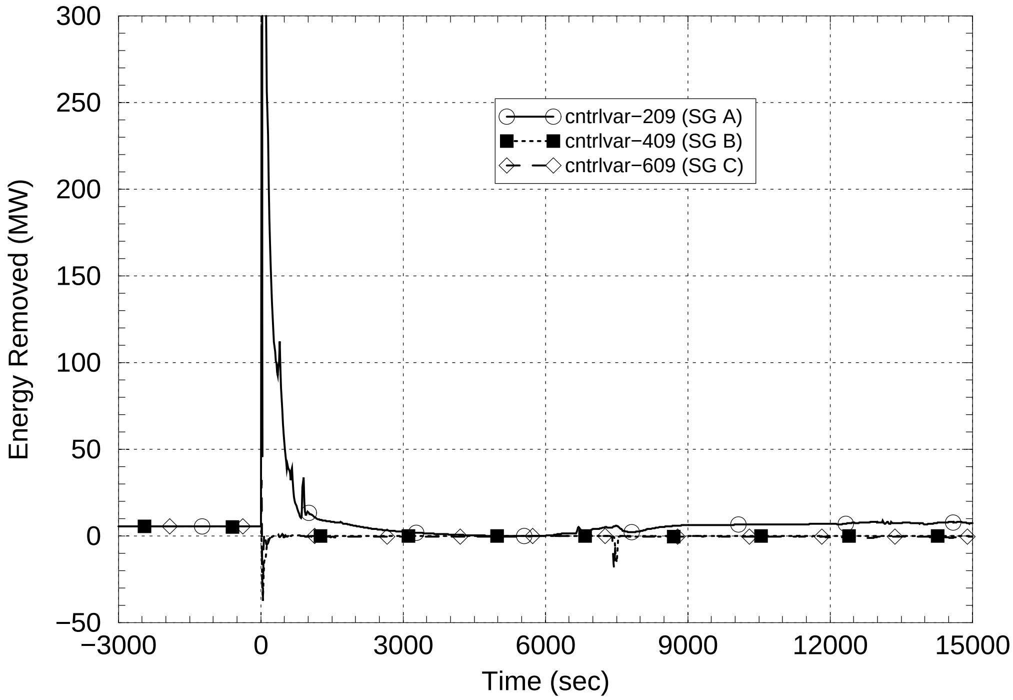


Figure 3.2.4-24 Steam Generator Energy Removal Rate – BV Case 105

3.2.5 Beaver Valley Stuck Open Primary Relief Valves Which Reclose From Hot Full Power

The transients in this group were initiated from full power steady state operating conditions (nominal temperature and pressure) and all control systems were in automatic control. The first transient is a reactor/turbine trip with one stuck open pressurizer safety relieve valve which recloses at 6,000 s. The SRV is assumed to open upon the reactor/turbine trip and remains full open until the specified closing time. The second case is a reactor/turbine trip with one stuck open pressurizer safety relief valve which recloses at 6,000 s and operator control of HHSI (10-minute delay).

In order to model the stuck open safety relieve valve which recloses, a general data table was added to the RELAP5 transient restart input file which contains the valve position versus time. The valve was also set to point to the data table, rather than the original control system. This valve was set to open at time zero and close at 6,000 s. Note that the data table opens the RELAP5 valve component to a position of one third which models one of the three safety relief valves stuck open. In addition to the stuck open SRV, a reactor trip is set to occur at time zero.

In case 126, the HHSI pumps are controlled by the operator. At Beaver Valley, the HHSI pumps cannot be "throttled" to adjust the flow rate. To adjust HHSI pump flow, the operators must turn pumps on/off.

A sequence of events table for both stuck open pressurizer SRV cases is provided as Table 3.2-5.

Table 3.2-5 Sequence of Events for Stuck Open Pressurizer SRV which Reclose from Hot Full Power

	Case 060 - RTT with one stuck open pressurizer SRV which recloses at 6,000 s	Case 126 - RTT with one stuck open pressurizer SRV which recloses at 6,000 s and HHSI control (10 minute delay)
	Event Time (s)	
Pressurizer SRV opened	0.0	0.0
Reactor/turbine trip	0.0	0.0
SIAS generated	11.1	11.2
MFW stopped	11.1	11.2
AFW started	11.1	11.2
HHSI flow initiated	11.1	11.2
RCPs trip	48.1	68.1
Pressurizer fills	125.0	125.0
Accumulators begin injecting	2,520	2,530
Break valve closed	6,000	6,000
Accumulators stop injecting	6,630	6,001
Primary Repressurizes to PORV setpoint	7,640	7,640
First HHSI pump stopped	N/A	7,825
Second HHSI pump stopped	N/A	8,125

3.2.5.1 Beaver Valley Stuck Open Pressurizer SRV Which Recloses From Hot Full Power (BV Case 060)

This case is one stuck open pressurizer safety relief valve which recloses from hot full power. This case is identified as Beaver Valley Case 060 in Appendix B, Table B-1. The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.5-1 through 3.2.5-3 respectively.

Each of the three pressurizer SRVs has an effective diameter of 5.38 cm [2.12 in], so a stuck open SRV will be similar to 5.08 cm [2.0 in] diameter surge line break. As a result of the stuck open valve, the primary system rapidly depressurizes as shown in Figure 3.2.5-1. In addition, since the valve is located at the top of the pressurizer, the pressurizer fills solid due to the primary system water flowing towards the valve. By 125 s, the pressurizer is filled, and remains filled for the duration of the transient as seen in Figure 3.2.5-4. Due to the loss of inventory, the primary system begins voiding in the reactor vessel upper head.

At approximately 11 s, a SIAS was generated. The SIAS results in actuation of both the HHSI, and LHSI. In addition, it also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated. Note that while LHSI is activated, there is no flow unless the primary pressure falls below the LHSI pump shutoff head.

A plot of pressurizer SRV flow versus total safety injection flow is provided as Figure 3.2.5-5. Total SI flow includes high pressure injection, low pressure injection, accumulators and charging/letdown. High pressure injection flow is shown in Figure 3.2.5-6. For about the first 2,500 s break flow is slightly larger than safety injection flow. By 2,500 s the primary pressure has decreased to below the accumulator pressure, resulting in accumulator injection as shown in Figure 3.2.5-7. With this additional flow, the total SI is about equal to the flow through the stuck open valve. The primary pressure never drops to below the low pressure injection pump shutoff head, therefore, there is no low pressure injection for this case.

At approximately 48 s, the reactor coolant pumps were tripped due to an operator action. This causes the flow in the loops to decrease to near zero. Figure 3.2.5-8 presents the hot leg mass flow for all three loops at the exit of the vessel. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops quickly from an initial value of 24,073 $W/m^2{\cdot}K$ [1.178 $Btu/s{\cdot}ft^2{\cdot}°F$] as seen in Figure 3.2.5-3. Until the system repressurizes around 7,640 s the heat transfer coefficient drops gradually to 400 $W/m^2{\cdot}K$ [0.020 $Btu/s{\cdot}ft^2{\cdot}°F$]. After the system repressurizes, the heat transfer coefficient remains around 1,250 $W/m^2{\cdot}K$ [0.0611 $Btu/s{\cdot}ft^2{\cdot}°F$].

Figure 3.2.5-9 shows the core power versus the energy lost through the stuck open valve. As seen in this figure, the energy lost out of the valve when it is open is larger than the assumed core decay heat, thus, heat is being removed from the system causing the temperature to decrease. The average downcomer fluid temperature is shown in Figure 3.2.5-2. By 6,000 s, the downcomer temperature has reached a minimum value of 330 K [134°F].

Figure 3.2.5-10 shows the steam generator narrow range water level. Upon the SIAS being generated, the MFW is isolated. AFW is started and begins controlling the generators to the setpoint of 33% NRL (120.7 cm [47.52 in]). Figure 3.2.5-11 shows the auxiliary feedwater flow which comes on initially to maintain steam generator water level. The steam generator secondary side pressure is shown in Figure 3.2.5-12.

At 6,000 s, the stuck open pressurizer SRV is reclosed. The high head injection pumps continue to supply cold water, and the primary system begins to repressurize. Note that no operator actions, such as controlling HHSI flow, were taken to control primary system pressure or level. By 6,630 s, the primary pressure has increased to above the accumulator pressure, thus stopping accumulator flow. By 7,600 s, the SI flow has repressurized the primary to the pressurizer PORV opening setpoint and flow begins to leave the primary system through the valve.

During the initial part of the LOCA, the steam generator tubes voided as shown in Figure 3.2.5-13. Once the pressurizer SRV recloses the steam generator tubes begin to refill. During the refill time (6,500 to 7,150 s) there are minor condensation/vaporization effects. Figure 3.2.5-14 shows the vapor generation rate for the steam generator tubes (hot leg side). Note that positive values show vaporization while negative values show condensation. Figure 3.2.5-8 shows that the hot leg flow oscillations occur during this period of steam generator tube condensation/vaporization.

As a consequence of the stuck open pressurizer safety relief valve, it is shown that the loss of inventory through the SRV is capable of removing more than the assumed core decay heat. This leads to the downcomer fluid temperature decreasing to a value of 330 K [134°F] at the valve reclosure time. Shortly after the pressurizer SRV recloses, the primary pressure increases to the pressurizer PORV opening setpoint of 16.2 MPa [2,350 psia]. While the system is repressurizing (6,000 to 7,600 s), the downcomer fluid temperature rises slightly to 350 K [170°F]. After the system has repressurized, the downcomer fluid temperature rises to 460 K [368°F] with the pressure remaining at the pressurizer PORV opening setpoint.

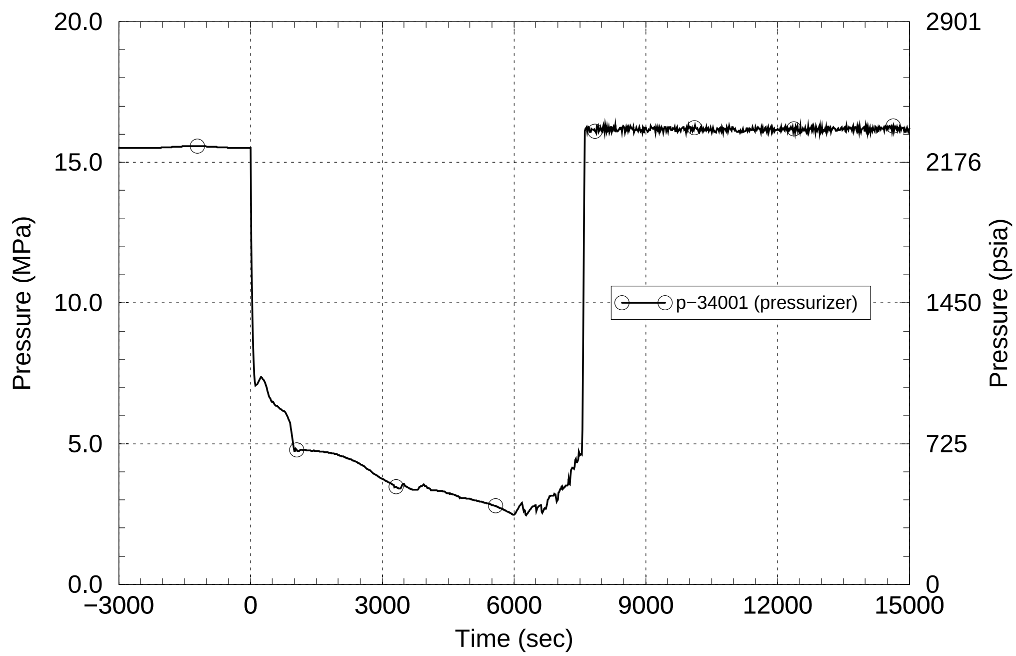


Figure 3.2.5-1 Primary System Pressure - BV Case 060

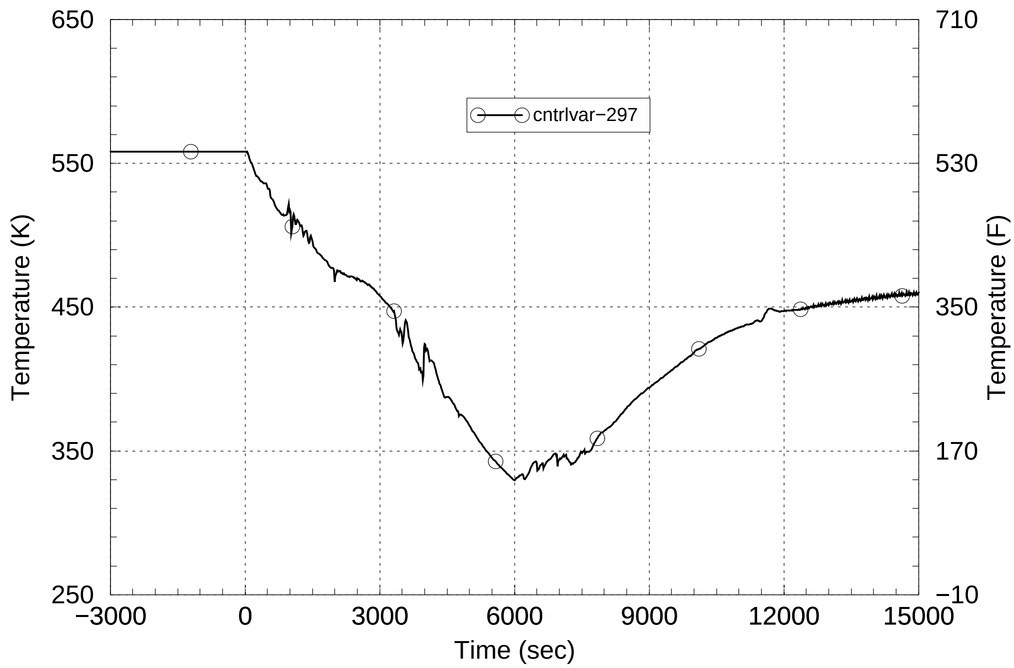


Figure 3.2.5-2 Average Downcomer Fluid Temperature - BV Case 060

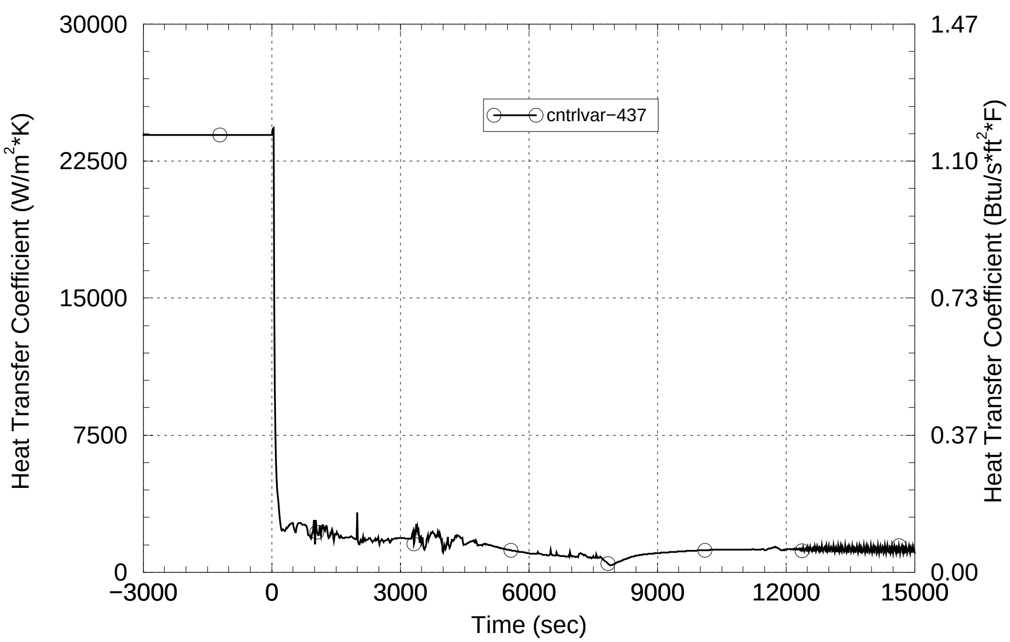


Figure 3.2.5-3 Downcomer Heat Transfer Coefficient - BV Case 060

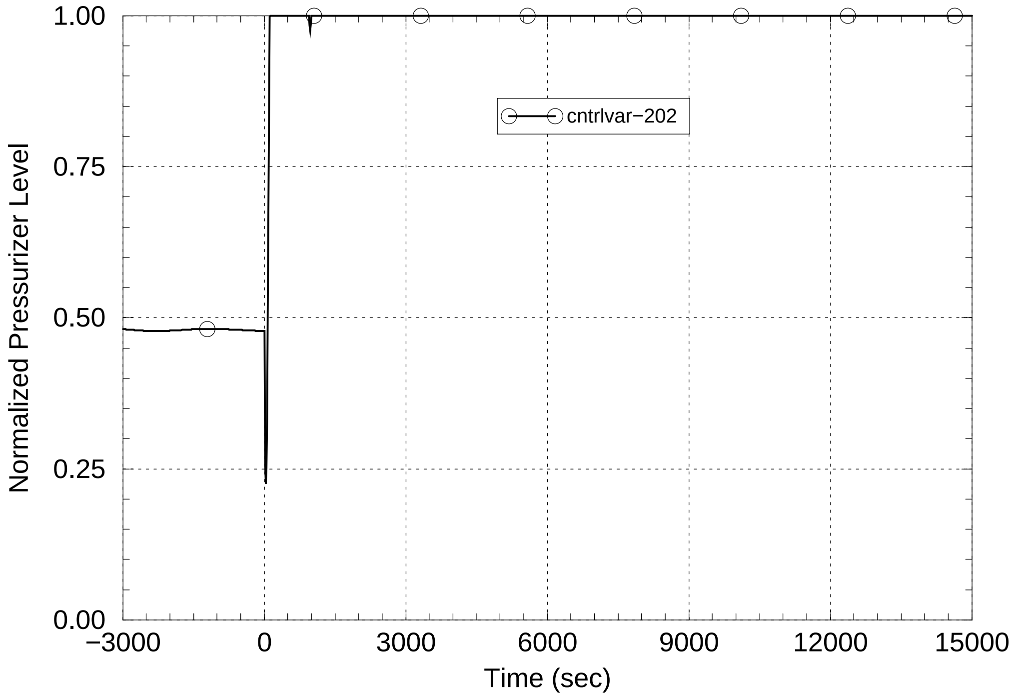


Figure 3.2.5-4 Pressurizer Water Level - BV Case 060

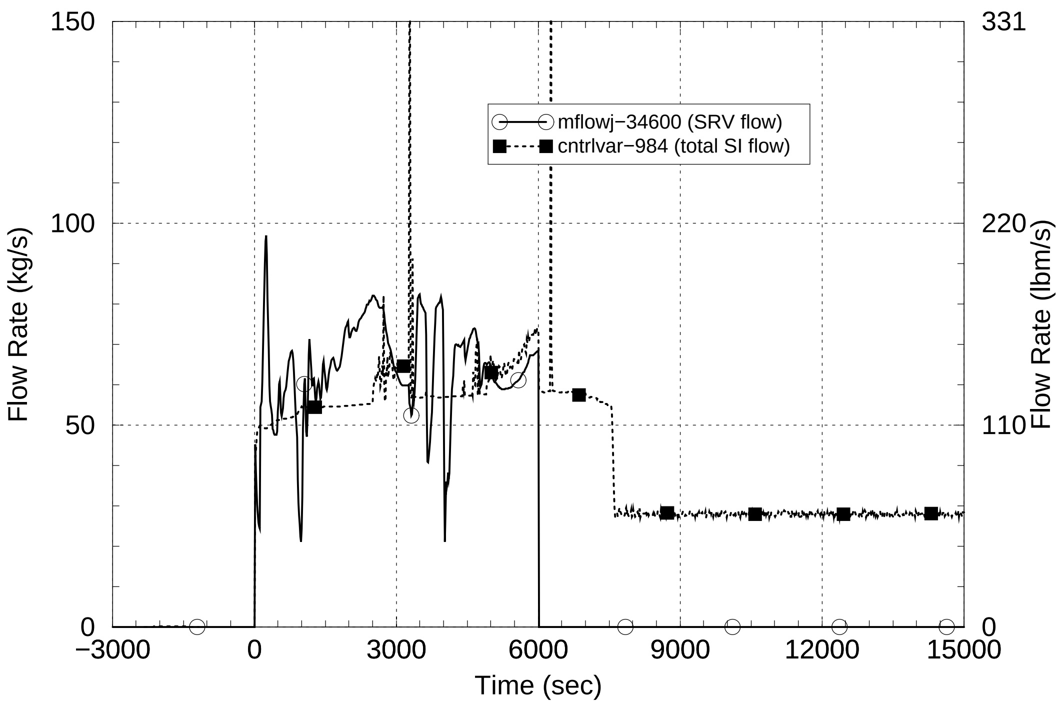


Figure 3.2.5-5 Break Flow and Total Safety Injection Flow - BV Case 060

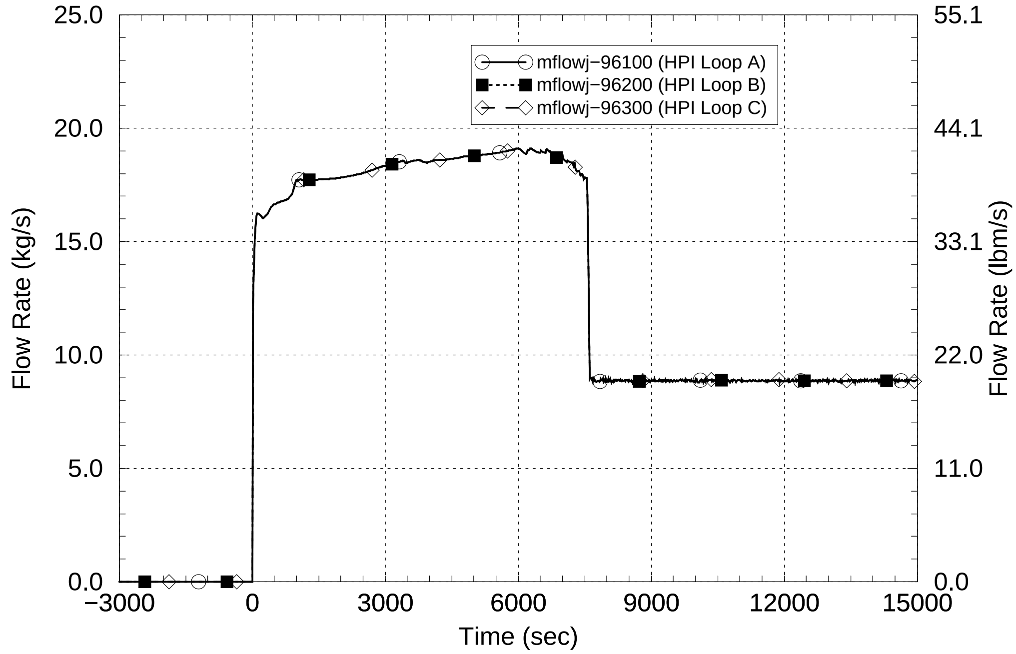


Figure 3.2.5-6   High Pressure Injection Flow Rate - BV Case 060

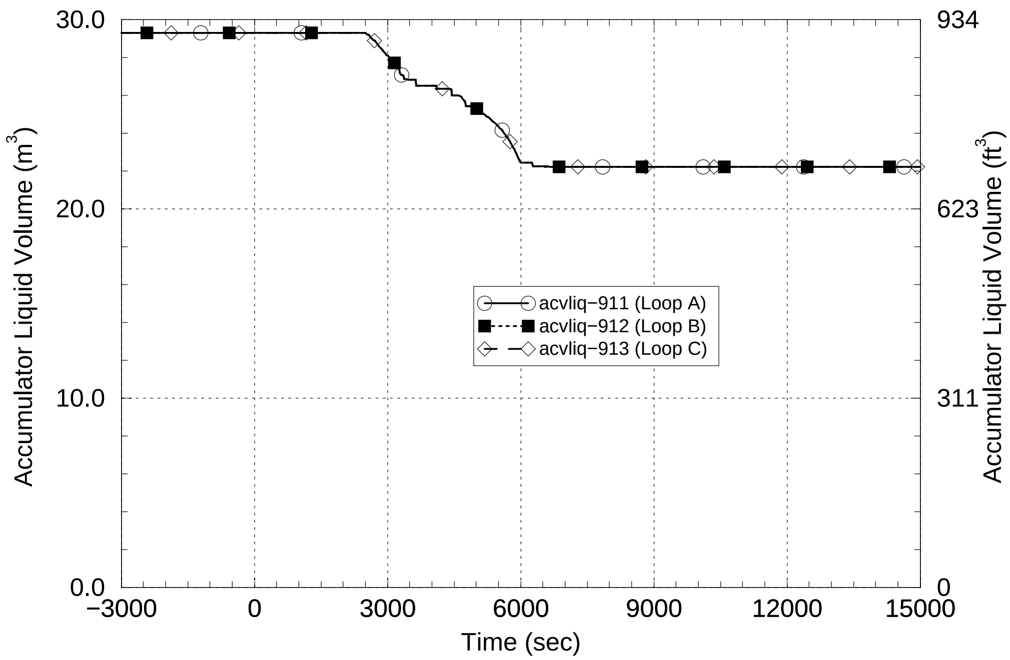


Figure 3.2.5-7   Accumulator Liquid Volume - BV Case 060

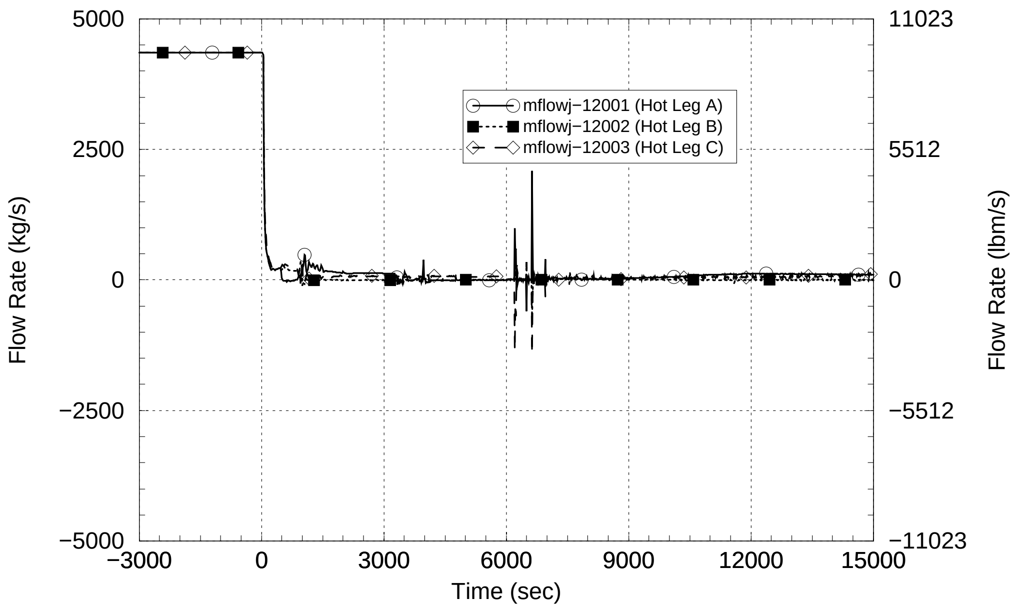


Figure 3.2.5-8 Hot Leg Mass Flow Rate - BV Case 060

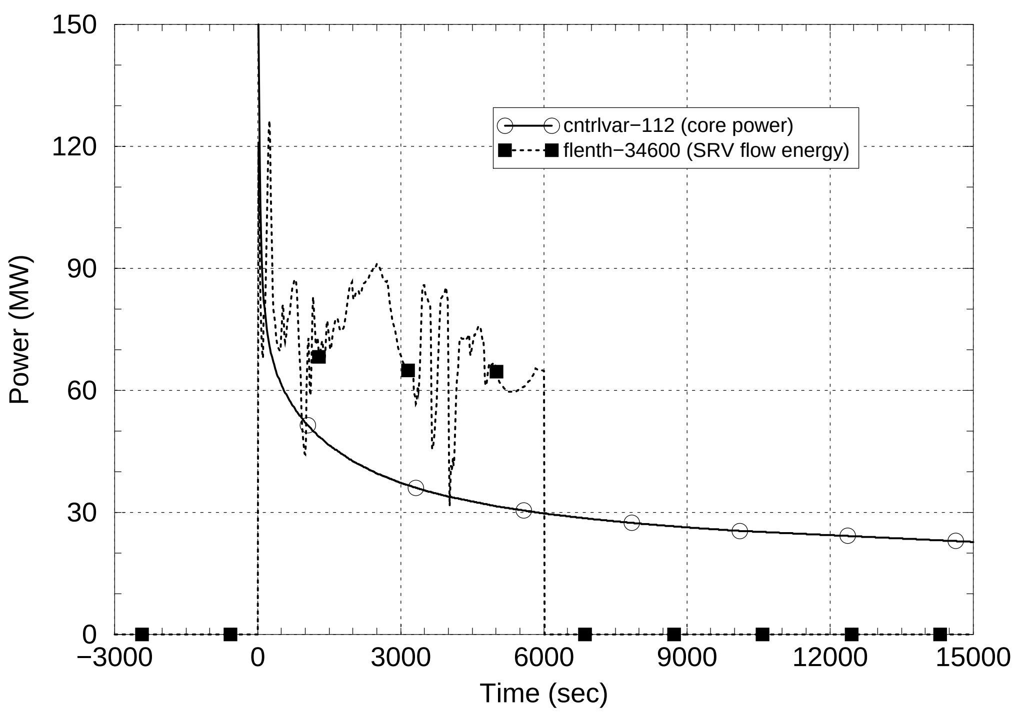


Figure 3.2.5-9 Core Power and Break Energy - BV Case 060

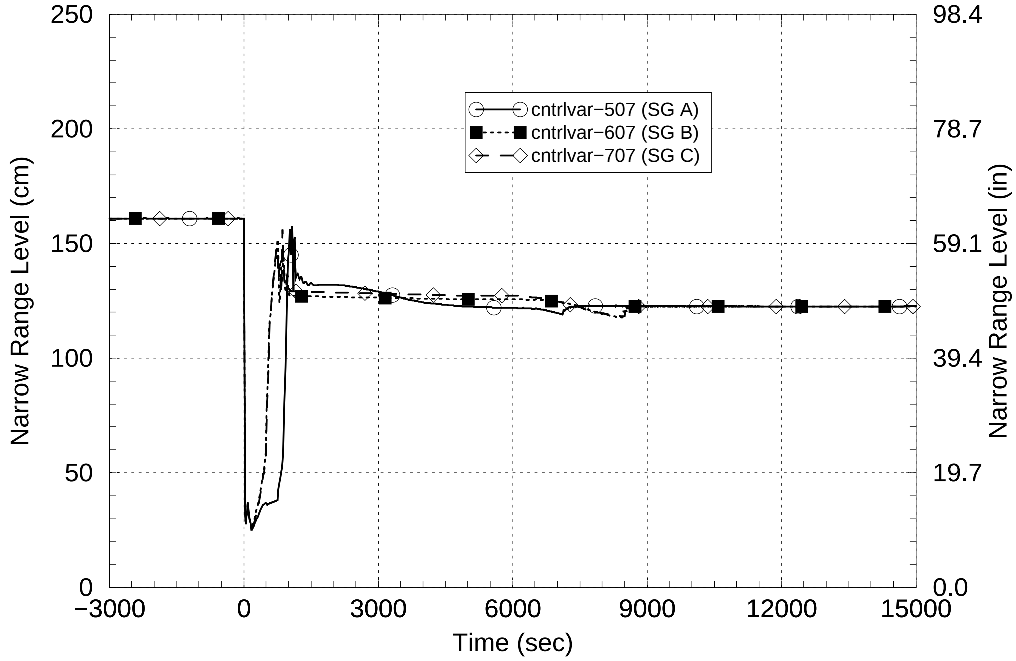


Figure 3.2.5-10 Steam Generator Narrow Range Water Level - BV Case 060

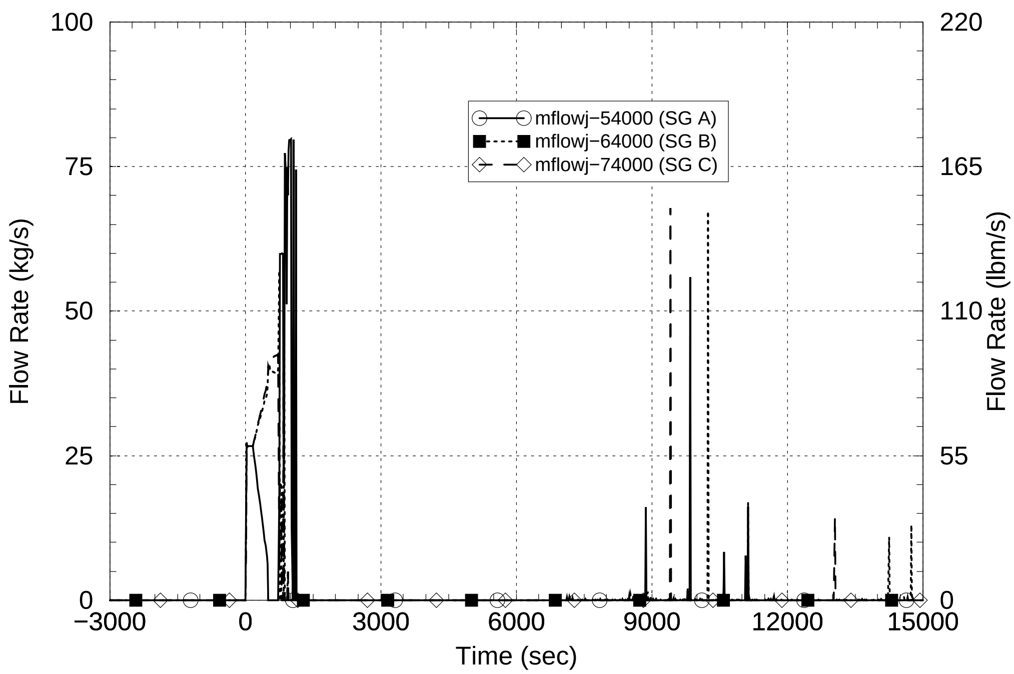


Figure 3.2.5-11 Auxiliary Feedwater Flow Rate - BV Case 060

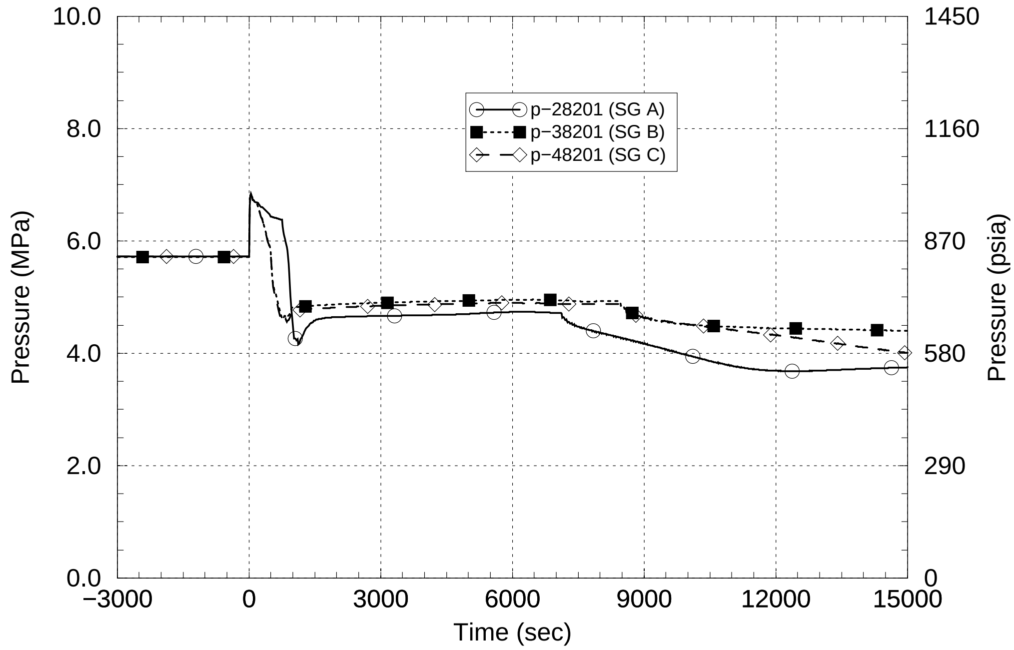


Figure 3.2.5-12 Steam Generator Pressure - BV Case 060

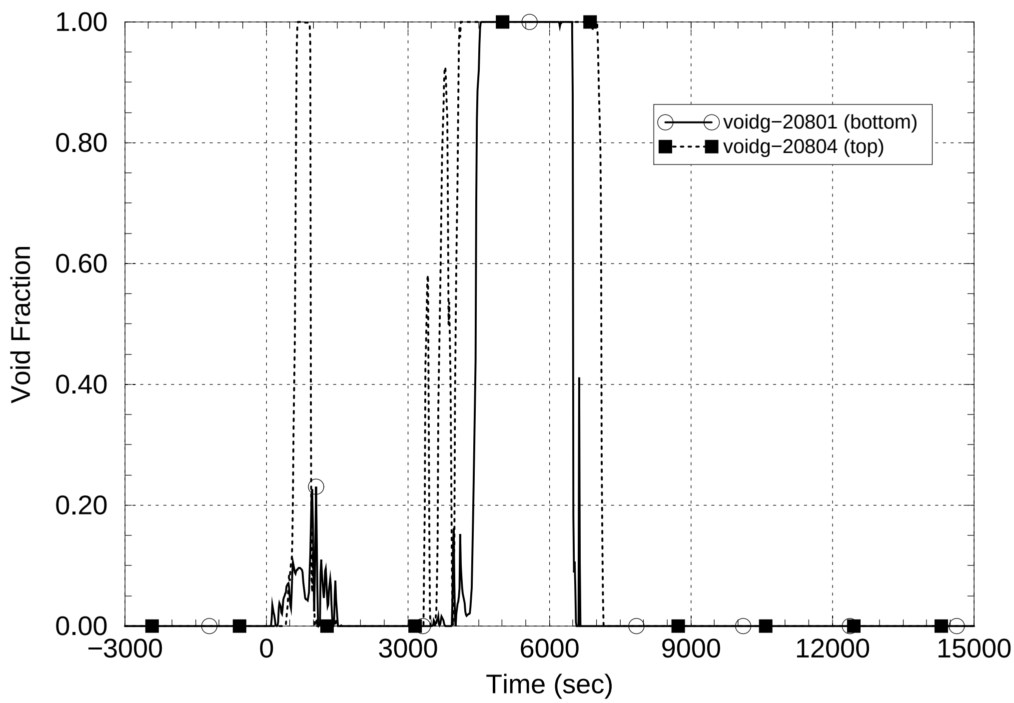


Figure 3.2.5-13 Void Fraction in Steam Generator Tubes - BV Case 060

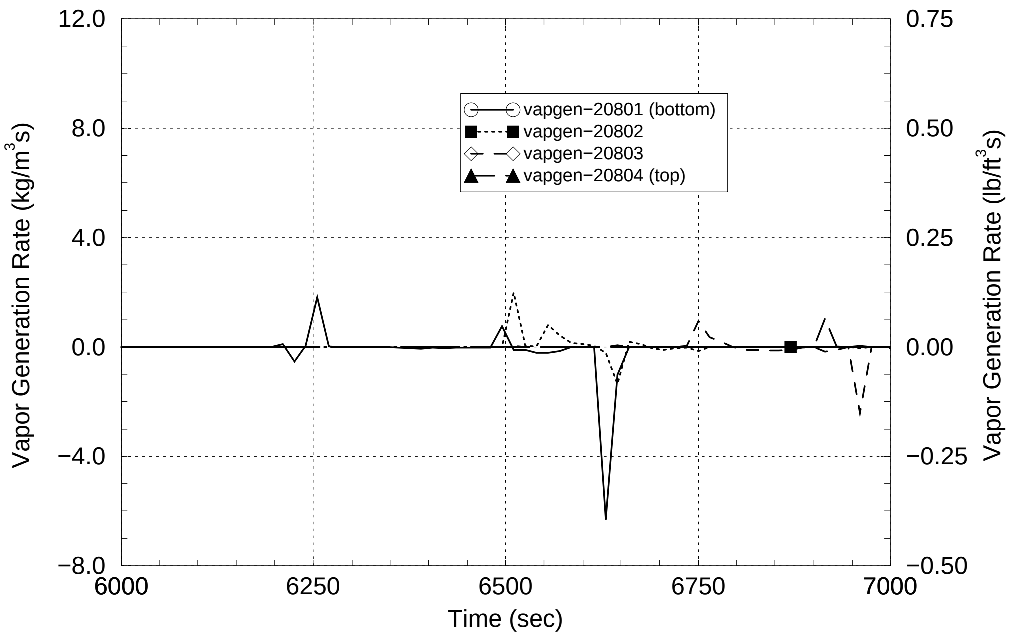


Figure 3.2.5-14 Vapor Generation Rate in Steam Generator Tubes - BV Case 060

3.2.5.2 Beaver Valley Stuck Open Pressurizer SRV Which Recloses with Operator Control of HHSI From Hot Full Power (BV Case 126)

This case is one stuck open pressurizer safety relief valve which recloses at 6,000 s with operator control of HHSI from hot full power. This case is identified as Beaver Valley Case 126 in Appendix B, Table B-1. This case has several differences versus the case 60 described above in Section 3.2.5.1. The major difference is that the operator controls HHSI. This is done by turning HHSI pumps on/off. The criteria for turning off a HHSI pump are as follows:

- Core exit subcooling > 23.9 K [43°F]
- SG NRL in any SG > 6%
- Pressurizer level > 5%
- Pressure stable or increasing; defined as pressure increased by 0.345 MPa [50 psi] over a 300 s period

Note that these criteria are based on normal containment conditions, whereas the criteria used in the MSLB cases previously described were based on “adverse” containment conditions.

After the conditions are met for HHSI control, a delay time is assumed before the first HHSI pump is stopped. In case 126 this time is ten minutes. After turning off the first HHSI pump, the operator waits five minutes and if the conditions are still met the second pump is stopped. Note that at any time if the above conditions are not met, both HHSI pumps are turned back on.

Other changes include the following:

- Momentum flux was turned off in both the axial and cross flow direction in the downcomer
- The downcomer wall was renodalized from 14 mesh points to 80 mesh points
- Running averages of the parameters of interest were computed
- Minor edit frequency was changed from one point every fifteen seconds to one point every second

The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.5-15 through 3.2.5-17 respectively.

As a result of the stuck open valve, the primary system rapidly depressurizes as shown in Figure 3.2.5-15. In addition, since the valve is located at the top of the pressurizer, the pressurizer fills solid due to the primary system water flowing towards the valve. By 125 s, the pressurizer is filled, and remains filled for the duration of the transient as seen in Figure 3.2.5-18. Due to the loss of inventory, the primary system begins voiding in the reactor vessel upper head.

At approximately 11 s, a SIAS was generated. The SIAS results in actuation of both the HHSI, and LHSI. In addition, it also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated. Note that while LHSI is activated, there is no flow unless the primary pressure falls below the LHSI pump shutoff head.

A plot of pressurizer SRV flow versus total safety injection flow is provided as Figure 3.2.5-19. Total SI flow includes high pressure injection, low pressure injection, accumulators and charging/letdown. High pressure injection flow is shown in Figure 3.2.5-20. For about the first 2,500 s break flow is slightly larger than safety injection flow. By 2,500 s the primary pressure has decreased to below the accumulator pressure, resulting in accumulator injection as shown in Figure 3.2.5-21. With this additional flow, the total SI is about equal to the flow through the stuck open valve. The primary pressure never drops to below the low pressure injection pump shutoff head, therefore, there is no low pressure injection for this case.

At approximately 68 s, the reactor coolant pumps were tripped due to an operator action. This causes the flow in the loops to decrease to near zero. Figure 3.2.5-22 presents the hot leg mass flow for all three loops at the exit of the vessel. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops quickly from an initial value of 24,073 $W/m^2{\cdot}K$ [1.178 $Btu/s{\cdot}ft^2{\cdot}°F$] as seen in Figure 3.2.5-17. Until the system repressurizes around 7,640 s the heat transfer coefficient drops gradually to 500 $W/m^2{\cdot}K$ [0.024 $Btu/s{\cdot}ft^2{\cdot}°F$]. After the system repressurizes, the heat transfer coefficient remains around 1,400 $W/m^2{\cdot}K$ [0.0685 $Btu/s{\cdot}ft^2{\cdot}°F$].

Figure 3.2.5-23 shows the core power versus the energy lost through the stuck open valve. As seen in this figure, the energy lost out of the valve when it is open is larger than the assumed core decay heat, thus, heat is being removed from the system causing the temperature to decrease.

The average downcomer fluid temperature is shown in Figure 3.2.5-16. By 6,000 s, the downcomer temperature has reached a minimum value of 340 K [152°F].

Figure 3.2.5-24 shows the steam generator narrow range water level. Upon the SIAS being generated, the MFW is isolated. AFW is started and begins controlling the generators to the setpoint of 33% NRL (120.7 cm [47.52 in]). Figure 3.2.5-25 shows the auxiliary feedwater flow which comes on initially to maintain steam generator water level. The steam generator secondary side pressure is shown in Figure 3.2.5-26.

At 6,000 s, the stuck open pressurizer SRV is reclosed. The high head injection pumps continue to supply cold water, and the primary system begins to repressurize. By 6,000 s, the primary pressure has increased to above the accumulator pressure, thus stopping accumulator flow. At 7,225 s all the conditions are met to begin HHSI control. These include:

- Core exit subcooling > 23.9 K [43°F] (Figure 3.2.5-27)
- SG NRL in any SG > 6% (Figure 3.2.5-24)
- Pressurizer level > 5% (Figure 3.2.5-18)
- Pressure stable or increasing; defined as pressure increased by 0.345 MPa [50 psi] over a 300 s period (Figure 3.2.5-15)

Note that in Figure 3.2.5-27, the core exit subcooling is zero prior to time zero. This is because the calculation was not performed in the steady state and there is no data during this time. By 7,640 s, the SI flow has repressurized the primary to the pressurizer PORV opening setpoint and flow begins to leave the primary system through the valve. After waiting the specified ten minutes, the first HHSI pump is turned off at 7,825 s. After waiting another five minutes, the second HHSI pump is turned off at 8,125 s. The conditions for stopping a HHSI pump remain met for the duration of the transient and both HHSI pumps remain turned off.

During the initial part of the LOCA, the steam generator tubes voided as shown in Figure 3.2.5-28. Once the pressurizer SRV recloses the steam generator tubes begin to refill. During the refill time (6,300 to 7,000 s) there are minor condensation/vaporization effects. Figure 3.2.5-22 shows that the hot leg flow oscillations occur during this period of steam generator tube condensation/vaporization.

As a consequence of the stuck open pressurizer safety relief valve, it is shown that the loss of inventory through the SRV is capable of removing more than the assumed core decay heat. This leads to the downcomer fluid temperature decreasing to a value of 340 K [152°F] at the valve reclosure time. Shortly after the pressurizer SRV recloses, the primary pressure increases to the pressurizer PORV opening setpoint of 16.2 MPa [2,350 psia]. While the system is repressurizing (6,000 to 7,640 s), the downcomer fluid temperature rises slightly to 375 K [215°F]. After the system has repressurized and the HHSI pumps are stopped, the downcomer fluid temperature rises to 555 K [539°F] with the pressure remaining at the pressurizer PORV opening setpoint.

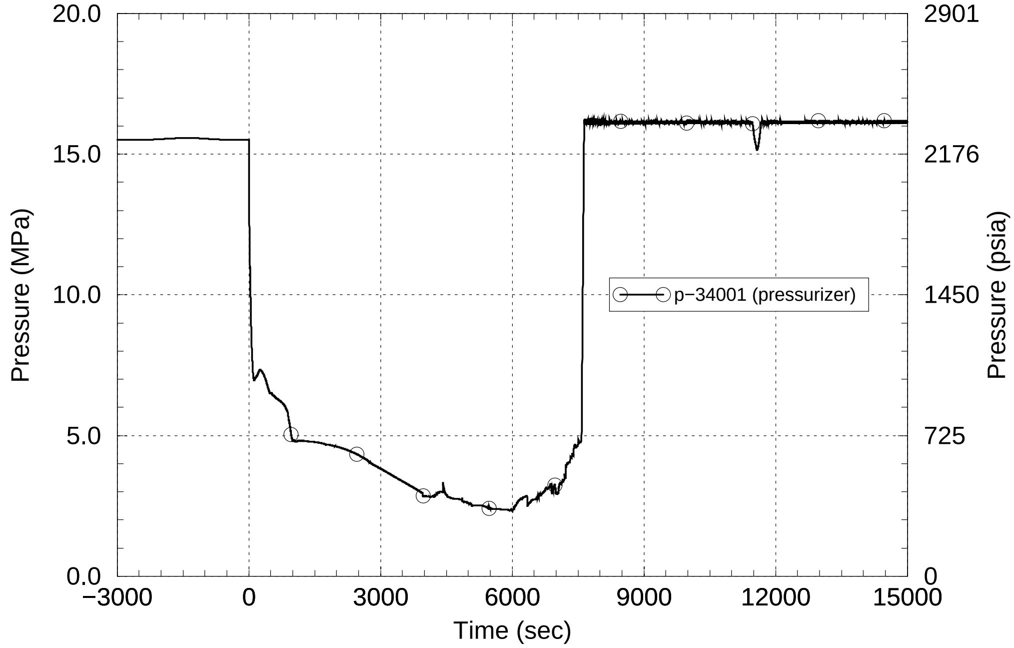


Figure 3.2.5-15 Primary System Pressure - BV Case 126

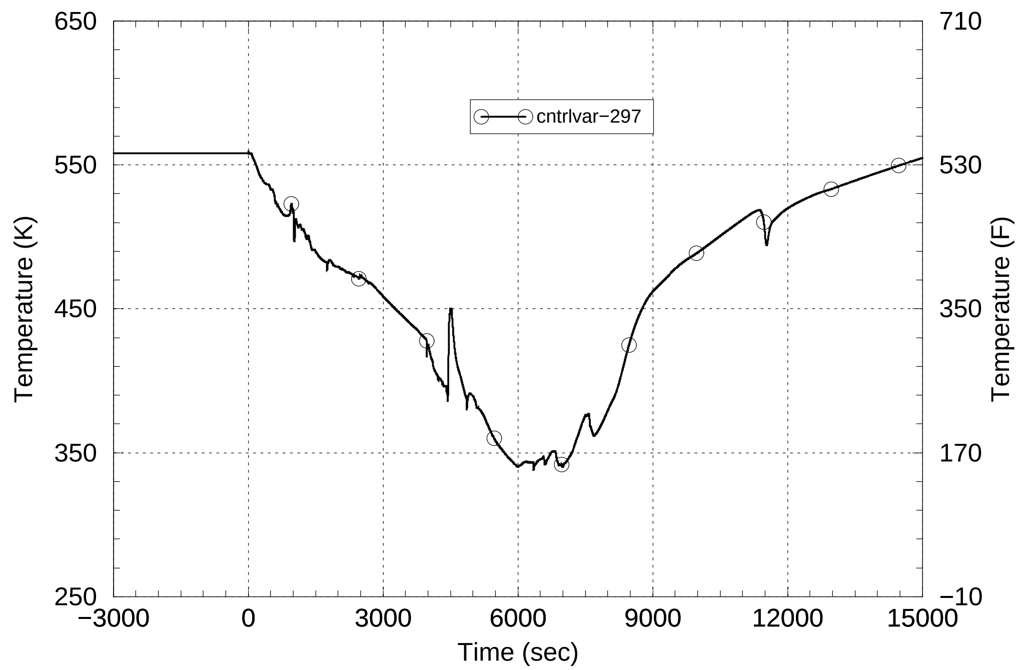


Figure 3.2.5-16 Average Downcomer Fluid Temperature - BV Case 126

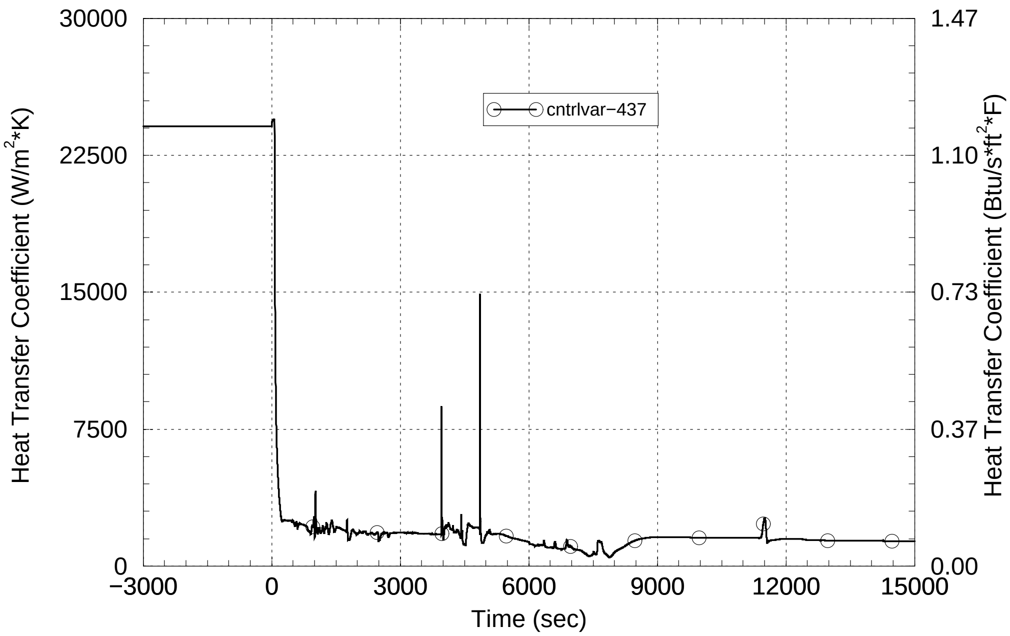


Figure 3.2.5-17 Downcomer Heat Transfer Coefficient - BV Case 126

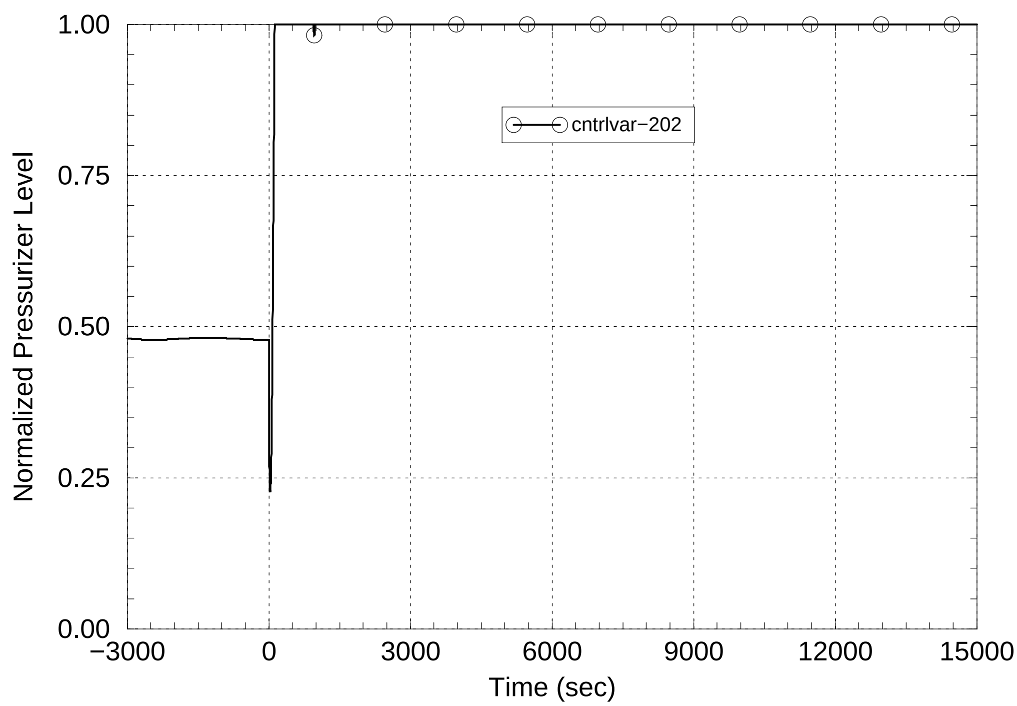


Figure 3.2.5-18 Pressurizer Water Level - BV Case 126

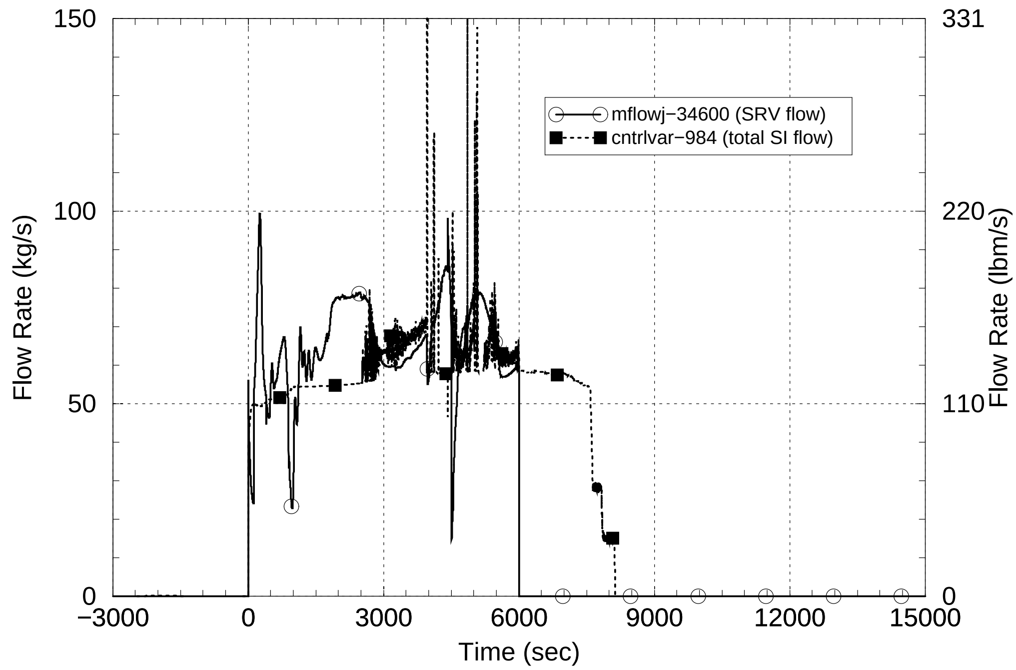


Figure 3.2.5-19 Break Flow and Total Safety Injection Flow - BV Case 126

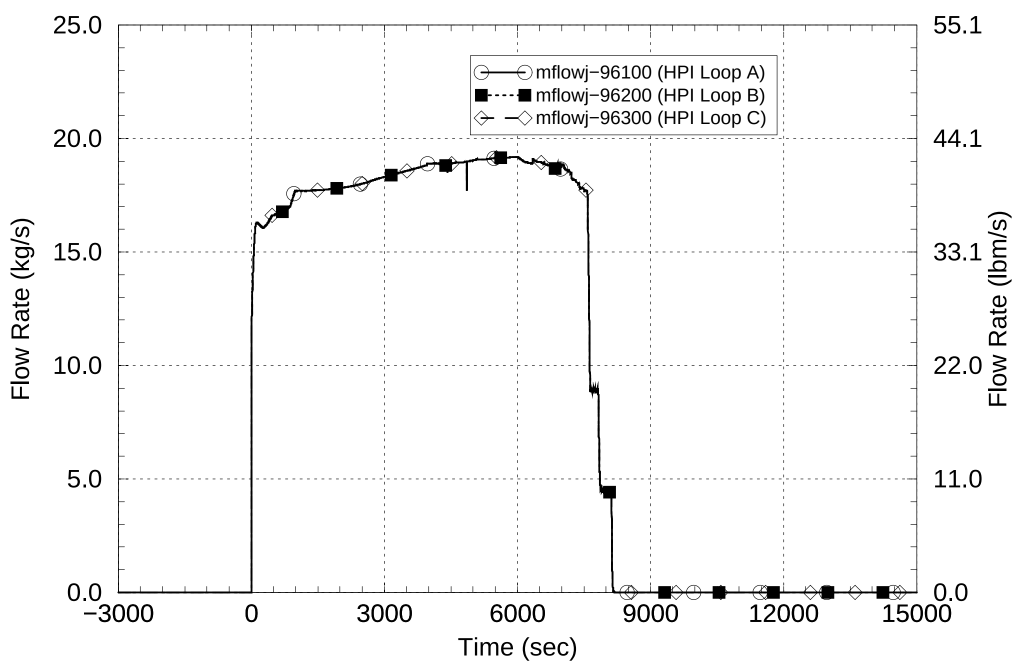


Figure 3.2.5-20 High Pressure Injection Flow Rate - BV Case 126

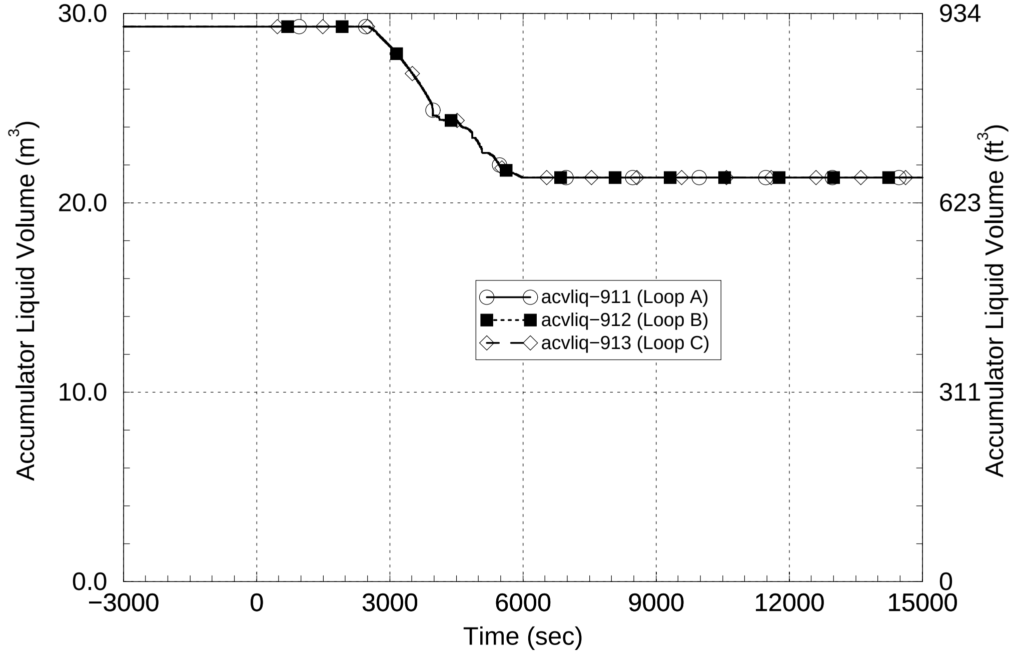


Figure 3.2.5-21 Accumulator Liquid Volume - BV Case 126

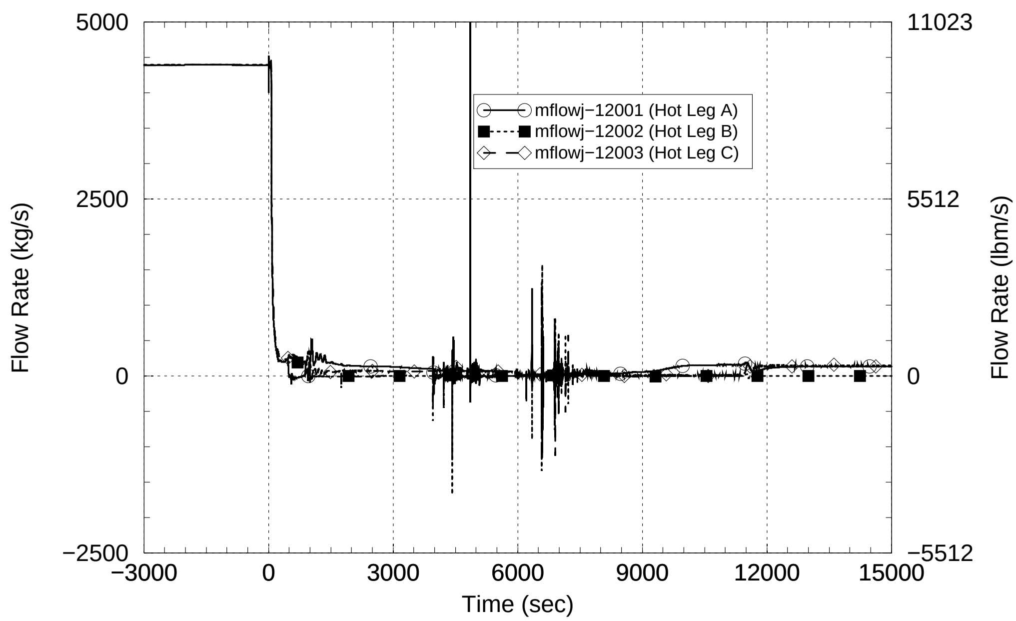


Figure 3.2.5-22 Hot Leg Mass Flow Rate - BV Case 126

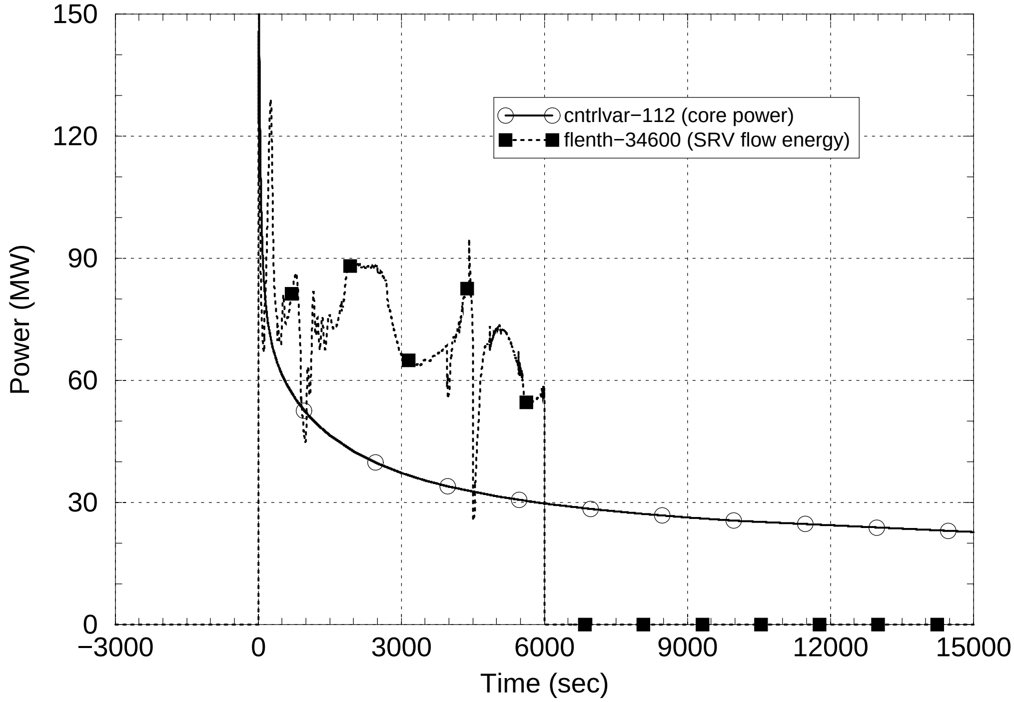


Figure 3.2.5-23 Core Power and Break Energy - BV Case 126

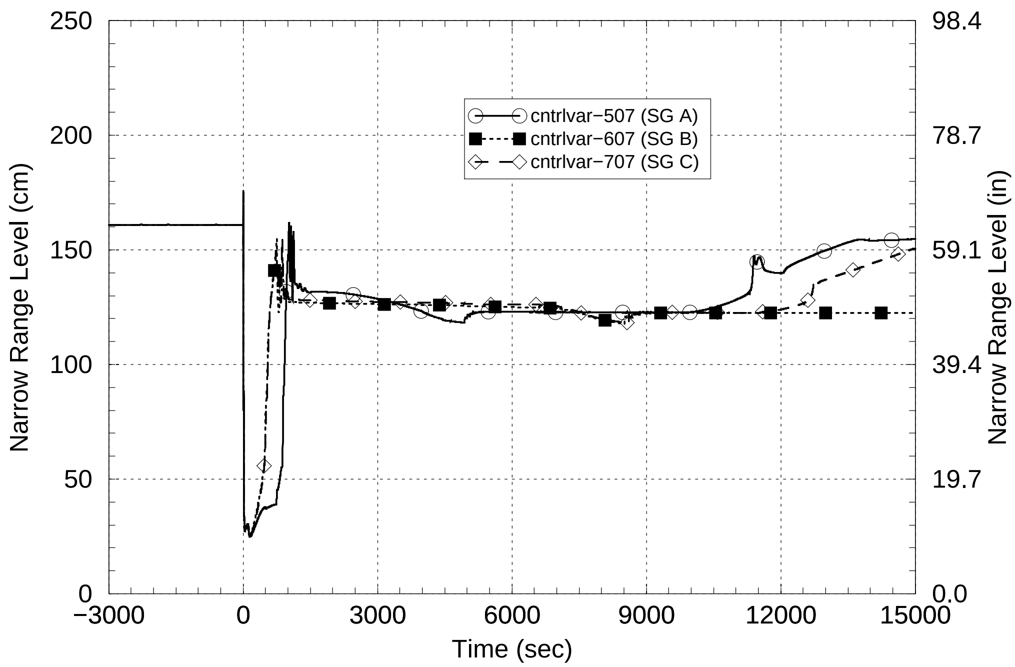


Figure 3.2.5-24 Steam Generator Narrow Range Water Level - BV Case 126

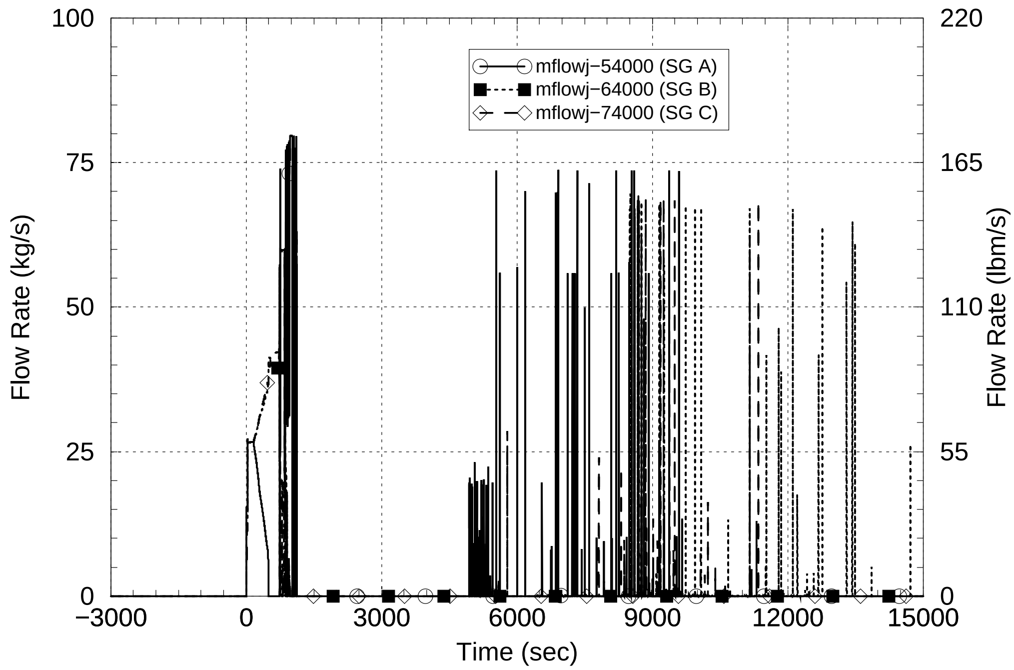


Figure 3.2.5-25 Auxiliary Feedwater Flow Rate - BV Case 126

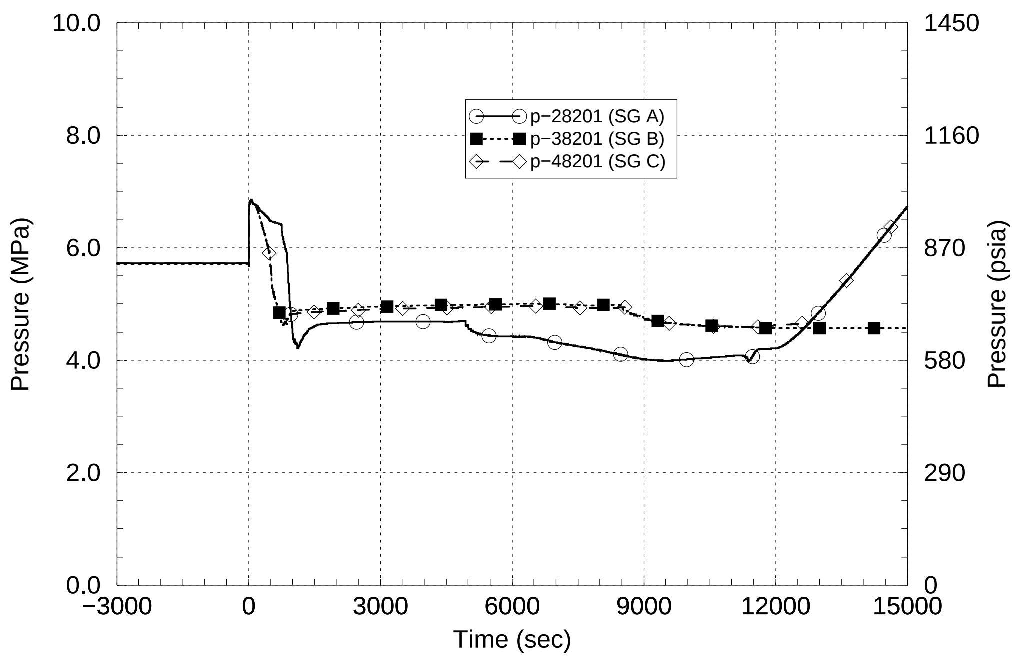


Figure 3.2.5-26 Steam Generator Pressure - BV Case 126

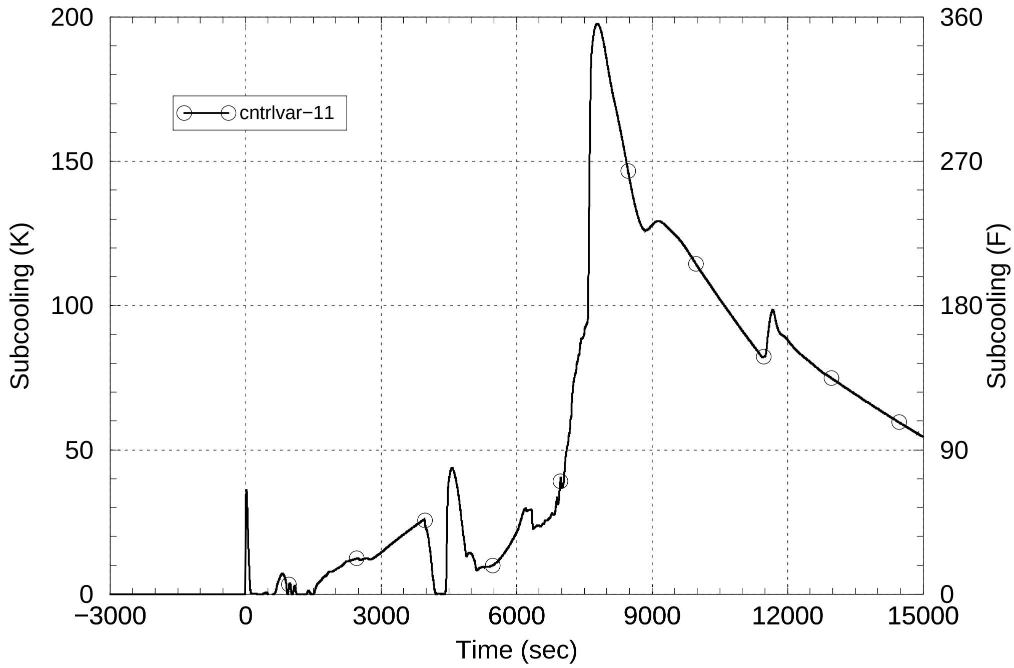


Figure 3.2.5-27 Core Exit Subcooling - BV Case 126

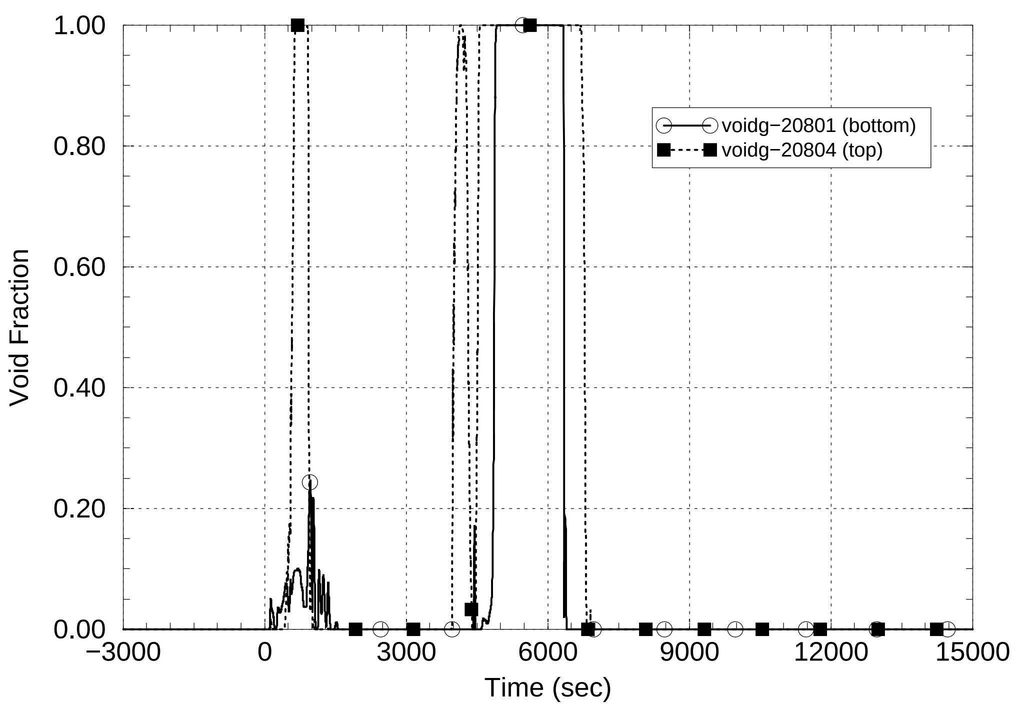


Figure 3.2.5-28 Void Fraction in Steam Generator Tubes - BV Case 126

3.2.6 Beaver Valley Stuck Open Primary Relief Valves Which Reclose From Hot Zero Power

The transients in this group were initiated from hot zero power steady state operating conditions. At hot zero power, the core power is nearly zero and the reactor coolant pumps are operating at normal speed, adding heat to the reactor coolant system (RCS). Because the RCS heat load is small, the fluid temperatures in all portions of the RCS (cold legs, hot legs and reactor vessel) and the steam generator (SG) secondary system are virtually the same. This temperature defines the HZP secondary system pressure (the secondary is at the saturation pressure corresponding to the RCS temperature). The steam dump valve controllers in the plant and model modulate the steam dump valve to attain this SG pressure and RCS average temperature.

On the SG secondary side, the turbine is tripped at HZP and therefore the turbine stop valves are closed. Main feedwater is delivered at a very low rate, consistent with the low RCS heat load. Because the feedwater train heaters depend on turbine extraction steam for operation, feedwater is delivered to the SGs at the low condenser temperature, rather than the elevated temperature associated with main feedwater at HFP operation.

The reduced steam generator heat load at HZP results in much less steam production and voiding in the SG boiler sections than is present at full power. Therefore, SG water mass is significantly higher for HZP operation than for HFP operation.

In the hot full power steady state model, core power is input using a table. Power is held constant until the time of reactor trip and it decays afterward on the basis of ANS standard decay heat. In the HZP condition, the reactor is critical with control element assemblies withdrawn. From a modeling view, it is difficult to initialize a plant model with zero core power because of the plant system's long thermal time constants. For these reasons, the Beaver Valley Unit 1 hot zero power RELAP5 model assumes a constant 5.32 MW core power, both at steady state and during transients. This value represents the heat load at 1 month after shutdown and is 0.2% of the rated thermal power. The core power table was revised to reflect this assumption.

The first transient in this group is a reactor/turbine trip with one stuck open pressurizer safety relief valve which recloses at 6,000 s. The second transient is a reactor/turbine trip with one stuck open pressurizer safety relief valve which recloses at 3,000 s. The third transient in this group is a reactor/turbine trip with one stuck open pressurizer safety relief valve which recloses at 3,000 s where the operator controls HHSI (10 minute delay). Operator control of HHSI is described in Section 3.2.5. All three of these transients are restarted from the hot zero power null transient described in Section 2.2.

In order to model the stuck open pressurizer safety relief valve which recloses, a general data table was added to the RELAP5 transient restart input file which contains the safety relief valve position versus time. The SRV valve component was also set to point to the data table, rather than the original control system. This valve was set to spuriously open at time zero and close at the desired time. Note that the data table opens the RELAP5 valve component to a position of one third which models one of three SRVs stuck open.

A sequence of events table for the stuck open pressurizer safety relief valve cases at hot zero power is provided as Table 3.2-6.

Table 3.2-6 Sequence of Events for Stuck Open Primary Relief Valves Which Reclose from Hot Zero Power

	Case 071 - One stuck open pressurizer SRV which recloses at 6,000 s from HZP	Case 097 - One stuck open pressurizer SRV which recloses at 3,000 s from HZP	Case 130 - One stuck open pressurizer SRV which recloses at 3,000 s from HZP w/operator actions
	Event Time (s)		
Pressurizer SRV opened	0.0	0.0	0.0
SIAS generated	20.1	20.1	20.3
HHSI flow initiated	20.1	20.1	20.3
MFW stopped	20.1	20.1	20.3
AFW started	20.1	20.1	20.3
Pressurizer fills solid	150	150	145
RCPs trip	53.8	53.8	72.0
Accumulators begin injecting	1,615	1,530	1,660
Accumulators stop injecting	4,715	3,195	3,030
Break valve closed	6,000	3,000	3,000
Primary Repressurizes to PORV setpoint	6,470	4,335	4,319
First HHSI pump stopped	N/A	N/A	4,161
Second HHSI pump stopped	N/A	N/A	4,461

3.2.6.1 Beaver Valley Stuck Open Pressurizer Safety Relief Valve Which Recloses From Hot Zero Power (BV Case 071)

This case is one stuck open pressurizer safety relief valve which recloses at 6,000 s from hot zero power. This case is identified as Beaver Valley Case 071 in Appendix B, Table B-1. The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.6-1 through 3.2.6-3 respectively.

As a result of the stuck open valve, the primary system rapidly depressurizes as shown in Figure 3.2.6-1. In addition, since the valve is located at the top of the pressurizer, the pressurizer fills solid due to the primary system water flowing towards the valve. By 150 s, the pressurizer is filled, and remains filled for the duration of the transient as seen in Figure 3.2.6-4. Due to the loss of inventory, the primary system begins voiding in the reactor vessel upper head.

At approximately 20 s, a SIAS was generated. The SIAS results in actuation of both the HHSI, and LHSI. In addition, it also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated.

A plot of pressurizer SRV flow versus total safety injection flow is provided as Figure 3.2.6-5. Total SI flow includes high pressure injection, low pressure injection, accumulators and charging/letdown. High pressure injection flow is shown in Figure 3.2.6-6. For about the first 1,500 s break flow is larger than safety injection flow. By 1,615 s the primary pressure has decreased to below the accumulator pressure, resulting in accumulator injection as shown in Figure 3.2.6-7. With this additional flow, the total SI is about equal to the flow through the stuck open valve. The primary pressure never drops to below the low pressure injection pump shutoff head, therefore, there is no low pressure injection for this case.

At approximately 53.8 s, the reactor coolant pumps were tripped due to an operator action. This causes the flow in the loops to decrease to near zero. Figure 3.2.6-8 presents the hot leg mass flow for all three loops at the exit of the vessel. After RCP trip the only loop with flow is the C loop, where the pressurizer and stuck open valve are located. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops quickly from an initial value of 24,073 $W/m^2{\cdot}K$ [1.178 $Btu/s{\cdot}ft^2{\cdot}°F$]. During the remainder of the transient, this drops gradually to 330 $W/m^2{\cdot}K$ [0.016 $Btu/s{\cdot}ft^2{\cdot}°F$].

Figure 3.2.6-9 shows the core power versus the energy lost through the stuck open valve. As seen in this figure, the energy lost out of the valve when it is open is larger than the assumed core decay heat, thus, heat is being removed from the system causing the temperature to decrease. Note that in this case power is held constant at 5.32 MW. The average downcomer fluid temperature is shown in Figure 3.2.6-2. By 6,000 s when the pressurizer SRV recloses, the downcomer temperature has reached a value of 305 K [89.3°F]. During the remainder of the transient, the average downcomer fluid temperature gradually drops to 295 K [71.3°F].

Figure 3.2.6-10 shows the steam generator narrow range water level. Upon the SIAS being generated, the MFW is isolated. Since the MFW at hot zero power is very small (approximately 2 kg/s [4.4 lbm/s]), the isolation of MFW does not have a significant effect on steam generator water level. AFW is started, and begins controlling the generators to the setpoint of 33% NRL (120.7 cm [47.52 in]). Note that the hot zero power pre/post trip level setpoints are the same. Figure 3.2.6-11 shows the auxiliary feedwater flow which comes on initially to maintain steam generator water level. The steam generator secondary side pressure is shown in Figure 3.2.6-12.

By 4,715 s, the accumulator pressure has fallen below the primary pressure, thus accumulator flow is stopped. At 6,000 s, the stuck open pressurizer SRV is reclosed. The high head injection pumps continue to supply cold water, and the primary system begins to repressurize. Note that no operator actions, such as controlling HHSI flow, were taken to control primary system pressure or level. By 6,470 s, the SI flow has repressurized the primary to the pressurizer PORV opening setpoint and flow begins to leave the primary system through the valve.

During the initial part of the transient, the steam generator tubes voided as shown in Figure 3.2.6-13. Once the SI flow increases to above the SRV flow, the steam generator tubes begin to refill. During the refill time (4,220 to 6,450 s) there are condensation/vaporization effects. Figure 3.2.6-14 shows the vapor generation rate for the steam generator tubes (hot leg side). Note that positive values show vaporization while negative values show condensation. Figure 3.2.6-8 shows that the hot leg flow oscillations occur during this period of steam generator tube condensation/vaporization. It is seen in this period that the hot leg flow oscillations cause the downcomer fluid to become well mixed and the average downcomer temperature increases as seen in Figure 3.2.6-2.

As a consequence of the stuck open pressurizer safety relief valve, it is shown that the loss of inventory through the SRV is capable of removing more than the assumed core decay heat at hot zero power. This leads to the downcomer fluid temperature decreasing to a value of 305 K [89.3°F] at the valve reclosure time. Shortly after the pressurizer SRV recloses, the primary pressure increases to the pressurizer PORV opening setpoint of 16.2 MPa [2350 psia]. After the system has repressurized, the downcomer fluid temperature falls gradually to a minimum value of 295 K [71.3°F] with the pressure remaining at the pressurizer PORV opening setpoint.

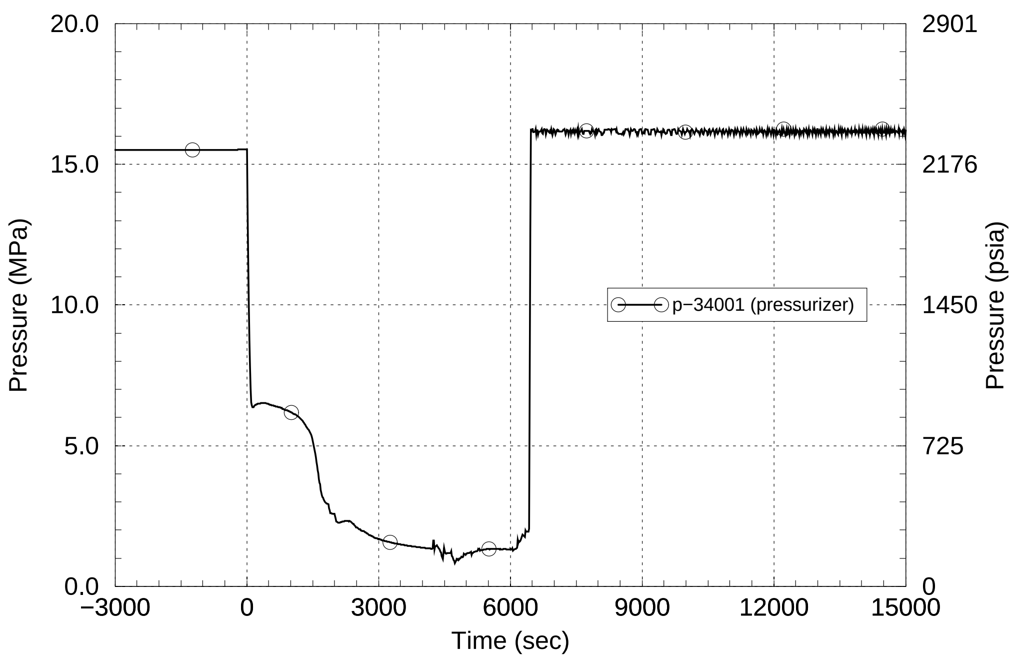


Figure 3.2.6-1 Primary System Pressure - BV Case 071

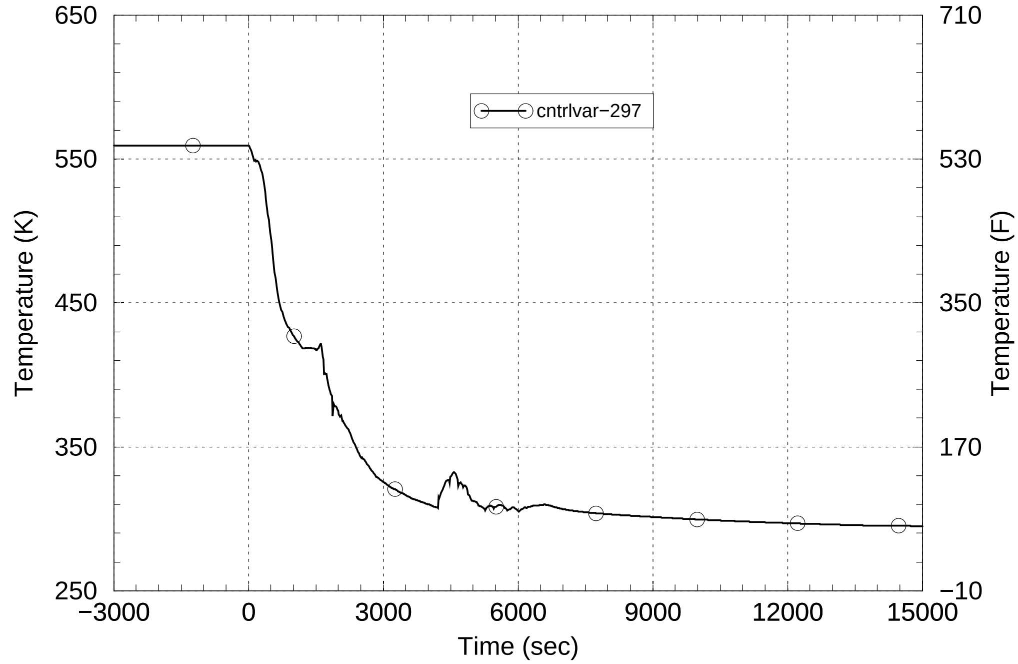


Figure 3.2.6-2   Average Downcomer Fluid Temperature - BV Case 071

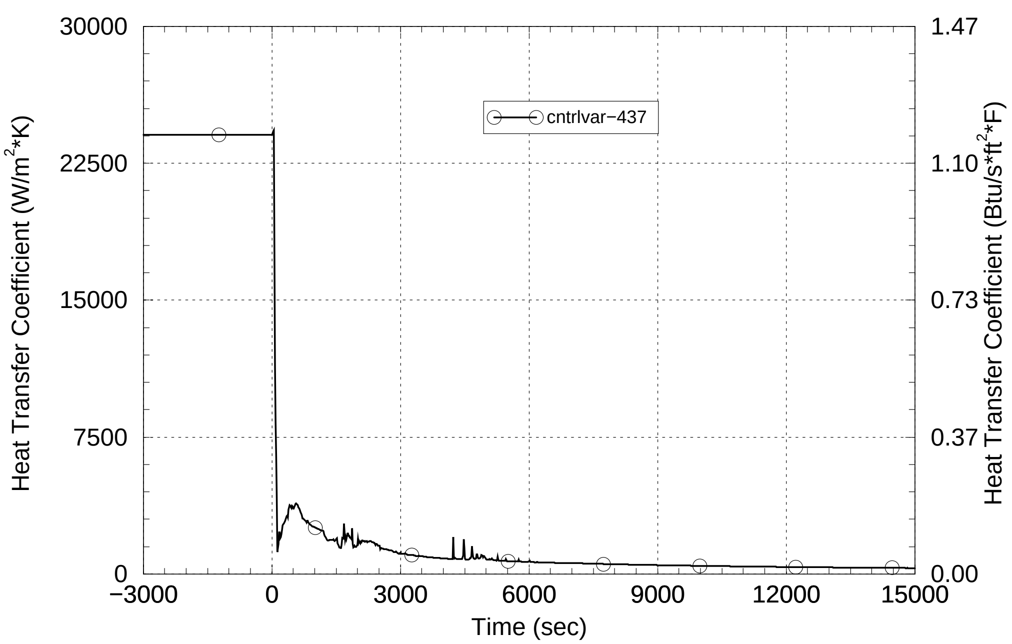


Figure 3.2.6-3   Downcomer Heat Transfer Coefficient - BV Case 071

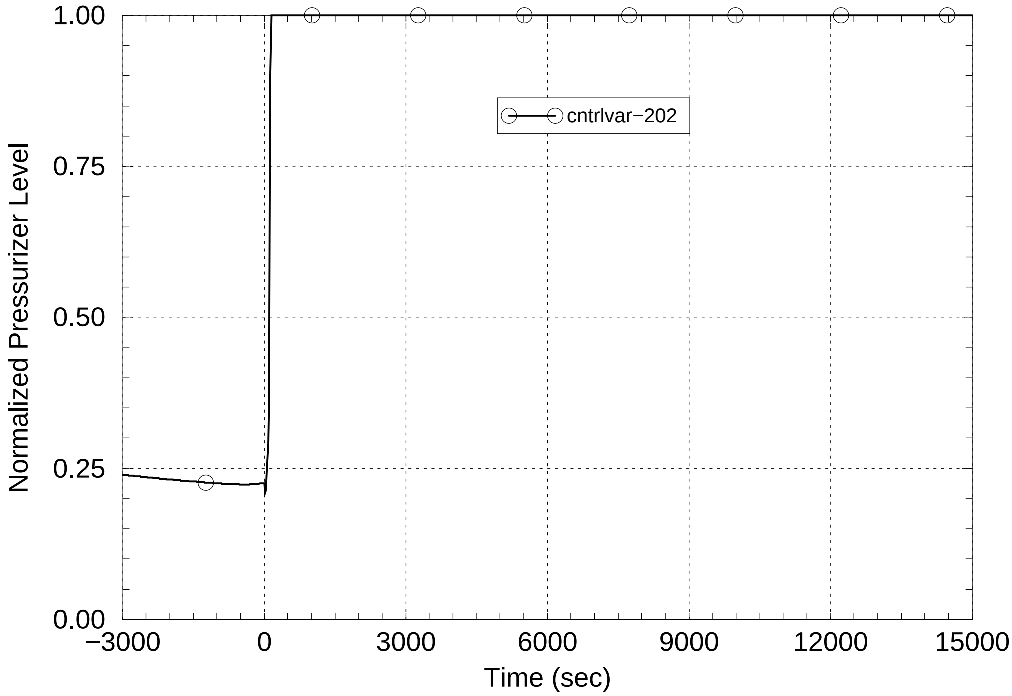


Figure 3.2.6-4 Pressurizer Water Level - BV Case 071

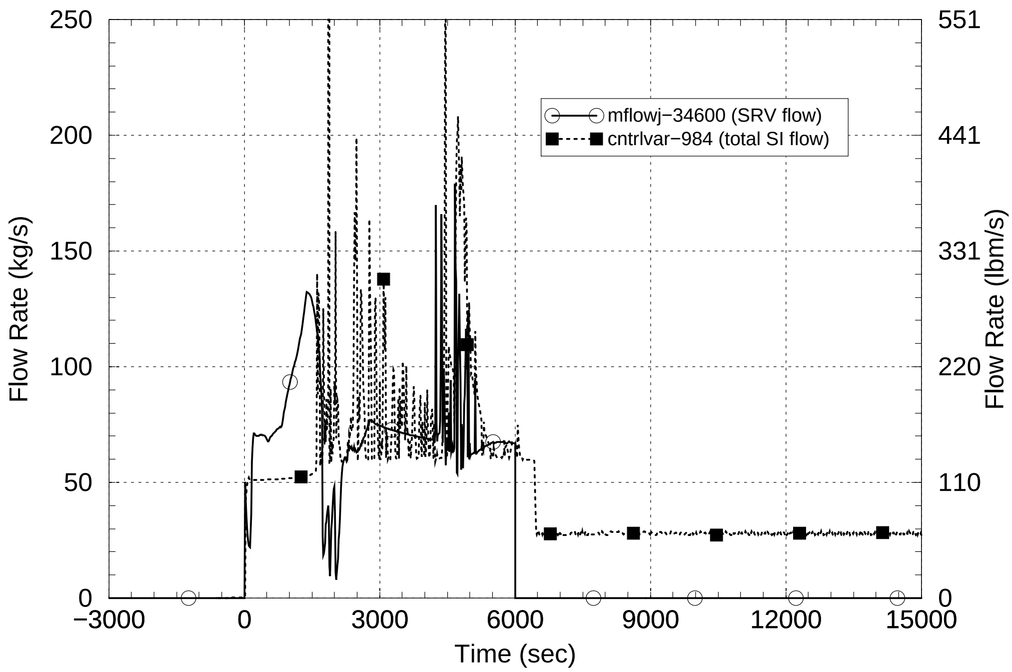


Figure 3.2.6-5 Break Flow and Total Safety Injection Flow - BV Case 071

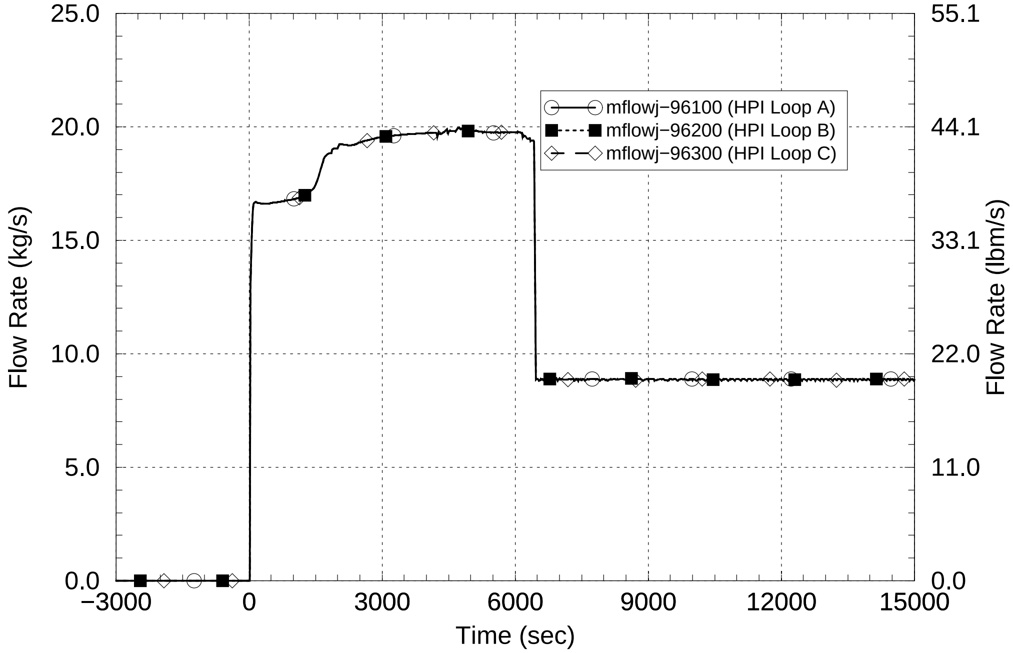


Figure 3.2.6-6   High Pressure Injection Flow Rate - BV Case 071

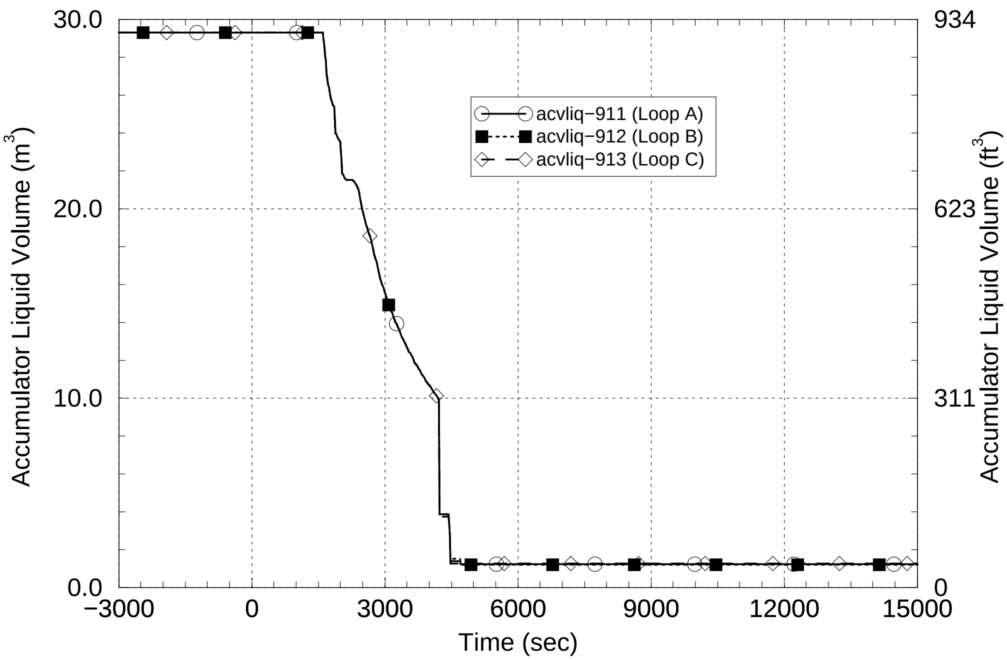


Figure 3.2.6-7   Accumulator Liquid Volume - BV Case 071

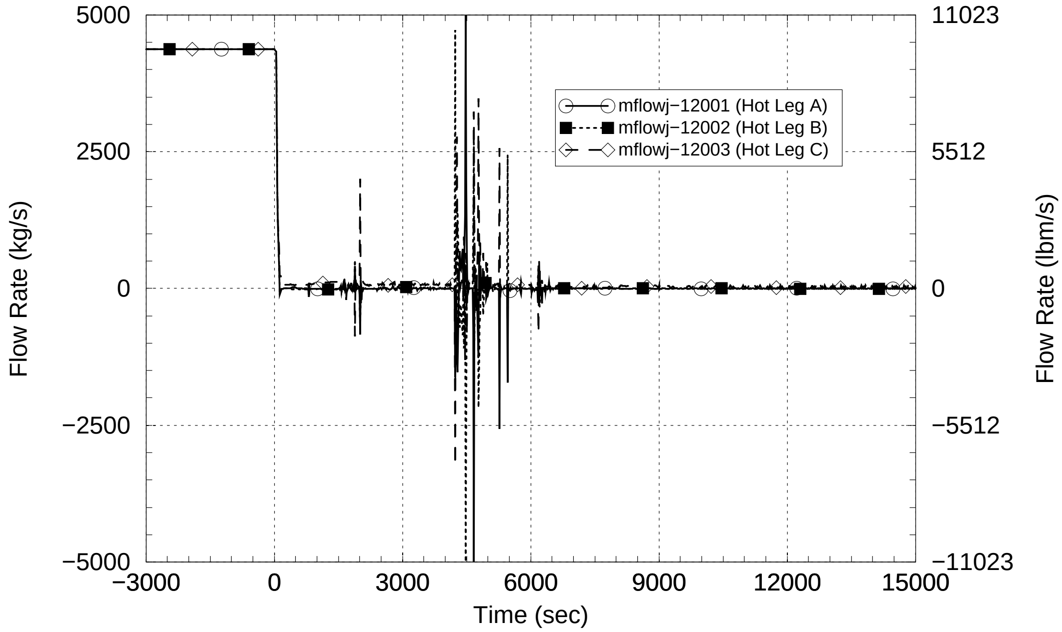


Figure 3.2.6-8 Hot Leg Mass Flow Rate - BV Case 071

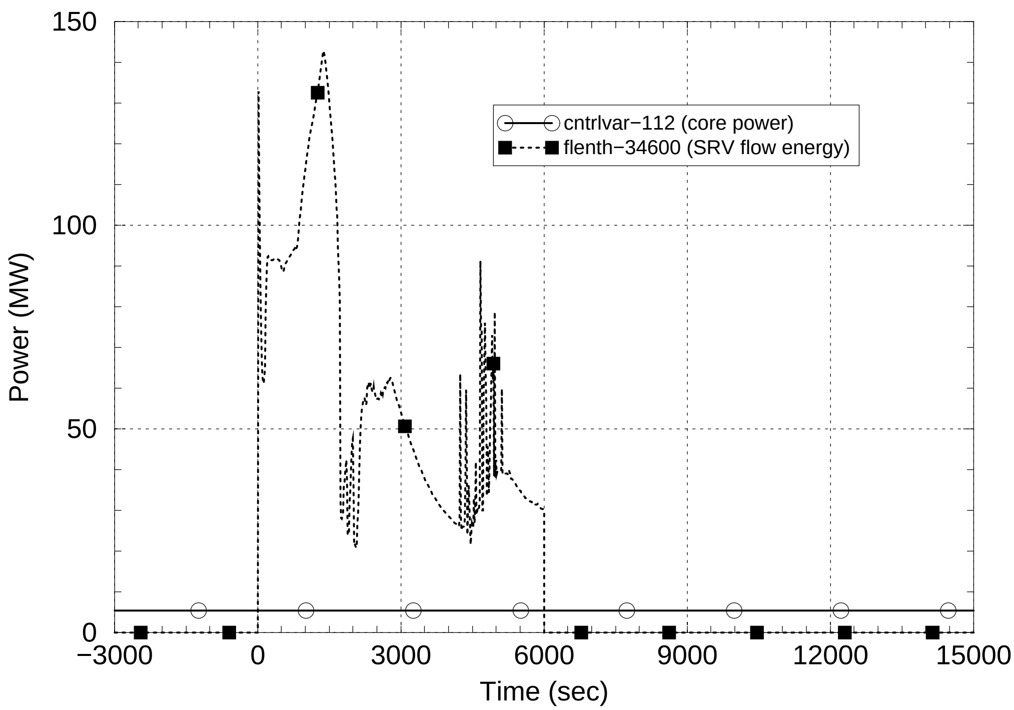


Figure 3.2.6-9 Core Power and Break Energy - BV Case 071

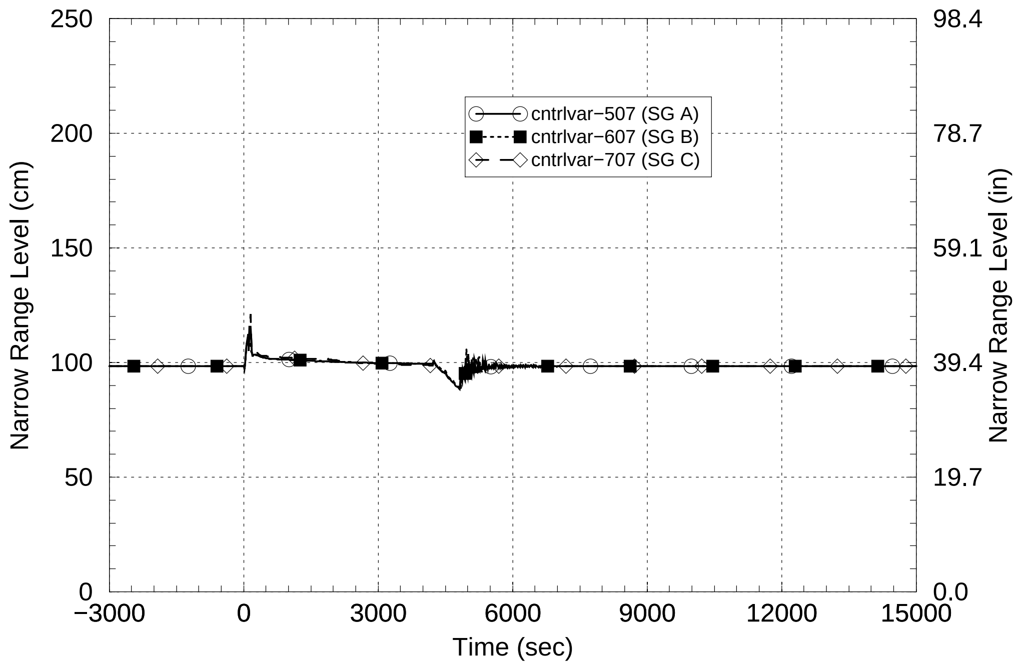


Figure 3.2.6-10 Steam Generator Narrow Range Water Level - BV Case 071

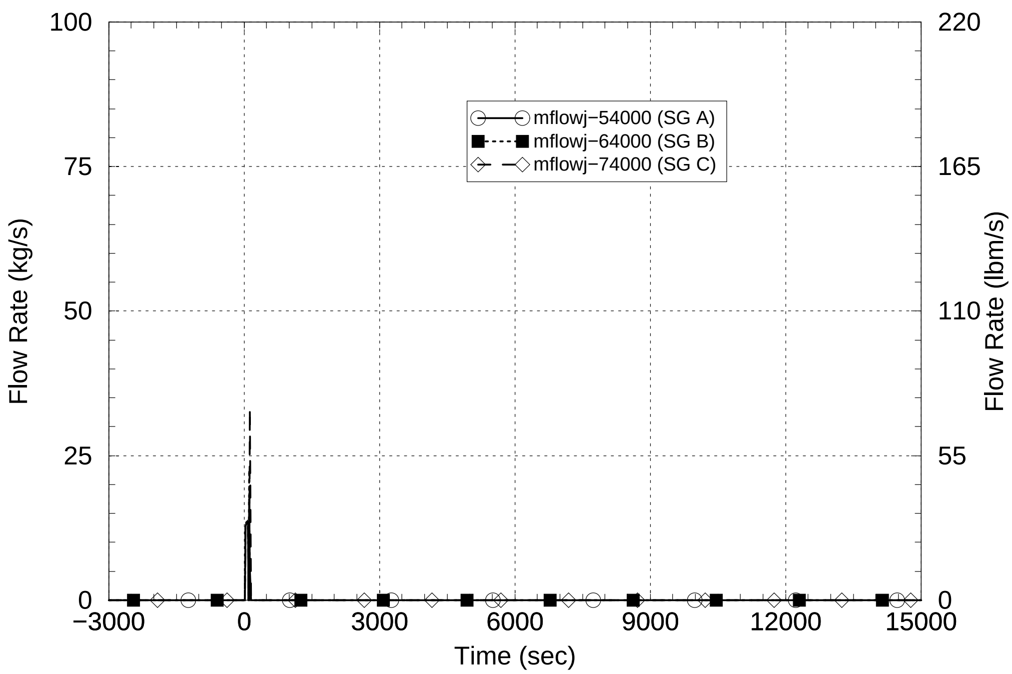


Figure 3.2.6-11 Auxiliary Feedwater Flow Rate - BV Case 071

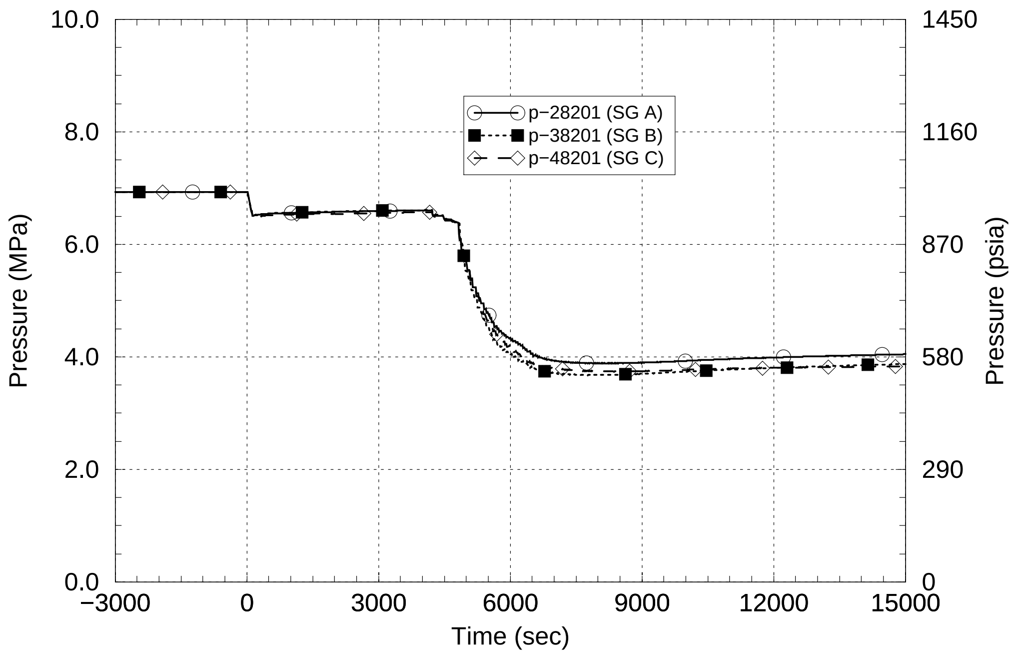


Figure 3.2.6-12   Steam Generator Pressure - BV Case 071

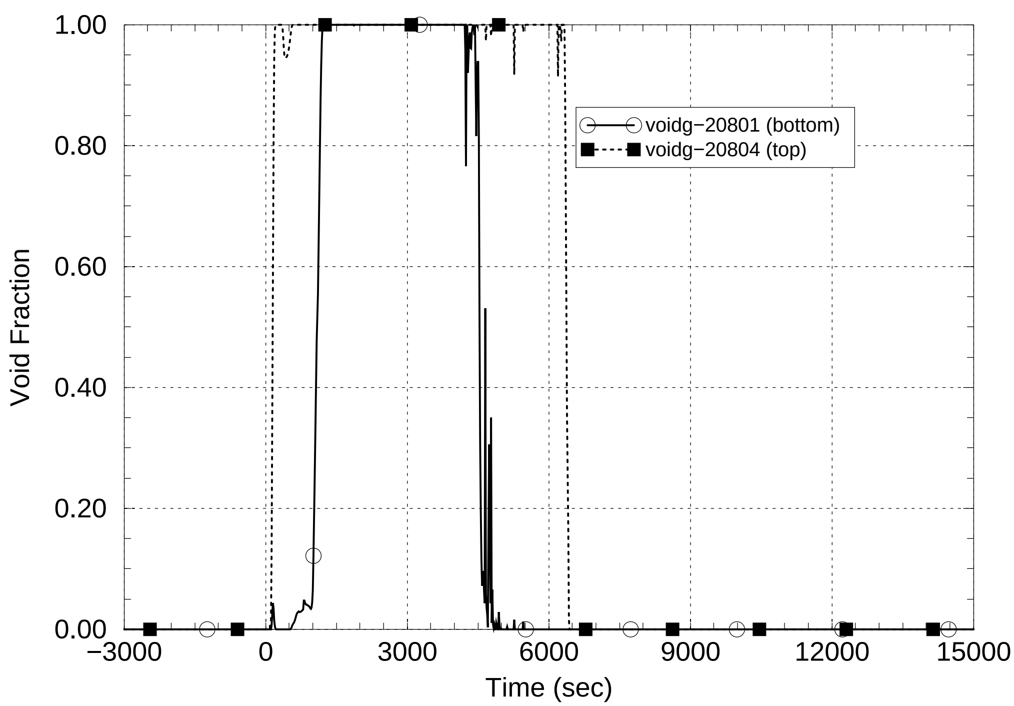


Figure 3.2.6-13   Void Fraction in Steam Generator Tubes - BV Case 071

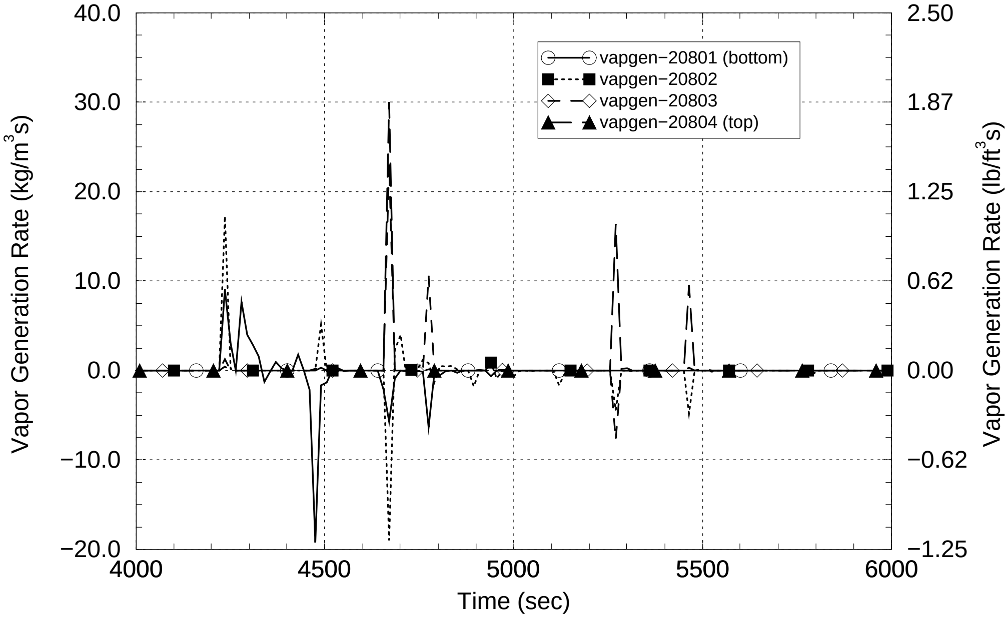


Figure 3.2.6-14 Vapor Generation Rate in Steam Generator Tubes - BV Case 071

3.2.6.2 Beaver Valley Stuck Open Pressurizer SRV Which Recloses From Hot Zero Power (BV Case 097)

This case is one stuck open pressurizer safety relief valve which recloses at 3,000 s from hot zero power. This case is identified as Beaver Valley Case 097 in Appendix B, Table B-1. The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.6-15 through 3.2.6-17 respectively.

Each of the three pressurizer SRVs has an effective diameter of 5.38 cm [2.12 in]. As a result of the stuck open valve, the primary system rapidly depressurizes as shown in Figure 3.2.6-15. In addition, since the valve is located at the top of the pressurizer, the pressurizer fills solid due to the primary system water flowing towards the valve. By 150 s, the pressurizer is filled, and remains filled for the duration of the transient as seen in Figure 3.2.6-18. Due to the loss of inventory, the primary system begins voiding in the reactor vessel upper head.

At approximately 20 s, a SIAS was generated. The SIAS results in actuation of both the HHSI, and LHSI. In addition, it also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated.

A plot of pressurizer SRV flow versus total safety injection flow is provided as Figure 3.2.6-19. Total SI flow includes high pressure injection, low pressure injection, accumulators and charging/letdown. High pressure injection flow is shown in Figure 3.2.6-20. For about the first 1,500 s break flow is larger than safety injection flow. By 1,515 s the primary pressure has decreased to below the accumulator pressure, resulting in accumulator injection as shown in Figure 3.2.6-21. With this additional flow, the total SI is about equal to the flow through the stuck open valve. The primary pressure never drops to below the low pressure injection pump shutoff head, therefore, there is no low pressure injection for this case.

At approximately 53.8 s, the reactor coolant pumps were tripped due to an operator action. This causes the flow in the loops to decrease to near zero. Figure 3.2.6-22 presents the hot leg mass flow for all three loops at the exit of the vessel. After RCP trip and up until 3,000 s, the only loop with flow is the C loop, where the pressurizer and stuck open valve are located. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops quickly from an initial value of 24,073 $W/m^2 \cdot K$ [1.178 $Btu/s \cdot ft^2 \cdot {}^\circ F$]. During the remainder of the transient, this drops gradually to 400 $W/m^2 \cdot K$ [0.020 $Btu/s \cdot ft^2 \cdot {}^\circ F$].

Figure 3.2.6-23 shows the core power versus the energy lost through the stuck open valve. As seen in this figure, the energy lost out of the valve when it is open is larger than the assumed core decay heat, thus, heat is being removed from the system causing the temperature to decrease. Note that in this case power is held constant at 5.32 MW. The average downcomer fluid temperature is shown in Figure 3.2.6-16. By 3,000 s, the downcomer temperature has reached a value of 321 K [118°F].

Figure 3.2.6-24 shows the steam generator narrow range water level. Upon the SIAS being generated, the MFW is isolated. Since the MFW at hot zero power is very small (approximately 2 kg/s [4.4 lbm/s]), the isolation of MFW does not have a significant effect on steam generator water level. AFW is started, and begins controlling the generators to the setpoint of 33% NRL (120.7 cm [47.52 in]). Note that the hot zero power pre/post trip level setpoints are the same. Figure 3.2.6-25 shows the auxiliary feedwater flow which comes on initially to maintain steam generator water level. The steam generator secondary side pressure is shown in Figure 3.2.6-26.

At 3,000 s, the stuck open pressurizer SRV is reclosed. The high head injection pumps continue to supply cold water, and the primary system begins to repressurize. Note that no operator actions, such as controlling HHSI flow, were taken to control primary system pressure or level. By 3,195 s, the primary pressure has increased to above the accumulator pressure, thus stopping accumulator flow. By 4,335 s, the SI flow has repressurized the primary to the pressurizer PORV opening setpoint and flow begins to leave the primary system through the valve.

During the initial part of the LOCA, the steam generator tubes voided as shown in Figure 3.2.6-27. Once the pressurizer SRV recloses the steam generator tubes begin to refill. During the refill time (3,180 to 4,200 s) there are condensation/vaporization effects. Figure 3.2.6-28 shows the vapor generation rate for the steam generator tubes (hot leg side). Note that positive values show vaporization while negative values show condensation. Figure 3.2.6-22 shows that the hot leg flow oscillations occur during this period of steam generator tube condensation/vaporization. Once the hot leg flow oscillations are finished (by 4,200 s), the downcomer fluid temperature gradually decreases reaching a final minimum of 297 K [75°F] at the end of the transient (15,000 s).

As a consequence of the stuck open pressurizer safety relief valve, it is shown that the loss of inventory through the SRV is capable of removing more than the assumed core decay heat at hot zero power. This leads to the downcomer fluid temperature decreasing to a value of 321 K [118°F] at the valve reclosure time. Shortly after the pressurizer SRV recloses, the primary pressure increases to the pressurizer PORV opening setpoint of 16.2 MPa [2350 psia]. While the system is repressurizing (3,000 to 4,335 s), the downcomer fluid temperature rises slightly to 336 K [145°F]. After the system has repressurized, the downcomer fluid temperature falls gradually to a minimum value of 297 K [75°F] with the pressure remaining at the pressurizer PORV opening setpoint.

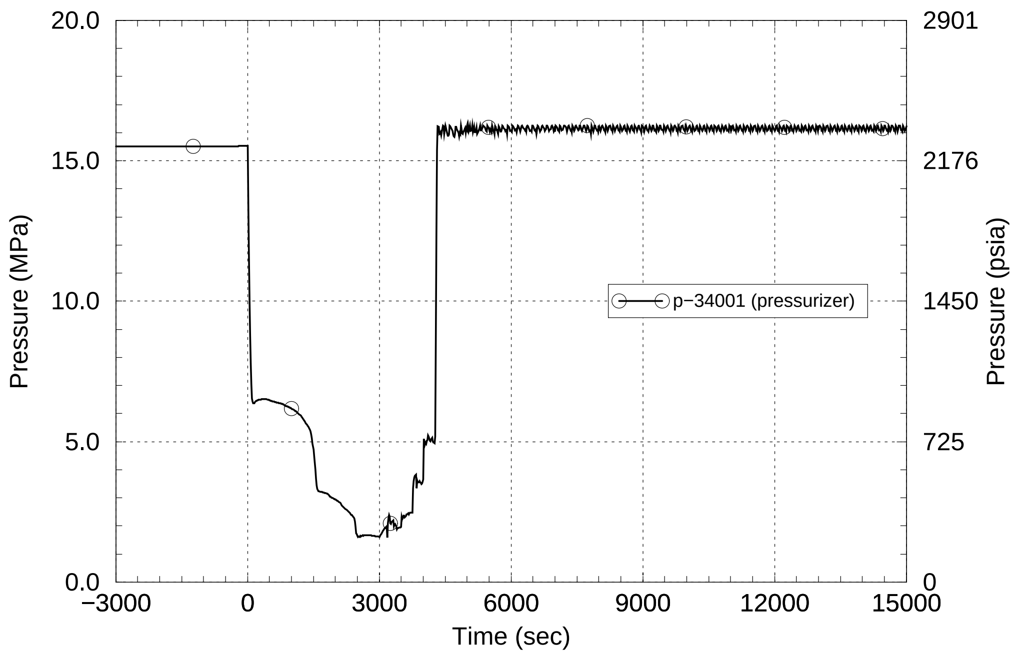


Figure 3.2.6-15 Primary System Pressure – BV Case 097

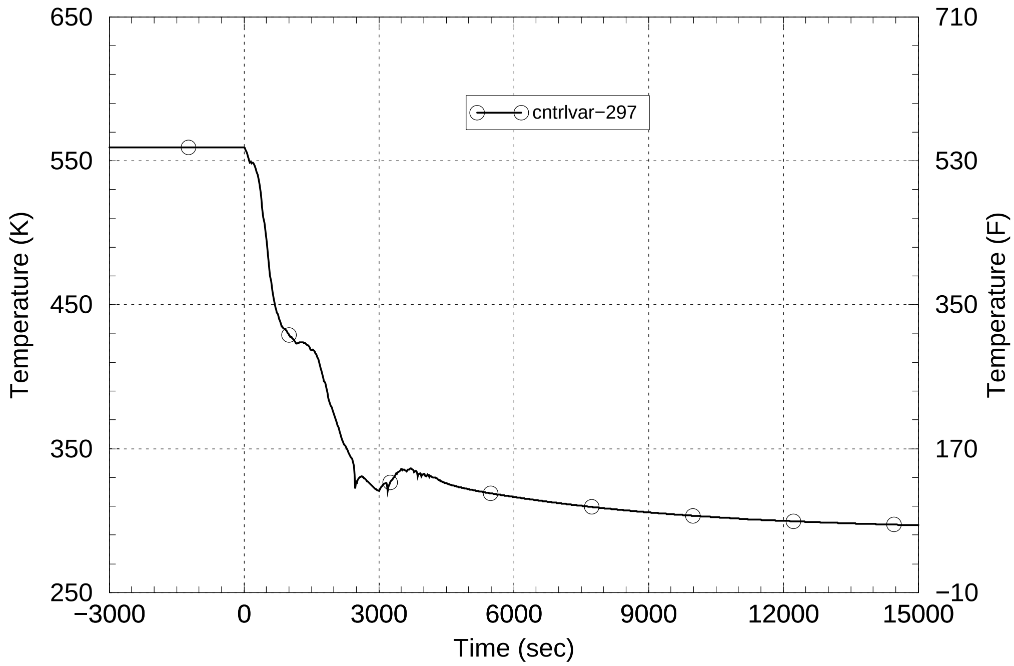


Figure 3.2.6-16 Average Downcomer Fluid Temperature – BV Case 097

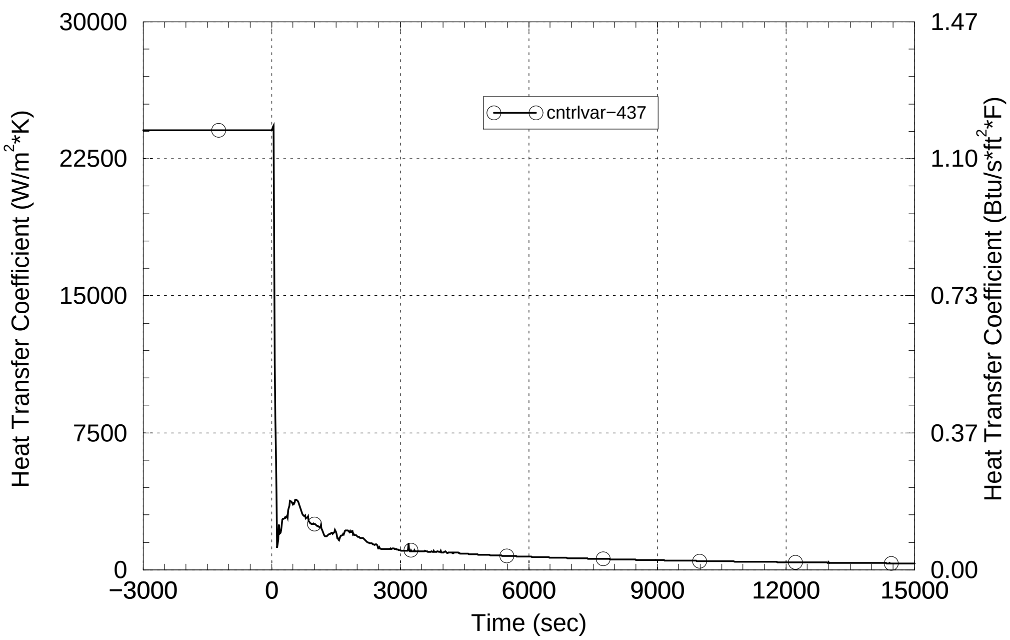


Figure 3.2.6-17 Downcomer Heat Transfer Coefficient – BV Case 097

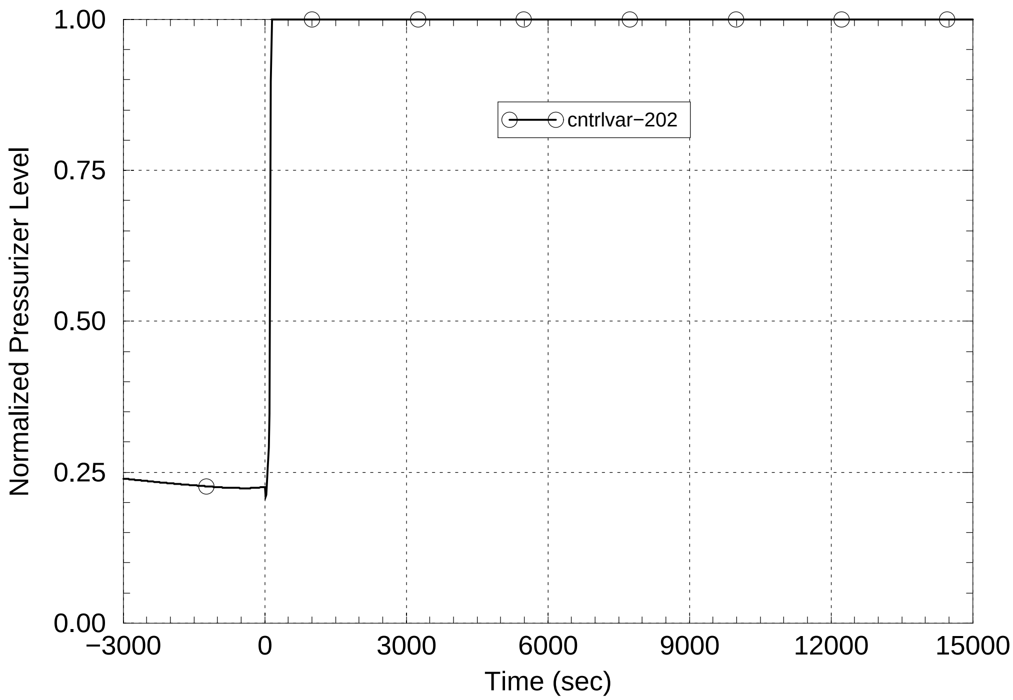


Figure 3.2.6-18 Pressurizer Water Level – BV Case 097

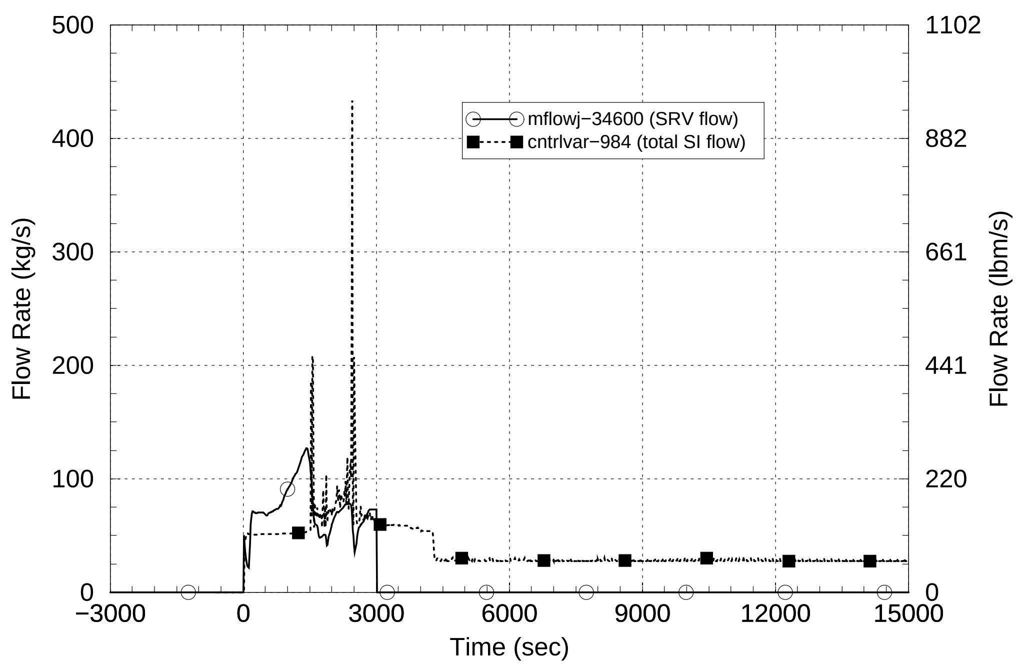


Figure 3.2.6-19 Break Flow and Total Safety Injection Flow – BV Case 097

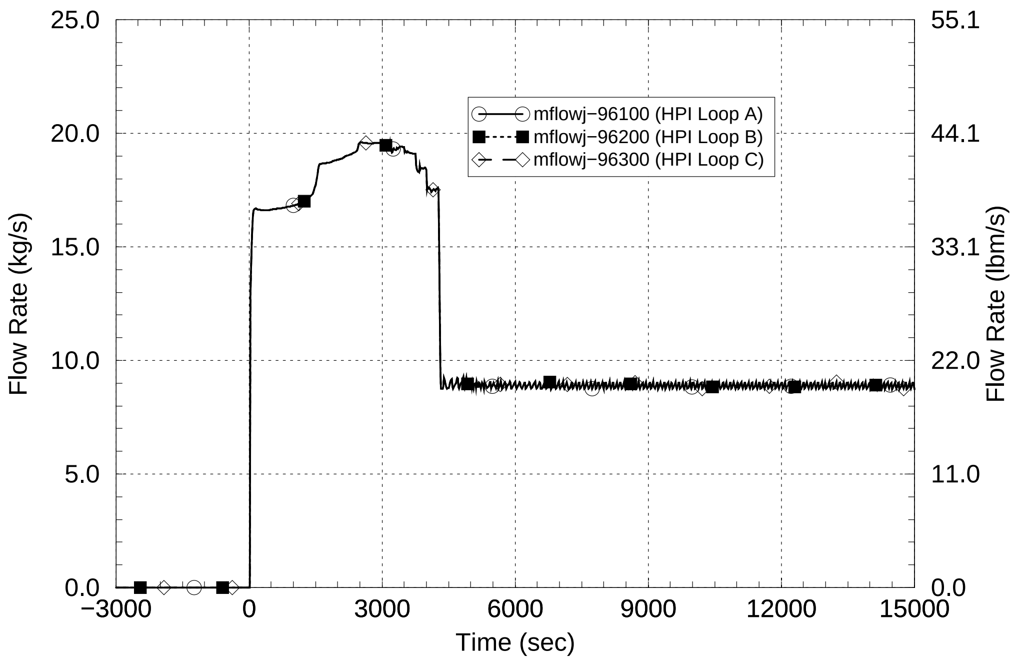


Figure 3.2.6-20 High Pressure Injection Flow Rate – BV Case 097

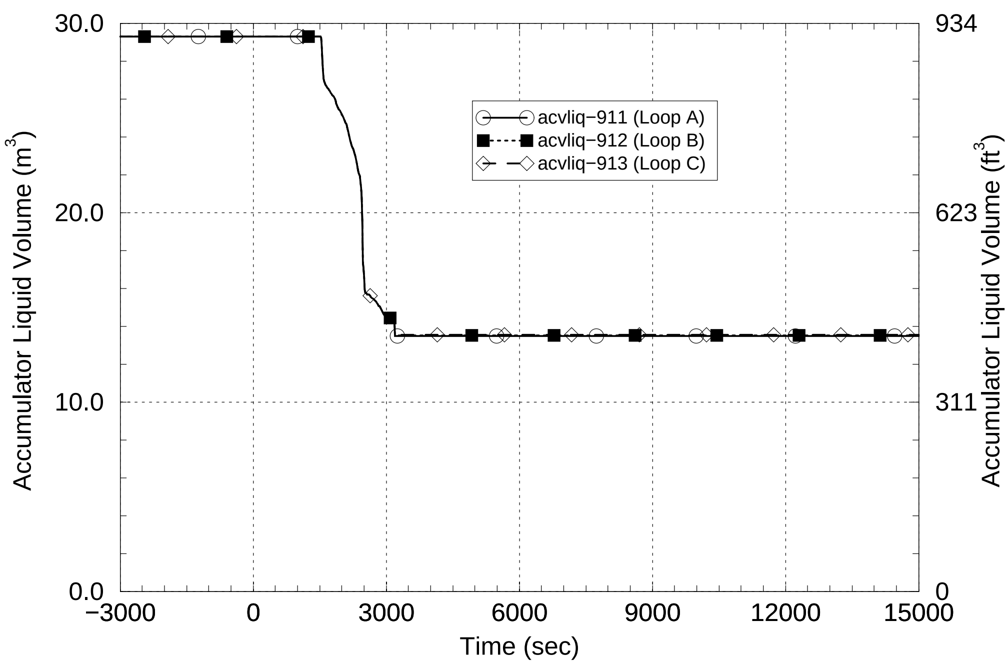


Figure 3.2.6-21 Accumulator Liquid Volume – BV Case 097

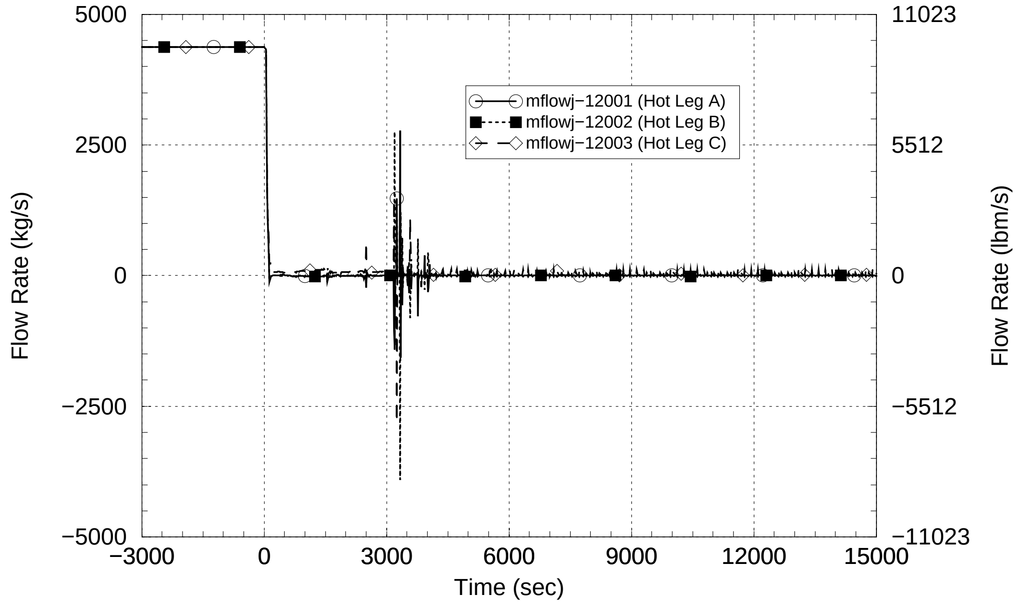


Figure 3.2.6-22   Hot Leg Mass Flow Rate – BV Case 097

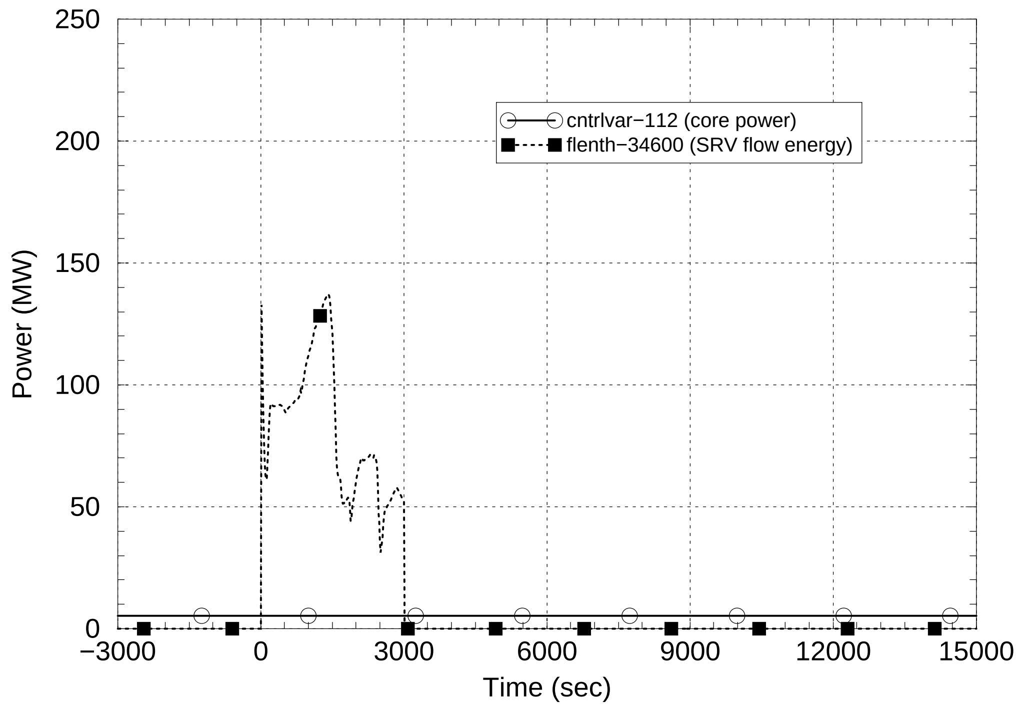


Figure 3.2.6-23   Core Power and Break Energy – BV Case 097

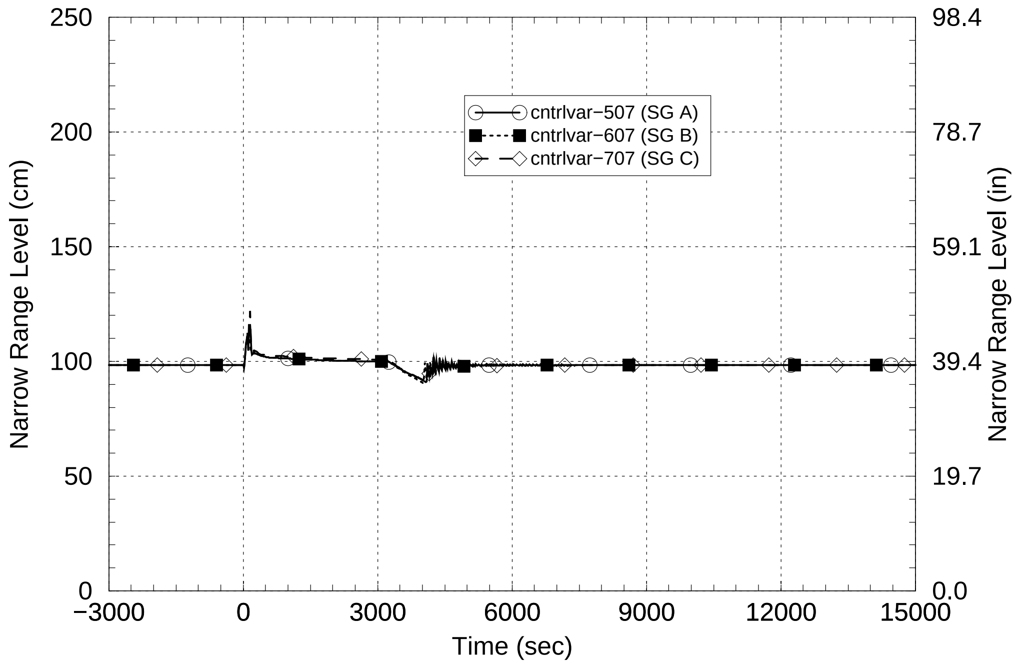


Figure 3.2.6-24   Steam Generator Narrow Range Water Level – BV Case 097

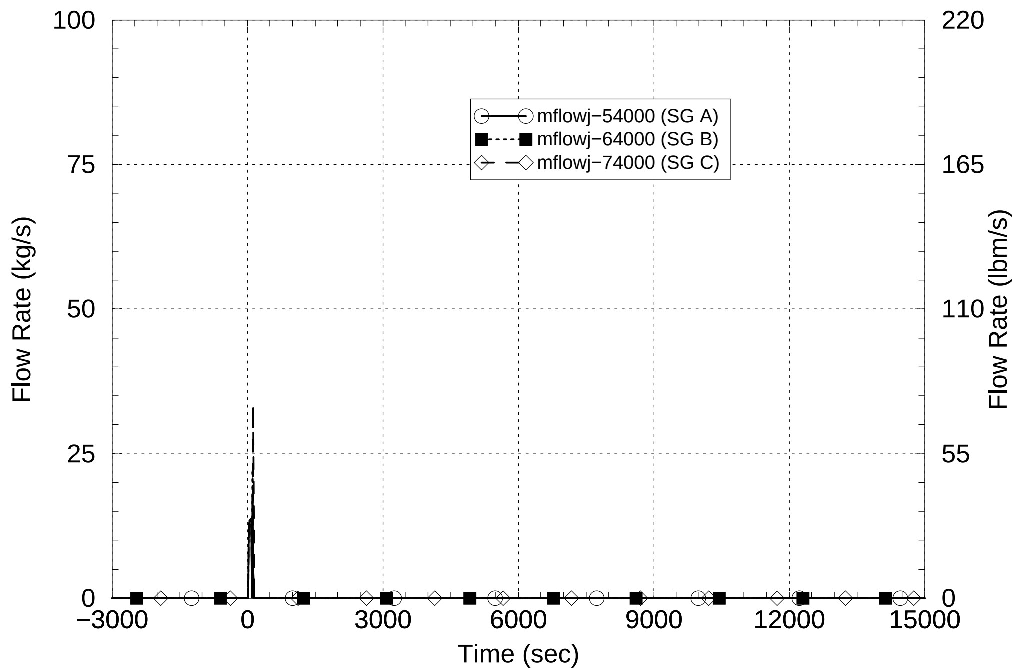


Figure 3.2.6-25   Auxiliary Feedwater Flow Rate – BV Case 097

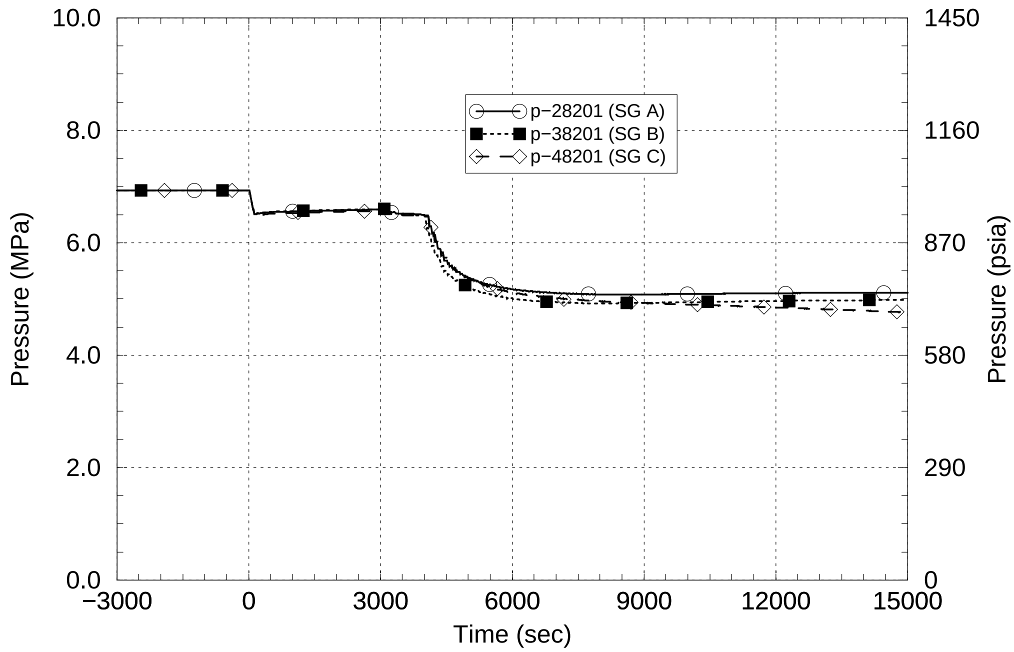


Figure 3.2.6-26 Steam Generator Pressure – BV Case 097

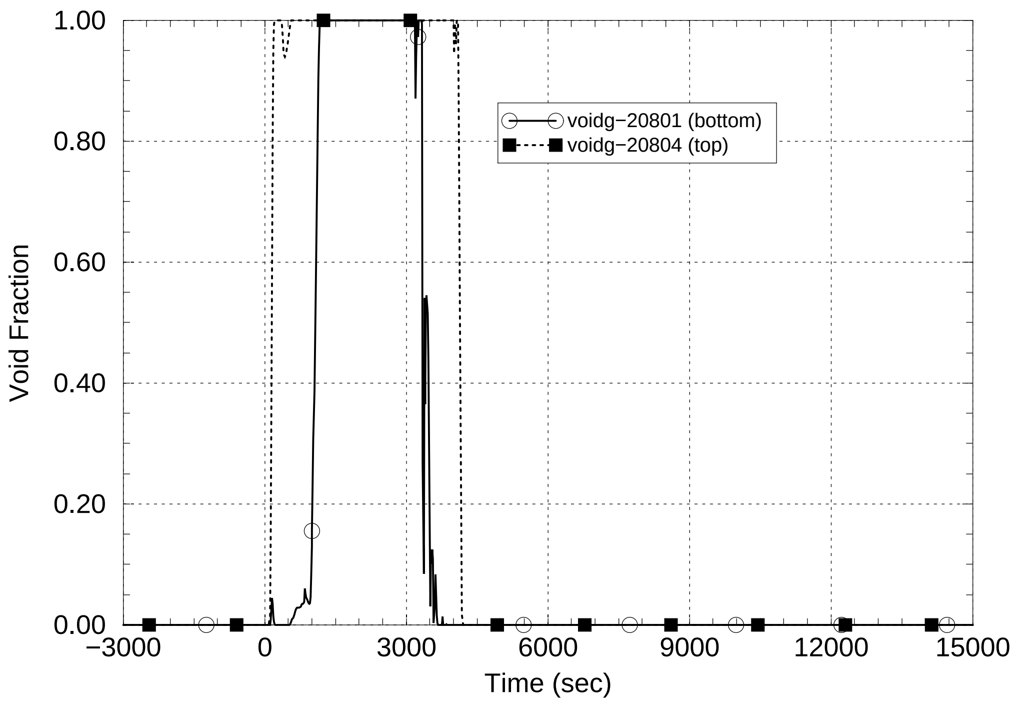


Figure 3.2.6-27 Void Fraction in Steam Generator Tubes – BV Case 097

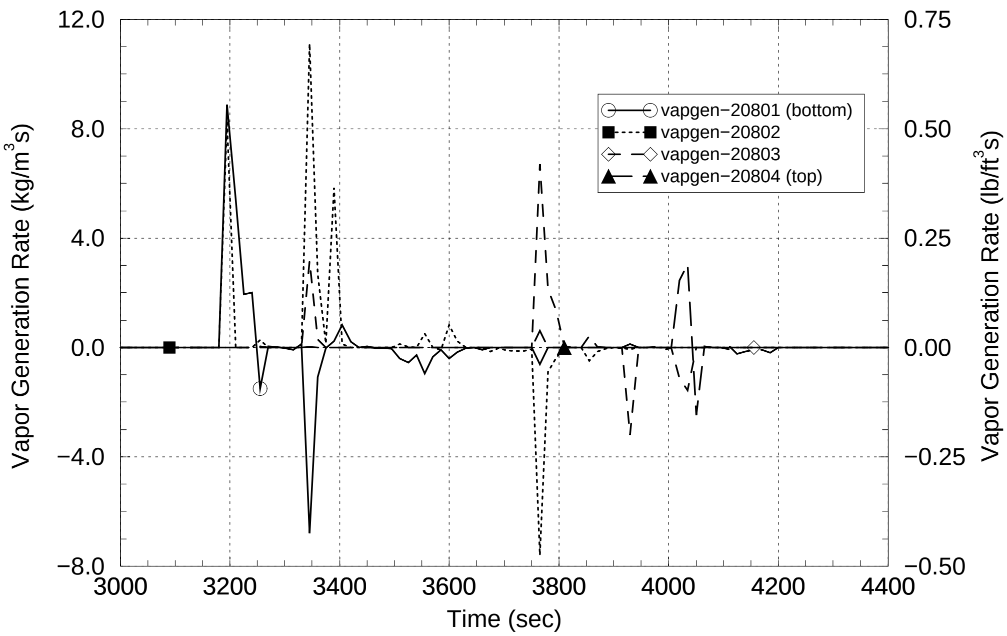


Figure 3.2.6-28 Vapor Generation Rate in Steam Generator Tubes – BV Case 097

3.2.6.3 Beaver Valley Stuck Open Pressurizer SRV Which Recloses From Hot Zero Power with Operator Action (BV Case 130)

This case is one stuck open pressurizer safety relief valve which recloses at 3,000 s from hot zero power with operator control of HHSI (10 minute delay). This case is identified as Beaver Valley Case 130 in Appendix B, Table B-1. This case has several differences versus the case 97 described above in Section 3.2.6.2. The major difference is that the operator controls HHSI. This is done by turning HHSI pumps on/off. The criteria for turning off a HHSI pump with normal containment conditions are as follows:

- Core exit subcooling > 23.9 K [43°F]
- SG NRL in any SG > 6%
- Pressurizer level > 5%
- Pressure stable or increasing; defined as pressure increased by 0.345 MPa [50 psi] over a 300 s period

After the conditions are met for HHSI control, a delay time is assumed before the first HHSI pump is stopped. In case 130 this time is ten minutes. After turning off the first HHSI pump, the operator waits five minutes and if the conditions are still met the second pump is stopped. Note that at any time if the above conditions are not met, both HHSI pumps are turned back on.

Other changes include the following:

- Momentum flux was turned off in both the axial and cross flow direction in the downcomer
- The downcomer wall was renodalized from 14 mesh points to 80 mesh points
- Running averages of the parameters of interest were computed
- Minor edit frequency was changed from one point every fifteen seconds to one point every second

The parameters of interest for fracture mechanics analysis; primary pressure, average downcomer fluid temperature and downcomer fluid-wall heat transfer coefficient are provided as Figures 3.2.6-29 through 3.2.6-31 respectively.

As a result of the stuck open valve, the primary system rapidly depressurizes as shown in Figure 3.2.6-29. In addition, since the valve is located at the top of the pressurizer, the pressurizer fills solid due to the primary system water flowing towards the stuck open valve. By 145 s, the pressurizer is filled solid, and remains filled for the duration of the transient as seen in Figure 3.2.6-32. Due to the loss of inventory, the primary system begins voiding in the reactor vessel upper head.

At approximately 20 s, a SIAS was generated. The SIAS results in actuation of both the HHSI, and LHSI. In addition, it also initiates a full feedwater isolation signal which trips both main feedwater pumps and closes the main feedwater and bypass feedwater regulation valves. Due to the SIAS as well as both main feedwater pumps being tripped, auxiliary feedwater is activated. Note that while LHSI is activated, there is no flow unless the primary pressure falls below the LHSI pump shutoff head.

A plot of pressurizer SRV flow versus total safety injection flow is provided as Figure 3.2.6-33. Total SI flow includes high pressure injection, low pressure injection, accumulators and charging/letdown. High pressure injection flow is shown in Figure 3.2.6-34. For about the first 1,500 s break flow is larger than safety injection flow. By 1,660 s the primary pressure has decreased to below the accumulator pressure, resulting in accumulator injection as shown in Figure 3.2.6-35. With this additional flow, the total SI is larger than the break flow. The primary pressure never drops to below the low pressure injection pump shutoff head, therefore, there is no low pressure injection for this case.

At approximately 72 s, the reactor coolant pumps were tripped due to an operator action. This causes the flow in the loops to decrease to near zero. Figure 3.2.6-36 presents the hot leg mass flow for all three loops at the exit of the vessel. After RCP trip and up until 3,000 s, the only loop with flow is the C loop, which has the pressurizer and stuck open valve. Upon the forced flow stopping (i.e., reactor coolant pumps tripped), the heat transfer coefficient drops quickly from an initial value of 24,230 $W/m^2{\cdot}K$ [1.185 $Btu/s{\cdot}ft^2{\cdot}°F$]. During the remainder of the transient, this drops gradually to 500 $W/m^2{\cdot}K$ [0.024 $Btu/s{\cdot}ft^2{\cdot}°F$], then increases to around 1,000 $W/m^2{\cdot}K$ [0.049 $Btu/s{\cdot}ft^2{\cdot}°F$].

Figure 3.2.6-37 shows the core power versus the energy lost through the stuck valve. As seen in this figure, the energy lost out of the valve when it is open is larger than the assumed core decay heat, thus heat is being removed from the system causing the temperature to decrease. Note that in this case power is held constant at 5.32 MW. The average downcomer fluid temperature is shown in Figure 3.2.6-30. By 3,000 s, the downcomer temperature has reached a value of 316 K [109°F].

Figure 3.2.6-38 shows the steam generator narrow range water level. Upon the SIAS being generated, the MFW is isolated. Since the MFW at hot zero power is very small (approximately 2 kg/s [4.4 lbm/s]), the isolation of MFW does not have a significant effect on steam generator water level. AFW is started, and begins controlling the generators to the setpoint of 33% NRL (120.7 cm [47.52 in]). Note that the hot zero power pre/post trip level setpoints are the same. Figure 3.2.6-39 shows the auxiliary feedwater flow which comes on initially to maintain steam generator water level. The steam generator secondary side pressure is shown in Figure 3.2.6-40.

At 3,000 s, the stuck open pressurizer SRV is closed. The high head injection pumps continue to supply cold water, and the primary system begins to repressurize. Note that up to this point, no operator actions have been taken to control primary system pressure or level. By 3,030 s, the primary pressure has increased to above the accumulator pressure, thus stopping accumulator flow. By 4,320 s, the SI flow has repressurized the primary to the pressurizer PORV opening setpoint and flow begins to leave the primary system.

During the initial part of the LOCA, the steam generator tubes voided as shown in Figure 3.2.6-41. Once the pressurizer SRV recloses the steam generator tubes begin to refill. During the refill time (3,020 to 4,120 s) there are condensation/vaporization effects. Figure 3.2.6-42 shows the vapor generation rate for the steam generator tubes (hot leg side). Note that positive values show vaporization while negative values show condensation. Figure 3.2.6-36 shows that the hot leg flow oscillations occur during this period of steam generator tube condensation/vaporization. It is seen in this period that the hot leg flow oscillations cause the downcomer fluid to become well mixed and the average downcomer temperature increases as seen in Figure 3.2.6-30.

By 3,561 s the system has met all of the conditions for stopping an HHSI pump. These conditions include: core exit subcooling greater than 23.9 K [43°F] (Figure 3.2.6-43), any steam generator NRL greater than 6% (Figure 3.2.6-38), pressurizer water level greater than 5% (Figure 3.2.6-32) and pressure stable or increasing (Figure 3.2.6-29). After waiting an additional ten minutes (as given in the case description), the operator is assumed to stop a single HHSI pump (at 4,161 s). After waiting five more minutes, the above conditions are still met so the second HHSI pump is stopped (at 4,461 s). Both HHSI pumps remain off for the remainder of the transient. By stopping the HHSI pumps, the primary pressure decreases significantly as shown in Figure 3.2.6-29. In addition, the lack of cold SI water causes the downcomer fluid temperature to gradually rise for the remainder of the transient.

As a consequence of the stuck open pressurizer safety relief valve, it is shown that the loss of inventory through the pressurizer SRV is capable of removing more than the assumed core decay heat at hot zero power. This leads to the downcomer fluid temperature decreasing to a value 316 K [109°F] at valve the reclosure time of 3,000 s. After the pressurizer SRV recloses, the primary pressure increases to the PORV setpoint of 16.2 MPa [2350 psia] by 4,300 s. After this time, the operator has taken control of the HHSI and the pressure decreases to near 4.13 MPa [600 psia] by 7,250 s. The pressure gradually decreases for the remainder of the transient. Once the pressurizer SRV recloses and the HHSI flow is controlled, the downcomer fluid temperature begins increasing for the remainder of the transient.

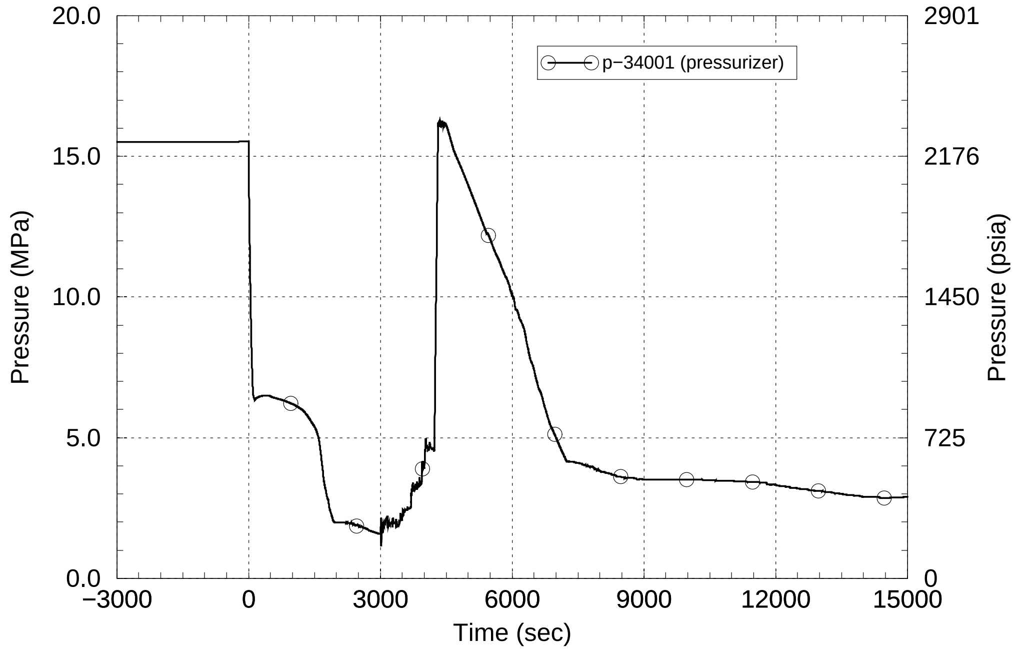


Figure 3.2.6-29 Primary System Pressure - BV Case 130

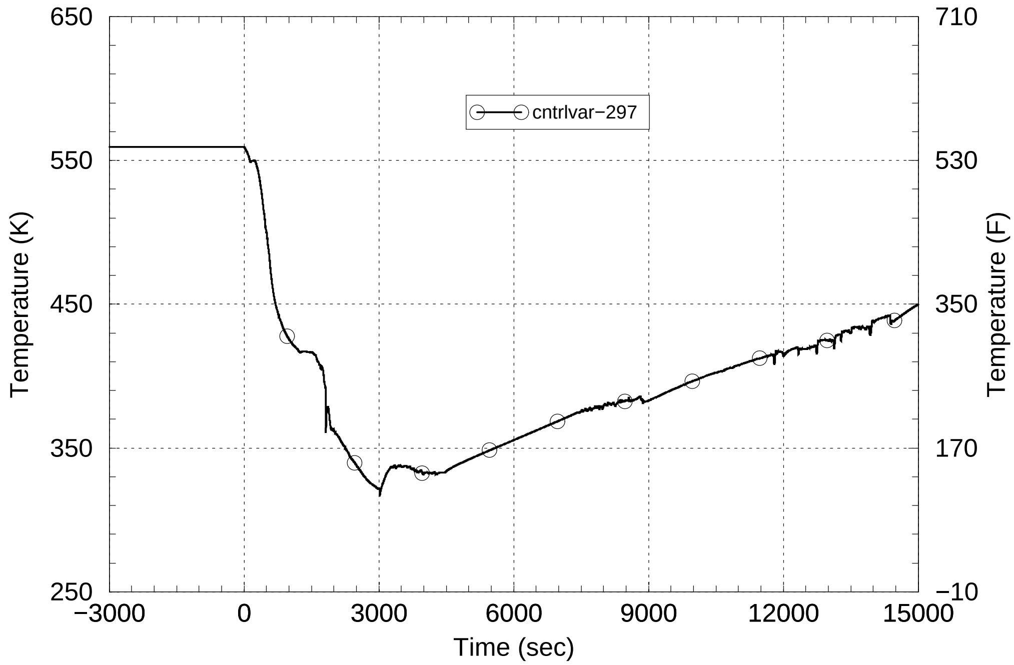


Figure 3.2.6-30 Average Downcomer Fluid Temperature - BV Case 130

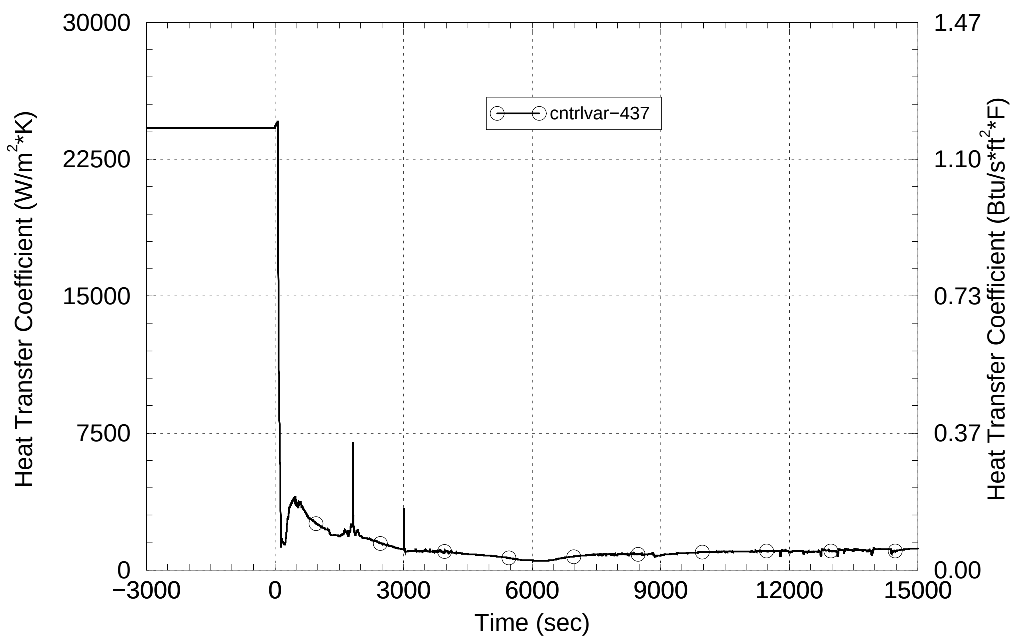


Figure 3.2.6-31 Downcomer Wall Heat Transfer Coefficient - BV Case 130

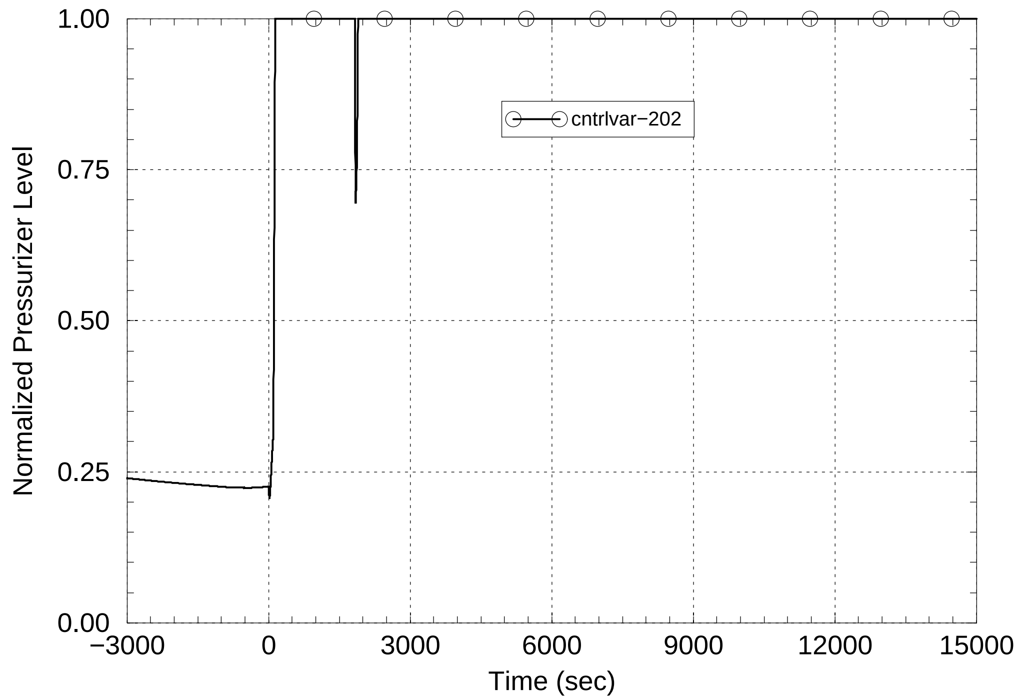


Figure 3.2.6-32 Pressurizer Water Level - BV Case 130

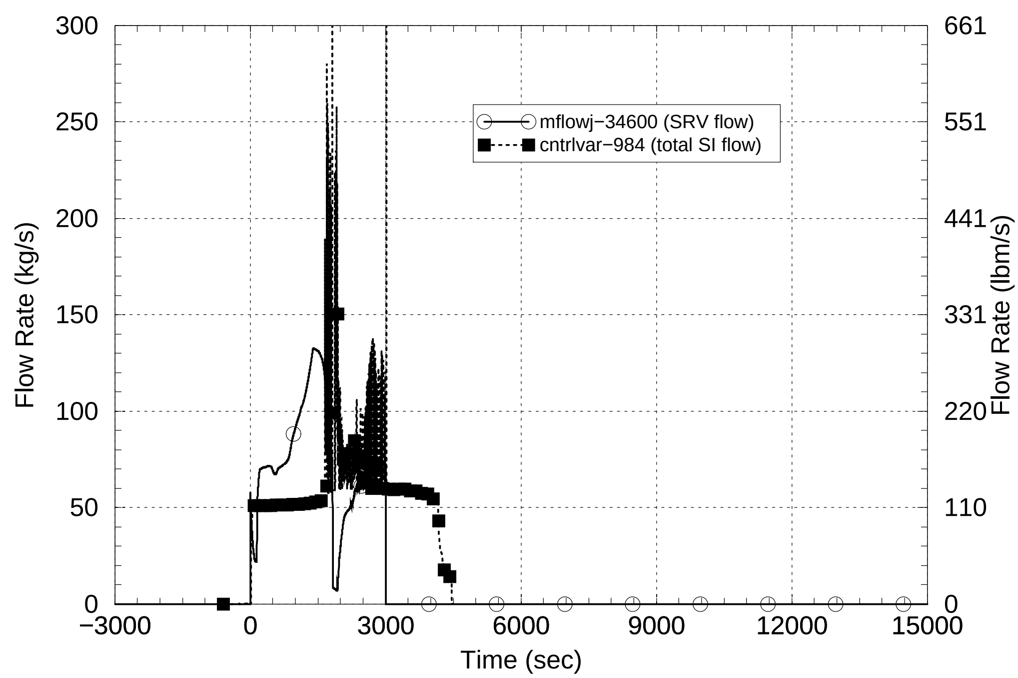


Figure 3.2.6-33 Break Flow and Total Safety Injection Flow - BV Case 130

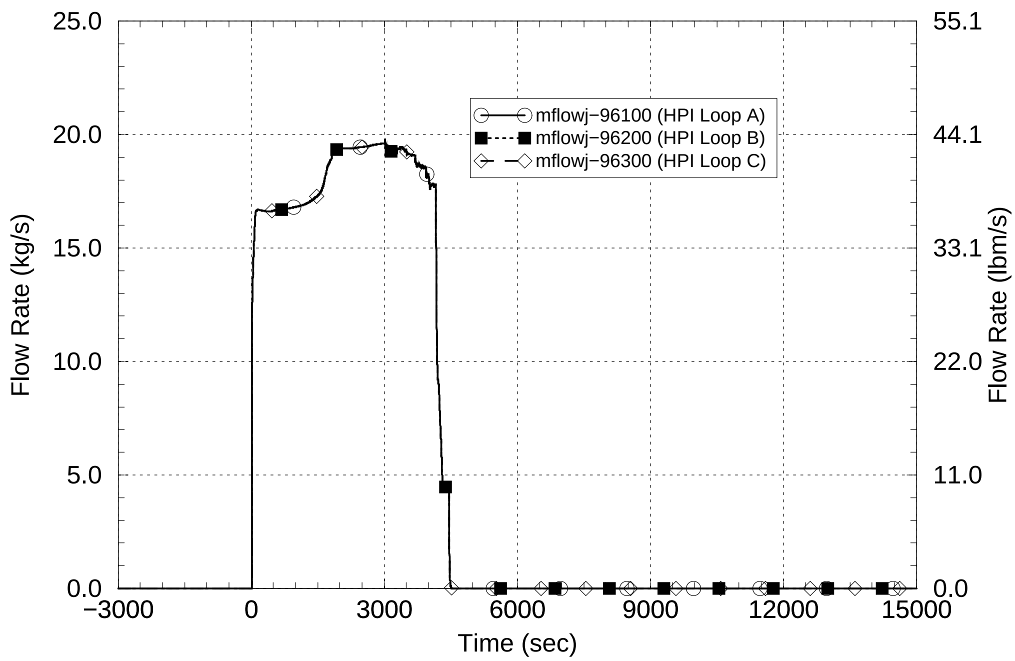


Figure 3.2.6-34 High Pressure Injection Flow Rate - BV Case 130

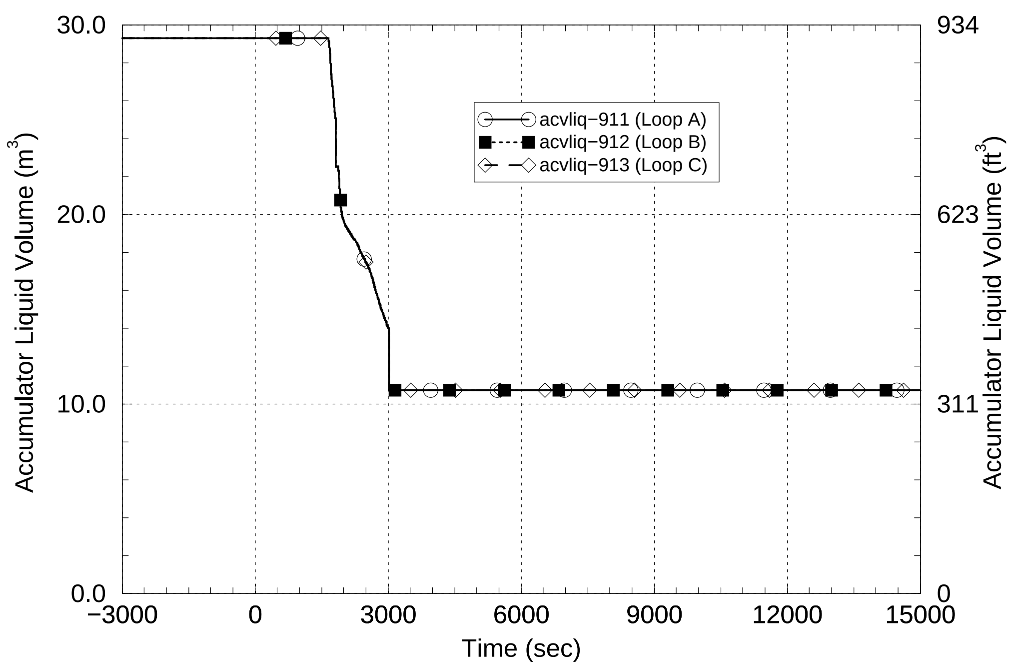


Figure 3.2.6-35 Accumulator Liquid Volume - BV Case 130

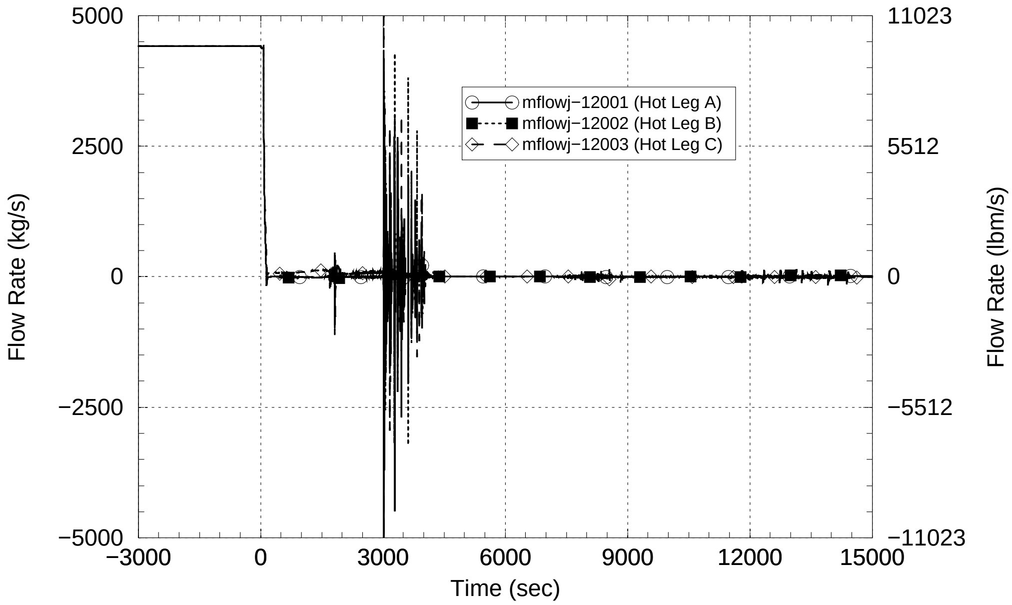


Figure 3.2.6-36 Hot Leg Mass Flow Rate - BV Case 130

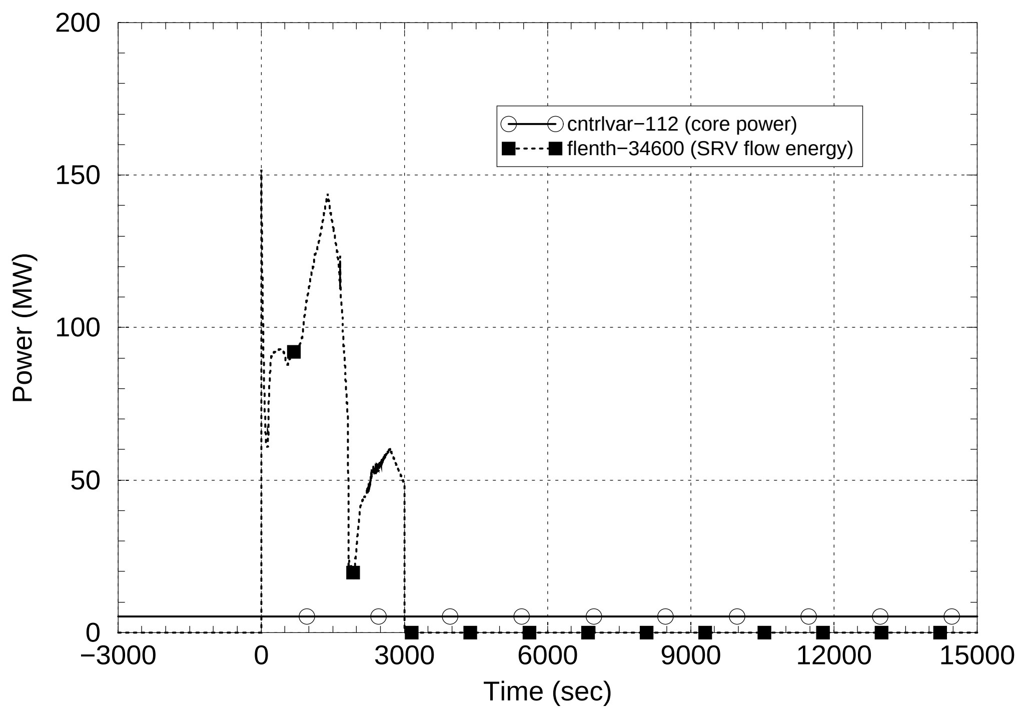


Figure 3.2.6-37 Core Power and Break Energy - BV Case 130

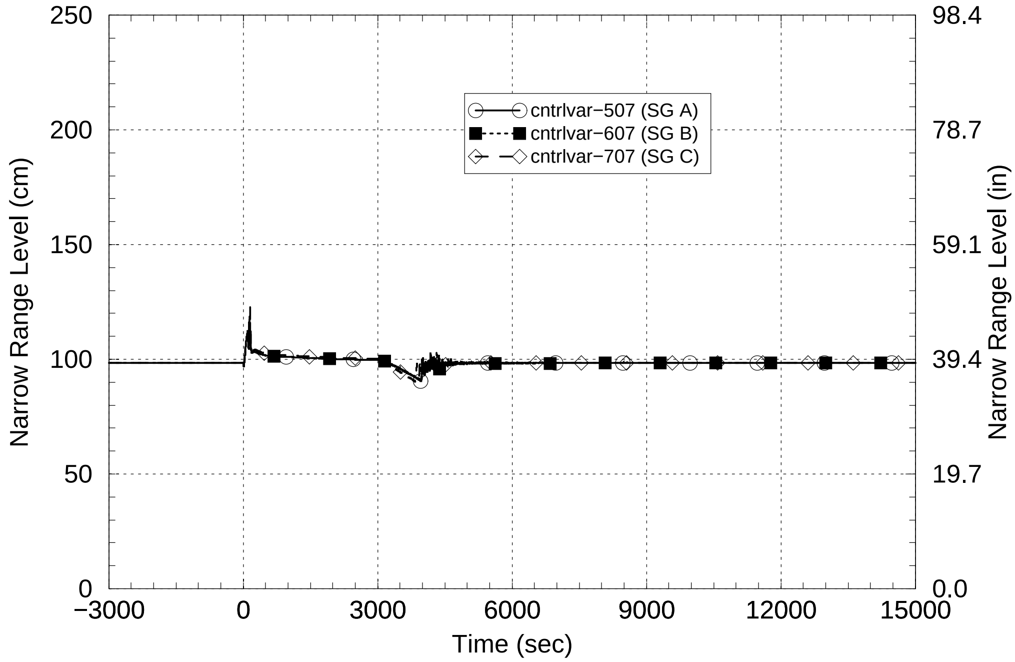


Figure 3.2.6-38   Steam Generator Narrow Range Water Level - BV Case 130

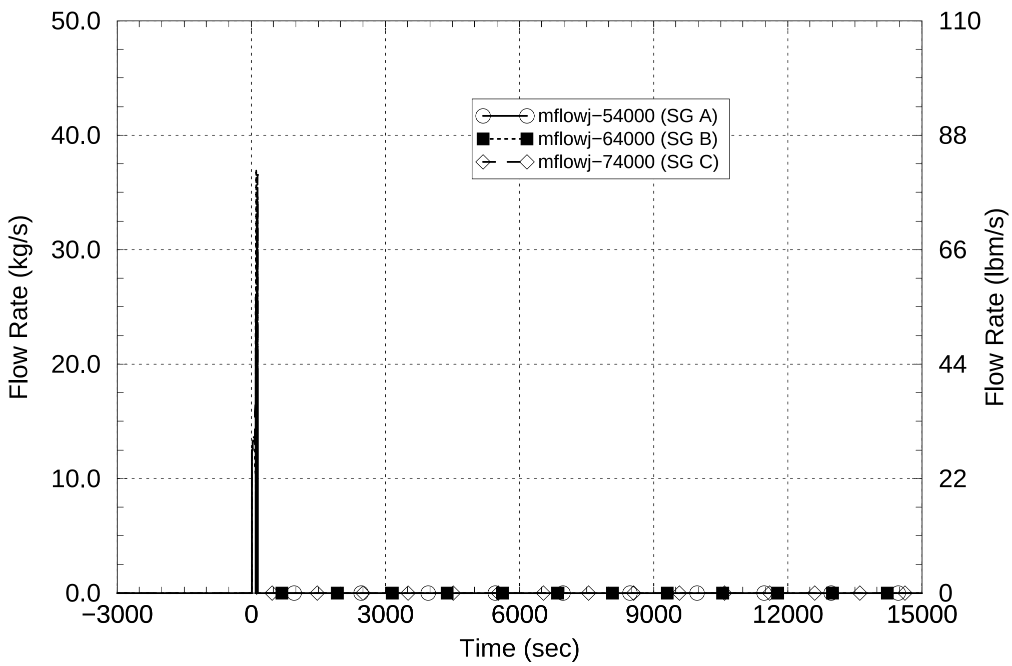


Figure 3.2.6-39   Auxiliary Feedwater Flow Rate - BV Case 130

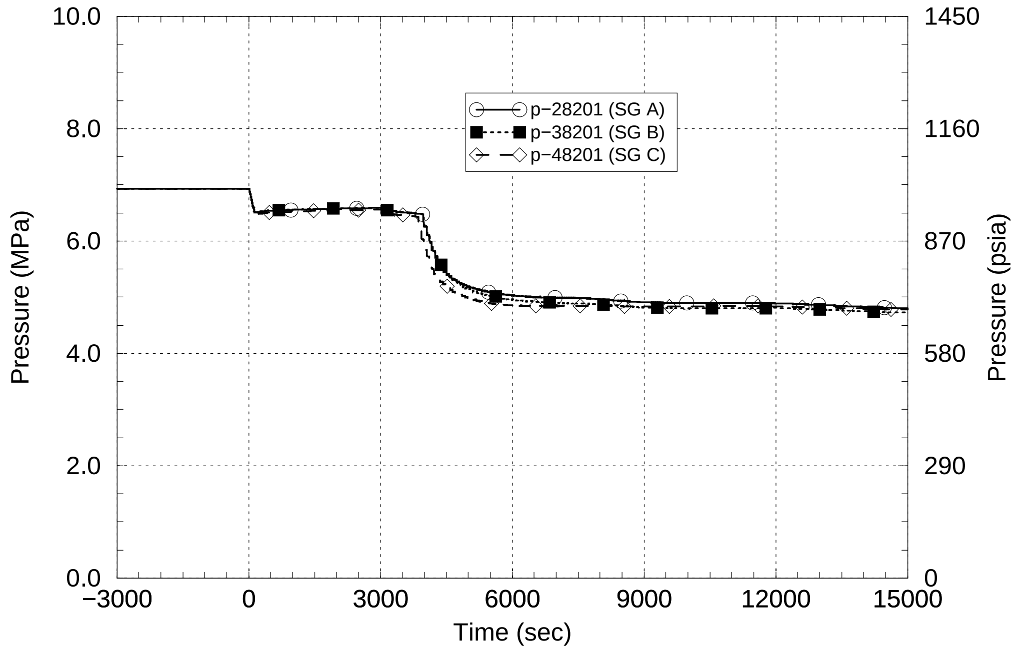


Figure 3.2.6-40 Steam Generator Pressure - BV Case 130

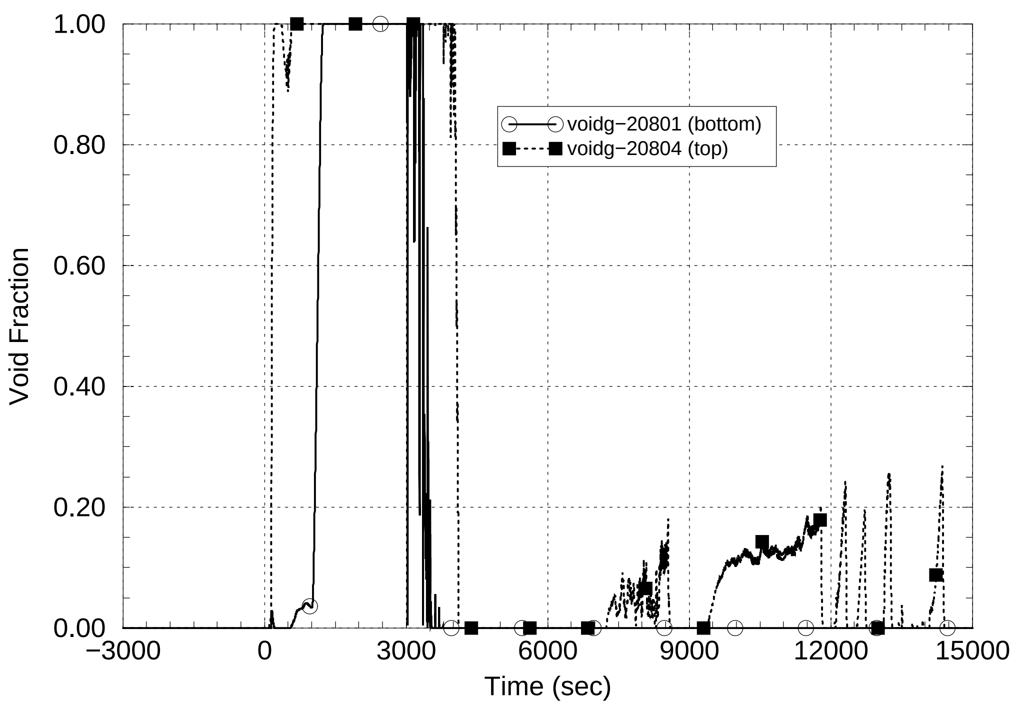


Figure 3.2.6-41 Void Fraction in Steam Generator Tubes - BV Case 130

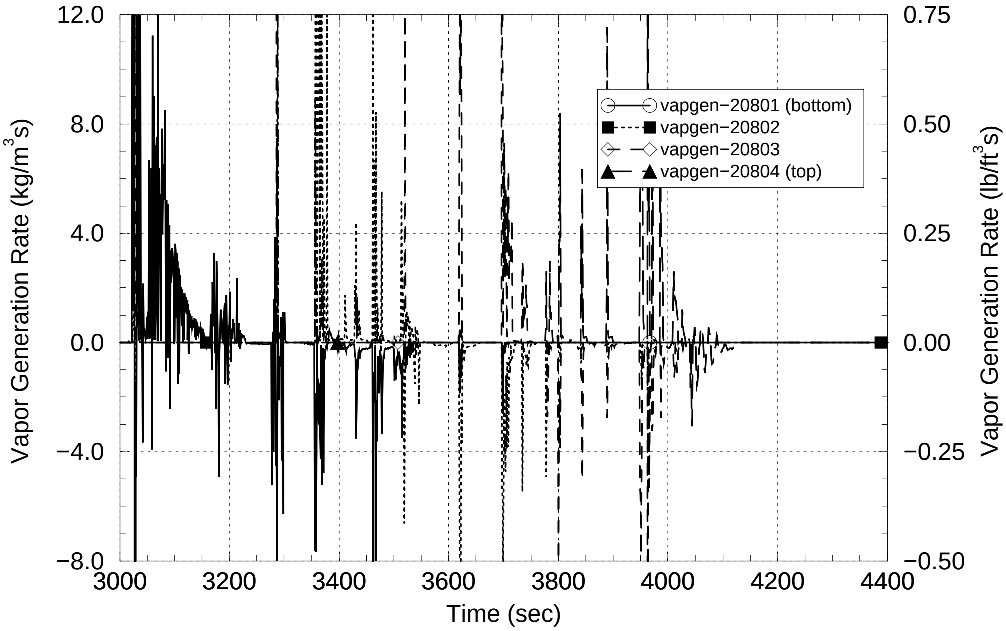


Figure 3.2.6-42 Vapor Generation Rate in Steam Generator Tubes - BV Case 130

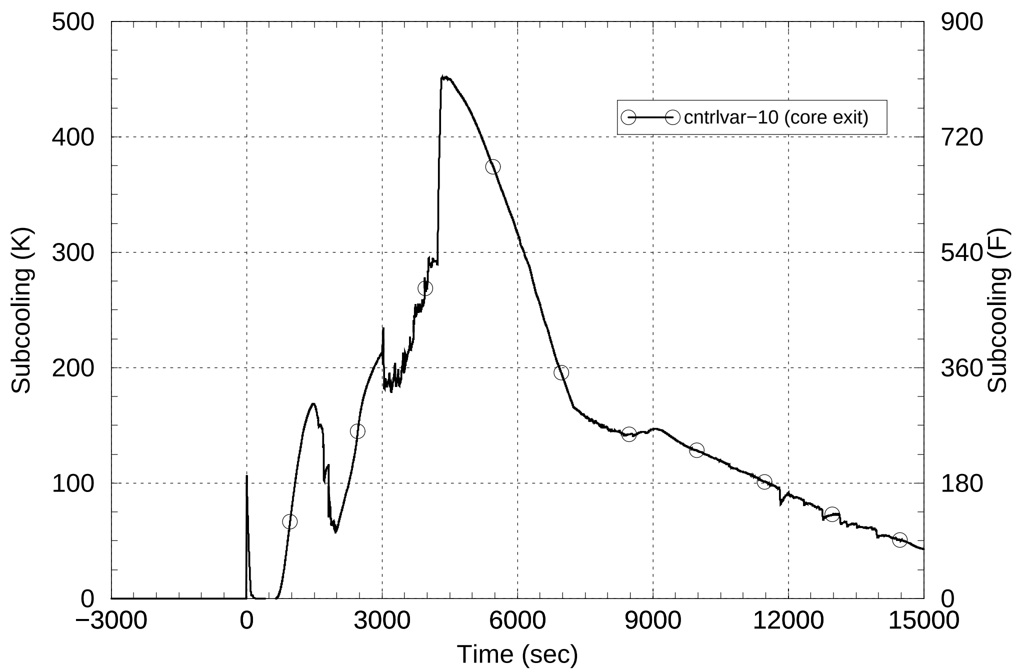


Figure 3.2.6-43 Core Exit Subcooling - BV Case 130

3.3 Palisades Transient Results of Dominant Sequences

Dominant sequences for the Palisades plant are segregated into four groups as follows. Group 1 comprises event sequences involving depressurization of the main steam system caused by stuck-open valves or steam line breaks. Group 2 comprises event sequences initiated by primary coolant system LOCAs with effective break sizes of 5.08-cm [2-in] diameter and smaller. Group 3 comprises event sequences initiated by a primary-system LOCAs with an effective break size of 10.16-cm [4-in] diameter. Group 4 comprises event sequences initiated by primary coolant system LOCAs with effective break sizes of 14.36-cm [5.656-in] diameter and larger. The thermal-hydraulic results for these four groups of event sequences are presented in the subsections below.

All RELAP5 transient case calculations were restarted from the end points of the steady state runs representing hot full power and hot zero power operation of the Palisades plant, as described in Section 2.3.2. All RELAP5 transient-case calculations were run for a period of 15,000 s following the occurrence of the sequence initiating event. On the accompanying plots, the data shown prior to time zero represents the calculated steady-state condition prior to the transient initiation.

3.3.1 Sequences with Depressurization of the Main Steam System Caused by Stuck-Open Valves or Steam Line Breaks

Four of the 12 Palisades PTS-risk-dominant event sequences involved stuck-open steam system valves or steam line breaks. These four sequences are described as follows:

Case 19 is an event initiated by a reactor trip and the spurious sticking-open of one of the two atmospheric dump valves (ADVs) on Steam Generator A (SG A) with the plant in hot zero power (HZP) operation. The operator is assumed not to isolate auxiliary feedwater (AFW) to the affected SG and not to throttle high pressure injection (HPI) flow.

Case 52 is an event initiated by a reactor trip and the spurious sticking-open of one ADV on SG A combined with a failure of both of the main steam isolation valves (MSIVs) to close with the plant in HZP operation. The operator is assumed not to isolate AFW to the affected SG and not to throttle HPI flow.

Case 54 is an event initiated by the double-ended rupture of the main steam line on SG A inside containment combined with a failure of both of the MSIVs to close with the plant in hot full power (HFP) operation. The operator is assumed not to isolate AFW to the affected SG and not to throttle HPI flow.

Case 55 is an event initiated by reactor and turbine trips and the spurious sticking-open of the two ADVs on SG A combined with aggravating hardware failures and operator actions with plant in HFP operation. Flow controller hardware failures and an operator action to start the second motor-driven AFW pump are assumed, resulting in the delivery of two-pump AFW flow to the affected steam generator. The operator is assumed throttle HPI flow if the reactor coolant system subcooling and pressurizer level requirements for doing so are satisfied.

The common features of the steam-system break sequences are RCS overcooling and depressurization caused by excessive SG heat removal, followed by RCS repressurization caused by the effects of safety injection and charging system flow. The results for the four event sequences in this group are described in the following subsections.

3.3.1.1 One Stuck-Open Atmospheric Dump Valve from Hot Zero Power Condition - Palisades Case 19

With the plant in hot zero power operation, this event starts with a reactor trip and the spurious sticking-open of one of the two ADVs on SG A. The operator is assumed not to isolate the AFW flow to the affected SG and not to throttle the HPI flow.

The following modeling changes were implemented to simulate this event sequence. A manual reactor trip was implemented at the beginning of the transient calculation. Unlike a reactor trip initiated from full power conditions, the ADVs are not demanded following a reactor trip from hot zero power conditions because the average primary system temperature is already below that to which the ADVs control. Therefore, for hot zero power conditions a stuck-open ADV represents a spurious failure assumed to occur at the time of the reactor trip. The RELAP5 ADV model (Valve 480 in Figure 2.3-3) represents a combination of the two ADVs on SG A. To represent a single ADV sticking open, the normalized flow area for this valve component was set to 0.5, providing an effective flow area of 0.0113 m^2 [0.1215 ft^2].

The RELAP5-calculated sequence of events for Case 19 is shown in Table 3.3-1. The RELAP5-calculated responses for the RCS pressure, average reactor vessel downcomer fluid temperature and average reactor vessel wall inside surface heat transfer coefficient for this case are shown in Figures 3.3.1-1, 3.3.1-2 and 3.3.1-3, respectively.

When the ADV sticks open, the secondary system pressures in both SGs rapidly decline, as shown in Figure 3.3.1-4. A MSIV closure signal is generated at 775 s as a result of the steam pressure falling below 3.447 MPa [500 psia]. A 5-second MSIV closure time was used in the model. After MSIV closure, the pressures in the two SGs diverged, with the unaffected SG B pressure rising moderately before falling again as a result of secondary-to-primary heat transfer.

Figure 3.3.1-5 shows the AFW flows to the two SGs. AFW flow to both SGs began early during the event sequence as a result of low SG level indications. AFW flow to affected SG A continued through the remainder of the event sequence as a result of a continued low-level condition; it is assumed that the operator does not intervene to isolate this flow. The loss of unaffected SG B fluid mass was stopped as a result of the MSIV closure and the AFW flow to SG B continued only until its level had been recovered into the normal range; afterward, the AFW flow to SG B stopped. Figure 3.3.1-6 shows the secondary mass responses for the two SGs.

The cooling afforded to the RCS fluid as a result of heat transfer from the RCS to the depressurizing SG steam systems resulted in a rapid RCS cooldown as shown in Figure 3.3.1-2. This cooling also caused the RCS fluid volume to shrink, which rapidly depressurized the RCS as shown in Figure 3.3.1-1.

The RCS depressurization led to a safety injection actuation signal at a pressure of 10.98 MPa [1593 psia], which results in the starting of the HPI and LPI pumps after a 27-second delay. The calculated HPI flow rate for Cold Leg A1 is shown in Figure 3.3.1-7; the total HPI flow rate is four times the flow shown in the figure. The flow delivered from the centrifugal pumps of the HPI system is a function of the cold leg pressure, with lower pressures resulting in higher HPI flow and with no HPI flow delivered whenever the RCS pressure exceeds the shutoff head of the HPI system (8.906 MPa [1291.7 psia]). The RCS pressure did not decline below the initial pressure of the safety injection tanks (SITs) or below shutoff head of the LPI system and therefore no SIT or LPI flow was delivered.

The RCS depressurization below 8.963 MPa [1300 psia] also led to operator tripping of one reactor coolant pump in each loop. Figure 3.3.1-8 shows the flow rates through the two Loop-1 cold legs at their connections with the reactor vessel. After the reactor coolant pump trip, the flow through the cold leg with the pump that remained operating increased, while the flow through the cold leg with the pump that was tripped reversed. The flow behavior in Loop 2 is similar to that in Loop 1. The remaining two reactor coolant pumps continued to operate throughout the event sequence because the low RCS fluid subcooling requirement (subcooling less than 13.9 K [25 ^{o}F]) for the operators to trip those pumps was not met. The effect of tripping the two reactor coolant pumps on the reactor vessel inside-wall heat transfer coefficient is evident in Figure 3.3.1-3.

The pressurizer level response is shown in Figure 3.3.1-9. The RCS fluid volume shrinkage initially caused by the cooldown is sufficient to completely drain the pressurizer. The HPI and net charging (i.e., charging flow less letdown) flows replenished the RCS fluid volume lost due to shrinkage and this resulted in the pressurizer refilling. Since the RCS is a closed system during this event sequence, the pressurizer refill is accompanied by a RCS repressurization to above the HPI system shutoff head and this terminates the HPI flow.

Figure 3.3-10 shows the charging and letdown flow responses (charging flow is injected equally into two cold legs, the figure shows the flow delivered to one cold leg). The letdown flow is isolated as a result of the safety injection actuation signal and the three charging pumps are of the positive-displacement type. One charging pump continues to deliver flow, regardless of the pressurizer level response. Although RCS cooldown and fluid shrinkage continue as a result of heat removal to the affected SG, the cooldown rate declines as RCS temperatures approach their eventual lower limit (the saturation temperature at atmospheric pressure). The RCS repressurizes because the charging volumetric flow rate exceeds the fluid volume shrinkage rate associated with the slower RCS cooldown rate. The charging flow eventually refills the pressurizer and raises the RCS pressure up to the 17.24-MPa [2500-psia] opening setpoint pressure of the pressurizer safety relief valves (SRVs). Afterward, the RCS pressure remains high, with the charging flow balanced by the pressurizer SRV flow.

The minimum average reactor vessel downcomer fluid temperature, 423 K [301 °F], is reached at the 15000-second end time of the calculation, when the RCS pressure was at the pressurizer SRV opening setpoint pressure.

Table 3.3-1 Comparison of Event Timing for Dominant Palisades Event Sequences - Group 1, Steam System Breaks

	Event Time (seconds)			
Event(s)	Case 19 - HZP, 1 Stuck-Open ADV on SG A	Case 52 - HZP, 1 Stuck-Open ADV on SG A, MSIVs Fail Open	Case 54 - HFP, MSLB on SG A, MSIVs Fail Open	Case 55 - HFP, 2 Stuck-Open ADVs on SG A, AFW overfeed
Manual reactor trip (results in a turbine trip for the HFP case)	0	0	N/A	0
Double-ended guillotine rupture of the SG A steam line, downstream of the flow restrictor and inside the containment	N/A	N/A	0	N/A
One ADV on the SG A steam line fails open	0	0	N/A	N/A
Two ADVs on the SG A steam line fail open	N/A	N/A	N/A	0
Containment high pressure signal (results in reactor and turbine trips and tripping of all four reactor coolant pumps)	N/A	N/A	7	N/A
Safety injection signal	564	564	21	256
ECCS available	592	591	48	283
MSIV closure signal	775	775	12	584
MSIVs fully closed	780	N/A	N/A	589
Pressurizer level reaches zero	1065	1050	30	450
One reactor coolant pump tripped in each coolant loop	1248	1301	N/A	601
HPI flow begins	1440	1500	48	615
Pressurizer level reaches 100%	4665	4650	6165	4320
Steam Line A begins to fill with water, AFW flow terminated to SG A	N/A	N/A	N/A	4332

Event(s)	Event Time (seconds)			
	Case 19 - HZP, 1 Stuck-Open ADV on SG A	Case 52 - HZP, 1 Stuck-Open ADV on SG A, MSIVs Fail Open	Case 54 - HFP, MSLB on SG A, MSIVs Fail Open	Case 55 - HFP, 2 Stuck-Open ADVs on SG A, AFW overfeed
RCS pressure exceeds pressurizer SRV opening setpoint pressure	7770	9210	11265	4830
Calculation terminated	15000	15000	15000	15000
Note: N/A indicates this event is not applicable for the event sequence.				

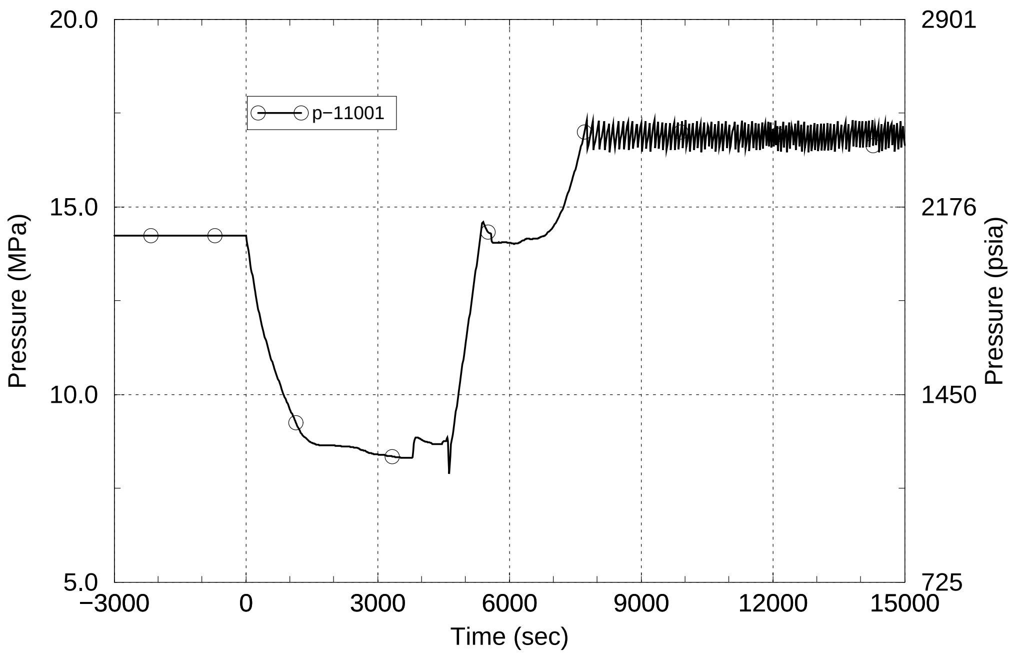


Figure 3.3.1-1 Reactor Coolant System Pressure - Palisades Case 19

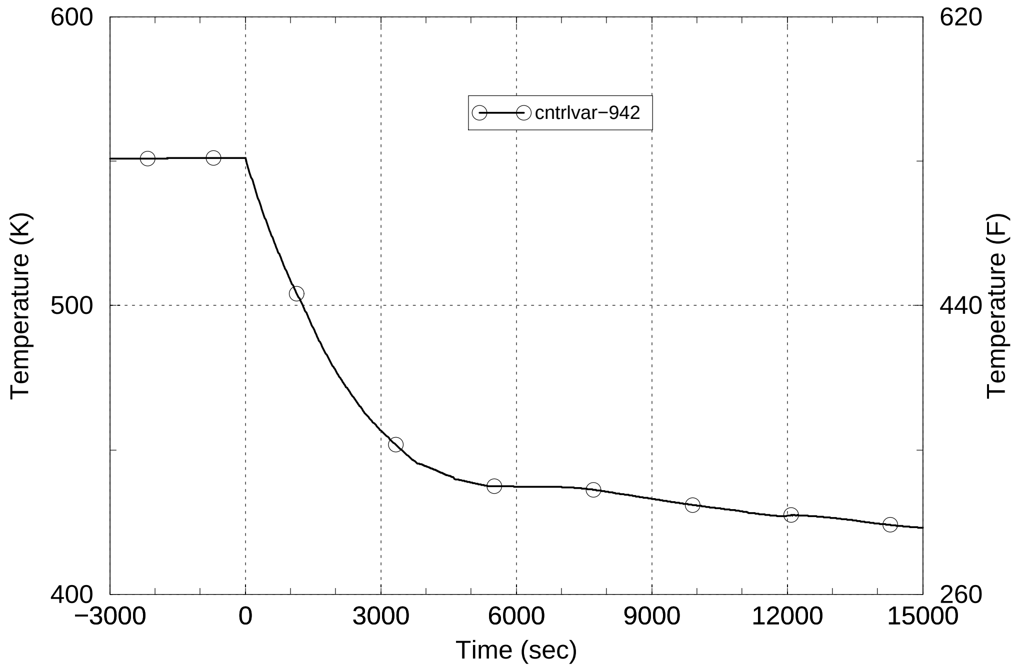


Figure 3.3.1-2 Average Reactor Vessel Downcomer Fluid Temperature - Palisades Case 19

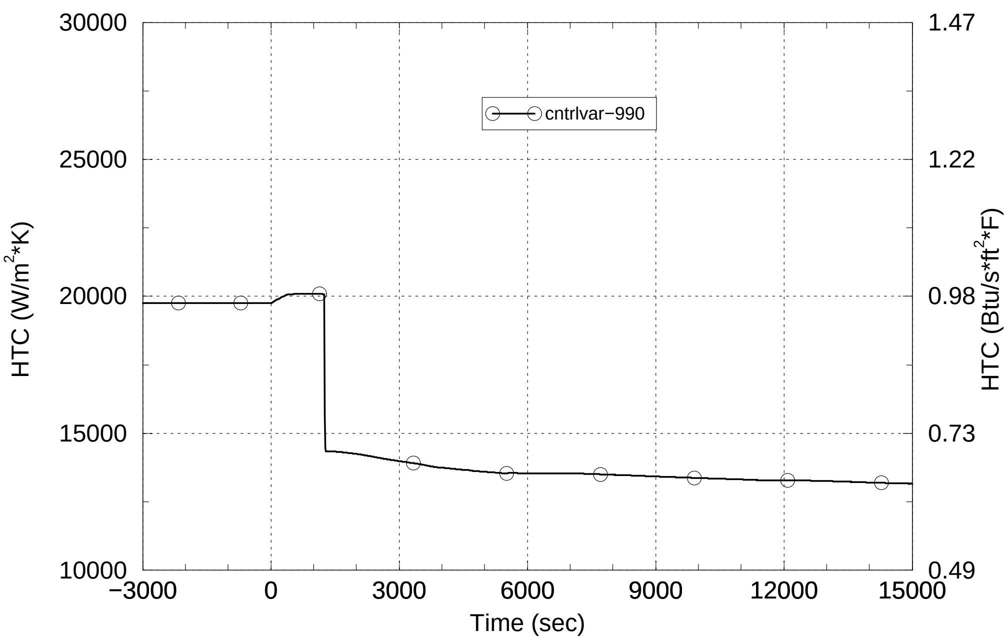


Figure 3.3.1-3 Average Reactor Vessel Inner-Wall Heat Transfer Coefficient - Palisades Case 19

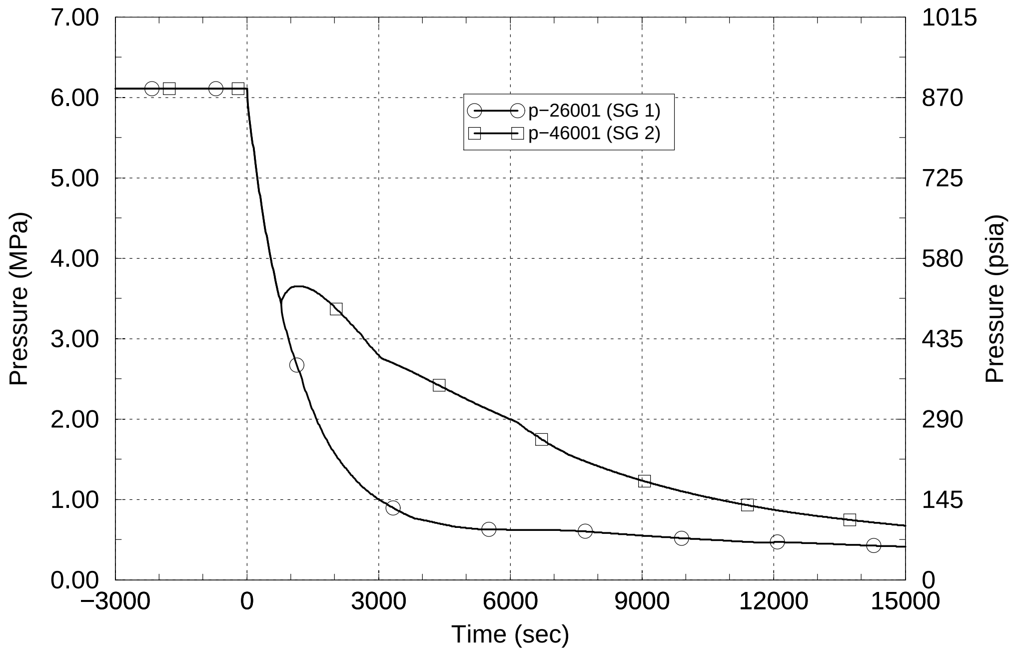


Figure 3.3.1-4 Steam Generator Pressures - Palisades Case 19

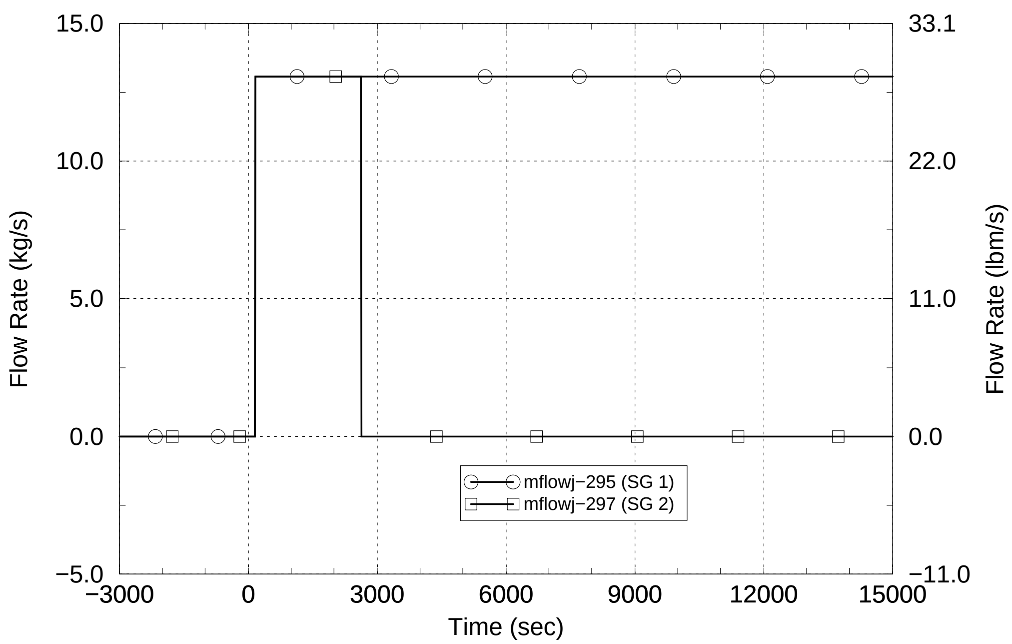


Figure 3.3.1-5 Auxiliary Feedwater Flows - Palisades Case 19

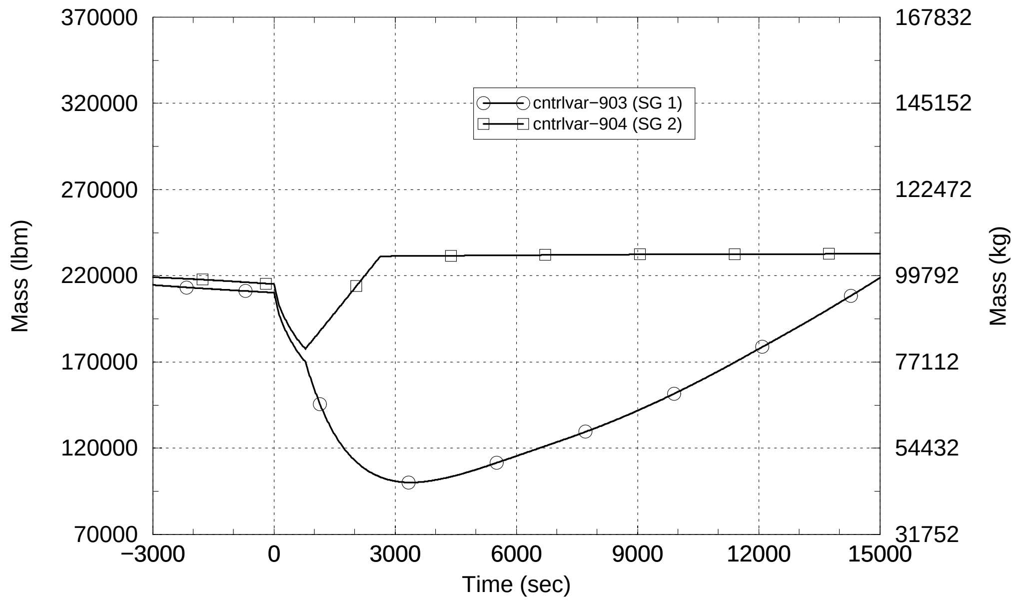


Figure 3.3.1-6 Steam Generator Secondary Fluid Masses - Palisades Case 19

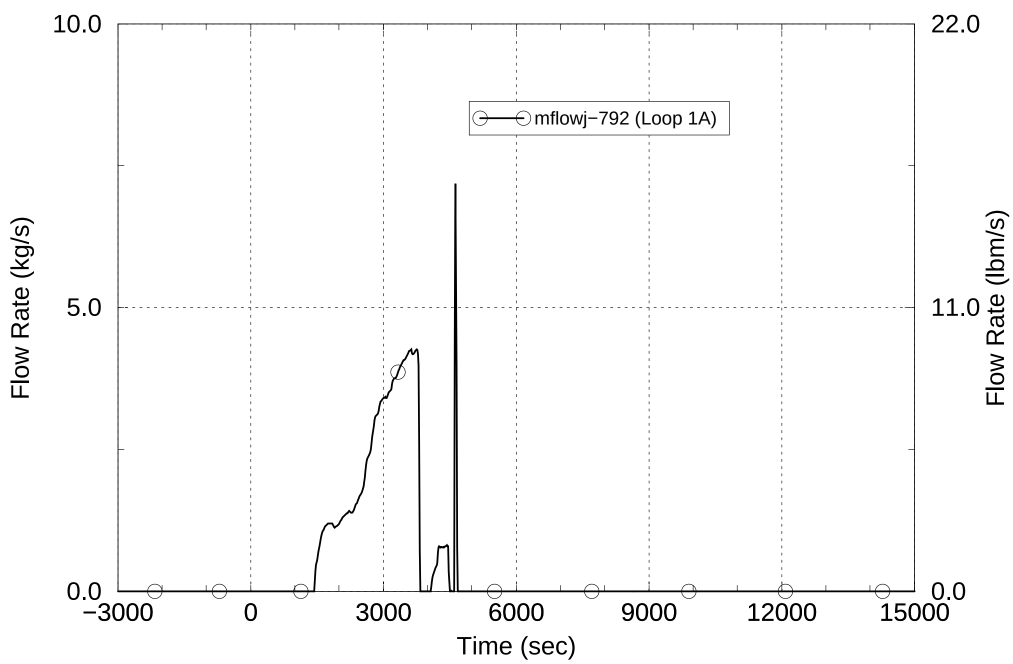


Figure 3.3.1-7 Loop A1 High Pressure Injection Flow - Palisades Case 19

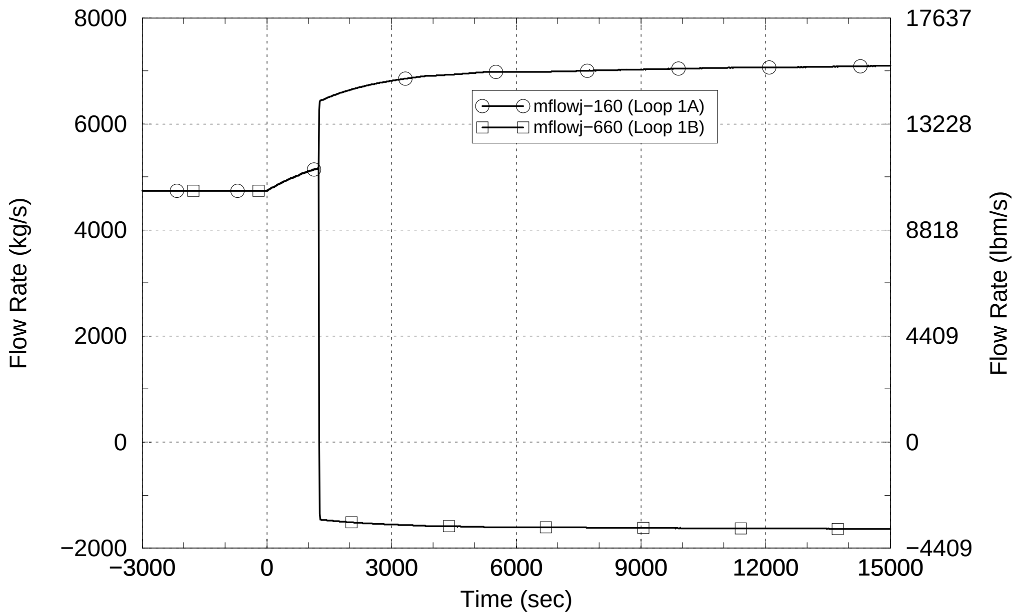


Figure 3.3.1-8 Loop 1 Cold Leg Flows - Palisades Case 19

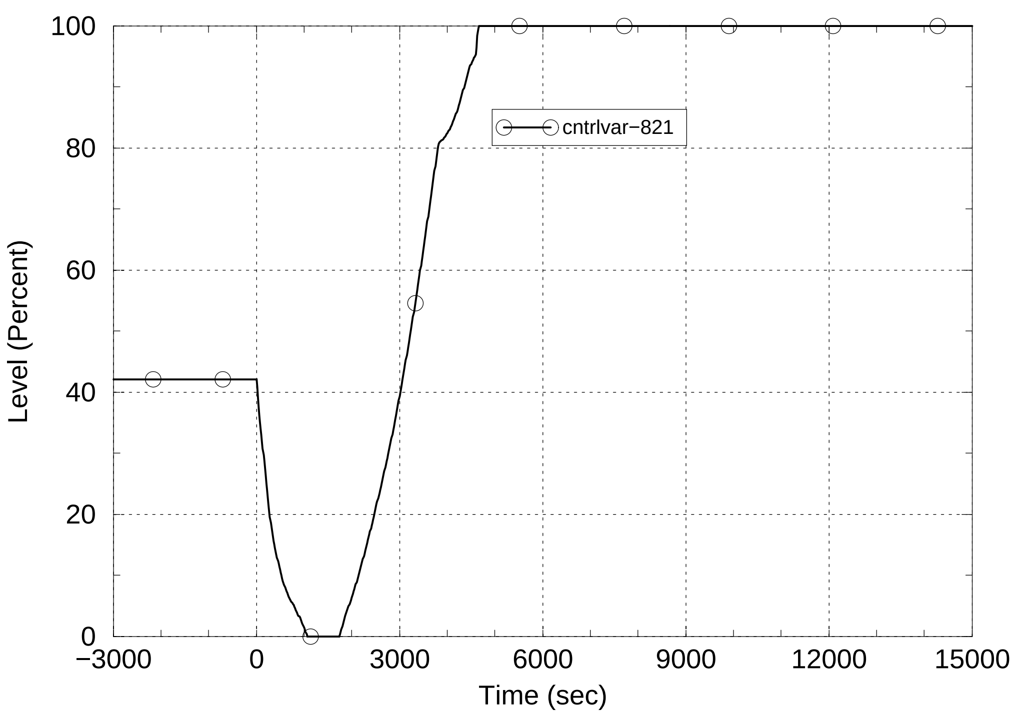


Figure 3.3.1-9 Pressurizer Level - Palisades Case 19

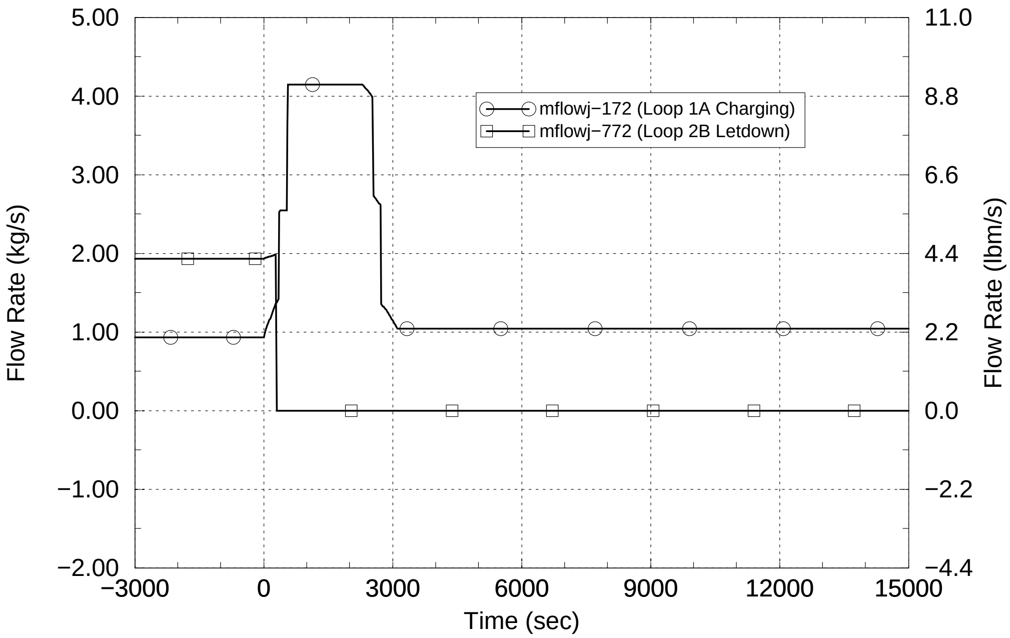


Figure 3.3.1-10   Charging and Letdown Flows - Palisades Case 19

3.3.1.2   One Stuck-Open Atmospheric Dump Valve and Failure of Both MSIVs to Close from Hot Zero Power Condition - Palisades Case 52

With the plant in hot zero power operation, this event starts with a reactor trip and the spurious sticking-open of one of the two ADVs on SG A. The MSIVs on both steam lines fail to close, resulting in a symmetric blowdown of the two SGs. The operator is assumed not to isolate the AFW flow to either SG and not to throttle the HPI flow.

The following modeling changes were implemented to simulate this event sequence. A manual reactor trip was implemented at the beginning of the transient calculation. Unlike a reactor trip initiated from full power conditions, the ADVs are not demanded following a reactor trip from hot zero power conditions because the average primary system temperature is already below that to which the ADVs control. Therefore, for hot zero power conditions a stuck-open ADV represents a spurious failure assumed to occur at the time of the reactor trip. The RELAP5 ADV model (Valve 480 in Figure 2.3-3) represents a combination of the two ADVs on SG A. To represent a single ADV sticking open, the normalized flow area for this valve component was set to 0.5, providing an effective flow area of 0.0113 m^2 [0.1215 ft^2]. The control logic of the model was modified to prevent the closure of the MSIVs (which are represented by Valves 811 and 831 in Figure 2.3-3).

The RELAP5-calculated sequence of events for Case 52 is shown in Table 3.3-1. The RELAP5-calculated responses for the RCS pressure, average reactor vessel downcomer fluid temperature and average reactor vessel wall inside surface heat transfer coefficient for this case are shown in Figures 3.3.1-11, 3.3.1-12 and 3.3.1-13, respectively.

When the ADV sticks open, the secondary system pressures in both SGs rapidly decline, as shown in Figure 3.3.1-14. A MSIV closure signal is generated at 775 s as a result of the steam pressure falling below 3.447 MPa [500 psia], but in this event sequence the two MSIVs are assumed to fail open, resulting in a symmetric blowdown of the two SGs throughout the transient period.

Figure 3.3.1-15 shows the AFW flows to the two SGs. AFW flow to both SGs began early during the event sequence as a result of low SG level indications. As the SG secondary pressures fell, the flow through the failed-open SG A ADV eventually became smaller than the AFW flow and the AFW flow replenished the SG secondary inventories that had been lost. Figure 3.3.1-16 shows the secondary fluid mass responses for the two SGs. AFW flow to both steam generators was throttled when the SG inventories and levels had recovered. Afterward, AFW flow to both SGs was throttled by the automatic controllers to maintain the SG levels within their normal range.

The cooling afforded to the RCS fluid as a result of heat transfer from the RCS to the depressurizing SG steam systems resulted in a rapid RCS cooldown as shown in Figure 3.3.1-12. This cooling also caused the RCS fluid volume to shrink, which rapidly depressurized the RCS as shown in Figure 3.3.1-11.

The RCS depressurization led to a safety injection actuation signal at a pressure of 10.98 MPa [1593 psia], which results in the starting of the HPI and LPI pumps after a 27-second delay. The calculated HPI flow rate for Cold Leg A1 is shown in Figure 3.3.1-17; the total HPI flow rate is four times the flow shown in the figure. The flow delivered from the centrifugal pumps of the HPI system is a function of the cold leg pressure, with lower pressures resulting in higher HPI flow and with no HPI flow delivered whenever the RCS pressure exceeds the shutoff head of the HPI system (8.906 MPa [1291.7 psia]). The RCS pressure did not decline below the initial pressure of the safety injection tanks (SITs) or below shutoff head of the LPI system and therefore no SIT or LPI flow was delivered.

The RCS depressurization below 8.963 MPa [1300 psia] also led to operator tripping of one reactor coolant pump in each loop. Figure 3.3.1-18 shows the flow rates through the two Loop-1 cold legs at their connections with the reactor vessel. After the reactor coolant pump trip, the flow through the cold leg with the pump that remained operating increased, while the flow through the cold leg with the pump that was tripped reversed. The flow behavior in Loop 2 is similar to that in Loop 1. The remaining two reactor coolant pumps continued to operate throughout the event sequence because the low RCS fluid subcooling requirement (subcooling less than 13.9 K [25°F]) for the operators to trip those pumps was not met. The effect of tripping the two reactor coolant pumps on the reactor vessel inside-wall heat transfer coefficient is evident in Figure 3.3.1-13.

The pressurizer level response is shown in Figure 3.3.1-19. The RCS fluid volume shrinkage initially caused by the cooldown is sufficient to completely drain the pressurizer. The HPI and net charging (i.e., charging flow less letdown) flows replenished the RCS fluid volume lost due to shrinkage and this resulted in the pressurizer refilling. Since the RCS is a closed system during this event sequence, the pressurizer refill is accompanied by a RCS repressurization to above the HPI system shutoff head and this terminates the HPI flow.

Figure 3.3.1-20 shows the charging and letdown flow responses (charging flow is injected equally into two cold legs, the figure shows the flow delivered to one cold leg). The letdown flow is isolated as a result of the safety injection actuation signal and the three charging pumps are of the positive-displacement type. One charging pump continues to deliver flow, regardless of the pressurizer level response. Although RCS cooldown and fluid shrinkage continue as a result of heat removal to the affected SG, the cooldown rate declines as RCS temperatures approach their eventual lower limit (the saturation temperature at atmospheric pressure). The RCS repressurizes because the charging volumetric flow rate exceeds the fluid volume shrinkage rate associated with the slower RCS cooldown rate. The charging flow eventually refills the pressurizer and raises the RCS pressure up to the 17.24-MPa [2500-psia] opening setpoint pressure of the pressurizer safety relief valves (SRVs). Afterward, the RCS pressure remains high, with the charging flow balanced by the pressurizer SRV flow.

The minimum average reactor vessel downcomer fluid temperature, 425 K [305°F], is reached at the 15000-second end time of the calculation, when the RCS pressure was at the pressurizer SRV opening setpoint pressure.

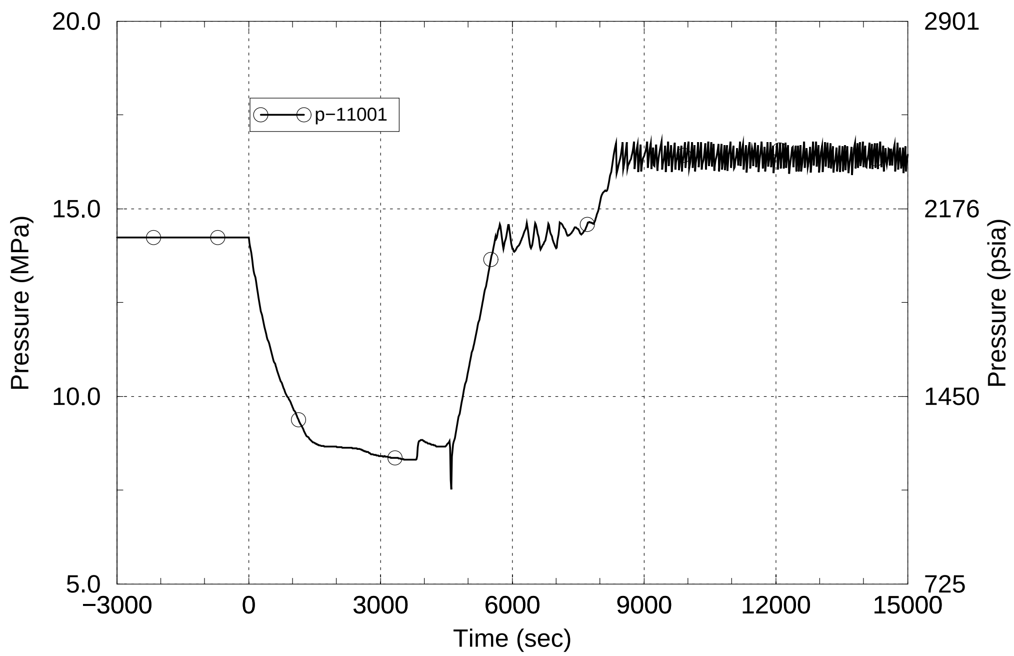


Figure 3.3.1-11 Reactor Coolant System Pressure - Palisades Case 52

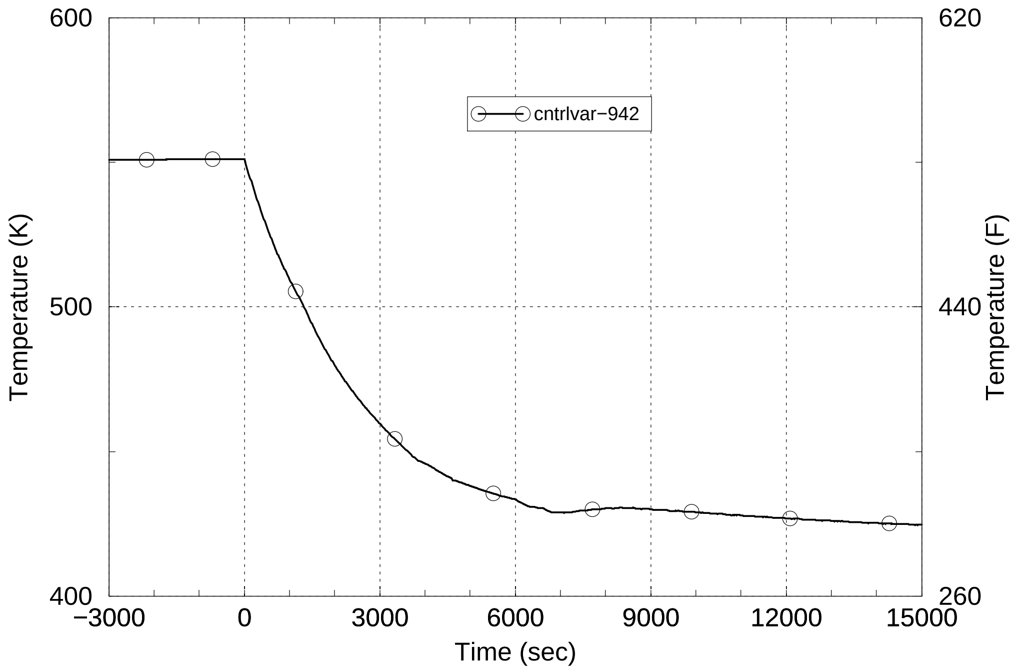


Figure 3.3.1-12 Average Reactor Vessel Downcomer Fluid Temperature - Palisades Case 52

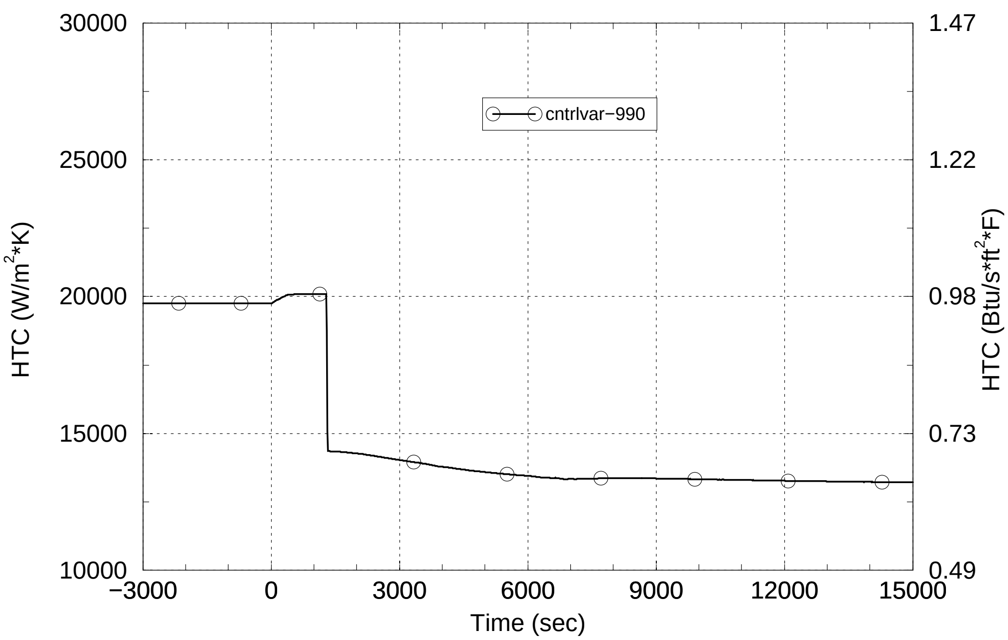


Figure 3.3.1-13 Avg Reactor Vessel Inner-Wall Heat Transfer Coefficient - Palisades Case 52

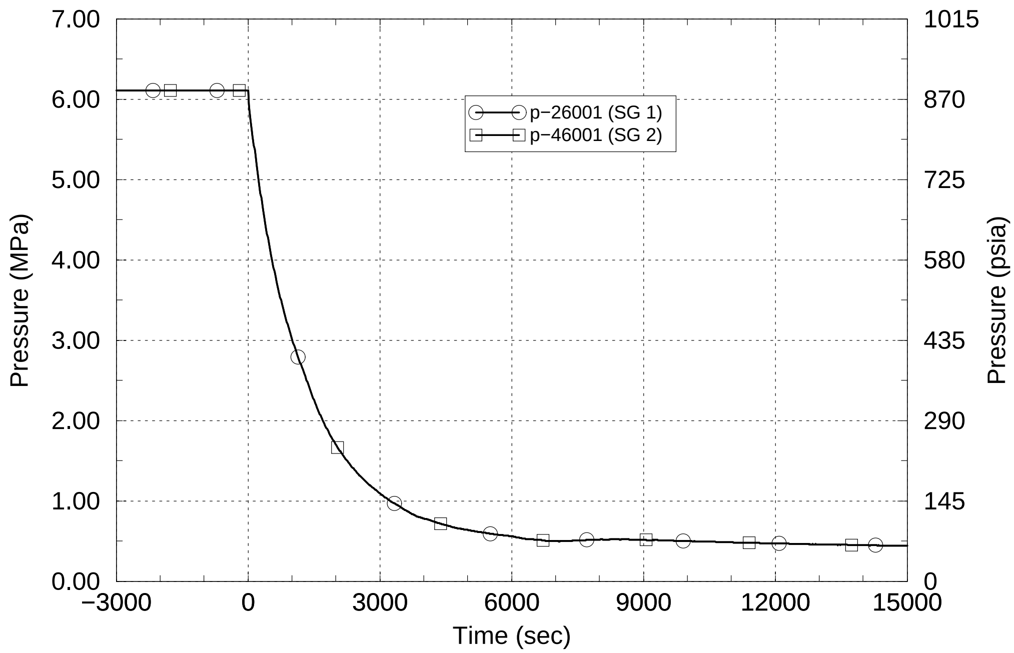


Figure 3.3.1-14 Steam Generator Pressures - Palisades Case 52

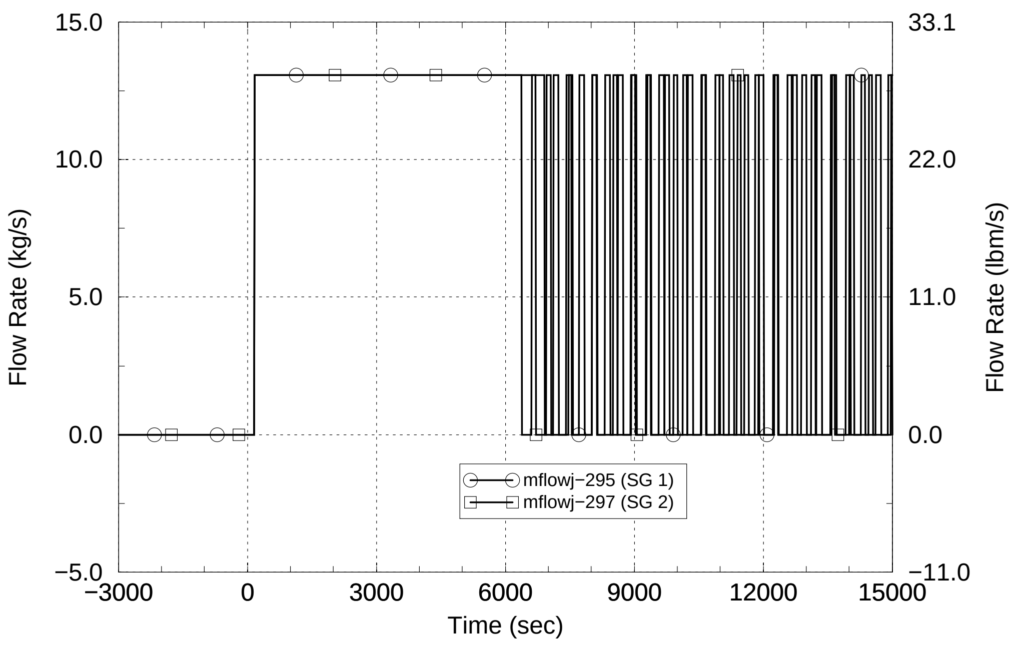


Figure 3.3.1-15 Auxiliary Feedwater Flows - Palisades Case 52

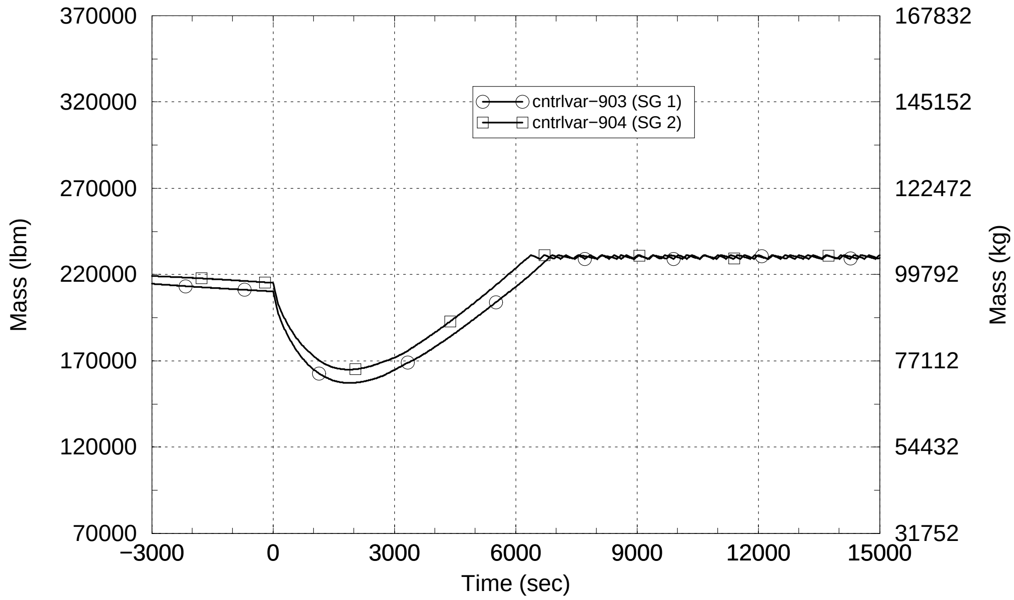


Figure 3.3.1-16 Steam Generator Secondary Fluid Masses - Palisades Case 52

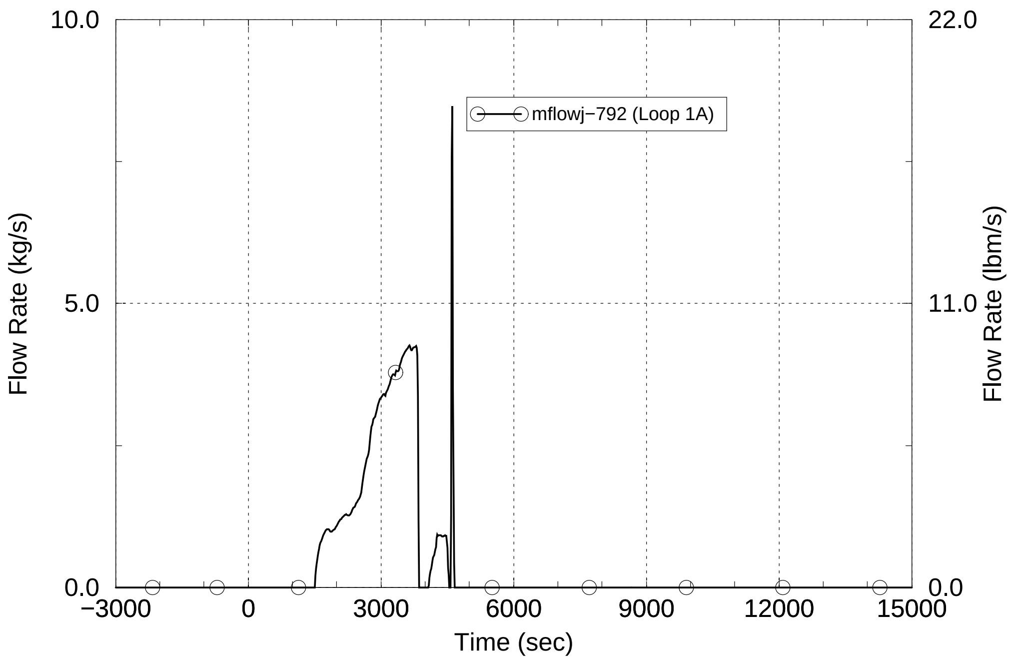


Figure 3.3.1-17 Loop A1 High Pressure Injection Flow - Palisades Case 52

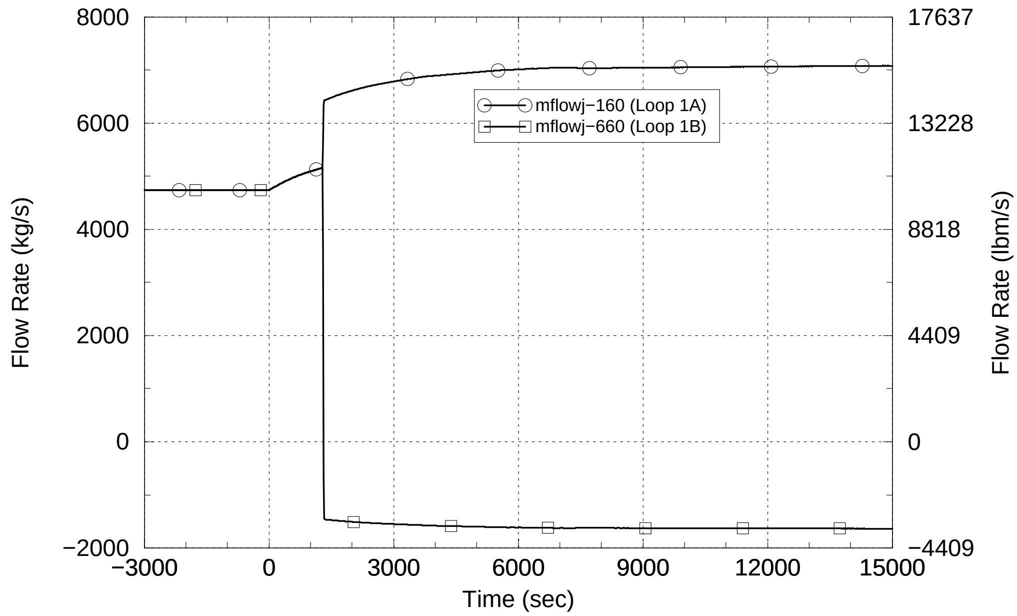


Figure 3.3.1-18   Loop 1 Cold Leg Flows - Palisades Case 52

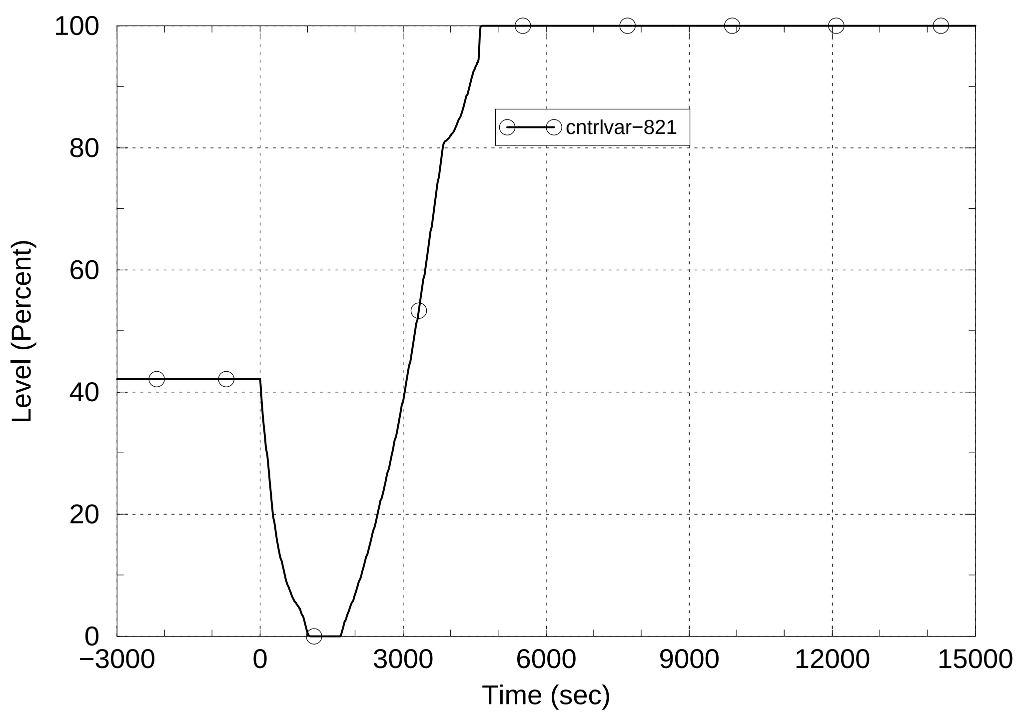


Figure 3.3.1-19   Pressurizer Level - Palisades Case 52

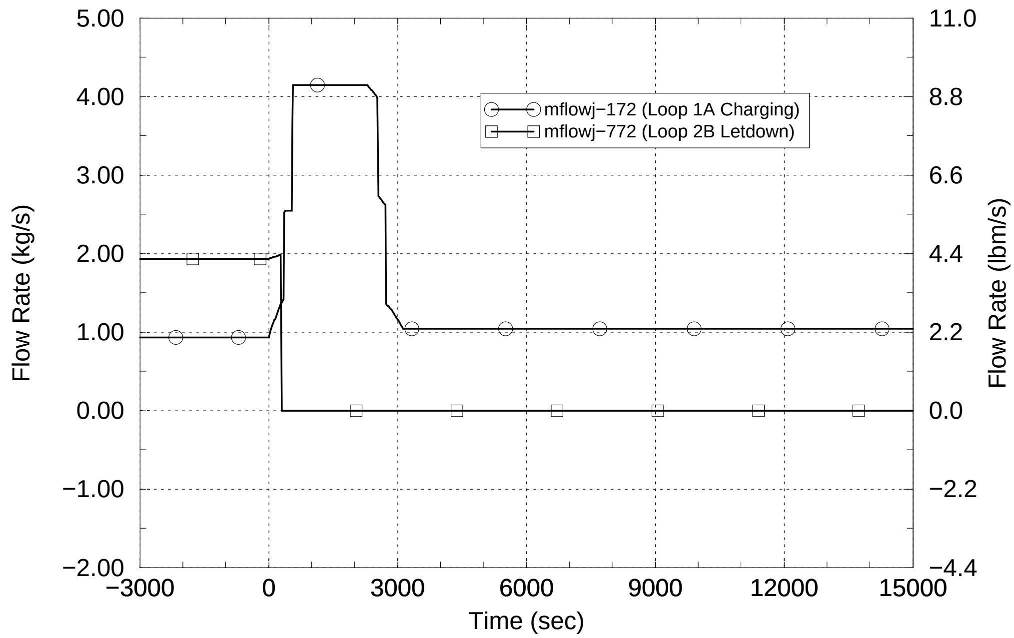


Figure 3.3.1-20 Charging and Letdown Flows - Palisades Case 52

3.3.1.3 Double-Ended Main Steam Line Break and Failure of Both MSIVs to Close from Hot Full Power Condition - Palisades Case 54

With the plant in hot full power operation, this event starts with the double-ended rupture of the main steam line on SG A. The rupture is assumed to be downstream of the steam line flow restrictor and inside containment. The MSIVs on both steam lines fail to close, resulting in a rapid symmetric blowdown of the two SGs. The operator is assumed not to isolate the AFW flow to either SG and not to throttle the HPI flow.

The following modeling changes were made to simulate this event sequence. The steam line rupture is implemented at the connection between SG A and its steam line (Junction 262 in Figure 2.3-3). Breaks were modeled from both sides (SG and steam line) to constant atmospheric-pressure containment boundary conditions. The break from the SG side used a flow area of 0.1758 m^2 [1.892 ft^2], which represents the flow area of the steam line flow restrictor and the break from the steam-line side used a flow area of 0.6567 m^2 [7.069 ft^2], which represents the full steam-line flow area. The RELAP5 critical flow model was activated at the break junctions and the initial velocities for the junctions at the time of break were set equal to those present in the steady-state calculation. The control logic of the model was modified to prevent the closure of the MSIVs (which are represented by Valves 811 and 831 in Figure 2.3-3). A containment high pressure signal was set to occur at 6.7 s following the opening of the break. This signal time, which is based on the largest LOCA event in a data set of calculations obtained from the Palisades plant, is important for the simulation of this event sequence because it results in reactor trip, turbine trip, operator tripping of all four reactor coolant pumps and initiation of the containment spray system. The operation of the containment spray system is further significant for this event sequence because it rapidly draws fluid from the safety injection refueling water storage tank (SIRWT), the draining of which automatically affects many plant systems. When the RWST drains, the suction for the HPI system is switched from it to the containment sump (resulting in an increase in the HPI fluid temperature), tripping of the LPI pumps and (after a 30-minute delay) tripping of the charging pumps.

The RELAP5-calculated sequence of events for Case 54 is shown in Table 3.3-1. The RELAP5-calculated responses for the RCS pressure, average reactor vessel downcomer fluid temperature and average reactor vessel wall inside surface heat transfer coefficient for this case are shown in Figures 3.3.1-21, 3.3.1-22 and 3.3.1-23, respectively.

When the steam line break opens, the secondary system pressures in both SGs rapidly decline, as shown in Figure 3.3.1-24. A MSIV closure signal is generated at 12 s as a result of the containment high pressure signal (which is set for 6.8 s), but in this event sequence the two MSIVs are assumed to fail open, resulting in a symmetric blowdown of the two SGs throughout the transient period.

Figure 3.3.1-25 shows the AFW flows to the two SGs. AFW flow began early during the event sequence as a result of low SG level indications in both SGs. As the SG secondary pressures rapidly fell the flow through the break eventually became smaller than the AFW flow, and afterward the AFW flow replenished the SG secondary inventories that had been lost. Figure 3.3.1-26 shows the secondary fluid mass responses for the two SGs. AFW flow to both steam generators was throttled near the end of the event sequence, when the SG inventories and levels had recovered. Afterward, AFW flow to both SGs was throttled by the automatic controllers to maintain the SG levels within their normal range.

The cooling afforded to the RCS fluid as a result of heat transfer from the RCS to the depressurizing SG steam systems resulted in a rapid RCS cooldown as shown in Figure 3.3.1-22. This cooling also caused the RCS fluid volume to shrink, which rapidly depressurized the RCS as shown in Figure 3.3.1-21.

The RCS depressurization led to a safety injection actuation signal at a pressure of 10.98 MPa [1593 psia], which results in the starting of the HPI and LPI pumps after a 27-second delay. The calculated HPI flow rate for Cold Leg A1 is shown in Figure 3.3.1-27; the total HPI flow rate is four times the flow shown in the figure. The flow delivered from the centrifugal pumps of the HPI system is a function of the cold leg pressure, with lower pressures resulting in higher HPI flow and with no HPI flow delivered whenever the RCS pressure exceeds the shutoff head of the HPI system (8.906 MPa [1291.7 psia]). The RCS pressure did not decline below the initial pressure of the safety injection tanks (SITs) or below shutoff head of the LPI system and therefore no SIT or LPI flow was delivered.

The containment pressure signal results in operator tripping of all four reactor coolant pumps. Figure 3.3.1-28 shows the flow rates through the two Loop-1 cold legs at their connections with the reactor vessel. The flow behavior in Loop 2 is similar to that in Loop 1. The pumps coast down following trip, but strong coolant loop natural circulation flow continues in both loops as a result of the continual heat removal to the SGs. The effects on the reactor vessel inside-wall heat transfer coefficient of the reactor coolant pump trips and the slow decline in the loop natural circulation flow rates are evident in Figure 3.3.1-23.

The pressurizer level response is shown in Figure 3.3.1-29. The RCS fluid volume shrinkage initially caused by the cooldown is sufficient to rapidly and completely drain the pressurizer. The HPI and net charging (i.e., charging flow less letdown) flows replenished the RCS fluid volume lost due to shrinkage and this resulted in the pressurizer refilling. Since the RCS is a closed system during this event sequence, the pressurizer refill is accompanied by a RCS repressurization to above the HPI system shutoff head and this terminates the HPI flow.

In this event sequence, the RWST is used as a water source for the HPI, charging and containment spray systems. As indicated above, when the RWST draining signal occurs the HPI water source automatically switches from the RWST to the containment sump. The RWST inventory is tracked in the model during the calculation. The draining signal was predicted to occur at 3,627 s after the event initiation. At that time the HPI temperature used in the model was increased from the nominal RWST temperature, 304.2 K [87.9°F], to the containment sump temperature, 343.2 K [158.1°F]. Afterward, the sump temperature slowly declines, to 322.9 K [121.5 °F] by the end of the calculation. These sump temperatures were those provided for the largest LOCA (for a break in the RCS cold leg, with a diameter of 0.2032 m [8 in]) in a data set based on independent Palisades containment calculations.

Figure 3.3-30 shows the charging and letdown flow responses (charging flow is injected equally into two cold legs, the figure shows the flow delivered to one cold leg). The letdown flow is isolated early in the event sequence as a result of the safety injection actuation signal. The charging pumps continue to run for 30 minutes following the RWST draining signal and then are automatically stopped. In the calculation, the charging pumps were tripped at 5,427 s after the event initiation.

The minimum average reactor vessel downcomer fluid temperature, 377 K [219°F], is reached at 4,110 s after the event initiation. The temperature increases slightly after that time as a result of the increased HPI fluid temperature. This slight warming of the RCS fluid resulted in the RCS pressure increasing to the pressurizer SRV opening setpoint pressure.

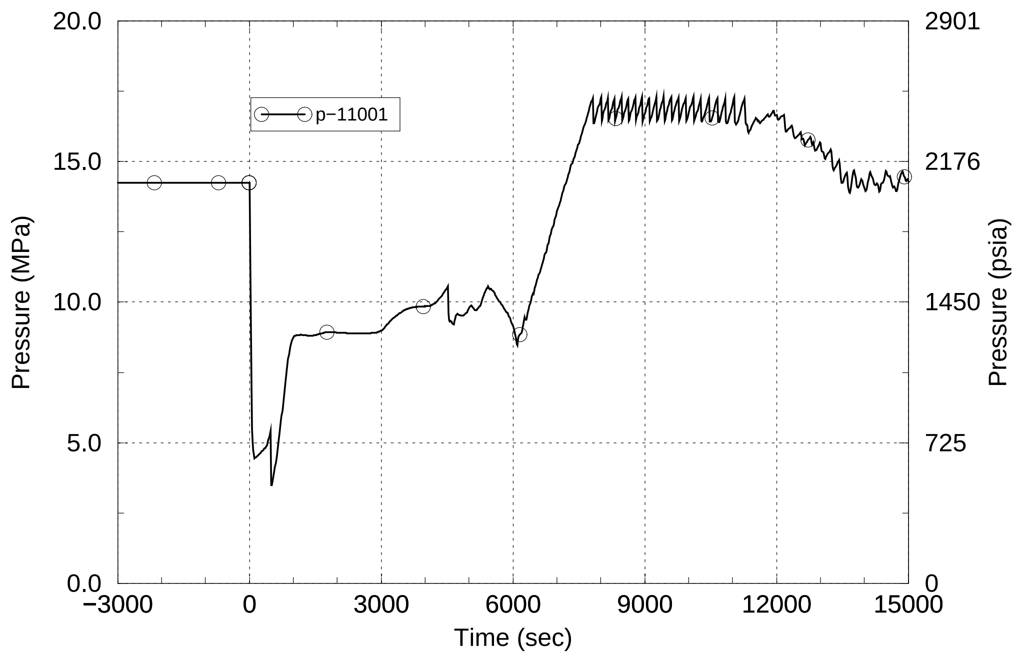


Figure 3.3.1-21 Reactor Coolant System Pressure - Palisades Case 54

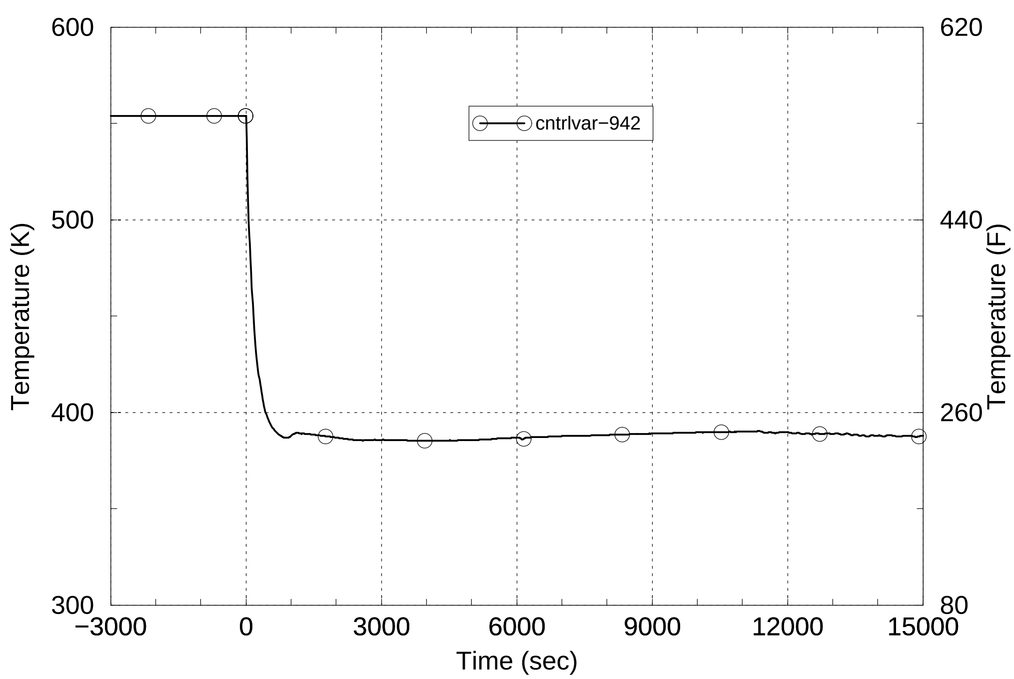


Figure 3.3.1-22 Average Reactor Vessel Downcomer Fluid Temperature - Palisades Case 54

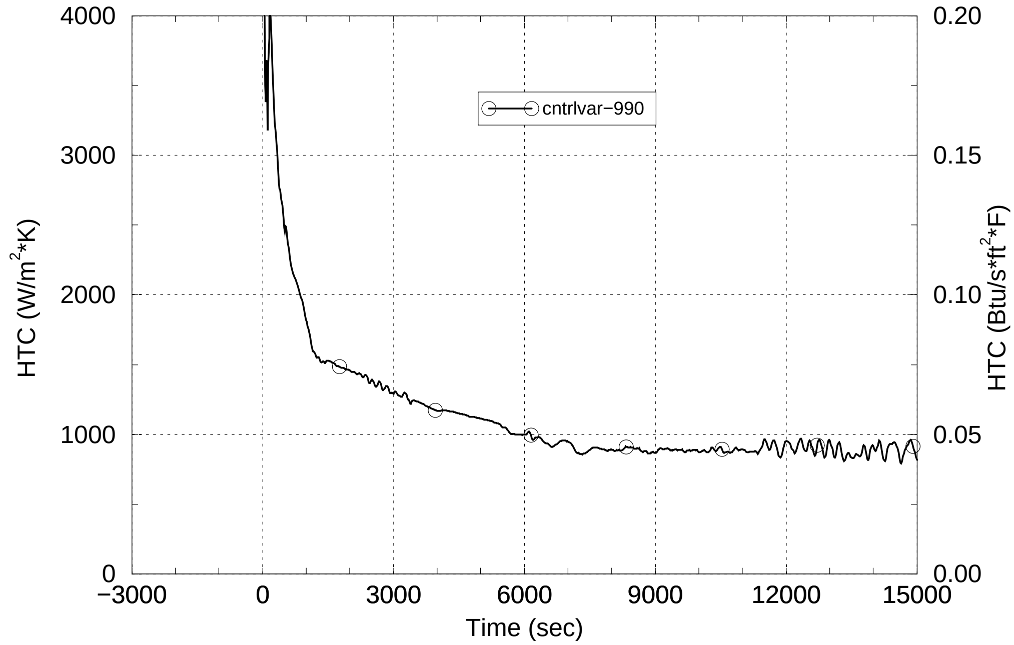


Figure 3.3.1-23 Avg Reactor Vessel Inner-Wall Heat Transfer Coefficient - Palisades Case 54

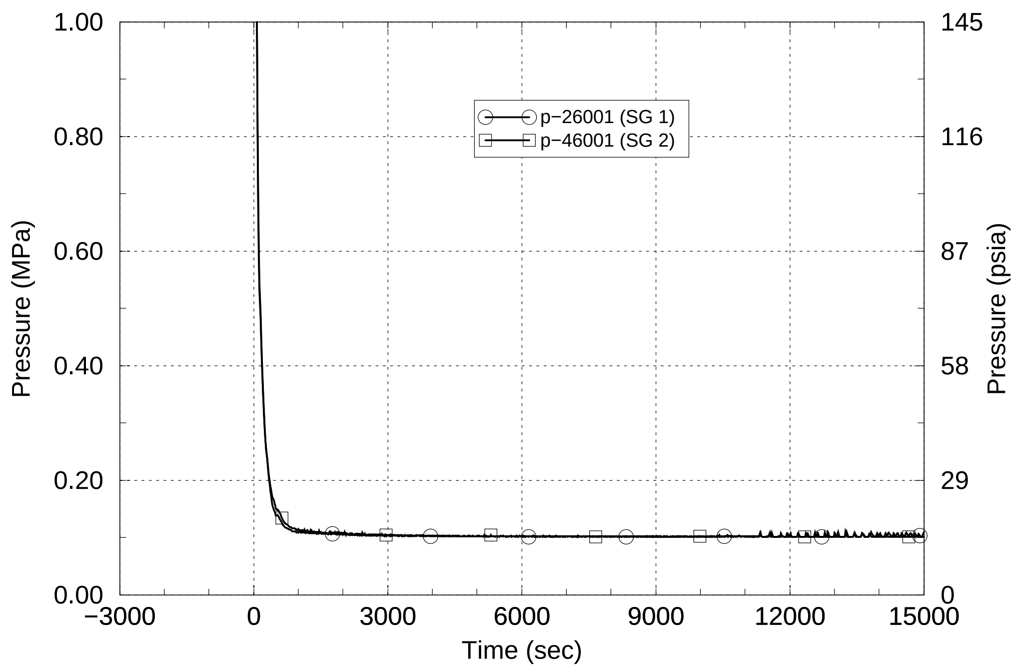


Figure 3.3.1-24 Steam Generator Pressures - Palisades Case 54

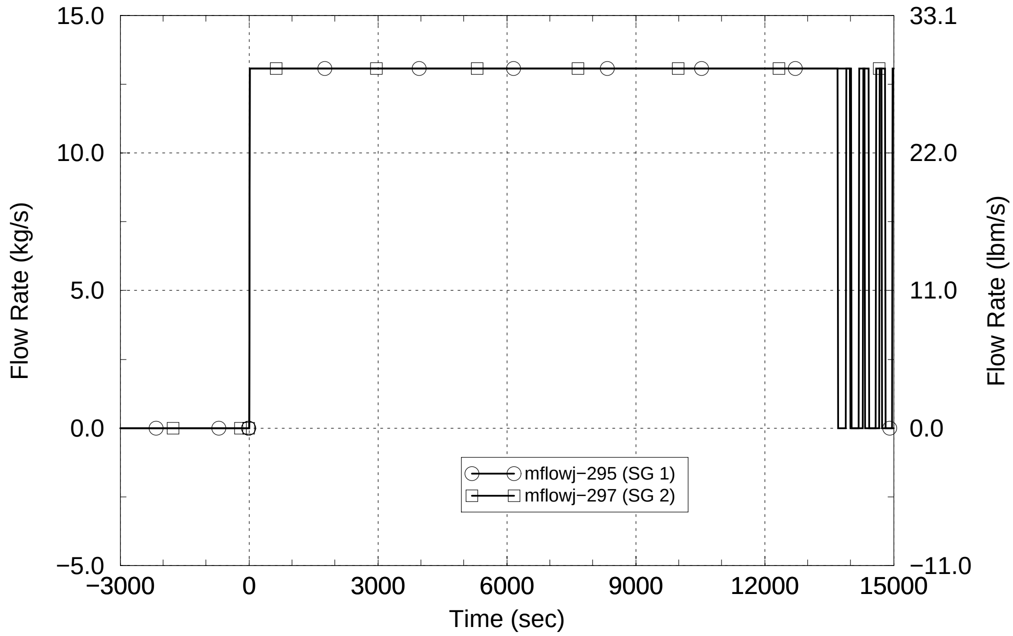


Figure 3.3.1-25 Auxiliary Feedwater Flows - Palisades Case 54

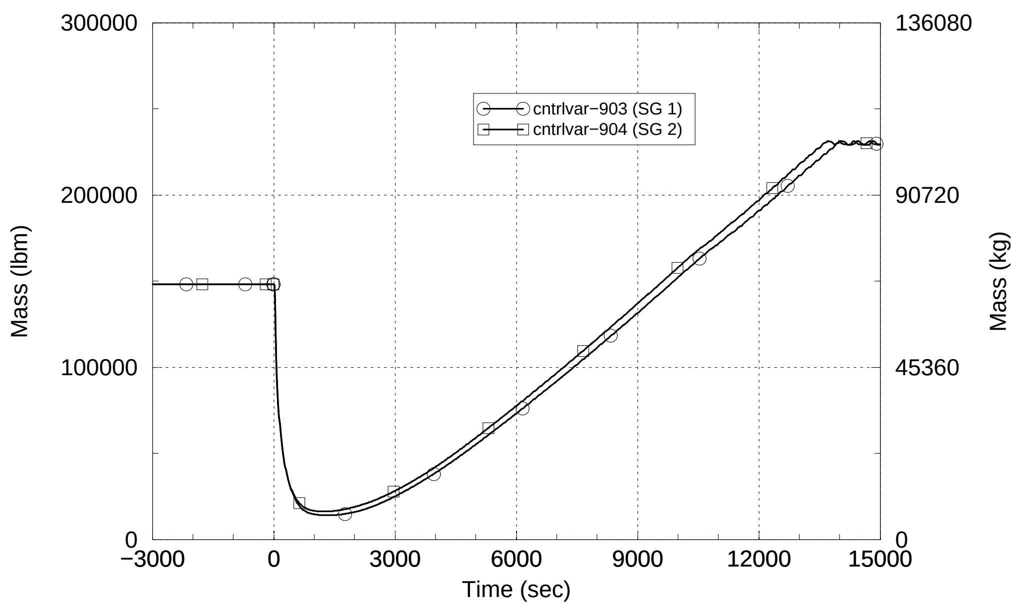


Figure 3.3.1-26 Steam Generator Secondary Fluid Masses - Palisades Case 54

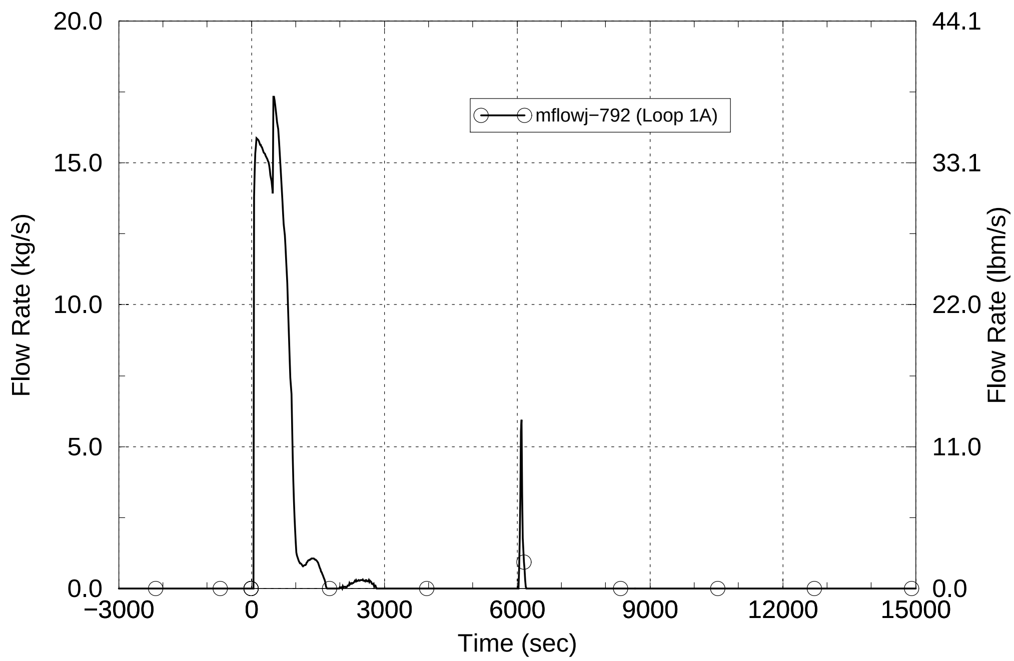


Figure 3.3.1-27   Loop A1 High Pressure Injection Flow - Palisades Case 54

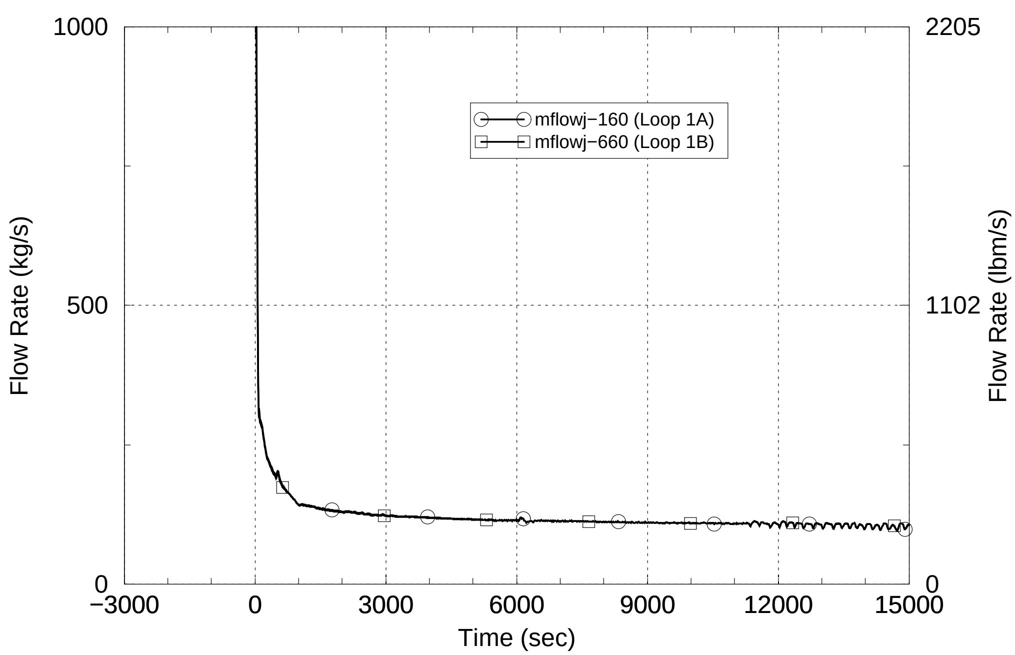


Figure 3.3.1-28   Loop 1 Cold Leg Flows - Palisades Case 54

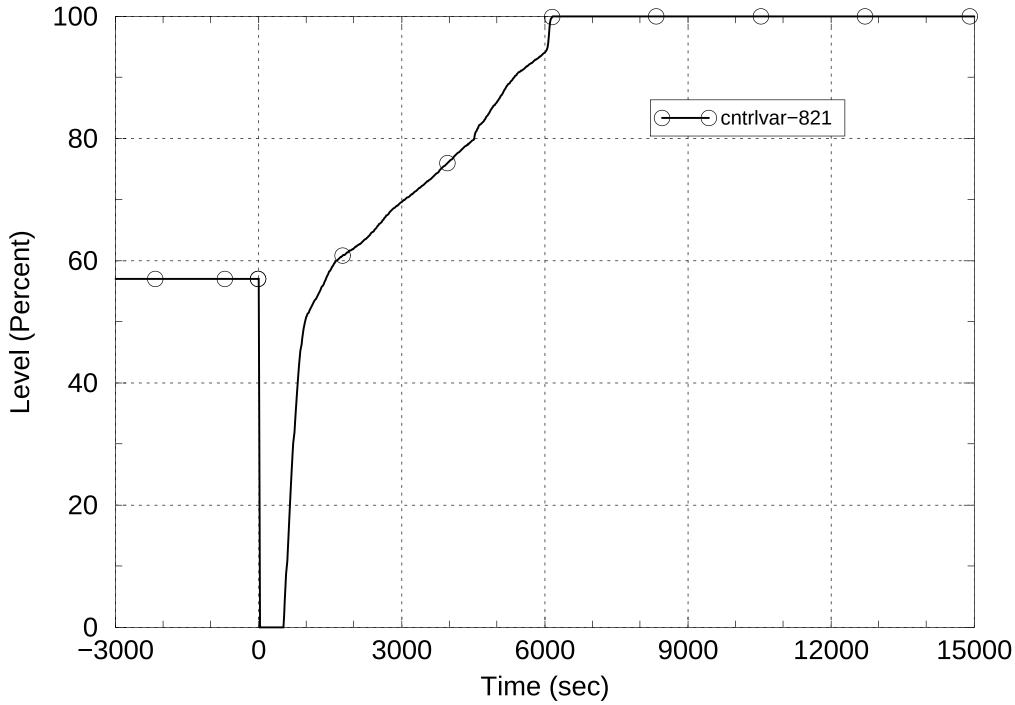


Figure 3.3.1-29 Pressurizer Level - Palisades Case 54

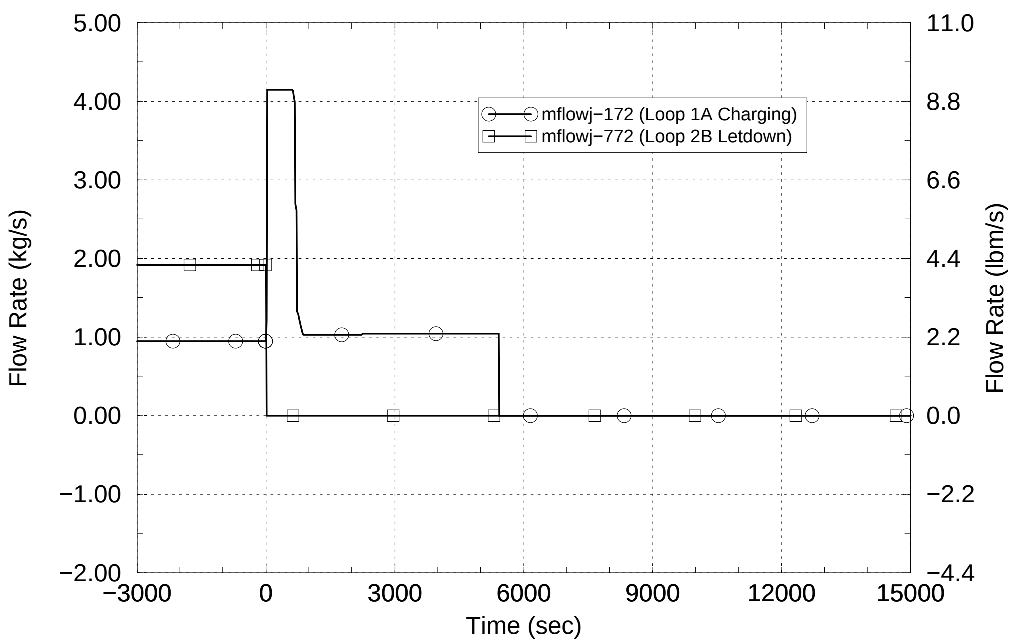


Figure 3.3.1-30 Charging and Letdown Flows - Palisades Case 54

3.3.1.4 Two Stuck-Open Atmospheric Dump Valves with Operator Action and Controller Failures Leading to Maximum AFW Flow from Hot Full Power Condition - Palisades Case 55

With the plant in hot full power operation, this event starts with reactor and turbine trips and the sticking-open of the two ADVs on SG A. Two aggravating failures are also assumed for this sequence. First, an incorrect diagnosis of the event is assumed to cause the operator to start the second motor-driven AFW pump (which can only be started by operator action). Second, a flow control system software or hardware failure is assumed to result in delivery of the entire AFW flow to affected SG A. The net effect of these two assumptions is to multiply by four the AFW flow rate delivered to affected SG A. In the calculation, it is assumed that the operator terminates the AFW flow to SG A when its steam line begins to fill with water. The operator is also assumed not to throttle the HPI flow.

The following modeling changes were made to simulate this event sequence. Manual reactor and turbine trips were implemented at the beginning of the transient calculation. The ADVs are normally demanded within a second following a reactor trip from hot full power conditions. Therefore, a potential for stuck-open ADVs exists for this event sequence. The RELAP5 ADV model (Valve 480 in Figure 2.3-3) represents a combination of the two ADVs on SG A. To represent the two ADVs sticking open, the normalized flow area for this valve component was set to 1.0, providing an effective flow area of 0.0226 m^2 [0.2430 ft^2]. The trip and control functions of the model were modified to implement the AFW behavior described in the preceding paragraph. The effect of these modifications is to initially deliver four times the normal AFW flow to SG A and none to SG B. The SG A water inventory is monitored during the calculation and when the SG A steam line begins to fill with water the AFW flow to SG A stops and normal AFW flow behavior is restored for SG B.

The RELAP5-calculated sequence of events for Case 55 is shown in Table 3.3-1. The RELAP5-calculated responses for the RCS pressure, average reactor vessel downcomer fluid temperature and average reactor vessel wall inside surface heat transfer coefficient for this case are shown in Figures 3.3.1-31, 3.3.1-32 and 3.3.1-33, respectively.

When the two ADVs stick open, the secondary system pressures in both SGs rapidly decline, as shown in Figure 3.3.1-34. A MSIV closure signal is generated at 584 s as a result of the steam pressure falling below 3.447 MPa [500 psia]. A 5-second MSIV closure time was used in the model. After MSIV closure, the pressures in the two SGs diverged somewhat, but the unaffected SG B pressure continued to fall as a result of secondary-to-primary heat transfer.

Figure 3.3.1-35 shows the AFW flows to the two SGs. The high AFW flow to SG A began early during the event sequence as a result of low the SG A level indication and the assumed operator action and flow controller failures. The AFW flow to affected SG A continued until the SG A steam line began to fill with water, which occurred at 4,332 s in the calculation. At that time the AFW flow to SG A stopped and the normal AFW behavior was restored for SG B. Figure 3.3.1-36 shows the secondary fluid mass inventory responses for the two SGs. The inventory in SG A first rapidly increases due to the AFW overfeed, then rapidly declines to zero after the AFW flow is terminated. The inventory in SG B first rapidly falls because no AFW is being delivered, then stabilizes when the MSIVs are closed. The SG B inventory increases when AFW flow to it is restored and then stabilizes again when the normal level range is attained.

The cooling afforded to the RCS fluid as a result of heat transfer from the RCS to the depressurizing SG steam systems resulted in a rapid RCS cooldown as shown in Figure 3.3.1-32. This cooling also caused the RCS fluid volume to shrink, which rapidly depressurized the RCS as shown in Figure 3.3.1-31.

The RCS depressurization led to a safety injection actuation signal at a pressure of 10.98 MPa [1593 psia], which results in the starting of the HPI and LPI pumps after a 27-second delay. The calculated HPI flow rate for Cold Leg A1 is shown in Figure 3.3.1-37; the total HPI flow rate is four times the flow shown in the figure. The flow delivered from the centrifugal pumps of the HPI system is a function of the cold leg pressure, with lower pressures resulting in higher HPI flow and with no HPI flow delivered whenever the RCS pressure exceeds the shutoff head of the HPI system (8.906 MPa [1291.7 psia]). The RCS pressure did not decline below the initial pressure of the safety injection tanks (SITs) or below shutoff head of the LPI system and therefore no SIT or LPI flow was delivered.

The RCS depressurization below 8.963 MPa [1300 psia] also led to operator tripping of one reactor coolant pump in each loop. Figure 3.3.1-38 shows the flow rates through the two Loop-1 cold legs at their connections with the reactor vessel. The flow behavior in Loop 2 is similar to that in Loop 1. After the reactor coolant pump trip, the flow through the cold leg with the pump that remained operating increased, while the flow through the cold leg with the pump that was tripped reversed. The remaining two reactor coolant pumps continued to operate throughout the event sequence because the low RCS fluid subcooling requirement (subcooling less than 13.9 K [25 ^{o}F]) for the operators to trip those pumps was not met. The effect of tripping the two reactor coolant pumps on the reactor vessel inside-wall heat transfer coefficient is evident in Figure 3.3.1-33.

The pressurizer level response is shown in Figure 3.3.1-39. The RCS fluid volume shrinkage initially caused by the cooldown is sufficient to completely drain the pressurizer. HPI and net charging system injection flow (i.e., charging flow less letdown flow, see Figure 3.3.1-40) replenished the RCS fluid volume lost due to shrinkage and this resulted in the pressurizer refilling. Since the RCS is a closed system during this event sequence, the pressurizer refill is accompanied by a RCS repressurization to above the HPI system shutoff head and this terminates the HPI flow.

The letdown flow is isolated as a result of the safety injection actuation signal and the three charging pumps are of the positive-displacement type. One charging pump continues to deliver flow, regardless of the pressurizer level response. The RCS cooldown and fluid shrinkage stop when the AFW flow to SG A is terminated and afterward the charging flow completely refills the pressurizer and raises the RCS pressure up to the 17.24-MPa [2500-psia] opening setpoint pressure of the pressurizer safety relief valves (SRVs). The RCS pressure remains high through the remainder of the event sequence, with the charging flow balanced by the pressurizer SRV flow.

The minimum average reactor vessel downcomer fluid temperature, 437 K [328 ^{o}F], is reached at 4,320 s, when the AFW flow to SG A is stopped. The RCS pressure reaches the pressurizer SRV opening setpoint pressure shortly thereafter.

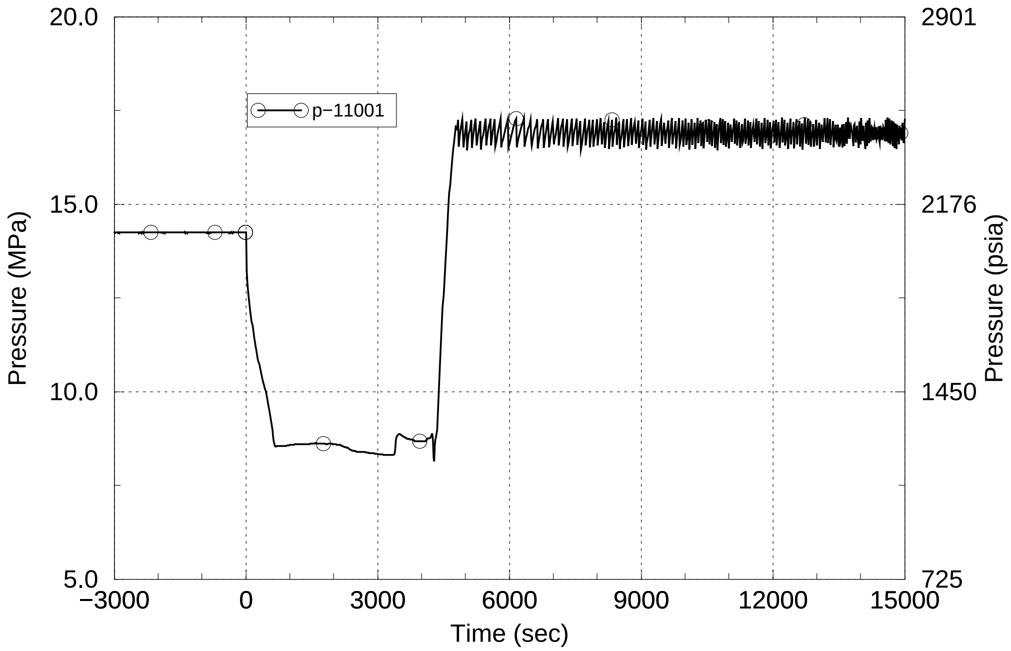


Figure 3.3.1-31 Reactor Coolant System Pressure - Palisades Case 55

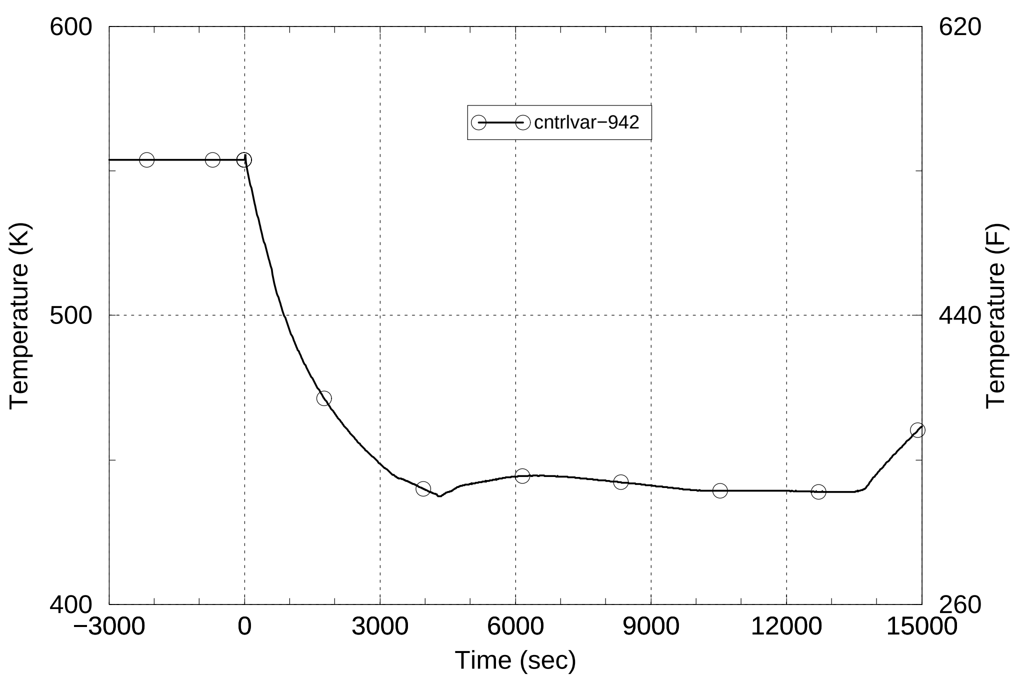


Figure 3.3.1-32 Average Reactor Vessel Downcomer Fluid Temperature - Palisades Case 55

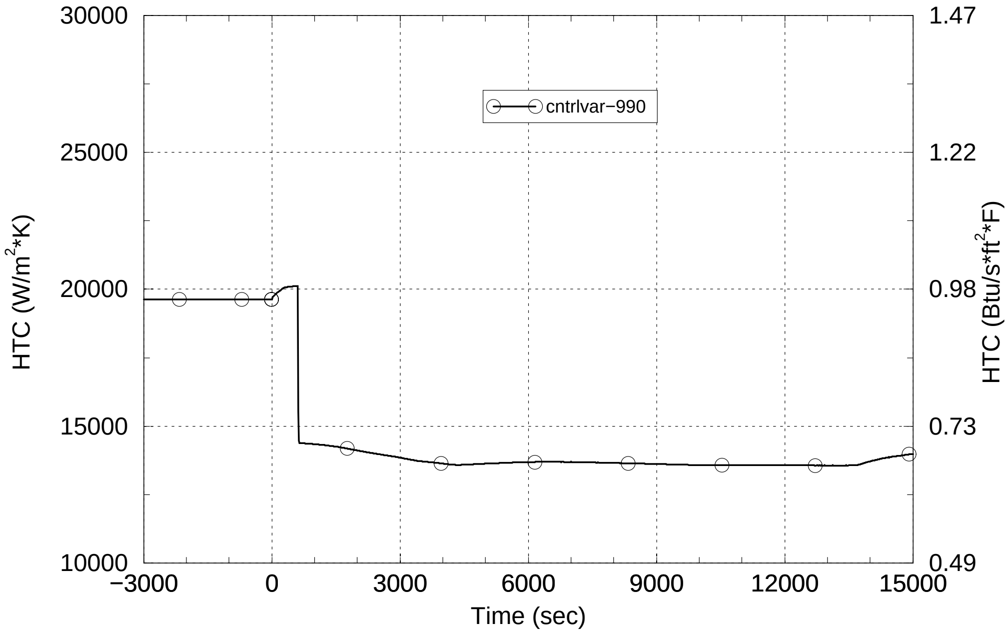


Figure 3.3.1-33 Avg Reactor Vessel Inner-Wall Heat Transfer Coefficient - Palisades Case 55

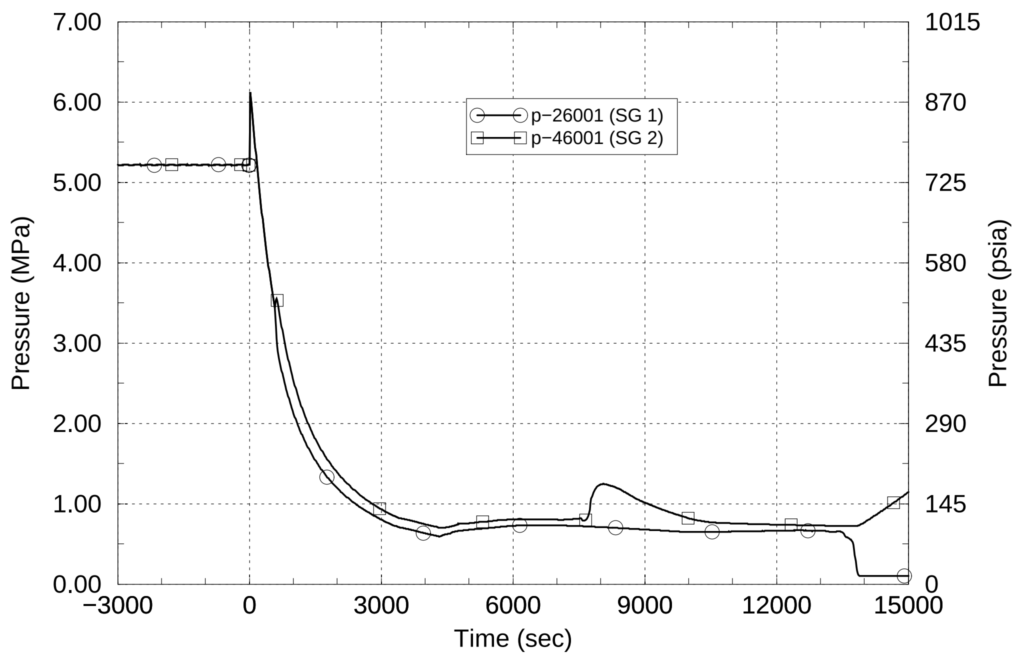


Figure 3.3.1-34 Steam Generator Pressures - Palisades Case 55

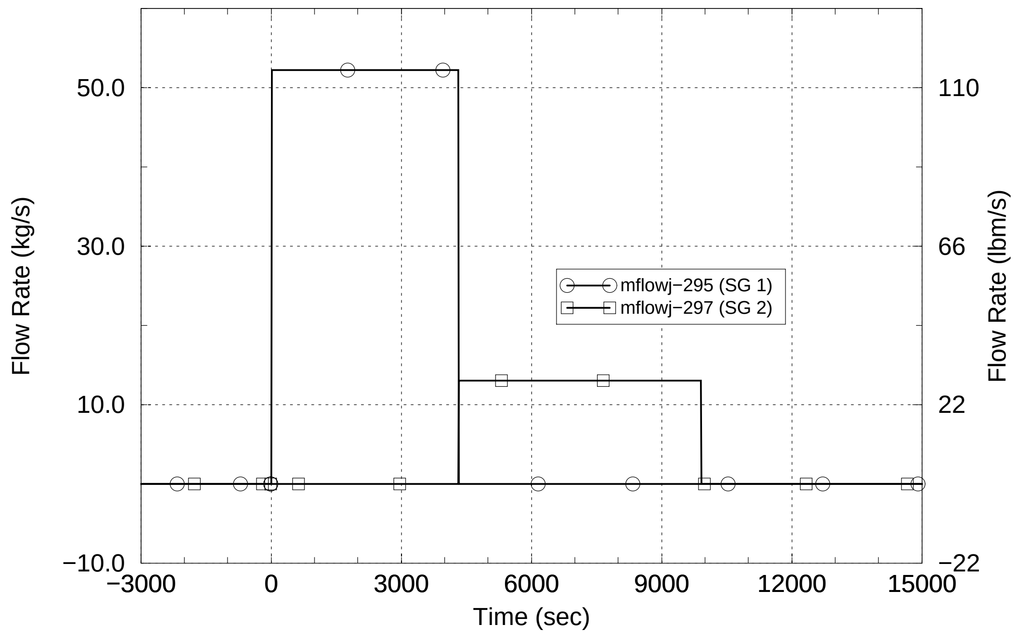


Figure 3.3.1-35 Auxiliary Feedwater Flows - Palisades Case 55

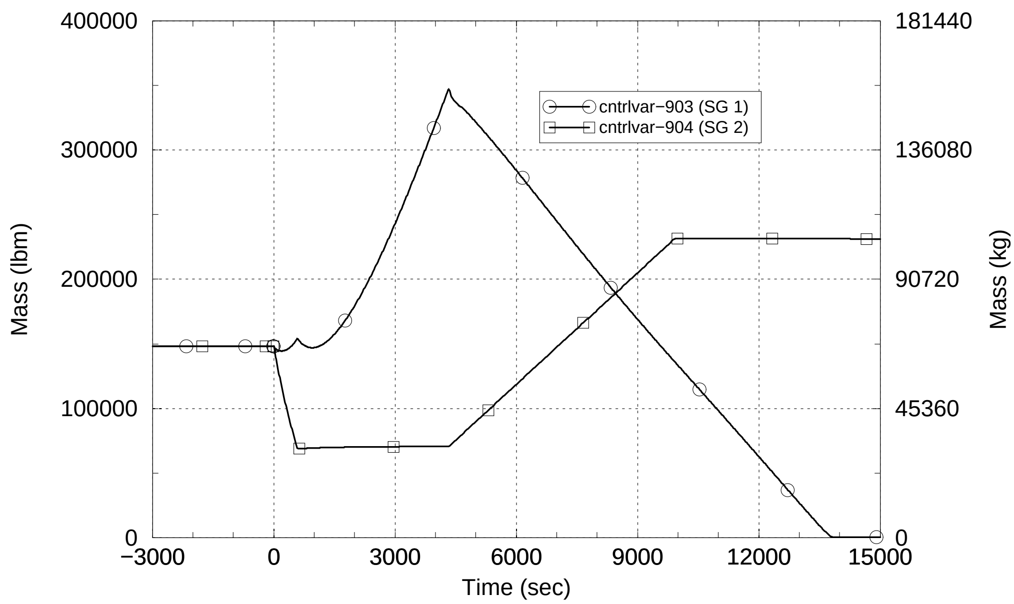


Figure 3.3.1-36 Steam Generator Secondary Fluid Masses - Palisades Case 55

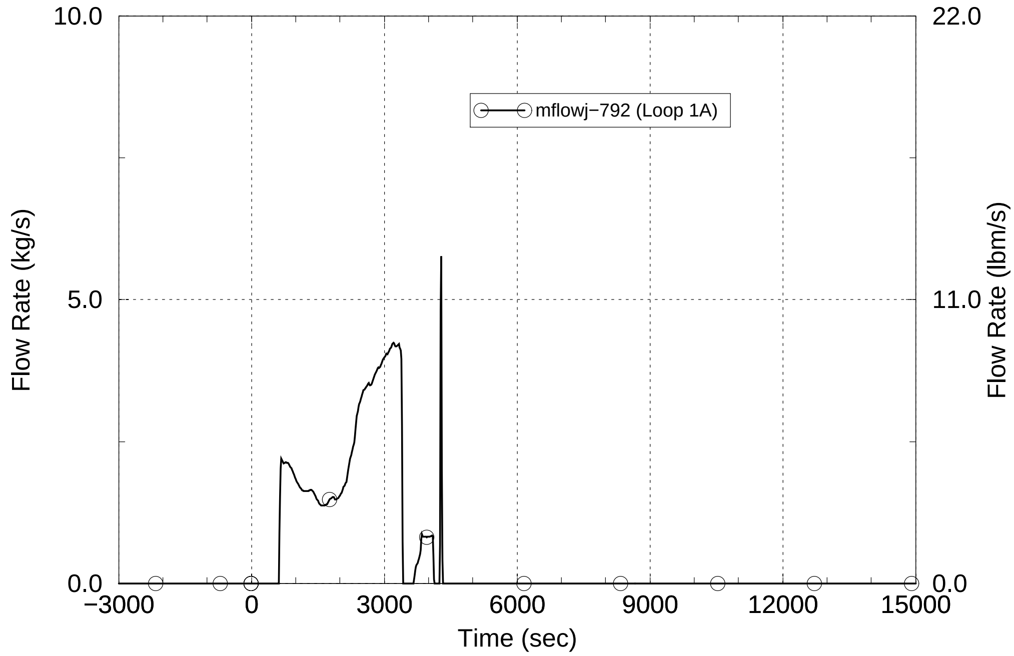


Figure 3.3.1-37 Loop A1 High Pressure Injection Flow - Palisades Case 55

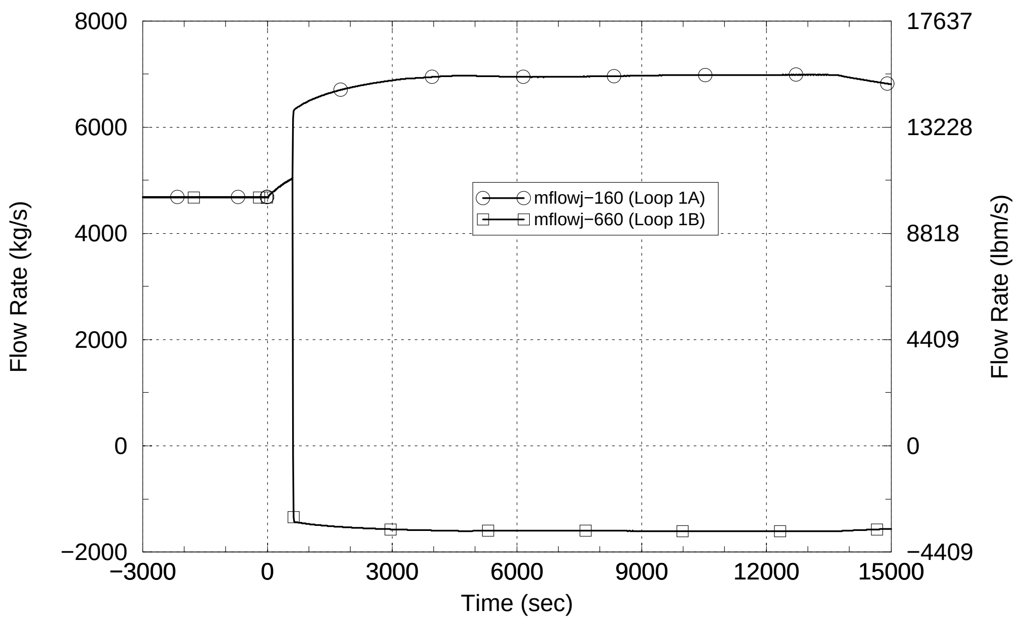


Figure 3.3.1-38 Loop 1 Cold Leg Flows - Palisades Case 55

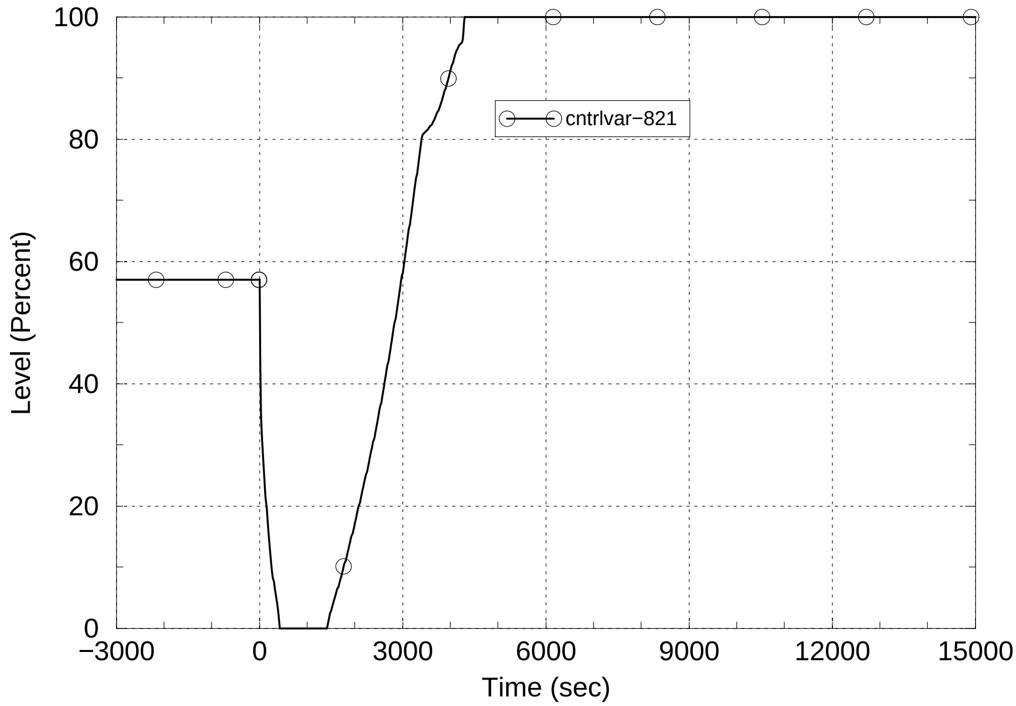


Figure 3.3.1-39   Pressurizer Level - Palisades Case 55

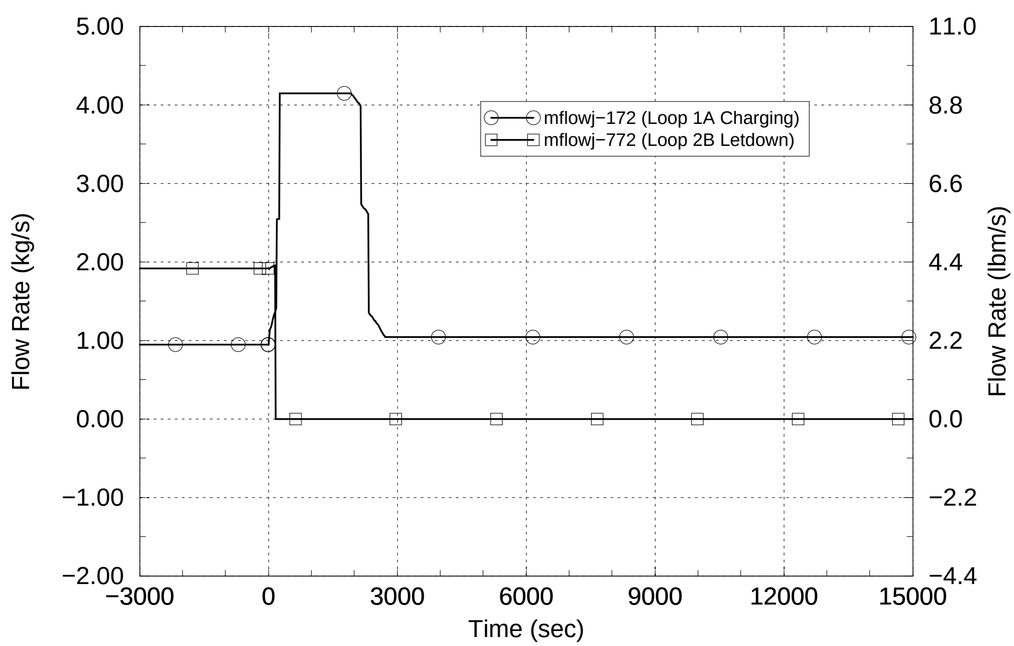


Figure 3.3.1-40   Charging and Letdown Flows - Palisades Case 55

3.3.2 Sequences Initiated by Primary Coolant System Breaks with Effective Diameters of 5.08 cm [2 in] and Smaller

Two of the 12 Palisades PTS-risk-dominant event sequences involved primary coolant system breaks with effective diameters of 5.08 cm [2 in] and smaller. These two sequences are described as follows:

<u>Case 60</u> is an event initiated by a 5.08-cm [2-in] diameter break in the pressurizer surge line with the reactor in hot full power (HFP) operation. The operator is assumed not to throttle HPI flow. Temperatures representing winter conditions are assumed for the fluids in the HPI, LPI and SIT systems.

<u>Case 65</u> is an event initiated by a reactor trip and the spurious sticking-open of one pressurizer safety relief valve (SRV) with the reactor in hot zero power (HZP) operation. The SRV is assumed to re-close 6,000 s after the event initiation. The flow from the SRV is assumed not to result in a containment pressurization sufficient to initiate containment spray system operation. The operator is assumed not to throttle HPI flow.

The common features of this group of smaller primary-system break sequences are RCS depressurization caused by the break and RCS cooldown caused by the depressurization and the injection of cold HPI fluid. The break sizes for this group are large enough to result in tripping of all four reactor coolant pumps and RCS draining which leads to an interruption of coolant loop natural circulation flow. However, the break sizes for this group are not large enough to allow the RCS to depressurize sufficiently to permit LPI and SIT ECCS flow; only the HPI and charging systems deliver flow to the RCS.

3.3.2.1 5.08-cm [2-in] Diameter Pressurizer Surge Line Break from Hot Full Power Condition - Palisades Case 60

With the plant in HFP operation, this event starts with a 5.08-cm [2-in] diameter break in the pressurizer surge line. The operator is assumed not to throttle the HPI flow, which is normally done when RCS subcooling and pressurizer level criteria have been met. The calculation assumes that the temperatures of the ECCS fluids are representative of winter-season conditions: HPI and LPI temperatures of 277.6 K [40°F] and SIT temperatures of 288.7 K [60°F] (the nominal ECCS fluid temperatures are listed in Table 2.0-1).

The following modeling changes were made to simulate this event sequence. The pressurizer surge line break to a constant atmospheric-pressure containment boundary condition was added to the model. The equivalent break flow area for a circular break with a diameter 5.08 cm [2 in] was specified. The break was connected on a vertical section of the surge line, from Component 180-2, as shown in Figure 2.3-2. The critical flow model was activated at the break junction and the flow loss coefficients specified were based on AP600-derived flow loss coefficients (Reference 3.3-1) and scaled for the specific break size and location for this event sequence. The boundary conditions for the HPI, LPI and SIT fluids were changed to represent the winter-season conditions listed above. At the time the reactor coolant pump coast-down was complete, large reverse flow loss coefficients were implemented in the loop seal cold leg regions of the model (Components

140, 340, 640 and 740 in Figure 2.3-2) to prevent the setting up of same-loop cold leg circulation, as discussed in Section 2.0. The containment high pressure signal, which results in containment spray actuation and tripping of all reactor coolant pumps, was specified as 125.8 s after event initiation. The modeling for the HPI fluid temperature was modified so as to represent the constant safety injection refueling water storage tank (SIRWT) winter-season temperature prior to the draining of that tank then switch to a representation of a variable containment sump temperature (specified as a function of the time after the switch). The HPI fluid temperature in the model rises from 319.2 K [114.9 °F] at the time of the switch to 327.8 K [130.4 °F] at 7,979 s and then falls to 326.3 K [127.6 °F] at the end of the calculation (15,000 s after the break opens). The model input data for the containment spray actuation time and the containment sump fluid temperature were obtained from an independent Palisades containment analysis for a 5.08-cm [2-in] diameter break in the RCS.

The RELAP5-calculated sequence of events for Case 60 is shown in Table 3.3-2. The RELAP5-calculated responses for the RCS pressure, average reactor vessel downcomer fluid temperature and average reactor vessel wall inside surface heat transfer coefficient for this case are shown in Figures 3.3.2-1, 3.3.2-2 and 3.3.2-3, respectively.

The calculated break flow response is shown in Figure 3.3.2-4. When the break opens, the RCS pressure falls rapidly at first, then more slowly as flashing within the RCS is encountered. The RCS depressurization causes a reactor trip signal at 55 s. The reactor trip causes a turbine trip, isolating the steam generator systems.

Figure 3.3.2-5 shows the calculated SG secondary system pressure responses. The turbine trip causes the secondary system pressures to rise; the pressure increase is limited by the opening of the turbine bypass and atmospheric dump valves. The steam pressures did not increase sufficiently to open the main steam safety relief valves. The declining SG pressures after 2,000 s are an indication of reverse (i.e., secondary system to primary system) SG heat transfer caused by the cooling down of the primary coolant system The SG secondary fluid mass responses are shown in Figure 3.3.2-6. The turbine trip resulted in collapse of the secondary system indicated levels, which initiated auxiliary feedwater (AFW) flow to both SGs. The AFW flow replenished the SG secondary fluid inventories; AFW flow was throttled to maintain the SG levels within the normal range.

At 113 s, the RCS pressure had fallen to 8.963 MPa [1300 psia], resulting in the operator tripping one reactor coolant pump in each loop. The decline in the coolant loop flows caused by the pump trip is indicated in Figure 3.3.2-7, which shows the two hot leg flows at the reactor vessel connections. At 126 s the containment high pressure signal resulted in the operators tripping the two remaining reactor coolant pumps. Afterward the coolant loop flows transitioned from forced circulation behavior to coolant loop natural circulation behavior. Figure 3.3.2-7 shows that coolant loop natural circulation flow continued in both loops up to about 1,000 s. After that time, the loss of RCS fluid inventory was sufficient to drain fluid from inside the upper regions of the SG tubes, which stopped coolant loop natural circulation flow through both loops. The Loop 1 hot leg flow response shown after 1,000 s reflects the fluid flowing toward the pressurizer surge line break. The effects of loop flow stagnation on the reactor vessel downcomer fluid temperature are evident in Figure 3.3.2-2. Under the stagnant coolant loop conditions, the effects of injecting cold HPI fluid into the cold legs are directly felt in the vessel downcomer and the fluid temperatures there decline rapidly.

RCS depressurization to 10.98 MPa [1593 psia] led to a safety injection actuation signal at 69 s and the starting of the HPI and LPI pumps after a 27-second delay (which represents effects related to plant instrumentation, control systems and pump start up timing). The calculated HPI flow rate for Cold Leg A1 is shown in Figure 3.3.2-8; the total HPI flow rate is four times the flow shown in the figure. The flow delivered from the centrifugal pumps of the HPI system is a function of the cold leg pressure, with lower pressures resulting in higher HPI flow and with no HPI flow delivered whenever the RCS pressure exceeds the shutoff head of the HPI system (8.906 MPa [1291.7 psia]). At 3,157 s, a recirculation actuation signal was calculated as a result of a low RWST level condition. The model tracks RWST inventory and level based on the flows drawn from the tank by the containment spray, HPI and charging systems. At this time the suction for the HPI system is switched from the RWST to the containment sump, with the resulting increase in HPI fluid temperature described above. During this event sequence calculation, the RCS pressure did not decline below the initial pressure of the SITs or below the shutoff head of the LPI system and therefore no SIT or LPI flow was delivered.

The effects of RCS coolant inventory loss through the break are evident in the declining pressurizer level response shown in Figure 3.3.2-9. The pressurizer was completely drained over the first 90 s of the event sequence. The charging and letdown flow responses are shown in Figure 3.3.2-10. The letdown flow was isolated early in the event sequence at the time of the safety injection actuation signal. The charging system flow increased in response to the low pressurizer level condition, with all three charging pumps delivering flow. Charging flow was terminated at 4,957 s, which is 1,800 s after the time of the recirculation actuation signal. It is estimated that 30 minutes would be required after the recirculation actuation signal for the charging system to completely drain the RWST of its remaining inventory. Afterward, no source of fluid is available for the charging system.

During the latter portion of the event sequence the calculated conditions reflect balances in the RCS mass and energy flows. The break mass flow rate is balanced by the HPI mass addition rate. The core heat addition rate is balanced by the cooling afforded to the RCS from adding cold HPI fluid and removing warm fluid at the break. These balanced conditions were reached at about 8,000 s with a steady pressurizer level of about 22% (see Figure 3.3.2-9).

The minimum average reactor vessel downcomer fluid temperature, 351 K [173 ^{o}F], is reached at 3,540 s, shortly after the time when the suction for the HPI system is switched to the containment sump. The RCS pressure, which was calculated to be 2.303 MPa [334 psia] at 3,540 s, rose moderately afterward as a result of the effects of warming the HPI fluid.

Table 3.3-2 Comparison of Event Timing for Dominant Palisades Event Sequences - Group 2, Primary System Breaks with Diameters of 5.08-cm [2-in] and Smaller

	Event Time (seconds)	
Event(s)	Case 60, HFP, 5.08-cm [2-in] Diameter Surge Line Break	Case 65, HZP, One Stuck-Open Pressurizer SRV which Re-Closes at 6,000 s
Break opens (Case 60), one pressurizer SRV spuriously fails open (Case65)	0	0
Reactor trip signal (both cases), turbine trip (Case 60 only)	55	0
Safety injection actuation signal, isolate letdown flow	69	82
Pressurizer level reaches 0%	90	N/A
HPI and LPI systems available	96	109
Low RCS pressure condition causes operator to trip one reactor coolant in each coolant loop	113	150
Containment high pressure signal, results in containment spray system initiation and operator tripping of the remaining two reactor coolant pumps	126	N/A
Minimum pressurizer level reached, 34%	N/A	165
Low RCS subcooling condition causes operator to trip the remaining two reactor coolant pumps	N/A	214
Pressurizer level reaches 100%	N/A	2145
Recirculation actuation signal, suction for HPI system switched from RWST to containment sump	3157	N/A
Stuck-open pressurizer SRV assumed to reclose	N/A	6000
Minimum reactor vessel downcomer fluid temperature attained	3540	6555
RCS pressure reaches opening setpoint pressure of the non-failed pressurizer SRV	N/A	6885
Pressurizer level reestablished above 0%	4390	N/A
Charging flow stops	4957	N/A
Calculation terminated	15000	15000
Note: N/A indicates this event is not applicable for the event sequence.		

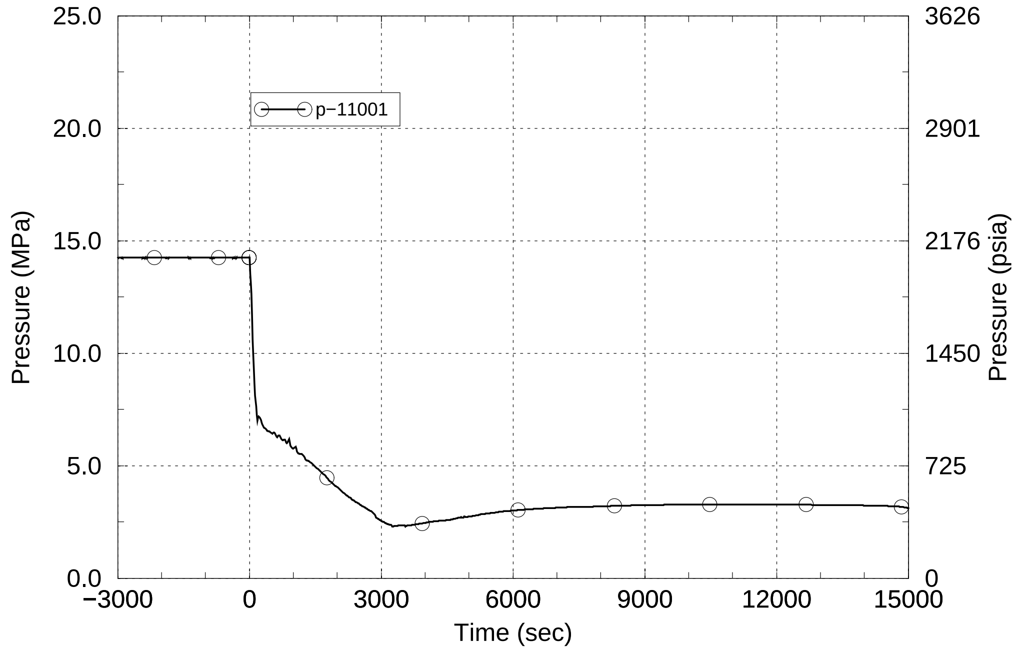


Figure 3.3.2-1 Reactor Coolant System Pressure - Palisades Case 60

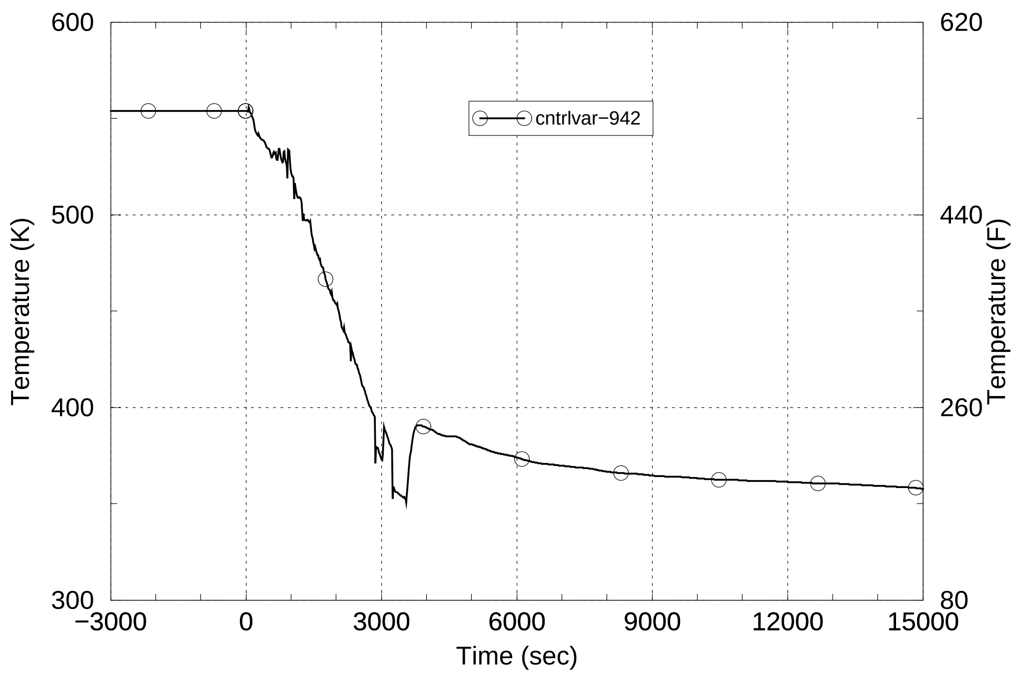


Figure 3.3.2-2 Average Reactor Vessel Downcomer Fluid Temperature - Palisades Case 60

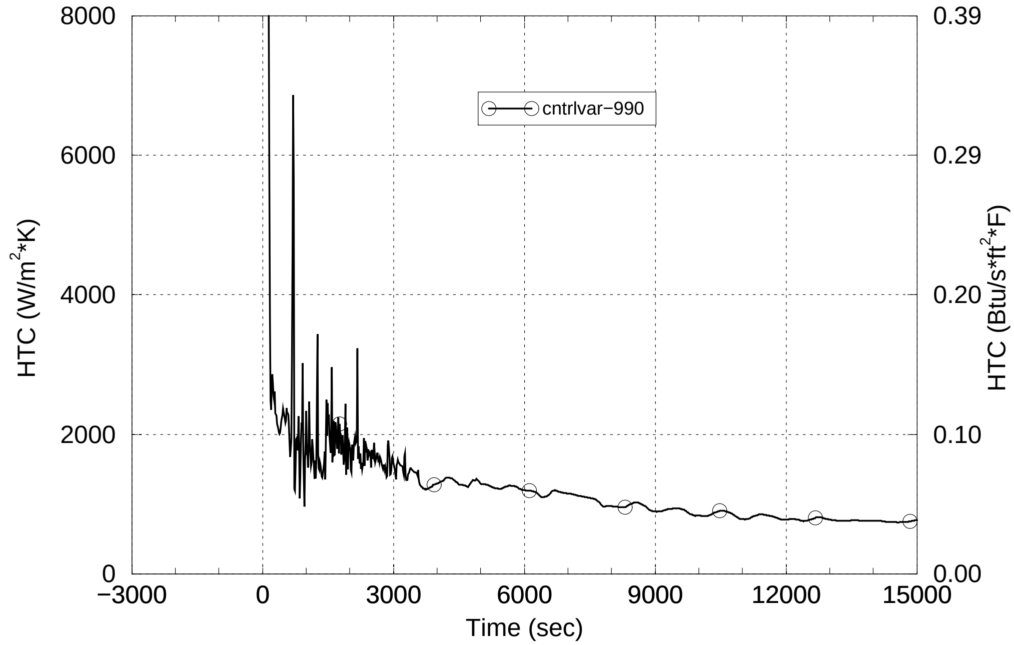


Figure 3.3.2-3 Avg Reactor Vessel Inner-Wall Heat Transfer Coefficient - Palisades Case 60

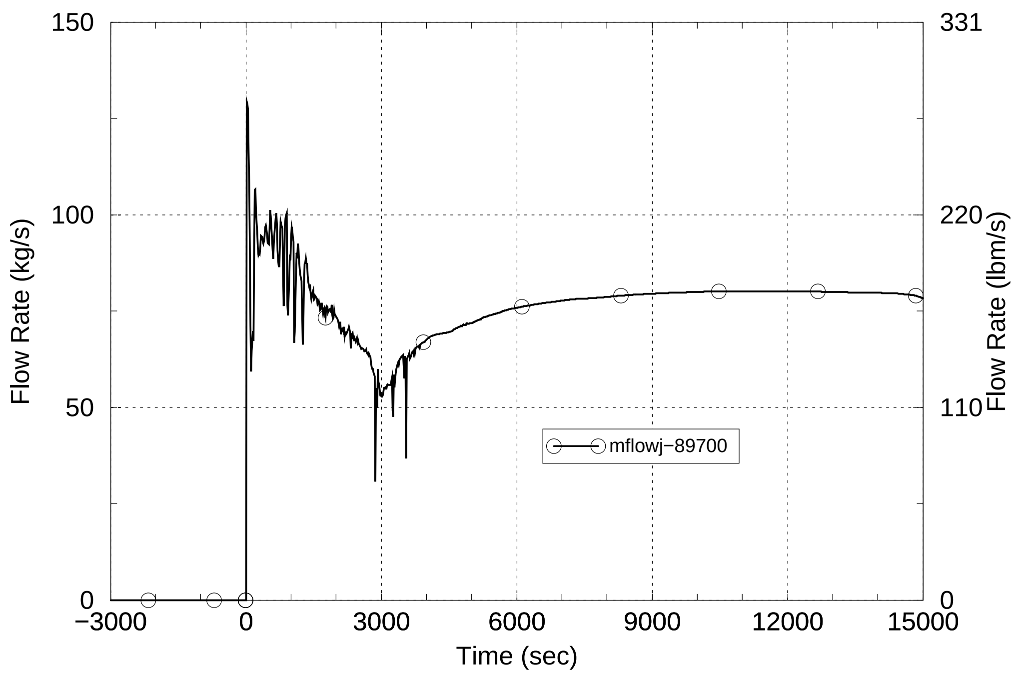


Figure 3.3.2-4 Break Flow - Palisades Case 60

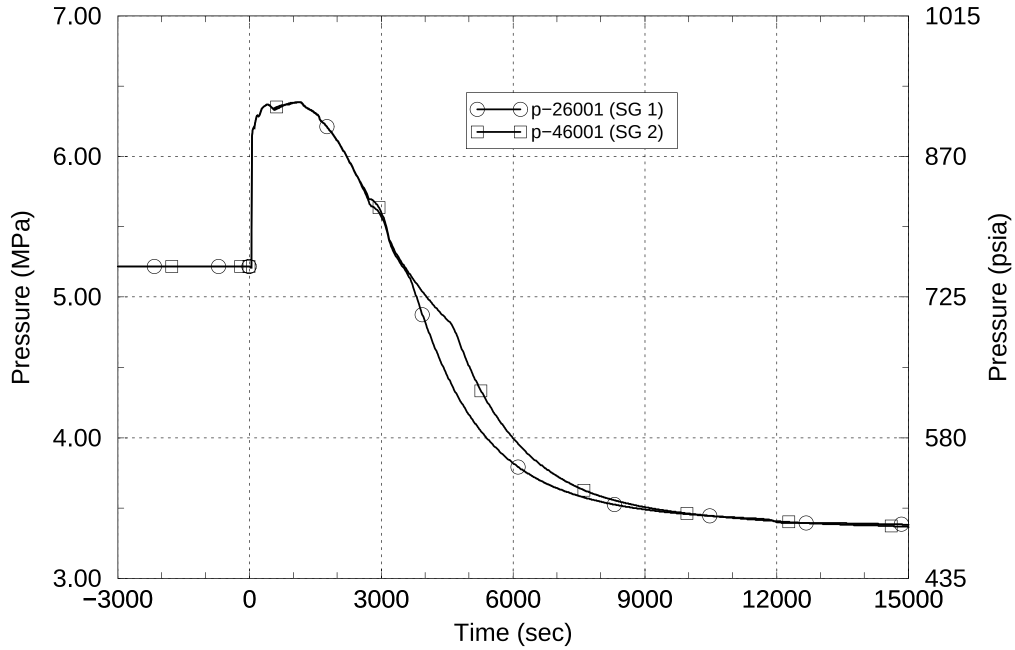


Figure 3.3.2-5 Steam Generator Pressures - Palisades Case 60

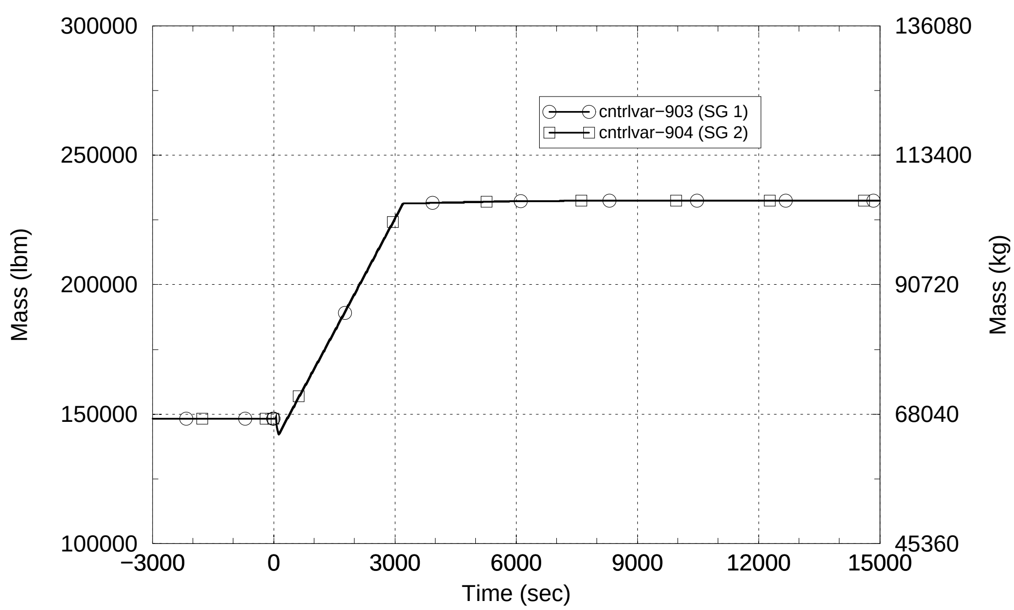


Figure 3.3.2-6 Steam Generator Secondary Fluid Masses - Palisades Case 60

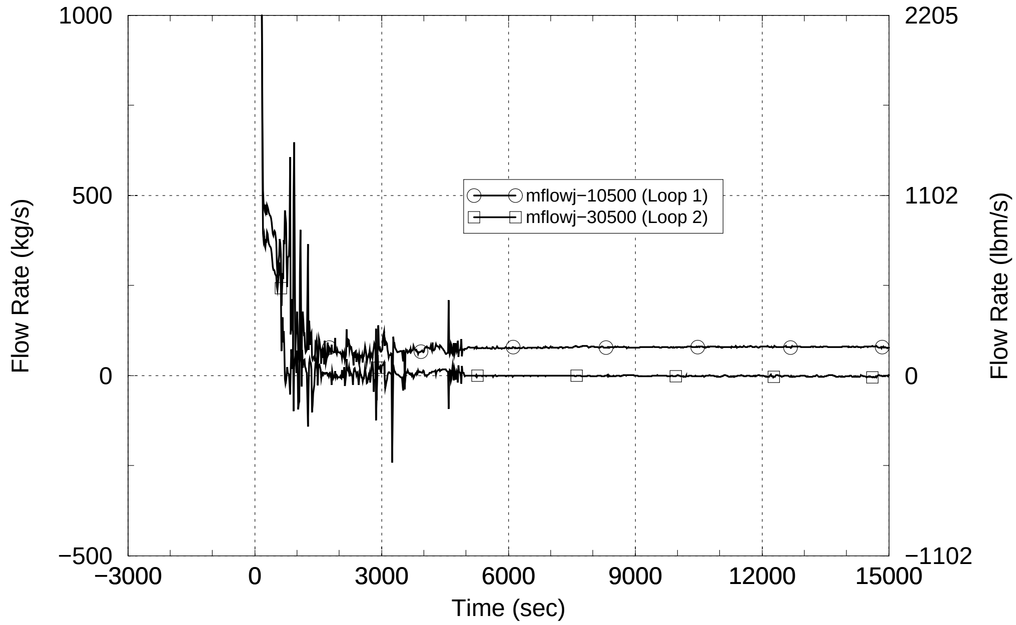


Figure 3.3.2-7 Hot Leg Flows - Palisades Case 60

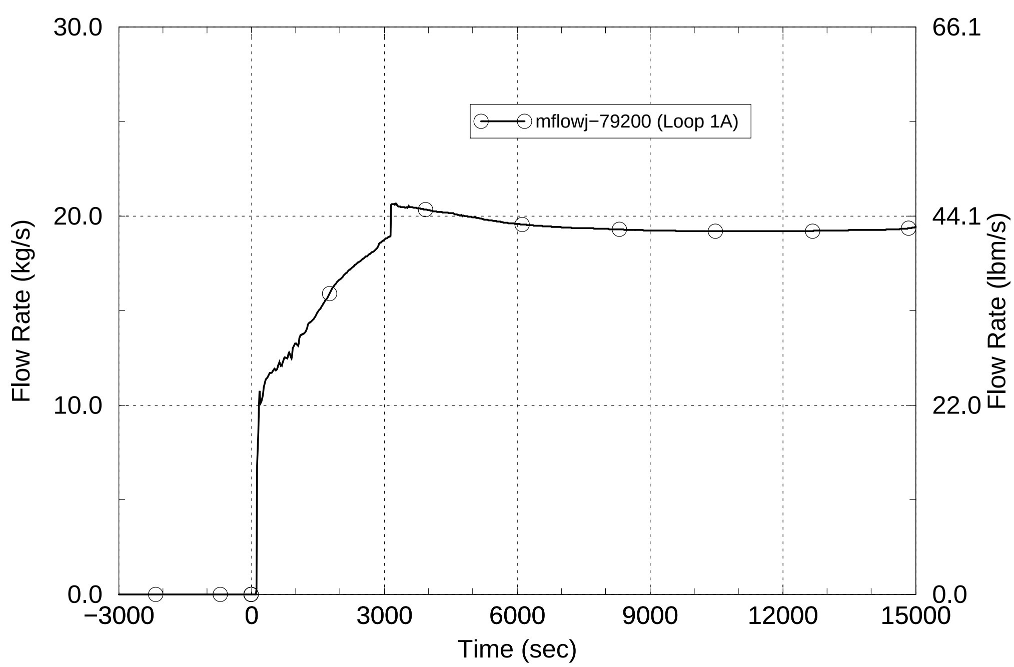


Figure 3.3.2-8 Loop A1 High Pressure Injection Flow - Palisades Case 60

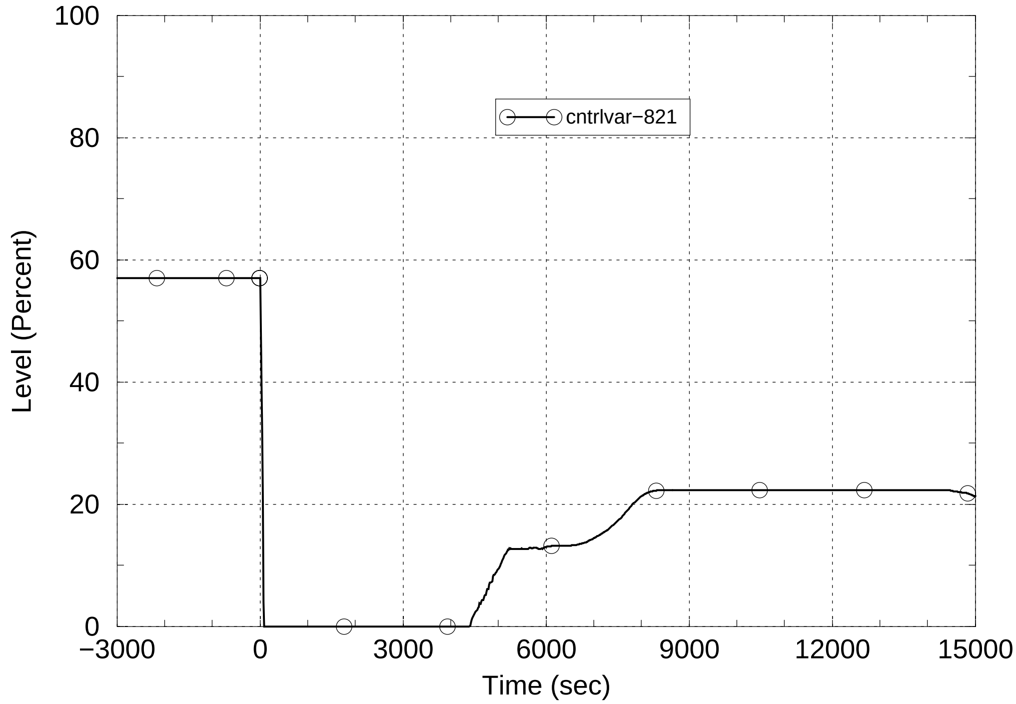


Figure 3.3.2-9 Pressurizer Level - Palisades Case 60

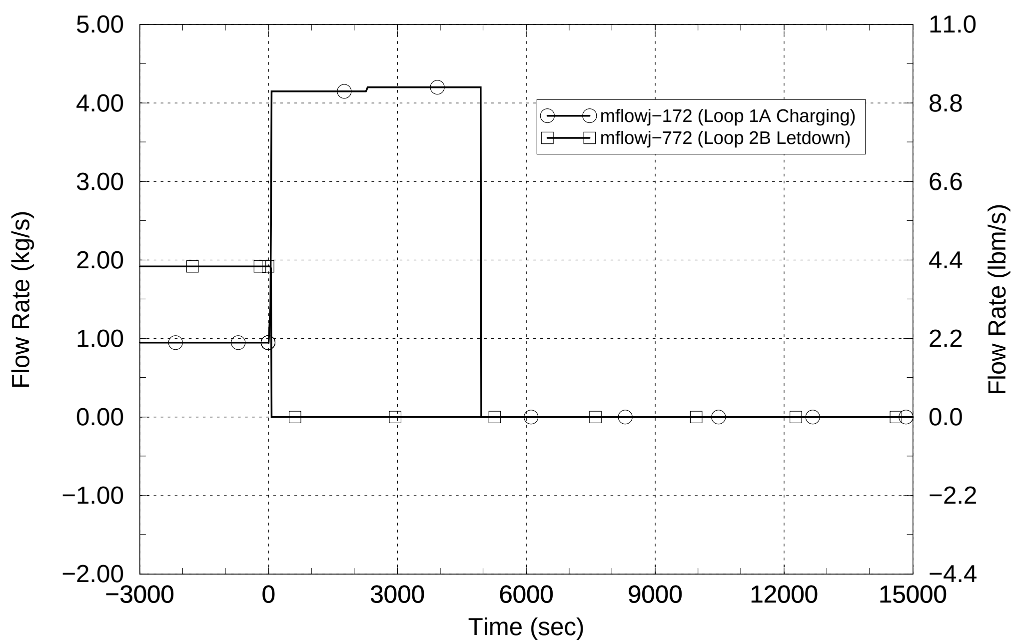


Figure 3.3.2-10 Charging and Letdown Flows - Palisades Case 60

3.3.2.2 Reactor Trip with One Stuck-Open Pressurizer Safety Relief Valve which Re-Closes at 6000 Seconds from Hot Zero Power Condition - Palisades Case 65

With the plant in HZP operation, this event starts with a reactor trip and the failing-open of one of the three pressurizer safety relief valves (SRVs). Since the pressurizer SRVs are not normally challenged during reactor trip from HZP conditions, the failing open of an SRV represents a spurious failure. The failed-open SRV is assumed to re-close 6,000 s into the event sequence, after the RCS has depressurized and cooled. The discharge from the failed-open SRV through the pressurizer relief tank is assumed not to result in a containment high pressure signal. As a result of this assumption, the containment spray system is not initiated and the safety injection refueling water storage tank (SIRWT) inventory is not drawn down sufficiently to result in a realignment of the suction for the HPI system from the RWST to the containment sump (an event which leads to warmer HPI fluid temperatures). The operator is assumed not to throttle the HPI flow, which is normally done when RCS subcooling and pressurizer level criteria have been met.

The following modeling changes were made to simulate this event sequence. Model input was changed to trip the reactor and open the pressurizer SRV with the lowest opening setpoint pressure at the start of the transient calculation. Trip input also was changed to re-close the failed-open SRV at 6,000 s. The model of the failed-open SRV (Valve 193 in Figure 2.3-2) discharges to a constant atmospheric-pressure boundary condition representing the pressurizer relief tank. The equivalent diameter for the failed-open SRV is 3.62 cm [1.425 in]. The model assumes that this SRV is open from 0 to 6,000 s and is then inoperable afterward. The other two pressurizer SRVs are assumed to be operable throughout the calculation period and therefore are available to limit RCS repressurization following the closure of the failed-open SRV. During HZP operation, the feedwater function is under manual operator control. The main feedwater flow boundary condition in the model (which delivers flow at the small rate needed to remove the HZP steady-state core power and reactor coolant pump heat) was modified to terminate the feedwater flow 1 s after the start of the event sequence. This change, which represents the expected operator response, is needed to avoid overfilling the SGs during the event sequence calculation.

The RELAP5-calculated sequence of events for Case 65 is shown in Table 3.3-2. The RELAP5-calculated responses for the RCS pressure, average reactor vessel downcomer fluid temperature and average reactor vessel wall inside surface heat transfer coefficient for this case are shown in Figures 3.3.2-11, 3.3.2-12 and 3.3.2-13, respectively.

The calculated flow responses of the failed-open pressurizer SRV and the functional SRV with the lower opening setpoint pressure are shown in Figure 3.3.2-14. The functional SRV with the higher opening setpoint pressure did not open during the calculation and a response for it is not shown on the figure. The mass flow rate through the failed-open SRV increases over the first 2,000 s of the event sequence as water is drawn upward through the pressurizer toward it. When the SRV fails opens, the RCS pressure falls rapidly at first, then more slowly as flashing within the RCS is encountered. The RCS depressurization causes a reactor trip signal at 82 s. By definition, the turbine is tripped during steady HZP operation, so for this sequence the reactor trip event does not affect the SG isolation status.

Figure 3.3.2-15 shows the calculated SG secondary pressure responses. Because the core power is so low during HZP operation, the steam pressures do not increase at the beginning of the event sequence. The slowly-declining SG pressures shown in the figure are an indication of reverse (i.e., secondary system to primary system) SG heat transfer caused by the cooling down of the primary coolant system. The SG secondary fluid mass responses are shown in Figure 3.3.2-16. The SG heat loads during this transient are small, so no SG inventory is lost through the main steam SRVs and no AFW flow is needed to maintain SG levels within the normal range.

At 150 s the RCS pressure had fallen to 8.963 MPa [1300 psia], resulting in the operator tripping one reactor coolant pump in each loop. At 214 s the minimum RCS subcooling fell below 13.9 K [25 ^{o}F], a condition that leads the operator to trip the remaining two reactor coolant pumps. The decline in the coolant loop flows caused by the pump trip is indicated in Figure 3.3.2-17, which shows the two hot leg flows at the reactor vessel connections. Because the core power at HZP conditions is so low, the SGs are not needed to remove the RCS heat load and therefore no period of coolant loop natural circulation flow is seen in Figure 3.3.2-17. Instead, after the reactor coolant pumps were tripped both loops rapidly transitioned from forced circulation to stagnant conditions. The Loop 1 hot leg flow response shown after the time of the pump trip and before 6,000 s reflects the fluid flowing toward the failed-open pressurizer SRV. The effects of coolant loop flow stagnation on the reactor vessel downcomer fluid temperature are evident in Figure 3.3.2-12. Under the stagnant coolant loop conditions, the effects of injecting cold HPI fluid into the cold legs are directly felt in the vessel downcomer and the fluid temperatures there decline rapidly.

RCS depressurization to 10.98 MPa [1593 psia] led to a safety injection actuation signal at 82 s and the starting of the HPI and LPI pumps after a 27-second delay (which represents effects related to plant instrumentation, control systems and pump start up timing). The calculated HPI flow rate for Cold Leg A1 is shown in Figure 3.3.2-18; the total HPI flow rate is four times the flow shown in the figure. The flow delivered from the centrifugal pumps of the HPI system is a function of the cold leg pressure, with lower pressures resulting in higher HPI flow and with no HPI flow delivered whenever the RCS pressure exceeds the shutoff head of the HPI system (8.906 MPa [1291.7 psia]). During this event sequence calculation, the RCS pressure did not decline below the initial pressure of the SITs or below the shutoff head of the LPI system and therefore no SIT or LPI flow was delivered.

The pressurizer level response shown in Figure 3.3.2-19. The failed-open SRV on the top of the pressurizer draws fluid upward inside the pressurizer. The pressurizer level reaches 100% at 2,145 s and remains there afterward. The charging and letdown flow responses are shown in Figure 3.3.2-20. The letdown flow was isolated early in the event sequence at the time of the safety injection actuation signal. Because of the high pressurizer level condition, the charging flow does not increase during this event sequence. However, the charging flow continues throughout the event sequence at a rate representing the minimum flow from one of the three charging pumps. Once it was filled, the pressurizer remained full as a result of this charging flow. The charging pumps are of positive-displacement type, so they deliver flow at a rate that is independent of the RCS pressure.

At 6,000 s, the failed-open pressurizer SRV was assumed to re-close. This event resulted in a rapid RCS repressurization (Figure 3.3.2-11) to above the shutoff head of the HPI system pumps, stopping the HPI flow (Figure 3.3.2-18) and reversing the RCS cooldown (Figure 3.3.2-12). The RCS pressure increase was limited by the opening of one of the operable pressurizer SRVs (Figure 3.3.2-19). During the latter portion of the event sequence the calculated conditions reflect an RCS mass balance and a partial RCS energy balance. The time-averaged flow through the operable pressurizer SRV is balanced by the steady charging system mass addition rate. However, the core heat addition rate is only partially balanced by the cooling afforded to the RCS from adding cold charging fluid and removing warm fluid through the operable pressurizer SRVs. Since this cooling was not sufficient to remove the entire core decay heat rate, the RCS continued to slowly heat up (see Figure 3.3.2-12).

The minimum average reactor vessel downcomer fluid temperature, 366 K [199°F], is reached at 6,570 s, shortly after the time when the failed-open pressurizer SRV is assumed to re-close. After the minimum downcomer temperature is achieved, the RCS pressure rapidly increases to above the opening setpoint pressure of the operable pressurizer SRVs, 17.51 MPa [2540 psia].

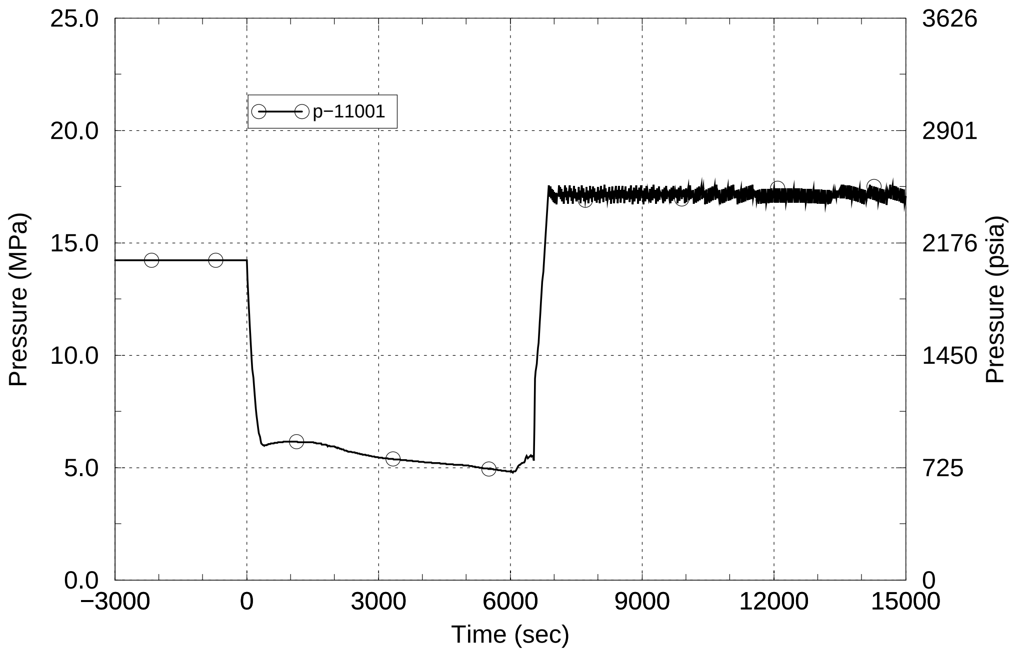


Figure 3.3.2-11 Reactor Coolant System Pressure - Palisades Case 65

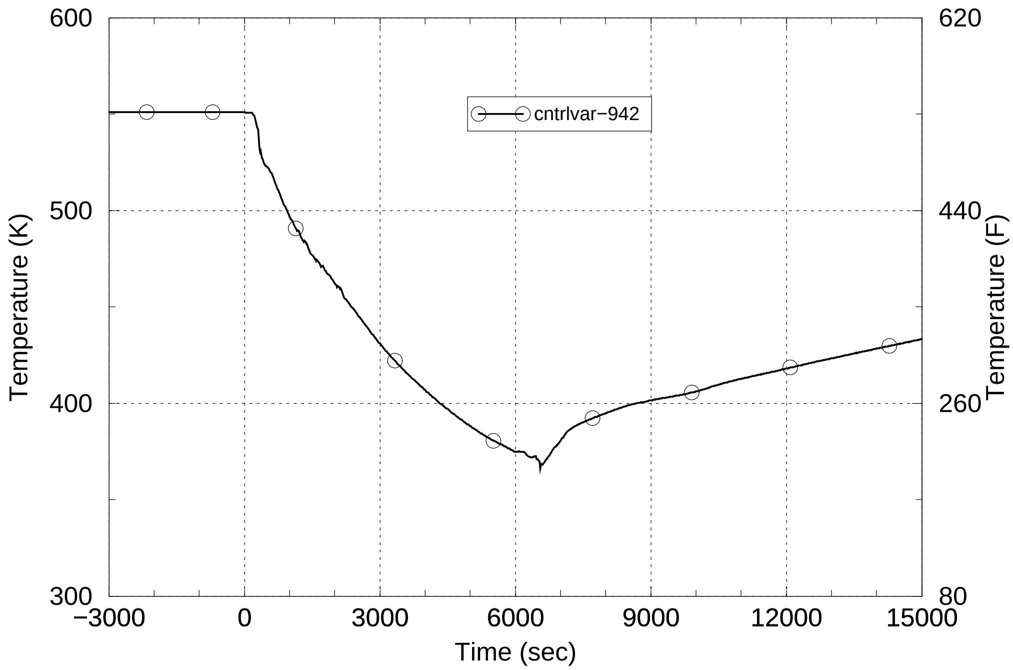


Figure 3.3.2-12 Average Reactor Vessel Downcomer Fluid Temperature - Palisades Case 65

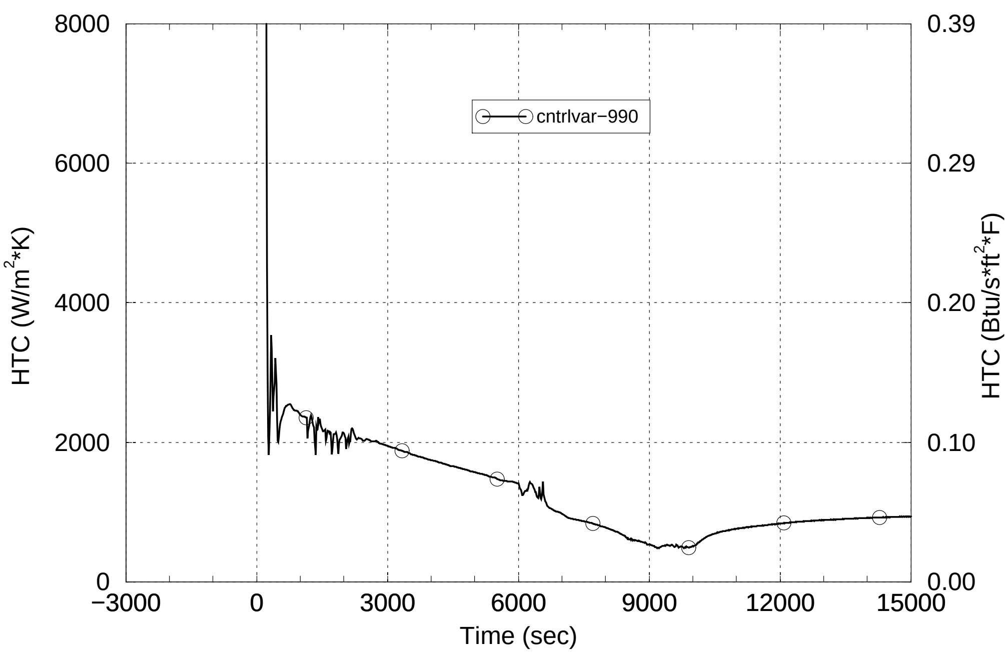


Figure 3.3.2-13 Avg Reactor Vessel Inner-Wall Heat Transfer Coefficient - Palisades Case 65

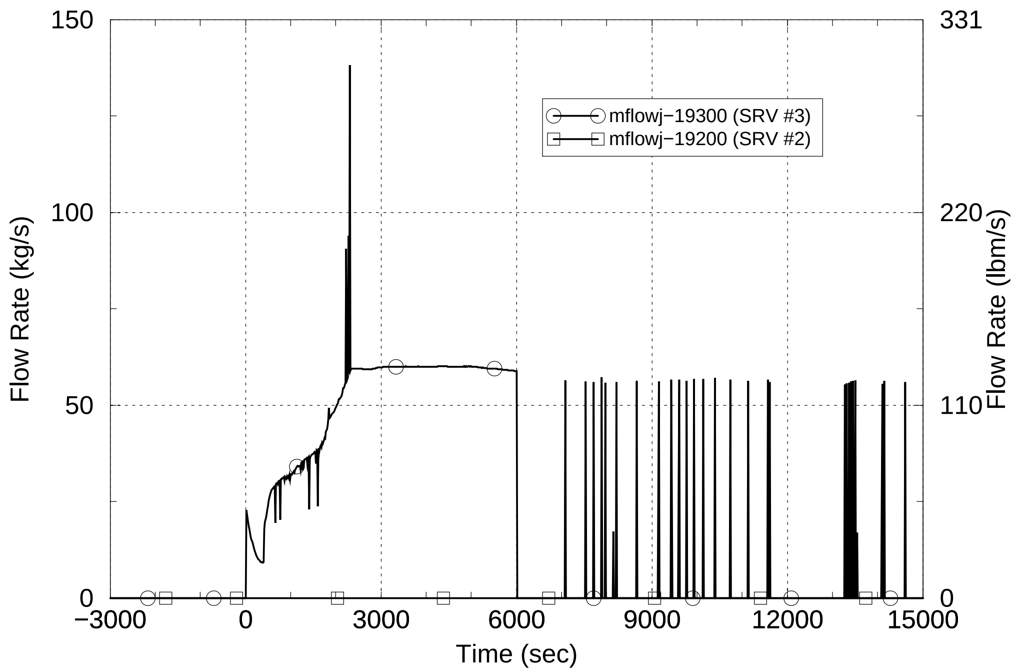


Figure 3.3.2-14 Break Flow - Palisades Case 65

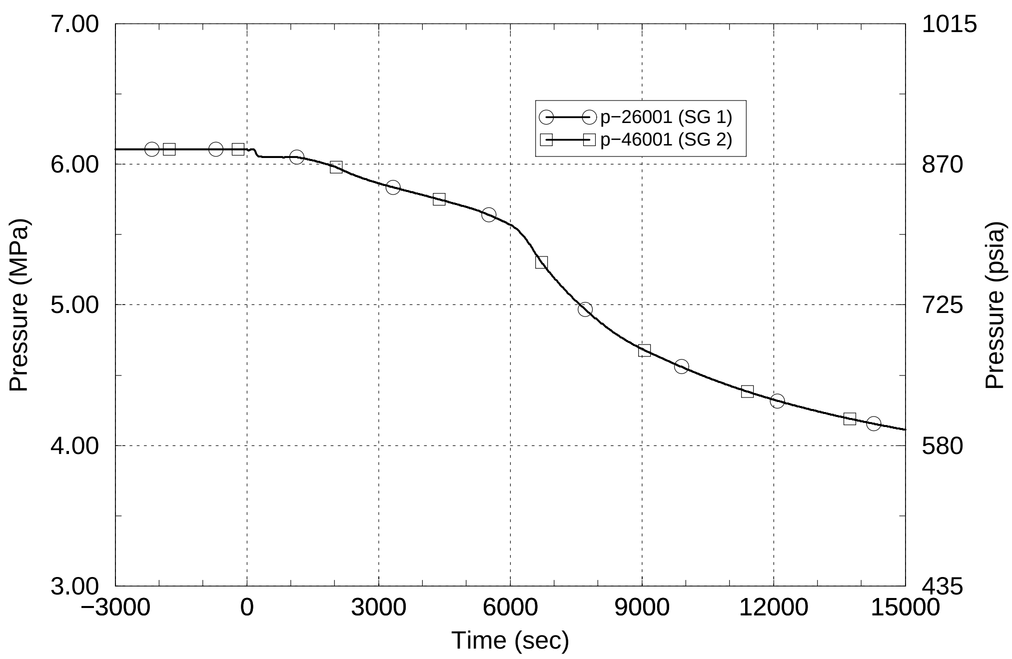


Figure 3.3.2-15 Steam Generator Pressures - Palisades Case 65

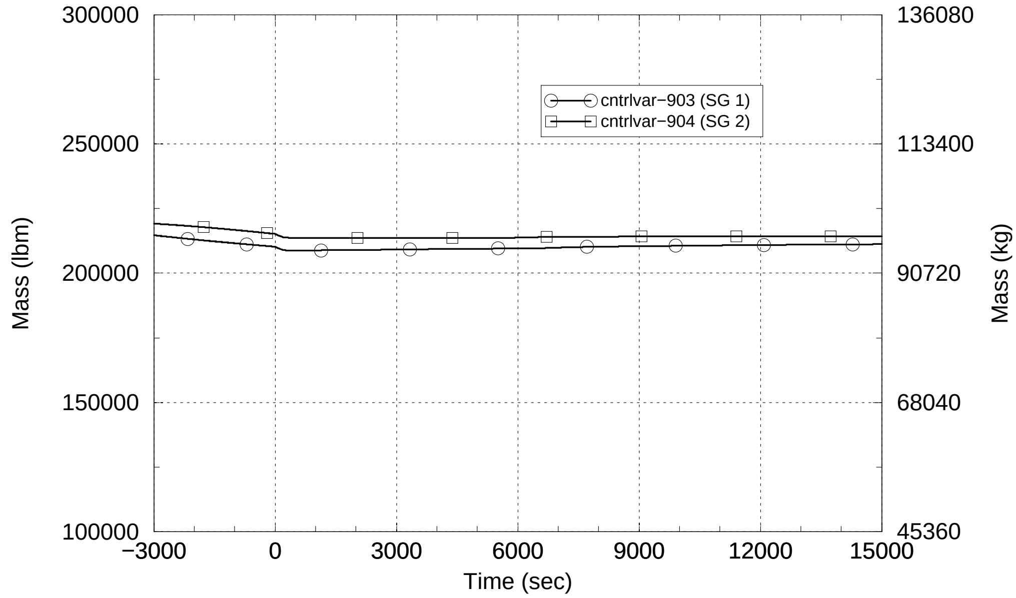


Figure 3.3.2-16 Steam Generator Secondary Fluid Masses - Palisades Case 65

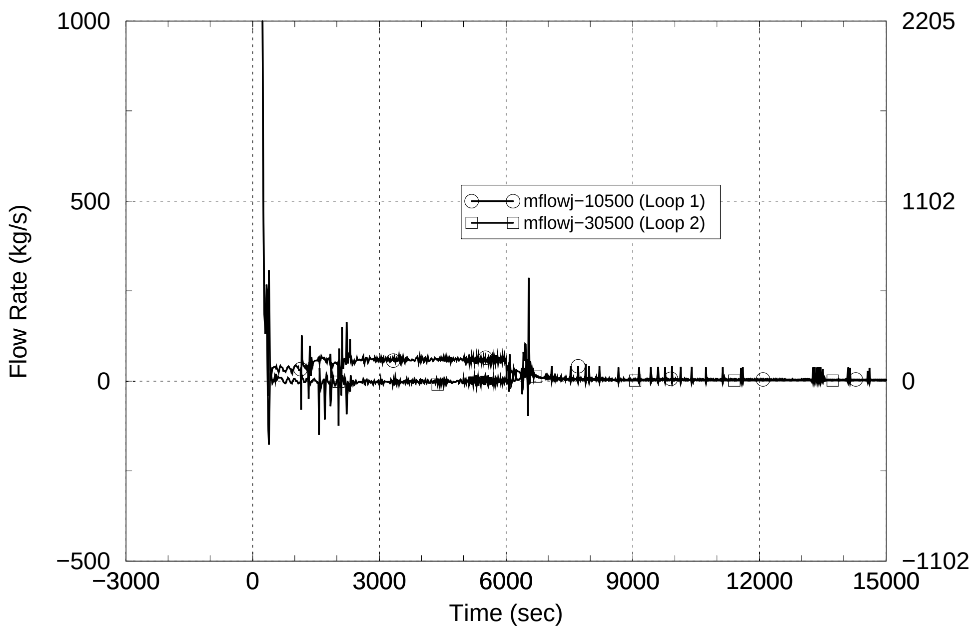


Figure 3.3.2-17 Hot Leg Flows - Palisades Case 65

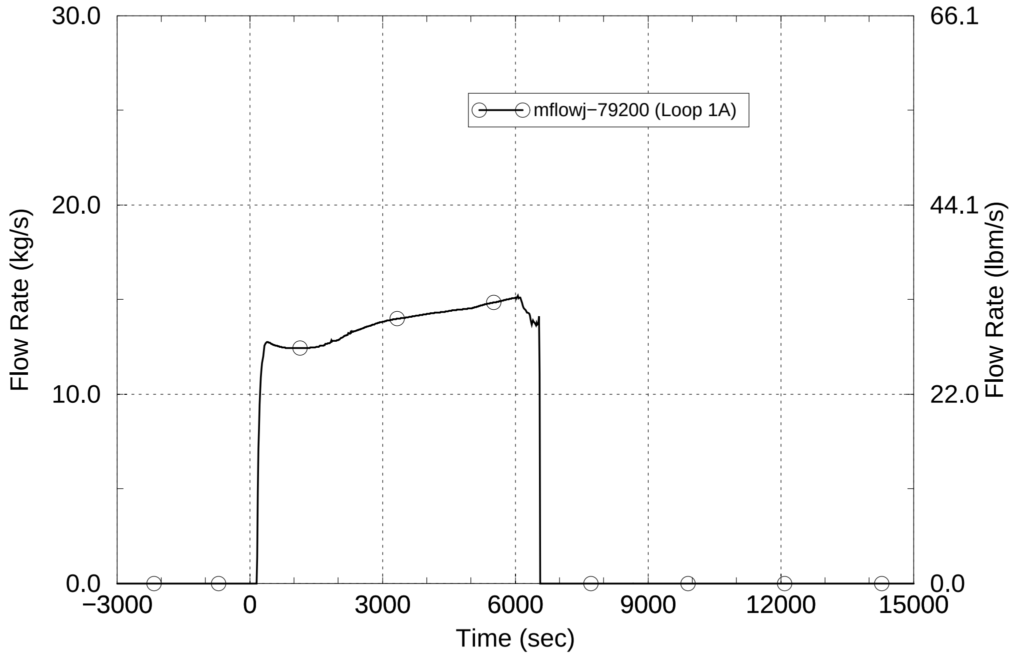


Figure 3.3.2-18 Loop A1 High Pressure Injection Flow - Palisades Case 65

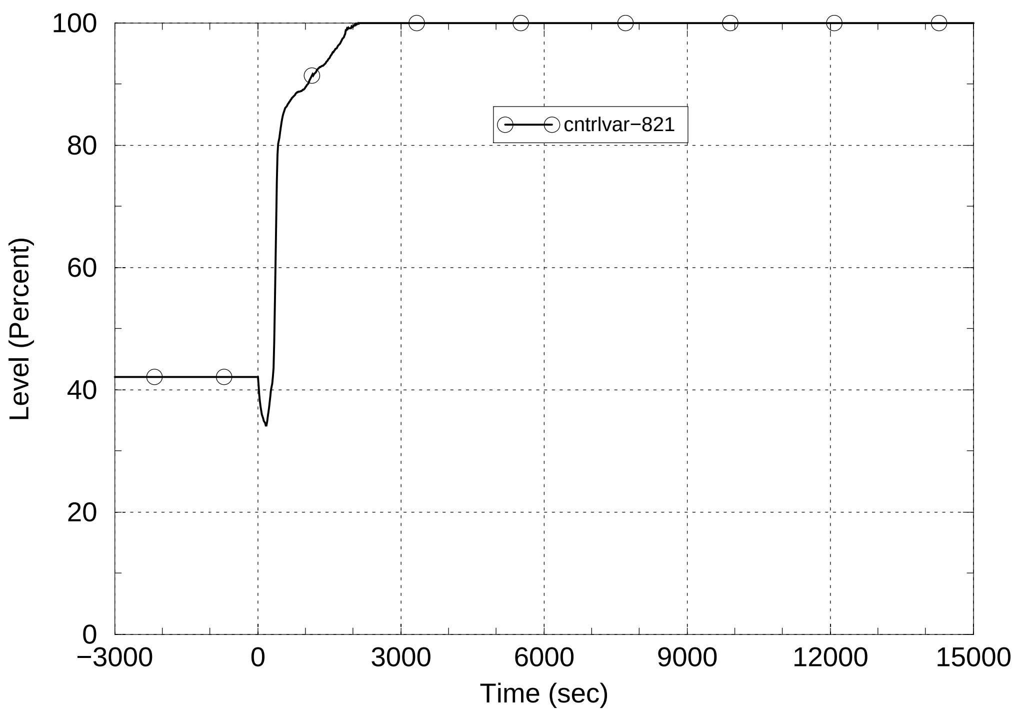


Figure 3.3.2-19 Pressurizer Level - Palisades Case 65

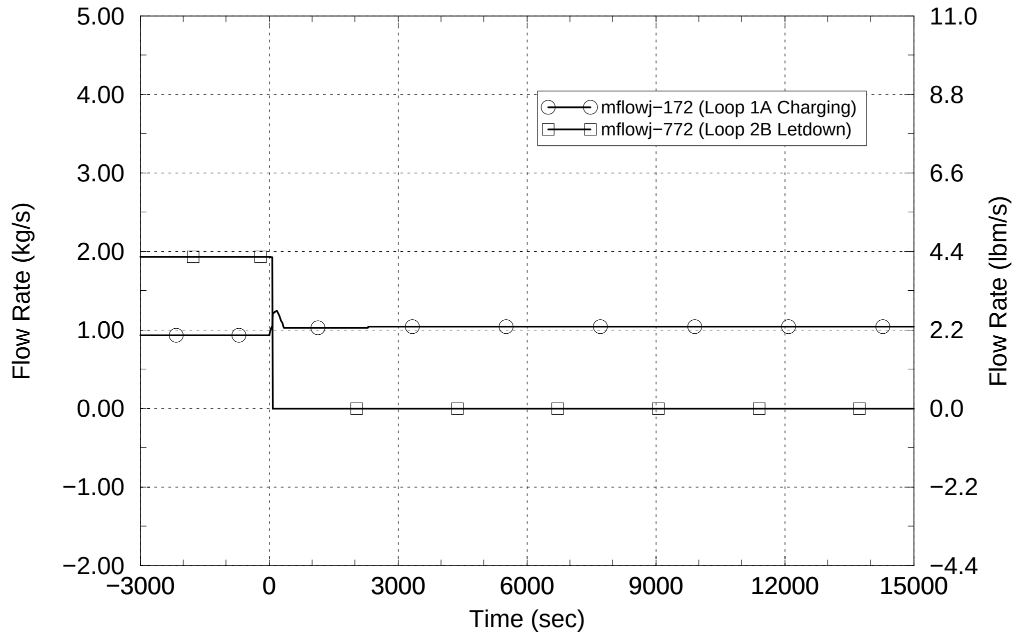


Figure 3.3.2-20 Charging and Letdown Flows - Palisades Case 65

3.3.3 Sequences Initiated by Primary Coolant System Breaks with a 10.16-cm [4-in] Diameter

Three of the 12 Palisades PTS-risk-dominant event sequences involved primary coolant system breaks with a 10.16-cm [4- in] diameter. These three sequences are described as follows:

<u>Case 58</u> is an event initiated by a 10.14-cm [4-in] diameter break in the pump-discharge cold leg with the reactor in hot full power (HFP) operation. The operator is assumed not to throttle HPI flow. Temperatures representing winter conditions are assumed for the fluids in the HPI, LPI and SIT ECC systems.

<u>Case 59</u> is an event initiated by a 10.14-cm [4-in] diameter break in the pump-discharge cold leg with the reactor in HFP operation. The operator is assumed not to throttle HPI flow. Temperatures representing summer conditions are assumed for the fluids in the HPI, LPI and SIT ECC systems.

<u>Case 64</u> is an event initiated by a 10.14-cm [4-in] diameter break in the pressurizer surge line with the reactor in HFP operation. The operator is assumed not to throttle HPI flow. Temperatures representing summer conditions are assumed for the fluids in the HPI, LPI and SIT ECC systems.

The common features of this sequence group are RCS depressurization caused by the break and RCS cooldown caused by the depressurization and the injection of cold HPI, LPI and SIT fluid. The break size for this group is large enough to result in tripping of all four reactor coolant pumps and RCS draining which leads to an interruption of coolant loop natural circulation flow. The break size for this group is also large enough to allow the RCS to depressurize sufficiently to permit HPI, LPI and SIT ECCS flows.

3.3.3.1 10.16-cm [4-in] Diameter Cold Leg Break from Hot Full Power Condition with Winter-Season ECCS Temperatures - Palisades Case 58

With the plant in HFP operation, this event starts with a 10.16-cm [4-in] diameter break in the pump-discharge cold leg. The operator is assumed not to throttle the HPI flow, which is normally done if RCS subcooling and pressurizer level criteria have been met. The calculation assumes that the temperatures of the ECCS fluids are representative of winter-season conditions: HPI and LPI temperatures of 277.6 K [40 °F] and SIT temperatures of 288.7 K [60°F] (the nominal ECCS fluid temperatures are listed in Table 2.0-1).

The following modeling changes were made to simulate this event sequence. The cold leg break to a constant atmospheric-pressure containment boundary condition was added to the model in Loop 1A. The equivalent break flow area for a circular break with a diameter of 10.16 cm [4 in] was specified. The break was connected on the side of the horizontal cold leg, at the junction between Cells 1 and 2 of Component 150, as shown in Figure 2.3-2. The critical flow model was activated at the break junction and the flow loss coefficients specified were based on AP600-derived flow loss coefficients (Reference 3.3-1) and scaled for the specific break size and location for this event sequence. The boundary conditions for the HPI, LPI and SIT fluids were changed to represent the winter-season conditions listed above. At the time the reactor coolant pump coast-down was complete, large reverse flow loss coefficients were implemented in the loop seal cold leg regions of the model (Components 140, 340, 640 and 740 in Figure 2.3-2) to prevent the setting up of same-loop cold leg circulation, as discussed in Section 2.0. To eliminate non-physical numerically-driven circulations within the reactor vessel downcomer portion of the model, momentum flux was disabled in all junctions internal to the downcomer region (see discussion in Section 2.3.1). The containment high pressure signal, which results in containment spray actuation, was specified as 31.32 s after event initiation. The modeling for the HPI fluid temperature was modified so as to represent the constant safety injection refueling water tank (SIRWT) winter-season temperature prior to the draining of that tank then switch to a representation of a variable containment sump temperature (specified as a function of the time after the switch). The HPI fluid temperature falls from 331.8 K [137.5°F] immediately following the switch to 323.7 K [123.0°F] at the end of the calculation (15,000 s after the break opens). The model input data for the containment spray actuation time and the containment sump fluid temperature were obtained from an independent Palisades containment analysis for a 10.16-cm [4-in] diameter break in the RCS.

The RELAP5-calculated sequence of events for Case 58 is shown in Table 3.3-3. The RELAP5-calculated responses for the RCS pressure, average reactor vessel downcomer fluid temperature and average reactor vessel wall inside surface heat transfer coefficient for this case are shown in Figures 3.3.3-1, 3.3.3-2 and 3.3.3-3, respectively.

The calculated break flow response is shown in Figure 3.3.3-4. When the break opens, the RCS pressure falls rapidly at first, then more slowly as flashing within the RCS is encountered. The

RCS depressurization causes a reactor trip signal at 11 s. The reactor trip causes a turbine trip, isolating the steam generator systems.

Figure 3.3.3-5 shows the calculated SG secondary system pressure responses. The turbine trip causes the secondary system pressures to rise; the pressure increase is limited by the opening of the turbine bypass and atmospheric dump valves. The steam pressures did not increase sufficiently to open the main steam safety relief valves. The declining SG pressures after 1,000 s are an indication of reverse (i.e., secondary system to primary system) SG heat transfer caused by the cooling down of the primary coolant system. The SG secondary fluid mass responses are shown in Figure 3.3.3-6. The turbine trip resulted in collapse of the secondary system indicated levels, which initiated auxiliary feedwater (AFW) flow to both SGs. The AFW flow replenished the SG secondary fluid inventories; AFW flow was throttled to maintain the SG levels within the normal range.

At 26 s, the RCS pressure had fallen to 8.963 MPa [1300 psia], resulting in the operator tripping one reactor coolant pump in each loop. At 27 s the minimum RCS subcooling fell below 13.9 K [25°F], resulting in the operator tripping the remaining two reactor coolant pumps. The decline in the coolant loop flows caused by the pump trip is indicated in Figure 3.3.3-7, which shows the two hot leg flows at the reactor vessel connections. The decline in the coolant loop flows was rapid and total, with no significant period of natural circulation prior to complete stagnation of the loop flows. The effects of loop flow stagnation on the reactor vessel downcomer fluid temperature are evident in Figure 3.3.3-2. Under the stagnant coolant loop conditions, the effects of injecting cold HPI, LPI and SIT fluid into the cold legs are directly felt in the vessel downcomer and the fluid temperatures there decline rapidly.

RCS depressurization to 10.98 MPa [1593 psia] led to a safety injection actuation signal at 17 s and the starting of the HPI and LPI pumps after a 27-second delay (which represents effects related to plant instrumentation, control systems and pump start-up timing). The calculated HPI and LPI flow rates for Cold Leg A1 are shown in Figure 3.3.3-8; the total HPI and LPI flow rates are four times the flows shown in the figure. The flow delivered from the centrifugal pumps of the HPI and LPI systems are functions of the cold leg pressure, with lower pressures resulting in higher injection flows and with no injection flow delivered whenever the RCS pressure exceeds the shutoff heads of the systems (8.906 MPa [1291.7 psia] for HPI and 1.501 MPa [217.7 psia] for LPI). At 2,702 s, a recirculation actuation signal was calculated as a result of a low SIRWT level condition. The model tracks SIRWT inventory and level based on the flows drawn from the tank by the containment spray, HPI, LPI and charging systems. At this time the suction for the HPI system is switched from the SIRWT to the containment sump (with the resulting increase in HPI fluid temperature described above) and the LPI pumps are automatically tripped.

The effects of RCS coolant inventory loss through the break are evident in the declining pressurizer level response shown in Figure 3.3.3-9. The pressurizer was completely drained over the first 30 s of the event sequence and remained empty thereafter. The letdown flow was isolated early in the event sequence at the time of the safety injection actuation signal. The charging system flow increased in response to the low pressurizer level condition, with all three charging pumps delivering flow. Charging flow was terminated at 4,502 s, which is 1,800 s after the time of the recirculation actuation signal. It is estimated that 30 minutes would be required after the recirculation actuation signal for the charging system to completely drain the SIRWT of its remaining inventory. Afterward, no source of fluid is available for the charging system. Because the break size for this event sequence is large, the charging system flow is of relatively small importance in relation to the HPI, LPI and SIT ECCS flows.

The Loop 1A SIT discharge flow rate response is shown in Figure 3.3.3-10; the total SIT flow rate is four times the flow shown in the figure. Intermittent SIT flow began at 1,628 s, when the RCS pressure fell below the initial SIT pressure, 1.480 MPa [214.7 psia]. The SITs discharge whenever the RCS pressure is below the tank pressure (which declines as the liquid inventory flows out of the SITs). The SIT discharge period ended at 6,052 s as a result of the minor RCS repressurization shown in Figure 3.3.3-1, with a remaining liquid inventory of 0.355 m^3 [12.53 ft^3] in each of the four SITs.

During the latter portion of the event sequence the calculated conditions reflect balances in the RCS mass and energy flows. The break mass flow rate is balanced by the HPI mass addition rate. The core heat addition rate is balanced by the cooling afforded to the RCS from adding cold HPI fluid and removing warm fluid at the break. These balanced conditions were reached at about 10,000 s.

The minimum average reactor vessel downcomer fluid temperature, 331 K [136°F], is reached at 2,700 s, shortly after the time when the suction for the HPI system is switched to the containment sump and the LPI pumps are tripped. The RCS pressure, which was calculated to be 1.319 MPa [191.3 psia] at 2,709 s, rose moderately later during the event sequence as a result of the effects of warming the HPI fluid.

Table 3.3-3 Comparison of Event Timing for Dominant Palisades Event Sequences - Group 3, Primary System Breaks with a Diameter of 10.16 cm [4 in]

	Event Time (seconds)		
Event(s)	Case 58, HFP, 10.16-cm [4-in] Diameter Cold Leg Break, Winter ECCS	Case 59, HFP, 10.16-cm [4-in] Diameter Cold Leg Break. Summer ECCS	Case 64, HFP, 10.16-cm [4-in] Diameter Surge Line Break, Summer ECCS
Break opens	0	0	0
Reactor trip signal, turbine trip	11	11	14
Safety injection actuation signal, isolate letdown flow	17	17	20
Low RCS pressure condition causes operator to trip one reactor coolant in each coolant loop	26	26	30
Low RCS subcooling condition causes operator to trip the two remaining reactor coolant pumps	27	27	31

	Event Time (seconds)		
Event(s)	Case 58, HFP, 10.16-cm [4-in] Diameter Cold Leg Break, Winter ECCS	Case 59, HFP, 10.16-cm [4-in] Diameter Cold Leg Break. Summer ECCS	Case 64, HFP, 10.16-cm [4-in] Diameter Surge Line Break, Summer ECCS
Pressurizer level reaches 0%	30	30	30
Containment high pressure signal, results in containment spray system initiation	31	31	31
HPI and LPI systems available, HPI flow begins	44	44	47
Reactor coolant pump coast-down completed	113	114	114
SIT flow begins	1628	2138	1418
LPI flow begins	1913	2349	1539
Pressurizer level reestablished above 0%	N/A	N/A	1885
Recirculation actuation signal, suction for HPI system switched from SIRWT to containment sump, LPI pumps tripped	2702	2832	2550
Charging flow stops, SIRWT completely drained	4502	4632	4350
Calculation terminated	15000	15000	15000
Note: N/A indicates this event is not applicable for the event sequence.			

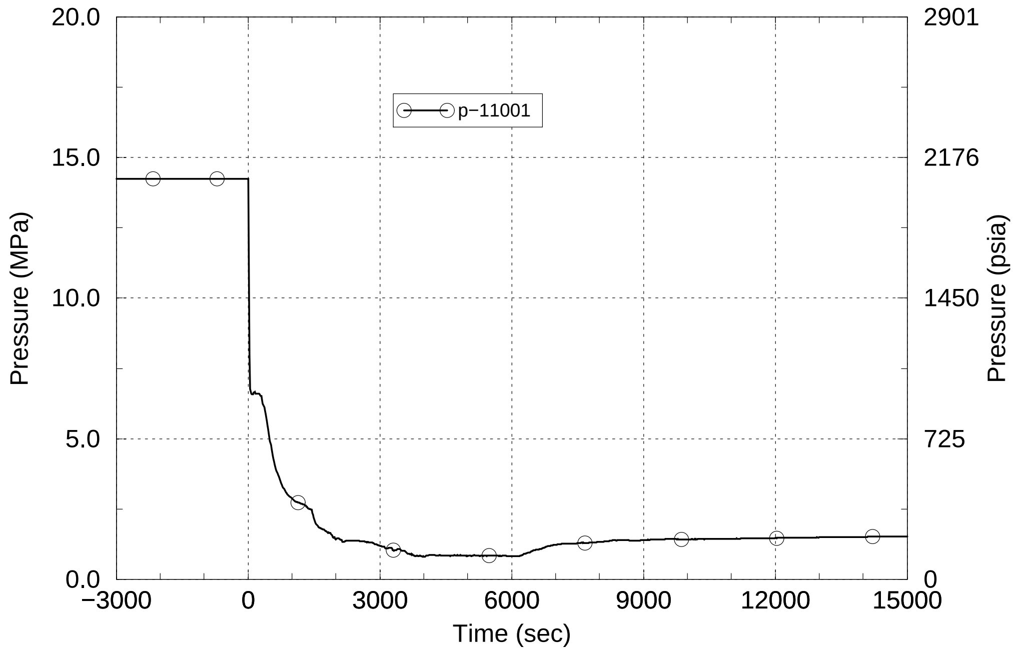


Figure 3.3.3-1 Reactor Coolant System Pressure - Palisades Case 58

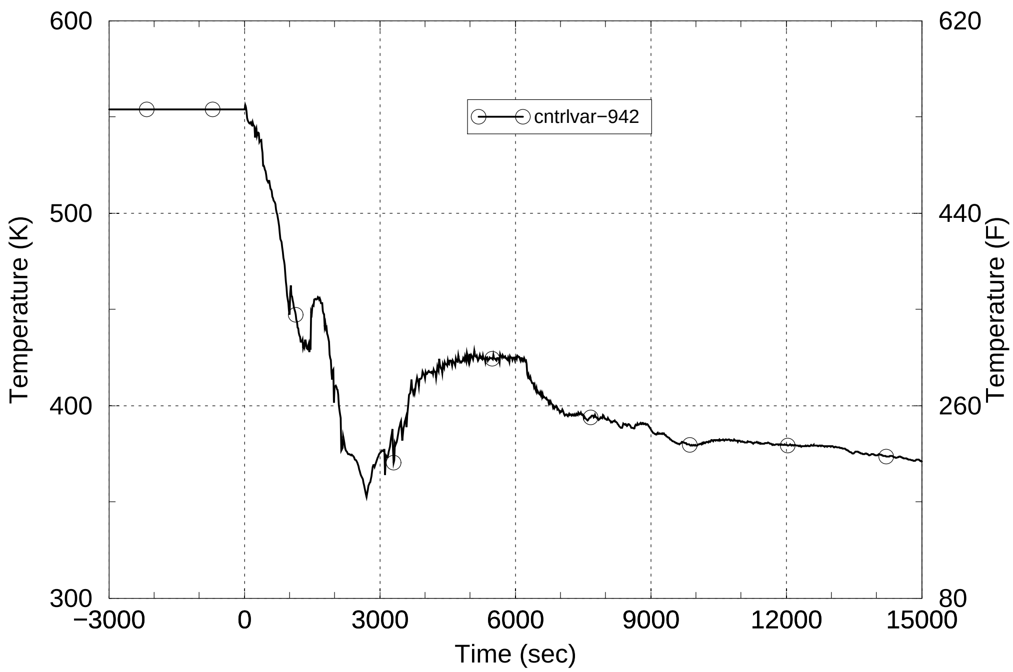


Figure 3.3.3-2 Average Reactor Vessel Downcomer Fluid Temperature - Palisades Case 58

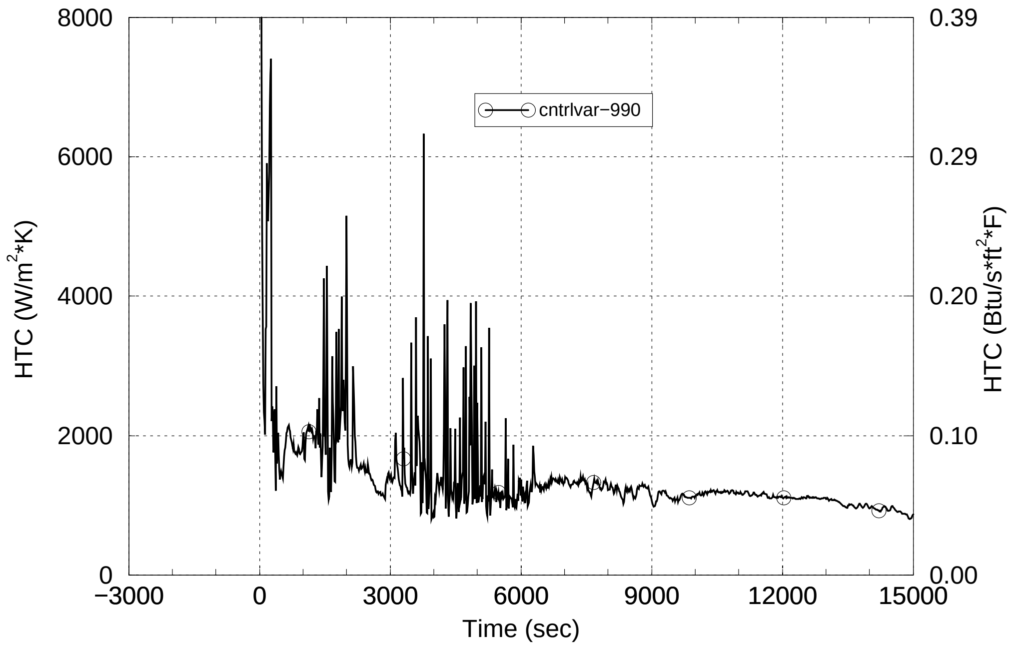


Figure 3.3.3-3 Average Reactor Vessel Inner-Wall Heat Transfer Coefficient - Palisades Case 58

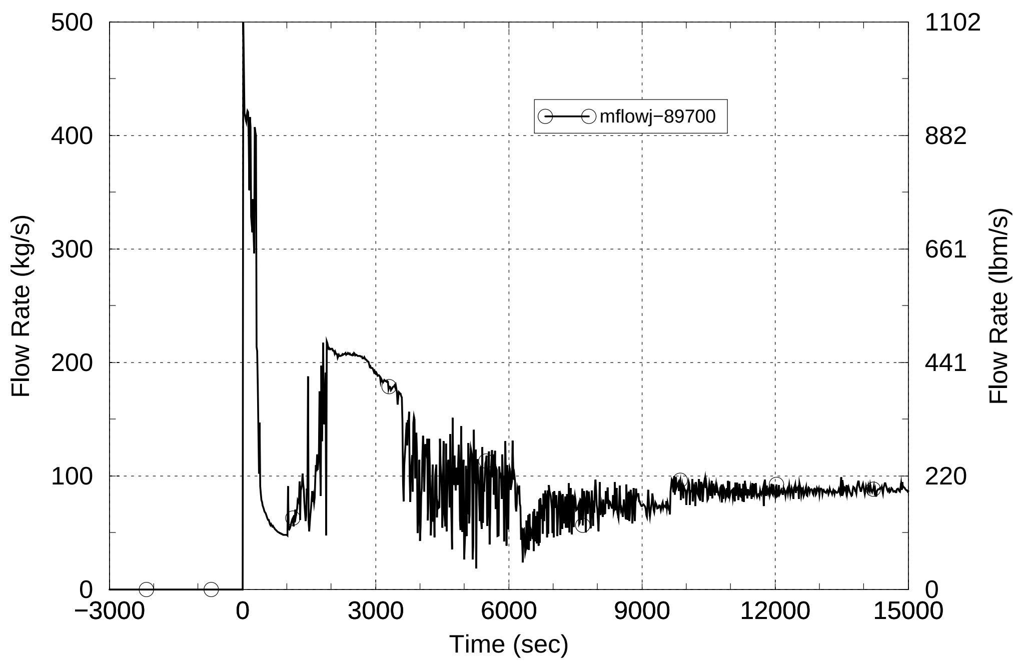


Figure 3.3.3-4 Break Flow - Palisades Case 58

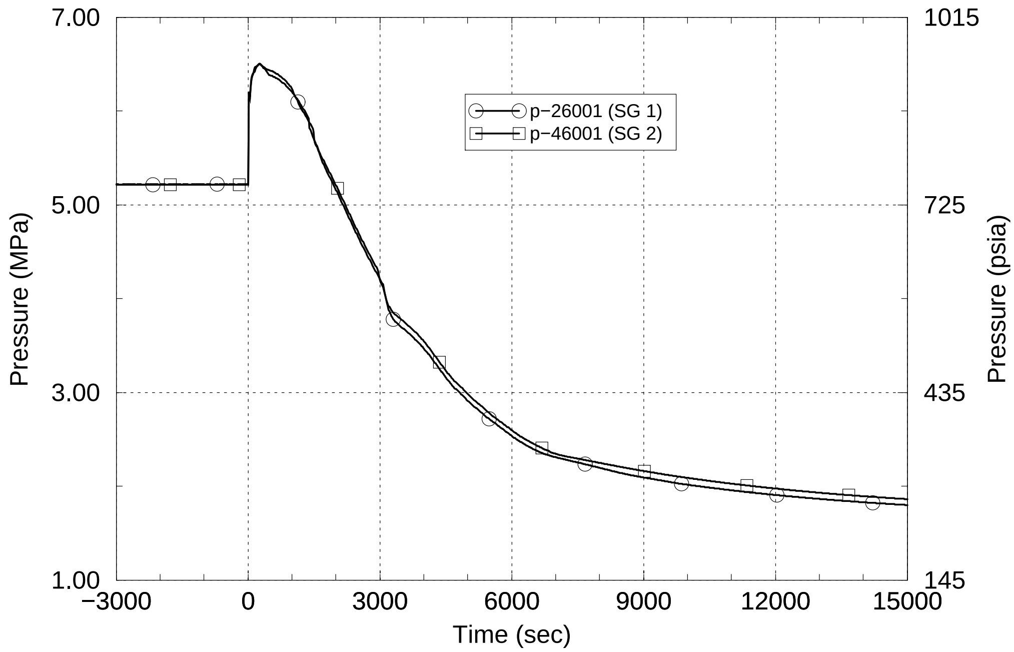


Figure 3.3.3-5 Steam Generator Pressures - Palisades Case 58

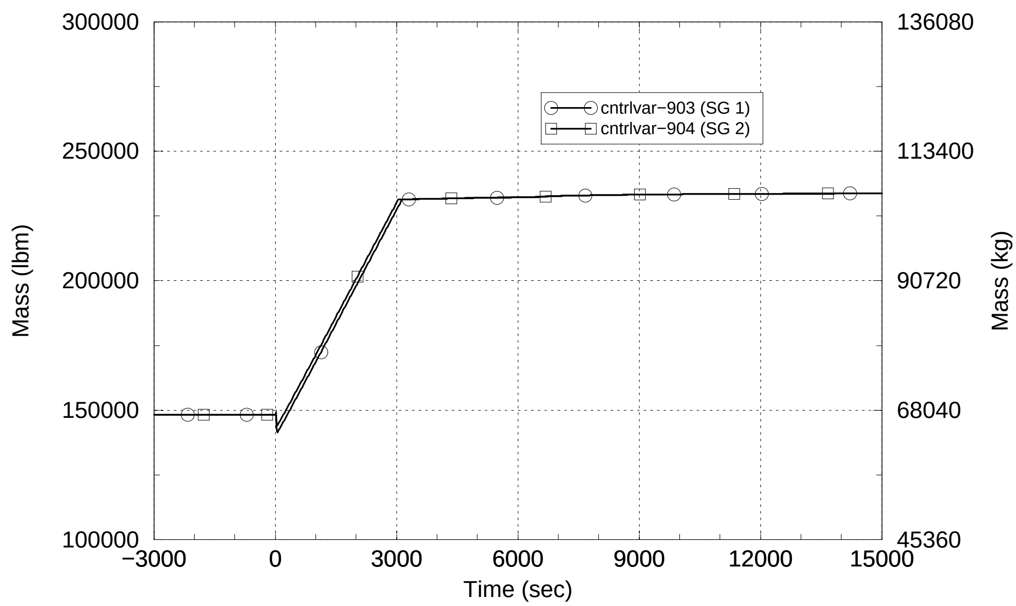


Figure 3.3.3-6 Steam Generator Secondary Fluid Masses - Palisades Case 58

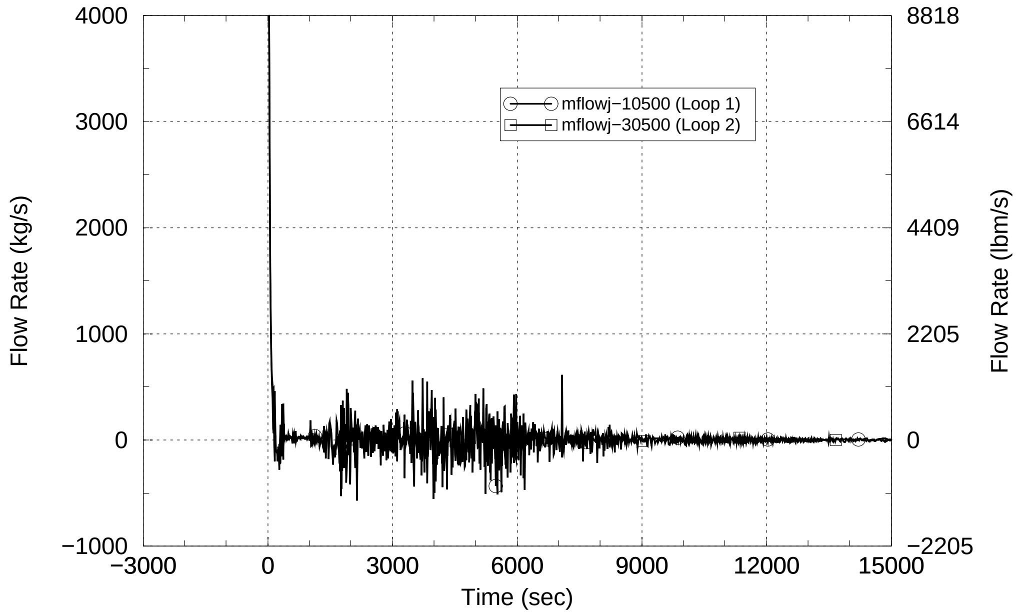


Figure 3.3.3-7 Hot Leg Flows - Palisades Case 58

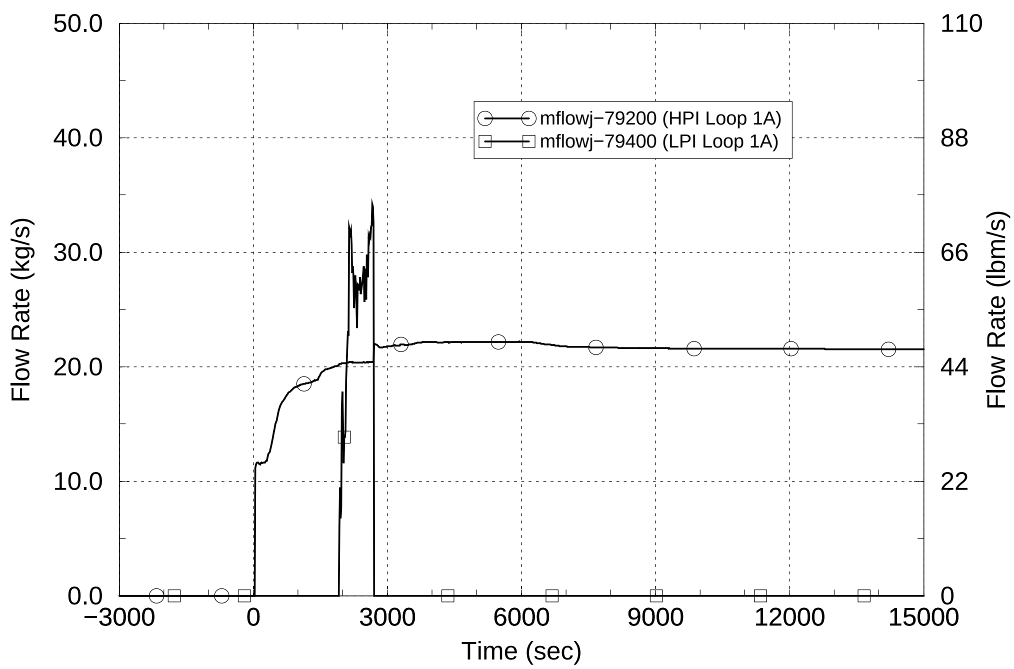


Figure 3.3.3-8 Loop A1 HPI and LPI Flows - Palisades Case 58

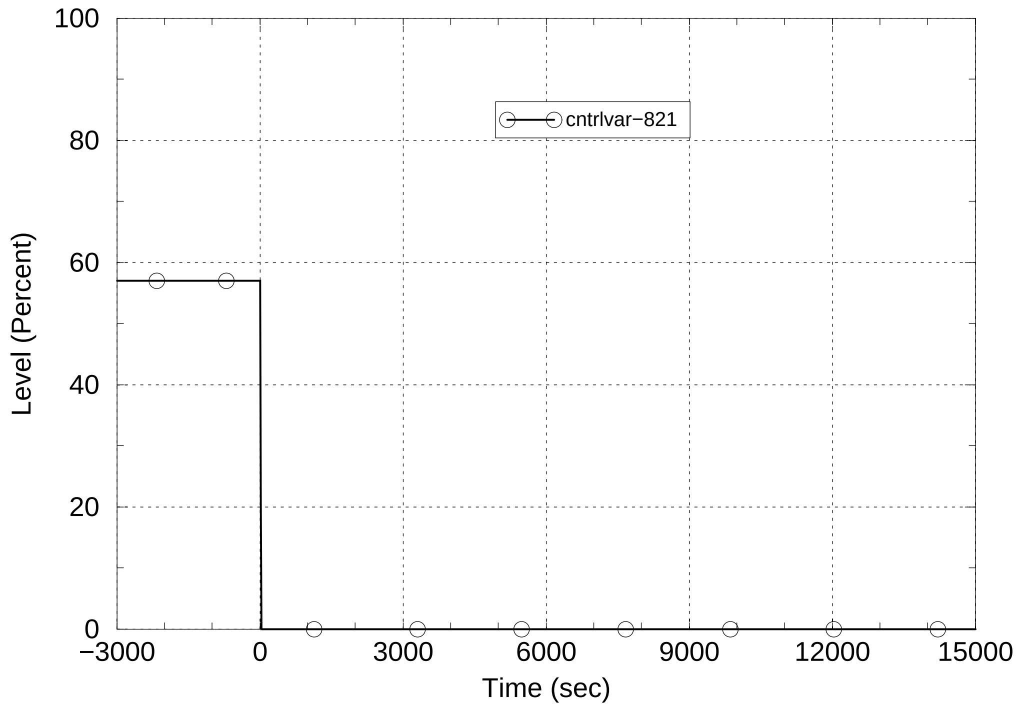


Figure 3.3.3-9   Pressurizer Level - Palisades Case 58

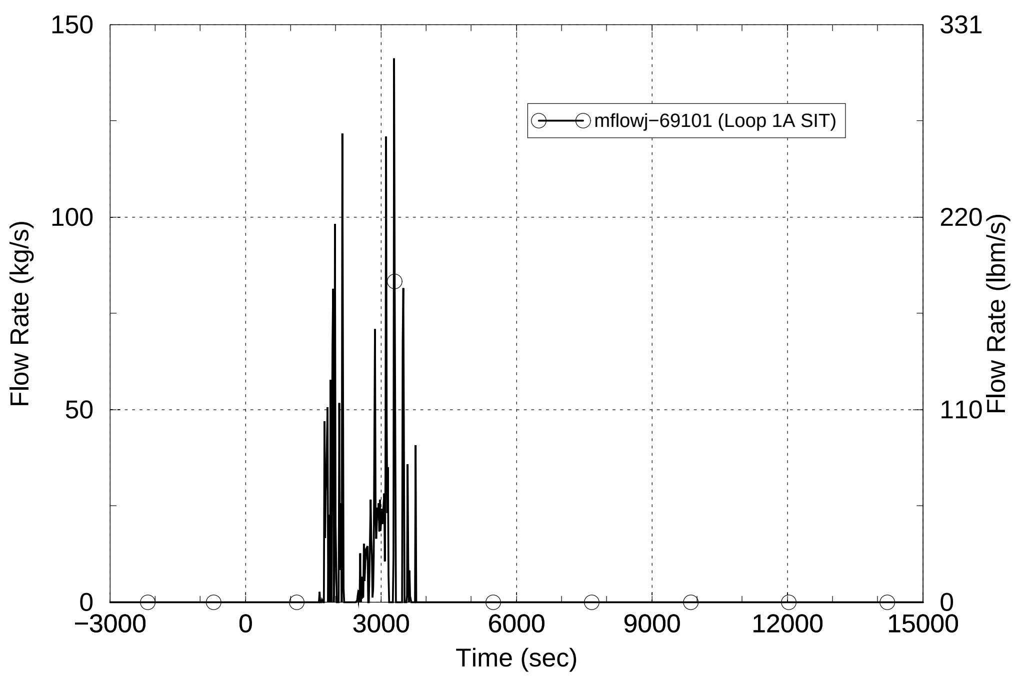


Figure 3.3.3-10   Loop 1A SIT Flow - Palisades Case 58

3.3.3.2 10.16-cm [4-in] Diameter Cold Leg Break from Hot Full Power Condition with Summer-Season ECCS Temperatures - Palisades Case 59

With the plant in HFP operation, this event starts with a 10.16-cm [4-in] diameter break in the pump-discharge cold leg. The operator is assumed not to throttle the HPI flow, which is normally done if RCS subcooling and pressurizer level criteria have been met. The calculation assumes that the temperatures of the ECCS fluids are representative of summer-season conditions: HPI and LPI temperatures of 310.9 K [100°F] and SIT temperatures of 305.4 K [90°F] (the nominal ECCS fluid temperatures are listed in Table 2.0-1).

The following modeling changes were made to simulate this event sequence. The cold leg break to a constant atmospheric-pressure containment boundary condition was added to the model in Loop 1A. The equivalent break flow area for a circular break with a diameter of 10.16 cm [4 in] was specified. The break was connected on the side of the horizontal cold leg, at the junction between Cells 1 and 2 of Component 150, as shown in Figure 2.3-2. The critical flow model was activated at the break junction and the flow loss coefficients specified were based on AP600-derived flow loss coefficients (Reference 3.3-1) and scaled for the specific break size and location for this event sequence. The boundary conditions for the HPI, LPI and SIT fluids were changed to represent the summer-season conditions listed above. At the time the reactor coolant pump coast-down was complete, large reverse flow loss coefficients were implemented in the loop seal cold leg regions of the model (Components 140, 340, 640 and 740 in Figure 2.3-2) to prevent the setting up of same-loop cold leg circulation, as discussed in Section 2.0. To eliminate non-physical numerically-driven circulations within the reactor vessel downcomer portion of the model, momentum flux was disabled in all junctions internal to the downcomer region (see discussion in Section 2.3.1). The containment high pressure signal, which results in containment spray actuation, was specified as 31.32 s after event initiation. The modeling for the HPI fluid temperature was modified so as to represent the constant safety injection refueling water tank (SIRWT) summer-season temperature prior to the draining of that tank then switch to a representation of a variable containment sump temperature (specified as a function of the time after the switch). The HPI fluid temperature falls from 331.8 K [137.5 °F] immediately following the switch to 323.7 K [123.0 °F] at the end of the calculation (15,000 s after the break opens). The model input data for the containment spray actuation time and the containment sump fluid temperature were obtained from an independent Palisades containment analysis for a 10.16-cm [4-in] diameter break in the RCS.

The RELAP5-calculated sequence of events for Case 59 is shown in Table 3.3-3. The RELAP5-calculated responses for the RCS pressure, average reactor vessel downcomer fluid temperature and average reactor vessel wall inside surface heat transfer coefficient for this case are shown in Figures 3.3.3-11, 3.3.3-12 and 3.3.3-13, respectively.

The calculated break flow response is shown in Figure 3.3.3-14. When the break opens, the RCS pressure falls rapidly at first, then more slowly as flashing within the RCS is encountered. The RCS depressurization causes a reactor trip signal at 11 s. The reactor trip causes a turbine trip, isolating the steam generator systems.

Figure 3.3.3-15 shows the calculated SG secondary system pressure responses. The turbine trip causes the secondary system pressures to rise; the pressure increase is limited by the opening of the turbine bypass and atmospheric dump valves. The steam pressures did not increase sufficiently to open the main steam safety relief valves. The declining SG pressures after 1,000 s are an indication of reverse (i.e., secondary system to primary system) SG heat transfer caused by the cooling down of the primary coolant system. The SG secondary fluid mass responses are shown in Figure 3.3.3-16. The turbine trip resulted in collapse of the secondary system indicated levels, which initiated auxiliary feedwater (AFW) flow to both SGs. The AFW flow replenished the SG secondary fluid inventories; AFW flow was throttled to maintain the SG levels within the normal range.

At 26 s, the RCS pressure had fallen to 8.963 MPa [1300 psia], resulting in the operator tripping one reactor coolant pump in each loop. At 27 s the minimum RCS subcooling fell below 13.9 K [25 ^{o}F], resulting in the operator tripping the remaining two reactor coolant pumps. The decline in the coolant loop flows caused by the pump trip is indicated in Figure 3.3.3-17, which shows the two hot leg flows at the reactor vessel connections. The decline in the coolant loop flows was rapid and total, with no significant period of natural circulation prior to complete stagnation of the loop flows. The effects of loop flow stagnation on the reactor vessel downcomer fluid temperature are evident in Figure 3.3.3-12. Under the stagnant coolant loop conditions, the effects of injecting cold HPI, LPI and SIT fluid into the cold legs are directly felt in the vessel downcomer and the fluid temperatures there decline rapidly.

RCS depressurization to 10.98 MPa [1593 psia] led to a safety injection actuation signal at 17 s and the starting of the HPI and LPI pumps after a 27-second delay (which represents effects related to plant instrumentation, control systems and pump start-up timing). The calculated HPI and LPI flow rates for Cold Leg A1 are shown in Figure 3.3.3-18; the total HPI and LPI flow rates are four times the flows shown in the figure. The flow delivered from the centrifugal pumps of the HPI and LPI systems are functions of the cold leg pressure, with lower pressures resulting in higher injection flows and with no injection flow delivered whenever the RCS pressure exceeds the shutoff heads of the systems (8.906 MPa [1291.7 psia] for HPI and 1.501 MPa [217.7 psia] for LPI). At 2,832 s, a recirculation actuation signal was calculated as a result of a low SIRWT level condition. The model tracks SIRWT inventory and level based on the flows drawn from the tank by the containment spray, HPI, LPI and charging systems. At this time the suction for the HPI system is switched from the SIRWT to the containment sump (with the resulting increase in HPI fluid temperature described above) and the LPI pumps are automatically tripped.

The effects of RCS coolant inventory loss through the break are evident in the declining pressurizer level response shown in Figure 3.3.3-19. The pressurizer was completely drained over the first 30 s of the event sequence and remained empty thereafter. The letdown flow was isolated early in the event sequence at the time of the safety injection actuation signal. The charging system flow increased in response to the low pressurizer level condition, with all three charging pumps delivering flow. Charging flow was terminated at 4,632 s, which is 1,800 s after the time of the recirculation actuation signal. It is estimated that 30 minutes would be required after the recirculation actuation signal for the charging system to completely drain the SIRWT of its remaining inventory. Afterward, no source of fluid is available for the charging system.

Because the break size for this event sequence is large, the charging system flow is of relatively small importance in relation to the HPI, LPI and SIT ECCS flows.

The Loop 1A SIT discharge flow rate response is shown in Figure 3.3.3-20; the total SIT flow rate is four times the flow shown in the figure. Intermittent SIT flow began at 2,138 s, when the RCS pressure fell below the initial SIT pressure, 1.480 MPa [214.7 psia]. The SITs discharge whenever the RCS pressure is below the tank pressure (which declines as the liquid inventory flows out of the SITs). The SIT discharge period ended at 6,374 s as a result of the minor RCS repressurization shown in Figure 3.3.3-11, with a remaining liquid inventory of 0.605 m^3 [21.37 ft^3] in each of the four SITs.

During the latter portion of the event sequence the calculated conditions reflect balances in the RCS mass and energy flows. The break mass flow rate is balanced by the HPI mass addition rate. The core heat addition rate is balanced by the cooling afforded to the RCS from adding cold HPI fluid and removing warm fluid at the break. These balanced conditions were reached at about 10,000 s.

The minimum average reactor vessel downcomer fluid temperature, 351 K [171°F], is reached at 14,940 s, near the end of the calculation. The RCS pressure at the time of the minimum temperature was calculated to be 1.53 MPa [222 psia].

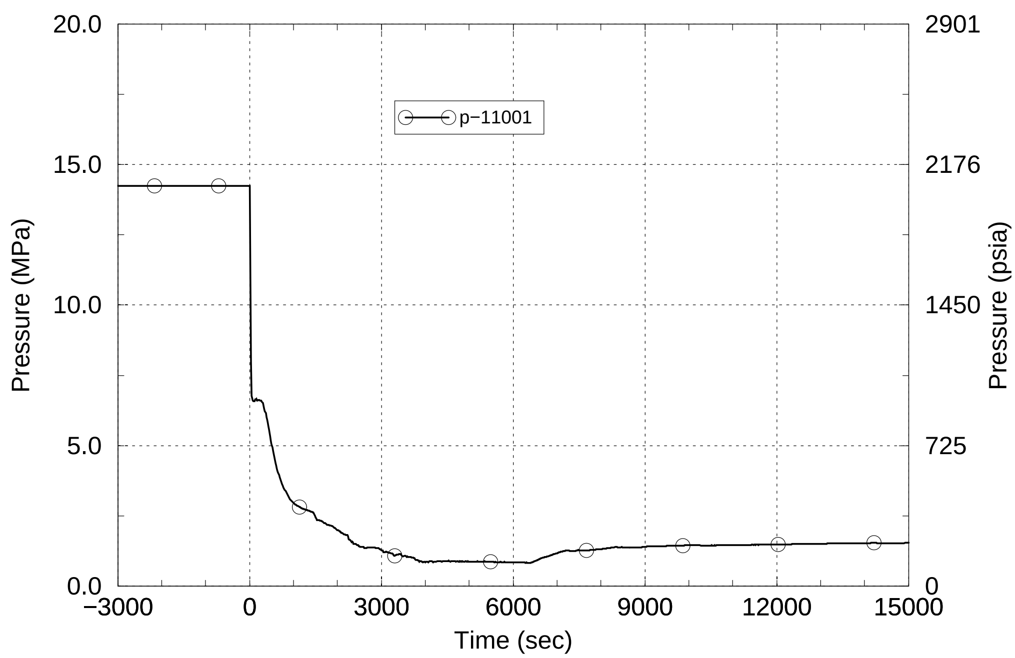


Figure 3.3.3-11 Reactor Coolant System Pressure - Palisades Case 59

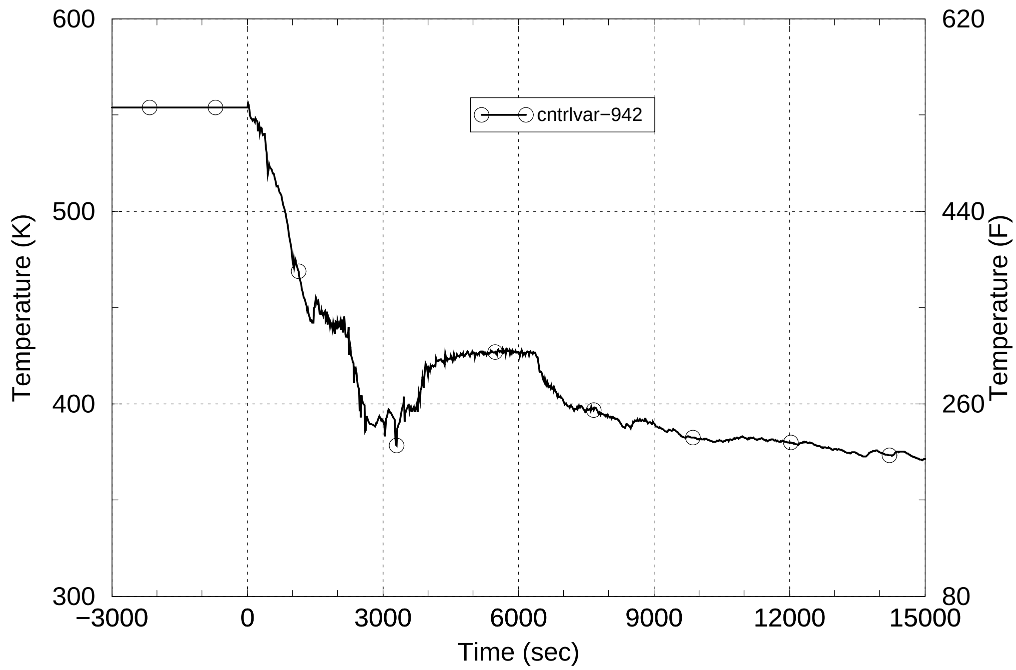


Figure 3.3.3-12 Average Reactor Vessel Downcomer Fluid Temperature - Palisades Case 59

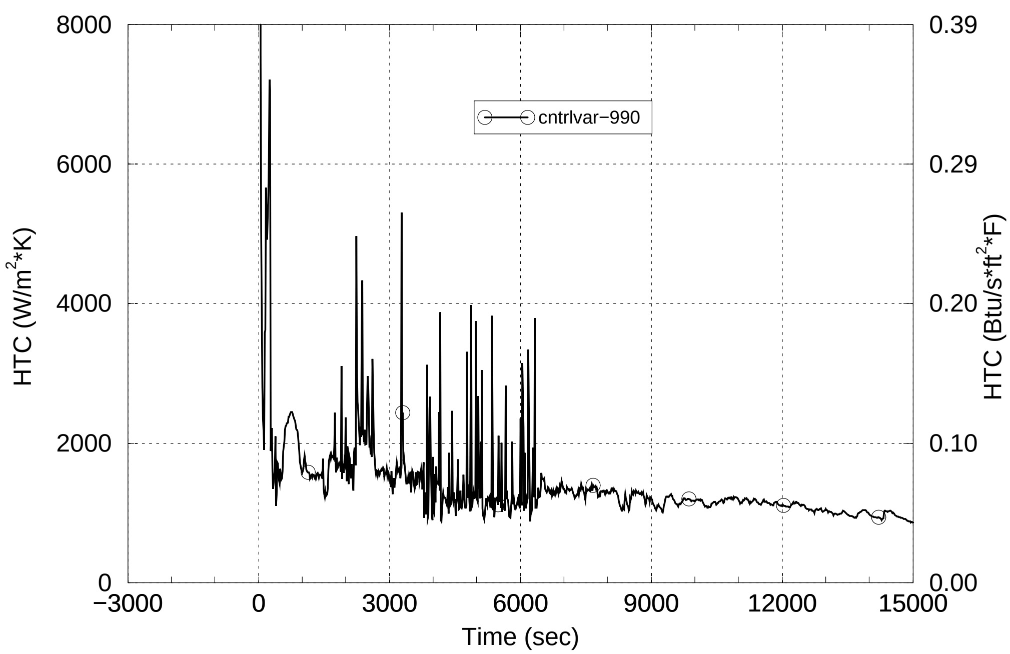


Figure 3.3.3-13 Avg Reactor Vessel Inner-Wall Heat Transfer Coefficient - Palisades Case 59

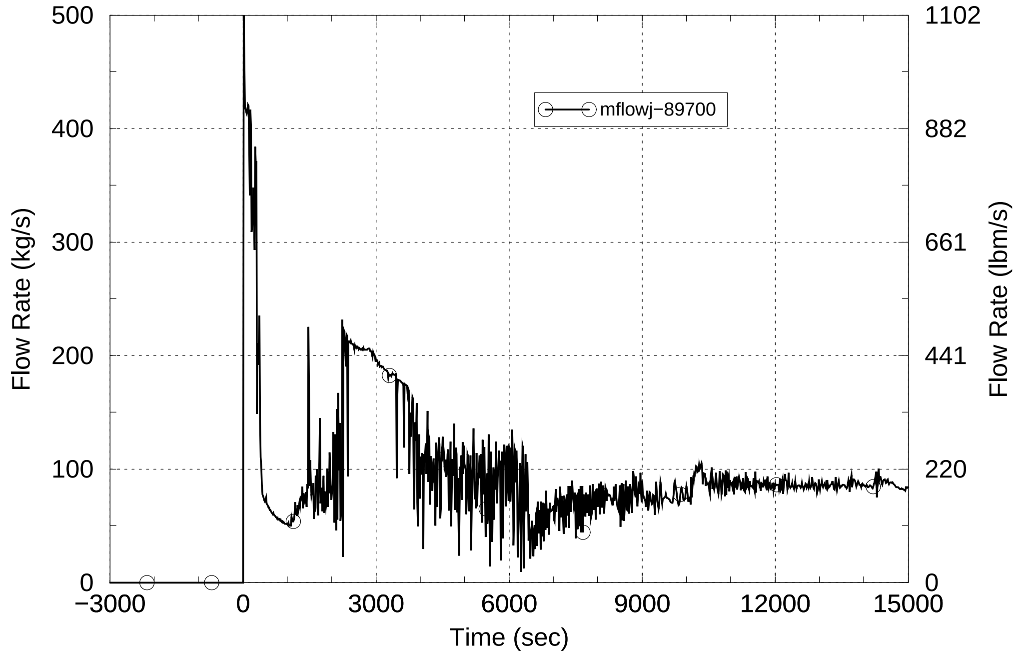


Figure 3.3.3-14 Break Flow - Palisades Case 59

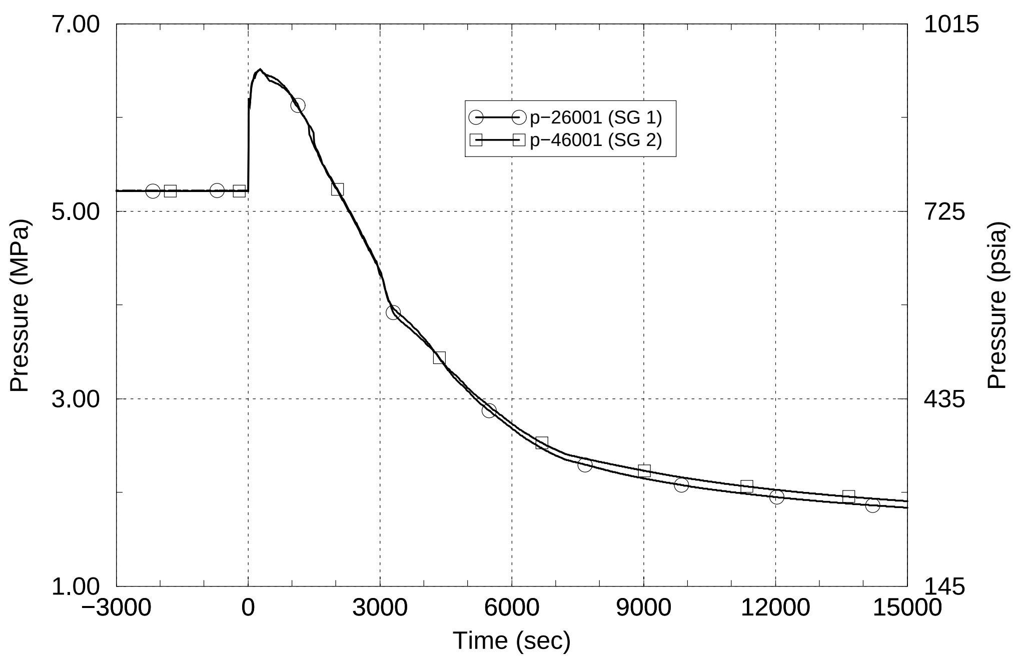


Figure 3.3.3-15 Steam Generator Pressures - Palisades Case 59

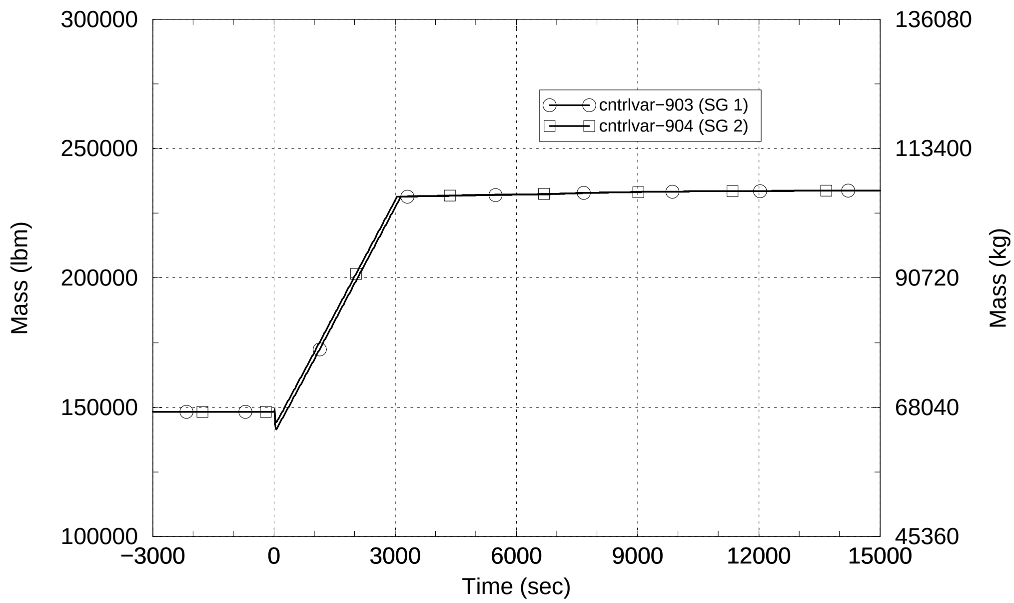


Figure 3.3.3-16 Steam Generator Secondary Fluid Masses - Palisades Case 59

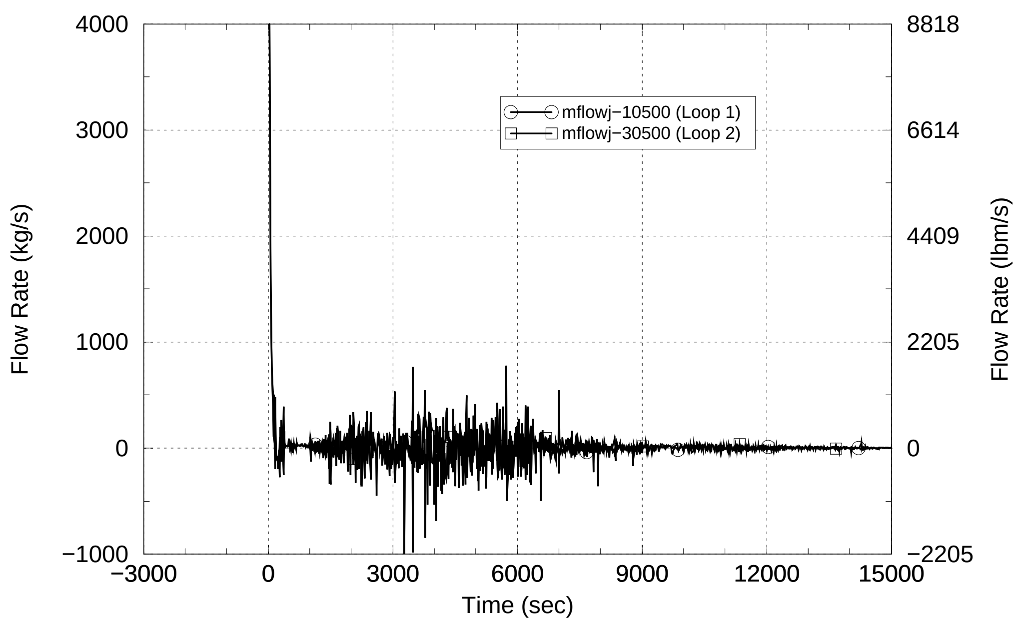


Figure 3.3.3-17 Hot Leg Flows - Palisades Case 59

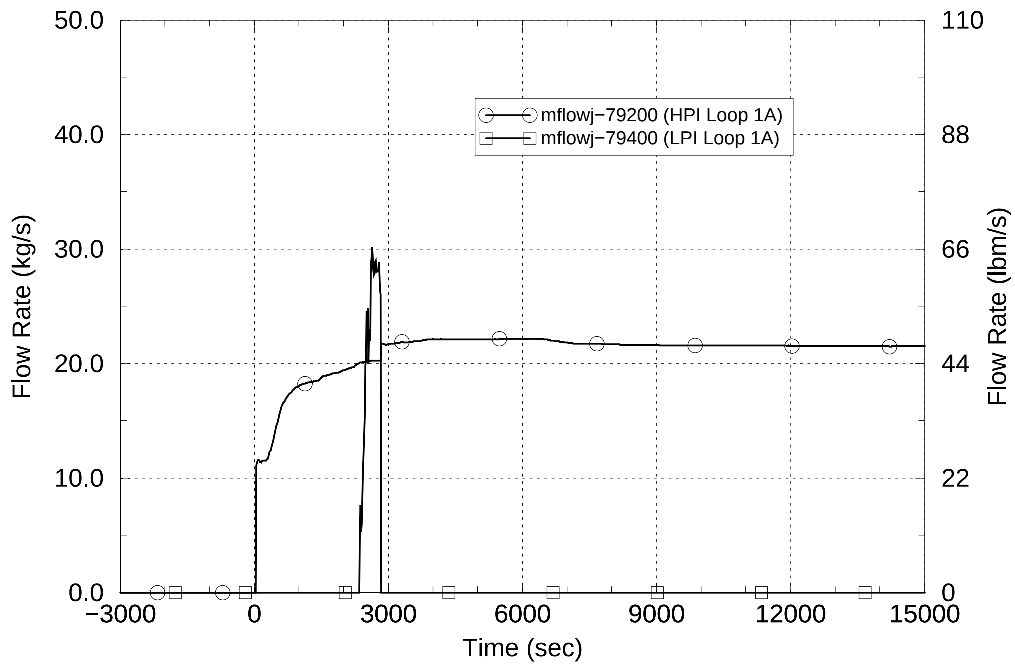


Figure 3.3.3-18   Loop A1 HPI and LPI Flows - Palisades Case 59

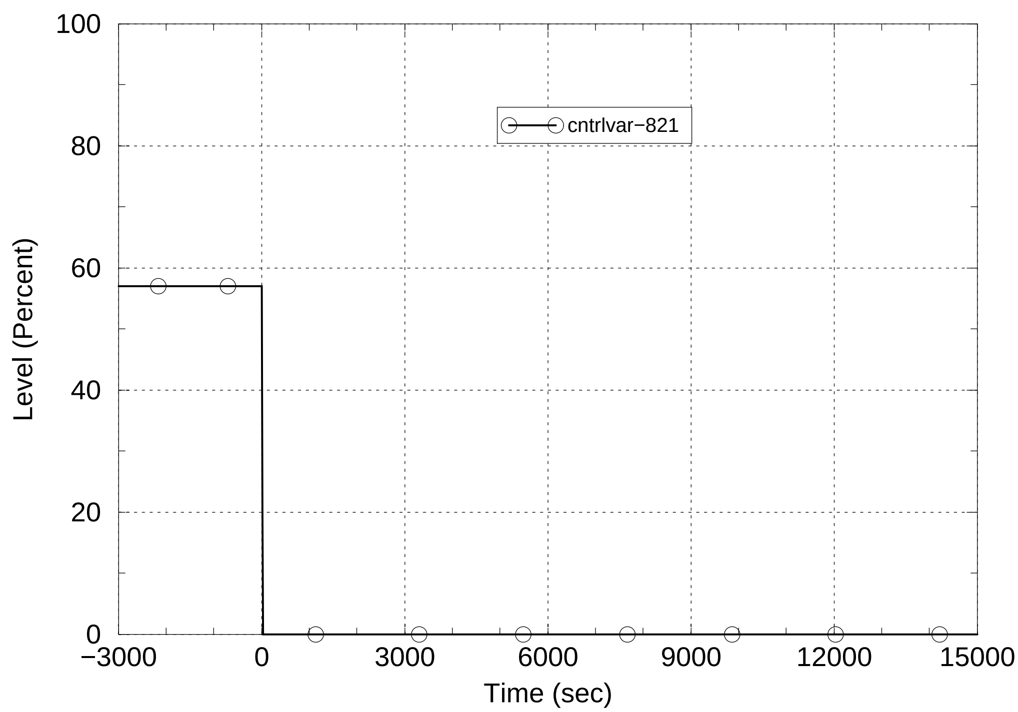


Figure 3.3.3-19   Pressurizer Level - Palisades Case 59

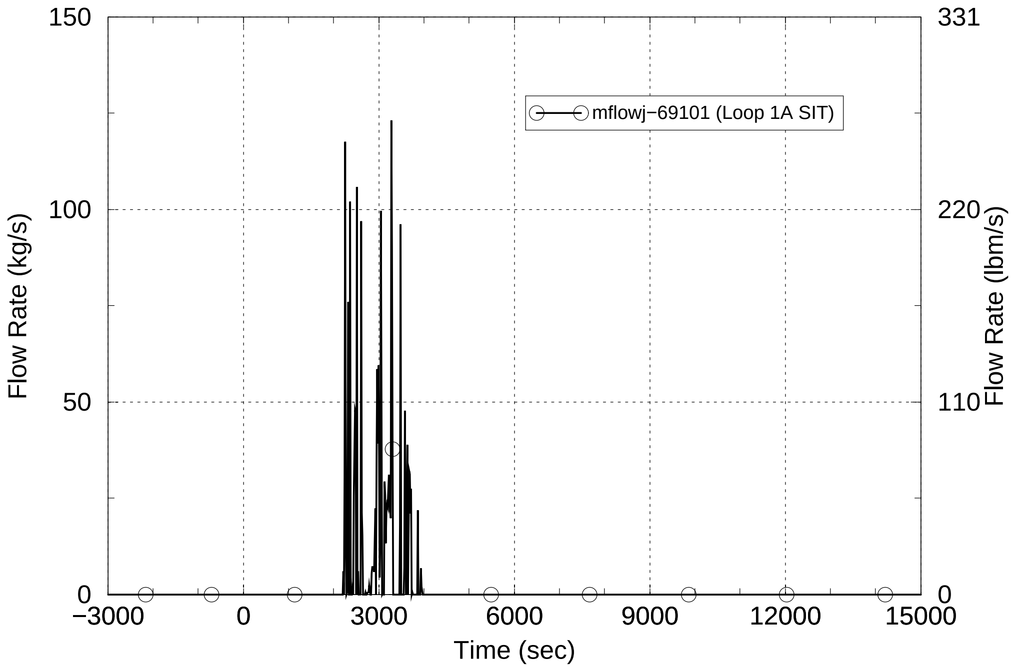


Figure 3.3.3-20 Loop 1A SIT Flow - Palisades Case 59

3.3.3.3 10.16-cm [4-in] Diameter Pressurizer Surge Line Break from Hot Full Power Condition with Summer-Season ECCS Temperatures - Palisades Case 64

With the plant in HFP operation, this event starts with a 10.16-cm [4-in] diameter break in the pressurizer surge line. The operator is assumed not to throttle the HPI flow, which is normally done if RCS subcooling and pressurizer level criteria have been met. The calculation assumes that the temperatures of the ECCS fluids are representative of summer-season conditions: HPI and LPI temperatures of 310.9 K [100 °F] and SIT temperatures of 305.4 K [90 °F] (the nominal ECCS fluid temperatures are listed in Table 2.0-1).

The following modeling changes were made to simulate this event sequence. The pressurizer surge line break to a constant atmospheric-pressure containment boundary condition was added to the model. The equivalent break flow area for a circular break with a diameter 10.16 cm [4 in] was specified. The break was connected on a vertical section of the surge line, from Component 180-2, as shown in Figure 2.3-2. The critical flow model was activated at the break junction and the flow loss coefficients specified were based on AP600-derived flow loss coefficients (Reference 3.3-1) and scaled for the specific break size and location for this event sequence. The boundary conditions for the HPI, LPI and SIT fluids were changed to represent the summer-season conditions listed above. At the time the reactor coolant pump coast-down was complete, large reverse flow loss coefficients were implemented in the loop seal cold leg regions of the model (Components 140, 340, 640 and 740 in Figure 2.3-2) to prevent the setting up of same-loop cold leg circulation, as discussed in Section 2.0. To eliminate non-physical numerically-driven circulations within the reactor vessel downcomer portion of the model, momentum flux was disabled in all junctions internal to the downcomer region (see discussion in Section 2.3.1). The containment high pressure signal, which results in containment spray actuation, was specified as 31.32 s after event initiation. The modeling for the HPI fluid temperature was modified so as to represent the constant safety injection refueling water tank (SIRWT) summer-season temperature prior to the draining of that tank then switch to a representation of a variable containment sump temperature (specified as a function of the time after the switch). The HPI fluid temperature falls from 331.8 K [137.5°F] immediately following the switch to 323.7 K [123.0 °F] at the end of the calculation (15,000 s after the break opens). The model input data for the containment spray actuation time and the containment sump fluid temperature were obtained from an independent Palisades containment analysis for a 10.16-cm [4-in] diameter break in the RCS.

The RELAP5-calculated sequence of events for Case 64 is shown in Table 3.3-3. The RELAP5-calculated responses for the RCS pressure, average reactor vessel downcomer fluid temperature and average reactor vessel wall inside surface heat transfer coefficient for this case are shown in Figures 3.3.3-21, 3.3.3-22 and 3.3.3-23, respectively.

The calculated break flow response is shown in Figure 3.3.3-24. When the break opens, the RCS pressure falls rapidly at first, then more slowly as flashing within the RCS is encountered. The RCS depressurization causes a reactor trip signal at 14 s. The reactor trip causes a turbine trip, isolating the steam generator systems.

Figure 3.3.3-25 shows the calculated SG secondary system pressure responses. The turbine trip causes the secondary system pressures to rise; the pressure increase is limited by the opening of the turbine bypass and atmospheric dump valves. The steam pressures did not increase sufficiently to open the main steam safety relief valves. The declining SG pressures after 1,000 s are an indication of reverse (i.e., secondary system to primary system) SG heat transfer caused by the cooling down of the primary coolant system. The SG secondary fluid mass responses are shown in Figure 3.3.3-26. The turbine trip resulted in collapse of the secondary system indicated levels, which initiated auxiliary feedwater (AFW) flow to both SGs. The AFW flow replenished the SG secondary fluid inventories; AFW flow was throttled to maintain the SG levels within the normal range.

At 30 s, the RCS pressure had fallen to 8.963 MPa [1300 psia], resulting in the operator tripping one reactor coolant pump in each loop. At 31 s the minimum RCS subcooling fell below 13.9 K [25 °F], resulting in the operator tripping the remaining two reactor coolant pumps. The decline in the coolant loop flows caused by the pump trip is indicated in Figure 3.3.3-27, which shows the two hot leg flows at the reactor vessel connections. The decline in the coolant loop flows was rapid and total, with no significant period of natural circulation prior to complete stagnation of the loop flows.. The Loop 1 hot leg flow response reflects the fluid flowing toward the pressurizer surge line break. The effects of loop flow stagnation on the reactor vessel downcomer fluid temperature are evident in Figure 3.3.3-22. Under the stagnant coolant loop conditions, the effects of injecting cold HPI, LPI and SIT fluid into the cold legs are directly felt in the vessel downcomer and the fluid temperatures there decline rapidly.

RCS depressurization to 10.98 MPa [1593 psia] led to a safety injection actuation signal at 20 s and the starting of the HPI and LPI pumps after a 27-second delay (which represents effects related to plant instrumentation, control systems and pump start-up timing). The calculated HPI and LPI flow rates for Cold Leg A1 are shown in Figure 3.3.3-28; the total HPI and LPI flow rates are four times the flows shown in the figure. The flow delivered from the centrifugal pumps of the HPI and LPI systems are functions of the cold leg pressure, with lower pressures resulting in higher injection flows and with no injection flow delivered whenever the RCS pressure exceeds the shutoff heads of the systems (8.906 MPa [1291.7 psia] for HPI and 1.501 MPa [217.7 psia] for LPI). At 2550 s, a recirculation actuation signal was calculated as a result of a low SIRWT level condition. The model tracks SIRWT inventory and level based on the flows drawn from the tank by the containment spray, HPI, LPI and charging systems. At this time the suction for the HPI system is switched from the SIRWT to the containment sump (with the resulting increase in HPI fluid temperature described above) and the LPI pumps are automatically tripped.

The effects of RCS coolant inventory loss through the break are evident in the declining pressurizer level response shown in Figure 3.3.3-29. The pressurizer was completely drained over the first 30 s of the event sequence. The pressurizer later refilled between 2727 and 2,980 s from the effects of rapidly injecting cold HPI, LPI and SIT water into the RCS and the momentum of that cold fluid toward the surge line break, which is in close proximity to the pressurizer tank. After the LPI pumps were tripped and the SIT discharge flow stopped, the pressurizer drained again and was empty by 5,057 s. The letdown flow was isolated early in the event sequence at the time of the safety injection actuation signal. The charging system flow increased in response to the low pressurizer level condition, with all three charging pumps delivering flow. Charging flow was terminated at 4350 s, which is 1,800 s after the time of the recirculation actuation signal. It is estimated that 30 minutes would be required after the recirculation actuation signal for the charging system to completely drain the SIRWT of its remaining inventory. Afterward, no source of fluid is available for the charging system. Because the break size for this event sequence is large, the charging system flow is of relatively small importance in relation to the HPI, LPI and SIT ECCS flows.

The Loop 1A SIT discharge flow rate response is shown in Figure 3.3.3-30; the total SIT flow rate is four times the flow shown in the figure. Intermittent SIT flow began at 1418 s, when the RCS pressure fell below the initial SIT pressure, 1.480 MPa [214.7 psia]. The SITs discharge whenever the RCS pressure is below the tank pressure (which declines as the liquid inventory flows out of the SITs). The SIT discharge period ended at 2,950 s when the liquid inventories of the SITs had been completely discharged.

During the latter portion of the event sequence the calculated conditions reflect balances in the RCS mass and energy flows. The break mass flow rate is balanced by the HPI mass addition rate. The core heat addition rate is balanced by the cooling afforded to the RCS from adding cold HPI fluid and removing warm fluid at the break. These balanced conditions were reached at about 6,000 s.

The minimum average reactor vessel downcomer fluid temperature, 323 K [121 ^{o}F], is reached at 2730 s, shortly after the time when the suction for the HPI system is switched to the containment sump and the LPI pumps are tripped. The RCS pressure, which was calculated to be 1.06 MPa [154 psia] at the time of the minimum temperature, fell slowly over the remainder of the event sequence calculation.

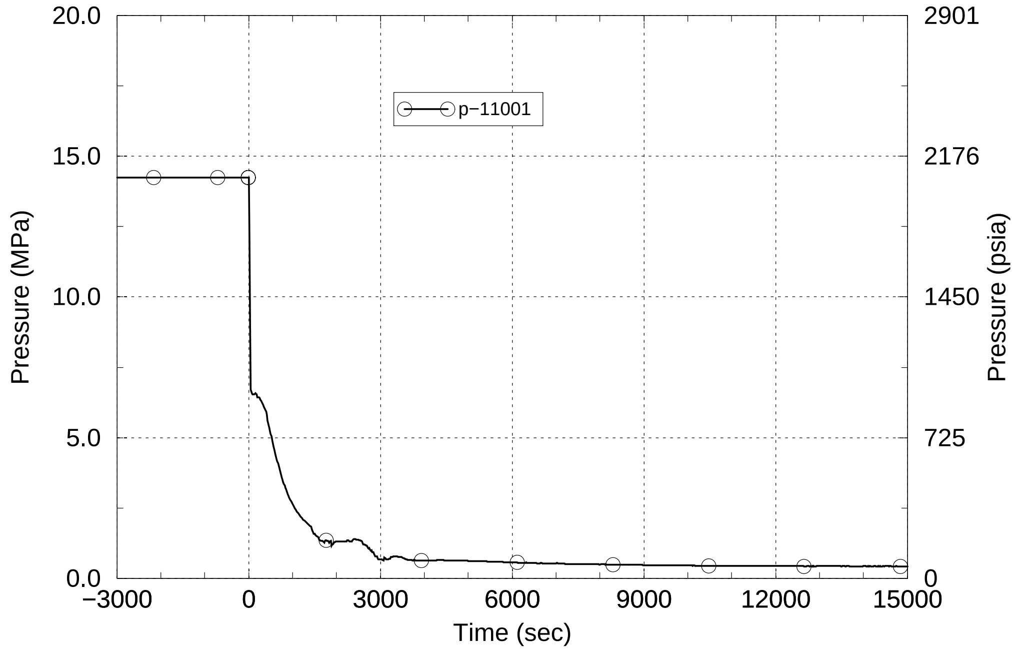


Figure 3.3.3-21 Reactor Coolant System Pressure - Palisades Case 64

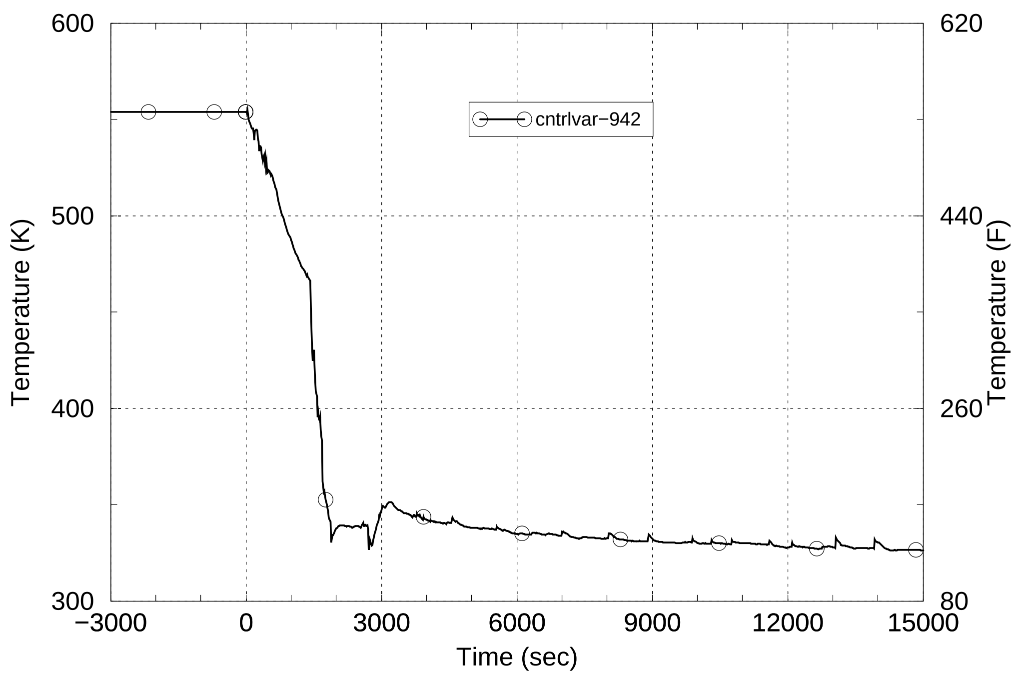


Figure 3.3.3-22 Average Reactor Vessel Downcomer Fluid Temperature - Palisades Case 64

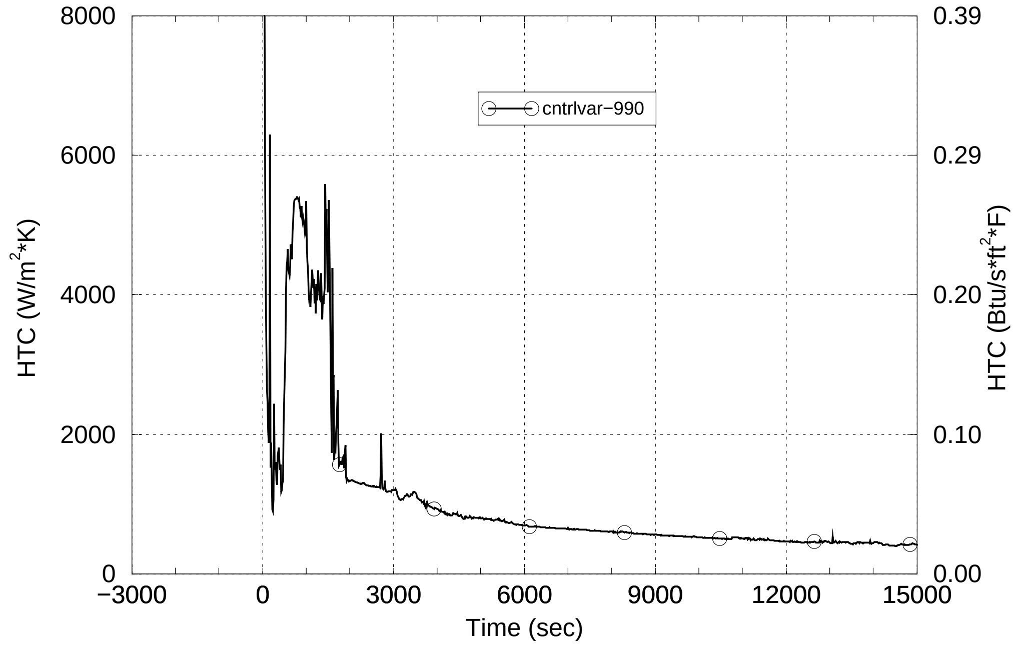


Figure 3.3.3-23 Avg Reactor Vessel Inner-Wall Heat Transfer Coefficient - Palisades Case 64

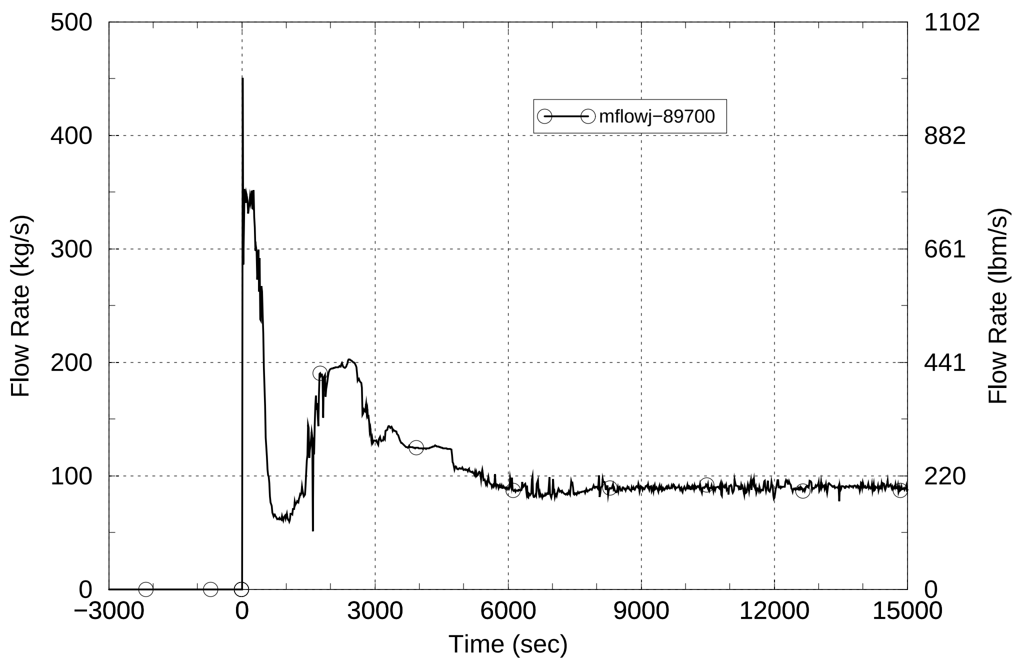


Figure 3.3.3-24 Break Flow - Palisades Case 64

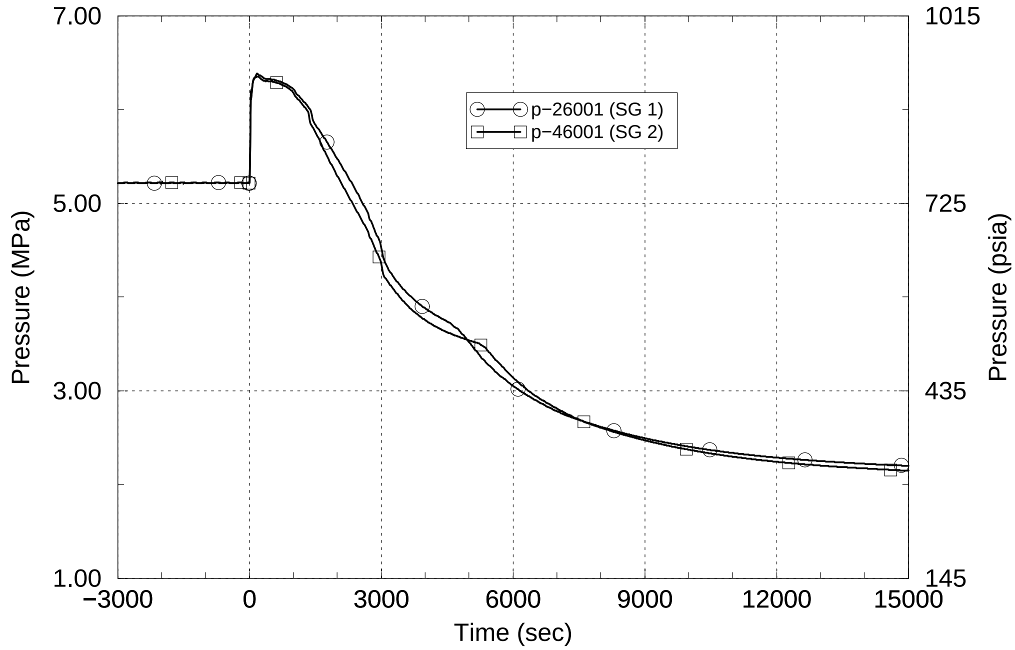


Figure 3.3.3-25 Steam Generator Pressures - Palisades Case 64

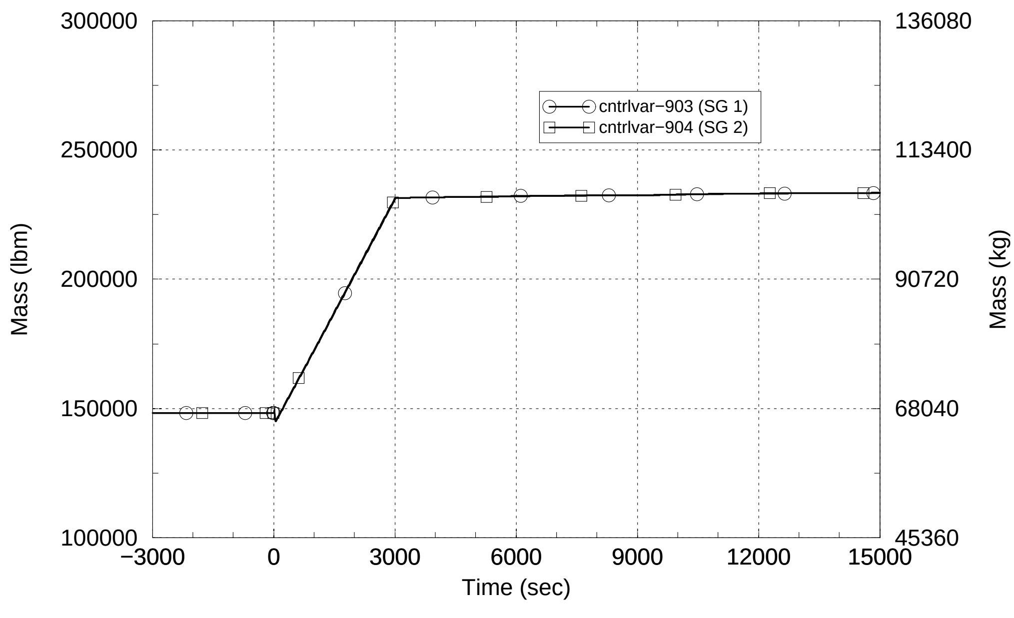


Figure 3.3.3-26 Steam Generator Secondary Fluid Masses - Palisades Case 64

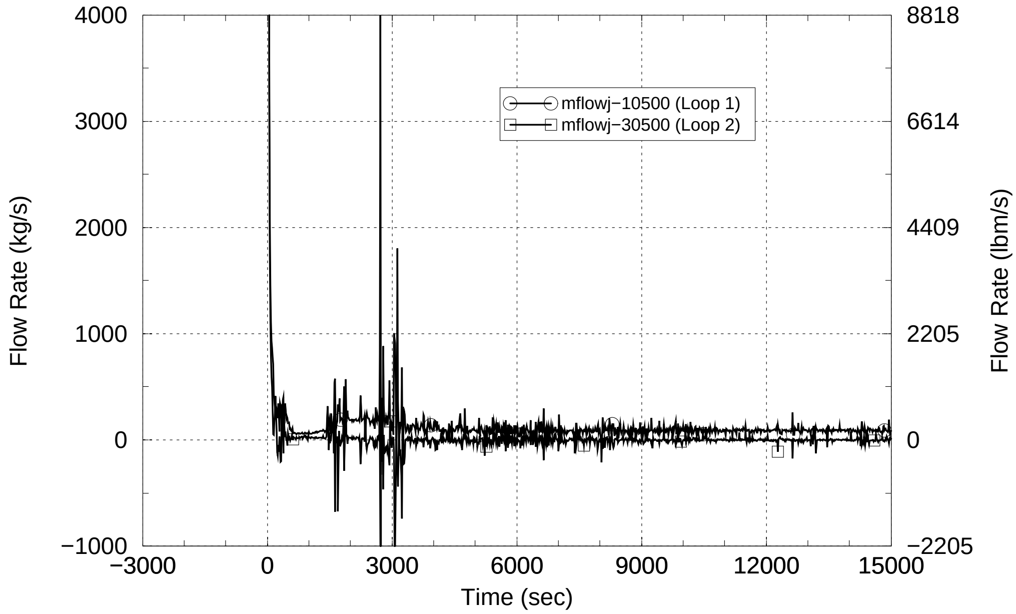


Figure 3.3.3-27 Hot Leg Flows - Palisades Case 64

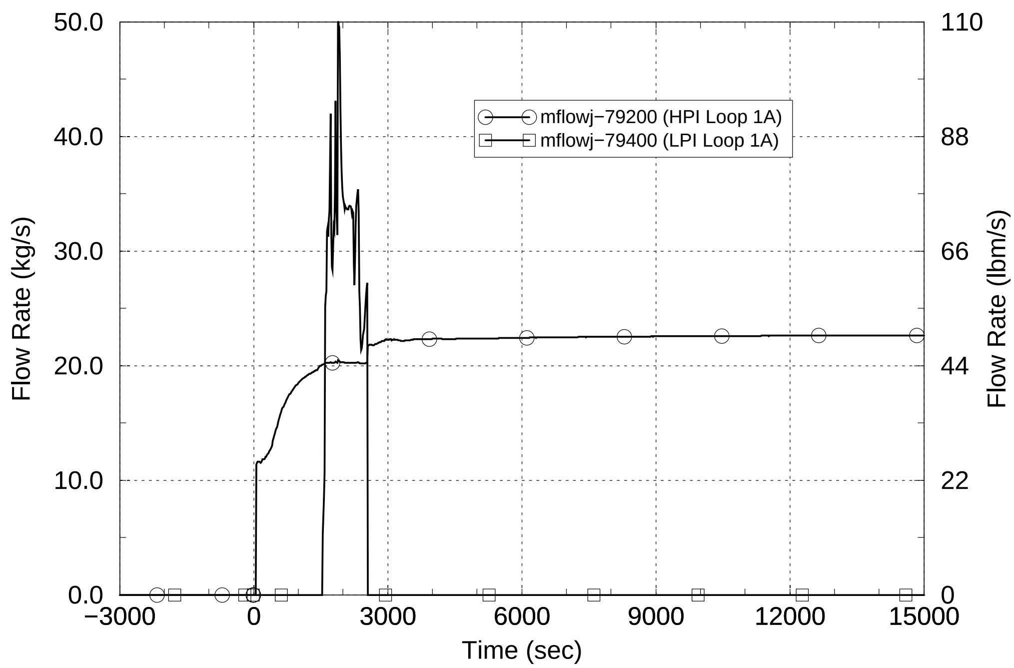


Figure 3.3.3-28 Loop A1 HPI and LPI Flows - Palisades Case 64

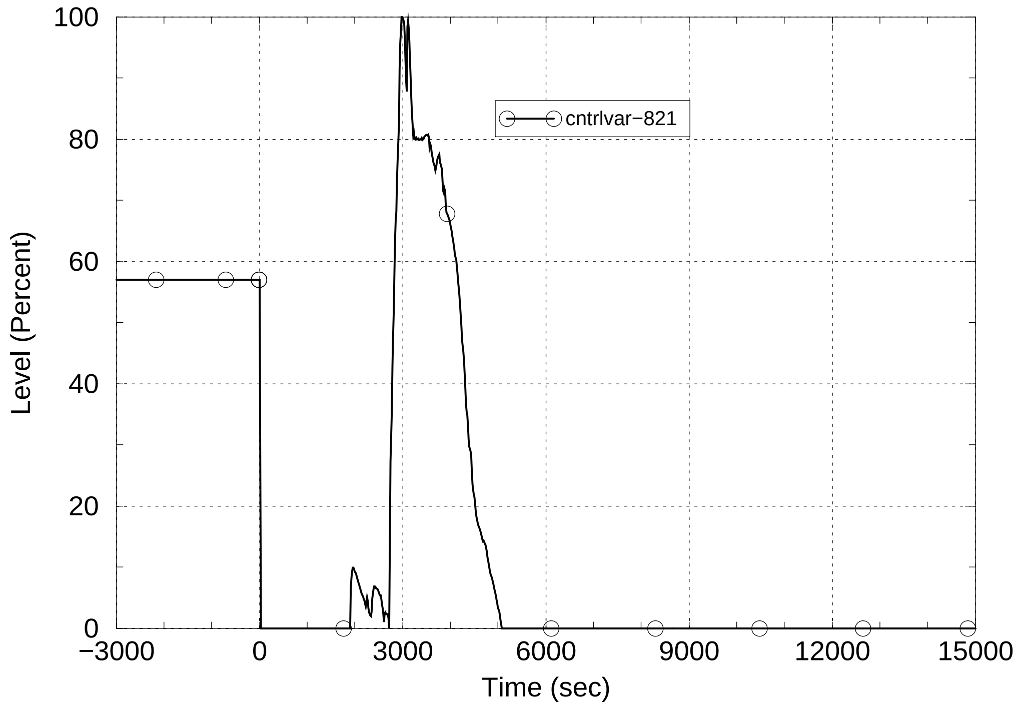


Figure 3.3.3-29 Pressurizer Level - Palisades Case 64

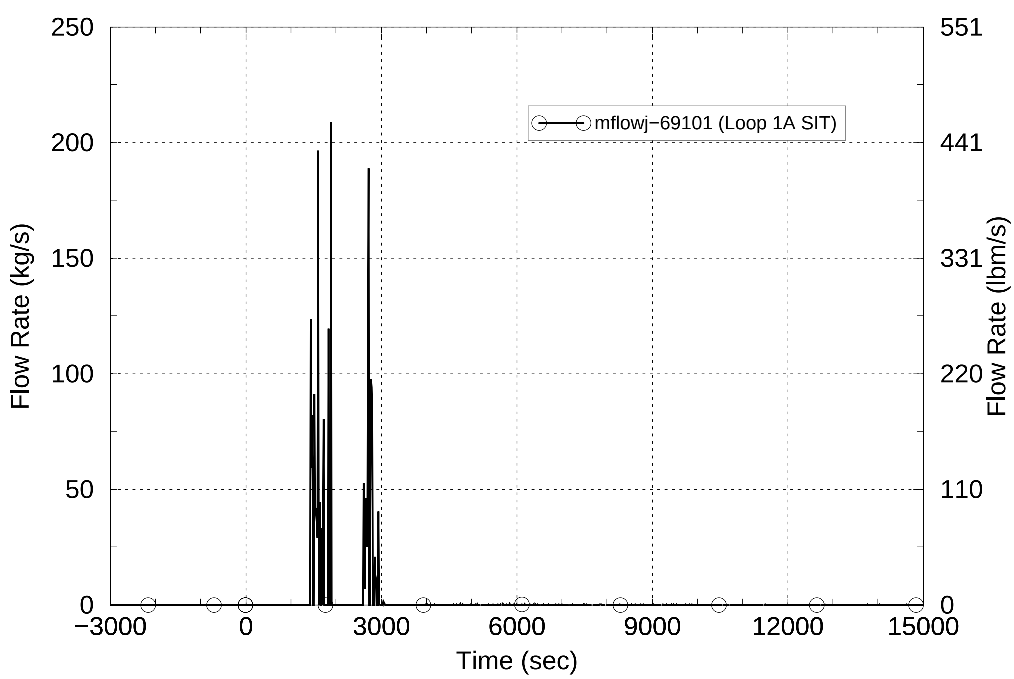


Figure 3.3.3-30 Loop 1A SIT Flow - Palisades Case 64

3.3.4 Group 4 - Sequences Initiated by Primary Coolant System Breaks with Diameters Greater Than 10.16-cm [4-in]

Three of the 12 Palisades PTS-risk-dominant event sequences involved primary coolant system breaks with diameters greater than 10.16 cm [4 in]. These three sequences are described as follows:

Case 40 is an event initiated by a 40.64-cm [16-in] diameter break in a hot leg with the reactor in hot full power (HFP) operation. The operator is assumed not to throttle HPI flow.

Case 62 is an event initiated by a 20.32-cm [8-in] diameter break in the pump-discharge cold leg with the reactor in HFP operation. The operator is assumed not to throttle HPI flow. Temperatures representing winter conditions are assumed for the fluids in the HPI, LPI and SIT ECC systems.

Case 63 is an event initiated by a 14.37-cm [5.656-in] diameter break in the pump-discharge cold leg with the reactor in HFP operation. The operator is assumed not to throttle HPI flow. Temperatures representing winter conditions are assumed for the fluids in the HPI, LPI and SIT ECC systems.

The common features of this sequence group are very rapid RCS depressurization caused by the break and RCS cooldown caused by the depressurization and the injection of cold HPI, LPI and SIT fluid. The break sizes for this group are very large, thus precluding RCS repressurization. The event sequences quickly result in tripping of all four reactor coolant pumps and stagnation of the reactor coolant loops.

3.3.4.1 40.64-cm [16-in] Diameter Hot Leg Break from Hot Full Power Condition - Palisades Case 40

With the plant in HFP operation, this event starts with a 40.64-cm [16-in] diameter break in the hot leg. The operator is assumed not to throttle the HPI flow, which is normally done if RCS subcooling and pressurizer level criteria have been met.

The following modeling changes were made to simulate this event sequence. The hot leg break to a constant atmospheric-pressure containment boundary condition was added to the model in Loop 1. The equivalent break flow area for a circular break with a diameter of 40.64 cm [16 in] was specified. The break was connected on the side of the horizontal hot leg, at the junction between Cells 1 and 2 of Component 120, as shown in Figure 2.3-2. The critical flow model was activated at the break junction and the flow loss coefficients specified were based on AP600-derived flow loss coefficients (Reference 3.3-1) and scaled for the specific break size and location for this event sequence. At the time the reactor coolant pump coast-down was complete, large reverse flow loss coefficients were implemented in the loop seal cold leg regions of the model (Components 140, 340, 640 and 740 in Figure 2.3-2) to prevent the setting up of same-loop cold leg circulation, as discussed in Section 2.0. To eliminate non-physical numerically-driven circulations within the reactor vessel downcomer portion of the model, momentum flux was disabled in all junctions internal to the downcomer region (see discussion in Section 2.3.1). The containment high pressure signal, which results in containment spray actuation, was specified as 6.7 s after event initiation. The modeling for the HPI fluid temperature was modified so as to represent the constant nominal safety injection refueling water tank (SIRWT) temperature prior to the draining of that tank then switch to a representation of a variable containment sump temperature (specified as a function of the time after the switch). The HPI fluid temperature falls from 343.2 K [158.1 °F] immediately following the switch to 323.6 K [122.8 °F] at the end of the calculation (15,000 s after the break opens). The model input data for the containment spray actuation time and the containment sump fluid temperature were obtained from an independent Palisades containment analysis for a 20.32-cm [8-in] diameter break in the RCS, the largest break size for which containment analyses were performed. The containment spray actuation time for a 40.64-cm [16-in] RCS break is expected to occur before 6.7 s, however the effect of delaying the start of containment spray by a few seconds in the RELAP5 calculation is not considered consequential for this analysis. The containment sump fluid temperatures for a 40.64 cm [16 in] RCS break are expected to be higher than those based on a 20.32-cm [8-in] RCS break used in the RELAP5 analysis. The effect of this analysis compromise is conservative for PTS because it leads to lower calculated reactor vessel downcomer fluid temperatures.

The RELAP5-calculated sequence of events for Case 40 is shown in Table 3.3-4. The RELAP5-calculated responses for the RCS pressure, average reactor vessel downcomer fluid temperature and average reactor vessel wall inside surface heat transfer coefficient for this case are shown in Figures 3.3.4-1, 3.3.4-2 and 3.3.4-3, respectively.

The calculated break flow response is shown in Figure 3.3.4-4. When the break opens, the RCS pressure falls very rapidly to near atmospheric pressure (it requires only 332 s for the hot leg pressure to reach 0.2 MPa [30 psia]). The depressurization causes a reactor trip signal at 3 s. The reactor trip causes a turbine trip, isolating the steam generator systems.

Figure 3.3.4-5 shows the calculated SG secondary system pressure responses. The turbine trip causes the secondary system pressures to rise; the pressure increase is limited by the opening of the atmospheric dump valves. The steam pressures did not increase sufficiently to open the turbine bypass or main steam safety relief valves. The declining SG pressures an indication of reverse (i.e., secondary system to primary system) SG heat transfer caused by the cooling down of the primary coolant system. The SG secondary fluid mass responses are shown in Figure 3.3.4-6. The turbine trip resulted in collapse of the secondary system indicated levels, which initiated auxiliary feedwater (AFW) flow to both SGs. The AFW flow replenished the SG secondary fluid inventories; AFW flow was throttled to maintain the SG levels within the normal range.

At 7 s the minimum RCS subcooling fell below 13.9 K [25 °F], resulting in the operator tripping one reactor coolant pump in each loop. At 9 s the RCS pressure had fallen to 8.963 MPa [1300 psia], resulting in the operator tripping the remaining two reactor coolant pumps. The decline in the coolant loop flows caused by the pump trip is indicated in Figure 3.3.4-7, which shows the two hot leg flows at the reactor vessel connections. The decline in the coolant loop flows was rapid and total, with no period of natural circulation prior to complete stagnation of the loop flows. The Loop 1 hot leg flow response reflects the fluid flowing toward the hot leg break in that loop. The effects of loop flow stagnation on the reactor vessel downcomer fluid temperature are evident in Figure 3.3.4-2. Under the stagnant coolant loop conditions, the effects of injecting cold HPI, LPI and SIT fluid into the cold legs are directly felt in the vessel downcomer and the fluid temperatures there decline rapidly.

RCS depressurization to 10.98 MPa [1593 psia] led to a safety injection actuation signal at 5 s and the starting of the HPI and LPI pumps after a 27-second delay (which represents effects related to plant instrumentation, control systems and pump start-up timing). The calculated HPI and LPI flow rates for Cold Leg A1 are shown in Figure 3.3.4-8; the total HPI and LPI flow rates are four times the flows shown in the figure. The flow delivered from the centrifugal pumps of the HPI and LPI systems are functions of the cold leg pressure, with lower pressures resulting in higher injection flows and with no injection flow delivered whenever the RCS pressure exceeds the shutoff heads of the systems (8.906 MPa [1291.7 psia] for HPI and 1.501 MPa [217.7 psia] for LPI). At 1263 s, a recirculation actuation signal was calculated as a result of a low SIRWT level condition. The model tracks SIRWT inventory and level based on the flows drawn from the tank by the containment spray, HPI, LPI and charging systems. At this time the suction for the HPI system is switched from the SIRWT to the containment sump (with the resulting increase in HPI fluid temperature described above) and the LPI pumps are automatically tripped.

The effects of RCS coolant inventory loss through the break are evident in the declining pressurizer level response shown in Figure 3.3.4-9. The pressurizer was completely drained over the first 15 s of the event sequence and, except for a brief and minor refill caused by the rapid influx of LPI and SIT water, the pressurizer remained empty thereafter. The letdown flow was isolated early in the event sequence at the time of the safety injection actuation signal. The charging system flow increased in response to the low pressurizer level condition, with all three charging pumps delivering flow. Charging flow was terminated at 3063 s, which is 1,800 s after the time of the recirculation actuation signal. It is estimated that 30 minutes would be required after the recirculation actuation signal for the charging system to completely drain the SIRWT of its remaining inventory. Afterward, no source of fluid is available for the charging system. Because the break size for this event sequence is large, the charging system flow is of relatively small importance in relation to the HPI, LPI and SIT ECCS flows.

The Loop 1A SIT discharge flow rate response is shown in Figure 3.3.4-10; the total SIT flow rate is four times the flow shown in the figure. Intermittent SIT flow began at 60 s, when the RCS pressure fell below the initial SIT pressure, 1.480 MPa [214.7 psia]. The SITs discharge whenever the RCS pressure is below the tank pressure (which declines as the liquid inventory flows out of the SITs). The SIT discharge period ended at 134 s when the liquid inventories of the SITs had been completely discharged.

During the latter portion of the event sequence the calculated conditions reflect balances in the RCS mass and energy flows. The break mass flow rate is balanced by the HPI mass addition rate. The core heat addition rate is balanced by the cooling afforded to the RCS from adding cold HPI fluid and removing warm fluid at the break. These balanced conditions were reached at about 5,000 s.

The minimum average reactor vessel downcomer fluid temperature, 308 K [94°F], is reached at 1260 s, shortly before the time when the suction for the HPI system is switched to the containment sump (which warms the HPI fluid) and the LPI pumps are tripped. The RCS pressure, which was calculated to be 0.14 MPa [20.8 psia] at that time, remained low through the remainder of the event sequence.

Table 3.3-4 Comparison of Event Timing for Dominant Palisades Event Sequences - Group 4, Primary System Breaks with a Diameter Greater than 10.16 cm [4 in]

	Event Time (seconds)		
Event(s)	Case 40, HFP, 40.64-cm [16-in] Diameter Hot Leg Break	Case 62, HFP, 20.32-cm [8-in] Diameter Cold Leg Break. Winter ECCS	Case 63, HFP, 14.37-cm [5.656-in] Diameter Cold Leg Break, Winter ECCS
Break opens	0	0	0
Reactor trip signal, turbine trip	3	4	5
Safety injection actuation signal, isolate letdown flow	5	7	10
Low RCS subcooling condition causes operator to trip one reactor coolant pump in each loop	7	7	15
Containment high pressure signal, results in containment spray system initiation	7	7	16
Low RCS pressure condition causes operator to trip the two remaining reactor coolant pumps	9	12	16
Pressurizer level reaches 0%	15	15	15
HPI and LPI systems available, HPI flow begins	32	34	37
SIT flow begins	60	259	664
LPI flow begins	60	275	905
Reactor coolant pump coast-down completed	119	95	95
Recirculation actuation signal, suction for HPI system switched from SIRWT to containment sump, LPI pumps tripped	1263	1614	2085
Charging flow stops, SIRWT completely drained	3063	3414	3885
Calculation terminated	15000	15000	15000

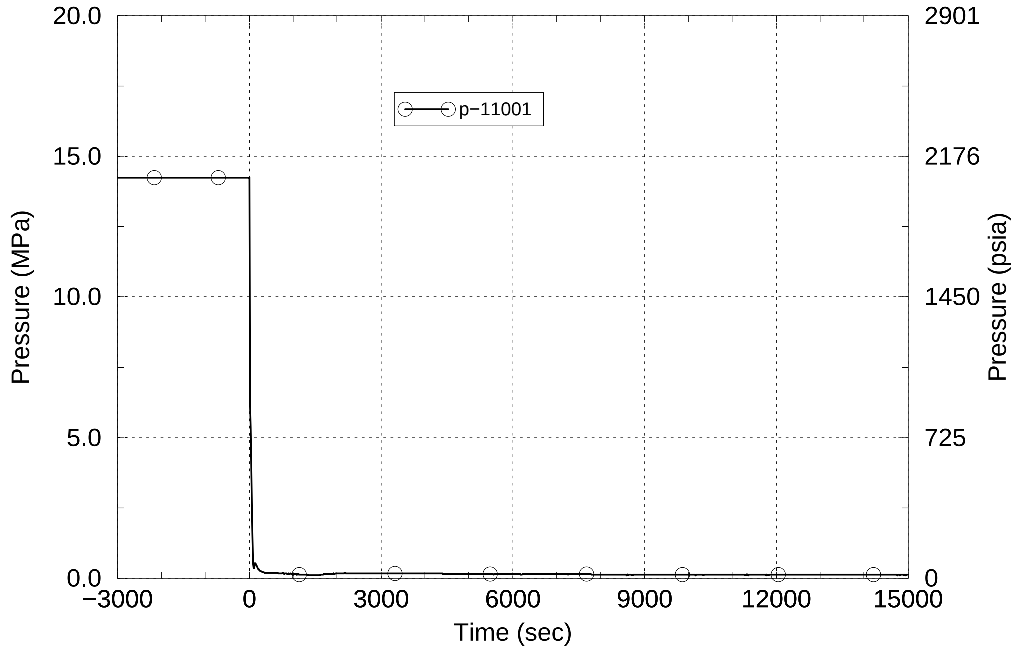


Figure 3.3.4-1 Reactor Coolant System Pressure - Palisades Case 40

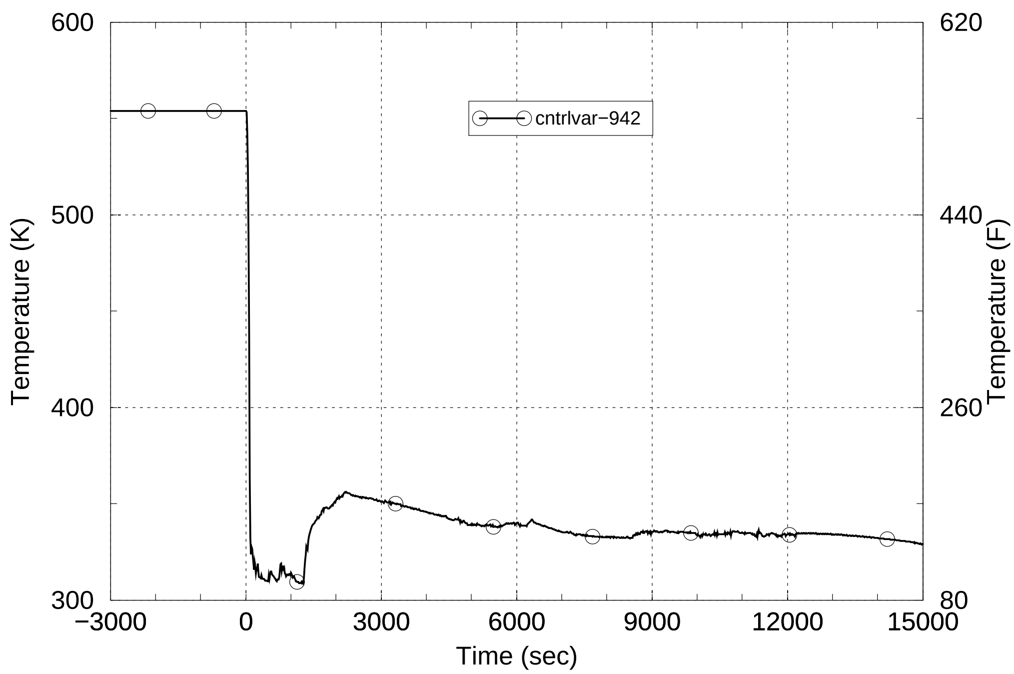


Figure 3.3.4-2 Average Reactor Vessel Downcomer Fluid Temperature - Palisades Case 40

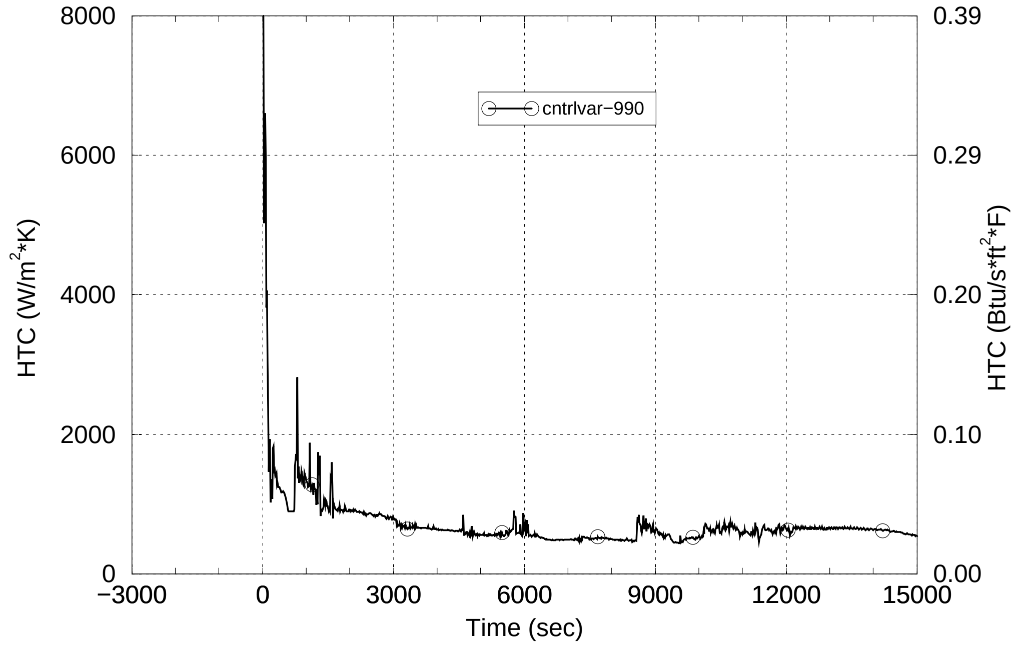


Figure 3.3.4-3 Average Reactor Vessel Inner-Wall Heat Transfer Coefficient - Palisades Case 40

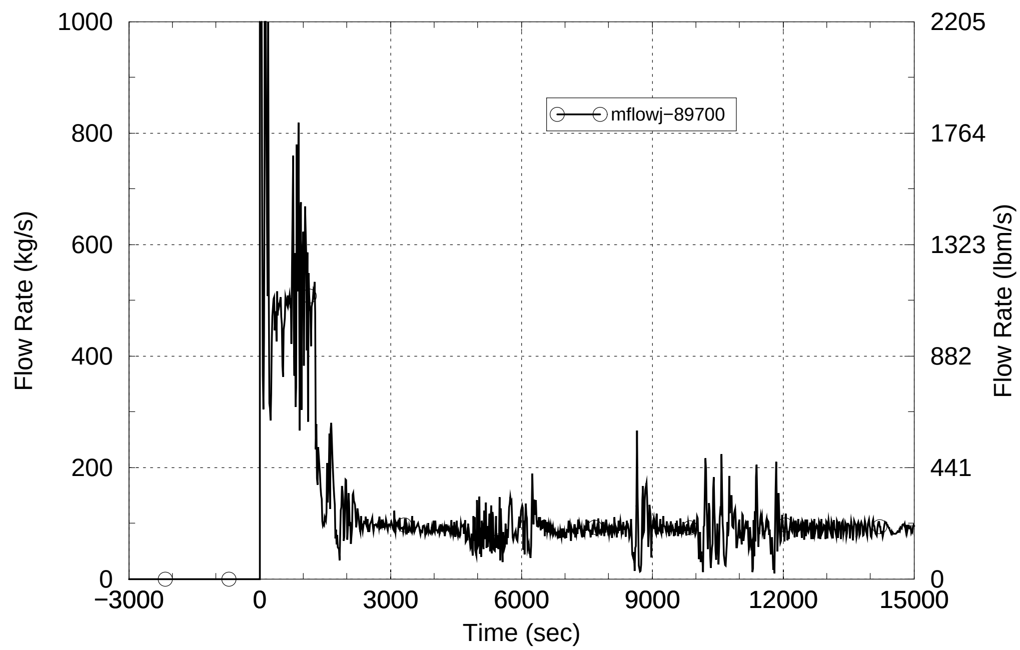


Figure 3.3.4-4 Break Flow - Palisades Case 40

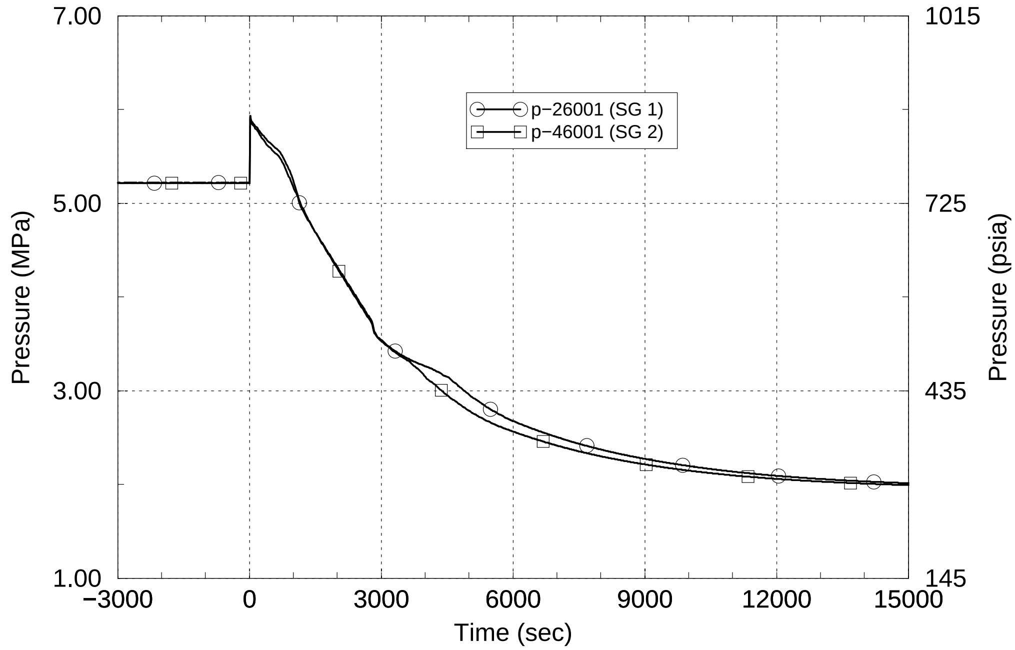


Figure 3.3.4-5 Steam Generator Pressures - Palisades Case 40

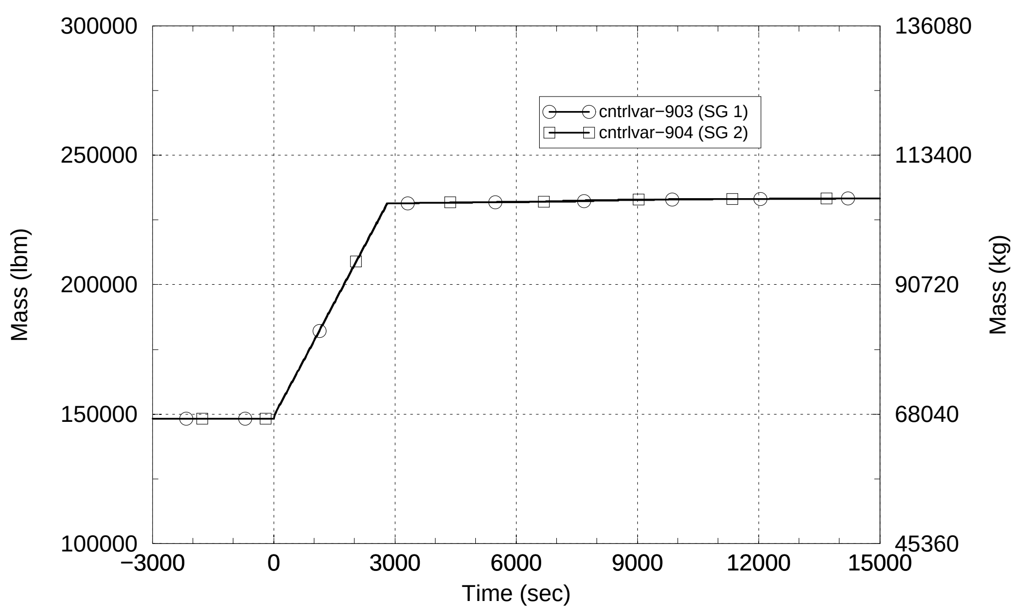


Figure 3.3.4-6 Steam Generator Secondary Fluid Masses - Palisades Case 40

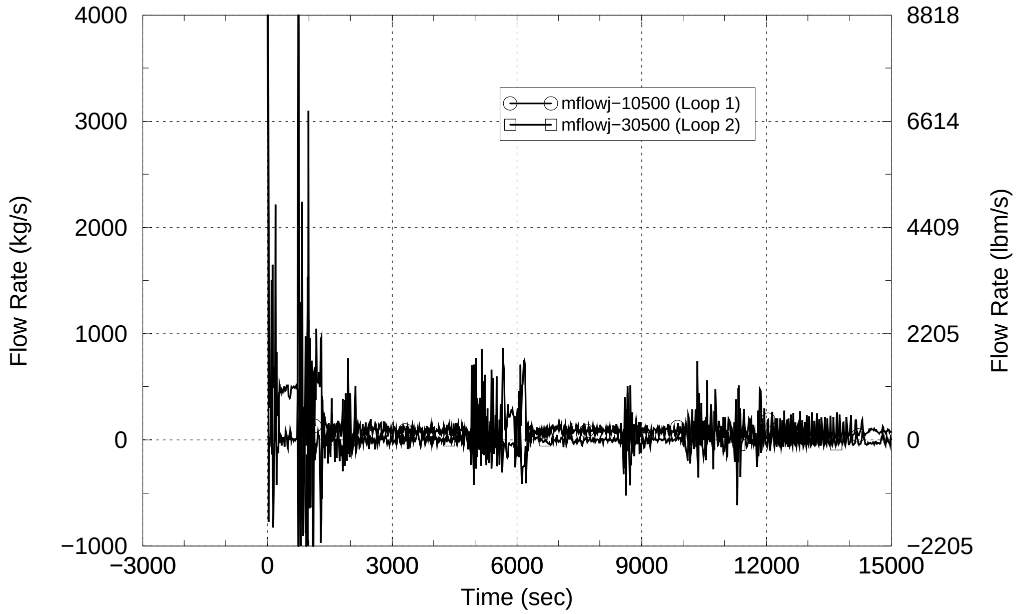


Figure 3.3.4-7 Hot Leg Flows - Palisades Case 40

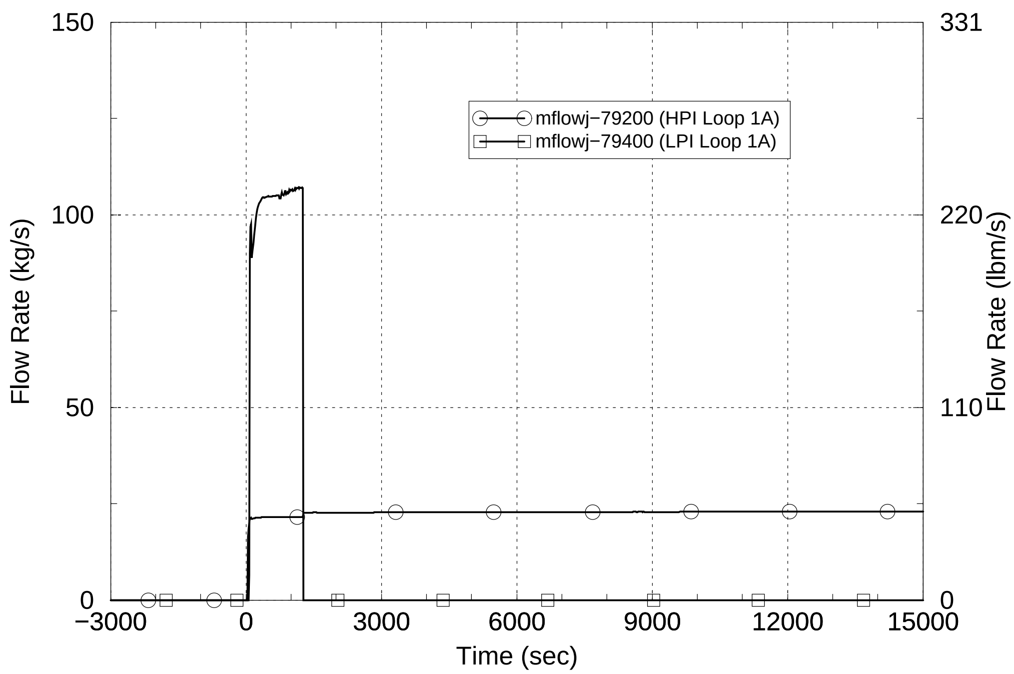


Figure 3.3.4-8 Loop A1 HPI and LPI Flows - Palisades Case 40

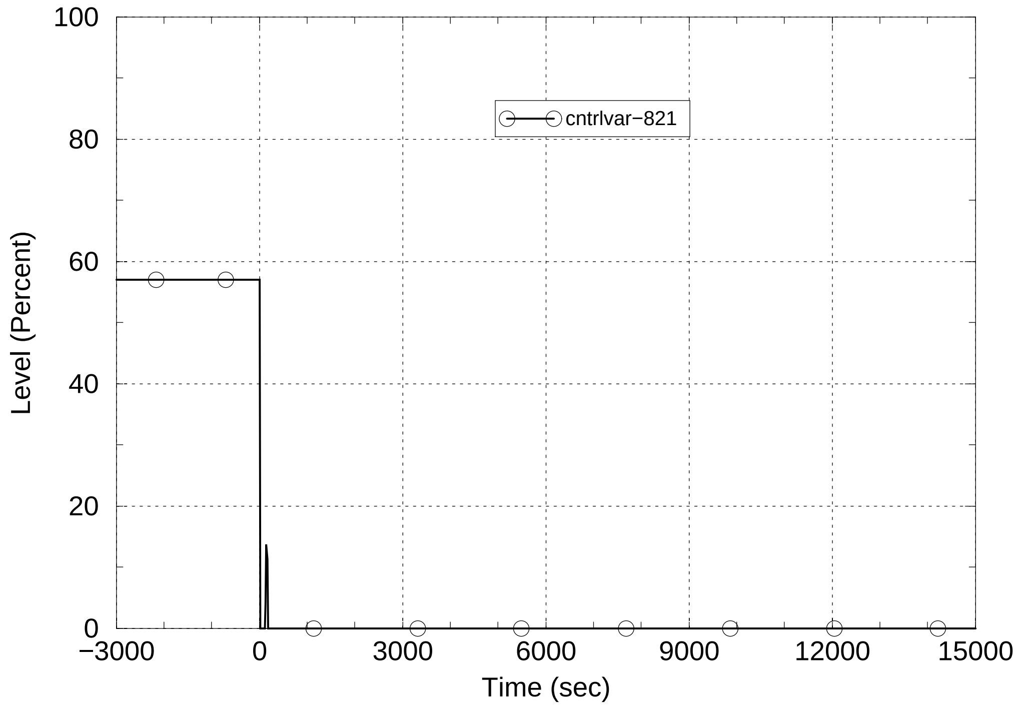


Figure 3.3.4-9 Pressurizer Level - Palisades Case 40

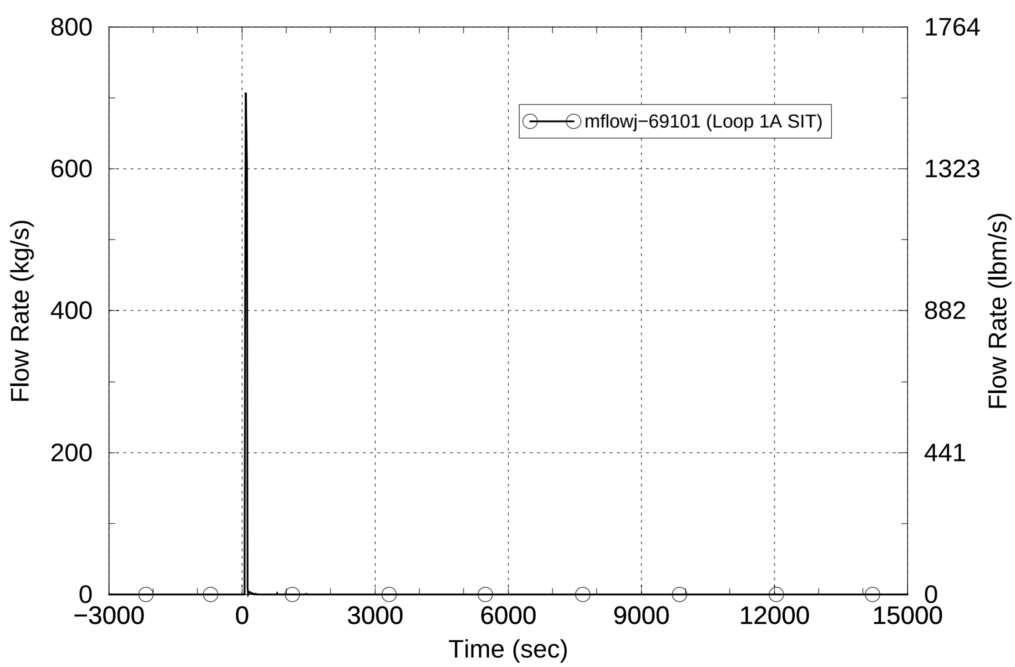


Figure 3.3.4-10 Loop 1A SIT Flow - Palisades Case 40

3.3.4.2 20.32-cm [8-in] Diameter Cold Leg Break from Hot Full Power Condition with Winter-Season ECCS Temperatures - Palisades Case 62

With the plant in HFP operation, this event starts with a 20.32-cm [8-in] diameter break in the pump-discharge cold leg. The operator is assumed not to throttle the HPI flow, which is normally done if RCS subcooling and pressurizer level criteria have been met. The calculation assumes that the temperatures of the ECCS fluids are representative of winter-season conditions: HPI and LPI temperatures of 277.6 K [40°F] and SIT temperatures of 288.7 K [60°F] (the nominal ECCS fluid temperatures are listed in Table 2.0-1).

The following modeling changes were made to simulate this event sequence. The cold leg break to a constant atmospheric-pressure containment boundary condition was added to the model in Loop 1A. The equivalent break flow area for a circular break with a diameter of 20.32 cm [8 in] was specified. The break was connected on the side of the horizontal cold leg, at the junction between Cells 1 and 2 of Component 150, as shown in Figure 2.3-2. The critical flow model was activated at the break junction and the flow loss coefficients specified were based on AP600-derived flow loss coefficients (Reference 3.3-1) and scaled for the specific break size and location for this event sequence. The boundary conditions for the HPI, LPI and SIT fluids were changed to represent the winter-season conditions listed above. At the time the reactor coolant pump coast-down was complete, large reverse flow loss coefficients were implemented in the loop seal cold leg regions of the model (Components 140, 340, 640 and 740 in Figure 2.3-2) to prevent the setting up of same-loop cold leg circulation, as discussed in Section 2.0. To eliminate non-physical numerically-driven circulations within the reactor vessel downcomer portion of the model, momentum flux was disabled in all junctions internal to the downcomer region (see discussion in Section 2.3.1). The containment high pressure signal, which results in containment spray actuation, was specified as 6.7 s after event initiation. The modeling for the HPI fluid temperature was modified so as to represent the constant safety injection refueling water tank (SIRWT) winter-season temperature prior to the draining of that tank then switch to a representation of a variable containment sump temperature (specified as a function of the time after the switch). The HPI fluid temperature falls from 343.2 K [158.1 °F] immediately following the switch to 323.7 K [123.0 °F] at the end of the calculation (15,000 s after the break opens). The model input data for the containment spray actuation time and the containment sump fluid temperature were obtained from an independent Palisades containment analysis for a 20.32-cm [8-in] diameter break in the RCS.

The RELAP5-calculated sequence of events for Case 62 is shown in Table 3.3-4. The RELAP5-calculated responses for the RCS pressure, average reactor vessel downcomer fluid temperature and average reactor vessel wall inside surface heat transfer coefficient for this case are shown in Figures 3.3.4-11, 3.3.4-12 and 3.3.4-13, respectively.

The calculated break flow response is shown in Figure 3.3.4-14. When the break opens, the RCS pressure falls very rapidly to near atmospheric pressure (it requires only 1,760 s for the hot leg pressure to reach 0.5 MPa [72 psia]). The depressurization causes a reactor trip signal at 4 s. The reactor trip causes a turbine trip, isolating the steam generator systems.

Figure 3.3.4-15 shows the calculated SG secondary system pressure responses. The turbine trip causes the secondary system pressures to rise; the pressure increase is limited by the opening of the turbine bypass and atmospheric dump valves. The steam pressures did not increase sufficiently to open the main steam safety relief valves. The declining SG pressures are an indication of reverse (i.e., secondary system to primary system) SG heat transfer caused by the cooling down of the primary coolant system. The SG secondary fluid mass responses are shown in Figure 3.3.4-16. The turbine trip resulted in collapse of the secondary system indicated levels, which initiated auxiliary feedwater (AFW) flow to both SGs. The AFW flow replenished the SG secondary fluid inventories; AFW flow was throttled to maintain the SG levels within the normal range.

At 7 s the minimum RCS subcooling fell below 13.9 K [25 ^{o}F], resulting in the operator tripping one reactor coolant pump in each loop. At 12 s the RCS pressure had fallen to 8.963 MPa [1,300 psia], resulting in the operator tripping the remaining two reactor coolant pumps. The decline in the coolant loop flows caused by the pump trip is indicated in Figure 3.3.4-17, which shows the two hot leg flows at the reactor vessel connections. The decline in the coolant loop flows was rapid and total, with no period of natural circulation prior to complete stagnation of the loop flows. The effects of loop flow stagnation on the reactor vessel downcomer fluid temperature are evident in Figure 3.3.4-12. Under the stagnant coolant loop conditions, the effects of injecting cold HPI, LPI and SIT fluid into the cold legs are directly felt in the vessel downcomer and the fluid temperatures there decline rapidly.

RCS depressurization to 10.98 MPa [1593 psia] led to a safety injection actuation signal at 7 s and the starting of the HPI and LPI pumps after a 27-second delay (which represents effects related to plant instrumentation, control systems and pump start-up timing). The calculated HPI and LPI flow rates for Cold Leg A1 are shown in Figure 3.3.4-18; the total HPI and LPI flow rates are four times the flows shown in the figure. The flow delivered from the centrifugal pumps of the HPI and LPI systems are functions of the cold leg pressure, with lower pressures resulting in higher injection flows and with no injection flow delivered whenever the RCS pressure exceeds the shutoff heads of the systems (8.906 MPa [1291.7 psia] for HPI and 1.501 MPa [217.7 psia] for LPI). At 1614 s, a recirculation actuation signal was calculated as a result of a low SIRWT level condition. The model tracks SIRWT inventory and level based on the flows drawn from the tank by the containment spray, HPI, LPI and charging systems. At this time the suction for the HPI system is switched from the SIRWT to the containment sump (with the resulting increase in HPI fluid temperature described above) and the LPI pumps are automatically tripped.

The effects of RCS coolant inventory loss through the break are evident in the declining pressurizer level response shown in Figure 3.3.4-19. The pressurizer was completely drained over the first 15 s of the event sequence and remained empty thereafter. The letdown flow was isolated early in the event sequence at the time of the safety injection actuation signal. The charging system flow increased in response to the low pressurizer level condition, with all three charging pumps delivering flow. Charging flow was terminated at 3,414 s, which is 1,800 s after the time of the recirculation actuation signal. It is estimated that 30 minutes would be required after the recirculation actuation signal for the charging system to completely drain the SIRWT of its remaining inventory. Afterward, no source of fluid is available for the charging system. Because the break size for this event sequence is large, the charging system flow is of relatively small importance in relation to the HPI, LPI and SIT ECCS flows.

The Loop 1A SIT discharge flow rate response is shown in Figure 3.3.4-20; the total SIT flow rate is four times the flow shown in the figure. Intermittent SIT flow began at 259 s, when the RCS pressure fell below the initial SIT pressure, 1.480 MPa [214.7 psia]. The SITs discharge whenever the RCS pressure is below the tank pressure (which declines as the liquid inventory flows out of the SITs). The SIT discharge period ended at 949 s when the liquid inventories of the SITs had been completely discharged.

During the latter portion of the event sequence the calculated conditions reflect balances in the RCS mass and energy flows. The break mass flow rate is balanced by the HPI mass addition rate. The core heat addition rate is balanced by the cooling afforded to the RCS from adding cold HPI fluid and removing warm fluid at the break. These balanced conditions were reached at about 3,000 s.

The minimum average reactor vessel downcomer fluid temperature, 308 K [95°F], is reached at 1470 s, shortly before the time when the suction for the HPI system is switched to the containment sump (which warms the HPI fluid) and the LPI pumps are tripped. The RCS pressure at the time of the minimum temperature was calculated to be 0.72 MPa [104 psia].

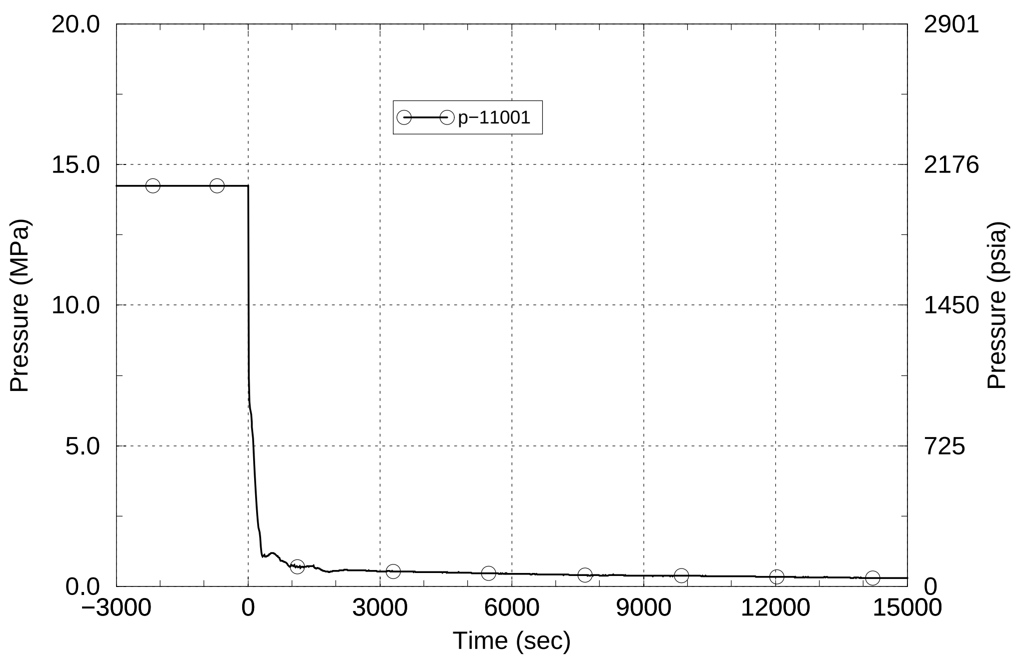


Figure 3.3.4-11 Reactor Coolant System Pressure - Palisades Case 62

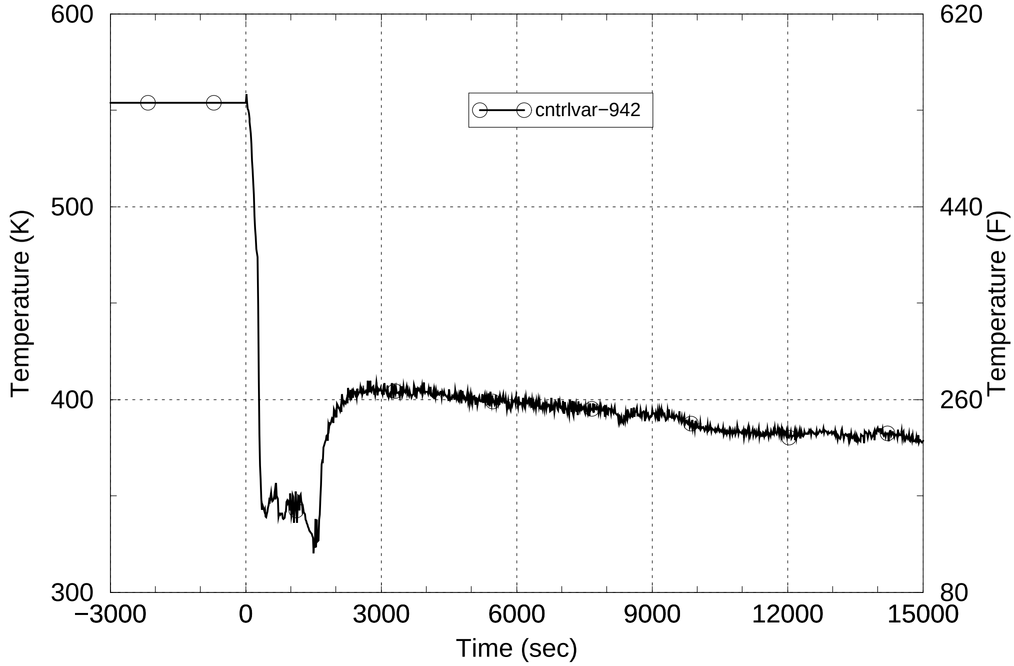


Figure 3.3.4-12 Average Reactor Vessel Downcomer Fluid Temperature - Palisades Case 62

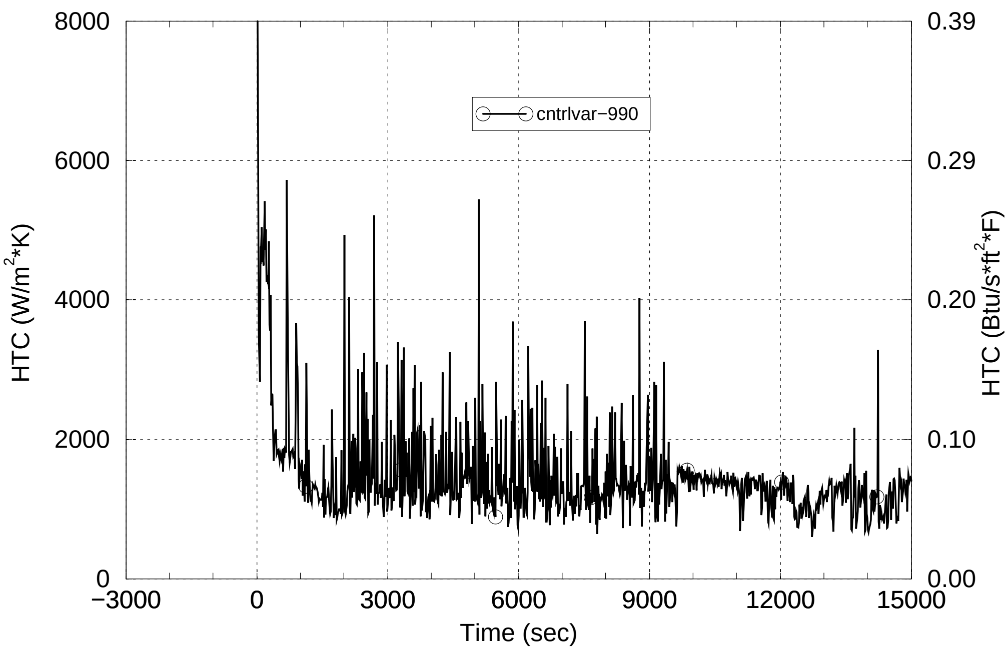


Figure 3.3.4-13 Avg Reactor Vessel Inner-Wall Heat Transfer Coefficient - Palisades Case 62

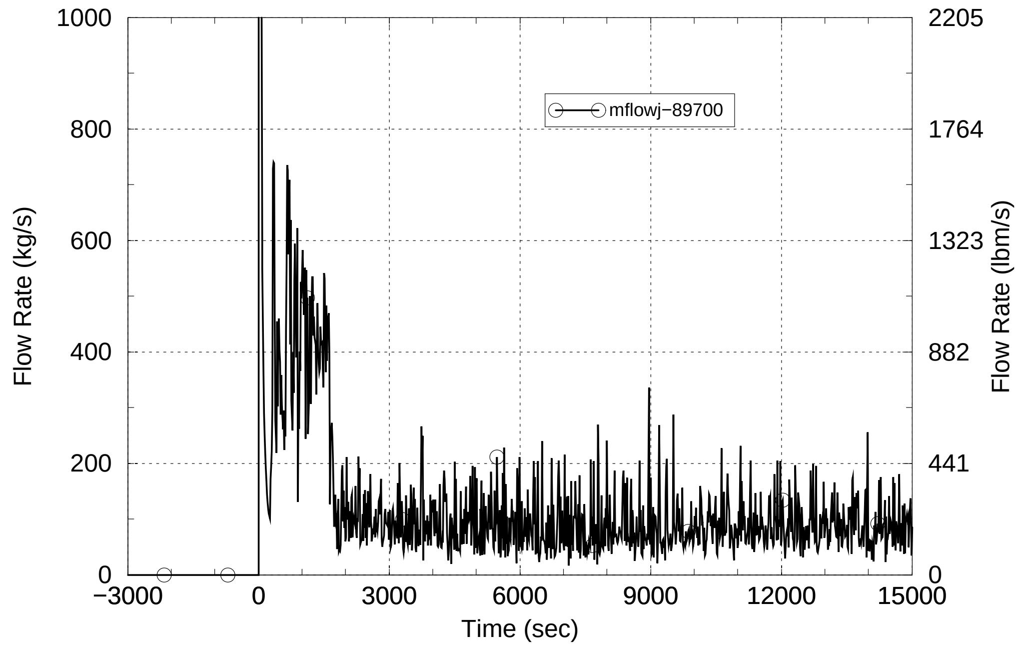


Figure 3.3.4-14   Break Flow - Palisades Case 62

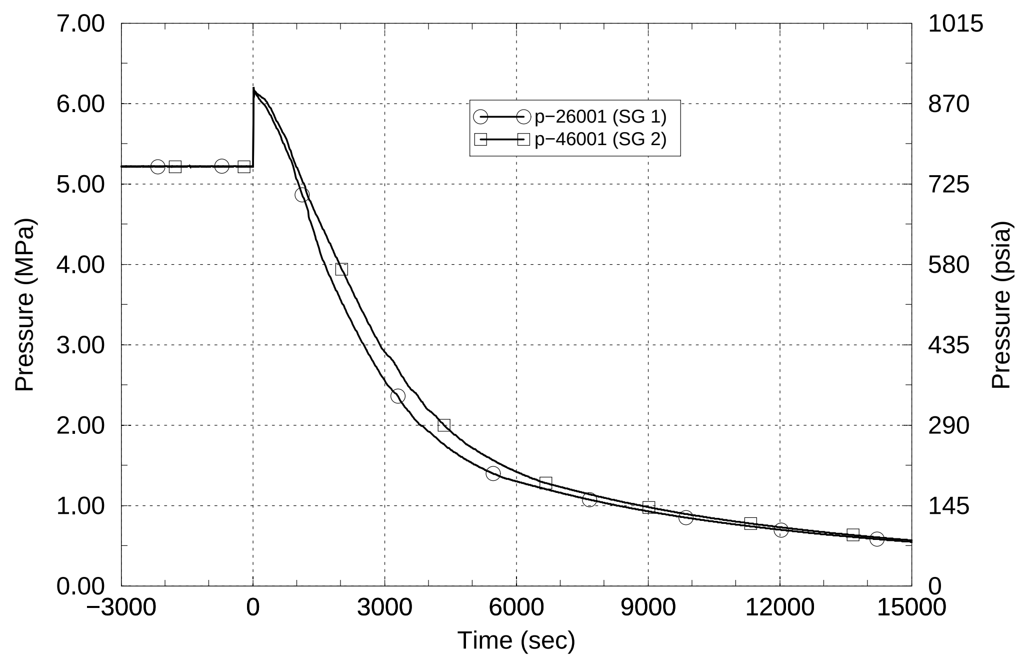


Figure 3.3.4-15   Steam Generator Pressures - Palisades Case 62

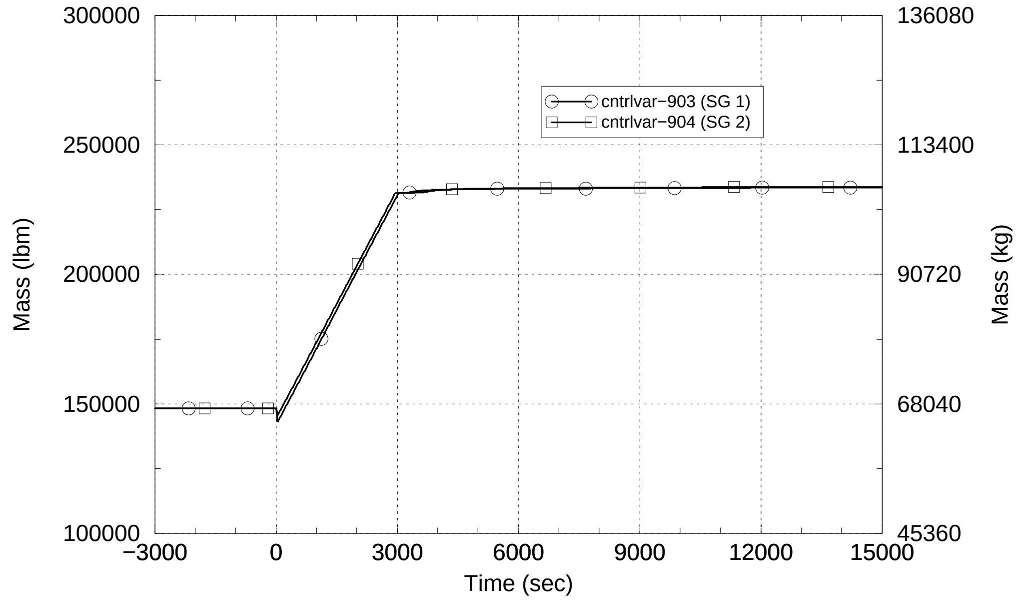


Figure 3.3.4-16   Steam Generator Secondary Fluid Masses - Palisades Case 62

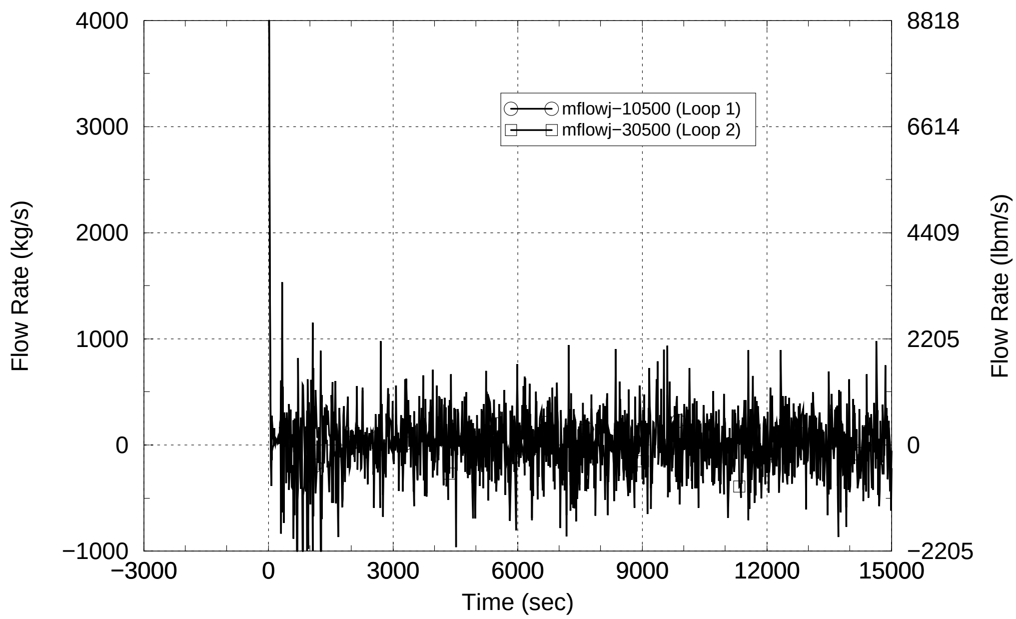


Figure 3.3.4-17   Hot Leg Flows - Palisades Case 62

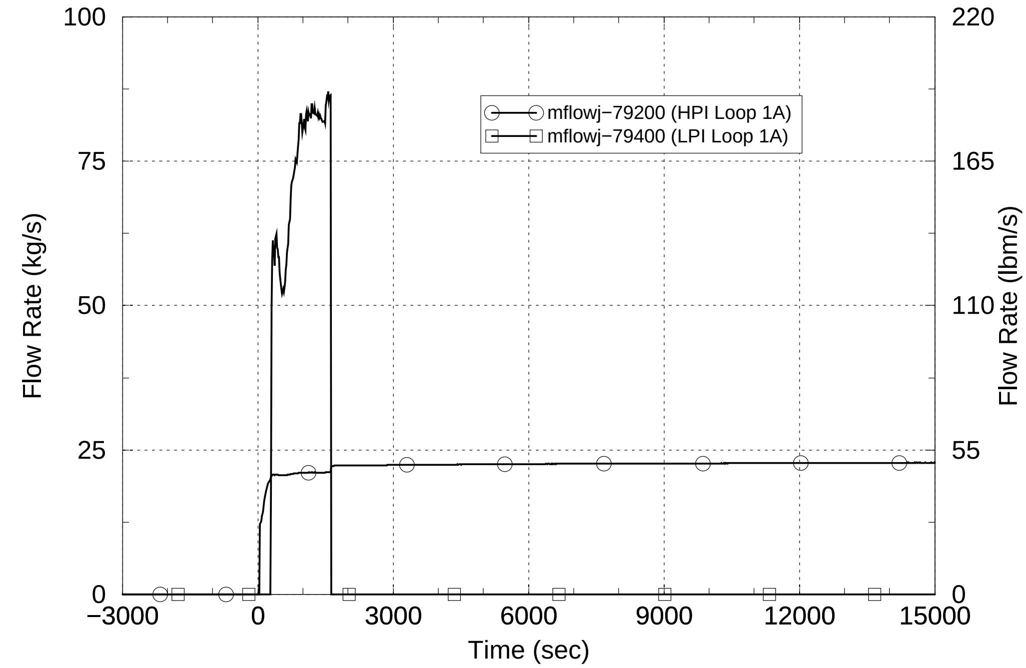


Figure 3.3.4-18 Loop A1 HPI and LPI Flows - Palisades Case 62

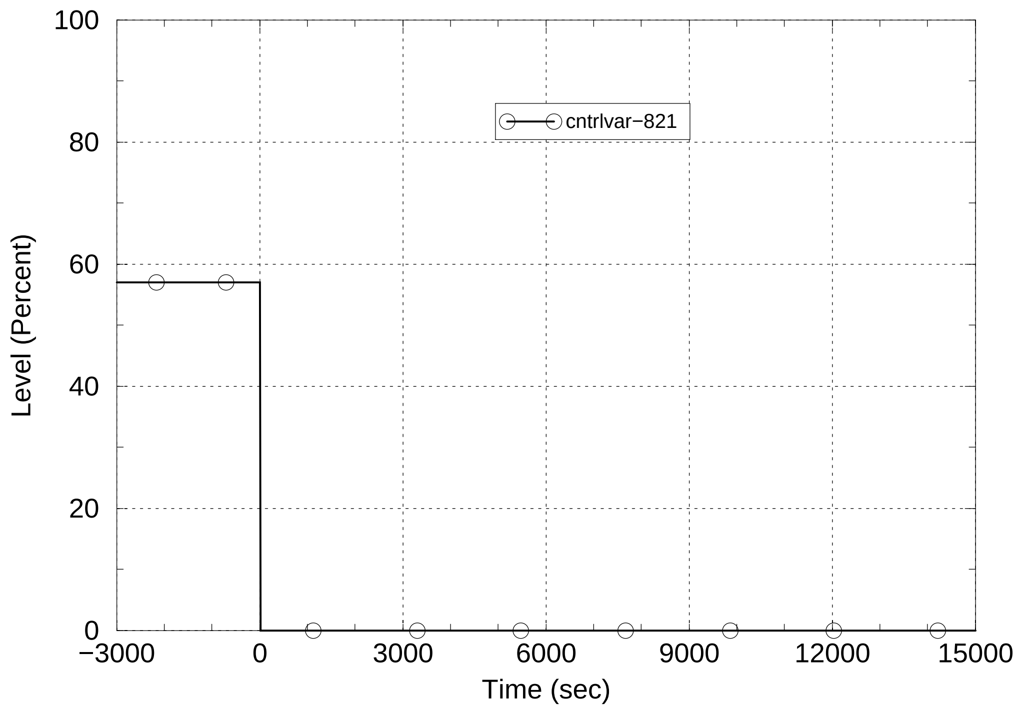


Figure 3.3.4-19 Pressurizer Level - Palisades Case 62

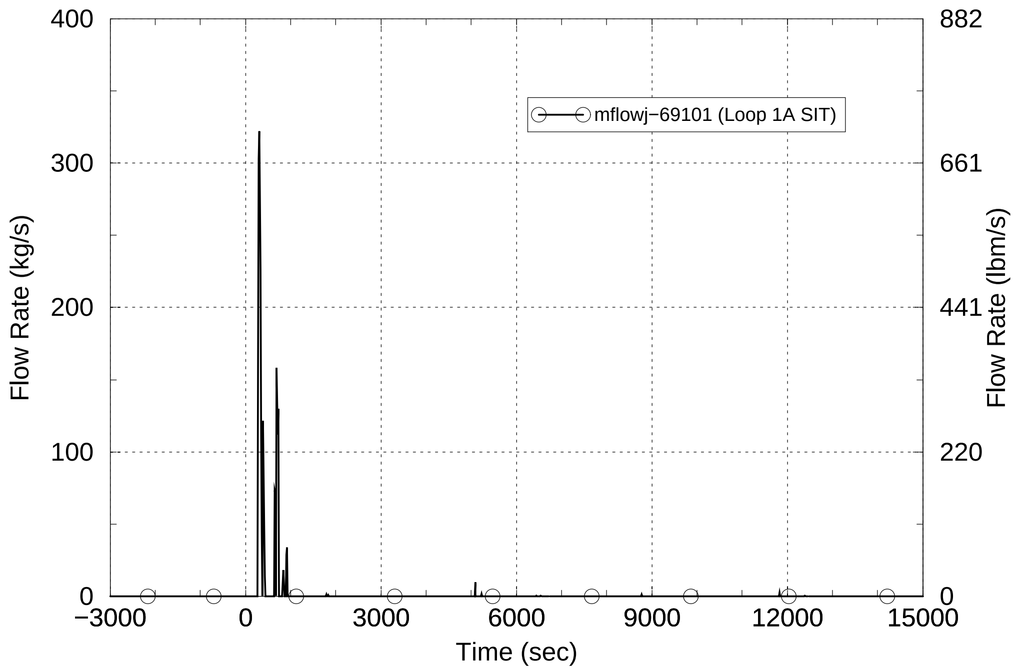


Figure 3.3.4-20   Loop 1A SIT Flow - Palisades Case 62

3.3.4.3   14.37-cm [5.656-in] Diameter Cold Leg Break from Hot Full Power Condition with Winter-Season ECCS Temperatures - Palisades Case 63

With the plant in HFP operation, this event starts with a 14.47-cm [5.656-in] diameter break in the pump-discharge cold leg. The operator is assumed not to throttle the HPI flow, which is normally done if RCS subcooling and pressurizer level criteria have been met. The calculation assumes that the temperatures of the ECCS fluids are representative of winter-season conditions: HPI and LPI temperatures of 277.6 K [40 °F] and SIT temperatures of 288.7 K [60°F] (the nominal ECCS fluid temperatures are listed in Table 2.0-1).

The following modeling changes were made to simulate this event sequence. The cold leg break to a constant atmospheric-pressure containment boundary condition was added to the model in Loop 1A. The equivalent break flow area for a circular break with a diameter of 14.47 cm [5.656 in] was specified. The break was connected on the side of the horizontal cold leg, at the junction between Cells 1 and 2 of Component 150, as shown in Figure 2.3-2. The critical flow model was activated at the break junction and the flow loss coefficients specified were based on AP600-derived flow loss coefficients (Reference 3.3-1) and scaled for the specific break size and location for this event sequence. The boundary conditions for the HPI, LPI and SIT fluids were changed to represent the winter-season conditions listed above. At the time the reactor coolant pump coast-down was complete, large reverse flow loss coefficients were implemented in the loop seal cold leg regions of the model (Components 140, 340, 640 and 740 in Figure 2.3-2) to prevent the setting up of same-loop cold leg circulation, as discussed in Section 2.0. To eliminate non-physical numerically-driven circulations within the reactor vessel downcomer portion of the model, momentum flux was disabled in all junctions internal to the downcomer region (see discussion in Section 2.3.1). The containment high pressure signal, which results in containment spray actuation, was specified as 15.6 s after event initiation. The modeling for the HPI fluid temperature was modified so as to represent the constant safety injection refueling water tank (SIRWT) winter-season temperature prior to the draining of that tank then switch to a representation of a variable containment sump temperature (specified as a function of the time after the switch). The HPI fluid temperature rises from 337.0 K [147.0°F] immediately following the switch to 339.3 K [151.1°F] at 210 s and then falls to 324.0 K [123.6°F] at the end of the calculation (15,000 s after the break opens). The model input data for the containment spray actuation time and the containment sump fluid temperature were obtained from an independent Palisades containment analysis for a 14.37-cm [5.656-in] diameter break in the RCS.

The RELAP5-calculated sequence of events for Case 63 is shown in Table 3.3-4. The RELAP5-calculated responses for the RCS pressure, average reactor vessel downcomer fluid temperature and average reactor vessel wall inside surface heat transfer coefficient for this case are shown in Figures 3.3.4-21, 3.3.4-22 and 3.3.4-23, respectively.

The calculated break flow response is shown in Figure 3.3.4-24. When the break opens, the RCS pressure falls rapidly at first, then more slowly as flashing within the RCS is encountered. The RCS depressurization causes a reactor trip signal at 5 s. The reactor trip causes a turbine trip, isolating the steam generator systems.

Figure 3.3.4-25 shows the calculated SG secondary system pressure responses. The turbine trip causes the secondary system pressures to rise; the pressure increase is limited by the opening of the turbine bypass and atmospheric dump valves. The steam pressures did not increase sufficiently to open the main steam safety relief valves. The declining SG pressures are an indication of reverse (i.e., secondary system to primary system) SG heat transfer caused by the cooling down of the primary coolant system. The SG secondary fluid mass responses are shown in Figure 3.3.4-26. The turbine trip resulted in collapse of the secondary system indicated levels, which initiated auxiliary feedwater (AFW) flow to both SGs. The AFW flow replenished the SG secondary fluid inventories; AFW flow was throttled to maintain the SG levels within the normal range.

At 15 s the minimum RCS subcooling fell below 13.9 K [25°F], resulting in the operator tripping one reactor coolant pump in each loop. At 16 s the RCS pressure had fallen to 8.963 MPa [1300 psia], resulting in the operator tripping the remaining two reactor coolant pumps. The decline in the coolant loop flows caused by the pump trip is indicated in Figure 3.3.4-27, which shows the two hot leg flows at the reactor vessel connections. The decline in the coolant loop flows was rapid and total, with no period of natural circulation prior to complete stagnation of the loop flows. The effects of loop flow stagnation on the reactor vessel downcomer fluid temperature are evident in Figure 3.3.4-22. Under the stagnant coolant loop conditions, the effects of injecting cold HPI, LPI and SIT fluid into the cold legs are directly felt in the vessel downcomer and the fluid temperatures there decline rapidly.

RCS depressurization to 10.98 MPa [1593 psia] led to a safety injection actuation signal at 10 s and the starting of the HPI and LPI pumps after a 27-second delay (which represents effects related to plant instrumentation, control systems and pump start-up timing). The calculated HPI and LPI flow rates for Cold Leg A1 are shown in Figure 3.3.4-28; the total HPI and LPI flow rates are four times the flows shown in the figure. The flow delivered from the centrifugal pumps of the HPI and LPI systems are functions of the cold leg pressure, with lower pressures resulting in higher injection flows and with no injection flow delivered whenever the RCS pressure exceeds the shutoff heads of the systems (8.906 MPa [1291.7 psia] for HPI and 1.501 MPa [217.7 psia] for LPI). At 2085 s, a recirculation actuation signal was calculated as a result of a low SIRWT level condition. The model tracks SIRWT inventory and level based on the flows drawn from the tank by the containment spray, HPI, LPI and charging systems. At this time the suction for the HPI system is switched from the SIRWT to the containment sump (with the resulting increase in HPI fluid temperature described above) and the LPI pumps are automatically tripped.

The effects of RCS coolant inventory loss through the break are evident in the declining pressurizer level response shown in Figure 3.3.4-29. The pressurizer was completely drained over the first 15 s of the event sequence and it remained empty afterward. The letdown flow was isolated early in the event sequence at the time of the safety injection actuation signal. The charging system flow increased in response to the low pressurizer level condition, with all three charging pumps delivering flow. Charging flow was terminated at 3885 s, which is 1,800 s after the time of the recirculation actuation signal. It is estimated that 30 minutes would be required after the recirculation actuation signal for the charging system to completely drain the SIRWT of its remaining inventory. Afterward, no source of fluid is available for the charging system. Because the break size for this event sequence is large, the charging system flow is of relatively small importance in relation to the HPI, LPI and SIT ECCS flows.

The Loop 1A SIT discharge flow rate response is shown in Figure 3.3.4-30; the total SIT flow rate is four times the flow shown in the figure. Intermittent SIT flow began at 664 s, when the RCS pressure fell below the initial SIT pressure, 1.480 MPa [214.7 psia]. The SITs discharge whenever the RCS pressure is below the tank pressure (which declines as the liquid inventory flows out of the SITs). The SIT discharge period ended at 2449 when the liquid inventories of the SITs had been completely discharged.

During the latter portion of the event sequence the calculated conditions reflect balances in the RCS mass and energy flows. The break mass flow rate is balanced by the HPI mass addition rate. The core heat addition rate is balanced by the cooling afforded to the RCS from adding cold HPI fluid and removing warm fluid at the break. These balanced conditions were reached at about 4,000 s.

The minimum average reactor vessel downcomer fluid temperature, 306 K [92 ^{o}F], is reached at 2070 s, during the SIT injection period. The RCS pressure, which was calculated to be 1.07 MPa [155 psia] at the time of the minimum temperature, fell slowly over the remainder of the event sequence calculation.

3.3.5 References

3.3-1 SCIENTECH, Inc., RELAP5.Mod 3 Code Manual, Volume IV: Models and Correlations, Formally NUREG/CR-5535, Volume IV, June 1999 (Section 7.3).

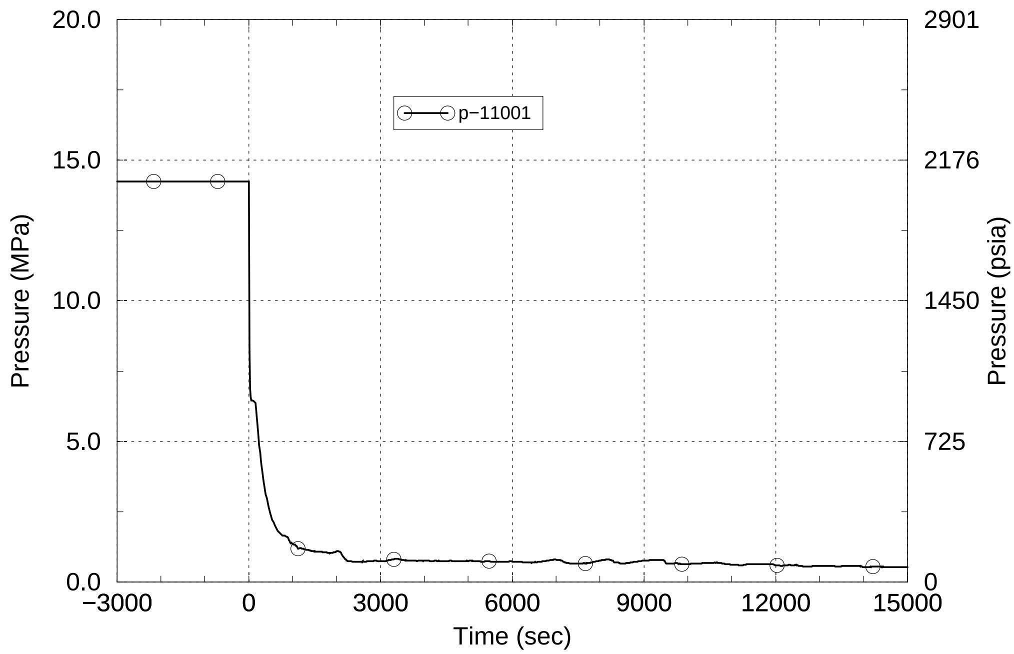


Figure 3.3.4-21 Reactor Coolant System Pressure - Palisades Case 63

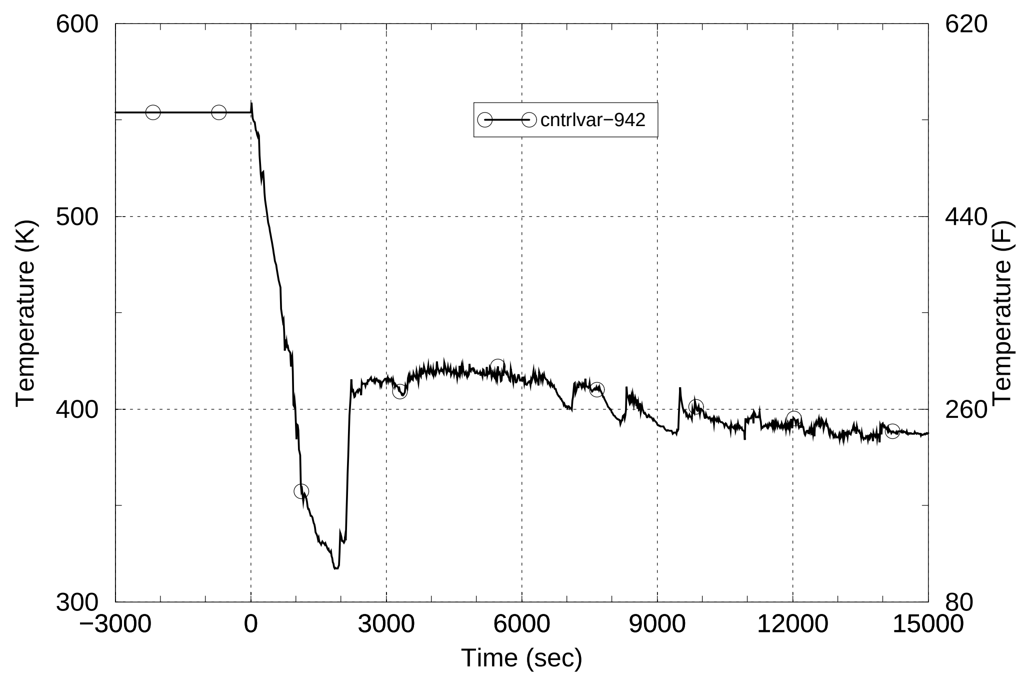


Figure 3.3.4-22 Average Reactor Vessel Downcomer Fluid Temperature - Palisades Case 63

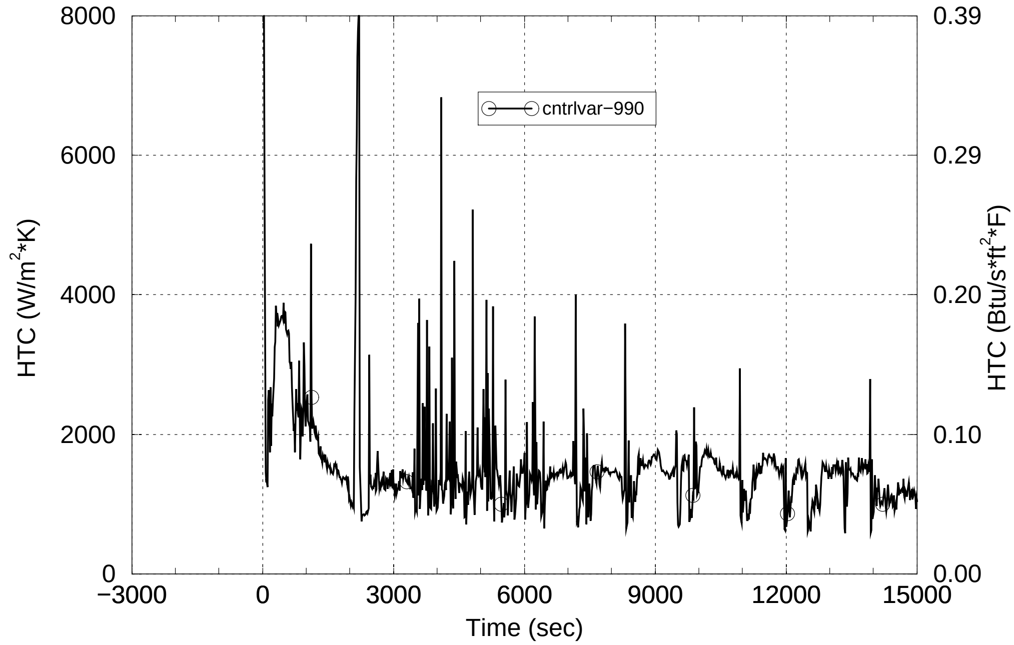


Figure 3.3.4-23 Avg Reactor Vessel Inner-Wall Heat Transfer Coefficient - Palisades Case 63

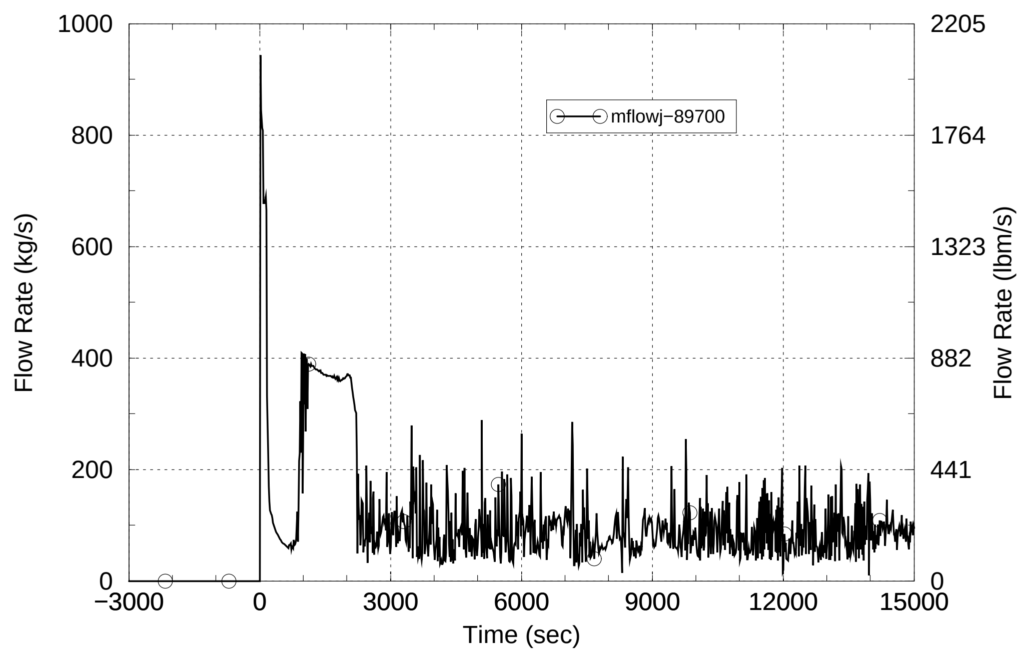


Figure 3.3.4-24 Break Flow - Palisades Case 63

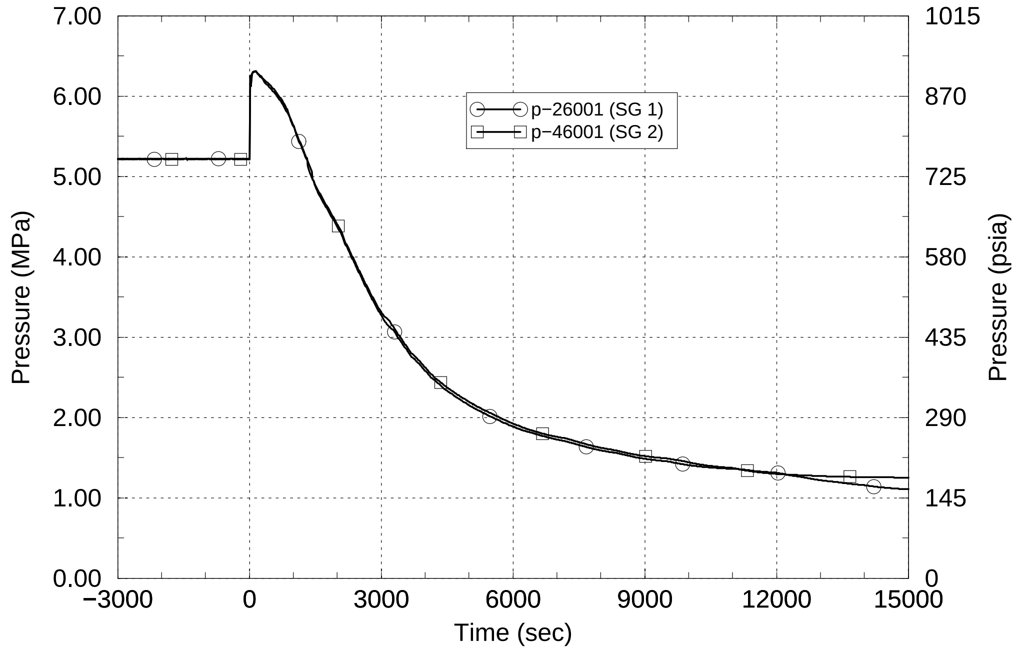


Figure 3.3.4-25 Steam Generator Pressures - Palisades Case 63

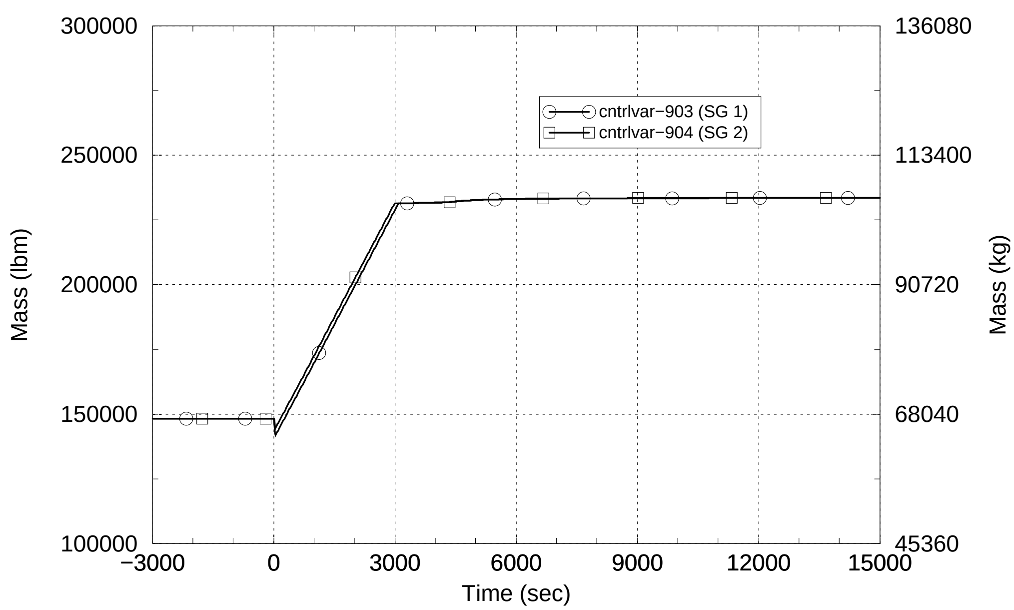


Figure 3.3.4-26 Steam Generator Secondary Fluid Masses - Palisades Case 63

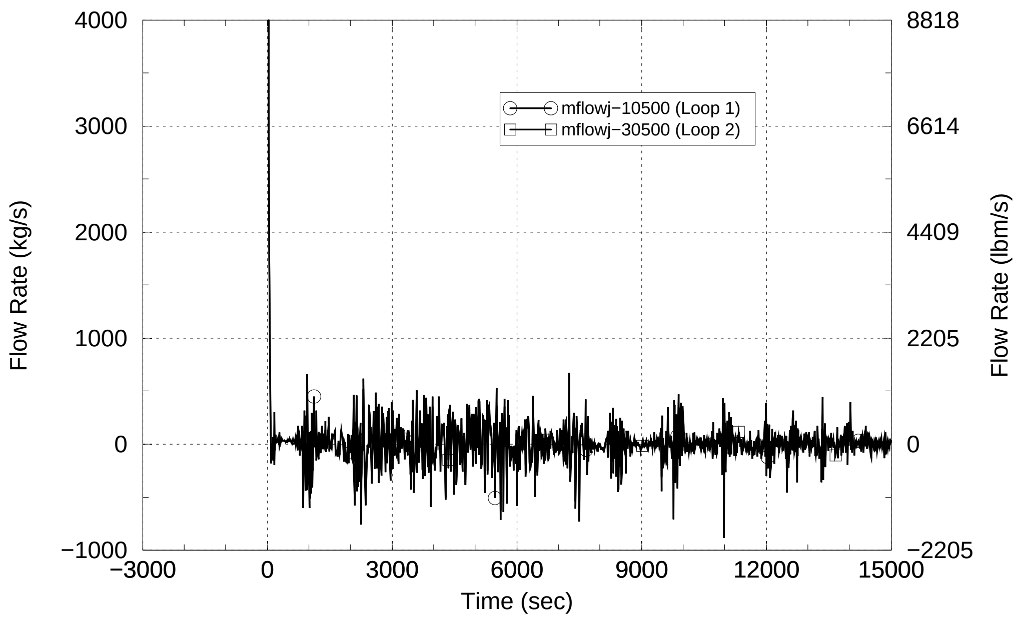


Figure 3.3.4-27 Hot Leg Flows - Palisades Case 63

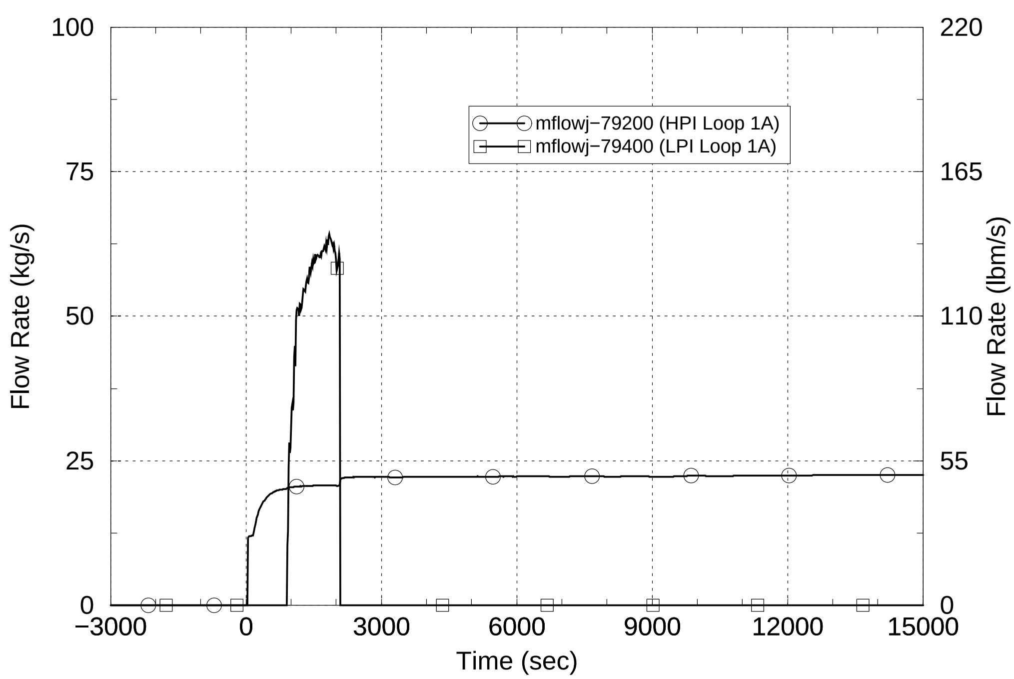


Figure 3.3.4-28 Loop A1 HPI and LPI Flows - Palisades Case 63

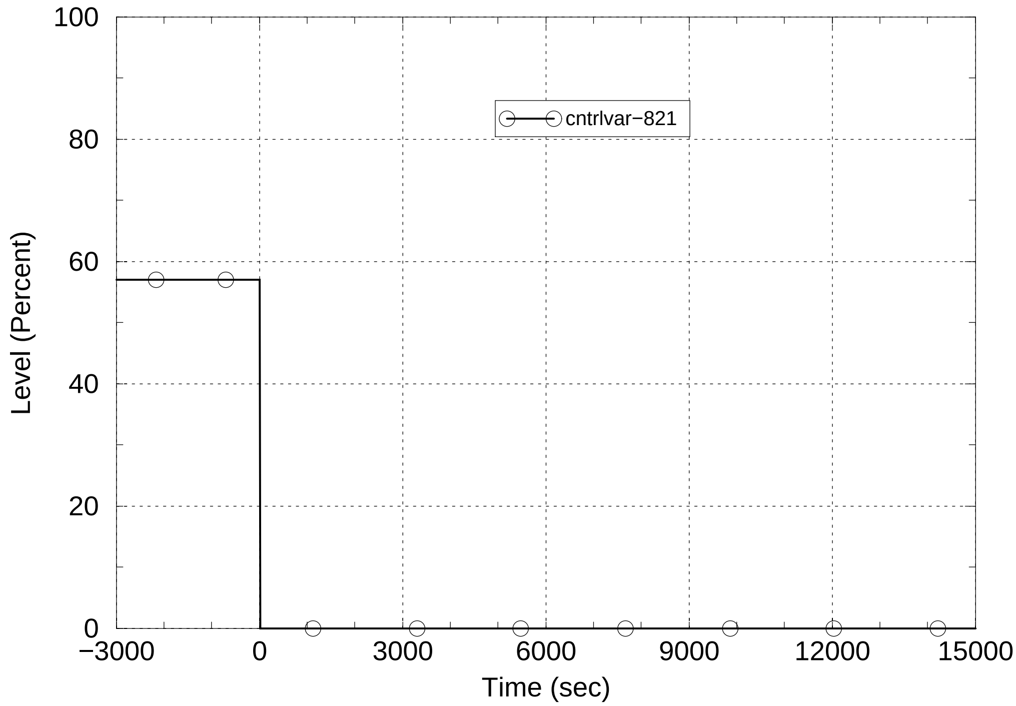


Figure 3.3.4-29   Pressurizer Level - Palisades Case 63

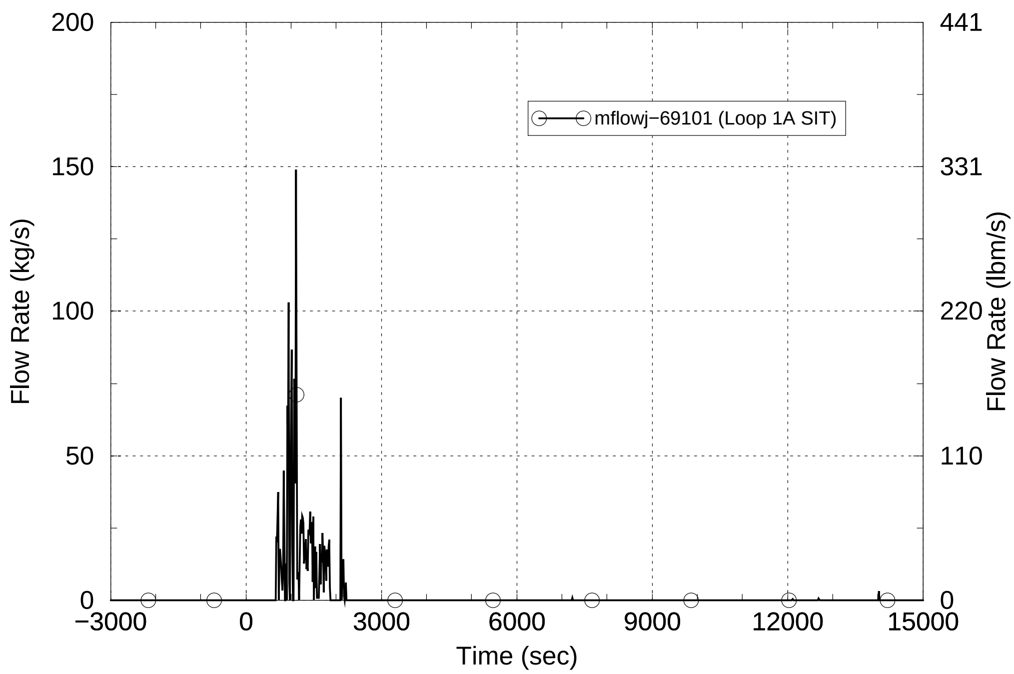


Figure 3.3.4-30   Loop 1A SIT Flow - Palisades Case 63

4.0 SUMMARY OF THE PTS THERMAL HYDRAULIC RESULTS

4.1 Summary of the Oconee, Beaver Valley and Palisades Results

Tables 4.1-1, 4.1-2, and 4.1-3 present a summary of the reactor vessel downcomer temperature and primary system pressure for the transient sequences discussed in Section 3 for the Oconee, Beaver Valley and Palisades Plants, respectively. This summary is presented to facilitate comparison of the results of the cases analyzed. Direct comparisons of downcomer temperature and system pressure results for many of the sequences analyzed among the plants show similar results. In other instances, direct comparisons are more difficult because of plant design differences and differences in sequence modeling assumptions.

The LOCA analyses for the Oconee, Beaver Valley and Palisades plants show similar results as might be expected. Minor differences exist in the time that the minimum temperature is reached. For the 40.64 cm [16 in] break from HFP operation, the Oconee minimum temperature is 298 K [76°F] at 1,721 s (Case 156) while the Beaver Valley and Palisades temperature results (Cases 009 and 40, respectively) are 291 K [64°F] at 960 s and 308 K [94°F] at 1260 s, respectively. The difference in the temperature is principally driven by the ECCS injection temperature assumed. The ECCS injection temperature for Beaver Valley is the lowest at 283 K [50°F] while the Oconee and Palisades injection temperatures are 300 K [80°F] and 304 K [88°F], respectively (See Table 2.0-1). Plant design differences may have some impact on the time that the minimum temperature occurs, but do not have much of an impact of the minimum temperature results in the case of a LOCA of this size. For smaller breaks, the minimum temperature is also generally dependent on the assumed ECCS injection temperature, although the time that the minimum temperature is reached is later since the blowdown time and time that the various ECCS systems start is longer. Also, plant differences in ECCS flow capability and shutoff head can lead to differences in results. In general, the downcomer temperature decreases to near the injection temperature because the ECCS systems continue to inject cold water into the reactor coolant system with the time that the minimum is reached dependent on the break size.

Other scenarios involving stuck open pressurizer safety valves are not as directly comparable because of differences in valve sizes and sequence definitions, although portions of the transients may be comparable. For example, the downcomer temperature for the Oconee case where a stuck open pressurizer safety valve occurs during HZP operation and recloses at 3,000 s (Case 124) is 360 K [188°F]. In this analysis, the operator is assumed to throttle HPI to maintain 27.8 K [50°F] subcooling, but throttling does not occur until after the valve recloses. In comparison, Case 097 for Beaver Valley, which is also a stuck-open pressurizer safety relief valve case with reclosure at 3,000 s that occurs during HZP operation, results in a downcomer temperature of 321 K [118°F] at 3,000 s.

The comparison of the first part of the transient up to the point that the valve recloses is of interest. The Beaver Valley downcomer temperature is lower because of several factors; the safety relief valve has a somewhat larger capacity at Beaver Valley than Oconee (See Table 2.0.1) and the injection temperature at Beaver Valley is colder. A third factor relates to the vessel vent valves which are part of the Oconee plant design but are not part of the Beaver Valley and Palisades designs. The vent valves connect the vessel upper plenum to the upper part of the downcomer and open on small pressure differences to vent steam from the upper plenum to the downcomer and out the break during a LOCA. A consequence of vent valve operation is that warm water from the upper plenum can flow to the downcomer, resulting in higher temperature predictions than would otherwise be the case.

For main steam line breaks, the downcomer temperature results for the three plants are similar despite differences in assumptions for operator actions for HPI throttling, break location inside and outside containment, and timing of AFW isolation to the affected steam generator. For example, Beaver Valley Case 102 is a MSLB from HFP conditions where AFW continues to feed the affected steam generator for 30 minutes and the operator controls HHSI 30 minutes after allowed. In this case, the minimum downcomer temperature is 373 K [212°F] at 3,990 s. In comparison, Palisades Case 54, a MSLB that occurs inside containment and where the AFW continues to feed the affected steam generator and the operator does not throttle HPI flow, results in a minimum downcomer temperature of 377 K [219°F] at 4,110 s. The results are not that different (4 K [7°F]) even given the modeling differences. One reason is that the RCS generally remains full during MSLBs with loop natural circulation (and forced circulation in some cases) continuing throughout the event sequences. This circulation tends to keep the RCS fluid well mixed, so that the downcomer temperature does not drop to the ECCS injection temperature. Instead, the downcomer temperature tends to approach 373 K [212°F], which is the saturation temperature at the atmospheric pressure present in the affected steam generator secondary side. In contrast to the LOCA where the temperature of ECCS injection drives the downcomer temperature, MSLBs remove heat from the reactor coolant system uniformly, so that minimum downcomer temperatures tend to be higher.

Some generic conclusions regarding classes of sequences that have been evaluated in this analysis are presented below:

- Large break LOCAs cause the downcomer temperature to rapidly drop with a corresponding rapid drop in primary system pressure. There is no possibility of reactor coolant system repressurization. Downcomer temperatures will approach the ECCS injection temperature with the timing dependent principally on the break size.

- Small break LOCAs (includes stuck open primary relief valves) cause the downcomer temperature to drop to intermediate temperatures and RCS pressures, but the values are break-size dependent . Plant-specific complexities are added, that are caused by different design parameters such as initial accumulator pressures, HPI and LPI shutoff head, HPI throttling criteria, and containment sump switchover timing and corresponding change in injection temperature. Stuck open primary relief valve cases are one category of small break LOCA with the potential for extreme RCS repressurization should the valves later reclose.

- Main steam line breaks cause the downcomer temperature to decrease to values somewhat higher than the small break LOCA with extreme RCS repressurization a likelihood unless operator action is taken.

The thermal hydraulic analysis discussed in this report is a part of an overall risk analysis where the risk of vessel failure due to a PTS event is determined by sequence probabilities that define the sequences analyzed and the fracture mechanics analysis that, combined with the sequence probabilities and thermal hydraulic results, determine the risk.

Table 4.1-1 Summary of Oconee Thermal Hydraulic Results

Case #	Description	Minimum Downcomer Fluid Temperature	Corresponding Primary System Pressure
27	Main steam line break from hot full power conditions. Both turbine driven and auxiliary driven feedwater are assumed to be operating. Operator throttles HPI (Note 2)	380 K [224°F] at 4,400 s.	1.8 MPa [261 psia]. No repressurization.
101	Main steam line break from hot zero power conditions. Both turbine driven and auxiliary driven feedwater are assumed to be operating. Operator throttles HPI (Note 2)	377 K [219°F] at 2,600 s.	1.8 MPa [261 psia]. No repressurization.
109	Stuck open pressurizer safety valve that recloses at 6,000 s from hot full power conditions. No HPI throttling by the operator.	350 K [170°F] at 6,010 s.	2.3 MPa [330 psia]. System repressurizes to 17 MPa [2,465 psia]
113	Stuck open pressurizer safety valve that recloses at 6,000 s from hot full power conditions. Operator throttles HPI (Note 1)	350 K [170°F] at 6,030 s.	2.3 MPa [330 psia]. System repressurizes to 17 MPa [2,465 psia]
115	Stuck open pressurizer safety valve that recloses at 3,000 s from hot full power conditions. Operator throttles HPI.	433 K [320°F] at 3,010 s.	3.7 MPa [537 psia]. System repressurizes to 17 MPa [2,465 psia]

Case #	Description	Minimum Downcomer Fluid Temperature	Corresponding Primary System Pressure
122	Stuck open pressurizer safety valve that recloses at 6,000 s from hot zero power conditions. Operator throttles HPI.	307 K [93°F] at 6,010 s	1.7 MPa [249 psia]. System repressurizes to 17 MPa [2,465 psia] then depressurizes to a stable pressure of 2.5 MPa [363 psia].
124	Stuck open pressurizer safety valve that recloses at 3,000 s from hot zero power conditions. Operator throttles HPI.	360 K [188°F] at 4,000 s.	2.8 MPa [406 psia]. System repressurizes to 17 MPa [2,465 psia] and then depressurizes to 4.6 MPa [667 psia]
156	40.64 cm [16 in] break in the hot leg from hot full power	300 K [80°F] at 600 s	0.18 MPa [26 psia]. No repressurization.
160	14.37 cm [5.656 in] surge line break from hot full power	299 K [78°F] at 2,300 s	0.9 MPa [130 psia]. No repressurization.
164	20.32 cm [8 in] surge line break from hot full power	300 K [80°F] at 1,200 s	0.56 MPa [80 psia]. No repressurization.
165	Stuck open pressurizer safety valve that recloses at 6,000 s from hot zero power conditions. No operator actions considered.	306 K [91°F] at 6,010 s	1.8 MPa [261 psia]. Repressurizes to 17 MPa [2,465 psia]
172	10.16 cm [4 in] cold leg break from hot full power	355 K [180°F] at 2,700 s	1.1 MPa [160 psia]. No repressurization.

Notes:

(1) Operator throttles HPI 10 minutes after 2.7 K [5°F] subcooling and 254 cm [100 in] pressurizer level is reached. The throttling criteria is 27.8 K [50°F] subcooling.
(2) Operator throttles HPI to maintain 27.8 K [50°F] subcooling.

Table 4.1-2 Summary of Beaver Valley Thermal Hydraulic Results

Case #	Description	Minimum Downcomer Fluid Temperature	Corresponding Primary System Pressure
007	20.32 cm [8.0 in] diameter surge line break from hot full power	291 K [64.1°F] at about 1,000 s	0.21 MPa [30.0 psia]. No repressurization.
009	40.64 cm [16.0 in] diameter hot leg break from hot full power	291 K [64.1°F] at about 1,000 s	0.097 MPa [14.0 psia]. No repressurization.
056	10.16 cm [4.0 in] diameter surge line break from hot zero power	288.5 K [59.6°F] at about 2,975 s.	0.917 MPa [133 psia]. No repressurization.
060	One stuck open pressurizer SRV that recloses at 6,000 s from hot full power conditions	330 K [134°F] at 6,000 s	2.62 MPa [380 psia]. Repressurizes to 16.2 MPa [2,350 psia]
071	One stuck open pressurizer SRV which recloses at 6,000 s from hot zero power conditions	295 K [71°F] at 15,000 s	16.3 MPa [2,371 psia]
097	Stuck open pressurizer SRV which recloses (at 3,000 s) from hot zero power	321 K [118°F] at 3000 s	1.62 MPa [235 psia]. Repressurizes to 16.2 MPa [2,350 psia]
102	Main steam line break with AFW continuing to feed affected generator for 30 minutes and operator controls HHSI 30 minutes after allowed from hot full power	373 K [212°F] at 3990 s	16.2 MPa [2,350 psia]. System depressurizes due to HHSI control, but repressurizes due to heatup.
103	Main steam line break with AFW continuing to feed affected generator for 30 minutes and operator controls HHSI 30 minutes after allowed from hot zero power	362 K [192°F] at 3420 s	16.2 MPa [2,350 psia]. System pressure decreases to 4.69 MPa [680 psia] by 15,000 s due to HHSI control.

Case #	Description	Minimum Downcomer Fluid Temperature	Corresponding Primary System Pressure
104	Main steam line break with AFW continuing to feed affected generator for 30 minutes and operator controls HHSI 60 minutes after allowed from hot full power	370 K [206°F] at 5820 s	16.2 MPa [2,350 psia]. System depressurizes due to HHSI control, but repressurizes due to heatup.
105	Main steam line break with AFW continuing to feed affected generator for 30 minutes and operator controls HHSI 60 minutes after allowed from hot zero power	355 K [179°F] at 5220 s	16.2 MPa [2,350 psia]. System pressure decreases to 4.27 MPa [620 psia] by 15,000 s due to HHSI control.
108	Small main steam line break with AFW continuing to feed affected generator for 30 minutes and operator controls HHSI 30 minutes after allowed from hot full power	395 K [252°F] at 3600 s	16.2 MPa [2,350 psia]. System depressurizes due to HHSI control, but repressurizes due to heatup.
114	7,184 cm [2.828 in] surge line break from hot ful power. Summer conditions assumed. Heat transfer to passive structures increased by 30%	304 K [88°F] at 4,890 s	1.34 MPa [195 psia]. No repressurization
126	One stuck open pressurizer SRV that recloses at 6,000 s from hot full power conditions (10 minute delay)	338 K [148°F] at 6,354 s	2.64 MPa [383 psia] Repressurizes to 16.2 MPa [2,350 psia]
130	One stuck open pressurizer SRV which recloses at 3,000 s. Operator controls HHSI (10 minute delay).	316 K [110°F] at 3,026 s	1.52 MPa [221 psia]. Repressurizes to 16.2 MPa [2,350 psia], then depressurizes due to HHSI control.

Table 4.1-3 Summary of Palisades Thermal Hydraulic Results

Case #	Description	Minimum Downcomer Fluid Temperature	Corresponding Primary System Pressure
19	One stuck-open ADV) on SG-A from HZP operation. Operator does not isolate AFW to SG-A and does not throttle HPI.	423 K [301°F] at 15,000 s.	17.24 MPa [2500 psia]
40	40.64 cm [16 in] break in a hot leg from HFP operation. Operator does not throttle HPI flow.	308 K [94°F] at 1,260 s.	0.14 MPa [21 psia].
52	One stuck-open ADV on SG-A with failure of both MSIVs to close from HZP operation. Operator does not isolate AFW to SG-A and does not throttle HPI.	425 K [305°F] at 15,000 s.	17.24 MPa [2500 psia]
54	Double-ended MSLB on SG-A inside containment with a failure of both of the MSIVs to close from HFP operation. Operator does not isolate AFW to SG-A and does not throttle HPI flow.	377 K [219°F] at 4,110 s.	9.61 MPa [1395 psia]. Repressurizes to 17.24 MPa [2500 psia] due to system heatup.
55	Two stuck-open ADVs on SG A from HFP operation. A flow controller failure and an operator action to start the second motor-driven AFW pump are assumed, resulting in the delivery of two-pump AFW flow.	437 K [328°F] at 4,320 s.	17.24 MPa [2500 psia].
58	10.14 cm [4 in] break in the pump-discharge cold leg from HFP. Operator does not throttle HPI. Winter conditions assumed for the ECCS injection water temperatures.	331 K [136°F] at 2,700 s.	1.32 MPa [191 psia].
59	10.14 cm [4 in] break in the pump-discharge cold leg from HFP. Operator does not throttle HPI flow. Summer conditions assumed for the ECCS injection water temperatures.	351 K [171°F] at 14,940 s.	1.53 MPa [222 psia].

Case #	Description	Minimum Downcomer Fluid Temperature	Corresponding Primary System Pressure
60	5.08 cm [2 in] break in the surge line from HFP operation. Operator does not throttle HPI flow. Winter conditions assumed for the HPI, LPI and SIT injection water temperatures.	351 K [173°F] at 3,540 s.	2.30 MPa [334 psia].
62	20.32 cm [8 in] break in the pump-discharge cold leg from HFP. Operator does not throttle HPI flow. Winter conditions assumed for the ECCS injection water temperatures.	308 K [95°F] at 1,470 s.	0.72 MPa [104 psia].
63	14.37 cm [5.656 in] break in the pump-discharge cold leg from HFP. Operator is assumed not to throttle HPI flow. Winter conditions assumed for the ECCS injection water temperatures.	306 K [92°F] at 2,070 s.	1.07 MPa [155 psia].
64	10.14 cm [4 in] break in the pressurizer surge line from HFP. Operator does not throttle HPI flow. Summer conditions assumed for the ECCS injection water temperatures.	323 K [121°F] at 2,730 s.	1.06 MPa [154 psia].
65	One stuck-open pressurizer SRV from HZP. The SRV recloses at 6,000 s after initiation. Operator does not throttle HPI flow.	366 K [199°F] at 6,570 s.	10.55 MPa [1530 psia]. Repressurizes to 17.51 MPa [2540 psia] due to system heatup.

4.2 Comparison of Current Results to the Previous Study

Limited comparisons to thermal hydraulic results reported in the 1980's PTS study are presented in this section for the Oconee plant. More extensive comparisons are difficult to make because of differences in the plants analyzed and in many of the sequences analyzed. The plants analyzed in the 1980's were Oconee, H.B. Robinson, and Calvert Cliffs. In the present set of results, only Oconee is discussed. Also, the sequences considered are somewhat different, with greater emphasis placed on LOCAs of larger sizes (10.16 cm [4 in] in diameter or greater) in the present study. The results from the 1980's study are taken from NUREG/CR-3761 (Ref 4-1).

One sequence that is common to both the NUREG/CR-3761 results and the present effort is the main steam line break although they were analyzed differently. In both cases, the MSLB is initiated by a double-ended rupture of a steam line in one steam generator. In the NUREG/CR-3761 analysis, the operator was assumed to trip the reactor coolant pumps 30 s after initiation of high pressure injection and also terminated all feedwater and turbine bypass on both steam generators after ten minutes. The reactor coolant pumps were restarted after subcooling was attained. Emergency feedwater and turbine bypass to the unaffected steam generator was reactivated at fifteen minutes in the NUREG/CR-3761 analysis. The analysis was initiated from hot full power conditions. The comparable case in the current study is Case 27, although there are key differences. In Case 27, the reactor coolant pumps remain running because the loss of subcooling criteria where it was assumed that the operator would trip the RCPs (trip criteria is 0.27 K [0.5°F] at hot full power) was not met. Also, emergency feedwater was assumed to continue operation and to feed the affected steam generator.

Table 4.2-1 presents a tabulation of the comparison. NUREG/CR-3761 lists a downcomer temperature of 415 K [287°F] at about 600 s (lower uncertainty bound) for the case where the reactor coolant pumps were restarted when subcooling was attained. The Case 27 result is 380 K [225°F] which was attained at 4,300 s. The Case 27 results are lower mostly because of the continued feed to the affected steam generator by the EFW. There is also a large difference in the pressure as seen in the results presented in NUREG/CR-3761. This difference is due to the assumption of the operator throttling HPI to maintain 27.8 K [50°F] subcooling.

In looking at comparison of thermal hydraulic results either among the plants discussed in this report or to past results, it should be remembered that thermal hydraulic analysis discussed in this report is a part of an overall risk analysis. The risk of vessel failure due to a PTS event is determined by sequence probabilities that define the sequences analyzed and the fracture mechanics analysis that, combined with the sequence probabilities and thermal hydraulic results, determine the risk.

4.3 References

4-1 Fletcher, C. D., et. al., RELAP5 Thermal Hydraulic Analyses of Pressurized Thermal Shock Sequences for the Oconee-1 Pressurized Water Reactor, NUREG/CR-3761, June 1984.

Table 4.2-1 Comparison of Current PTS Thermal Hydraulic Results to Results from NUREG/CR-3761

Description	Minimum Downcomer Fluid Temperature	Corresponding Pressure
NUREG/CR-3761 - MSLB with RCP restarted 10 minutes after subcooling was attained	481 K [407°F]	17.0 MPa [2465 psia]
NUREG/CR-3761 - MSLB with RCP restarted 10 minutes after subcooling was attained - lower uncertainty bound	403 K [266°F]	17.34 MPa [2515 psia]
NUREG/CR-3761 - MSLB with RCP restarted at time subcooling was attained	494 K [429°F]	17.0 MPa [2465 psia]
NUREG/CR-3761 - MSLB with RCP restarted at time subcooling was attained - lower uncertainty bound	415 K [287°F]	17.34 MPa [2515 psia]
Case 27 - MSLB from hot full power conditions. Both turbine driven and auxiliary driven feedwater are assumed to be operating. Operator throttles HPI.	378 K [220°F]	1.56 MPa [227 psia]. No repressurization

Appendix A - Summary of Oconee Base Case Results

September 23, 2004

Appendix A - Summary of Oconee Base Case Results

This appendix presents an overview of the RELAP5 modeling details and the results of the 55 base cases evaluated for the Oconee plant. Table A-1 presents a list of the cases analyzed. These cases include a mix of LOCAs, stuck open pressurizer safety valves, main steam line breaks, and secondary side failures from both hot full power and hot zero power conditions.

Results for each of the 55 cases are presented below as Figures A-1 to A-55. For each case, the following information is given in tabular format.

Case Category	LOCA, RT/TT, MSLB, etc.
Primary Failures	Description of the primary side failure
Secondary Failures	Description of the secondary side failure
Operator Actions	Description of any operator actions
Min DC Temp	The minimum average downcomer fluid temperature and associated time that minimum occurred
Comments	Any comments specific to the event

In addition to the information described above, plots of average downcomer fluid temperature, primary system pressure, and downcomer wall heat transfer coefficient are presented. Any analytical assumptions used in each case are also presented. To facilitate comparisons among cases, each figure presents summary information for the minimum downcomer average temperature in the reactor vessel and the time during the event sequence when that minimum is reached. The results shown in these figures are used in the FAVOR probabilistic fracture mechanics analysis.

Table A-1   List of Oconee Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
8	2.54 cm [1 in] surge line break with 1 stuck open safety valve in SG-A.	None	No	No	No
9	2.54 cm [1 in] surge line break with 2 stuck open safety valves in SG-A.	None	No	No	No
12	2.54 cm [1 in] surge line break with 1 stuck open safety valve in SG-A.	HPI throttled to maintain 27.8 K [50° F] subcooling margin	No	No	No
15	2.54 cm [1 in] surge line break with HPI Failure	At 15 minutes after transient initiation, operator opens all TBVs to lower primary system pressure and allow CFT and LPI injection.	No	No	No
17	2.54 cm [1 in] surge line break with 1 stuck open safety valve in SG-A.	None	No	No	No
27	MSLB without trip of turbine driven emergency feedwater.	Operator throttles HPI to maintain 27.8 K [50° F] subcooling margin.	No	No	No
28	Reactor/turbine trip with 1 stuck open safety valve in SG-A	None	No	No	No
29	Reactor/turbine trip with 1 stuck open safety valve in SG-A and a second stuck open safety valve in SG-B	None	No	No	No
30	Reactor/turtine trip with 1 stuck open safety valve in SG-A	None	Yes	No	No
31	Reactor/turbine trip with 1 stuck open safety valve in SG-A and a second stuck open safety valve in SG-B	None	Yes	No	No
36	Reactor/turbine trip with 1 stuck open safety valve in SG-A and a second stuck open safety valve in SG-B	Operator throttles HPI to maintain 27.8 K [50° F] subcooling and 304.8 cm [120 in] pressurizer level.	No	No	No
37	Reactor/turbine trip with 1 stuck open safety valve in SG-A	Operator throttles HPI to maintain 27.8 K [50° F] subcooling and 304.8 cm [120 in] pressurizer level.	Yes	No	No
38	Reactor/turbine trip with 1 stuck open safety valve in SG-A and a second stuck open safety valve in SG-B	Operator throttles HPI to maintain 27.8 K [50° F] subcooling and 304.8 cm [120 in] pressurizer level.	Yes	No	No

Table A-1 List of Oconee Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
44	2.54 cm [1 in] surge line break with HPI Failure	At 15 minutes after initiation, operators open all TBVs to depressurize the system to the CFT setpoint. When the CFTs are 50 percent discharged, HPI is assumed to be recovered. The TBVs are assumed remain open for the duration of the transient.	No	No	No
45	Loss of MFW and EFW. At 30 minutes after operator starts HPI and opens the PORV, EFW is restored. Normal EFW level control is assumed.	Operator starts primary system "feed and bleed" cooling by starting the HPI and opening the PORV at RCS pressure > 2275 psia. Operator also trips one RCP in each steam generator loop (if 0.27 K (0.5° F) subcooling margin is reached, the remaining two RCPs are tripped). The operator then closes the PORV and throttles HPI to maintain 55 K (100° F) subcooling.	No	No	No
46	Loss of MFW and EFW. At 30 minutes after operator starts HPI and opens the PORV, EFW is restored. Normal EFW level control is assumed.	Operator starts primary system "feed and bleed" cooling by starting the HPI and opening the PORV at RCS pressure > 2275 psia. Operator also trips one RCP in each steam generator loop (if 0.27 K (0.5° F) subcooling margin is reached, the remaining two RCPs are tripped). The operator then closes the PORV but fails to throttle HPI.	No	No	No
57	Two stuck open safety valves in SG-A.	Operator isolates EFW in SG-A.	No	No	No
59	Two stuck open safety valves in SG-A.	Operator throttles HPI to maintain 27.8 K (50oF) subcooling and pressurizer level of 304 cm (120 inches). The operator stops emergency feedwater flow to SG-A at 15 minutes after accident initiation.	No	No	No

Table A-1   List of Oconee Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
60	Two stuck open safety valves in SG-A	Operator throttles HPI to maintain 27.8 K (50° F) subcooling and pressurizer level of 304 cm (120 inches). The operator stops emergency feedwater flow to SG-A at 15 minutes after accident initiation.	Yes	No	No
62	MSLB with shutdown of the MFW and the turbine driven EFW pumps by the MSLB circuitry. Break occurs in the containment so that RCP trip occurs due to a containment isolation signal at 1 minute after break initiation.	None	No	No	No
89	Reactor/turbine trip with Loss of MFW and EFW.	Operator opens all TBVs to depressurize the secondary side to below the condensate booster pump shutoff head so that these pumps feed the steam generators. Booster pumps are assumed to be initially uncontrolled so that the steam generators are overfilled (609 cm [240 in] startup level). Operator controls booster pump flow to maintain SG level at 76 cm [30 in] due to continued RCP operation. Operator also throttles HPI to maintain 55 K [100°F] subcooling and a pressurizer level of 254 cm [100 in]. The TBVs are kept fully opened due to operator error.	No	No	No
90	Reactor/turbine trip with 2 stuck open safety valves in SG-A	Operator throttles HPI 20 minutes after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached [throttling criteria is 27.8 K [50°F] subcooling].	No	No	No

Table A-1 List of Oconee Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
91	SGTR with a stuck open SRV in SG-B. A reactor trip is assumed to occur at the time of the tube rupture. Stuck safety relief valve is assumed to reclose 10 minutes after initiation.	Operator trips RCP's 1 minute after initiation. Operator also throttles HPI 10 minutes after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached [assumed throttling criteria is 27.8 K [50°F] subcooling].	No	No	No
98	Reactor/turbine trip with loss of MFW and EFW	Operator opens all TBVs to depressurize the secondary side to below the condensate booster pump shutoff head so that these pumps feed the steam generators. Booster pumps are assumed to be initially uncontrolled so that the steam generators are overfilled (610 cm [240 in] startup level). Operator controls booster pump flow to maintain SG level at 76 cm [30 in] due to continued RCP operation. Operator also throttles HPI to maintain 55 K [100°F] subcooling and a pressurizer level of 254 cm [100 in]. The TBVs are kept fully opened due to operator error.	Yes	No	No
99	MSLB with trip of turbine driven EFW by MSLB Circuitry	HPI is throttled 20 minutes after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached (throttling criteria is 27.8 K [50°F] subcooling).	No	No	No
100	MSLB with trip of turbine driven EFW by MSLB Circuitry	Operator throttles HPI 20 minutes after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached (throttling criteria is 27.8 K [50°F] subcooling).	Yes	No	No
101	MSLB without trip of turbine driven EFW by MSLB Circuitry	Operator throttles HPI to maintain 27.8 K [50° F] subcooling margin (throttling criteria is 27.8 K [50°F] subcooling).	Yes	No	No

Table A-1 List of Oconee Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
102	Reactor/turbine trip with 2 stuck open safety valves in SG-A	Operator throttles HPI 20 minutes after 2.77 K [5°F] subcooling and 254 cm [100 in] pressurizer level is reached (throttling criteria is 27 K [50°F] subcooling).	Yes	No	No
107	2.54 cm (1 inch) surge line break with 2 stuck open safety valves in SG-A.	HPI terminated when subcooling margin exceeds 55.6 K (100°F)	No	Yes	No
108	Stuck open pressurizer safety valve	None	No	Yes	No
109	Stuck open pressurizer safety valve. Valve recloses at 6000 secs [RCS low pressure point].	None	No	Yes	No
110	5.08 cm [2 inch] surge line break with HPI failure	At 15 minutes after transient initiation, operator opens both TBV to lower primary system pressure and allow CFT and LPI injection.	No	Yes	No
111	2.54 cm [1 in] surge line break with HPI failure	At 15 minutes after initiation, operator opens all TBVs to lower primary pressure and allow CFT and LPI injection. When the CFTs are 50% discharged, HPI is recovered. At 3000 seconds after initiation, operator starts throttling HPI to 55 K [100°F] subcooling and 254 cm [100"] pressurizer level.	No	Yes	No
112	Stuck open pressurizer safety valve. Valve recloses at 6000 secs.	After valve recloses, operator throttles HPI 1 minute after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached (throttling criteria is 27 K [50°F] subcooling)	No	Yes	No
113	Stuck open pressurizer safety valve. Valve recloses at 6000 secs.	After valve recloses, operator throttles HPI 10 minutes after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached (throttling criteria is 27.8 K [50°F] subcooling)	No	Yes	No

Table A-1 List of Oconee Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
114	Stuck open pressurizer safety valve. Valve recloses at 3000 secs.	After valve recloses, operator throttles HPI 1 minute after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached (throttling criteria is 50°F subcooling)	No	Yes	No
115	Stuck open pressurizer Safety Valve. Valve recloses at 3000 secs.	After valve recloses, operator throttles HPI 10 minutes after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached (throttling criteria is 50°F subcooling)	No	Yes	No
116	Stuck open pressurizer safety valve and HPI failure	At 15 minutes after initiation, operator opens all TBVs to lower primary pressure and allow CFT and LPI injection. When the CFTs are 50% discharged, HPI is recovered. The HPI is throttled 20 minutes after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached (throttling criteria is 50°F subcooling).	No	Yes	No
117	Stuck open pressurizer safety valve and HPI failure	At 15 minutes after initiation, operator opens all TBV to lower primary pressure and allow CFT and LPI injection. When the CFTs are 50% discharged, HPI is recovered. The SRV is closed 5 minutes after HPI recovered. HPI is throttled at 1 minute after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached (throttling criteria is 27.8 K [50°F] subcooling).	No	Yes	No
118	5.08 cm (2 in) surge line break	None	Yes	Yes	No
119	2.54 cm [1 in] surge line break with HPI Failure	At 15 minutes after transient initiation, the operator opens all turbine bypass valves to lower primary system pressure and allow core flood tank and LPI injection.	Yes	Yes	No

Table A-1 List of Oconee Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
120	2.54 cm [1 in] surge line break with HPI Failure	At 15 minutes after sequence initiation, operators open all TBVs to depressurize the system to the CFT setpoint. When the CFTs are 50 percent discharged, HPI is assumed to be recovered. The TBVs are assumed remain opened for the duration of the transient.	Yes	Yes	No
121	Stuck open pressurizer safety valve. Valve recloses at 6000 secs .	Operator throttles HPI at 1 minute after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached [throttling criteria is 27.8 K [50°F] subcooling].	Yes	Yes	No
122	Stuck open pressurizer safety valve. Valve recloses at 6000 secs.	Operator throttles HPI at 10 minutes after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached (throttling criteria is 27.8 K [50°F] subcooling).	Yes	Yes	No
123	Stuck open pressurizer safety valve. Valve recloses at 3000 secs.	Operator throttles HPI at 1 minute after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached (throttling criteria is 27.8 K [50°F] subcooling).	Yes	Yes	No
124	Stuck open pressurizer safety valve. Valve recloses at 3000 secs.	Operator throttles HPI at 10 minutes after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached (throttling criteria is 27.8 K [50°F] subcooling).	Yes	Yes	No
125	Stuck open pressurizer safety valve and HPI Failure	At 15 minutes after initiation, operator opens all TBVs to lower primary pressure and allow CFT and LPI injection. When the CFTs are 50% discharged, HPI is recovered. HPI is throttled 20 minutes after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached (throttling criteria is 27.8 K [50°F] subcooling).	Yes	Yes	No

Table A-1 List of Oconee Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
126	Stuck open pressurizer safety valve and HPI Failure	At 15 minutes after initiation, operator opens all TBVs to lower primary pressure and allow CFT and LPI injection. When the CFTs are 50% discharged, HPI is recovered. SRV is closed at 5 minutes after HPI is recovered. HPI is throttled at 1 minute after 2.7 K [5°F] subcooling and 254 cm [100"] pressurizer level is reached (throttling criteria is 27.8 K [50°F] subcooling).	Yes	Yes	No
127	SGTR with a stuck open SRV in SG-B. A reactor trip is assumed to occur at the time of the tube rupture. Stuck safety relief valve is assumed to reclose 10 minutes after initiation.	Operator trips RCP's 1 minute after initiation. Operator also throttles HPI 10 minutes after 2.77 K [5° F] subcooling and 254 cm [100 in] pressurizer level is reached (assumed throttling criteria is 27 K [50°F] subcooling).	Yes	Yes	No
128	7.18 cm (2.828 in) surge line break	None	Yes	Yes	No
133	10.16 cm (4 inch) surge line break	None	Yes	Yes	No
134	20.32 cm (8 inch) surge line break	None	Yes	Yes	No
138	TT/RT with stuck open pzr SRV. Summer conditions assumed (HPI, LPI temp = 302 K (85° F) and CFT temp = 310 K (100° F)).	None	No	No	No
140	TT/RT with stuck open pzr SRV. SRV assumed to reclose at 3000 secs. Operator does not throttle HPI.	None	No	No	No
141	8.19 cm [3.22 in] surge line break [Break flow area increased by 30% from 7.18 cm [2.828 in] break].	None	No	Yes	No
142	6.01 cm [2.37 in] surge line break [Break flow area decreased by 30% from 7.18 cm [2.828 in] break].	None	No	Yes	No

Table A-1 List of Oconee Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
145	4.34 cm [1.71 in] surge line break [Break flow area increased by 30% from 3.81 cm [1.5 in] break]. Winter conditions assumed [HPI, LPI temp = 277 K [40° F] and CFT temp = 294 K [70° F]].	None	No	Yes	No
146	TT/RT with stuck open pzr SRV [valve flow area reduced by 30 percent]. Summer conditions assumed [HPI, LPI temp = 302 K [85°F] and CFT temp = 310 K [100° F]]. Vent valves do not function.	None	No	Yes	No
147	TT/RT with stuck open pzr SRV. Summer conditions assumed [HPI, LPI temp = 302 K [85°F] and CFT temp = 310 K [100°F]].	None	No	Yes	No
148	TT/RT with partially stuck open pzr SRV [flow area equivalent to 1.5 in diameter opening]. HTC coefficients increased by 1.3.	None	No	Yes	No
149	TT/RT with stuck open pzr SRV. SRV assumed to reclose at 3000 s. Operator does not throttle HPI.	None	No	Yes	No
154	8.53 cm [3.36 in] surge line break [Break flow area reduced by 30% from 10.16 cm [4 in] break]. Vent valves do not function. ECC suction switch to the containment sump included in the analysis.	None	No	Yes	No
156	40.64 cm [16 in] hot leg break. ECC suction switch to the containment sump included in the analysis.	None	No	Yes	Yes
160	14.37 cm [5.656 in] surge line break. ECC suction switch to the containment sump included in the analysis.	None	No	Yes	Yes
164	20.32 cm [8 inch] surge line break. ECC suction switch to the containment sump included in the analysis.	None	No	Yes	Yes

Table A-1 List of Oconee Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
165	Stuck open pressurizer safety valve. Valve recloses at 6000 s [RCS low pressure point].	None	Yes	Yes	No
166	Stuck open pressurizer safety valve. Valve recloses at 6000 s.	After valve recloses, operator throttles HPI 1 minute after 2.7 K (5°F) subcooling and 254 cm (100") pressurizer level is reached (throttling criteria is 50°F subcooling)	Yes	Yes	No
168	TT/RT with stuck open pzr SRV. SRV assumed to reclose at 3000 s. Operator does not throttle HPI.	None	Yes	Yes	No
169	TT/RT with stuck open pzr SRV [valve flow area reduced by 30 percent]. Summer conditions assumed [HPI, LPI temp = 302 K [85°F] and CFT temp = 310 K [100°F]]. Vent valves do not function.	None	Yes	Yes	No
170	TT/RT with stuck open pzr SRV. Summer conditions assumed [HPI, LPI temp = 302 K [85°F] and CFT temp = 310 K [100°F]].	None	Yes	Yes	No
171	TT/RT with partially stuck open pzr SRV [flow area equivalent to 1.5 in diameter opening]. HTC coefficients increased by 1.3.	None	Yes	Yes	No
172	10.16 cm [4 in] cold leg break. ECC suction switch to the containment sump included in the analysis.	None	No	Yes	Yes
174	MSLB with trip of turbine driven EFW by MSLB Circuitry. Decay power set to 0.003 of full power and held constant (7.70 MW).	Operator throttles HPI 20 minutes after 2.7 K (5°F) subcooling and 254 cm (100") pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).	No	No	No
176	Stuck open pressurizer safety valve. Valve recloses at 6000 s. Decay power set to 0.003 of full power and held constant (7.70 MW).	Operator throttles HPI at 10 minutes after 2.7 K (5°F) subcooling and 254 cm (100") pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).	No	Yes	No

Table A-1 List of Oconee Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
178	8.53 cm [3.36 in] surge line break [Break flow area reduced by 30% from 10.16 cm [4 in] break]. Vent valves do not function. ECC suction switch to the containment sump included in the analysis.	None	No	Yes	No
Note: Case 178 is a duplicate of 154. Intentionally entered for bookkeeping to track a split in sequence frequency.					

Case Category	LOCA
Primary Failures	2.54 cm (1 inch) surge line break
Secondary Failures	1 stuck open safety valve in SG-A
Operator Actions	None
Min DC Temperature	441.4 K [334.8°F] at 9977 s
Comments	None.

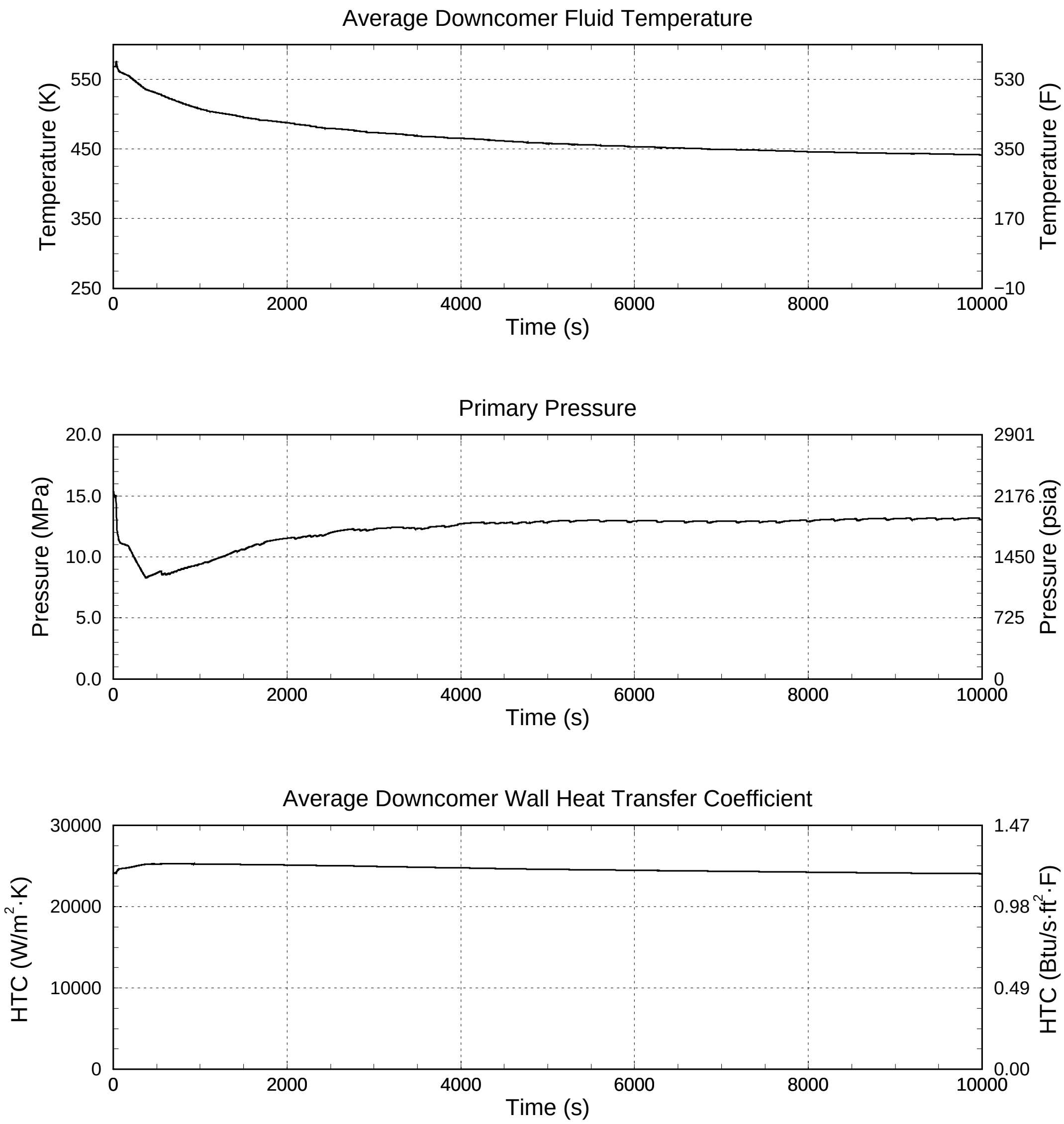


Figure A-1   Oconee PTS Results for Case 008

Case Category	LOCA
Primary Failures	2.54 cm (1 inch) surge line break
Secondary Failures	2 stuck open safety valves in SG-A
Operator Actions	None
Min DC Temperature	425.8 K [306.8°F] at 10000 s
Comments	None.

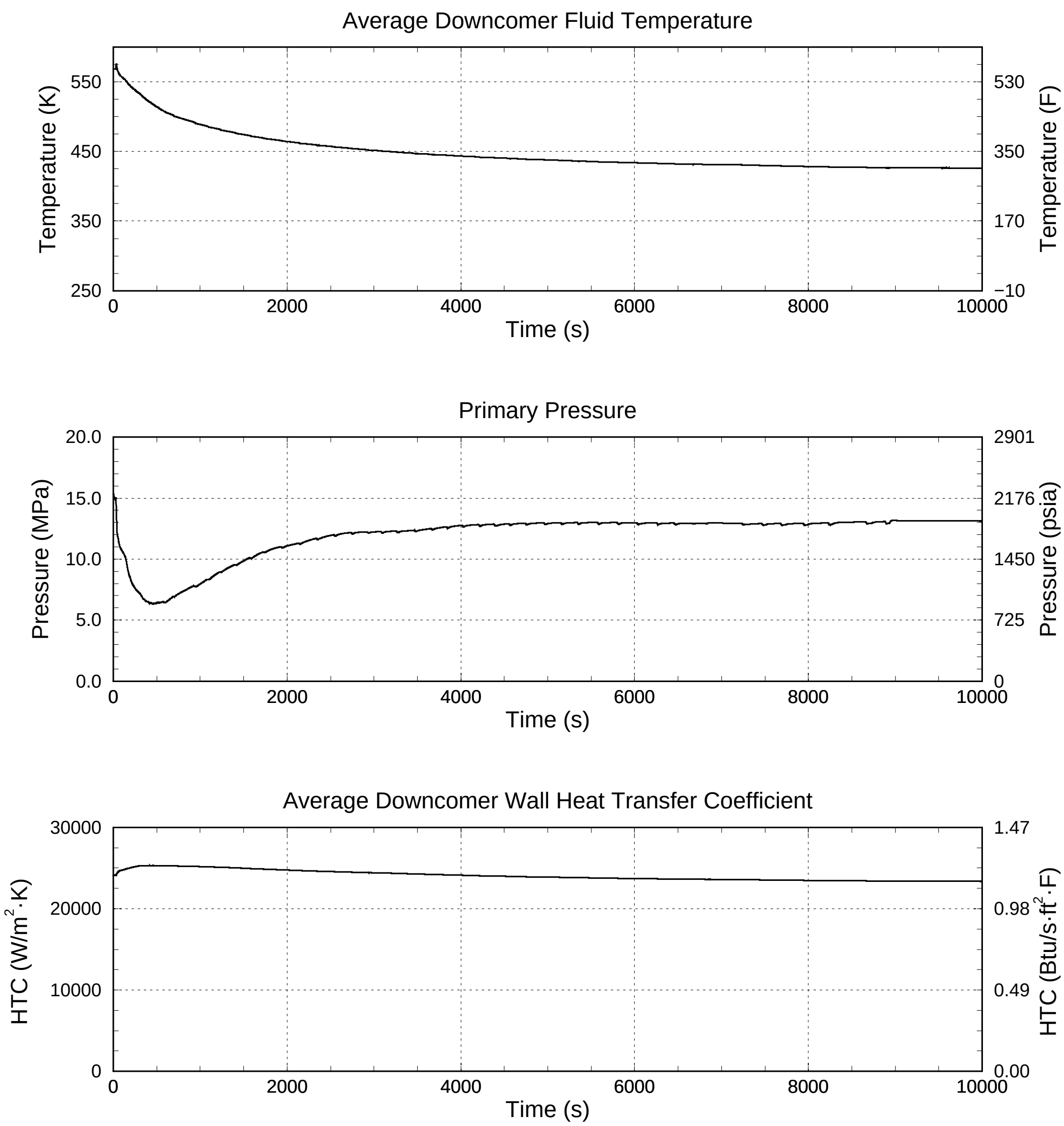


Figure A-2 Oconee PTS Results for Case 009

Case Category	LOCA
Primary Failures	2.54 cm (1 inch) surge line break
Secondary Failures	1 stuck open safety valve in SG-A
Operator Actions	HPI throttled to maintain 27.8 K (50°F) subcooling margin
Min DC Temperature	459.5 K [367.5°F] at 9992 s
Comments	None.

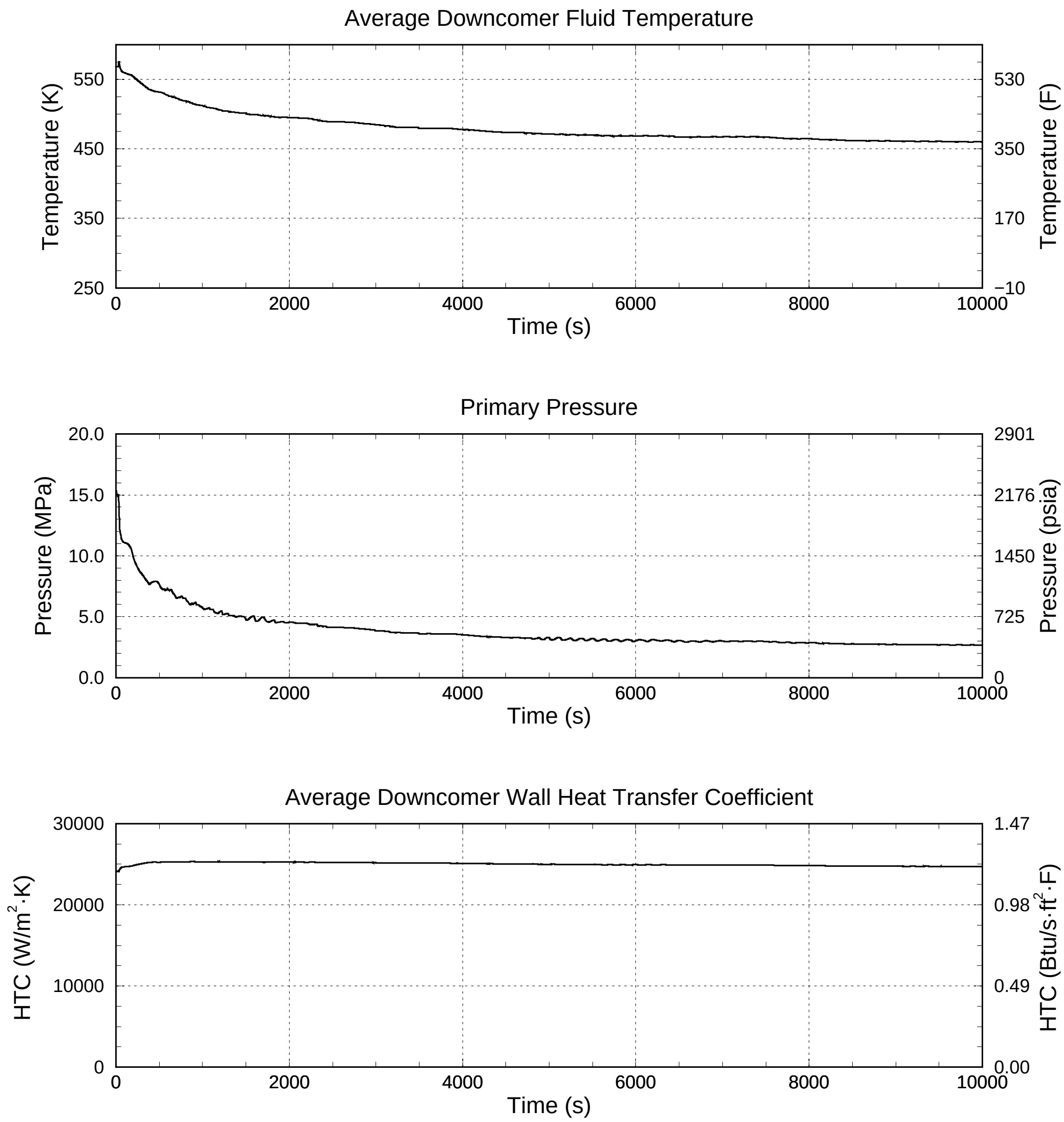


Figure A-3 Oconee PTS Results for Case 012

Case Category	LOCA
Primary Failures	2.54 cm (1 in) surge line break with HPI Failure
Secondary Failures	None
Operator Actions	At 15 minutes after transient initiation, operator opens all TBVs to lower primary system pressure and allow CFT and LPI injection.
Min DC Temperature	372.6 K [211.0°F] at 9964 s
Comments	None.

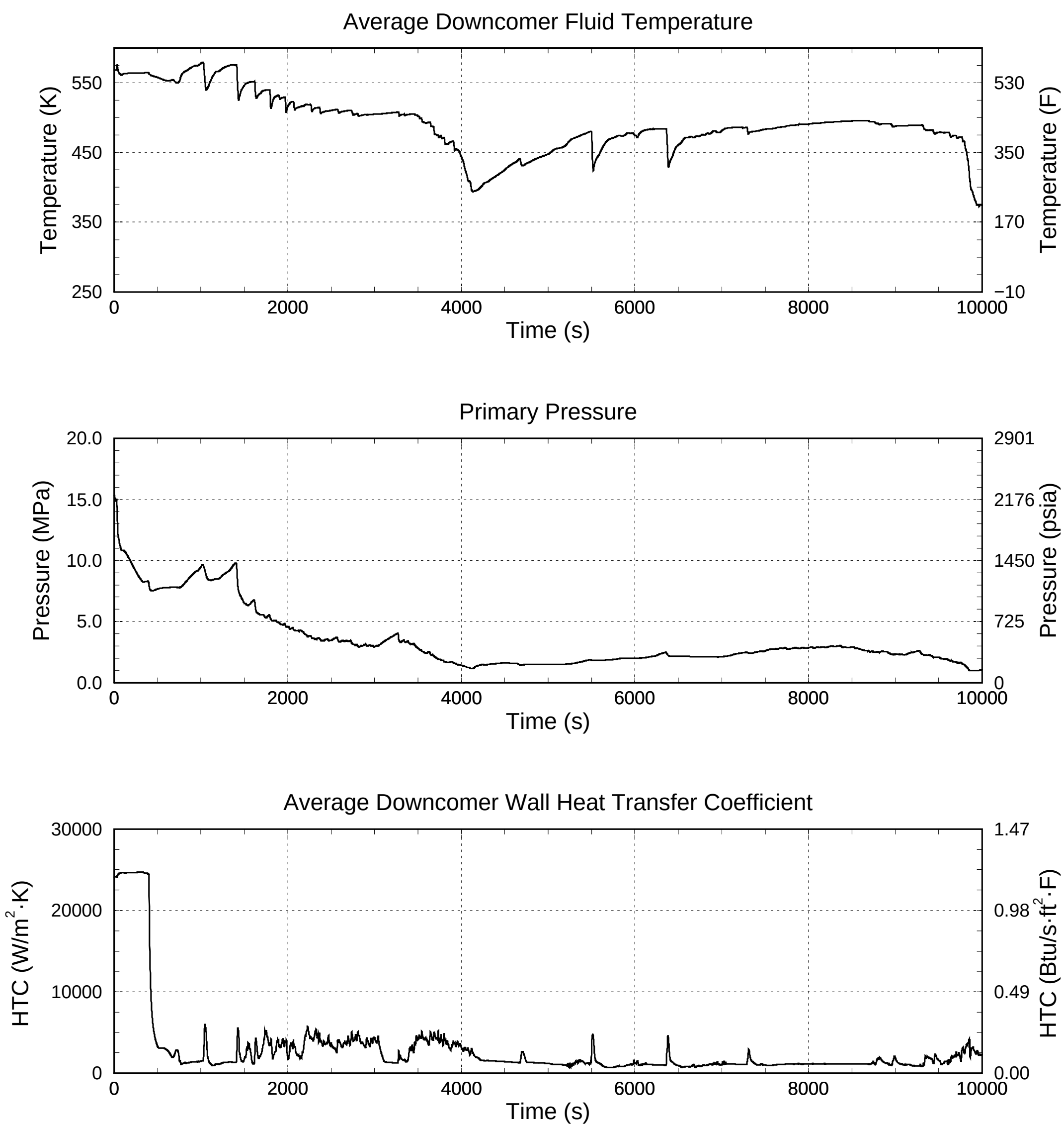


Figure A-4 Oconee PTS Results for Case 015

Case Category	LOCA - HZP
Primary Failures	2.54 cm (1 in) surge line break
Secondary Failures	1 stuck open safety valve in SG-A
Operator Actions	None
Min DC Temperature	407.8 K [274.3°F] at 10000 s
Comments	None.

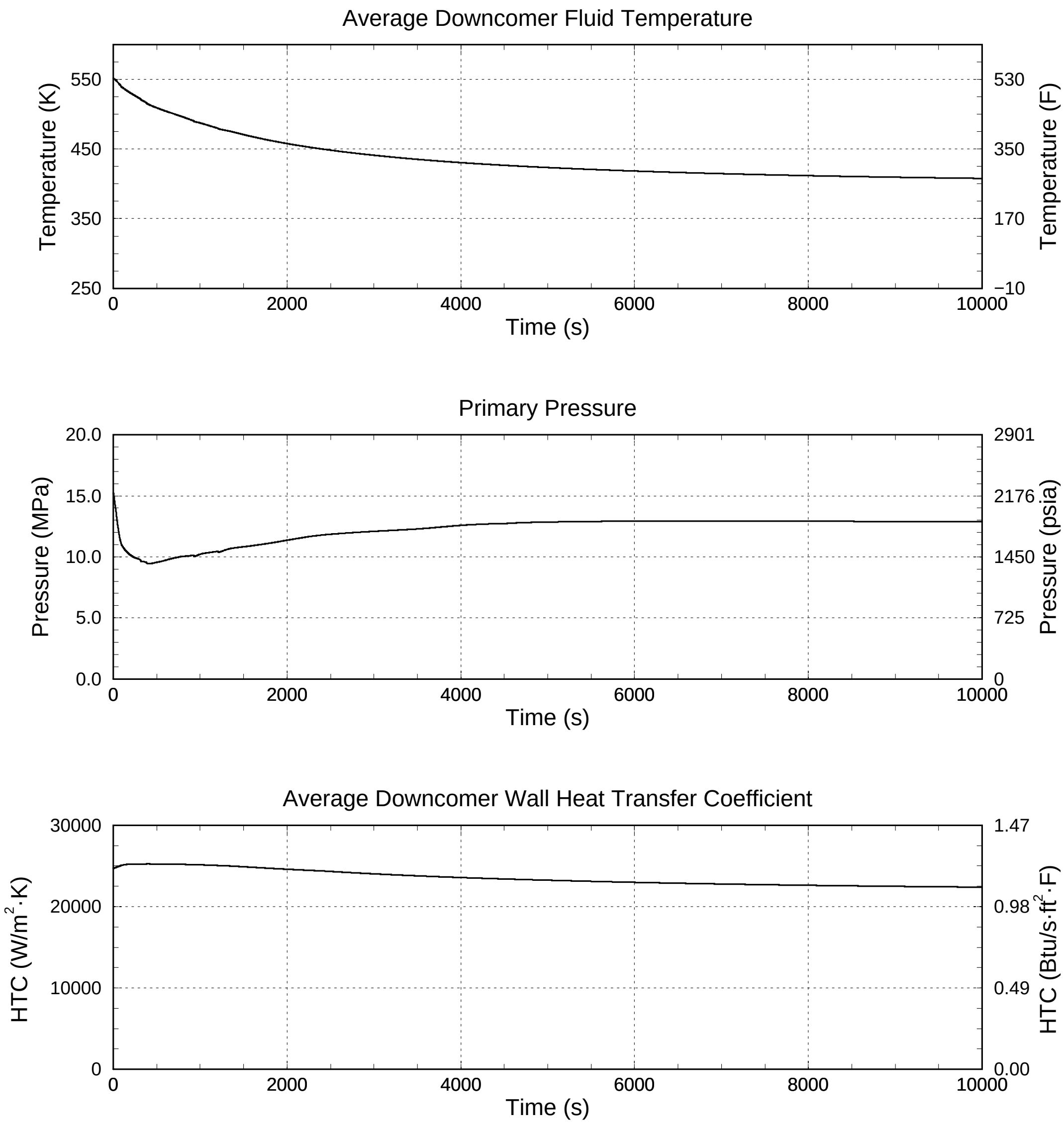


Figure A-5   Oconee PTS Results for Case 017

Case Category	MSLB
Primary Failures	None
Secondary Failures	MSLB without trip of turbine driven emergency feedwater.
Operator Actions	Operator throttles HPI to maintain 27.8 K (50°F) subcooling margin.
Min DC Temperature	377.7 K [220.2°F] at 8196 s
Comments	None.

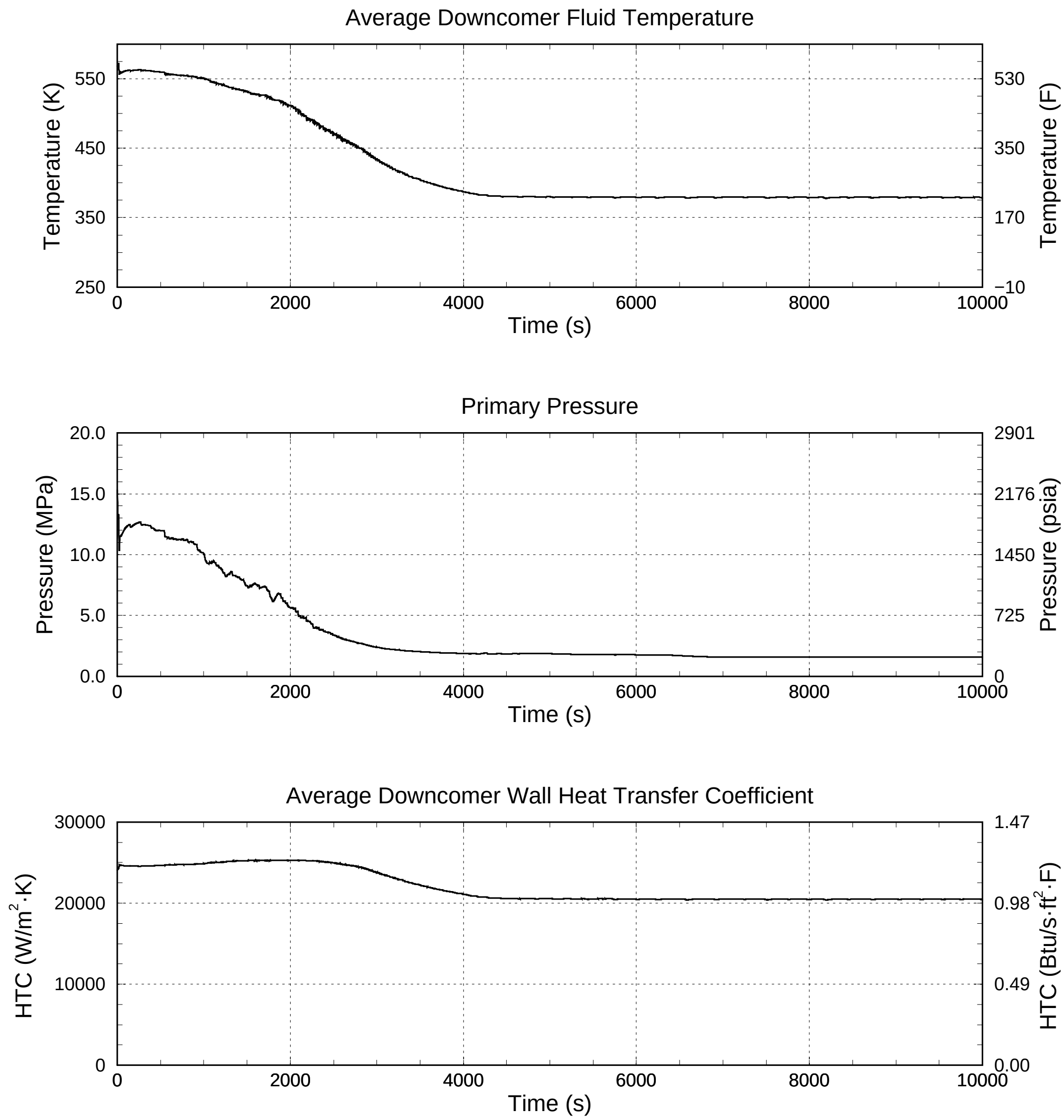


Figure A-6 Oconee PTS Results for Case 027

Case Category	TT/RT
Primary Failures	None
Secondary Failures	1 stuck open safety valve in SG-A
Operator Actions	None
Min DC Temperature	456.0 K [361.2°F] at 9980 s
Comments	None.

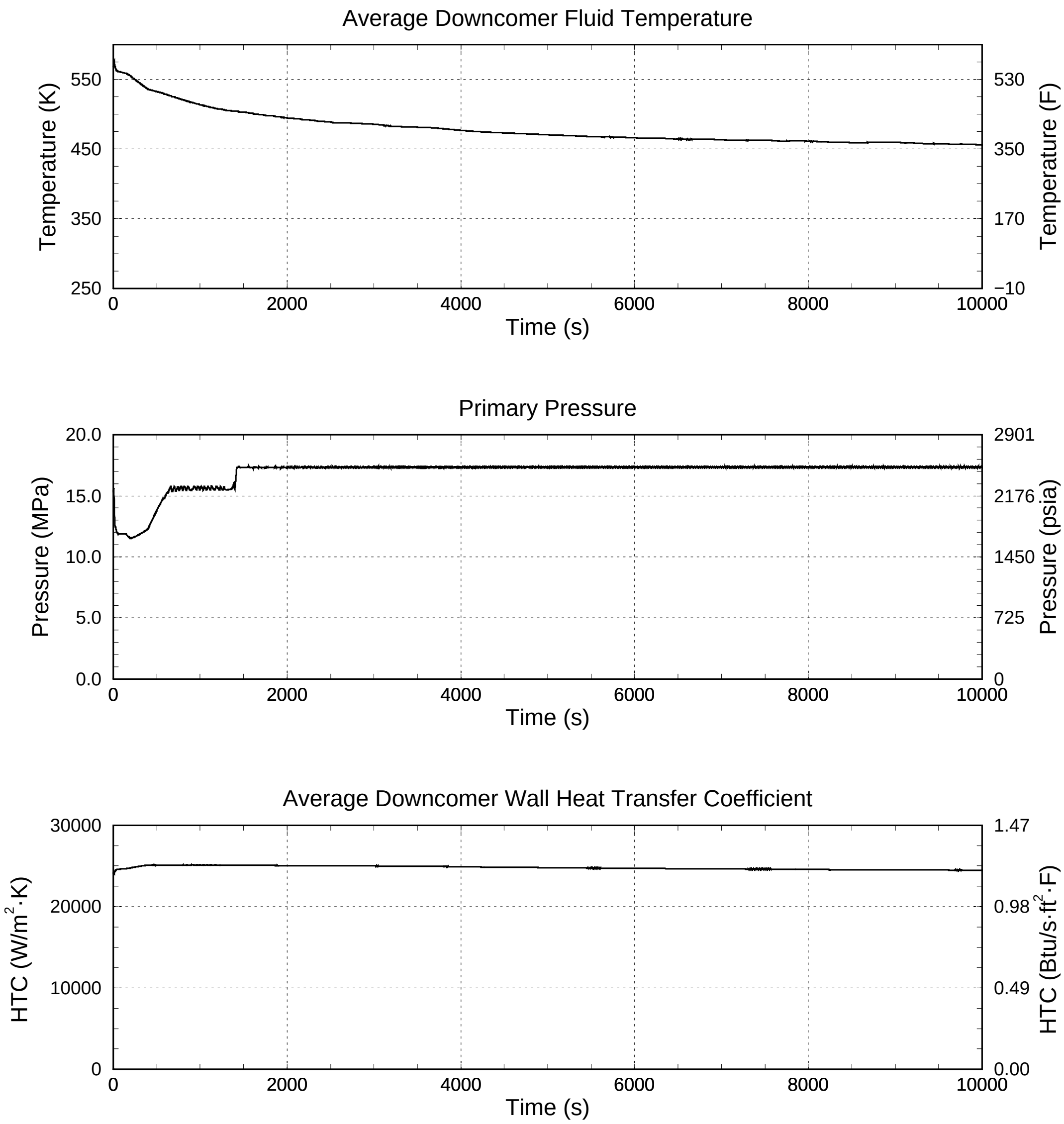


Figure A-7   Oconee PTS Results for Case 028

Case Category	TT/RT
Primary Failures	None
Secondary Failures	1 stuck open safety valve in SG-A and a second stuck open safety valve in SG-B
Operator Actions	None
Min DC Temperature	430.5 K [315.2°F] at 9673 s
Comments	None.

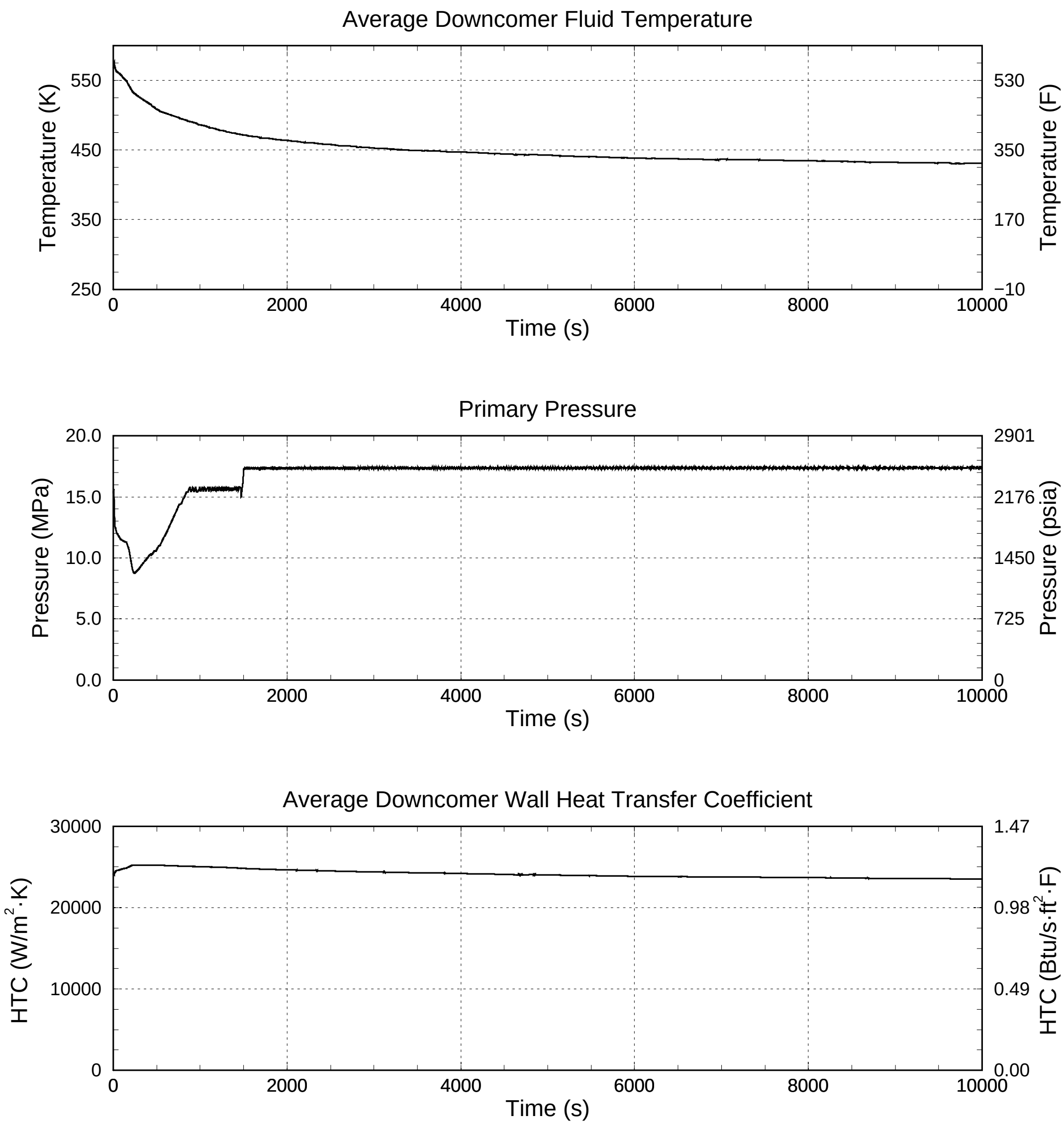
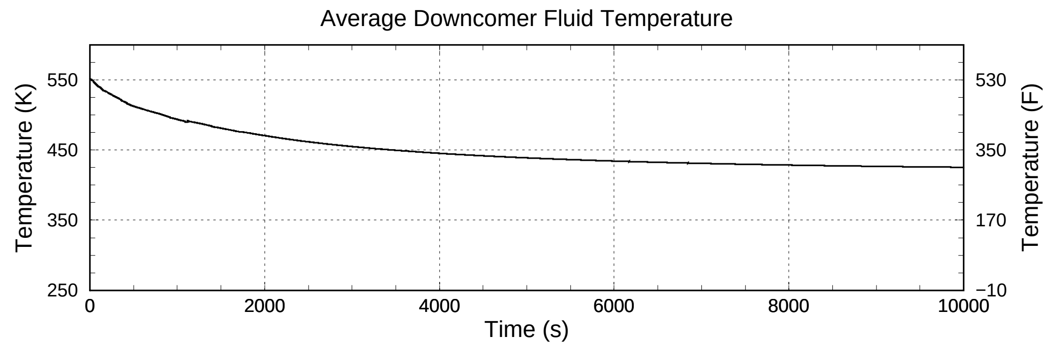
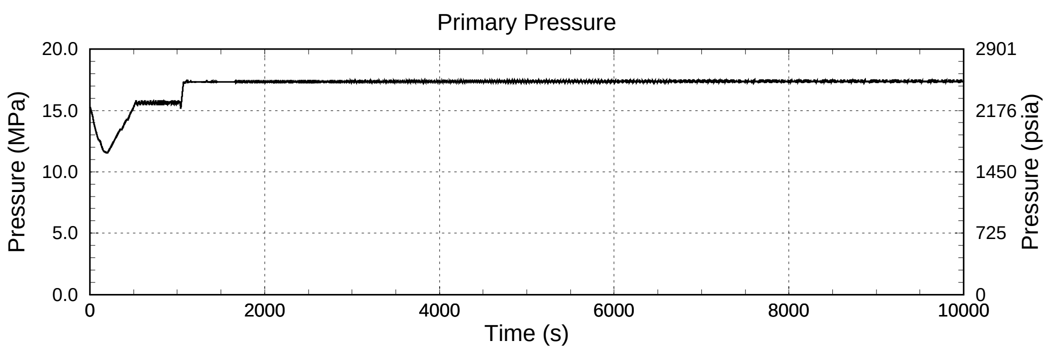


Figure A-8 Oconee PTS Results for Case 029

Case Category	TT/RT - HZP
Primary Failures	None
Secondary Failures	1 stuck open safety valve in SG-A
Operator Actions	None
Min DC Temperature	425.4 K [306.0°F] at 10000 s
Comments	None.





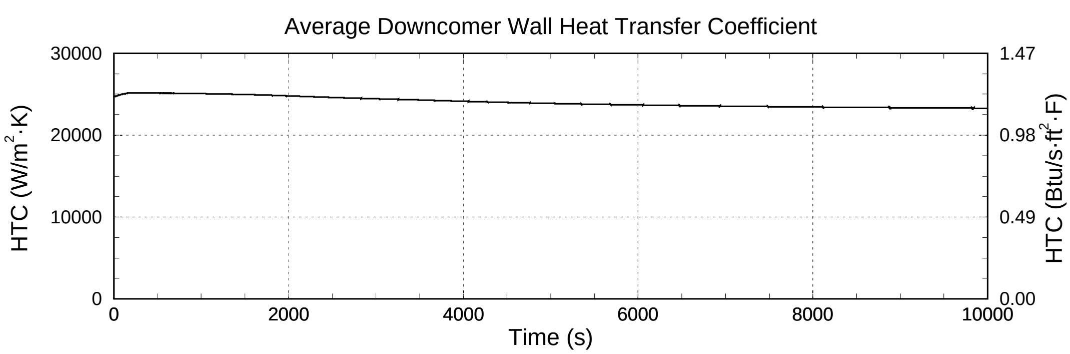


Figure A-9 Oconee PTS Results for Case 030

Case Category	TT/RT - HZP
Primary Failures	None
Secondary Failures	1 stuck open safety valve in SG-A and a second stuck open safety valve in SG-B
Operator Actions	None
Min DC Temperature	404.6 K [268.5°F] at 9998 s
Comments	None.

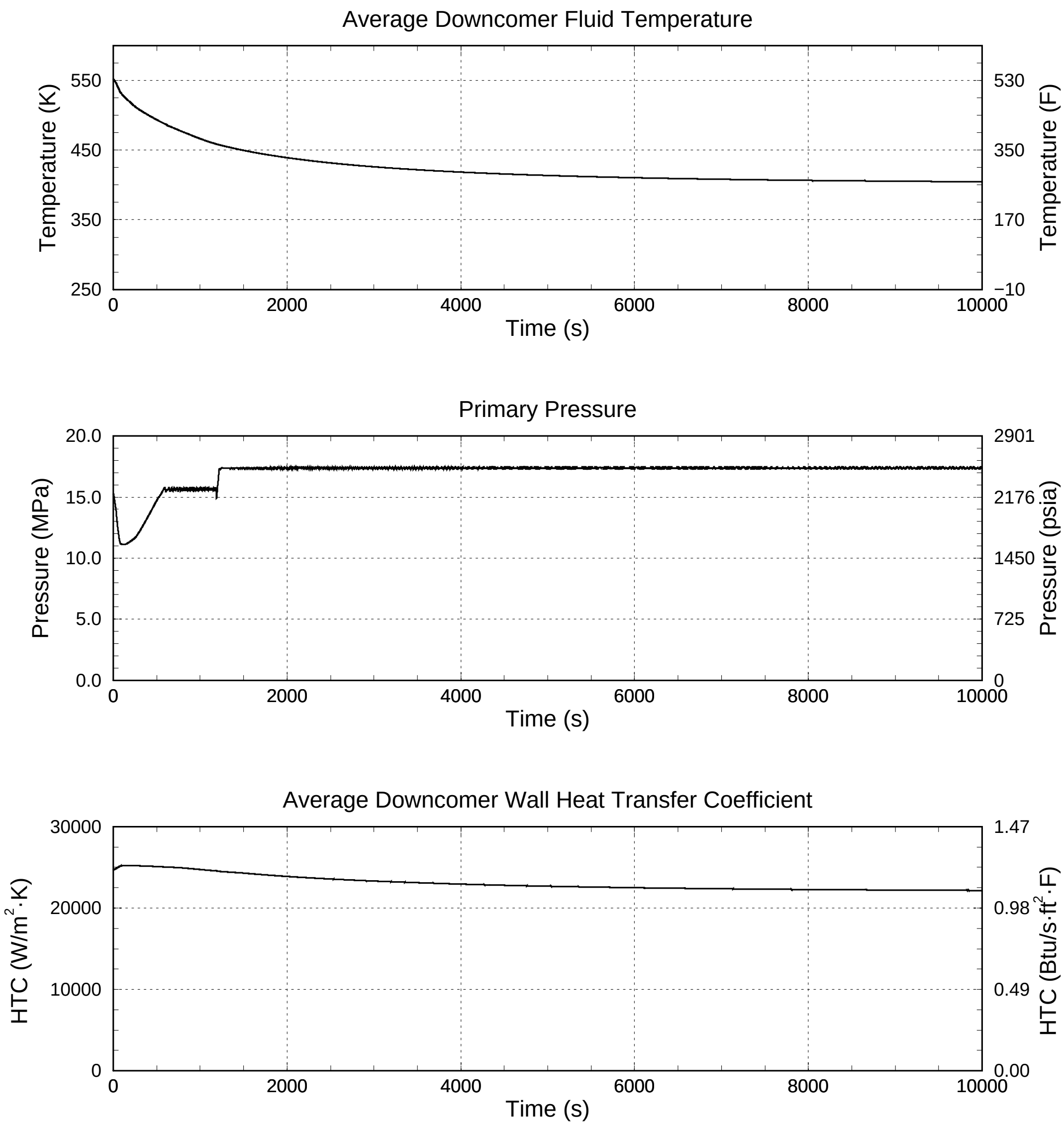


Figure A-10 Oconee PTS Results for Case 031

Case Category	TT/RT
Primary Failures	None
Secondary Failures	1 stuck open safety valve in SG-A and a second stuck open safety valve in SG-B
Operator Actions	Operator throttles HPI to maintain 27.8 K (50°F) subcooling and 304.8 cm (120 in) pressurizer level.
Min DC Temperature	442.9 K [337.6°F] at 9802 s
Comments	None.

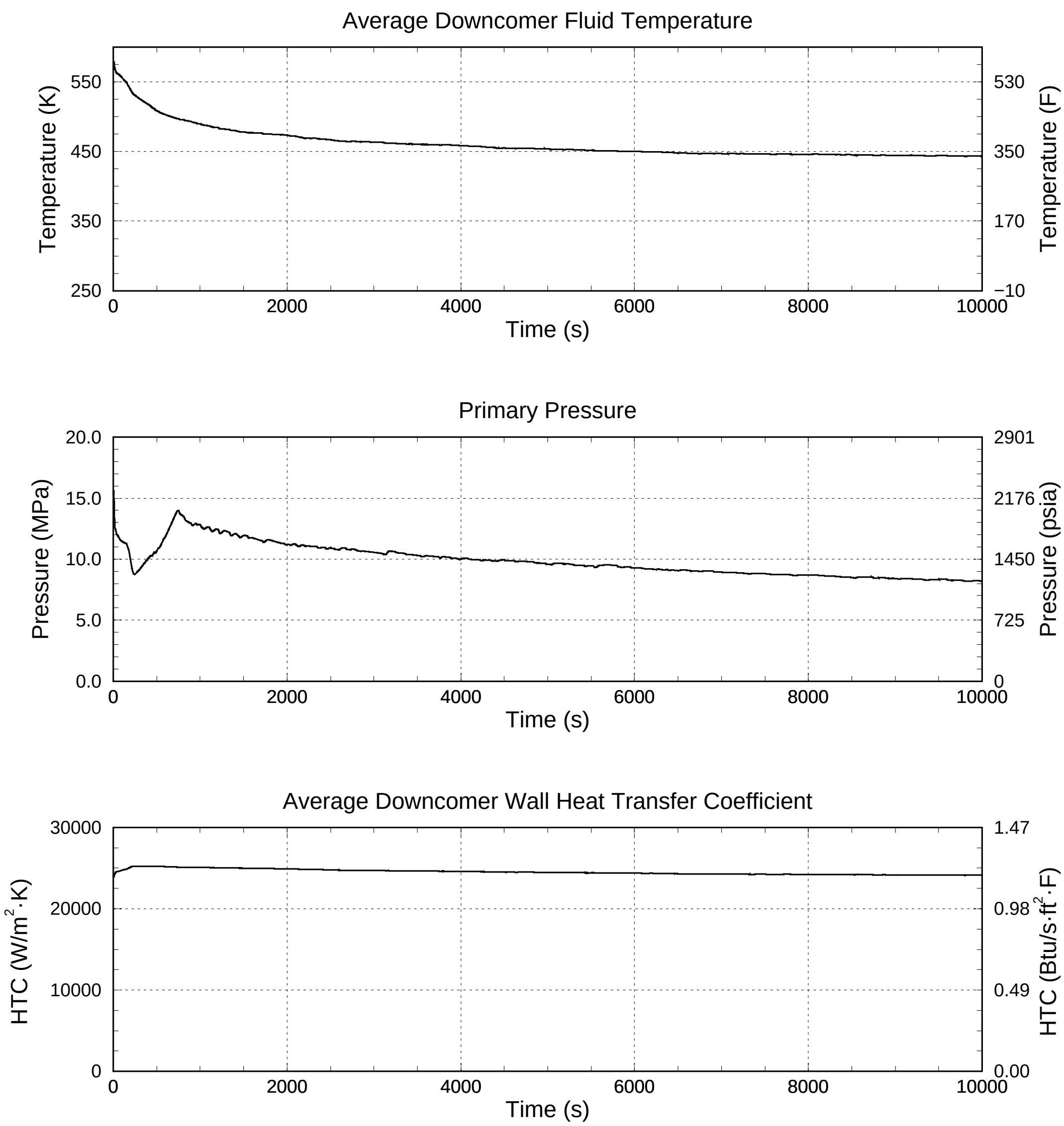


Figure A-11 Oconee PTS Results for Case 036

Case Category	TT/RT - HZP
Primary Failures	None
Secondary Failures	1 stuck open safety valve in SG-A
Operator Actions	Operator throttles HPI to maintain 27.8 K (50°F) subcooling and 304.8 cm (120 in) pressurizer level.
Min DC Temperature	447.3 K [345.5°F] at 10000 s
Comments	None.

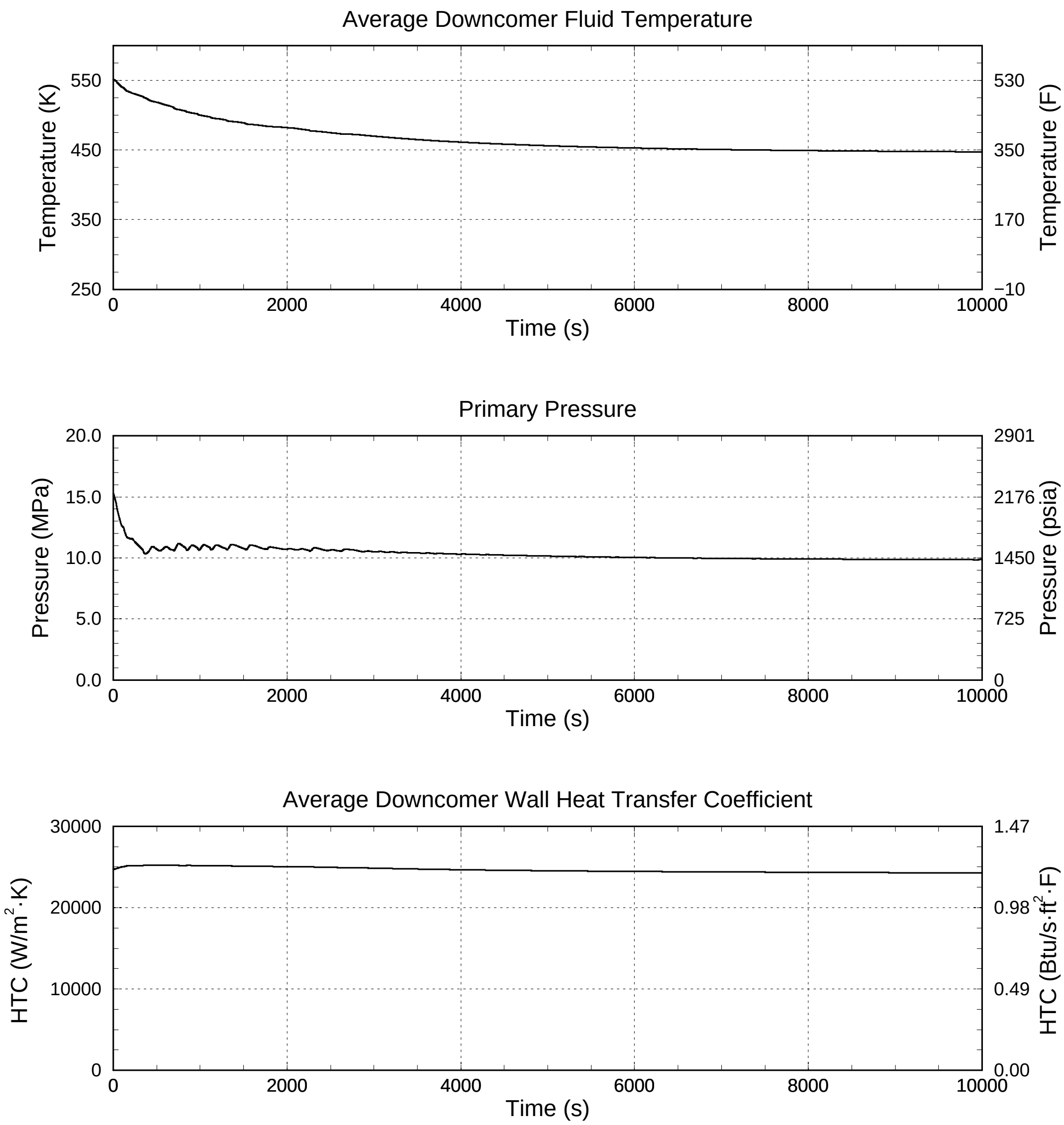


Figure A-12 Oconee PTS Results for Case 037

Case Category	TT/RT-HZP
Primary Failures	None
Secondary Failures	1 stuck open safety valve in SG-A and a second stuck open safety valve in SG-B
Operator Actions	Operator throttles HPI to maintain 27.8 K (50°F) subcooling and 304.8 cm (120 in) pressurizer level.
Min DC Temperature	420.2 K [296.7°F] at 10000 s
Comments	None.

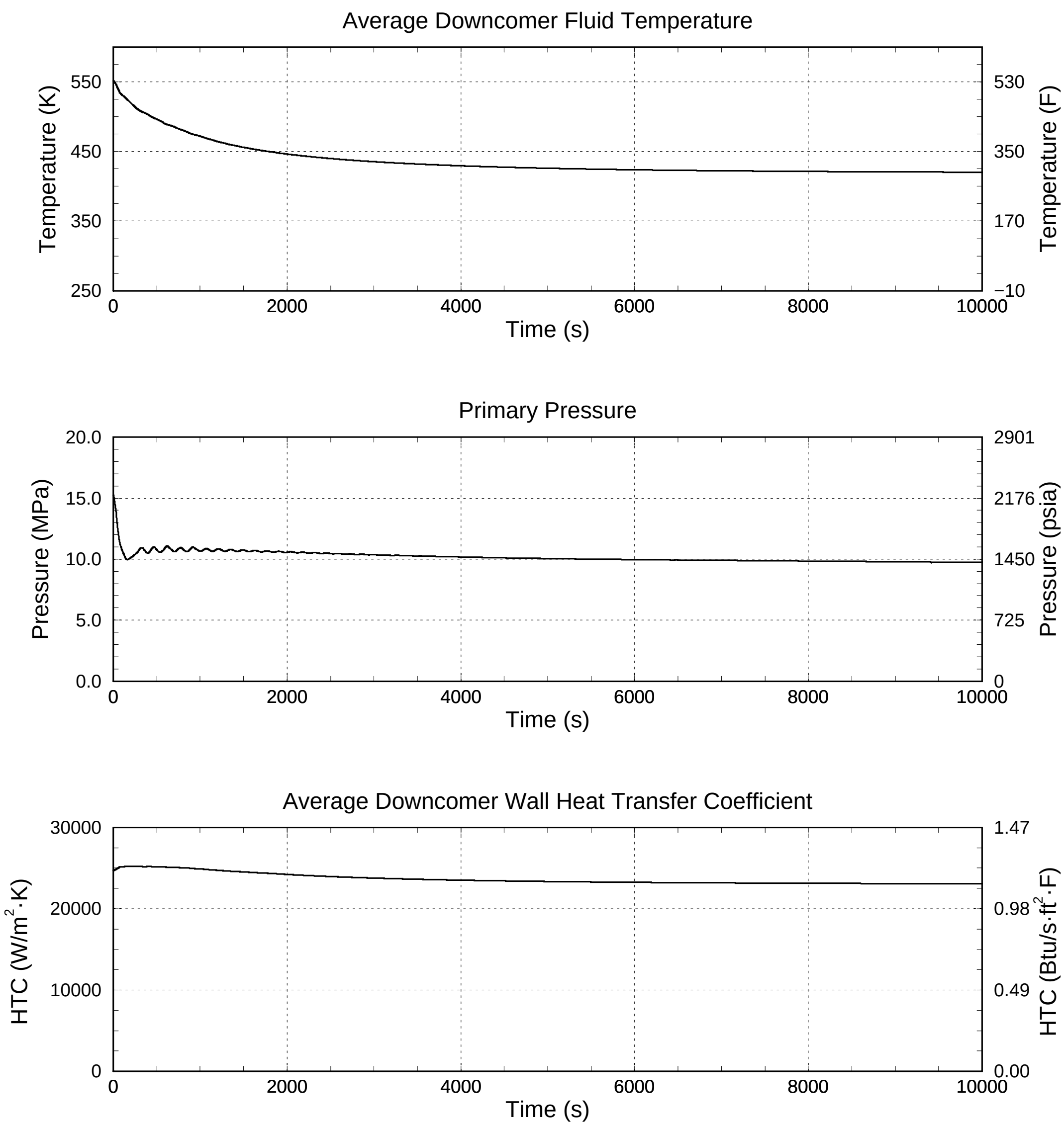


Figure A-13   Oconee PTS Results for Case 038

Case Category	LOCA
Primary Failures	2.54 cm (1 in) surge line break with HPI Failure
Secondary Failures	None.
Operator Actions	At 15 minutes after initiation, operators open all TBVs to depressurize the system to the CFT setpoint. When the CFTs are 50% discharged, HPI is assumed to be recovered. The TBVs are assumed remain open for the duration of the transient.
Min DC Temperature	372.6 K [210.9°F] at 9851 s
Comments	None.

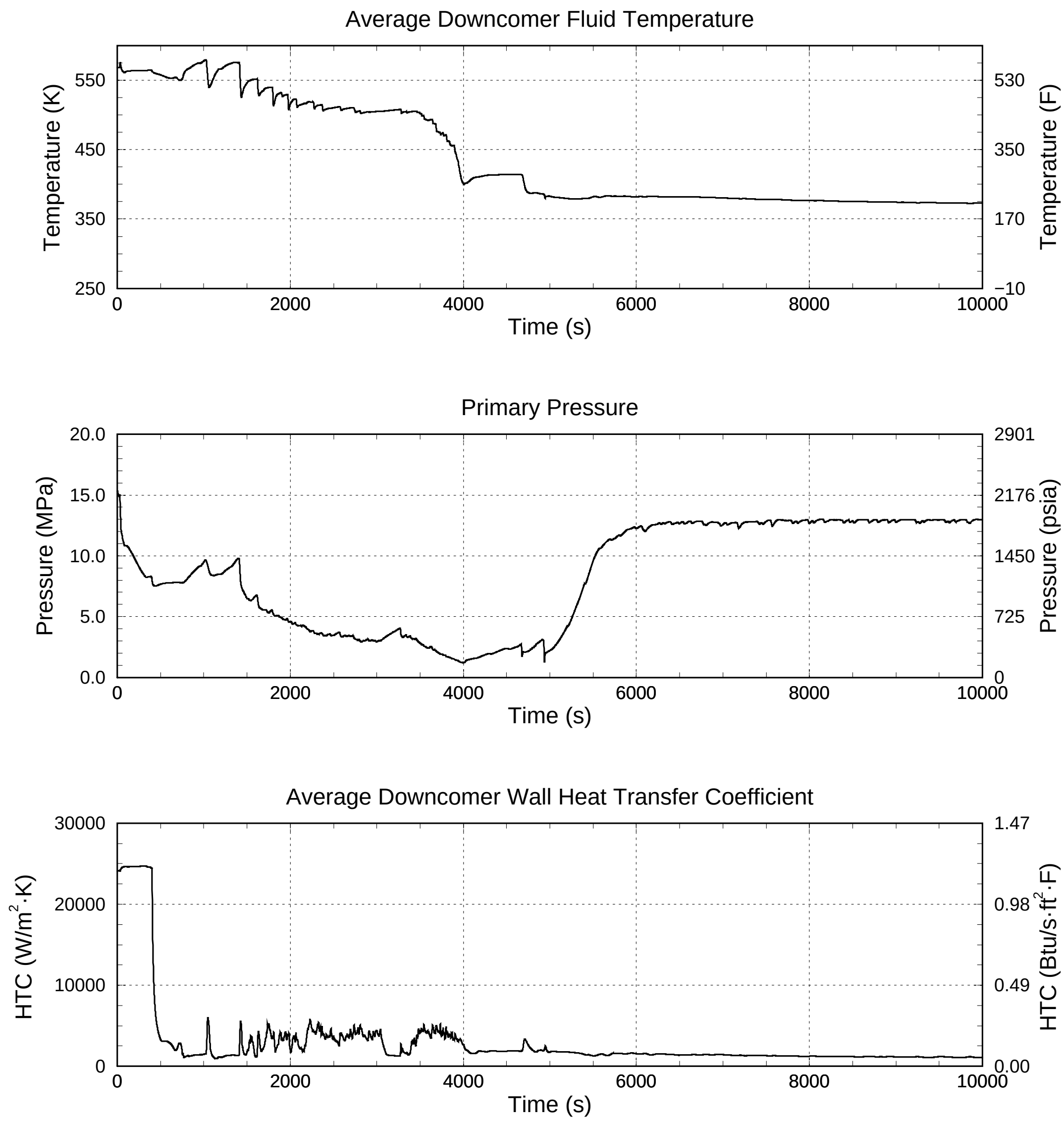
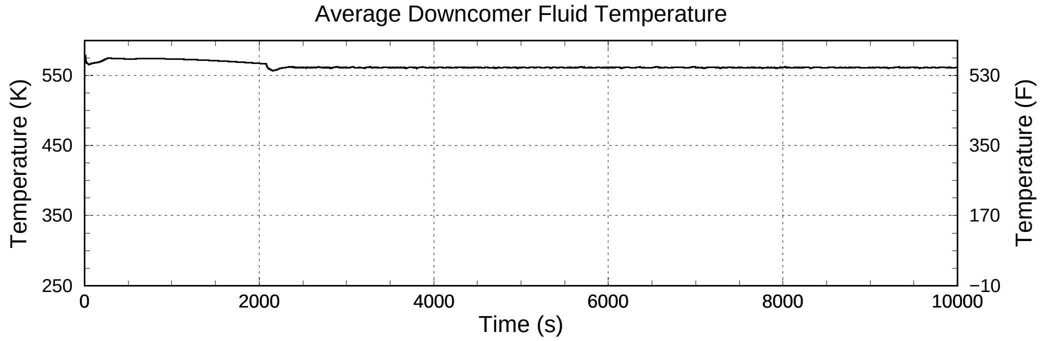
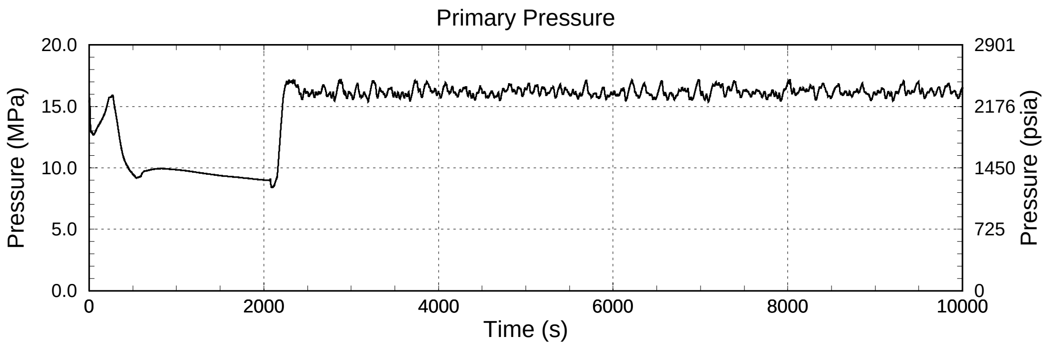


Figure A-14 Oconee PTS Results for Case 044

Case Category	TT/RT
Primary Failures	None
Secondary Failures	Loss of MFW and EFW. At 30 minutes after operator starts HPI and opens the PORV, EFW is restored. Normal EFW level control is assumed.
Operator Actions	Operator starts primary system "feed and bleed" cooling by starting the HPI and opening the PORV at RCS pressure > 2275 psia. Operator also trips one RCP in each SG loop (if 0.27 K (0.5°F) subcooling margin is reached, the remaining two RCPs are tripped). The operator then closes the PORV and throttles HPI to maintain 55 K (100°F) subcooling.
Min DC Temperature	556.5 K [542.1°F] at 2157 s
Comments	None.





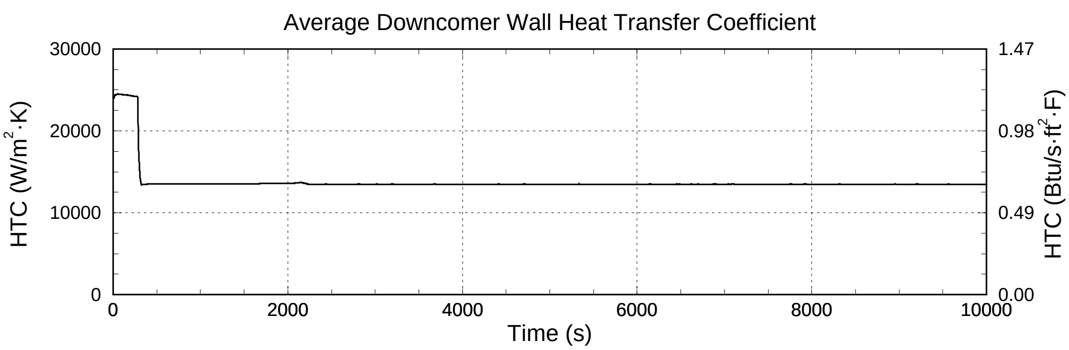


Figure A-15 Oconee PTS Results for Case 045

Case Category	TT/RT
Primary Failures	None
Secondary Failures	Loss of MFW and EFW. At 30 minutes after operator starts HPI and opens the PORV, EFW is restored. Normal EFW level control is assumed.
Operator Actions	Operator starts primary system "feed and bleed" cooling by starting the HPI and opening the PORV at RCS pressure > 2275 psia. Operator also trips one RCP in each SG loop (if 0.27 K (0.5°F) subcooling margin is reached, the remaining two RCPs are tripped). The operator then closes the PORV but fails to throttle HPI.
Min DC Temperature	556.7 K [542.4°F] at 2158 s
Comments	None.

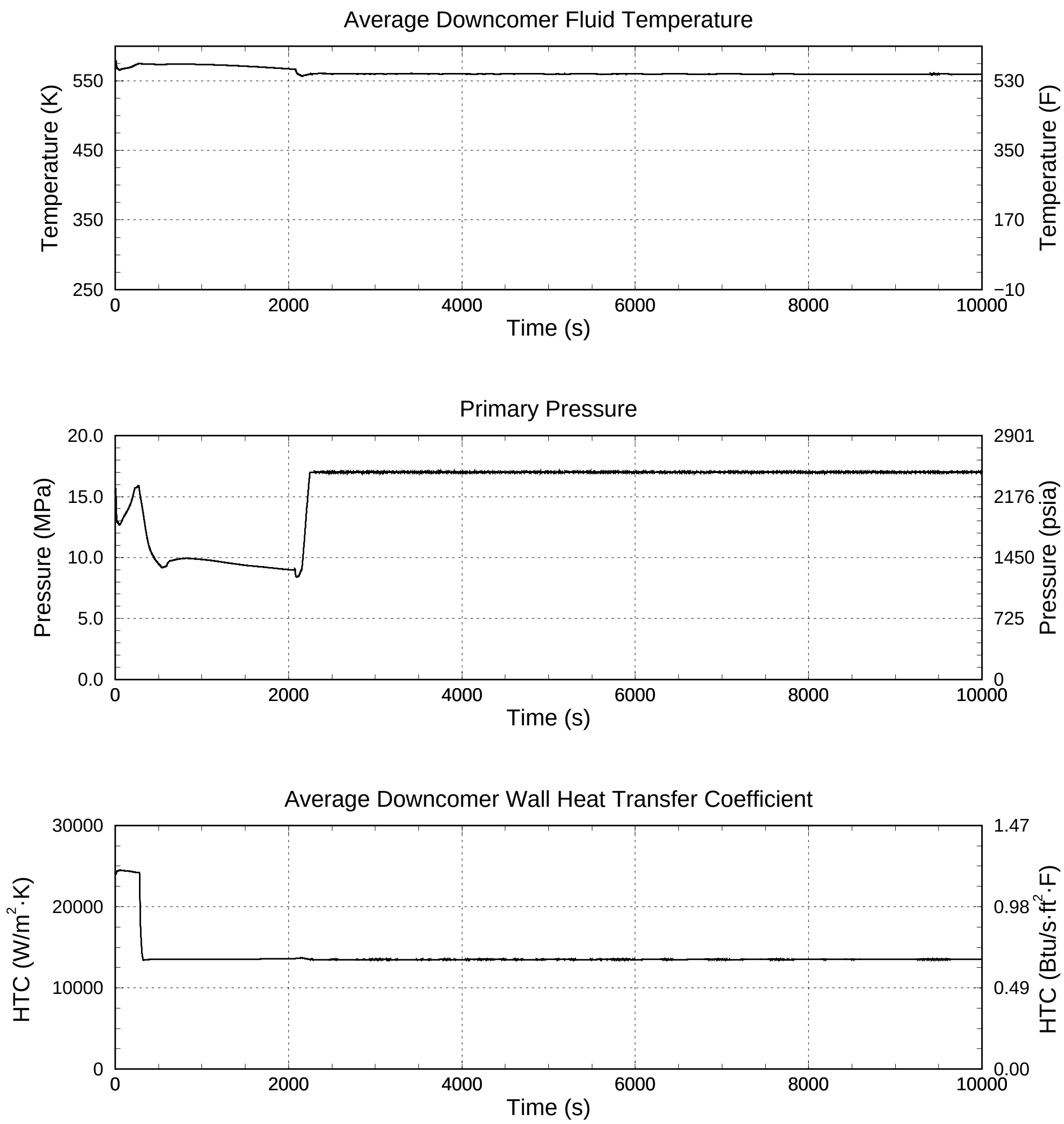


Figure A-16 Oconee PTS Results for Case 046

Case Category	TT/RT
Primary Failures	None
Secondary Failures	Two stuck open safety valves in SG-A.
Operator Actions	Operator isolates EFW in SG-A.
Min DC Temperature	530.4 K [495.0°F] at 949 s
Comments	None.

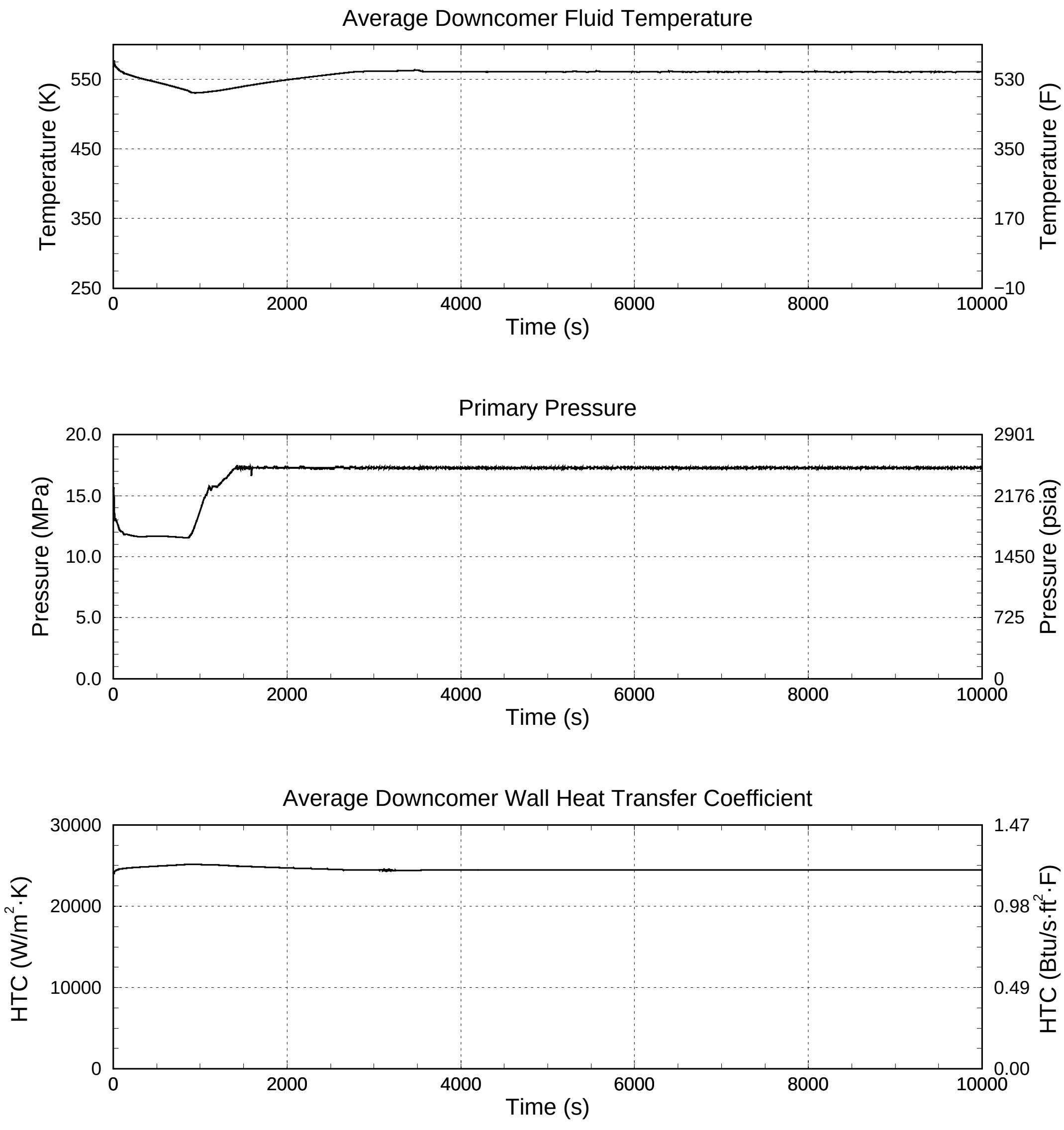


Figure A-17 Oconee PTS Results for Case 057

Case Category	TT/RT
Primary Failures	None
Secondary Failures	2 stuck open safety valves in SG-A
Operator Actions	Operator throttles HPI to maintain 27.8 K (50oF) subcooling and pressurizer level of 304 cm (120 inches). The operator stops emergency feedwater flow to SG-A at 15 minutes after accident initiation.
Min DC Temperature	489.6 K [421.5°F] at 934 s
Comments	None.

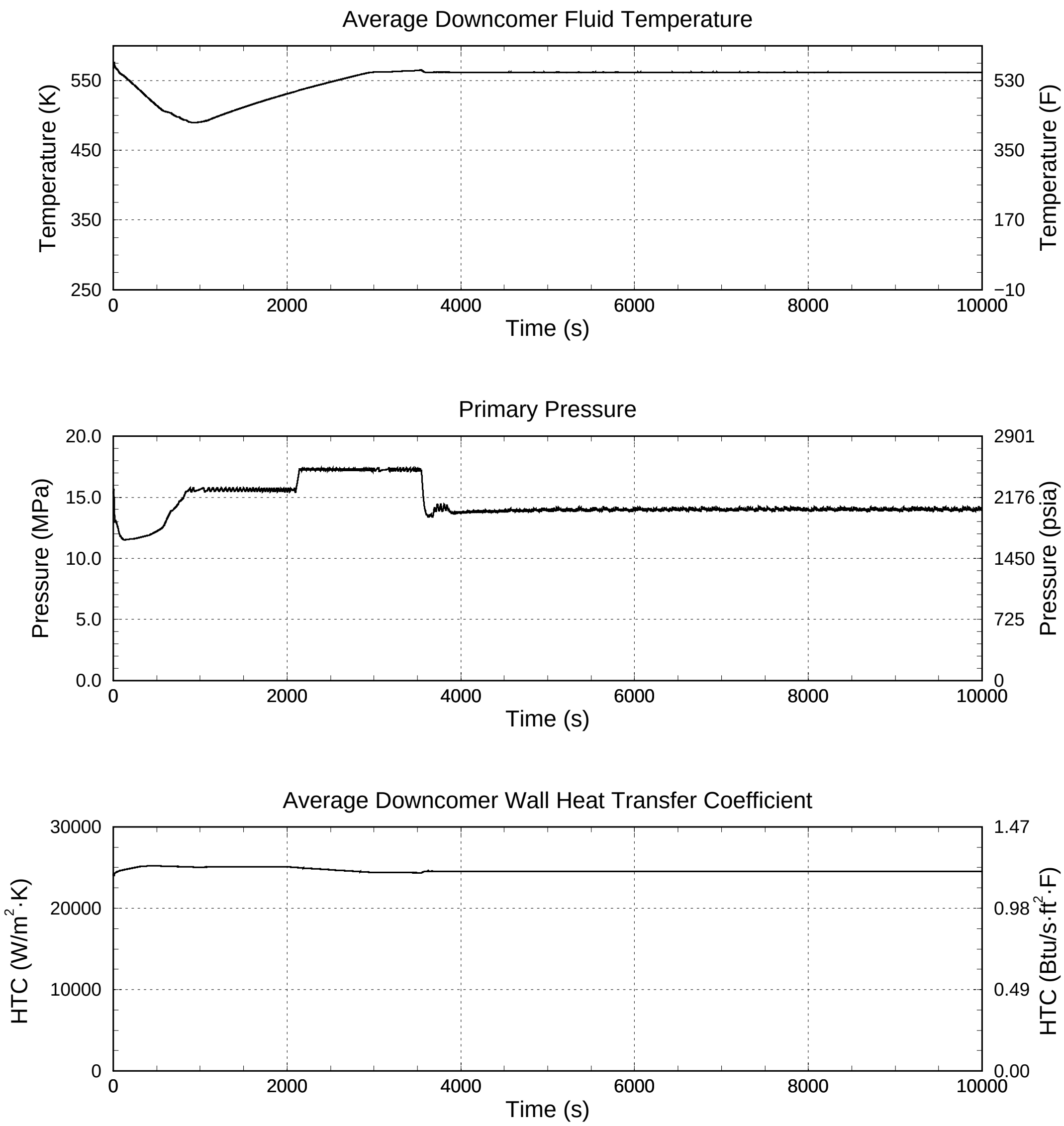


Figure A-18 Oconee PTS Results for Case 059

Case Category	TT/RT - HZP
Primary Failures	None
Secondary Failures	2 stuck open safety valves in SG-A
Operator Actions	Operator throttles HPI to maintain 27.8 K (50°F) subcooling and pressurizer level of 304 cm (120 inches). The operator stops emergency feedwater flow to SG-A at 15 minutes after accident initiation.
Min DC Temperature	426.7 K [308.4°F] at 10000 s
Comments	None.

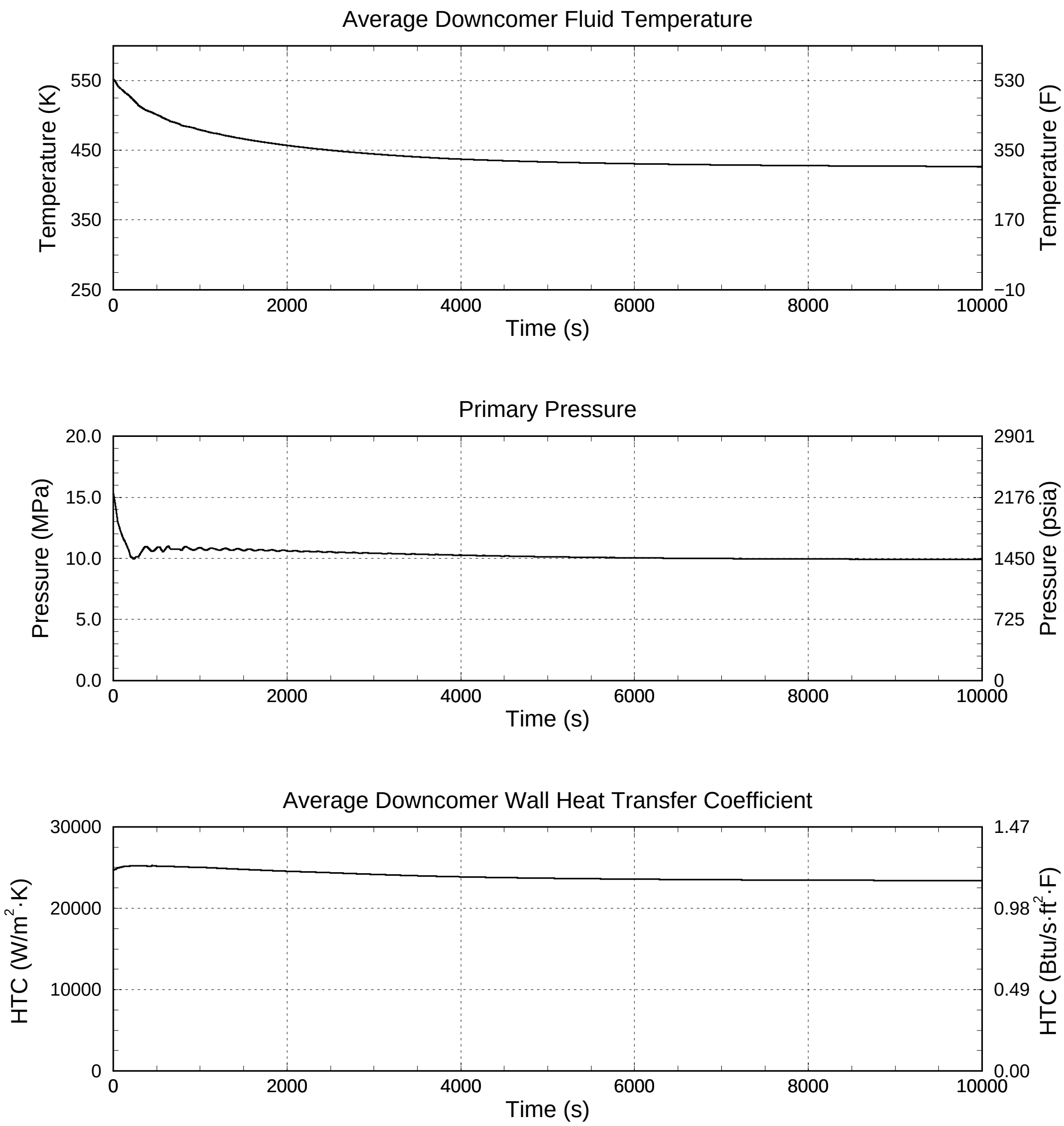


Figure A-19 Oconee PTS Results for Case 060

Case Category	MSLB
Primary Failures	None
Secondary Failures	MSLB with shutdown of the MFW and the turbine driven EFW pumps by the MSLB circuitry. Break occurs in the containment so that RCP trip occurs due to a containment isolation signal at 1 minute after break initiation.
Operator Actions	None
Min DC Temperature	378.1 K [220.9°F] at 6297 s
Comments	None.

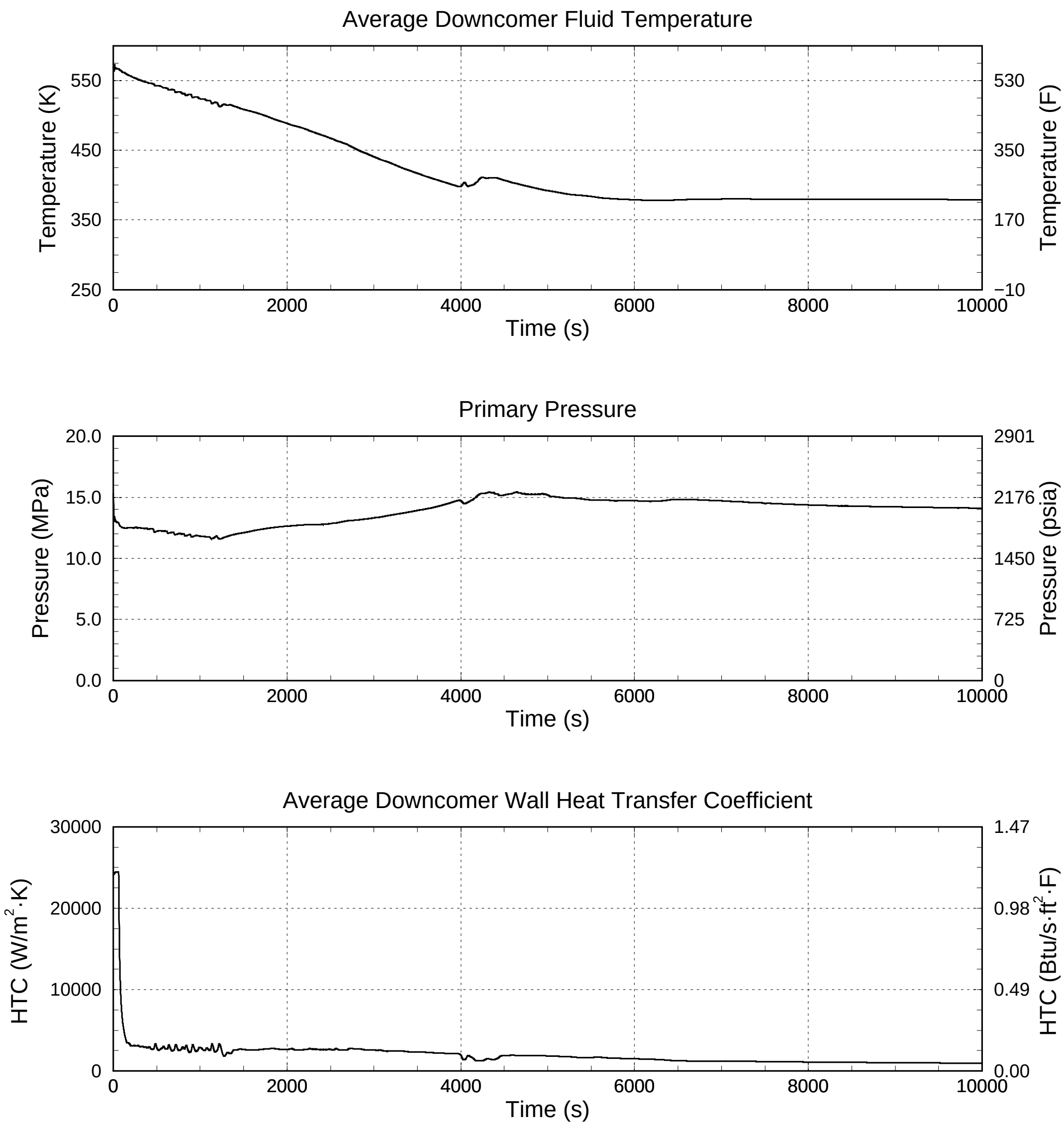
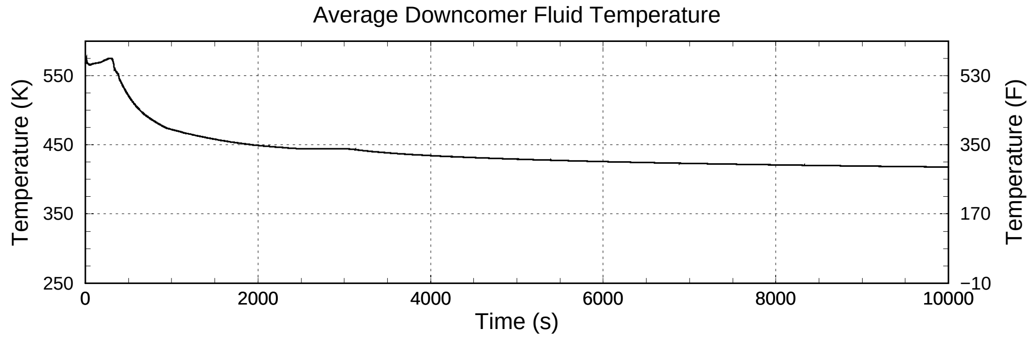
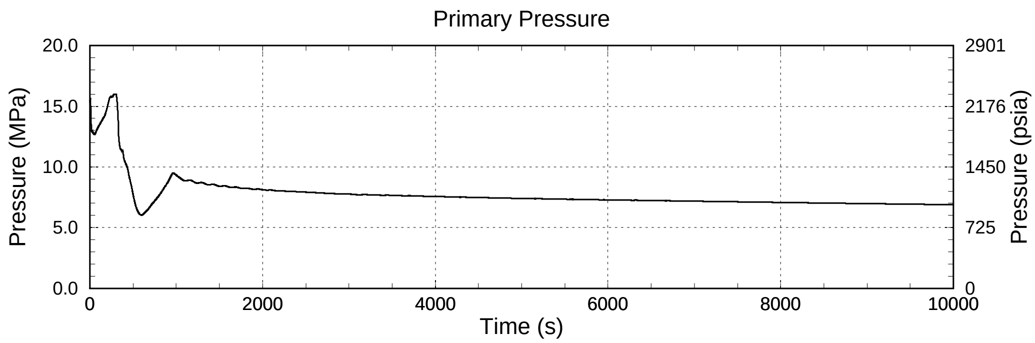


Figure A-20 Oconee PTS Results for Case 062

Case Category	TT/RT
Primary Failures	None
Secondary Failures	Loss of MFW and EFW.
Operator Actions	Opens all TBVs to depressurize the secondary side so the condensate booster pumps feed the SGs. Booster pumps are assumed to be initially uncontrolled so that the SGs are overfilled (609 cm (240 in) startup level). Controls booster pump flow to maintain SG level at 76 cm (30 in) due to continued RCP operation. Throttles HPI to maintain 55 K (100°F) subcooling and a pressurizer level of 254 cm (100 in). The TBVs are kept fully opened due to operator error.
Min DC Temperature	417.8 K [292.4°F] at 9998 s
Comments	None.





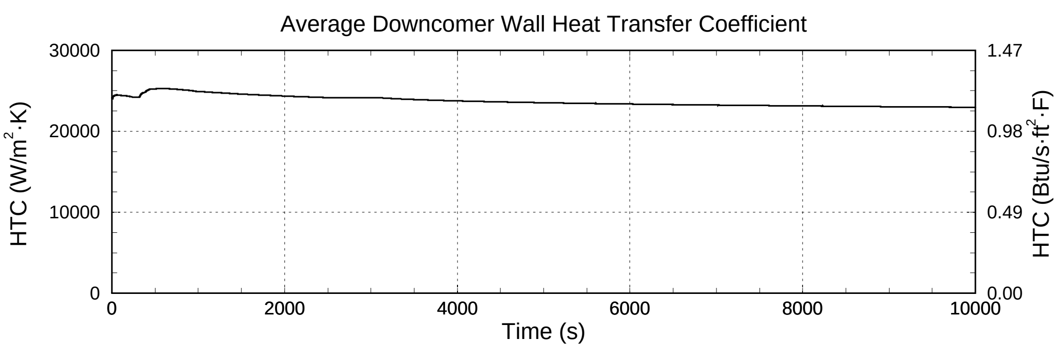


Figure A-21 Oconee PTS Results for Case 089

Case Category	TT/RT
Primary Failures	None
Secondary Failures	2 stuck open safety valves in SG-A
Operator Actions	Operator throttles HPI 20 minutes after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	448.6 K [347.9°F] at 9878 s
Comments	None.

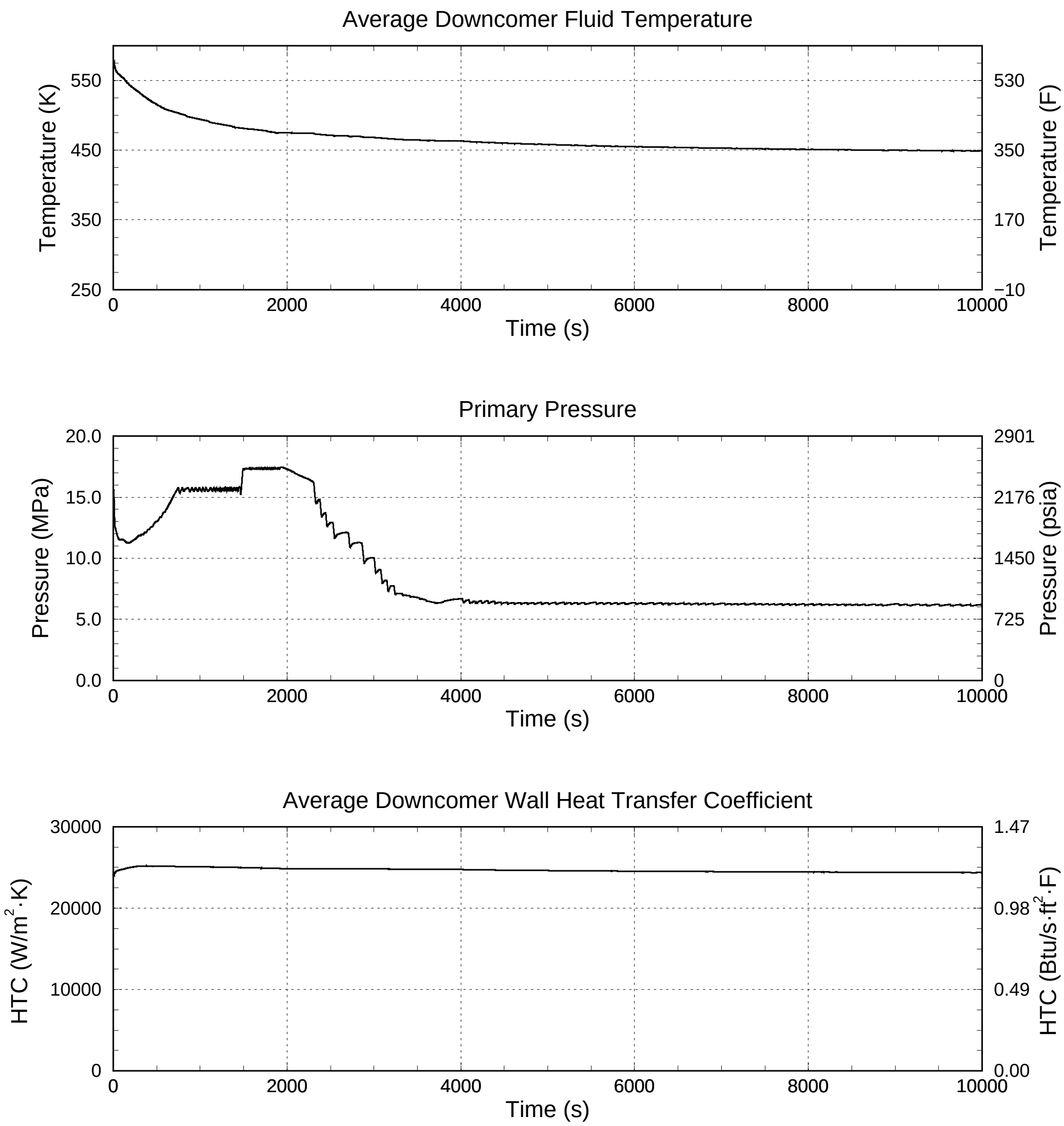
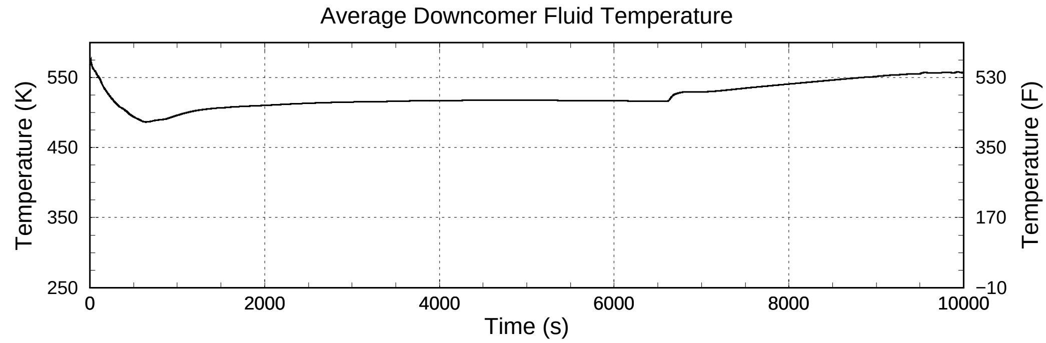
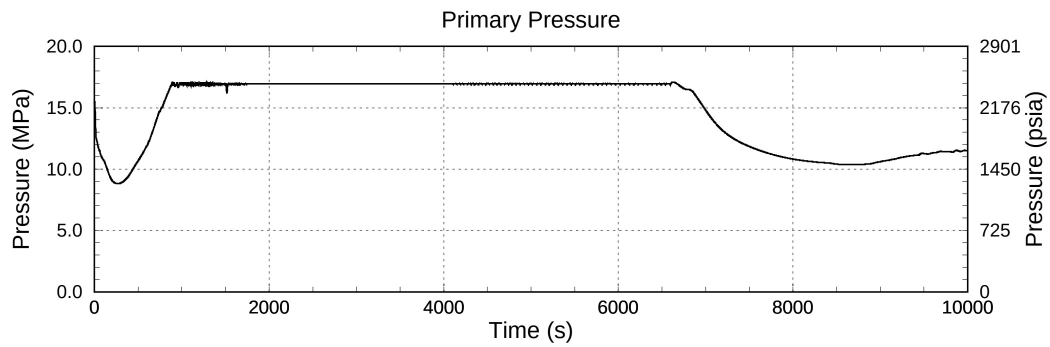


Figure A-22 Oconee PTS Results for Case 090

Case Category	SGTR
Primary Failures	None
Secondary Failures	SGTR with a stuck open SRV in SG-B. A reactor trip is assumed to occur at the time of the tube rupture. Stuck safety relief valve is assumed to reclose 10 minutes after initiation.
Operator Actions	Operator trips RCP's 1 minute after initiation. Operator also throttles HPI 10 minutes after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (assumed throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	486.4 K [415.8°F] at 641 s
Comments	None.





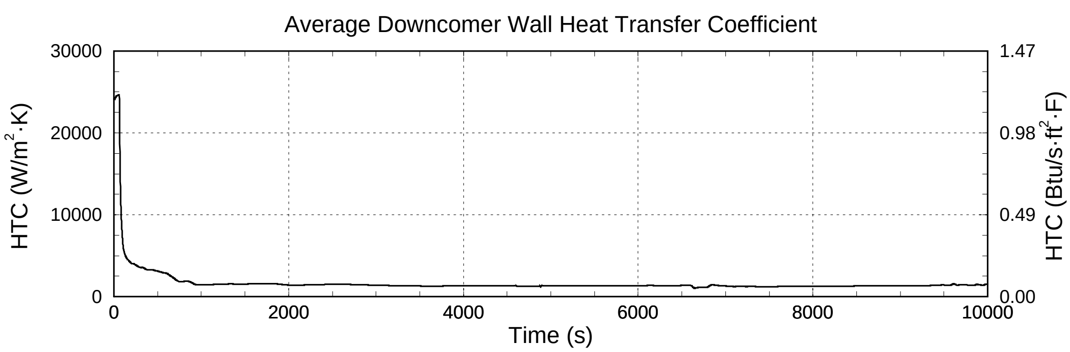
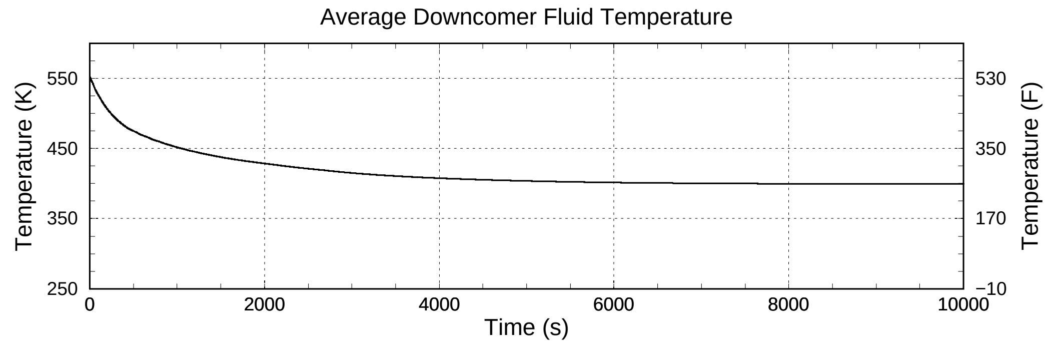
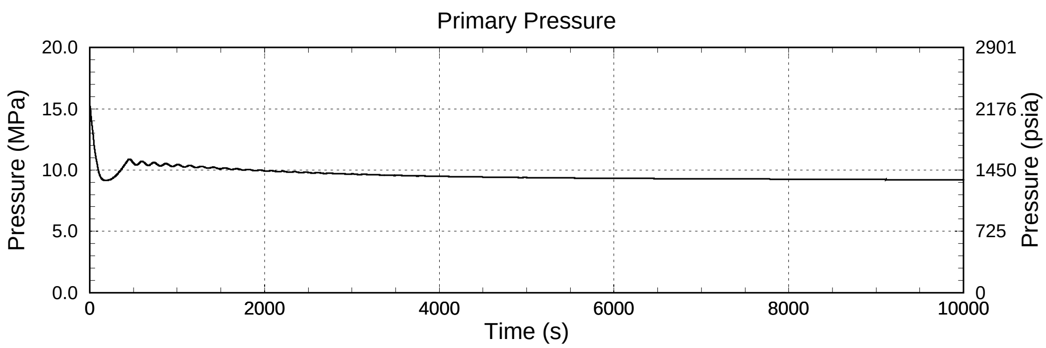


Figure A-23 Oconee PTS Results for Case 091

Case Category	TT/RT-HZP
Primary Failures	None
Secondary Failures	Loss of MFW and EFW.
Operator Actions	Opens all TBVs to depressurize the secondary side so the condensate booster pumps feed the SGs. Booster pumps are assumed to be initially uncontrolled so that the SGs are overfilled (610 cm (240 in) startup level). Controls booster pump flow to maintain SG level at 76 cm (30 in) due to continued RCP operation. Throttles HPI to maintain 55 K (100°F) subcooling and a pressurizer level of 254 cm (100 in). The TBVs are kept fully opened due to operator error.
Min DC Temperature	399.1 K [258.8°F] at 9993 s
Comments	None.





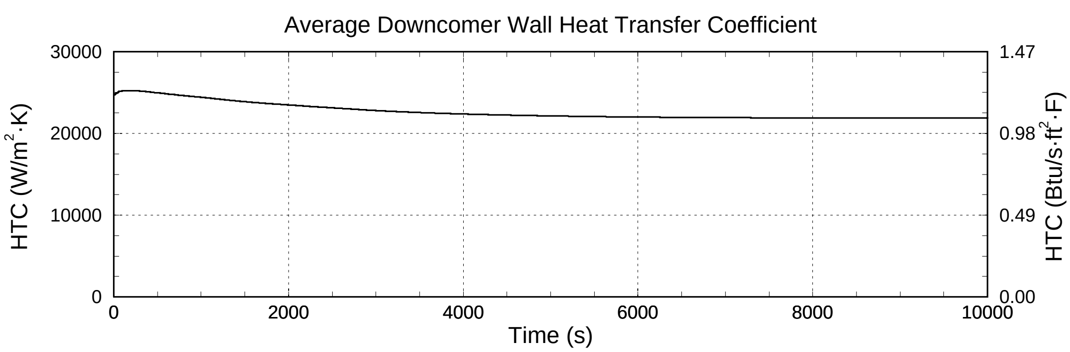


Figure A-24 Oconee PTS Results for Case 098

Case Category	MSLB
Primary Failures	None
Secondary Failures	MSLB with trip of turbine driven EFW by MSLB Circuitry.
Operator Actions	HPI is throttled 20 minutes after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	377.9 K [220.5°F] at 9439 s
Comments	None.

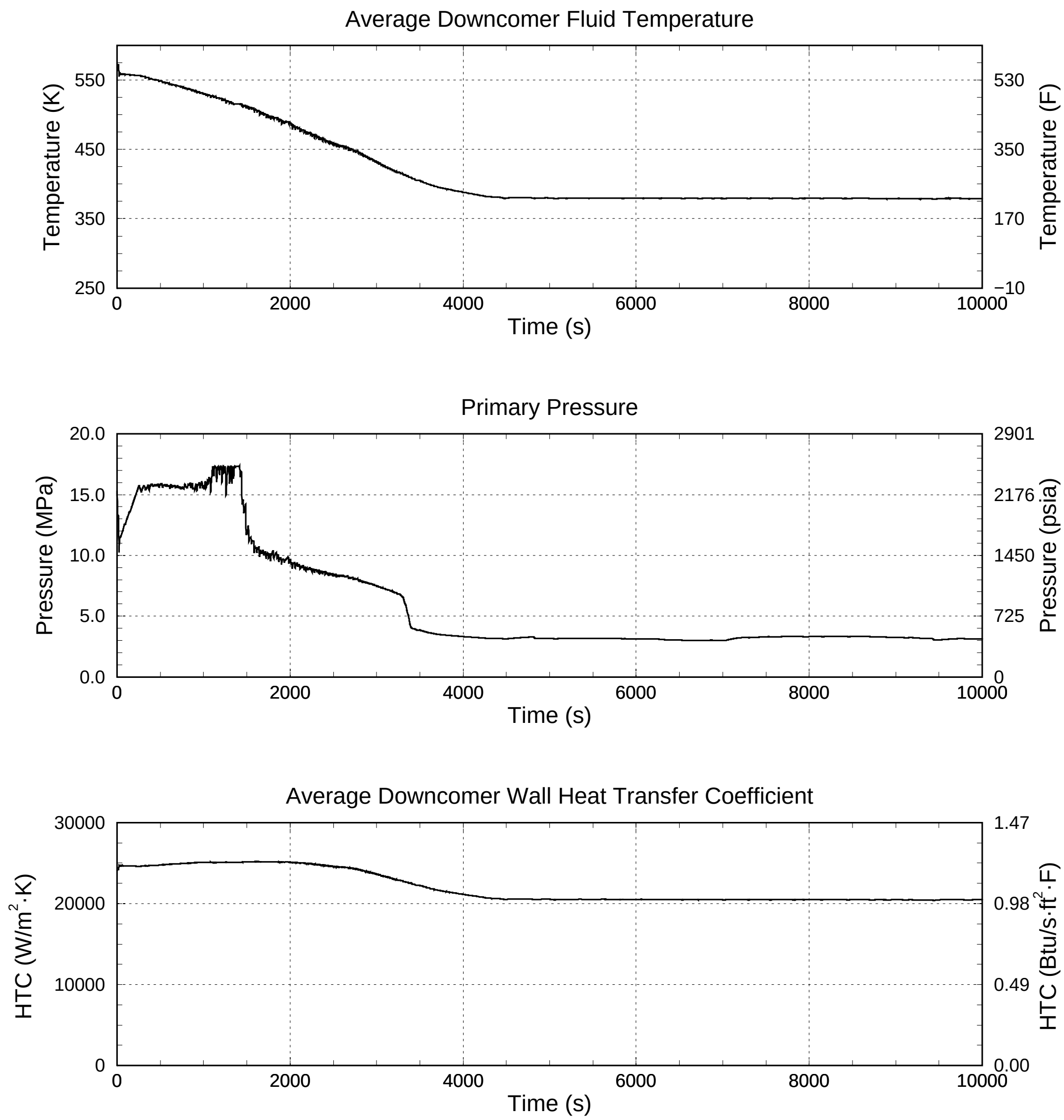


Figure A-25 Oconee PTS Results for Case 099

Case Category	MSLB-HZP
Primary Failures	None
Secondary Failures	MSLB with trip of turbine driven EFW by MSLB Circuitry
Operator Actions	Operator throttles HPI 20 minutes after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	376.3 K [217.7°F] at 4440 s
Comments	None.

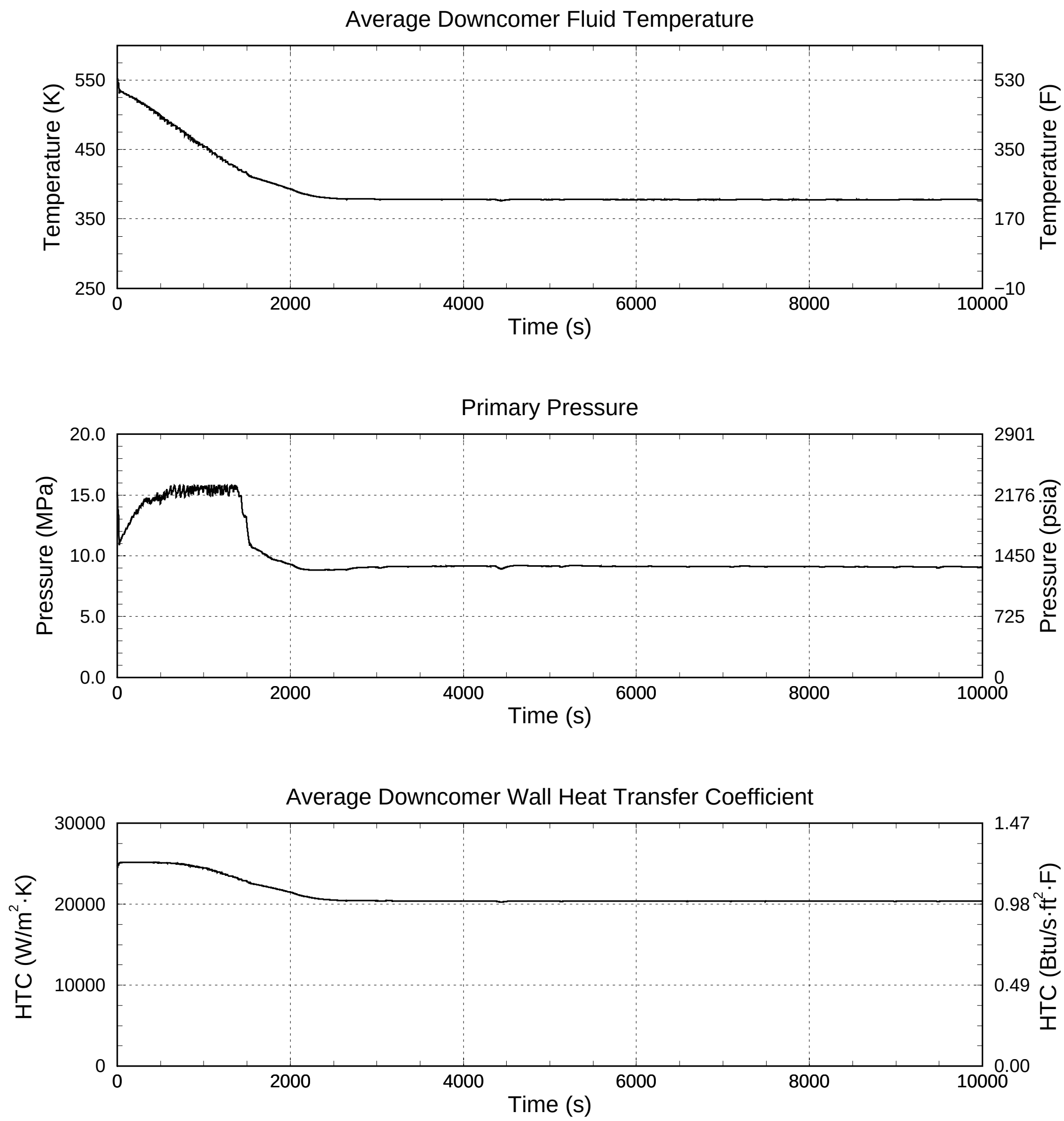


Figure A-26 Oconee PTS Results for Case 100

Case Category	MSLB-HZP
Primary Failures	None
Secondary Failures	MSLB without trip of turbine driven EFW by MSLB Circuitry
Operator Actions	Operator throttles HPI to maintain 27.8 K (50°F) subcooling margin (throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	376.2 K [217.6°F] at 3849 s
Comments	None.

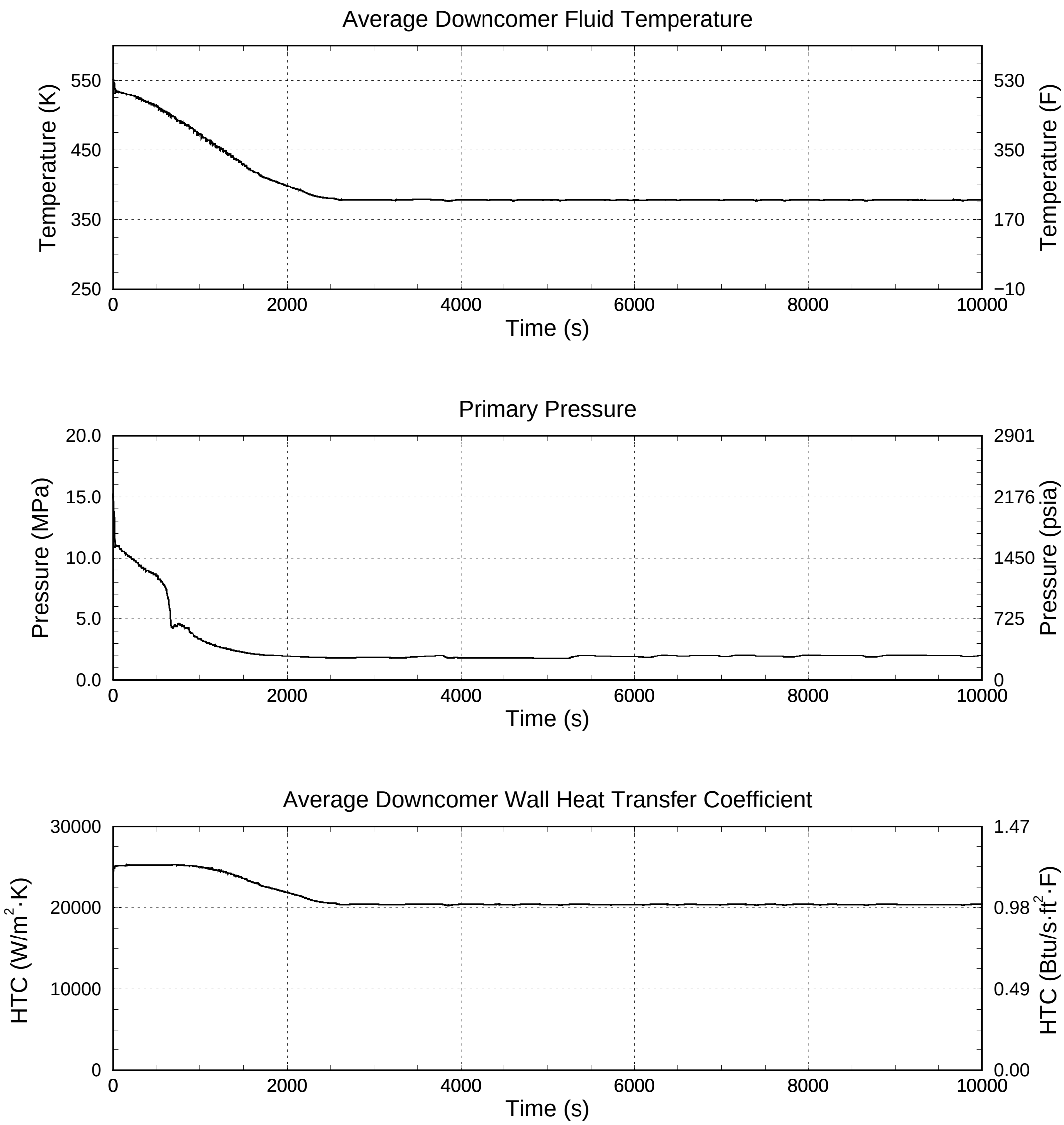
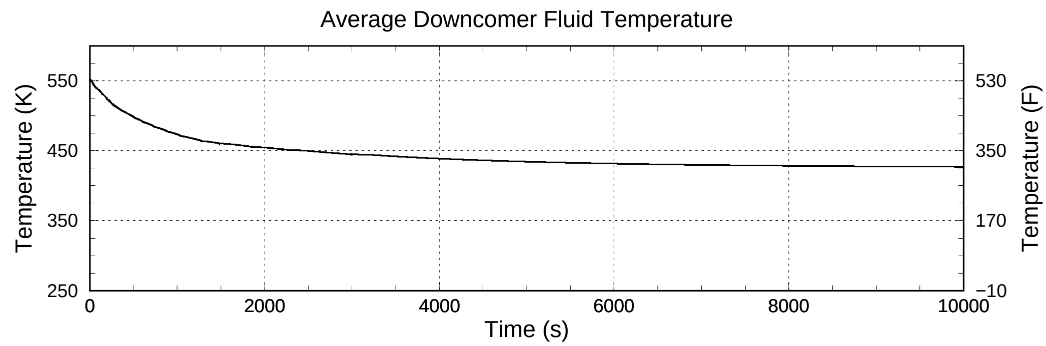
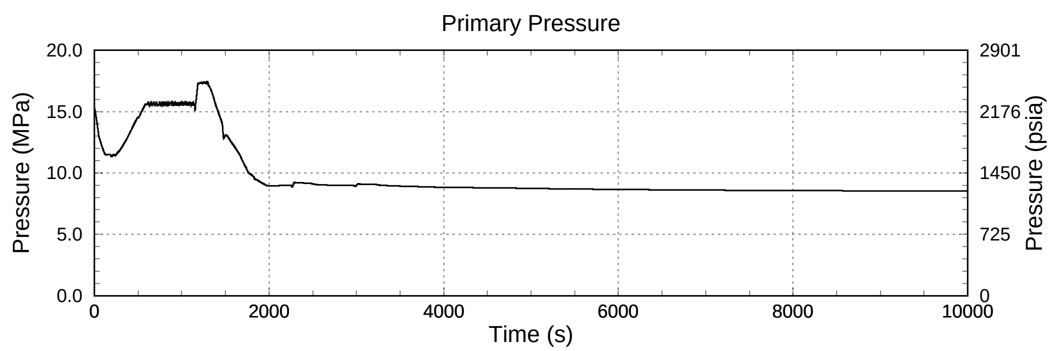


Figure A-27   Oconee PTS Results for Case 101

Case Category	TT/RT-HZP
Primary Failures	None
Secondary Failures	2 stuck open safety valves in SG-A
Operator Actions	Operator throttles HPI 20 minutes after 2.77 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27 K (50°F) subcooling).
Min DC Temperature	426.9 K [308.8°F] at 10000 s
Comments	None.





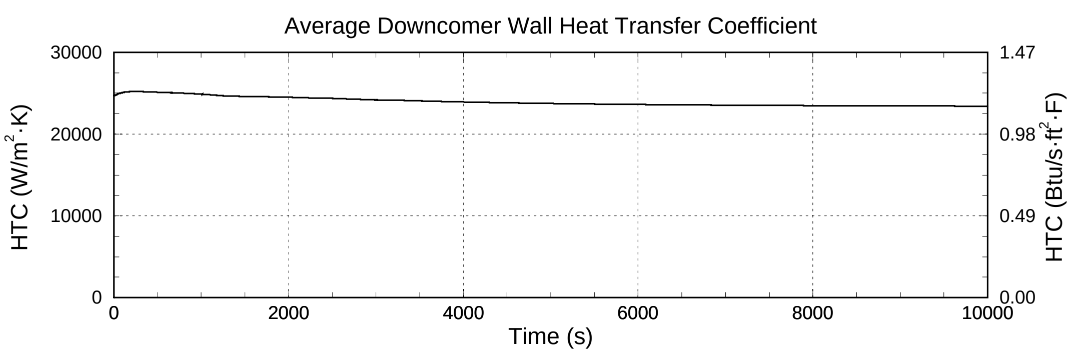


Figure A-28 Oconee PTS Results for Case 102

Case Category	LOCA-Hi K
Primary Failures	2.54 cm (1 inch) surge line break
Secondary Failures	2 stuck open safety valves in SG-A
Operator Actions	HPI terminated when subcooling margin exceeds 55.6 K (100°F)
Min DC Temperature	454.6 K [358.5°F] at 4406 s
Comments	None.

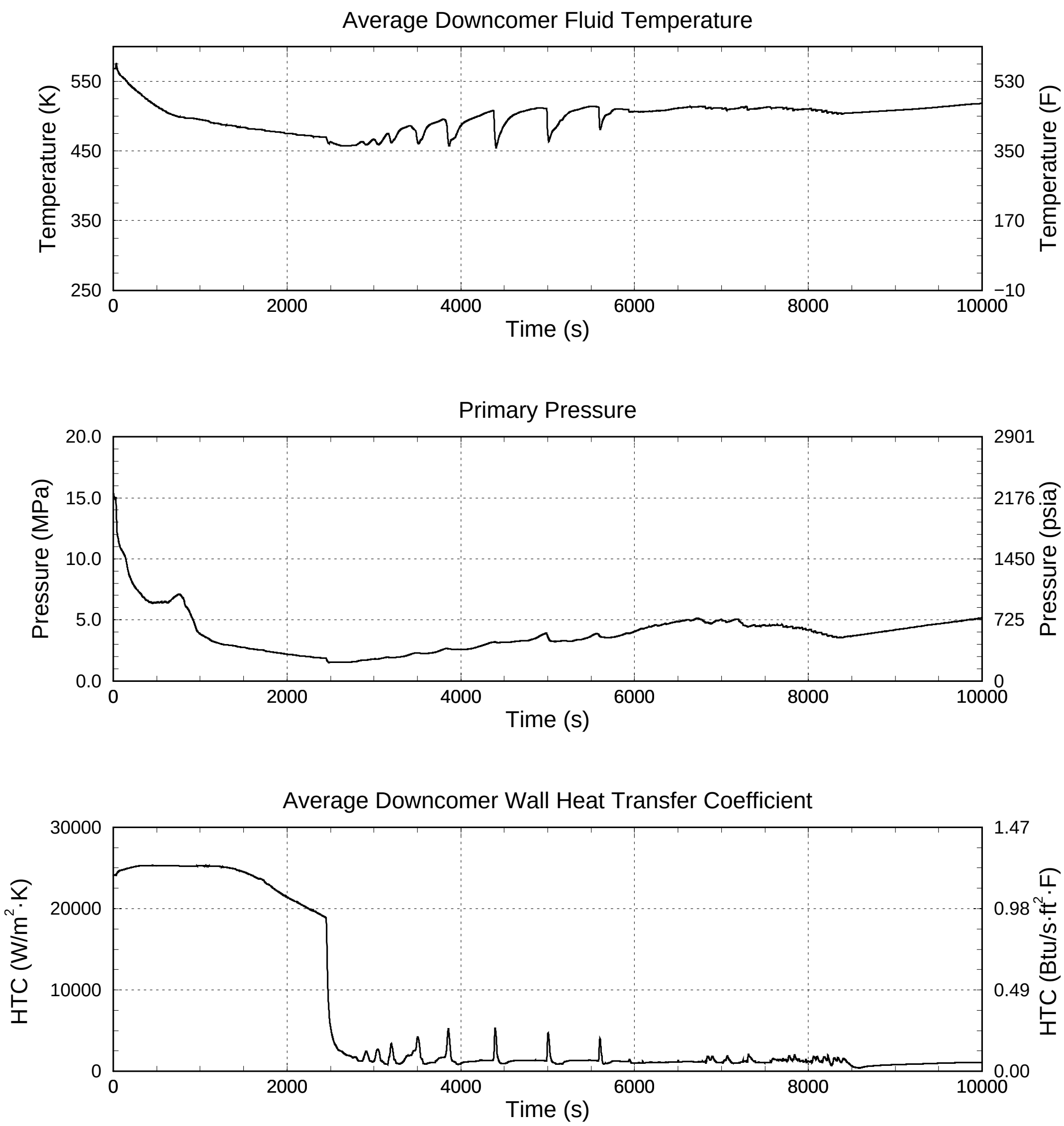


Figure A-29 Oconee PTS Results for Case 107

Case Category	TT/RT-Hi K
Primary Failures	Stuck open pressurizer safety valve
Secondary Failures	None
Operator Actions	None
Min DC Temperature	345.8 K [162.8°F] at 10000 s
Comments	None.

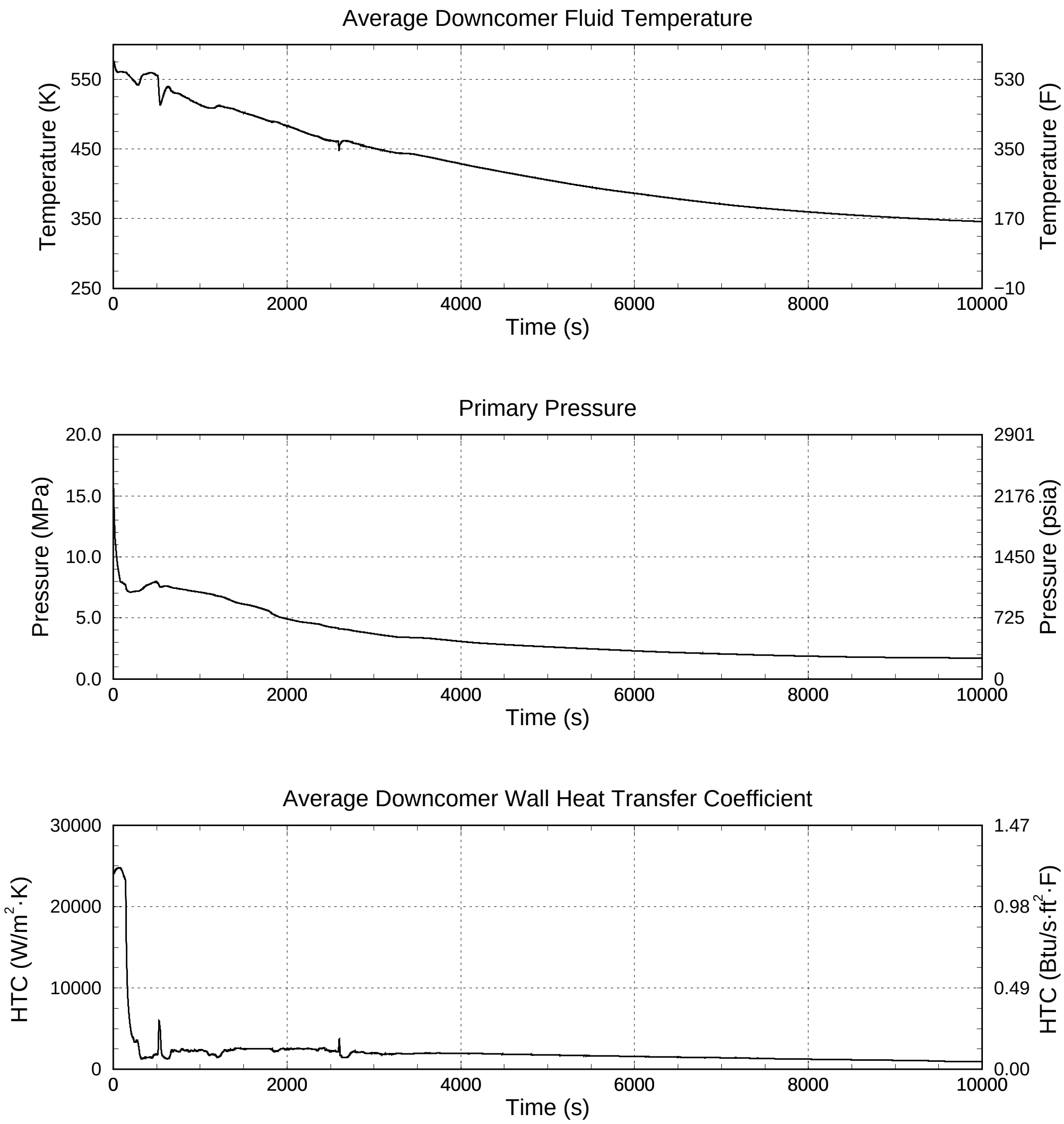
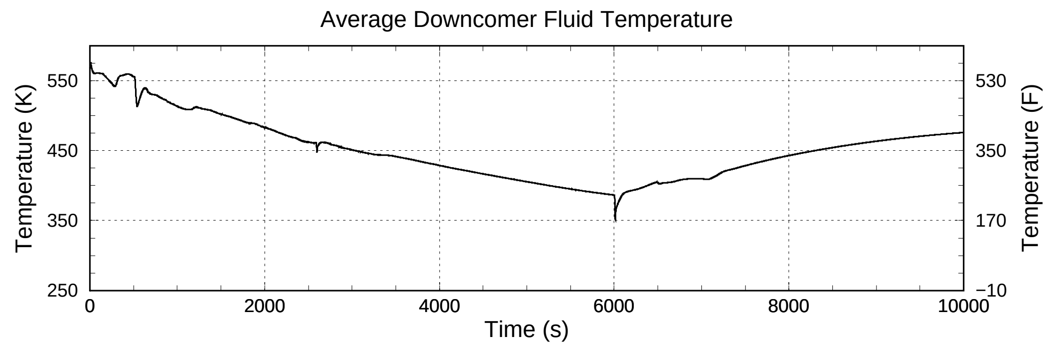
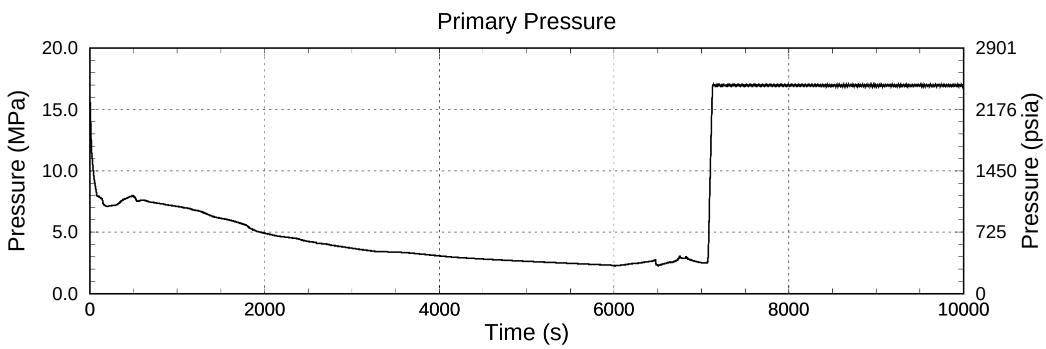


Figure A-30 Oconee PTS Results for Case 108

Case Category	TT/RT-Hi K
Primary Failures	Stuck open pressurizer safety valve. Valve recloses at 6000 secs (RCS low pressure point).
Secondary Failures	None
Operator Actions	None
Min DC Temperature	351.1 K [172.3°F] at 6012 s
Comments	None.





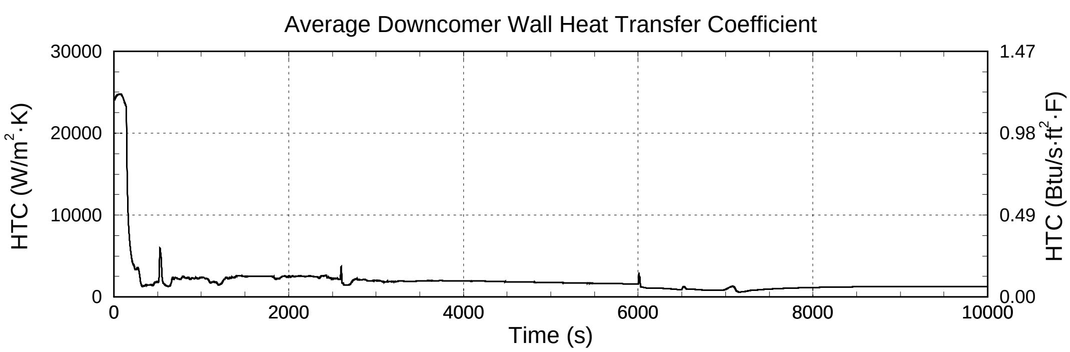


Figure A-31 Oconee PTS Results for Case 109

Case Category	LOCA-Hi K
Primary Failures	
Secondary Failures	None
Operator Actions	At 15 minutes after transient initiation, operator opens both TBV to lower primary system pressure and allow CFT and LPI injection.
Min DC Temperature	330.7 K [135.6°F] at 1823 s
Comments	None.

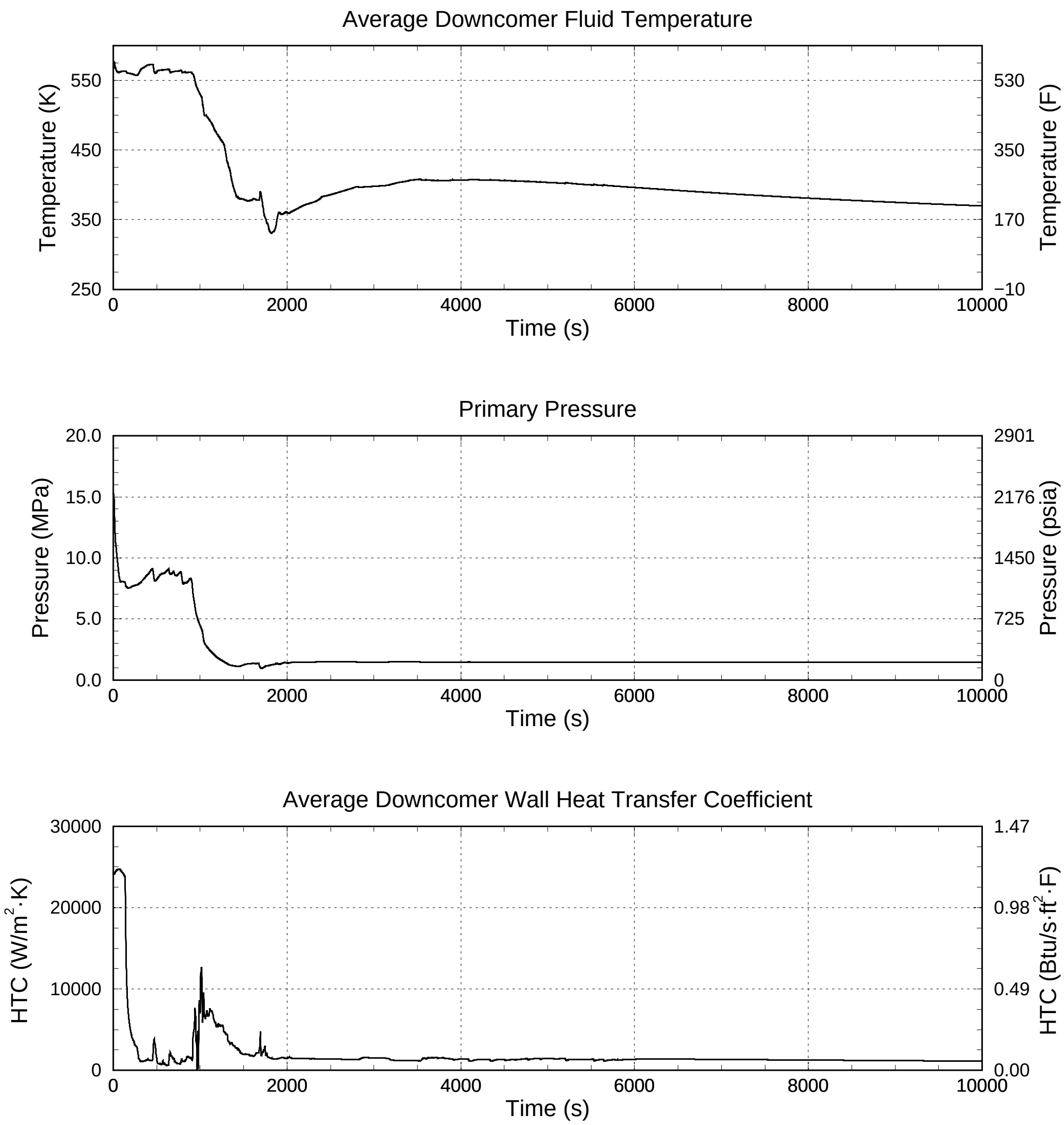


Figure A-32 Oconee PTS Results for Case 110

Case Category	LOCA-Hi K
Primary Failures	
Secondary Failures	None
Operator Actions	At 15 minutes after initiation, operator opens all TBVs to lower primary pressure and allow CFT and LPI injection. When the CFTs are 50% discharged, HPI is recovered. At 3000 seconds after initiation, operator starts throttling HPI to 55 K (100°F) subcooling and 254 cm (100 in) pressurizer level.
Min DC Temperature	390.6 K [243.4°F] at 4448 s
Comments	None.

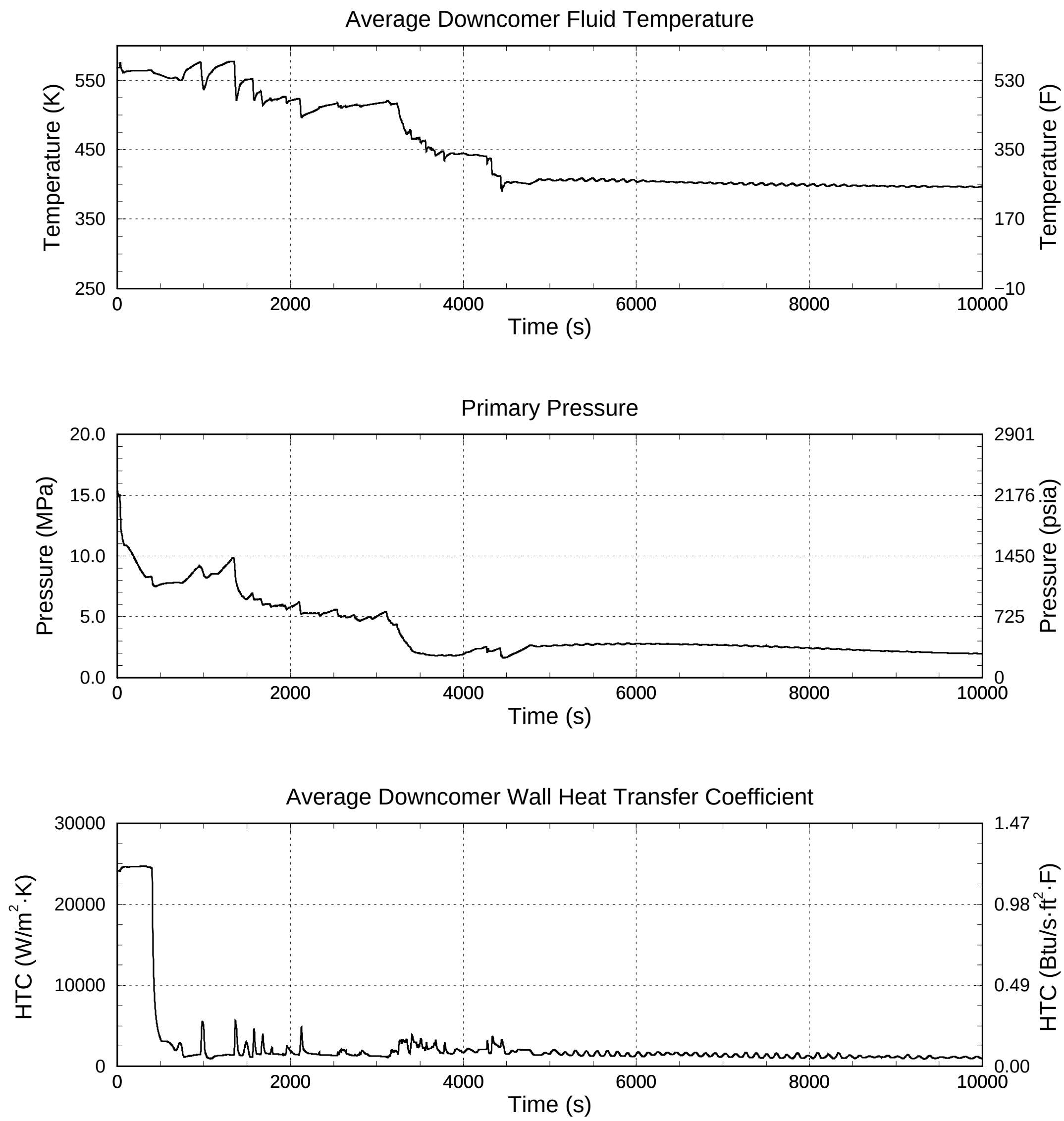


Figure A-33 Oconee PTS Results for Case 111

Case Category	TT/RT-Hi K
Primary Failures	Stuck open pressurizer safety valve. Valve recloses at 6000 secs.
Secondary Failures	None
Operator Actions	After valve recloses, operator throttles HPI 1 minute after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27 K (50°F) subcooling)
Min DC Temperature	351.1 K [172.3°F] at 6012 s
Comments	None.

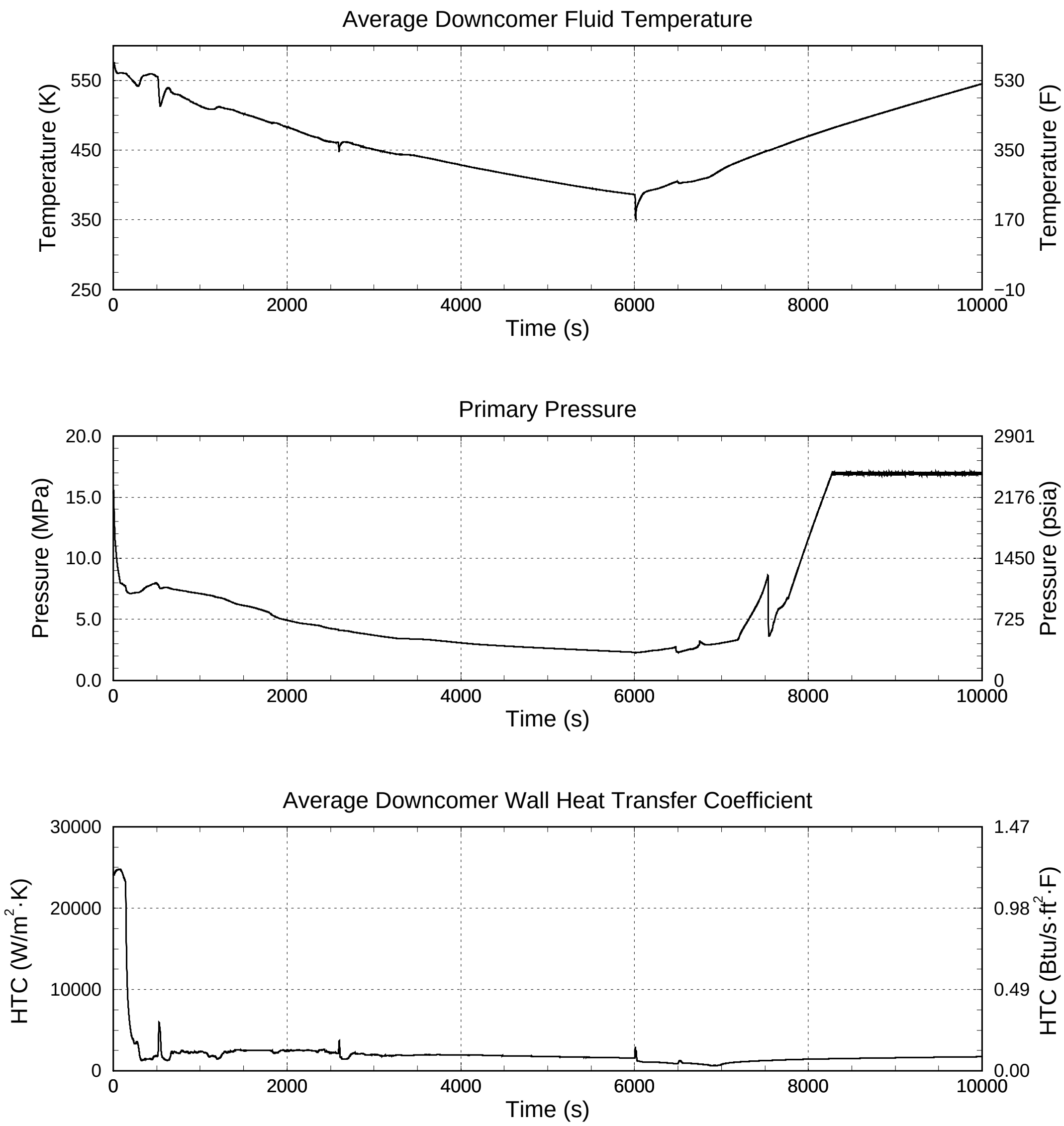


Figure A-34 Oconee PTS Results for Case 112

Case Category	TT/RT-Hi K
Primary Failures	Stuck open pressurizer safety valve. Valve recloses at 6000 secs.
Secondary Failures	None
Operator Actions	After valve recloses, operator throttles HPI 10 minutes after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling)
Min DC Temperature	351.1 K [172.3°F] at 6012 s
Comments	None.

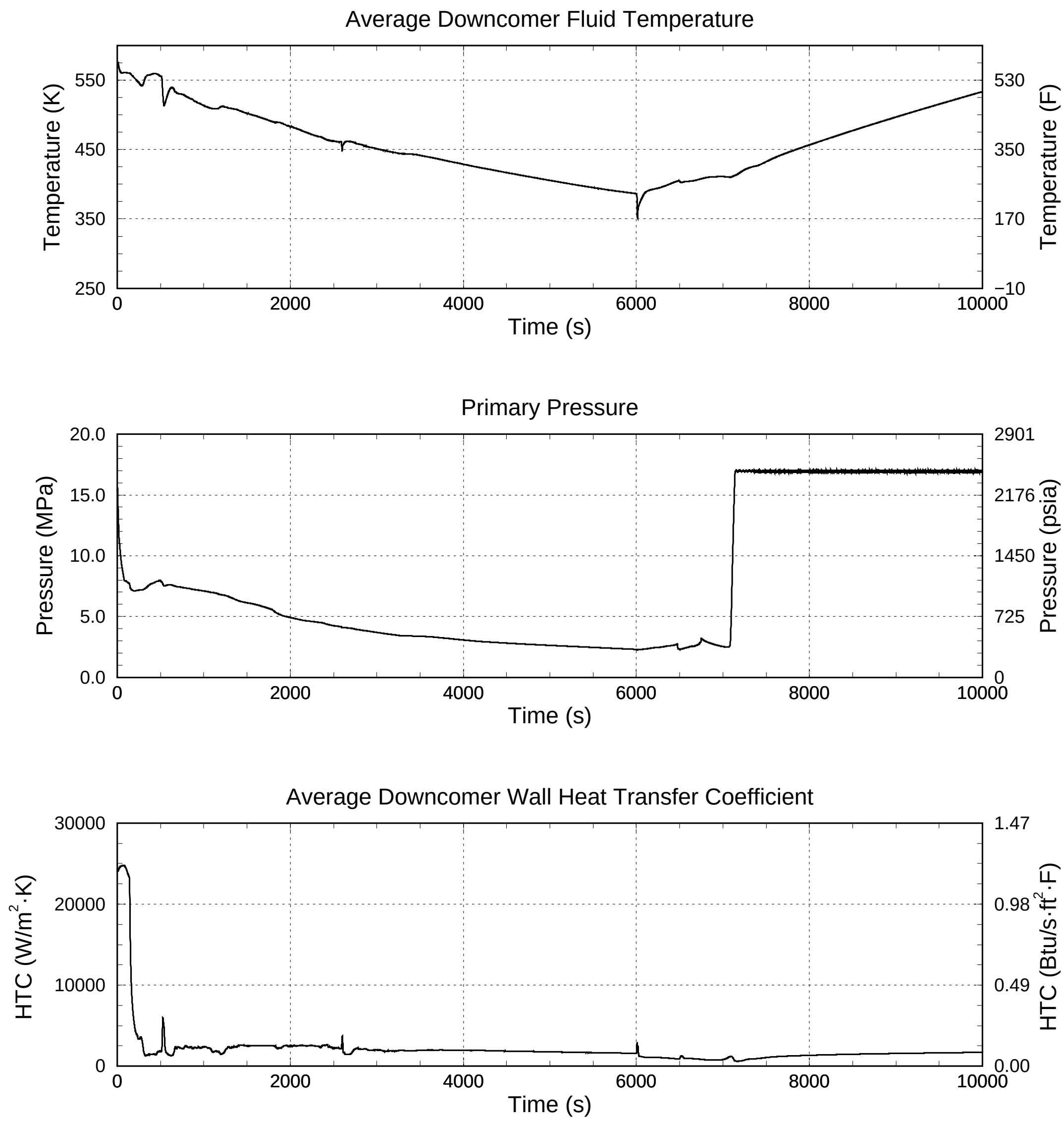
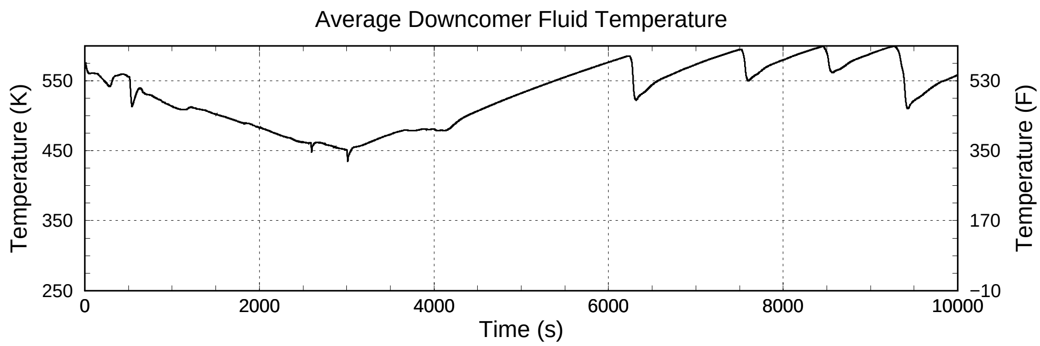
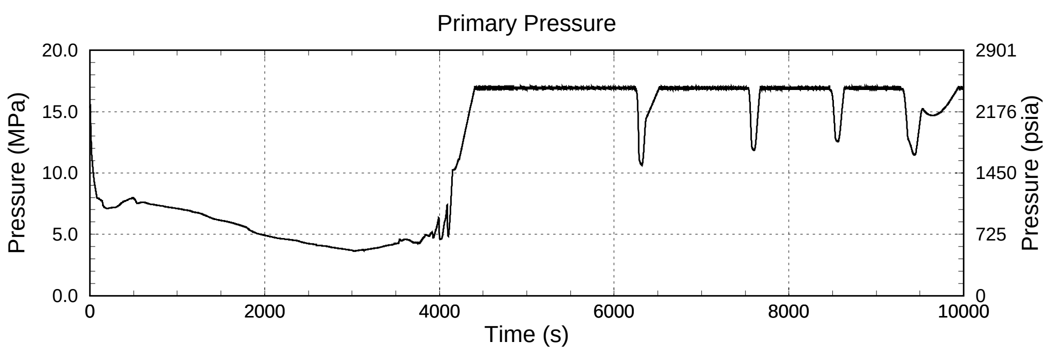


Figure A-35 Oconee PTS Results for Case 113

Case Category	TT/RT-Hi K
Primary Failures	Stuck open pressurizer safety valve. Valve recloses at 3000 secs.
Secondary Failures	None
Operator Actions	After valve recloses, operator throttles HPI 1 minute after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 50°F subcooling)
Min DC Temperature	433.8 K [321.3°F] at 3011 s
Comments	None.





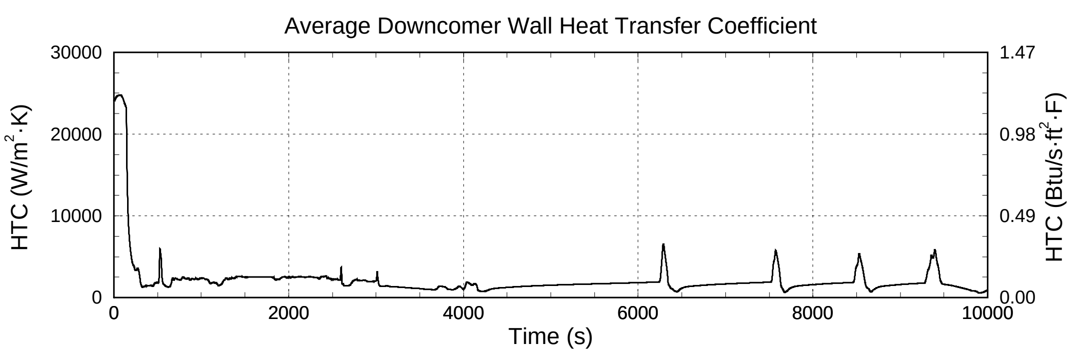


Figure A-36 Oconee PTS Results for Case 114

Case Category	TT/RT-Hi K
Primary Failures	
Secondary Failures	None
Operator Actions	After valve recloses, operator throttles HPI 10 minutes after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 50°F subcooling)
Min DC Temperature	433.8 K [321.3°F] at 3011 s
Comments	None.

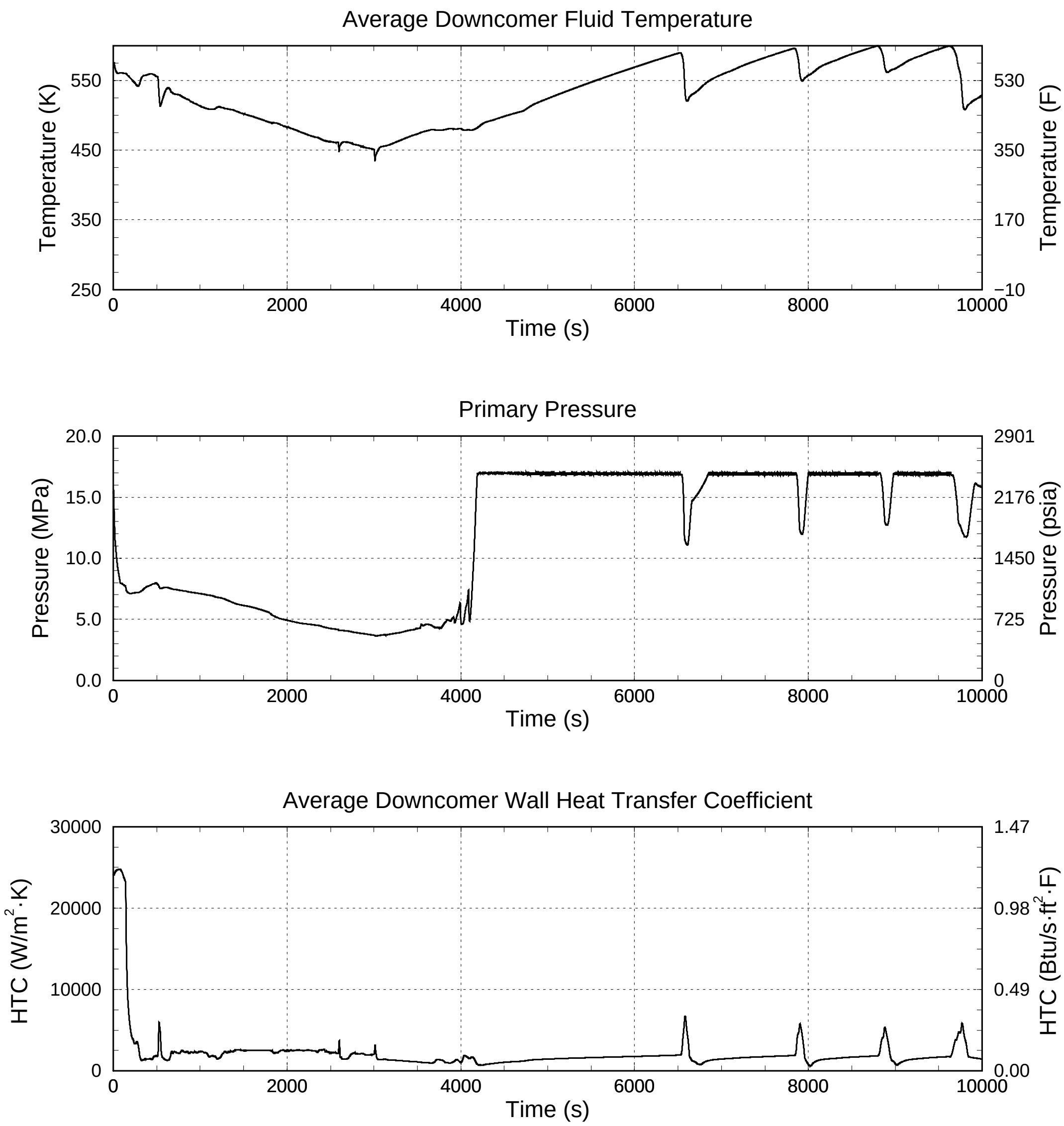
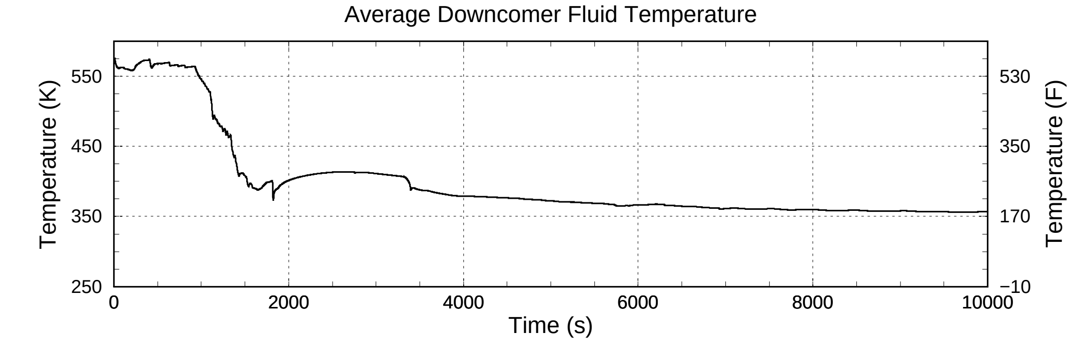
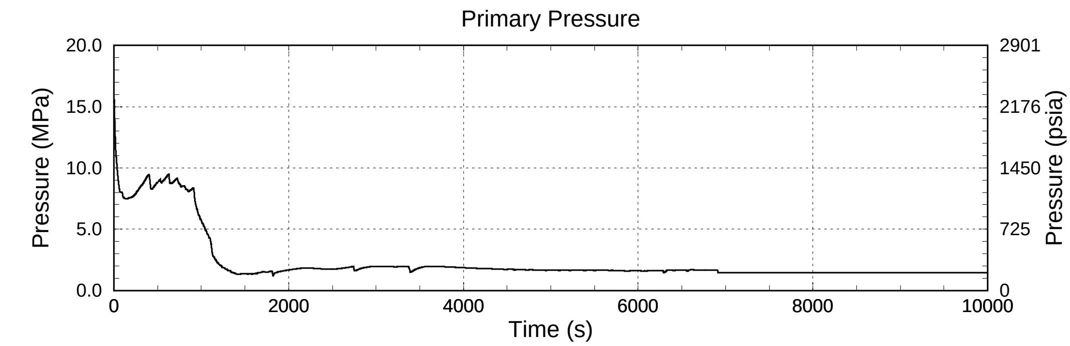


Figure A-37   Oconee PTS Results for Case 115

Case Category	TT/RT-Hi K
Primary Failures	
Secondary Failures	None
Operator Actions	At 15 minutes after initiation, operator opens all TBVs to lower primary pressure and allow CFT and LPI injection. When the CFTs are 50% discharged, HPI is recovered. The HPI is throttled 20 minutes after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 50°F subcooling).
Min DC Temperature	356.2 K [181.5°F] at 9709 s
Comments	None.





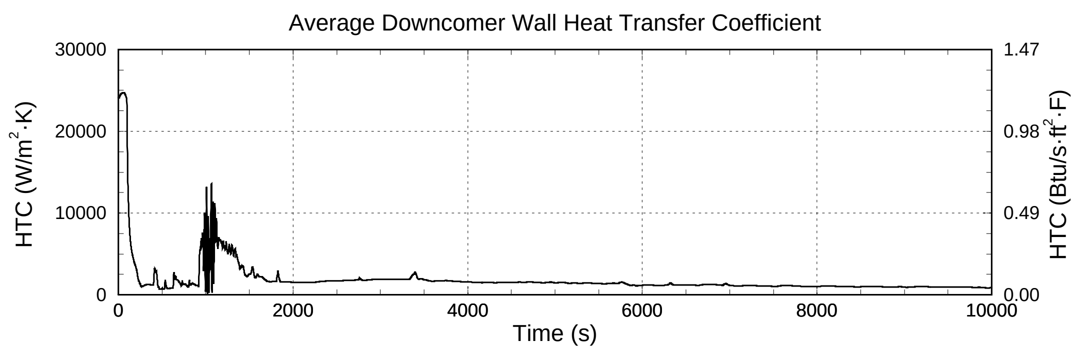


Figure A-38 Oconee PTS Results for Case 116

Case Category	TT/RT-Hi K
Primary Failures	
Secondary Failures	None
Operator Actions	At 15 minutes after initiation, operator opens all TBV to lower primary pressure and allow CFT and LPI injection. When the CFTs are 50% discharged, HPI is recovered. The SRV is closed 5 minutes after HPI recovered. HPI is throttled at 1 minute after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	366.1 K [199.4°F] at 1661 s
Comments	None.

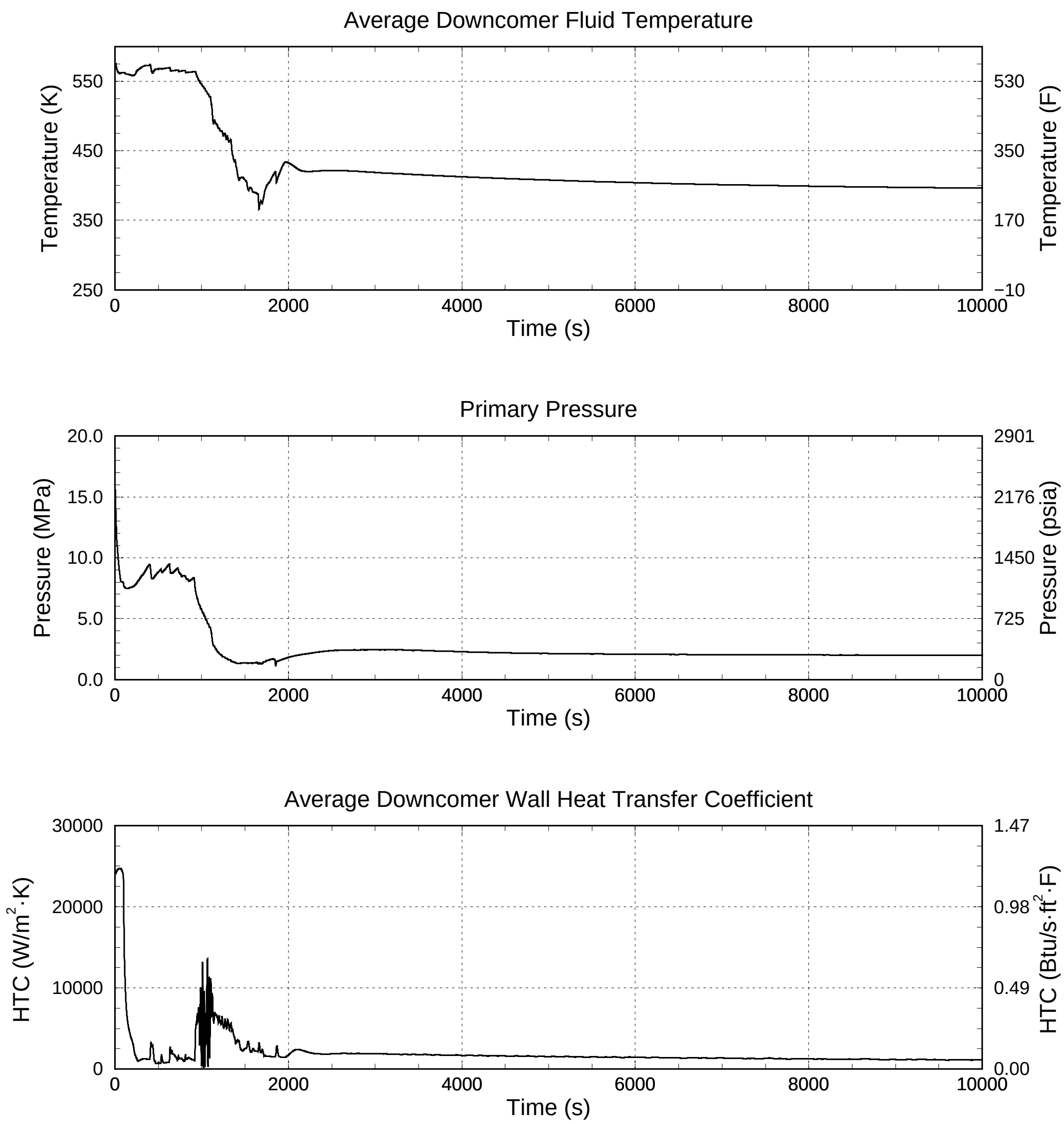


Figure A-39 Oconee PTS Results for Case 117

Case Category	LOCA-Hi K, HZP
Primary Failures	5.08 cm (2 inch) surge line break
Secondary Failures	None
Operator Actions	None
Min DC Temperature	298.1 K [76.9°F] at 10000 s
Comments	None.

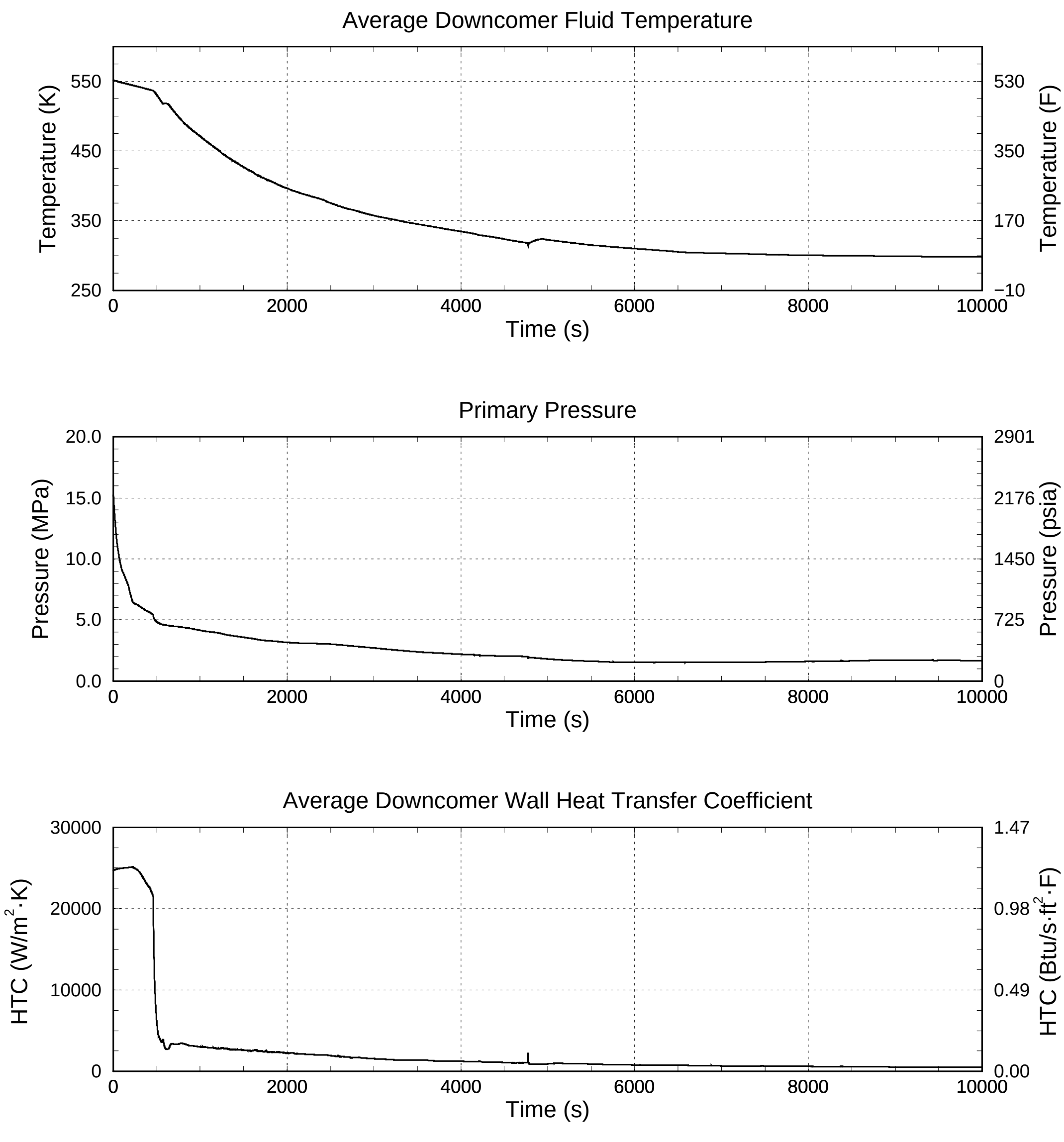


Figure A-40 Oconee PTS Results for Case 118

Case Category	LOCA-Hi K, HZP
Primary Failures	2.54 cm (1 in) surge line break with HPI Failure
Secondary Failures	None
Operator Actions	At 15 minutes after transient initiation, the operator opens all turbine bypass valves to lower primary system pressure and allow core flood tank and LPI injection.
Min DC Temperature	355.1 K [179.5°F] at 3252 s
Comments	None.

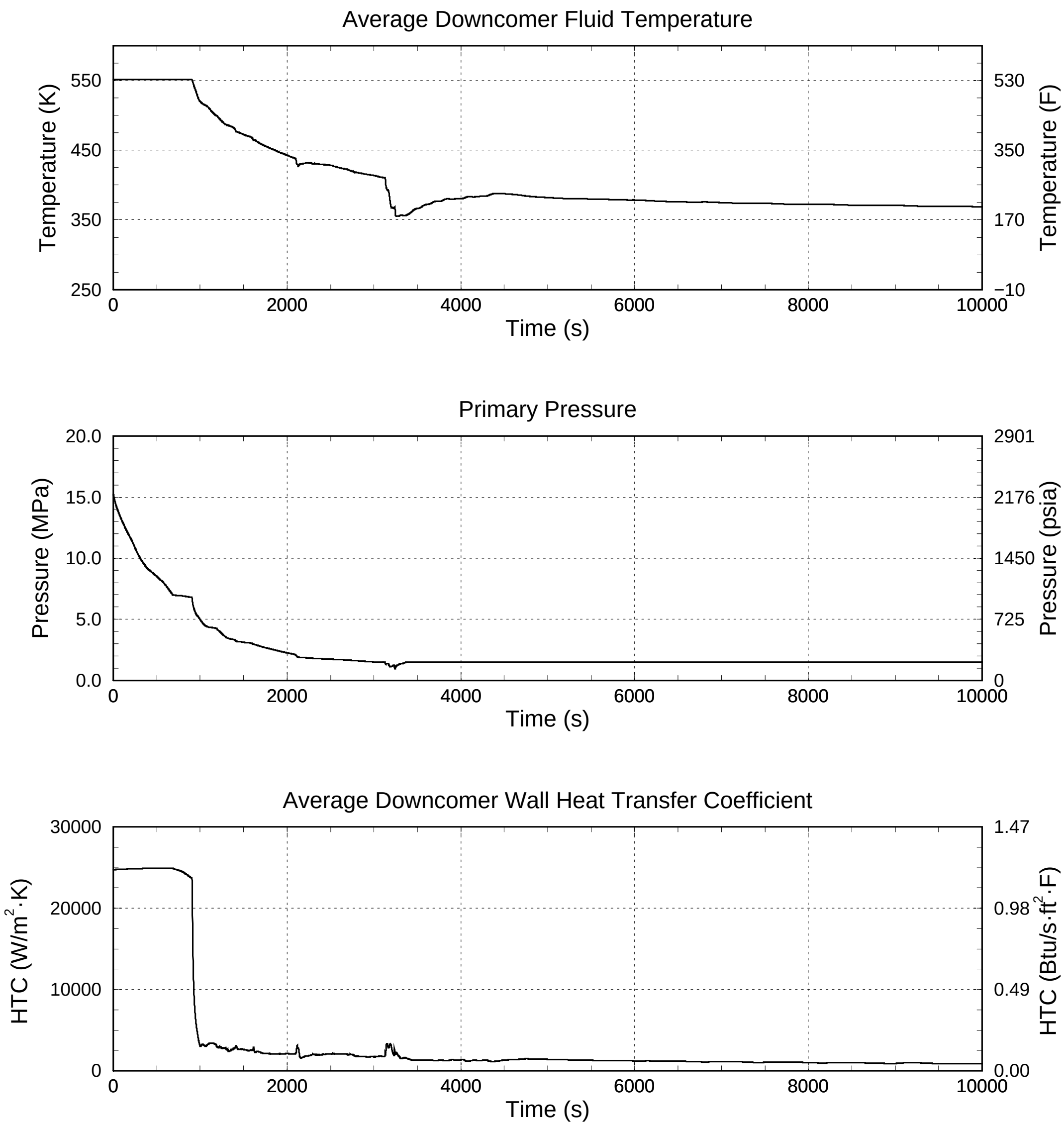


Figure A-41   Oconee PTS Results for Case 119

Case Category	LOCA-Hi K, HZP
Primary Failures	2.54 cm (1 in) surge line break with HPI Failure
Secondary Failures	None
Operator Actions	At 15 minutes after sequence initiation, operators open all TBVs to depressurize the system to the CFT setpoint. When the CFTs are 50 percent discharged, HPI is assumed to be recovered. The TBVs are assumed remain opened for the duration of the transient.
Min DC Temperature	308.5 K [95.7°F] at 10000 s
Comments	None.

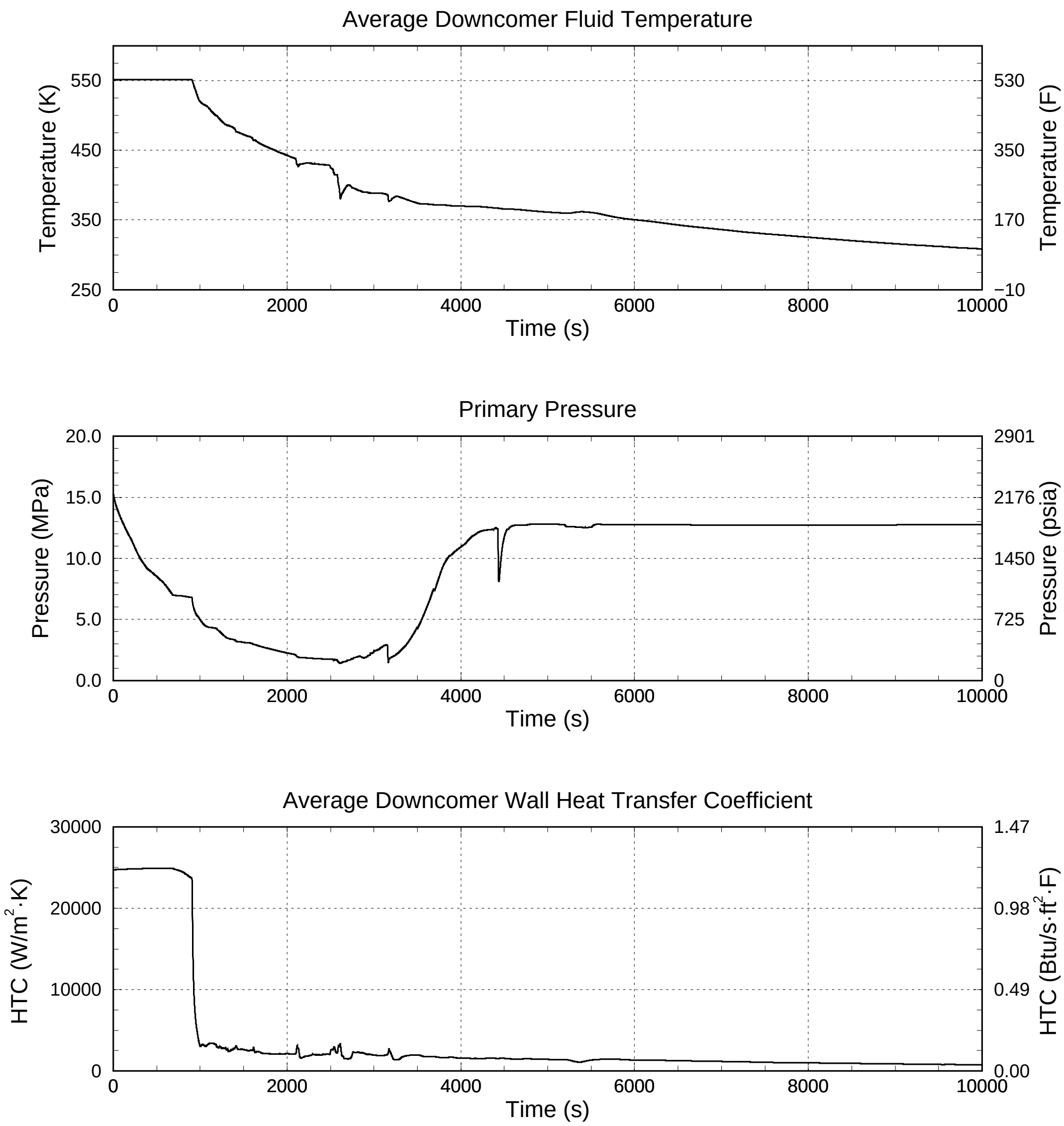


Figure A-42 Oconee PTS Results for Case 120

Case Category	TT/RT-Hi K, HZP
Primary Failures	Stuck open pressurizer safety valve. Valve recloses at 6000 secs .
Secondary Failures	None
Operator Actions	Operator throttles HPI at 1 minute after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	306.9 K [92.8°F] at 6010 s
Comments	None.

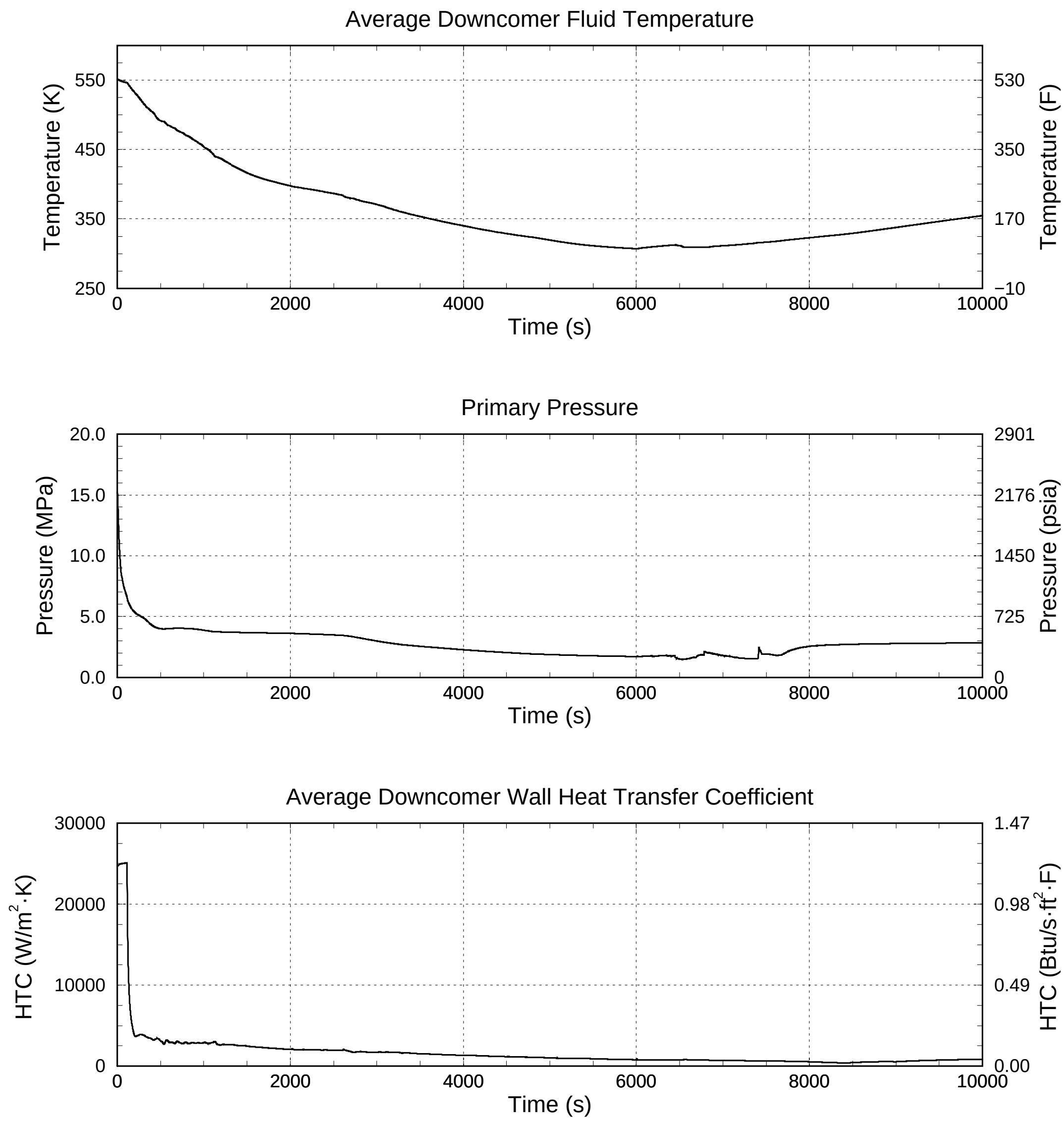


Figure A-43 Oconee PTS Results for Case 121

Case Category	TT/RT-Hi K, HZP
Primary Failures	Stuck open pressurizer safety valve. Valve recloses at 6000 secs.
Secondary Failures	None
Operator Actions	Operator throttles HPI at 10 minutes after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	306.9 K [92.8°F] at 6010 s
Comments	None.

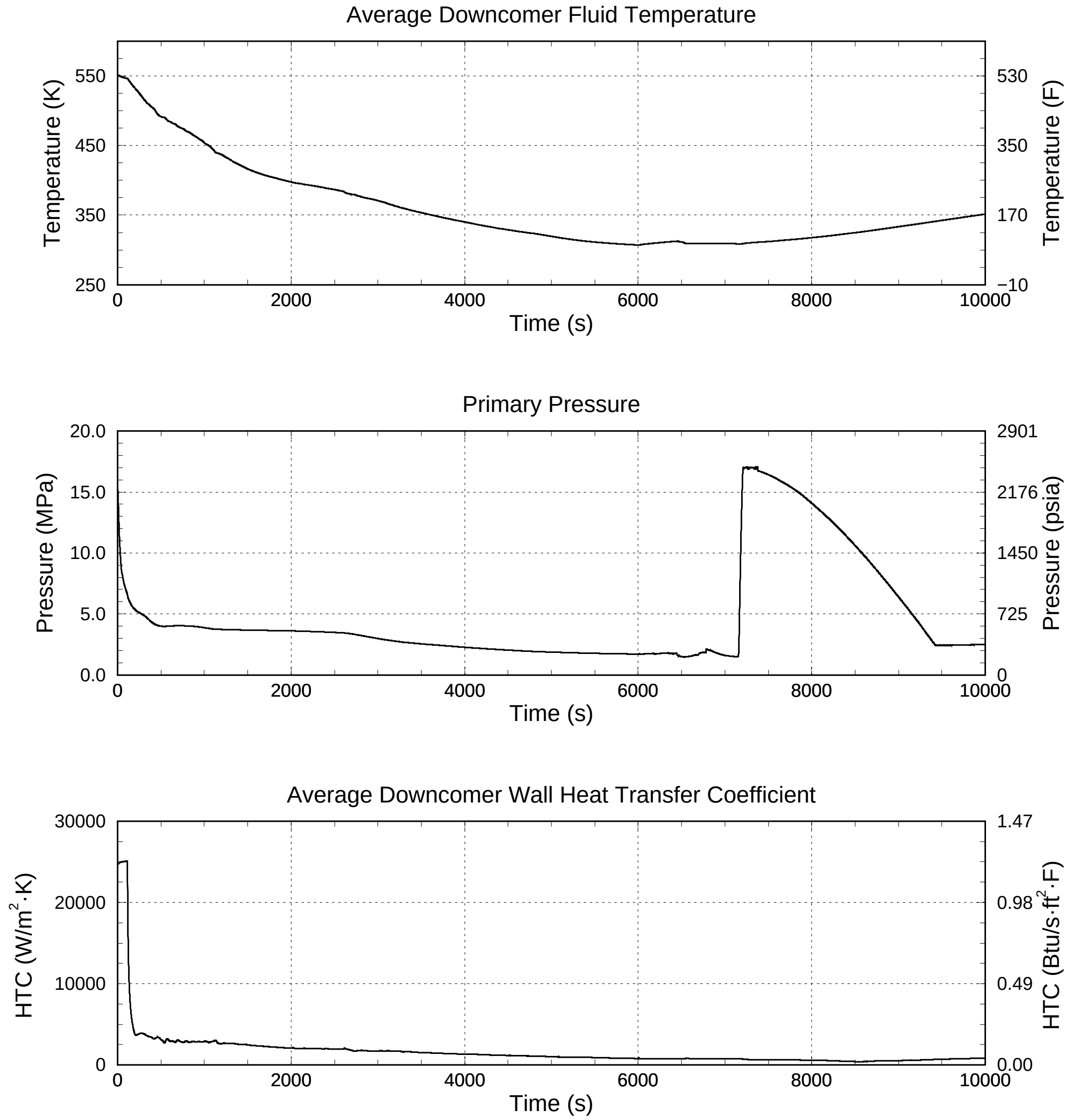


Figure A-44 Oconee PTS Results for Case 122

Case Category	TT/RT-Hi K, HZP
Primary Failures	Stuck open pressurizer safety valve. Valve recloses at 3000 secs.
Secondary Failures	None
Operator Actions	Operator throttles HPI at 1 minute after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	359.6 K [187.7°F] at 3650 s
Comments	None.

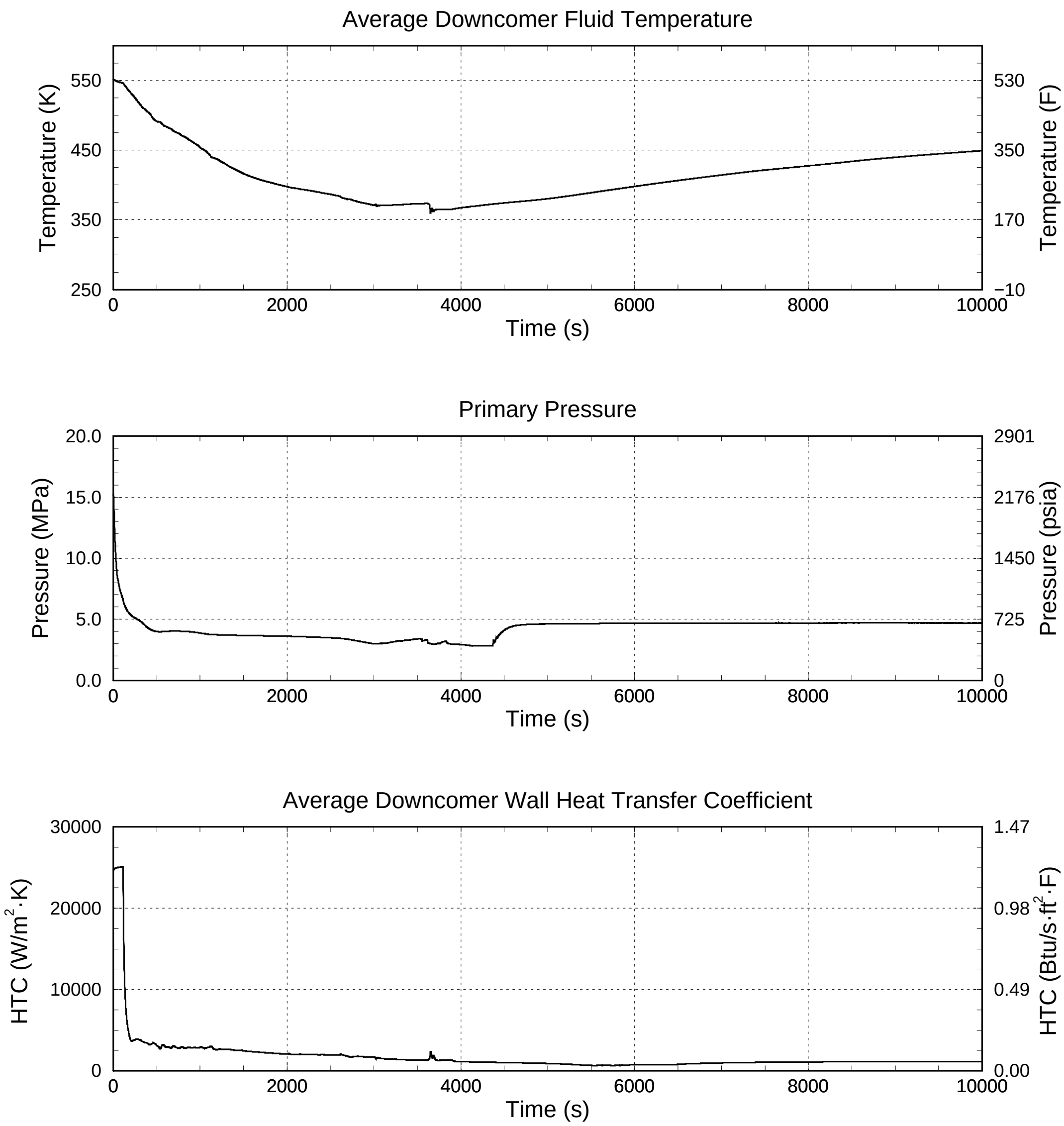


Figure A-45 Oconee PTS Results for Case 123

Case Category	TT/RT-Hi K, HZP
Primary Failures	Stuck open pressurizer safety valve. Valve recloses at 3000 secs.
Secondary Failures	None
Operator Actions	Operator throttles HPI at 10 minutes after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	359.6 K [187.7°F] at 3650 s
Comments	None.

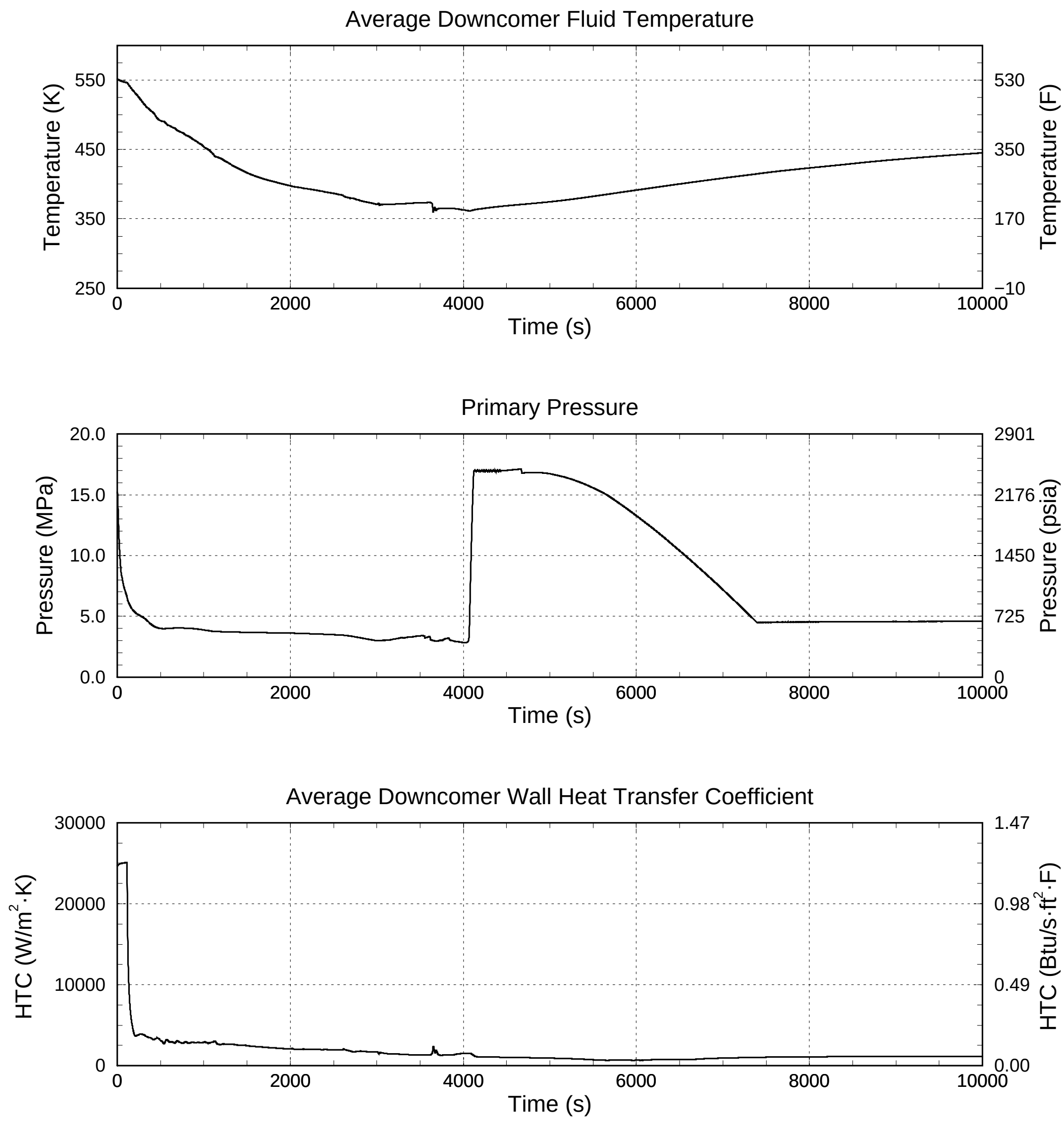


Figure A-46 Oconee PTS Results for Case 124

Case Category	TT/RT-Hi K, HZP
Primary Failures	Stuck open pressurizer safety valve and HPI Failure
Secondary Failures	None
Operator Actions	At 15 minutes after initiation, operator opens all TBVs to lower primary pressure and allow CFT and LPI injection. When the CFTs are 50% discharged, HPI is recovered. HPI is throttled 20 minutes after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	298.2 K [77.1°F] at 9992 s
Comments	None.

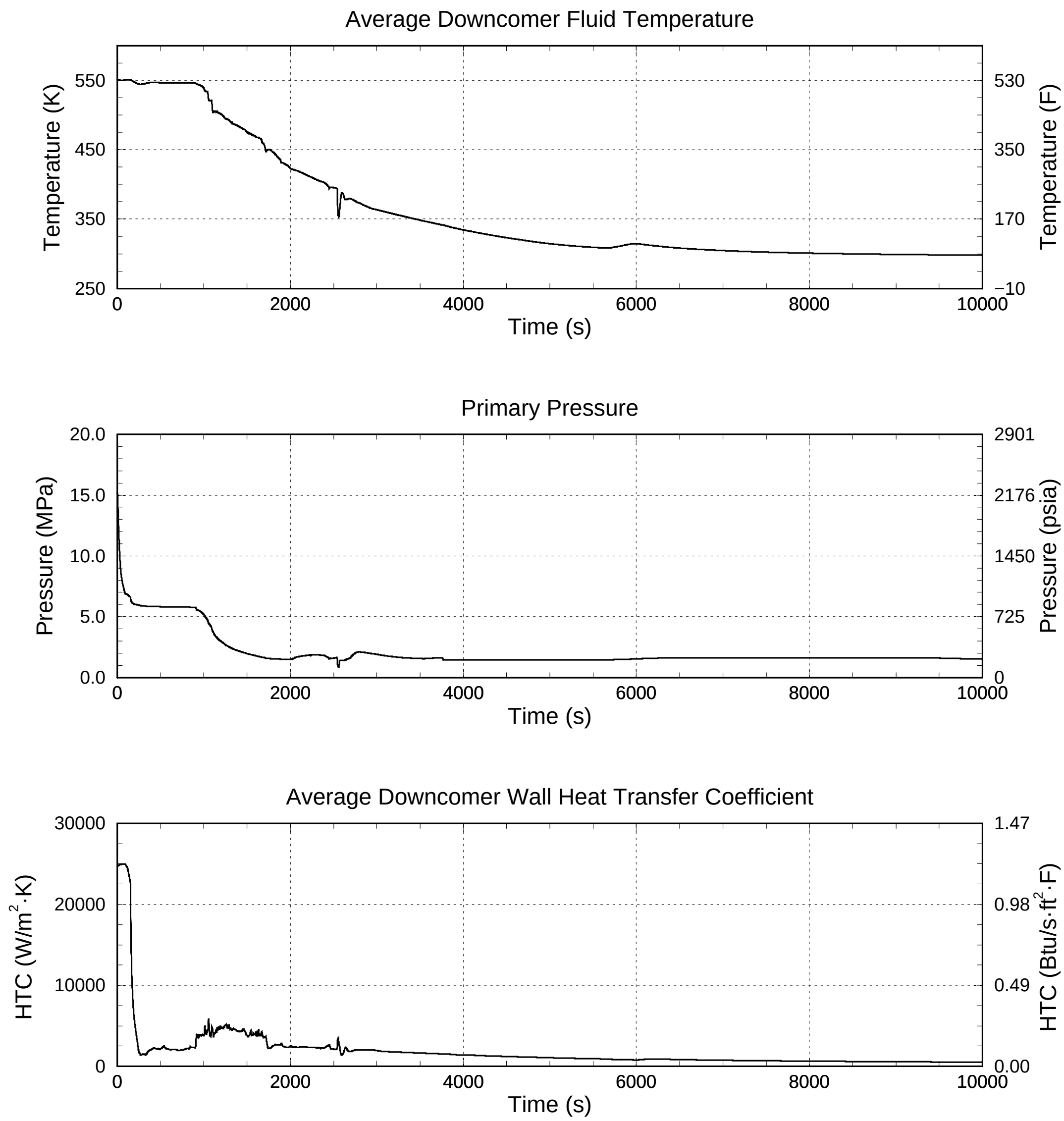


Figure A-47 Oconee PTS Results for Case 125

Case Category	TT/RT-Hi K, HZP
Primary Failures	Stuck open pressurizer safety valve and HPI Failure
Secondary Failures	None
Operator Actions	At 15 minutes after initiation, operator opens all TBVs to lower primary pressure and allow CFT and LPI injection. When the CFTs are 50% discharged, HPI is recovered. SRV is closed at 5 minutes after HPI is recovered. HPI is throttled at 1 minute after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	381.8 K [227.6°F] at 9883 s
Comments	None.

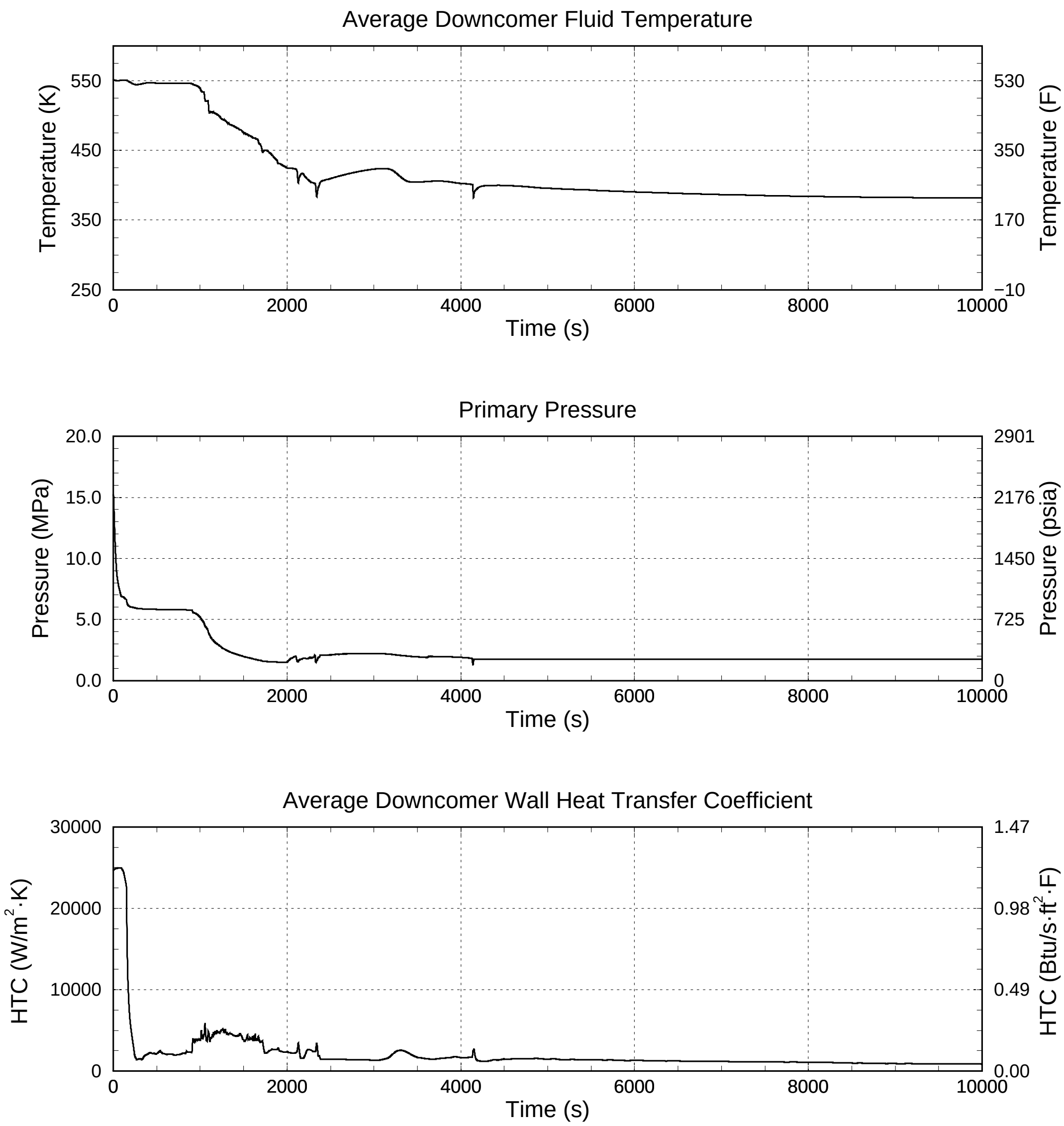


Figure A-48 Oconee PTS Results for Case 126

Case Category	SGTR-Hi K, HZP
Primary Failures	None
Secondary Failures	SGTR with a stuck open SRV in SG-B. A reactor trip is assumed to occur at the time of the tube rupture. Stuck safety relief valve is assumed to reclose 10 minutes after initiation.
Operator Actions	Operator trips RCP's 1 minute after initiation. Operator also throttles HPI 10 minutes after 2.77 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (assumed throttling criteria is 27 K (50°F) subcooling).
Min DC Temperature	464.9 K [377.2°F] at 626 s
Comments	None.

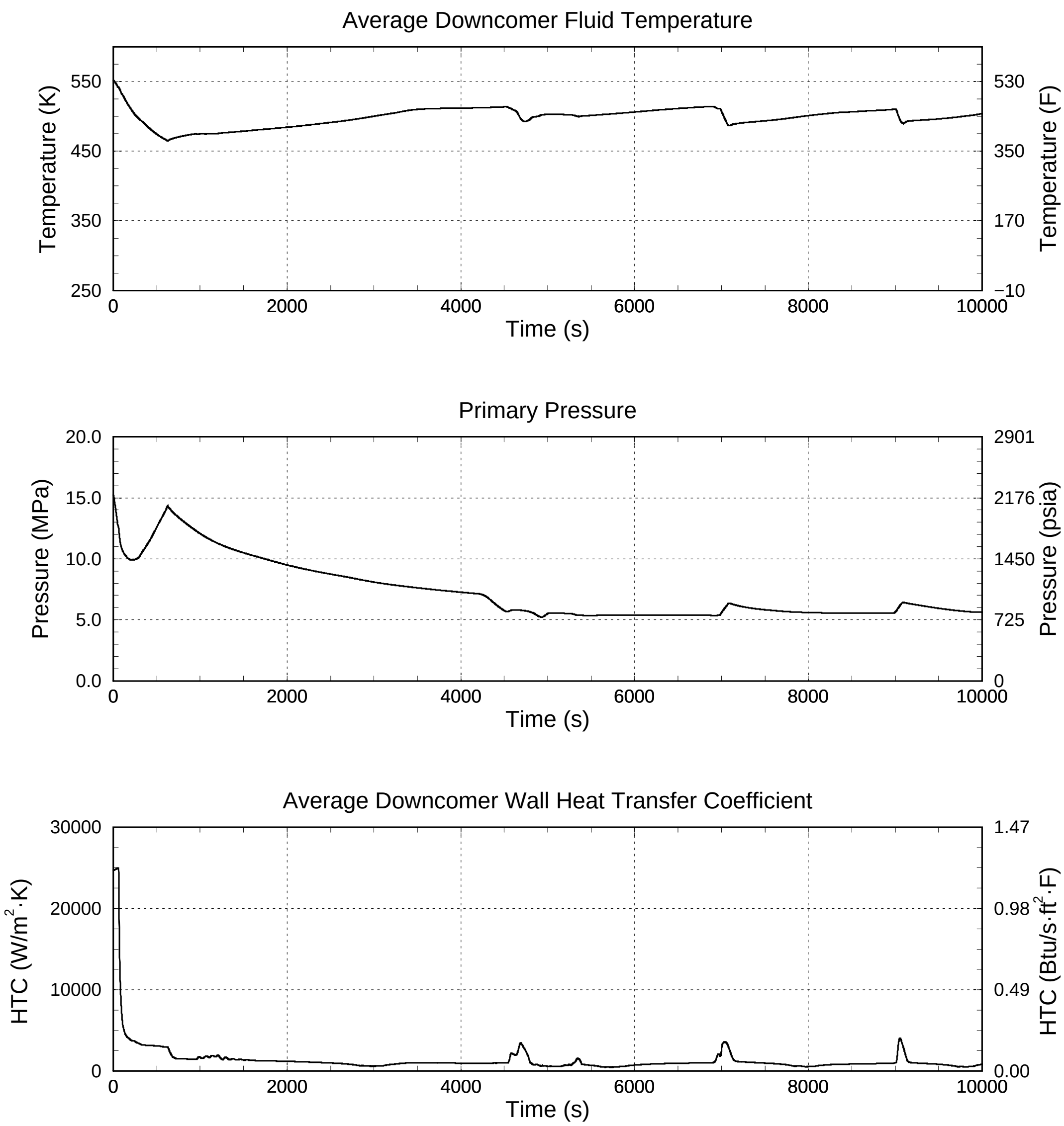


Figure A-49 Oconee PTS Results for Case 127

Case Category	LOCA-Hi K, HZP
Primary Failures	7.18 cm (2.828 in) surge line break
Secondary Failures	None
Operator Actions	None
Min DC Temperature	295.7 K [72.6°F] at 10000 s
Comments	None.

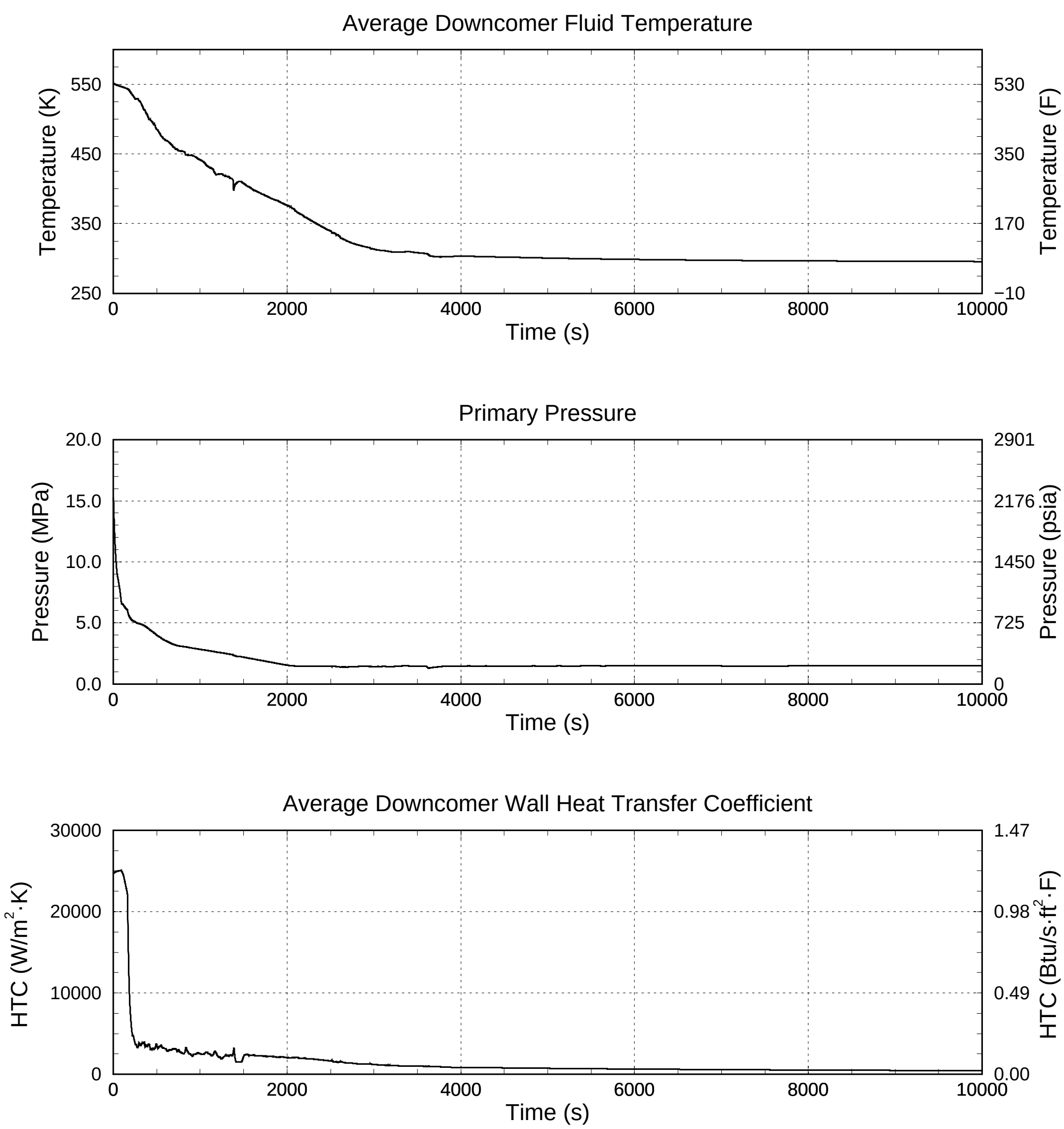


Figure A-50   Oconee PTS Results for Case 128

Case Category	LOCA-HiK, HZP
Primary Failures	10.16 cm (4 inch) surge line break
Secondary Failures	None
Operator Actions	None
Min DC Temperature	294.9 K [71.2°F] at 10000 s
Comments	None.

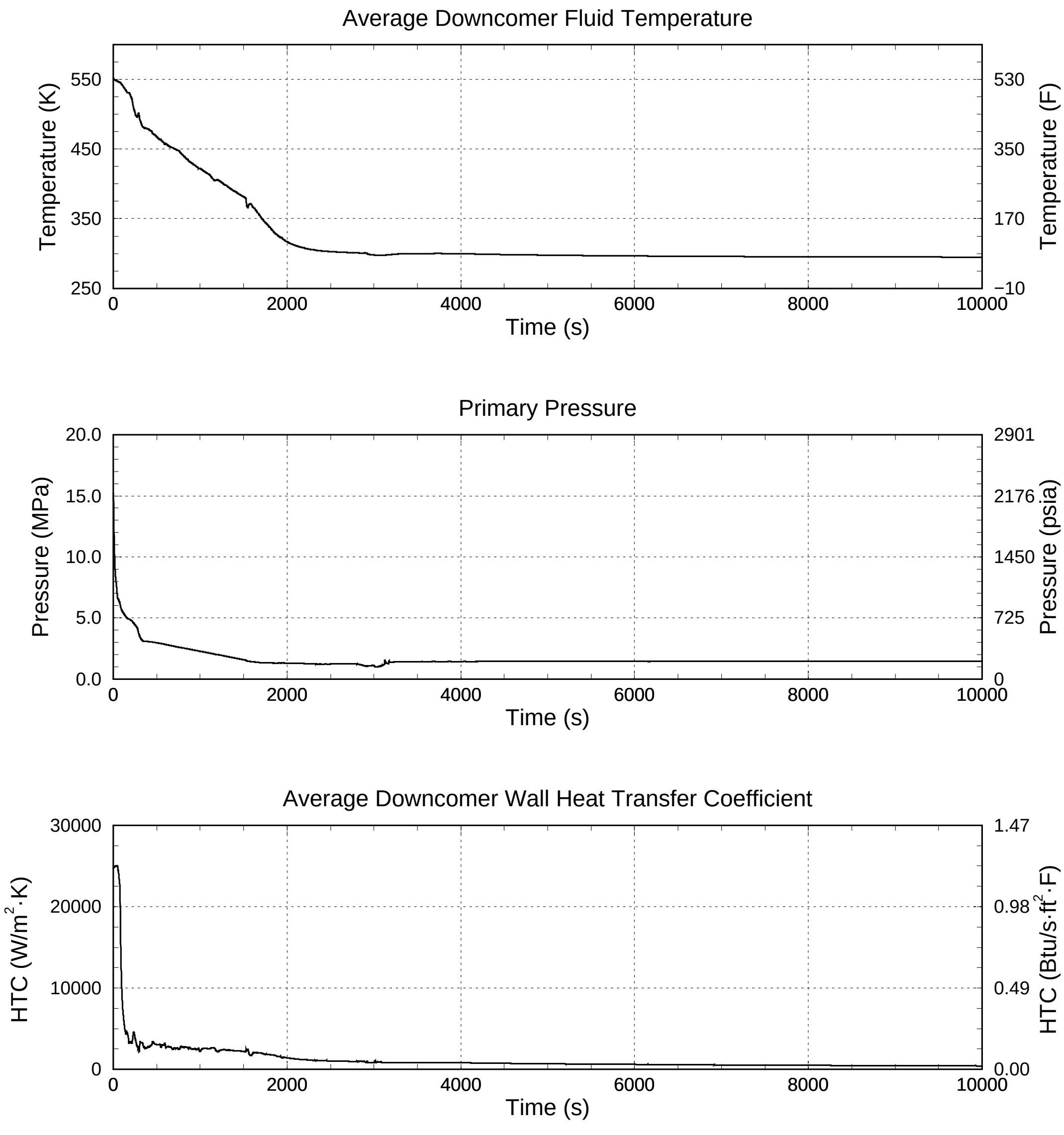
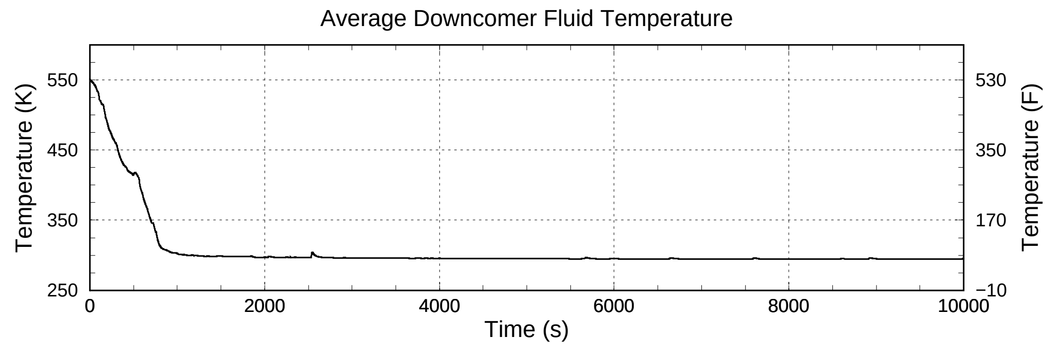
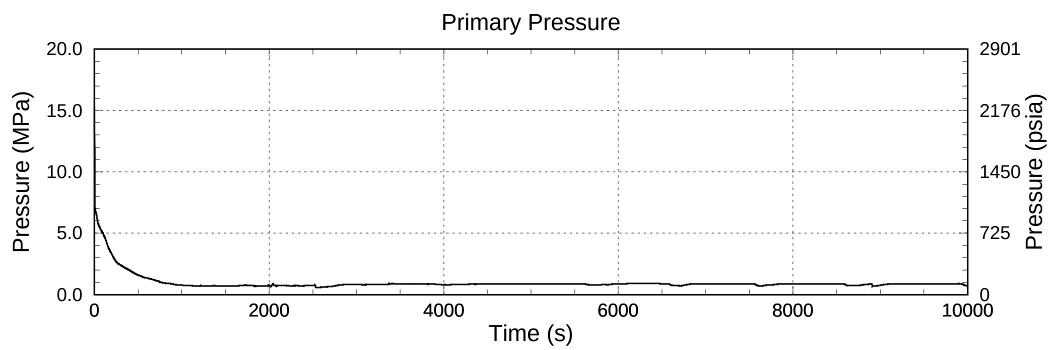


Figure A-51 Oconee PTS Results for Case 133

Case Category	LOCA-Hi K, HZP
Primary Failures	20.32 cm (8 inch) surge line break
Secondary Failures	None
Operator Actions	None
Min DC Temperature	294.4 K [70.3°F] at 9973 s
Comments	None.





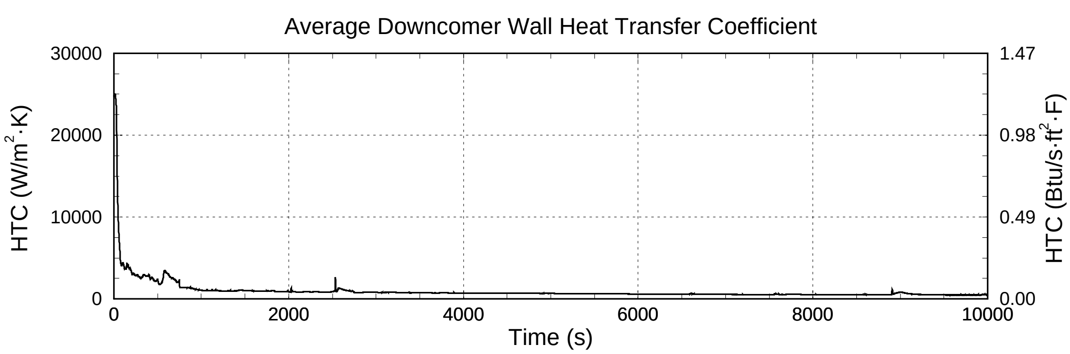


Figure A-52 Oconee PTS Results for Case 134

Case Category	TT/RT
Primary Failures	TT/RT with stuck open pzr SRV. Summer conditions assumed (HPI, LPI temp = 302 K (85°F) and CFT temp = 310 K (100°F)).
Secondary Failures	None
Operator Actions	None
Min DC Temperature	362.1 K [192.2°F] at 10000 s
Comments	None.

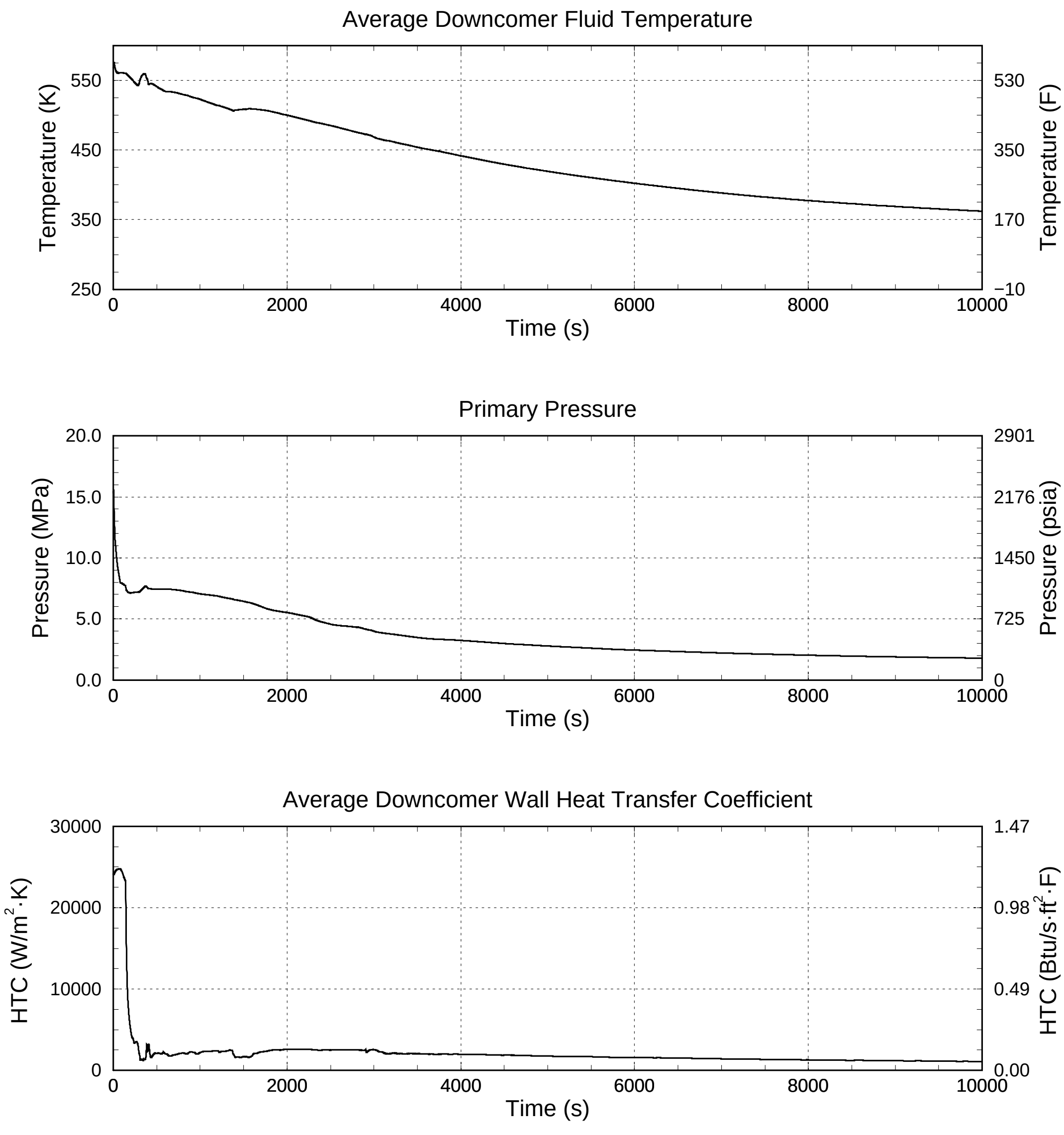


Figure A-53 Oconee PTS Results for Case 138

Case Category	TT/RT
Primary Failures	TT/RT with stuck open pzr SRV. SRV assumed to reclose at 3000 secs. Operator does not throttle HPI.
Secondary Failures	None
Operator Actions	None
Min DC Temperature	457.4 K [363.7°F] at 3207 s
Comments	None.

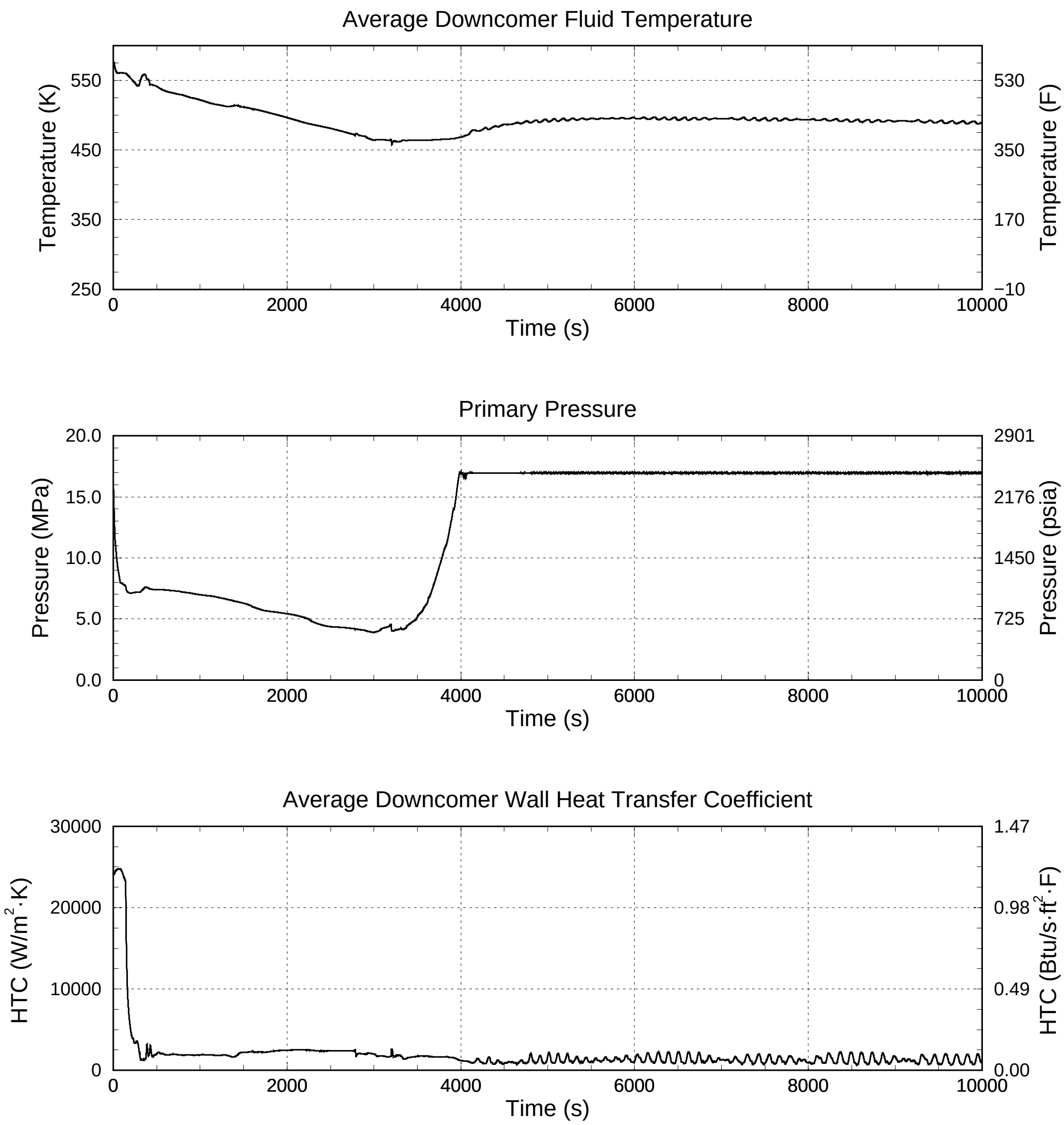


Figure A-54 Oconee PTS Results for Case 140

Case Category	LOCA-HiK
Primary Failures	8.19 cm (3.22 in) surge line break (Break flow area increased by 30% from 7.18 cm (2.828 in) break).
Secondary Failures	None
Operator Actions	None
Min DC Temperature	296.2 K [73.4°F] at 10000 s
Comments	None.

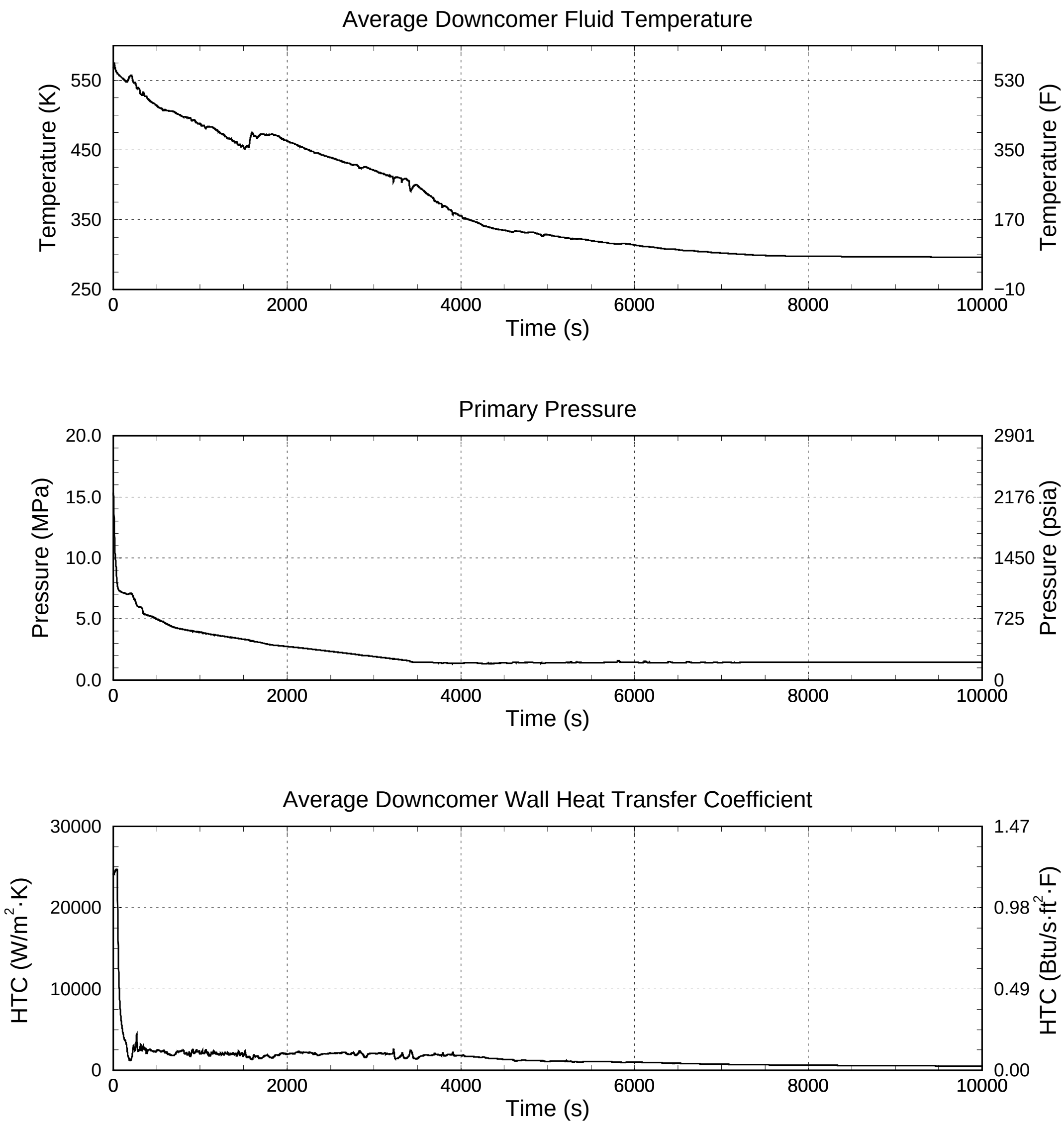
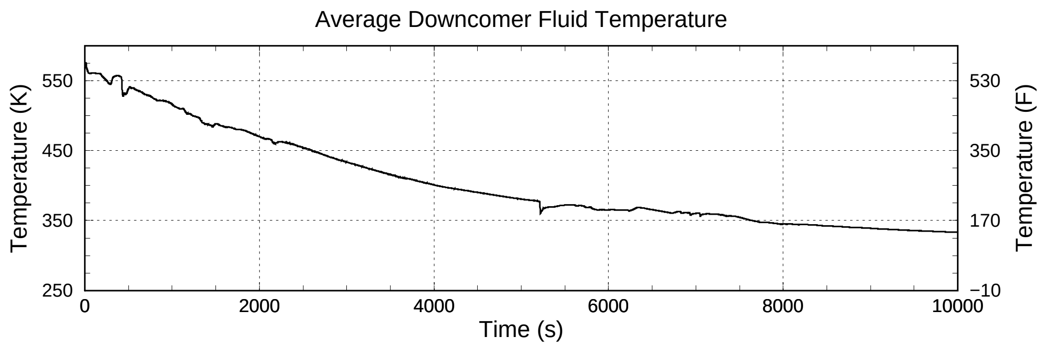
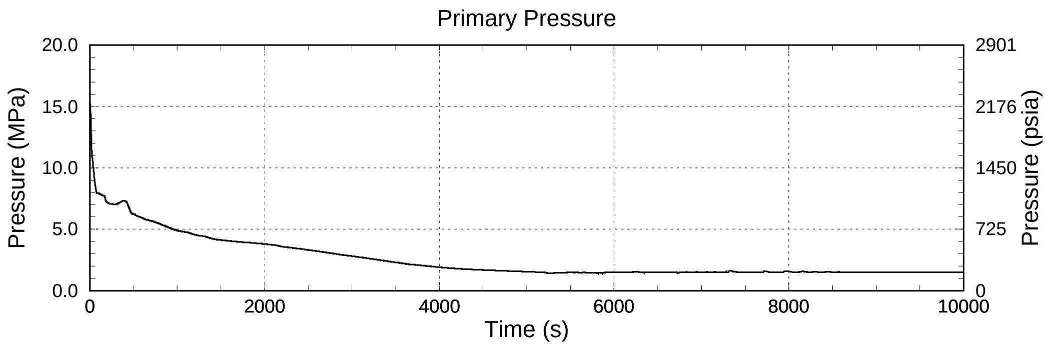


Figure A-55 Oconee PTS Results for Case 141

Case Category	LOCA-HiK
Primary Failures	6.01 cm (2.37 in) surge line break (Break flow area decreased by 30% from 7.18 cm (2.828 in) break).
Secondary Failures	None
Operator Actions	None
Min DC Temperature	333.1 K [140.0°F] at 10000 s
Comments	None.





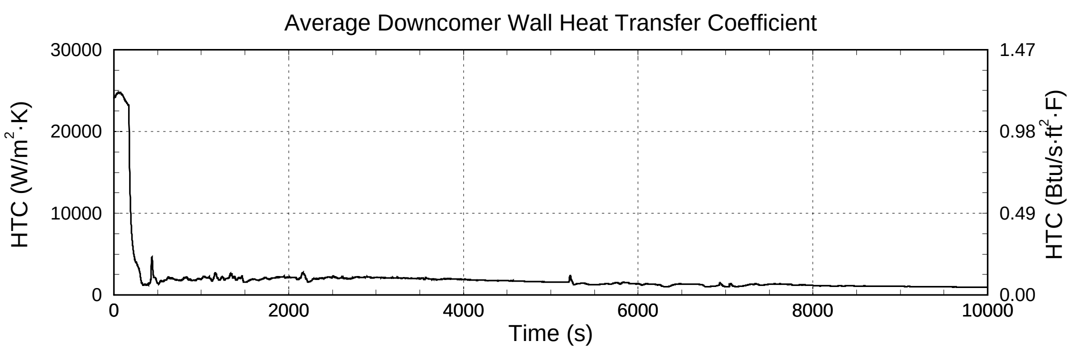


Figure A-56 Oconee PTS Results for Case 142

Case Category	LOCA-HiK
Primary Failures	4.34 cm (1.71 in) surge line break (Break flow area increased by 30% from 3.81 cm (1.5 in) break). Winter conditions assumed (HPI, LPI temp = 277 K (40°F) and CFT temp = 294 K (70°F)).
Secondary Failures	None
Operator Actions	None
Min DC Temperature	470.0 K [386.3°F] at 9987 s
Comments	None.

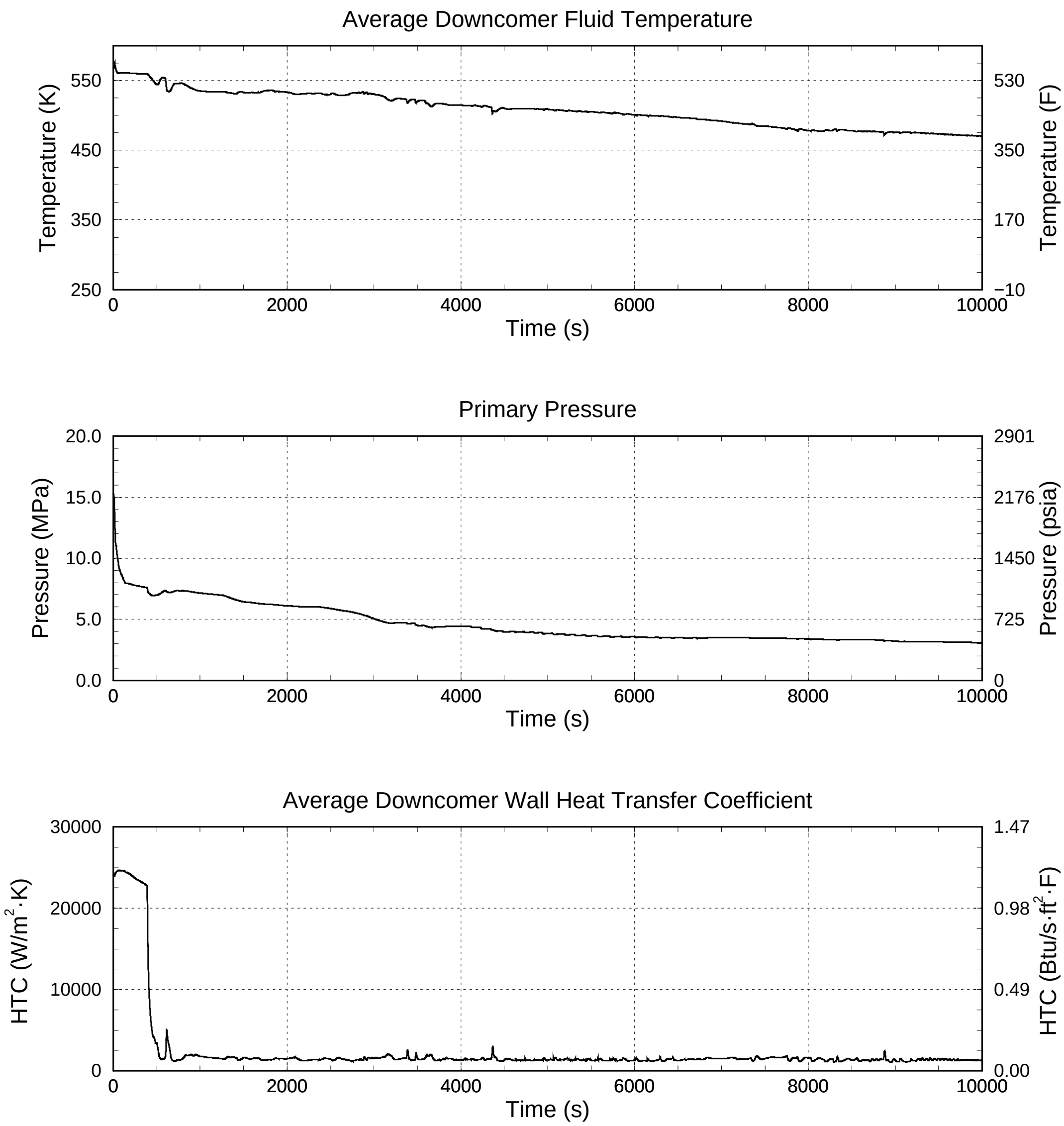


Figure A-57 Oconee PTS Results for Case 145

Case Category	TT/RT-HiK
Primary Failures	TT/RT with stuck open pzr SRV (valve flow area reduced by 30 percent). Summer conditions assumed (HPI, LPI temp = 302 K (85°F) and CFT temp = 310 K (100°F)). Vent valves do not function.
Secondary Failures	None
Operator Actions	None
Min DC Temperature	313.8 K [105.2°F] at 10000 s
Comments	None.

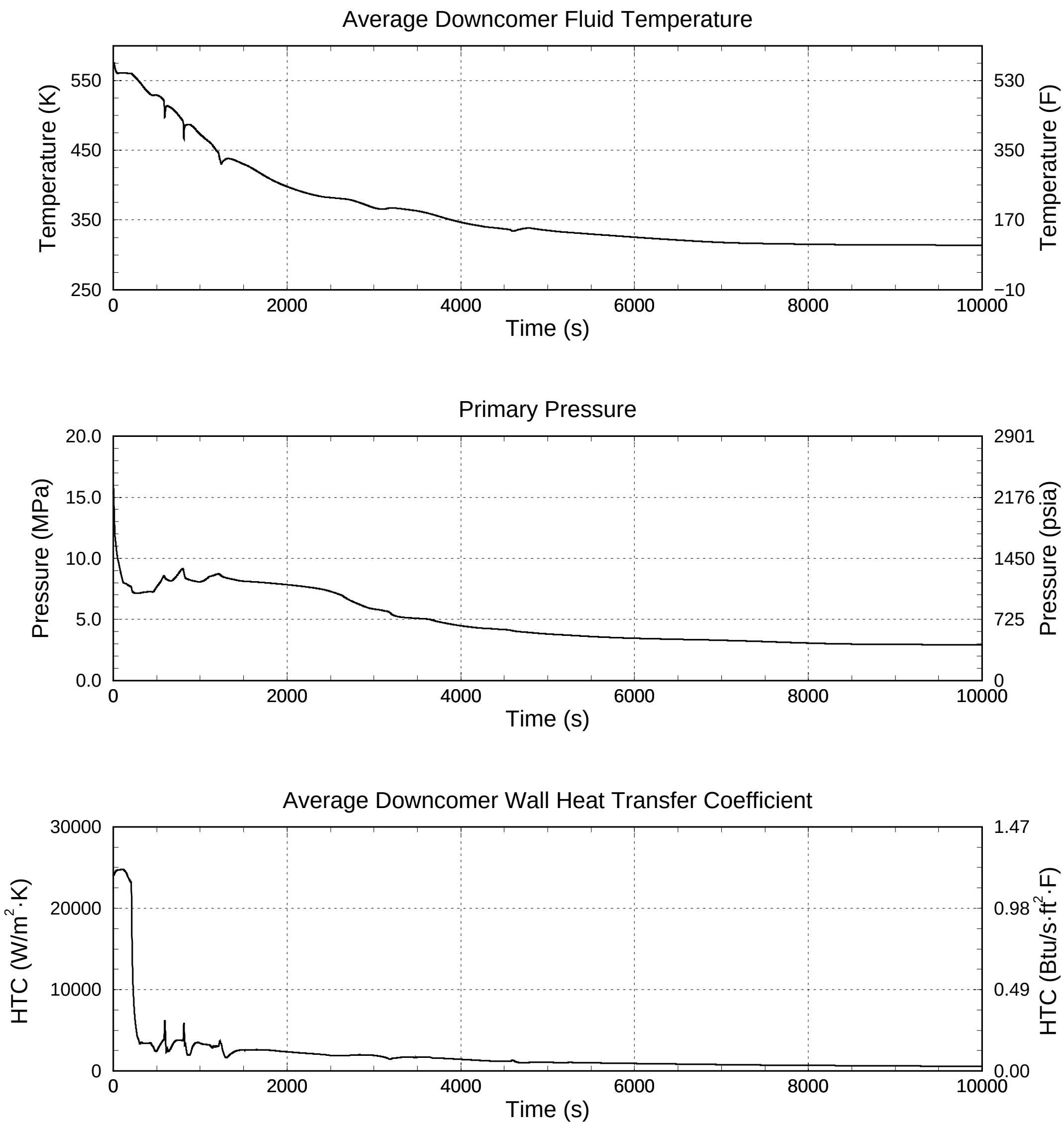


Figure A-58 Oconee PTS Results for Case 146

Case Category	TT/RT-Hi K
Primary Failures	TT/RT with stuck open pzr SRV. Summer conditions assumed (HPI, LPI temp = 302 K (85°F) and CFT temp = 310 K (100°F)).
Secondary Failures	None
Operator Actions	None
Min DC Temperature	355.8 K [180.8°F] at 10000 s
Comments	None.

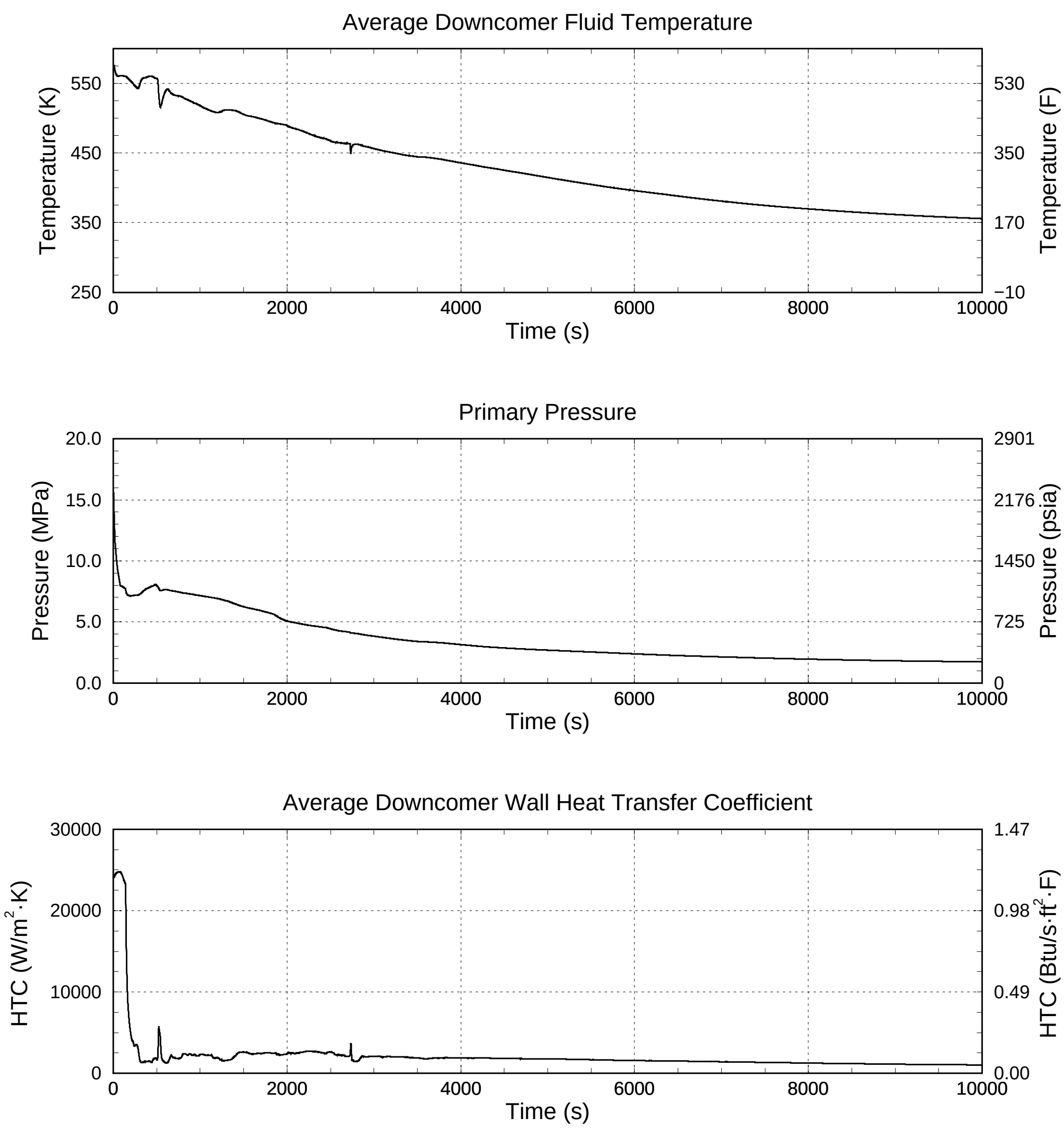


Figure A-59 Oconee PTS Results for Case 147

Case Category	TT/RT-Hi K
Primary Failures	TT/RT with partially stuck open pzr SRV (flow area equivalent to 1.5 in diameter opening). HTC coefficients increased by 1.3.
Secondary Failures	None
Operator Actions	None
Min DC Temperature	364.5 K [196.5°F] at 10000 s
Comments	None.

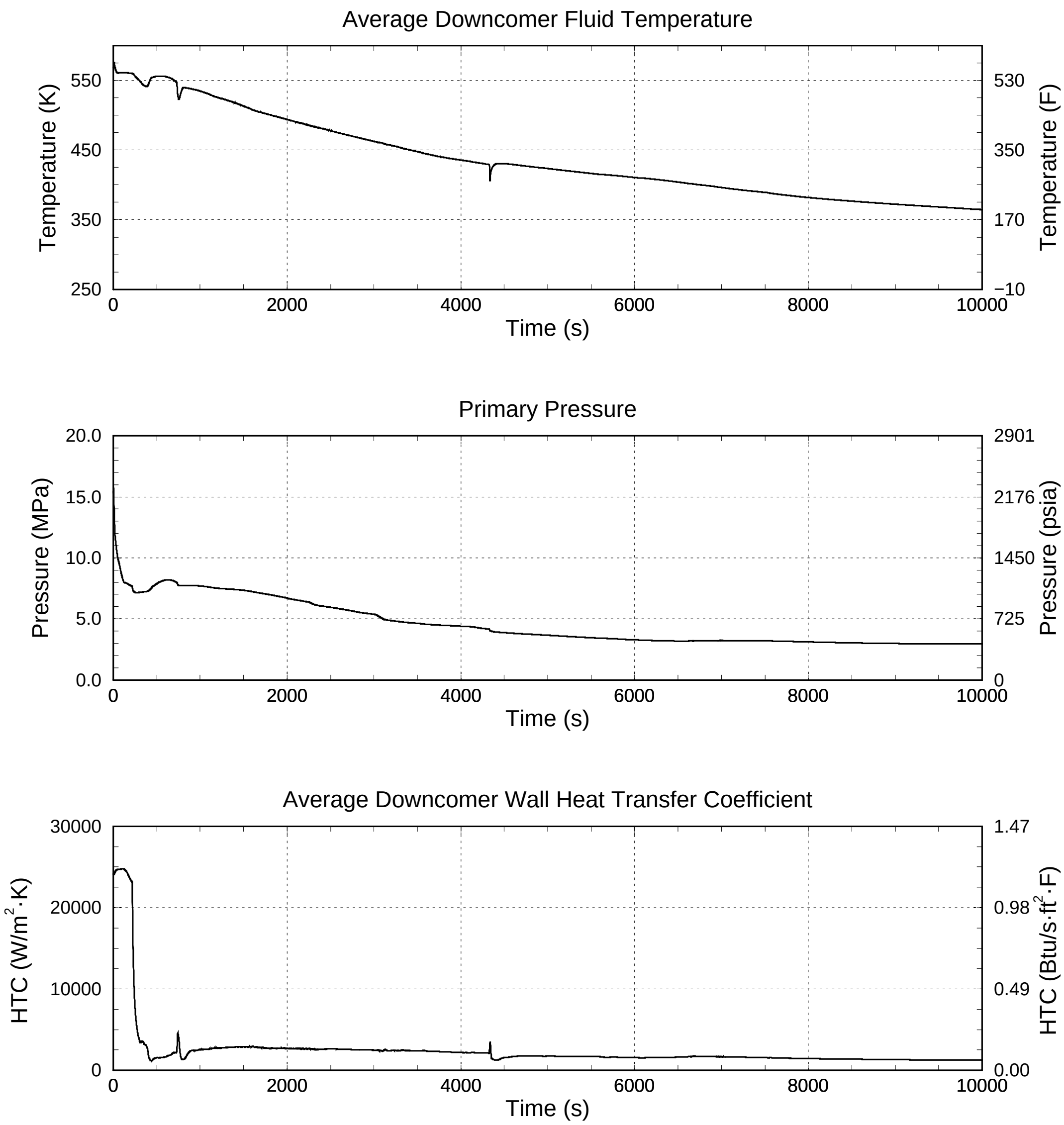


Figure A-60 Oconee PTS Results for Case 148

Case Category	TT/RT-Hi K
Primary Failures	TT/RT with stuck open pzr SRV. SRV assumed to reclose at 3000 secs. Operator does not throttle HPI.
Secondary Failures	None
Operator Actions	None
Min DC Temperature	433.8 K [321.3°F] at 3011 s
Comments	None.

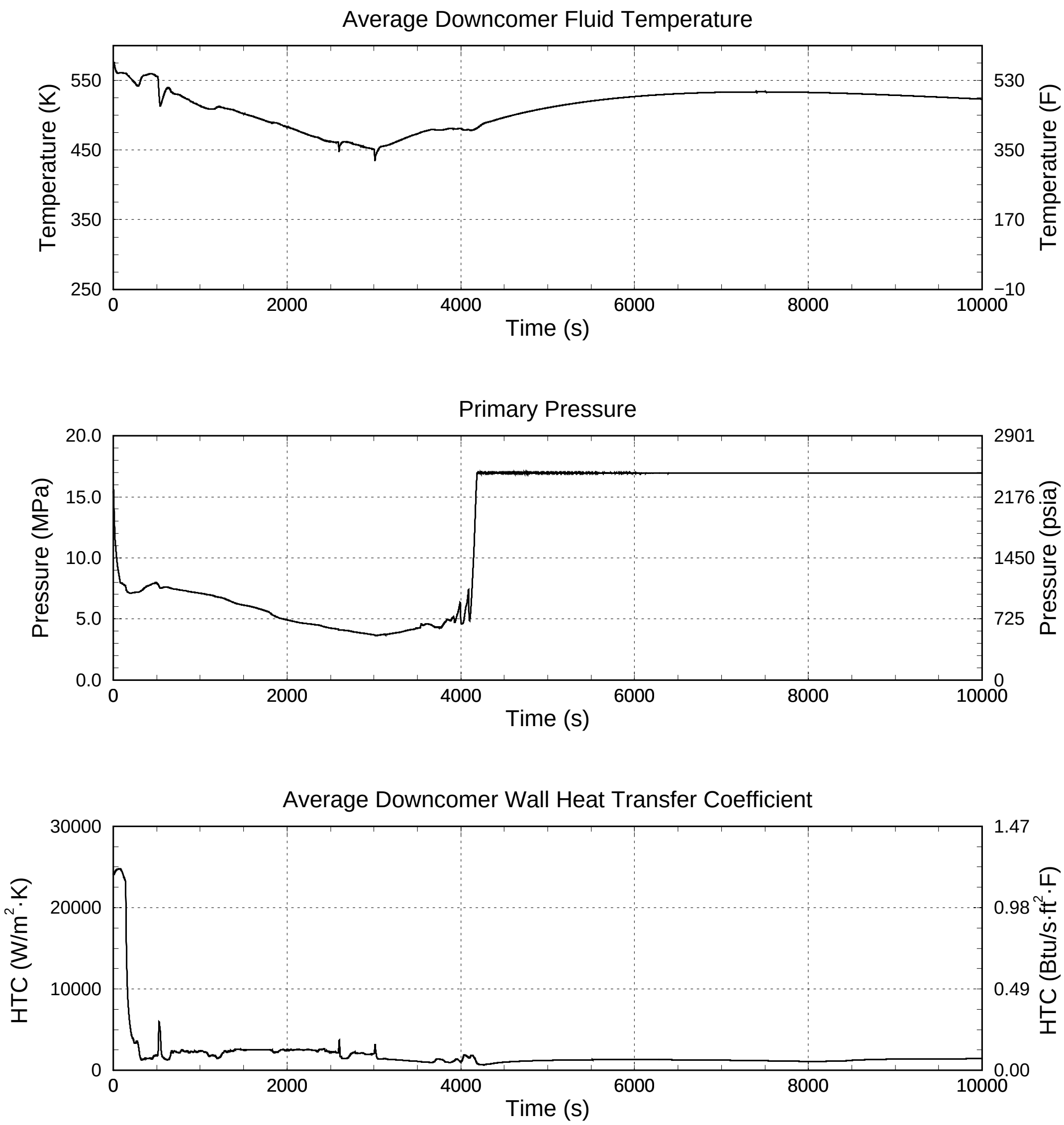


Figure A-61 Oconee PTS Results for Case 149

Case Category	LOCA-HiK
Primary Failures	8.53 cm (3.36 in) surge line break (Break flow area reduced by 30% from 10.16 cm (4 in) break). Vent valves do not function. ECC suction switch to the containment sump included in the analysis.
Secondary Failures	None
Operator Actions	None
Min DC Temperature	301.9 K [83.7°F] at 4623 s
Comments	None.

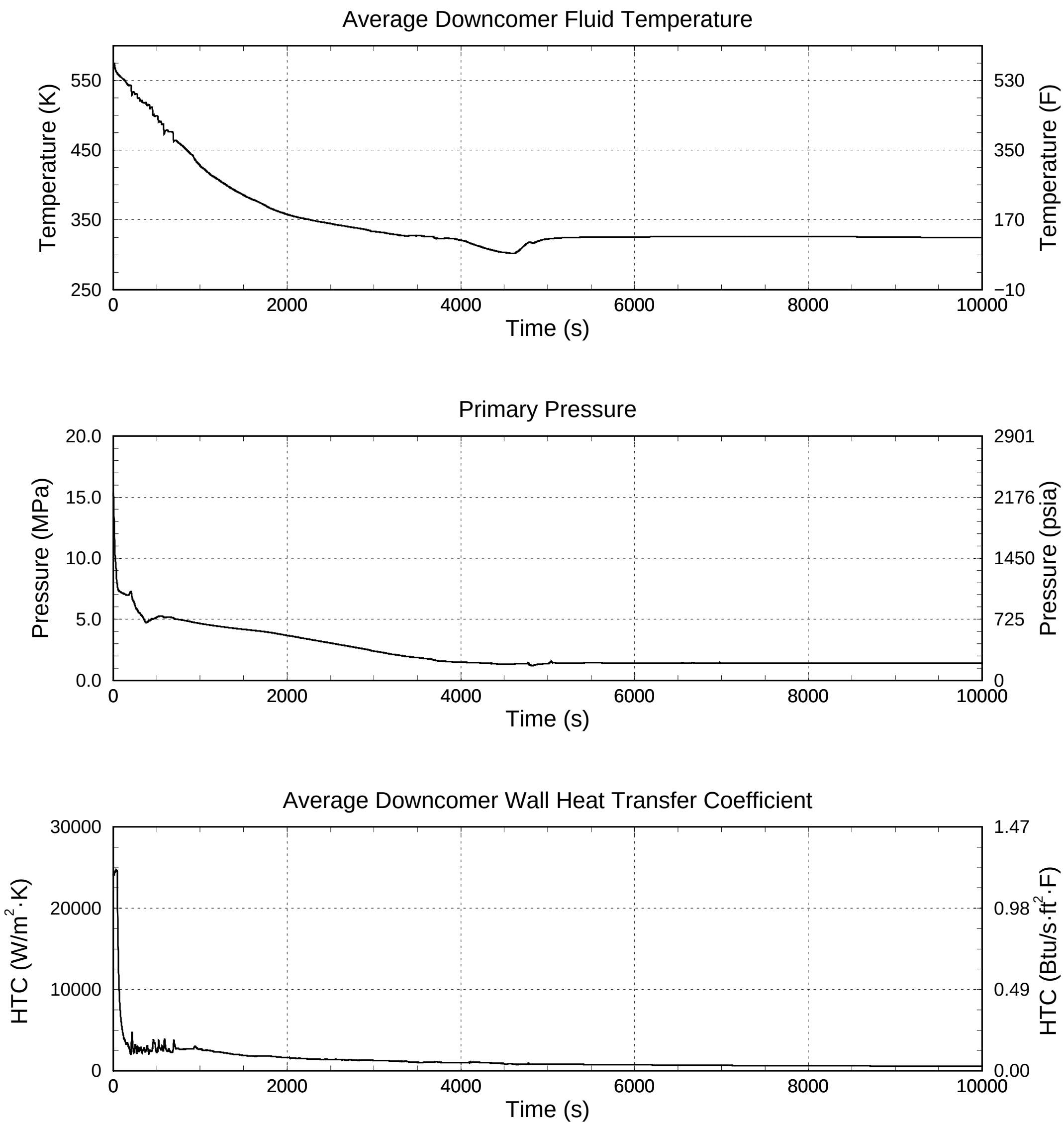
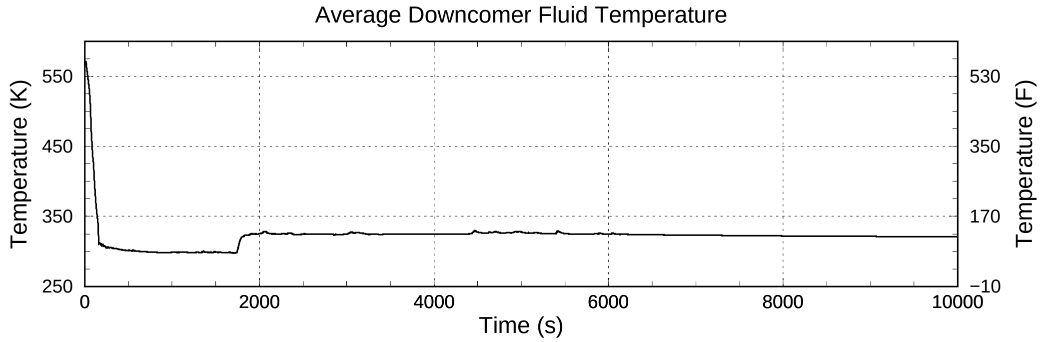
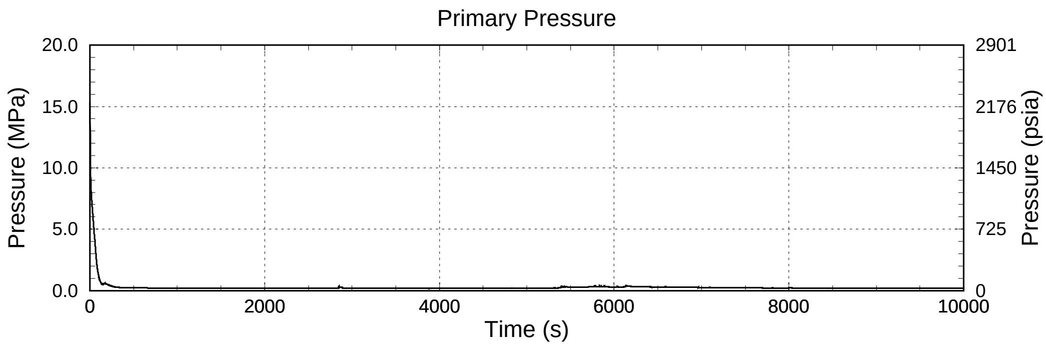


Figure A-62 Oconee PTS Results for Case 154

Case Category	LOCA-HiK
Primary Failures	40.64 cm (16 in) hot leg break. ECC suction switch to the containment sump included in the analysis.
Secondary Failures	None
Operator Actions	None
Min DC Temperature	297.8 K [76.4°F] at 1721 s
Comments	None.





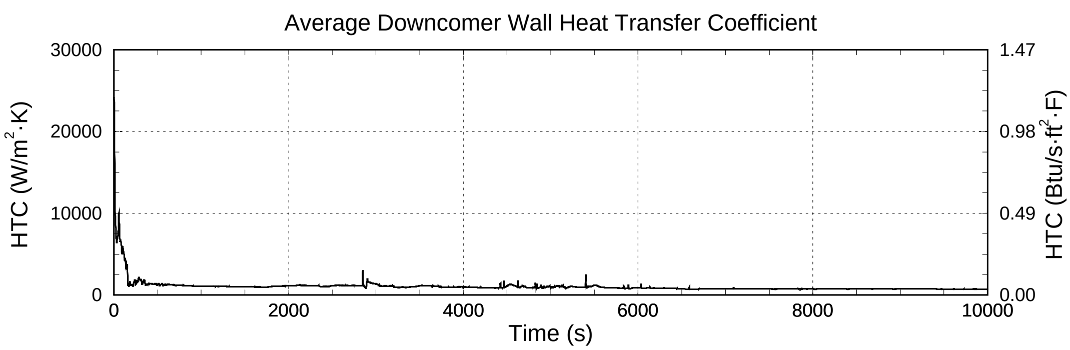


Figure A-63 Oconee PTS Results for Case 156

Case Category	LOCA-HiK
Primary Failures	14.37 cm (5.656 in) surge line break. ECC suction switch to the containment sump included in the analysis.
Secondary Failures	None
Operator Actions	None
Min DC Temperature	298.9 K [78.3°F] at 2889 s
Comments	None.

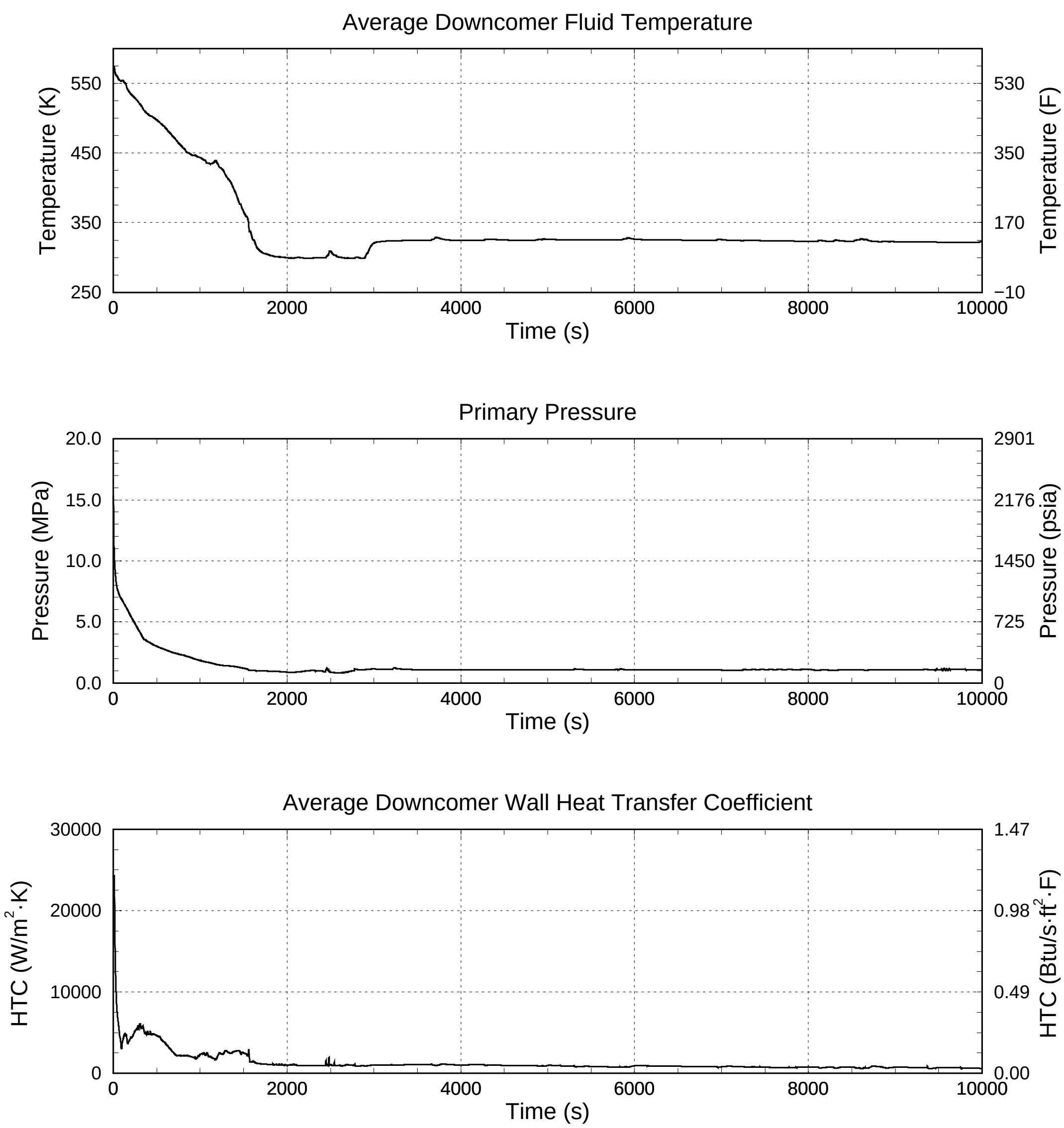


Figure A-64 Oconee PTS Results for Case 160

Case Category	LOCA-HiK, HZP
Primary Failures	14.366 cm (5.656 in) surge line break. ECC suction switch to the containment sump included in the analysis.
Secondary Failures	None
Operator Actions	None
Min DC Temperature	297.8 K [76.4°F] at 1986 s
Comments	None.

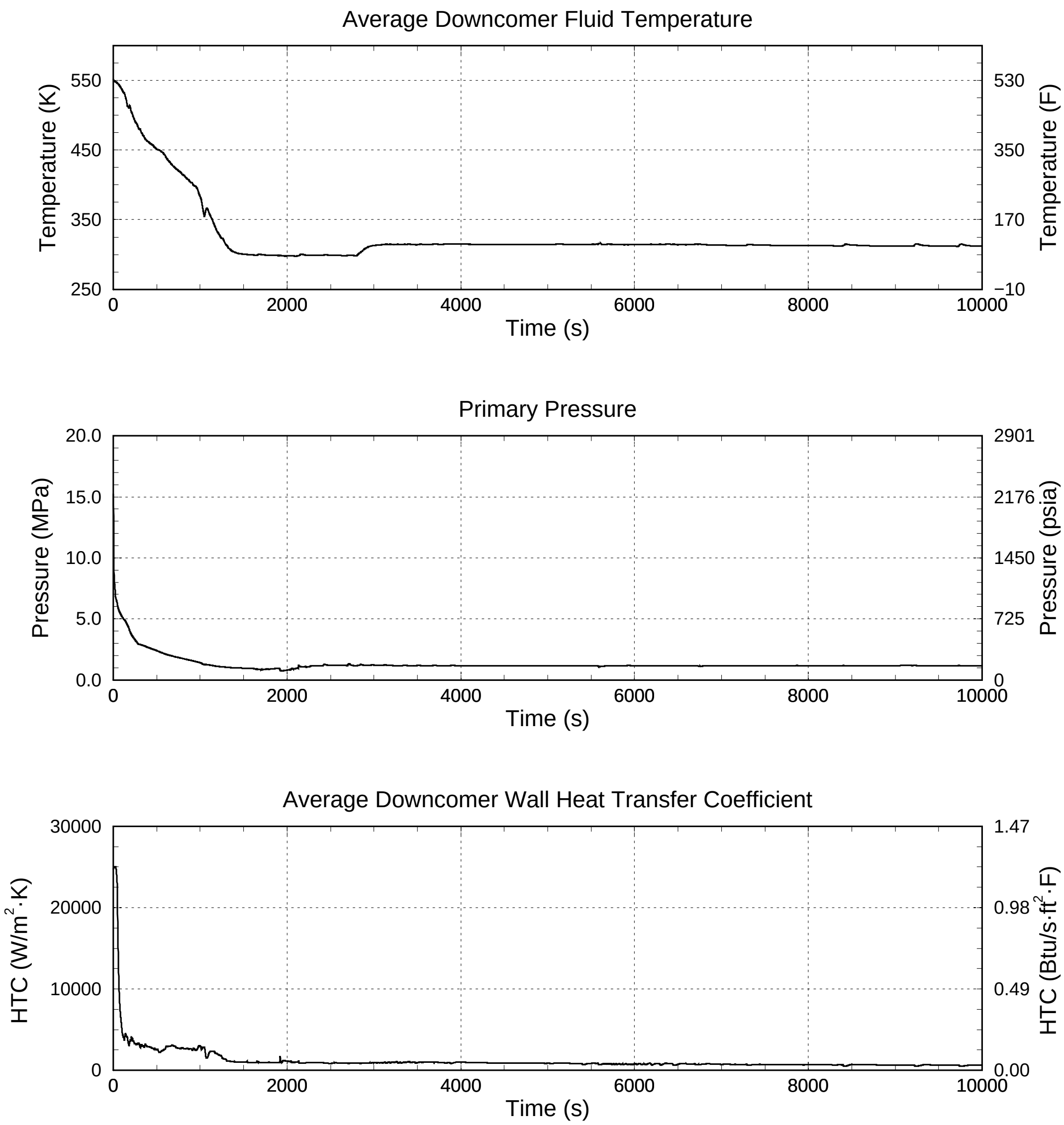


Figure A-65 Oconee PTS Results for Case 162

Case Category	LOCA-HiK
Primary Failures	20.32 cm (8 inch) surge line break. ECC suction switch to the containment sump included in the analysis.
Secondary Failures	None
Operator Actions	None
Min DC Temperature	296.7 K [74.3°F] at 2169 s
Comments	None.

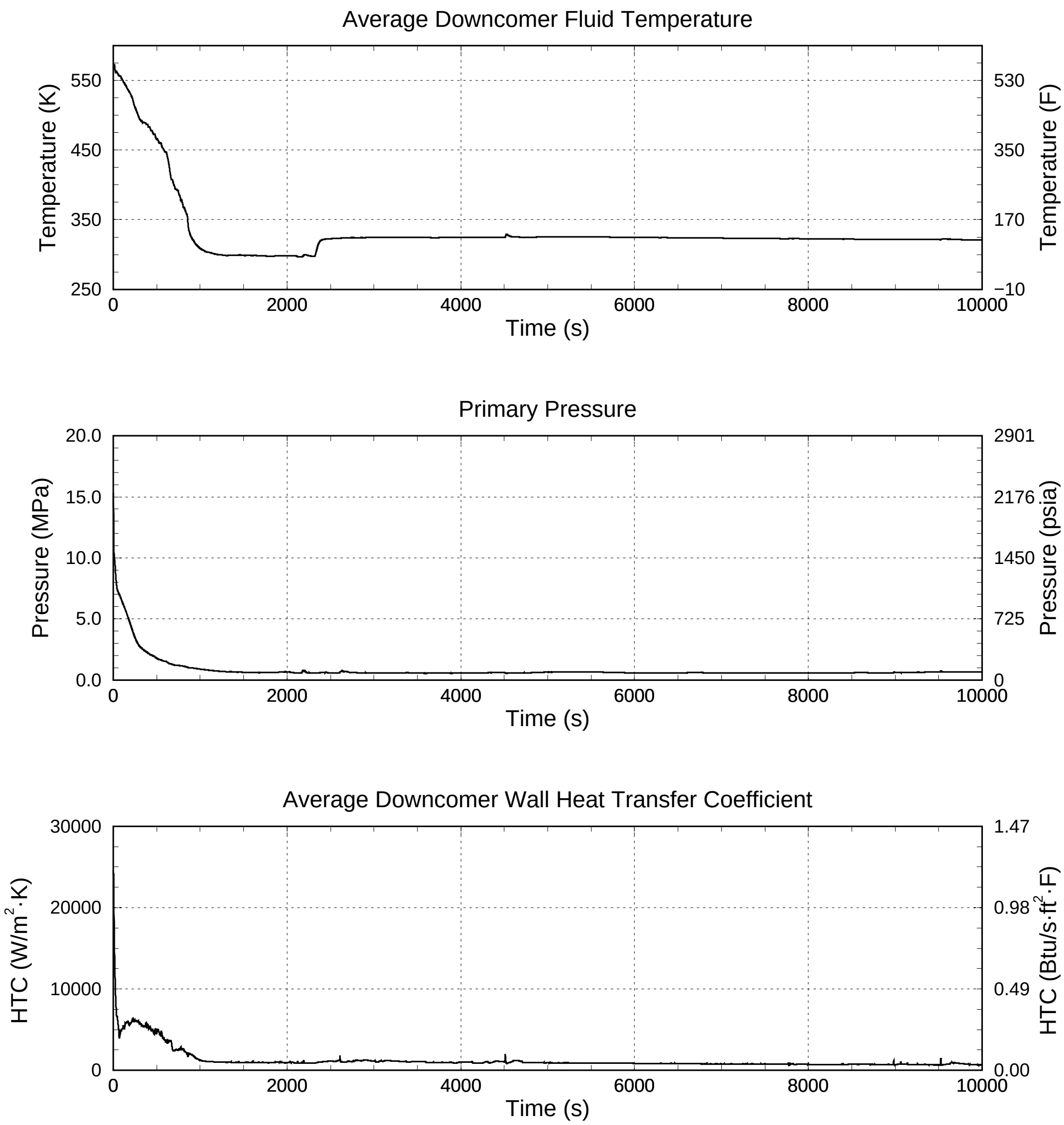
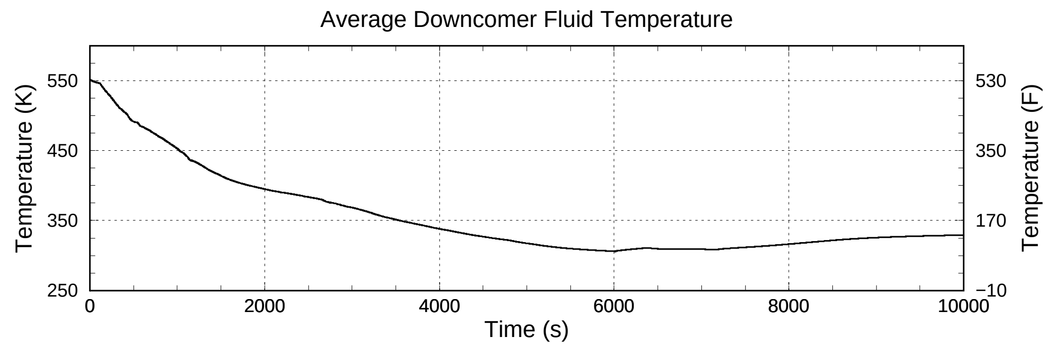
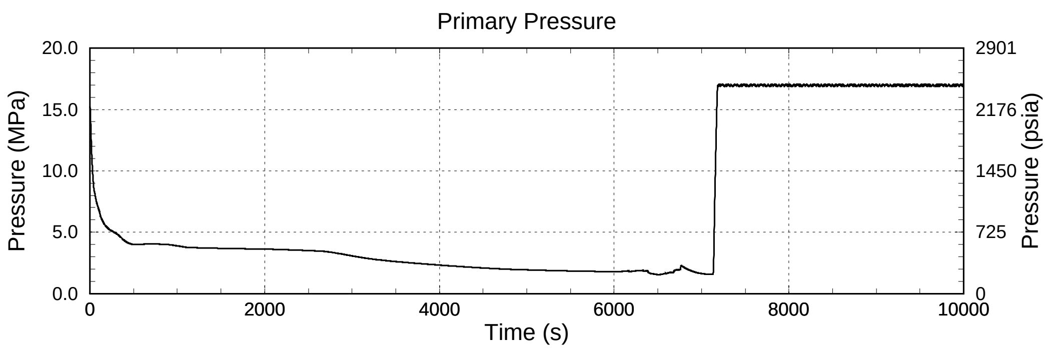


Figure A-66 Oconee PTS Results for Case 164

Case Category	TT/RT-Hi K, HZP
Primary Failures	Stuck open pressurizer safety valve. Valve recloses at 6000 secs (RCS low pressure point).
Secondary Failures	None
Operator Actions	None
Min DC Temperature	305.9 K [90.9°F] at 6010 s
Comments	None.





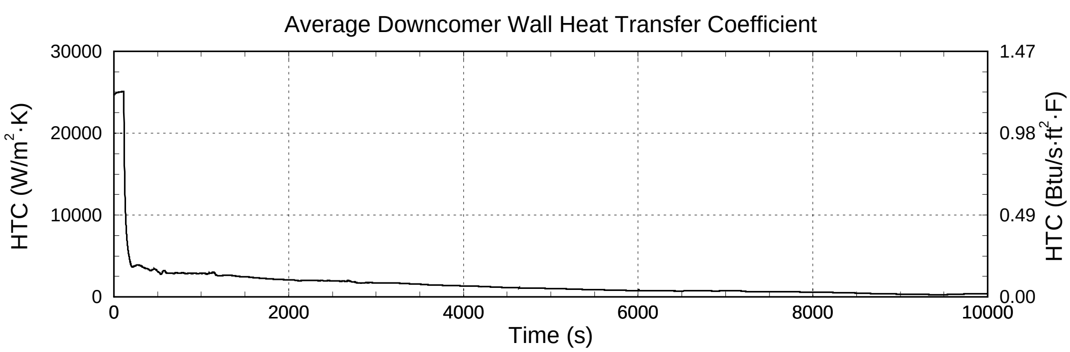
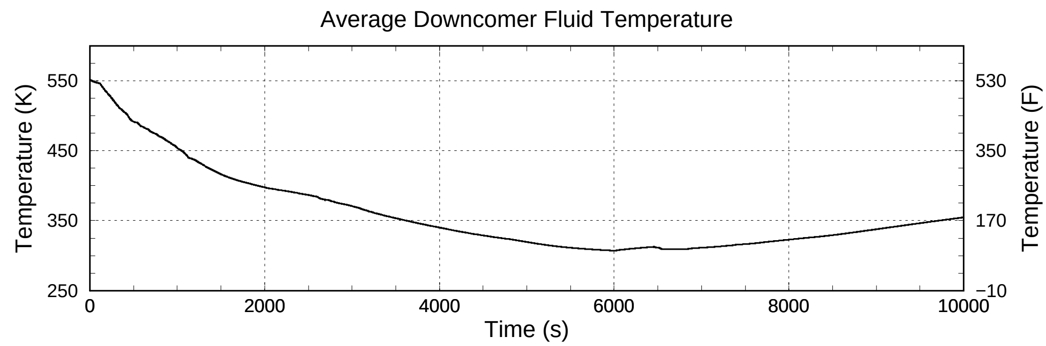
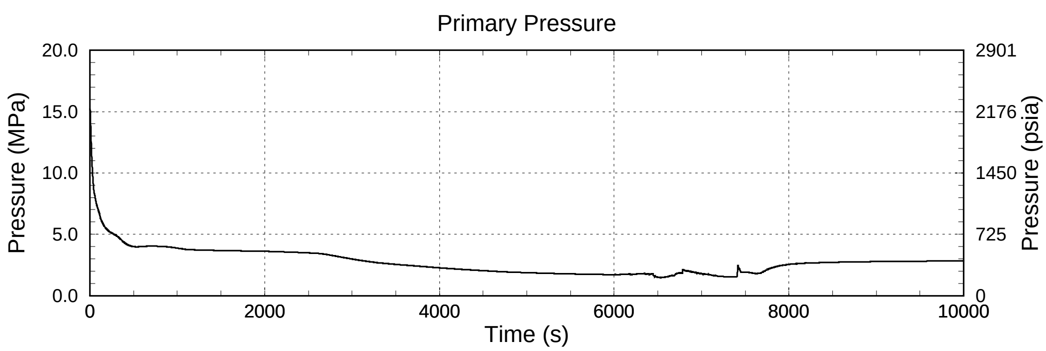


Figure A-67 Oconee PTS Results for Case 165

Case Category	TT/RT-Hi K, HZP
Primary Failures	Stuck open pressurizer safety valve. Valve recloses at 6000 secs.
Secondary Failures	None
Operator Actions	After valve recloses, operator throttles HPI 1 minute after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 50°F subcooling)
Min DC Temperature	306.9 K [92.8°F] at 6010 s
Comments	None.





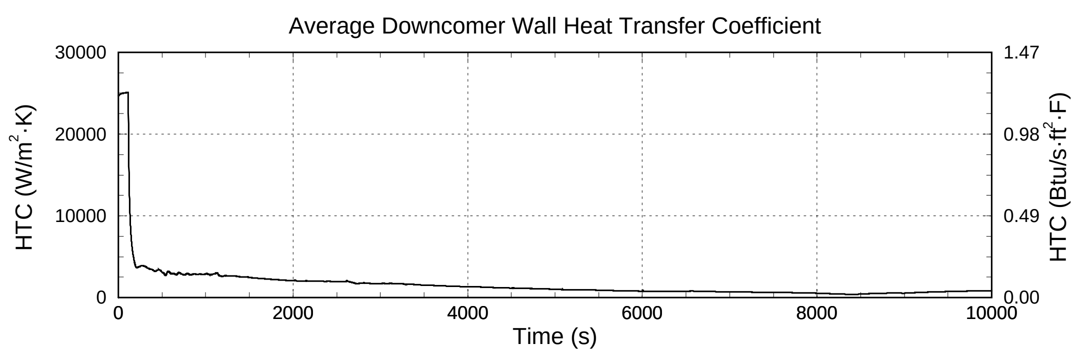


Figure A-68 Oconee PTS Results for Case 166

Case Category	TT/RT-Hi K, HZP
Primary Failures	TT/RT with stuck open pzr SRV. SRV assumed to reclose at 3000 secs. Operator does not throttle HPI.
Secondary Failures	None
Operator Actions	None
Min DC Temperature	357.4 K [183.6°F] at 3571 s
Comments	None.

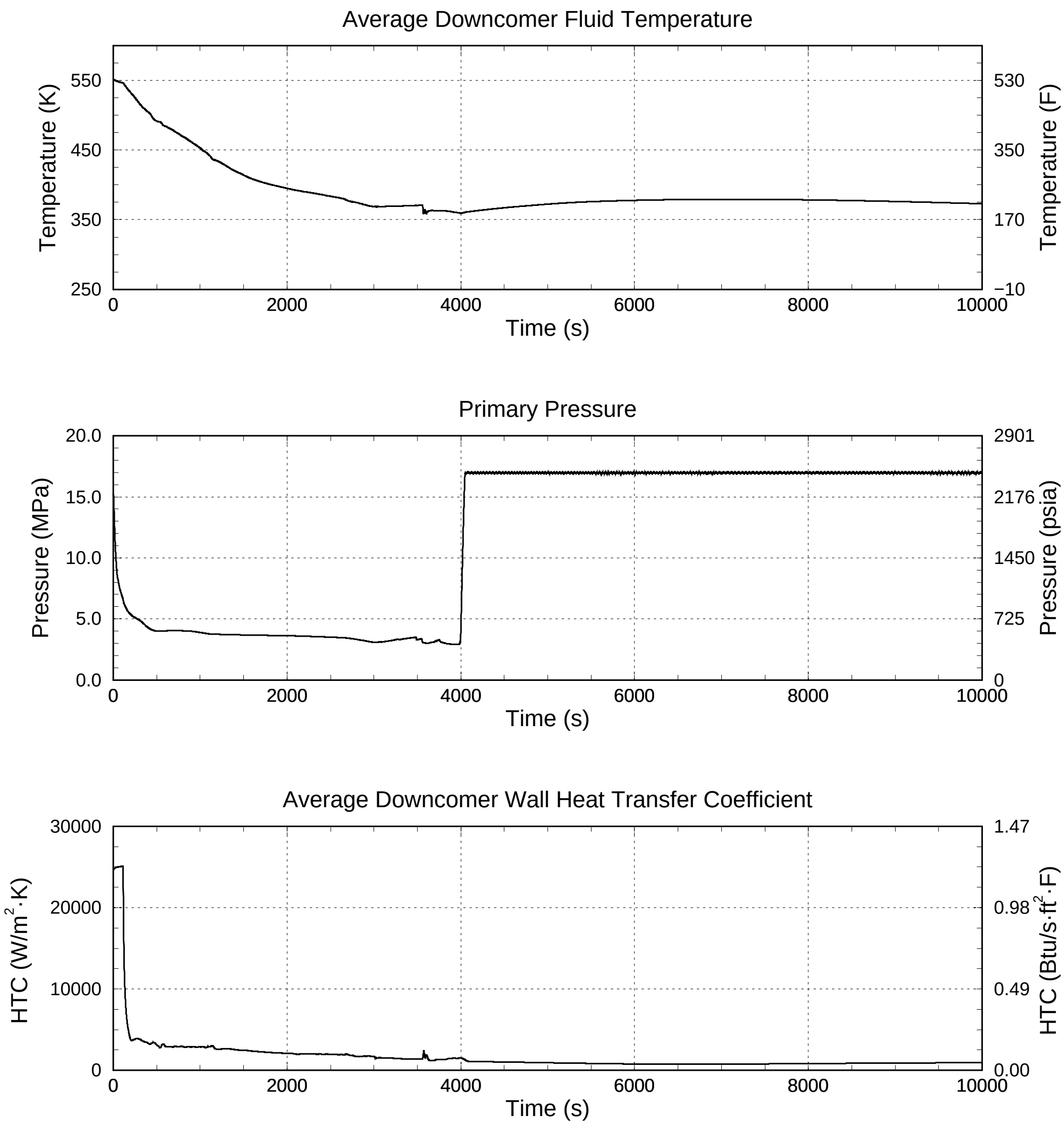


Figure A-69 Oconee PTS Results for Case 168

Case Category	LOCA-HiK, HZP
Primary Failures	TT/RT with stuck open pzr SRV (valve flow area reduced by 30 percent). Summer conditions assumed (HPI, LPI temp = 302 K (85°F) and CFT temp = 310 K (100°F)). Vent valves do not function.
Secondary Failures	None
Operator Actions	None
Min DC Temperature	314.2 K [105.9°F] at 10000 s
Comments	None.

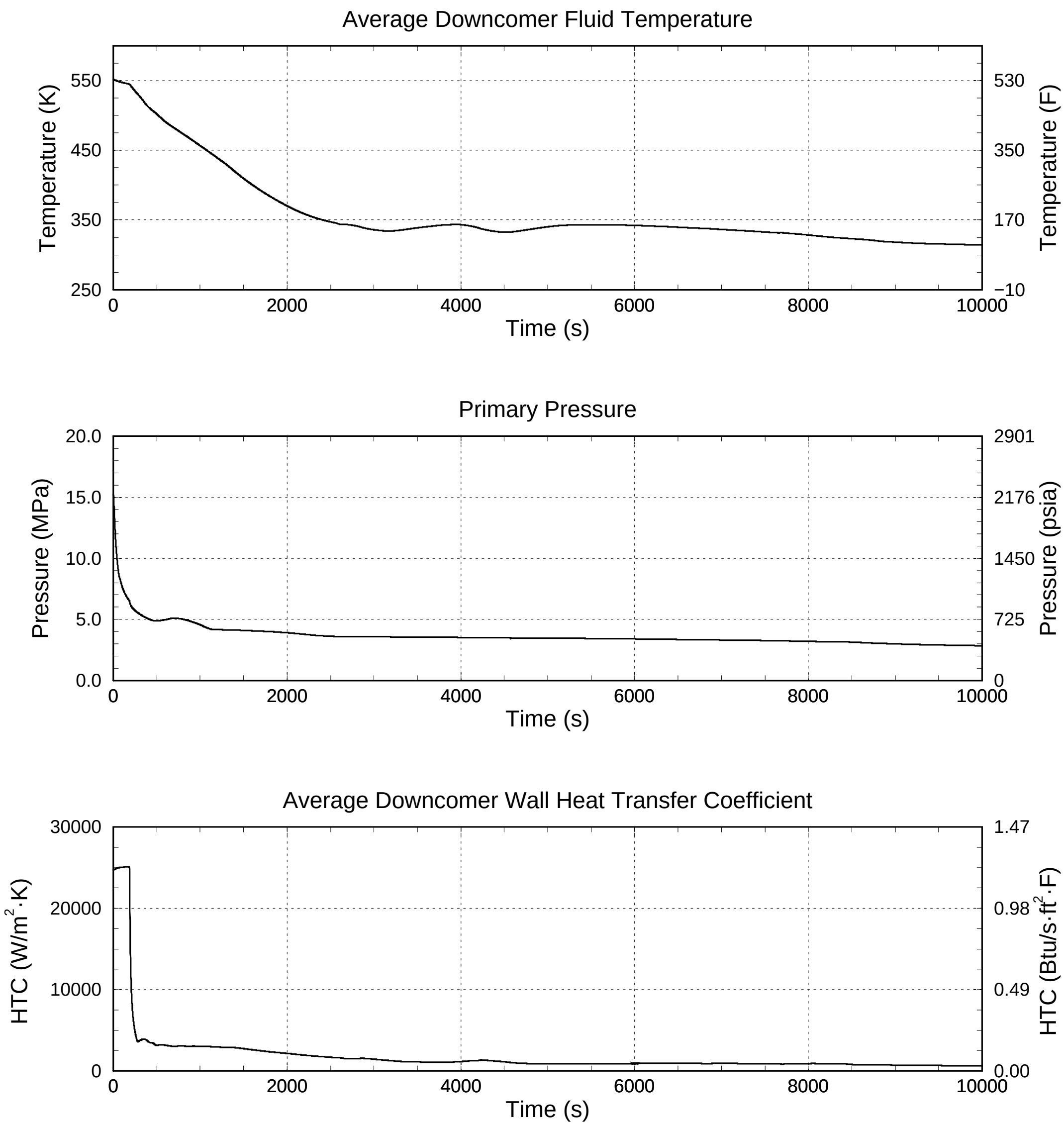


Figure A-70 Oconee PTS Results for Case 169

Case Category	TT/RT-Hi K, HZP
Primary Failures	TT/RT with stuck open pzr SRV. Summer conditions assumed (HPI, LPI temp = 302 K (85°F) and CFT temp = 310 K (100°F)).
Secondary Failures	None
Operator Actions	None
Min DC Temperature	306.2 K [91.5°F] at 10000 s
Comments	None.

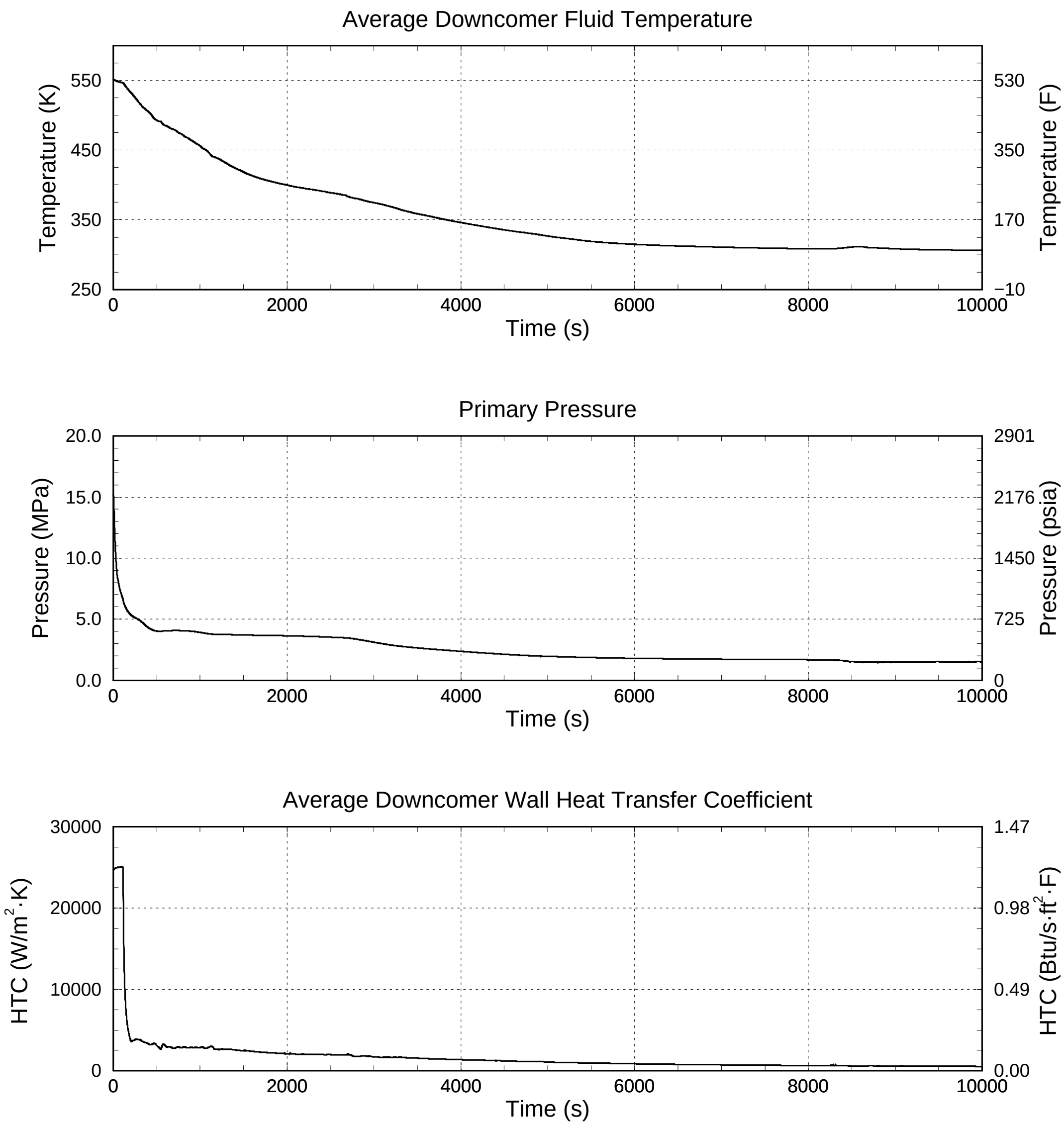


Figure A-71 Oconee PTS Results for Case 170

Case Category	TT/RT-Hi K, HZP
Primary Failures	TT/RT with partially stuck open pzr SRV (flow area equivalent to 1.5 in diameter opening). HTC coefficients increased by 1.3.
Secondary Failures	None
Operator Actions	None
Min DC Temperature	430.2 K [314.7°F] at 10000 s
Comments	None.

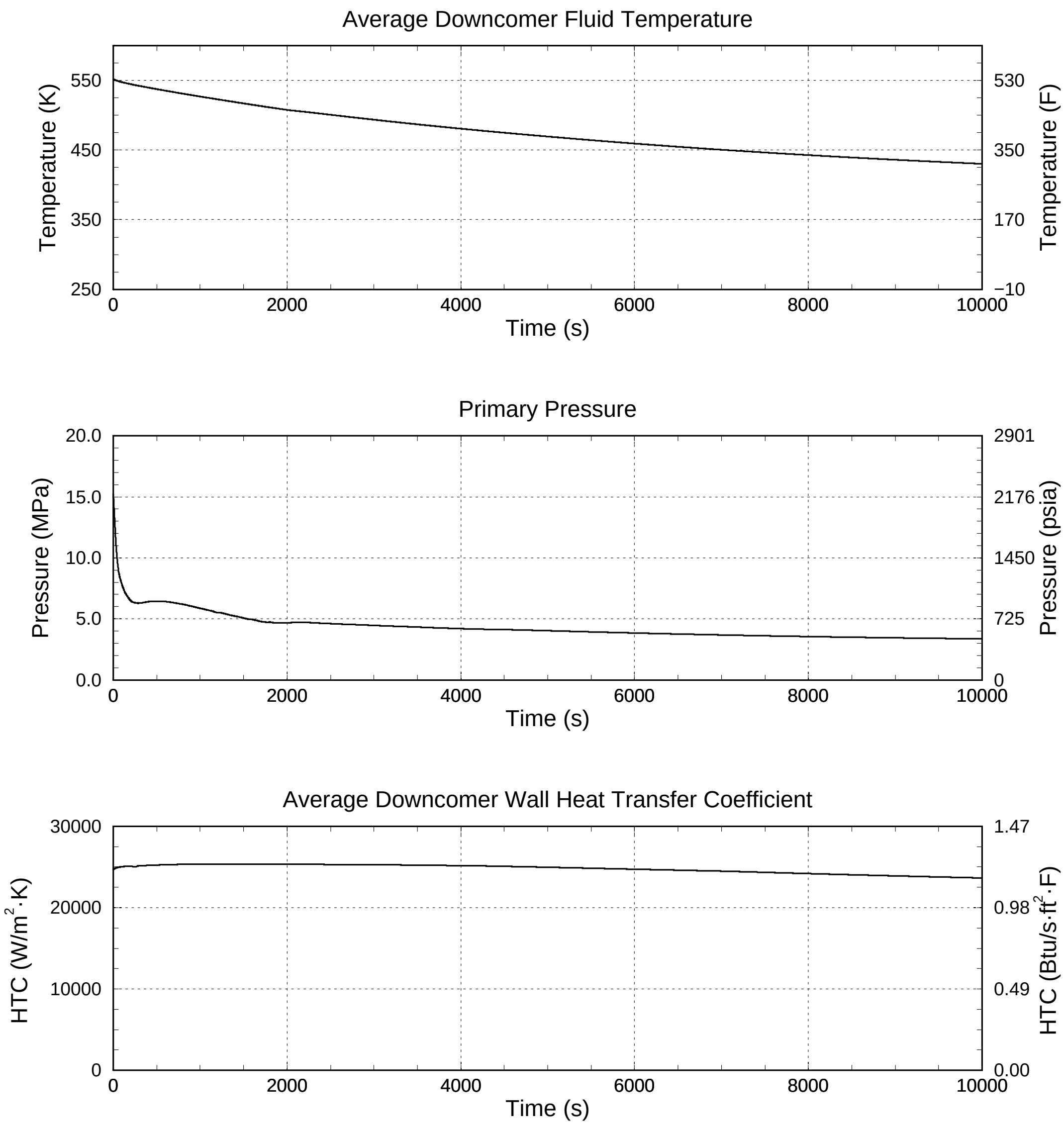


Figure A-72 Oconee PTS Results for Case 171

Case Category	LOCA-HiK
Primary Failures	10.16 cm (4 in) cold leg break. ECC suction switch to the containment sump included in the analysis.
Secondary Failures	None
Operator Actions	None
Min DC Temperature	347.9 K [166.5°F] at 10000 s
Comments	None.

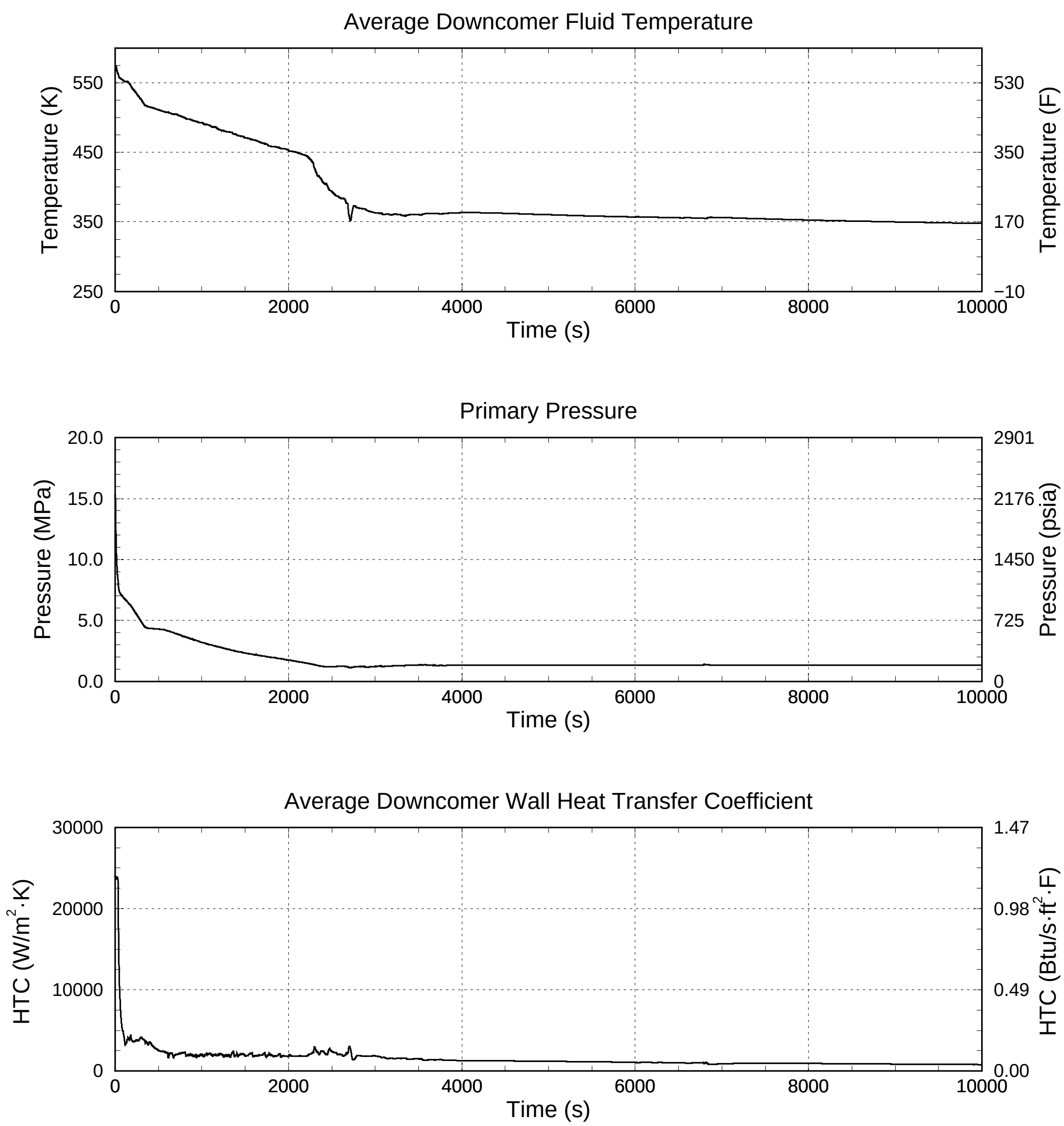
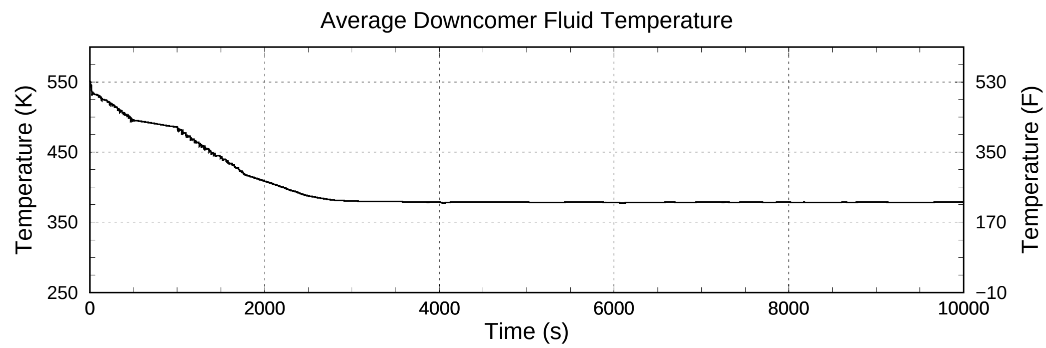
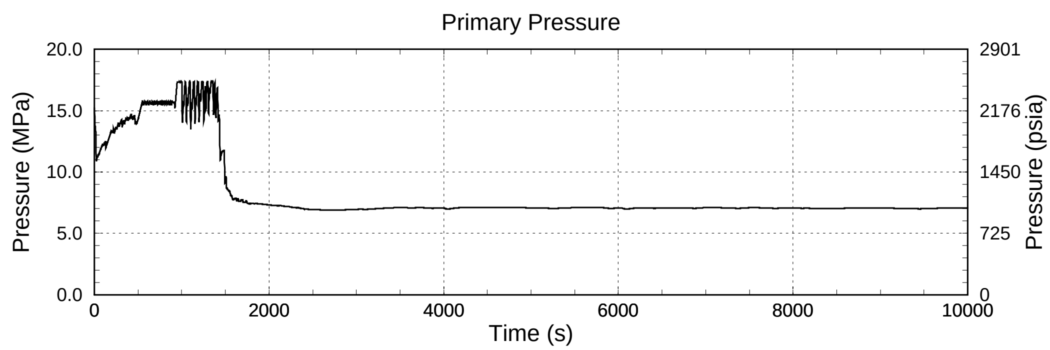


Figure A-73 Oconee PTS Results for Case 172

Case Category	MSLB-HZP
Primary Failures	No primary side failure. Decay power set to 0.003 of full power and held constant (7.70 MW).
Secondary Failures	MSLB with trip of turbine driven EFW by MSLB Circuitry
Operator Actions	Operator throttles HPI 20 minutes after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	377.2 K [219.4°F] at 6099 s
Comments	None.





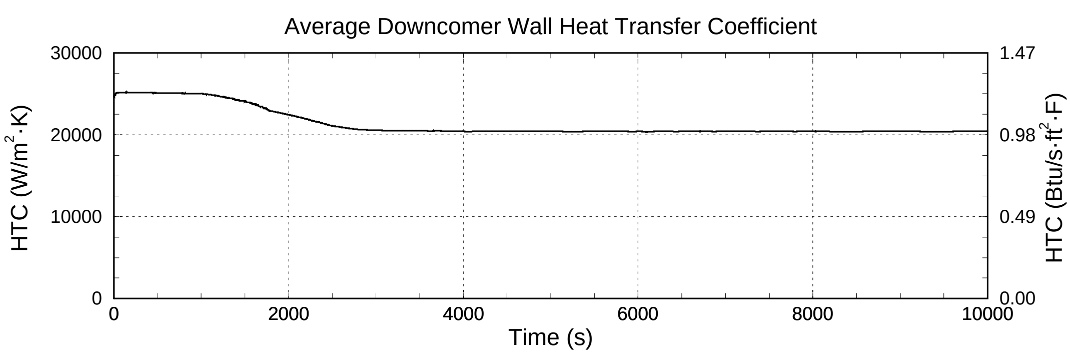


Figure A-74 Oconee PTS Results for Case 174

Case Category	TT/RT-Hi K, HZP
Primary Failures	Stuck open pressurizer safety valve. Valve recloses at 6000 secs. Decay power set to 0.003 of full power and held constant (7.70 MW).
Secondary Failures	None
Operator Actions	Operator throttles HPI at 10 minutes after 2.7 K (5°F) subcooling and 254 cm (100 in) pressurizer level is reached (throttling criteria is 27.8 K (50°F) subcooling).
Min DC Temperature	452.4 K [354.6°F] at 6001 s
Comments	None.

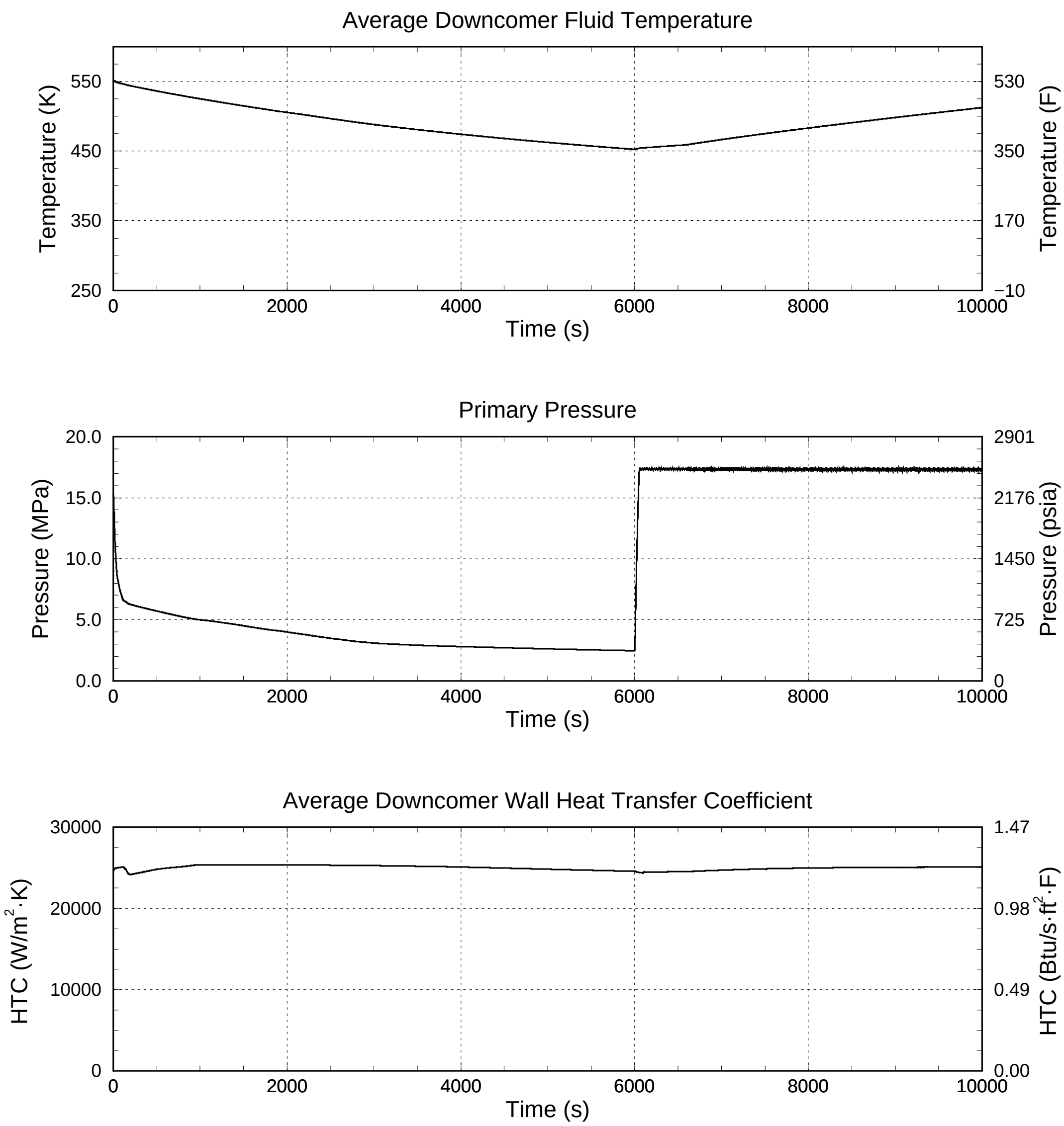


Figure A-75 Oconee PTS Results for Case 176

Appendix B - Summary of Beaver Valley Base Case Results

September 23, 2004

Appendix B - Summary of Beaver Valley Base Case Results

This appendix presents an overview of the RELAP5 modeling details and the results of the 62 base cases evaluated for the Beaver Valley plant. Table B-1 presents a list of the cases analyzed. These cases include a mix of LOCAs, stuck open pressurizer safety valves, main steam line breaks, and secondary side failures from both hot full power and hot zero power conditions.

Results for each of the base cases are presented below as Figures B-1 to B-62. For each case, the following information is given in tabular format.

Case Category	LOCA, RT/TT, MSLB, etc.
Primary Failures	Description of the primary side failure
Secondary Failures	Description of the secondary side failure
Operator Actions	Description of any operator actions
Min DC Temp	The minimum average downcomer fluid temperature and associated time that minimum occurred
Comments	Any comments specific to the event

In addition to the information described above, plots of average downcomer fluid temperature, primary system pressure, and downcomer wall heat transfer coefficient are presented. Any analytical assumptions used in each case are also presented. To facilitate comparisons among cases, each figure presents summary information for the minimum downcomer average temperature in the reactor vessel and the time during the event sequence when that minimum is reached. The results shown in these figures are used in the FAVOR probabilistic fracture mechanics analysis.

Table B-1 List of Beaver Valley Base Cases

Case	System Failure	Operator Action	HZP	Dominant
002	3.59 cm [1.414 in] surge line break	None.	No	No
003	5.08 cm [2.0 in] surge line break	None.	No	No
007	2.54 cm [8.0 in] surge line break	None.	No	Yes
009	2.54 cm [16.0 in] hot leg break	None.	No	Yes
014	Reactor/turbine trip w/one stuck open pressurizer SRV	None.	No	No
031	Reactor/turbine trip w/feed and bleed (Operator open all pressurizer PORVs and use all charging/HHSI pumps)	None.	No	No
034	Reactor/turbine trip w/two stuck open pressurizer SRV's	None.	No	No
056	10.16 cm [4.0 in] surge line break	None.	Yes	Yes
059	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 3,000 s.	None.	No	No
060	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 6,000 s.	None.	No	Yes
061	Reactor/turbine trip w/two stuck open pressurizer SRV which recloses at 3,000 s.	None.	No	No
062	Reactor/turbine trip w/two stuck open pressurizer SRV which recloses at 6,000 s.	None.	No	No
064	Reactor/turbine trip w/two stuck open pressurizer SRV's	None.	Yes	No
065	Reactor/turbine trip w/two stuck open pressurizer SRV's and HHSI failure	Operator opens all ASDVs 5 minutes after HHSI would have come on.	No	No

Table B-1 List of Beaver Valley Base Cases

Case	System Failure	Operator Action	HZP	Dominant
066	Reactor/turbine trip w/two stuck open pressurizer SRV's. One valve recloses at 3000 seconds while the other valve remains open.	None.	No	No
067	Reactor/turbine trip w/two stuck open pressurizer SRV's. One valve recloses at 6000 seconds while the other valve remains open.	None.	No	No
068	Reactor/turbine trip w/two stuck open pressurizer SRV's that reclose at 6000 s with HHSI failure.	Operator opens all ASDVs 5 minutes after HHSI would have come on.	No	No
069	Reactor/turbine trip w/two stuck open pressurizer SRVs which reclose at 3,000 s.	None.	Yes	No
070	Reactor/turbine trip w/two stuck open pressurizer SRVs which reclose at 6,000 s.	None.	Yes	No
071	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 6,000 s.	None.	Yes	Yes
072	Reactor/turbine trip w/one stuck open pressurizer SRV with HHSI failure.	Operator opens all ASDVs 5 minutes after HHSI would have come on.	No	No
073	Reactor/turbine trip w/one stuck open pressurizer SRV with HHSI failure	Operator open all ASDVs 5 minutes after HHSI would have come on.	Yes	No
074	Main steam line break with AFW continuing to feed affected generator	None.	No	No
075	Reactor/turbine trip w/full MFW to all 3 SGs (MFW maintains SG level near top) and RCPs tripped	None.	No	No
076	Reactor/turbine trip w/full MFW to all 3 SGs (MFW maintains SG level near top).	Operator trips reactor coolant pumps.	Yes	No
078	Reactor/turbine trip with failure of MFW and AFW.	Operator opens all ASDVs to let condensate fill SGs.	No	No

Table B-1 List of Beaver Valley Base Cases

Case	System Failure	Operator Action	HZP	Dominant
080	Main Steam Line Break with AFW continuing to feed affected generator.	Operator trips reactor coolant pumps.	Yes	No
081	Main Steam Line Break with AFW continuing to feed affected generator and with HHSI failure initially.	Operator opens ADVs (on intact generators). HHSI is restored after CFTs discharge 50%.	No	No
082	Reactor/turbine trip w/one stuck open pressurizer SRV (recloses at 6000 s) and with HHSI failure.	Operator opens all ASDVs 5 minutes after HHSI would have started.	No	No
083	2.54 cm [1.0 in] surge line break with HHSI failure and motor driven AFW failure. MFW is tripped. Level control failure causes all steam generators to be overfed with turbine AFW, with the level maintained at top of SGs.	Operator trips RCPs. Operator opens all ASDVs 5 minutes after HHSI would have come on.	No	No
086	Reactor/turbine trip w/two stuck open pressurizer SRV which recloses at 6,000 s	Operator controls HHSI (1 minute delay)	No	No
087	Reactor/turbine trip w/two stuck open pressurizer SRV which recloses at 6,000 s	Operator controls HHSI (10 minute delay)	No	No
088	Reactor/turbine trip w/two stuck open pressurizer SRV which recloses at 3,000 s.	Operator controls HHSI (1 minute delay).	Yes	No
089	Reactor/turbine trip w/two stuck open pressurizer SRVs which reclose at 6,000 s.	Operator controls HHSI (1 minute delay)	Yes	No
090	Reactor/turbine trip w/two stuck open pressurizer SRVs which reclose at 3,000 s.	Operator controls HHSI (10 minute delay)	Yes	No
091	Reactor/turbine trip w/two stuck open pressurizer SRVs which reclose at 6,000 s.	Operator controls HHSI (10 minute delay)	Yes	No

Table B-1 List of Beaver Valley Base Cases

Case	System Failure	Operator Action	HZP	Dominant
092	Reactor/turbine trip w/two stuck open pressurizer SRV's, one recloses at 3000 s.	None.	Yes	No
093	Reactor/turbine trip w/two stuck open pressurizer SRV's. One valve recloses at 6000 seconds while the other valve remains open.	None.	Yes	No
094	Reactor/turbine trip w/one stuck open pressurizer SRV.	None.	Yes	No
095	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 6,000 s	Operator controls HHSI (1 minute delay)	No	No
096	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 6,000 s.	Operator controls HHSI (10 minute delay)	No	No
097	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 3,000 s.	None.	Yes	Yes
098	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 6,000 s.	Operator controls HHSI (1 minute delay)	Yes	No
099	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 3,000 s.	Operator controls HHSI (1 minute delay)	Yes	No
100	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 6,000 s.	Operator controls HHSI (10 minute delay)	Yes	No
101	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 3,000 s.	Operator controls HHSI (10 minute delay)	Yes	No

Table B-1 List of Beaver Valley Base Cases

Case	System Failure	Operator Action	HZP	Dominant
102	Main steam line break with AFW continuing to feed affected generator for 30 minutes.	Operator controls HHSI (30 minute delay). Break is assumed to occur inside containment so that the operator trips the RCPs due to adverse containment conditions.	No	Yes
103	Main steam line break with AFW continuing to feed affected generator for 30 minutes.	Operator controls HHSI (30 minute delay). Break is assumed to occur inside containment so that the operator trips the RCPs due to adverse containment conditions.	Yes	Yes
104	Main steam line break with AFW continuing to feed affected generator for 30 minutes.	Operator controls HHSI (60 minute delay). Break is assumed to occur inside containment so that the operator trips the RCPs due to adverse containment conditions.	No	Yes
105	Main steam line break with AFW continuing to feed affected generator for 30 minutes.	Operator controls HHSI (60 minute delay). Break is assumed to occur inside containment so that the operator trips the RCPs due to adverse containment conditions.	Yes	Yes
106	Main steam line break with AFW continuing to feed affected generator.	Operator controls HHSI (30 minute delay). Break is assumed to occur inside containment so that the operator trips the RCPs due to adverse containment conditions.	No	No
107	Main steam line break with AFW continuing to feed affected generator.	Operator controls HHSI (30 minute delay). Break is assumed to occur inside containment so that the operator trips the RCPs due to adverse containment conditions.	Yes	No
108	Small steam line break (simulated by sticking open all SG-A SRVs) with AFW continuing to feed affected generator for 30 minutes.	Operator controls HHSI (30 minute delay)	Yes	Yes

Table B-1   List of Beaver Valley Base Cases

Case	System Failure	Operator Action	HZP	Dominant
109	Small steam line break (simulated by sticking open all SG-A SRVs) with AFW continuing to feed affected generator for 30 minutes.	Operator controls HHSI (30 minute delay). Break is assumed to occur inside containment so that the operator trips the RCPs due to adverse containment conditions.	Yes	No
110	Small steam line break (simulated by sticking open all SG-A SRVs) with AFW continuing to feed affected generator for 30 minutes	Operator controls HHSI (60 minute delay)	No	No
111	Small steam line break (simulated by sticking open all SG-A SRVs) with AFW continuing to feed affected generator for 30 minutes.	Operator controls HHSI (60 minute delay). Break is assumed to occur inside containment so that the operator trips the RCPs due to adverse containment conditions.	Yes	No
112	Small steam line break (simulated by sticking open all SG-A SRVs) with AFW continuing to feed affected generator.	Operator controls HHSI (30 minute delay). Break is assumed to occur inside containment so that the operator trips the RCPs due to adverse containment conditions.	No	No
113	Small steam line break (simulated by sticking open all SG-A SRVs) with AFW continuing to feed affected generator.	Operator controls HHSI (30 minute delay). Break is assumed to occur inside containment so that the operator trips the RCPs due to adverse containment conditions.	Yes	No
114	7.18 cm [2.828 in] surge line break, summer conditions (HHSI, LHSI temp = 55°F, Accumulator Temp = 105°F), heat transfer coefficient increased 30% (modeled by increasing heat transfer surface area by 30% in passive heat structures).	None.	No	Yes
115	7.18 cm [2.828 in] cold leg break	None.	No	No

Table B-1 List of Beaver Valley Base Cases

Case	System Failure	Operator Action	HZP	Dominant
116	14.366 cm [5.657 in] cold leg break with break area increased 30%	None.	No	No
117	14.366 cm [5.657 in] cold leg break, summer conditions (HHSI, LHSI temp = 55°F, Accumulator Temp = 105°F)	None.	No	No
118	Small steam line break (simulated by sticking open all SG-A SRVs) with AFW continuing to feed affected generator	None.	No	No
119	Reactor/turbine trip w/two stuck open pressurizer SRV which recloses at 6,000 s	Operator controls HHSI (1 minute delay). Updated control logic.	No	No
120	Reactor/turbine trip w/two stuck open pressurizer SRV which recloses at 6,000 s	Operator controls HHSI (10 minute delay). Updated control logic.	No	No
121	Reactor/turbine trip w/two stuck open pressurizer SRV which recloses at 3,000 s	Operator controls HHSI (1 minute delay). Updated control logic.	Yes	No
122	Reactor/turbine trip w/two stuck open pressurizer SRVs which reclose at 6,000 s	Operator controls HHSI (1 minute delay). Updated control logic.	Yes	No
123	Reactor/turbine trip w/two stuck open pressurizer SRVs which reclose at 3,000 s	Operator controls HHSI (10 minute delay). Updated control logic.	Yes	No
124	Reactor/turbine trip w/two stuck open pressurizer SRVs which reclose at 6,000 s	Operator controls HHSI (10 minute delay). Updated control logic.	Yes	No
125	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 6,000 s	Operator controls HHSI (1 minute delay). Updated control logic.	No	No
126	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 6,000 s	Operator controls HHSI (10 minute delay). Updated control logic.	No	Yes

Table B-1 List of Beaver Valley Base Cases

Case	System Failure	Operator Action	HZP	Dominant
127	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 6,000 s	Operator controls HHSI (1 minute delay). Updated control logic.	Yes	No
128	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 3,000 s	Operator controls HHSI (1 minute delay). Updated control logic.	Yes	No
129	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 6,000 s	Operator controls HHSI (10 minute delay). Updated control logic.	Yes	No
130	Reactor/turbine trip w/one stuck open pressurizer SRV which recloses at 3,000 s	Operator controls HHSI (10 minute delay). Updated control logic.	Yes	Yes

Case Category	LOCA
Primary Failures	3.59 cm (1.414 in) surge line break
Secondary Failures	None
Operator Actions	None
Min DC Temperature	401.6 K [263.2°F] at 12300 s
Comments	None

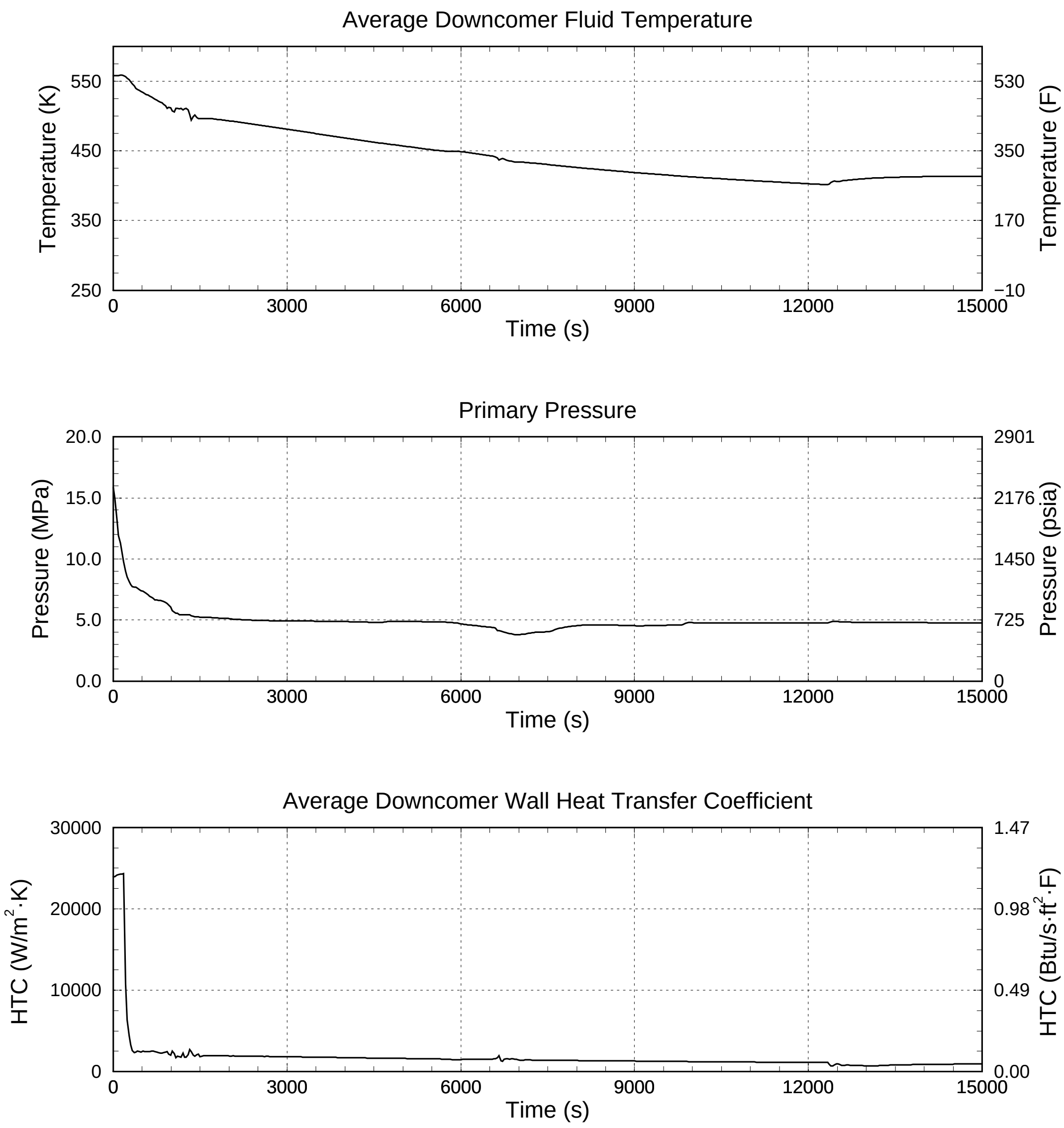


Figure B-1 Beaver Valley PTS Results for Case 002

Case Category	LOCA
Primary Failures	5.08 cm (2.0 in) surge line break
Secondary Failures	None
Operator Actions	None
Min DC Temperature	310.9 K [100.0°F] at 7290 s
Comments	None

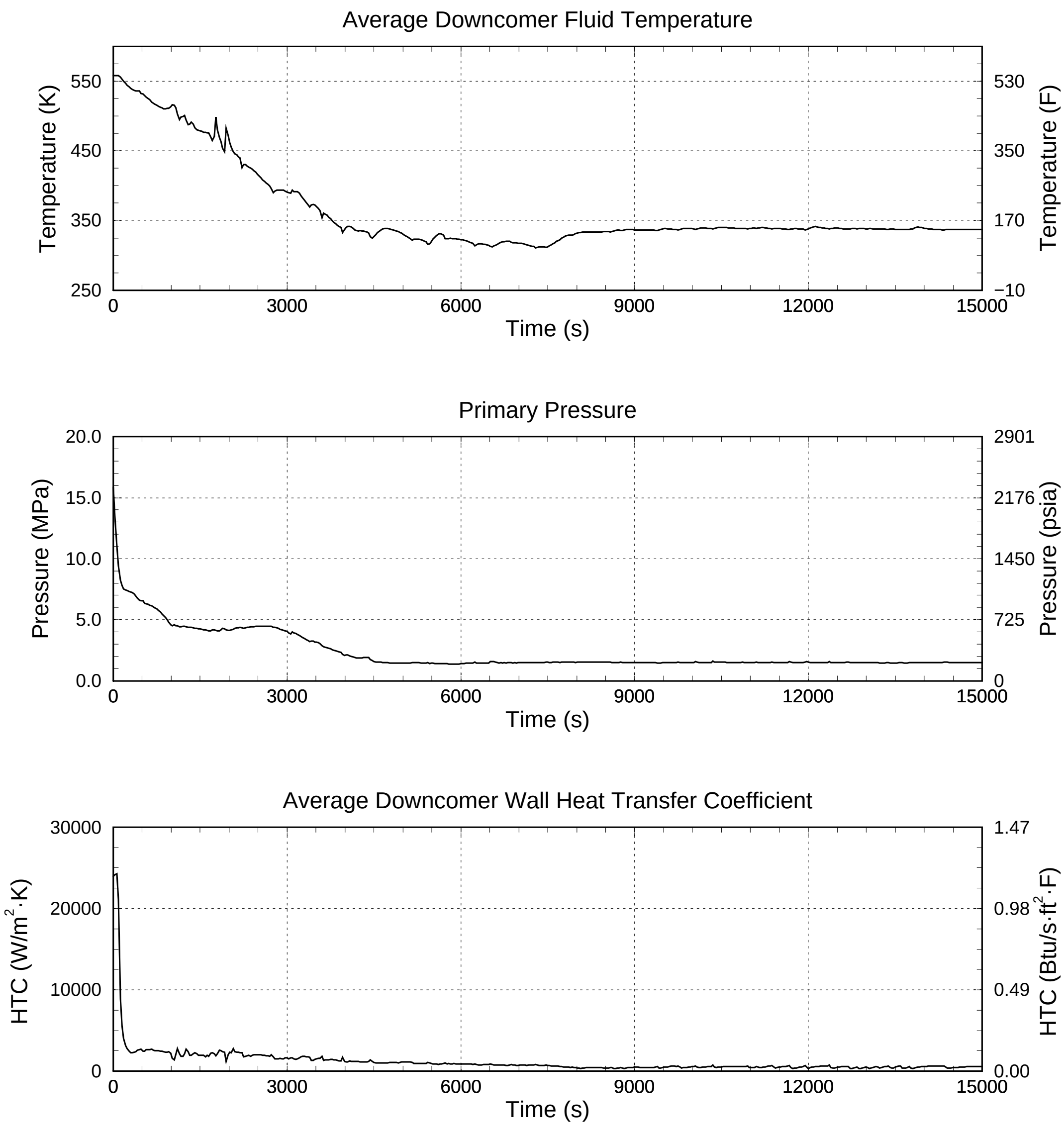


Figure B-2 Beaver Valley PTS Results for Case 003

Case Category	LOCA
Primary Failures	20.32 cm (8.0 in) surge line break
Secondary Failures	None
Operator Actions	None
Min DC Temperature	291.2 K [64.5°F] at 1050 s
Comments	None

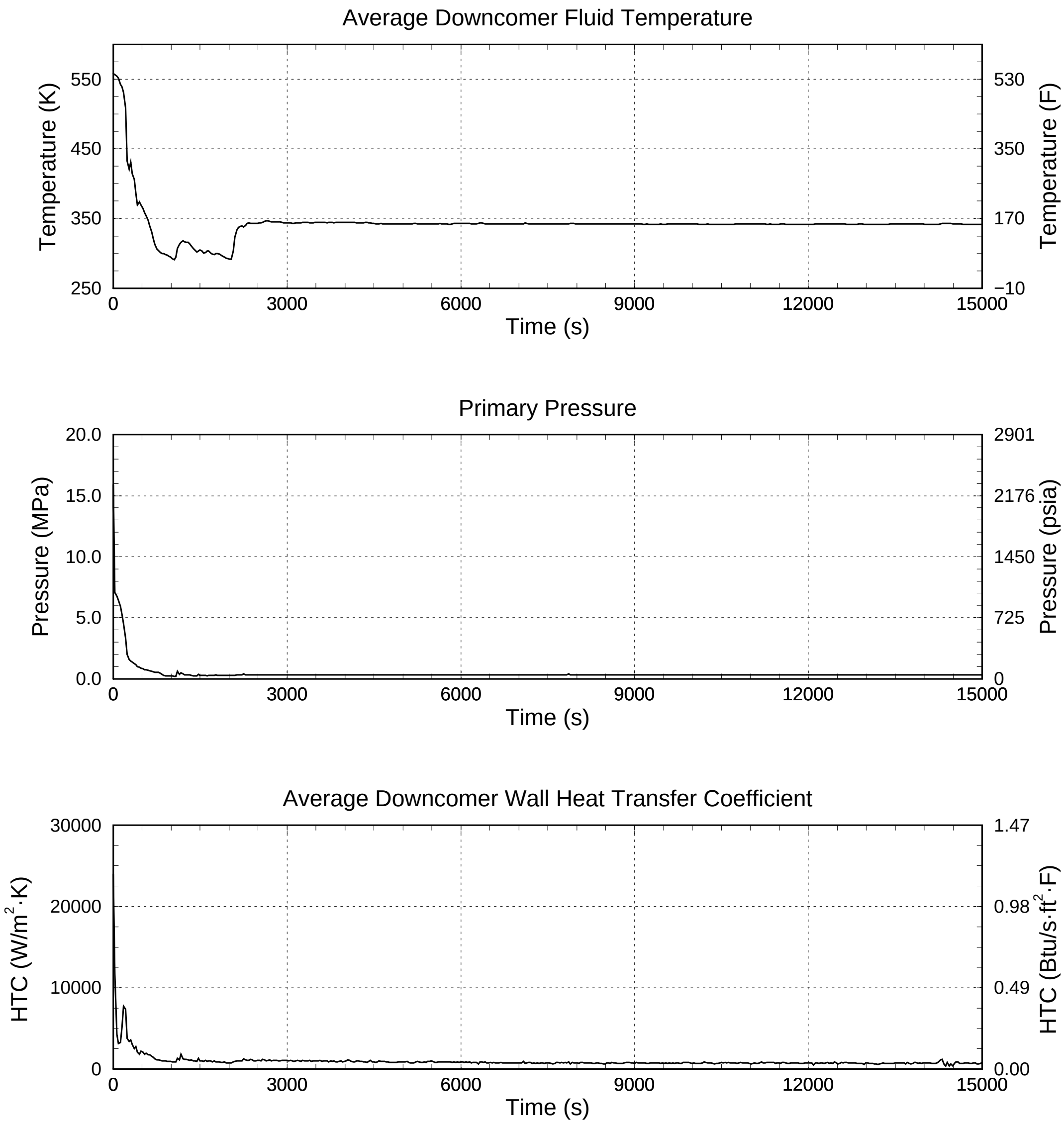


Figure B-3 Beaver Valley PTS Results for Case 007

Case Category	LOCA
Primary Failures	40.64 cm (16.0 in) hot leg break
Secondary Failures	None
Operator Actions	None
Min DC Temperature	291.2 K [64.6°F] at 960 s
Comments	None

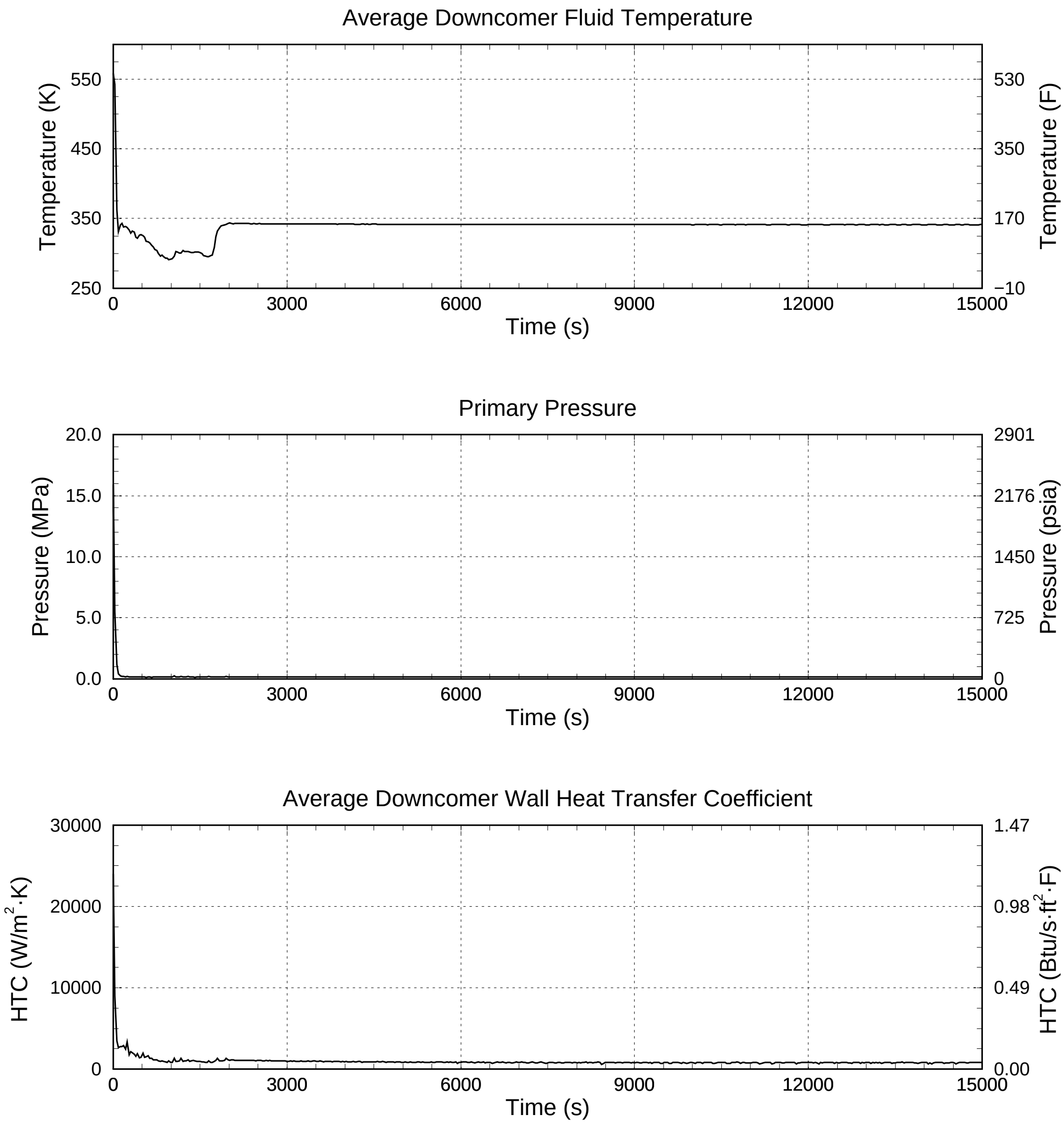


Figure B-4 Beaver Valley PTS Results for Case 009

Case Category	SOV
Primary Failures	One stuck open pressurizer SRV
Secondary Failures	None
Operator Actions	None
Min DC Temperature	294.8 K [70.9°F] at 14730 s
Comments	None

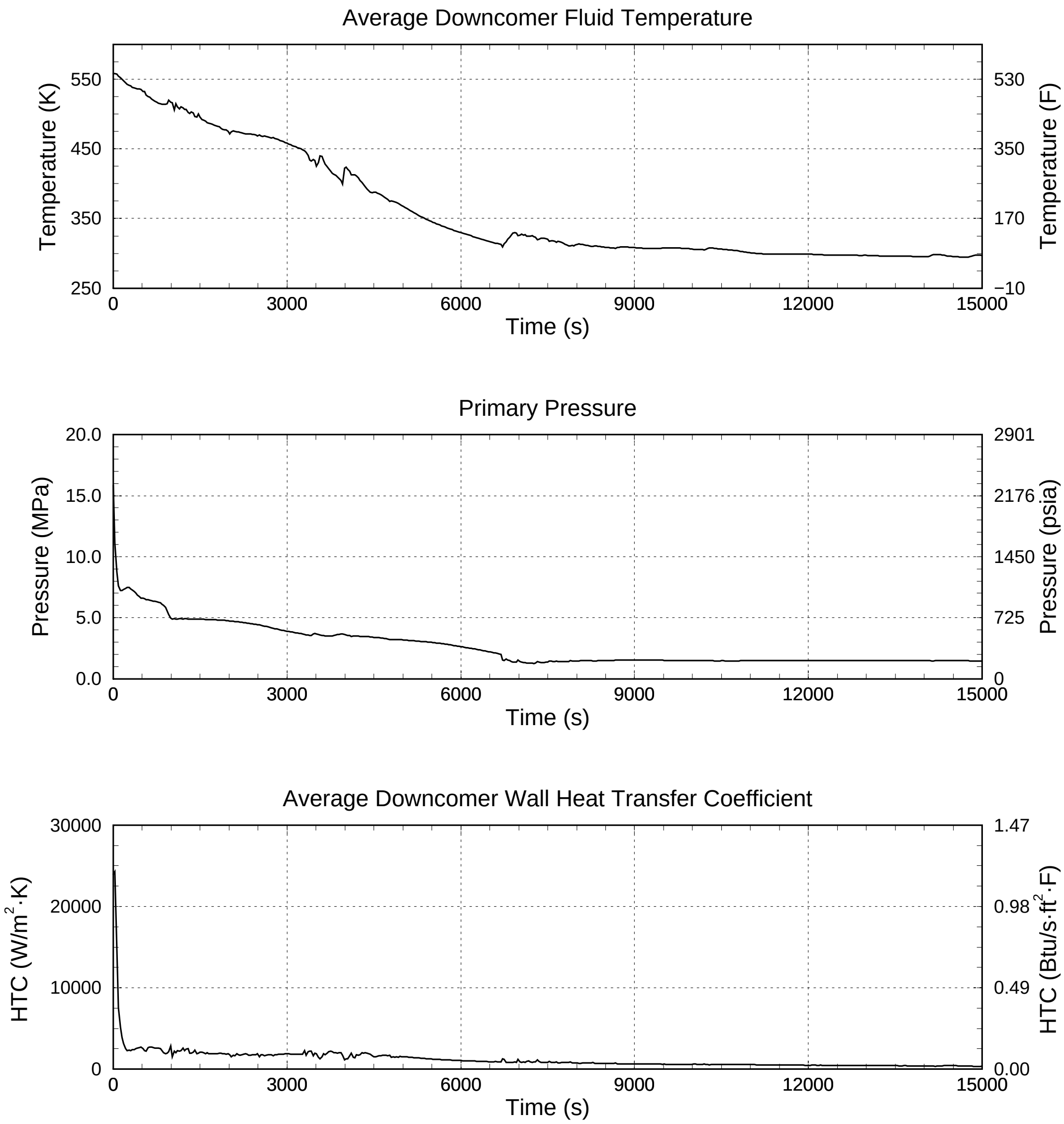


Figure B-5 Beaver Valley PTS Results for Case 014

Case Category	RT/TT
Primary Failures	None
Secondary Failures	Loss of all feedwater
Operator Actions	Opens all pressurizer PORVs and uses all HHSI pumps
Min DC Temperature	287.7 K [58.2°F] at 15000 s
Comments	Feed and bleed started upon high pressurizer pressure or low SG level.

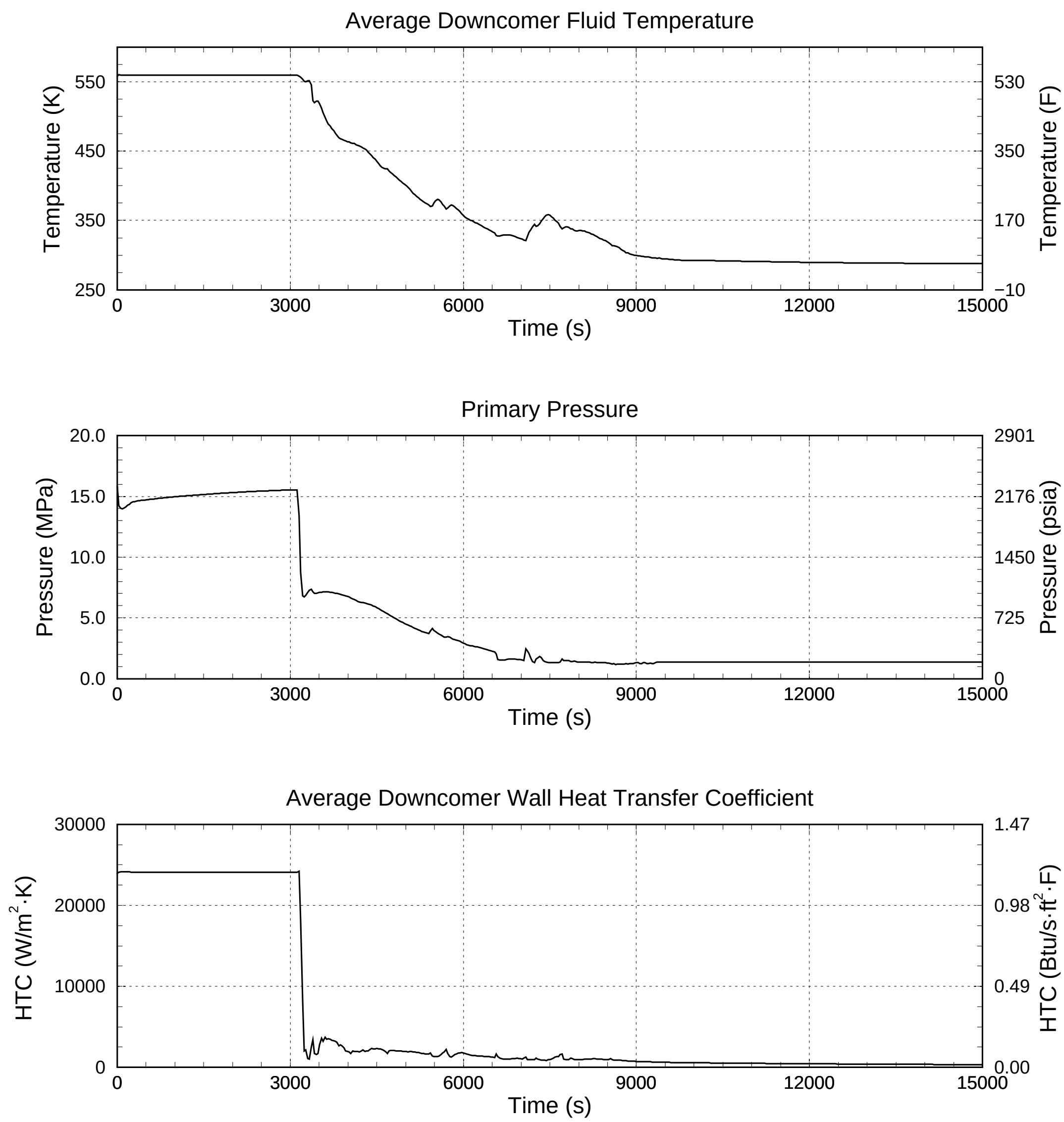


Figure B-6 Beaver Valley PTS Results for Case 031

Case Category	SOV
Primary Failures	Two stuck open pressurizer SRVs
Secondary Failures	None
Operator Actions	None
Min DC Temperature	287.5 K [57.9°F] at 9930 s
Comments	None

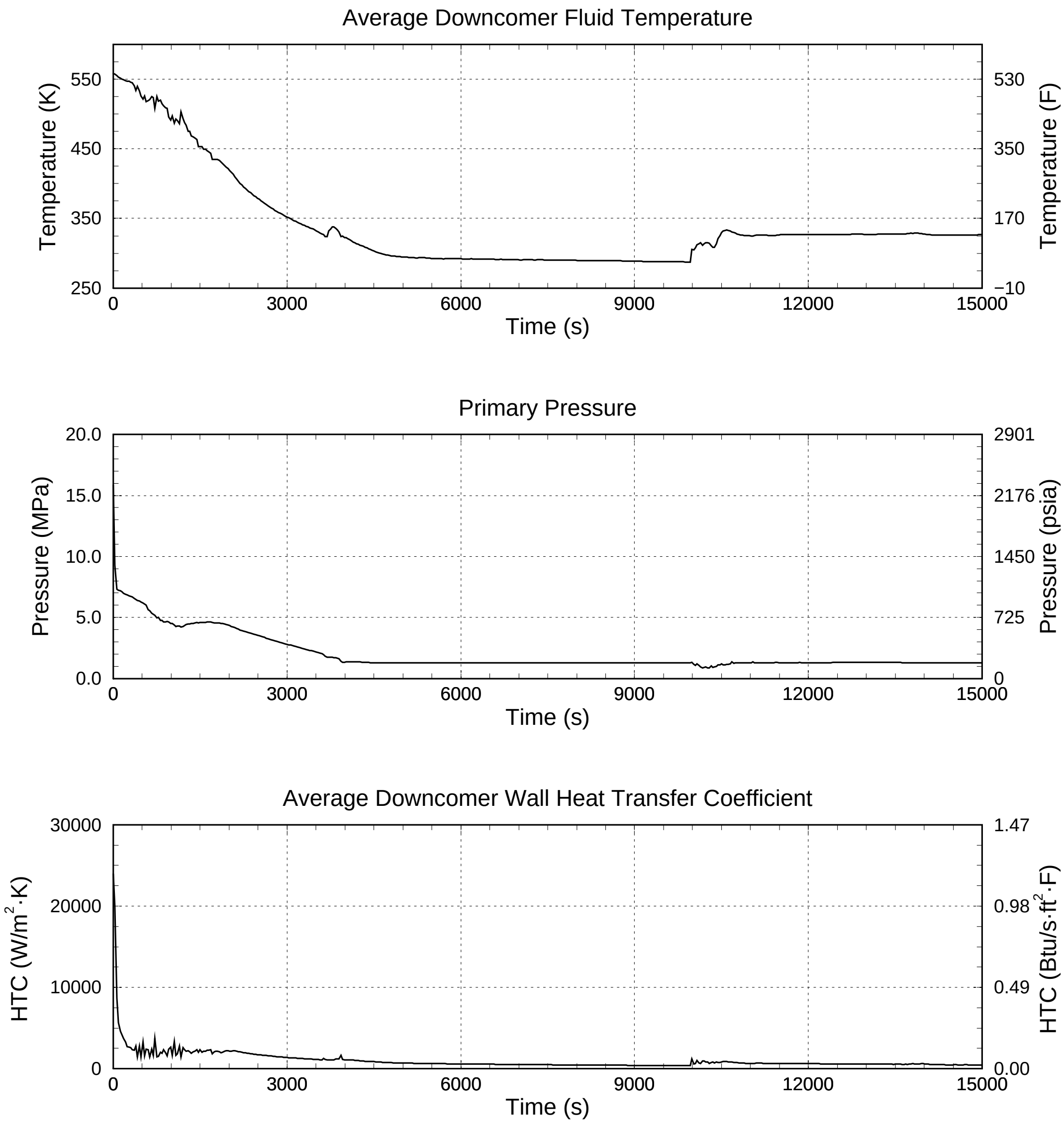
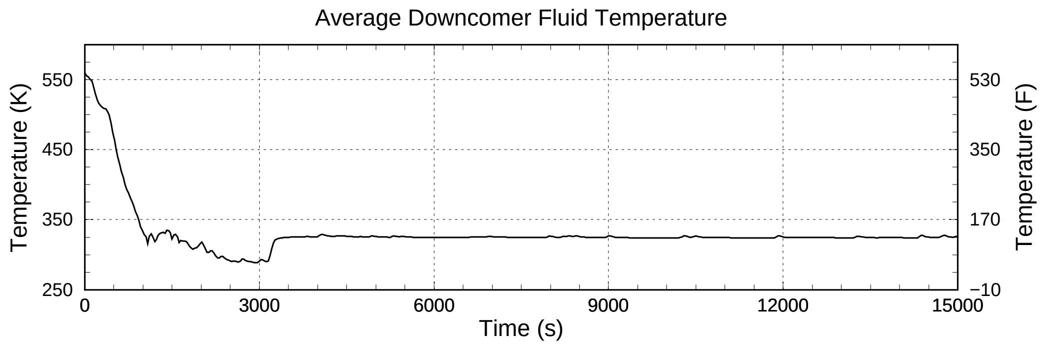
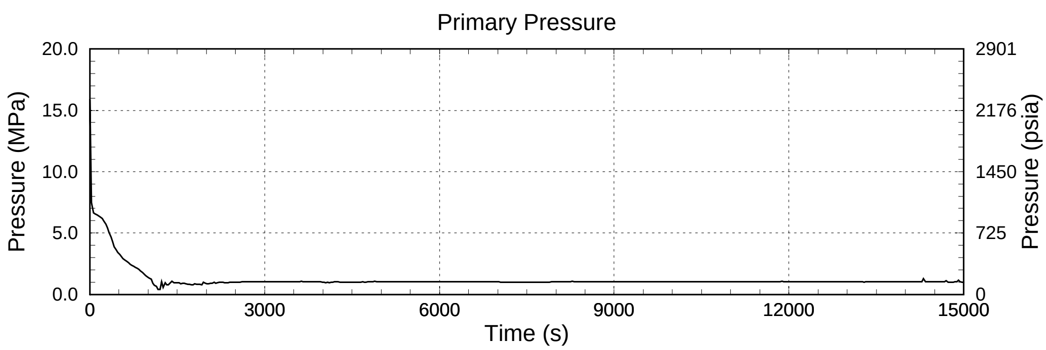


Figure B-7 Beaver Valley PTS Results for Case 034

Case Category	LOCA, HZP
Primary Failures	10.16 cm (4.0 in) surge line break
Secondary Failures	None
Operator Actions	None
Min DC Temperature	288.4 K [59.5°F] at 2970 s
Comments	Case 005 @ HZP





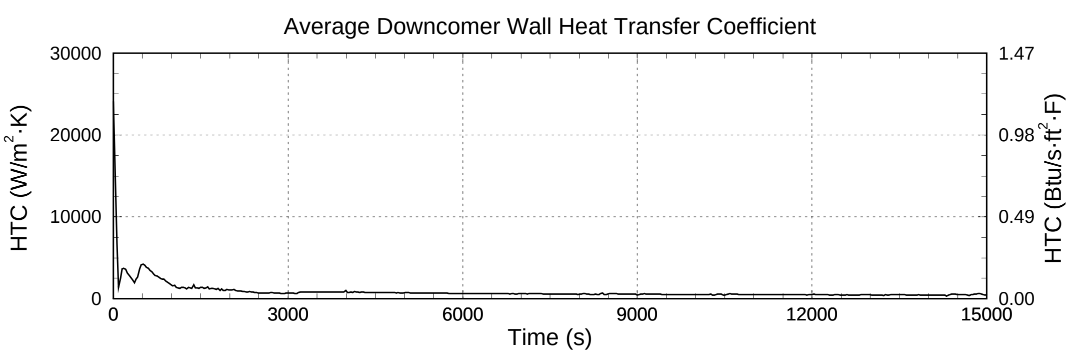


Figure B-8 Beaver Valley PTS Results for Case 056

Case Category	SOV
Primary Failures	One stuck open pressurizer SRV (recloses at 3,000 s)
Secondary Failures	None
Operator Actions	None
Min DC Temperature	429.6 K [313.7°F] at 4410 s
Comments	

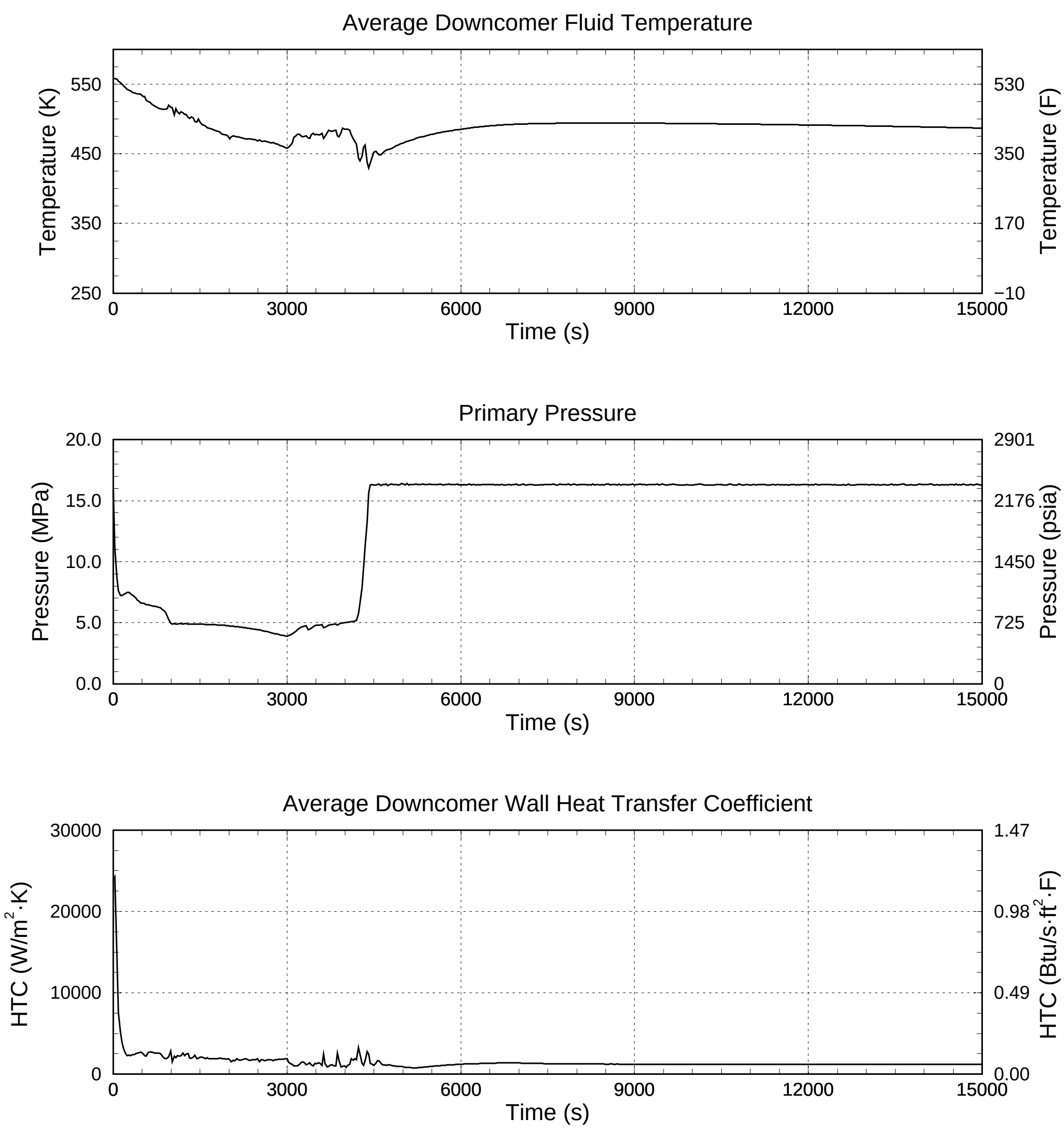


Figure B-9 Beaver Valley PTS Results for Case 059

Case Category	SOV
Primary Failures	One stuck open pressurizer SRV (recloses at 6,000 s)
Secondary Failures	None
Operator Actions	None
Min DC Temperature	329.8 K [133.9°F] at 6000 s
Comments	

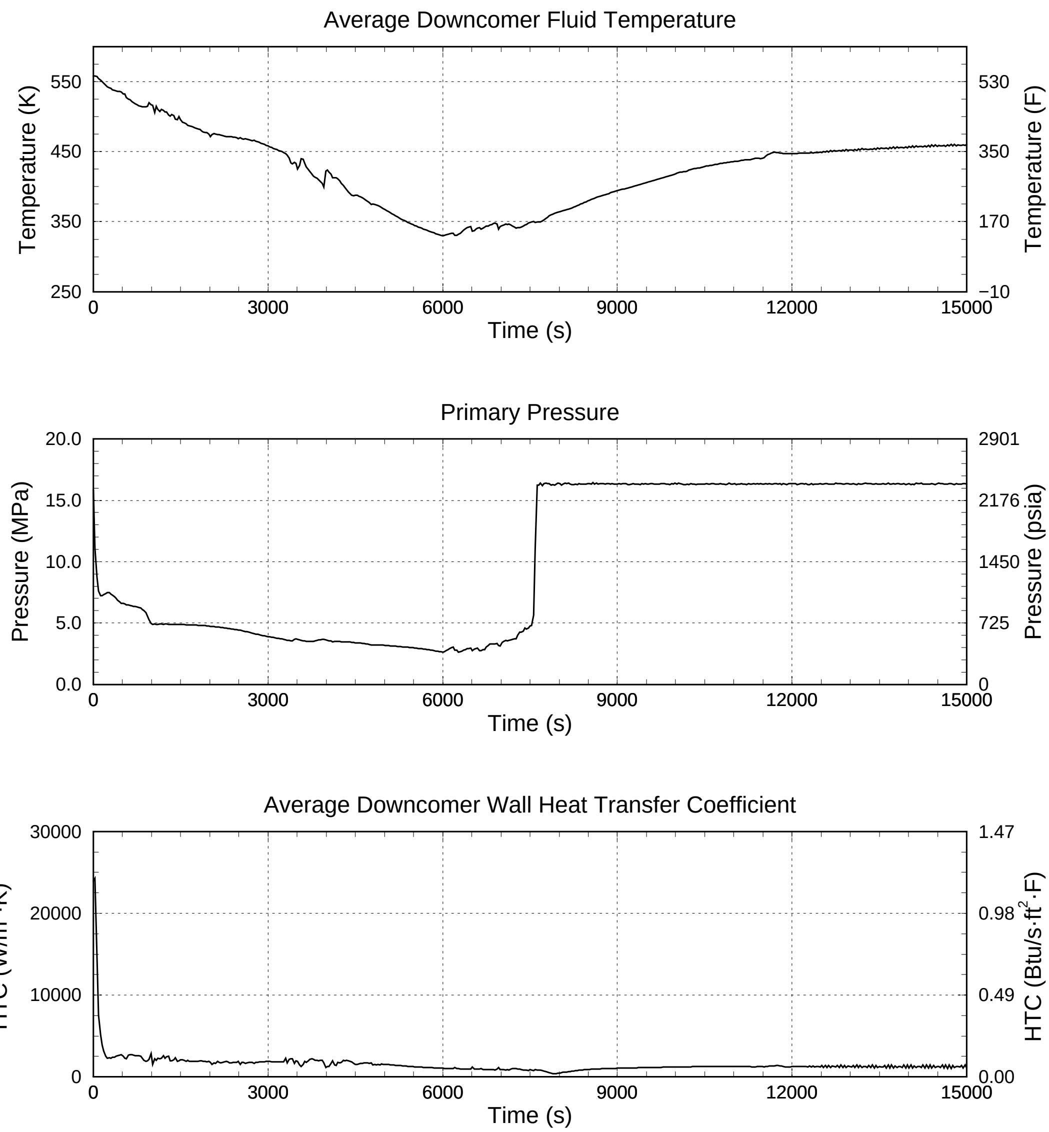


Figure B-10 Beaver Valley PTS Results for Case 060

Case Category	SOV
Primary Failures	Two stuck open pressurizer SRVs (recloses at 3,000 s)
Secondary Failures	None
Operator Actions	None
Min DC Temperature	357.1 K [183.2°F] at 3450 s
Comments	

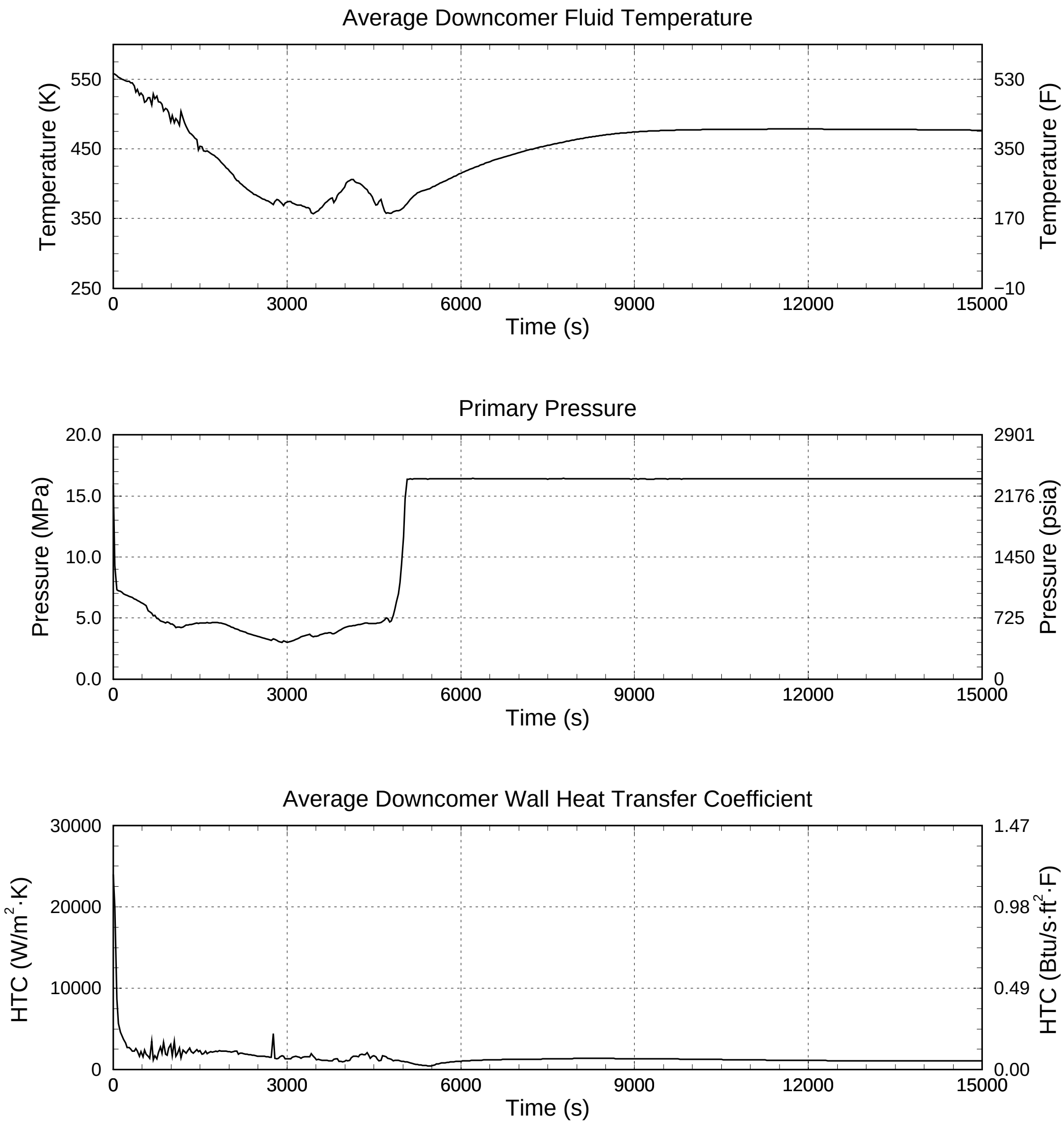


Figure B-11 Beaver Valley PTS Results for Case 061

Case Category	SOV
Primary Failures	Two stuck open pressurizer SRVs (recloses at 6,000 s)
Secondary Failures	None
Operator Actions	None
Min DC Temperature	292.0 K [66.0°F] at 5700 s
Comments	

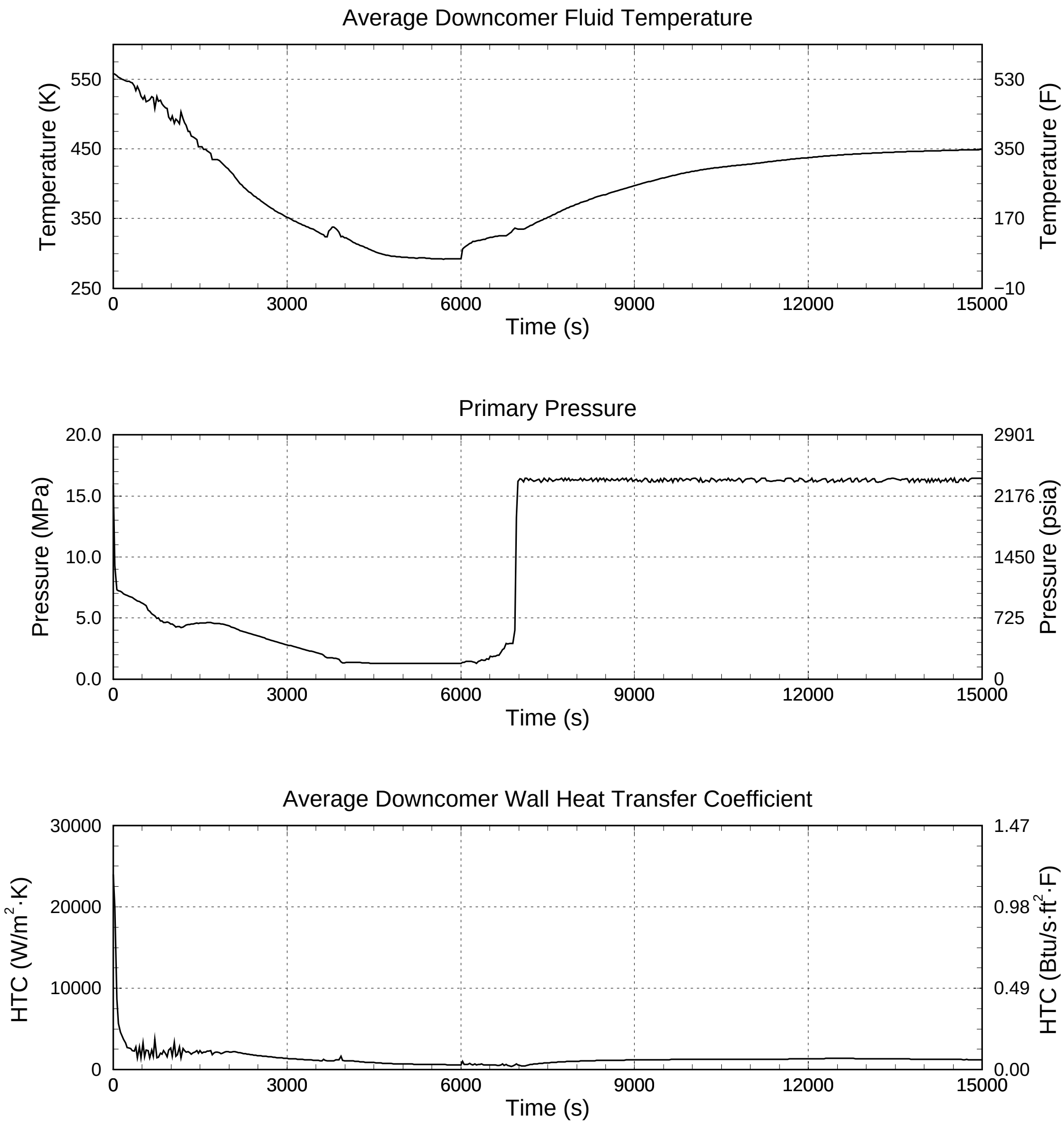
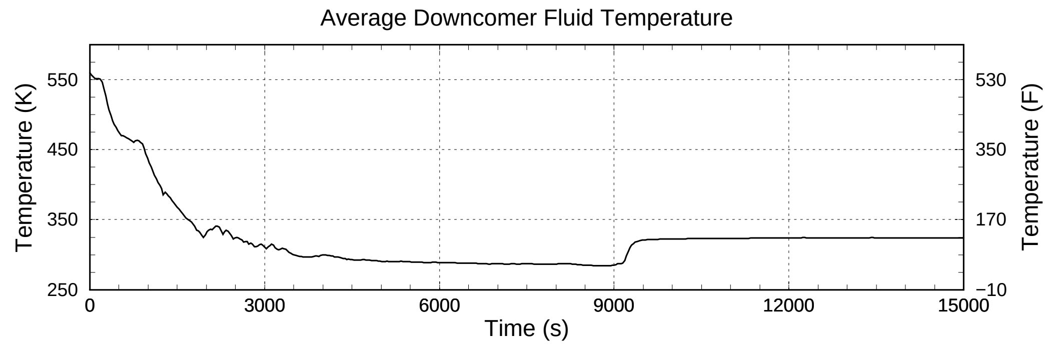
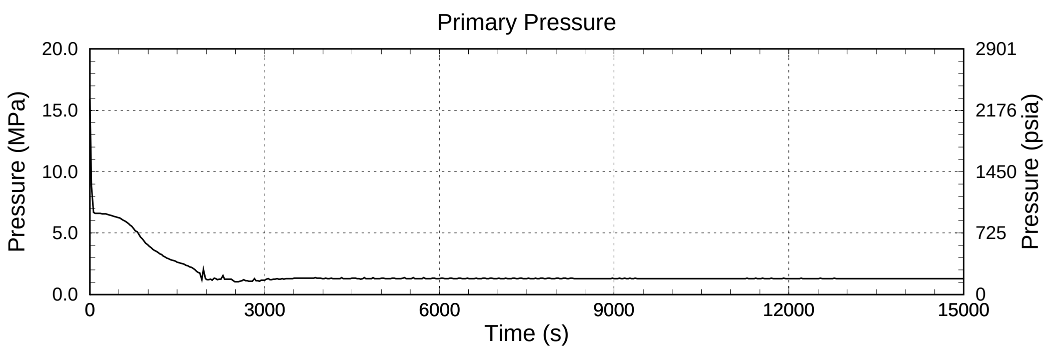


Figure B-12 Beaver Valley PTS Results for Case 062

Case Category	SOV, HZP
Primary Failures	Two stuck open pressurizer SRVs
Secondary Failures	None
Operator Actions	None
Min DC Temperature	284.4 K [52.2°F] at 8880 s
Comments	Case 034 @ HZP





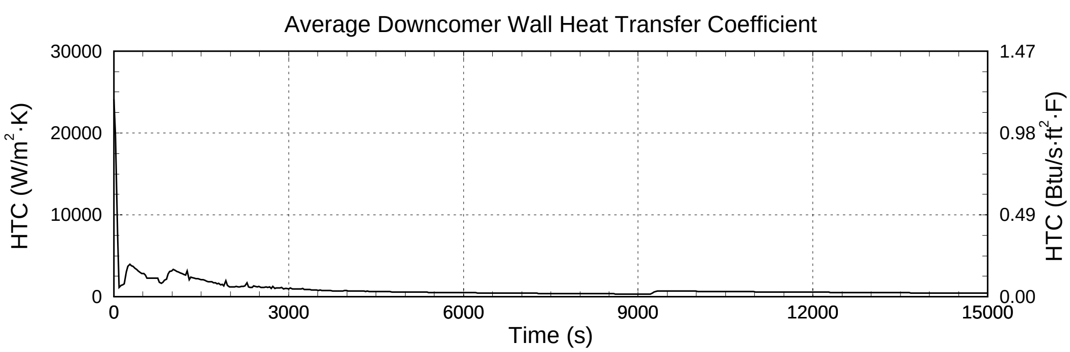


Figure B-13 Beaver Valley PTS Results for Case 064

Case Category	SOV
Primary Failures	Two stuck open pressurizer SRVs, no HHSI
Secondary Failures	None
Operator Actions	Open all ASDVs 5 minutes after HHSI would have come on
Min DC Temperature	327.3 K [129.5°F] at 10350 s
Comments	None

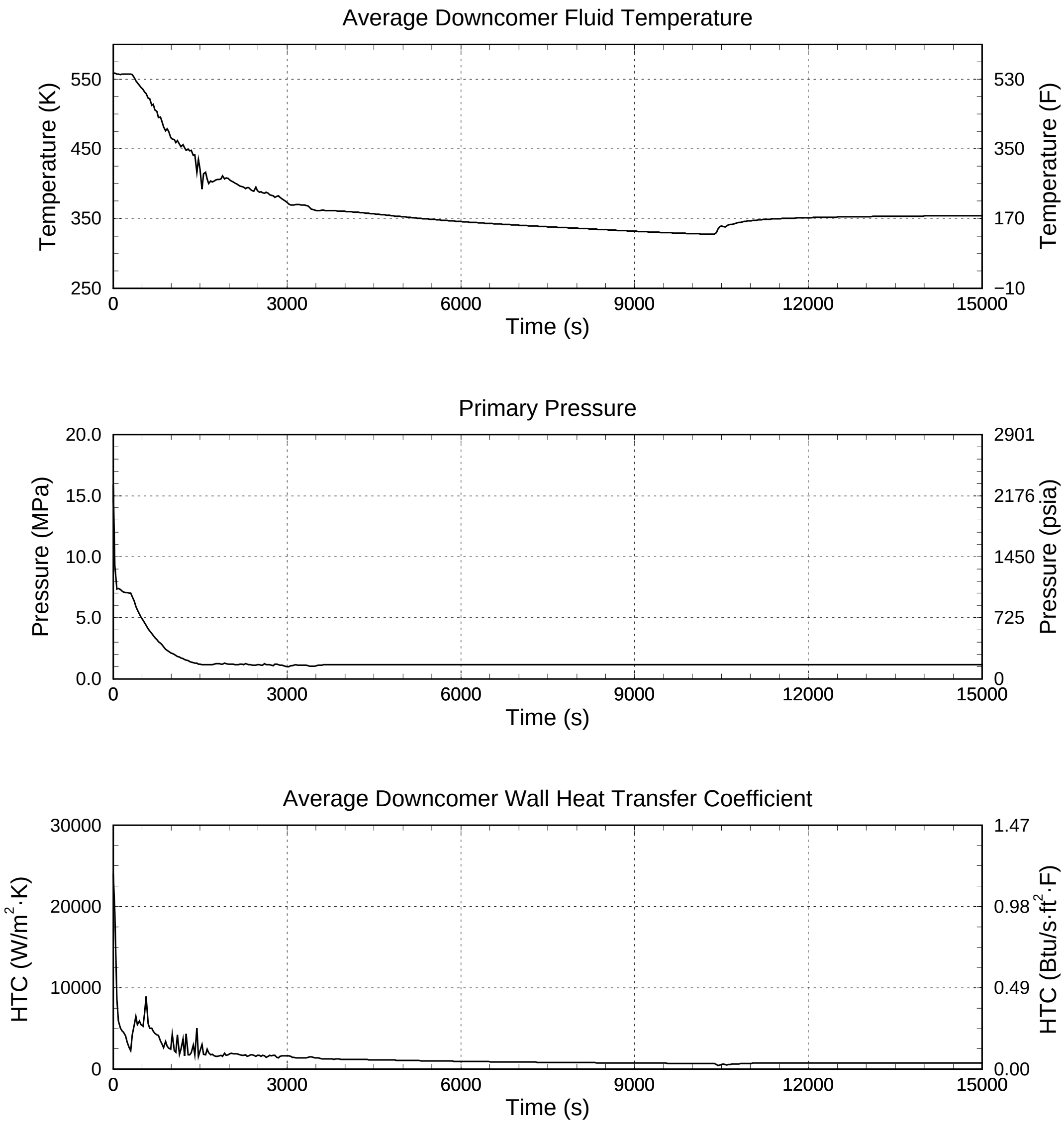


Figure B-14 Beaver Valley PTS Results for Case 065

Case Category	SOV
Primary Failures	Two stuck open pressurizer SRVs (one recloses at 3,000 s)
Secondary Failures	None
Operator Actions	None
Min DC Temperature	295.4 K [72.1°F] at 13800 s
Comments	

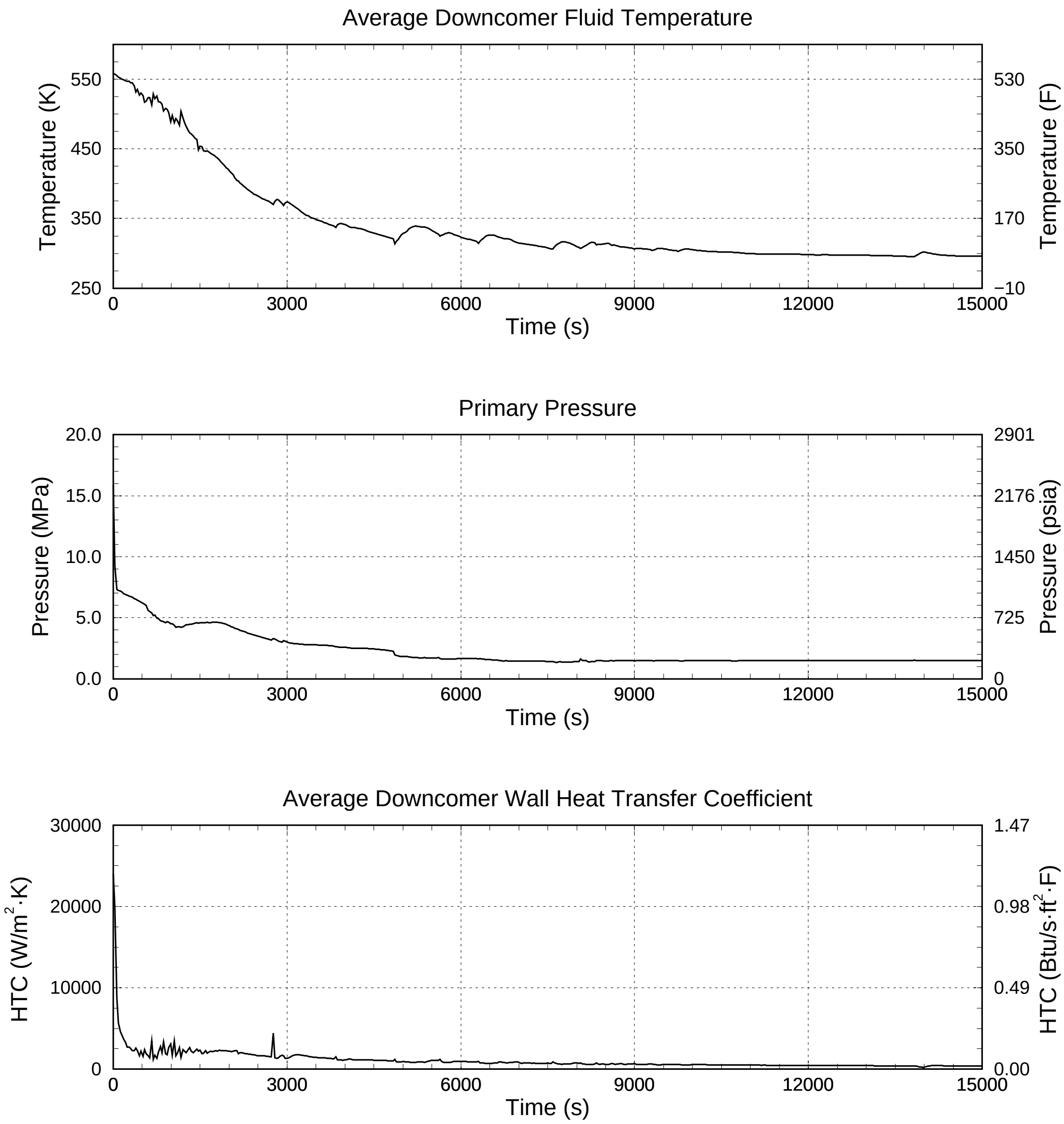


Figure B-15 Beaver Valley PTS Results for Case 066

Case Category	SOV
Primary Failures	Two stuck open pressurizer SRVs (one recloses at 6,000 s)
Secondary Failures	None
Operator Actions	None
Min DC Temperature	294.4 K [70.3°F] at 12960 s
Comments	

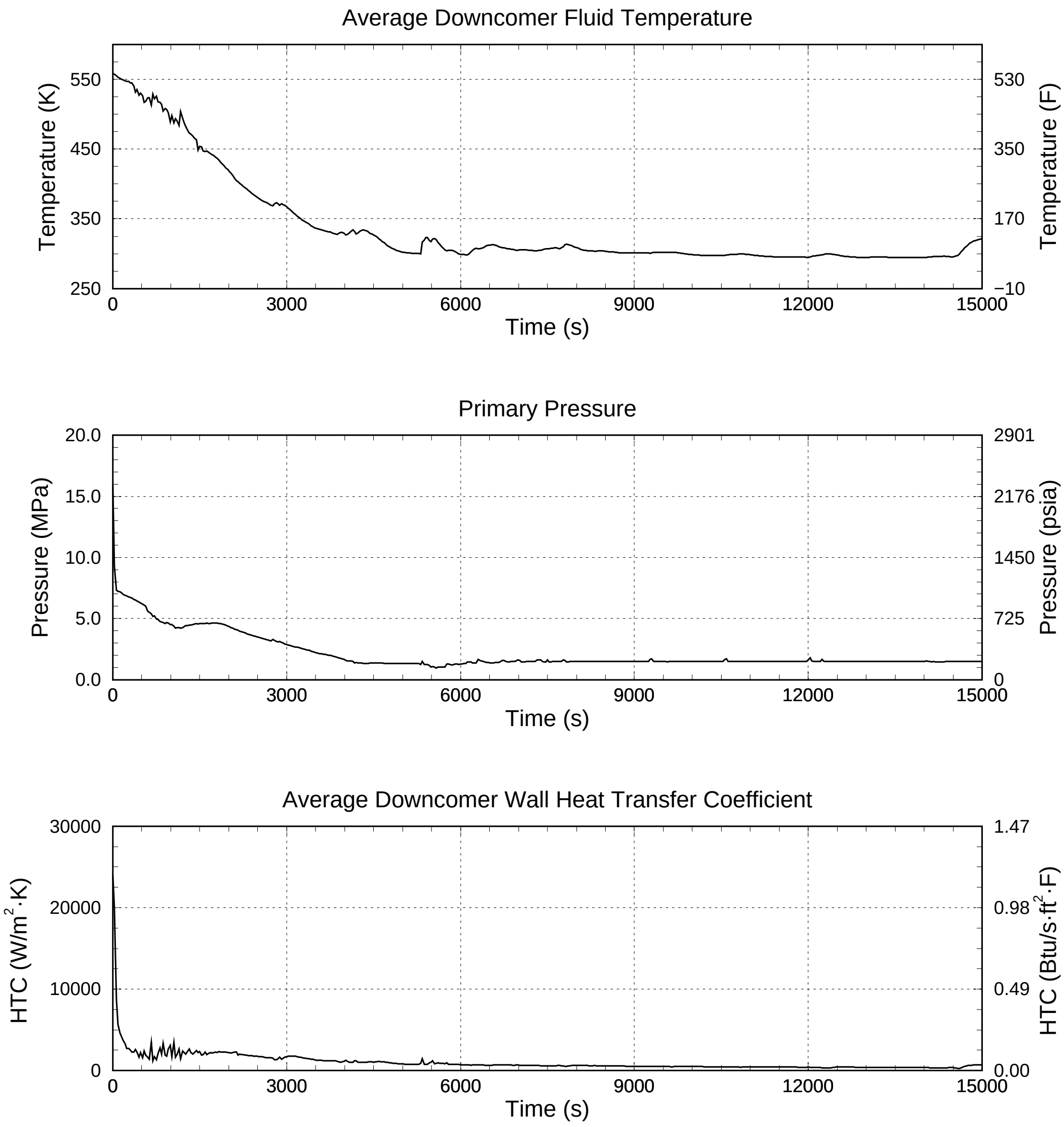
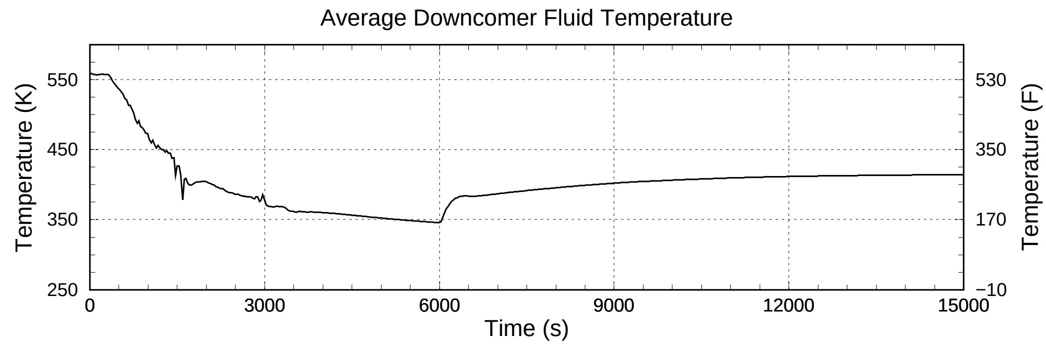
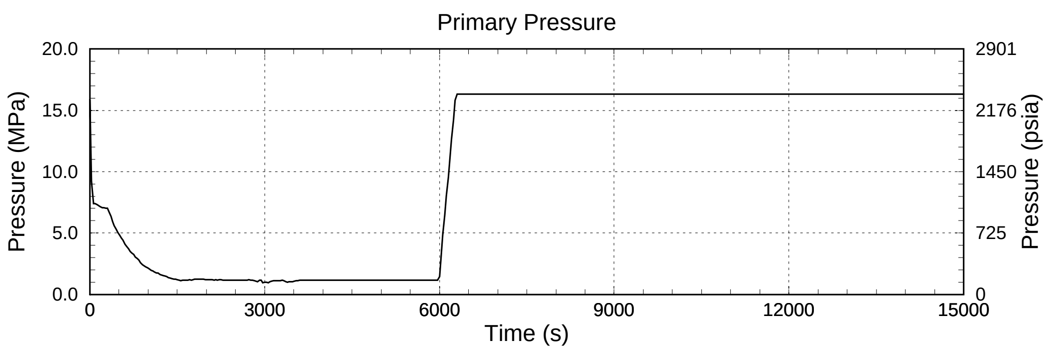


Figure B-16 Beaver Valley PTS Results for Case 067

Case Category	SOV
Primary Failures	Two stuck open pressurizer SRVs (recloses at 6,000 s), no HHSI
Secondary Failures	None
Operator Actions	Open all ASDVs 5 minutes after HHSI would have come on
Min DC Temperature	345.7 K [162.6°F] at 6000 s
Comments	





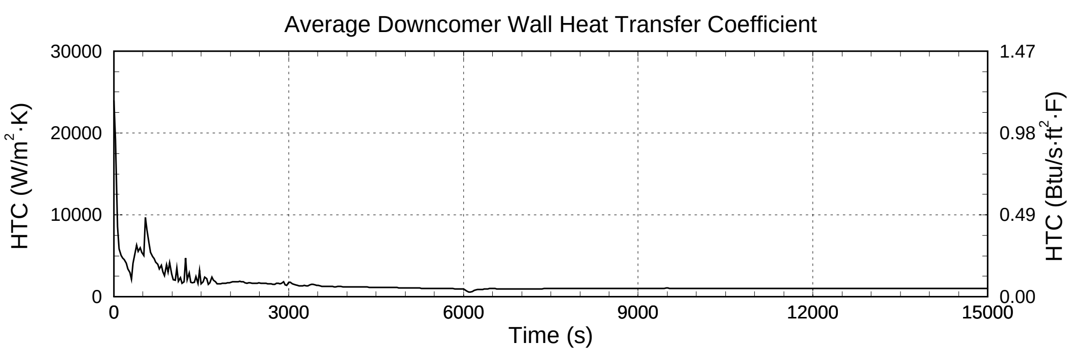


Figure B-17 Beaver Valley PTS Results for Case 068

Case Category	SOV, HZP
Primary Failures	Two stuck open pressurizer SRVs (recloses at 3,000 s)
Secondary Failures	None
Operator Actions	None
Min DC Temperature	295.4 K [72.1°F] at 15000 s
Comments	Case 061 @ HZP

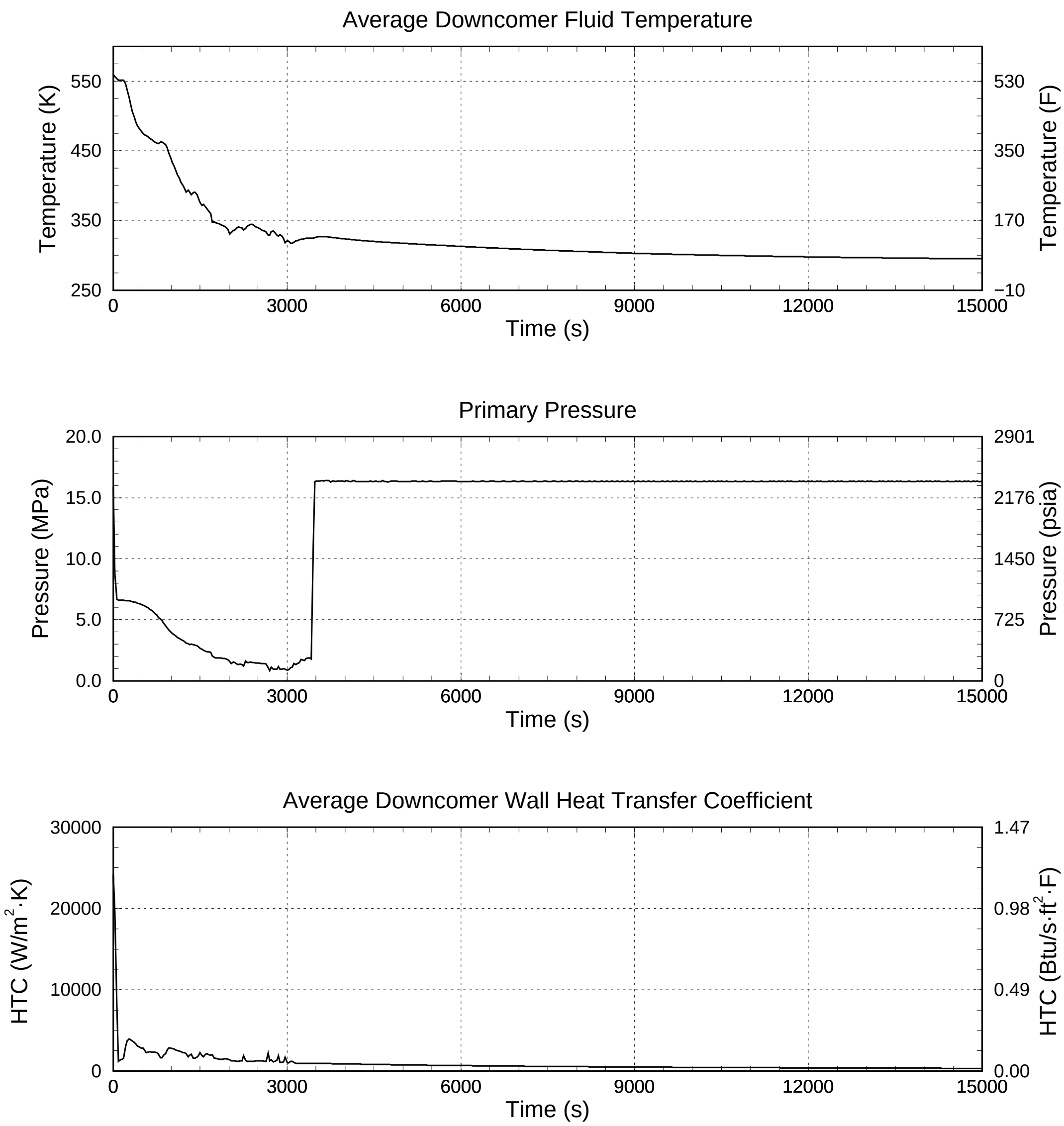


Figure B-18 Beaver Valley PTS Results for Case 069

Case Category	SOV, HZP
Primary Failures	Two stuck open pressurizer SRVs (recloses at 6,000 s)
Secondary Failures	None
Operator Actions	None
Min DC Temperature	288.6 K [59.7°F] at 5790 s
Comments	Case 062 @ HZP

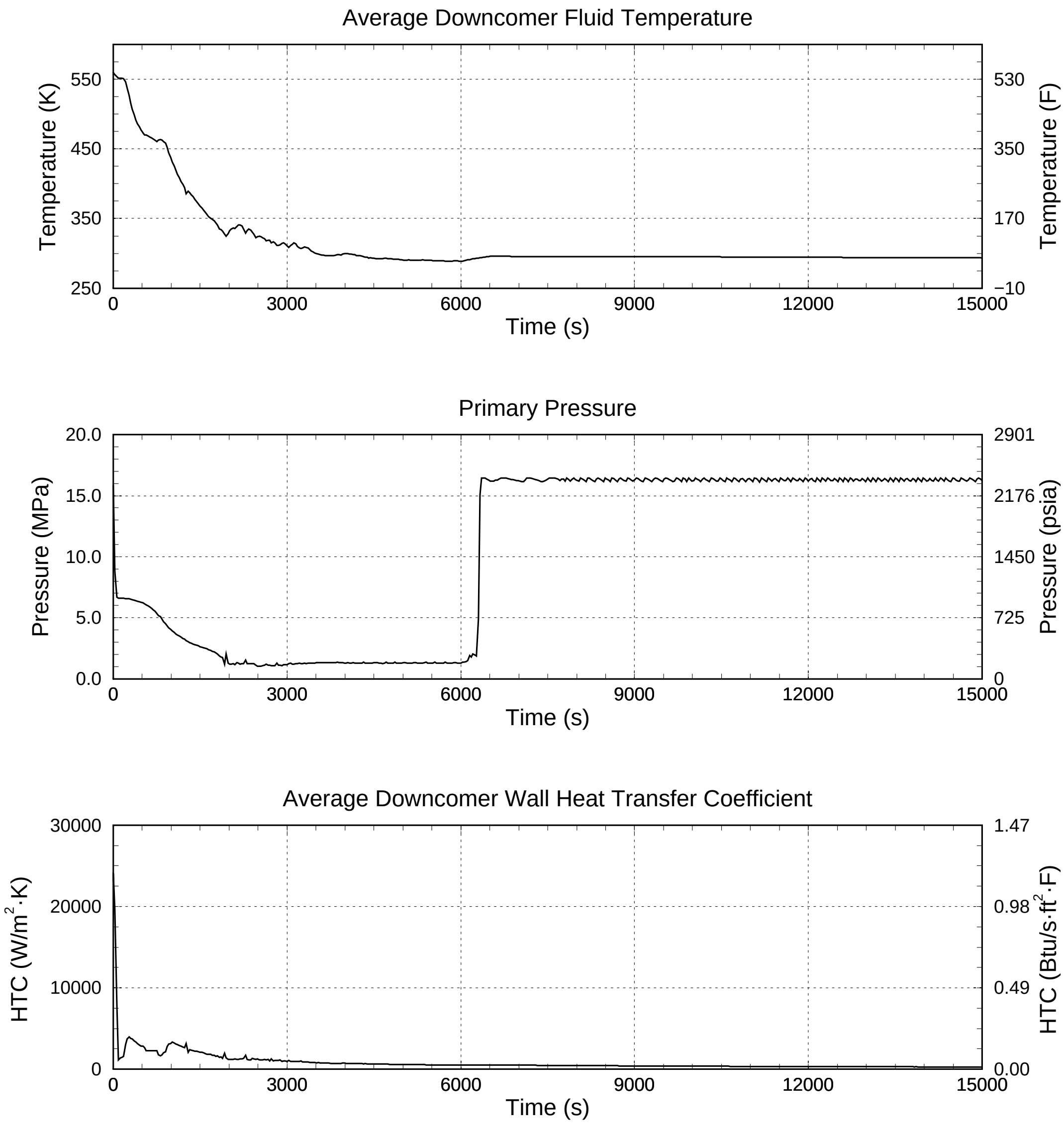


Figure B-19   Beaver Valley PTS Results for Case 070

Case Category	SOV, HZP
Primary Failures	One stuck open pressurizer SRV (recloses at 6,000 s)
Secondary Failures	None
Operator Actions	None
Min DC Temperature	295.0 K [71.2°F] at 15000 s
Comments	Case 060 @ HZP

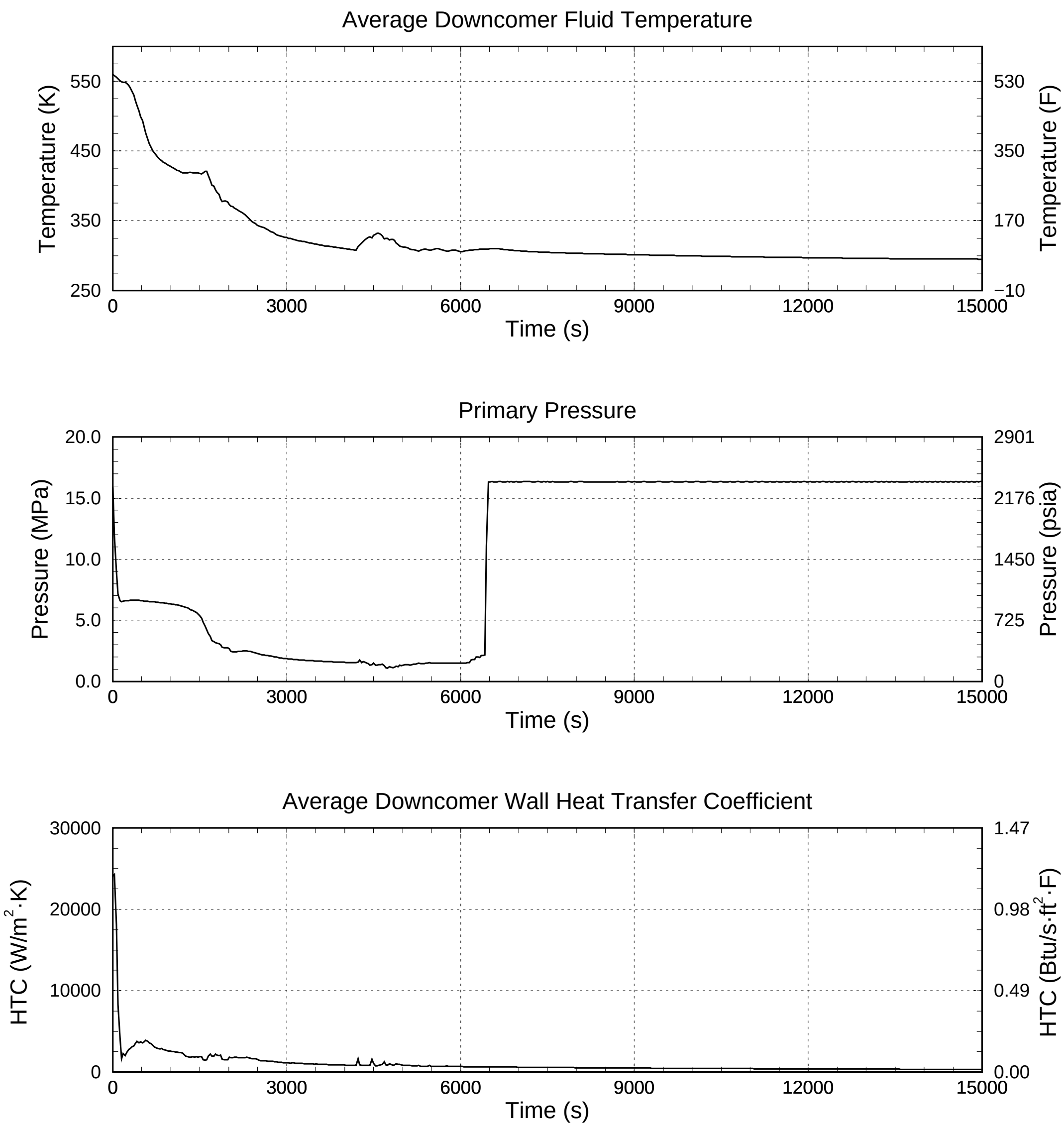


Figure B-20 Beaver Valley PTS Results for Case 071

Case Category	SOV
Primary Failures	One stuck open pressurizer SRV, no HHSI
Secondary Failures	None
Operator Actions	Open all ASDVs 5 minutes after HHSI would have come on
Min DC Temperature	358.3 K [185.2°F] at 15000 s
Comments	None

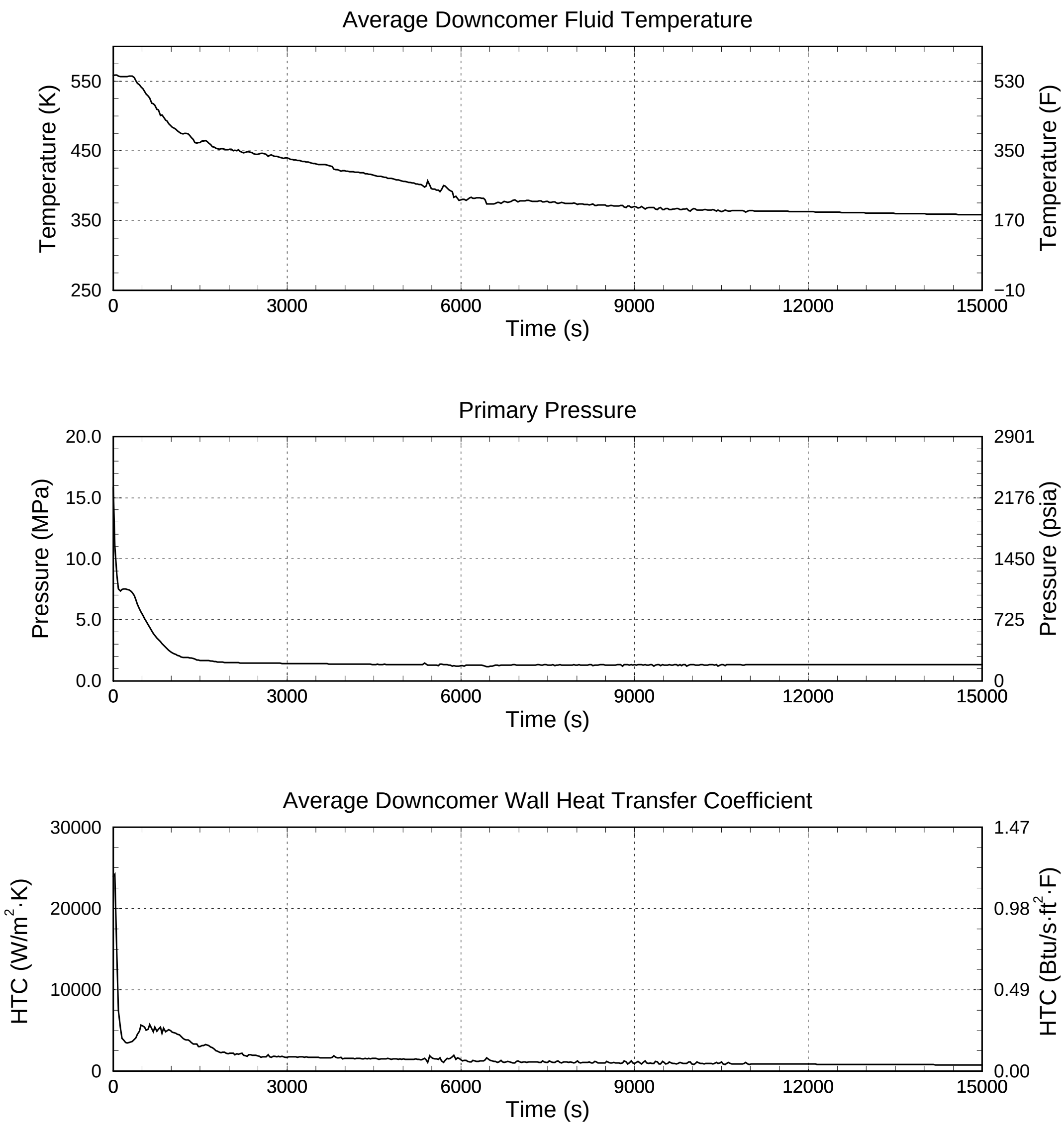


Figure B-21 Beaver Valley PTS Results for Case 072

Case Category	SOV, HZP
Primary Failures	One stuck open pressurizer SRV, no HHSI
Secondary Failures	None
Operator Actions	Open all ASDVs 5 minutes after HHSI would have come on
Min DC Temperature	285.0 K [53.3°F] at 15000 s
Comments	Case 072 @ HZP

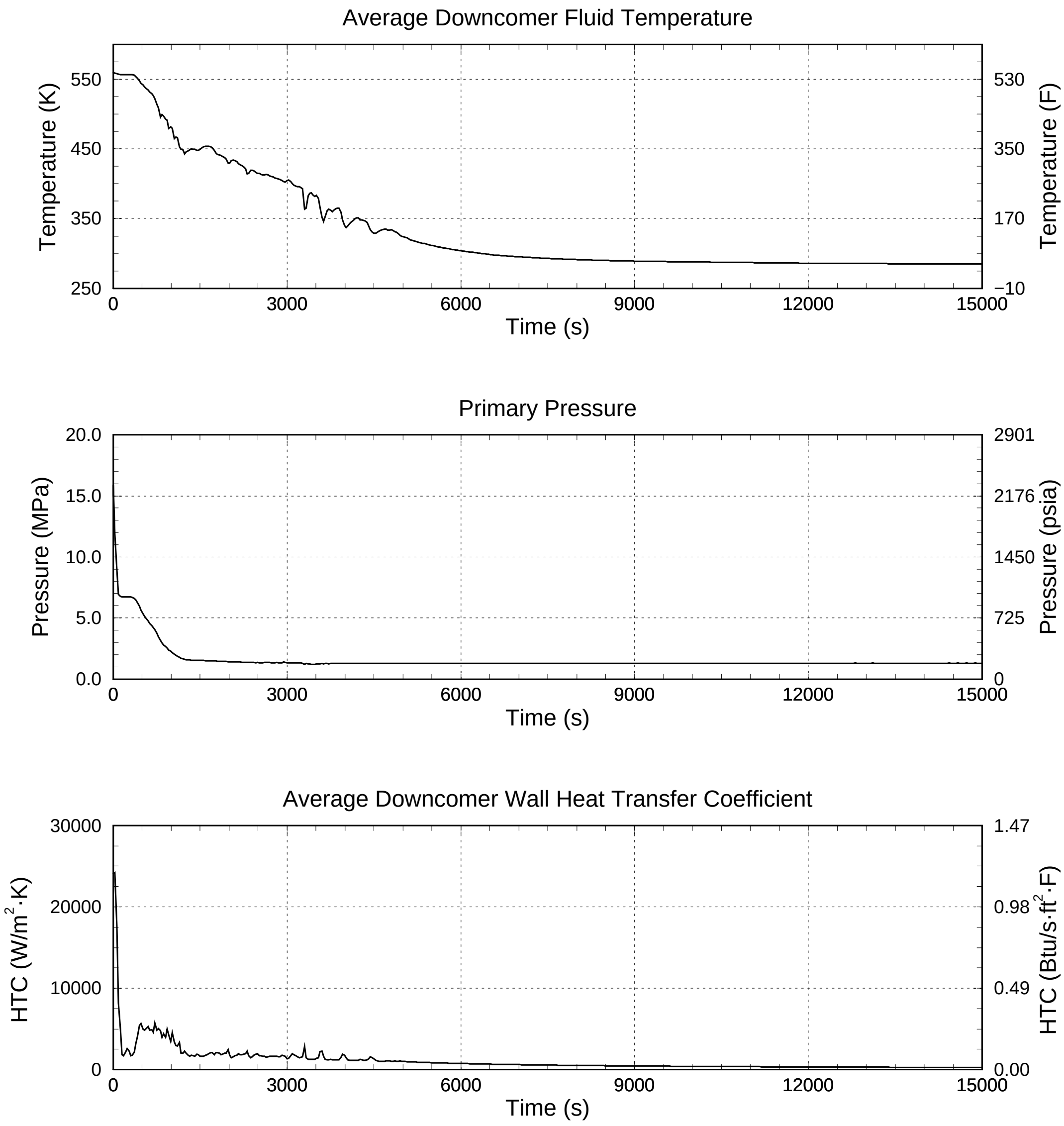


Figure B-22 Beaver Valley PTS Results for Case 073

Case Category	MSLB
Primary Failures	None
Secondary Failures	Double ended guillotine break of steam line A
Operator Actions	None
Min DC Temperature	378.9 K [222.4°F] at 13710 s
Comments	AFW continues to feed SG A

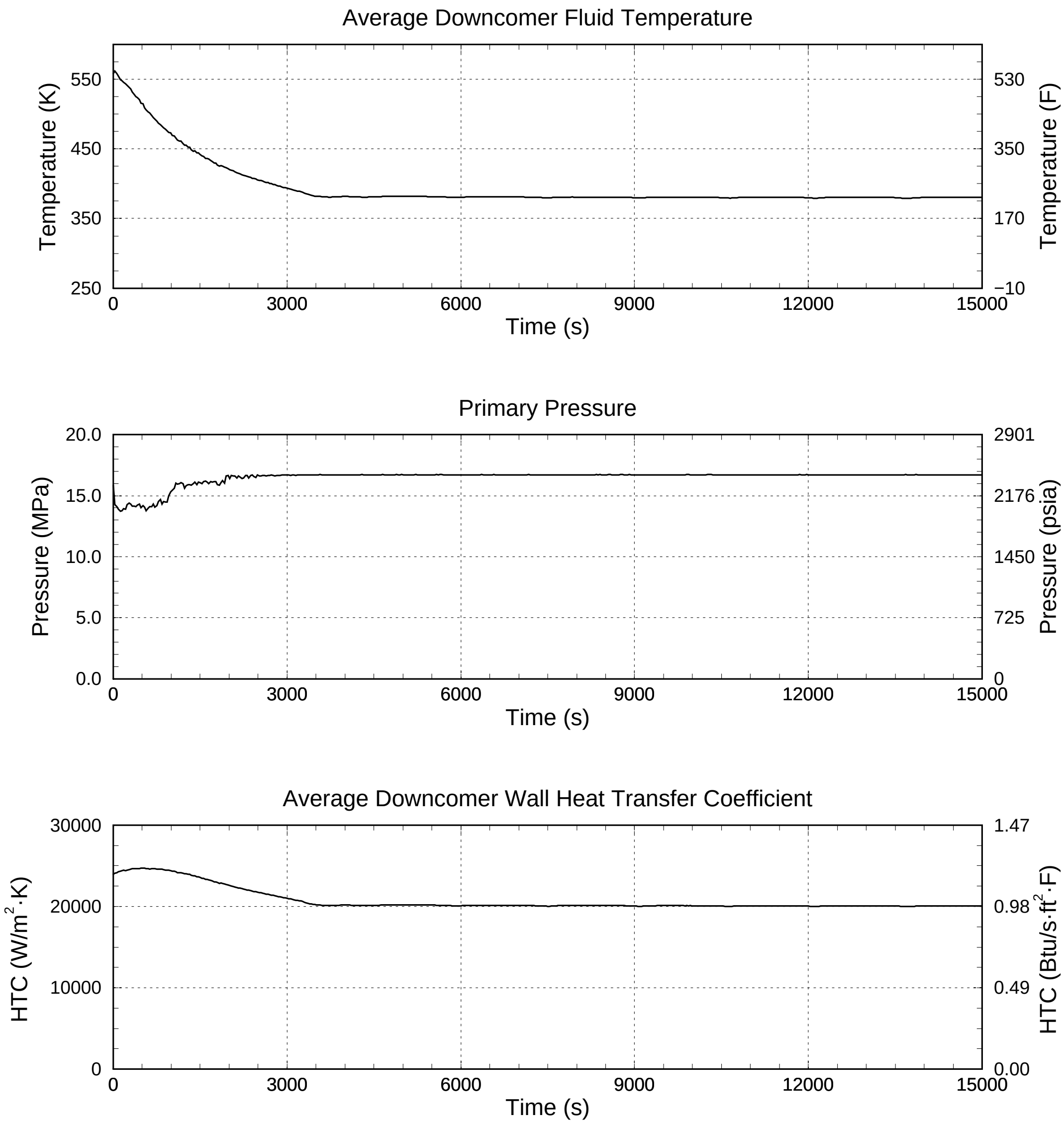


Figure B-23 Beaver Valley PTS Results for Case 074

Case Category	RT/TT
Primary Failures	None
Secondary Failures	MFW overfeed of all SGs
Operator Actions	RCP's are tripped
Min DC Temperature	507.8 K [454.4°F] at 15000 s
Comments	MFW keeps SGs filled to top.

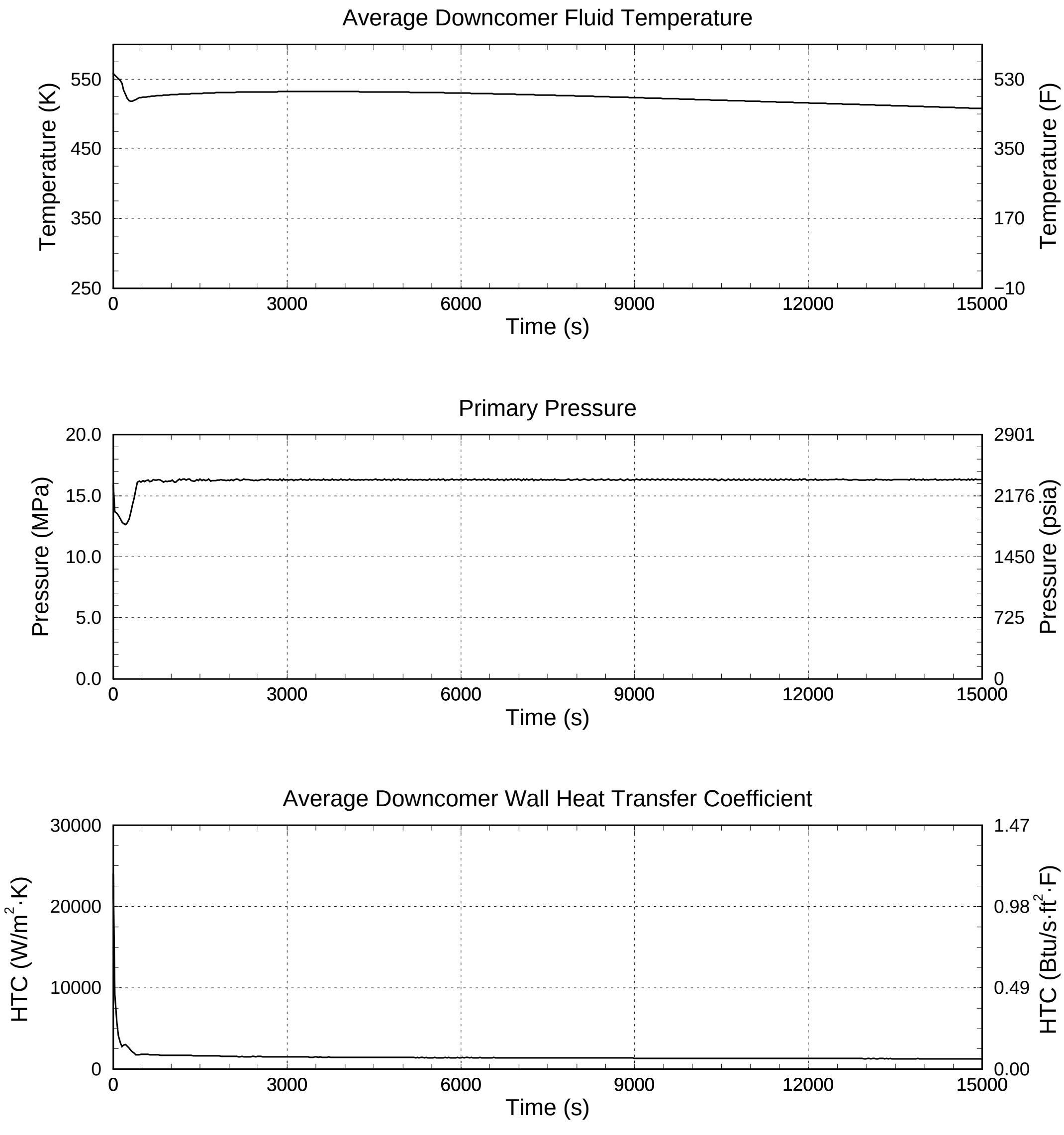
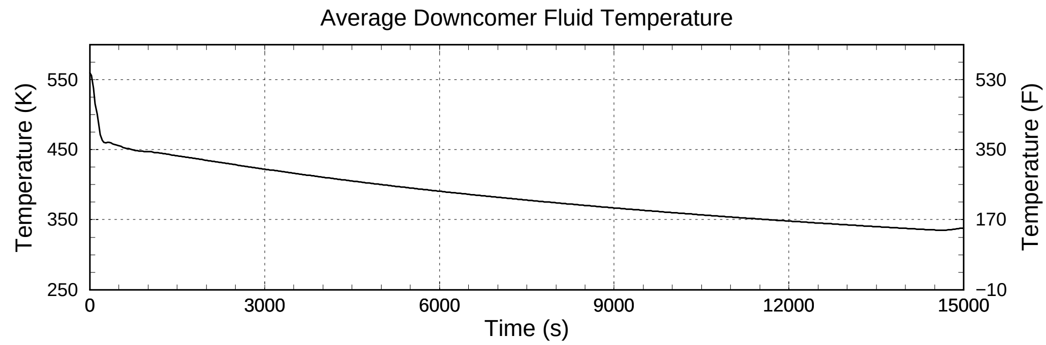
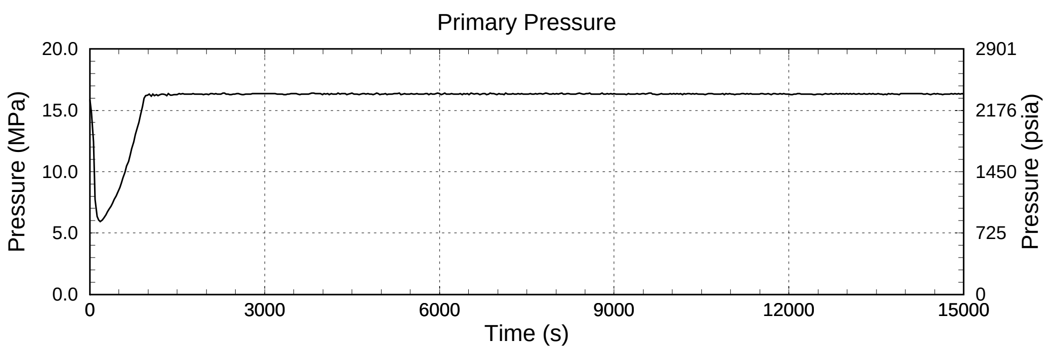


Figure B-24 Beaver Valley PTS Results for Case 075

Case Category	RT/TT, HZP
Primary Failures	None
Secondary Failures	MFW overfeed of all SGs
Operator Actions	RCP's are tripped
Min DC Temperature	335.0 K [143.4°F] at 14610 s
Comments	MFW keeps SGs filled to top. Case 075 @ HZP





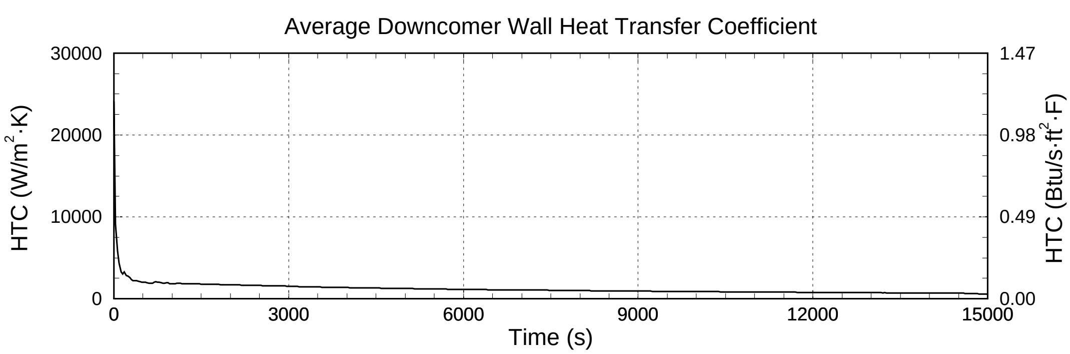


Figure B-25   Beaver Valley PTS Results for Case 076

Case Category	RT/TT
Primary Failures	None
Secondary Failures	Loss of MFW and AFW
Operator Actions	Open all ASDVs
Min DC Temperature	429.8 K [313.9°F] at 15000 s
Comments	Condensate pumps used to supply feedwater.

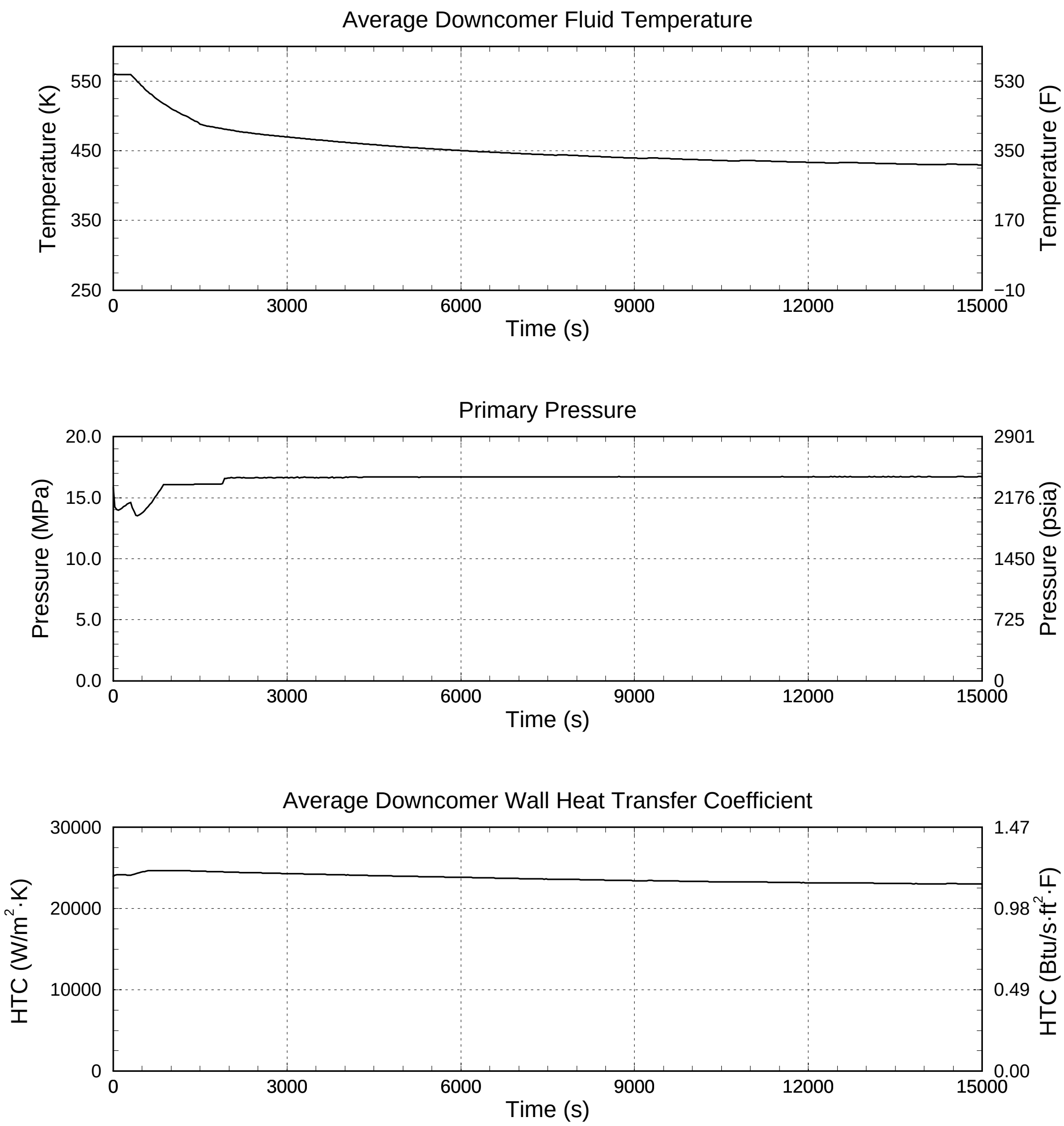


Figure B-26   Beaver Valley PTS Results for Case 078

Case Category	MSLB
Primary Failures	Initial HHSI failure
Secondary Failures	Double ended guillotine break of steam line A
Operator Actions	Open ASDVs on SG A
Min DC Temperature	388.5 K [239.6°F] at 3120 s
Comments	AFW continues to feed SG A. HHSI is available after CFTs discharge 50%.

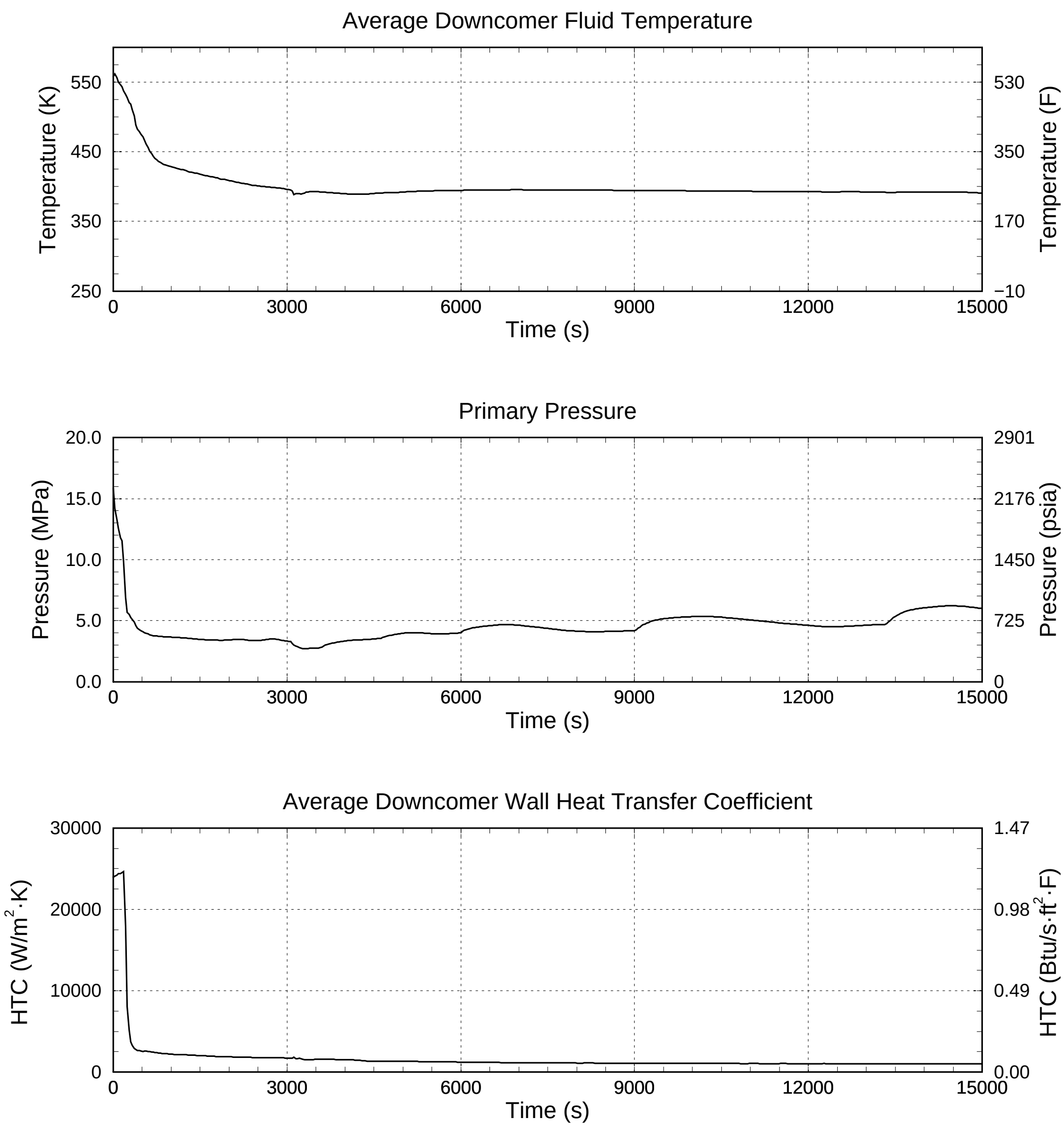
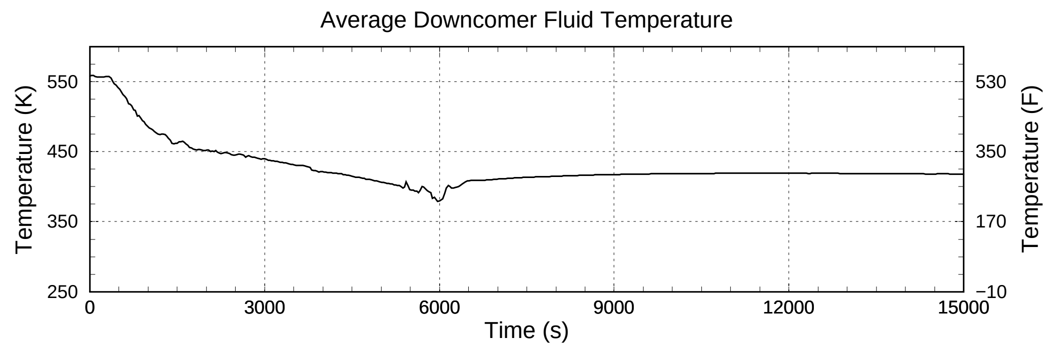
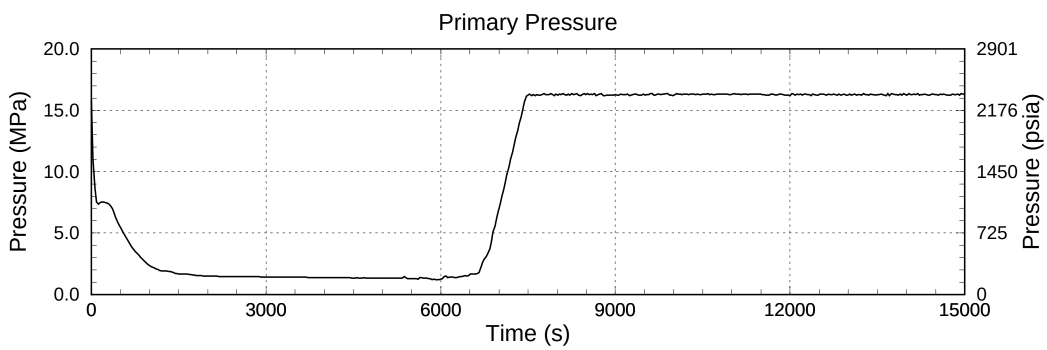


Figure B-27 Beaver Valley PTS Results for Case 081

Case Category	SOV
Primary Failures	One stuck open pressurizer SRV (recloses at 6,000 s), no HHSI
Secondary Failures	None
Operator Actions	Open all ASDVs 5 minutes after HHSI would have come on
Min DC Temperature	379.0 K [222.6°F] at 5970 s
Comments	





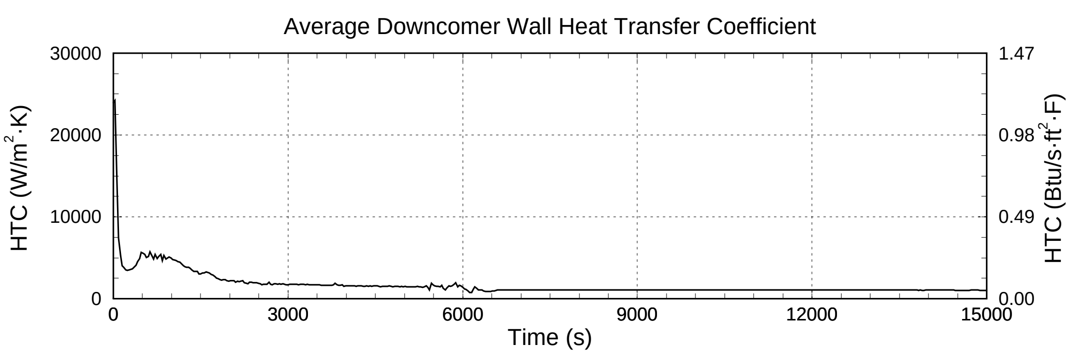


Figure B-28 Beaver Valley PTS Results for Case 082

Case Category	LOCA
Primary Failures	2.54 cm (1.0 in) surge line break, no HHSI
Secondary Failures	no motor AFW, overfeed of SGs with turbine AFW
Operator Actions	RCP's are tripped, MFW tripped, open all ASDVs 5 minutes after HHSI would have come on
Min DC Temperature	392.8 K [247.3°F] at 14400 s
Comments	None

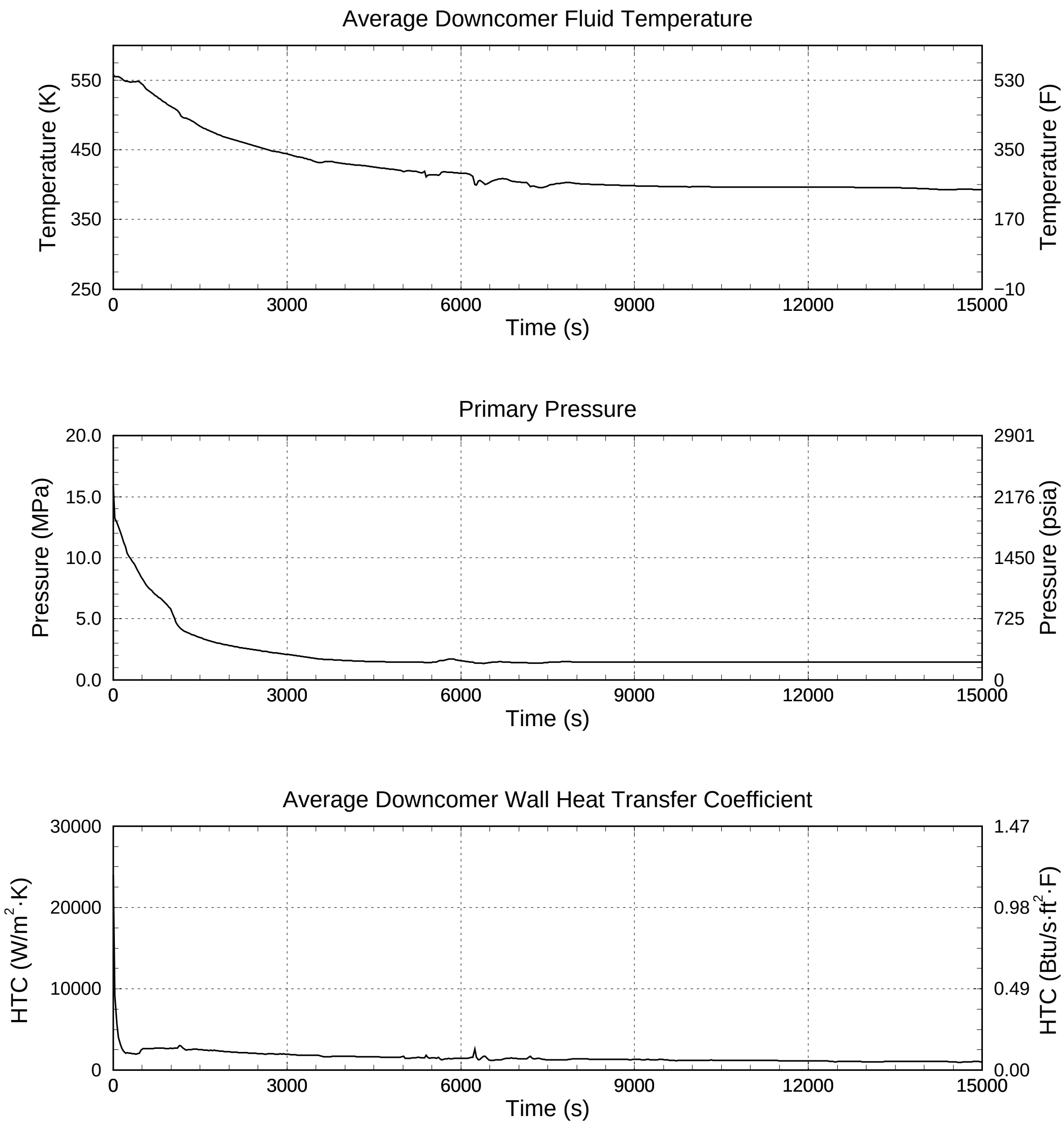


Figure B-29 Beaver Valley PTS Results for Case 083

Case Category	SOV, HZP
Primary Failures	Two stuck open pressurizer SRVs (one SRV recloses at 3,000 s)
Secondary Failures	None
Operator Actions	None
Min DC Temperature	288.9 K [60.3°F] at 14610 s
Comments	Case 066 @ HZP.

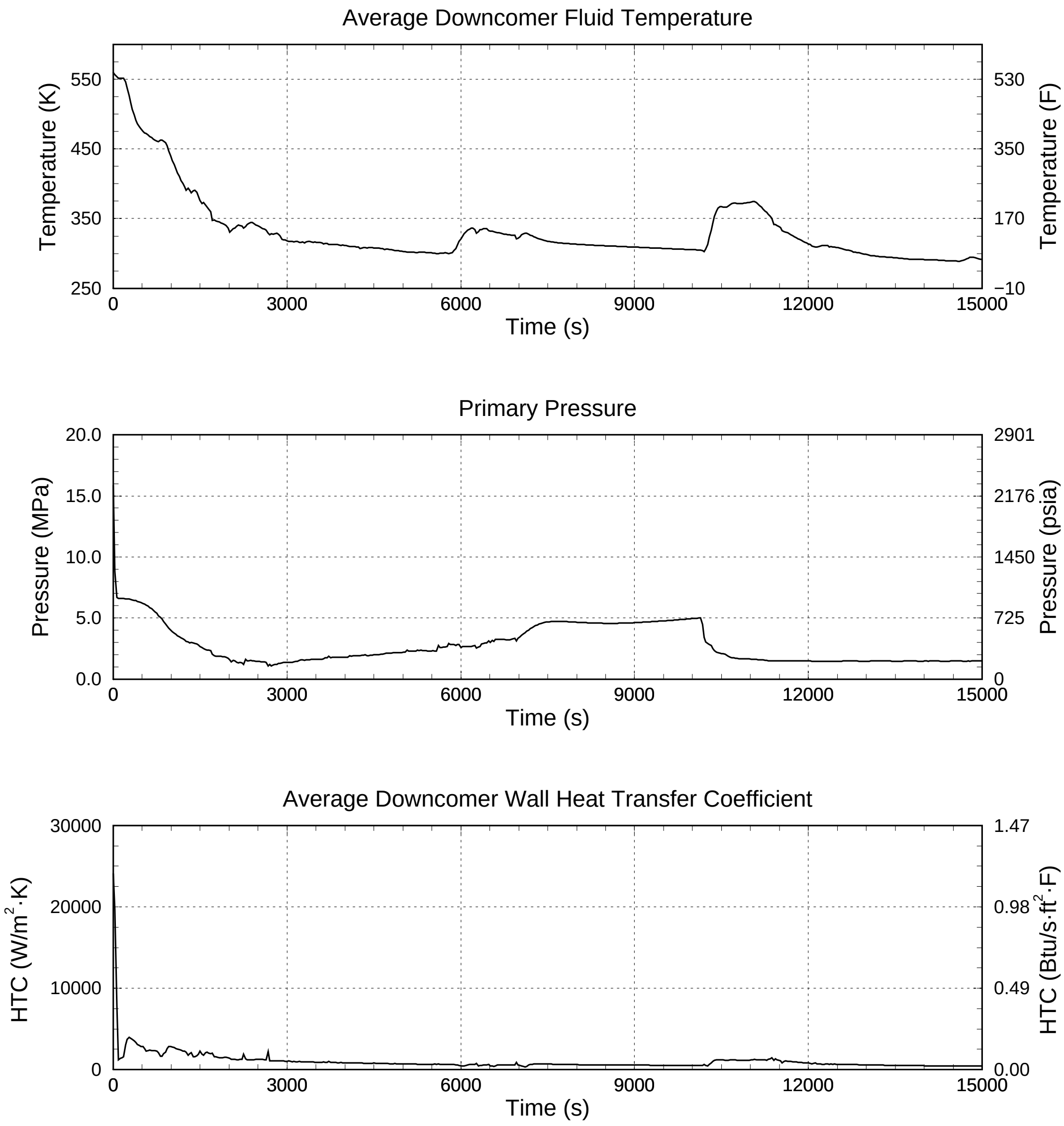


Figure B-30 Beaver Valley PTS Results for Case 092

Case Category	SOV, HZP
Primary Failures	Two stuck open pressurizer SRVs (one SRV recloses at 6,000 s)
Secondary Failures	None
Operator Actions	None
Min DC Temperature	291.5 K [65.0°F] at 15000 s
Comments	Case 067 @ HZP

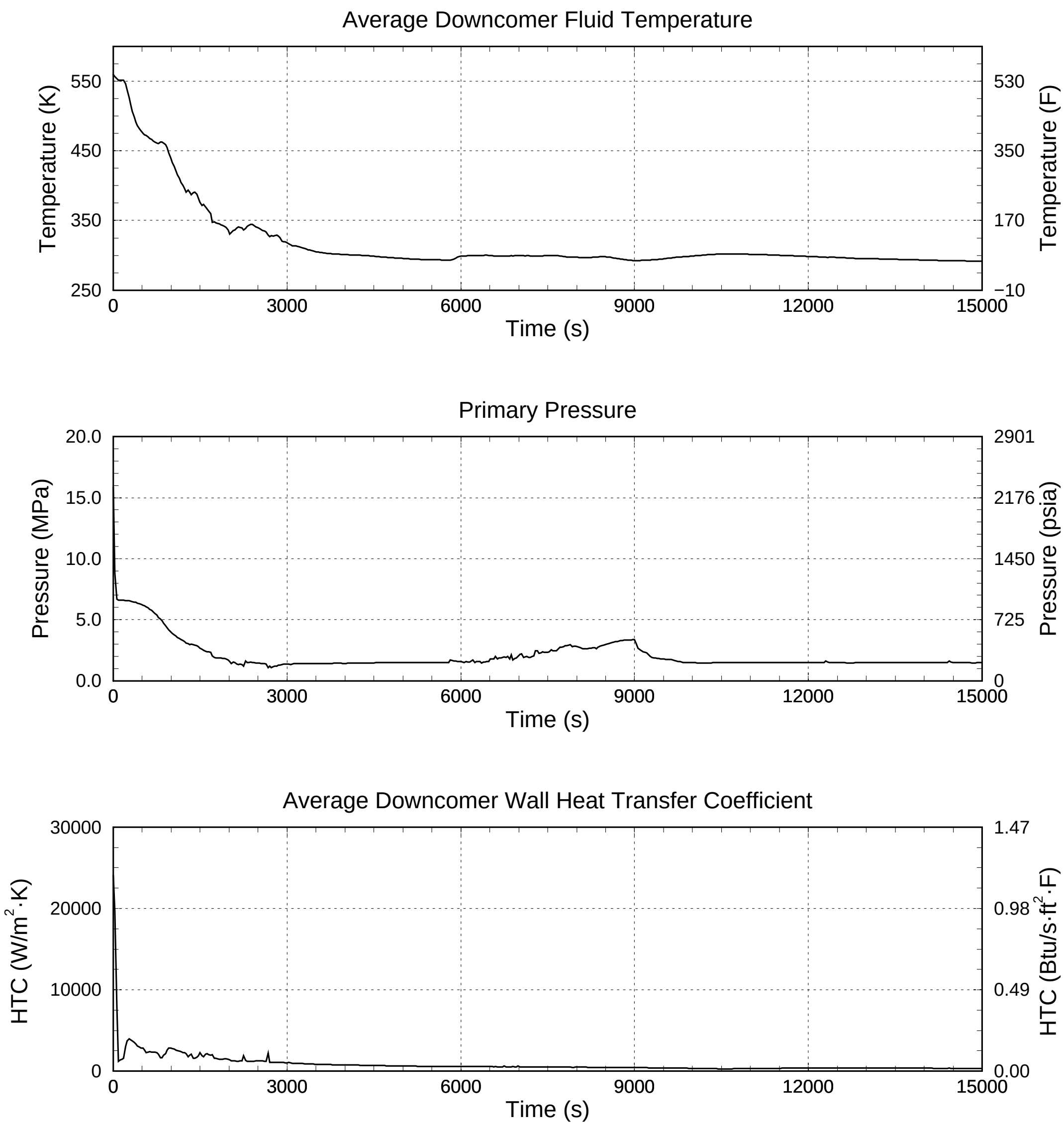


Figure B-31 Beaver Valley PTS Results for Case 093

Case Category	SOV, HZP
Primary Failures	One stuck open pressurizer SRV
Secondary Failures	None
Operator Actions	None
Min DC Temperature	285.4 K [54.1°F] at 15000 s
Comments	Case 014 @ HZP.

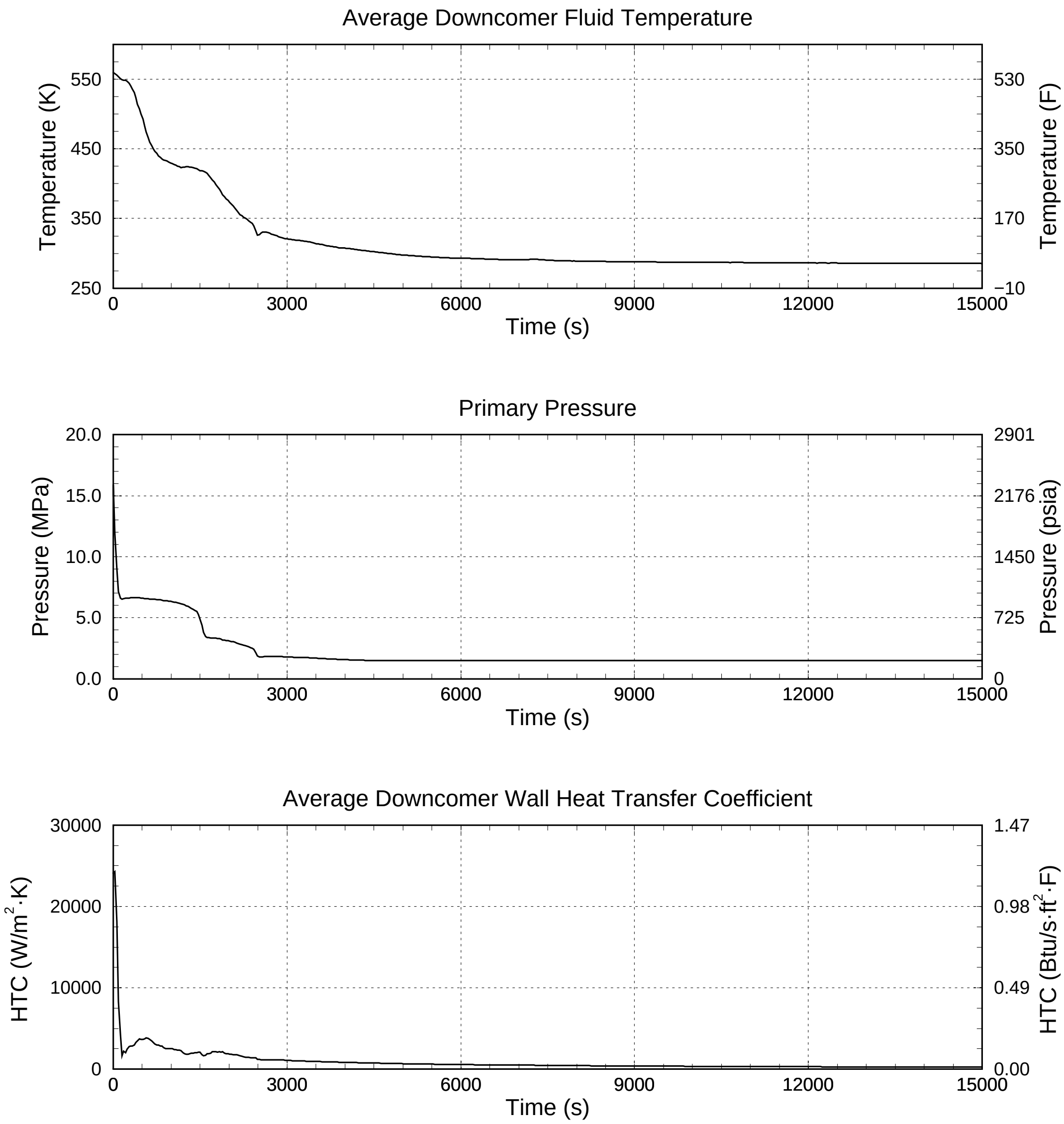


Figure B-32 Beaver Valley PTS Results for Case 094

Case Category	SOV, HZP
Primary Failures	One stuck open pressurizer SRV (recloses at 3,000 s)
Secondary Failures	None
Operator Actions	None
Min DC Temperature	296.8 K [74.6°F] at 15000 s
Comments	

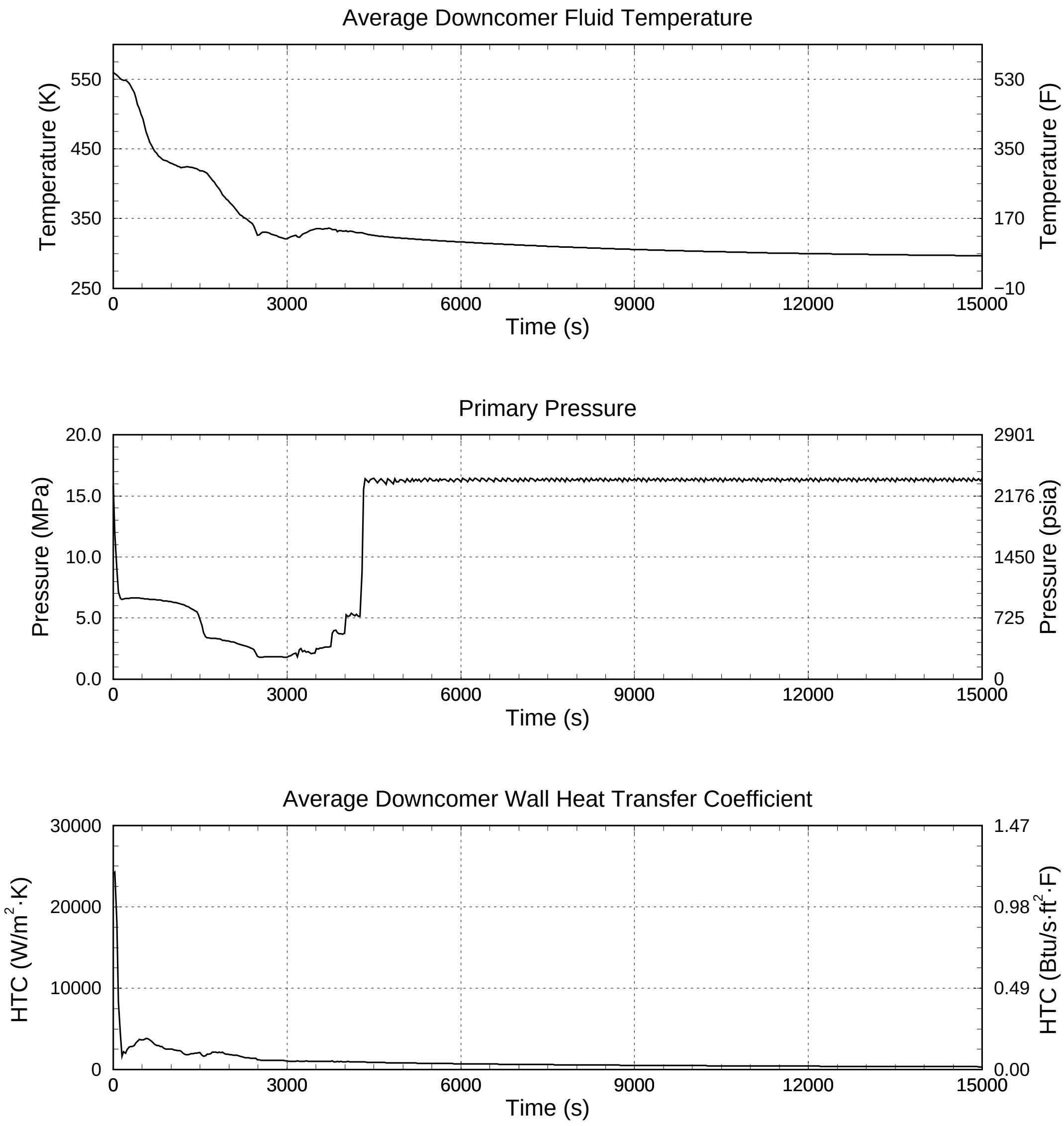
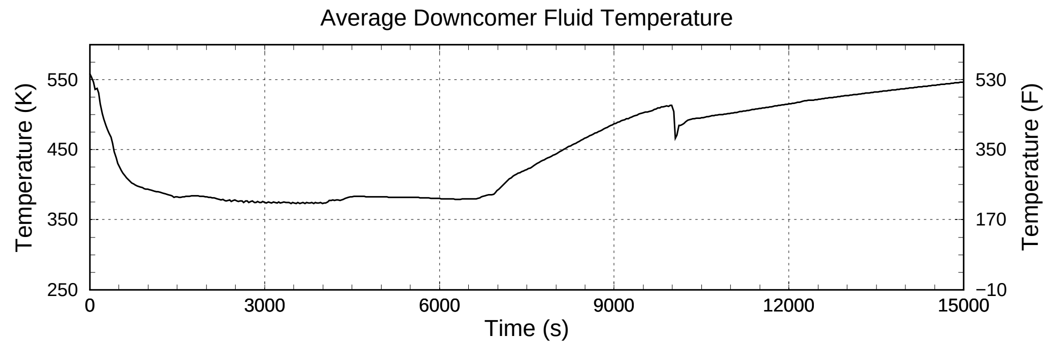
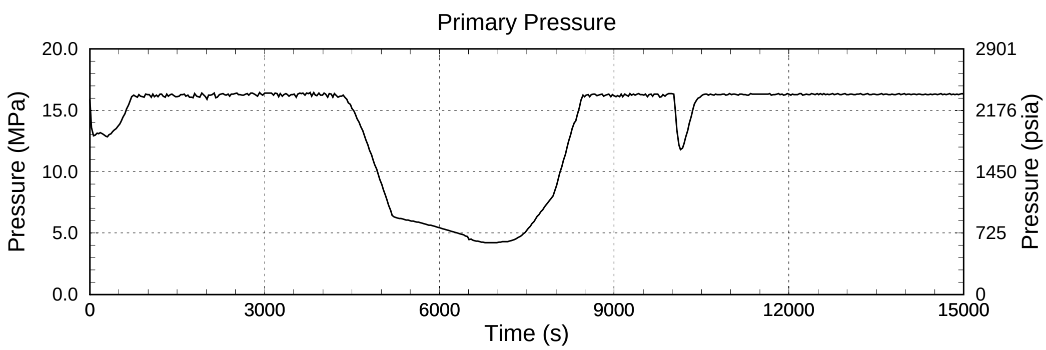


Figure B-33 Beaver Valley PTS Results for Case 097

Case Category	MSLB
Primary Failures	None
Secondary Failures	Double ended guillotine break of steam line A
Operator Actions	RCP's are tripped. Operator controls HHSI (30 minute delay)
Min DC Temperature	373.3 K [212.2°F] at 3990 s
Comments	AFW continues to feed SG A for 30 minutes.





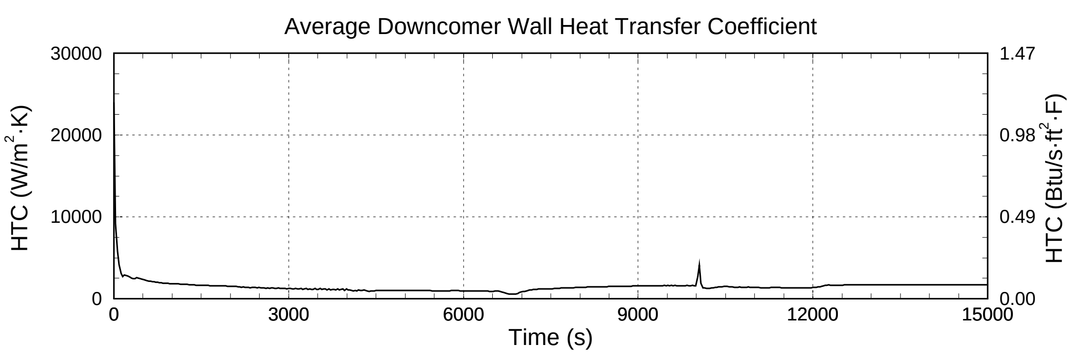


Figure B-34 Beaver Valley PTS Results for Case 102

Case Category	MSLB, HZP
Primary Failures	None
Secondary Failures	Double ended guillotine break of steam line A
Operator Actions	RCP's are tripped. Operator controls HHSI (30 minute delay)
Min DC Temperature	361.7 K [191.5°F] at 3420 s
Comments	AFW continues to feed SG A for 30 minutes. Case 102 @ HZP.

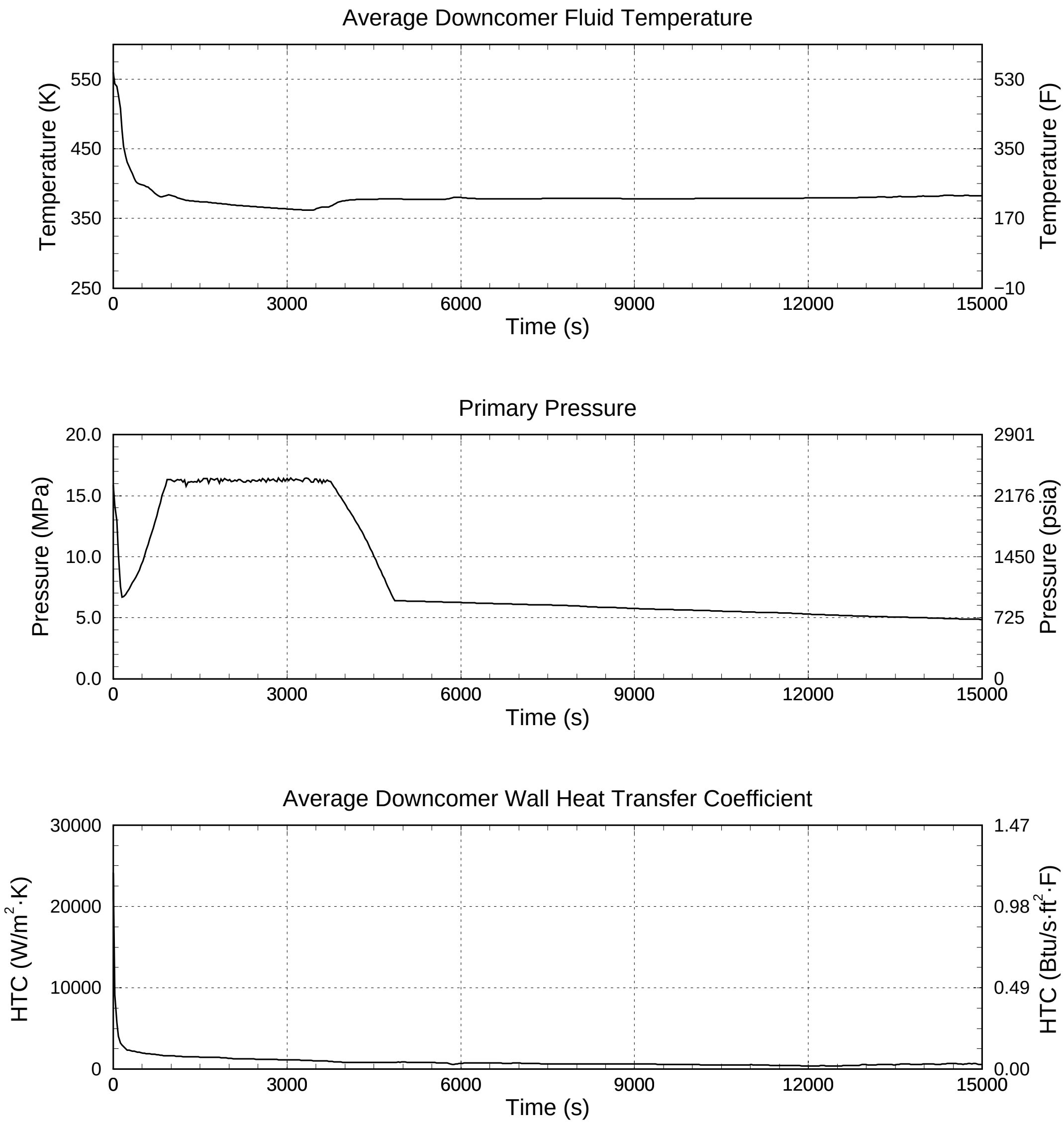
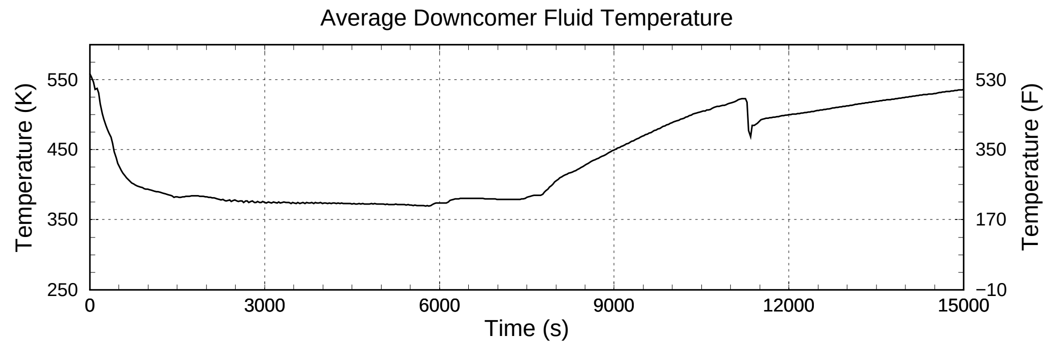
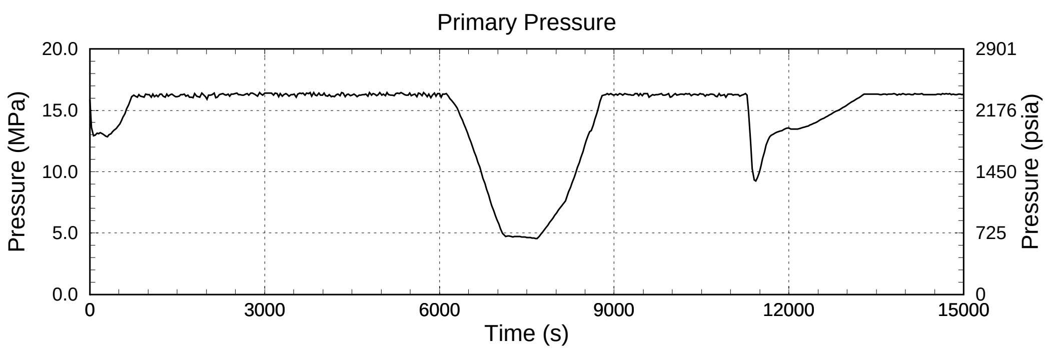


Figure B-35 Beaver Valley PTS Results for Case 103

Case Category	MSLB
Primary Failures	None
Secondary Failures	Double ended guillotine break of steam line A
Operator Actions	RCP's are tripped. Operator controls HHSI (60 minute delay)
Min DC Temperature	369.6 K [205.6°F] at 5820 s
Comments	AFW continues to feed SG A for 30 minutes.





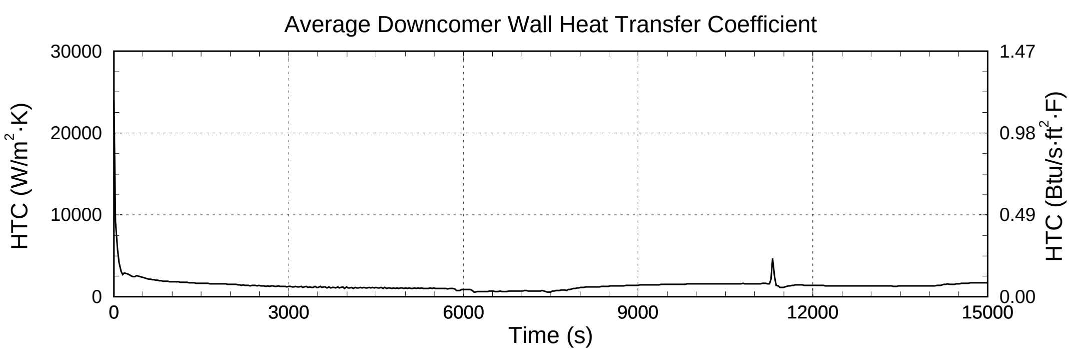


Figure B-36 Beaver Valley PTS Results for Case 104

Case Category	MSLB, HZP
Primary Failures	None
Secondary Failures	Double ended guillotine break of steam line A
Operator Actions	RCP's are tripped. Operator controls HHSI (60 minute delay)
Min DC Temperature	355.0 K [179.4°F] at 5220 s
Comments	AFW continues to feed SG A for 30 minutes. Case 104 @ HZP.

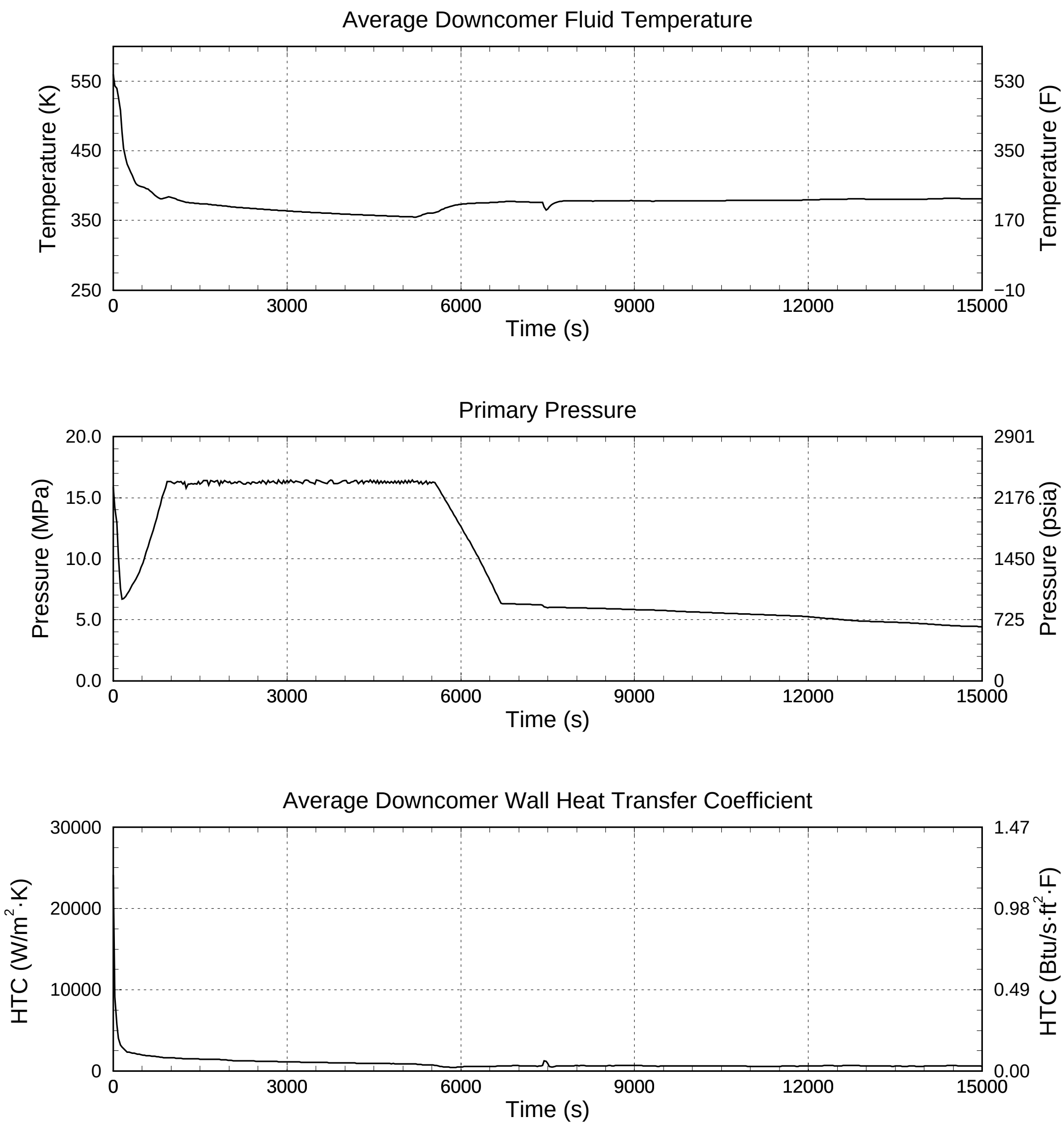
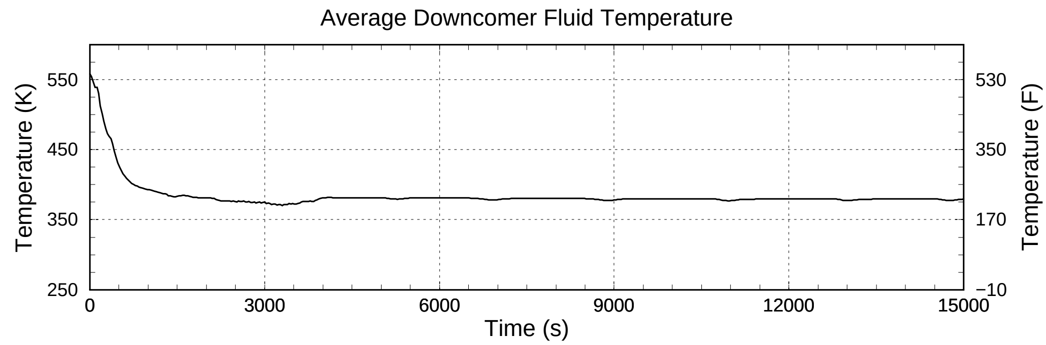
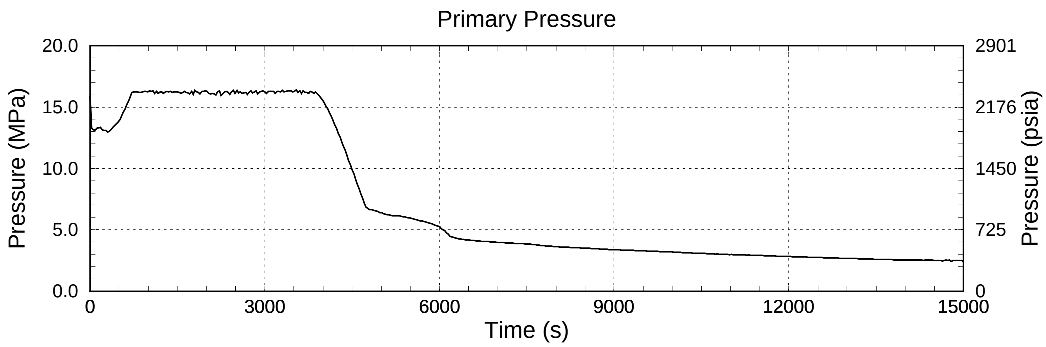


Figure B-37 Beaver Valley PTS Results for Case 105

Case Category	MSLB
Primary Failures	None
Secondary Failures	Double ended guillotine break of steam line A
Operator Actions	RCP's are tripped. Operator controls HHSI (30 minute delay)
Min DC Temperature	370.4 K [207.1°F] at 3300 s
Comments	AFW continues to feed SG A.





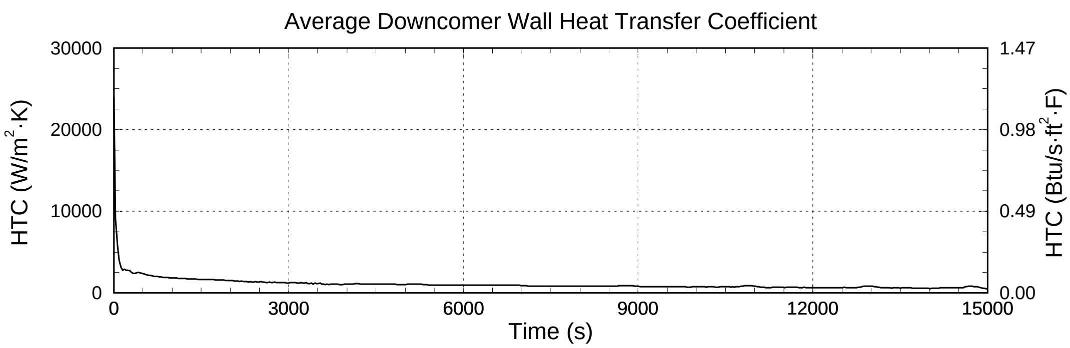
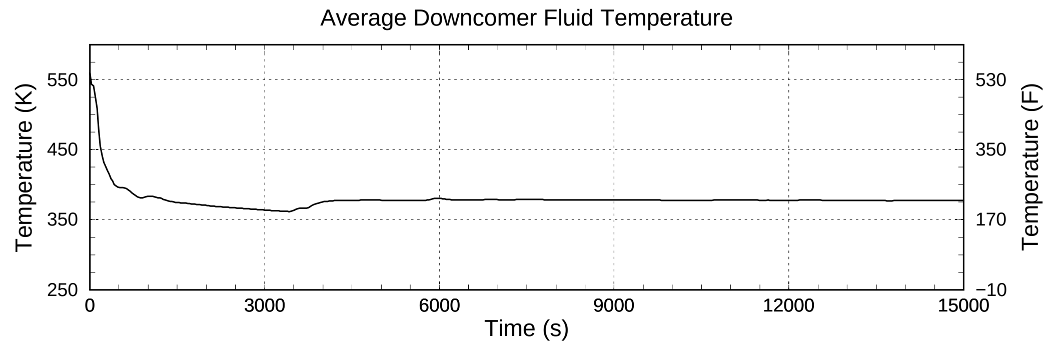
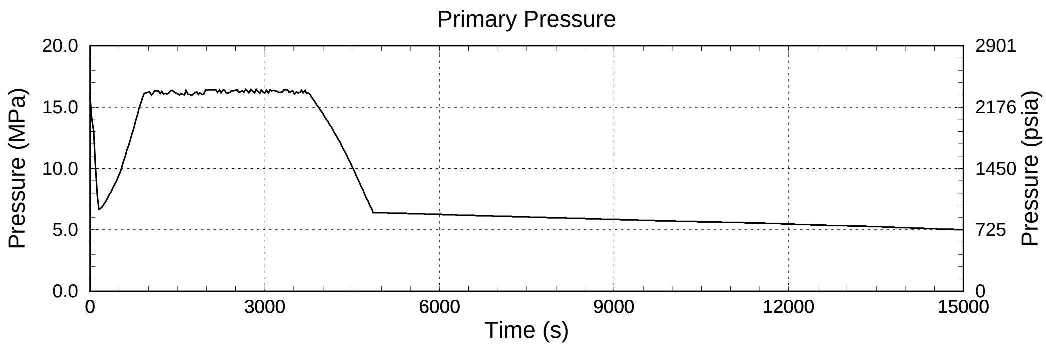


Figure B-38 Beaver Valley PTS Results for Case 106

Case Category	MSLB, HZP
Primary Failures	None
Secondary Failures	Double ended guillotine break of steam line A
Operator Actions	RCP's are tripped. Operator controls HHSI (30 minute delay)
Min DC Temperature	361.6 K [191.3°F] at 3420 s
Comments	AFW continues to feed SG A.





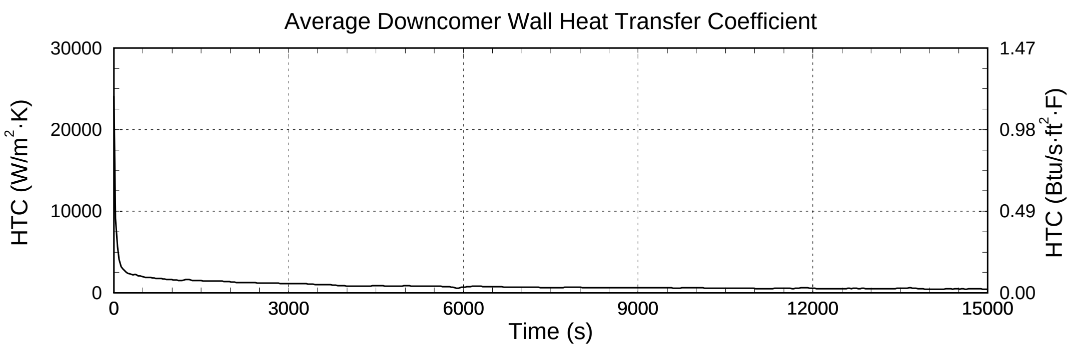
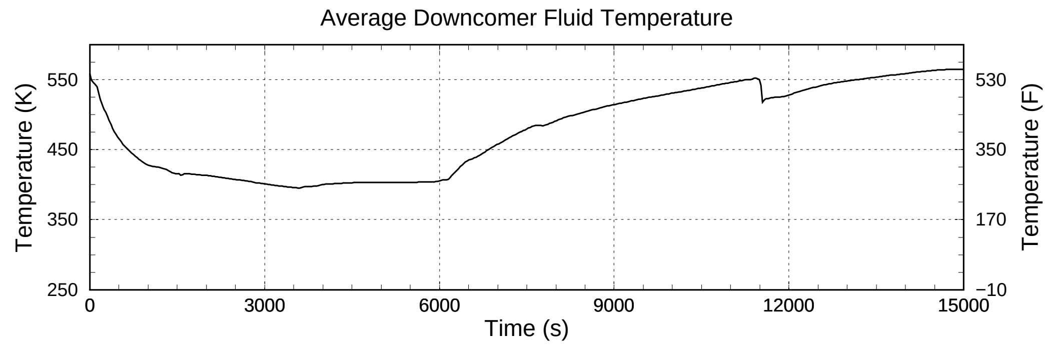
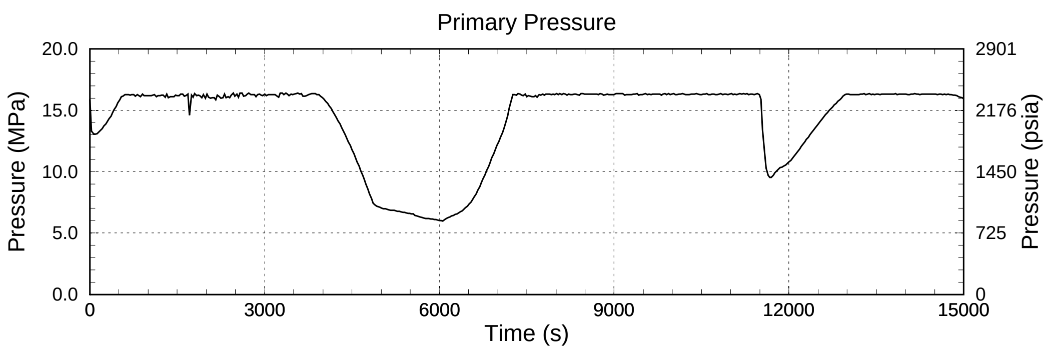


Figure B-39   Beaver Valley PTS Results for Case 107

Case Category	MSLB
Primary Failures	None
Secondary Failures	All MS-SRVs on SG A stuck open
Operator Actions	Operator controls HHSI (30 minute delay)
Min DC Temperature	395.3 K [251.8°F] at 3600 s
Comments	AFW continues to feed SG A for 30 minutes.





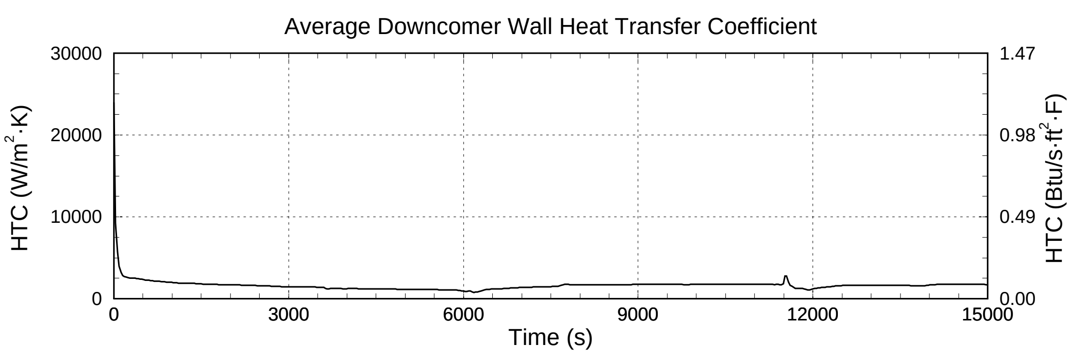
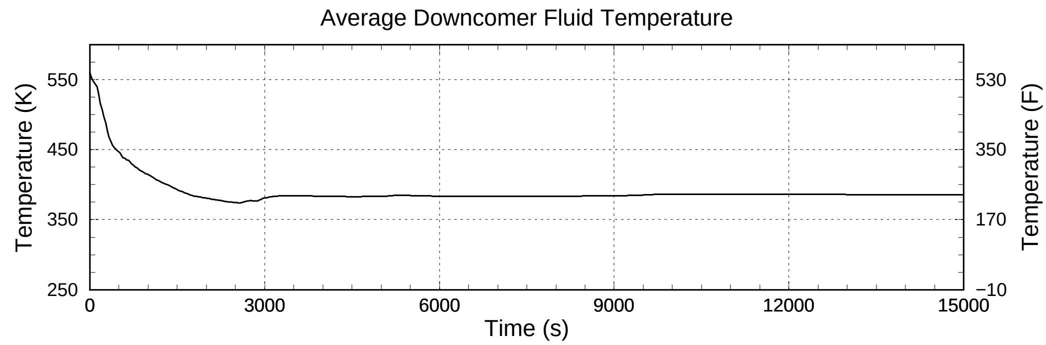
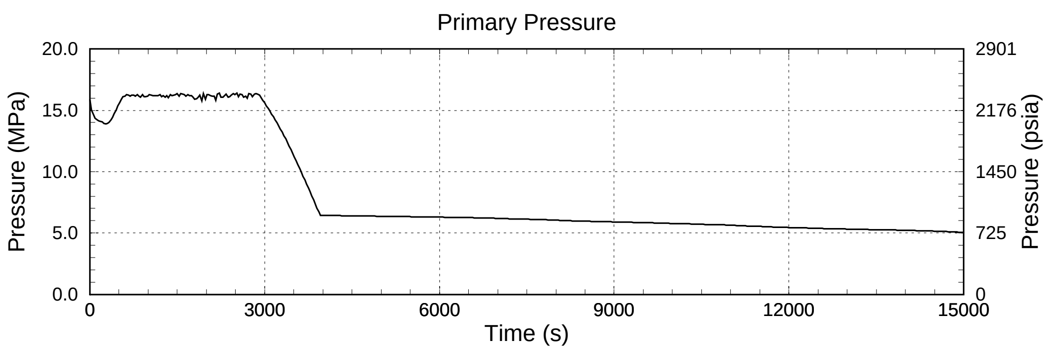


Figure B-40 Beaver Valley PTS Results for Case 108

Case Category	MSLB, HZP
Primary Failures	None
Secondary Failures	All MS-SRVs on SG A stuck open
Operator Actions	RCP's are tripped. Operator controls HHSI (30 minute delay)
Min DC Temperature	373.7 K [213.0°F] at 2580 s
Comments	AFW continues to feed SG A for 30 minutes.





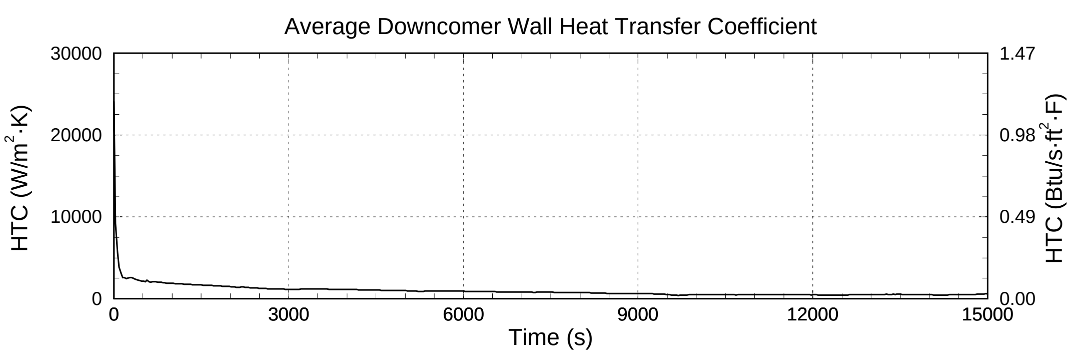


Figure B-41   Beaver Valley PTS Results for Case 109

Case Category	MSLB
Primary Failures	None
Secondary Failures	All MS-SRVs on SG A stuck open
Operator Actions	Operator controls HHSI (60 minute delay)
Min DC Temperature	383.9 K [231.3°F] at 5400 s
Comments	AFW continues to feed SG A for 30 minutes.

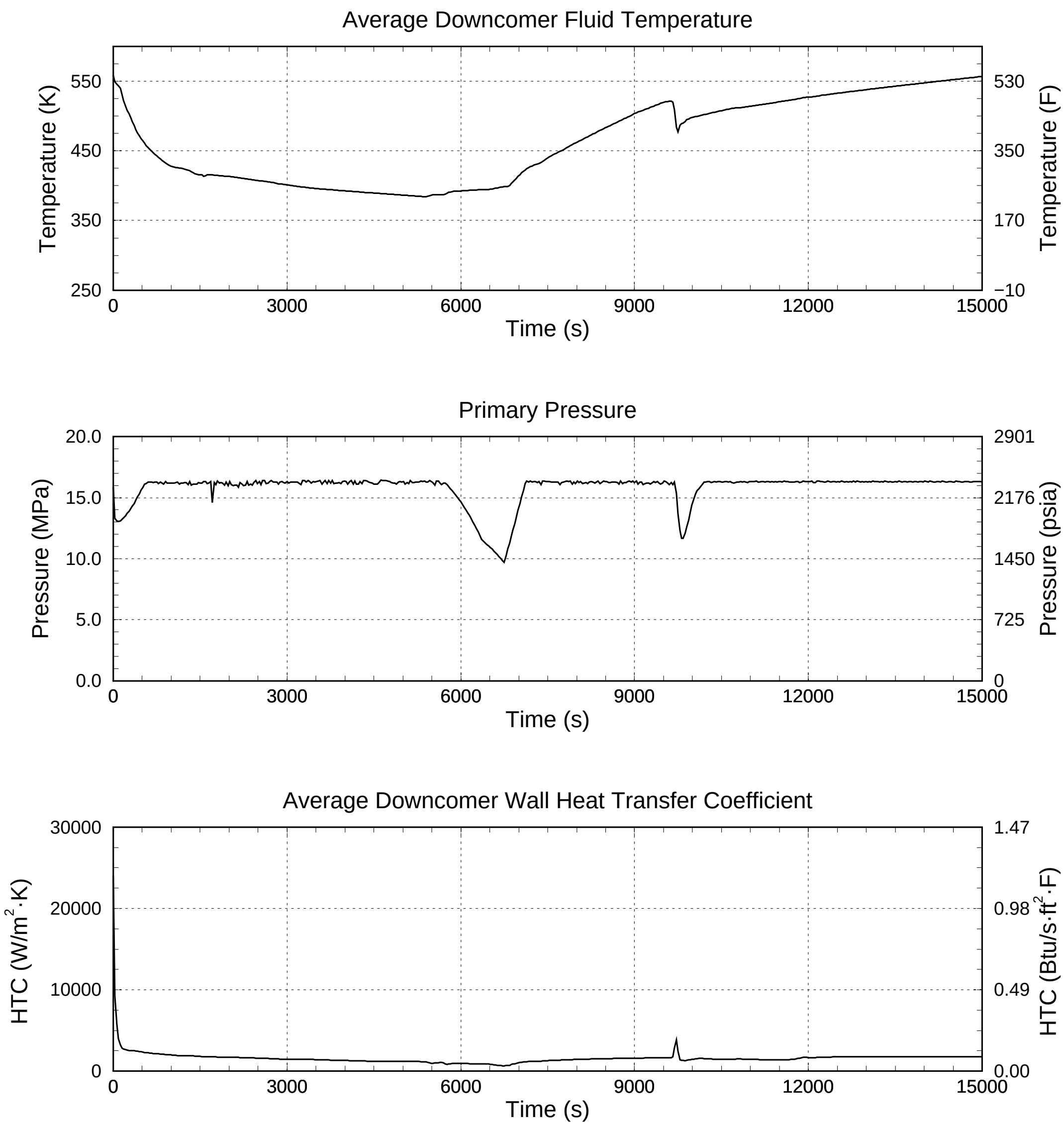
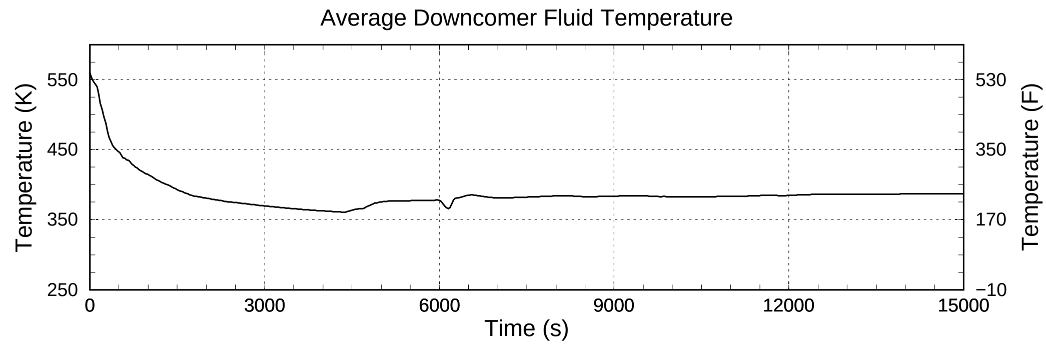
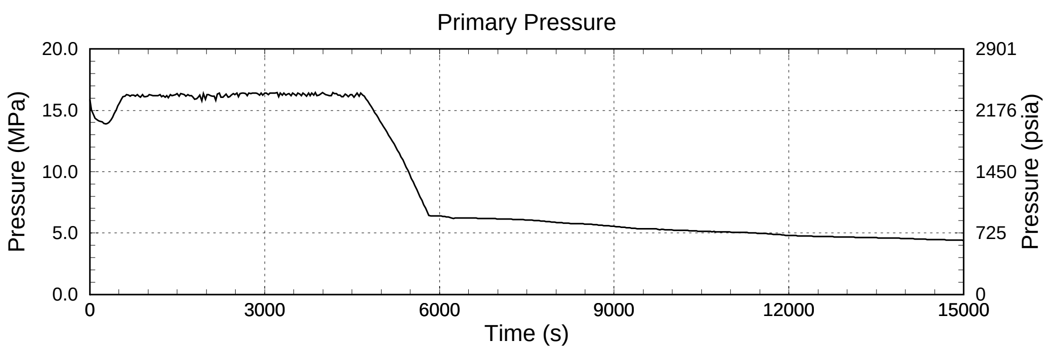


Figure B-42 Beaver Valley PTS Results for Case 110

Case Category	MSLB, HZP
Primary Failures	None
Secondary Failures	All MS-SRVs on SG A stuck open
Operator Actions	RCP's are tripped. Operator controls HHSI (60 minute delay)
Min DC Temperature	360.6 K [189.4°F] at 4380 s
Comments	AFW continues to feed SG A for 30 minutes.





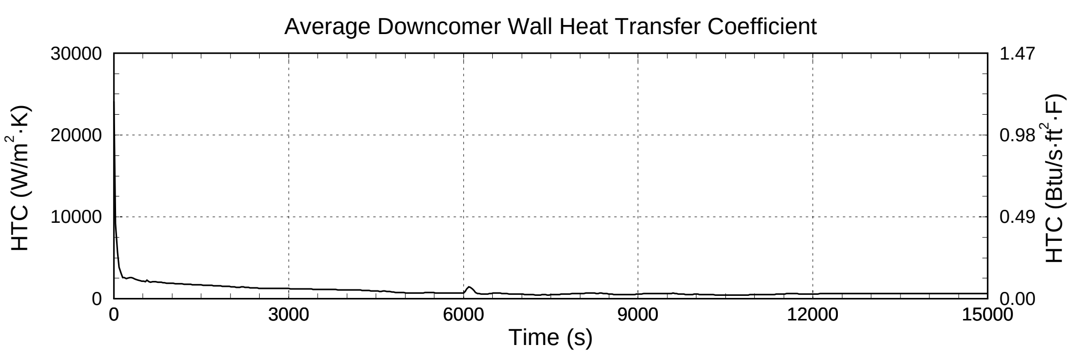


Figure B-43 Beaver Valley PTS Results for Case 111

Case Category	MSLB
Primary Failures	None
Secondary Failures	All MS-SRVs on SG A stuck open
Operator Actions	RCP's are tripped. Operator controls HHSI (30 minute delay)
Min DC Temperature	391.7 K [245.4°F] at 10980 s
Comments	AFW continues to feed SG A.

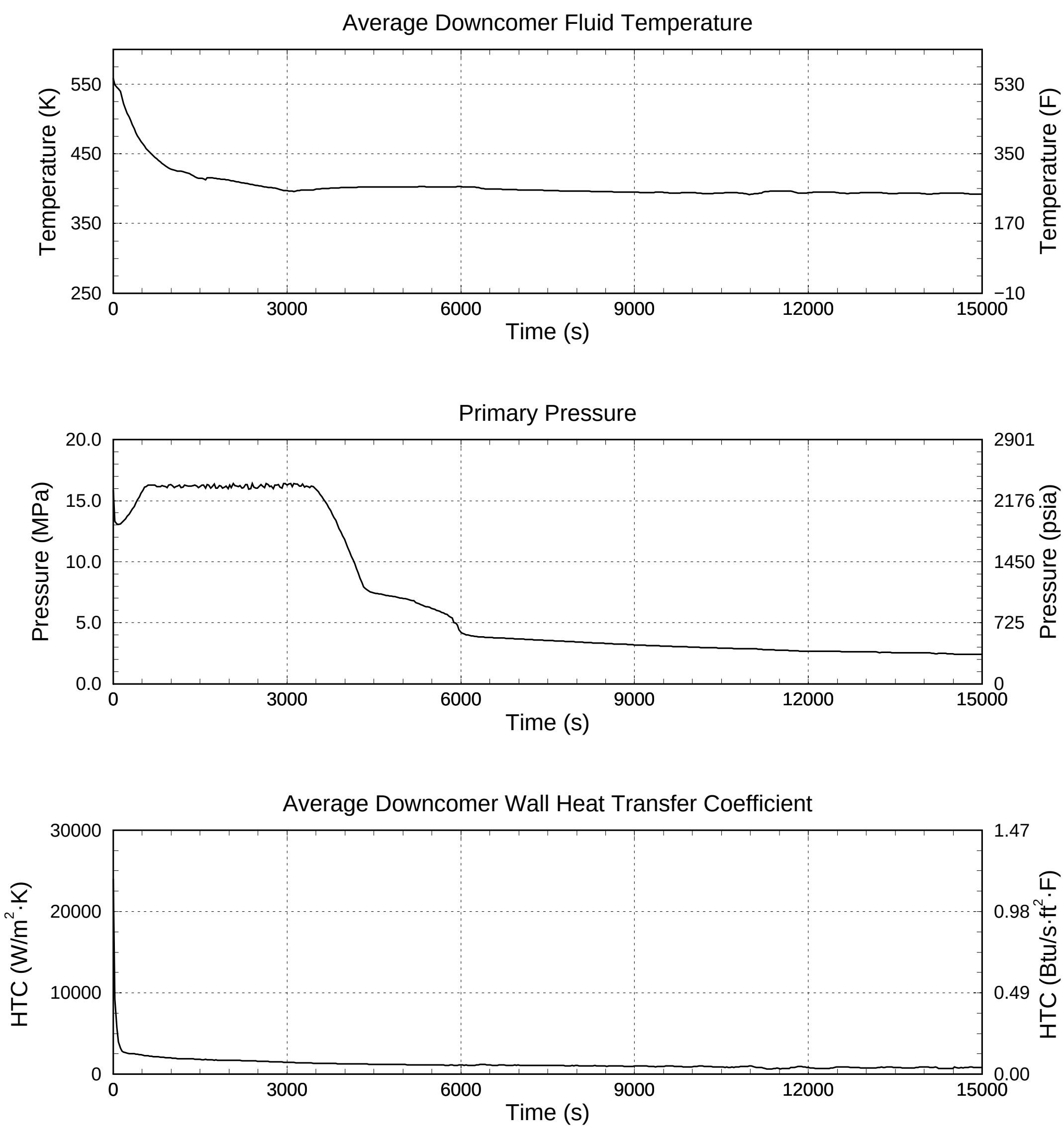


Figure B-44 Beaver Valley PTS Results for Case 112

Case Category	MSLB, HZP
Primary Failures	None
Secondary Failures	All MS-SRVs on SG A stuck open
Operator Actions	RCP's are tripped. Operator controls HHSI (30 minute delay)
Min DC Temperature	372.2 K [210.4°F] at 4860 s
Comments	AFW continues to feed SG A.

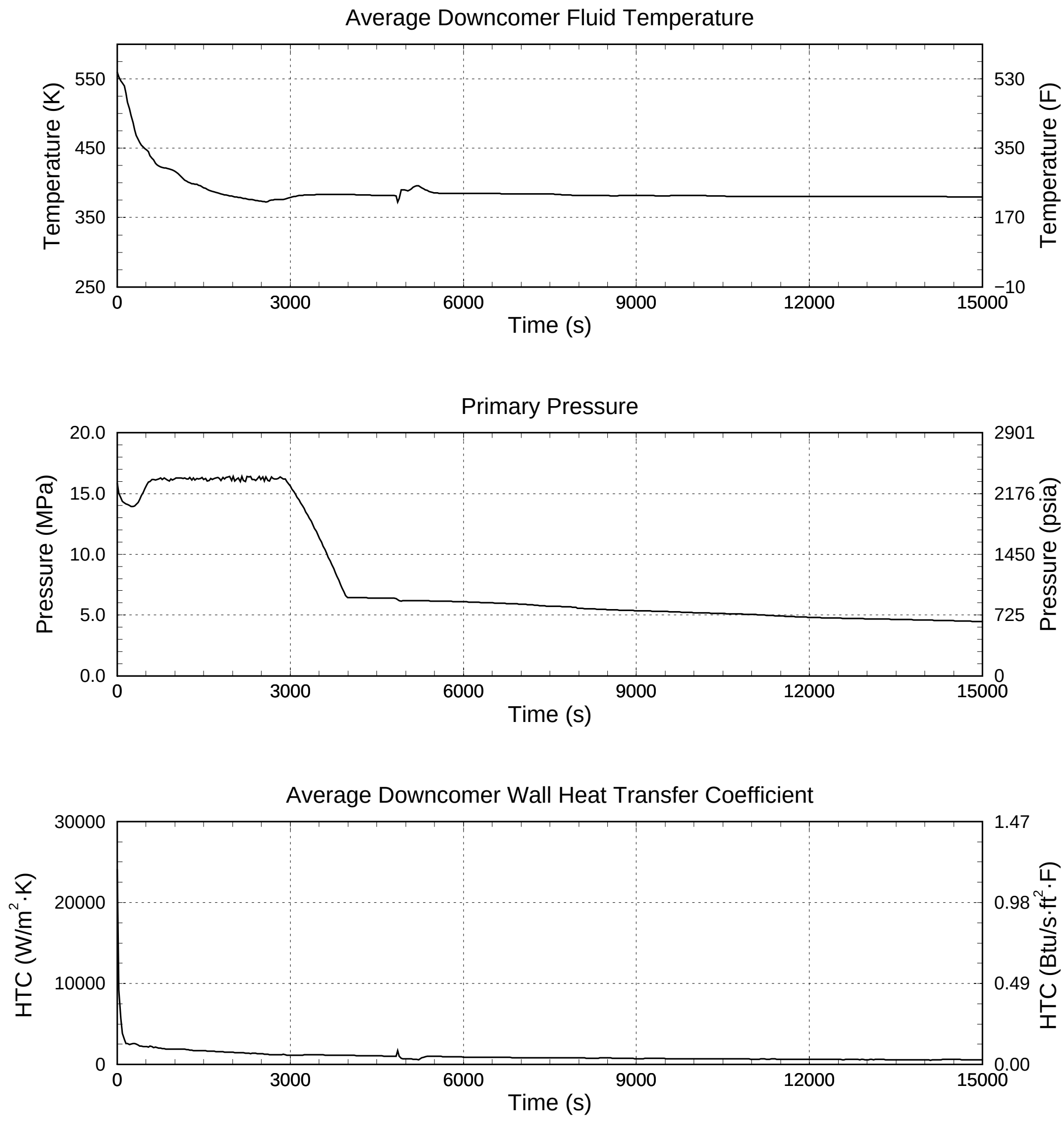


Figure B-45 Beaver Valley PTS Results for Case 113

Case Category	LOCA
Primary Failures	7.18 cm (2.828 in) surge line break
Secondary Failures	None
Operator Actions	None
Min DC Temperature	304.0 K [87.5°F] at 4890 s
Comments	Sensitivity case; summer conditions and heat transfer coefficient increased 30%.

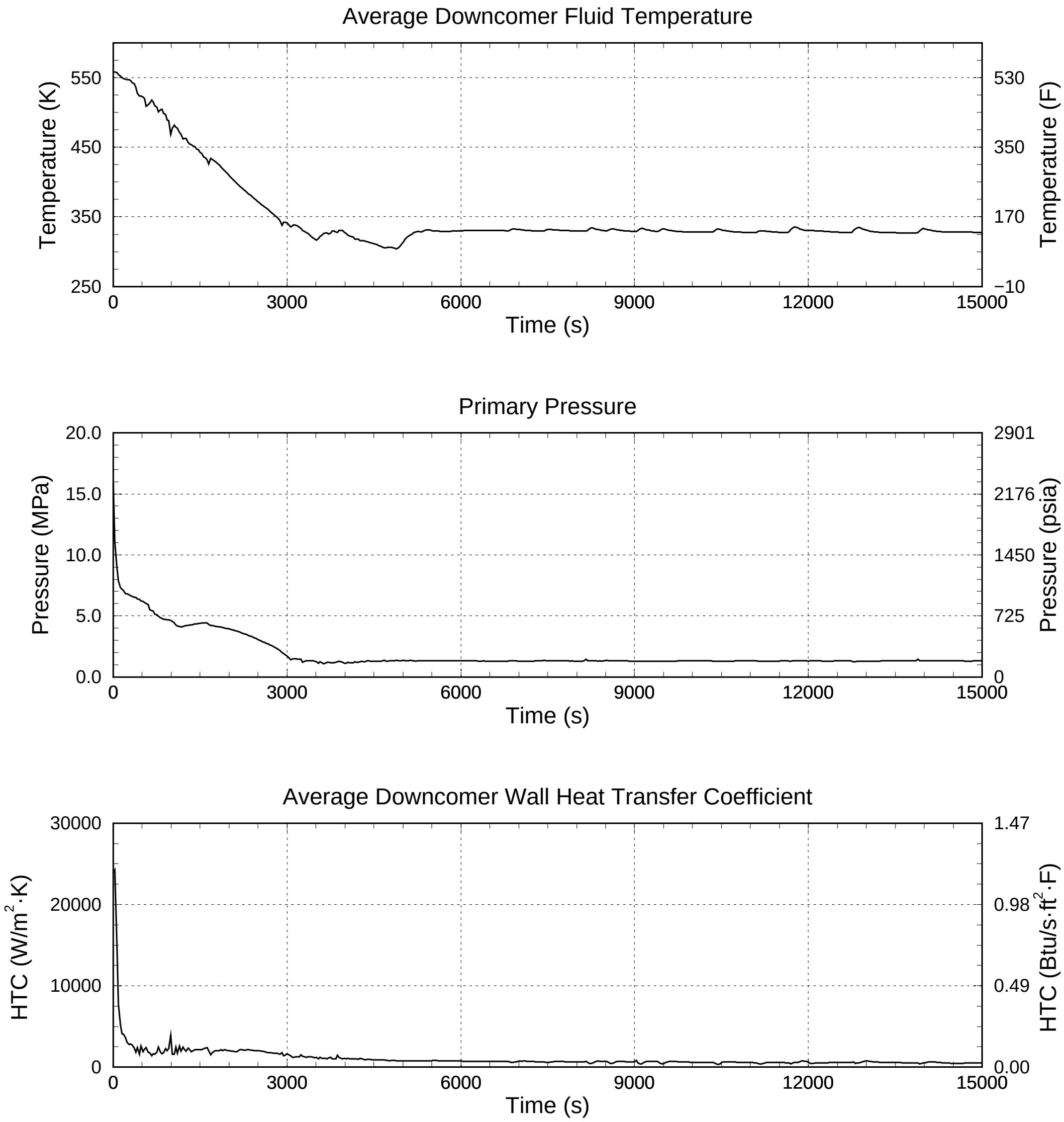


Figure B-46 Beaver Valley PTS Results for Case 114

Case Category	LOCA
Primary Failures	7.18 cm (2.828 in) cold leg break
Secondary Failures	None
Operator Actions	None
Min DC Temperature	369.9 K [206.2°F] at 14760 s
Comments	None

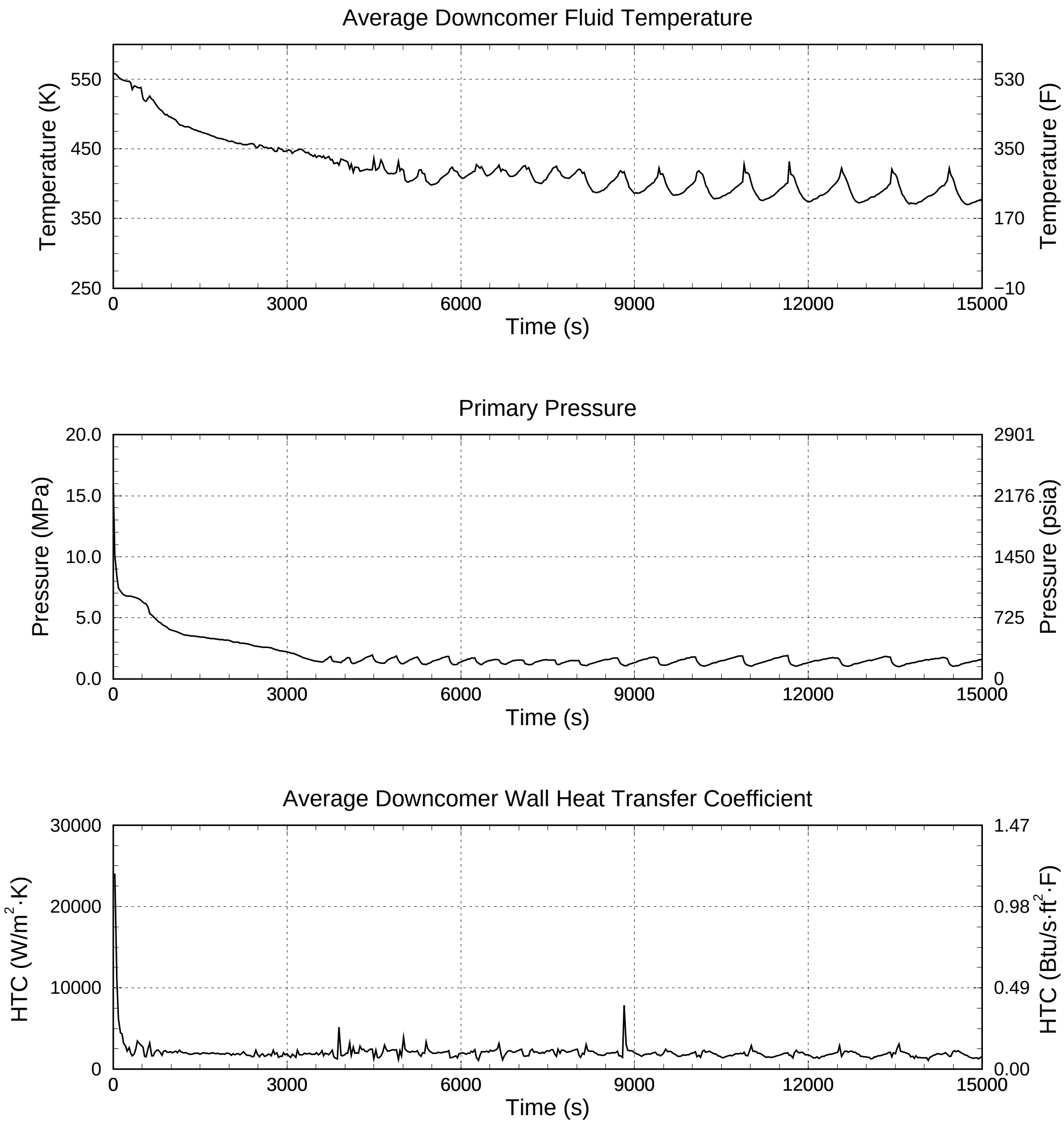
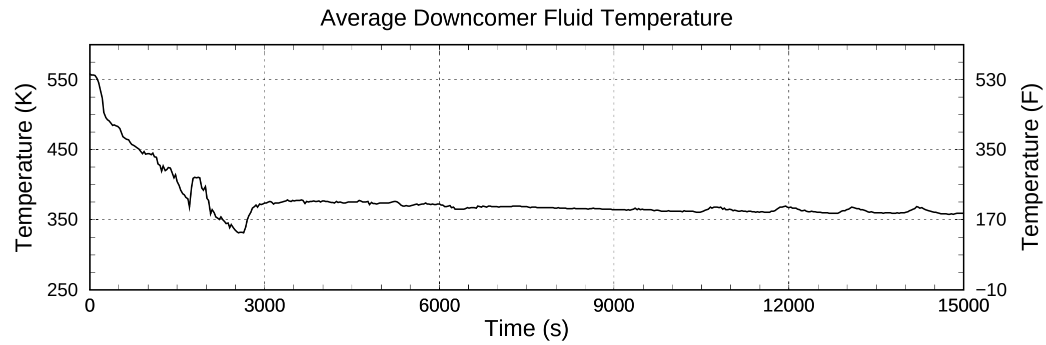
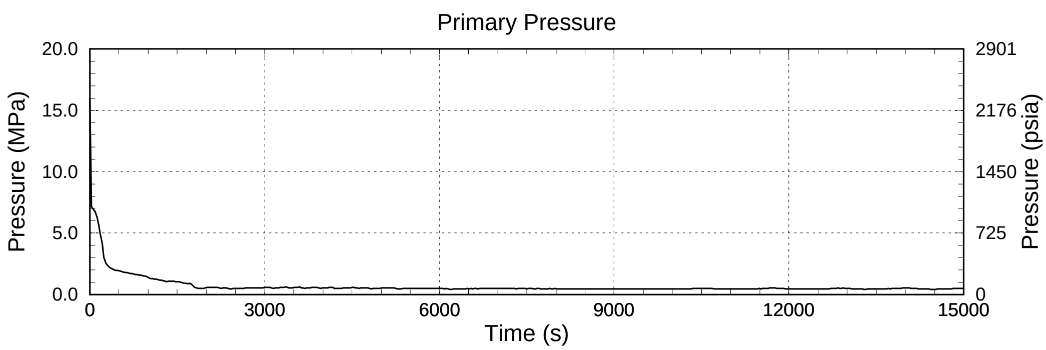


Figure B-47 Beaver Valley PTS Results for Case 115

Case Category	LOCA
Primary Failures	16.38 cm (6.45 in) cold leg break
Secondary Failures	None
Operator Actions	None
Min DC Temperature	331.4 K [136.9°F] at 2550 s
Comments	Break area increased 30% over 14.37 cm (5.657 in) case.





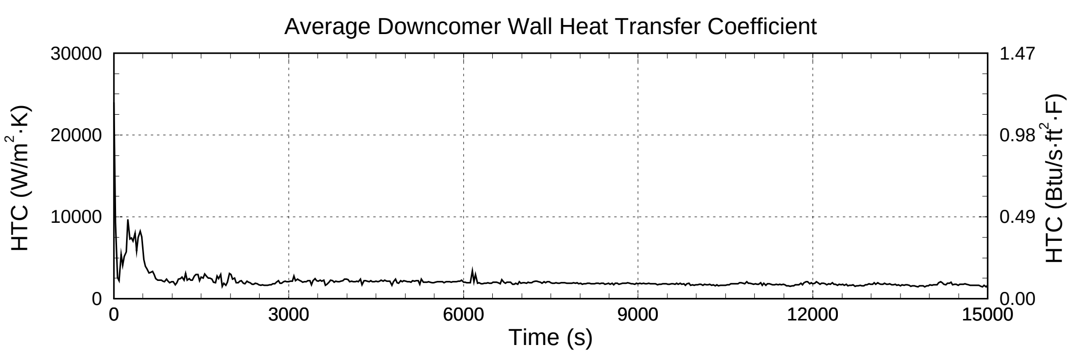


Figure B-48 Beaver Valley PTS Results for Case 116

Case Category	LOCA
Primary Failures	14.37 cm (5.657 in) cold leg break
Secondary Failures	None
Operator Actions	None
Min DC Temperature	336.3 K [145.6°F] at 2820 s
Comments	Sensitivity case; summer conditions.

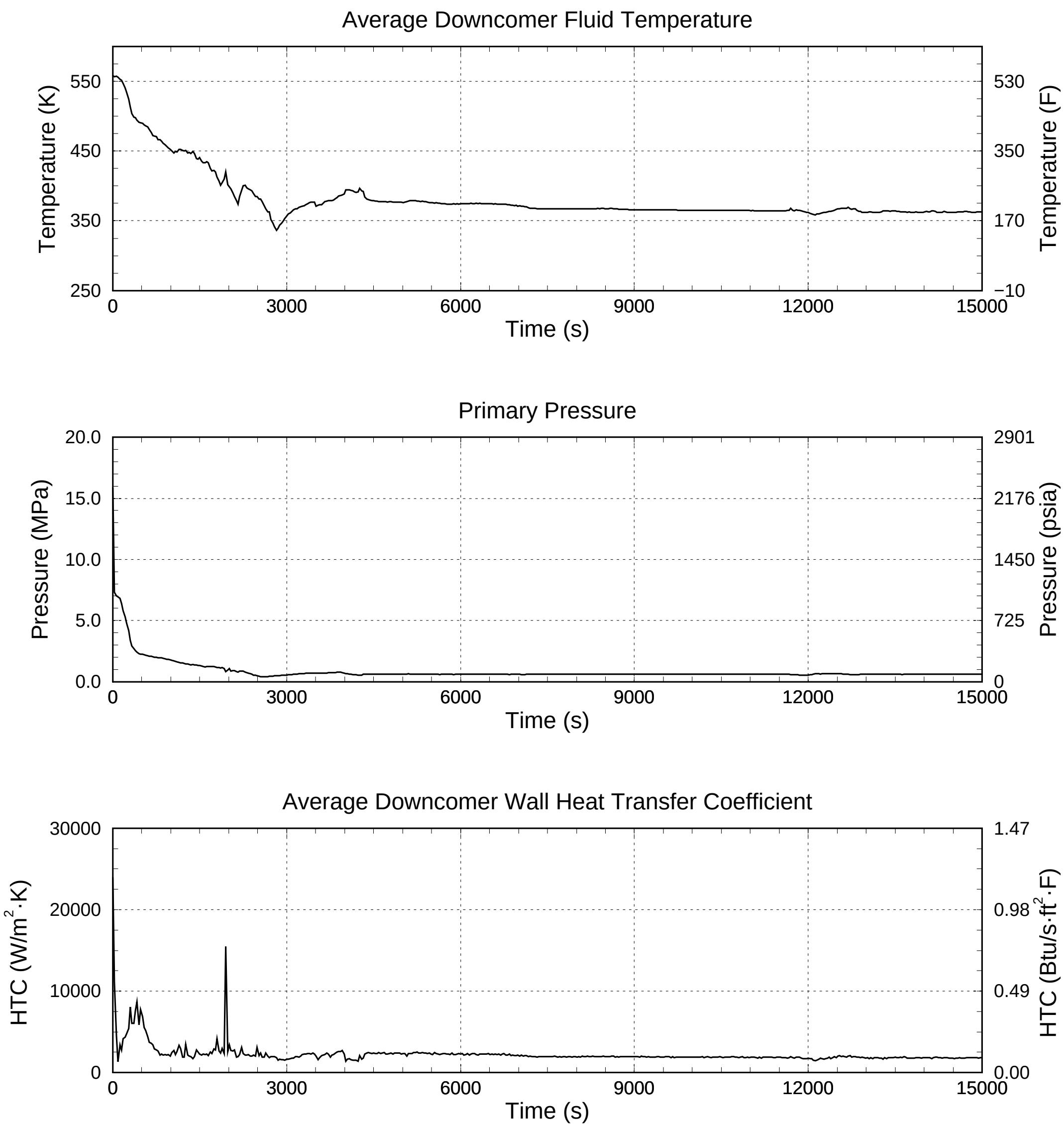


Figure B-49 Beaver Valley PTS Results for Case 117

Case Category	MSLB
Primary Failures	None
Secondary Failures	All MS-SRVs on SG A stuck open
Operator Actions	None
Min DC Temperature	373.9 K [213.4°F] at 15000 s
Comments	AFW continues to feed SG A.

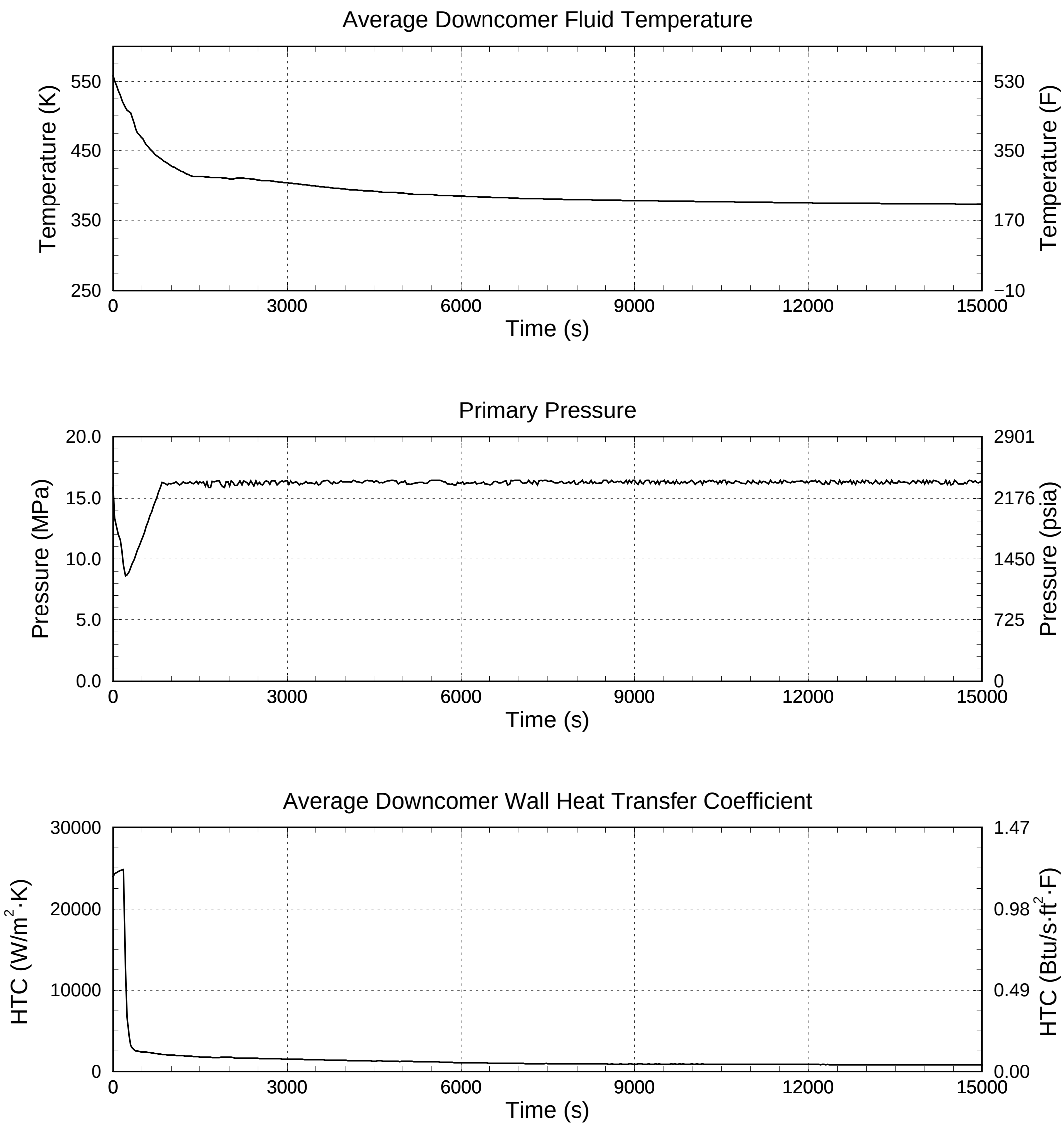


Figure B-50 Beaver Valley PTS Results for Case 118

Case Category	SOV
Primary Failures	Two stuck open pressurizer SRVs (recloses at 6,000 s)
Secondary Failures	None
Operator Actions	Operator controls HHSI (1 minute delay)
Min DC Temperature	300.6 K [81.4°F] at 6006 s
Comments	Updated HHSI control strategy

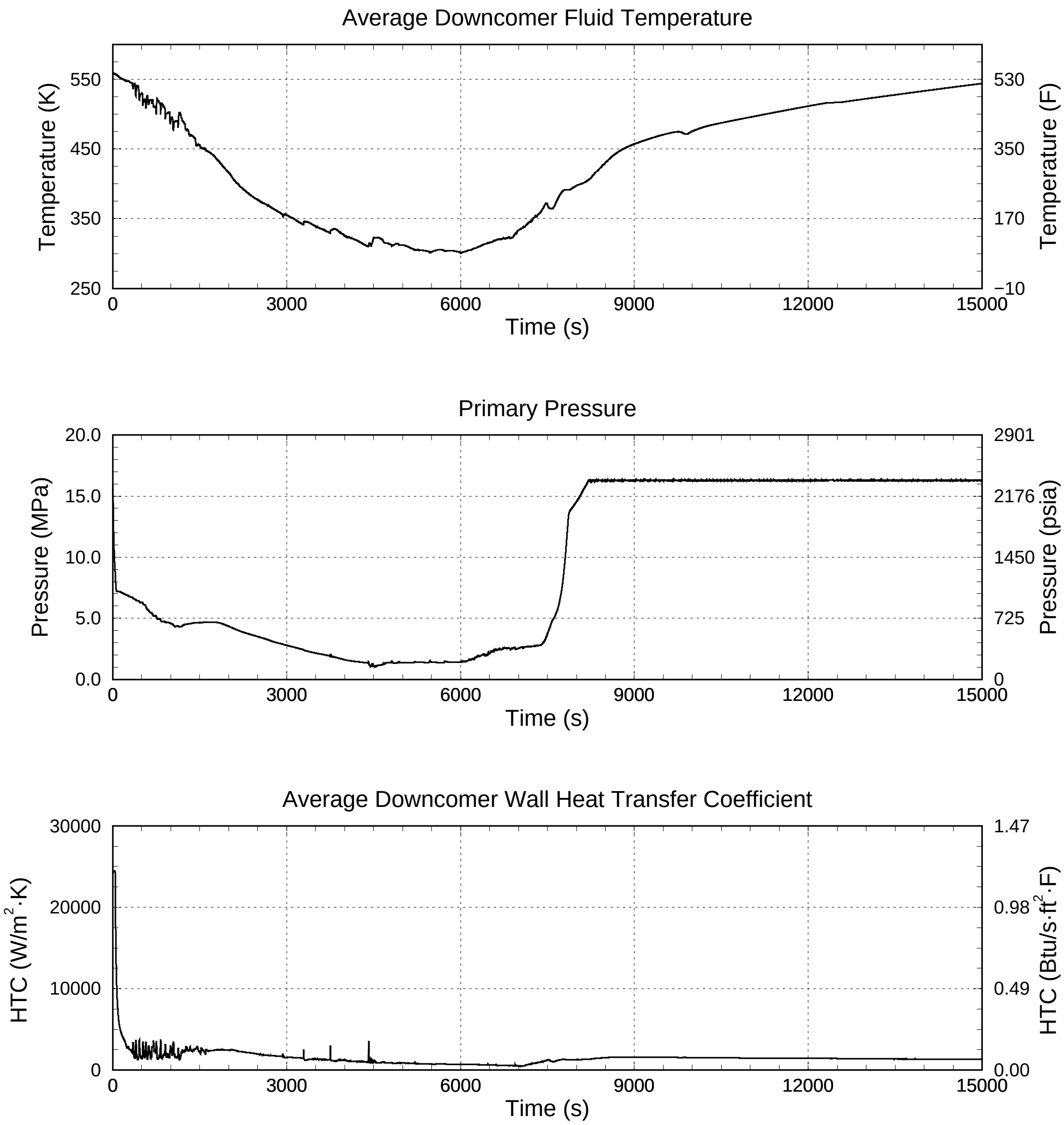
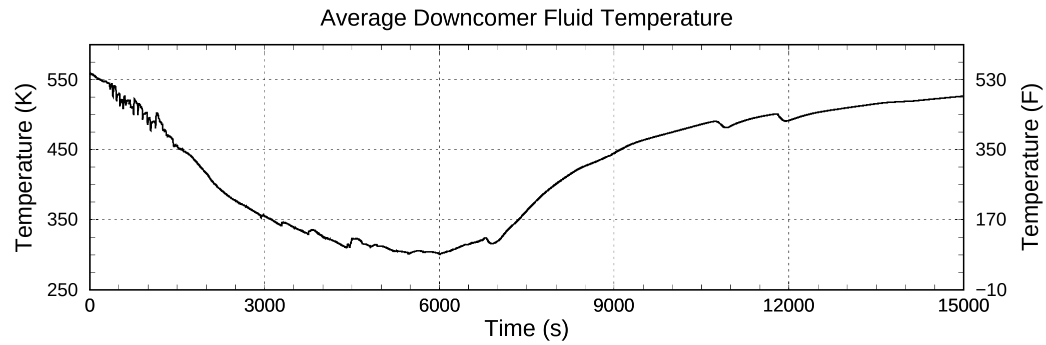
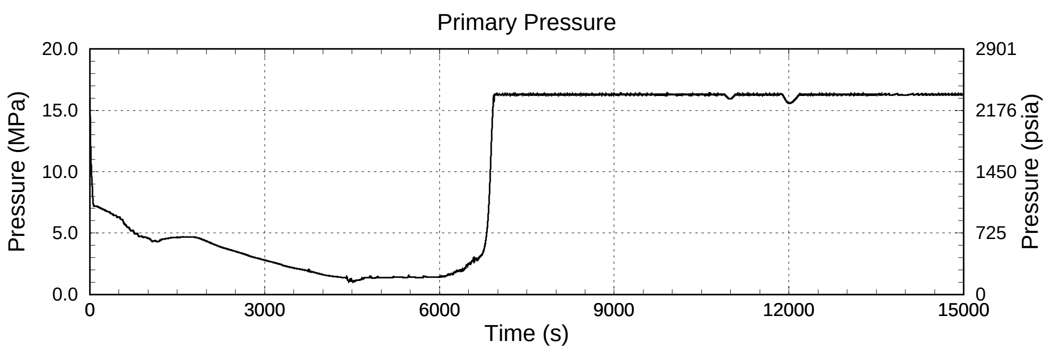


Figure B-51 Beaver Valley PTS Results for Case 119

Case Category	SOV
Primary Failures	Two stuck open pressurizer SRVs (recloses at 6,000 s)
Secondary Failures	None
Operator Actions	Operator controls HHSI (10 minute delay)
Min DC Temperature	300.6 K [81.4°F] at 6006 s
Comments	Updated HHSI control strategy





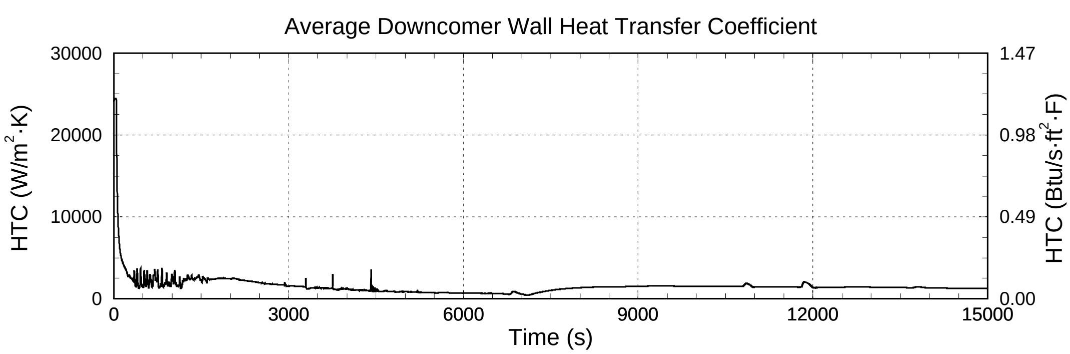
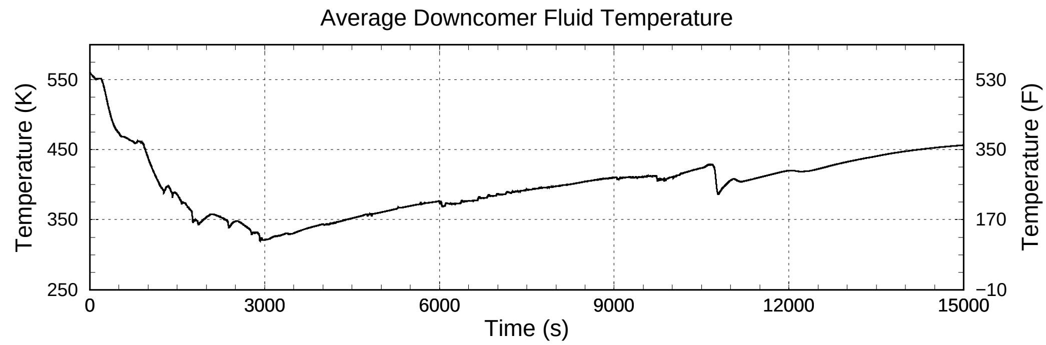
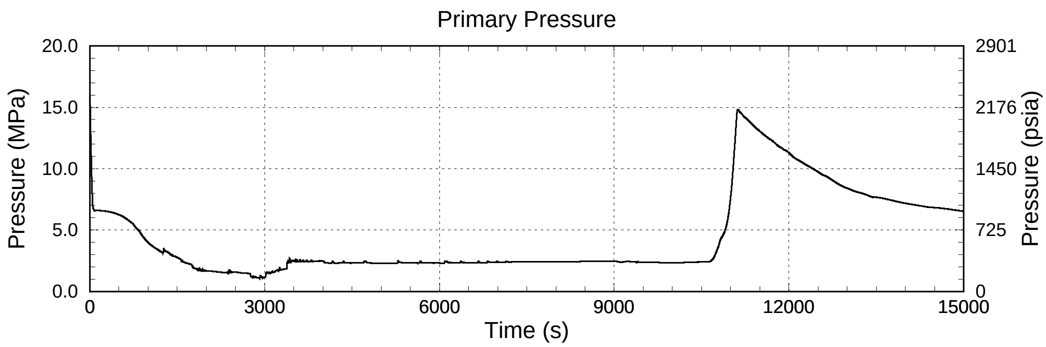


Figure B-52 Beaver Valley PTS Results for Case 120

Case Category	SOV, HZP
Primary Failures	Two stuck open pressurizer SRVs (recloses at 3,000 s)
Secondary Failures	None
Operator Actions	Operator controls HHSI (1 minute delay)
Min DC Temperature	319.8 K [116.0°F] at 2920 s
Comments	Updated HHSI control strategy





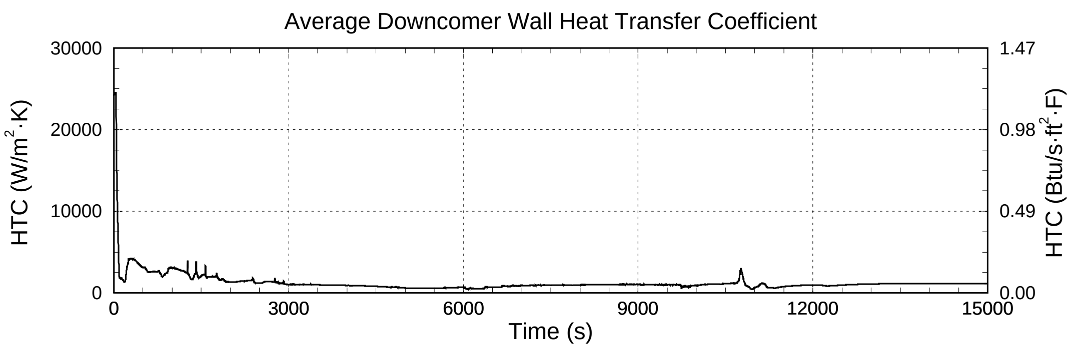


Figure B-53 Beaver Valley PTS Results for Case 121

Case Category	SOV, HZP
Primary Failures	Two stuck open pressurizer SRVs (recloses at 6,000 s)
Secondary Failures	None
Operator Actions	Operator controls HHSI (1 minute delay)
Min DC Temperature	294.1 K [69.8°F] at 5974 s
Comments	Updated HHSI control strategy

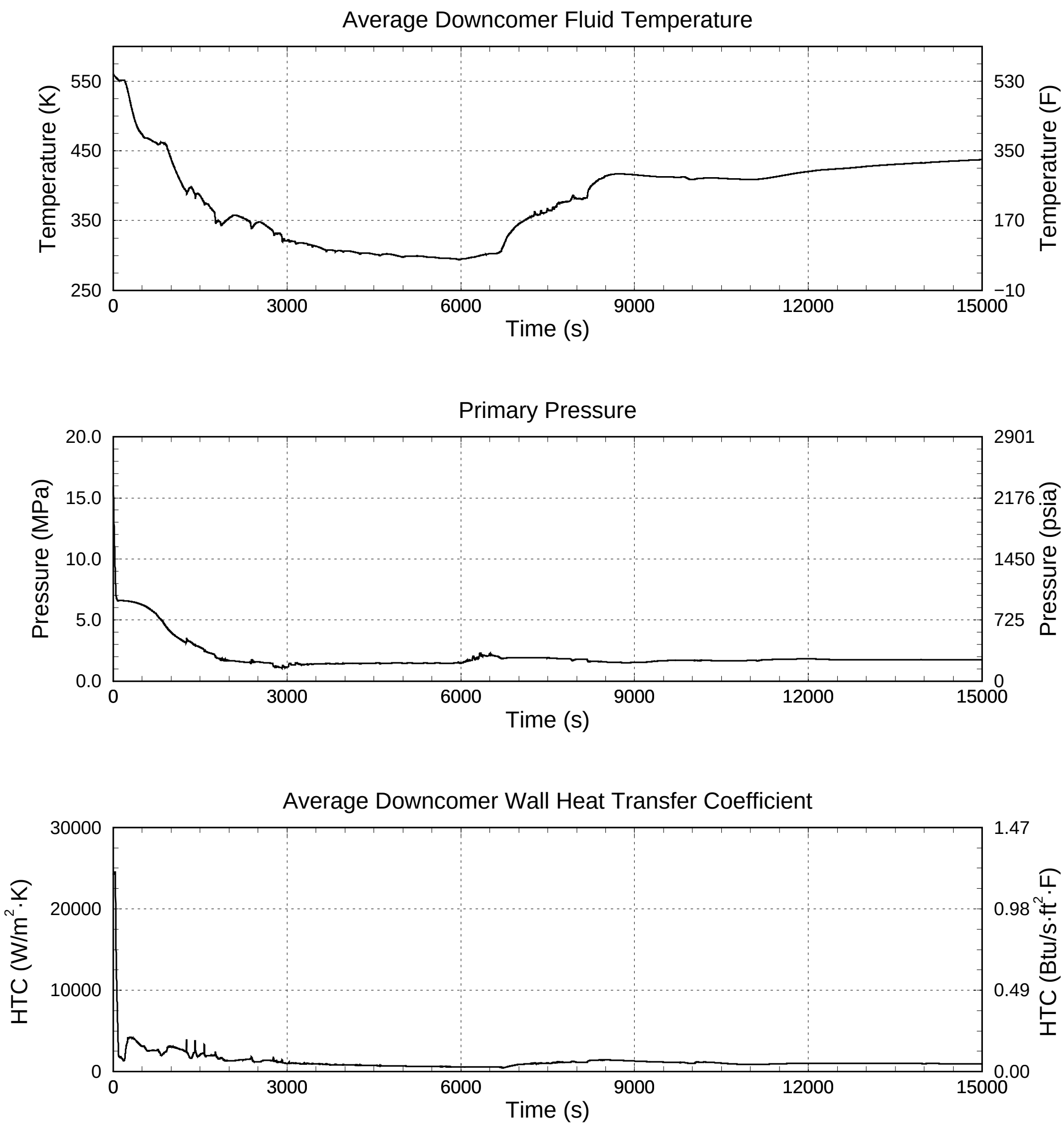


Figure B-54 Beaver Valley PTS Results for Case 122

Case Category	SOV, HZP
Primary Failures	Two stuck open pressurizer SRVs (recloses at 3,000 s)
Secondary Failures	None
Operator Actions	Operator controls HHSI (10 minute delay)
Min DC Temperature	319.8 K [116.0°F] at 2920 s
Comments	Updated HHSI control strategy

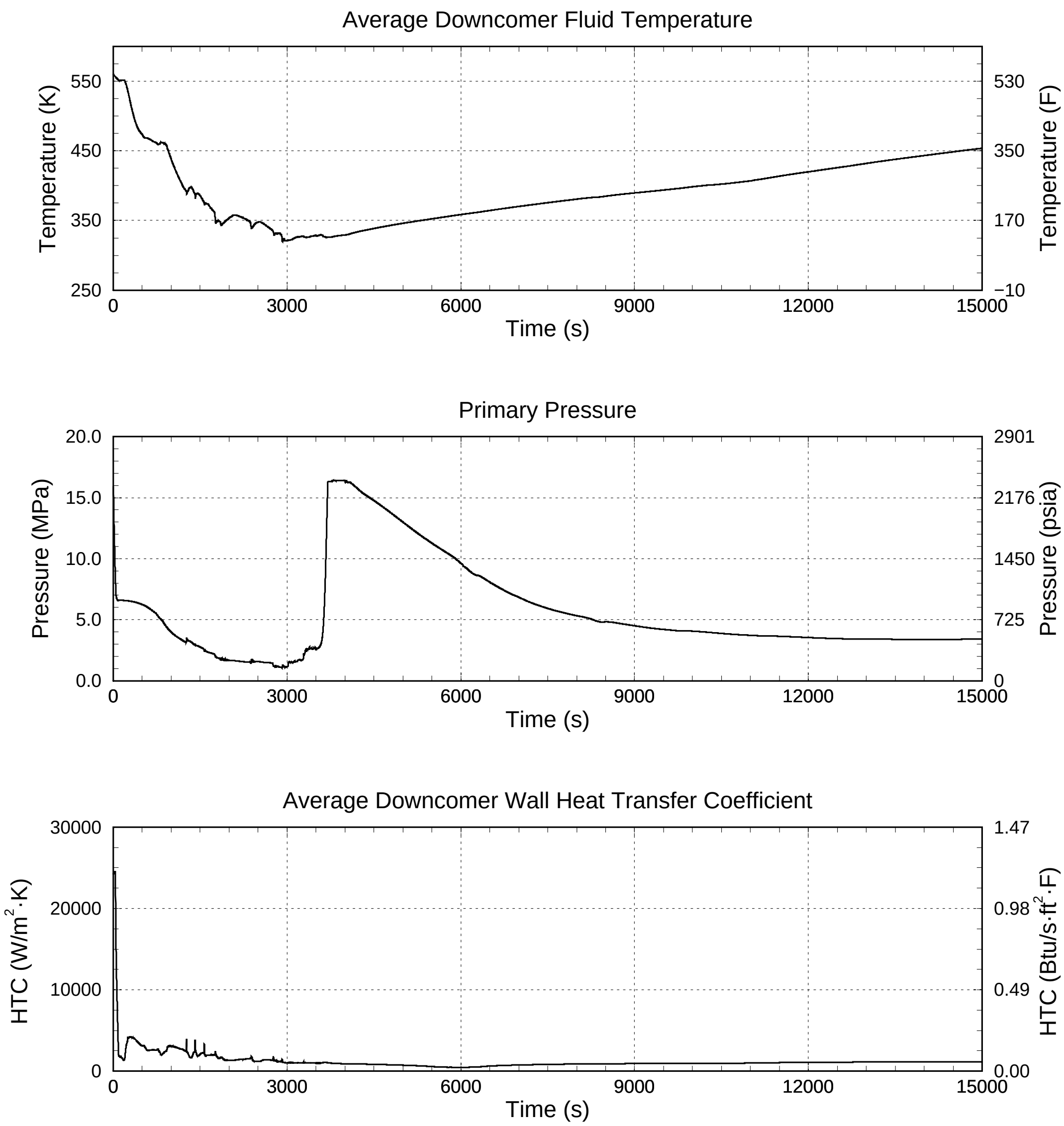
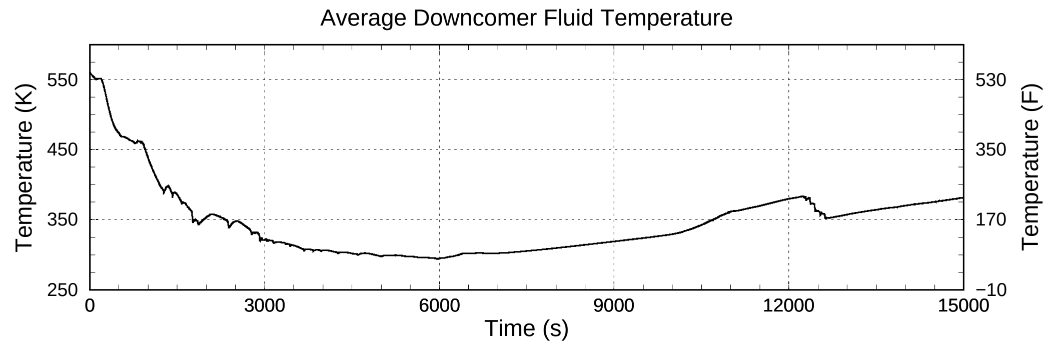
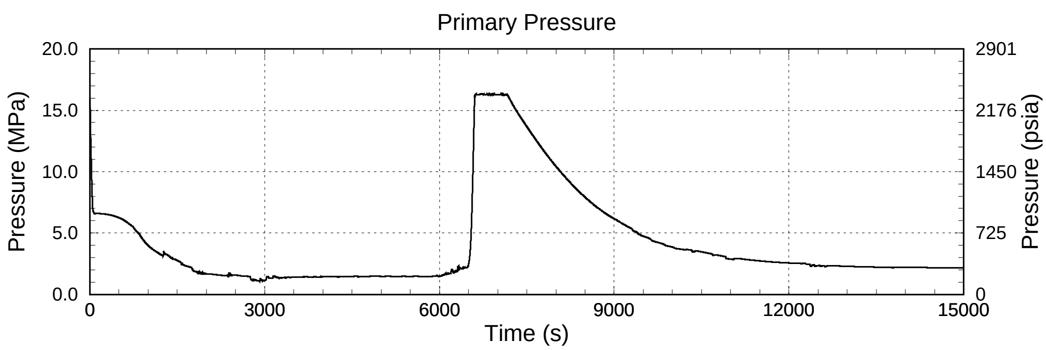


Figure B-55 Beaver Valley PTS Results for Case 123

Case Category	SOV, HZP
Primary Failures	Two stuck open pressurizer SRVs (recloses at 6,000 s)
Secondary Failures	None
Operator Actions	Operator controls HHSI (10 minute delay)
Min DC Temperature	294.1 K [69.8°F] at 5974 s
Comments	Updated HHSI control strategy





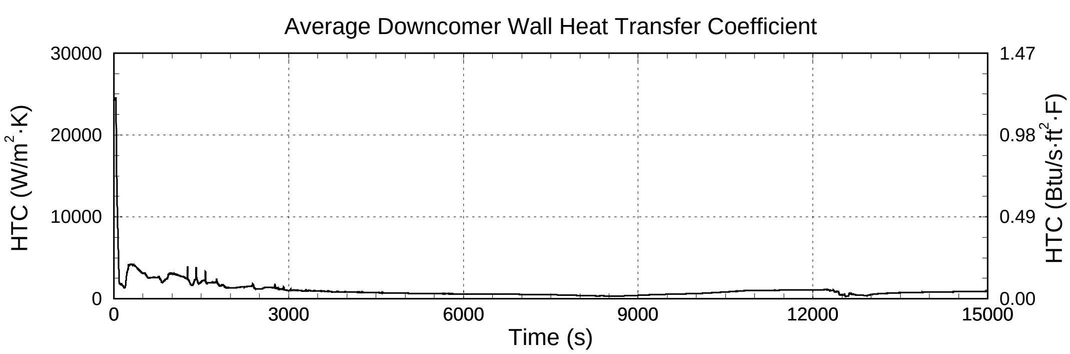


Figure B-56 Beaver Valley PTS Results for Case 124

Case Category	SOV
Primary Failures	One stuck open pressurizer SRV (recloses at 6,000 s)
Secondary Failures	None
Operator Actions	Operator controls HHSI (1 minute delay)
Min DC Temperature	340.1 K [152.5°F] at 6006 s
Comments	Updated HHSI control strategy

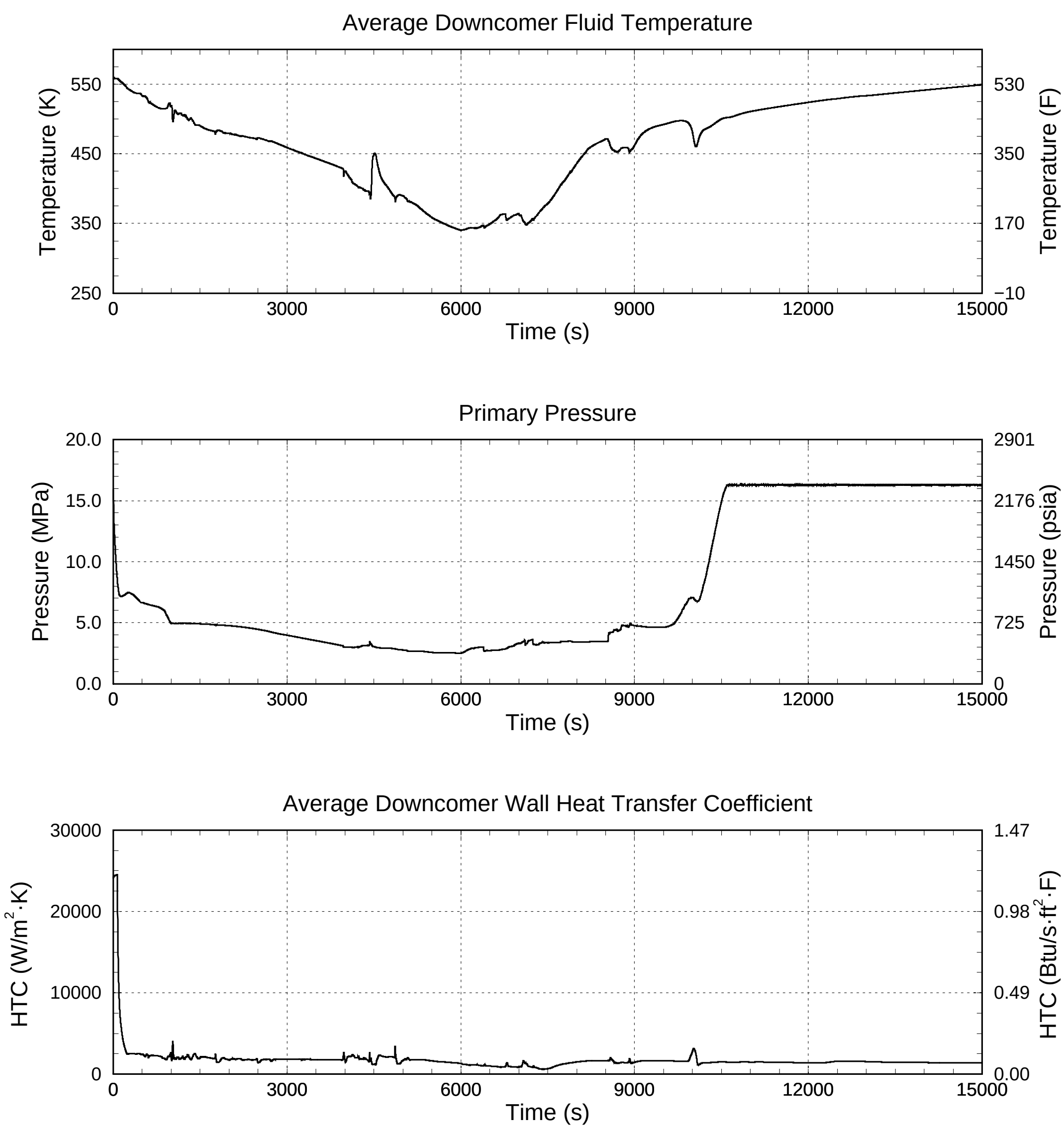


Figure B-57 Beaver Valley PTS Results for Case 125

Case Category	SOV
Primary Failures	One stuck open pressurizer SRV (recloses at 6,000 s)
Secondary Failures	None
Operator Actions	Operator controls HHSI (10 minute delay)
Min DC Temperature	337.7 K [148.2°F] at 6354 s
Comments	Updated HHSI control strategy

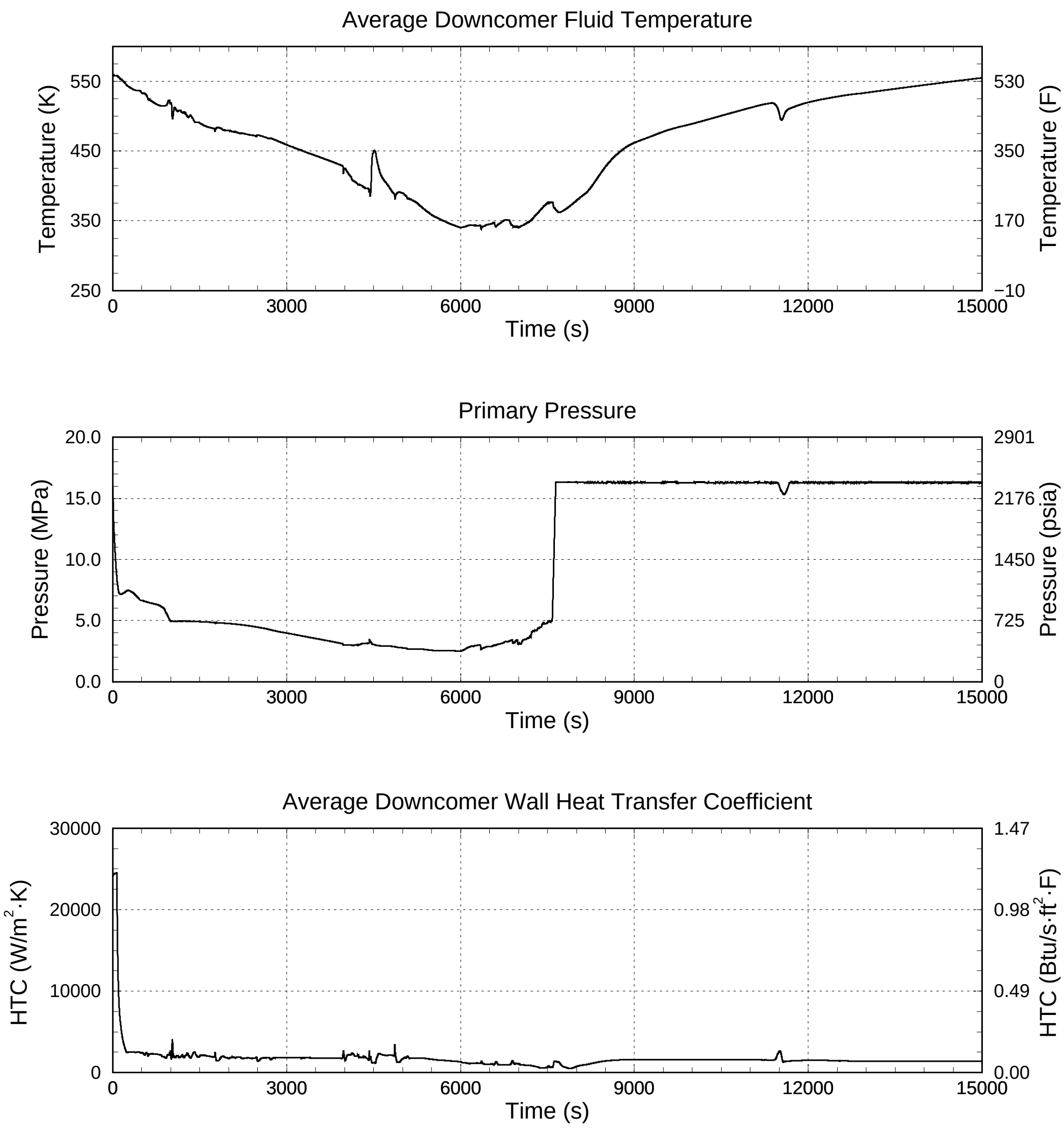


Figure B-58 Beaver Valley PTS Results for Case 126

Case Category	SOV, HZP
Primary Failures	One stuck open pressurizer SRV (recloses at 6,000 s)
Secondary Failures	None
Operator Actions	Operator controls HHSI (1 minute delay)
Min DC Temperature	293.3 K [68.3°F] at 6003 s
Comments	Updated HHSI control strategy

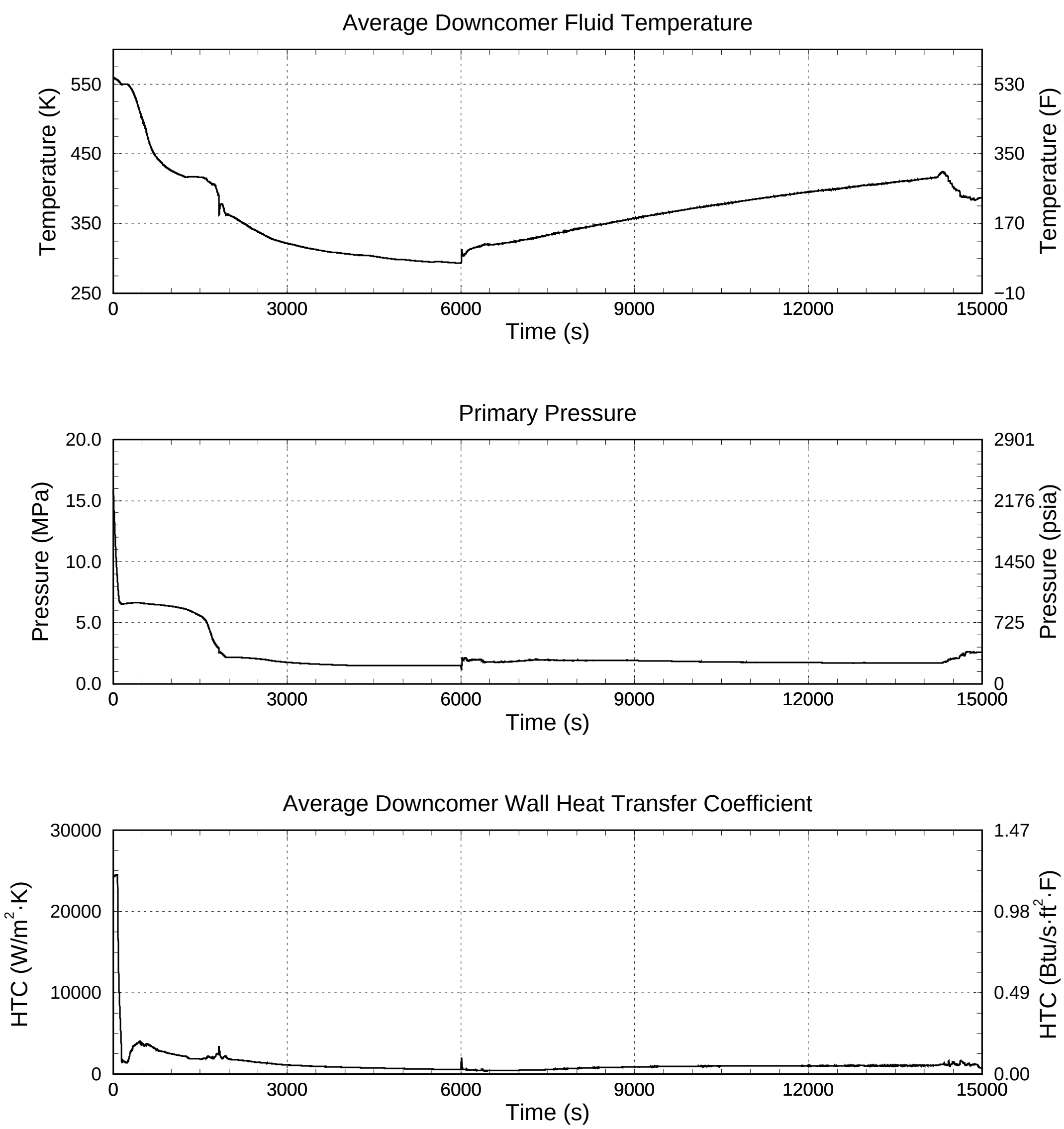


Figure B-59 Beaver Valley PTS Results for Case 127

Case Category	SOV, HZP
Primary Failures	One stuck open pressurizer SRV (recloses at 3,000 s)
Secondary Failures	None
Operator Actions	Operator controls HHSI (1 minute delay)
Min DC Temperature	316.5 K [110.0°F] at 3026 s
Comments	Updated HHSI control strategy

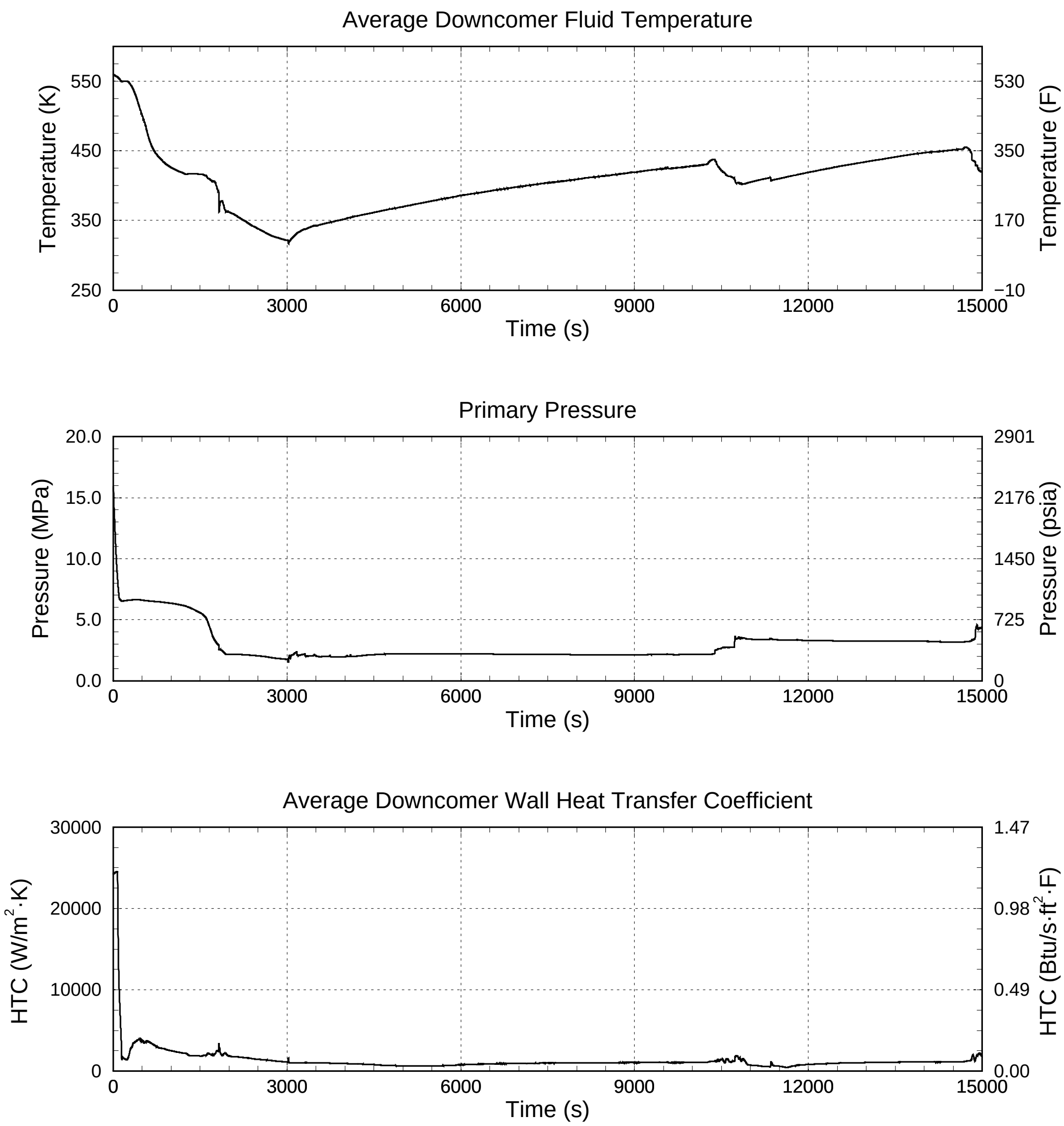


Figure B-60 Beaver Valley PTS Results for Case 128

Case Category	SOV, HZP
Primary Failures	One stuck open pressurizer SRV (recloses at 6,000 s)
Secondary Failures	None
Operator Actions	Operator controls HHSI (10 minute delay)
Min DC Temperature	293.3 K [68.3°F] at 6003 s
Comments	Updated HHSI control strategy

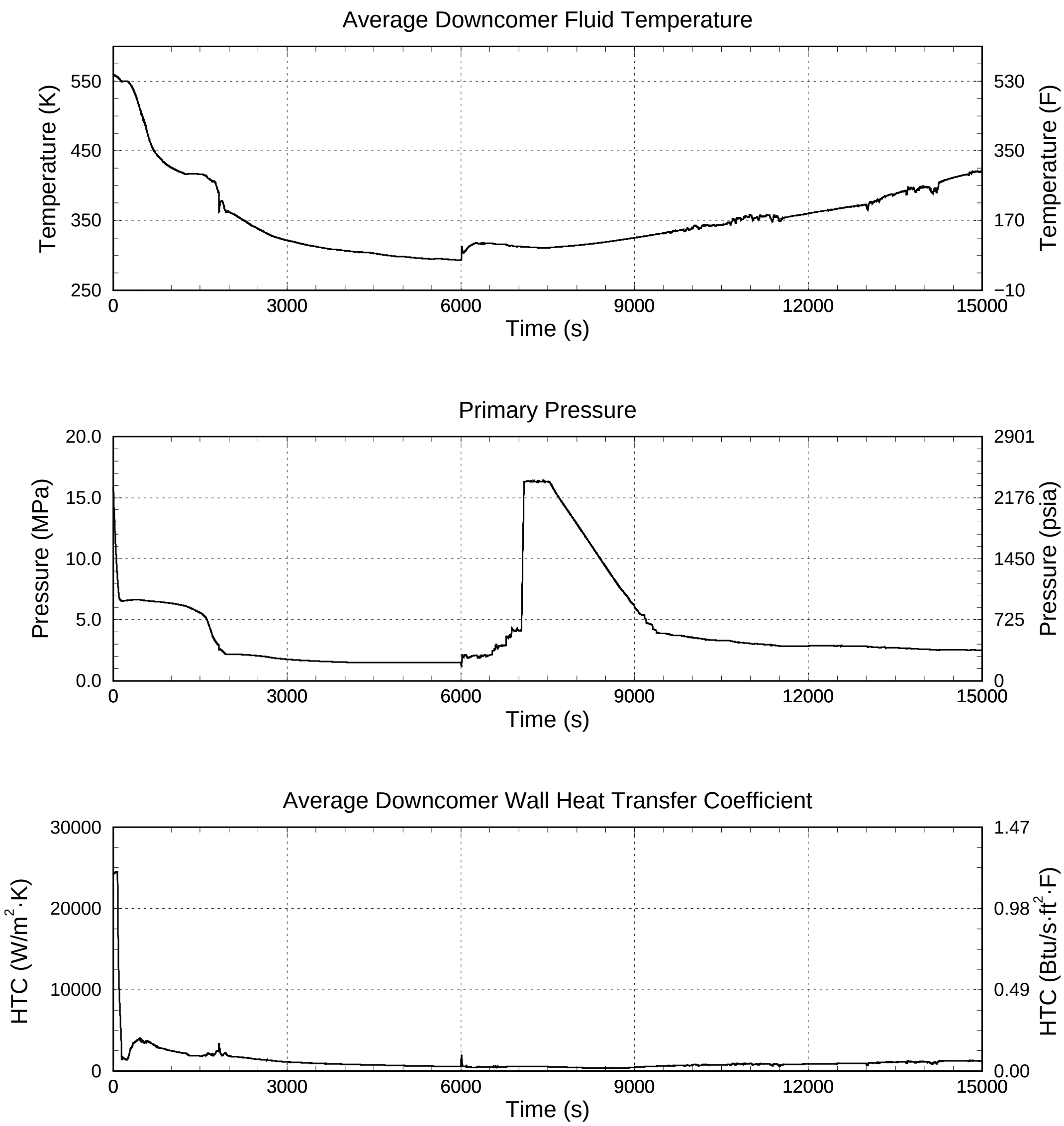
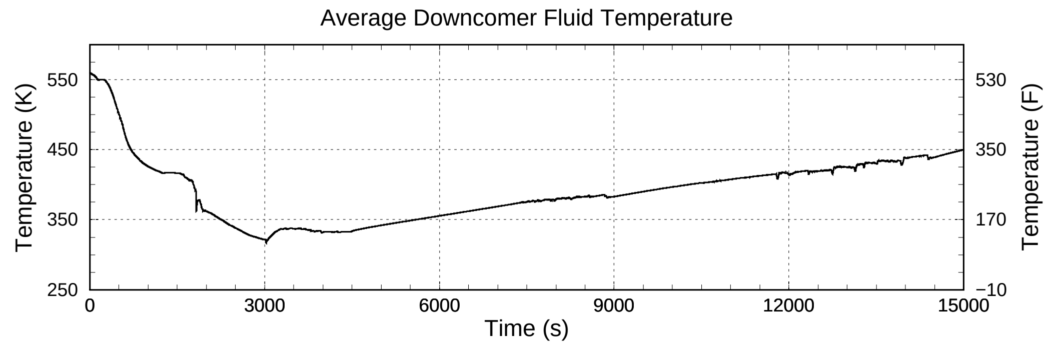
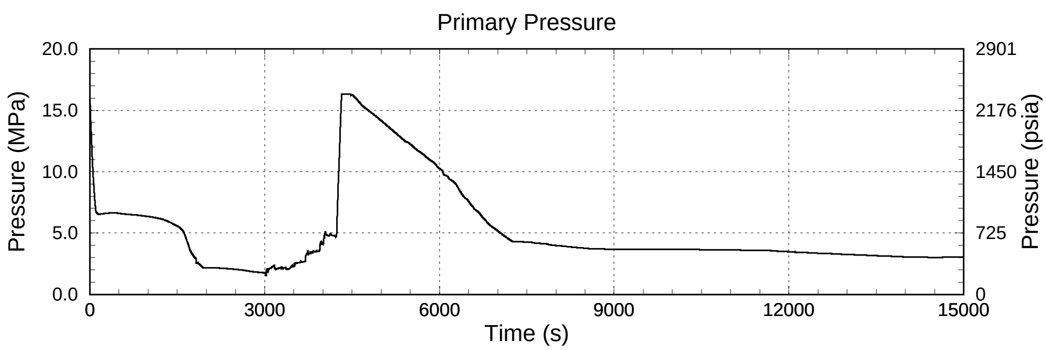


Figure B-61 Beaver Valley PTS Results for Case 129

Case Category	SOV, HZP
Primary Failures	One stuck open pressurizer SRV (recloses at 3,000 s)
Secondary Failures	None
Operator Actions	Operator controls HHSI (10 minute delay)
Min DC Temperature	316.5 K [110.0°F] at 3026 s
Comments	Updated HHSI control strategy





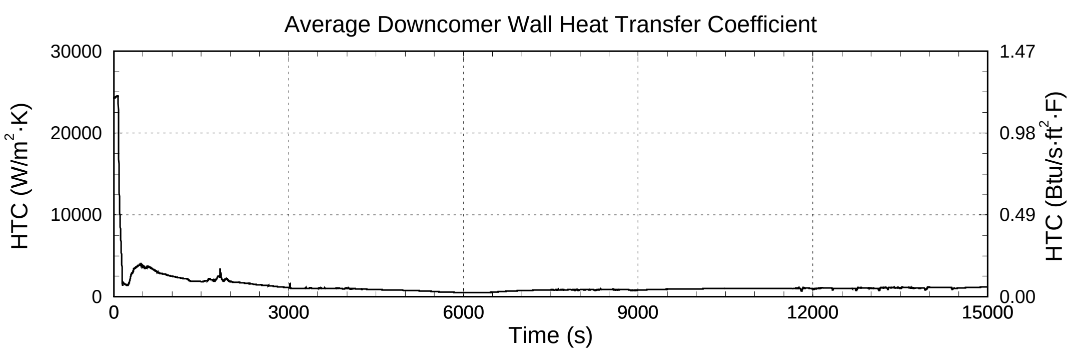


Figure B-62 Beaver Valley PTS Results for Case 130

Appendix C - Summary of Palisades Base Case Results

September 23, 2004

Appendix C - Summary of Palisades Base Case Results

This appendix presents an overview of the RELAP5 modeling details and the results of the 30 base cases evaluated for the Beaver Valley plant. Table C-1 presents a list of the cases analyzed. These cases include a mix of LOCAs, stuck open pressurizer safety valves, main steam line breaks, and secondary side failures from both hot full power and hot zero power conditions.

Results for each of the base cases are presented below as Figures C-1 to C-30. For each case, the following information is given in tabular format.

Case Category	LOCA, RT/TT, MSLB, etc.
Primary Failures	Description of the primary side failure
Secondary Failures	Description of the secondary side failure
Operator Actions	Description of any operator actions
Min DC Temp	The minimum average downcomer fluid temperature and associated time that minimum occurred
Comments	Any comments specific to the event

In addition to the information described above, plots of average downcomer fluid temperature, primary system pressure, and downcomer wall heat transfer coefficient are presented. Any analytical assumptions used in each case are also presented. To facilitate comparisons among cases, each figure presents summary information for the minimum downcomer average temperature in the reactor vessel and the time during the event sequence when that minimum is reached. The results shown in these figures are used in the FAVOR probabilistic fracture mechanics analysis.

Table C-1   List of Palisades Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
2	3.59 cm (1.414 in) surge line break. Containment sump recirculation included in the analysis.	None	No	Yes	No
16	Turbine/reactor trip with 2 stuck-open ADVs on SG-A combined with controller failure resulting in the flow from two AFW pumps into affected steam generator.	Operator starts second AFW pump. Operator isolates AFW to affected SG at 30 minutes after initiation. Operator assumed to throttle HPI if auxiliary feedwater is running with SG wide range level > -84% and RCS subcooling > 45 K [25°F]. HPI is throttled to maintain pressurizer level between 40 and 60 %.	No	No	No
18	Turbine/reactor trip with 1 stuck-open ADV on SG-A. Failure of both MSIVs (SG-A and SG-B) to close.	Operator does not isolate AFW on affected SG. Normal AFW flow assumed (200 gpm). Operator assumed to throttle HPI if auxiliary feedwater is running with SG wide range level > -84% and RCS subcooling > 45 K [25°F]. HPI is throttled to maintain pressurizer level between 40 and 60 %.	No	No	No
19	Reactor trip with 1 stuck-open ADV on SG-A.	None. Operator does not throttle HPI.	Yes	No	Yes
22	Turbine/reactor trip with loss of MFW and AFW.	Operator depressurizes through ADVs and feeds SG's using condensate booster pumps. Operators maintain a cooldown rate within technical specification limits and throttle condensate flow at 84 % level in the steam generator.	No	No	No
24	Main steam line break with the break assumed to be inside containment causing containment spray actuation.	None	No	No	No
26	Main steam line break with the break assumed to be inside containment causing containment spray actuation.	Operator isolates AFW to affected SG at 30 minutes after initiation.	No	No	No
27	Main steam line break with controller failure resulting in the flow from two AFW pumps into affected steam generator. Break assumed to be inside containment causing containment spray actuation.	Operator starts second AFW pump.	No	No	No

Table C-1 List of Palisades Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
29	Main steam line break with break assumed to be inside containment causing containment spray actuation.	None. Operator does not throttle HPI.	Yes	No	No
31	Turbine/reactor trip with failure of MFW and AFW. Containment spray actuation assumed due to PORV discharge.	Operator maintains core cooling by "feed and bleed" using HPI to feed and two PORVs to bleed.	No	No	No
32	Turbine/reactor trip with failure of MFW and AFW. Containment spray actuation assumed due to PORV discharge.	Operator maintains core cooling by "feed and bleed" using HPI to feed and two PORV to bleed. AFW is recovered 15 minutes after initiation of "feed and bleed" cooling. Operator closes PORVs when SG level reaches 60 percent.	No	No	No
34	Main steam line break concurrent with a single tube failure in SG-A due to MSLB vibration.	Operator isolates AFW to affected SG at 15 minutes after initiation. Operator trips RCPs assuming that they do not trip as a result of the event. Operator assumed to throttle HPI if auxiliary feedwater is running with SG wide range level > -84% and RCS subcooling > 45 K [25°F]. HPI is throttled to maintain pressurizer level between 40 and 60 %.	No	No	No
40	40.64 cm (16 in) hot leg break. Containment sump recirculation included in the analysis.	None. Operator does not throttle HPI.	No	Yes	Yes
42	Turbine/reactor trip with two stuck open pressurizer SRVs. Containment spray is assumed not to actuate.	Operator assumed to throttle HPI if auxiliary feedwater is running with SG wide range level > -84% and RCS subcooling > 45 K [25°F]. HPI is throttled to maintain pressurizer level between 40 and 60 %.	No	No	No
48	Two stuck-open pressurizer SRVs that reclose at 6000 sec after initiation. Containment spray is assumed not to actuate.	None. Operator does not throttle HPI.	Yes	No	No
49	Main steam line break with the break assumed to be inside containment causing containment spray actuation.	Operator isolates AFW to affected SG at 30 minutes after initiation. Operator does not throttle HPI.	Yes	No	No

Table C-1 List of Palisades Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
50	Main steam line break with controller failure resulting in the flow from two AFW pumps into affected steam generator. Break assumed to be inside containment causing containment spray actuation.	Operator starts second AFW pump. Operator does not throttle HPI.	Yes	No	No
51	Main steam line break with failure of both MSIVs to close. Break assumed to be inside containment causing containment spray actuation.	Operator does not isolate AFW on affected SG. Operator does not throttle HPI.	Yes	No	No
52	Reactor trip with 1 stuck-open ADV on SG-A. Failure of both MSIVs (SG-A and SG-B) to close.	Operator does not isolate AFW on affected SG. Normal AFW flow assumed (200 gpm). Operator does not throttle HPI.	Yes	No	Yes
53	Turbine/reactor trip with two stuck-open pressurizer SRVs that reclose at 6000 sec after initiation. Containment spray is assumed not to actuate.	None. Operator does not throttle HPI.	No	No	No
54	Main steam line break with failure of both MSIVs to close. Break assumed to be inside containment causing containment spray actuation.	Operator does not isolate AFW on affected SG. Operator does not throttle HPI.	No	No	Yes
55	Turbine/reactor trip with 2 stuck-open ADVs on SG-A combined with controller failure resulting in the flow from two AFW pumps into affected steam generator.	Operator starts second AFW pump.	No	No	Yes
58	10.16 cm (4 in) cold leg break. Winter conditions assumed (HPI and LPI injection temp = 278 K [40°F], Accumulator temp = 289 K [60°F])	None. Operator does not throttle HPI.	No	Yes	Yes
59	10.16 cm (4 in) cold leg break. Summer conditions assumed (HPI and LPI injection temp = 311 K [100°F], Accumulator temp = 305 K [90°F])	None. Operator does not throttle HPI.	No	Yes	Yes
60	5.08 cm (2 in) surge line break. Winter conditions assumed (HPI and LPI injection temp = 278 K [40°F], Accumulator temp = 289 K [60°F])	None. Operator does not throttle HPI.	No	Yes	Yes

Table C-1 List of Palisades Base Cases

Case	System Failure	Operator Action	HZP	Hi K	Dominant
61	7.18 cm (2.8 in) cold leg break. Summer conditions assumed (HPI and LPI injection temp = 311 K [100°F], Accumulator temp = 305 K [90°F])	None. Operator does not throttle HPI.	No	Yes	No
62	20.32 cm (8 in) cold leg break. Winter conditions assumed (HPI and LPI injection temp = 278 K [40°F], Accumulator temp = 289 K [60°F])	None. Operator does not throttle HPI.	No	Yes	Yes
63	14.37 cm (5.656 in) cold leg break. Winter conditions assumed (HPI and LPI injection temp = 278 K [40°F], Accumulator temp = 289 K [60° F])	None. Operator does not throttle HPI.	No	Yes	Yes
64	10.16 cm (4 in) surge line break. Summer conditions assumed (HPI and LPI injection temp = 311 K [100°F], Accumulator temp = 305 K [90°F])	None. Operator does not throttle HPI.	No	Yes	Yes
65	One stuck-open pressurizer SRV that recloses at 6000 sec after initiation. Containment spray is assumed not to actuate.	None. Operator does not throttle HPI.	Yes	No	Yes

Case Category	LOCA
Primary Failures	3.59 cm (1.414 in) surge line break. Containment sump recirculation included in the analysis.
Secondary Failures	None.
Operator Actions	None.
Min DC Temperature	436.5 K [326.0°F] at 15000 s
Comments	None.

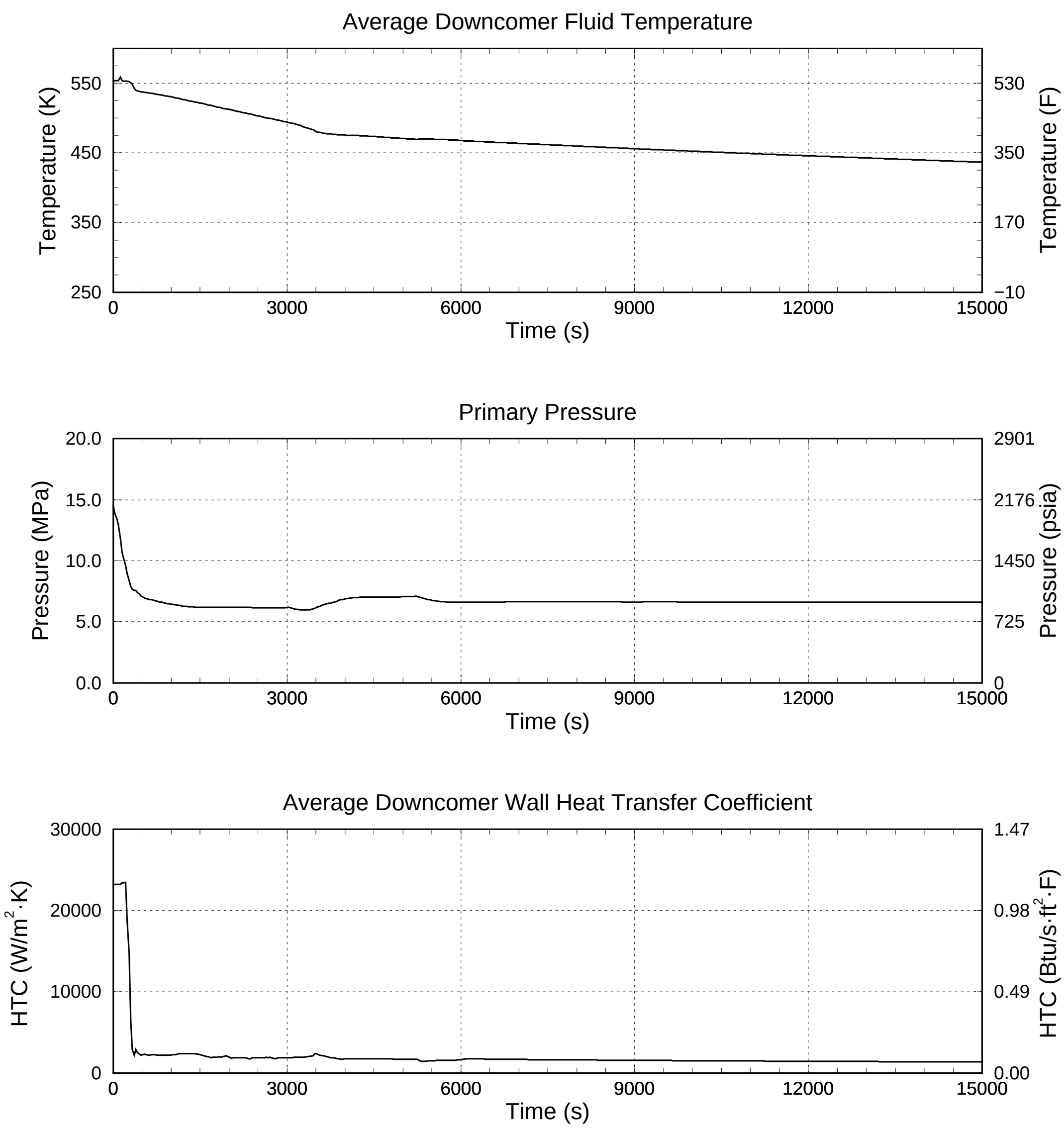


Figure C-1 Palisades PTS Results for Case 002

Case Category	TT/RT
Primary Failures	None.
Secondary Failures	2 stuck-open ADVs on SG-A combined with controller failure resulting in the flow from two AFW pumps into affected steam generator.
Operator Actions	Operator starts second AFW pump. Operator isolates AFW to affected SG at 30 minutes after initiation. Operator assumed to throttle HPI if AFW is running with SG WRL > -84% and RCS subcooling > 25 F. HPI is throttled to maintain pressurizer level between 40 and 60 %.
Min DC Temperature	451.4 K [352.9°F] at 4620 s
Comments	None.

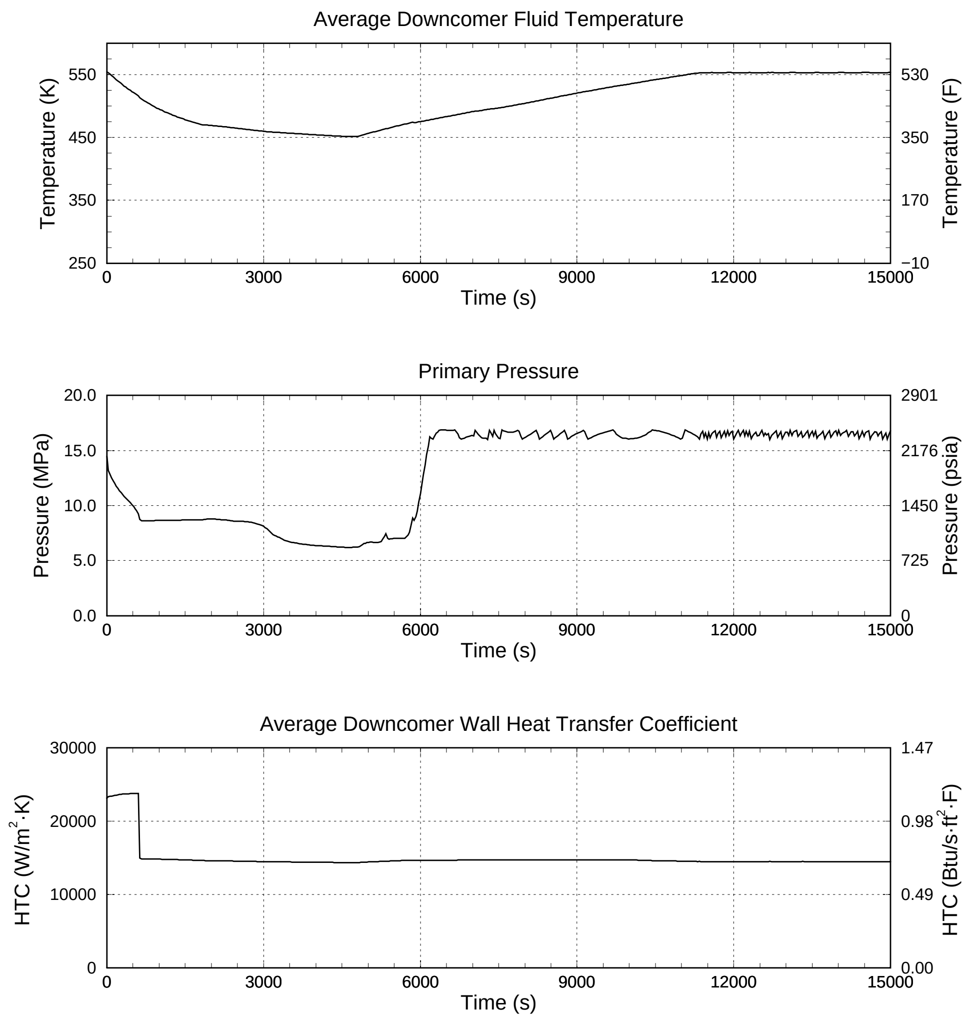


Figure C-2 Palisades PTS Results for Case 016

Case Category	TT/RT
Primary Failures	None.
Secondary Failures	1 stuck-open ADV on SG-A. Failure of both MSIVs (SG-A and SG-B) to close.
Operator Actions	Operator does not isolate AFW on affected SG. Normal AFW flow assumed (200 gpm). Operator assumed to throttle HPI if AFW is running with SG WRL > -84% and RCS subcooling > 25 F. HPI is throttled to maintain pressurizer level between 40 and 60 %.
Min DC Temperature	443.4 K [338.5°F] at 14130 s
Comments	None.

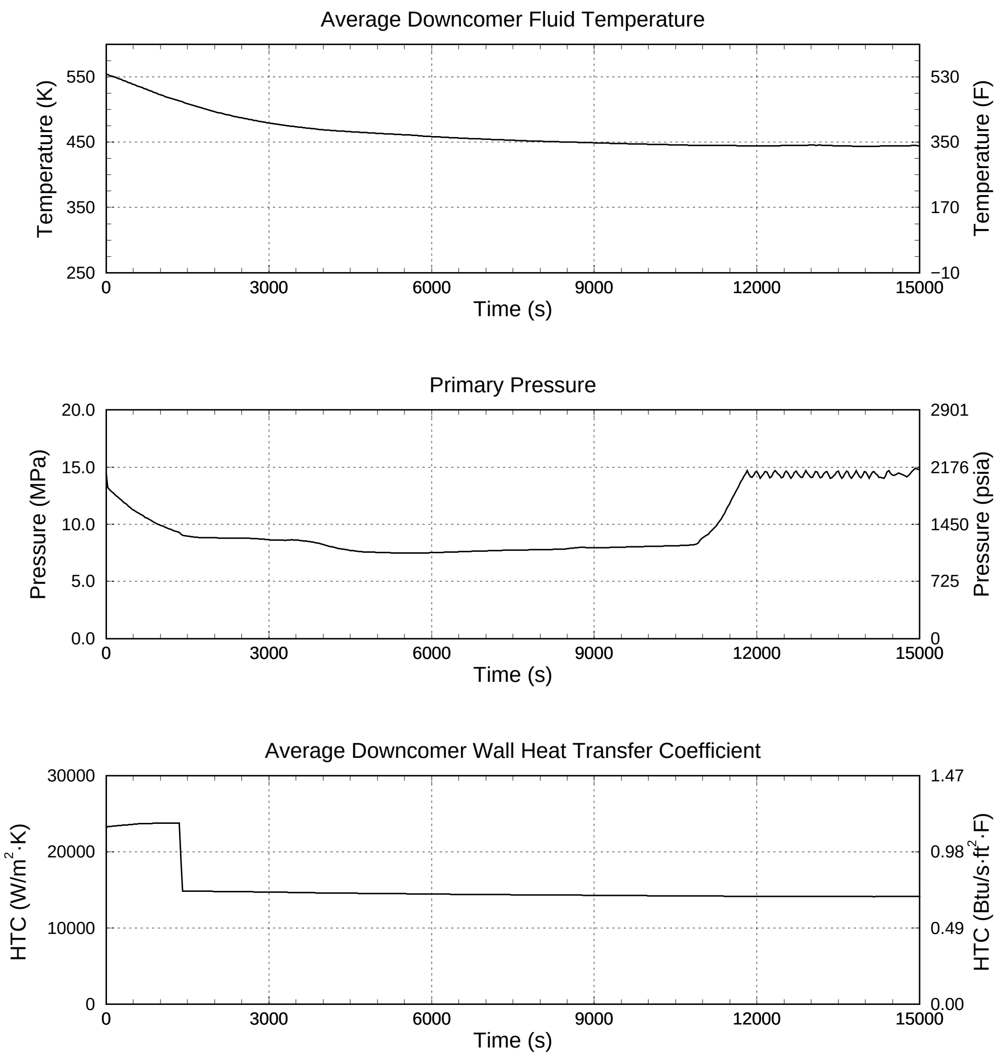


Figure C-3 Palisades PTS Results for Case 018

Case Category	TT/RT, HZP
Primary Failures	None.
Secondary Failures	1 stuck-open ADV on SG-A
Operator Actions	None. Operator does not throttle HPI.
Min DC Temperature	423.0 K [301.7°F] at 15000 s
Comments	None.

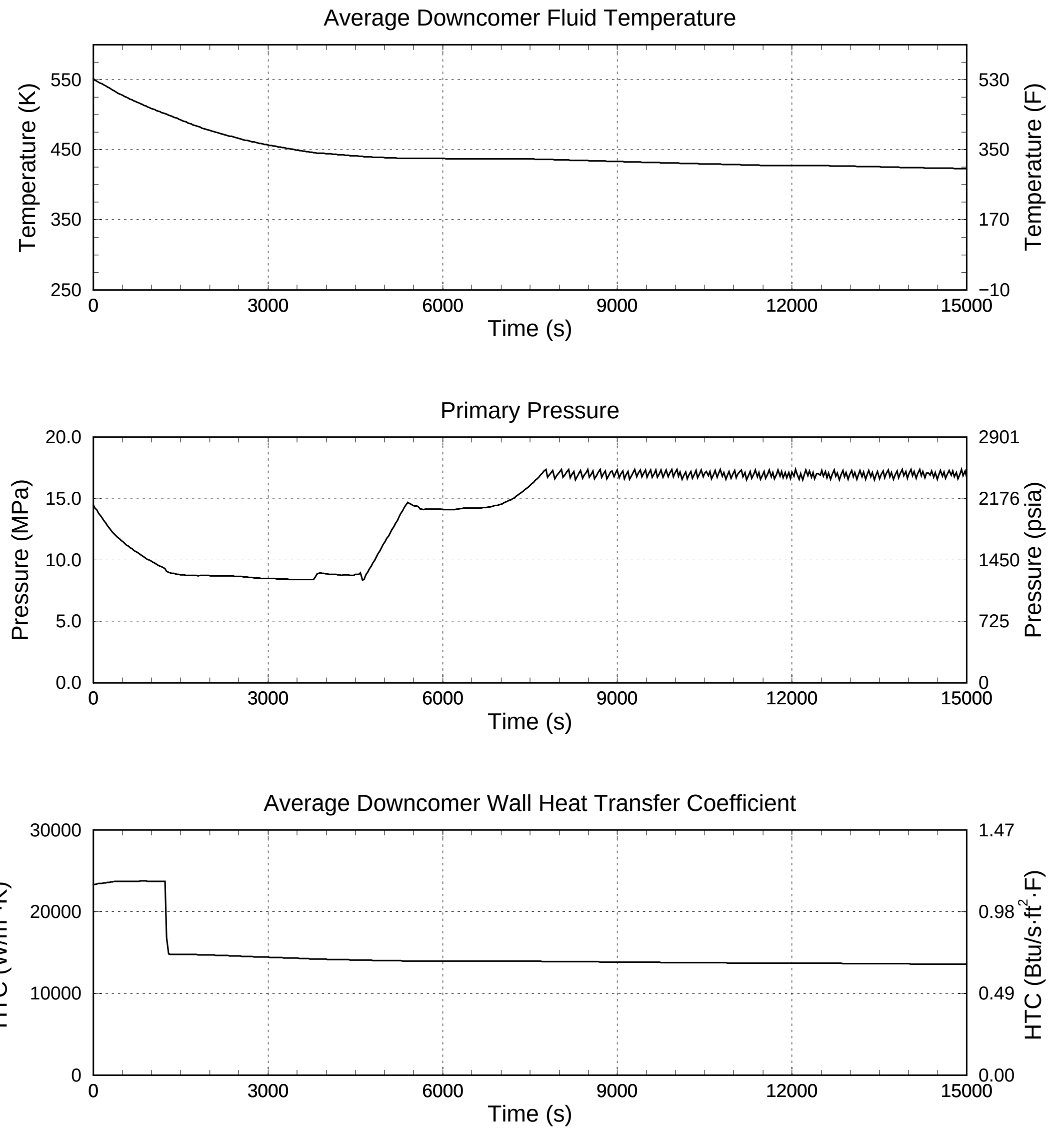


Figure C-4 Palisades PTS Results for Case 019

Case Category	TT/RT
Primary Failures	None.
Secondary Failures	Loss of MFW and AFW.
Operator Actions	Operator depressurizes through ADVs and feeds SG's using condensate booster pumps. Operators maintain a cooldown rate within technical specification limits and throttle condensate flow at 84 % level in the steam generator.
Min DC Temperature	394.9 K [251.1°F] at 15000 s
Comments	None.

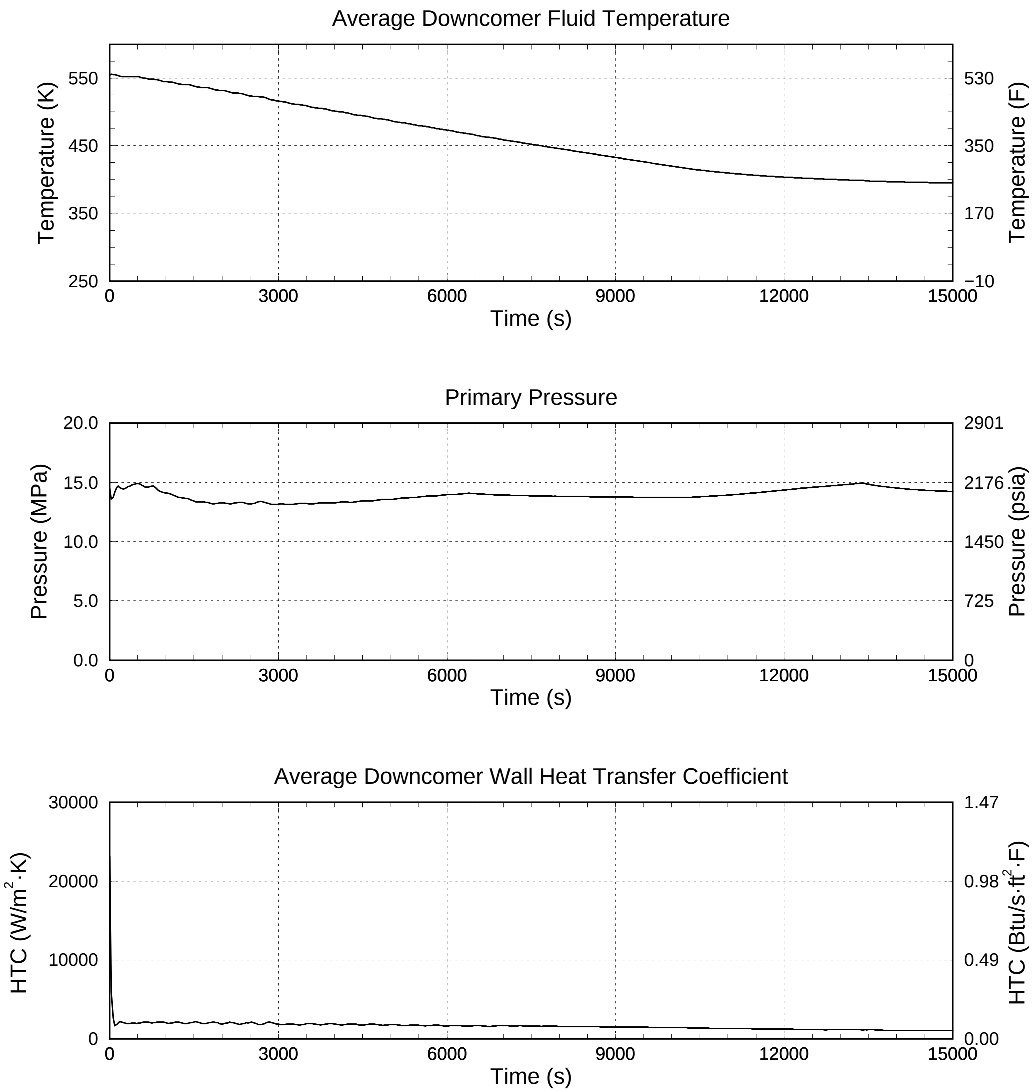


Figure C-5 Palisades PTS Results for Case 022

Case Category	MSLB
Primary Failures	None.
Secondary Failures	Break assumed to be inside containment causing containment spray actuation.
Operator Actions	None.
Min DC Temperature	431.0 K [316.1°F] at 450 s
Comments	None.

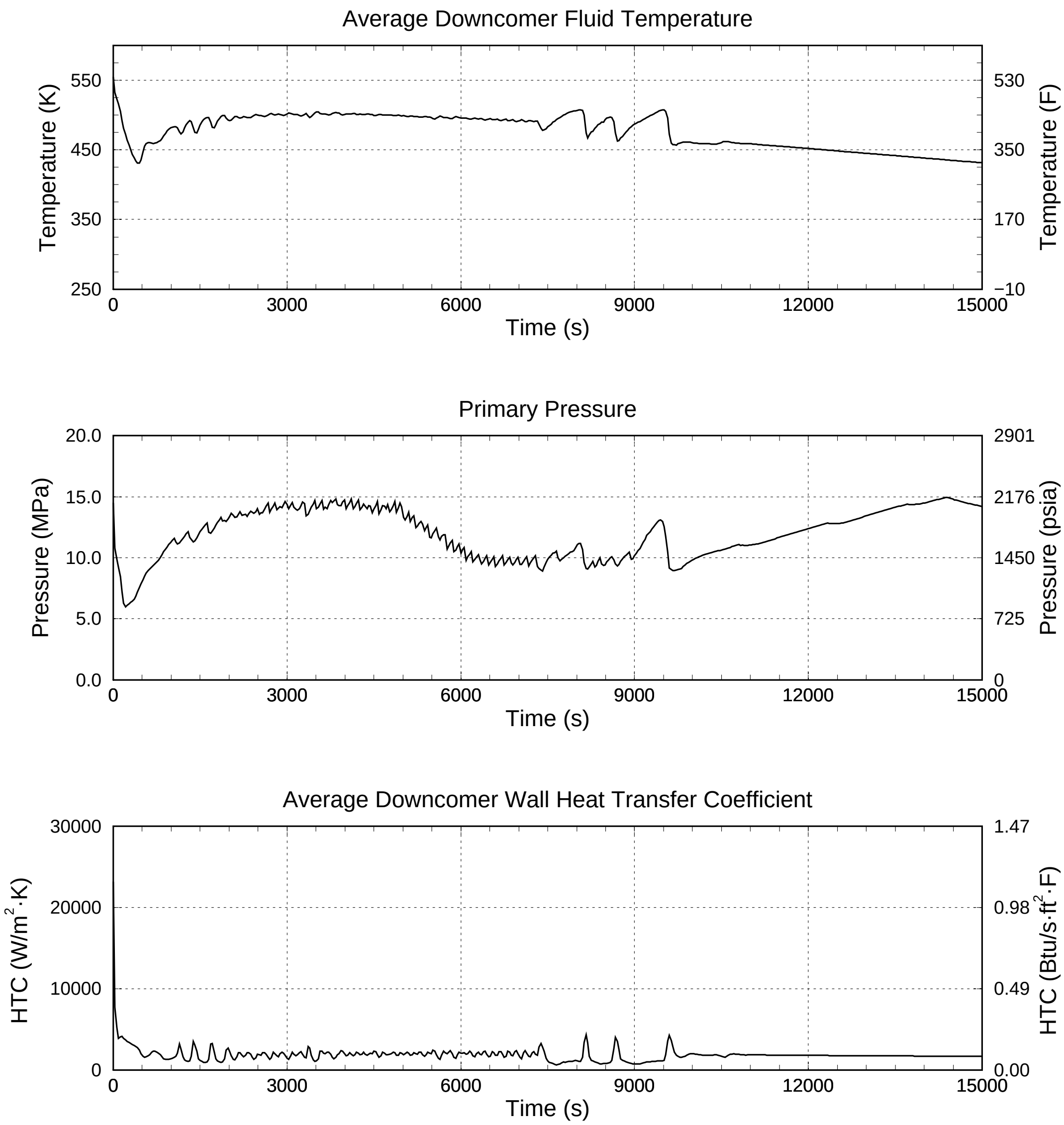


Figure C-6 Palisades PTS Results for Case 024

Case Category	MSLB
Primary Failures	None.
Secondary Failures	Break assumed to be inside containment causing containment spray actuation.
Operator Actions	Operator isolates AFW to affected SG at 30 minutes after initiation.
Min DC Temperature	431.0 K [316.1°F] at 450 s
Comments	None.

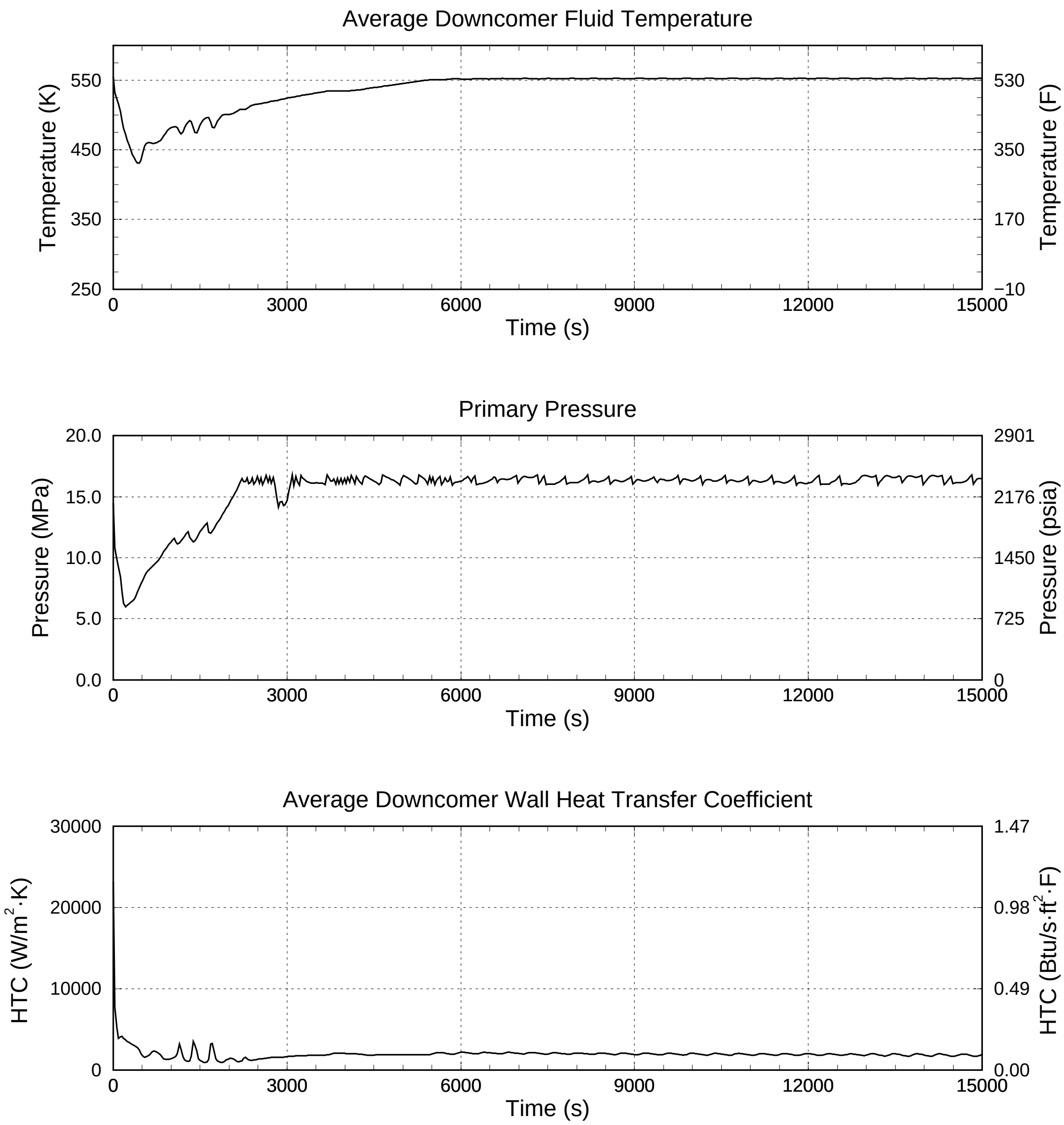
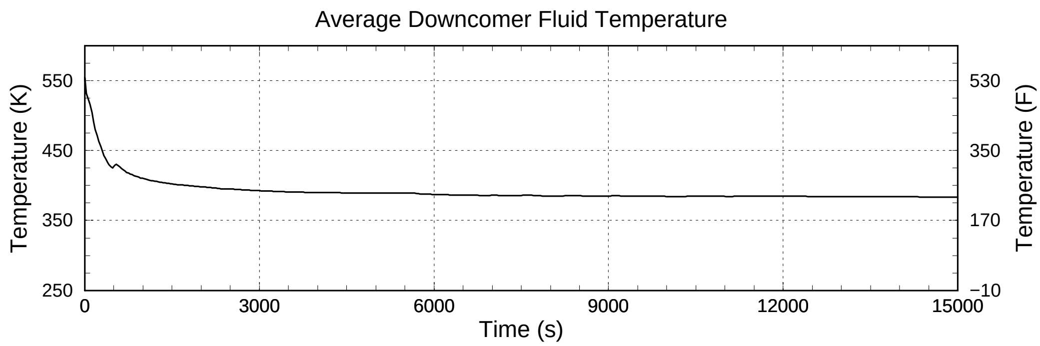
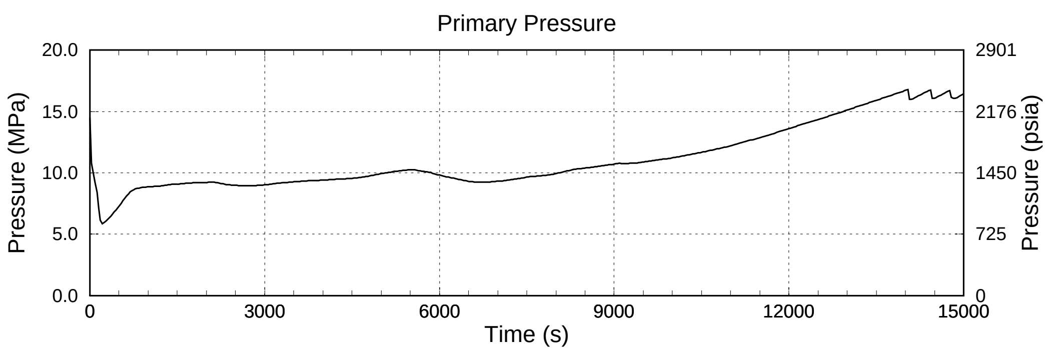


Figure C-7 Palisades PTS Results for Case 026

Case Category	MSLB
Primary Failures	None.
Secondary Failures	Controller failure resulting in the flow from two AFW pumps into affected steam generator. Break assumed to be inside containment causing containment spray actuation.
Operator Actions	Operator starts second AFW pump.
Min DC Temperature	383.5 K [230.6°F] at 15000 s
Comments	None.





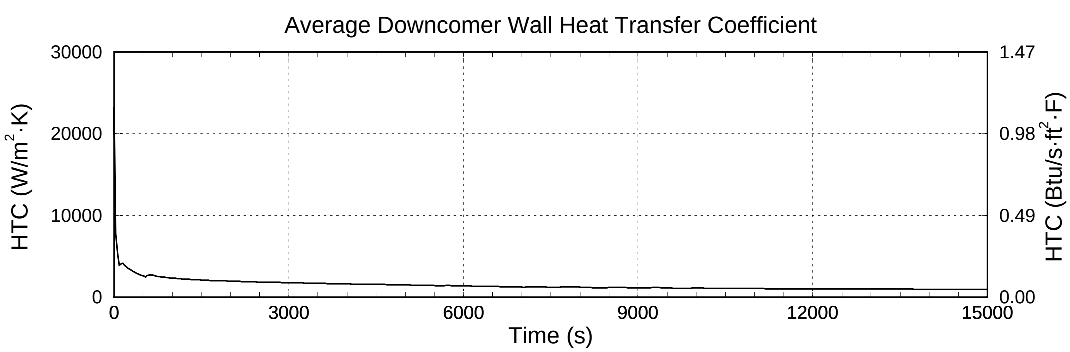


Figure C-8 Palisades PTS Results for Case 027

Case Category	MSLB, HZP
Primary Failures	None.
Secondary Failures	None. Break assumed to be inside containment causing containment spray actuation.
Operator Actions	None. Operator does not throttle HPI.
Min DC Temperature	379.9 K [224.2°F] at 7410 s
Comments	None.

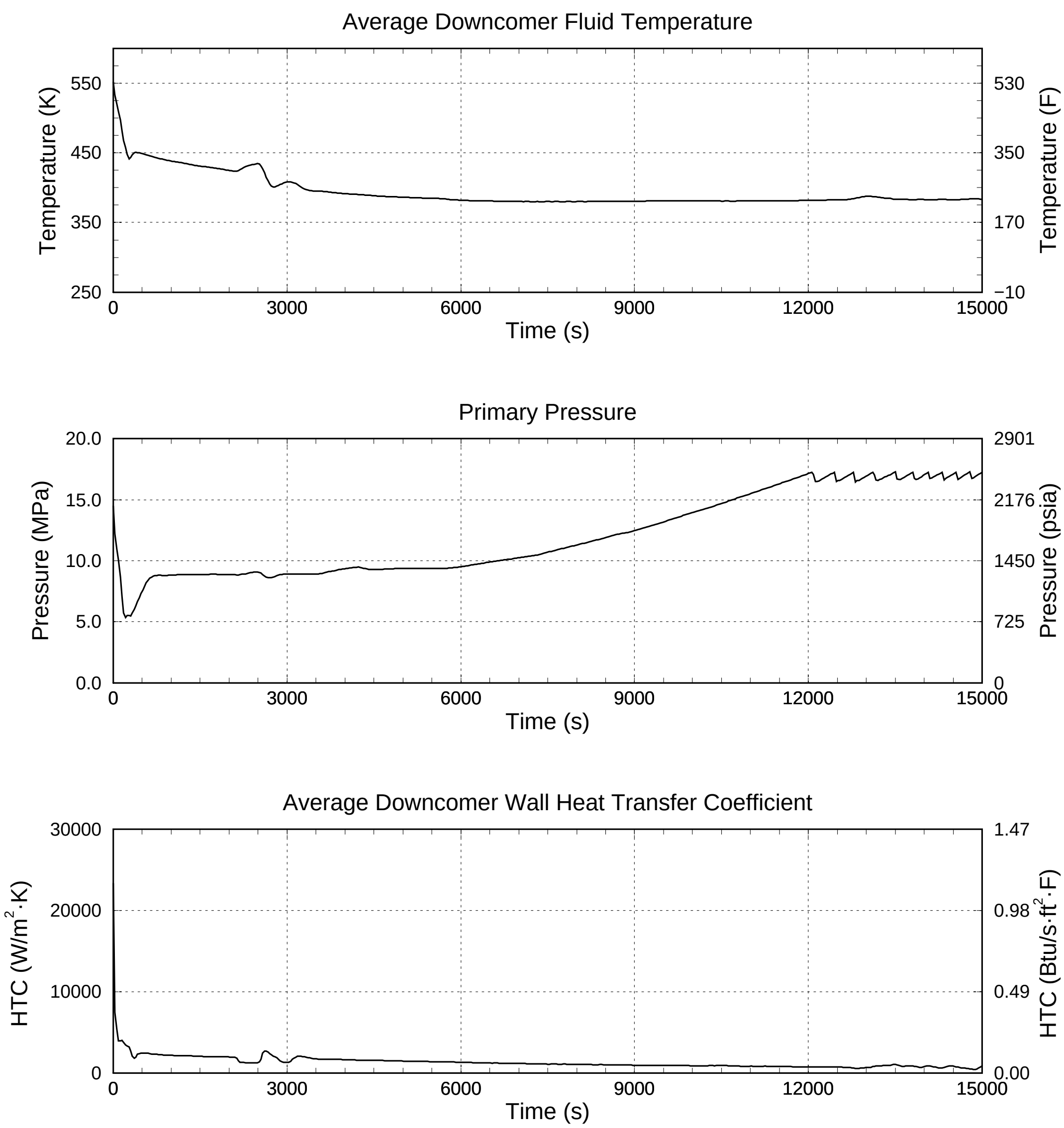


Figure C-9 Palisades PTS Results for Case 029

Case Category	TT/RT
Primary Failures	None.
Secondary Failures	Failure of MFW and AFW. Containment spray actuation assumed due to PORV discharge.
Operator Actions	Operator maintains core cooling by "feed and bleed" using HPI to feed and two PORVs to bleed.
Min DC Temperature	356.9 K [182.8°F] at 15000 s
Comments	None.

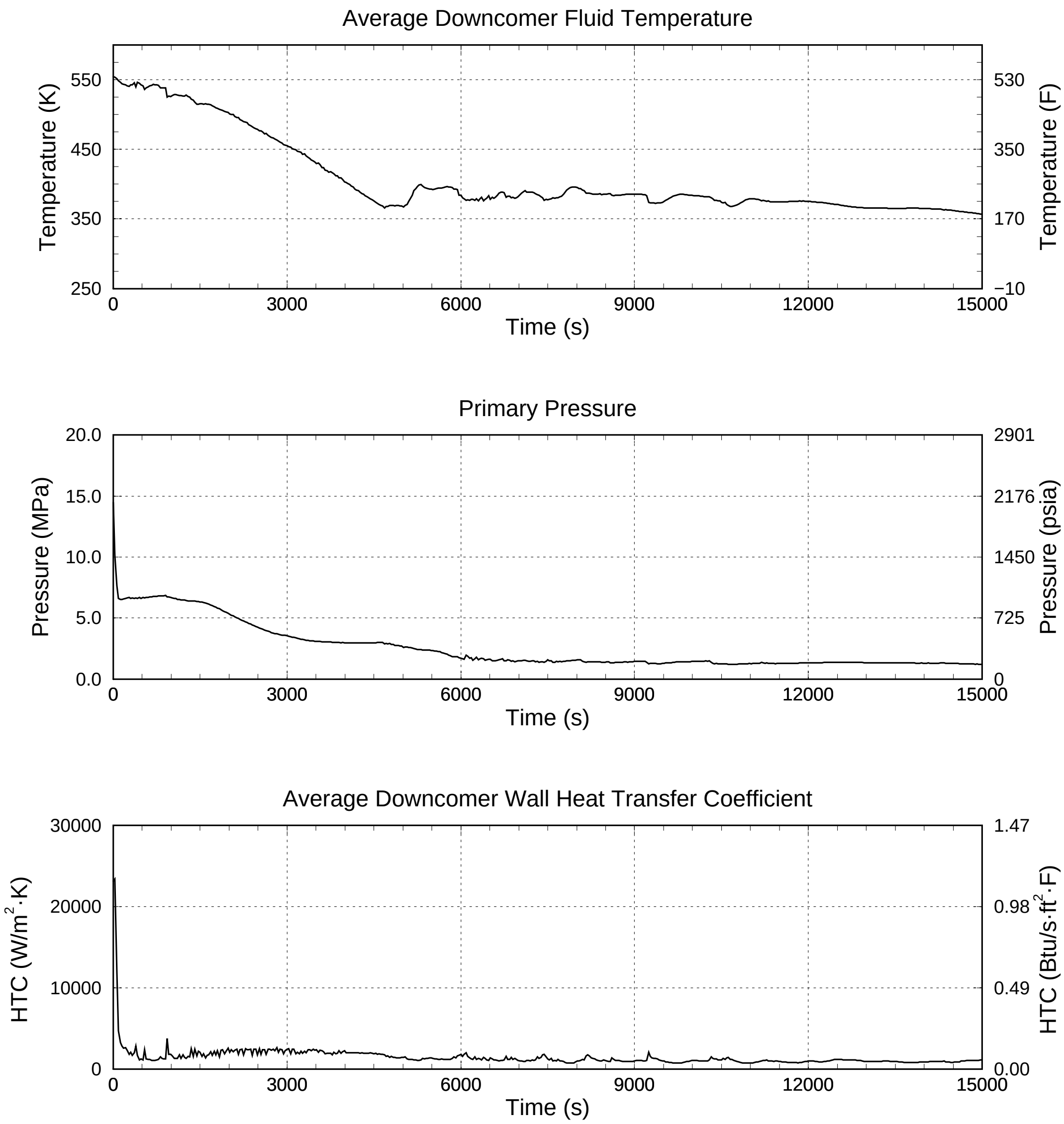


Figure C-10 Palisades PTS Results for Case 031

Case Category	TT/RT
Primary Failures	None.
Secondary Failures	Failure of MFW and AFW. Containment spray actuation assumed due to PORV discharge.
Operator Actions	Operator maintains core cooling by "feed and bleed" using HPI to feed and two PORV to bleed. AFW is recovered 15 minutes after initiation of "feed and bleed" cooling. Operator closes PORVs when SG level reaches 60 percent.
Min DC Temperature	411.1 K [280.4°F] at 4230 s
Comments	None.

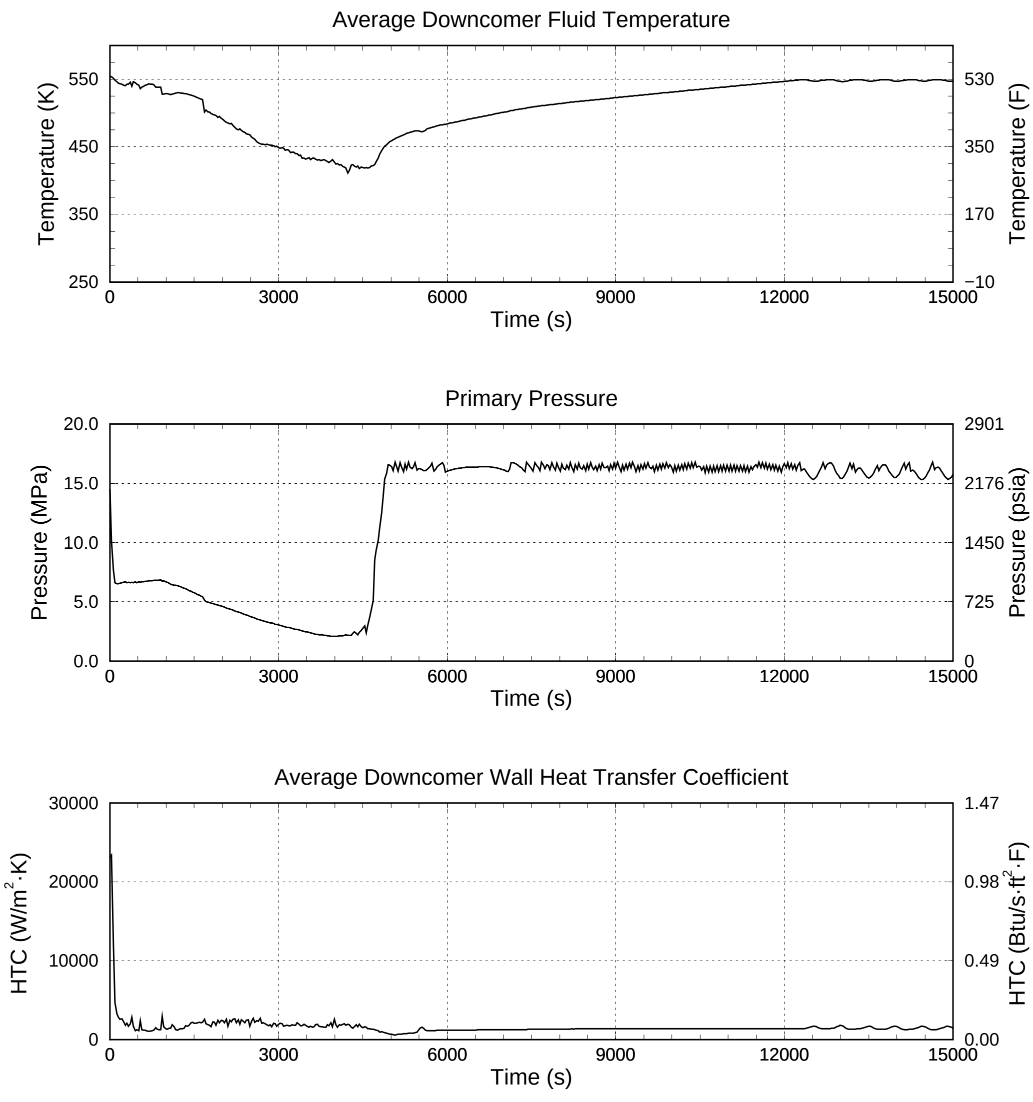


Figure C-11 Palisades PTS Results for Case 032

Case Category	MSLB
Primary Failures	Single SG tube ruptures in SG-A due to MSLB vibration.
Secondary Failures	None.
Operator Actions	Operator isolates AFW to affected SG at 15 minutes after initiation. Operator trips RCPs assuming that they do not trip as a result of the event. Operator assumed to throttle HPI if AFW is running with SG WRL > -84% and RCS subcooling > 25 F. HPI is throttled to maintain pressurizer level between 40 and 60 %.
Min DC Temperature	377.4 K [219.6°F] at 13770 s
Comments	None.

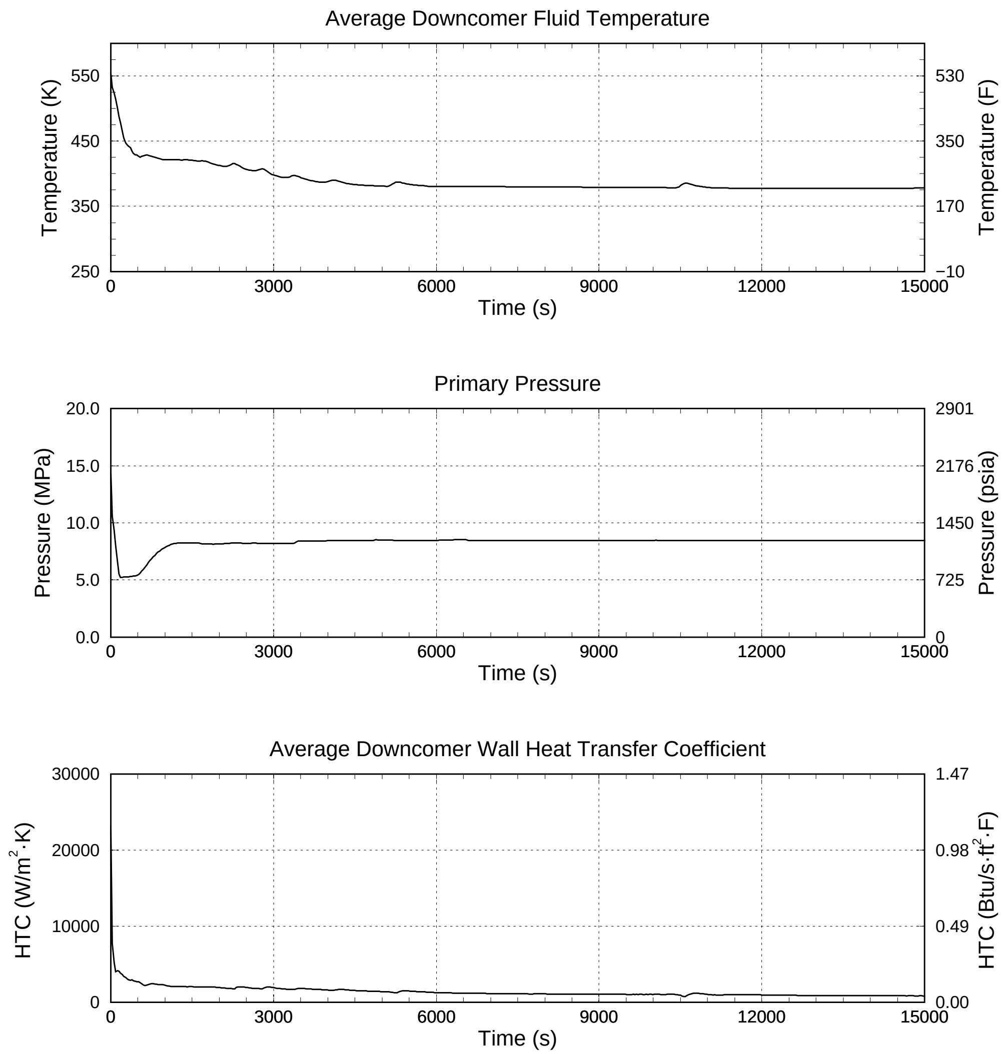


Figure C-12   Palisades PTS Results for Case 034

Case Category	LOCA
Primary Failures	40.64 cm (16 in) hot leg break. Containment sump recirculation included in the analysis.
Secondary Failures	None.
Operator Actions	None. Operator does not throttle HPI.
Min DC Temperature	307.8 K [94.4°F] at 1260 s
Comments	Momentum Flux Disabled in DC

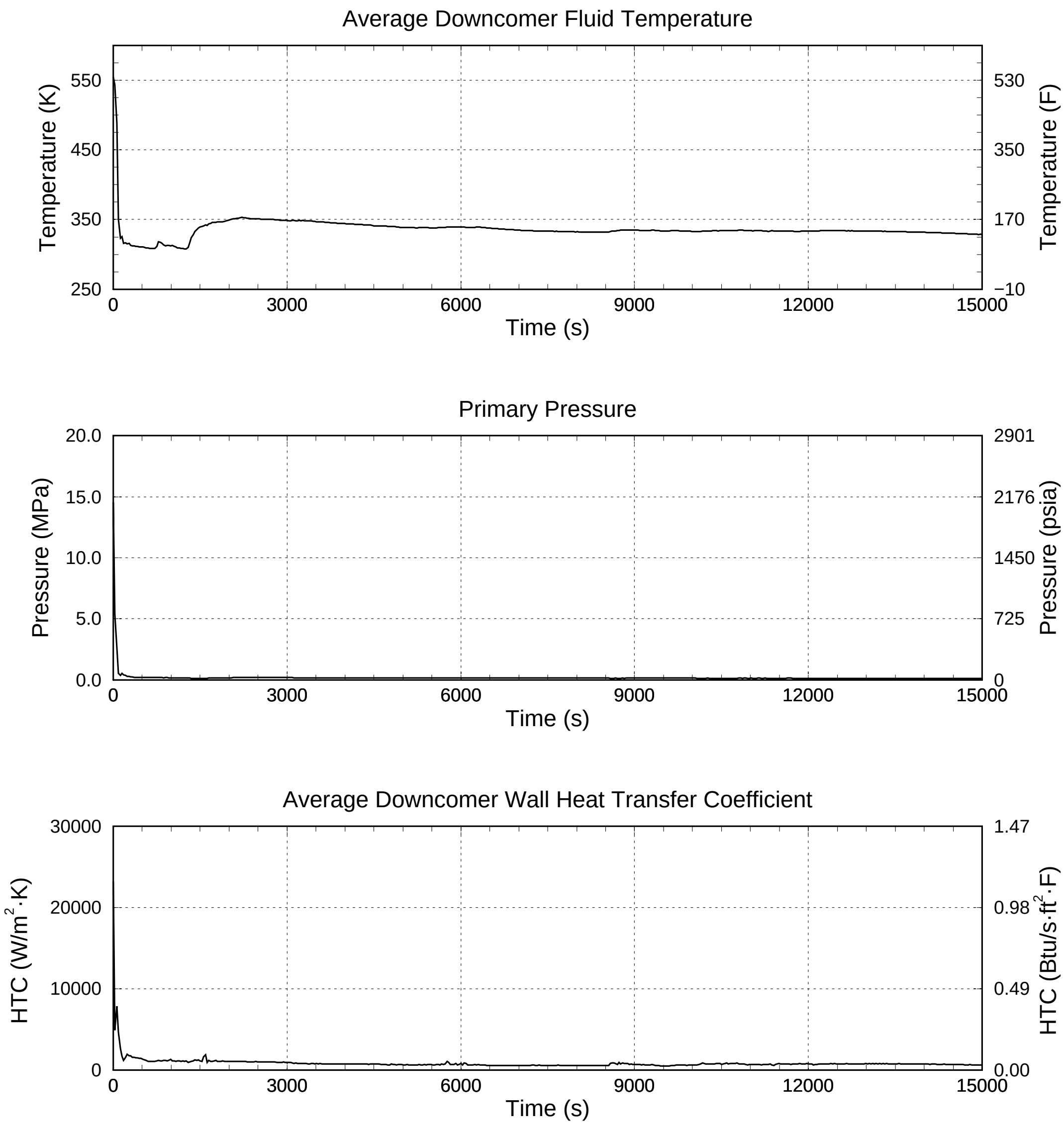


Figure C-13 Palisades PTS Results for Case 040

Case Category	TT/RT
Primary Failures	Two stuck open pressurizer SRVs. Containment spray is assumed not to actuate.
Secondary Failures	None.
Operator Actions	Operator assumed to throttle HPI if AFW is running with SG WRL > -84% and RCS subcooling > 25 F. HPI is throttled to maintain pressurizer level between 40 and 60 %.
Min DC Temperature	419.1 K [294.8°F] at 14910 s
Comments	None.

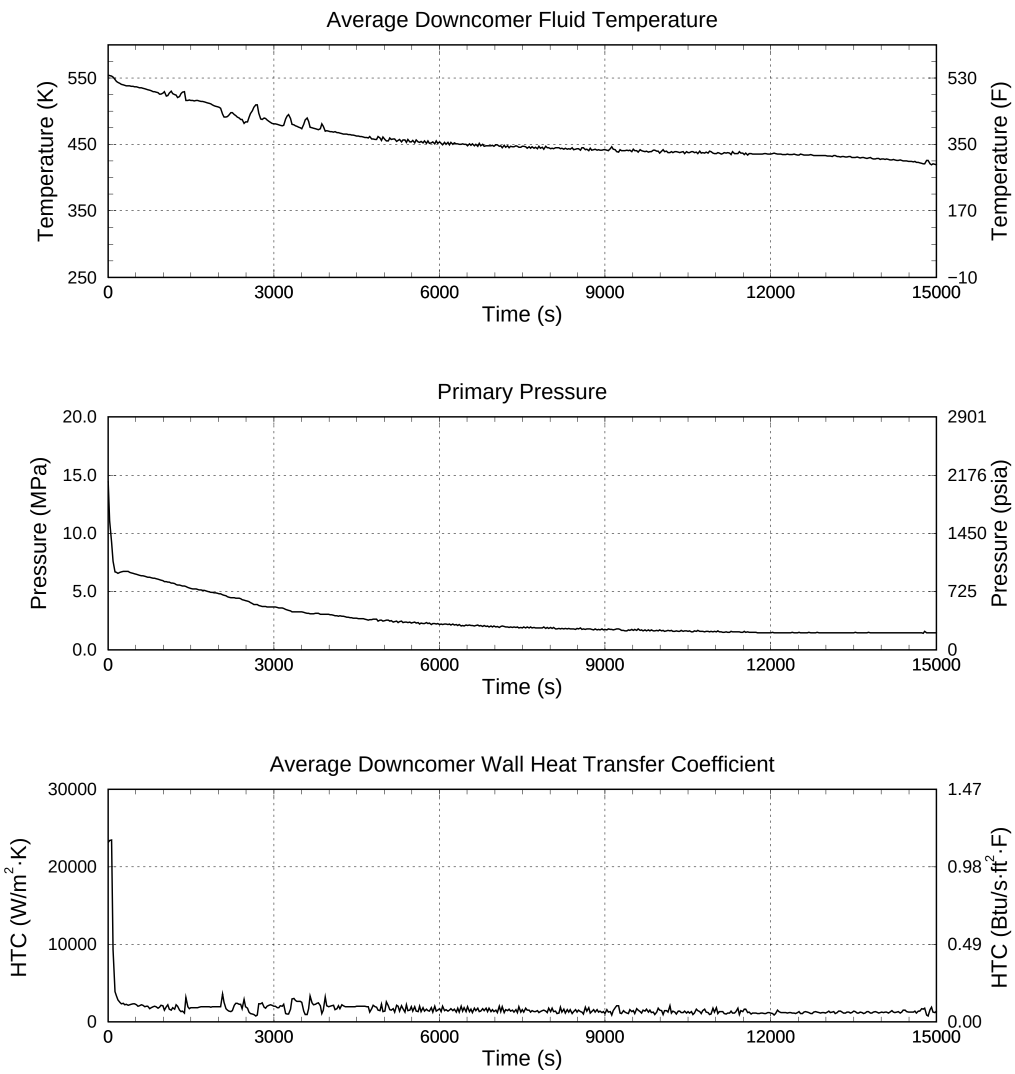


Figure C-14 Palisades PTS Results for Case 042

Case Category	TT/RT, HZP
Primary Failures	Two stuck-open pressurizer SRVs that reclose at 6000 sec after initiation. Containment spray is assumed not to actuate.
Secondary Failures	None.
Operator Actions	None. Operator does not throttle HPI.
Min DC Temperature	351.3 K [172.6°F] at 6360 s
Comments	None.

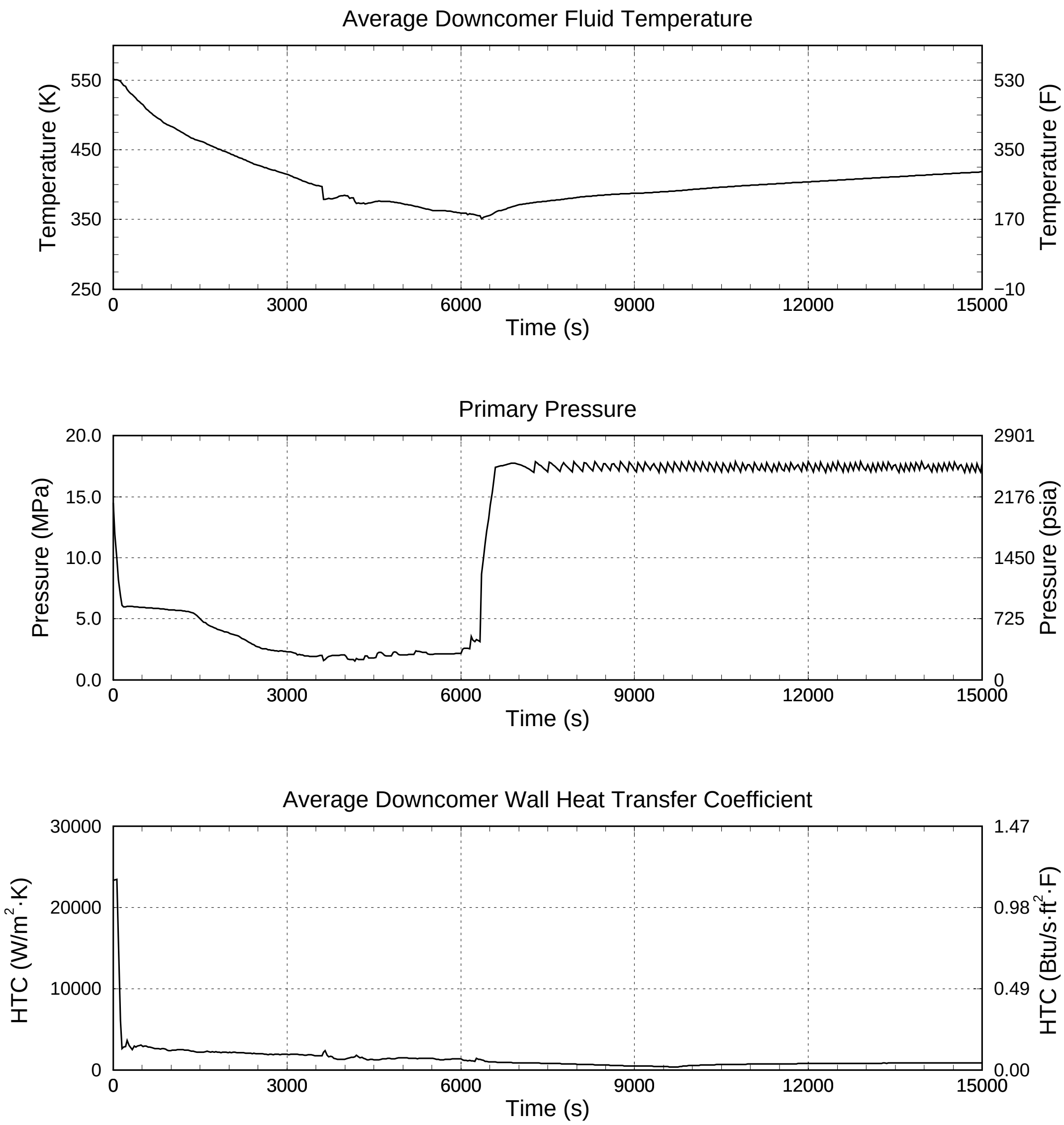


Figure C-15 Palisades PTS Results for Case 048

Case Category	MSLB, HZP
Primary Failures	None.
Secondary Failures	Break assumed to be inside containment causing containment spray actuation.
Operator Actions	Operator isolates AFW to affected SG at 30 minutes after initiation. Operator does not throttle HPI.
Min DC Temperature	426.1 K [307.4°F] at 1920 s
Comments	None.

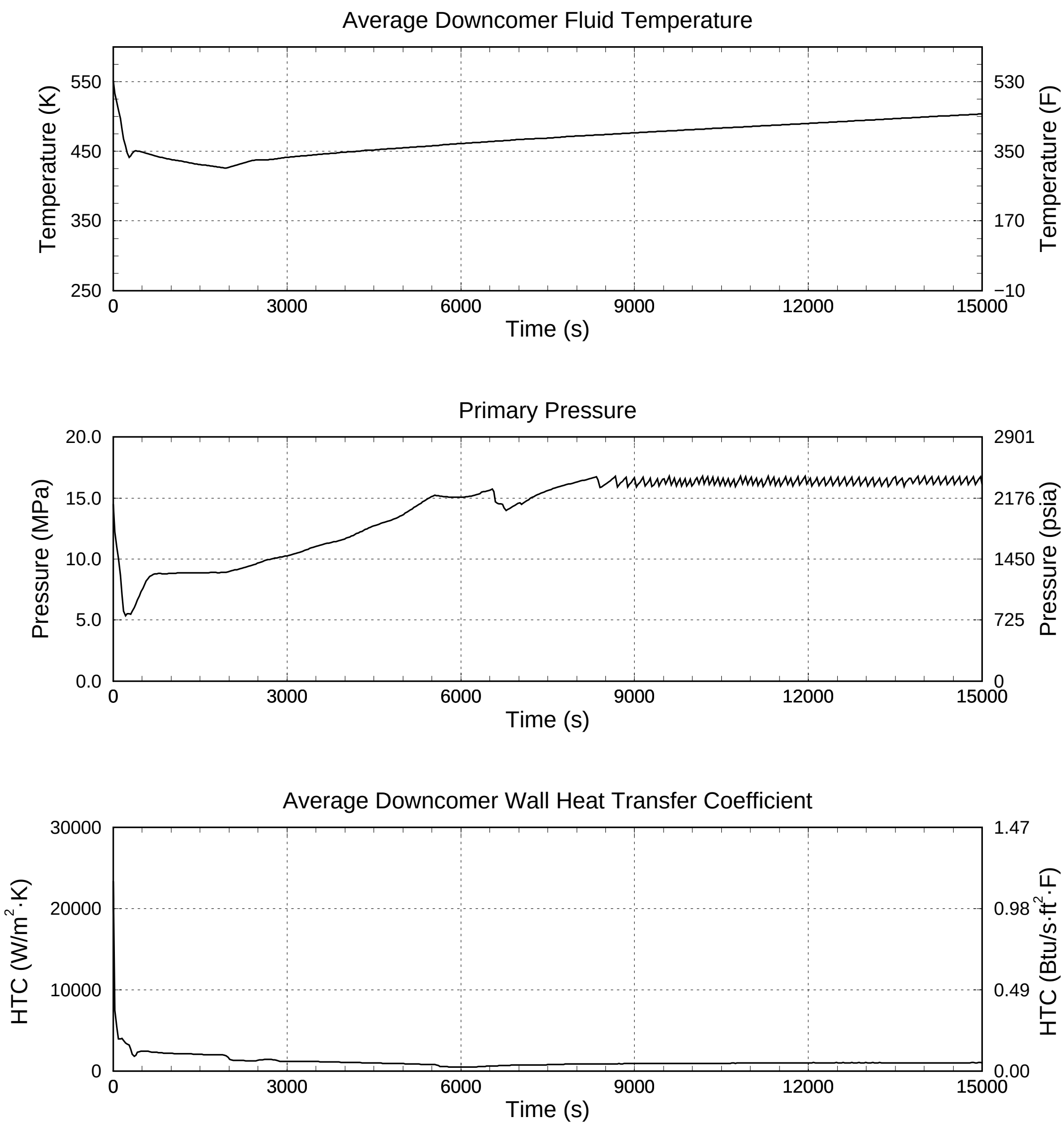
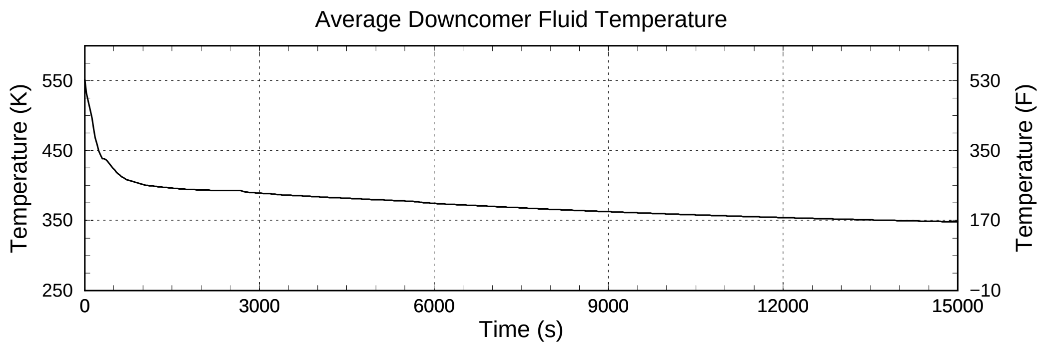
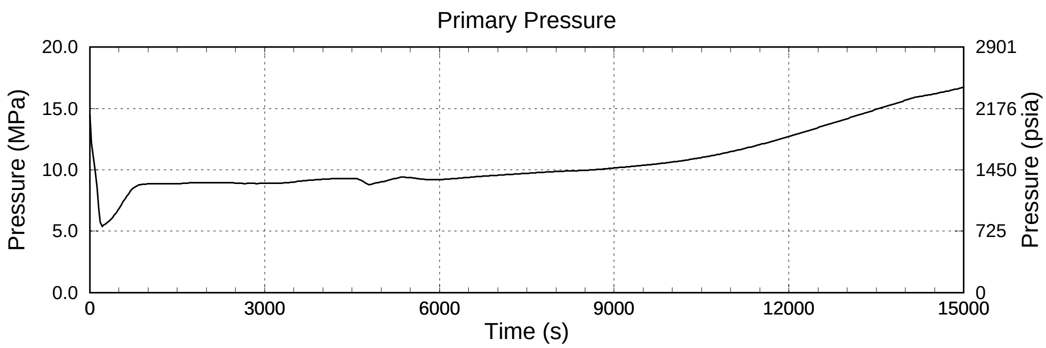


Figure C-16 Palisades PTS Results for Case 049

Case Category	MSLB, HZP
Primary Failures	None.
Secondary Failures	Controller failure resulting in the flow from two AFW pumps into affected steam generator. Break assumed to be inside containment causing containment spray actuation.
Operator Actions	Operator starts second AFW pump. Operator does not throttle HPI.
Min DC Temperature	348.0 K [166.8°F] at 15000 s
Comments	None.





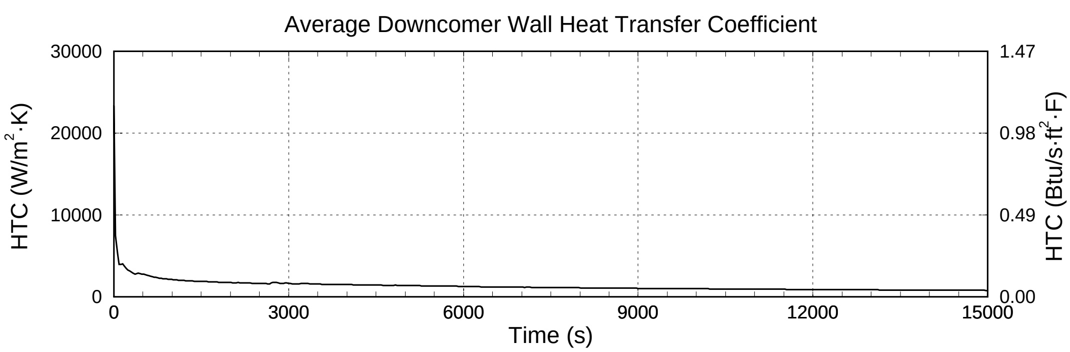


Figure C-17 Palisades PTS Results for Case 050

Case Category	MSLB, HZP
Primary Failures	None.
Secondary Failures	Failure of both MSIVs to close. Break assumed to be inside containment causing containment spray actuation.
Operator Actions	Operator does not isolate AFW on affected SG. Operator does not throttle HPI.
Min DC Temperature	375.3 K [215.9°F] at 3150 s
Comments	None.

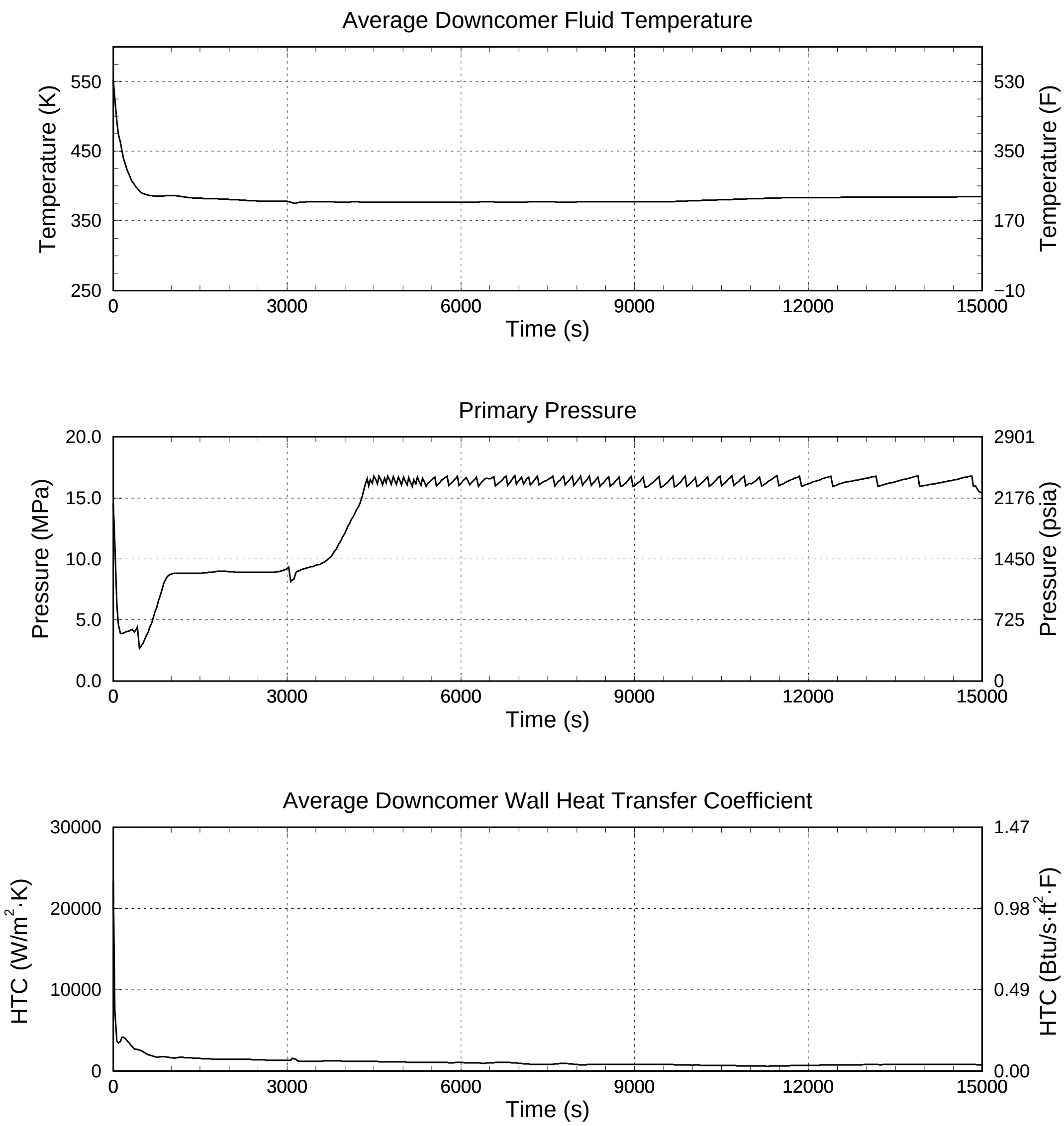


Figure C-18 Palisades PTS Results for Case 051

Case Category	TT/RT, HZP
Primary Failures	None.
Secondary Failures	1 stuck-open ADV on SG-A. Failure of both MSIVs (SG-A and SG-B) to close.
Operator Actions	Operator does not isolate AFW on affected SG. Normal AFW flow assumed (200 gpm). Operator does not throttle HPI.
Min DC Temperature	424.6 K [304.7°F] at 14850 s
Comments	None.

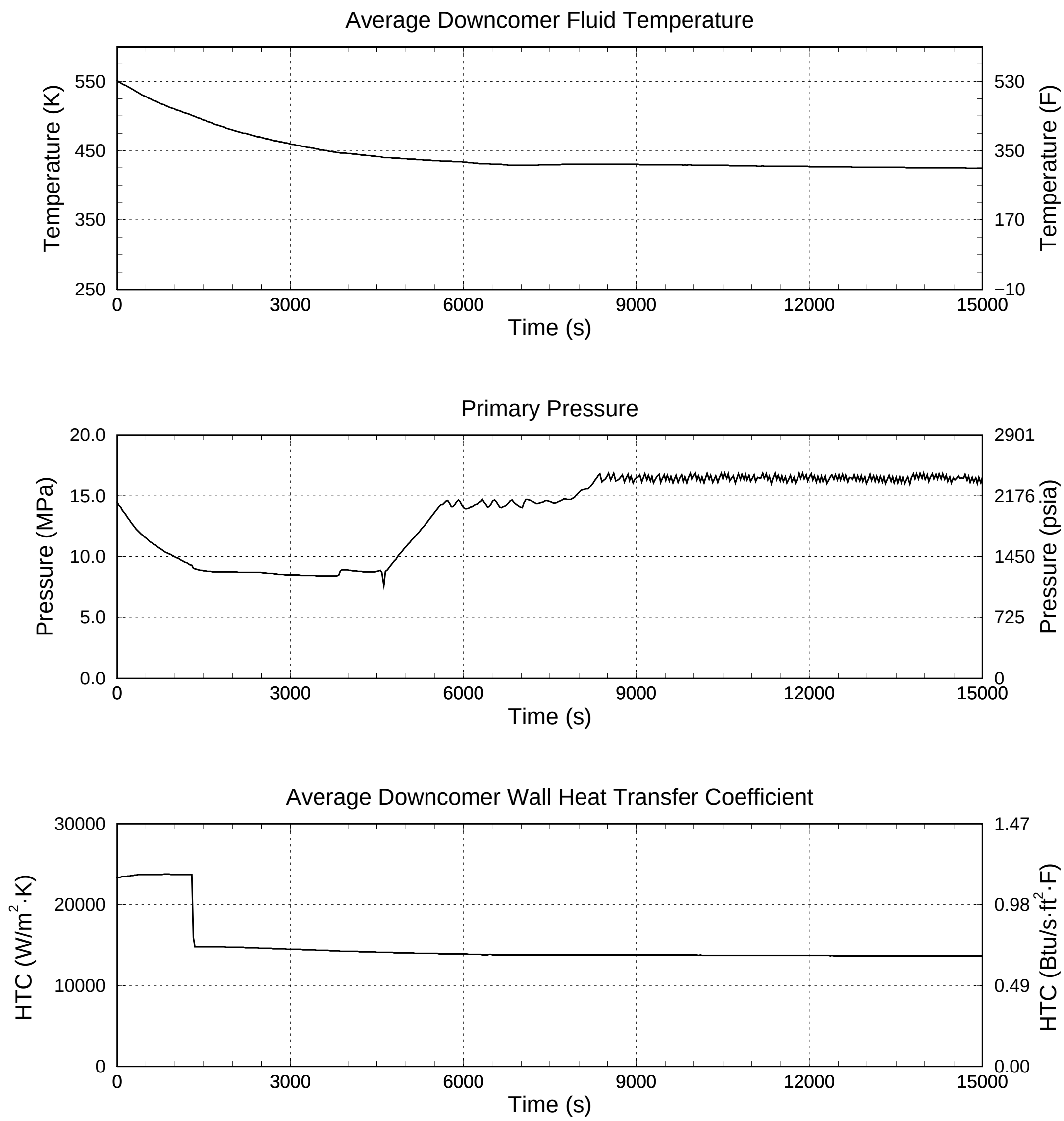


Figure C-19 Palisades PTS Results for Case 052

Case Category	TT/RT
Primary Failures	Two stuck-open pressurizer SRVs that reclose at 6000 sec after initiation. Containment spray is assumed not to actuate.
Secondary Failures	None.
Operator Actions	None. Operator does not throttle HPI.
Min DC Temperature	433.1 K [319.9°F] at 5970 s
Comments	None.

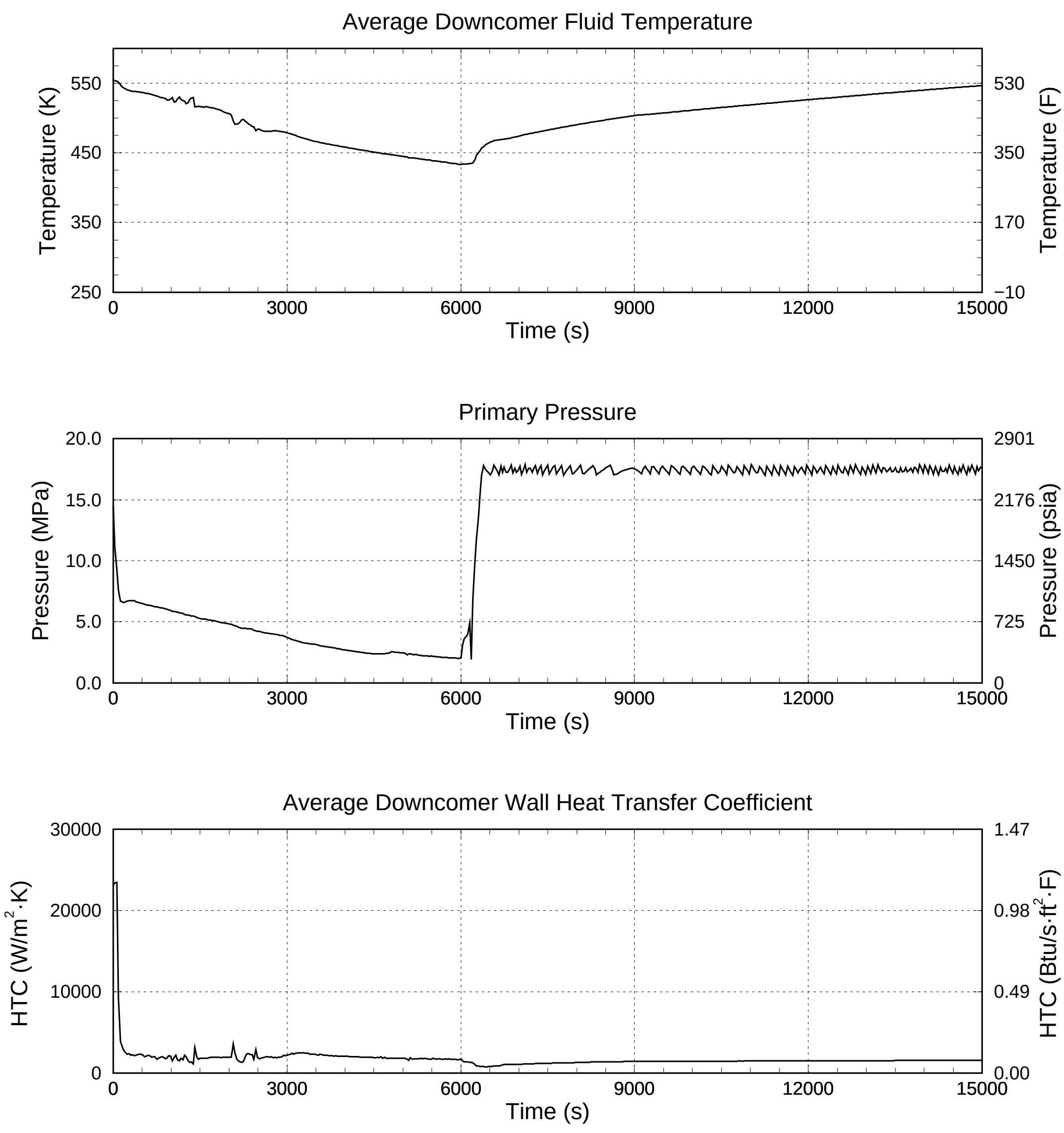


Figure C-20 Palisades PTS Results for Case 053

Case Category	MSLB
Primary Failures	None.
Secondary Failures	Failure of both MSIVs to close. Break assumed to be inside containment causing containment spray actuation.
Operator Actions	Operator does not isolate AFW on affected SG. Operator does not throttle HPI.
Min DC Temperature	377.1 K [219.1°F] at 4110 s
Comments	None.

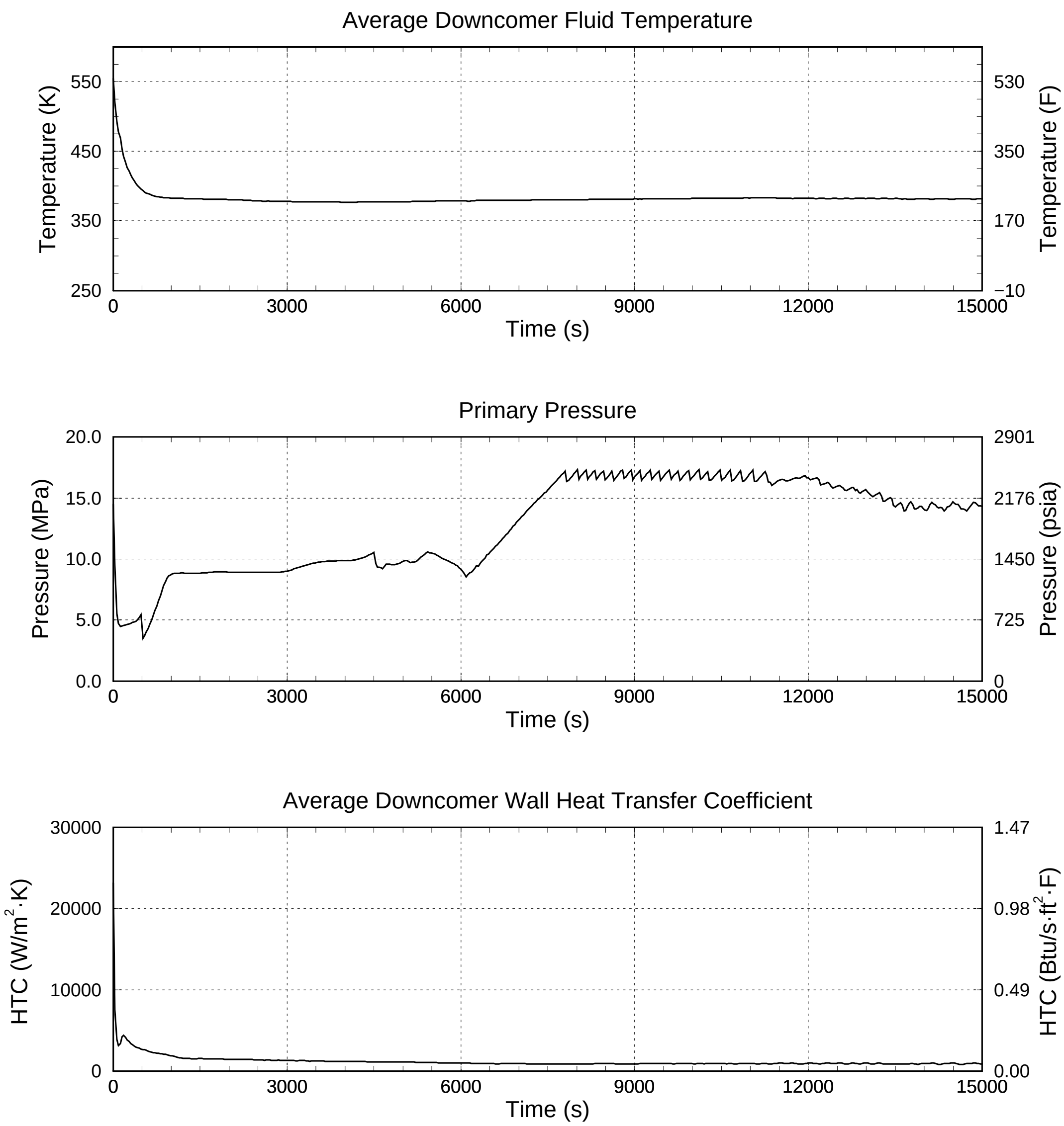


Figure C-21   Palisades PTS Results for Case 054

Case Category	TT/RT
Primary Failures	None.
Secondary Failures	2 stuck-open ADVs on SG-A combined with controller failure resulting in the flow from two AFW pumps into affected steam generator.
Operator Actions	Operator starts second AFW pump.
Min DC Temperature	437.4 K [327.7°F] at 4320 s
Comments	None.

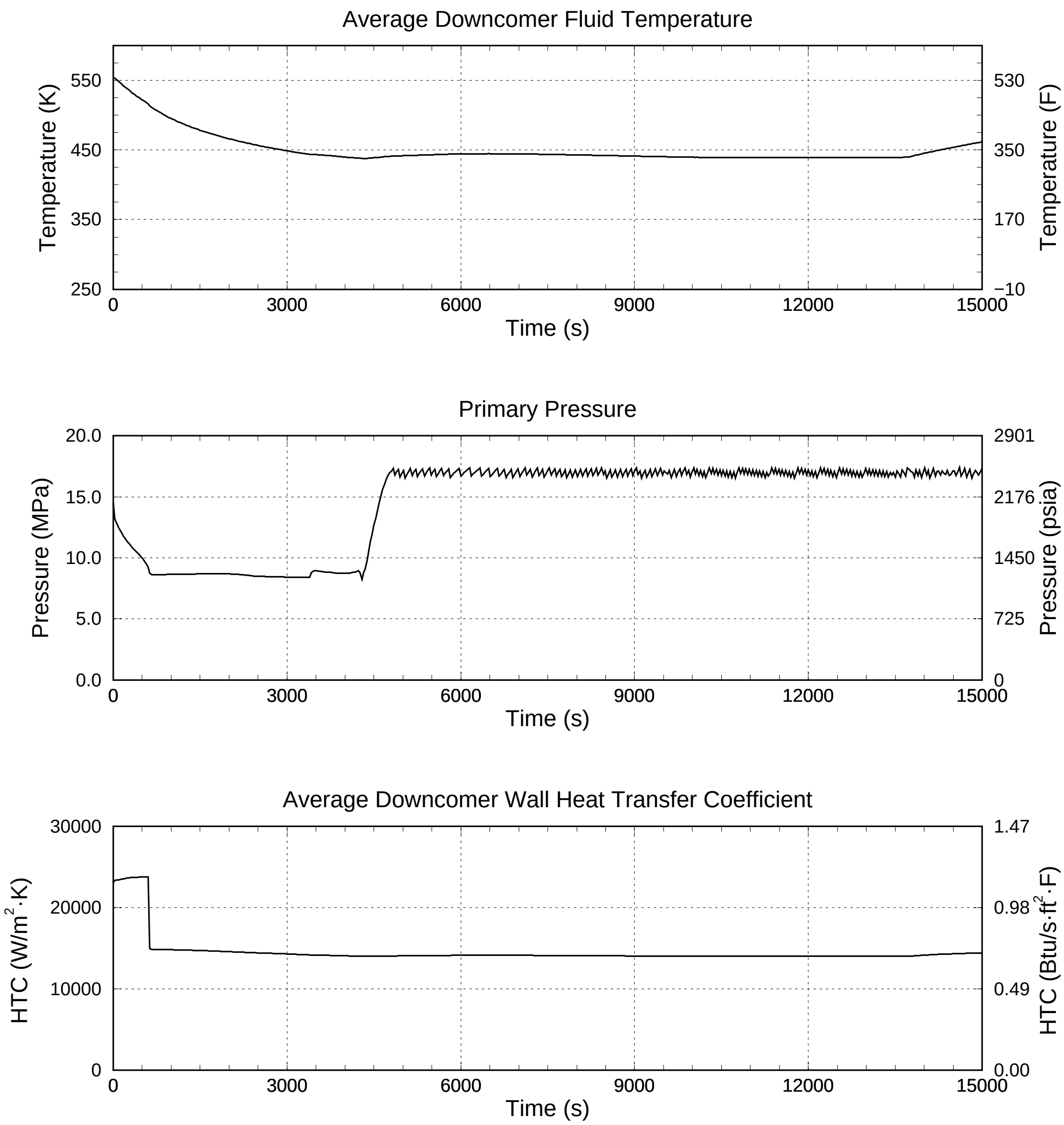


Figure C-22 Palisades PTS Results for Case 055

Case Category	LOCA
Primary Failures	10.16 cm (4 in) cold leg break. Winter conditions assumed (HPI and LPI injection temp = 40 F, Accumulator temp = 60 F)
Secondary Failures	None.
Operator Actions	None. Operator does not throttle HPI.
Min DC Temperature	331.0 K [136.2°F] at 2700 s
Comments	Momentum Flux Disabled in the DC

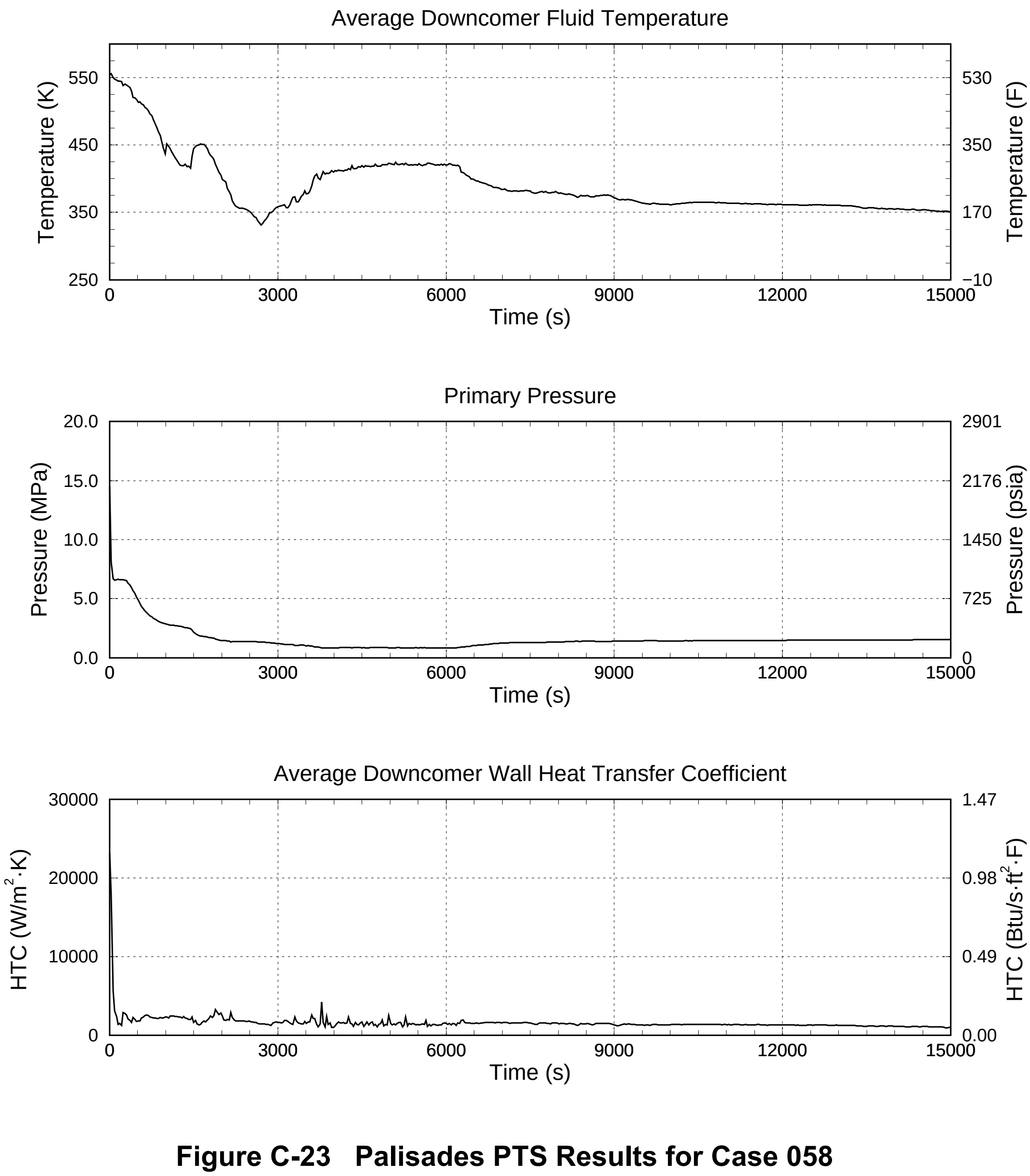


Figure C-23 Palisades PTS Results for Case 058

Case Category	LOCA
Primary Failures	10.16 cm (4 in) cold leg break. Summer conditions assumed (HPI and LPI injection temp = 100 F, Accumulator temp = 90 F)
Secondary Failures	None.
Operator Actions	None. Operator does not throttle HPI.
Min DC Temperature	350.7 K [171.6°F] at 14940 s
Comments	Momentum Flux Disabled in the DC

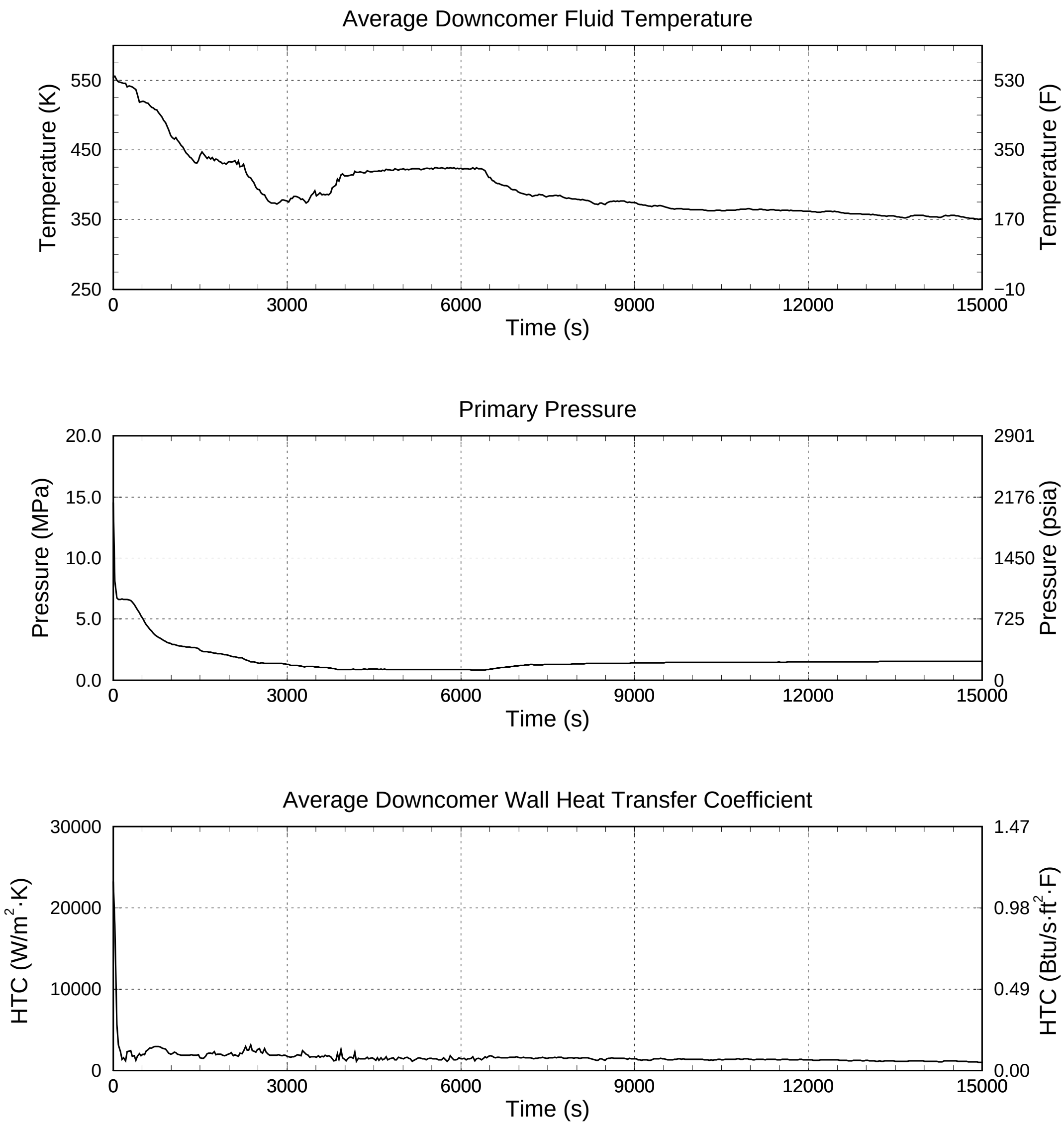
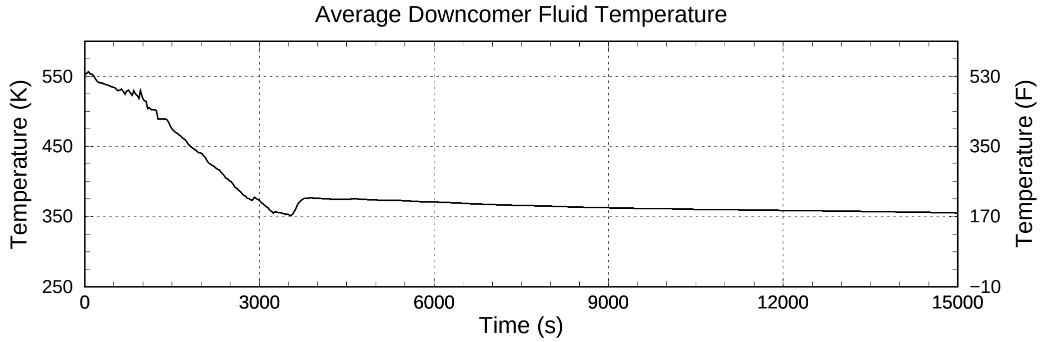
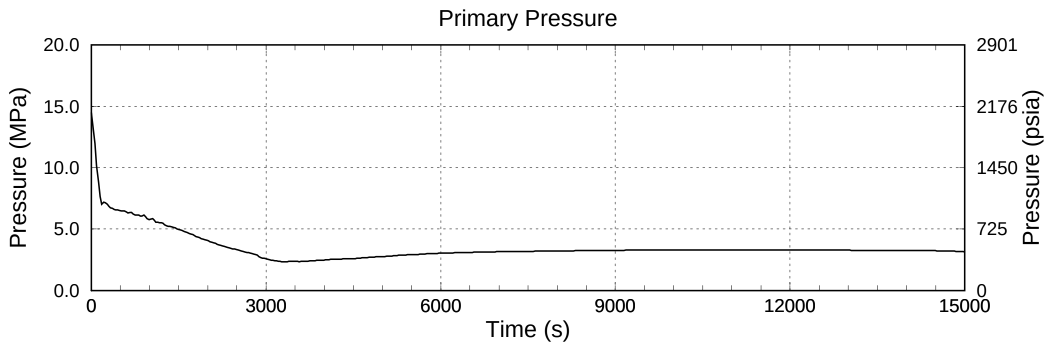


Figure C-24 Palisades PTS Results for Case 059

Case Category	LOCA
Primary Failures	5.08 cm (2 in) surge line break. Winter conditions assumed (HPI and LPI injection temp = 40 F, Accumulator temp = 60 F)
Secondary Failures	None.
Operator Actions	None. Operator does not throttle HPI.
Min DC Temperature	351.3 K [172.7°F] at 3540 s
Comments	None.





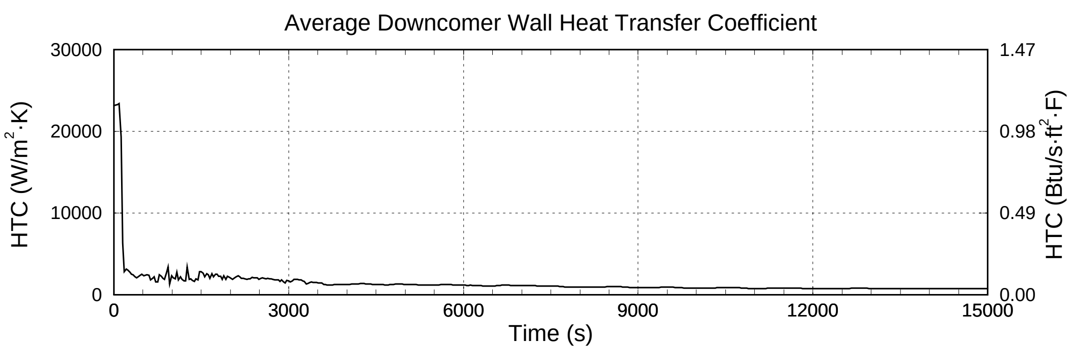


Figure C-25 Palisades PTS Results for Case 060

Case Category	LOCA
Primary Failures	7.18 cm (2.8 in) cold leg break. Summer conditions assumed (HPI and LPI injection temp = 100 F, Accumulator temp = 90 F)
Secondary Failures	None.
Operator Actions	None. Operator does not throttle HPI.
Min DC Temperature	383.4 K [230.4°F] at 8940 s
Comments	Momentum Flux Disabled in the DC

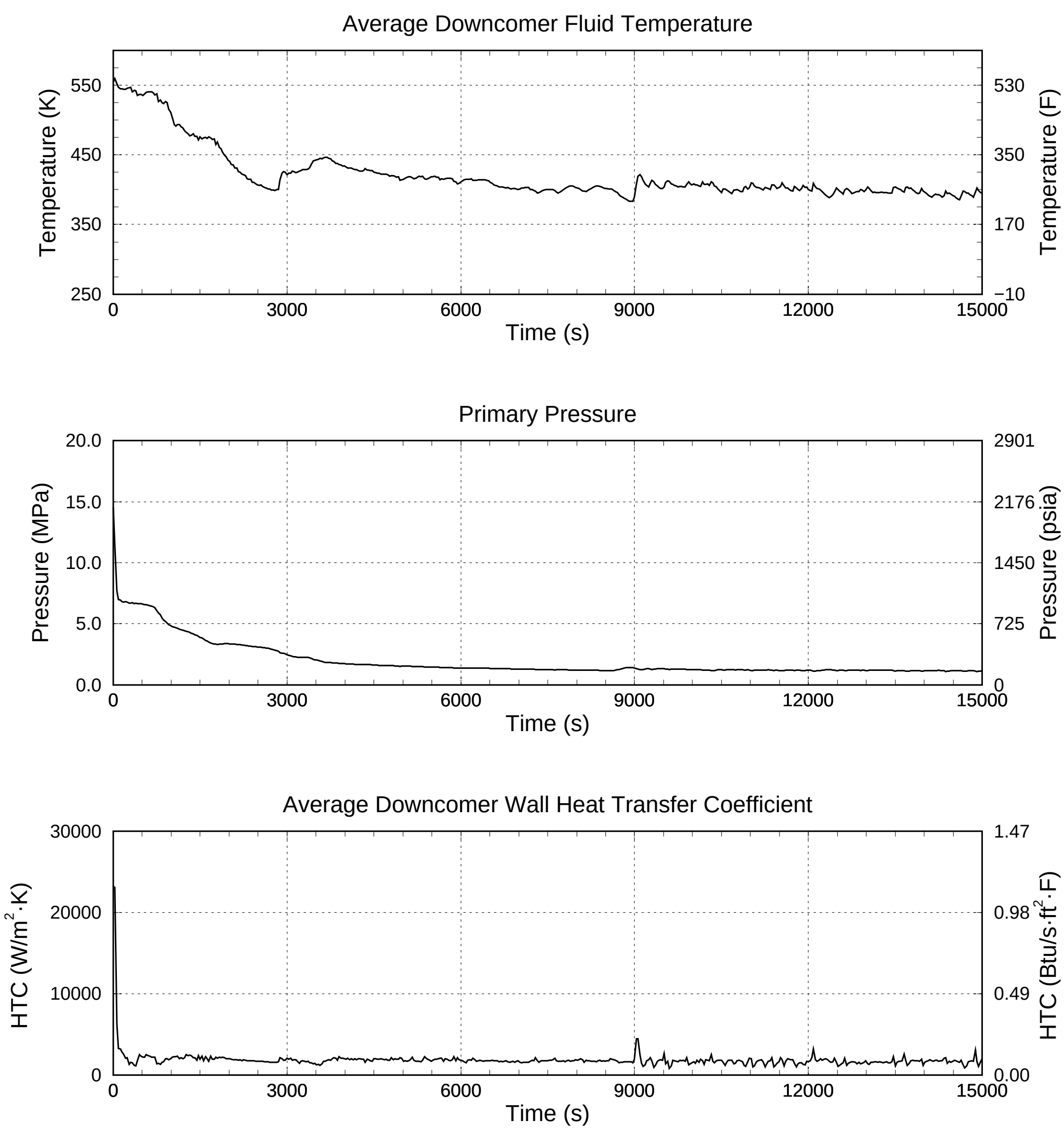


Figure C-26 Palisades PTS Results for Case 061

Case Category	LOCA
Primary Failures	20.32 cm (8 in) cold leg break. Winter conditions assumed (HPI and LPI injection temp = 40 F, Accumulator temp = 60 F)
Secondary Failures	None.
Operator Actions	None. Operator does not throttle HPI.
Min DC Temperature	308.0 K [94.7°F] at 1470 s
Comments	Momentum Flux Disabled in the DC

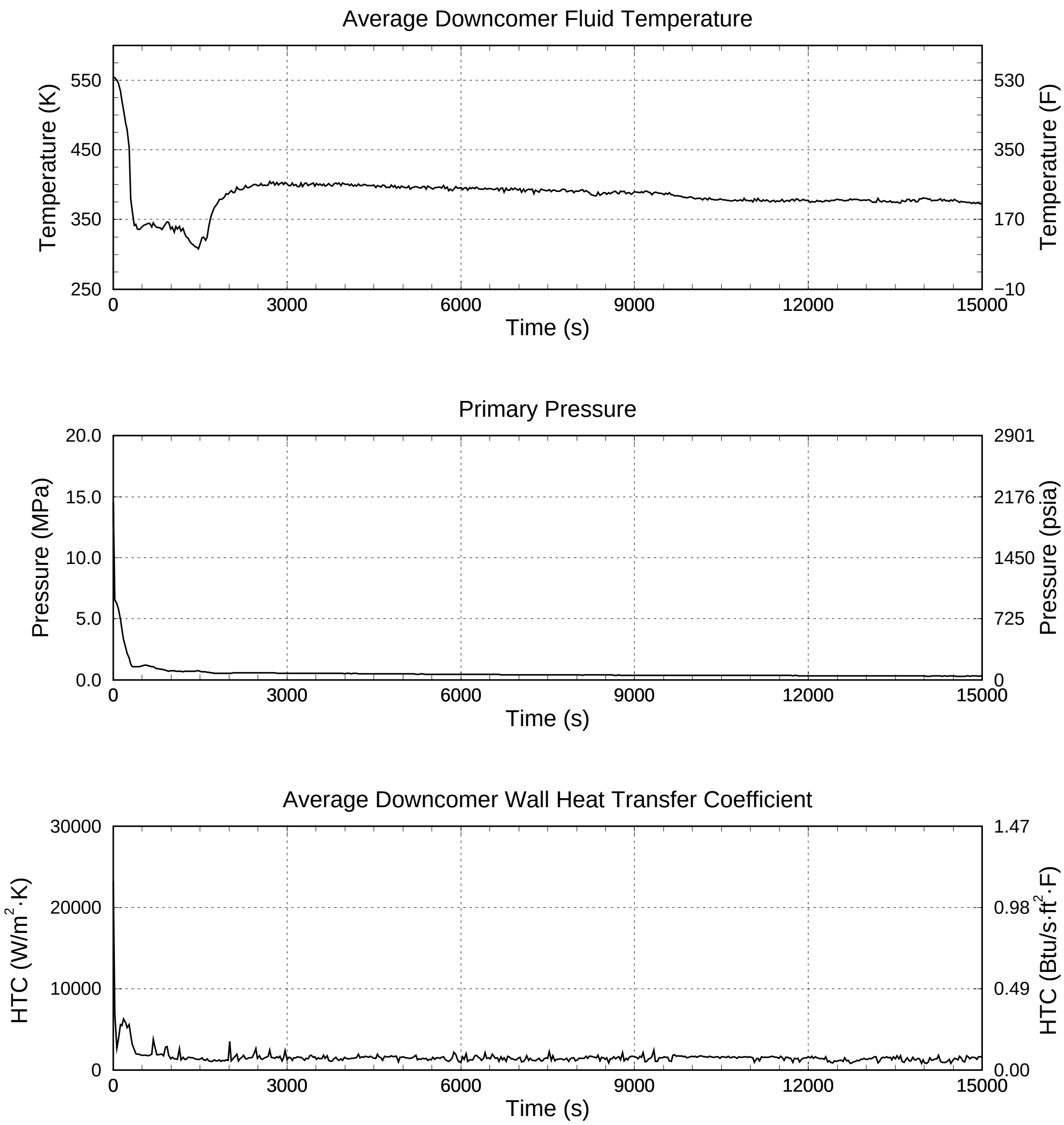


Figure C-27 Palisades PTS Results for Case 062

Case Category	LOCA
Primary Failures	14.37 cm (5.656 in) cold leg break. Winter conditions assumed (HPI and LPI injection temp = 40 F, Accumulator temp = 60 F)
Secondary Failures	None.
Operator Actions	None. Operator does not throttle HPI.
Min DC Temperature	306.4 K [91.8°F] at 2070 s
Comments	Momentum Flux Disabled in the DC

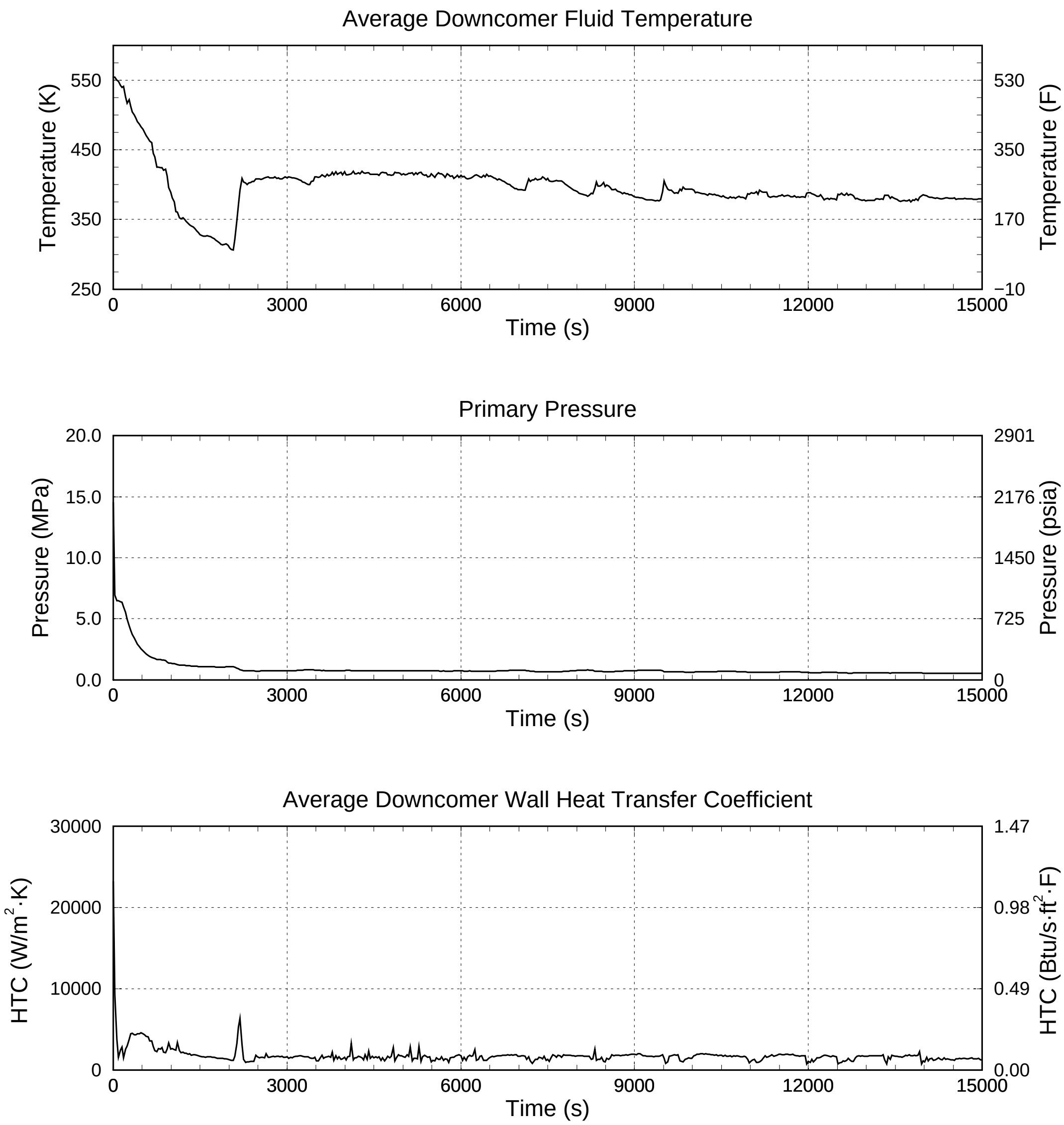


Figure C-28 Palisades PTS Results for Case 063

Case Category	LOCA
Primary Failures	10.16 cm (4 in) surge line break. Summer conditions assumed (HPI and LPI injection temp = 100 F, Accumulator temp = 90 F)
Secondary Failures	None.
Operator Actions	None. Operator does not throttle HPI.
Min DC Temperature	322.8 K [121.4°F] at 2730 s
Comments	None.

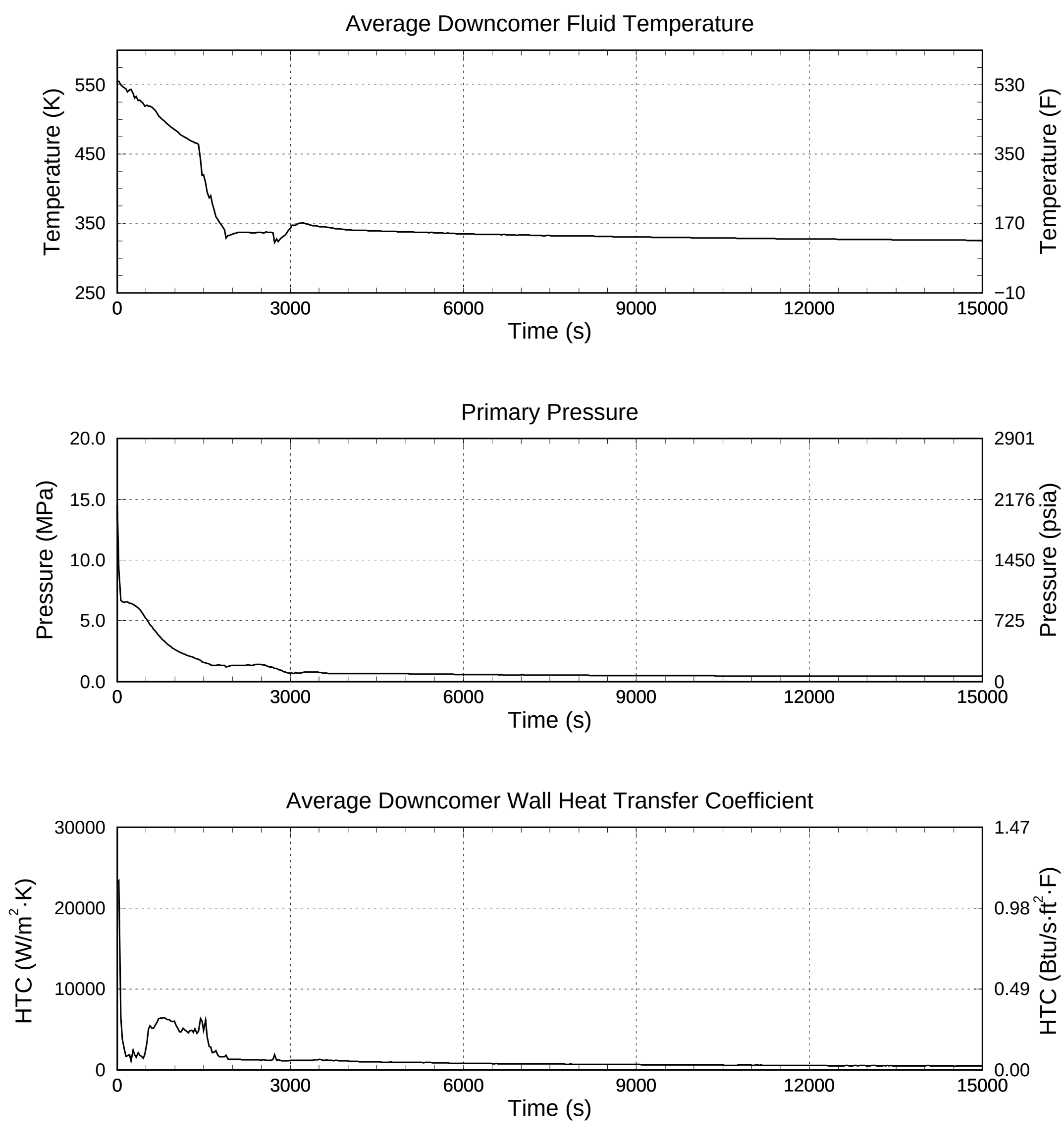


Figure C-29 Palisades PTS Results for Case 064

Case Category	LOCA
Primary Failures	10.16 cm (4 in) surge line break. Summer conditions assumed (HPI and LPI injection temp = 100 F, Accumulator temp = 90 F)
Secondary Failures	None.
Operator Actions	None. Operator does not throttle HPI.
Min DC Temperature	366.1 K [199.3°F] at 6570 s
Comments	None.

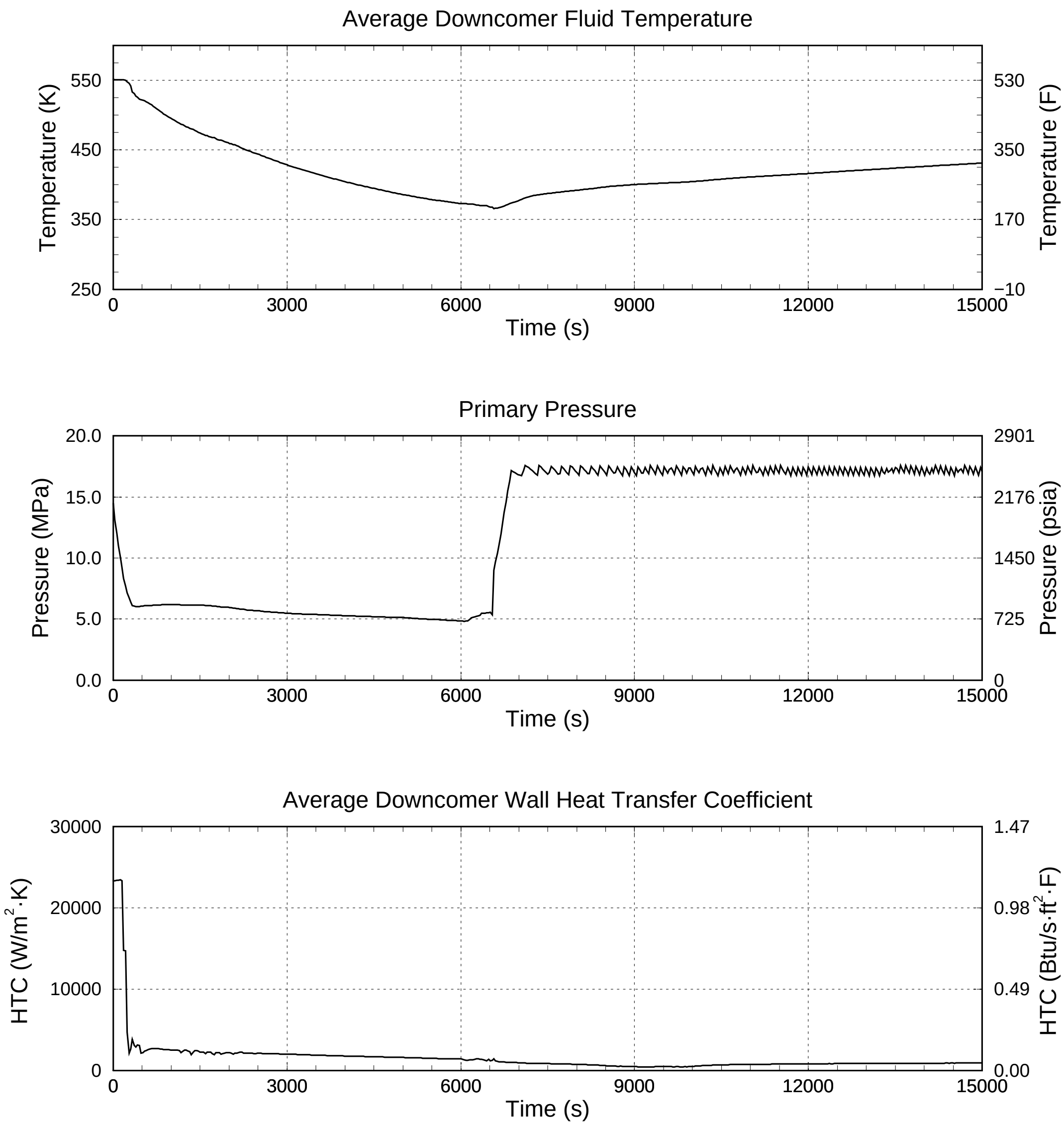


Figure C-30 Palisades PTS Results for Case 065

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10. SUPPLEMENTARY NOTES

M. B. Rubin, NRC Project Manager and D. E. Bessette, Technical Monitor

11. ABSTRACT *(200 words or less)*

ABSTRACT

As part of the Pressurized Thermal Shock Rebaseline Program, thermal hydraulic calculations were performed for the Oconee-1, Beaver Valley-1, and Palisades Nuclear Power Plants using the RELAP5/ MOD3.2.2gamma computer program. Transient sequences that are important to the risk due to a PTS event were defined as part of a risk assessment by Sandia National Laboratories. These sequences include loss of coolant accidents (LOCA) of various sizes with and without secondary side failures and also non-break transients with primary and secondary side failure. Operator actions are considered in many of the sequences analyzed. The results of these thermal hydraulic calculations are used as boundary conditions to the fracture mechanics analysis performed by Oak Ridge National Laboratory.

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