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U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION
DOCKET NOS. 50-445 AND 50-446
SUPPLEMENT TO LICENSE AMENDMENT REQUEST (LAR) 07-003
REVISION TO TECHNICAL SPECIFICATION 3.1, "REACTIVITY CONTROL SYSTEMS," 3.2, "POWER DISTRIBUTION LIMITS," 3.3, "INSTRUMENTATION," AND 5.6.5b, "CORE OPERATING LIMITS REPORT (COLR)."

REFERENCES:
1. Letter logged TXX-07063 from Mike Blevins of Luminant Power to the NRC, dated April 10, 2007, transmitting License Amendment Request (LAR) 07-003.
2. Letter logged TXX- 07107 from Mike Blevins of Luminant Power to the NRC, dated July 31, 2007

Dear Sir or Madam:

Per Reference 1, TXU Generation Company LP (Luminant Power) requested an amendment to the Comanche Peak Steam Electric Station, herein called Comanche Peak Nuclear Power Plant (CPNPP), Unit 1 Operating License (NPF-87) and CPNPP Unit 2 Operating License (NPF-89). The referenced letter proposes to revise Technical Specifications (TS) 3.1 entitled "Reactivity Control Systems," 3.2 entitled "Power Distribution Limits," 3.3 entitled "Instrumentation," and 5.6.5b entitled "Core Operating Limits Report (COLR)." The requested change proposes to incorporate standard Westinghouse-developed and NRC-approved analytical methods into the lists of methodologies used to establish the core operating limits.

This letter supplements the proposed License Amendment in Reference 1 with additional information. Attachment 1 provides more detailed discussions of the conditions identified in the methodology reports and the associated NRC Safety Evaluations, and the applications of those methodologies at CPNPP. Attachment 2 provides representative safety analyses demonstrating the intended applications of the methodologies described in the referenced letter to CPNPP. Per Reference 2, Luminant Power previously submitted the small break LOCA and large break LOCA evaluation models for CPNPP, developed in accordance with the proposed methodologies.

Should you have any questions, please contact Mr. J. D. Seawright at (254) 897-0140.

A001

NRR

I state under penalty of perjury that the foregoing is true and correct.

Executed on August 16, 2007.

Sincerely,

TXU Generation Company LP

By: TXU Generation Management Company LLC,
Its General Partner

Mike Blevins

By: Rafael Flores
Rafael Flores
Site Vice President

Attachments - 1. Comanche Peak Nuclear Power Plant WCAP SER Conditions and Justifications for CPNPP Analyses

2. Comanche Peak Nuclear Power Plant Transition of Methods Safety Analyses

c - B. S. Mallett, Region IV
B. K. Singal, NRR
Resident Inspectors, CPNPP

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August 2007

Attachment 1 to TXX-07126

Comanche Peak Nuclear Power Plant

WCAP SER Conditions and Justifications for CPNPP Analyses

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INTRODUCTION

In this report, TXU Generation Company LP (herein after referred to as Luminant Power) is providing supplemental information to the Nuclear Regulatory Commission (NRC) to aid in the review of the transition licensing report for Unit 1 and Unit 2 Comanche Peak Steam Electric Station (herein after referred to as Comanche Peak Nuclear Power Plant (CPNPP)).

Luminant Power is transitioning to Westinghouse safety evaluation methodology. The means that Luminant Power used to address the Safety Evaluation Report (SER) conditions identified by the NRC for the topical reports used in the safety analyses is further described below. This supplemental information is provided for these reports: WCAP-14882-P-A (RETRAN), WCAP-14565-P-A (VIPRE), WCAP-8745-P-A (Overpower ΔT / Overtemperature ΔT Reactor Trip Functions), WCAP-12472-P-A (BEACON), WCAP-11397-P-A (RTDP), WCAP-10079-P-A, WCAP-10054-P-A, WCAP-10054-P-A, Addendum 2, Revision 1 (NOTRUMP/SBLOCTA (LOCTA IV)) and WCAP-16009-P-A (ASTRUM). The following sections list the NRC SER conditions for each WCAP and provide the justification for CPNPP applications.

WCAP-14882-P-A (RETRAN)

RETRAN is used for studies of transient response of a pressurized water reactor (PWR) system to specified perturbations in process parameters. This code simulates a multi-loop system by a lumped parameter model containing the reactor vessel, hot- and cold-leg piping, reactor coolant pumps (RCPs), steam generators (tube and shell sides), main steam lines, and the pressurizer. The pressurizer heaters, spray, relief valves, and safety valves can also be modeled. RETRAN includes a point neutron kinetics model and reactivity effects of the moderator, fuel, boron, and control rods. The secondary side of the steam generator uses a detailed nodalization for the thermal transients. The reactor trip system (RTS) simulated in the code includes reactor trips on high neutron flux, high neutron flux rate, OTN-16, OPN-16, low reactor coolant flow, high- and low-pressurizer pressure, high pressurizer level, and low-low steam generator water level. Control systems are also simulated including rod control and pressurizer pressure control. Parts of the safety injection system (SIS), including the accumulators, are also modeled. Also, a conservative approximation of the transient departure from nucleate boiling ratio (DNBR), based on the core thermal limits, is calculated via RETRAN.

The SER for WCAP-14882-P-A (Reference 1) identifies three conditions of acceptance, which are summarized below along with justifications for application to CPNPP.

1. *"The transients and accidents that Westinghouse proposes to analyze with RETRAN are listed in this SER (Table 1) and the NRC staff review of RETRAN usage by Westinghouse was limited to this set. Use of the code for other analytical purposes will require additional justification."*

Justification

The transients listed in Table 1 of the SER are:

Feedwater system malfunctions,
Excessive increase in steam flow,
Inadvertent opening of a steam generator relief or safety valve,
Steam line break,
Loss of external load/turbine trip,
Loss of offsite power,
Loss of normal feedwater flow,
Feedwater line rupture,
Loss of forced reactor coolant flow,
Locked reactor coolant pump rotor/sheared shaft,
Control rod cluster withdrawal at power,
Dropped control rod cluster/dropped control bank,
Inadvertent increase in coolant inventory,
Inadvertent opening of a pressurizer relief or safety valve,
Steam generator tube rupture.

The transients that were explicitly analyzed for CPNPP using RETRAN are:

Feedwater system malfunctions (FSAR 15.1.1 and 15.1.2),
Steam line break (FSAR 15.1.5),
Loss of external load/turbine trip (FSAR 15.2.2, 15.2.3),
Loss of non-emergency AC power (loss of offsite power) (FSAR 15.2.6),
Loss of normal feedwater flow (FSAR 15.2.7),
Feedwater system pipe break (feedwater line rupture) (FSAR 15.2.8),
Loss of forced reactor coolant flow (FSAR 15.3.1, 15.3.2),
Locked reactor coolant pump rotor/shaft break (FSAR 15.3.3, 15.3.4),
Uncontrolled RCCA withdrawal at power (FSAR 15.4.2),
Inadvertent operation of the ECCS (inadvertent increase in coolant inventory) (FSAR 15.5.1),
Inadvertent opening of a pressurizer safety or relief valve (FSAR 15.6.1),
Steam generator tube rupture (FSAR 15.6.3).

As each transient analyzed for CPNPP using RETRAN matches one of the transients listed in Table 1 of the SER, additional justification is not required.

2. *"WCAP-14882 describes modeling of Westinghouse designed 4-, 3-, and 2-loop plants of the type that are currently operating. Use of the code to analyze other designs, including the Westinghouse AP600, will require additional justification."*

Justification

The CPNPP consists of two four-loop Westinghouse-designed units that were "currently operating" at the time the SER was written (February 11, 1999). Therefore, additional justification is not required.

3. *"Conservative safety analyses using RETRAN are dependent on the selection of conservative input. Acceptable methodology for developing plant-specific input is discussed in WCAP-14882 and in Reference 14 [WCAP-9272-P-A] (Reference 2 in this document). Licensing applications using RETRAN should include the source of and justification for the input data used in the analysis."*

Justification

The input data used in the RETRAN analyses performed by Westinghouse were obtained from both Luminant Power and Westinghouse sources. Assurance that the RETRAN input data is conservative for CPNPP was provided via Westinghouse's use of transient-specific analysis guidance documents. Each analysis guidance document provided a description of the subject transient, a discussion of the plant protection systems that are expected to function, a list of the applicable event acceptance criteria, a list of the analysis input assumptions (e.g., directions of conservatism for initial condition values), a detailed description of the transient model development method, and a discussion of the expected transient analysis results. Based on the analysis guidance documents, conservative plant-specific input values were requested and collected from the responsible Luminant Power and Westinghouse sources. Consistent with the Westinghouse Reload Evaluation Methodology described in WCAP-9272-P-A (Reference 2), the safety analysis input values used in the CPNPP analyses were selected to conservatively bound the values expected in subsequent operating cycles. Attached to this supplemental information is a description of the safety analyses with the results of those safety analyses, which is titled "Comanche Peak Nuclear Power Plant Transition of Methods Safety Analyses."

Note that since CPNPP has OTN-16 and OPN-16 reactor trips rather than overtemperature and overpower ΔT, an N-16 model that is equivalent to that currently being used by Luminant Power in support of CPNPP is applied.

The RETRAN nodalization modeling used in the CPNPP analyses is consistent with the Westinghouse four-loop plant nodalization model of WCAP-14882-P-A, except for the preheat steam generator model used for CPNPP Unit 2 (see discussion below) and the nodalization of the hot legs. Since the approval of WCAP-14882, the hot leg modeling was enhanced to minimize code instabilities attributed to pressurizer insurge and outsurge. This hot leg model enhancement, which has been applied in other RETRAN analyses performed by Westinghouse, consisted of dividing each hot leg control volume into three equal control volumes. Although it was needed only for the hot leg connected to the pressurizer, all loops were divided in the same manner.

Preheat Steam Generator Model for CPNPP Unit 2

As noted in WCAP-14882-P-A, multi-node RETRAN models were developed for Westinghouse feedring and preheat steam generators. The nodalization of the feedring and preheat steam generators explicitly models the circulation loop and allows for the calculation of the indicated water level. The multi-node secondary model also allows for a detailed transient response during the steam line break and other secondary side transients.

Figure 3.6-1 of WCAP-14882-P-A (Reference 1) presents the nodalization of a preheat steam generator model that was based on the Westinghouse Model E steam generator design. The Comanche Peak Unit 2 Westinghouse Model D-5 steam generator design includes variations in the preheater and feedwater designs when compared to the Model E steam generator, and thus the RETRAN model nodalization was revised. Figure 1 provides the revised nodalization used for the Model D-5 steam generator. The Model D-5 steam generator features a split feedwater flow injection design, which, at full power, has approximately 80 percent of the flow entering the preheater region and 20 percent of the flow entering the downcomer region below the water level via the auxiliary feedwater nozzle.

- The feedwater entering the preheater enters a region of the cold side of the tube bundle (Volume x60) and then splits into two streams. Most of this feedwater flow passes up through the upper sections of the preheater (Volumes x61 and x62) and joins the flow rising in the hot tube side of the tube bundle in Volume x72. The remainder of the feedwater entering the preheater travels down to the lower section of the preheater and joins with recirculated water before passing to the hot side of the tube bundle (Volume x71).

- The feedwater entering the feedring in the upper downcomer region (Volume x77) enters and mixes with the recirculated liquid from Volume x76 and flows to the lower downcomer (Volume x78) where it enters the tube bundle on the cold side (Volume x69) or hot side (Volume x71).

The CPNPP Model D-5 tube bundle region above the preheater is modeled as three sequential secondary side nodes (Volumes x72, x73, and x74) and combines the flows from both the hot tube side (Volumes x70 and x71) and the flow exiting from the top of the preheater. This is similar to the Model E steam generator design documented in WCAP-14882-P-A. Two-phase fluid exits the tube bundle and flows through the riser (Volume x75) and enters Volume x76 where phase separation is modeled using the RETRAN bubble rise model. The phase separation in Volume x76 simulates the steam generator moisture separators, i.e., the swirl vane and demister vane separators. The steam fraction rises to the top of Volume x76 and exits the steam generator through the steam nozzle, while the liquid fraction mixes with feedwater and continues the cycle by mixing with the feedwater nozzle flow in Volume x77.

On the primary side of the Unit 2 Model D-5 steam generator, primary coolant passes from the hot leg (Volume x03) to the steam generator inlet plenum (Volume x20) through the U-tubes (Volumes x21 through x32), into the steam generator outlet plenum (Volume x40), and exits the steam generator into the cold leg (Volume x09). Twelve conducting heat exchangers transfer heat from the primary to the secondary during normal operation and transient conditions.

This D-5 SG model has been benchmarked against the Westinghouse preheat steam generator design code, including the primary and secondary side volumes, primary side pressure drops for zero percent and maximum tube plugging levels, secondary side pressure drops, heat transfer characteristics for zero percent and maximum tube plugging levels, and SG masses versus both power and water levels.

References

1. WCAP-14882-P-A, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," D. S. Huegel, et al., April 1999.

2. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," S. L. Davidson (Ed.), July 1985.

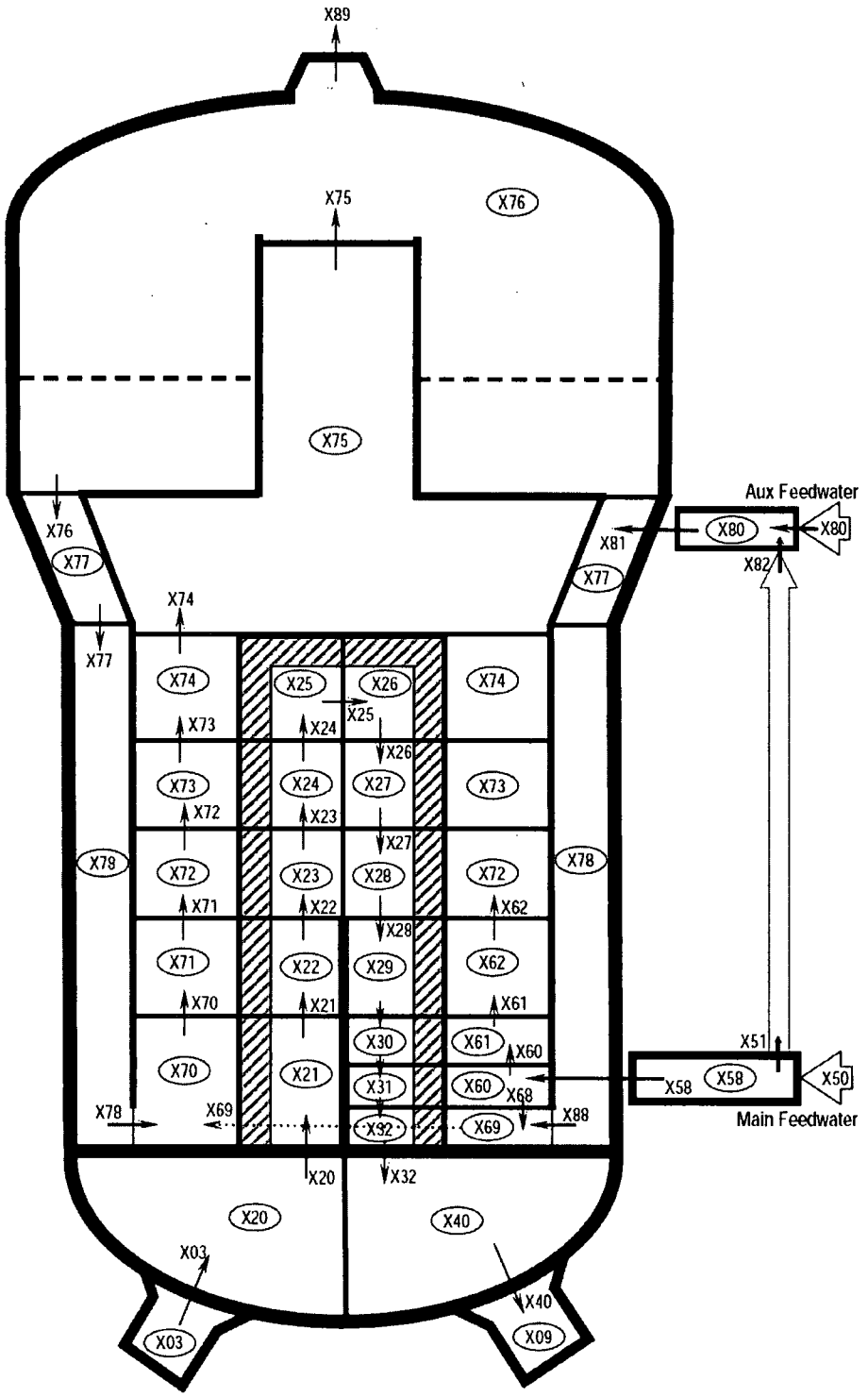

Figure 1 RETRAN Nodalization Diagram for Model D-5 Steam Generator

WCAP-14565-P-A (VIPRE)

The VIPRE computer program is used to perform thermal-hydraulic calculations. This code calculates coolant density, mass velocity, enthalpy, void fractions, static pressure, and DNBR distributions along flow channels within a reactor core.

The SER for WCAP-14565-P-A (Reference 1) identifies four conditions of acceptance, which are summarized below along with justification for application to CPNPP.

1. *"Selection of the appropriate CHF correlation, DNBR limit, engineered hot channel factors for enthalpy rise and other fuel-dependent parameters for a specific plant application should be justified with each submittal."*

   Justification

   The WRB-2 correlation with a 95/95 correlation limit of 1.17 was used in the departure from nucleate boiling (DNB) analyses for the CPNPP 17x17 Vantage+ fuel type. The use of the WRB-2 DNB correlation for Vantage 5 fuel was approved September 1985 (Letter from C. O. Thomas (NRC) to E. P. Rahe (Westinghouse), "Acceptance for Referencing of Licensing Topical Report WCAP-10444, Vantage 5 Fuel Assembly," Reference 2). WCAP-12610-P-A extended the use of the WRB-2 correlation to Vantage+ fuel and was approved July 1, 1991 (Letter from A. C. Thadani (NRC) to S. R. Tritch (Westinghouse), "Acceptance for Referencing of Topical Report WCAP-12610 Vantage+ Fuel Assembly Reference Core Report," Reference 3).

   The use of the plant-specific hot channel factors and other fuel dependent parameters in the DNB analysis for the CPNPP Vantage+ fuel is justified using the same methodologies as for previously approved safety evaluations of other Westinghouse four-loop plants using the same fuel design.

2. *"Reactor core boundary conditions determined using other computer codes are generally input into VIPRE for reactor transient analyses. These inputs include core inlet coolant flow and enthalpy, core average power, power shape and nuclear peaking factors. These inputs should be justified as conservative for each use of VIPRE."*

   Justification

   The core boundary conditions for the VIPRE calculations for the CPNPP fuel were generated from NRC-approved codes and analysis methodologies. Conservative reactor core boundary conditions were justified for use as input to VIPRE. Continued applicability of the input assumptions is verified on a cycle-by-cycle basis using the Westinghouse reload methodology described in WCAP-9272-P-A (Reference 4).

3. *"The NRC Staff's generic SER for VIPRE set requirements for use of new CHF correlations with VIPRE. Westinghouse has met these requirements for using WRB-1, WRB-2 and WRB-2M correlations. The DNBR limit for WRB-1 and WRB-2 is 1.17. The WRB-2M correlation has a DNBR limit of 1.14. Use of other CHF correlations not currently included in VIPRE will require additional justification."*

Justification

As discussed in response to Condition 1, the WRB-2 correlation with a limit of 1.17 was used for the DNB analyses of the CPNPP fuel. For conditions where WRB-2 is not applicable, the W-3 DNB correlation was used with a limit of 1.30 (1.45 for pressures between 500 psia and 1000 psia).

4. *"Westinghouse proposes to use the VIPRE code to evaluate fuel performance following postulated design-basis accidents, including beyond-CHF heat transfer conditions. These evaluations are necessary to evaluate the extent of core damage and to ensure that the core maintains a coolable geometry in the evaluation of certain accident scenarios. The NRC Staff's generic review of VIPRE did not extend to post CHF calculations. VIPRE does not model the time-dependent physical changes that may occur within the fuel rods at elevated temperatures. Westinghouse proposes to use conservative input in order to account for these effects. The NRC Staff requires that appropriate justification be submitted with each usage of VIPRE in the post-CHF region to ensure that conservative results are obtained."*

Justification

As for application to CPNPP safety analysis, the usage of VIPRE in the post-critical heat flux region is limited to the peak clad temperature calculation for the locked rotor transient. The calculation has demonstrated that the peak clad temperature in the reactor core is well below the allowable limit to prevent clad embrittlement. VIPRE modeling of the fuel rod is consistent with the model described in WCAP-14565-P-A, and includes the following conservative assumptions:

- DNB is assumed to occur at the beginning of the transient.
- Film boiling is calculated using the Bishop-Sandberg-Tong correlation.
- The Baker-Just correlation accounts for heat generation in fuel cladding due to zirconium-water reaction.

Conservative results are further ensured with the following input:

- Fuel rod input is based on the maximum fuel temperature at the given power.
- The hot spot power factor is equal to or greater than the design linear heat rate.

Uncertainties are applied to the initial operating conditions in the limiting direction.

References

1. WCAP-14565-P-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," Y. X. Sung, et al., October 1999.

2. WCAP-10444-P-A, "Reference Core Report Vantage 5 Fuel Assembly," September 1985.

3. WCAP-12610-P-A, "VANTAGE+ Fuel Assembly Reference Core Report," April 1995.
   WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," S. L. Davidson (Ed.), July 1985.

4. WCAP-9272-P-A, Westinghouse Reload Safety Evaluation Methodology, S. L. Davidson (Ed.), July 1985.

WCAP-8745-P-A (OVERPOWER ΔT / OVERTEMPERATURE ΔT REACTOR TRIP FUNCTIONS)

The methodology described in WCAP-8745-P-A (Reference 1) is used as the basis for the calculation of the overtemperature and overpower N-16 (OTN-16/OPN-16) reactor trip setpoints. The SER for WCAP-8745-P-A identifies two conditions of acceptance, which are identified below. Justification for these two SER conditions for the application of WCAP-8745 to the calculation of the OTN-16/OPN-16 reactor trip setpoints for CPNPP is also provided.

1. *"While we agree that the basic design philosophy described in WCAP-8745 is not invalidated by changes in DNB analysis methodology, fuel design, and plant operating procedure, the application of this methodology must account for changes in system design and operation. The adequacy of the standard power shapes in establishing the core DNB protection system must be evaluated whenever changes are introduced that could potentially effect the core power distribution."*

   Justification

   The application of the WCAP-8745-P-A methodology accounts for the appropriate plant-specific system design and operation features of CPNPP. Specifically, it accounts for the use of the following: 17x17 Vantage+ fuel, Revised Thermal Design Procedure (RTDP) (Reference 2), WRB-2 DNB correlation, and relaxed axial offset control. Also, the fact that CPNPP has overtemperature N-16 and overpower N-16 reactor trip functions rather than overtemperature ΔT and overpower ΔT does not invalidate the applicability of the WCAP-8745-P-A methodology. This is because the N-16-based functions and ΔT-based functions share the same design intents of ensuring that the DNB design basis is satisfied and that fuel centerline melting is precluded. The two overtemperature functions are very similar in design in that they both use inputs of reactor coolant temperature, pressurizer pressure, and axial offset.

2. *"We have reviewed the Westinghouse design bases for the thermal overpower and overtemperature ΔT Trip functions described in WCAP-8745, and find them acceptable for referencing by Westinghouse in licensing documents for plants that operate under constant axial offset control."*

   Justification

   Although this SER statement indicates that WCAP-8745-P-A applies only to plants that operate under constant axial offset control, the justification for SER requirement 1 above confirms the applicability to CPNPP with relaxed axial offset control.

References

1. WCAP-8745-P-A, "Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions," S. L. Ellenberger, et al., September 1986.

2. WCAP-11397-P-A, "Revised Thermal Design Procedure," A. J. Friedland and S. Ray, April 1989.

WCAP-12472-P-A (BEACON)

The BEACON Power Distribution Monitoring System (PDMS) that will be used at CPNPP is comprised of the BEACON computer code and the plant data fed to the plant process computer from the incore thermocouples and the excore nuclear instruments. BEACON serves as a three-dimensional core monitor, operational analysis tool, and operational support package. Luminant Power will use BEACON to augment the functional capability of the flux mapping system for the purpose of power distribution surveillances. Reference 1 discusses an application of the BEACON PDMS in which the Technical Specifications and core power distribution limits are changed to take credit for continuous monitoring by plant operators. Luminant Power will use a more conservative application of the BEACON PDMS where the core power distribution limits remain unchanged. This limited application of BEACON is referred to as the BEACON Technical Specification Monitor (TSM).

The SER for WCAP-12472-P-A identifies two conditions of acceptance, which are summarized below along with justification for application to CPNPP.

1. *"In the cycle-specific applications of BEACON, the power peaking uncertainties FΔh and FQ must provide 95-percent probability upper tolerance limits at the 95-percent confidence level."*

   Justification

   The analyses of Reference 1 determined the power peaking 95-percent probability upper tolerance limits, but did not include the tolerance factor to insure a 95-percent confidence level as the calculation is plant specific. In Response 21 to the request for additional information in Reference 1, Westinghouse stated that this factor will be included in the plant-specific applications of BEACON.

2. *"In order to insure that the assumptions made in the BEACON uncertainty analysis remain valid, the generic uncertainty components may require reevaluation when BEACON is applied to plant or core designs that differ sufficiently to have a significant impact on the WCAP-12472-P data-base."*

   Justification

   The plant/core designs of Comanche Peak Nuclear Power Plant do not significantly differ from those evaluated in Reference 1. The plant/core design components will be evaluated each cycle for changes impacting the BEACON assumptions.

References

1. WCAP 12472-P-A, "BEACON Core Monitoring and Operations Support System," August 1994.

WCAP-11397-P-A (RTDP)

The thermal-hydraulic analyses for CPNPP are based on the RTDP. With the RTDP methodology, uncertainties are combined statistically to obtain the overall DNB uncertainty and the resulting design limit DNBR. The SER for WCAP-11397-P-A (Reference 1) identifies seven conditions of acceptance, which are summarized below along with justification for application to CPNPP.

1. *"Sensitivity factors for a particular plant and their ranges of applicability should be included in the Safety Analysis Report or reload submittal."*

   Justification

   Sensitivity factors were evaluated using the WRB-2 DNB correlation and the VIPRE code for parameter values applicable to the CPNPP operating conditions. These sensitivity factors were used to determine the RTDP design limit DNBR for both typical and thimble cell. The ranges of applicability of each parameter in the RTDP analyses were determined and the safety analyses use RTDP only if they fall within the applicable ranges.

2. *"Any changes in DNB correlation, THINC-IV correlations, or parameter values listed in Table 3-1 of WCAP-11397 outside of previously demonstrated acceptable ranges require re-evaluation of the sensitivity factors and of the use of Equation (2-3) of the topical report."*

   Justification

   Because the VIPRE code was used to replace the THINC-IV code for DNBR calculations, sensitivity factors were evaluated using the WRB-2 DNB correlation and the VIPRE code for parameter values applicable to the CPNPP (see Condition 1 response). See the response to SER Condition 3 for a discussion of the use of Equation (2-3) of the topical report.

3. *"If the sensitivity factors are changed as a result of correlation changes or changes in the application or use of the THINC code, then the use of an uncertainty allowance for application of Equation (2 3) must be re-evaluated and the linearity assumption made to obtain Equation (2-17) of the topical report must be validated."*

   Justification

   Equation (2-3) of WCAP-11397-P-A and the linearity approximation made to obtain Equation (2-17) were confirmed to be valid using the combination of the WRB-2 DNB correlation and the VIPRE code that was used for the application of RTDP to the VANTAGE+ fuel in CPNPP.

4. *"Variances and distributions for input parameters must be justified on a plant-by-plant basis until generic approval is obtained."*

Justification

The licensee provided measurement uncertainties based on plant specific calculations performed according to their Quality Assurance procedures.

5. *"Nominal initial condition assumptions apply only to DNBR analyses using RTDP. Other analyses, such as overpressure calculations, require the appropriate conservative initial condition assumptions."*

Justification

For the CPNPP, nominal initial conditions were only applied to DNBR calculations using RTDP. Other analyses used the appropriate conservative initial condition assumptions.

6. *"Nominal conditions chosen for use in analyses should bound all permitted methods of plant operation."*

Justification

The CPNPP DNBR calculations with RTDP used nominal conditions which bound all permitted plant operation. The continued applicability of the bounding input assumptions are verified on a cycle-by-cycle basis using the Westinghouse reload methodology described in Reference 2.

7. *"The code uncertainties specified in Table 3-1 (± 4 percent for THINC-IV and ± 1 percent for transients) must be included in the DNBR analyses using RTDP."*

Justification

The code uncertainties specified in Table 3-1 of WCAP-11397-P-A were included in the DNBR analyses using RTDP. Based on the equivalence of the VIPRE model approved in WCAP-14565-P-A to THINC IV, the code uncertainty for VIPRE that were included in the CPNPP RTDP design limit DNBR is ±4 percent, which is the same code uncertainty as for THINC-IV. A transient code uncertainty of 1 percent was used in the RTDP DNBR analyses.

References

1. WCAP-11397-P-A, "Revised Thermal Design Procedure," Friedland, A. J. and Ray, S., April 1989.

2. WCAP 9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," Davidson, S. L. (Editor) et al., July 1985.

WCAP-10079-P-A, WCAP-10054-P-A, WCAP-10054-P-A, ADDENDUM 2, REVISION 1 (NOTRUMP/SBLOCTA (LOCTA IV))

The codes used in the approved small-break loss-of-coolant (LOCA) evaluation model with NOTRUMP (NOTRUMP-EM) are NOTRUMP and SBLOCTA (References 1, 2, and 3). NOTRUMP is used to model the thermal-hydraulic behavior of the system and thereby obtain time dependent values of various core region parameters, such as system pressure, temperature, fluid levels, and flow rates. These are provided as boundary conditions to SBLOCTA. SBLOCTA, a version of the LOCTA-IV computer code (Reference 4), is used to model the fuel rod response to the small-break LOCA transient. SBLOCTA uses the NOTRUMP boundary conditions and various hot channel inputs to calculate the rod heatup and ultimately, the peak cladding temperature for a given transient.

The SER for WCAP-10054-P-A and WCAP-10079-P-A identifies five conditions of acceptance, which are summarized below along with justification for application to CPNPP.

1. *"To assure the validity of this application, the bubble diameter should be on the order of 10-1 to 2 cm. As long as steam generator tube uncovery (concurrent with a severe depressurization rate) does not occur, this option is acceptable."*

   Justification

   Westinghouse complies with this restriction for all Appendix K licensing basis calculations. Typical Appendix K calculations do not undergo a significant secondary side system depressurization in conjunction with steam generator tube uncovery due to the modeling methodology utilized.

2. *"The two phase multiplier used is the Thom modification of the Martinelli Nelson correlation. This model is acceptable per 10 CFR Part 50 Appendix K for LOCA analysis at pressure above 250 psia."*

   Justification

   The original NOTRUMP model was limited to no less than 250 psia since the model, as contained in the NOTRUMP code, did not contain information below this range. Westinghouse extended the model to below 250 psia, as allowed by Appendix K paragraph I C 2, and reported these modifications to the NRC via the 1995 annual reporting period (NSD NRC 96 4639).

3. *"Axial heat conduction is not modeled." and "Deletion of clad axial heat conduction maximizes the peak clad temperature."*

   Justification

   The Westinghouse small-break LOCA is comprised of two computer codes, the NOTRUMP code (which performs the detailed system wide thermal hydraulic

calculations) and the LOCTA code (which performs the detailed fuel rod heatup calculations). The NOTRUMP code does not model axial conduction in the fuel rod and, therefore, complies. The LOCTA code has always accounted for axial conduction as is clearly stated in WCAP 14710, which supplements the original NOTRUMP documentation.

4. *"The standard continuous contact model is not appropriate for vertical flow,...."*

   Justification

   The standard continuous contact flow links are not utilized when modeling vertical flow in the Appendix K NOTRUMP Evaluation Model analyses. Therefore, compliance is demonstrated.

5. *"Per generic letter 83 35, compliance with Action Item II. K.3.31 may be submitted generically. We require that the generic submittal include validation that the limiting break location has not shifted away from the cold legs to the hot or pump suction legs."*

   Justification

   Westinghouse submitted WCAP 11145 in support of Generic Letter 83 35 Action Item 11.K.3.31. As part of this effort, verification was provided that documented that the cold leg break location remains limiting

The SER for WCAP-10054-P-A, Addendum 2, Revision 1 and WCAP-10079-P-A identifies one condition of acceptance, which is summarized below along with justification for application to CPNPP.

1. *"It is stated in Ref. 5 that the range of injection jet velocities used in the experiments brackets the corresponding rates in small break LOCAs for Westinghouse plants and that the model will be used within the experimental range. Also in References 1 and 5 Westinghouse submitted analyses demonstrating that the condensation efficiency is virtually independent of RCS pressure and state that the COSI model will be applied within the pressure range of 550 to 1,200 psia."*

   Justification

   The coding implementation of the COSI model correlation in the NOTRUMP model restricts the application of the COSI condensation model to a default pressure range of 550 to 1,200 psia and limits the injection flow rate to a default value of 40 lbm/sec loop. The value of 40 lbm/sec loop corresponds to the 30 ft/sec velocity utilized in the COSI experiments. As such, the default NOTRUMP implementation of the COSI condensation model complies with the applicable SER restrictions.

References

1. WCAP 10079, "NOTRUMP, A Nodal Transient Small Break and General Network Code," August 1985.

2. WCAP 10054, "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," August 1985.

3. WCAP 10054, Addendum 2, Revision 1, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," July 1997.

4. WCAP 8301, "LOCTA IV Program: Loss of Coolant Transient Analysis," June 1974.

WCAP-16009-P-A (ASTRUM)

The computer code used to perform the large-break LOCA evaluation is described in WCAP-12945-P-A, which is referred to as the Code Qualification Document (CQD) (Reference 1) as well as WCAP-16009 P A, which describes the ASTRUM methodology (Reference 2).

The WCOBRA/TRAC uses a two-fluid, three-field representation of flow in the vessel component. The three fields are a vapor field, a continuous liquid field and an entrained liquid drop field. Each field in the vessel uses a set of three-dimensional continuity, momentum, and energy equations with one exception. A common energy equation is used by both the continuous liquid and the entrained liquid drop fields.

The one-dimensional components consist of all the major components in the primary system, such as pipes, pumps, valves, steam generators, and the pressurizer. The one-dimensional components are represented by a two-phase, five-equation, drift flux model. This formulation consists of two equations for the conservation of mass, two equations for the conservation of energy, and a single equation for the conservation of momentum. Closure for the field equations requires specification of the interphase relative velocities, interfacial heat and mass transfer, and other thermodynamic and constitutive relationships.

The SER for WCAP-16009-P-A states that:

1. *"the conditions and limitations previously identified for WCOBRA/TRAC continue to apply for usage of WCOBRA/TRAC as part of the ASTRUM methodology."*

   Justification

   The NRC staff reviewed Section 13.3 of WCAP-16009-P and found that it acceptably dispositions each of the identified conditions and limitations related to WCOBRA/TRAC and the CQD uncertainty approach.

References

1. WCAP 12945-P-A, Volume 1, Revision 2 and Volumes 2 through 5, "Code Qualification Document for Best-Estimate LOCA Analysis," 1998.

2. WCAP 16009-P-A, "Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM)," January 2005.

August 2007

Attachment 2 to TXX-07126

Comanche Peak Nuclear Power Plant

Transition of Methods Safety Analyses

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List of Acronyms

AC	alternating current
AFW	auxiliary feedwater
AFWS	auxiliary feedwater system
AMSAC	ATWS mitigation system actuation circuitry
ANS	American Nuclear Society
ANSI	American National Standards Institute
ARV	atmospheric relief valve
ASME	American Society of Mechanical Engineers
ASTRUM	automated statistical treatment of uncertainty method
ATWS	anticipated transient without scram
BELOCA	best-estimate LOCA
BOL	beginning of life
CHF	critical heat flux
CPNPP	Comanche Peak Nuclear Power Plant
CPT	critical power trajectory
CRDM	control rod drive mechanism
CSAU	code scaling, applicability, and uncertainty
CVCS	chemical and volume control system
CWO	core-wide oxidation
DNB	departure from nucleate boiling
DNBR	departure from nucleate boiling ratio
ECCS	emergency core cooling system
EOC	end of cycle
EOL	end of life
EOP	emergency operating procedure
ESFAS	engineered safety features actuation system
FCV	flow control valve
FSAR	Final Safety Analysis Report
GDC	general design criterion
HFP	hot full power
HLSO	hot leg switchover
HZP	hot zero power
IFM	intermediate flow mixer
LBLOCA	large-break LOCA
LOCA	loss-of-coolant accident
LOL	loss of load
LONF	loss of normal feedwater
MDAFW	motor-driven auxiliary feedwater
MMF	minimum measured flow
MSIV	main steam isolation valve

List of Acronyms (cont.)

MSS	main steam system
MSSV	main steam safety valve
MTC	moderator temperature coefficient
MUR	measurement uncertainty recapture
NRC	Nuclear Regulatory Commission
NRS	narrow-range span
NSSS	nuclear steam supply system
PCT	peak cladding temperature
PCWG	Performance Capabilities Working Group
PORV	power-operated relief valve
PSV	pressurizer safety valve
PWR	pressurized water reactor
RAI	request for additional information
RCCA	rod cluster control assembly
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RHR	residual heat removal
RHRS	residual heat removal system
RMWS	reactor makeup water system
RPV	reactor pressure vessel
RTDP	Revised Thermal Design Procedure
RTP	rated thermal power
RTS	reactor trip system
RWST	refueling water storage tank
SBLOCA	small-break LOCA
SER	Safety Evaluation Report
SGTP	steam generator tube plugging
SGTR	steam generator tube rupture
SI	safety injection
SIS	safety injection signal
SPU	stretch power uprate
STDP	Standard Thermal Design Procedure
TDAFW	turbine-driven auxiliary feedwater
TDF	thermal design flow
TPI	thimble plug installed
TT	turbine trip
TM	transition of methods

List of Acronyms (cont.)

UET	unfavorable exposure time
VCT	volume control tank
1-D	one-dimensional
2-D	two-dimensional
3-D	three-dimensional

1.0 INTRODUCTION

General Overview

This Transition of Methods Safety Analyses report is provided by TXU Generation Company LP (herein after referred to as Luminant Power) in support of the Unit 1 and Unit 2 Comanche Peak Steam Electric Station (herein after referred to as Comanche Peak Nuclear Power Plant (CPNPP) transition of methods (TM) license application. Luminant Power plans to transition from its current methodology (developed by TXU) for performing non-loss-of-coolant-accident (non-LOCA) and LOCA safety analyses to the Westinghouse methodologies for performing these analyses.

This report summarizes the safety evaluations and analyses that were performed to confirm that applicable acceptance criteria are met. Sections 2.1 through 2.8 of this Transition of Methods Safety Analyses report provide the results of the accident analyses.

The technical evaluations contained in this report address both CPNPP Units 1 and 2. For the most part, a single analysis that bounds both units is presented, since the two units are almost identical. In cases where substantive differences exist, separate evaluations are performed and described in the appropriate report section.

1.1 NUCLEAR STEAM SUPPLY SYSTEM PARAMETERS

1.1.1 Introduction

The nuclear steam supply system (NSSS) design parameters are the fundamental parameters used as input in all of the NSSS accident analyses. The current CPNPP Units 1 and 2 NSSS design parameters are summarized in Table 5.1-1 of the CPNPP Units 1 and 2 Final Safety Analysis Report (FSAR). The NSSS design parameters provide the primary and secondary side system conditions (thermal power, temperatures, pressures, and flows) that serve as the basis for all of the NSSS analyses and evaluations. As a result of the TM program, the CPNPP Units 1 and 2 NSSS design parameters have been revised, as shown in Tables 1.1-1 and 1.1-2. Tables 1.1-1 and 1.1-2 provide information for the four cases associated with the TM and stretch power uprate (SPU). These parameters have been incorporated, as appropriate, into the applicable NSSS systems and components evaluations, as well as safety analyses, performed in support of the TM and SPU.

1.1.2 Input Parameters, Assumptions, and Acceptance Criteria

The NSSS design parameters, also referred to as the Performance Capability Working Group (PCWG) parameters, provide the reactor coolant system (RCS) and secondary system conditions (thermal power, temperatures, pressures, and flows) that are used as the basis for the NSSS accident and fuel analyses and evaluations.

The major input parameters and assumptions used in the calculation of the four cases of NSSS design parameters are summarized as follows:

- The parameters are based on Westinghouse Model Δ76 steam generators for CPNPP Unit 1 and Westinghouse Model D-5 steam generators for CPNPP Unit 2.
- The uprated thermal power of 3,612 MWt is approximately 4.5 percent higher than the current licensed power of 3,458 MWt and approximately 5.9 percent higher than the original licensed power of 3,411 MWt.
- The uprated NSSS power level of 3,628 MWt (3,612 MWt core power + 16 MWt net heat input) was assumed.
- A nominal feedwater temperature (T_{feed}) range of 390.0° to 450.3°F was selected.
- The design core bypass flow was assumed to be 5.8 percent; this accounts for fuel with thimble plugs installed (TPI) and intermediate flow mixing vane (IFM) grids.
- A thermal design flow (TDF) of 95,700 gpm/loop was used.

- A full-power normal operating vessel average temperature (T_{avg}) range of 574.2° to 589.2°F was assumed. This provides the basis for CPNPP Units 1 and 2 to operate within this window. Any exceptions to these values will be addressed in the affected sections.

- Steam generator tube plugging (SGTP) levels of 0 and 10 percent were assumed.

- A maximum steam generator moisture carryover of 0.10 percent was utilized for CPNPP Unit 1 and 0.25 percent was utilized for CPNPP Unit 2.

Acceptance Criteria

The acceptance criteria for determining the NSSS design parameters were that the results of the accident analyses and evaluations continue to comply with all CPNPP Units 1 and 2 applicable industry and regulatory requirements, and that they provide CPNPP Units 1 and 2 with adequate flexibility and margin during plant operation.

1.1.3 Description of Analyses and Evaluation

Table 1.1-1 provides the NSSS design parameter cases that were generated and serve as the CPNPP Unit 1 basis for the analyses. These cases are as follows:

- Cases 1 and 2 of Table 1.1-1 represent parameters based on a T_{avg} of 574.2°F. Case 2, which is based on an average 10-percent SGTP, yields the minimum secondary side steam generator pressure and temperature. Note that all primary side temperatures are identical for these two cases.

- Cases 3 and 4 of Table 1.1-1 represent parameters based on the T_{avg} of 589.2°F. Case 3, which is based on 0-percent SGTP, yields the highest secondary side steam generator pressure performance conditions. Note that all primary side temperatures are identical for these two cases. As provided via footnote "(2)" of Table 1.1-1, for instances where an absolute upper limit steam generator outlet pressure is conservative for any analyses, these data are based on the Case 3 parameters with 0-percent SGTP and in addition assume a steam generator fouling factor of zero.

Table 1.1-2 provides the NSSS design parameter cases that were generated and serve as the Unit 2 basis for the analyses. These cases are:

- Cases 1 and 2 of Table 1.1-2 represent parameters based on a T_{avg} of 574.2°F. Case 2, which is based on an average 10-percent SGTP, yields the minimum secondary side steam generator pressure and temperature. Note that all primary side temperatures are identical for these two cases.

- Cases 3 and 4 of Table 1.1-2 represent parameters based on the T_{avg} of 589.2°F. Case 3, which is based on 0-percent SGTP, yields the highest secondary side steam generator pressure performance conditions. Note that all primary side temperatures are

identical for these two cases. As provided via footnote "(2)" of Table 1.1-2, for instances where an absolute upper limit steam generator outlet pressure is conservative for any analyses, these data are based on the Case 3 parameters with 0-percent SGTP. In addition they assume a steam generator fouling factor of zero.

1.1.4 Conclusions

The resulting PCWG parameters (Tables 1.1-1 and 1.1-2) were used by Westinghouse as the basis for all the NSSS analytical efforts. Westinghouse performed the analyses and evaluations based on the parameter sets that were most limiting, so that the analyses would support operation over the entire range of conditions specified. In cases where the analyses performed do not bound the entire range of conditions specified (such as a restricted T_{avg} operating range), the applicable report section identifies the range of conditions analyzed.

Table 1.1-1
NSSS PCWG Parameters for CPNPP Unit 1 Transition of Methods Program

Thermal Design Parameters	Uprate Program			
	Case 1	Case 2	Case 3	Case 4
NSSS Power, MWt	3,628	3,628	3,628	3,628
10^6 Btu/hr	12,379	12,379	12,379	12,379
Reactor Power, MWt	3,612	3,612	3,612	3,612
10^6 Btu/hr	12,325	12,325	12,325	12,325
Thermal Design Flow, loop gpm	95,700	95,700	95,700	95,700
Reactor 10^6 lb/hr	145.5	145.5	142.4	142.4
Reactor Coolant Pressure, psia	2,250	2,250	2,250	2,250
Core Bypass, %	5.8(1)	5.8(1)	5.8(1)	5.8(1)
Reactor Coolant Temperature, °F				
Core Outlet	609.8	609.8	623.8	623.8
Vessel Outlet	606.2	606.2	620.4	620.4
Core Average	577.6	577.6	592.8	592.8
Vessel Average	574.2	574.2	589.2	589.2
Vessel/Core Inlet	542.2	542.2	558.0	558.0
Steam Generator Outlet	541.9	541.9	557.6	557.6
Steam Generator				
Steam Outlet Temperature, °F	528.9	526.9	545.1(2)	543.1
Steam Outlet Pressure, psia	877	862	1,005(2)	988
Steam Outlet Flow, 10^6 lb/hr total	14.89/16.17	14.88/16.16	14.97/16.26(2)	14.96/16.25
Feed Temperature, °F	390.0/450.3	390.0/450.3	390.0/450.3	390.0/450.3
Steam Outlet Moisture, % max.	0.10	0.10	0.10	0.10
Tube Plugging Level, %	0	10	0	10
Zero-Load Temperature, °F	557	557	557	557
Hydraulic Design Parameters				
Pump Design Point, Flow (gpm)/Head (ft)	101,000/286			
Mechanical Design Flow, gpm	109,000			
Minimum Measured Flow, gpm total	396,400			

Notes:

1. Core bypass flow accounts for TPI and IFMs.
2. Where appropriate for NSSS analyses, a greater steam pressure of 1,032 psia, steam temperature of 548.4°F, and steam flow of 16.29 x 10^6 lb/hr total is assumed. This envelopes more efficient steam generator performance.

Table 1.1-2

NSSS PCWG Parameters for CPNPP Unit 2 Transition of Methods Program

Thermal Design Parameters	Uprate Program			
	Case 1	**Case 2**	**Case 3**	**Case 4**
NSSS Power, MWt	3,628	3,628	3,628	3,628
10^6 Btu/hr	12,379	12,379	12,379	12,379
Reactor Power, MWt	3,612	3,612	3,612	3,612
10^6 Btu/hr	12,325	12,325	12,325	12,325
Thermal Design Flow, loop gpm	95,700	95,700	95,700	95,700
Reactor 10^6 lb/hr	145.5	145.5	142.4	142.4
Reactor Coolant Pressure, psia	2,250	2,250	2,250	2,250
Core Bypass, %	5.8(1)	5.8(1)	5.8(1)	5.8(1)
Reactor Coolant Temperature, °F				
Core Outlet	609.8	609.8	623.8	623.8
Vessel Outlet	606.2	606.2	620.4	620.4
Core Average	577.6	577.6	592.8	592.8
Vessel Average	574.2	574.2	589.2	589.2
Vessel/Core Inlet	542.2	542.2	558.0	558.0
Steam Generator Outlet	541.9	541.9	557.6	557.6
Steam Generator				
Steam Outlet Temperature, °F	525.8/522.6	522.0/518.7	543.2/539.7(2)	539.4/535.9
Steam Outlet Pressure, psia	854/831	826/804	989/961(2)	958/930
Steam Outlet Flow, 10^6 lb/hr total	14.90/16.17	14.89/16.15	14.99/16.26(2)	14.97/16.24
Feed Temperature, °F	390.0/450.3	390.0/450.3	390.0/450.3	390.0/450.3
Steam Outlet Moisture, % max.	0.25	0.25	0.25	0.25
Tube Plugging Level, %	0	10	0	10
Zero Load Temperature, °F	557	557	557	557
Hydraulic Design Parameters				
Pump Design Point, Flow (gpm)/Head (ft)	101,000/286			
Mechanical Design Flow, gpm	105,000			
Minimum Measured Flow, gpm total	408,000			

Notes:

1. Core bypass flow accounts for TPI and IFMs.
2. If a high steam pressure is more limiting for analysis purposes, a greater steam pressure of 1,017 psia, steam temperature of 546.6°F, and steam flow of 15.01 x 10^6 lb/hr total should be assumed. This envelopes more efficient steam generator performance.

2.0 ACCIDENT AND TRANSIENT ANALYSES

2.1 NON-LOCA ANALYSES INTRODUCTION

This section summarizes the non-LOCA transient analyses and evaluations performed to support the transition of methods (TM) and the stretch power uprate (SPU) programs for the Comanche Peak Nuclear Power Plant (CPNPP) Units 1 and 2.

2.1.1 Fuel Design Mechanical Features

The fuel type currently in use at CPNPP Units 1 and 2 is the Westinghouse 17×17 VANTAGE+ fuel design which contains IFM grids that are designed to improve fuel performance. The fuel rod cladding material is ZIRLO™, as is the material for the mid-grids, IFM grids, guide tubes, and instrument tubes. The burnable absorber types in use at CPNPP are the integral fuel burnable absorber pellets and the wet annular burnable absorber (WABA) rodlets. With respect to the non-LOCA transient analyses, the effects of fuel design mechanical features were accounted for in fuel-related input assumptions, such as fuel and cladding dimensions, cladding material, fuel temperatures, and core bypass flow.

2.1.2 Peaking Factors, Kinetics Parameters

Relative to the fuel, the power distribution is characterized by a nuclear enthalpy rise hot channel factor (radial peaking factor, $F^N_{\Delta H}$) of 1.538 for analyses employing the Revised Thermal Design Procedure (RTDP) (Reference 1), and 1.600 for non-RTDP analyses, and a full-power heat flux hot channel factor (total peaking factor, F_Q) of 2.50. $F^N_{\Delta H}$ is important for transients that are analyzed for departure from nucleate boiling (DNB) concerns (Table 2.1-1 identifies which events are analyzed for DNB concerns, as well as the DNB methodology used (RTDP or non-RTDP)). As $F^N_{\Delta H}$ increases with decreasing power level, due to rod insertion, all transients analyzed for DNB concerns are assumed to begin with an $F^N_{\Delta H}$ consistent with the $F^N_{\Delta H}$ defined in the Core Operating Limits Report (COLR) identified in Technical Specifications 5.6.5 for the assumed nominal power level. The F_Q, for which the limits are specified in the COLR, is important for transients that are analyzed for overpower concerns, e.g., rod cluster control assembly (RCCA) ejection.

The minimum shutdown margin at hot zero power (HZP) conditions, with the most reactive RCCA fully withdrawn, is assumed to be 1.3-percent $\Delta k/k$. This was assumed in the HZP steam line break and HZP feedwater malfunction analyses.

2.1.3 TM and SPU Program Features

Key features considered in the non-LOCA transient analyses are as follows:

- A NSSS power level of 3,628 MWt (includes a net reactor coolant pump (RCP) heat of 16 MWt),
- 17×17 VANTAGE+ fuel with a fuel rod outer diameter of 0.360 inches,

- A nominal, full-power reactor coolant vessel average temperature (T_{avg}) window between 574.2° and 589.2°F was supported for most analyses. However, the minimum T_{avg} value is limited to 585.4°F for both units based on the analysis of the Inadvertent Actuation of the emergency core cooling system (ECCS) event discussed in Section 2.6.

- An RCS thermal design flow (TDF) of 382,800 gpm (95,700 gpm/loop), and a Technical Specifications minimum measured flow (MMF) of 396,400 gpm (99,100 gpm/loop). Although the Unit 2 Technical Specifications MMF is 408,000 gpm (102,000 gpm/loop), the more conservative Unit 1 value (396,400 gpm or 99,100 gpm/loop) was applied to both Units.

- Westinghouse Model Δ76 steam generators in Unit 1 and Westinghouse Model D-5 steam generators in Unit 2,

- Uniform steam generator tube plugging (SGTP) levels of 0 and 10 percent,

- A nominal operating pressurizer pressure of 2,250 psia,

- A design core bypass flow of 5.8 percent (non-RTDP analyses) and a statistical core bypass flow of 4.3 percent (RTDP analyses), with core thimble plugs installed,

- A nominal, full-power main feedwater temperature window between 390° and 450.3°F.

For most transients that were analyzed for DNB concerns, the RTDP methodology (Reference 1) was employed. With this methodology, nominal values are assumed for the initial RCS conditions of power, temperature, pressure, and flow, and the corresponding uncertainty allowances are accounted for statistically in defining the departure from nucleate boiling ratio (DNBR) safety analysis limit. Note that the nominal RCS flow modeled in RTDP transient analyses is the minimum measured flow of 396,400 gpm.

Uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions were combined statistically to obtain the overall DNB uncertainty factor, which was used to define the design-limit DNBR (1.23 for typical cell and 1.22 for thimble cell). In other words, the design limit DNBR is a DNBR value that is greater than the WRB-2 DNB correlation limit (1.17) by an amount that accounts for the RTDP uncertainties. To provide DNBR margin to offset various penalties such as those due to rod bow and instrument bias, and to provide flexibility in design and operation of the plant, the design limit DNBR was conservatively increased to a value designated as the safety analysis limit DNBR, to which transient-specific DNBR values were compared. The DNBR safety analysis limit selected for CPNPP is 1.61 for both typical and thimble cells.

For transient analyses that are not DNB-limited, or for which RTDP is not employed, the initial conditions were obtained by applying the maximum, steady-state uncertainties to the nominal values in the most conservative direction; this is known as Standard Thermal Design Procedure (STDP), or non-RTDP. In these analyses, the RCS flow was assumed to be equal to the TDF, and the following steady-state initial condition uncertainties were applied:

- ±0.6-percent NSSS power allowance for calorimetric measurement uncertainty,
- ± 6°F T_{avg} allowance for deadband and system measurement uncertainties,
- ± 30 psi pressurizer pressure allowance for steady-state fluctuations and measurement uncertainties.

2.1.4 Other Major Assumptions

Table 2.1-2 lists the non-LOCA initial condition assumptions used. Other major assumptions considered in the non-LOCA transient analyses are discussed below:

- Staggered lift setpoints were modeled for the main steam safety valves (MSSVs) using plant-specific Technical Specification setpoints. Each MSSV was modeled with a +3-percent setpoint tolerance and a 5-psi ramp from closed to full-open, which accounts for accumulation. A 3-percent setpoint tolerance is also supported, but because none of the non-LOCA transients are limiting with minimum setpoints, it has not been explicitly modeled.
- +1%/-3% setpoint tolerance was considered in the modeling of the pressurizer safety valves (PSVs), which have a required nominal setpoint pressure of 2,460 psig. (See License Amendment Request 06-006, submitted by TXX-07108.) Additionally, when it was conservative to do so (that is, for peak RCS pressure concerns), the effects of the PSV water-filled loop seals, as discussed in Reference 2, were explicitly modeled.
- Consistent with the CPNPP Technical Specifications (Figure 3.1.3-1), for minimum reactivity feedback, a maximum moderator temperature coefficient (MTC) of +0.5×10-4 Δk/k/°F (+5 pcm/°F) is applicable at power levels up to 70 percent. Between 70 percent and 100 percent power, the maximum MTC ramps linearly to 0 Δk/k/°F (0 pcm/°F). For maximum reactivity feedback, a maximum moderator density coefficient of 0.50 Δk/g/cc was assumed.
- The fission product contribution to decay heat assumed in the non-LOCA analyses is consistent with the American National Standards Institute/American Nuclear Society standard American Nuclear Standards Institute (ANSI)/American Nuclear Society (ANS)-5.1-1979 for decay heat power in light water reactors (Reference 3), including two standard deviations of uncertainty.

2.1.5 Overtemperature and Overpower Nitrogen-16 (N-16) Reactor Trip Setpoints

The overtemperature and overpower N-16 (OTN-16/OPN-16) reactor trip setpoints were recalculated based on the methodology described in WCAP-8745 (Reference 4). Conservative core thermal limits developed using the RTDP methodology were used to calculate the OTN-16 and OPN-16 reactor trip setpoints. The assumed core thermal limits are presented in Figure 2.1-1. The OTN-16 and OPN-16 trip setpoints for two sample pressures are illustrated in Figure 2.1-2 and presented in Table 2.1-3.

The adequacy of these setpoints was confirmed by showing that the DNB design basis is met in the analyses of those events that credit these functions for accident mitigation. The revised safety analysis setpoints are based upon the assumption that the reference cold leg temperature (T_c^0) used in the OTN-16 and OPN-16 setpoint equations is equal to the cold leg temperature (T_c) corresponding to nominal full power conditions.

The boundaries of operation defined by the OTN-16 and OPN-16 trips are represented as "protection lines" in Figure 2.1-2. The protection lines were drawn to include all adverse instrumentation and setpoint errors so that under nominal conditions, a trip would occur well within the area bounded by these lines. These protection lines are based upon the safety analysis limit OTN-16 and OPN-16 setpoint values, which are essentially the Technical Specification nominal values with allowances for instrumentation errors and acceptable drift between instrument calibrations. The diagram is useful in the fact that the limit imposed by any given DNBR can be represented as a line (T_{inlet} versus Power). The DNB lines represent the locus of conditions for which the DNBR equals the limit value (1.61 for both typical and thimble cells). All points below and to the left of a DNB line for a given pressure have a DNBR greater than the safety analysis limit DNBR value.

The area of permissible operation (power, temperature, and pressure) is bounded by the combination of the high neutron flux (fixed setpoint) reactor trip, the high- and low-pressurizer pressure reactor trips (fixed setpoints), the OTN-16 (variable setpoint) and OPN-16 (fixed setpoint) reactor trips, and the opening of the MSSVs, which limits the maximum RCS average temperature. The adequacy of the OTN-16 and OPN-16 setpoints was confirmed by demonstrating that the DNB design basis was met for those transients that credit these protection functions.

The resistance temperature detectors (RTDs) that measure the cold leg temperatures used to determine the T_c input of the OTN-16 setpoint equation are scaled with a range of 510° to 630°F. It was confirmed that this range bounds the T_c range that is required to be protected by the OTN-16 reactor protection function.

2.1.6 RTS and ESFAS Functions Assumed in Analyses

Table 2.1-4 contains a list of the different reactor trip system (RTS) and engineered safety feature actuation system (ESFAS) functions credited in the non-LOCA transient analyses. The safety analysis setpoints and associated time delays of each function are also presented in Table 2.1-4.

2.1.7 RCCA Insertion Characteristics

The negative reactivity insertion following a reactor trip is a function of the acceleration of the RCCAs and the variation in rod worth as a function of rod position. With respect to the non-LOCA transient analyses, the critical parameter is the time from the start of RCCA insertion to when the RCCAs reach the dashpot region, which is located at an insertion point corresponding to approximately 86 percent of the total RCCA travel distance. For the non-LOCA analyses, the RCCA insertion time from fully withdrawn to dashpot entry was modeled as 2.7 seconds. The assumed negative reactivity insertion following reactor trip is based on having the most reactive RCCA stuck in the fully withdrawn position.

Three figures relating to RCCA drop time and reactivity worth are presented in this report. The RCCA position (fraction of full insertion) versus the time from release is presented in Figure 2.1-3. The normalized reactivity worth assumed in the safety analyses is shown in Figure 2.1-4 as a function of rod insertion fraction and in Figure 2.1-5 as a function of time.

2.1.8 Reactivity Coefficients

The transient response of the reactor core is dependent on reactivity feedback effects, in particular the MTC and the Doppler power coefficient (DPC). Depending upon event-specific characteristics, conservatism dictates the use of either maximum or minimum reactivity coefficient values. Justification for the use of the reactivity coefficient values was treated on an event-specific basis. Table 2.1-5 presents the core kinetics parameters and reactivity feedback coefficients assumed in the non-LOCA analyses.

The maximum and minimum integrated DPCs assumed in the safety analyses are provided in Figure 2.1-6. Note that the HZP steam line break core response analysis used a different DPC, which was based on an RCCA being stuck out of the core (not shown in Figure 2.1-6).

2.1.9 Computer Codes Utilized

Summary descriptions of the principal computer codes used in the non-LOCA transient analyses are provided below. Table 2.1-6 lists the computer codes used in each of the non-LOCA analyses.

FACTRAN

FACTRAN calculates the transient temperature distribution in a cross-section of a metal-clad UO_2 fuel rod, and the transient heat flux at the surface of the cladding, using as input the

nuclear power and the time-dependent coolant parameters of pressure, flow, temperature, and density. The code uses a fuel model with the following features:

- A sufficiently large number of radial space increments to handle fast transients such as an RCCA ejection accident,
- Material properties that are functions of temperature,
- A sophisticated fuel-to-cladding gap heat transfer calculation, and
- Calculations to address post-DNB conditions (film boiling heat transfer correlations, Zircaloy-water reaction, and partial melting of the fuel).

The FACTRAN licensing topical report, WCAP-7908 (Reference 5), was approved by the NRC via a Safety Evaluation Report (SER) from C. E. Rossi (Nuclear Regulatory Commission (NRC)) to E. P. Rahe (Westinghouse), dated September 30, 1986. This SER issued for FACTRAN identifies seven conditions of acceptance, which are summarized below along with justifications for application to CPNPP.

1. "The fuel volume-averaged temperature or surface temperature can be chosen at a desired value which includes conservatisms reviewed and approved by the NRC."

   Justification

   The FACTRAN code was used in the analyses of the following transients for CPNPP: Uncontrolled RCCA Withdrawal from a Subcritical Condition (FSAR 15.4.1) and RCCA Ejection (FSAR 15.4.8). Initial fuel temperatures used as FACTRAN input in the RCCA Ejection analysis were calculated using the NRC-approved PAD 4.0 computer code as described in WCAP-15063 Revision 1 (Reference 6). As indicated in WCAP-15063 Revision 1, the NRC has approved the method of determining uncertainties for PAD 4.0 fuel temperatures.

2. "Table 2 presents the guidelines used to select initial temperatures."

   Justification

   In summary, Table 2 of the SER specifies that the initial fuel temperatures assumed in the FACTRAN analyses of the following transients should be "High" and include uncertainties: Loss of Flow, Locked Rotor, and Rod Ejection. As discussed above, fuel temperatures were used as input to the FACTRAN code in the RCCA Ejection analysis for CPNPP. The assumed fuel temperatures, which were calculated using the PAD 4.0 computer code (Reference 6), include uncertainties and are conservatively high. FACTRAN was not used in the Loss of Flow and Locked Rotor analyses.

3. "The gap heat transfer coefficient may be held at the initial constant value or can be varied as a function of time as specified in the input."

Justification

The gap heat transfer coefficients applied in the FACTRAN analyses are consistent with SER Table 2. For the RCCA Withdrawal from a Subcritical Condition transient, the gap heat transfer coefficient is kept at a conservative constant value throughout the transient; a high constant value is assumed to maximize the peak heat flux (for DNB concerns) and a low constant value is assumed to maximize fuel temperatures. For the RCCA Ejection transient, the initial gap heat transfer coefficient is based on the predicted initial fuel surface temperature, and is ramped rapidly to a very high value at the beginning of the transient to simulate clad collapse onto the fuel pellet.

4. "...the Bishop-Sandberg-Tong correlation is sufficiently conservative and can be used in the FACTRAN code. It should be cautioned that since these correlations are applicable for local conditions only, it is necessary to use input to the FACTRAN code which reflects the local conditions. If the input values reflecting average conditions are used, there must be sufficient conservatism in the input values to make the overall method conservative."

Justification

Local conditions related to temperature, heat flux, peaking factors and channel information were input to FACTRAN for each transient analyzed for CPNPP (RCCA Withdrawal from a Subcritical Condition (FSAR 15.4.1) and RCCA Ejection (FSAR 15.4.8)). Therefore, additional justification is not required.

5. "The fuel rod is divided into a number of concentric rings. The maximum number of rings used to represent the fuel is 10. Based on our audit calculations we require that the minimum of 6 should be used in the analyses."

Justification

At least 6 concentric rings were assumed in FACTRAN for each transient analyzed for CPNPP (RCCA Withdrawal from a Subcritical Condition (FSAR 15.4.1) and RCCA Ejection (FSAR 15.4.8)).

6. "Although time-independent mechanical behavior (e.g., thermal expansion, elastic deformation) of the cladding are considered in FACTRAN, time-dependent mechanical behavior (e.g., plastic deformation) is not considered in the code. ...for those events in which the FACTRAN code is applied (see Table 1), significant time-dependent deformation of the cladding is not expected to occur due to the short duration of these events or low cladding temperatures involved (where DNBR Limits apply), or the gap heat transfer coefficient is adjusted to a high value to simulate clad collapse onto the fuel pellet."

Justification

The two transients that were analyzed with FACTRAN for CPNPP (RCCA Withdrawal from a Subcritical Condition (FSAR 15.4.1) and RCCA Ejection (FSAR 15.4.8)) are included in the list of transients provided in Table 1 of the SER; each of these transients is of short duration. For the RCCA Withdrawal from a Subcritical Condition transient, relatively low cladding temperatures are involved, and the gap heat transfer coefficient is kept constant throughout the transient. For the RCCA Ejection transient, a high gap heat transfer coefficient is applied to simulate clad collapse onto the fuel pellet. The gap heat transfer coefficients applied in the FACTRAN analyses are consistent with SER Table 2.

7. "The one group diffusion theory model in the FACTRAN code slightly overestimates at beginning of life (BOL) and underestimates at end of life (EOL) the magnitude of flux depression in the fuel when compared to the LASER code predictions for the same fuel enrichment. The LASER code uses transport theory. There is a difference of about 3 percent in the flux depression calculated using these two codes. When [T(centerline) – T(Surface)] is on the order of 3,000°F, which can occur at the hot spot, the difference between the two codes will give an error of 100°F. When the fuel surface temperature is fixed, this will result in a 100°F lower prediction of the centerline temperature in FACTRAN. We have indicated this apparent nonconservatism to Westinghouse. In the letter NS-TMA-2026, dated January 12, 1979, Westinghouse proposed to incorporate the LASER-calculated power distribution shapes in FACTRAN to eliminate this non-conservatism. We find the use of the LASER-calculated power distribution in the FACTRAN code acceptable."

Justification

The condition of concern (T(centerline) – T(surface) on the order of 3,000°F) is expected for transients that reach, or come close to, the fuel melt temperature. As this applies only to the RCCA ejection transient, the LASER-calculated power distributions were used in the FACTRAN analysis of the RCCA ejection transient for CPNPP.

RETRAN

RETRAN is used for studies of transient response of a pressurized water reactor (PWR) system to specified perturbations in process parameters. This code simulates a multi-loop system by a lumped parameter model containing the reactor vessel, hot- and cold-leg piping, RCPs, steam generators (tube and shell sides), main steam lines, and the pressurizer. The pressurizer heaters, spray, relief valves, and safety valves can also be modeled. RETRAN includes a point neutron kinetics model and reactivity effects of the moderator, fuel, boron, and control rods. The secondary side of the steam generator uses a detailed nodalization for the thermal transients. The RTS simulated in the code includes reactor trips on high neutron flux, high neutron flux rate, OTN-16, OPN-16, low reactor coolant flow, high- and low-pressurizer pressure, high pressurizer level, and low-low steam generator water level. Control systems are also simulated including rod control and pressurizer pressure control. Parts of the safety injection system (SIS),

including the accumulators, are also modeled. Also, a conservative approximation of the transient DNBR, based on the core thermal limits, is calculated via RETRAN.

The RETRAN licensing topical report, WCAP-14882 (Reference 7), was approved by the NRC via an SER from F. Akstulewicz (NRC) to H. Sepp (Westinghouse), dated February 11, 1999. This SER issued for RETRAN identifies three conditions of acceptance, which are summarized below along with justifications for application to CPNPP.

1. "The transients and accidents that Westinghouse proposes to analyze with RETRAN are listed in this SER (Table 1) and the NRC staff review of RETRAN usage by Westinghouse was limited to this set. Use of the code for other analytical purposes will require additional justification."

   Justification

   The transients listed in Table 1 of the SER are:

   - Feedwater system malfunctions,
   - Excessive increase in steam flow,
   - Inadvertent opening of a steam generator relief or safety valve,
   - Steam line break,
   - Loss of external load/turbine trip,
   - Loss of offsite power,
   - Loss of normal feedwater flow,
   - Feedwater line rupture,
   - Loss of forced reactor coolant flow,
   - Locked reactor coolant pump rotor/sheared shaft,
   - Control rod cluster withdrawal at power,
   - Dropped control rod cluster/dropped control bank,
   - Inadvertent increase in coolant inventory,
   - Inadvertent opening of a pressurizer relief or safety valve,
   - Steam generator tube rupture.

   The transients explicitly analyzed for CPNPP using RETRAN are:

   - Feedwater system malfunctions (FSAR 15.1.1 and 15.1.2),
   - Steam line break (FSAR 15.1.5),
   - Loss of external load/turbine trip (FSAR 15.2.2, 15.2.3),
   - Loss of non-emergency alternating current (AC) power (loss of offsite power) (FSAR 15.2.6),
   - Loss of normal feedwater flow (FSAR 15.2.7),

- Feedwater system pipe break (feedwater line rupture) (FSAR 15.2.8),
- Loss of forced reactor coolant flow (FSAR 15.3.1, 15.3.2),
- Locked reactor coolant pump rotor/shaft break (FSAR 15.3.3, 15.3.4),
- Uncontrolled RCCA withdrawal at power (FSAR 15.4.2),
- Inadvertent operation of the ECCS (increase in coolant inventory) (FSAR 15.5.1),
- Inadvertent opening of a pressurizer safety or relief valve (FSAR 15.6.1),

As each transient analyzed for CPNPP using RETRAN matches one of the transients listed in Table 1 of the SER, additional justification is not required.

2. "WCAP-14882 describes modeling of Westinghouse designed 4-, 3-, and 2-loop plants of the type that are currently operating. Use of the code to analyze other designs, including the Westinghouse AP600, will require additional justification."

Justification

The CPNPP consists of two 4-loop Westinghouse-designed units that were "currently operating" at the time the SER was written (February 11, 1999). Therefore, additional justification is not required.

3. "Conservative safety analyses using RETRAN are dependent on the selection of conservative input. Acceptable methodology for developing plant-specific input is discussed in WCAP-14882 and in Reference 14 [WCAP-9272] (Reference 8 in this document). Licensing applications using RETRAN should include the source of and justification for the input data used in the analysis."

Justification

The input data used in the RETRAN analyses performed by Westinghouse came from both Luminant Power and Westinghouse sources. Assurance that the RETRAN input data is conservative for CPNPP is provided via Westinghouse's use of transient-specific analysis guidance documents. Each analysis guidance document provides a description of the subject transient, a discussion of the plant protection systems that are expected to function, a list of the applicable event acceptance criteria, a list of the analysis input assumptions (e.g., directions of conservatism for initial condition values), a detailed description of the transient model development method, and a discussion of the expected transient analysis results. Based on the analysis guidance documents, conservative plant-specific input values were requested and collected from the responsible Luminant Power and Westinghouse sources. Consistent with the Westinghouse Reload Evaluation Methodology described in WCAP-9272 (Reference 8),

the safety analysis input values used in the CPNPP analyses were selected to conservatively bound the values expected in subsequent operating cycles.

Note that since CPNPP has OTN-16 and OPN-16 reactor trips rather than overtemperature and overpower ΔT, an N-16 model, which is equivalent to that currently being used by Luminant Power in support of CPNPP, was applied.

The RETRAN nodalization modeling used in the CPNPP analyses is consistent with the Westinghouse 4-loop plant nodalization model of WCAP-14882, except for the preheat steam generator model used for CPNPP Unit 2 (see discussion below) and the nodalization of the hot legs. Since the approval of WCAP-14882, the hot leg modeling was enhanced to minimize code instabilities attributed to pressurizer insurge and outsurge. This hot leg model enhancement, which has been applied in other RETRAN analyses performed by Westinghouse, consisted of dividing each hot leg control volume into three equal control volumes. Although it was needed only for the hot leg connected to the pressurizer, all loops were divided in the same manner.

Preheat Steam Generator Model for CPNPP Unit 2

As noted in WCAP-14882, multi-node RETRAN models were developed for Westinghouse feedring and preheat steam generators. The nodalization of the feedring and preheat steam generators explicitly models the circulation loop and allows for the calculation of the indicated water level. The multi-node secondary model also allows for a detailed transient response during the steam line break and other secondary side transients.

Figure 3.6-1 of WCAP-14882 (Reference 7) presents the nodalization of a preheat steam generator model that was based on the Westinghouse Model E steam generator design. The Comanche Peak Unit 2 Westinghouse Model D-5 steam generator design includes variations in the preheater and feedwater designs when compared to the Model E steam generator, and thus the RETRAN model nodalization was revised. Figure 2.1-7 provides the revised nodalization used for the Model D-5 steam generator. The Model D-5 steam generator features a split feedwater flow injection design, which, at full power, has approximately 80 percent of the flow entering the preheater region and 20 percent of the flow entering the downcomer region below the water level via the auxiliary feedwater nozzle when operating at full power.

- The feedwater entering the preheater enters a region of the cold side of the tube bundle (Volume x60) and then splits into two streams. Most of this feedwater flow passes up through the upper sections of the preheater (Volumes x61 and x62) and joins the flow rising in the hot tube side of the tube bundle in Volume x72. The remainder of the feedwater entering the preheater travels down to the lower section of the preheater and joins with recirculated water before passing to the hot side of the tube bundle (Volume x71).

- The feedwater entering the feedring in the upper downcomer region (Volume x77) enters and mixes with the recirculated liquid from Volume x76 and flows to the lower downcomer (Volume x78) where it enters the tube bundle on the cold side (Volume x69) or hot side (Volume x71).

The CPNPP Model D-5 tube bundle region above the preheater is modeled as 3 sequential secondary side nodes (Volumes x72, x73, and x74) and combines the flows from both the hot tube side (Volumes x70 and x71) and the flow exiting from the top of the preheater. This is similar to the Model E steam generator design documented in WCAP-14882. Two-phase fluid exits the tube bundle and flows through the riser (Volume x75) and enters Volume x76 where phase separation is modeled using the RETRAN bubble rise model. The phase separation in Volume x76 simulates the steam generator moisture separators, i.e., the swirl vane and demister vane separators. The steam fraction rises to the top of Volume x76 and exits the steam generator through the steam nozzle while the liquid fraction mixes with feedwater and continues the cycle by mixing with the feedwater nozzle flow in Volume x77.

On the primary side of the Unit 2 Model D-5 steam generator, primary coolant passes from the hot leg (Volume x03) to the steam generator inlet plenum (Volume x20) through the U-tubes (Volumes x21 through x32), into the steam generator outlet plenum (Volume x40), and exits the steam generator into the cold leg (Volume x09). Twelve conducting heat exchangers transfer heat from the primary to the secondary during normal operation and transient conditions.

This D-5 model has been benchmarked against the Westinghouse preheat steam generator design code, including the primary and secondary side volumes, primary side pressure drops for 0 percent and maximum tube plugging levels, secondary side pressure drops, heat transfer characteristics for 0 percent and maximum tube plugging levels, and steam generator masses versus both power and water levels.

LOFTRAN

Transient response studies of a PWR to specified perturbations in process parameters use the LOFTRAN computer code. This code simulates a multi-loop system by a model containing the reactor vessel, hot- and cold-leg piping, steam generators (tube and shell sides), the pressurizer and the pressurizer heaters, spray, relief valves, and safety valves. LOFTRAN also includes a point neutron kinetics model and reactivity effects of the moderator, fuel, boron, and rods. The secondary side of the steam generator uses a homogeneous, saturated mixture for the thermal transients. The code simulates the reactor protection system, which includes reactor trips on high neutron flux, OTN-16 and OPN-16, high- and low-pressurizer pressure, low RCS flow, low-low steam generator water level, and high pressurizer level. Control systems are also simulated including rod control, steam dump, and pressurizer pressure control. The SIS, including the accumulators, is also modeled. LOFTRAN can also approximate the transient value of DNBR based on input from the core thermal safety limits.

The LOFTRAN licensing topical report, WCAP-7907 (Reference 9), was approved by the NRC via an SER from C. O. Thomas (NRC) to E. P. Rahe (Westinghouse), dated July 29, 1983. This SER for LOFTRAN identifies one condition of acceptance, which is summarized below along with justification for application to CPNPP.

1. "LOFTRAN is used to simulate plant response to many of the postulated events reported in Chapter 15 of PSARs and FSARs, to simulate anticipated transients without scram, for equipment sizing studies, and to define mass/energy releases for containment pressure analysis. The Chapter 15 events analyzed with LOFTRAN are:

   - Feedwater System Malfunction
   - Excessive Increase in Steam Flow
   - Inadvertent Opening of a Steam Generator Relief or Safety Valve
   - Steamline Break
   - Loss of External Load
   - Loss of Offsite Power
   - Loss of Normal Feedwater
   - Feedwater Line Rupture
   - Loss of Forced Reactor Coolant Flow
   - Locked Pump Rotor
   - Rod Withdrawal at Power
   - Rod Drop
   - Startup of an Inactive Pump
   - Inadvertent ECCS Actuation
   - Inadvertent Opening of a Pressurizer Relief or Safety Valve

   This review is limited to the use of LOFTRAN for the licensee safety analyses of the Chapter 15 events listed above, and for a steam generator tube rupture..."

   Justification

   For CPNPP, the LOFTRAN code was only used in the analysis of the dropped rod transient (FSAR 15.4.3) and in the analysis of the anticipated transients without scram (FSAR 15.8). As these transients match one of the transients listed in the SER, additional justification is not required.

TWINKLE

TWINKLE is a multi-dimensional spatial neutron kinetics code. The code uses an implicit finite-difference method to solve the two-group transient neutron diffusion equations in one, two, and three dimensions. The code uses six delayed neutron groups and contains a detailed multi-region fuel-cladding-coolant heat transfer model for calculating pointwise Doppler and moderator feedback effects. The code handles up to 8,000 spatial points and performs steady-state initialization. Aside from basic cross-section data and thermal-hydraulic parameters, the code accepts as input basic driving functions such as inlet temperature, pressure, flow, boron concentration, control rod motion, and others. The code provides various

outputs, such as channelwise power, axial offset, enthalpy, volumetric surge, pointwise power, and fuel temperatures. It also predicts the kinetic behavior of a reactor for transients that cause a major perturbation in the spatial neutron flux distribution.

The TWINKLE licensing topical report, WCAP-7979 (Reference 10), was approved by the U.S. Atomic Energy Commission (AEC) via an SER from D. B. Vassallo (AEC) to R. Salvatori (Westinghouse), dated July 29, 1974. This SER for TWINKLE does not identify any conditions, restrictions, or limitations that need to be addressed for application to CPNPP.

Advanced Nodal Code (ANC)

ANC is an advanced nodal code capable of two-dimensional (2-D) and three-dimensional (3-D) neutronics calculations. ANC is the reference model for certain safety analysis calculations, power distributions, peaking factors, critical boron concentrations, control rod worths, reactivity coefficients, etc. In addition, 3-D ANC validates one-dimensional (1-D) and 2-D results and provides information about radial (x-y) peaking factors as a function of axial position. It can calculate discrete pin powers from nodal information as well.

The ANC licensing topical report, WCAP-10965 (Reference 11), was approved by the NRC via an SER from C. Berlinger (NRC) to E. P. Rahe (Westinghouse), dated June 23, 1986. This SER for ANC does not identify any conditions, restrictions, or limitations that need to be addressed for application to CPNPP.

VIPRE

The VIPRE computer program performs thermal-hydraulic calculations. This code calculates coolant density, mass velocity, enthalpy, void fractions, static pressure, and DNBR distributions along flow channels within a reactor core.

The VIPRE licensing topical report, WCAP-14565 (Reference 12), was approved by the NRC via an SER from T. H. Essig (NRC) to H. Sepp (Westinghouse), dated January 19, 1999. This SER for VIPRE identifies four conditions of acceptance, which are summarized below along with justification for application to CPNPP.

1. "Selection of the appropriate critical heat flux (CHF) correlation, DNBR limit, engineered hot channel factors for enthalpy rise and other fuel-dependent parameters for a specific plant application should be justified with each submittal."

   <u>Justification</u>

   The WRB-2 correlation with a 95/95 correlation limit of 1.17 was used in the DNB analyses for the CPNPP 17x17 VANTAGE+ fuel type. The use of the WRB-2 DNB correlation for VANTAGE+ fuel was approved September 1985 (Letter from C. O. Thomas (NRC) to E. P. Rahe (Westinghouse), "Acceptance for Referencing of Licensing Topical Report WCAP-10444, VANTAGE+ Fuel Assembly," Reference 19). WCAP-12610 extended the use of the WRB-2 correlation to VANTAGE+ fuel and was

approved July 1, 1991 (Letter from A. C. Thadani (NRC) to S. R. Tritch (Westinghouse), "Acceptance for Referencing of Topical Report WCAP-12610 VANTAGE+ Fuel Assembly Reference Core Report," Reference 20).

The use of the plant specific hot channel factors and other fuel dependent parameters in the DNB analysis for the CPNPP VANTAGE+ fuel were justified using the same methodologies as for previously approved safety evaluations of other Westinghouse four-loop plants using the same fuel design.

2. "Reactor core boundary conditions determined using other computer codes are generally input into VIPRE for reactor transient analyses. These inputs include core inlet coolant flow and enthalpy, core average power, power shape and nuclear peaking factors. These inputs should be justified as conservative for each use of VIPRE."

   Justification

   The core boundary conditions for the VIPRE calculations for the CPNPP fuel are all generated from NRC-approved codes and analysis methodologies. Conservative reactor core boundary conditions were justified for use as input to VIPRE. Continued applicability of the input assumptions is verified on a cycle-by-cycle basis using the Westinghouse reload methodology described in WCAP-9272 (Reference 8).

3. "The NRC Staff's generic SER for VIPRE set requirements for use of new CHF correlations with VIPRE. Westinghouse has met these requirements for using WRB-1, WRB-2 and WRB-2M correlations. The DNBR limit for WRB-1 and WRB-2 is 1.17. The WRB-2M correlation has a DNBR limit of 1.14. Use of other CHF correlations not currently included in VIPRE will require additional justification."

   Justification

   As discussed in response to Condition 1, the WRB-2 correlation with a limit of 1.17 was used for the DNB analyses of the CPNPP fuel. For conditions where WRB-2 is not applicable, the W-3 DNB correlation was used with a limit of 1.30 (1.45, for pressures between 500 psia and 1,000 psia).

4. "Westinghouse proposes to use the VIPRE code to evaluate fuel performance following postulated design-basis accidents, including beyond-CHF heat transfer conditions. These evaluations are necessary to evaluate the extent of core damage and to ensure that the core maintains a coolable geometry in the evaluation of certain accident scenarios. The NRC Staff's generic review of VIPRE did not extend to post CHF calculations. VIPRE does not model the time-dependent physical changes that may occur within the fuel rods at elevated temperatures. Westinghouse proposes to use conservative input in order to account for these effects. The NRC Staff requires that appropriate justification be submitted with each usage of VIPRE in the post-CHF region to ensure that conservative results are obtained."

Justification

For application to CPNPP safety analysis, the usage of VIPRE in the post-critical heat flux region is limited to the peak clad temperature calculation for the locked rotor transient. The calculation demonstrated that the peak clad temperature in the reactor core is well below the allowable limit to prevent clad embrittlement. VIPRE modeling of the fuel rod is consistent with the model described in WCAP-14565 and included the following conservative assumptions:

- DNB was assumed to occur at the beginning of the transient
- Film boiling was calculated using the Bishop-Sandberg-Tong correlation
- The Baker-Just correlation accounted for heat generation in fuel cladding due to zirconium-water reaction

Conservative results were further ensured with the following input:

- Fuel rod input based on the maximum fuel temperature at the given power
- The hot spot power factor was equal to or greater than the design linear heat rate

Uncertainties were applied to the initial operating conditions in the limiting direction.

2.1.10 Classification of Events

Each of the non-LOCA events listed in Table 2.1-7 is presented in Section 15 of the FSAR (Reference 13). Each non-LOCA event is categorized with respect to its potential consequences. Since 1970, the classification of plant conditions in American Nuclear Society Standard ANSI N18.2-1973 (Reference 14) has often been used to facilitate the evaluation of nuclear plant safety and the functional requirements for structures, systems, and components. The plant conditions are divided into four categories in accordance with the anticipated frequencies of occurrence and potential radiological consequences. The four categories (or conditions) are:

- Condition I – Normal Operation
- Condition II – Faults of Moderate Frequency
- Condition III – Infrequent Faults
- Condition IV – Limiting Faults

The basic principle applied in relating requirements to each of the conditions is that the more probable occurrences must result in little or no risk to the public, and those extreme situations having the potential for greater risk should be those situations least likely to occur. Where applicable, the reactor trip system and/or engineered safety features are assumed in fulfilling this principle. Each condition is described in more detail as follows.

Condition I – Normal Operation

Condition I occurrences are those that are expected frequently or regularly during power operation, refueling, maintenance, or maneuvering of the plant. Condition I occurrences are accommodated with margin between any plant parameter and the value of the parameter that would require either automatic or manual protective action. In this regard, analysis of the fault condition is typically based on a conservative set of initial conditions corresponding to the most adverse set of conditions occurring during Condition I operation.

Condition II – Faults of Moderate Frequency

These faults occur with moderate frequency during the life of the plant, any one of which may occur during a calendar year (i.e., between 1/year and 1×10^{-1}/year). These faults, at worst, result in a reactor trip with the plant being capable of returning to operation after corrective action. Any release of radioactive materials in effluents to unrestricted areas should be in conformance with Title 10 Part 20 of the Code of Federal Regulations (10 CFR 20). A Condition II fault (or event), by itself, does not propagate to a more serious incident of the Condition III or Condition IV type without the occurrence of other independent incidents. A single Condition II incident should not cause the loss of any barrier to the escape of radioactive products.

Condition III – Infrequent Faults

Condition III faults occur very infrequently during the life of the plant, any one of which may occur during the plant's lifetime (i.e., between 1×10^{-1}/year and 1×10^{-2}/year). Condition III faults can be accommodated with the failure of only a small fraction of the fuel rods, although sufficient fuel damage might occur to preclude resumption of operation for a considerable outage time. The release of radioactivity due to Condition III faults may exceed the guidelines of 10 CFR 20, but is not sufficient to interrupt or restrict public use of those areas beyond the exclusion area boundary. A Condition III fault does not, by itself, generate a Condition IV fault or result in a consequential loss of function of the RCS or containment barriers.

Condition IV – Limiting Faults

Condition IV occurrences are faults that are not expected to occur (i.e., $< 1\times10^{-2}$/year), but are postulated because their consequences have the potential for the release of significant amounts of radioactive material. Condition IV faults are the most drastic occurrences that must be designed against, and represent the limiting design cases. Condition IV faults should not cause a fission product release to the environment resulting in an undue risk to public health and safety in excess of the guideline values in Title 10 Part 100 of the Code of Federal Regulations (10 CFR 100). A single Condition IV fault is not to cause a consequential loss of required functions of systems needed to cope with the fault including those of the RCS and the reactor containment.

2.1.11 Events Evaluated or Analyzed

Each of the FSAR transients listed in Table 2.1-1 were evaluated or analyzed as shown in Table 2.1-7 in support of the CPNPP Uprate Program. These transient evaluations and analyses demonstrate that all applicable safety analysis acceptance criteria are satisfied for CPNPP. Table 2.1-1 summarizes the results obtained for each of the non-LOCA transient analyses.

2.1.12 Analysis Methodology

The transient-specific analysis methodologies that were applied to CPNPP have been reviewed and approved by the NRC via transient-specific topical reports (e.g., WCAPs) and/or through the review and approval of plant-specific safety analysis reports. There are four non-LOCA transients analyzed for CPNPP that have an approved transient-specific topical report: steam line break (FSAR Section 15.1.5), dropped rod (FSAR Section 15.4.3), boron dilution (FSAR Section 15.4.6), and RCCA ejection (FSAR Section 15.4.8).

Steam Line Break Methodology

The steam line break licensing topical report, WCAP-9226 Revision 1 (Reference 21), was approved by the NRC via an SER from A. C. Thadani (NRC) to W. J. Johnson (Westinghouse), dated January 31, 1989. The steam line break SER identifies two conditions of acceptance, which are summarized below along with justification for application to CPNPP.

1. "Only those codes which have been accepted by the NRC should be used for licensing application."

   Justification

   As identified in Table 2.1-6, the computer codes used in the analysis of the steam line break event are RETRAN, ANC, and VIPRE. Per subsection 2.1.9, these codes have been accepted by the NRC, and therefore this condition of acceptance is satisfied for CPNPP.

2. "For the pressure between 500 and 1,000 psia, the 95/95 DNBR limit for the W-3 correlation is 1.45."

   Justification

   As shown in Table 2.1-1, 1.45 was applied as the DNBR limit in the steam line break analysis that used the W-3 DNB correlation. Thus, no further justification is required for CPNPP.

Dropped Rod Methodology

The dropped rod licensing topical report, WCAP-11394 (Reference 15), was approved by the NRC via an SER from A. C. Thadani (NRC) to R. A. Newton (Westinghouse Owner's Group), dated October 23, 1989. The dropped rod SER identifies one condition of acceptance, which is summarized below along with justification for application to CPNPP.

1. "The Westinghouse analysis, results and comparisons are reactor and cycle specific. No credit is taken for any direct reactor trip due to dropped RCCA(s). Also, the analysis assumes no automatic power reduction features are actuated by the dropped RCCA(s). A further review by the staff (for each cycle) is not necessary, given the utility assertion that the analysis described by Westinghouse has been performed and the required comparisons have been made with favorable results."

   Justification

   For the reference cycle assumed in the CPNPP Uprate Program, the methodology described in WCAP-11394 was applied and the required comparisons have been made with acceptable results (DNB limits were not exceeded). Future cycles will be assessed as part of the reload safety evaluation process described in Reference 8.

Boron Dilution Methodology

The boron dilution in modes 3, 4, and 5 licensing topical report, RXE-94-001-A (Reference 22), was approved by the NRC specifically for Comanche Peak via an SER from T. A. Bergman (NRC) to W. J. Cahill, Jr. (TU Electric), dated November 3, 1993. The SER does not identify any conditions, restrictions, or limitations that need to be addressed for application to CPNPP; note that the method of RXE-94-001-A was applied in support of the current licensing basis for CPNPP.

RCCA Ejection Methodology

The RCCA ejection licensing topical report, WCAP-7588 Rev. 1-A (Reference 16), was approved by the AEC via an SER from D. B. Vassallo (AEC) to R. Salvatori (Westinghouse), dated August 28, 1973. The RCCA ejection SER identifies two conditions of acceptance, which are summarized below along with justification for application to CPNPP.

1. "The staff position, as well as that of the reactor vendors over the last several years, has been to limit the average fuel pellet enthalpy at the hot spot following a rod ejection accident to 280 cal/gm. This was based primarily on the results of the SPERT tests which showed that, in general, fuel failure consequences for UO_2 have been insignificant below 300 cal/gm for both irradiated and unirradiated fuel rods as far as rapid fragmentation and dispersal of fuel and cladding into the coolant are concerned. In this report, Westinghouse has decreased their limiting fuel failure criterion from 280 cal/gm (somewhat less than the threshold of significant conversion of the fuel thermal energy to mechanical energy) to 225 cal/gm for unirradiated rods and 200 cal/gm for

irradiated rods. Since this is a conservative revision on the side of safety, the staff concludes that it is an acceptable fuel failure criterion."

Justification

The maximum fuel pellet enthalpy at the hot spot calculated for each CPNPP-specific RCCA ejection case was less than 200 cal/gm. These results satisfy the fuel failure criterion accepted by the NRC staff.

2. "Westinghouse proposes a clad temperature limitation of 2,700°F as the temperature above which clad embrittlement may be expected. Although this is several hundred degrees above the maximum clad temperature limitation imposed in the AEC ECCS Interim Acceptance Criteria, this is felt to be adequate in view of the relatively short time at temperature and the highly localized effect of a reactivity transient."

   Justification

   As discussed in Westinghouse letter NS-NRC-89-3466 written to the NRC (Reference 17), the 2,700°F clad temperature limit was historically applied by Westinghouse to demonstrate that the core remains in a coolable geometry during an RCCA ejection transient. This limit was never used to demonstrate compliance with fuel failure limits and is no longer used to demonstrate core coolability. The RCCA ejection acceptance criteria applied by Westinghouse to demonstrate long-term core coolability and compliance with applicable offsite dose requirements are identified in subsection 2.5.6.

2.1.13 Operator Actions

The feedwater system pipe break and inadvertent operation of the ECCS events are the only events for which operator action is credited in the analyses. Report subsections 2.3.4 and 2.6 discuss the details of the feedwater system pipe break and inadvertent operation of the ECCS analyses.

2.1.14 References

1. WCAP-11397, "Revised Thermal Design Procedure," April 1989.

2. WCAP-12910 Rev. 1-A, "Pressurizer Safety Valve Set Pressure Shift," May 1993.

3. ANSI/ANS-5.1-1979, "American National Standard for Decay Heat Power In Light Water Reactors," August 29, 1979.

4. WCAP-8745, "Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions," September 1986.

5. WCAP-7908, "FACTRAN – A FORTRAN IV Code for Thermal Transients in a UO_2 Fuel Rod," December 1989.

6. WCAP-15063 Revision 1, with Errata, "Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)," July 2000.

7. WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

8. WCAP-9272, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

9. WCAP-7907, "LOFTRAN Code Description," April 1984.

10. WCAP-7979, "TWINKLE – A Multi-Dimensional Neutron Kinetics Computer Code," January 1975.

11. WCAP-10965, "ANC: A Westinghouse Advanced Nodal Computer Code," September 1986.

12. WCAP-14565, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," October 1999.

13. CPSES FSAR, "Comanche Peak Steam Electric Station Final Safety Analysis Report," Amendment No. 101, February 1, 2007.

14. ANS N18.2-1973, "Nuclear Safety Criteria for the Design of Stationary PWRs, American Nuclear Society."

15. WCAP-11394, "Methodology for the Analysis of the Dropped Rod Event," January 1990.

16. WCAP-7588 Rev. 1-A, "An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Spatial Kinetics Methods," January 1975.

17. NS-NRC-89-3466, Letter from W. J. Johnson (Westinghouse) to R. C. Jones (NRC), dated October 23, 1989, "Use of 2700°F PCT Acceptance Limit in Non-LOCA Accidents."

18. NS-TMA-2182, Letter from T. M. Anderson (Westinghouse) to Dr. S. H. Hanauer (NRC), dated December 30, 1979, "Anticipated Transients Without Scram for Westinghouse Plants."

19. WCAP-10444, "Reference Core Report VANTAGE+ Fuel Assembly," September 1985.

20. WCAP-12610, "VANTAGE+ Fuel Assembly Reference Core Report," April 1995.

21. WCAP-9226 Revision 1, "Reactor Core Response to Excessive Secondary Steam Releases," February 1998.

22. RXE-94-001-A, "Safety Analysis of the Postulated Inadvertent Boron Dilution Event in Modes 3, 4, and 5," February 1994.

Table 2.1-1

Non-LOCA Analysis Limits and Analysis Results

FSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
15.1.1	Decrease in Feedwater Temperature	Minimum DNBR (RTDP, WRB-2)	1.61	1.90
15.1.2	Increase in Feedwater Flow	Minimum DNBR (RTDP, WRB-2) hot full power (HFP)) Minimum DNBR (non-RTDP, W-3) (HZP)	1.61 (HFP) 1.45 (HZP)	2.10 (HFP) (1) (HZP)
15.1.3	Excessive Increase in Secondary Steam Flow	Minimum DNBR (RTDP, WRB-2)	1.61	> 1.61
15.1.4	Inadvertent Opening of a Steam Generator Relief or Safety Valve	Bounded by Steam Line Break (FSAR Section 15.1.5)	N/A	N/A
15.1.5	Steam System Piping Failure – Zero Power (Core response only)	Minimum DNBR (non-RTDP, W-3) (typical/thimble)	1.45/1.45	3.067/2.861
	Steam System Piping Failure – Full Power (Core response only)	Minimum DNBR (RTDP, WRB-2 correlation) (typical/thimble)	1.61/1.61	2.015/1.963
		Peak Linear Heat Generation (kW/ft)	22.4(2)	21.6
15.2.1	Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow	There are no steam pressure regulators at CPNPP whose failure or malfunction could cause a steam flow transient (FSAR Section 15.2.1)	N/A	N/A
15.2.2	Loss of External Electrical Load	Bounded by Turbine Trip (FSAR Section 15.2.3)	N/A	N/A
15.2.3	Turbine Trip	Minimum DNBR (RTDP, WRB-2)	1.61	1.98
		Peak RCS Pressure, psia	2,748.2	2,746.0
		Peak MSS Pressure, psia	1,318.2	1,298.4
15.2.4	Inadvertent Closure of Main Steam Isolation Valves	Bounded by Turbine Trip (FSAR Section 15.2.3)	N/A	N/A

Table 2.1-1 (cont.)

Non-LOCA Analysis Limits and Analysis Results

FSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
15.2.5	Loss of Condenser Vacuum and Other Events Resulting in Turbine Trip	Bounded by Turbine Trip (FSAR Section 15.2.3)	N/A	N/A
15.2.6	Loss of Nonemergency AC Power to the Station Auxiliaries	Maximum pressurizer mixture volume, ft^3	1,800	1,600.4
15.2.7	Loss of Normal Feedwater	Maximum Pressurizer Mixture Volume, ft^3	1,800	1,747.9
15.2.8	Feedwater System Pipe Break	Minimum Margin to Hot Leg Saturation, °F	>0.0	10
15.3.1	Partial Loss of Forced Reactor Coolant Flow	Minimum DNBR (RTDP, WRB-2) (typical/thimble)	1.61/1.61	2.253/2.173
15.3.2	Complete Loss of Forced Reactor Coolant Flow	Minimum DNBR (RTDP, WRB-2) (typical/thimble)	1.61/1.61	1.940/1.901
15.3.3/ 15.3.4	Reactor Coolant Pump Shaft Seizure (Locked Rotor)/Shaft Break	Peak RCS Pressure, psia	2,748.2	2,574.5
		Peak Cladding Temperature, °F	2,700	1,723.6
		Maximum Zirconium-Water Reaction, %	16	0.22
		Maximum Percentage of Rods-in-DNB, %	10	<10
15.4.1	Uncontrolled RCCA Withdrawal from a Subcritical or Low Power Condition	Minimum DNBR Below First Mixing Vane Grid (non-RTDP, W-3 correlation) (typical/thimble)	1.30/1.30	1.824/1.616
		Minimum DNBR Above First Mixing Vane Grid (non-RTDP, WRB-2 correlation) (typical/thimble)	1.17/1.17	2.018/1.997
		Maximum Fuel Centerline Temperature, °F	4,800(3)	2,304
15.4.2	Uncontrolled RCCA Withdrawal at Power	Minimum DNBR (RTDP, WRB-2)	1.61	1.689
		Peak Main Steam System (MSS)	1,318.2	1,275.8

Table 2.1-1 (cont.) Non-LOCA Analysis Limits and Analysis Results				
FSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
		Pressure, psia		
15.4.3	RCCA Misalignment (Dropped Rod)	Minimum DNBR (RTDP, WRB-2)	1.61	> 1.61
		Peak Linear Heat Generation (kW/ft)	22.4[(2)]	< 22.4
		Peak Uniform Cladding Strain (%)	1.0	< 1.0
15.4.4	Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature	No Analysis Performed (See Report Subsection 2.5.4)	N/A	N/A
15.4.5	A Malfunction or Failure of the Flow Controller in a BWR Loop that Results in an Increased Reactor Coolant Flow Rate	This event is not applicable to CPNPP.	N/A	N/A
15.4.6	Chemical and Volume Control System (CVCS) Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant (Boron Dilution)	Minimum Time from Alarm to Operator Action to prevent a Complete Loss of Shutdown Margin, Minutes	15	48.2 (Mode 1 manual)
				49.8 (Mode 1 auto)
				52.5 (Mode 2)
				The maximum critical boron concentration is controlled as a function of the plant initial boron concentration to meet a minimum operator action time of 15 minutes. (Modes 3, 4 and 5)

Table 2.1-1 (cont.)

Non-LOCA Analysis Limits and Analysis Results

FSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
15.4.8	Spectrum of RCCA Ejection Accidents	Maximum Fuel Pellet Average Enthalpy, cal/g	200	114.3 (BOC-HZP)[4] 161.6 (BOC-HFP)[5] 138.9 (EOC-HZP)[6] 157.5 (EOC-HFP)[7]
		Maximum Fuel Melt, %	10[8]	0.00 (BOC-HZP)[4] 0.04 (BOC-HFP)[5] 0.00 (EOC-HZP)[6] 0.23 (EOC-HFP)[7]
		Peak RCS Pressure, psia	Generically addressed in Reference 16	
15.5.1	Inadvertent Operation of the Emergency Core Cooling System During Power Operation	Maximum pressurizer mixture volume, ft^3	1,800	1,780.0
15.5.2	Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory	Event is covered by the analyses of the Boron Dilution event (FSAR Section 15.4.6) and the Inadvertent Operation of the Emergency Core Cooling System During Power Operation event (FSAR Section 15.5.1).	N/A	N/A
15.5.3	A Number of BWR Transients	These events are not applicable to CPNPP.	N/A	N/A
15.6.1	Inadvertent Opening of a Pressurizer Safety or Relief Valve	Minimum DNBR (RTDP, WRB-2)	1.61	1.9
15.8	Anticipated Transient without Scram (ATWS)	Peak RCS Pressure, psig	3,200	<3,200

Table 2.1-1 (cont.) Non-LOCA Analysis Limits and Analysis Results				
FSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case

Notes:

1. Bounded by zero power steam system piping failure.
2. Corresponds to a conservative UO_2 fuel melting temperature of 4,700°F.
3. 4,800°F is the fuel melting temperature corresponding to a maximum UO_2 burnup at the hot spot of ~48,276 MWd/MTU.
4. BOC-HZP ≡ Beginning of cycle HZP.
5. BOC-HFP ≡ Beginning of cycle HFP.
6. End of cycle (EOC)-HZP ≡ End of cycle HZP.
7. EOC-HFP ≡ End of cycle HFP.
8. BOC and EOC fuel melting temperatures are 4,900 and 4,800°F, respectively. These temperatures correspond to hot spot burnups of approximately 31,034 MWD/MTU (BOC) and 48,276 MWD/MTU (EOC).

Table 2.1-2

Non-LOCA Plant Initial Condition Assumptions

Parameter	RTDP	Non-RTDP	Notes
NSSS Power (MWt)	3,628.0	3,628.0 * 1.006	1
Nominal Total Net RCP Heat (MWt)	16.0	16.0	1, 2, 3
Maximum Full-Power Vessel T_{avg} (°F)	589.2	589.2 ± 6.0	1, 4
Minimum Full-Power Vessel T_{avg} (°F)	574.2	574.2 ± 6.0	1, 4, 8
No-Load RCS Temperature (°F)	557.0	557.0	1, 4
Pressurizer Pressure (psia)	2,250	2,250 ± 30	1
Steam Flow (lbm/hr)	see Note 5	see Note 5	--
Steam Pressure (psia)	see Note 5	see Note 5	--
Full-Power Feedwater Temperature Range (°F)	390-450.3	390-450.3	1
Pressurizer Water Level (% span)	see Note 6	see Note 6	--
Steam Generator Water Level (% NRS)	see Note 7	see Note 7	--

Notes:

1. See Section 1.1 of this report.
2. Total RCP heat input minus RCS thermal losses.
3. A maximum net RCP heat of 20 MWt was conservatively assumed in some non-RTDP analyses, e.g., loss of normal feedwater and feedline break events.
4. All analyses assumed a programmed no-load T_{avg} of 557°F. For the events initiated from a no-load condition (rod withdrawal from subcritical, steam line break, rod ejection, boron dilution), the use of the no-load temperature as the initial temperature bounded the case of startup operations at Comanche Peak with a temperature less than 557°F.
5. The nominal steam flow rate and steam pressure are dependent on other nominal conditions.
6. The nominal/programmed pressurizer water level varies linearly from 25% of span at the no-load T_{avg} of 557°F to either 43.4% of span at the minimum full-power T_{avg} of 574.2°F or 60% of span at full-power T_{avg} values greater than or equal to 584.7°F. The programmed level is constant at the full-power T_{avg} level for T_{avg} values greater than the full-power T_{avg}. An uncertainty of ±5% of span was applied when conservative.
7. The programmed steam generator water level modeled in the Unit 1 analyses was a constant 67% narrow range span (NRS) for all power levels; uncertainty of ±10% NRS was applied when conservative. The programmed steam generator water level modeled in the Unit 2 analyses was a constant 64% NRS for all power levels; uncertainty of +18%/-7% NRS was applied when conservative. The "+" uncertainty means that the actual level is higher than indicated, and the "-" uncertainty means that the actual level is lower than indicated.
8. The minimum nominal full-power vessel average temperature is limited to 585.4°F for Unit 1 and 586.0°F for Unit 2, based on the analysis of the Inadvertent Actuation of the ECCS event discussed in Section 2.6.

Table 2.1-3 Overtemperature and Overpower N-16 Setpoints	
Allowable Full-Power T_{avg} Range	574.2°F[1] to 589.2°F
K_1 (safety analysis value)	1.31
K_2	0.0139/°F
K_3	0.00071/psi
K_4 (safety analysis value)	1.185
T_c^0	[2]
P^0	2,250 psia
f(Δq) Deadband	-18% Δq [3] to +10% Δq
f(Δq) Negative Gain	-2.78%/%Δq [3]
f(Δq) Positive Gain	+2.34%/%Δq
High Pressurizer Pressure Reactor Trip Setpoint (safety analysis value)	2,460 psia (Unit 1) 2,437 psia (Unit 2)
Low Pressurizer Pressure Reactor Trip Setpoint (safety analysis value)	1,860 psia

Notes:

1. Bounding value supported with respect to OTN-16/OPN-16, although the minimum T_{avg} value is limited to 585.4°F for Unit 1 and 586.0°F for Unit 2 based on the analysis of the Inadvertent Actuation of the ECCS event discussed in Section 2.6.
2. Value to be set equal to or less than the cold leg temperature corresponding to the chosen full power operating T_{avg}.
3. Value supported by non-LOCA transient analysis; it may change based on the fuel rod design analysis.

Table 2.1-4

Summary of RTS and ESFAS Functions Actuated

FSAR Section	Event Description	RTS or ESFAS Signal(s) Actuated	Analysis Setpoint	Delay (sec)
15.1.1	Decrease in Feedwater Temperature	Overpower N-16 Reactor Trip	See Table 2.1-3	2.0
15.1.2	Increase in Feedwater Flow	High-High Steam Generator Water Level Feedwater Isolation Valve Closure	100% NRS	11.0
15.1.3	Excessive Increase in Secondary Steam Flow	N/A	N/A	N/A
15.1.4	Inadvertent Opening of a Steam Generator Relief or Safety Valve	See Note 1		
15.1.5	Steam System Piping Failure – Zero Power (Core response only)	Low Steam Pressure Safety Injection (SI) and Steam Line Isolation Valve Closure	395 psia (lead/lag = 10/5)	2.0
		Steam Line Isolation Valve Closure Delay Following Low Steam Pressure Signal	N/A	5.0
		Feedwater Isolation Valve Closure Delay Following SI Signal	N/A	5.0
		SI Pumps at Full Flow Following SI Signal (with/without offsite power)	N/A	25/35
	Steam System Piping Failure – Full Power (Core response only)	Overpower N-16 Reactor Trip	See Table 2.1-3	2.0
15.2.1	Steam Pressure Regulator Malfunction or Failure That Results in Decreasing Steam Flow	There are no steam pressure regulators at CPNPP whose failure or malfunction could cause a steam flow transient (FSAR Section 15.2.1)		
15.2.2	Loss of External Electrical Load	See Note 2		
15.2.3	Turbine Trip	High Pressurizer Pressure Reactor Trip	2.460 psia (Unit 1) 2.437 psia (Unit 2)	1.25
		Overtemperature N-16 Reactor Trip	See Table 2.1-3	7.0(3)

Table 2.1-4 (cont.)

Summary of RTS and ESFAS Functions Actuated

FSAR Section	Event Description	RTS or ESFAS Signal(s) Actuated	Analysis Setpoint	Delay (sec)
15.2.4	Inadvertent Closure of Main Steam Isolation Valves	See Note 2		
15.2.5	Loss of Condenser Vacuum and Other Events Resulting in Turbine Trip	See Note 2		
15.2.6	Loss of Nonemergency AC Power to the Station Auxiliaries	Low-Low Steam Generator Water Level Reactor Trip	0% NRS	2.0
		Low-Low Steam Generator Water Level Auxiliary Feedwater (AFW) Pump Start	0% NRS	60.0
15.2.7	Loss of Normal Feedwater	Low-Low Steam Generator Water Level Reactor Trip	0% NRS (Unit 1) 10% NRS (Unit 2)	2.0
		Low-Low Steam Generator Water Level Motor-Driven AFW Pumps Start	0% NRS (Unit 1) 10% NRS (Unit 2)	60.0
15.2.8	Feedwater System Pipe Break	Low-Low Steam Generator Water Level in Any One Loop Reactor Trip	10% NRS (Unit 1) 7.5% NRS (Unit 2)	2.0
		Low-Low Steam Generator Water Level in Any One Loop Motor-Driven AFW Pump Start	10% NRS (Unit 1) 7.5% NRS (Unit 2)	60
		Low-Low Steam Generator Water Level in More than One Loop Turbine-Driven AFW Pump Start	10% NRS (Unit 1) 7.5% NRS (Unit 2)	85
15.3.1	Partial Loss of Forced Reactor Coolant Flow	Reactor Coolant Low Flow Reactor Trip	87%	1.0
15.3.2	Complete Loss of Forced Reactor Coolant Flow	Reactor Coolant Pump Undervoltage Reactor Trip	See Note 4	1.5
		Reactor Coolant Pump Underfrequency Reactor Trip	57.2 Hz	0.6

Table 2.1-4 (cont.)

Summary of RTS and ESFAS Functions Actuated

FSAR Section	Event Description	RTS or ESFAS Signal(s) Actuated	Analysis Setpoint	Delay (sec)
15.3.3/15.3.4	Reactor Coolant Pump Shaft Seizure (Locked Rotor)/Shaft Break	Reactor Coolant Low Flow Reactor Trip	87%	1.0
15.4.1	Uncontrolled RCCA Withdrawal from a Subcritical or Low Power Condition	Power-Range High Neutron Flux Reactor Trip (Low Setting)	35%	0.5
15.4.2	Uncontrolled RCCA Withdrawal at Power	Power-Range High Neutron Flux Reactor Trip (High Setting)	118%	0.5
		Overtemperature N-16 Reactor Trip	See Table 2.1-3	7.0(3)
15.4.3	RCCA Misalignment (Dropped Rod)	Low Pressurizer Pressure Reactor Trip	1,860 psia	2.0
15.4.4	Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature	N/A	N/A	N/A
15.4.5	A Malfunction or Failure of the Flow Controller in a BWR Loop that Results in an Increased Reactor Coolant Flow Rate	This event is not applicable to CPNPP.	N/A	N/A
15.4.6	CVCS Malfunction (Boron Dilution)	Overtemperature N-16 Reactor Trip(5)	See Table 2.1-3	7.0(3)
15.4.8	RCCA Ejection	Power-Range High Neutron Flux Reactor Trip (Low and High Settings)	35% (low setting)	0.5
			118% (high setting)	0.5
15.5.1	Inadvertent Operation of the Emergency Core Cooling System During Power Operation	Event is terminated by operator action (see Section 2.6).	N/A	N/A
15.5.2	Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory	Event is covered by the analyses of the Boron Dilution event (FSAR Section 15.4.6) and the Inadvertent Operation of the Emergency Core Cooling System During Power Operation event (FSAR Section 15.5.1).	N/A	N/A

Table 2.1-4 (cont.)

Summary of RTS and ESFAS Functions Actuated

FSAR Section	Event Description	RTS or ESFAS Signal(s) Actuated	Analysis Setpoint	Delay (sec)
15.5.3	A Number of BWR Transients	This event is not applicable to CPNPP.	N/A	N/A
15.6.1	Inadvertent Opening of a Pressurizer Safety or Relief Valve	Low Pressurizer Pressure Reactor Trip	1,860 psia	2.0
15.8	ATWS	ATWS Mitigation System Actuation Circuitry (AMSAC) – Turbine Trip (TT), AFW Pump Start	N/A	30 (TT) 60 (AFW)

Notes:

1. Transient bounded by steam system piping failure (FSAR Section 15.1.5).
2. Transient bounded by turbine trip (FSAR Section 15.2.3).
3. Modeling the overtemperature N-16 reactor trip included a time constant (first order lag) of 5 or 6 seconds for the cold leg RTDs and an additional delay of 2 seconds or 1 second to account for electronic delays, reactor trip breakers opening, and RCCA gripper release.
4. Reactor coolant pump power supply undervoltage reactor trip was assumed to occur 1.5 seconds following the loss of bus voltage. For a Westinghouse-designed plant, 1.5 seconds is a typical, conservative value for this delay. A typical breakdown of the time delay is as follows.

Undervoltage trip circuitry including adjustable delay preventing spurious trip	0.95	second
EMF decay	0.25	second
Trip breaker opening	0.15	second
RCCA release time	0.15	second
TOTAL DELAY TIME	1.50	seconds

However, only the total time is used in the analysis and it is verified during plant surveillance tests. It is conservative because the surveillance tests ensure that the assumed value bounds the measured plant value. Also, note that the analysis conservatively assumes that the pump coastdown begins at time zero, even though in reality pump speed will not be reduced as the EMF decays to the undervoltage setpoint.

5. Although not an RTS or ESFAS function, the volume control tank water level high alarm is credited in the boron dilution analyses for Modes 3, 4, and 5, consistent with the methodology of Reference 22; a setpoint of 70% of span was applied.

Table 2.1-5 Core Kinetics Parameters and Reactivity Feedback Coefficients		
Parameter	**Beginning of Cycle (Minimum Feedback)**	**End of Cycle (Maximum Feedback)**
MTC, pcm/°F	5.0 (≤ 70% RTP)[1] linearly ramping to 0.0 at 100% RTP)	N/A
Moderator Density Coefficient, Δk/(g/cc)	N/A	0.50
Doppler Temperature Coefficient, pcm/°F	-0.91	-2.90
Doppler-Only Power Coefficient, pcm/%power (Q = power in %)	-9.55 + 0.035Q	-19.4 + 0.068Q
Delayed Neutron Fraction	0.0070 (maximum)	0.0044 (minimum)
Minimum Doppler Power Defect, pcm		
– RCCA Ejection	1,000	950
– RCCA Withdrawal from Subcritical	1,000	N/A

Note:

1. RTP ≡ Rated Thermal Power

Table 2.1-6

Summary of Initial Conditions and Computer Codes Used

Accident	Computer Codes Used	DNB Correlation	RTDP	Initial Power, %	Vessel Coolant Flow, gpm	Vessel Average Coolant Temp, °F	RCS Pressure, psia
Decrease in Feedwater Temperature	RETRAN	WRB-2	Yes	100 (3,628 MWt - NSSS power)	396,400	589.2	2,250
Increase in Feedwater Flow	RETRAN VIPRE	WRB-2 (HFP) W-3 (HZP)	Yes (HFP) No (HZP)	100 0 (3,628 MWt - NSSS power)	396,400 (HFP) 382,800 (HZP)	589.2 (HFP) 557.0 (HZP)	2,250
Excessive Increase in Secondary Steam Flow	N/A	WRB-2	Yes	100 (3,612 MWt – Core Power)	396,400	589.2	2,250
Inadvertent Opening of a Steam Generator Relief or Safety Valve	Event bounded by the steam system piping failure event.						
Rupture of a Steam Pipe – Zero Power Core Response	RETRAN ANC VIPRE	W-3	No	0 (3,628 MWt - NSSS power)	382,800	557.0	2,250
Rupture of a Steam Pipe – Full Power Core Response	RETRAN VIPRE	WRB-2	Yes	100 (3,628 MWt - NSSS power)	396,400	589.2	2,250
Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow	There are no steam pressure regulators at CPNPP whose failure or malfunction could cause a steam flow transient (FSAR Section 15.2.1)						
Loss of External Electrical Load	Event bounded by the turbine trip event.						
Turbine Trip	RETRAN	N/A (pressure) WRB-2 (DNB)	N/A (pressure) Yes (DNB)	100.6 (pressure) 100 (DNB) (3,628 MWt - NSSS power)	382,800 (pressure) 396,400 (DNB)	583.2 (Unit 1) & 589.2 (Unit 2) (RCS pressure) 595.2 (MSS pressure) 589.2 (DNB)	2,220 (pressure) 2,250 (DNB)

Table 2.1-6 (cont.)

Summary of Initial Conditions and Computer Codes Used

Accident	Computer Codes Used	DNB Correlation	RTDP	Initial Power, %	Vessel Coolant Flow, gpm	Vessel Average Coolant Temp, °F	RCS Pressure, psia
Inadvertent Closure of Main Steam Isolation Valves	Event bounded by the turbine trip event.						
Loss of Condenser Vacuum and Other Events Resulting in Turbine Trip	Event bounded by the turbine trip event.						
Loss of Nonemergency AC Power to the Station Auxiliaries	RETRAN	N/A	N/A	100.6 (3,628 MWt - NSSS power)	382,800	568.2 (Unit 1) 595.2 (Unit 2)	2,280 (Unit 1) 2,220 (Unit 2)
Loss of Normal Feedwater	RETRAN	N/A	N/A	100.6 (3,628 MWt - NSSS power)	382,800	568.2 (Unit 1) 595.2 (Unit 2)	2,280 (Unit 1) 2,220 (Unit 2)
Feedwater System Pipe Break	RETRAN	N/A	N/A	100.6 (3,628 MWt - NSSS power)	382,800	595.2	2,220
Partial Loss of Forced Reactor Coolant Flow	RETRAN VIPRE	WRB-2	Yes	100 (3,628 MWt - NSSS power)	396,400	589.2	2,250
Complete Loss of Forced Reactor Coolant Flow	RETRAN VIPRE	WRB-2	Yes	100 (3,628 MWt - NSSS power)	396,400	589.2	2,250
Locked Rotor/Shaft Break	RETRAN VIPRE	N/A (pressure) WRB-2 (DNB)	N/A (pressure) Yes (DNB)	100.6 (pressure) 100 (DNB) (3,628 MWt - NSSS power)	382,800 (pressure) 396,400 (DNB)	595.2 (pressure) 589.2 (DNB)	2,280 (pressure) 2,250 (DNB)
Uncontrolled RCCA Withdrawal from a Subcritical or Low Power Condition	TWINKLE FACTRAN VIPRE	W-3[1] WRB-2[2]	No	0 (3,612 MWt - core power)	176,088[3]	557	2,220
Uncontrolled RCCA Withdrawal at Power	RETRAN	N/A (Pressure) WRB-2 (DNB)	N/A (Pressure) Yes (DNB)	100 60 10 (3,628 MWt - NSSS power)	396,400	589.2 (100%) 576.3 (60%) 560.2 (10%)	2,250

Table 2.1-6 (cont.)

Summary of Initial Conditions and Computer Codes Used

Accident	Computer Codes Used	DNB Correlation	RTDP	Initial Power, %	Vessel Coolant Flow, gpm	Vessel Average Coolant Temp, °F	RCS Pressure, psia
RCCA Misalignment (Dropped Rod)	LOFTRAN[4] ANC VIPRE	WRB-2	Yes	100 (3,612 MWt - core power)	396,400	589.2	2,250
Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature	See Report Subsection 2.5.4						
CVCS System Malfunction (Boron Dilution)	N/A	N/A	N/A	100 (Mode 1) 5 (Mode 2) 0 (Mode 3) 0 (Mode 4) 0 (Mode 5) N/A (Mode 6)	N/A	595.2 (Mode 1) 564.7 (Mode 2) 557.0 and 350.0 (Mode 3) 350.0 and 200.0 (Mode 4) 200.0 and 68.0 (Mode 5) N/A (Mode 6)	2,250 (Modes 1 and 2) 14.7 (Modes 3, 4, 5) N/A (Mode 6)
Spectrum of RCCA Ejection Accidents	TWINKLE FACTRAN	N/A	N/A	100.6 (HFP) 0 (HZP) (3,612 MWt - core power)	382,800 (HFP) 176,088 [3] (HZP)	589.2 (HFP) 557.0 (HZP)	2,220
Inadvertent Operation of the Emergency Core Cooling System During Power Operation	RETRAN	N/A (filling) WRB-2 (DNB)	N/A (filling) Yes (DNB)	100.6 (filling) 100 (DNB) (3,628 MWt - NSSS power)	382,800 (filling) 396,400 (DNB)	579.4 (Unit 1 filling) 580.0 (Unit 2 filling) 589.2 (DNB)	2,220 (filling) 2,250 (DNB)

Table 2.1-6 (cont.)

Summary of Initial Conditions and Computer Codes Used

Accident	Computer Codes Used	DNB Correlation	RTDP	Initial Power, %	Vessel Coolant Flow, gpm	Vessel Average Coolant Temp, °F	RCS Pressure, psia
Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory	Event is covered by the analyses of the Boron Dilution event and the Inadvertent Operation of the Emergency Core Cooling System During Power Operation event.						
Inadvertent Opening of a Pressurizer Safety or Relief Valve	RETRAN	WRB-2	Yes	100 (3,628 MWt - NSSS power)	396,400	589.2	2,250
ATWS	LOFTRAN	N/A	N/A	100 (3,628 MWt - NSSS power)	382,800	589.2	2,250

Notes:

1. Below the first mixing vane grid.
2. Above the first mixing vane grid.
3. Flow from two loops = 0.46 * TDF.
4. The LOFTRAN portion of the analysis was generic; the DNB evaluation performed with VIPRE utilized the plant-specific values presented.

Table 2.1-7 Non-LOCA Transients Evaluated or Analyzed[3]			
Transient	**Report Section**	**FSAR Section**	**Notes**
Decrease in Feedwater Temperature	2.1.1	15.1.1	1
Increase in Feedwater Flow	2.1.1	15.1.2	1
Excessive Increase in Secondary Steam Flow	2.1.1	15.1.3	2
Inadvertent Opening of a Steam Generator Relief or Safety Valve	2.1.1	15.1.4	2
Rupture of a Steam Pipe – Zero Power Core Response	2.2.2	15.1.5	1
Rupture of a Steam Pipe – Full Power Core Response	2.2.2	15.1.5	1
Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow	2.3.1	15.2.1	4
Loss of External Electrical Load	2.3.1	15.2.2	2
Turbine Trip	2.3.1	15.2.3	1
Inadvertent Closure of Main Steam Isolation Valves	2.3.1	15.2.4	2
Loss of Condenser Vacuum and Other Events Resulting in Turbine Trip	2.3.1	15.2.5	2
Loss of Nonemergency AC Power to the Station Auxiliaries	2.3.2	15.2.6	1
Loss of Normal Feedwater	2.3.3	15.2.7	1
Feedwater System Pipe Break	2.3.4	15.2.8	1
Partial Loss of Forced Reactor Coolant Flow	2.4.1	15.3.1	1
Complete Loss of Forced Reactor Coolant Flow	2.4.1	15.3.2	1
Locked Rotor/Shaft Break	2.4.2	15.3.3, 15.3.4	1
Uncontrolled RCCA Withdrawal from a Subcritical or Low Power Condition	2.5.1	15.4.1	1
Uncontrolled RCCA Withdrawal at Power	2.5.2	15.4.2	1
RCCA Misalignment (Dropped Rod)	2.5.3	15.4.3	1
Startup of an Inactive Reactor Coolant Pump at an Incorrect Temperature	2.5.4	15.4.4	2
A Malfunction or Failure of the Flow Controller in a BWR Loop that Results in an Increased Reactor Coolant Flow Rate	N/A	15.4.5	N/A
CVCS System Malfunction (Boron Dilution)	2.5.5	15.4.6	1
Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position	N/A	15.4.7	N/A

Table 2.1-7 (cont.) Non-LOCA Transients Evaluated or Analyzed[3]			
Transient	**Report Section**	**FSAR Section**	**Notes**
Spectrum of RCCA Ejection Accidents	2.5.6	15.4.8	1
Inadvertent Operation of the Emergency Core Cooling System During Power Operation	2.6	15.5.1	1
Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory	N/A	15.5.2	2
A Number of BWR Transients	N/A	15.5.3	N/A
Inadvertent Opening of a Pressurizer Safety or Relief Valve	2.6.1	15.6.1	1
ATWS	2.8	15.8	1

Notes:

1. Complete analysis.
2. Evaluation.
3. All analyses and evaluations cover Units 1 and 2.
4. There are no steam pressure regulators at CPNPP whose failure or malfunction could cause a steam flow transient (FSAR Section 15.2.1).

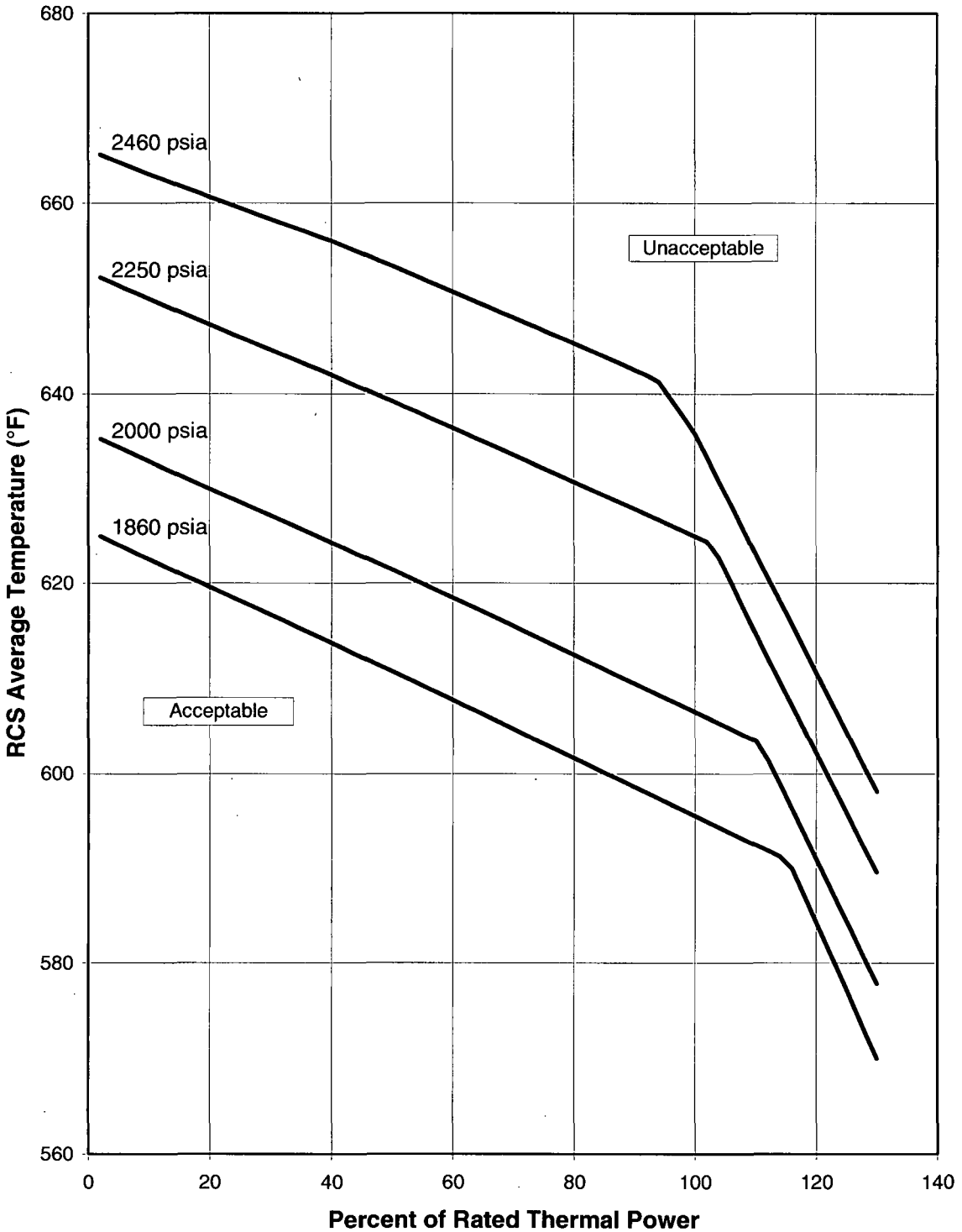


Figure 2.1-1 Reactor Core Safety Limits

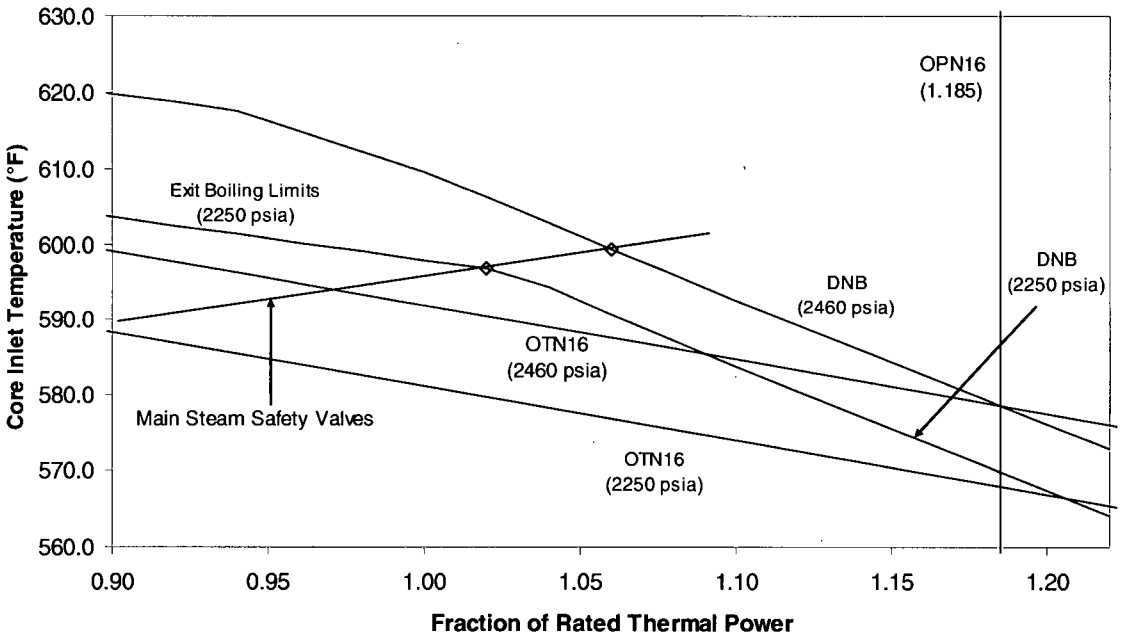


Figure 2.1-2 Illustration of OTN-16 and OPN-16 Protection

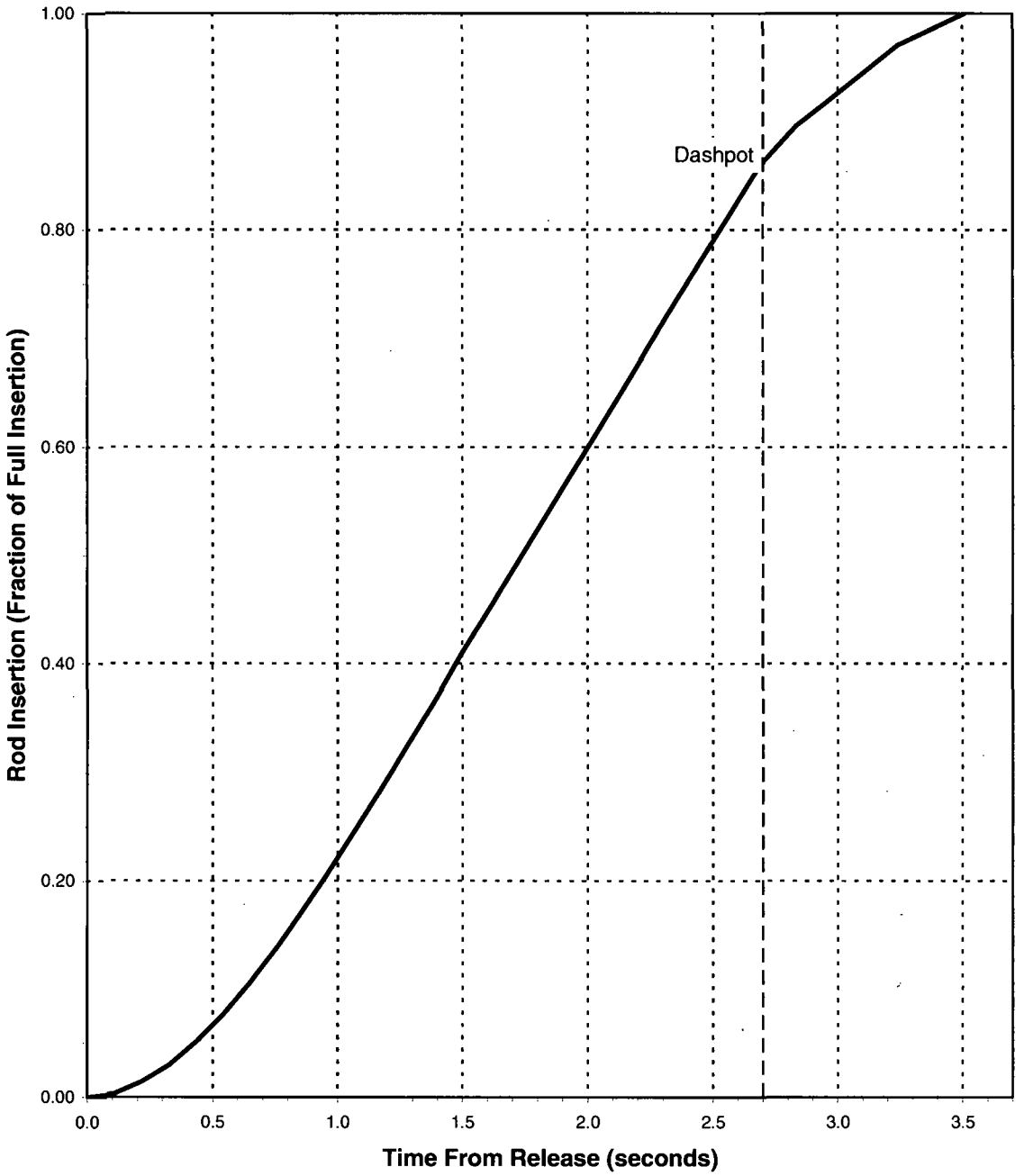


Figure 2.1-3 Fractional Rod Insertion Versus Time from Release

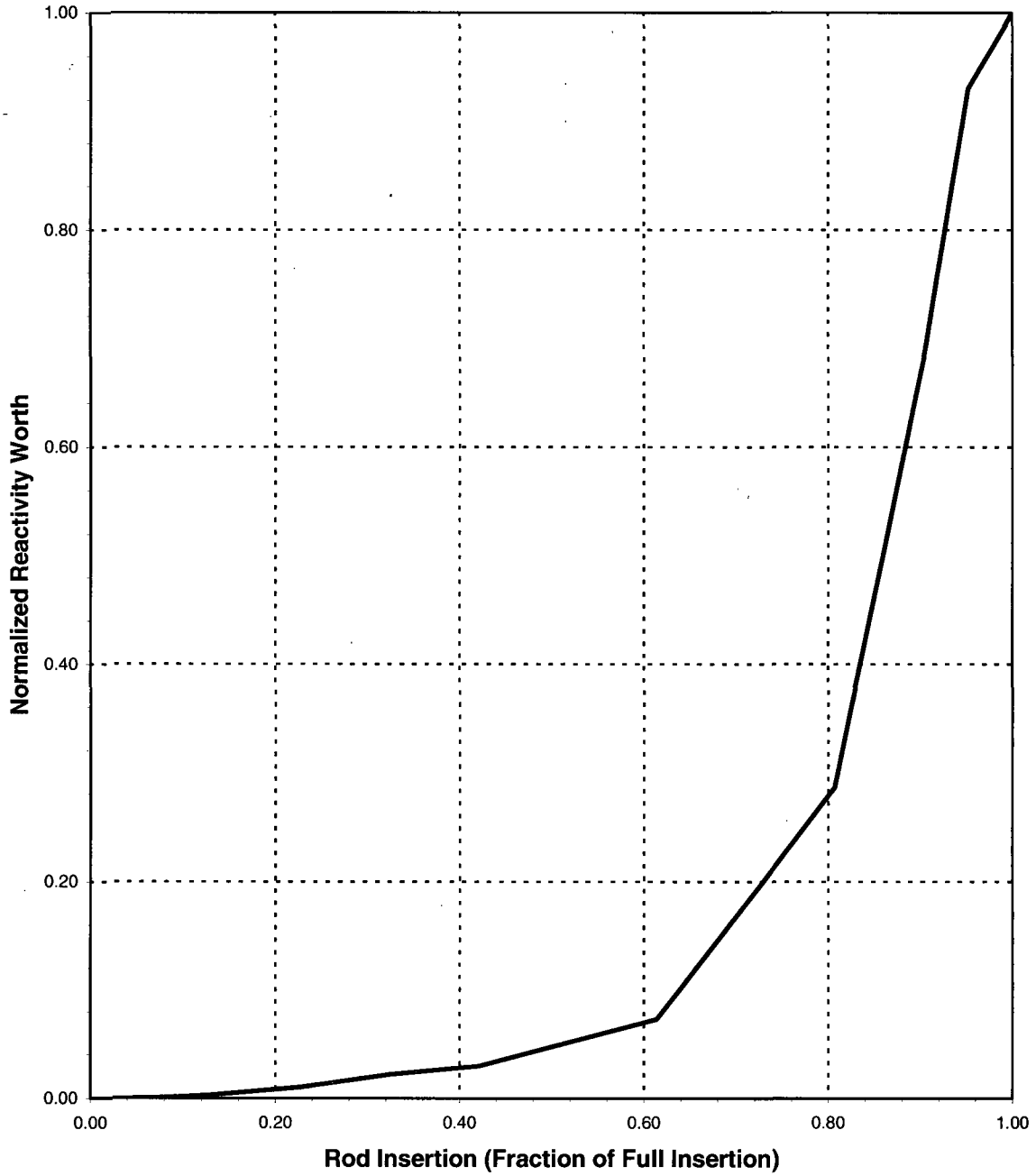


Figure 2.1-4 Normalized RCCA Reactivity Worth Versus Fractional Rod Insertion

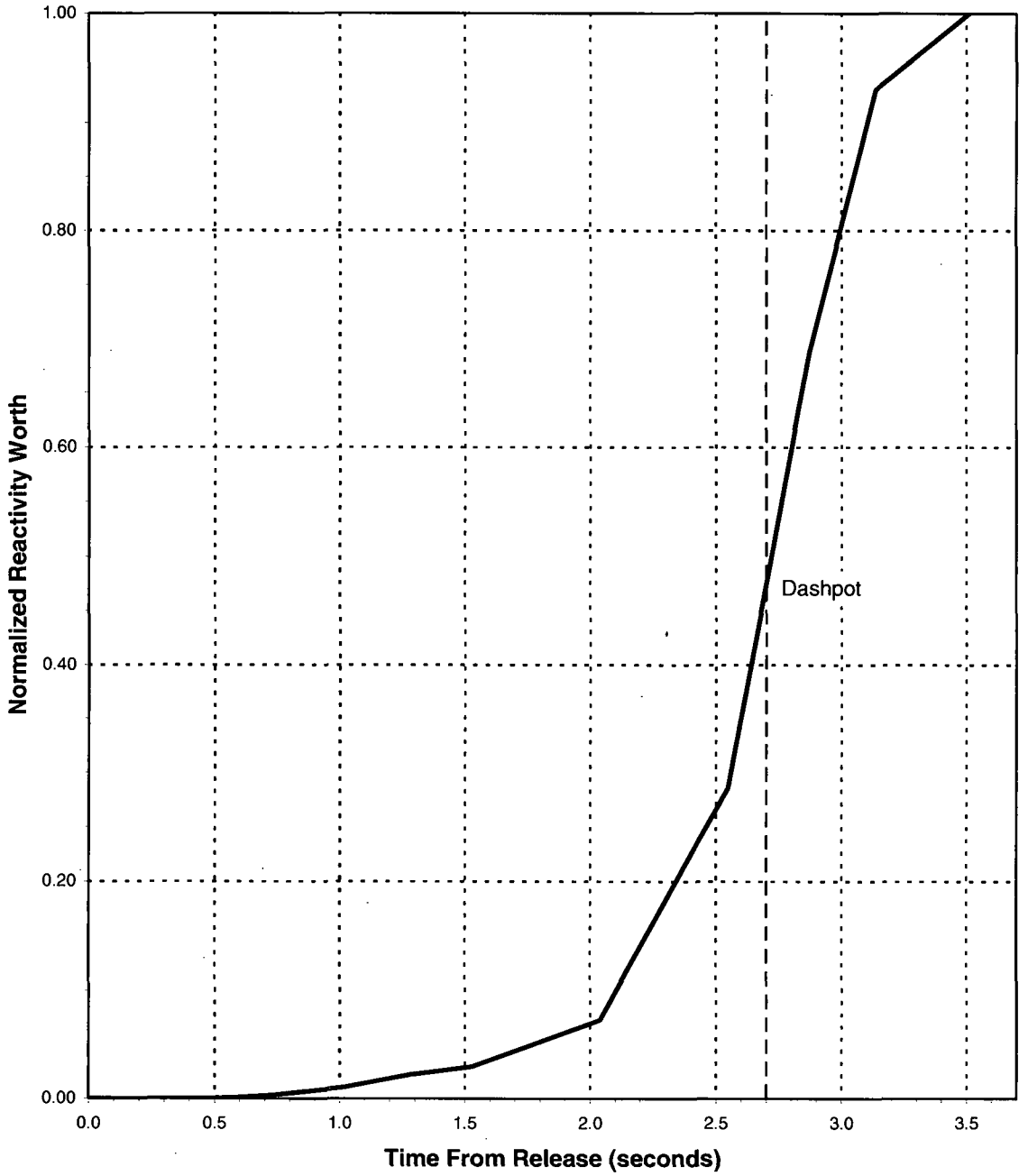


Figure 2.1-5 Normalized RCCA Reactivity Worth Versus Time from Release

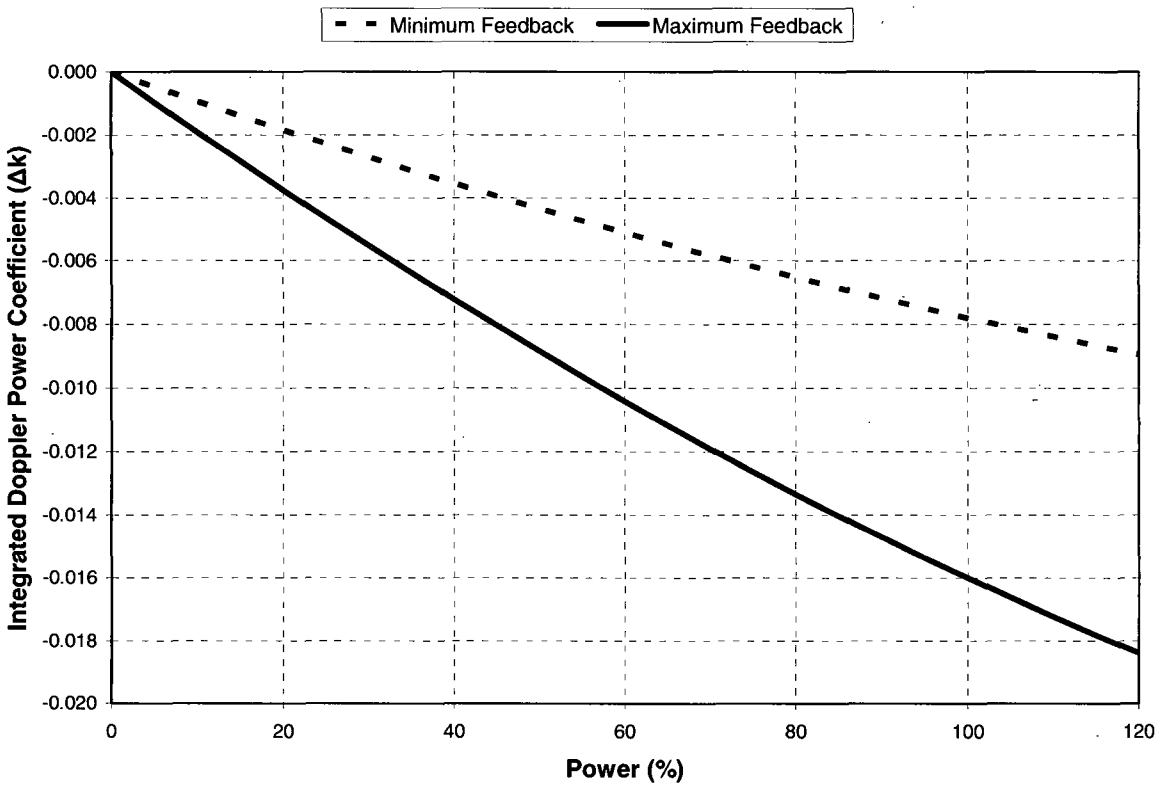


Figure 2.1-6 Integrated DPC Used in Non-LOCA Transient Analyses

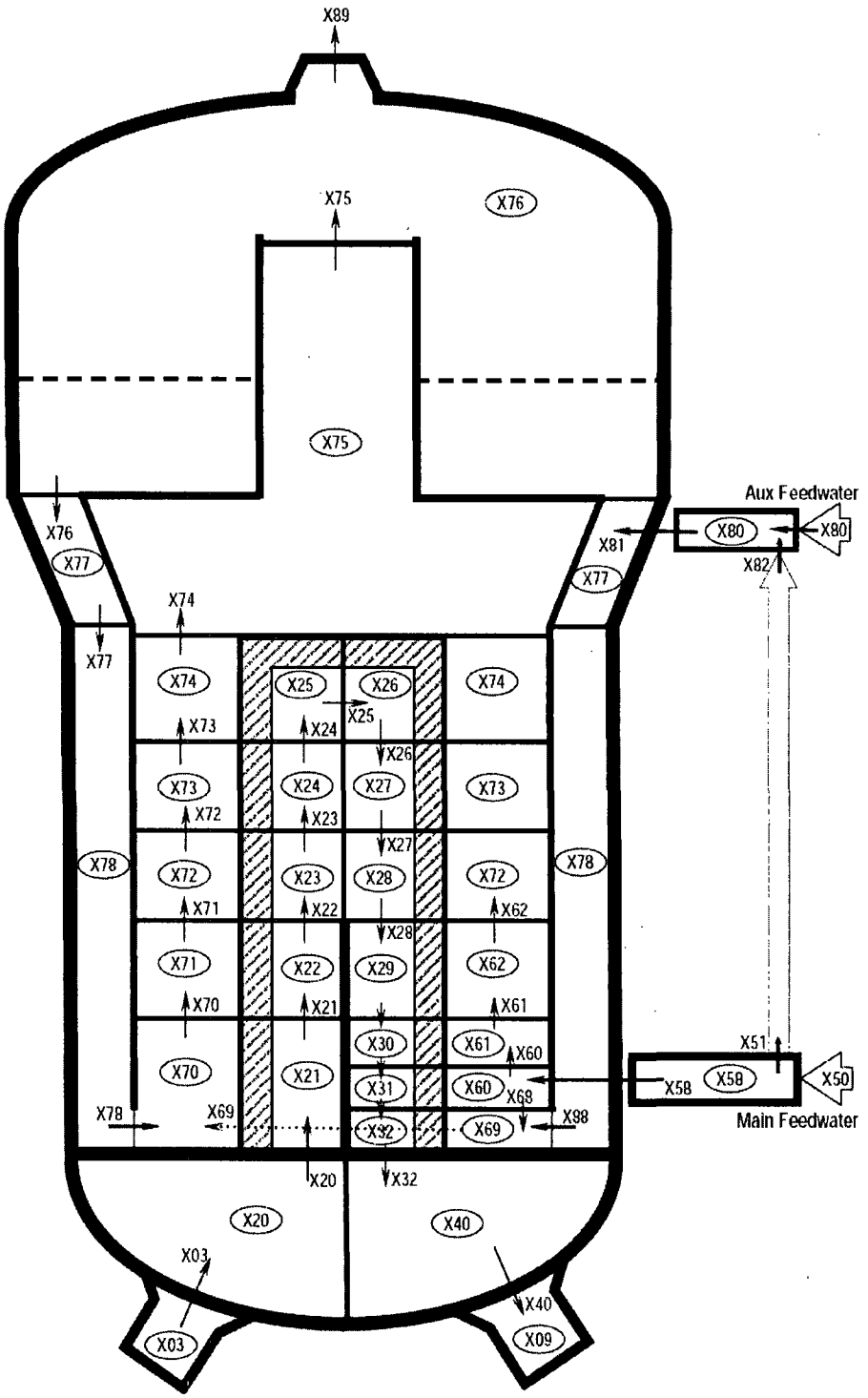


Figure 2.1-7 RETRAN Nodalization Diagram for Model D-5 Steam Generator

2.2 INCREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

2.2.1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

2.2.1.1 Technical Evaluation

2.2.1.1.1 Decrease in Feedwater Temperature

2.2.1.1.1.1 Introduction

Opening of a low-pressure heater bypass valve, tripping of the heater drain pumps, and isolating all high-pressure extraction steam causes a reduction in feedwater temperature that increases the thermal load on the primary system. For this event, there is a sudden reduction in feedwater temperature into the steam generators.

At power, the increased subcooling caused by the reduced feedwater temperature creates a greater load demand on the RCS. With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in RCS temperature, and thus a reactivity insertion due to the effects of the negative moderator temperature coefficient of reactivity. However, since the rate of energy change is reduced as the load and feedwater flow decrease, the no-load transient is less severe than the full power case.

Depending on the magnitude of the temperature reduction and the operation of the automatic rod control system, the net effect on the RCS can be similar to the effect of increasing secondary steam flow; that is, the reactor will reach a new equilibrium condition at a power level corresponding to the new temperature difference across the secondary-side of the steam generator. For large feedwater temperature reductions, the overpower N-16 reactor trip function will prevent a power increase that could lead to a DNBR that is lower than the safety analysis limit value.

2.2.1.1.1.2 Input Parameters, Assumptions and Acceptance Criteria

The decrease in feedwater temperature event was analyzed to confirm that the minimum DNBR and fuel centerline temperature design bases are met. The feedwater temperature reduction analysis was performed with the following assumptions to bound feedwater temperature reductions greater than 70°F:

- The RTDP (Reference 1) was used for the cases initiated from full power. The initial reactor power, RCS pressure and RCS temperature were assumed to be at the nominal values consistent with steady-state full-power operation. MMF was also modeled. Uncertainties for these initial conditions were accounted for in the DNBR safety analysis limit as described in Reference 1.

- The analyses were performed at the uprated NSSS power of 3,628 MWt.

- The analyses model CPNPP Unit 1 steam generators (Westinghouse Model Δ76). This is applicable since the CPNPP Units 1 and 2 primary-side models are not significantly different and because of the larger heat transfer area associated with the Model Δ76 steam generators. A larger heat transfer area is conservative with respect to the decrease in feedwater temperature transient.

- A conservative feedwater temperature reduction of 246°F was analyzed for the nominal high and nominal low feedwater temperatures. The temperature reduction was modeled as a step decrease from the nominal high and low full-power values of 450.3° and 390.0°F, respectively.

- The heat capacities of the RCS and steam generator thick metal were not considered, thereby maximizing the potential temperature reduction of the reactor coolant.

- The overpower N-16 reactor trip function was assumed to be available for event mitigation, as required. Depending on the magnitude of the feedwater temperature reduction and the availability of the rod control system, if core power increases, the reactor may reach a new equilibrium condition and not require actuation of the RTS.

- Both manual and automatic rod control cases were considered.

- An initial water level of nominal-minus-uncertainty was modeled for all four steam generators.

- Pressurizer sprays and power-operated relief valves (PORVs) were modeled to reduce RCS pressure, resulting in a conservative evaluation of the margin to the DNBR safety analysis limit.

Based on its frequency of occurrence, the decrease in feedwater temperature event is considered to be a Condition II event as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. As such, the applicable acceptance criteria for this incident are:

- Pressures in the RCS and MSS should be maintained below 110 percent of the respective design pressures.

- Fuel cladding integrity is maintained by ensuring that the minimum DNBR remains greater than the 95/95 DNBR safety analysis limit in the limiting fuel rods and that the centerline temperature of the fuel rods with the peak linear heat rate (kW/ft) does not exceed the UO_2 melting temperature. Fuel melting is precluded by ensuring that the maximum transient core average thermal power does not exceed a value that would result in exceeding the kW/ft value corresponding to fuel centerline melting at the core hot spot.

- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently. Demonstrating that the pressurizer does not become water-solid ensures a more serious plant condition is not generated. Since this event results in a cooldown of the RCS, the reactor coolant experiences a reduction in volume, and therefore pressurizer filling is not a concern.

2.2.1.1.1.3 Description of Analyses and Evaluation

The sudden decrease in feedwater temperature transient was analyzed using the RETRAN computer code (Reference 2). This code simulates a multi-loop RCS, core neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray and heaters, steam generators and MSSVs. The code computes pertinent plant variables including temperatures, pressures, and power level.

A decrease in feedwater temperature can be caused by an accidental opening of a low-pressure feedwater heater bypass valve or a load reduction. Evaluations of CPNPP plant transients concluded that a bypass of a low-pressure feedwater heater leads to an immediate consequential isolation of the other feedwater heaters, thereby resulting in a maximum feedwater temperature decrease of 246°F. It has been determined that the excessive increase in steam flow event (a step-load increase of 10 percent from full load), which is discussed in subsection 2.2.1.1.3, is equivalent to a 70°F reduction in the feedwater temperature. Therefore, the consequences of a feedwater temperature reduction of up to 70°F are equivalent or bounded by the consequences of a 10-percent load increase from full power. The 246°F feedwater temperature reduction analysis was performed to bound temperature reductions greater than 70°F. Table 2.2.1-1 summarizes the analyzed cases.

2.2.1.1.1.4 Decrease in Feedwater Temperature Results

The sudden decrease in feedwater temperature transient was analyzed for CPNPP for the TM and SPU programs. Manual and automatic rod control, as well as high and low nominal feedwater temperatures were considered. The most limiting case was the Unit 1 temperature reduction from the nominal high feedwater temperature with manual rod control. This case resulted in the largest reactivity feedback and produced the lowest DNBR. The reactor was tripped by the overpower N-16 signal. If the reactor was in automatic rod control mode, the control rods would be inserted at the maximum rate and the resulting transient would not be as limiting in terms of the minimum DNBR as the case with manual rod control. Table 2.2.1-2 shows the time sequence of events for the decrease in feedwater temperature transient and Table 2.2.1-3 provides the results. Figures 2.2.1-1 through 2.2.1-4 show transient responses of various system parameters for the limiting (Unit 1) decrease in feedwater temperature case.

2.2.1.1.2 Increase in Feedwater Flow

2.2.1.1.2.1 Introduction

Addition of excessive feedwater will cause an increase in core power by decreasing reactor coolant temperature. An example of excessive feedwater flow would be a full opening of a main feedwater flow control valve (FCV) due to a feedwater control system malfunction or an operator error. At power, this excess flow causes a greater load demand on the RCS due to increased subcooling in the steam generator. With the plant at no-load conditions, the addition of excess feedwater may cause a decrease in RCS temperature, and thus a reactivity insertion due to the effects of the negative moderator temperature coefficient of reactivity.

The transient is analyzed using the RETRAN (Reference 2) and VIPRE codes. RETRAN computes pertinent plant variables including temperatures, pressures, and power level. VIPRE is used to verify that the DNBR remains above the DNBR safety analysis limit.

2.2.1.1.2.2 Input Parameters, Assumptions and Acceptance Criteria

The feedwater flow increase event is analyzed to confirm that the minimum DNBR remains greater than the safety analysis limit. Therefore, the analysis uses the following key modeling assumptions:

- The RTDP (Reference 1) was used for the cases initiated from full power. The initial reactor power, RCS pressure, and RCS temperature were assumed to be at the nominal values consistent with steady-state full-power operation. MMF was also modeled. Uncertainties for these initial conditions were accounted for in the DNBR safety analysis limit as described in Reference 1.

- The analyses were performed at the uprated NSSS power of 3,628 MWt.

- The analyses model CPNPP Unit 1 steam generators (Westinghouse Model Δ76). This is applicable since the CPNPP Units 1 and 2 primary-side models are not significantly different and because of the larger heat transfer area associated with the Model Δ76 steam generators. A larger heat transfer area is conservative with respect to the increase in feedwater flow transient.

- For the single-loop feedwater flow increase event at full-power, one feedwater control valve was assumed to malfunction, resulting in a step increase to 207.5 percent of the nominal full-power feedwater flow to one steam generator.

- For the multiple-loop feedwater flow increase event at full-power, two feedwater control valves were assumed to malfunction, resulting in a step increase to 168.2 percent of the nominal full-power feedwater flow to two steam generators.

- The increase in feedwater flow rate results in a decrease in the feedwater temperature (enthalpy) due to the reduced efficiency of the feedwater heaters. For full-power, a

25 Btu/lbm decrease in the feedwater enthalpy was conservatively assumed to occur coincident with the feedwater flow increase.

- For the single-loop feedwater flow increase event at no-load conditions, one feedwater control valve was assumed to malfunction, resulting in a step increase to 254.3 percent of the full-power nominal flow to one steam generator.

- For the multiple-loop feedwater flow increase event at no-load conditions, two feedwater control valves were assumed to malfunction, resulting in a steam increase to 158.7 percent of the full-power nominal flow to two steam generators.

- For the cases initiated at zero power, initial reactor power, RCS pressure, and RCS temperature were assumed to be at levels corresponding to no-load conditions. Thermal design flow was also modeled. In addition, the reactor was assumed to be at the minimum shutdown margin condition of 1.3-percent $\Delta k/k$.

- For the full-power cases, an initial water level corresponding to the nominal level minus uncertainties was modeled in all four steam generators, while an initial water level corresponding to the nominal level was modeled for the zero-power cases.

- Pressurizer sprays and PORVs were modeled to reduce RCS pressure, resulting in a conservative evaluation of the margin to the DNBR safety analysis limit.

- The full-power cases were analyzed with manual and automatic rod control.

- For cases at zero-power conditions, the initial feedwater temperature was assumed to be 70°F.

- The heat capacities of the RCS and steam generator thick metal were not considered, thereby maximizing the potential temperature reduction of the reactor coolant.

- Reactor trip on turbine trip was assumed operable in the feedwater flow increase analyses. However, this trip is not required for core protection. Assuming reactor trip on turbine trip to be operable is consistent with the fact that an increase in feedwater flow is a cooldown transient. If this trip were not assumed, then following turbine trip and feedwater isolation on high-high steam generator level, the transient would resemble a loss of normal feedwater, an RCS heatup event, with level dropping until a reactor trip occurs on a low-low steam generator level.

Based on its frequency of occurrence, the increase in feedwater flow event is considered to be a Condition II event as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. As such, the applicable acceptance criteria for this incident are:

- Pressure in the RCS and MSS should be maintained below 110 percent of the design pressures.

- Fuel cladding integrity is maintained by ensuring that the minimum DNBR remains greater than the 95/95 DNBR safety analysis limit in the limiting fuel rods and that the centerline temperature of the fuel rods with the peak linear heat rate (kW/ft) does not exceed the UO_2 melting temperature. Fuel melting is precluded by ensuring that the maximum transient core average thermal power does not exceed a value that would result in exceeding the kW/ft value corresponding to fuel centerline melting at the core hot spot.

- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently. Demonstrating that the pressurizer does not become water-solid ensures a more serious plant condition is not generated. Since this event results in a cooldown of the RCS, the reactor coolant experiences a reduction in volume, and therefore pressurizer filling is not a concern.

The primary acceptance criterion used in this analysis is that the minimum DNBR remains greater than the safety analysis limit. The event does not challenge the primary- or secondary-side pressure limits since the increased heat removal results in an RCS cooldown.

2.2.1.1.2.3 Description of Analyses and Evaluations

The excessive heat removal due to a feedwater flow increase transient was analyzed with the RETRAN computer code (Reference 2). This code simulates a multi-loop RCS, core neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray and heaters, steam generators, and MSSVs. The code computes pertinent plant variables including temperatures, pressures, and power level.

The excessive feedwater flow event assumes an accidental opening of one or more feedwater control valves with the reactor at full- and zero-power conditions, and with automatic and manual rod control, where applicable. Both the automatic and manual rod control cases assume a conservatively large moderator density coefficient characteristic of end-of-life (EOL) conditions. Table 2.2.1-1 summarizes the analyzed cases.

2.2.1.1.2.4 Increase in Feedwater Flow Results

A comparison of the multiple-loop (failure of two feedwater control valves) and single-loop (failure of one feedwater control valve) cases demonstrates that the Unit 1 single-loop failure case with manual rod control is more limiting. The single-loop feedwater flow increase case with manual rod control produces the largest reactivity feedback, and therefore results in the greatest power increase. A turbine trip, which results in a reactor trip, is actuated when the steam generator water level in the affected steam generator(s) reaches the high-high water level setpoint.

The cases initiated at hot zero-power conditions are less limiting than the hot zero-power steam line break analysis. Therefore, the results of this case are not presented.

For all excessive feedwater flow cases, continuous addition of cold feedwater is prevented by automatic closure of all feedwater control and isolation valves, closure of all feedwater bypass valves, a trip of the feedwater pumps and a turbine trip on high-high steam generator water level. In addition, the feedwater pump discharge isolation valves will automatically close upon receipt of the feedwater pump trip signal.

Following turbine trip, the reactor will automatically be tripped, either directly due to the turbine trip or due to one of the reactor trip signals discussed in subsection 2.3.1 (Loss of External Electrical Load and/or Turbine Trip). With the rod control system in automatic mode, the control rods would be inserted at the maximum rate following the turbine trip, and the resulting transient would not be limiting in terms of peak RCS pressure.

Table 2.2.1-2 shows the time sequence of events for the limiting (Unit 1) single-loop, full-power feedwater flow increase transient with manual rod control and Table 2.2.1-3 provides the results. Figures 2.2.1-1 through 2.2.1-4 show the transient responses of various system parameters for the limiting (Unit 1) single-loop feedwater flow increase initiated from full-power conditions with manual rod control.

2.2.1.1.2.5 Conclusions

The decrease in feedwater temperature transient due to the opening of a condensate bypass valve diverting flow around the low-pressure feedwater heaters shows that the DNBRs encountered are above the safety analysis limit value and that the core average thermal power does not exceed a value that results in exceeding the kW/ft limit corresponding to fuel centerline melting at the core hot spot. Therefore, no fuel damage is predicted and all applicable acceptance criteria are satisfied for CPNPP Units 1 and 2.

For the excessive increase in feedwater flow event, the results show that the DNBRs encountered are above the safety analysis limit value and that the core average thermal power does not exceed a value that results in exceeding the kW/ft limit corresponding to fuel centerline melting at the core hot spot. Therefore, no fuel damage is predicted and all applicable acceptance criteria are satisfied for CPNPP Units 1 and 2.

2.2.1.1.2.6 References

1. WCAP-11397, "Revised Thermal Design Procedure," April 1989.

2. WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," May 1999.

2.2.1.1.3 Increase in Steam Flow

2.2.1.1.3.1 Introduction

An excessive load increase incident is defined as a rapid increase in steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The

reactor control system is designed to accommodate a 10-percent step-load increase or a 5-percent-per-minute ramp-load increase in the range of 15- to 100-percent of full power. Any loading rate in excess of these values may cause a reactor trip actuated by the reactor trip system. If the load increase exceeds the capability of the reactor control system, the transient would be terminated in sufficient time to prevent the DNB design basis from being violated. This incident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam bypass control system, or turbine speed control.

During power operation, steam dump to the condenser is controlled by reactor coolant condition signals, such as a high reactor coolant temperature indicates a need for steam dump. A single controller malfunction will not cause steam dump valves to open; an interlock is provided which blocks the opening of the valves unless a large turbine load decrease or a turbine trip has occurred. For all cases, the plant rapidly reaches a stabilized condition at a higher power level. Normal plant operating procedures would be followed to reduce power. The excessive load increase incident is an overpower transient for which the fuel temperatures will rise. Reactor trip may not occur for some cases, and the plant will reach a new equilibrium condition at a higher power level corresponding to the increase in steam flow. Protection against an excessive load increase incident, if necessary, is provided by the following reactor trip signals:

- Overpower N-16
- Overtemperature N-16
- Power range high neutron flux

2.2.1.1.3.2 Input Parameters, Assumptions, and Acceptance Criteria

An evaluation was performed to show that the DNB design basis is satisfied for the excessive load increase incident. Key aspects of the evaluation are provided as follows.

- The RTDP (Reference 1) was applied. Initial reactor power, RCS pressure, and RCS temperature were assumed to be at their nominal values, consistent with steady-state full-power operation. MMF was also assumed. Uncertainties in initial conditions were accounted for in the safety analysis DNBR limit value as described in Reference 1.

- The evaluation was performed for a step-load increase of 10-percent steam flow from 100-percent of core power.

- This event was evaluated for both automatic and manual rod control.

- The excessive load increase incident was evaluated for both minimum and maximum reactivity feedback conditions.

Based on its frequency of occurrence, the excessive load increase incident is considered to be a Condition II event as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. The following items summarize the acceptance criteria associated with this event:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the safety analysis limit value at any time during the transient.

- Pressures in the RCS and MSS should be maintained below 110 percent of the respective design pressures.

- The peak linear heat generation rate (expressed in kW/ft) should not exceed a value that would cause fuel centerline melt.

- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently.

2.2.1.1.3.3 Description of Analyses and Evaluations

Given the non-limiting nature of this event with respect to the safety analysis DNBR criterion, an explicit analysis was not performed. Instead, an evaluation of this event was performed. The evaluation process first involved the generation of plant-specific statepoints that are based on generic, conservative conditions that bound the conditions that are expected to occur following a 10-percent load increase incident. Each statepoint consists of post-incident conditions of core power, reactor vessel average temperature, and RCS pressure. The statepoints were compared to the conditions corresponding to operation at the safety analysis DNBR limit (core thermal limits) to ensure that the DNBR limit was not violated. The following three cases (statepoints) were examined in the evaluation:

- Reactor in manual rod control mode with minimum reactivity feedback
- Reactor in manual rod control mode with maximum reactivity feedback
- Reactor in automatic rod control mode (independent of the assumed reactivity feedback)

2.2.1.1.3.4 Results

The evaluation confirmed that for an excessive load increase incident at CPNPP Units 1 and 2, the minimum DNBR during the transient will not go below the safety analysis limit value, and the peak linear heat generation will not exceed the limit value, thus demonstrating that the applicable acceptance criteria for critical heat flux and fuel centerline melt are met. Following the initial load increase, the plant should reach a stabilized condition. With respect to peak pressures in the RCS and MSS, the excessive load increase incident is bounded by the loss-of-electrical-load/turbine-trip event because the loss-of-electrical-load/turbine-trip event results in a severe mismatch between the primary-side power and the secondary-side power. The analysis of the loss-of-electrical-load/turbine-trip event is described in subsection 2.3.1.

In addition, no adverse conditions are generated as a result of this event that would lead to a more serious plant condition without other faults occurring independently. All applicable acceptance criteria are therefore met for CPNPP Units 1 and 2.

2.2.1.1.3.5 References

1. WCAP-11397, "Revised Thermal Design Procedure," April 1989.

2.2.1.1.4 Inadvertent Opening of a Steam Generator Relief or Safety Valve

The inadvertent opening of a steam generator relief or safety valve event is more commonly referred to as a credible steam line break. It is always bounded by the analysis of the large steam line break (referred to as the hypothetical steam line break) presented in FSAR Section 15.1.5. The hypothetical steam line break is a Condition IV event that is analyzed to Condition II acceptance criteria. The credible steam line break is a Condition II event. Since the more severe Condition IV event is shown to meet the more restrictive Condition II acceptance criteria, it can be concluded that the credible steam line break event also meets the Condition II acceptance criteria. As such, no explicit analysis of the credible steam line break has been performed. The analyses documented in subsections 2.2.2.1.1 and 2.2.2.1.2 demonstrate that all applicable acceptance criteria are met for the hypothetical steam line break and, subsequently, all acceptance criteria are met for the credible steam line break.

2.2.1.2 Conclusions

The analyses of the excess heat removal events described above have been reviewed and it is concluded that the analyses have adequately accounted for operation of the plant at the proposed uprated power level and were performed using acceptable analytical models. It is further concluded that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the reactor coolant pressure boundary (RCPB) pressure limits will not be exceeded as a result of these events. Based on this, Luminant Power has concluded that the plant will continue to meet the requirements of General Design Criterions (GDCs) -10, -15, -20, and -26.

Table 2.2.1-1 Decrease in Feedwater Temperature Cases Analyzed			
Case	**Power Level**	**Initial Nominal Feedwater Temperature (°F)**	**Rod Control**
1	HFP	390.00	Manual
2	HFP	390.00	Automatic
3	HFP	450.30	Manual
4	HFP	450.30	Automatic

Table 2.2.1-2 Time Sequence of Events – Decrease in Feedwater Temperature (High Nominal Feedwater Temperature, HFP, Manual Rod Control)	
Event	**Time (Seconds)**
Sudden Step Decrease in Feedwater Temperature (Event Initiation)	0.01
Overpower N-16 Setpoint Reached	39.75
Reactor Trip (from Overpower N-16 setpoint)	41.75
Peak Core Thermal Power Occurs	42.10
Minimum DNBR Occurs	42.25
Turbine Trip (from Reactor Trip)	43.75
End of Run	51.75
Results	
Minimum DNBR	1.90
Peak Core Thermal Power	119.28%

Table 2.2.1-3 Results – Decrease in Feedwater Temperature (High Nominal Feedwater Temperature, HFP, Manual Rod Control)	
Event	**Time (Seconds)**
Minimum DNBR	1.90
Peak Core Thermal Power	118.5%

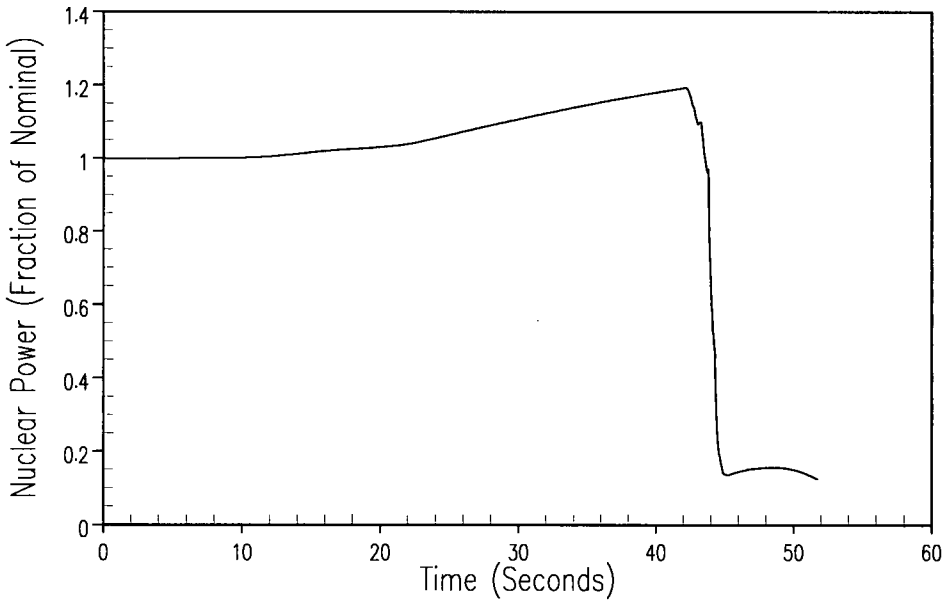
Table 2.2.1-4 Increase in Feedwater Flow Cases Analyzed				
Case	**Power Level**	**Failure**	**Affected Loop(s)**	**Rod Control**
1	HFP	FCV	Loop 1	Manual
2	HFP	FCV	Loop 1	Automatic
3	HFP	FCV	Loops 1 and 2	Manual
4	HFP	FCV	Loops 1 and 2	Automatic
5	HZP	FCV	Loop 1	Manual
6	HZP	FCV	Loops 1 and 2	Manual

Table 2.2.1-5 Time Sequence of Events – Increase in Feedwater Flow (HFP, Single-Loop, Manual Rod Control)	
Event	**Time (Seconds)**
One Feedwater Control Valve Fails Full-Open (Event Initiation)	0.01
Minimum DNBR Occurs	34.25
High-High Steam Generator Level Trip Setpoint Reached	41.94
Turbine Trip (from High-High Steam Generator Level Trip)	44.34
Reactor Trip (from Turbine Trip)	46.34
Feedwater Isolation Valves Close (from High-High Steam Generator Level Trip)	52.94(1)
End of Run	200.00

Note:

1. This includes a 0.1-second delay for valve closure.

Table 2.2.1-6 Results – Increase in Feedwater Flow (HFP, Single-Loop, Manual Rod Control)	
Event	**Time (Seconds)**
Minimum DNBR	2.10



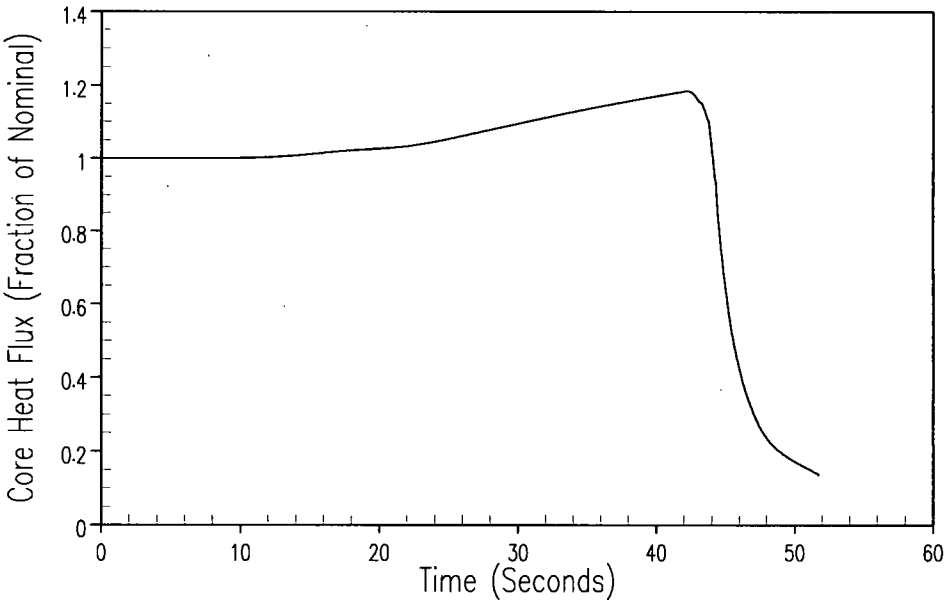
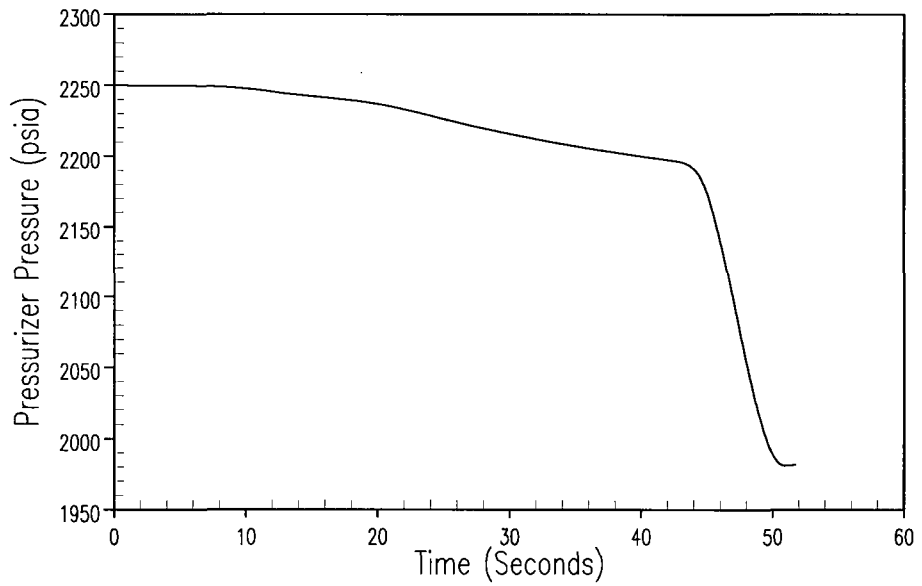


Figure 2.2.1-1 Decrease in Feedwater Temperature at Full Power – Manual Rod Control Nuclear Power and Core Heat Flux Versus Time



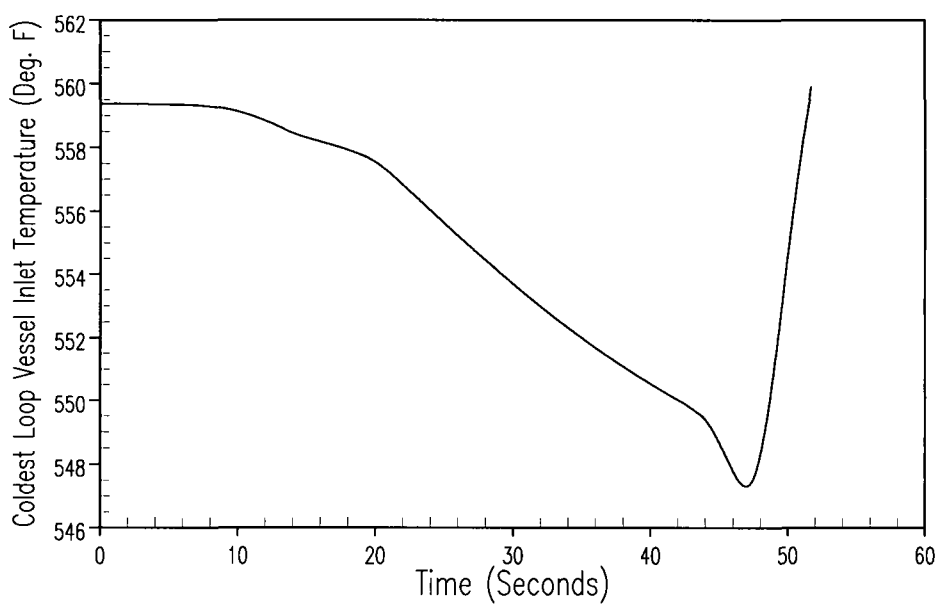
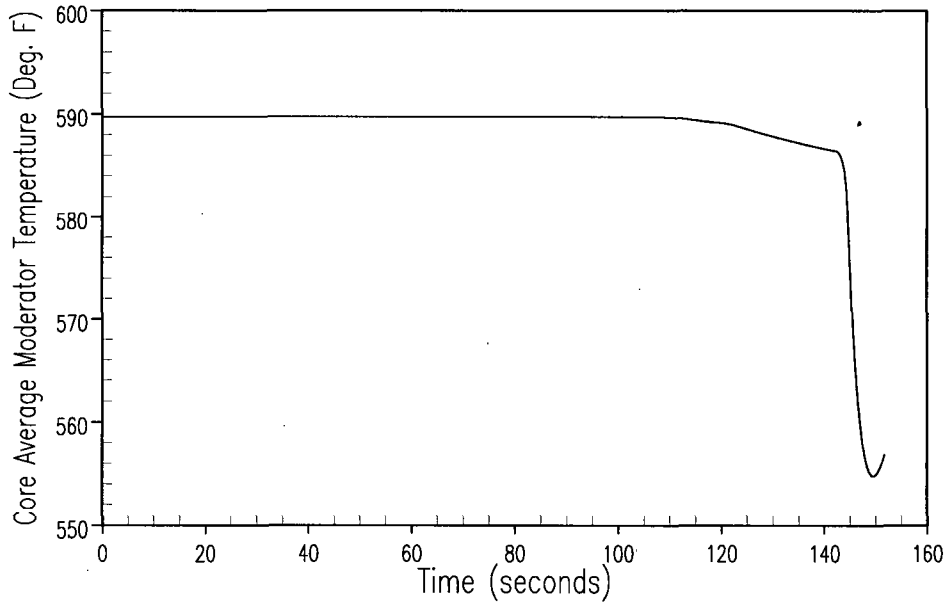


Figure 2.2.1-2 Decrease in Feedwater Temperature at Full Power – Manual Rod Control Pressurizer Pressure and Coldest Vessel Inlet Temperature Versus Time



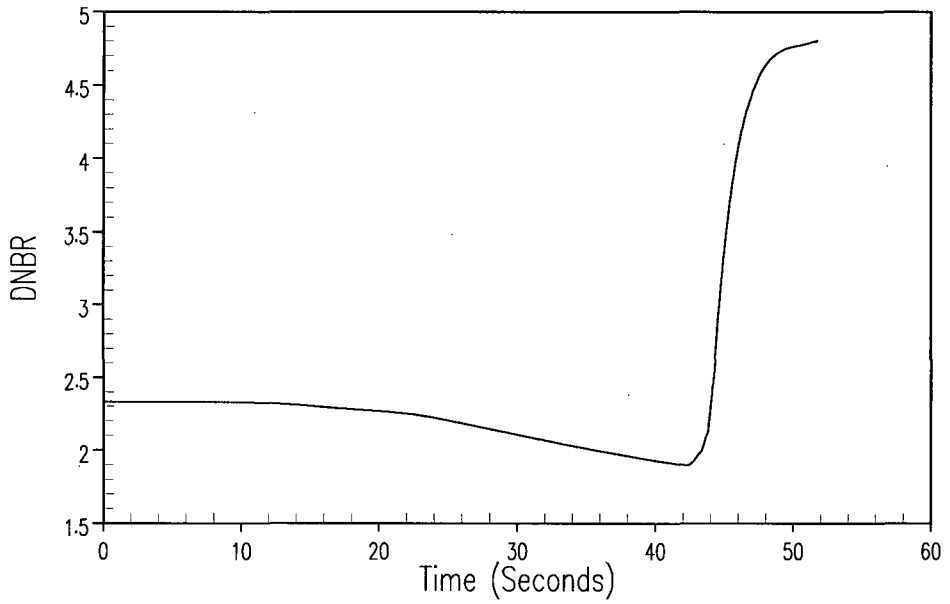
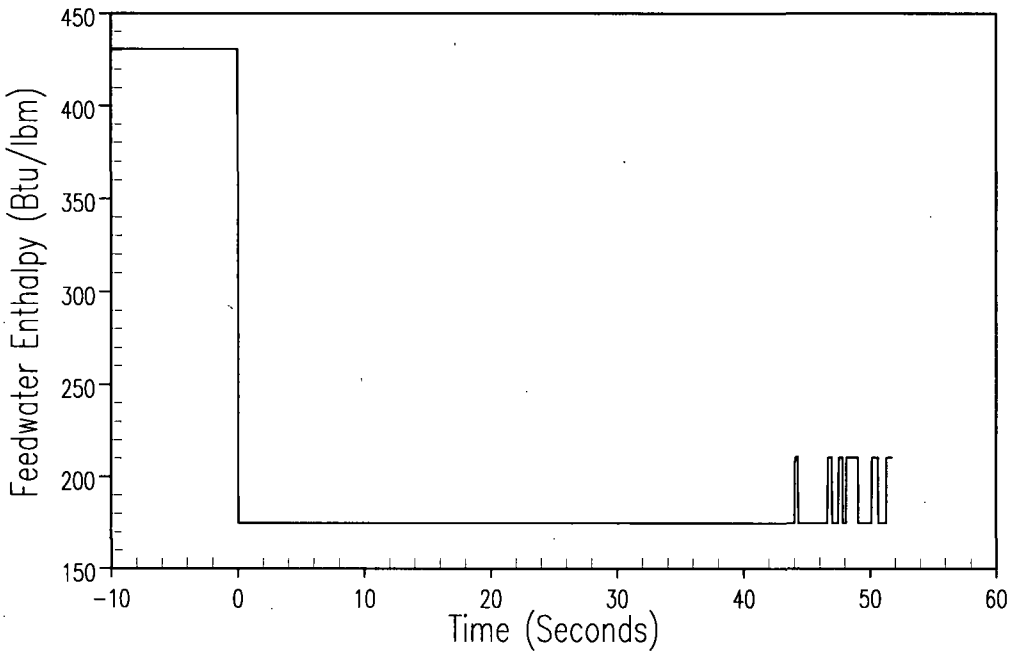
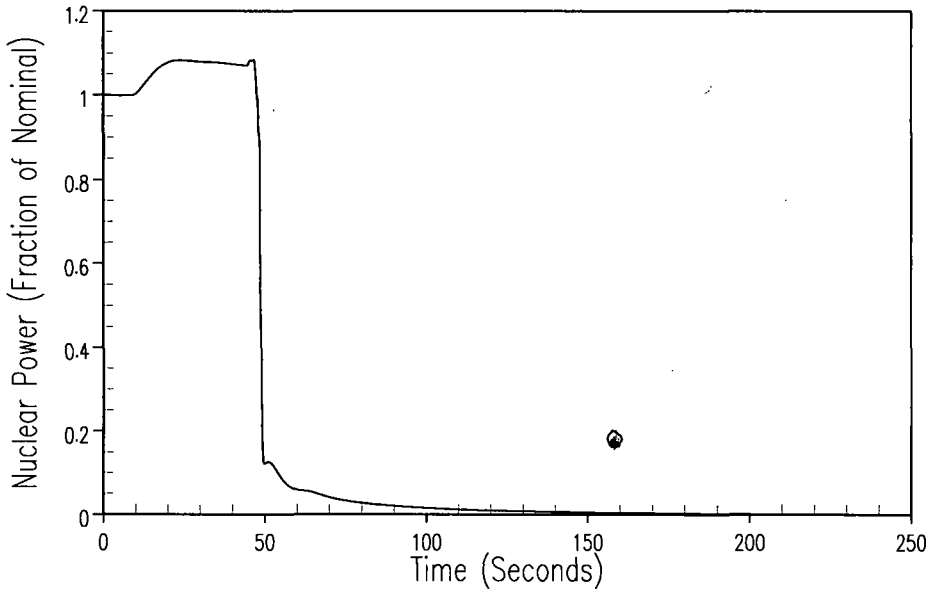


Figure 2.2.1-3 Decrease in Feedwater Temperature at Full Power – Manual Rod Control Core Average Moderator Temperature and DNBR Versus Time



(Note that the x-axis scale begins at -10 seconds so that the enthalpy step reduction at time zero is visible on the plot)

Figure 2.2.1-4 Decrease in Feedwater Temperature at Full Power – Manual Rod Control Feedwater Enthalpy Versus Time



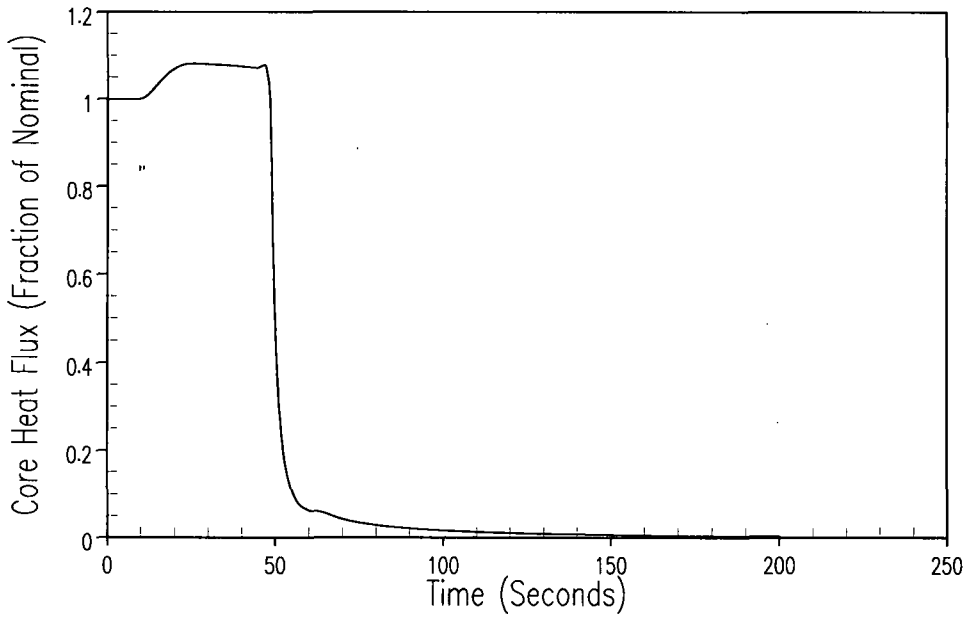


Figure 2.2.1-5 Increase in Feedwater Flow at Full Power – Manual Rod Control Nuclear Power and Core Heat Flux Versus Time

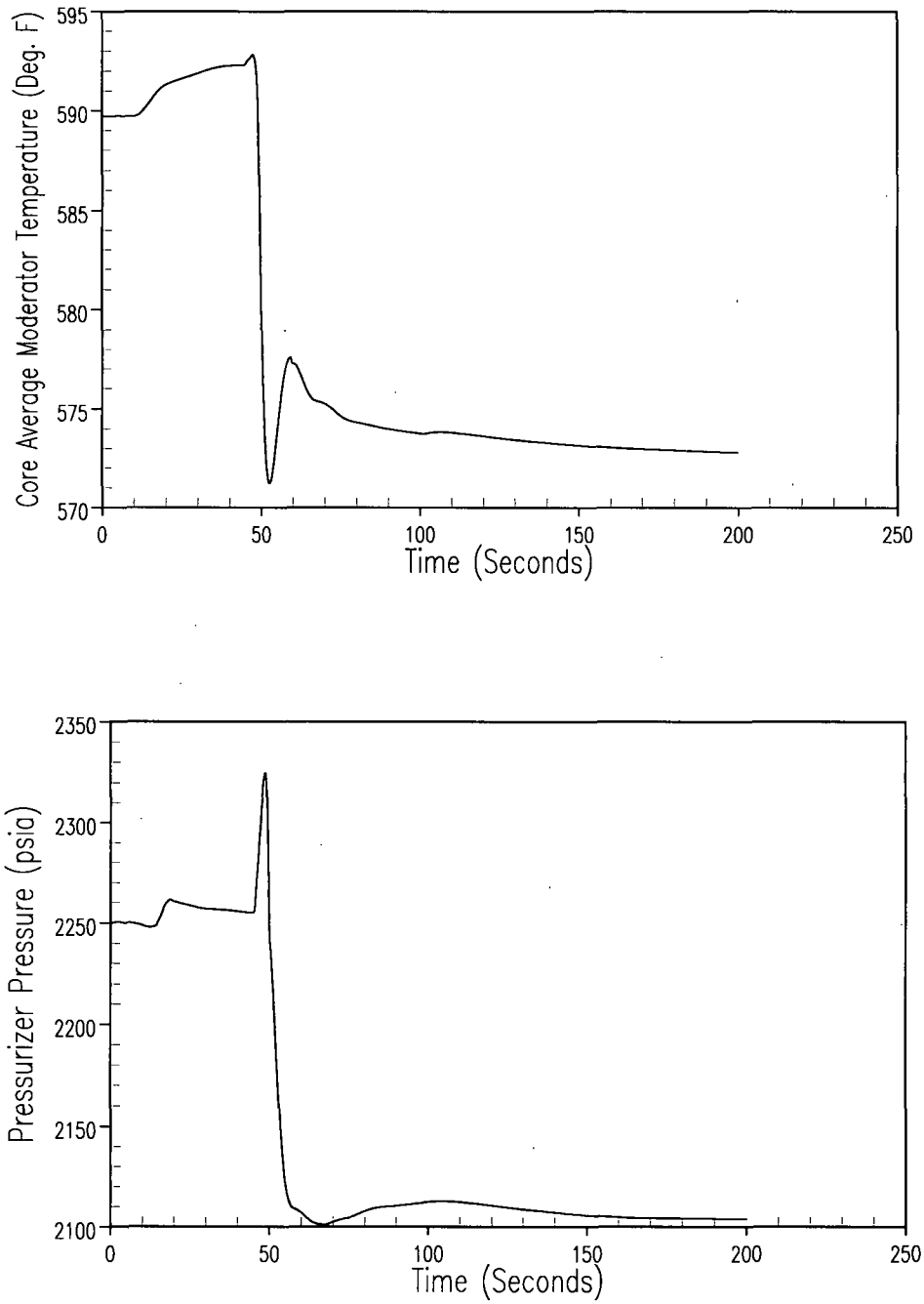


Figure 2.2.1-6 Increase in Feedwater Flow at Full Power – Manual Rod Control Core Average Moderator Temperature and Pressurizer Pressure Versus Time

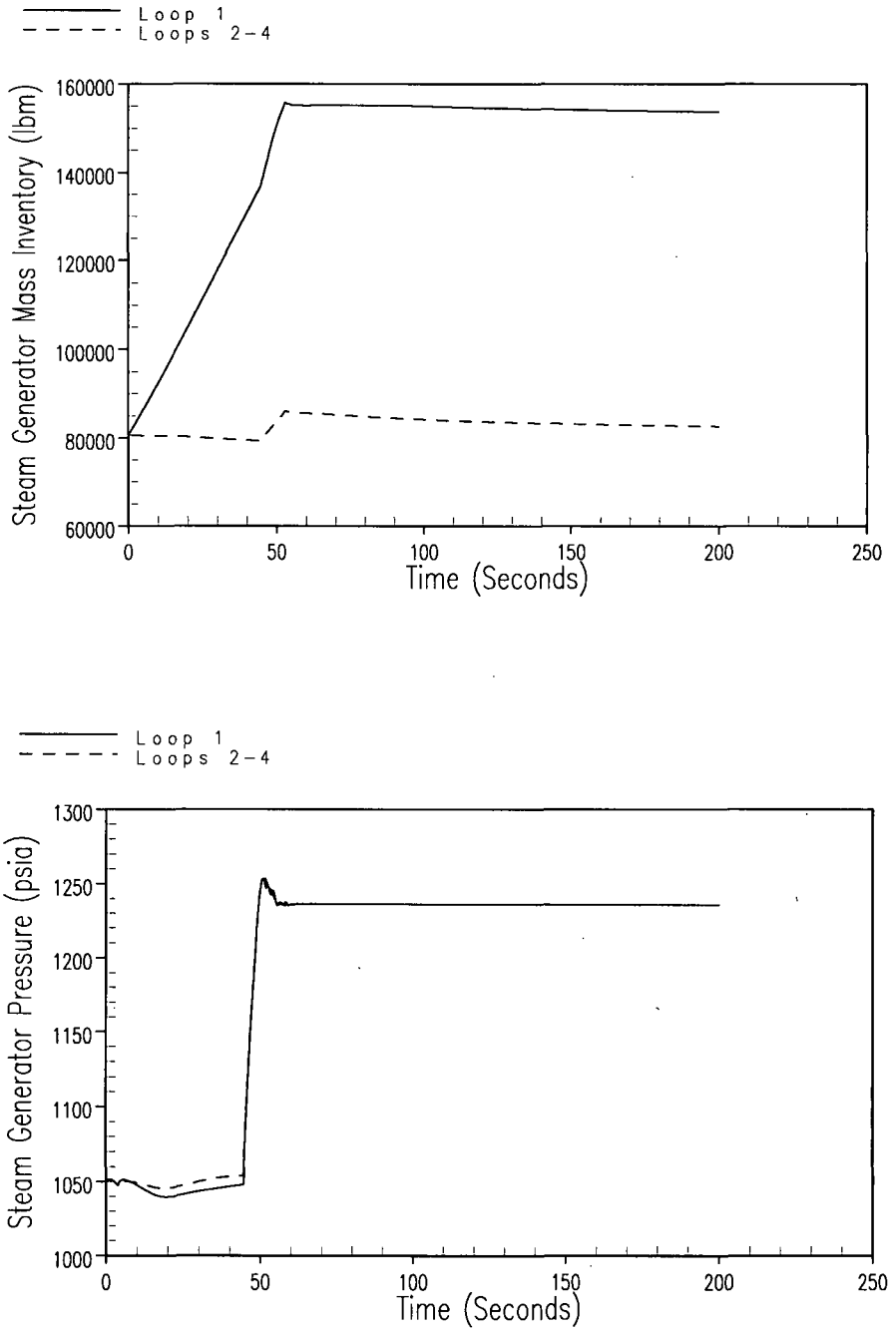


Figure 2.2.1-7 Increase in Feedwater Flow at Full Power – Manual Rod Control Steam Generator Mass Inventory and Steam Generator Pressure Versus Time

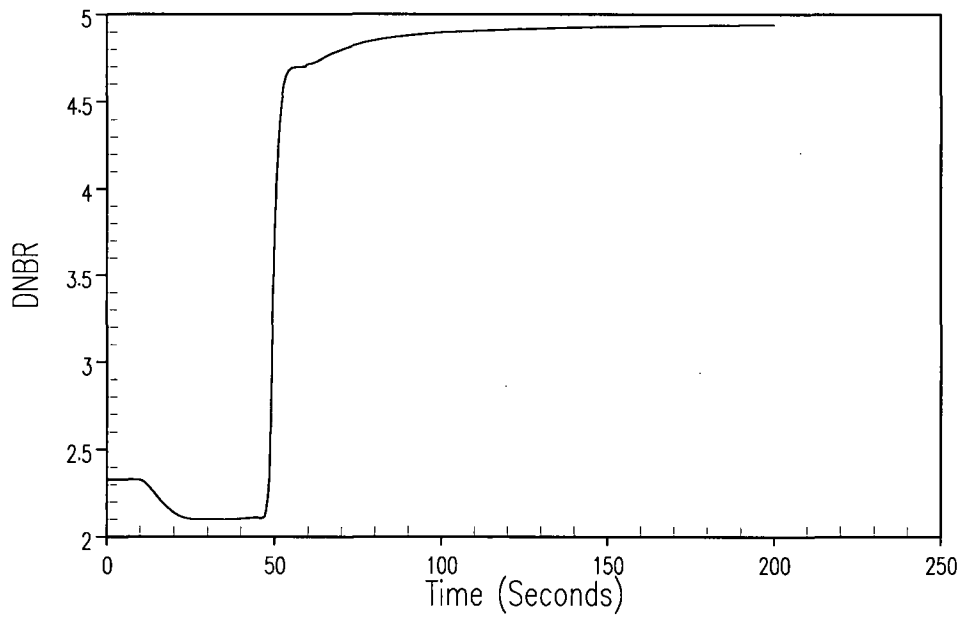


Figure 2.2.1-8 Increase in Feedwater Flow at Full Power – Manual Rod Control DNBR Versus Time

2.2.2 Steam System Piping Failures Inside and Outside Containment

2.2.2.1 Technical Evaluation

2.2.2.1.1 Steam System Piping Failure at Hot Zero Power

2.2.2.1.1.1 Introduction

The steam release arising from a major rupture of a main steam pipe will result in an initial increase in steam flow that decreases during the accident as the steam pressure falls. The increased energy removal from the RCS causes a reduction of reactor coolant temperature and pressure. In the presence of a negative MTC, the cooldown results in a positive reactivity insertion and subsequent reduction in core shutdown margin. If the most-reactive RCCA is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam pipe rupture is a concern primarily because of the high-power peaking factors that would exist assuming the most-reactive RCCA is stuck in its fully withdrawn position.

The major rupture of a main steam pipe is the most limiting cooldown transient. It is analyzed at HZP conditions with no decay heat (decay heat would retard the cooldown, thus reducing the return to power). A detailed discussion of this transient with the most limiting break size (a double-ended rupture) is presented below.

The primary design features which provide protection for steam pipe ruptures are:

- Actuation of the safety injection (SI) system from any of the following:
  - Two-out-of-four low pressurizer pressure signals
  - Two-out-of-three low steam line pressure signals in any loop
  - Two-out-of-three high-1 containment pressure signals
- Reactor trip can be actuated from overpower (neutron flux and N-16) or upon the receipt of a safety injection signal.
- Redundant isolation of the main feedwater lines to prevent sustained high feedwater flow that would cause additional cooldown. In addition to the normal control action which closes the main feedwater control valves, a safety injection signal rapidly closes all feedwater control valves and backup feedwater isolation valves, and trips the main feedwater pumps. A trip of the main feedwater pumps results in automatic closure of the respective pump discharge isolation valves.
- Closure of the fast-acting main steam isolation valves (MSIVs) on the following:
  - Two-out-of-three high-2 containment pressure signals

- Two-out-of-three low steam line pressure signals in any loop (above Permissive P-11)

- Two-out-of-three high negative steam pressure rate signals in any loop (below Permissive P-11)

For any break (in any location), no more than one steam generator would experience an uncontrolled blowdown, even if one of the MSIVs fails to close. For breaks downstream of the MSIVs, closure of all MSIVs completely terminates the blowdown of all steam generators. The valves on all steam lines are closed to isolate the steam generators. Thus, even with the worst possible break location (that is, upstream of an MSIV), only one steam generator can blow down, minimizing the potential steam release and resultant RCS cooldown. The remaining steam generators would still be available for dissipation of decay heat after the initial transient is over.

Following blowdown of the faulted steam generator, the unit can be brought to a stabilized hot standby condition through control of the auxiliary feedwater (AFW) flow and safety injection flow as prescribed by plant operating procedures. The operating procedures call for operator action to limit RCS pressure and pressurizer level by terminating safety injection flow and to control steam generator level and RCS coolant temperature using the AFW system (AFWS).

2.2.2.1.1.2 Input Parameters, Assumptions, and Acceptance Criteria

The following summarizes the major input parameters and/or assumptions used in the analysis of the main steam line rupture event at HZP conditions:

- HZP conditions were modeled with four loops in service, both with and without offsite power available.

- Cases were run modeling both the Unit 1 Model Δ76 steam generators and the Unit 2 Model D-5 steam generators.

- A 1.388 ft^2 break size was analyzed for both types of steam generators. This break size corresponds to the flow area of the flow restrictor built into the steam exit nozzle of each steam generator. The assumed steam generator tube plugging level was 0 percent.

- All control rods were inserted except the most reactive RCCA, which was assumed to be stuck out of the core.

- The shutdown margin was 1.30-percent $\Delta k/k$.

- The safety injection system and the accumulators were modeled with their minimum Technical Specification boron concentrations.

- The low steam line pressure signal was credited for safety injection actuation.

A major break in a steam system pipe is classified as a Condition IV event as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. Minor secondary system pipe breaks are classified as ANS Condition III events. The major steam system pipe break was analyzed to meet the more restrictive Condition II acceptance criteria and, therefore, bounds the less severe minor secondary system pipe break accident.

Pressure limits of the primary and secondary systems are not challenged because primary and secondary pressures decrease from their initial values during the transient. The only criterion that has the potential to be challenged during this event is that concerning the critical heat flux not being exceeded. The analysis demonstrates that this criterion is met by showing that the minimum DNBR does not go below the limit value at any time during the transient.

2.2.2.1.1.3 Description of Analyses and Evaluations

A detailed analysis using the RETRAN computer code (Reference 1) was performed in order to determine the plant transient conditions following a main steam line break. The code models the core neutron kinetics, RCS, pressurizer, steam generators, safety injection system, and the AFWS. The code computes pertinent variables, including the core heat flux, RCS temperature, and pressure. A detailed core analysis was then performed using the ANC code (Reference 2) to determine if the RETRAN-predicted reactivity feedback model is conservative. The core models developed in ANC were then used as input to the detailed thermal and hydraulic digital computer code, VIPRE (Reference 3), to determine if the DNB design basis is met.

2.2.2.1.1.4 Results

For CPNPP, the most limiting main steam line rupture at HZP case is the Unit 1 case in which offsite power was assumed to be available. The calculated sequence of events for the limiting case is shown in Table 2.2.2-1.

Figures 2.2.2-1 through 2.2.2-5 show the transient results for the most limiting case, a complete severance of a main steam pipe at initial no-load conditions with offsite power available. Since offsite power was assumed to be available, there is full reactor coolant flow.

Should the core be critical at or near zero power when the rupture occurs, the initiation of safety injection via a low steam line pressure signal trips the reactor. Steam release from more than one steam generator is prevented by automatic closure of the MSIVs in the steam lines by low steam line pressure signals.

As shown in Figure 2.2.2-4, the core attains criticality with the RCCAs inserted (that is, with the plant shut down assuming one stuck RCCA) before the transient is turned around by boron injected from the ECCS and accumulators.

The results of the major rupture of a main steam pipe event indicate that the DNB design basis is met. The calculated minimum DNBR is well above the limit value. The pressure limits of the primary and secondary systems are not challenged because primary and secondary pressures

decrease from their initial values during the transient. Therefore, this event does not adversely affect the core or the RCS, and all applicable acceptance criteria are met.

2.2.2.1.1.5 References

1. WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

2. WCAP-10965, "ANC: A Westinghouse Advanced Nodal Computer Code," September 1986.

3. WCAP-14565, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," October 1999.

2.2.2.1.2 Steam System Piping Failure at Full-Power

2.2.2.1.2.1 Introduction

This section describes the analysis of a steam system piping failure occurring from full-power initial conditions to demonstrate that core protection is maintained prior to, and immediately following, reactor trip. The steam release from a major rupture of a main steam pipe at full power will result in an increase in steam flow that stabilizes at a higher-than-initial flow rate as the steam pressure falls. The increased energy removal from the RCS causes a reduction of reactor coolant temperature and pressure. In the presence of a negative MTC, the cooldown results in a positive reactivity insertion and subsequent increase in power due to the higher steam load. The power increase is ultimately terminated by a reactor trip on either an overpower N-16 signal or a low steam pressure safety injection signal.

2.2.2.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Limiting transient condition statepoints (a table of critical analysis results for each time step, such as core average heat flux, vessel inlet temperatures, and core pressure) were generated using the RTDP (Reference 1). For RTDP applications, uncertainties on RCS initial conditions (temperature, pressure, and power) are statistically included in the development of the DNBR limit value.

The following summarizes the major input parameters and/or assumptions used in the analysis of the full power main steam line rupture event:

- Initial conditions – The initial core power (3,612 MWt), RCS temperature, and RCS pressure were assumed to be at their nominal steady-state, full-power values.

- RCS average temperature – The full-power RCS T_{avg} range is from 574.2° to 589.2°F. Since the full-power steam line rupture event is a DNB event, assuming a maximum RCS average temperature is limiting. Therefore, an initial RCS average temperature of 589.2°F was assumed.

- RCS flow – Minimum measured RCS flow was assumed. The initial loop flows were assumed to be symmetric.

- Feedwater temperature – The main feedwater analytical temperature range is from 390° to 450.3°F. A nominal feedwater temperature of 450.3°F is more limiting with respect to DNB for this event. Thus, a feedwater temperature of 450.3°F was assumed. For this event, the feedwater flow was set to match the steam flow.

- Break size – A spectrum of break sizes was analyzed to identify the most limiting overpower condition, which is typically identified by the largest break to produce a reactor trip on an overpower N-16 signal. The steam generators (Model Δ76 for Unit 1 and Model D-5 for Unit 2) have a steam exit nozzle flow restrictor that limits the flow area to 1.388 ft^2. Therefore, break sizes up to 1.388 ft^2 were analyzed. In addition, the largest break size for which there is no reactor trip was examined to determine if it is more limiting with respect to peak power level.

- Reactivity coefficients – The analysis assumed maximum moderator reactivity feedback and minimum Doppler power feedback to maximize the power increase following the break.

- Protection system – This analysis only considers the initial phase of the steam line rupture transient from full power conditions (that is, before and just following reactor trip). Protection in this phase of the transient is provided by reactor trip, if necessary. The primary credited functions for this case are the low steam pressure safety injection signal and the overpower N-16 reactor trip.

- Control systems – No control systems were assumed.

Depending on the size of the break, this event is classified as either a Condition III (infrequent fault) or Condition IV (limiting fault) event. However, the analysis was done to the more conservative Condition II acceptance criteria. Specifically, the acceptance criteria are met by showing that the minimum DNBR does not go below the limit value (1.61) and the peak linear heat rate (kW/ft) does not exceed the fuel melt limit value (22.4 kW/ft) at any time during the transient.

2.2.2.1.2.3 Description of Analysis and Evaluations

The analysis of the full-power steam line rupture event for the TM and SPU was performed as follows:

- The RETRAN computer code (Reference 2) was used to calculate the nuclear power, core average heat flux, vessel inlet temperatures, and core pressure transients resulting from the cooldown following the steam line break.

- The core radial and axial peaking factors were determined using the thermal-hydraulic conditions from RETRAN as input to the nuclear core models. The detailed

thermal-hydraulic computer code VIPRE (Reference 3) was used to calculate the DNBR for the limiting time during the transient. The DNBR calculations were performed using the WRB-2 DNB correlation and RTDP.

2.2.2.1.2.4 Results

The limiting break size from the spectrum of break sizes analyzed is 1.388 ft^2 for both units, which is the largest possible break size due to the steam generator outlet flow restrictors. This is expected since the reactor trips on an overpower N-16 signal for the entire spectrum of breaks (that is, the low steam pressure setpoint was not reached due to relaxed dynamic compensation), and the largest break that trips on overpower N-16 is typically limiting.

The limiting case between the two units with respect to minimum DNBR is for Unit 2, in which the minimum DNBR is 1.963/2.015 (thimble cell/typical cell) versus a 1.61 limit. With respect to peak linear heat rate (kW/ft), the limiting case between the two units is for Unit 1, in which the peak kW/ft is 21.6 kW/ft versus a 22.4 kW/ft limit.

The sequence of events for the limiting cases (the 1.388 ft^2 break) for Unit 1 and Unit 2 are shown in Tables 2.2.2-2 and 2.2.2-3, respectively. Plots for these cases are provided in Figures 2.2.2-6 through 2.2.2-9 (Unit 1) and Figures 2.2.2-10 through 2.2.2-13 (Unit 2).

The DNB design basis and peak linear heat rate limits are met for both units. Therefore, a steam line rupture occurring from full power conditions will not adversely affect the core or RCS.

The results of the analysis performed for the steam system piping failure at full power for the nuclear steam supply system power of 3,628 MWt support the implementation of the TM and SPU. Furthermore, the results and conclusions of this analysis will be confirmed on a cycle-specific basis as part of the normal reload safety evaluation process.

2.2.2.1.2.5 References

1. WCAP-11397, "Revised Thermal Design Procedure," April 1989.

2. WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

3. WCAP-14565, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," October 1999.

2.2.2.2 Conclusions

The analyses of steam system piping failure events have been reviewed and Luminant Power has concluded that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. It is further concluded that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a non-brittle manner, the probability of a propagating fracture of the RCPB is minimized, and abundant core cooling will be provided. Based on this, the conclusion is that the plant will continue to meet the requirements of GDCs -27, -28, -31, and -35.

Table 2.2.2-1 Time Sequence of Events – Steam System Piping Failure at Hot Zero Power		
Case	**Event**	**Time (sec)**
Unit 1 Double-Ended Rupture (1.388 ft^2) with Offsite Power Available	Steam Line Break Occurs	0.0
	Low Steam Pressure Setpoint Reached in Faulted Loop (Loop 1)	10.5
	Safety Injection and Steam Line Isolation Signals Generated (on low steam pressure)	12.5
	Pressurizer Empties	13.6
	Steam Line and Feedwater Isolation Complete	17.5
	Re-criticality Occurs	25.3
	SI Flow Initiated (Borated Water)	37.5
	Accumulators Inject	93.9
	Peak Core Heat Flux Reached	108.0
	Minimum DNBR Reached	108.3

Table 2.2.2-2 Time Sequence of Events – Steam System Piping Failure at Full-Power (Unit 1 Core Response – 1.388 ft^2 break)	
Event	**Time (seconds)**
Steam Line Ruptures	0.0
Overpower N-16 Reactor Trip Setpoint Reached	11.7
Rods Begin to Drop	13.7
Minimum DNBR Occurs	14.5
Peak Core Heat Flux Occurs	14.5

Table 2.2.2-3 Time Sequence of Events – Steam System Piping Failure at Full-Power (Unit 2 Core Response – 1.388 ft^2 break)	
Event	**Time (seconds)**
Steam Line Ruptures	0.0
Overpower N-16 Reactor Trip Setpoint Reached	13.1
Rods Begin to Drop	15.1
Minimum DNBR Occurs	15.5
Peak Core Heat Flux Occurs	15.5

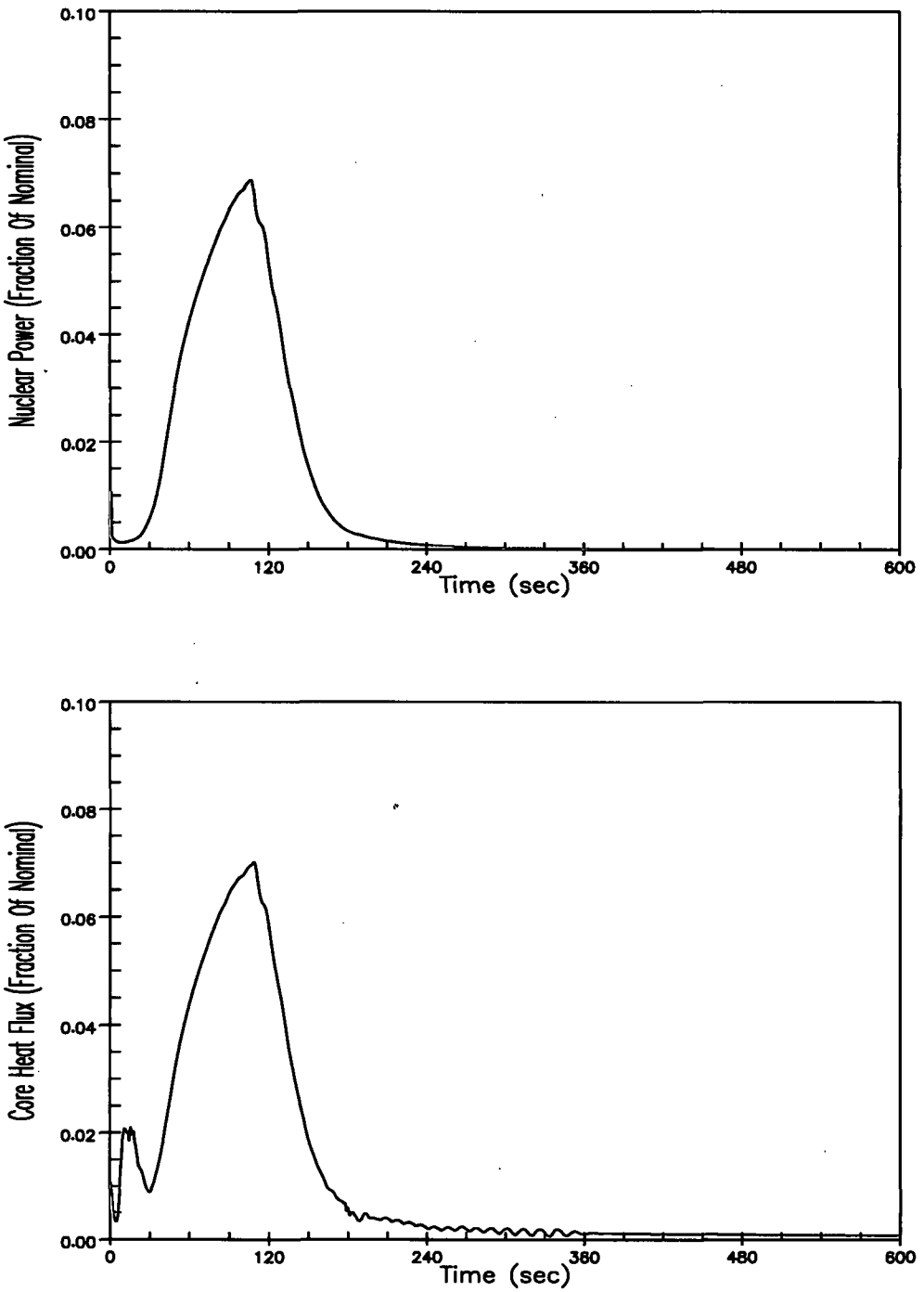


Figure 2.2.2-1 Piping Failure at Hot Zero Power – 1.388 ft^2 Break (with Offsite Power Available) Nuclear Power, and Core Heat Flux Versus Time

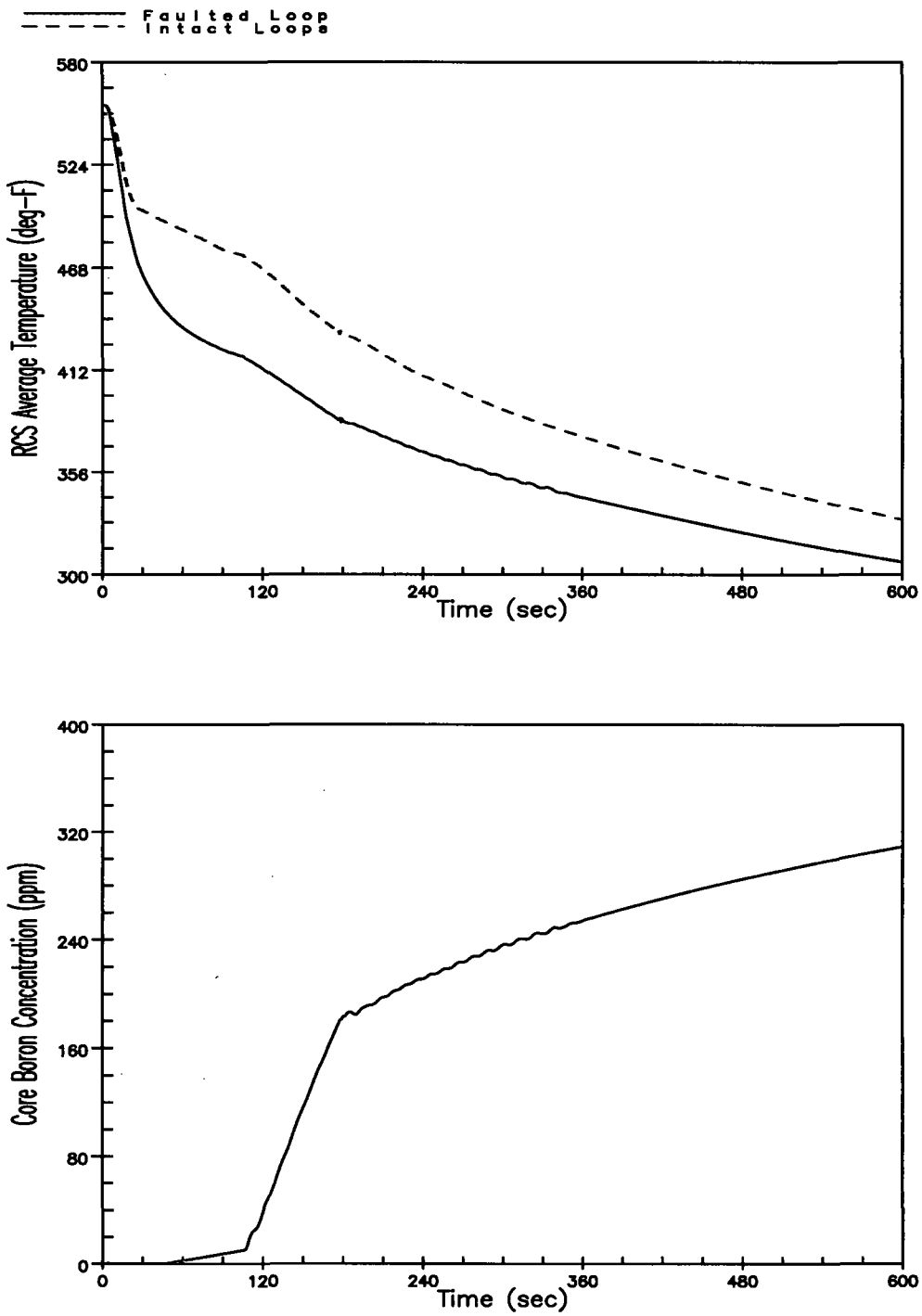


Figure 2.2.2-2 Piping Failure at Hot Zero Power – 1.388 ft^2 Break (with Offsite Power Available) RCS Average Temperature, and Core Boron Concentration Versus Time

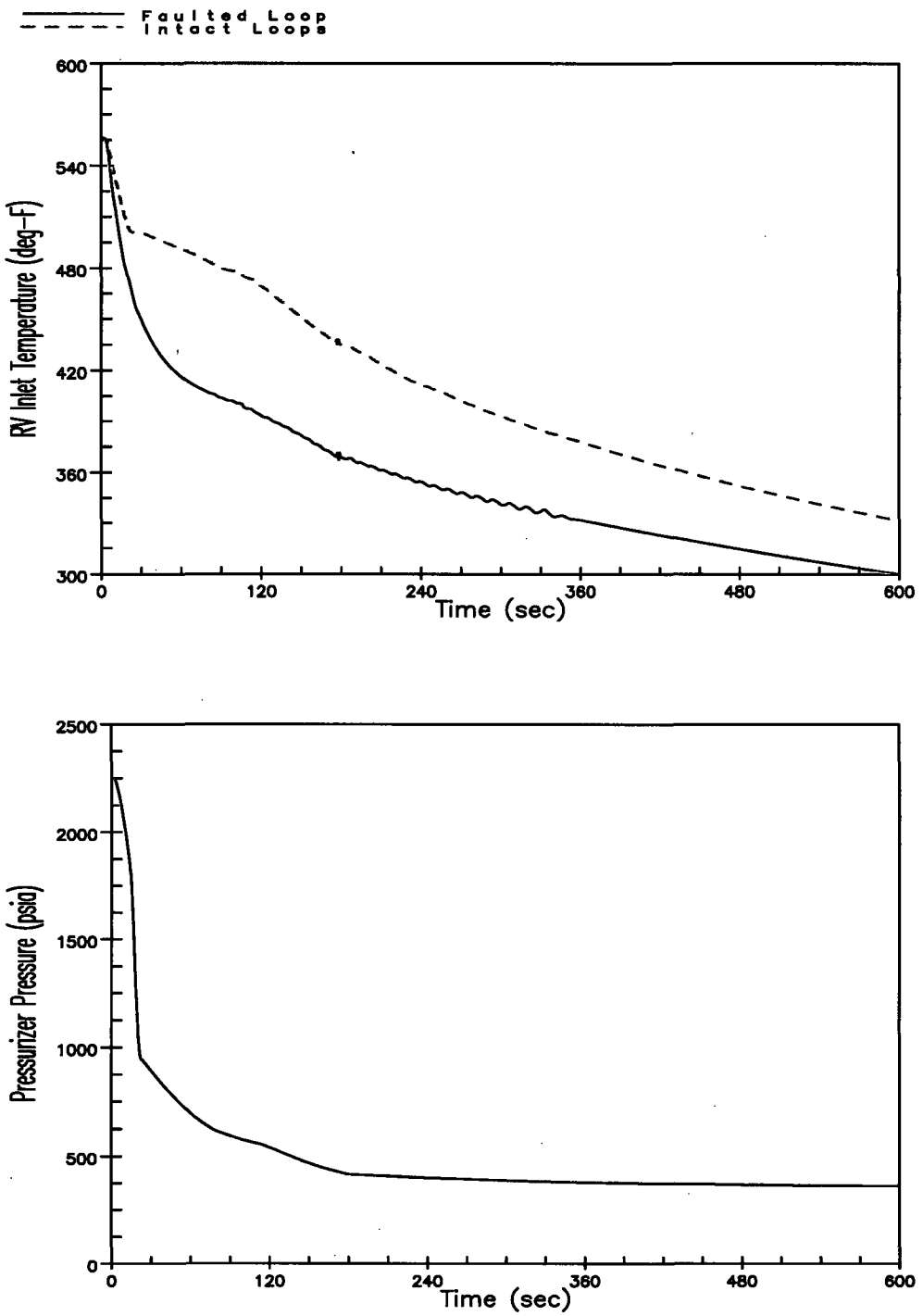


Figure 2.2.2-3 Piping Failure at Hot Zero Power – 1.388 ft^2 Break (with Offsite Power Available) Reactor Vessel Inlet Temperature, and Pressurizer Pressure Versus Time

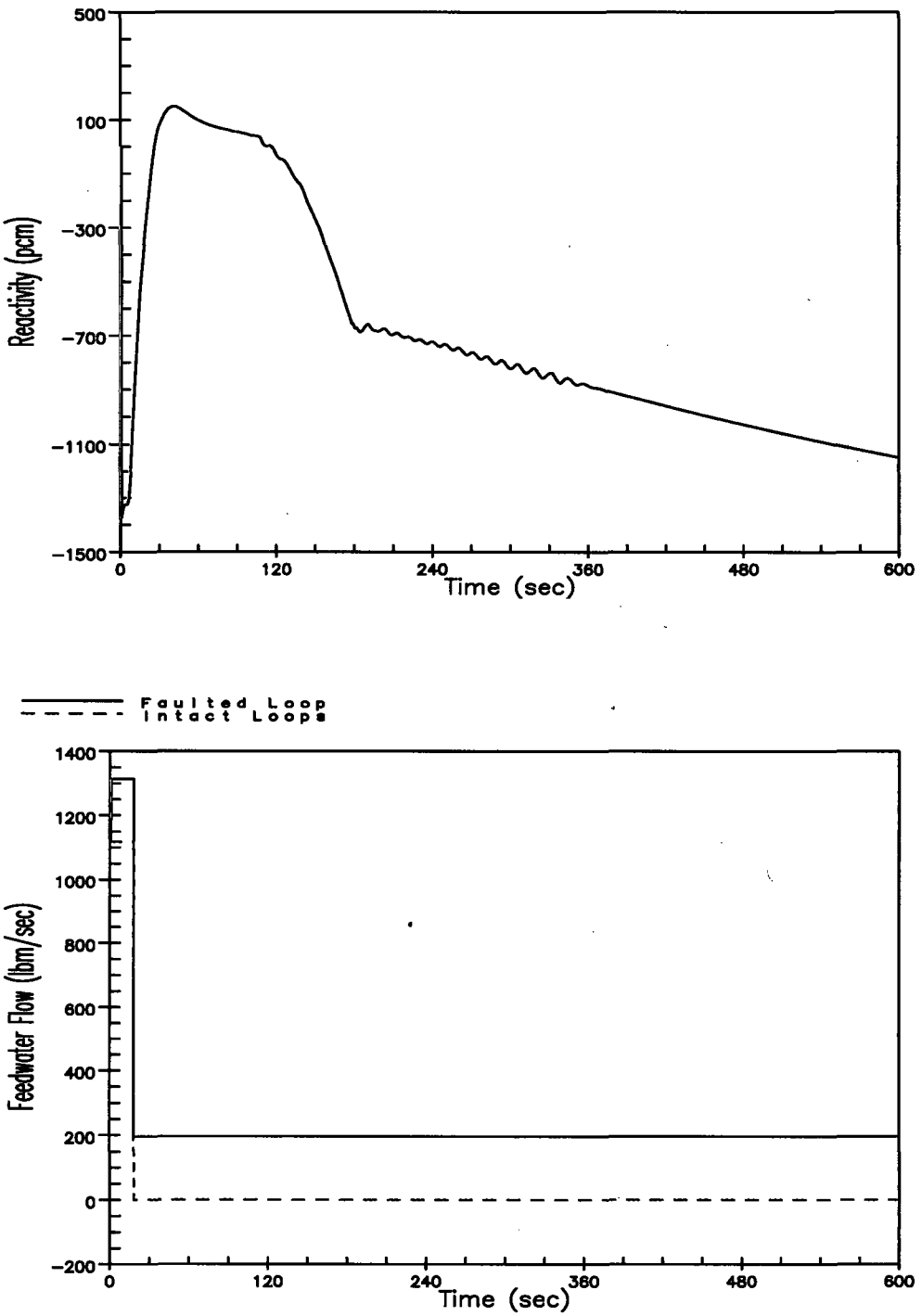
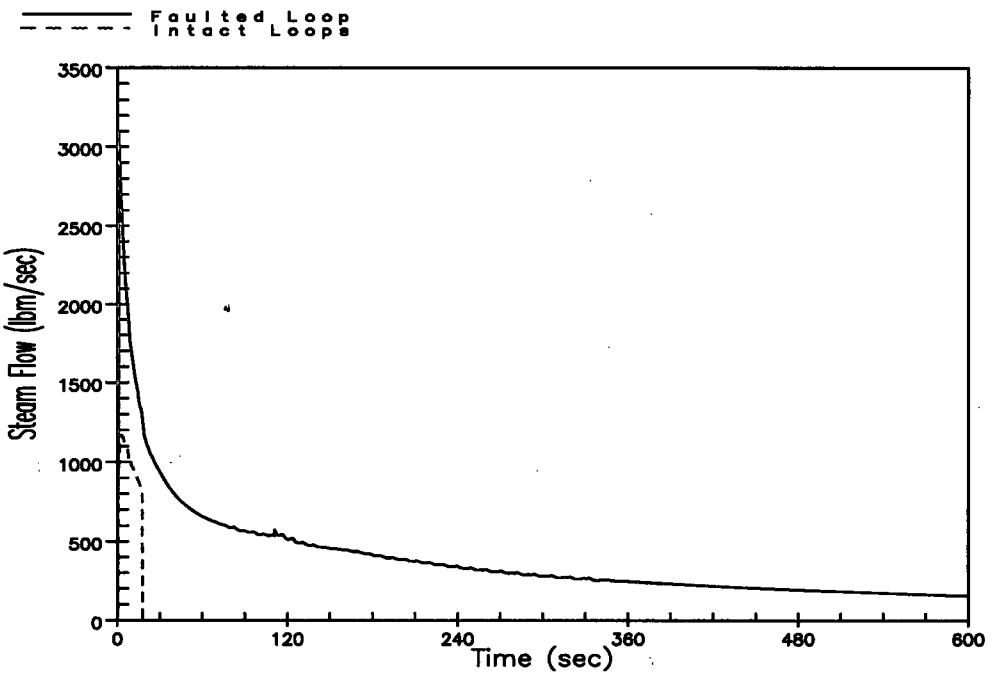


Figure 2.2.2-4 Piping Failure at Hot Zero Power – 1.388 ft^2 Break (with Offsite Power Available) Reactivity, and Feedwater Flow Versus Time



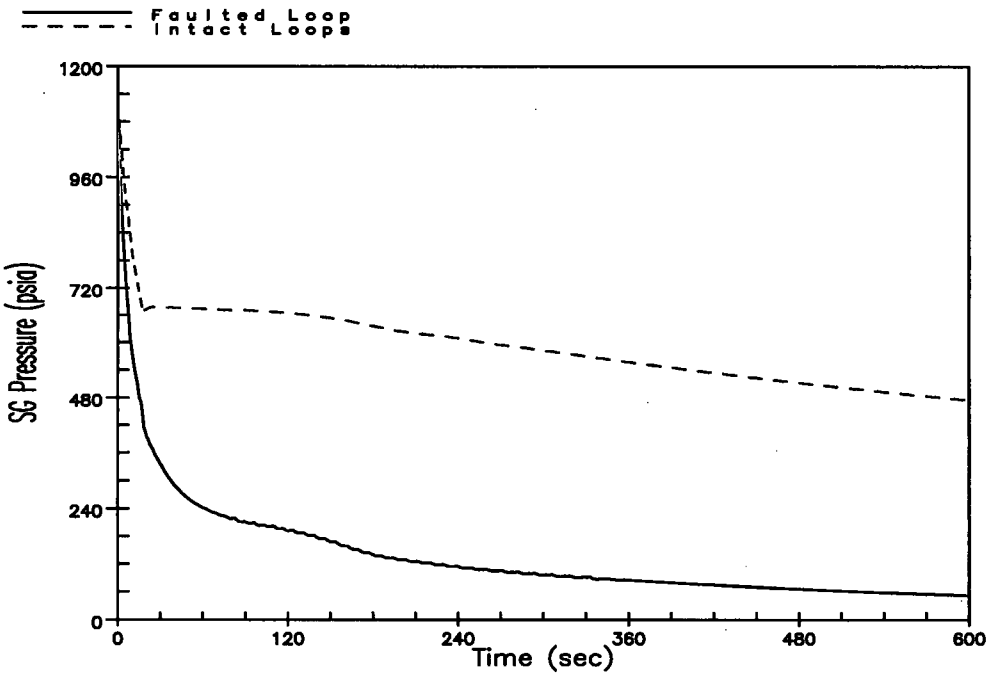
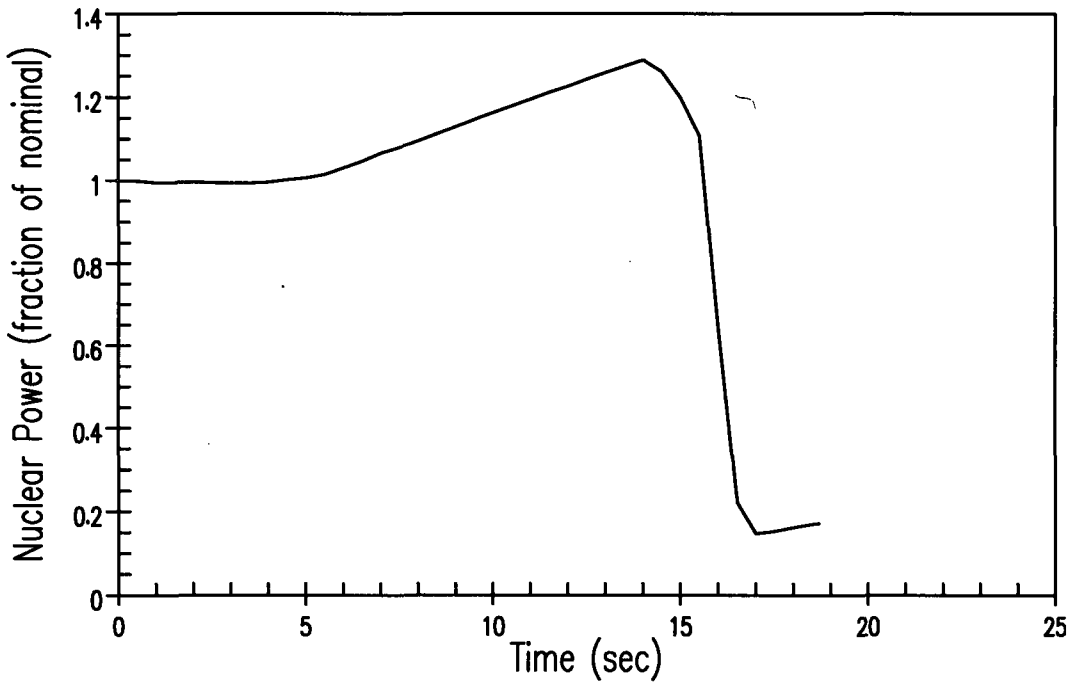


Figure 2.2.2-5 Piping Failure at Hot Zero Power – 1.388 ft^2 Break (with Offsite Power Available) Steam Flow, and Steam Generator Pressure Versus Time



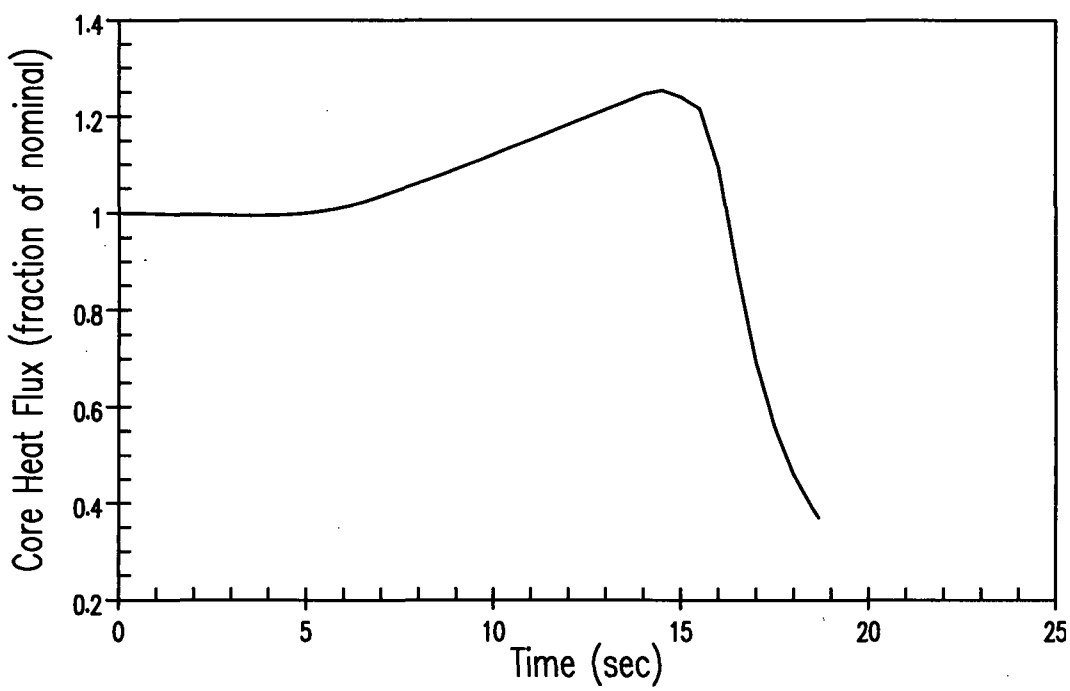


Figure 2.2.2-6 Steam System Piping Failure at Full-Power (Unit 1) – 1.388 ft^2 Break Nuclear Power and Core Heat Flux Versus Time

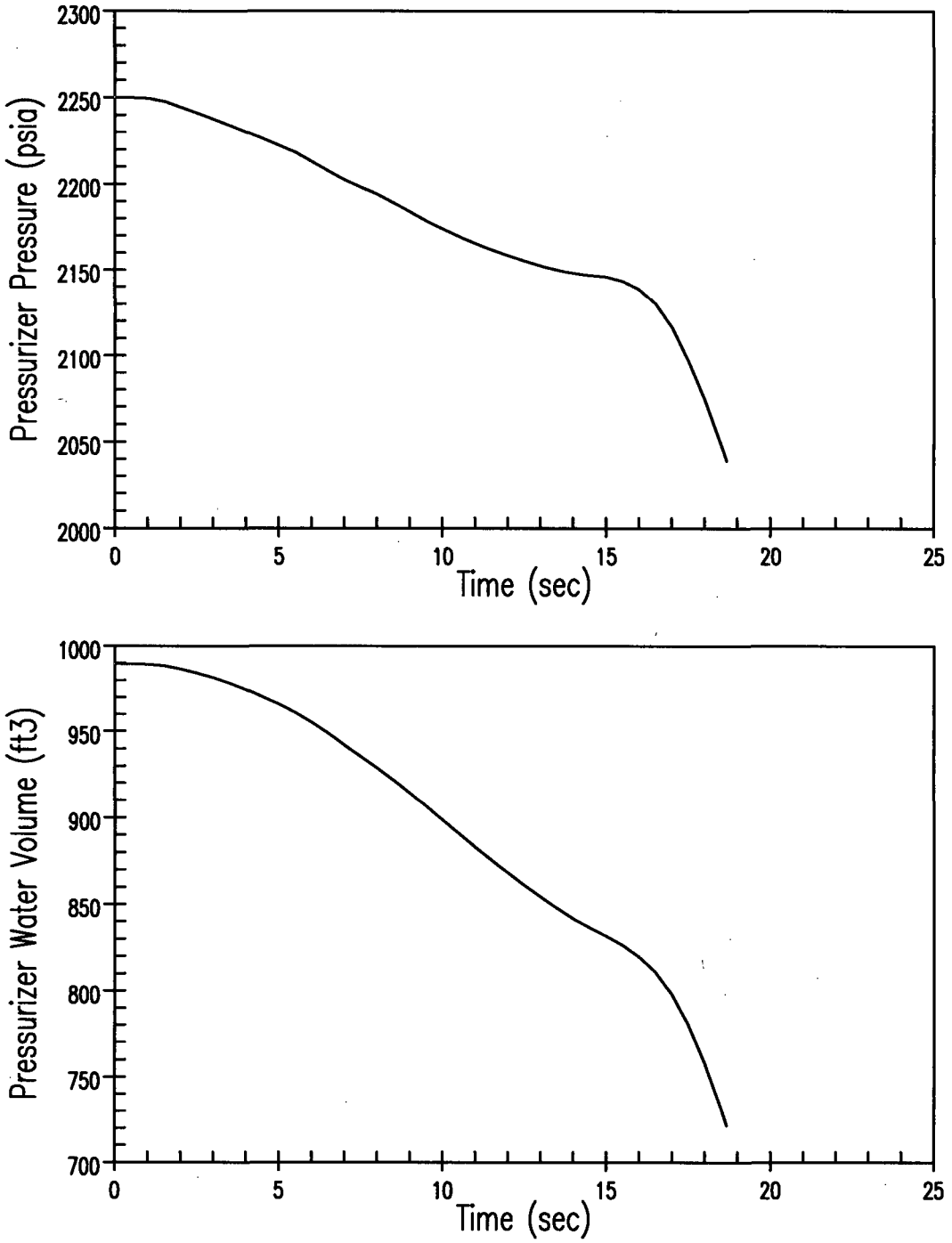


Figure 2.2.2-7 Steam System Piping Failure at Full-Power (Unit 1) – 1.388 ft^2 Break Pressurizer Pressure and Pressurizer Water Volume Versus Time

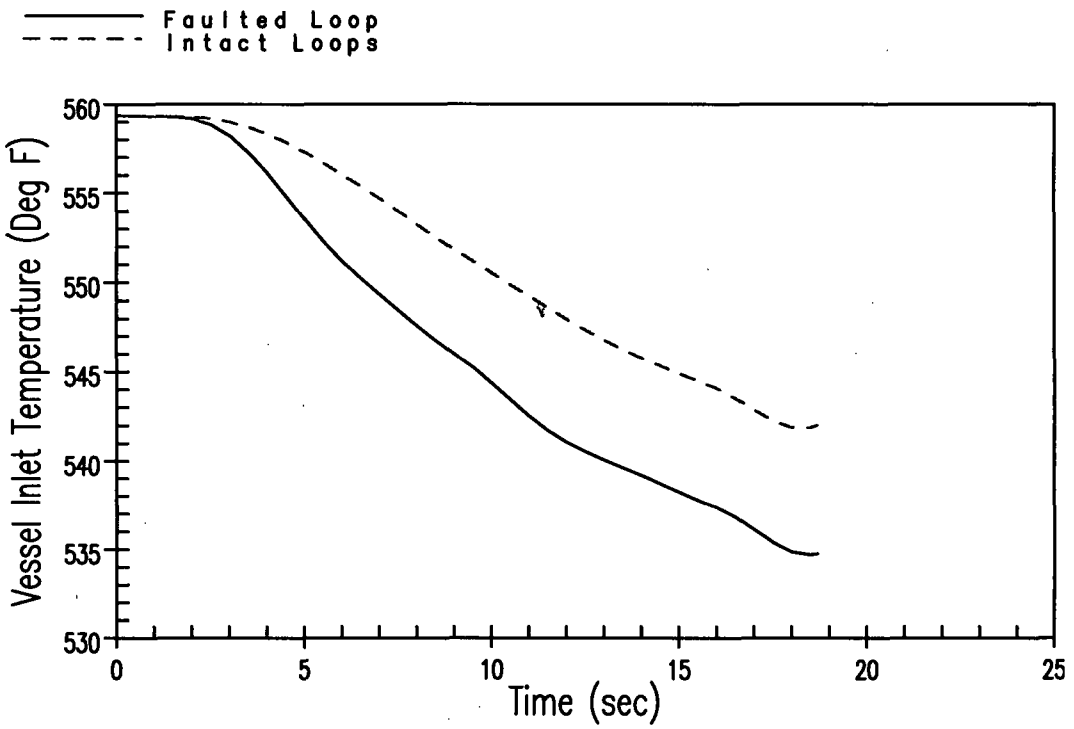


Figure 2.2.2-8 Steam System Piping Failure at Full-Power (Unit 1) – 1.388 ft^2 Break Vessel Inlet Temperature Versus Time

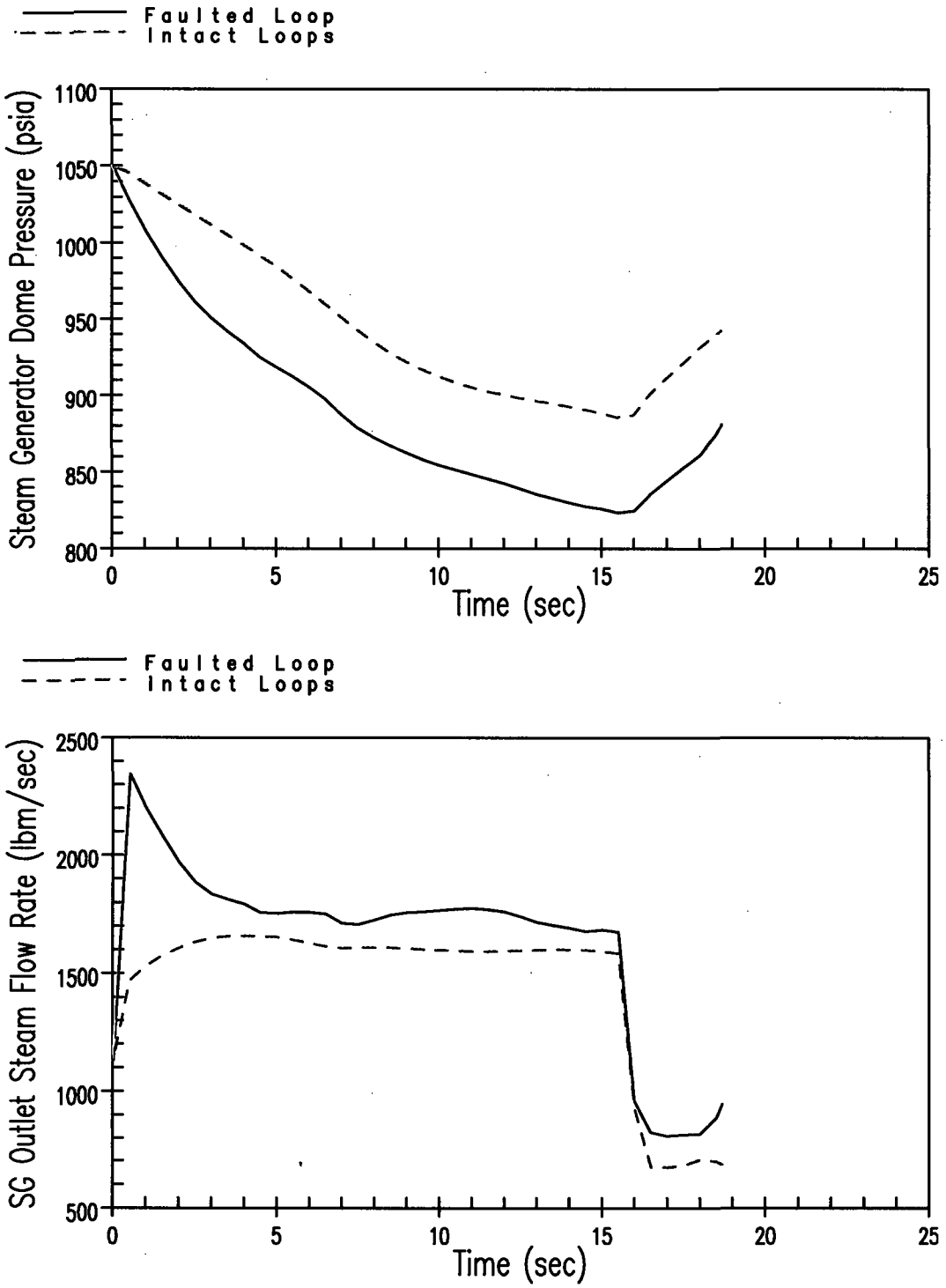


Figure 2.2.2-9 Steam System Piping Failure at Full-Power (Unit 1) – 1.388 ft^2 Break Steam Generator Dome Pressure and Steam Generator Outlet Steam Flow Rate Versus Time

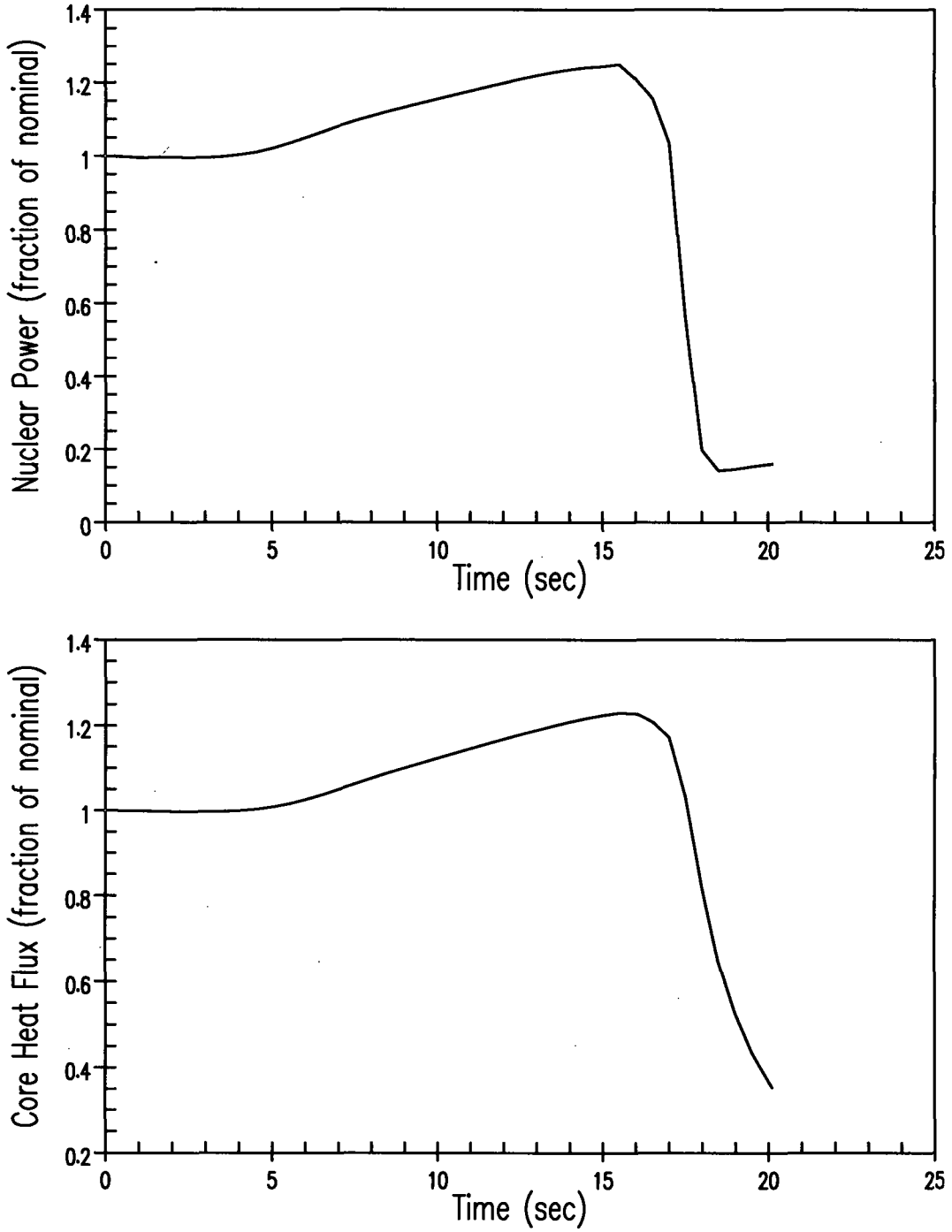
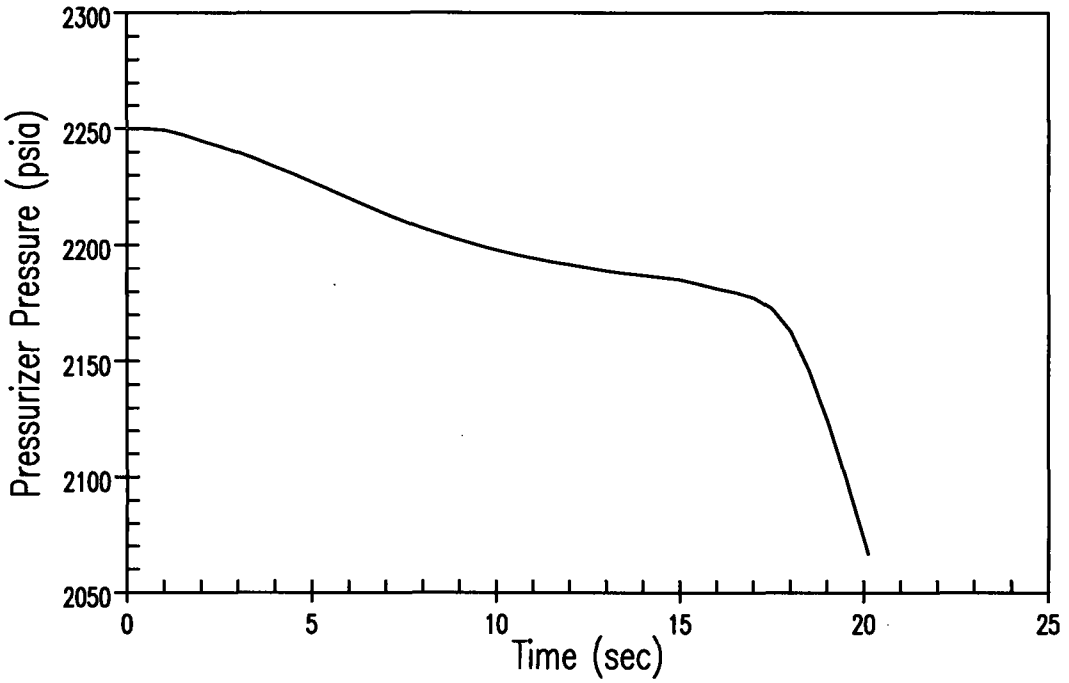


Figure 2.2.2-10 Steam System Piping Failure at Full-Power (Unit 2) – 1.388 ft^2 Break Nuclear Power and Core Heat Flux Versus Time



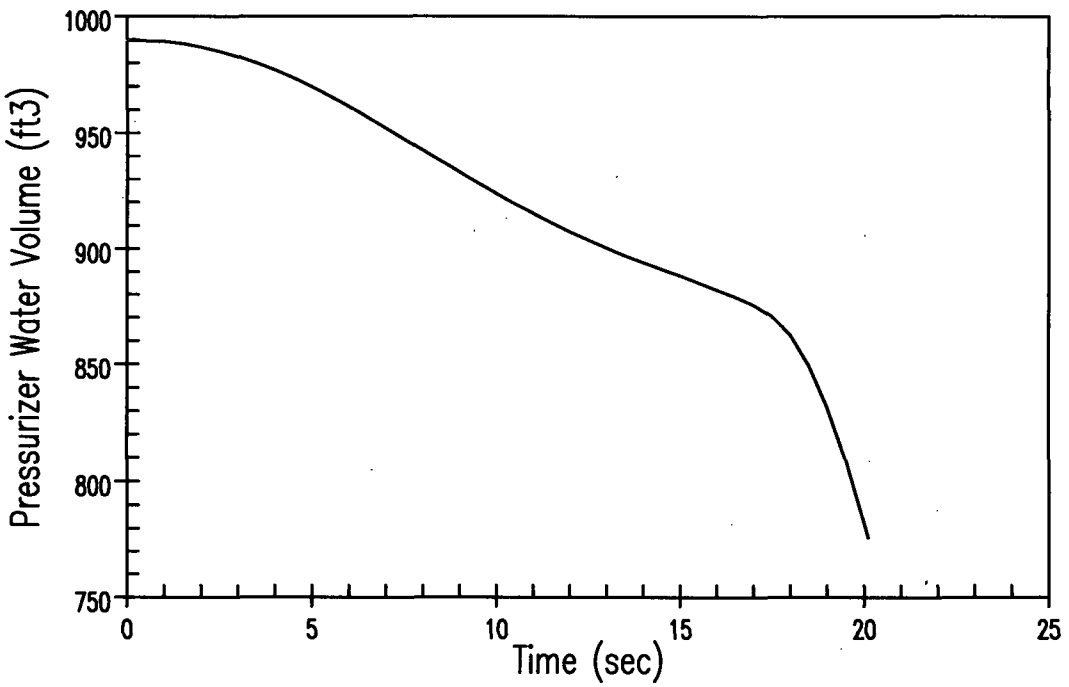


Figure 2.2.2-11 Steam System Piping Failure at Full-Power (Unit 2) – 1.388 ft^2 Break Pressurizer Pressure and Pressurizer Water Volume Versus Time

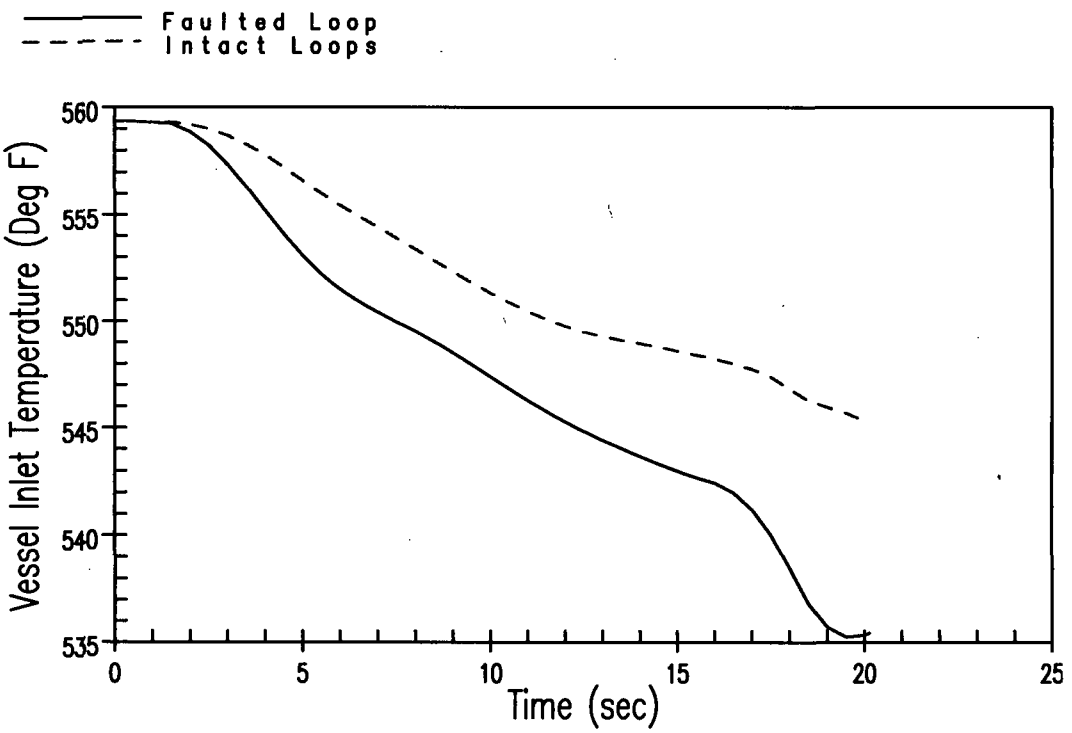


Figure 2.2.2-12 Steam System Piping Failure at Full-Power (Unit 2) – 1.388 ft^2 Break Vessel Inlet Temperature Versus Time

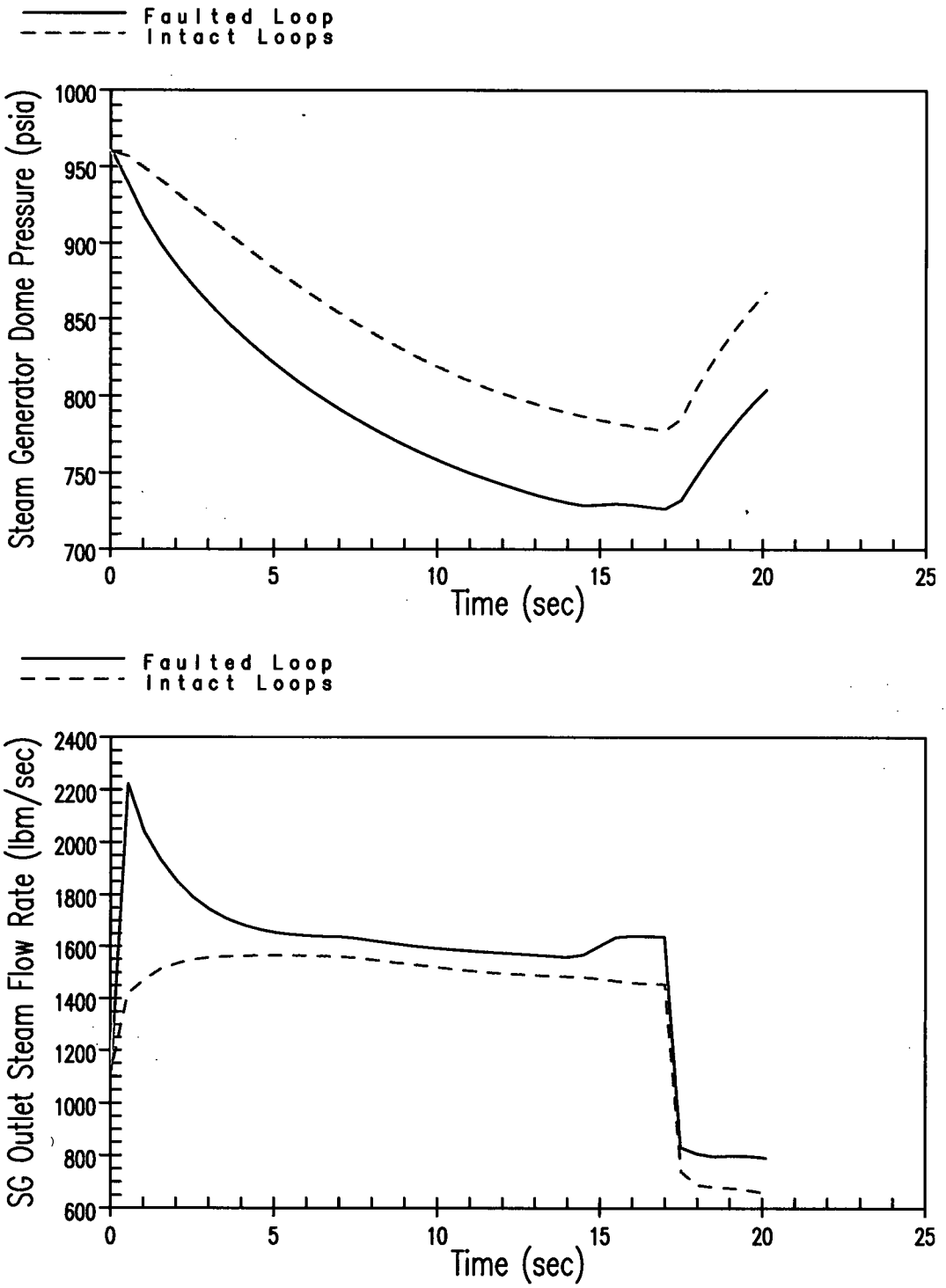


Figure 2.2.2-13 Steam System Piping Failure at Full-Power (Unit 2) – 1.388 ft^2 Break Steam Generator Dome Pressure and Steam Generator Outlet Steam Flow Rate Versus Time

2.3 DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

2.3.1 Loss of External Load, Turbine Trip, Steam Pressure Regulator Failure, and Loss of Condenser Vacuum

2.3.1.1 Technical Evaluation

2.3.1.1.1 Introduction

A major load loss on the plant can result from either a loss of external electrical load or from a turbine trip. A loss of external electrical load can result from an abnormal variation in network frequency or other adverse network operating condition. In either case, offsite power is available for the continued operation of plant components such as the RCPs.

The plant is designed to accept a 50-percent loss of electrical load while operating at full power, or a complete loss of load while operating below the P-9 setpoint without actuating a reactor trip with all NSSS control systems in automatic. A 50-percent loss of electrical load is handled by the steam dump system (which accommodates 40 percent of the nominal full-power load), the rod control system (which accommodates the remaining 10 percent of the load rejection by driving rods in to reduce coolant average temperature), and the pressurizer (which absorbs the change in coolant volume due to the heat addition resulting from the load rejection). Should a complete loss of load occur from full power, the reactor trip system automatically actuates a reactor trip.

The most likely source of a complete loss of load on the NSSS is a trip of the turbine generator. In this case, there is a direct reactor trip signal derived from either the turbine auto-stop oil pressure or closure of the turbine stop valves, provided the reactor is operating above the P-9 setpoint. Reactor temperature and pressure do not increase significantly if the steam dump system and pressurizer pressure control system are functioning properly. However, the RCS and MSS pressure-relieving capacities are designed to ensure the safety of the plant without requiring the use of automatic rod control, pressurizer pressure control, and/or steam dump control systems. In this analysis, the behavior of the plant is evaluated for a complete loss of steam load from full power without direct reactor trip in order to demonstrate the adequacy of the pressure-relieving devices and core protection margins.

In the event the steam dump valves fail to open following a large loss of load, the MSSVs can lift and the reactor can be tripped by the high pressurizer pressure signal, the overtemperature N-16 signal, or the overpower N-16 signal. The steam generator shell-side pressure and reactor coolant temperatures increase rapidly. The PSVs and MSSVs are sized to protect the RCS and steam generator against overpressurization for all load losses without assuming the operation of the steam dump system, pressurizer sprays, pressurizer PORVs, automatic rod control, or the direct reactor trip on turbine trip.

2.3.1.1.2 Input Parameters, Assumptions, and Acceptance Criteria

Three cases were analyzed for a loss of load (LOL)/TT event from full-power conditions:

- With automatic pressure control (DNBR case)
- With automatic pressure control and minimum steam generator tube plugging (SGTP) (MSS pressure case)
- Without automatic pressure control and maximum SGTP (RCS pressure case)

The DNBR case was analyzed using the RTDP (Reference 1). NSSS power, RCS temperature, and pressure were assumed to be at their nominal values consistent with steady-state, full-power operation. Minimum measured flow was modeled. Uncertainties in initial conditions were included in the safety analysis DNBR limit, as described in Reference 1.

The RCS and MSS peak pressure cases were analyzed using the standard thermal design procedure (STDP). Initial uncertainties on NSSS power, RCS temperature, and pressure were applied in the most conservative direction to obtain the initial plant conditions for the transient. Both cases modeled thermal design flow.

The LOL/TT transient was conservatively analyzed with minimum reactivity feedback (beginning of core life). All cases assumed the least-negative Doppler power coefficient and a 0 pcm/°F moderator temperature coefficient, which bounded part-power conditions, assuming a positive moderator temperature coefficient. Minimum reactivity conditions were conservative since reactor power was maintained until the time of reactor trip, which exacerbated the calculated minimum DNBR and maximum RCS and MSS pressures.

Manual rod control was modeled for all cases. If the reactor had been in automatic rod control, the control rod banks would have driven into the core prior to reactor trip, thereby reducing the severity of the transient.

The LOL/TT event was analyzed both with and without pressurizer pressure control. The pressurizer PORVs and sprays were assumed operable for the DNBR case to minimize the increase in primary pressure, which was conservative for the DNBR criterion. The pressurizer PORVs and sprays were also assumed operable for the MSS peak pressure case to minimize the increase in primary pressure, which delayed or prevented reactor trip on a high pressurizer pressure signal, resulting in a conservatively high calculated peak secondary-side pressure. The RCS pressure case was analyzed without pressure control to conservatively maximize the RCS pressure increase. In all cases, the MSSVs and pressurizer safety valves were assumed to be operable.

A total PSV setpoint tolerance of -3%/+1% was accounted for in the analysis. For the DNBR case, the negative tolerance was applied to conservatively reduce the setpoint. For the RCS peak pressure case and the MSS peak pressure case, the positive tolerance (in addition to a 0.9-percent setpoint shift) was applied to conservatively increase the setpoint pressure; in

addition to this, the peak RCS pressure care includes a 1.05-second purge time delay associated with the existence of PSV water-filled loop seals, as described in Reference 3.

Main feedwater flow to the steam generators was assumed to be lost at the time of turbine trip. The auxiliary feedwater system is modeled. However, the low-low steam generator water level setpoint is not reached to initiate auxiliary feedwater flow.

The following reactor trip setpoints are assumed to be operable:

- Reactor trip on high pressurizer pressure
- Reactor trip on overtemperature N-16
- Reactor trip on overpower N-16
- Reactor trip on low-low steam generator water level

The MSSV model for all cases includes a 3-percent setpoint tolerance and an accumulation model that assumes that the safety valves are wide open once the pressure exceeds the setpoint (plus tolerance) by 5 psi.

The limiting single failure is failure of one train of the reactor trip system. The remaining (operable) train trips the reactor. As described in FSAR Section 3.1.1, the MSSVs and pressurizer safety valves (that is, code safety valves) are considered especially qualified active components and are assumed to open on demand. Control systems are not assumed to operate abnormally during a transient except as an initial condition (such as a rod withdrawal event). Thus, a failure of a control system is not applicable as a limiting single failure. Feedwater isolation (redundant valves with different closure times), auxiliary feedwater (multiple pumps) and safety injection (multiple pumps) are susceptible to a single failure. However, none of these systems provide any mitigation for a LOL/TT event. Thus, these systems are not applicable as a limiting single failure. Furthermore, the protection system is designed to be single failure proof.

Maximum (10-percent) steam generator tube plugging is assumed in the DNBR case and RCS peak pressure case since it maximizes the RCS temperature transient following event initiation. However, the MSS peak pressure case is analyzed at zero steam generator tube plugging since this conservatively maximizes the primary-to-secondary side heat transfer; this assumption is slightly more limiting with respect to the secondary-side pressure transient.

Based on its frequency of occurrence, the LOL/TT accident is considered a Condition II event as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. The specific criteria for this accident, as stated in the Standard Review Plan, are as follows:

- Pressure in the RCS and MSS are maintained below 110 percent of the design values (for the CPNPP units, this represents an RCS pressure limit of 2,748.2 psia and secondary-side pressure limit of 1,318.2 psia).

- Fuel cladding integrity is maintained by demonstrating that the minimum DNBR remains above the 95/95 DNBR limit for PWRs (for the CPNPP units, the applicable safety analysis DNBR limit is 1.61).

- An incident of moderate frequency does not generate a more serious plant condition without other faults occurring independently.

  This criterion is conservatively satisfied by verifying that the pressurizer does not fill.

- An incident of moderate frequency in combination with any single active component failure, or single operator error, is considered an event for which an estimate of the number of potential fuel failures is provided for radiological dose calculations. For such accidents, fuel failure is assumed for all rods for which the DNBR falls below those values cited above for cladding integrity unless it can be shown that, based on an acceptable fuel damage model, fewer failures occur. There is no loss of function of any fission product barrier other than the fuel cladding.

  This criterion is satisfied by verifying that the DNBR remains above the 95/95 DNBR limit, discussed above.

2.3.1.1.3 Description of Analyses and Evaluations

A detailed analysis using the RETRAN (Reference 2) computer code was performed to determine the plant transient conditions following a total loss of load due to turbine trip without a direct reactor trip. The code models the core neutron kinetics, RCS, pressurizer, pressurizer PORVs and sprays, steam generators, MSSVs, and the auxiliary feedwater system. RETRAN computes pertinent variables, including the pressurizer pressure, steam generator pressure, and reactor coolant average temperature.

RETRAN has been approved by the NRC for the analysis of LOL/TT transient (Reference 2).

2.3.1.1.4 Results

The calculated sequence of events for all cases for both units is listed in Table 2.3.1-1, while the limiting values for each case are presented in Table 2.3.1-2.

2.3.1.1.4.1 DNBR

For both Units 1 and 2, the DNBR case was analyzed at the high nominal T_{avg} value (i.e., 589.2°F), nominal pressure (i.e., 2,250 psia), minimum measured flow, pressurizer pressure control available, 10 percent SGTP, and high main feedwater temperature (450.3°F) conditions.

The transient response plot results for the total loss-of-load/turbine trip event (DNBR case) are shown in Figures 2.3.1-1 through 2.3.1-6. The following results discussion is applicable to both units. The reactor was tripped on the OTN-16 reactor trip function. The nuclear power

increased slightly until the reactor was tripped. The pressurizer PORVs, safety valves, and sprays actuated to minimize the primary pressure transient, which was conservative for DNBR. Although the DNBR decreased below the initial value, it remained well above the safety analysis limit throughout the entire transient. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition. The MSSVs actuated to maintain the secondary side pressure below 110 percent of the design value.

2.3.1.1.4.2 MSS Pressure Case

For both Units 1 and 2, the MSS Pressure case was analyzed at the high nominal T_{avg} value plus uncertainties (that is, 589.2°F + 6°F), nominal pressure minus uncertainties (that is, 2,250 psia – 30 psi), thermal design flow, pressurizer pressure control available, 0-percent SGTP, and high main feedwater temperature (450.3°F) conditions.

The transient response plot results for the LOL/TT event (MSS pressure case) are shown in Figures 2.3.1-7 through 2.3.1-12. The reactor was tripped on the OTN-16 reactor trip function. The nuclear power remained essentially constant at full power until the reactor was tripped and the pressurizer PORVs and sprays (Units 1 and 2), and safety relief valves (Unit 2 only) minimized the primary pressure transient, which was conservative to prevent a reactor trip on high pressurizer pressure and exacerbate the peak secondary-side pressure. The MSSVs actuated to maintain the secondary-side pressure below 110 percent of the design value. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition.

2.3.1.1.4.3 RCS Pressure Case

For Unit 1 with the Model Δ76 steam generators, the most limiting LOL/TT RCS overpressurization case was that with the temperature uncertainty subtracted from the high nominal T_{avg} value (that is, 589.2° – 6°F), pressure uncertainty subtracted from the nominal value (that is, 2,250 – 30 psi), thermal design flow, pressurizer pressure control (PORVs and sprays) not available, 10–percent SGTP, and high main feedwater temperature (450.3°F) conditions.

For Unit 2 with the Model D-5 steam generators, the most limiting LOL/TT RCS overpressurization case was at the high nominal T_{avg} value (that is, 589.2°F), pressure uncertainty subtracted from the nominal value (that is, 2,250 – 30 psi), thermal design flow, pressurizer pressure control (PORVs, sprays) not available, 10-percent SGTP, and high main feedwater temperature (450.3°F) conditions.

The transient response plot results for the LOL/TT event (RCS pressure case) are shown in Figures 2.3.1-13 through 2.3.1-18. The following results discussion is applicable to both units. The reactor was tripped on the high pressurizer pressure reactor trip function. The nuclear power remained essentially constant at full power until the reactor was tripped. The PSVs actuated and maintained the primary-side pressure below 110 percent of the design value. The MSSVs also actuated and maintained the secondary side pressure below 110 percent of the

design value. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition.

2.3.1.2 Conclusions

From a review of the updated analyses of the LOL/TT event, it is concluded that these have adequately accounted for operation of the plant at the proposed uprated power level and that they were performed using acceptable analytical models. The results obtained demonstrate that the reactor protection and safety systems will continue to ensure that the SAFDLs are met and the RCS and MSS pressure boundary limits will not be exceeded as a result of the LOL/TT event. Furthermore, this event will not generate a more serious plant condition. Based on this, both units will continue to meet the requirements of GDCs -10, -15, and -26.

2.3.1.3 References

1. WCAP-11397, "Revised Thermal Design Procedure," April 1989.

2. WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

3. WCAP-12910, Rev. 1-A, "Pressurizer Safety Valve Set Pressure Shift," May 1993.

Table 2.3.1-1 Time Sequence of Events – Loss of External Electrical Load and/or Turbine Trip			
Case	Event	Time (sec)	
		Unit 1	Unit 2
DNBR Case	Loss of Electrical Load/Turbine Trip Occurs	0.0	0.0
	OTN-16 Reactor Trip Setpoint Reached	11.7	10.9
	Minimum DNBR Occurs	11.7	14.0
	Rods Begin to Drop	13.7	12.9
MSS Pressure Case	Loss of Electrical Load/Turbine Trip Occurs	0.0	0.0
	OTN-16 Reactor Trip Setpoint Reached	16.8	15.9
	Rods Begin to Drop	18.8	17.9
	Peak Secondary Side Pressure Occurs	21.7	21.7
RCS Pressure Case	Loss of Electrical Load/Turbine Trip Occurs	0.0	0.0
	High Pressurizer Pressure Reactor Trip Setpoint Reached	5.62	5.67
	Rods Begin to Drop	6.87	6.92
	Peak RCS Pressure Occurs	8.0	8.3

Table 2.3.1-2 Limiting Results – Loss of External Electrical Load and/or Turbine Trip			
Case	Parameter	Value	
		Unit 1	Unit 2
DNBR Case	Minimum DNBR	2.08	1.98
MSS Pressure Case	Peak MSS Pressure (psia)	1,298.4	1,297.2
RCS Pressure Case	Peak RCS Pressure (psia)	2,734.7	2,746.0

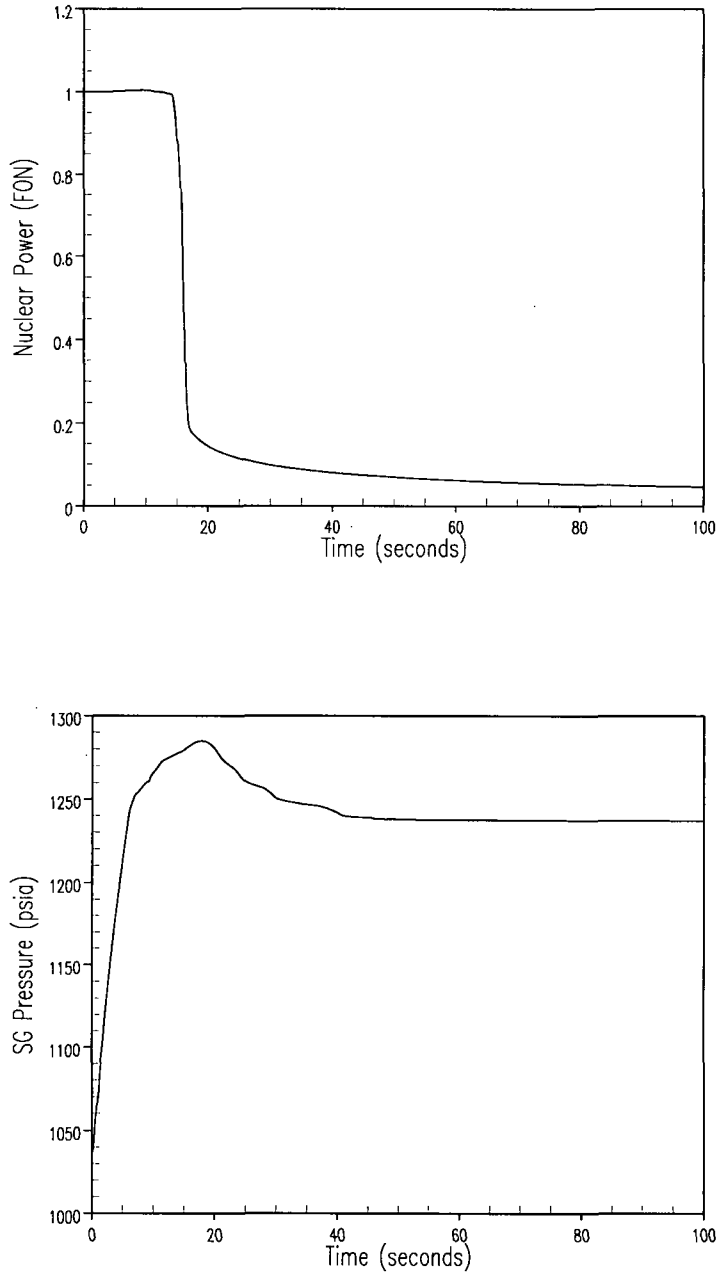
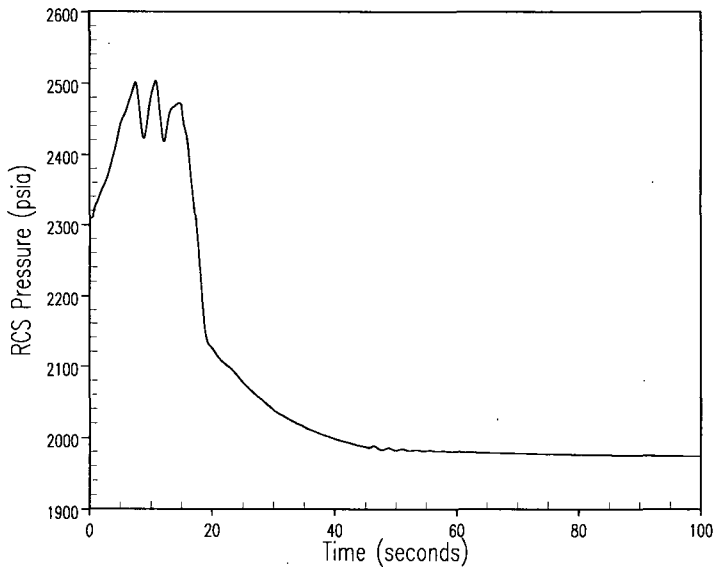


Figure 2.3.1-1 Unit 1 Loss of Load/Turbine Trip DNBR Case Nuclear Power/Heat Flux and Steam Generator Pressure Versus Time



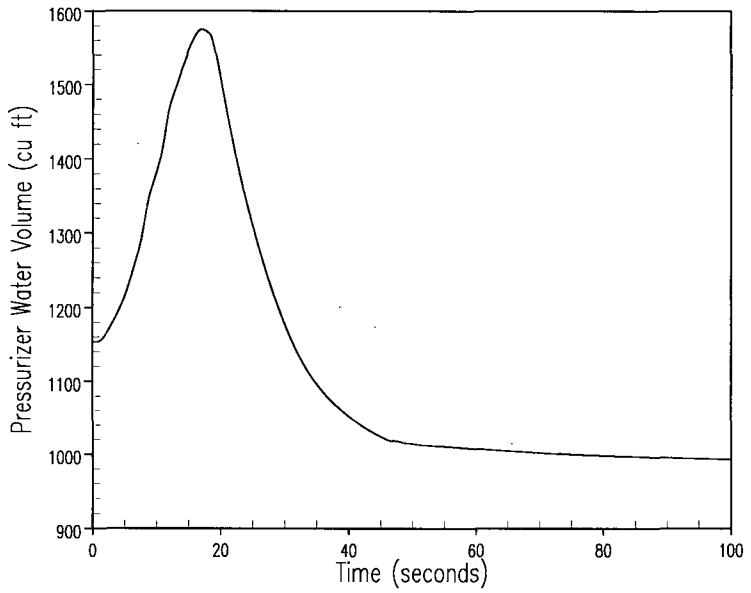
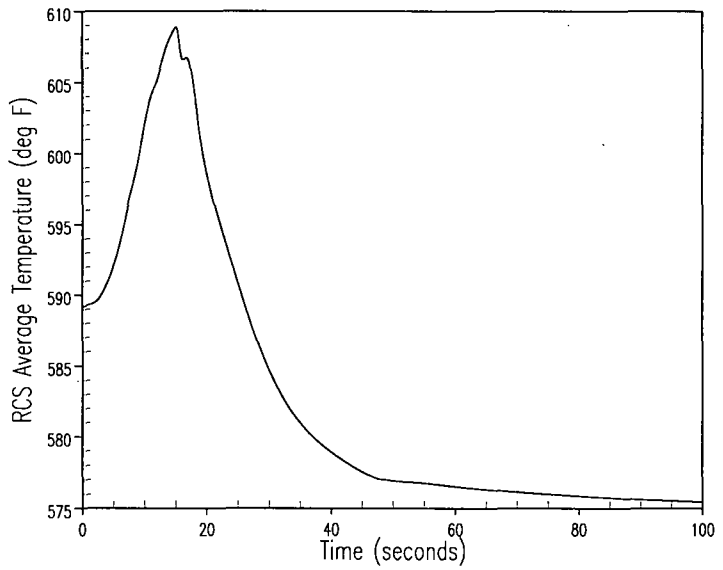


Figure 2.3.1-2 Unit 1 Loss of Load/Turbine Trip DNBR Case RCS Pressure and Pressurizer Water Volume Versus Time



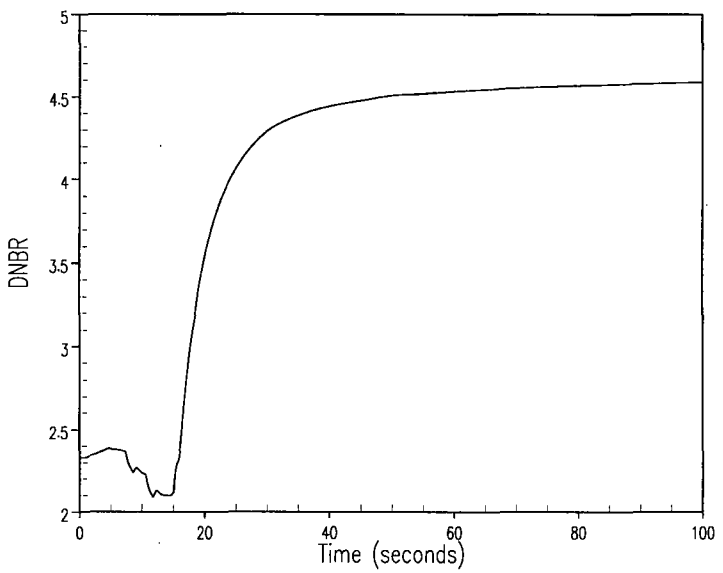
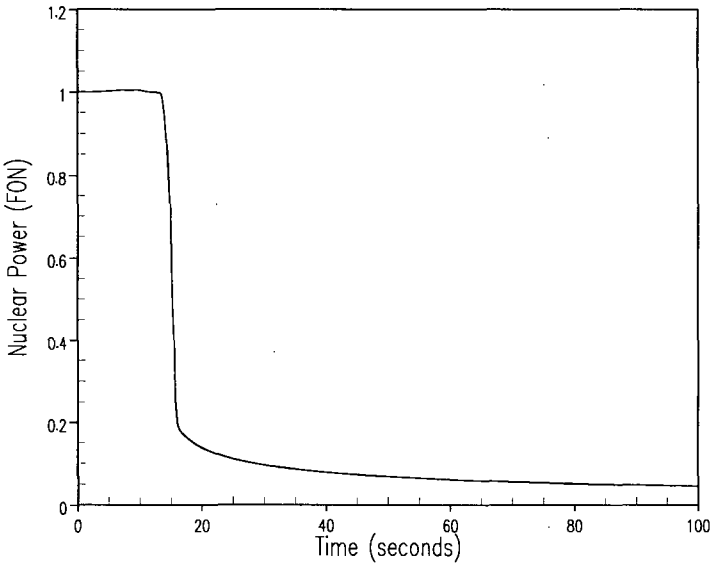


Figure 2.3.1-3 Unit 1 Loss of Load/Turbine Trip DNBR Case RCS Average Temperature and DNBR Versus Time



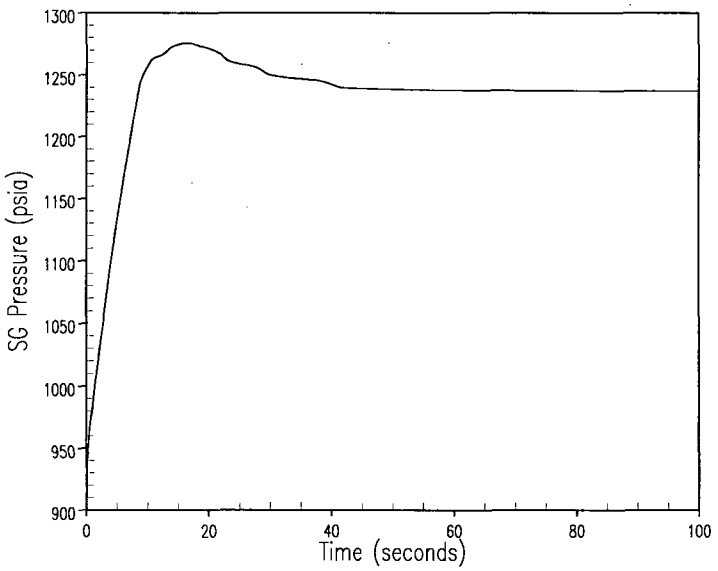
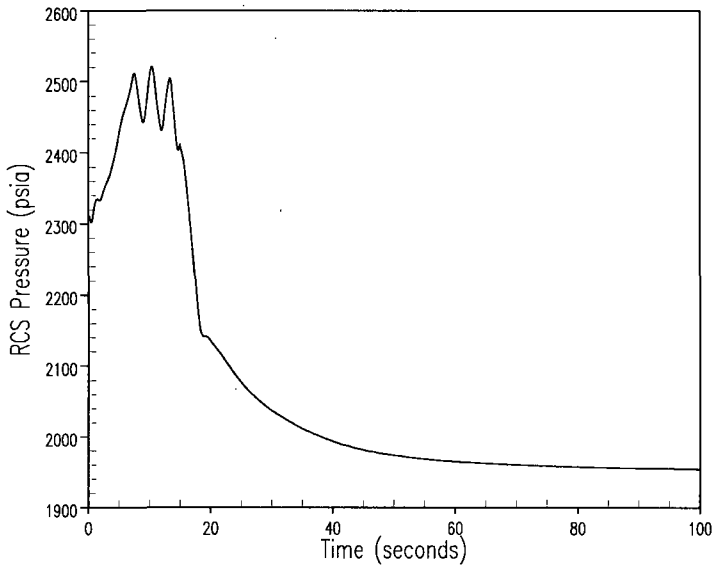


Figure 2.3.1-4 Unit 2 Loss of Load/Turbine Trip DNBR Case Nuclear Power and Steam Generator Pressure Versus Time



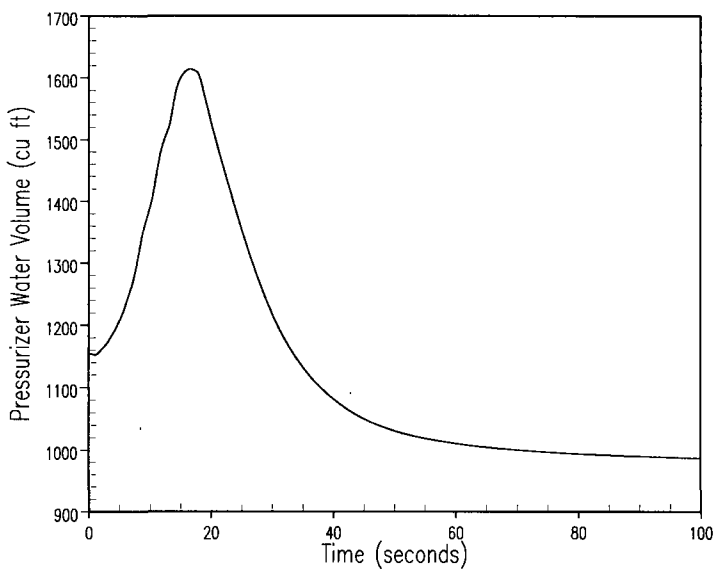
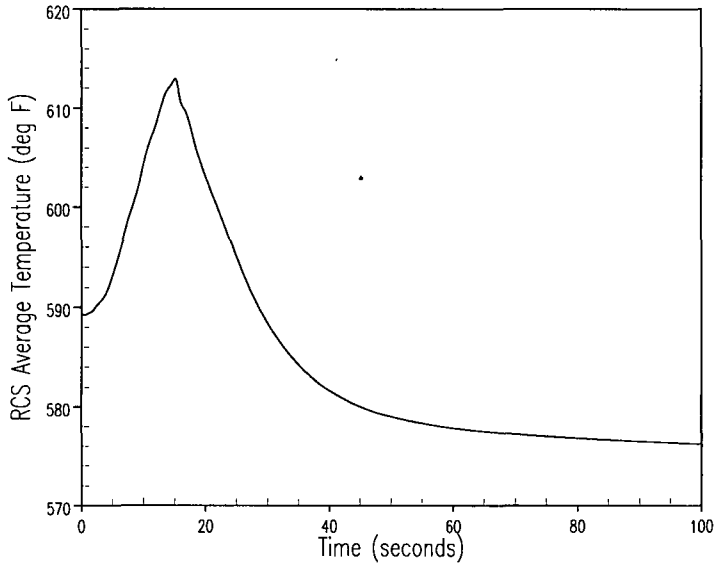


Figure 2.3.1-5 Unit 2 Loss of Load/Turbine Trip DNBR Case RCS Pressure and Pressurizer Water Volume Versus Time



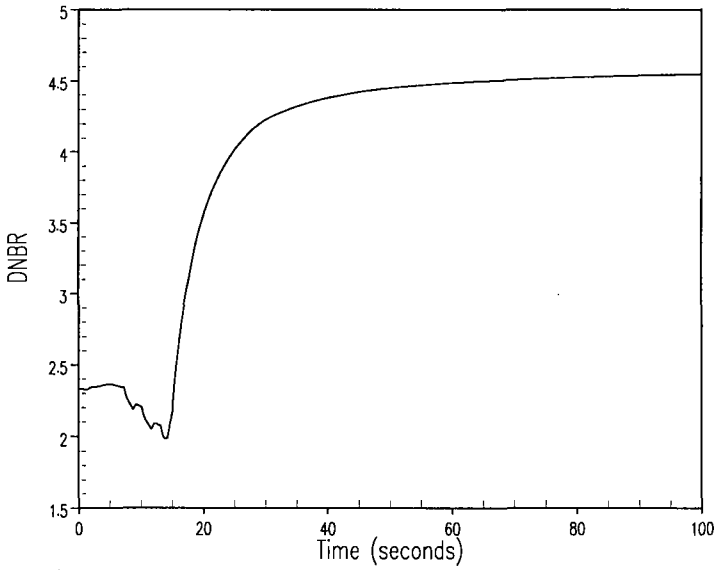


Figure 2.3.1-6 Unit 2 Loss of Load/Turbine Trip DNBR Case RCS Average Temperature and DNBR Versus Time

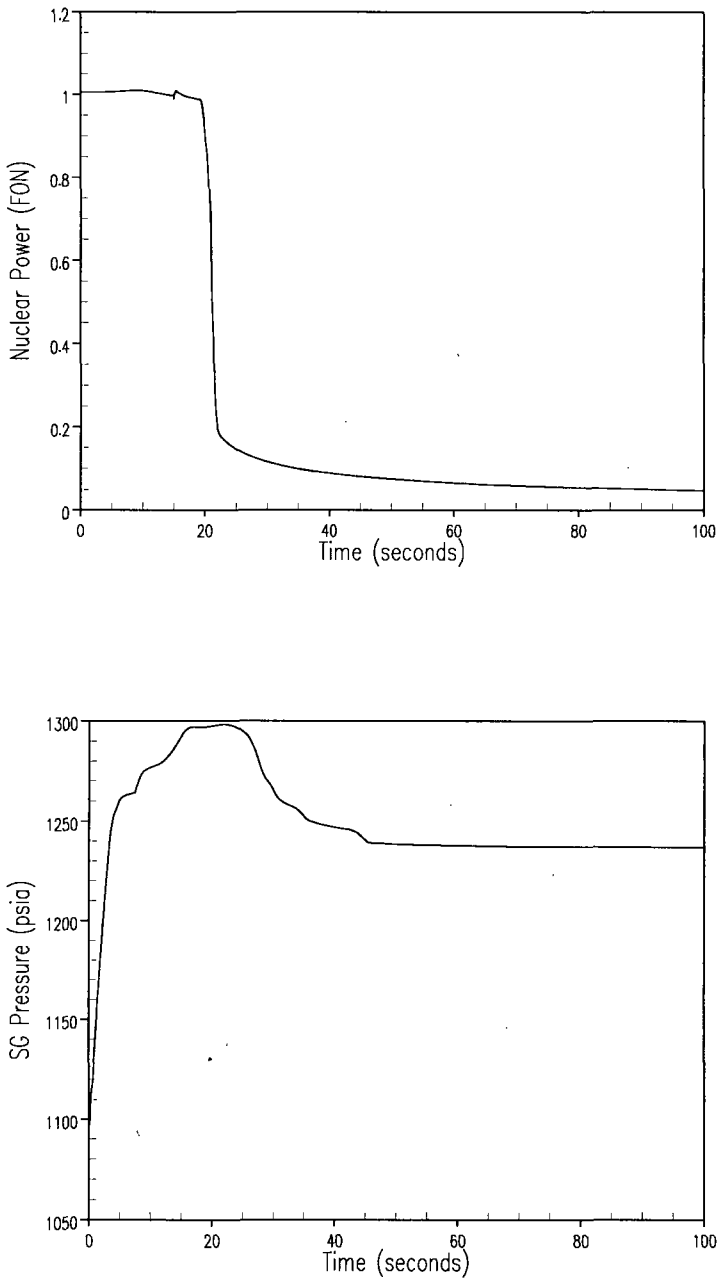
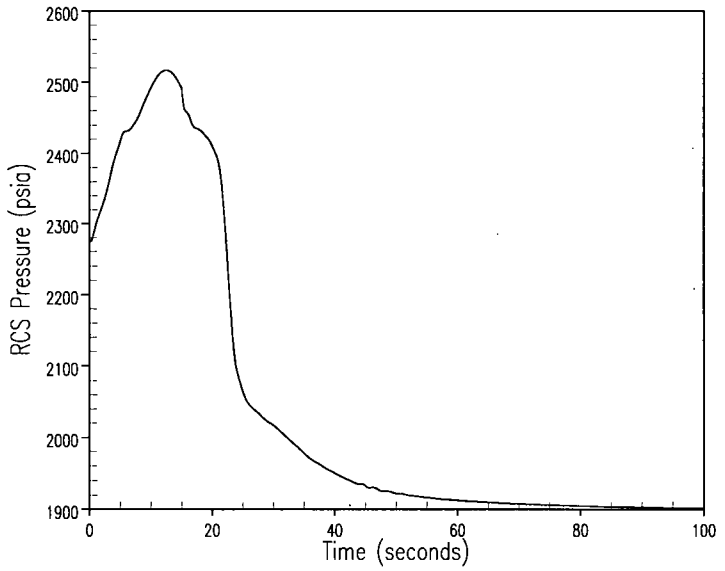


Figure 2.3.1-7 Unit 1 Loss of Load/Turbine Trip MSS Pressure Case Nuclear Power and Steam Generator Pressure Versus Time



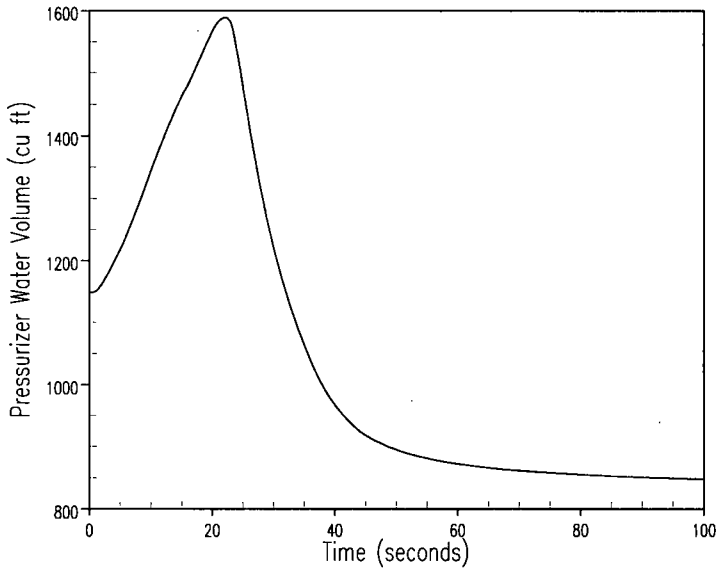


Figure 2.3.1-8 Unit 1 Loss of Load/Turbine Trip MSS Pressure Case RCS Pressure and Pressurizer Water Volume Versus Time

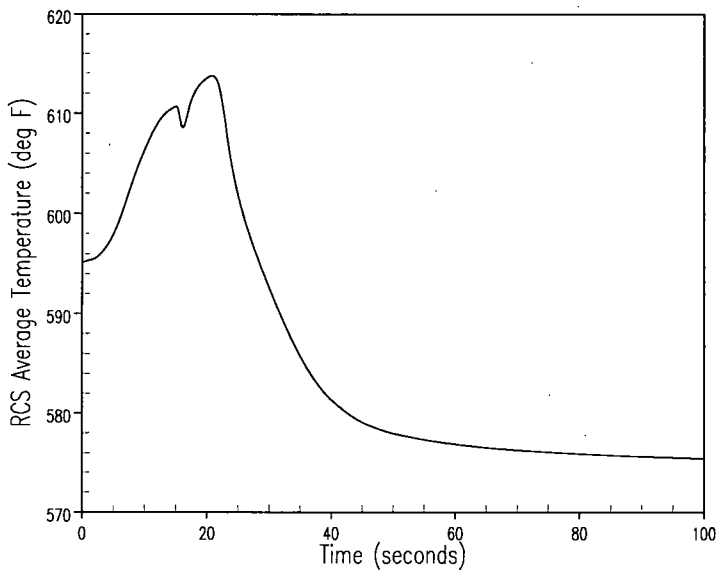


Figure 2.3.1-9 Unit 1 Loss of Load/Turbine Trip MSS Pressure Case RCS Average Temperature Versus Time

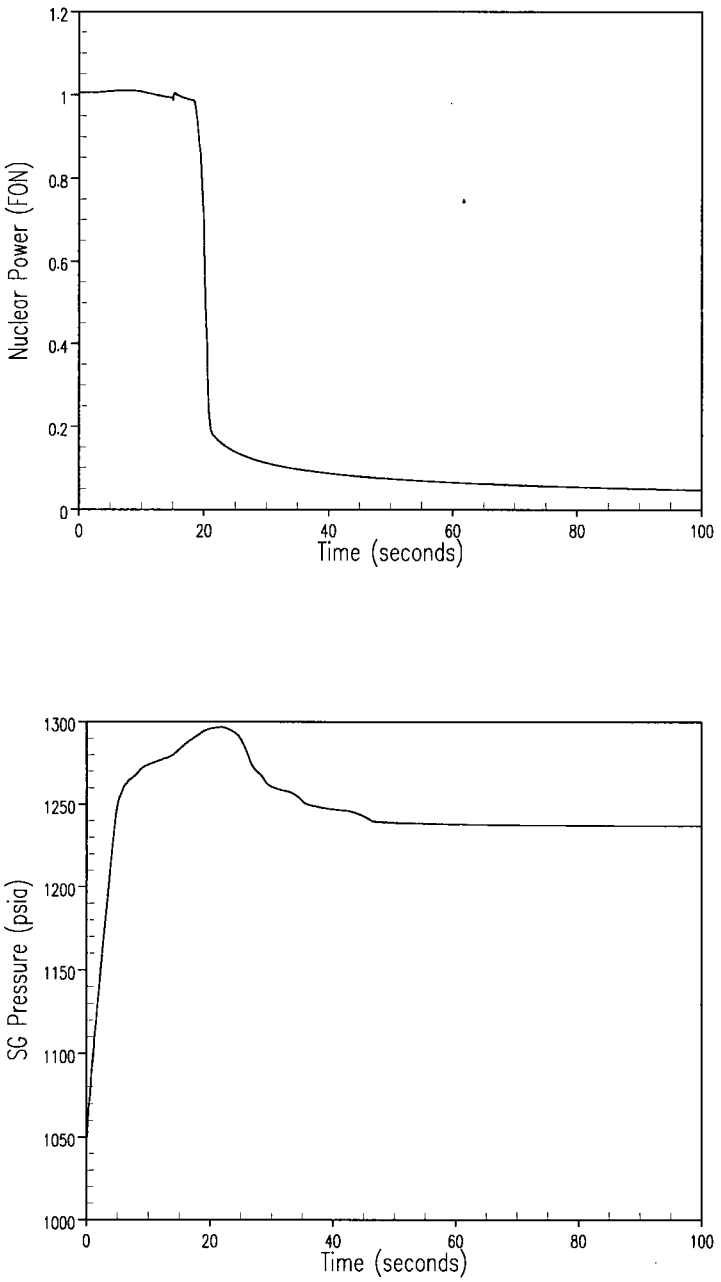


Figure 2.3.1-10 Unit 2 Loss of Load/Turbine Trip MSS Pressure Case Nuclear Power and Steam Generator Pressure Versus Time

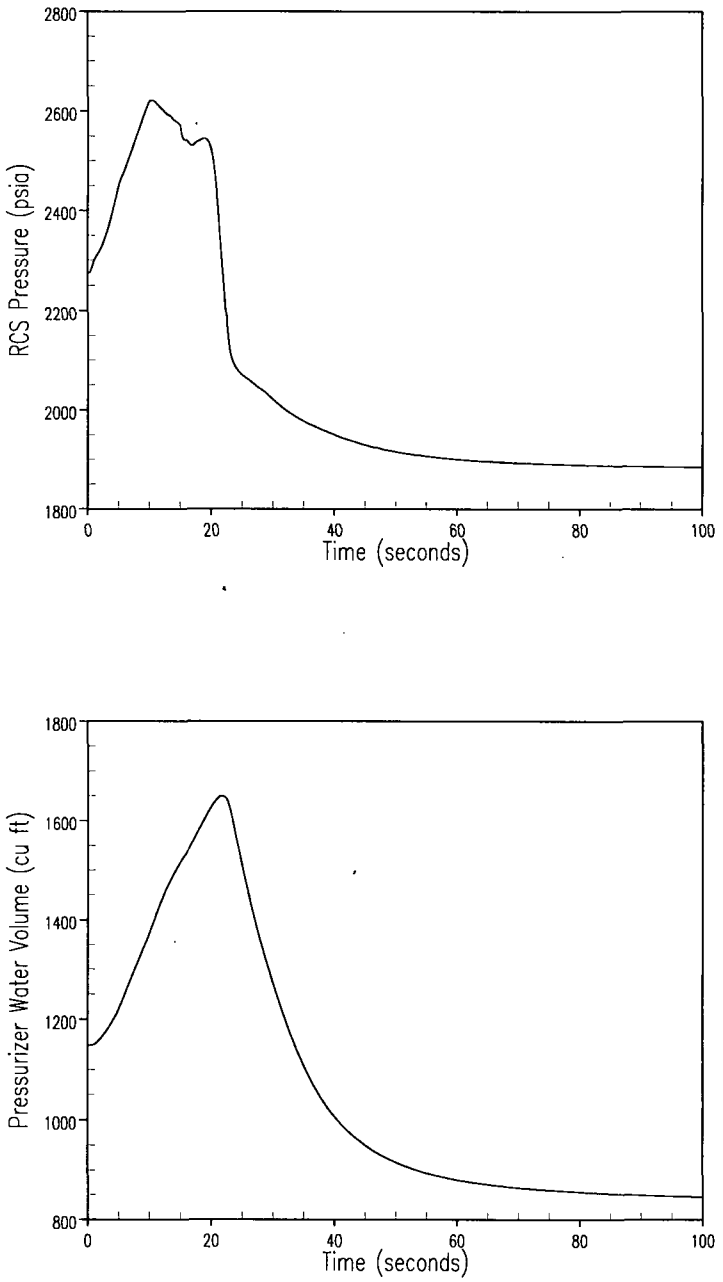


Figure 2.3.1-11 Unit 2 Loss of Load/Turbine Trip MSS Pressure Case RCS Pressure and Pressurizer Water Volume Versus Time

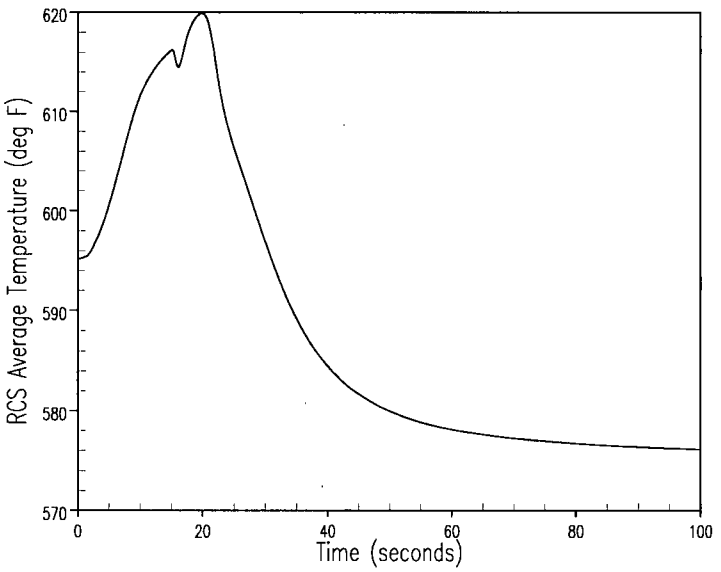


Figure 2.3.1-12 Unit 2 Loss of Load/Turbine Trip MSS Pressure Case RCS Average Temperature Versus Time

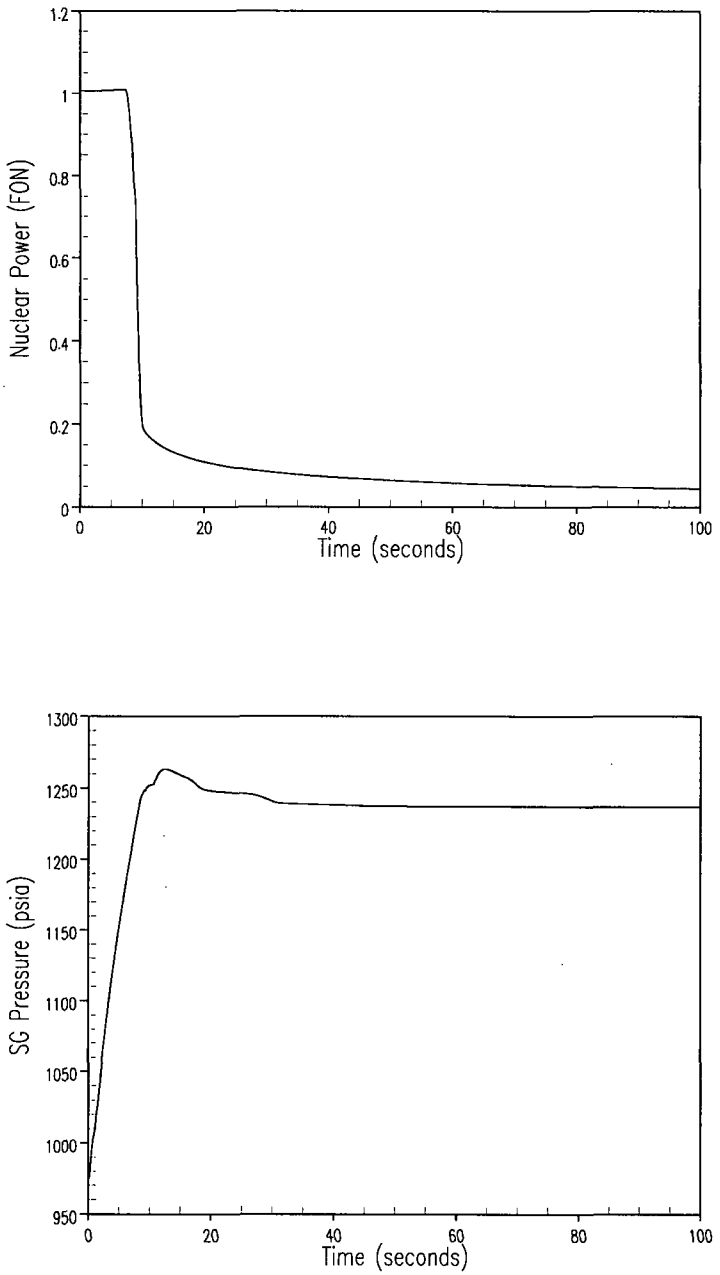


Figure 2.3.1-13 Unit 1 Loss of Load/Turbine Trip RCS Pressure Case Nuclear Power and Steam Generator Pressure Versus Time

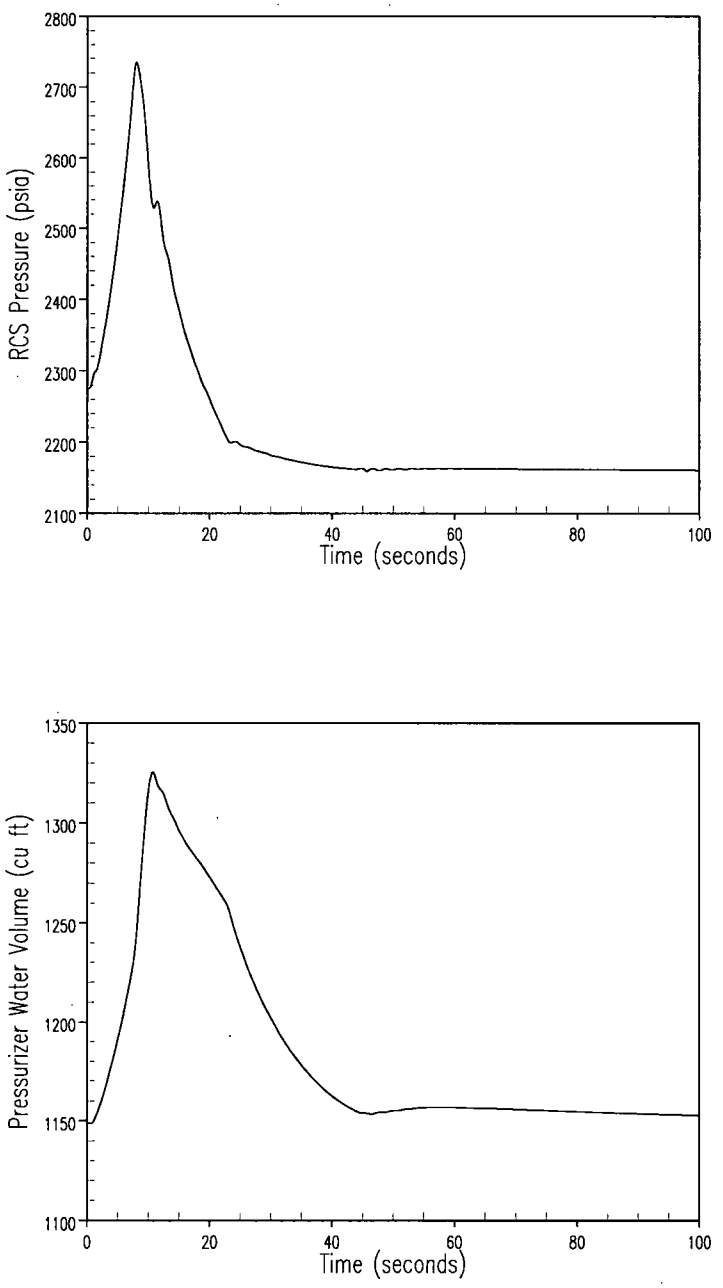


Figure 2.3.1-14 Unit 1 Loss of Load/Turbine Trip RCS Pressure Case RCS Pressure and Pressurizer Water Volume Versus Time

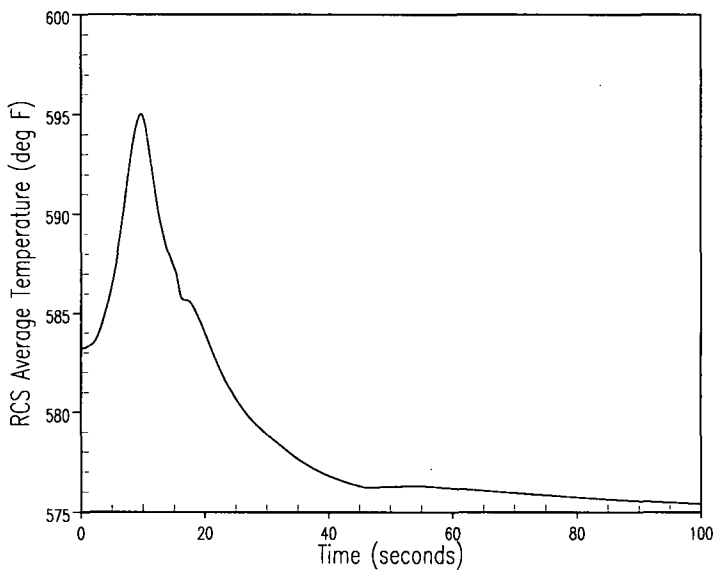
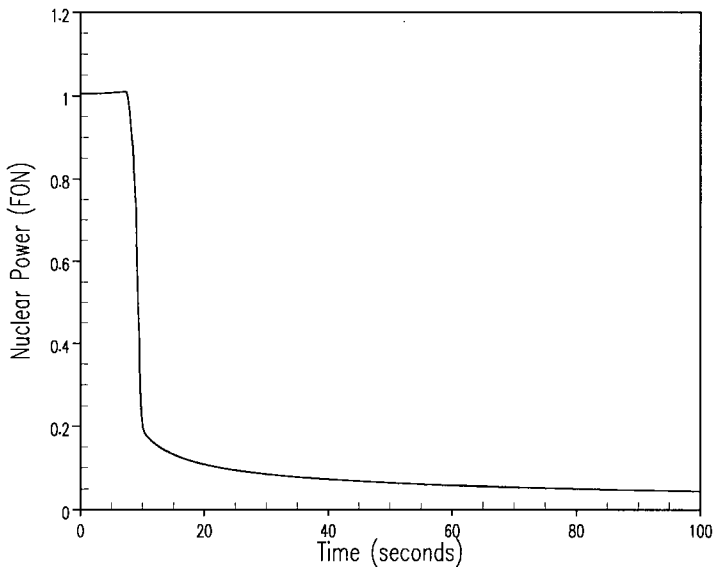


Figure 2.3.1-15 Unit 1 Loss of Load/Turbine Trip RCS Pressure Case RCS Average Temperature Versus Time



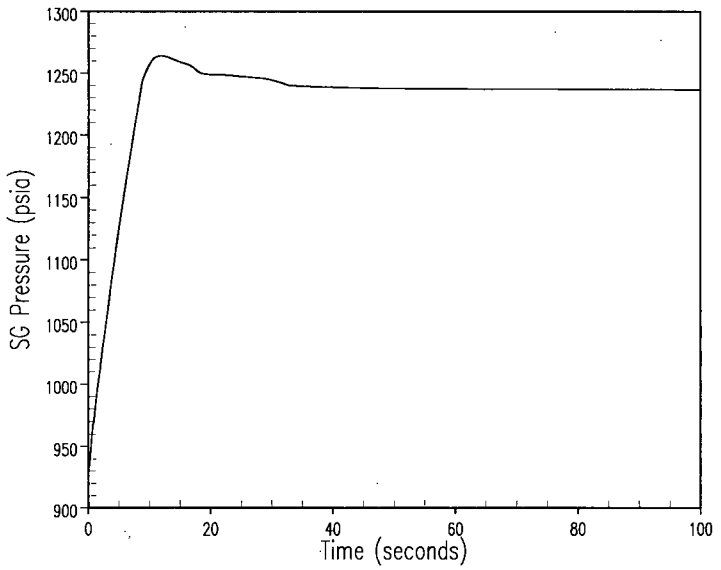


Figure 2.3.1-16 Unit 2 Loss of Load/Turbine Trip RCS Pressure Case Nuclear Power and Steam Generator Pressure Versus Time

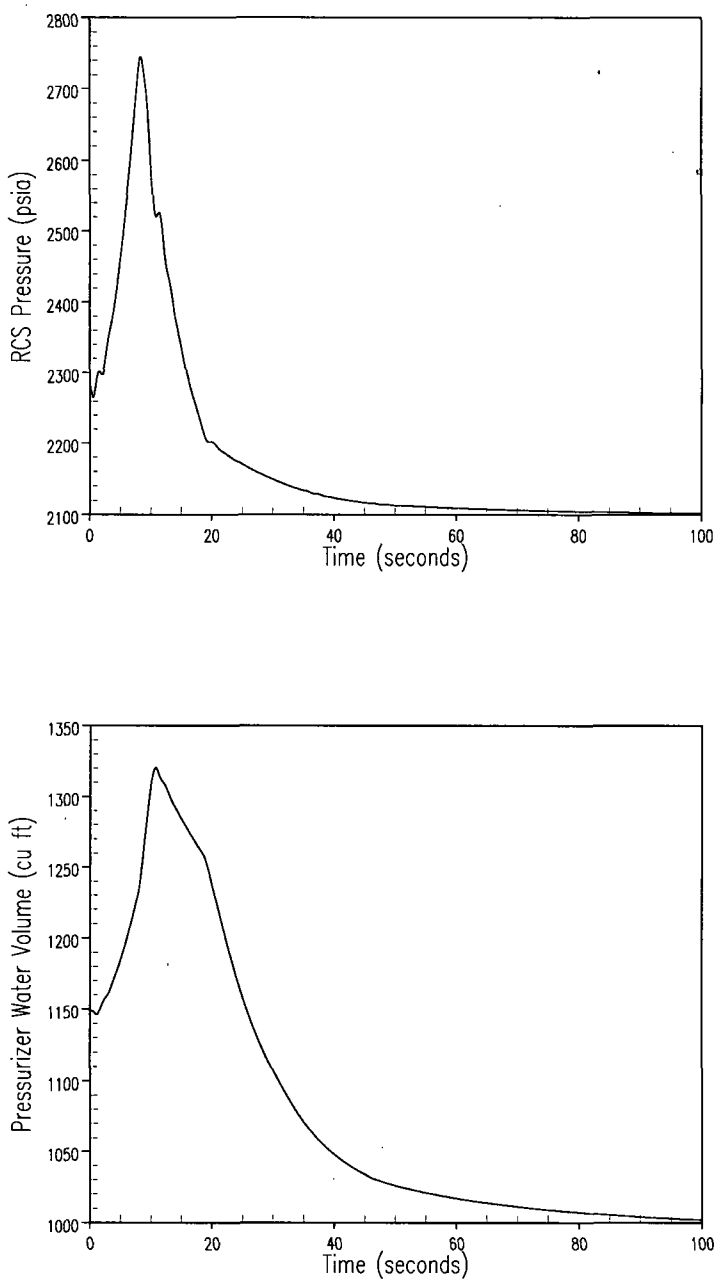


Figure 2.3.1-17 Unit 2 Loss of Load/Turbine Trip RCS Pressure Case RCS Pressure and Pressurizer Water Volume Versus Time

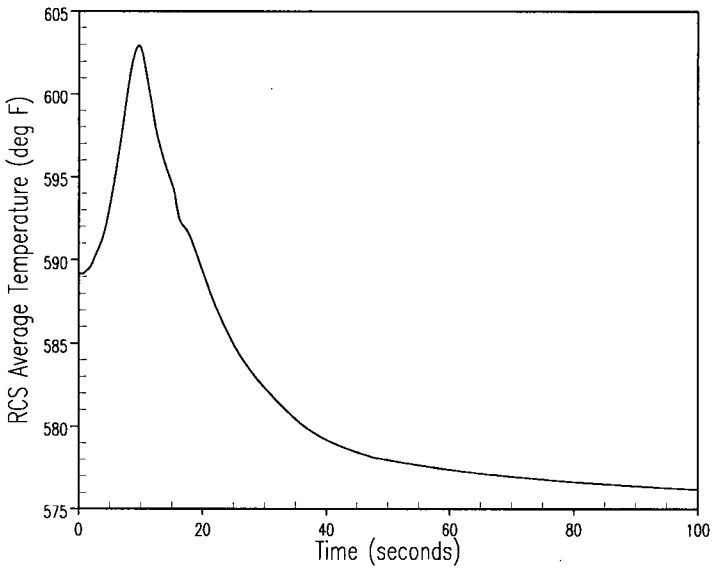


Figure 2.3.1-18 Unit 2 Loss of Load/Turbine Trip RCS Pressure Case RCS Average Temperature Versus Time

2.3.2 Loss of Non-Emergency AC Power to the Station Auxiliaries

2.3.2.1 Technical Evaluation

2.3.2.1.1 Introduction

A complete loss of non-emergency AC power (FSAR Section 15.2.6) may result in a loss of power to the plant auxiliaries, that is, the RCPs, main feedwater pumps, condensate pumps, etc. The loss of power may be caused by a complete loss-of-the-offsite grid accompanied by a turbine generator trip at the station, or by a loss-of-the-onsite-AC distribution system. The events following a loss-of-AC power with turbine and reactor trip are described in the sequence listed below:

- Plant vital instruments are supplied by emergency DC power sources.
- The steam generator PORVs are automatically opened to the atmosphere as the steam system pressure rises following the trip. The condenser is assumed unavailable for steam dump. If the relief capacity of the PORVs is inadequate, the MSSVs can lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.
- The steam generator PORVs (or MSSVs, if the PORVs are unavailable) are used to dissipate the residual decay heat and to maintain the plant at the Mode 3 (hot standby) condition as the no-load temperature is approached.
- The emergency diesel generators start on loss of voltage to the plant emergency busses and begin to supply plant vital loads.

The auxiliary feedwater system is started automatically as follows:

- Two motor-driven auxiliary feedwater (MDAFW) pumps are started on any of the following:
  - Low-low water level in two-out-of-four level signals in any steam generator
  - Trip of all main feedwater pumps
  - Safety injection signal
  - Loss of offsite power
  - Manual actuation
  - ATWS mitigation system actuation circuitry (AMSAC) actuation signal

- One turbine-driven auxiliary feedwater (TDAFW) pump is started on any of the following:
  - Low-low water level in two-out-of-four level signals in any two of the four steam generators
  - Loss of offsite power
  - Manual actuation
  - AMSAC actuation signal

Following the loss of power to the RCPs, heat removal is maintained by natural circulation in the RCS loops. Following the RCP coastdown, the natural circulation capability of the RCS will remove decay heat from the core, aided by the auxiliary feedwater (AFW) flow in the secondary system. Demonstrating that acceptable results can be obtained for this event proves that the resultant natural circulation flow in the RCS is adequate to remove decay heat from the core.

2.3.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

This event is considered to be bounded by other events as described below. Therefore, there are no explicit input parameters or assumptions.

Based on its frequency of occurrence, the loss-of-non-emergency-AC-power accident is considered a Condition II event as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. The following items summarize the acceptance criteria associated with this event:

- Fuel cladding integrity is maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit.
- Pressures in the RCS and MSS are maintained below 110 percent of the design pressures.
- An incident of moderate frequency does not generate a more serious plant condition without other faults occurring independently.

The first few seconds after a loss-of-AC-power to the RCPs closely resembles the analysis of the complete loss-of-flow event (see subsection 2.4.1) in that the RCS experiences a rapid flow reduction transient. This aspect of the loss-of-AC-power event is bounded by the analysis performed for the complete loss-of-flow event that demonstrates that the DNB design basis is met. With respect to overpressurization of the primary and secondary sides, this event is bounded by the loss of load/turbine trip event (see subsection 2.3.1).

The analysis of the loss of normal feedwater event with loss-of-AC-power (see subsection 2.3.3) demonstrates that RCS natural circulation and the AFW system are capable of removing the stored and residual heat. The plant is therefore able to return to a safe condition. A restrictive

acceptance criterion that the pressurizer does not become water-solid was used for this event. This criterion establishes the acceptable capacity of the AFW system, ensuring that the pressure criteria and minimum DNBR criterion remained satisfied for the long-term portion of the event, and demonstrated that a more serious plant condition is precluded.

2.3.2.1.3 Description of Analyses and Evaluations

As noted above, this event is bounded by events described in other sections of this report. Therefore, no explicit analyses were performed.

2.3.2.1.4 Results

As noted above, this event is bounded by events described in other sections of this report. Therefore, no explicit results are reported here. In addition, the transient response of the RCS following a loss-of-AC-power is less severe than for the loss of normal feedwater with a loss of offsite power event reported in subsection 2.3.3.1.4. Those results demonstrate that the available natural circulation flow is sufficient to provide adequate core decay heat removal following reactor trip and reactor coolant pump coastdown.

2.3.2.2 Conclusions

Luminant Power has concluded from the evaluation of the loss of non-emergency AC power to the station auxiliaries event that operation of the plant at the proposed power level is acceptable. It is further concluded that the evaluation has demonstrated that the reactor protection and safety systems will continue to ensure that the specified acceptable fuel design limits are met and the RCPB pressure limits will not be exceeded as a result of the loss of non-emergency AC power to the station auxiliaries. Based on this, the plant will continue to meet the requirements of GDCs -10, -15, and -26

2.3.3 Loss of Normal Feedwater Flow

2.3.3.1 Technical Evaluation

2.3.3.1.1 Introduction

A loss of normal feedwater (LONF) flow (FSAR Section 15.2.7) (from pump failures, valve malfunctions, or a complete loss of offsite AC power) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If an alternative supply of feedwater is not supplied, core residual heat following reactor trip would heat the primary system water to the point where water relief from the pressurizer could occur, resulting in a substantial loss of water from the RCS. Since the plant is tripped well before the steam generator heat transfer capability is reduced, the primary system variables do not approach a condition that causes a DNB ratio (DNBR) limit violation.

Two scenarios are analyzed for a LONF event. The first is a case where offsite AC power is maintained, and the second is a case where offsite AC power is lost, which results in reactor coolant pump coastdown as discussed in subsection 2.3.2.

The following events occur following the reactor trip for the LONF:

- The steam generator PORVs are automatically opened to the atmosphere as the steam system pressure rises following a loss of feedwater. The condenser is assumed unavailable for steam dump. If the relief capacity of the PORVs is inadequate, the MSSVs can lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

- Plant vital instruments are supplied from emergency DC power sources for the case with a loss of offsite power.

The following provide the necessary protection in the event of a LONF:

- The reactor can be tripped on one or more of the following reactor trip signals:

  - Pressurizer high pressure trip signal
  - Overtemperature N-16 trip signal
  - Low-low steam generator water level trip signal in any steam generator

- Two MDAFW pumps are started on any of the following:

  - Low-low water level in two-out-of-four level signals in any steam generator
  - Trip of all main feedwater pumps
  - Safety injection signal
  - Loss of offsite power
  - Manual actuation
  - ATWS mitigation system actuation circuitry (AMSAC) actuation signal

- One TDAFW pump is started on any of the following:

  - Low-low water level in two-out-of-four level signals in any two of the four steam generators

  - Loss of offsite power

  - Manual actuation

  - AMSAC actuation signal

- The MSSVs open to provide an additional heat sink and protection against secondary side overpressure.

- The PSVs may open to provide protection against overpressure of the RCS.

The analysis showed that following a LONF (with or without offsite power), the auxiliary feedwater (AFW) system is capable of removing the stored and residual heat, thus preventing overpressurization of the RCS, overpressurization of the secondary side, water relief from the pressurizer, and uncovery of the reactor core.

2.3.3.1.2 Input Parameters, Assumptions, and Acceptance Criteria

The following assumptions were made in the LONF analyses:

- The plant is initially operating at 100.6 percent of the NSSS power of 3,628 MWt.

- For the case with offsite power, a maximum RCP heat of 20.0 MWt was conservatively modeled. The RCPs were assumed to continuously operate throughout the transient providing a constant reactor coolant volumetric flow equal to the thermal design flow value. Although not assumed in this case, the RCPs could be manually tripped at some later time in the transient to reduce the heat addition to the RCS caused by the operation of the pumps.

- For the case without offsite power, power was assumed to be lost to the RCPs after the start of rod motion. For this case, the nominal RCP heat of 16.0 MWt was modeled. Assuming a nominal RCP heat was conservative since the RCPs coasted down and ceased to add heat to the primary coolant while the core decay heat was based on a slightly higher initial core power. The post-trip heat removal from the core relied upon natural circulation flow in the RCS loops.

- Main feedwater temperature conditions at 390° and 450.3°F were analyzed.

- Reactor vessel average coolant temperature (T_{avg}) conditions at the low and high ends of the full-power temperature window (574.2° to 589.2°F) were considered. In addition, since the pressurizer level program has a breakpoint at 584.7°F (that is, pressurizer level program is linear from 25-percent span at the no-load temperature of 557°F to 60-percent span at a full-power temperature of 584.7°F) that point was also specifically analyzed.

- The direction of conservatism for both initial reactor vessel average coolant temperature and pressurizer pressure can vary. As such, cases were considered with the initial temperature and pressure uncertainties applied in each direction. The initial average temperature uncertainty was assumed to be ± 6.0°F. The initial pressurizer pressure uncertainty was assumed to be ± 30 psi.

- Reactor trip occurs on steam generator low-low water level at 0 percent of the narrow-range span for Unit 1 with the Model Δ76 steam generators and at 10 percent of the narrow-range span for Unit 2 with the Model D-5 steam generators.

- It was assumed that two MDAFW pumps are available to supply flow to all four steam generators, 60 seconds following a low-low steam generator water level signal. The worst single failure for this analysis is the loss of the TDAFW pump.

- The pressurizer heaters were modeled to exacerbate the heatup and volumetric expansion of the water in the pressurizer. In addition, the pressurizer sprays were assumed to be operable, and cases were analyzed with and without the PORVs available to determine the limiting configuration. It was found that the cases without PORV availability were more limiting.

- Secondary system steam relief is achieved through the self-actuated MSSVs. Note that steam relief would normally be provided by the PORVs or condenser dump valves for most LONF cases. However, the condenser dump valves and the PORVs were assumed to be unavailable.

- The MSSVs were modeled assuming a 3-percent tolerance and an accumulation model that assumes that the valves were wide open once the pressure exceeded the setpoint (plus tolerance) by 5 psi (accumulation).

- Core residual heat generation was based on the 1979 version of ANS 5.1 (Reference 1). ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates. Long-term operation at the initial power level preceding the trip was assumed.

- Steam generator tube plugging (SGTP) levels of both 0 percent and 10 percent were analyzed.

Based on its frequency of occurrence, the LONF accident is considered a Condition II event as defined by the ANS. The following items summarize the acceptance criteria associated with this event:

- Fuel cladding integrity is maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit.

- Pressures in the RCS and MSS are maintained below 110 percent of the design pressures.

- An incident of moderate frequency does not generate a more serious plant condition without other faults occurring independently.

With respect to overpressurization, the LONF event, both with and without offsite power, is bounded by the loss of load/turbine trip (LOL/TT) event discussed in subsection 2.3.1 in which assumptions are made to conservatively calculate the RCS and MSS pressure transients. For the LONF event, turbine trip occurs after reactor trip, whereas for LOL/TT the turbine trip is the initiating fault. Therefore, the primary/secondary power mismatch and resultant RCS and MSS heatup and pressurization transients are always more severe for LOL/TT than for LONF.

With respect to DNB, the LONF event with offsite power is also bounded by the LOL/TT event. Both of these events represent a reduction in the heat removal capability of the secondary system. For the LONF event, the RCS temperature increases gradually as the steam generators boil down to the low-low level trip setpoint, at which time reactor trip occurs, followed by turbine trip. For the LOL/TT event, the turbine trip is the initiating event, and the loss of heat sink is much more severe. As such, the initial RCS heatup will be much more severe for the LOL/TT event than for the LONF event, and the LOL/TT event will always be more severe with respect to the minimum DNBR criterion. The LONF event without offsite power is bounded by the complete loss-of-flow event discussed in subsection 2.4.1. The DNBR consequences of the LONF event without offsite power are similar to those of the LONF event with offsite power, with the additional effect of a reduction in the core flow rate caused by loss of power to the RCPs. However, the LONF event without offsite power is bounded by the complete loss-of-flow event, for which the RCP coastdown is the initiating fault and the reactor trip occurs when the core flow is already degraded.

The restrictive acceptance criterion that the pressurizer does not reach a water-solid condition was used for this event. This criterion demonstrates that the capacity of the AFW system is sufficient to dissipate core residual heat, stored energy, and RCP heat (for the cases with offsite power available) without the event progressing into a more serious plant condition (water relief through the pressurizer PORVs or safety valves is precluded).

2.3.3.1.3 Description of Analyses and Evaluations

A detailed analysis using the RETRAN (Reference 2) computer code was performed to determine the plant transient conditions following a LONF. The code modeled the core neutron kinetics, RCS, pressurizer, pressurizer heaters, pressurizer sprays, steam generators, MSSVs, and the AFW system. The code also computed pertinent variables, including the pressurizer pressure, pressurizer water level, steam generator mass, and reactor coolant average temperature.

2.3.3.1.4 Results

LONF Flow Results with Offsite Power

For Unit 1 with the Model Δ76 steam generators, the most limiting LONF case with offsite power available was that with the temperature uncertainty subtracted from the nominal T_{avg} value at the low end of the full-power temperature window (that is, 574.2°F - 6°F), pressure uncertainty added to the nominal value (that is, 2,250 psia + 30 psi), PORVs not available, 0-percent SGTP, and high main feedwater temperature (450.3°F) conditions.

For Unit 2 with the Model D-5 steam generators, the most limiting LONF case with offsite power available was that with the temperature uncertainty added to the nominal T_{avg} value at the high end of the full-power temperature window (that is, 589.2°F + 6°F), pressure uncertainty subtracted from the nominal value (that is, 2,250 psia - 30 psi), PORVs not available, 10-percent SGTP, and low main feedwater temperature (390.0°F) conditions.

The calculated sequence of events for this event is listed in Tables 2.3.3-1 and 2.3.3-2 for Units 1 and 2, respectively. Figures 2.3.3-1 through 2.3.3-4 (Unit 1) and Figures 2.3.3-5 through 2.3.3-8 (Unit 2) present transient plots of the significant plant parameters following a LONF with offsite power for the limiting cases discussed above for Units 1 and 2. Note that there are noticeable differences between Unit 1 and Unit 2 in some of the transient trends shown in the figures, e.g., pressurizer pressure. These differences are due to the fact that the pressurizer safety valves actuate in the limiting Unit 2 case, but not the limiting Unit 1 case.

Following the reactor and turbine trip from full load, the water level in the steam generators fell due to a reduction of the steam generator void fraction and because steam flow through the safety valves continued to dissipate the stored and generated heat. One minute following the initiation of the low-low steam generator level trip, the MDAFW pumps automatically started, consequently reducing the rate at which the steam generator water level was decreasing.

The capacity of the MDAFW pumps enabled sufficient heat transfer from each steam generator to dissipate the core residual heat without the pressurizer reaching a water solid condition (as shown in Figures 2.3.3-3 and 2.3.3-7 for Units 1 and 2, respectively). This precluded any water relief through the RCS pressurizer relief valves or PSVs.

LONF Flow Results without Offsite Power

For Unit 1 with the Model Δ76 steam generators, the most limiting LONF case without offsite power available was with the temperature uncertainty subtracted from the nominal T_{avg} value at the low end of the full-power temperature window (that is, 574.2°F - 6°F), pressure uncertainty added to the nominal value (that is, 2,250 psia + 30 psi), PORVs not available, 0-percent SGTP, and low main feedwater temperature (390.0°F) conditions.

For Unit 2 with the Model D-5 steam generators, the most limiting LONF case without offsite power available was with the temperature uncertainty added to the nominal T_{avg} value at the high end of the full-power temperature window (that is, 589.2°F + 6°F), pressure uncertainty subtracted from the nominal value (that is, 2,250 psia - 30 psi), PORVs not available, 10-percent SGTP, and low main feedwater temperature (390.0°F) conditions.

The calculated sequence of events for this event is listed in Tables 2.3.3-3 and 2.3.3-4 for Units 1 and 2, respectively. Figures 2.3.3-9 through 2.3.3-12 (Unit 1) and Figures 2.3.3-13 through 2.3.3-16 (Unit 2) present transient plots of the significant plant parameters following a LONF without offsite power for the limiting cases discussed above for Units 1 and 2. Note that the pressurizer safety valves actuate in both the limiting Unit 1 case and the limiting Unit 2 case.

Following the reactor and turbine trip from full load, the water level in the steam generators fell due to a reduction of the steam generator void fraction and because steam flow through the safety valves continued to dissipate the stored and generated heat. One minute following the initiation of the low-low steam generator level trip, the MDAFW pumps automatically started, consequently reducing the rate at which the steam generator water level was decreasing.

The capacity of the MDAFW pumps enabled sufficient heat transfer from each steam generator to dissipate the core residual heat without the pressurizer reaching a water-solid condition (as shown in Figures 2.3.3-11 and 2.3.3-15 for Units 1 and 2, respectively). This precluded any water relief through the RCS pressurizer relief valves or PSVs.

The results of the analysis showed that the pressurizer did not reach a water-solid condition. Based on this, the LONF event will not progress into a more serious plant condition. Also, as discussed in subsection 2.3.3.1.2, with respect to overpressurization, the LONF event is bounded by the LOL/TT event. With respect to DNB, the LONF event with offsite power is bounded by the LOL/TT event and the LONF event without offsite power is bounded by the complete loss-of-flow event. Therefore, the LONF event will not adversely affect the core, the RCS, or the MSS.

2.3.3.2 Conclusion

The analyses of the LONF event were reviewed and Luminant Power has concluded that the analyses have adequately accounted for operation of the plant at the proposed uprated power level and was performed using acceptable analytical models. It is further concluded that the evaluation has demonstrated that the reactor protection and safety systems will continue to ensure that the specified acceptable fuel design limits are met and the RCPB pressure limits will not be exceeded as a result of the LONF. Based on this, the plant will continue to meet the requirements of GDCs -10, -15, and -26.

2.3.3.3 References

1. ANSI/ANS-5.1 – 1979, "American National Standard for Decay Heat Power in Light Water Reactors," August 1979.

2. WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

Table 2.3.3-1 Time Sequence of Events – Unit 1 LONF with Offsite Power	
Event	**Time (sec)**
Main Feedwater Flow Stops	0.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	50.7
Rods Begin to Drop	52.7
Flow from Two MDAFW Pumps is Initiated	110.7
Long-Term Peak Water Level in Pressurizer Occurs	5,484.0

Table 2.3.3-2 Time Sequence of Events – Unit 2 LONF with Offsite Power	
Event	**Time (sec)**
Main Feedwater Flow Stops	0.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	61.5
Rods Begin to Drop	63.5
Flow from Two MDAFW Pumps is Initiated	121.5
Long-Term Peak Water Level in Pressurizer Occurs	343.0

Table 2.3.3-3 Time Sequence of Events – Unit 1 LONF without Offsite Power	
Event	**Time (sec)**
Main Feedwater Flow Stops	0.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	59.1
Rods Begin to Drop	61.1
Reactor Coolant Pumps Tripped	63.1
Flow from Two MDAFW Pumps is Initiated	119.1
Long-Term Peak Water Level in Pressurizer Occurs	2,198.0

Table 2.3.3-4 Time Sequence of Events – Unit 2 LONF without Offsite Power	
Event	**Time (sec)**
Main Feedwater Flow Stops	0.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	55.1
Rods Begin to Drop	57.1
Reactor Coolant Pumps Tripped	59.1
Flow from Two MDAFW Pumps is Initiated	115.1
Long-Term Peak Water Level in Pressurizer Occurs	1,672.0

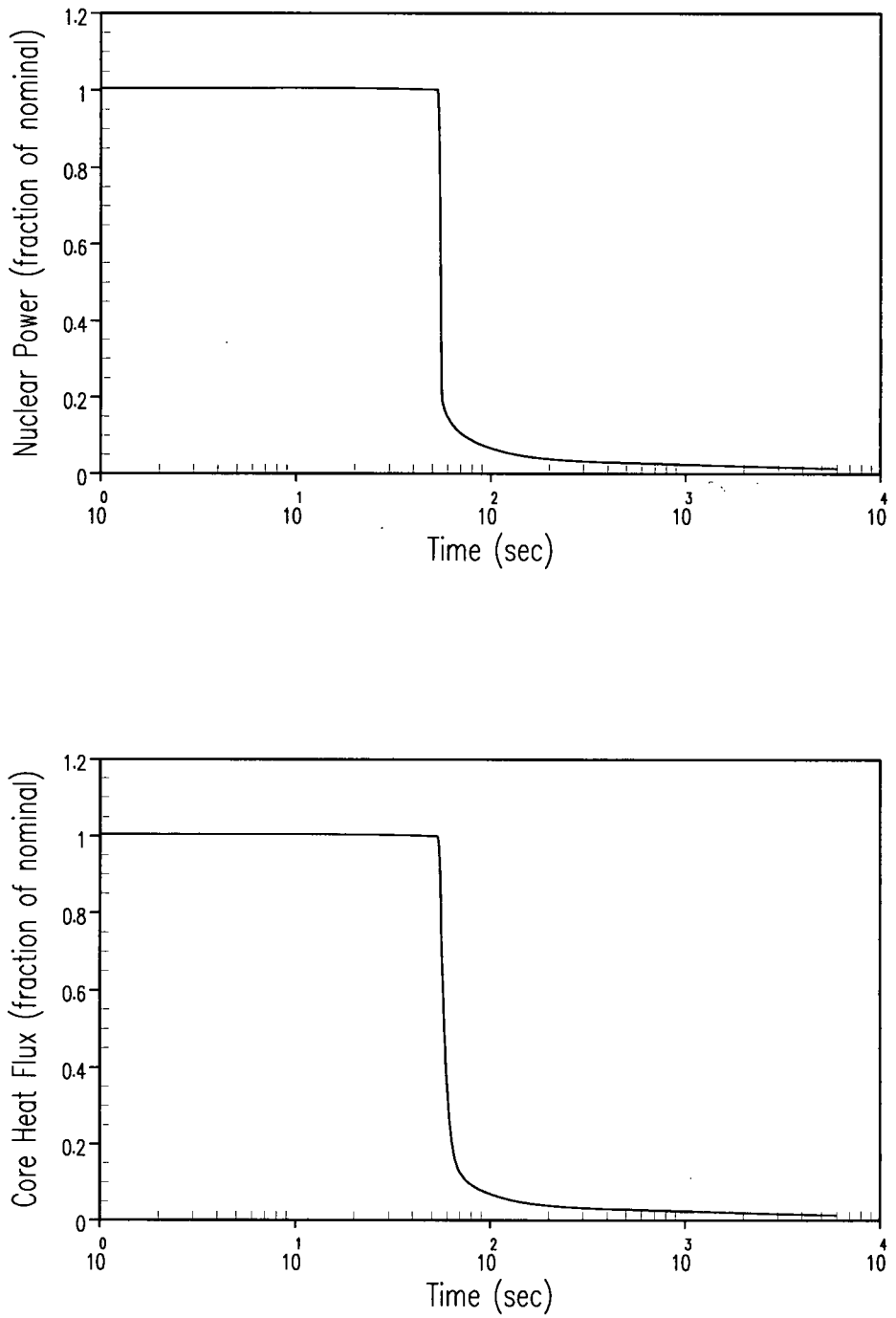


Figure 2.3.3-1 Unit 1 LONF with Offsite Power – Nuclear Power and Core Average Heat Flux Versus Time

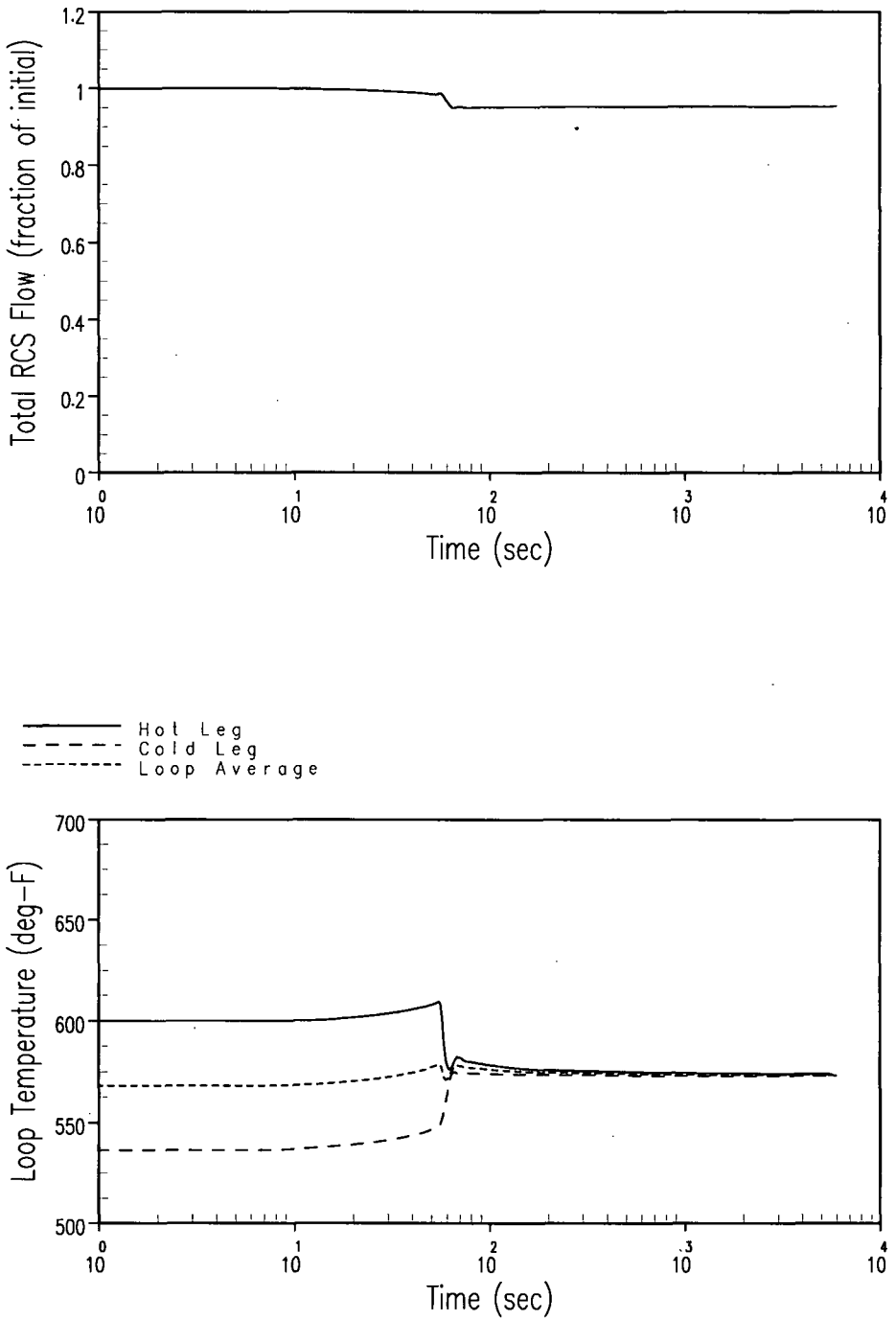


Figure 2.3.3-2 Unit 1 LONF with Offsite Power – Reactor Coolant Flow Rate and Loop Temperature Versus Time

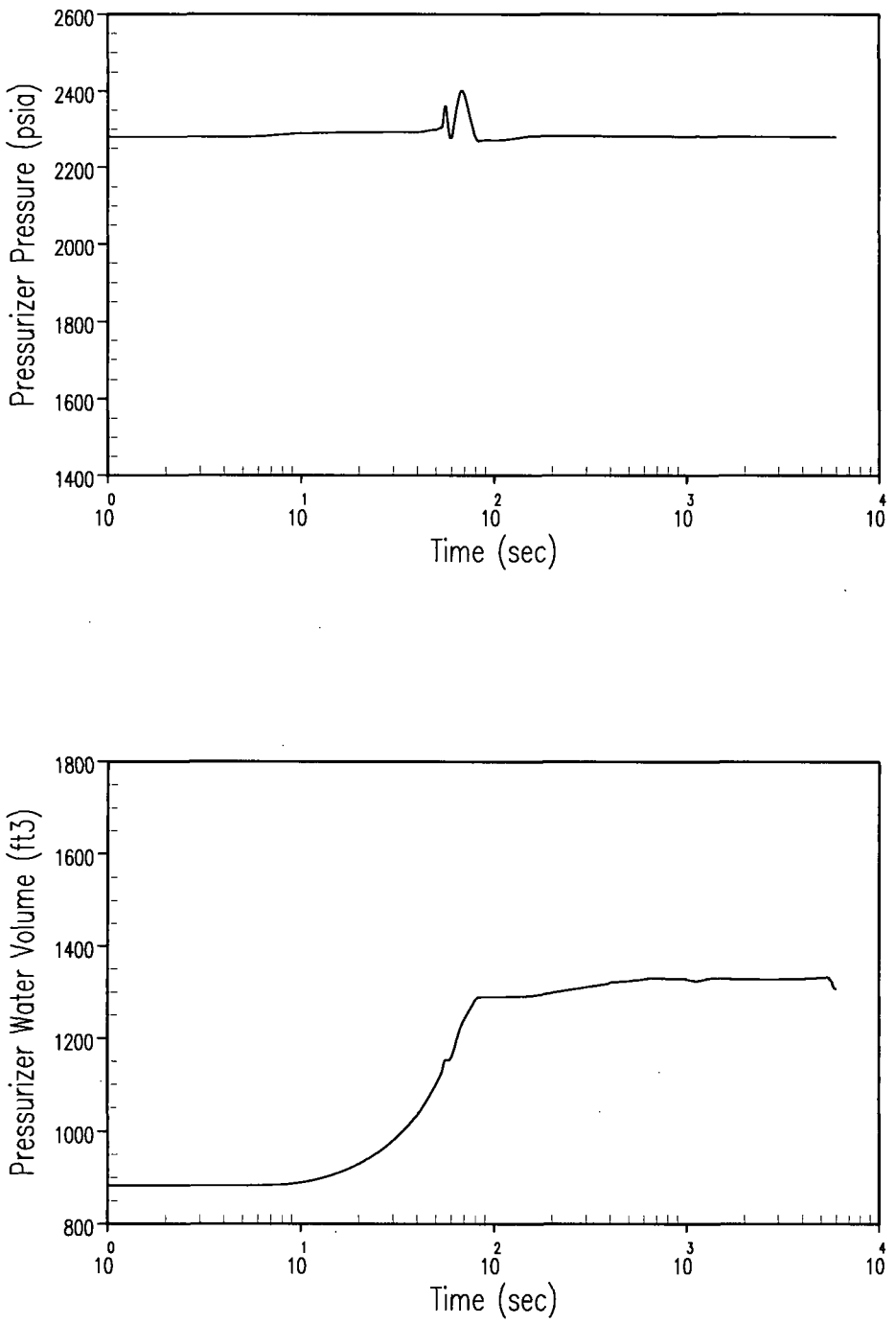
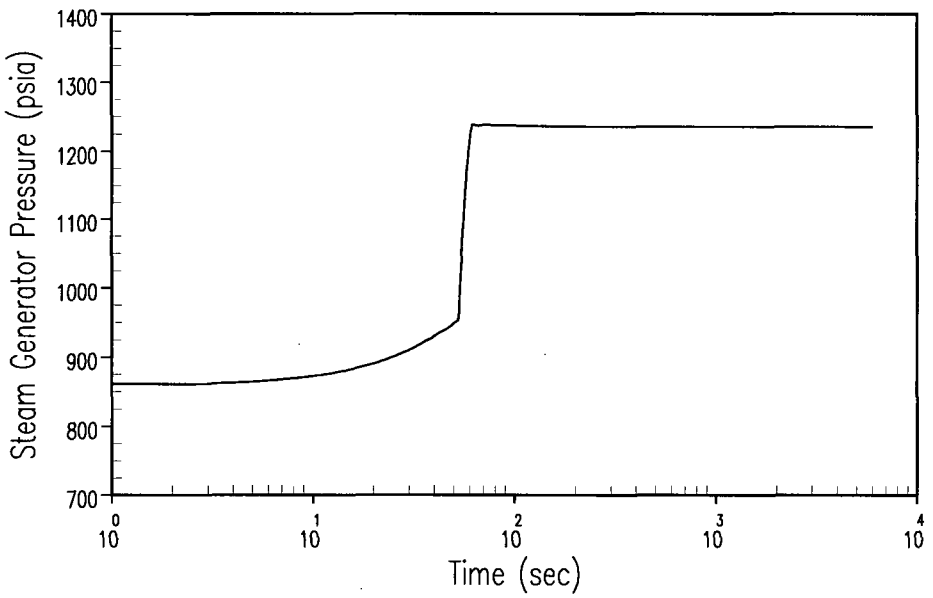


Figure 2.3.3-3 Unit 1 LONF with Offsite Power– Pressurizer Pressure and Water Volume Versus Time



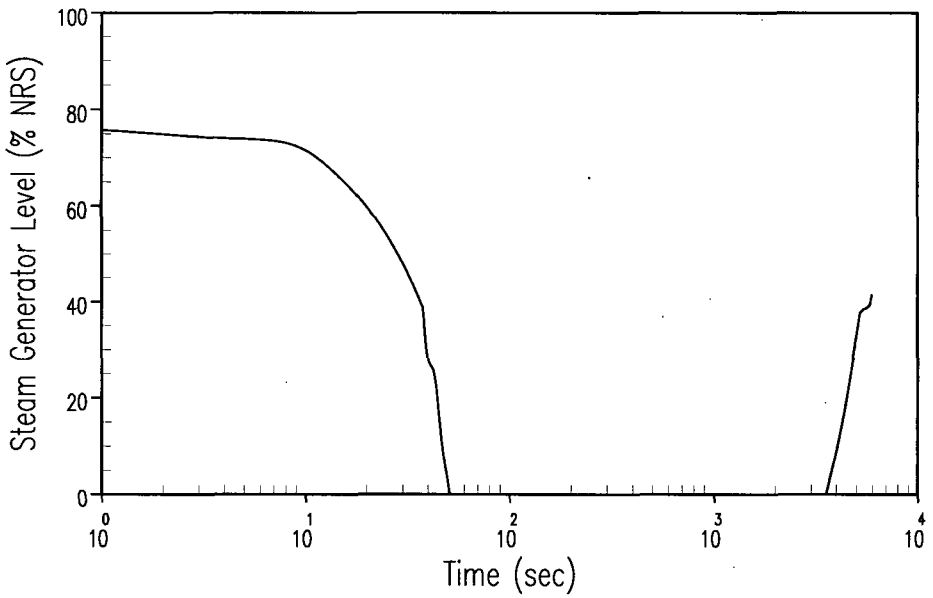


Figure 2.3.3-4 Unit 1 LONF with Offsite Power – Steam Generator Pressure and Level Versus Time

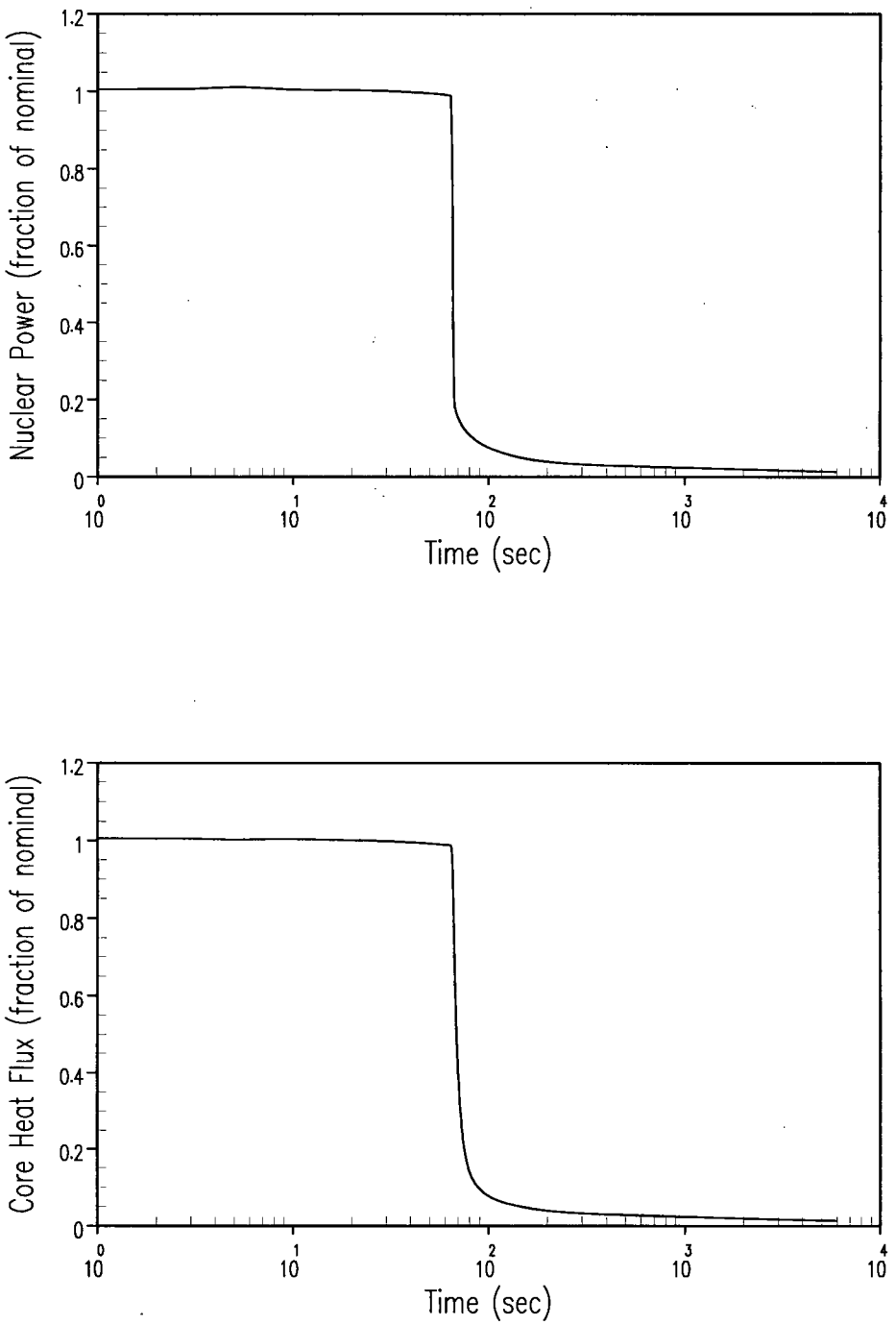
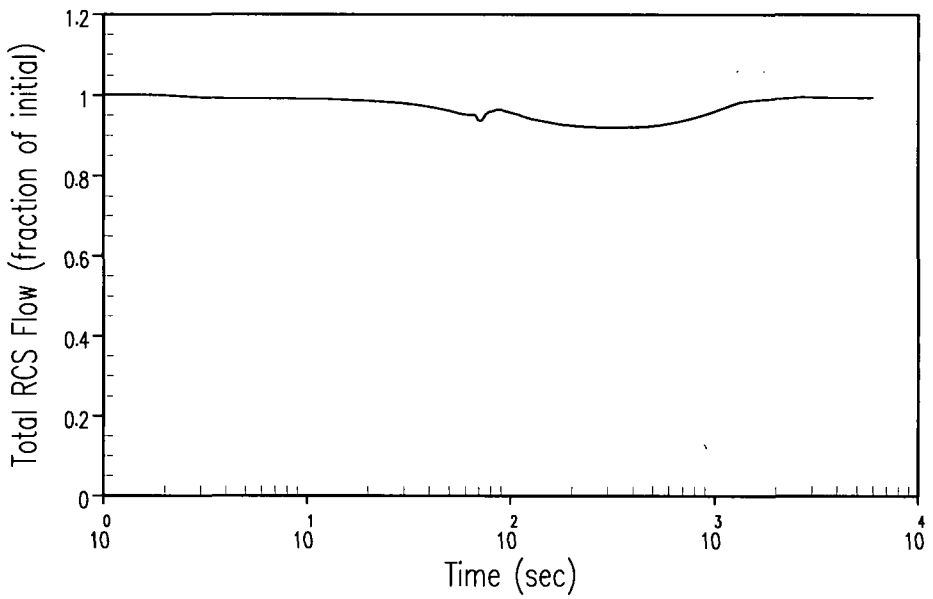


Figure 2.3.3-5 Unit 2 LONF with Offsite Power – Nuclear Power and Core Average Heat Flux Versus Time



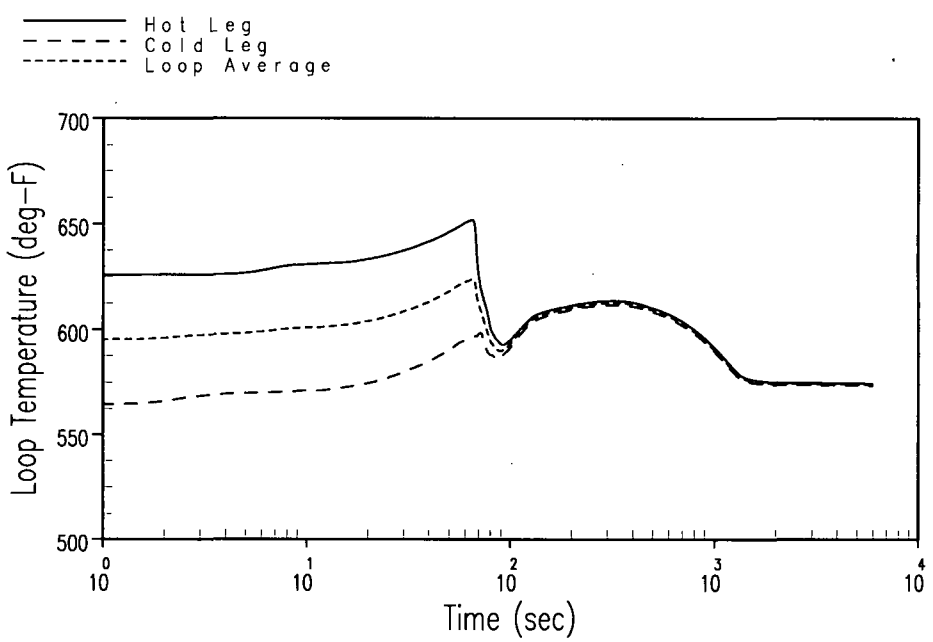


Figure 2.3.3-6 Unit 2 LONF with Offsite Power – Reactor Coolant Flow Rate and Loop Temperature Versus Time

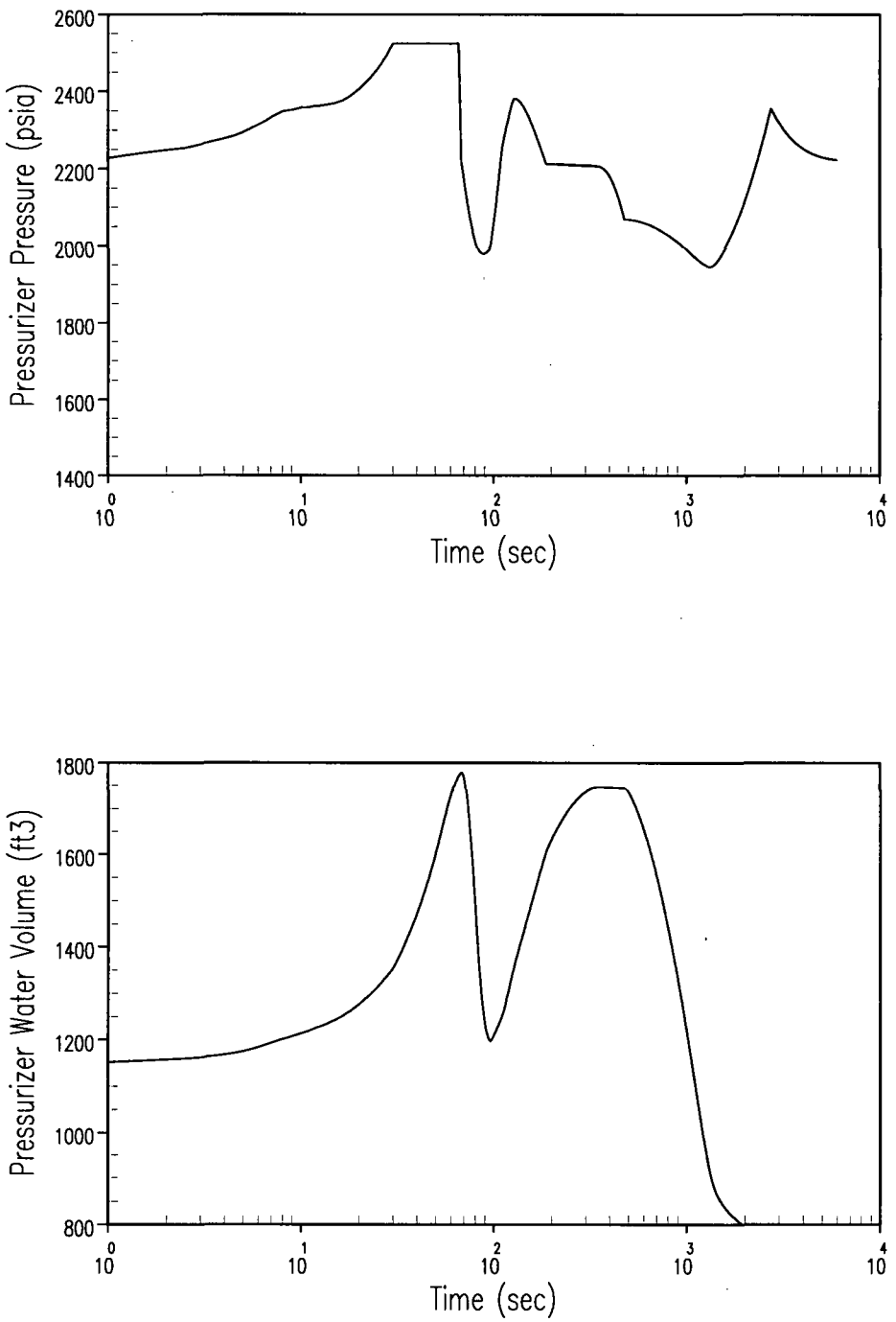


Figure 2.3.3-7 Unit 2 LONF with Offsite Power – Pressurizer Pressure and Water Volume Versus Time

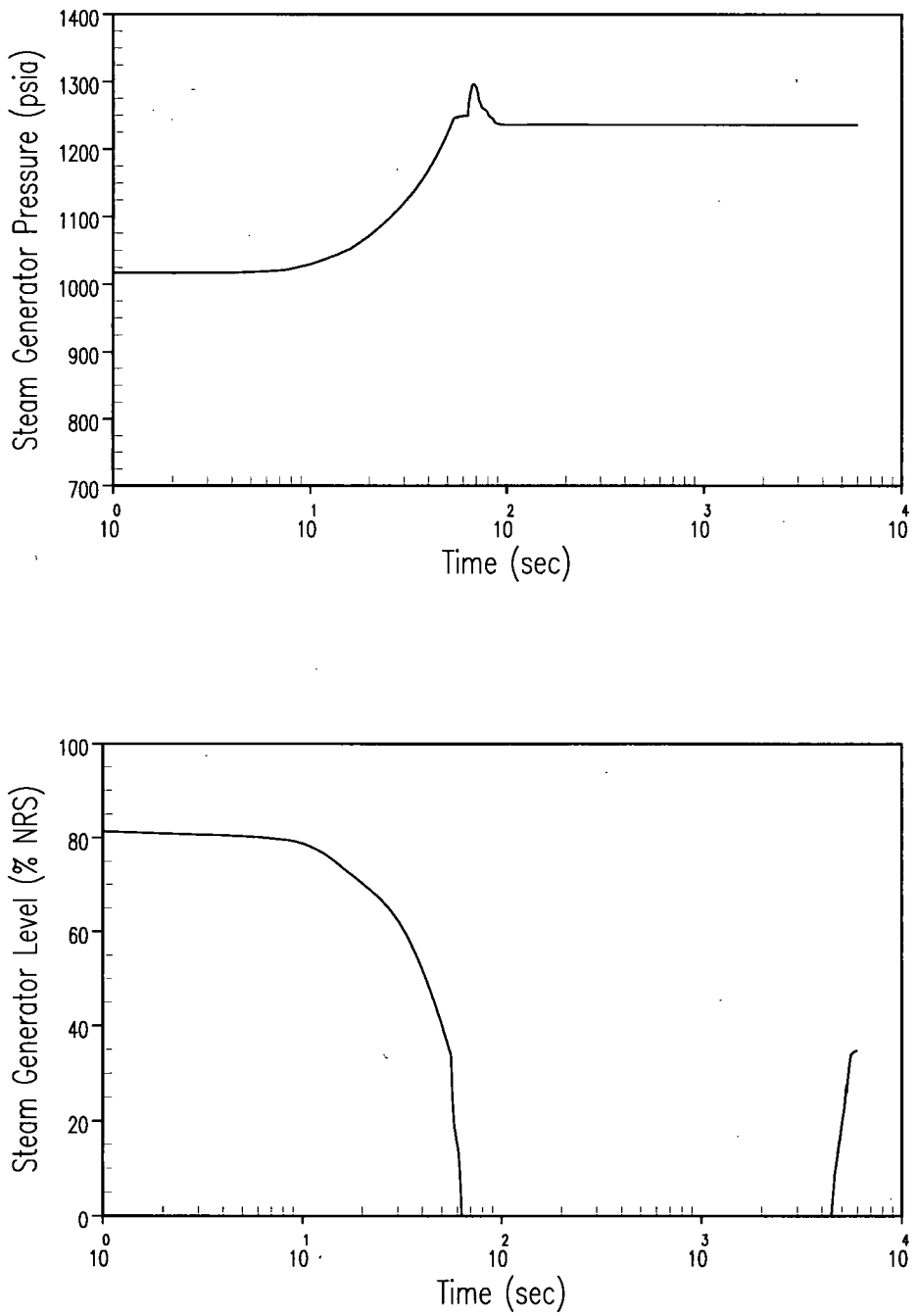
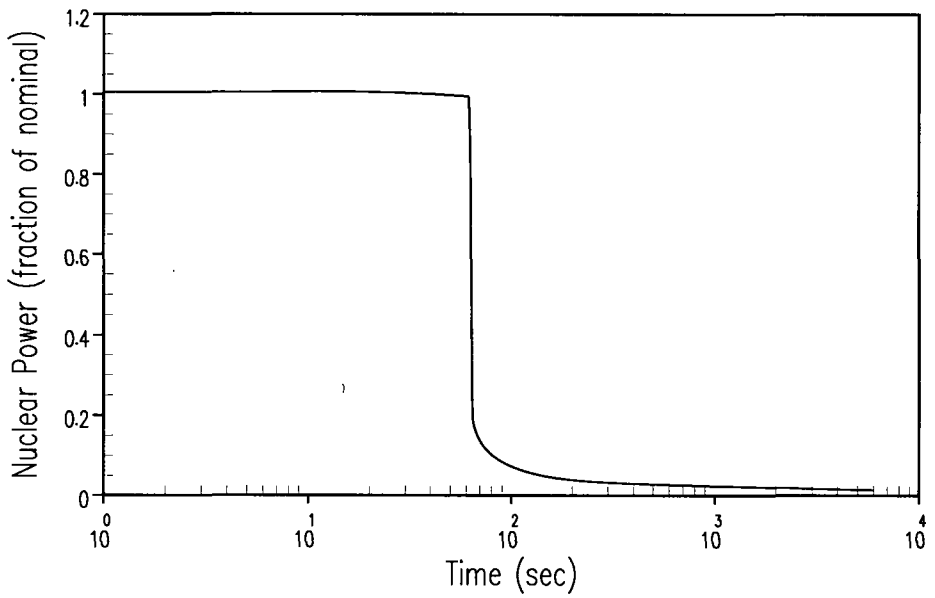


Figure 2.3.3-8 Unit 2 LONF with Offsite Power – Steam Generator Pressure and Level Versus Time



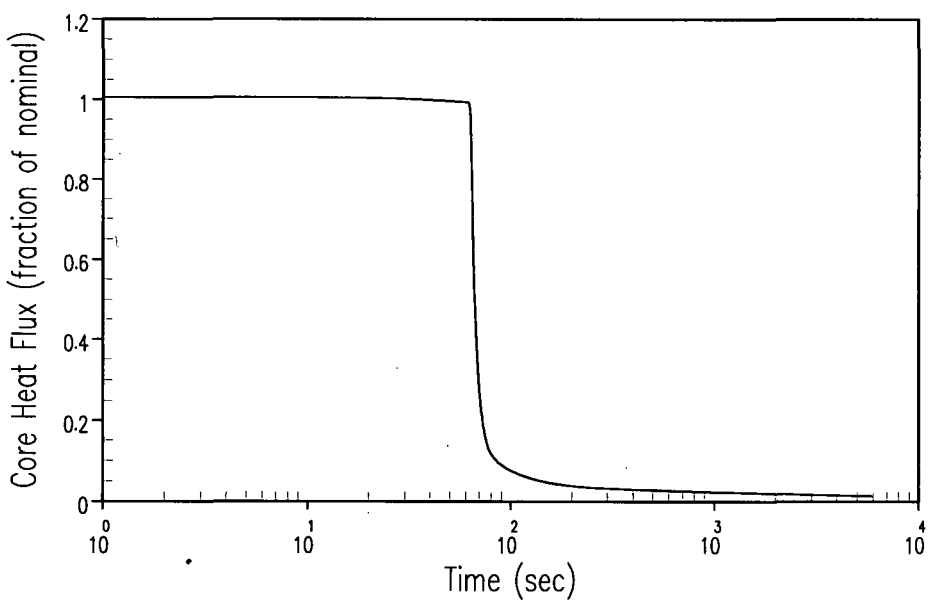
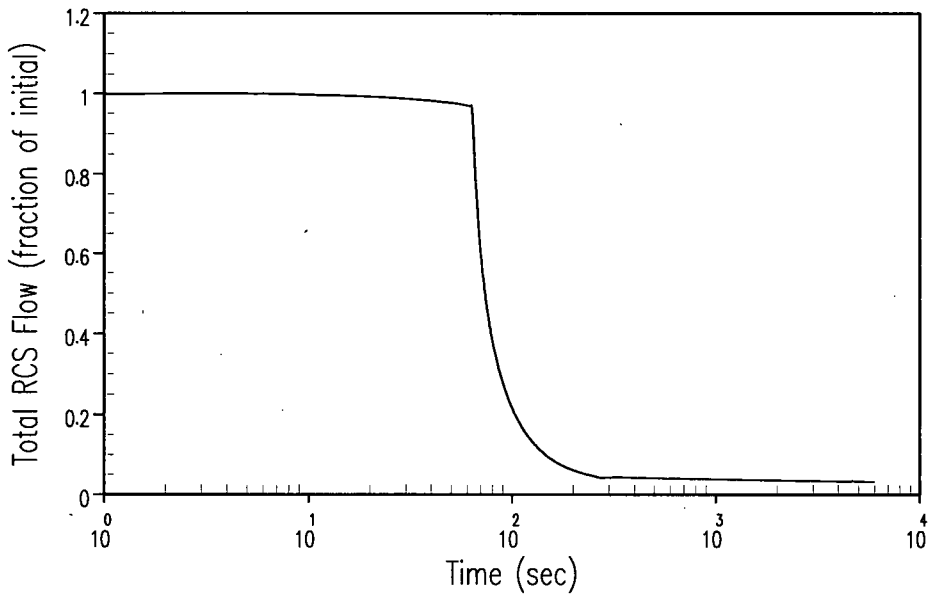


Figure 2.3.3-9 Unit 1 LONF without Offsite Power – Nuclear Power and Core Average Heat Flux Versus Time



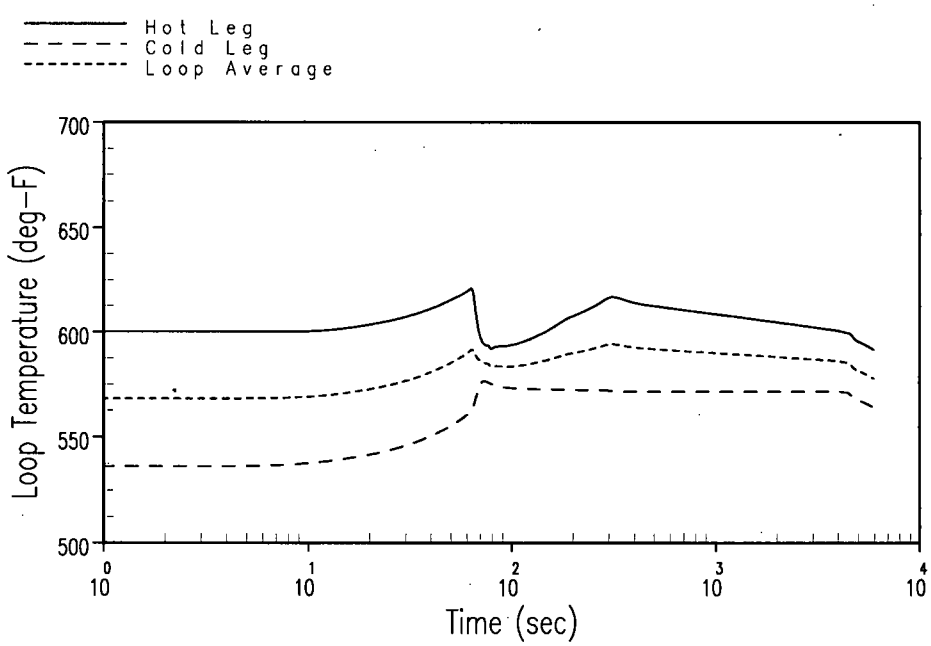
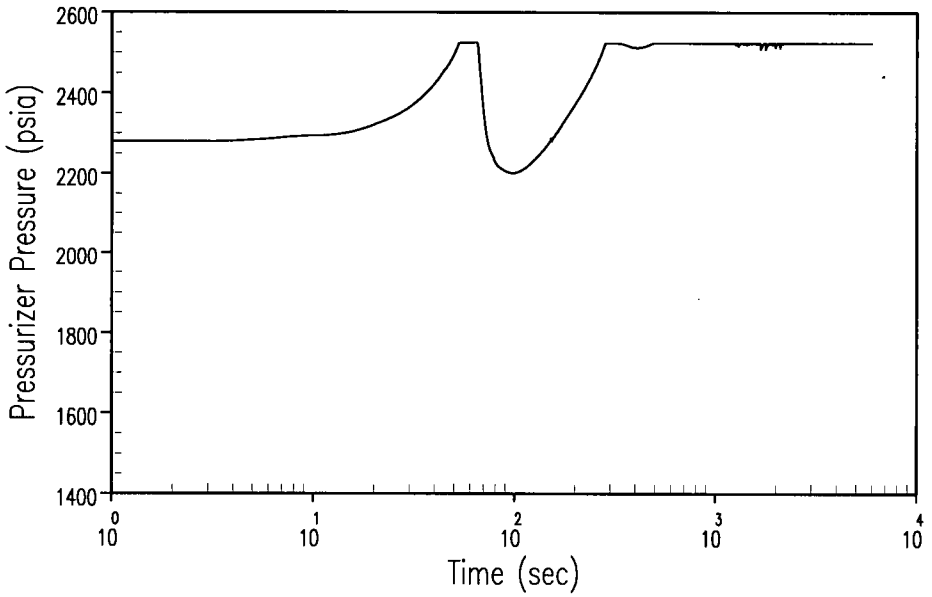


Figure 2.3.3-10 Unit 1 LONF without Offsite Power – Reactor Coolant Flow Rate and Loop Temperature Versus Time



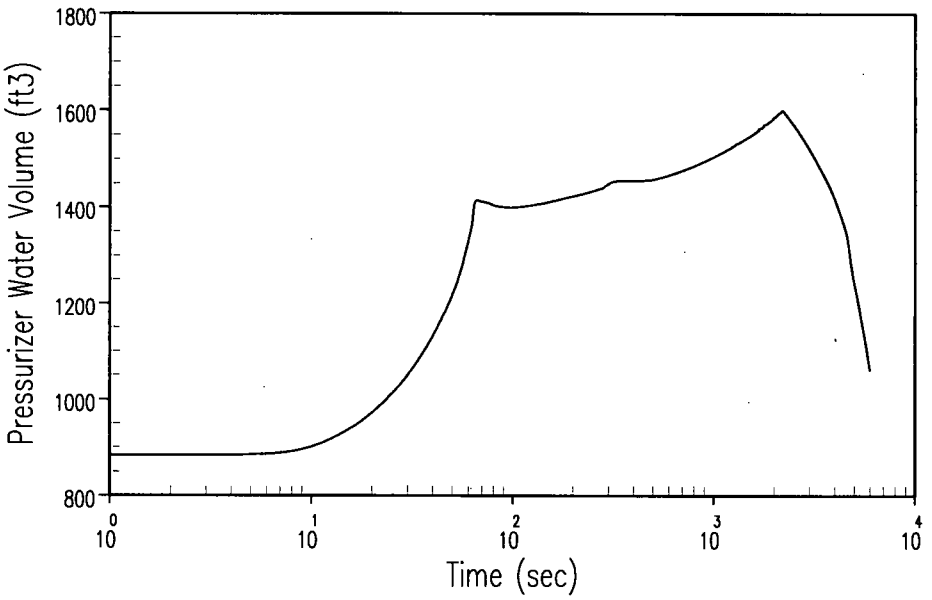


Figure 2.3.3-11 Unit 1 LONF without Offsite Power – Pressurizer Pressure and Water Volume Versus Time

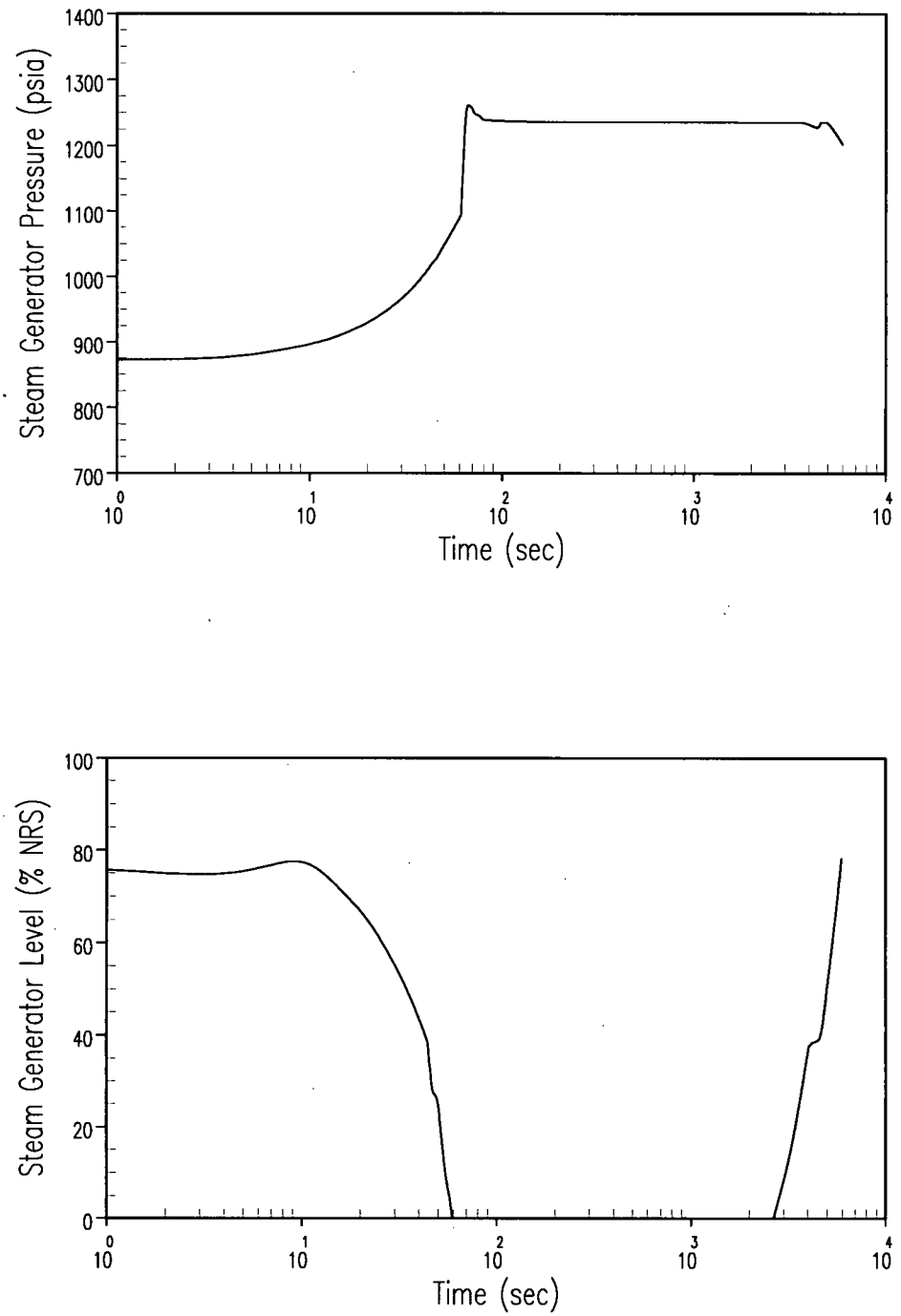
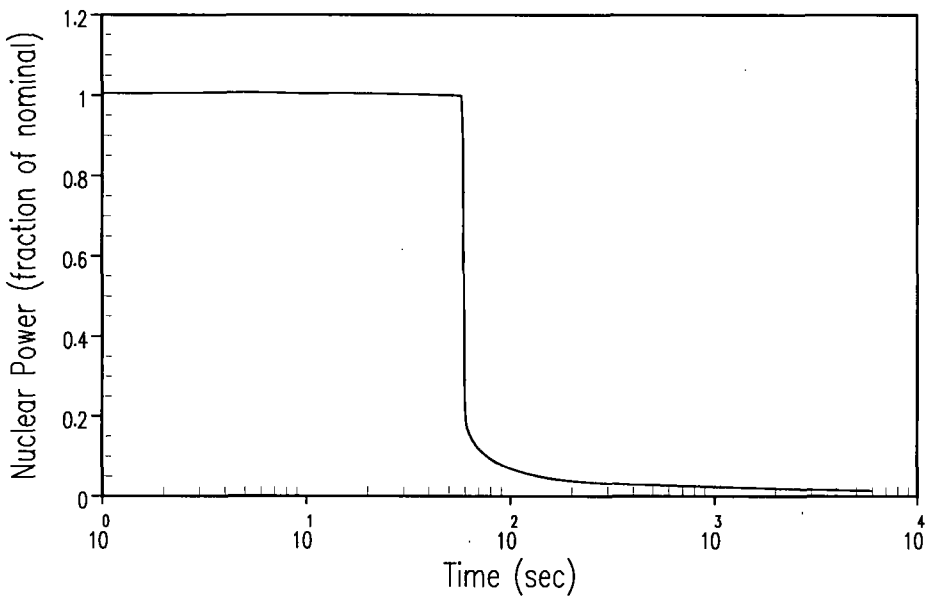


Figure 2.3.3-12 Unit 1 LONF without Offsite Power – Steam Generator Pressure and Level Versus Time



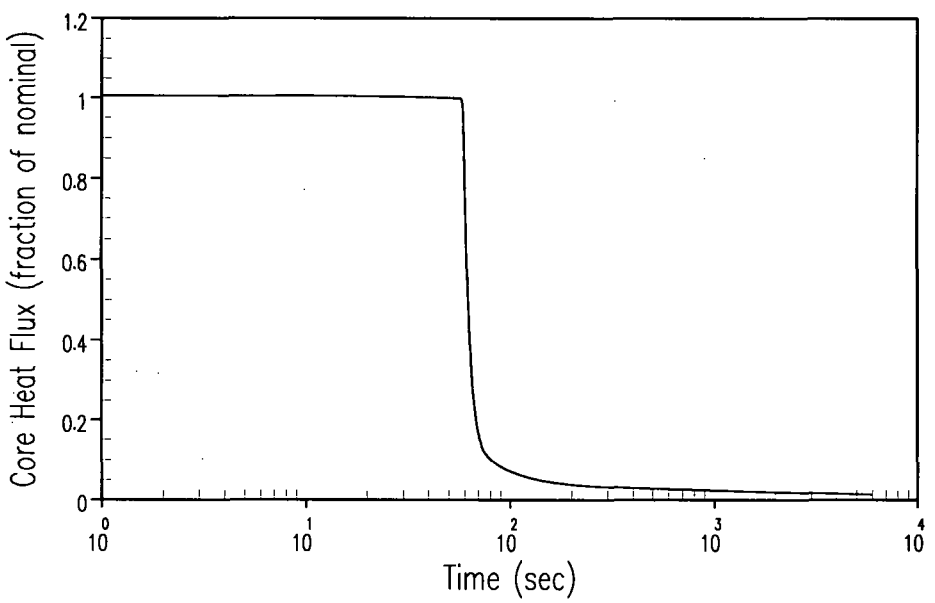
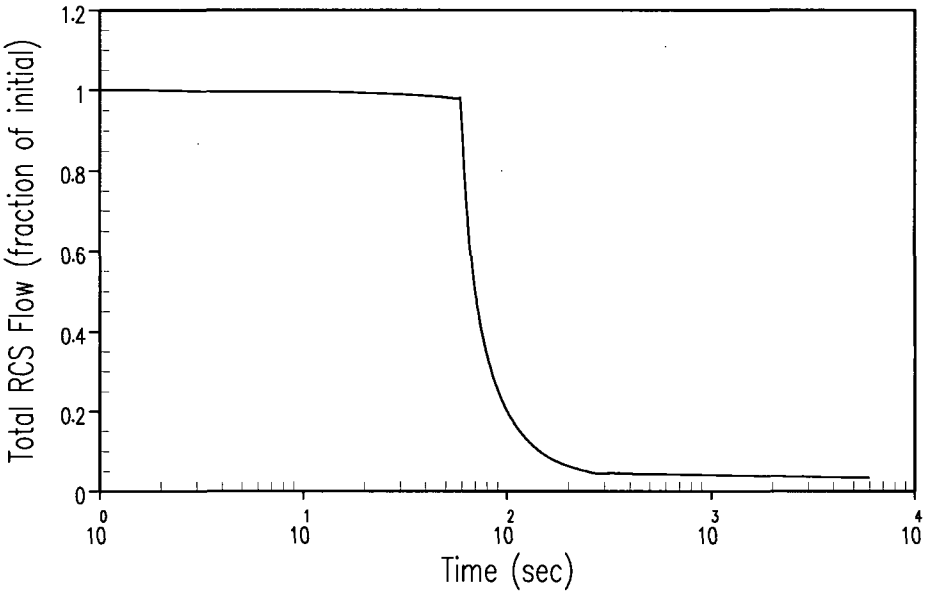


Figure 2.3.3-13 Unit 2 LONF without Offsite Power – Nuclear Power and Core Average Heat Flux Versus Time



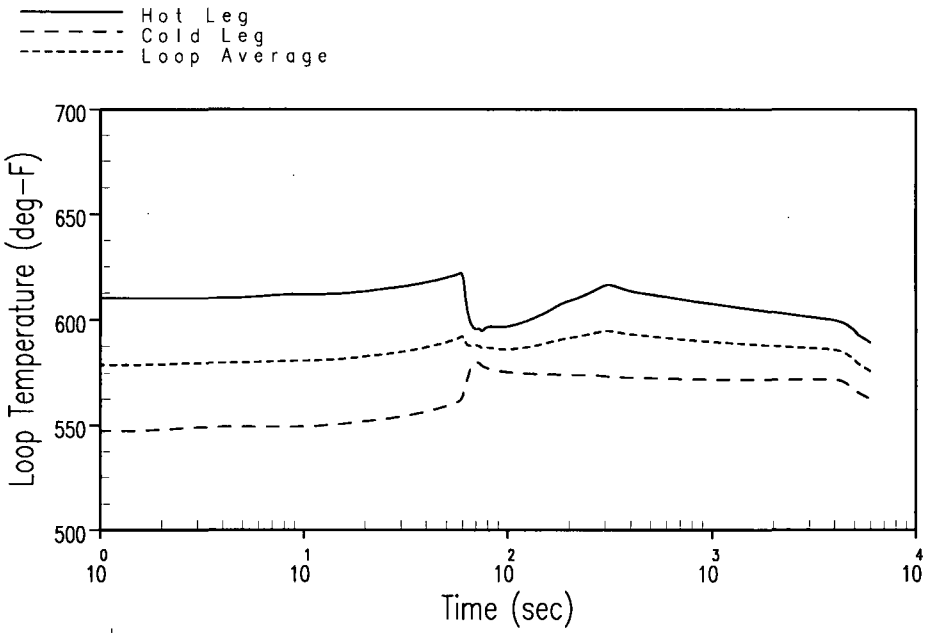


Figure 2.3.3-14 Unit 2 LONF without Offsite Power – Reactor Coolant Flow Rate and Loop Temperature Versus Time

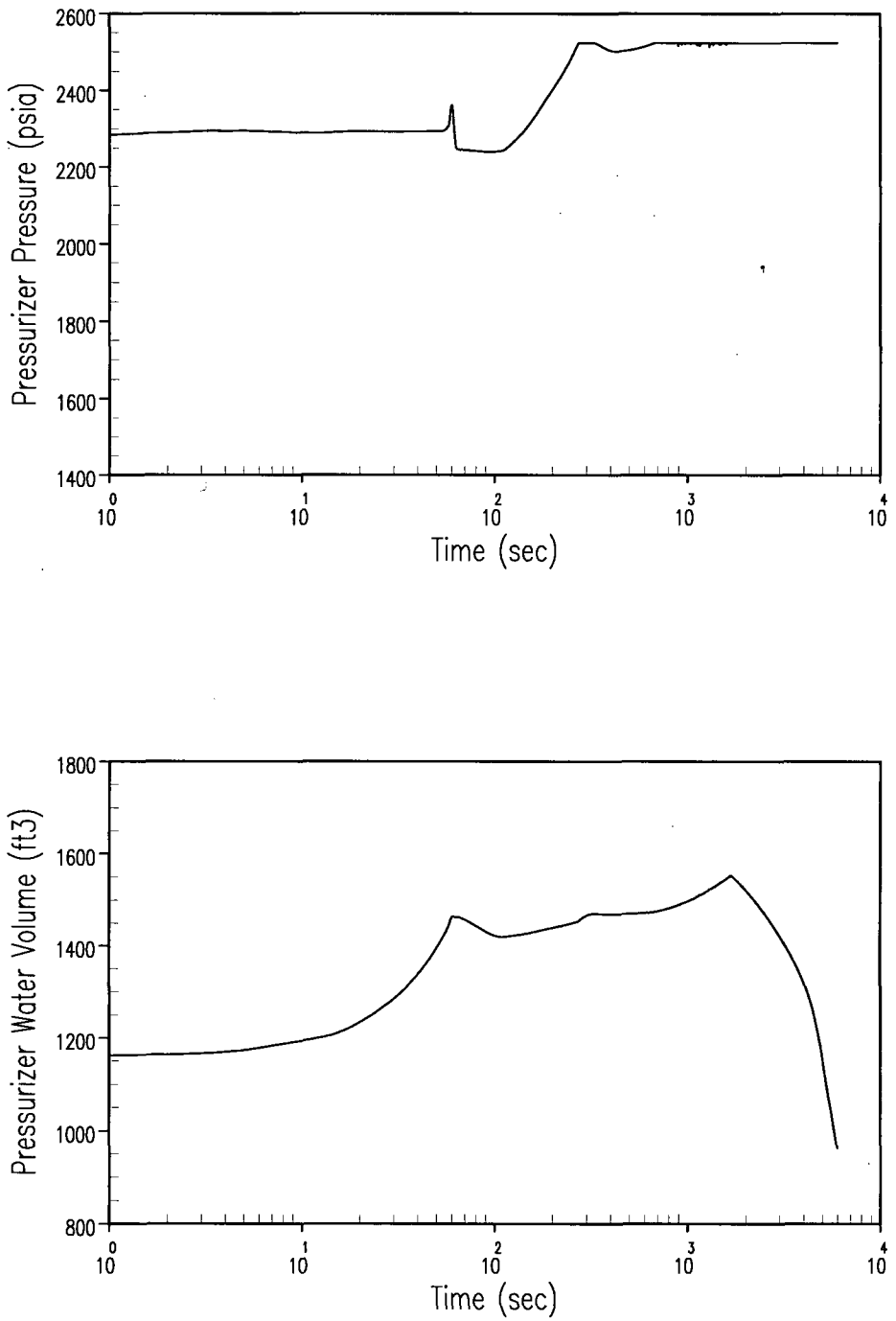


Figure 2.3.3-15 Unit 2 LONF without Offsite Power – Pressurizer Pressure and Water Volume Versus Time

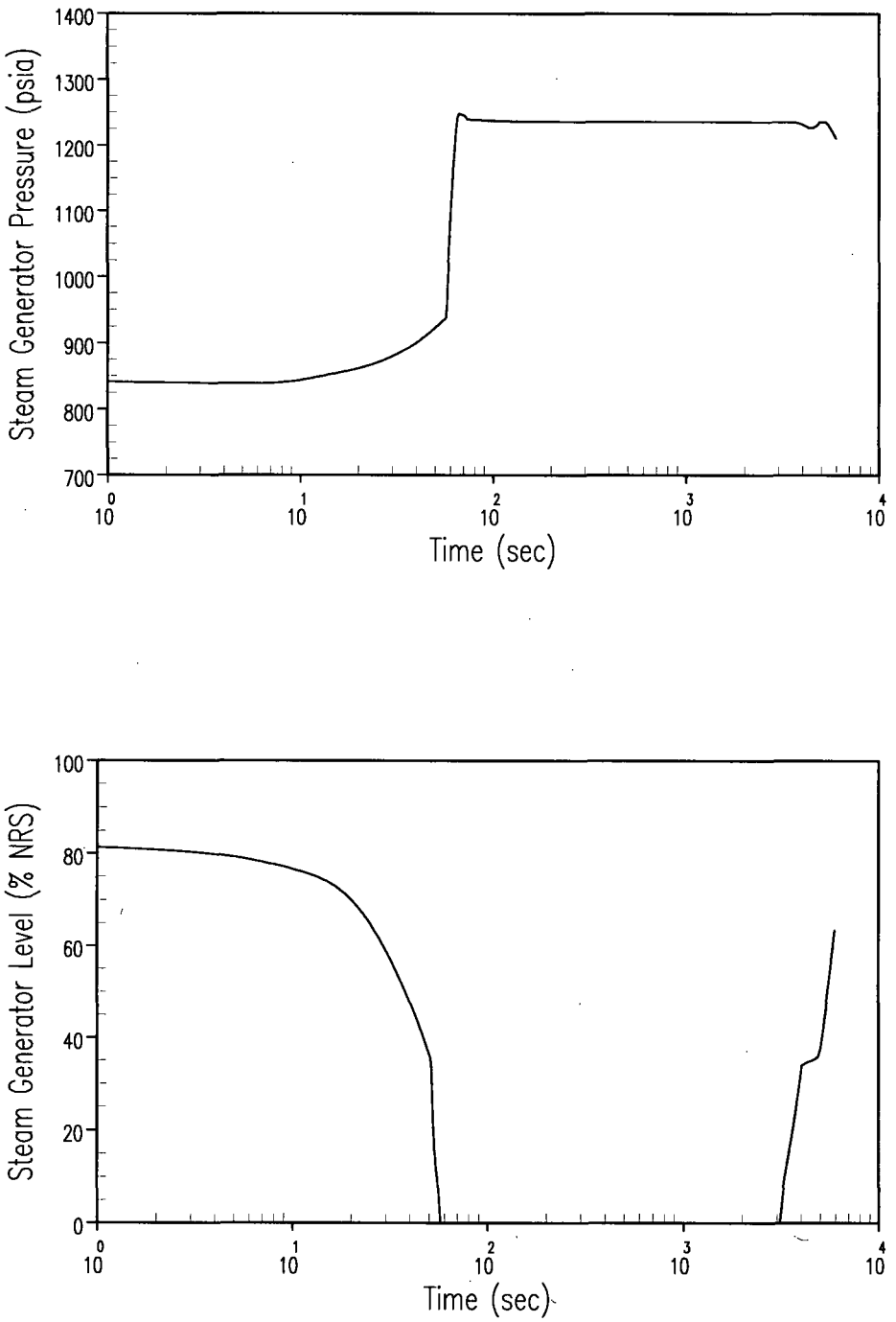


Figure 2.3.3-16 Unit 2 LONF without Offsite Power – Steam Generator Pressure and Level Versus Time

2.3.4 Feedwater System Pipe Breaks Inside and Outside Containment

2.3.4.1 Technical Evaluation

The specific acceptance criterion applied for this event is that no boiling occur in the hot or cold legs prior to the point in the transient where the heat removal capacity of the auxiliary feedwater (AFW) system exceeds the heat generation. This conservatively ensures that the core remains covered and geometrically intact for the duration of the event. Furthermore, the analysis ensures that appropriate margin for malfunctions, such as stuck rods, were accounted for in the safety analysis assumptions. This conservatively satisfies the CPNPP Units 1 and 2 current licensing basis with respect to the requirements of GDC-27, GDC-28, GDC-31, and GDC-35.

The discussion below demonstrates that all applicable acceptance criteria are met for this event at CPNPP Units 1 and 2 at uprated power conditions.

2.3.4.1.1 Introduction

A major feedwater line break (FSAR Section 15.2.8) is defined as a break in a feedwater pipe large enough to prevent the addition of sufficient feedwater to the steam generators to maintain shell-side fluid inventory in the steam generators. If the break is postulated in a feedline between the check valve and the steam generator, fluid from the steam generator can also be discharged through the break. Furthermore, a break in this location could preclude the subsequent addition of AFW to the affected steam generator. A break upstream of the feedline check valve would affect the NSSS only as a loss of feedwater. This case is covered by the LONF analysis presented in subsection 2.3.3.

Depending upon the size of the break and the plant operating conditions at the time of the rupture, the break could either cause an RCS heatup or cooldown. The potential RCS cooldown resulting from a secondary pipe break is evaluated in the steam line break analysis presented in subsection 2.2.2.1.1. Only the RCS heatup effects of a feedline break are presented in this section.

A feedline break reduces the ability to remove heat generated by the core from the RCS. The AFW system is provided to ensure that adequate feedwater is available to provide decay heat removal.

2.3.4.1.2 Input Parameters, Assumptions, and Acceptance Criteria

The following key assumptions were made in the analysis:

- NSSS power of 3,628 MWt plus 0.6-percent power uncertainty was assumed.
- The initial RCS average temperature was set to 595.2°F, the nominal high T_{avg} value of 589.2°F plus a T_{avg} uncertainty of 6.0°F.

- The initial pressurizer pressure was 30 psid below its nominal value of 2,250 psia to account for initial condition uncertainties.

- The initial pressurizer level was set to the nominal full-power programmed value of 60-percent span plus 5.0-percent span to account for initial condition uncertainties.

- The initial steam generator water level for Unit 1 was set to the nominal value (67-percent NRS) plus 10-percent NRS in the faulted steam generator, and the nominal value minus 10-percent NRS in the intact steam generators to account for initial condition uncertainties.

- The initial steam generator water level for Unit 2 was set to the nominal value (64-percent NRS) plus 18-percent NRS in the faulted steam generator, and the nominal value minus 7-percent NRS in the intact steam generators to account for initial condition uncertainties.

- The main feedwater flow to all steam generators was assumed to be lost at the time the break occurred (all main feedwater spilled out through the break).

- The full double-ended main feedwater pipe break was assumed. An effective break size of 1.11844 ft^2 was analyzed for CPNPP Unit 1 with Δ76 SGs and 0.2234 ft^2 for Unit 2 with D-5 SGs.

- The single-failure assumption was conservatively set as the loss of the motor driven AFW pump feeding two intact steam generators; all the flow from the second motor driven AFW pump is assumed to flow out the break along with a portion of the turbine driven AFW flow until the faulted steam generator is isolated.

- For the first 30 minutes following reactor trip, a total of 430 gpm of AFW flow from the turbine-driven AFW pump was split equally among the three intact steam generators. Following isolation of the faulted steam generator, an additional 370 gpm was made available to split among the 3 intact steam generators. No AFW flow is assumed to reach the faulted steam generator. AFW flow from the second motor-driven pump was conservatively not modeled.

- Although it is expected that the actuation of the safety injection system would occur during this event, the analysis conservatively did not model the safety injection flow.

- Pressurizer PORVs were assumed operable as they minimize RCS pressure, which results in a lower saturation temperature. The pressurizer sprays and heaters were assumed to be unavailable.

- Reactor trip was assumed to be actuated when the steam generator low-low water level trip setpoint was reached in the ruptured steam generator. A setpoint of 10-percent NRS was modeled for Unit 1 and 7.5-percent NRS was modeled for Unit 2. A description of

the method used by RETRAN to calculate steam generator level is provided in Section 3.8.2 of WCAP-14882 (Reference 1).

- The main steam line isolation valves serve to isolate the intact steam generators from the faulted steam generator.

- No credit was taken for heat energy deposited in portions of the RCS metal during the RCS heatup.

- No credit was taken for charging or letdown.

- Maximum steam generator tube plugging of 10 percent was assumed to minimize primary-to-secondary-side heat transfer.

- Steam generator heat transfer across the tubes was adjusted as the shell-side liquid inventory decreased. Specifically, the heat transfer correlation for the steam generator tubes (heat conductors) is automatically adjusted by the RETRAN code for the changing conditions as the tubes uncover.

- Core residual heat generation was based on the 1979 version of ANS 5.1 (Reference 2). ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates. Long-term operation at the initial power level preceding the trip was assumed.

- No credit was taken for the following potential protection logic signals to mitigate the consequences of the accident:

  - High-pressurizer pressure
  - High-pressurizer level
  - High-containment pressure
  - Overtemperature N-16

The feedline break accident is a Condition IV occurrence as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. Condition IV events are faults that are not expected to occur, but are postulated because their consequences would include the potential for release of significant amounts of radioactive material. The following items summarize the acceptance criteria associated with this event:

- Pressures in the RCS and MSS are maintained below 110 percent of the respective design pressures.

- Any activity release is such that the calculated doses are within acceptable limits.

- Any fuel damage that can occur during the transient is of a sufficiently limited extent that the core will remain in place and geometrically intact with no loss of core cooling capability.

With respect to overpressurization, the feedline break event, both with and without offsite power, is bounded by the loss-of-load/turbine trip event discussed in subsection 2.3.1 in which assumptions are made to conservatively calculate the RCS and MSS pressure transients. For the feedline break event, turbine trip occurs after reactor trip, whereas for the loss-of-load/turbine trip event, the turbine trip is the initiating fault. Therefore, the primary/secondary power mismatch and resultant RCS and MSS heatup and pressurization transients are always more severe for the loss-of-load/turbine trip than for the feedline break event. For this reason, no attempt is made to calculate the maximum RCS or MSS pressures for the feedline break event.

Although no explicit dose calculations are performed for the feedline break event, by demonstrating there is no fuel cladding damage as a result of this event, the radiological consequences can be shown to be bounded by those of the steam line rupture event.

With respect to fuel cladding damage due to "dryout," where the water level in the vessel drops below the top of the core, Westinghouse has established an internal criterion that no bulk boiling occurs in the primary coolant system prior to event turnaround. Turnaround occurs when the heat removal capability of the steam generators being fed auxiliary feedwater exceeds NSSS heat generation. This conservatively ensures that the core remains covered with water and thereby will remain in place and geometrically intact with no loss of core cooling capability. This single criterion is conservative and was chosen for convenience in interpreting the transient results.

With respect to fuel cladding damage due to departure from nucleate boiling, the pre-trip aspects of a feedline break event would be bounded by the loss-of-load/turbine trip heatup event, discussed in subsection 2.3.1, while the post-trip aspects of a feedline break event would be bounded by the steam line rupture event, discussed in subsection 2.2.2.1.1.

2.3.4.1.3 Description of Analyses and Evaluations

The transient response following a feedline break event was calculated by a detailed digital simulation of the plant. The analysis modeled a simultaneous loss of main feedwater to all steam generators and subsequent reverse blowdown of the faulted steam generator. The analysis was performed using the RETRAN code (Reference 1), which simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator safety valves. The code computed pertinent plant variables including temperatures, pressures, and power level. Also, RETRAN calculates the transient break flow quality as a function of temperature and pressure with respect to time.

The following two cases were analyzed for CPNPP Units 1 and 2:

- Unit 1: Maximum reactivity feedback, with offsite power, 1.11844 ft^2 break
  Maximum reactivity feedback, without offsite power, 1.11844 ft^2 break

- Unit 2: Minimum reactivity feedback, with offsite power, 0.2234 ft^2 break
  Minimum reactivity feedback, without offsite power, 0.2234 ft^2 break

2.3.4.1.4 Results

The results of the feedline break cases analyzed showed that no bulk boiling occurred in the primary coolant system following a feedline break prior to the time that the heat removal capability of the steam generators, being fed AFW, exceeded NSSS residual heat generation.

The limiting case for each unit was the case where offsite power was assumed to be available. The transient results for the limiting cases are presented in Figures 2.3.4-1 through 2.3.4-6 for Unit 1, and Figures 2.3.4-7 through 2.3.4-12 for Unit 2. The time sequence of events for these cases are presented in Table 2.3.4-1 and 2.3.4-2 for Units 1 and 2, respectively.

The results of the analyses performed for CPNPP Units 1 and 2 at uprated power conditions showed that for the postulated feedwater line rupture, AFW system capacity was adequate to remove decay heat, thus, ensuring that the applicable acceptance criteria are met.

2.3.4.2 Conclusion

The analyses of feedwater system pipe breaks have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The evaluation has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a non-brittle manner, the probability of propagating fracture of the RCPB will be minimized, and abundant core cooling will be provided. Based on this, it is concluded that the plant will continue to meet the CPNPP current licensing basis with respect to the requirements of GDC-27, GDC-28, GDC-31, and GDC-35.

2.3.4.3 References

1. WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

2. ANSI/ANS-5.1 – 1979, "American National Standard for Decay Heat Power in Light Water Reactors," August 1979.

Table 2.3.4-1 Unit 1 - Time Sequence of Events – Major Rupture of a Main Feedwater Pipe		
Case	**Event**	**Time (sec)[1]**
Feedline Rupture with Maximum Reactivity Feedback, Offsite Power Available, Break Size of 1.11844 ft^2	Main feedline rupture occurs	20.0
	Low-low steam generator water level reactor trip setpoint reached in ruptured steam generator	26.0
	Low-low steam generator water level trip signal is generated in ruptured steam generator and rods begin to fall	28.0
	Low-low steam generator water level reactor trip setpoint reached in second steam generator	37.2
	Flow from the turbine-driven AFW pump is initiated	122.2
	Low steamline pressure setpoint reached in ruptured steam generator	156.0
	All main steamline isolation valves close	161.0
	Pressurizer PORV setpoint reached (first occurrence)	338.6
	First steam generator safety valve setpoint reached in intact steam generators	662.1
	Minimum margin to hot leg saturation occurs (Hot and cold leg temperatures begin to decrease)	1,837.5

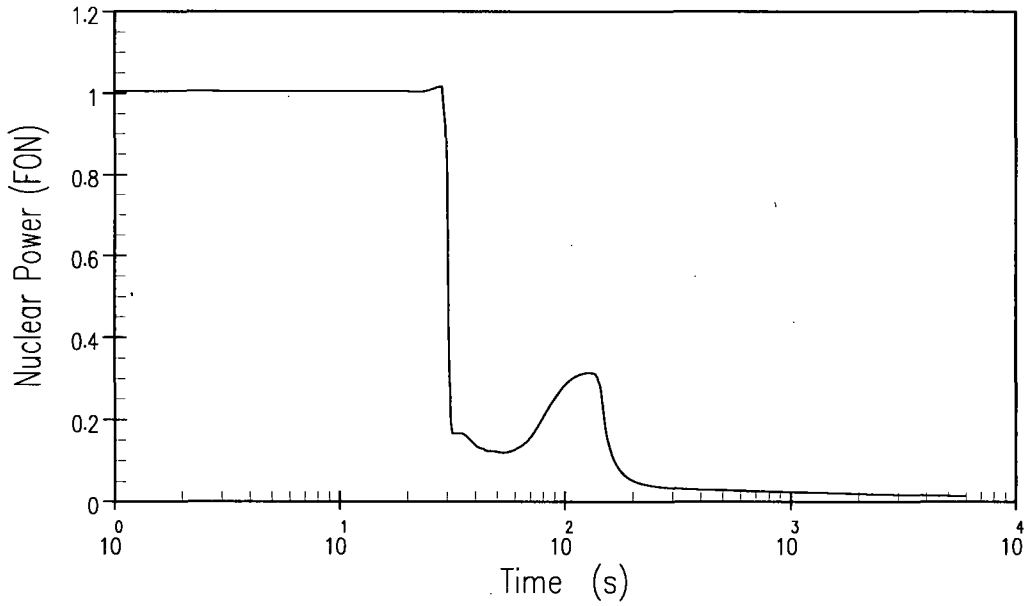
Note:

1. Time includes 20 seconds of steady-state.

Table 2.3.4-2 Unit 2 - Time Sequence of Events – Major Rupture of a Main Feedwater Pipe		
Case	**Event**	**Time (sec)[1]**
Feedline Rupture with Minimum Reactivity Feedback, Offsite Power Available, Break Size of 0.2234 ft^2	Main feedline rupture occurs	20.0
	Pressurizer PORV setpoint reached (first occurrence)	31.5
	Low-low steam generator water level reactor trip setpoint reached in ruptured steam generator	41.5
	Low-low steam generator water level trip signal is generated in ruptured steam generator and rods begin to fall	43.5
	Low-low steam generator water level reactor trip setpoint reached in second steam generator	47.2
	First steam generator safety valve setpoint reached in intact steam generators	48.9
	Flow from the turbine-driven AFW pump is initiated	132.2
	Low steamline pressure setpoint reached in ruptured steam generator	418.5
	All main steamline isolation valves close	423.5
	Minimum margin to hot leg saturation occurs (Hot and cold leg temperatures begin to decrease)	1,848.5

Note:

1. Time includes 20 seconds of steady-state.



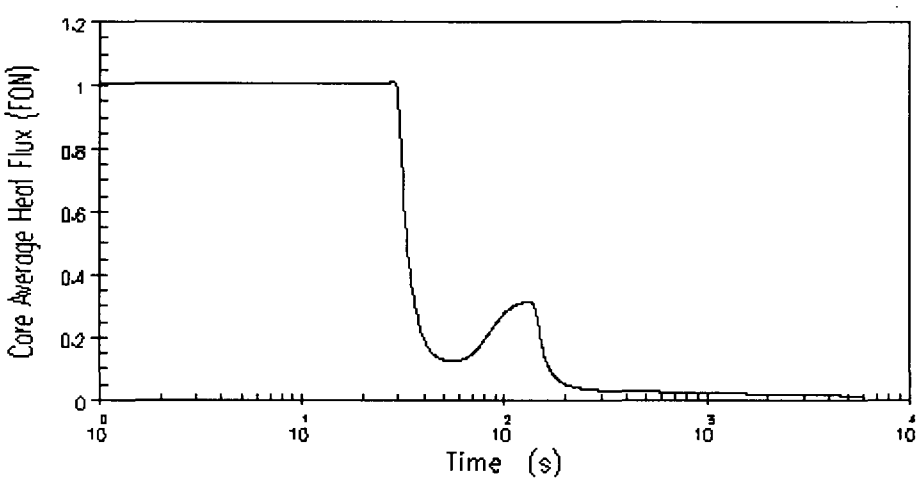


Figure 2.3.4-1 CPNPP Unit 1 – Feedline Break with Offsite Power – Nuclear Power and Core Average Heat Flux Versus Time

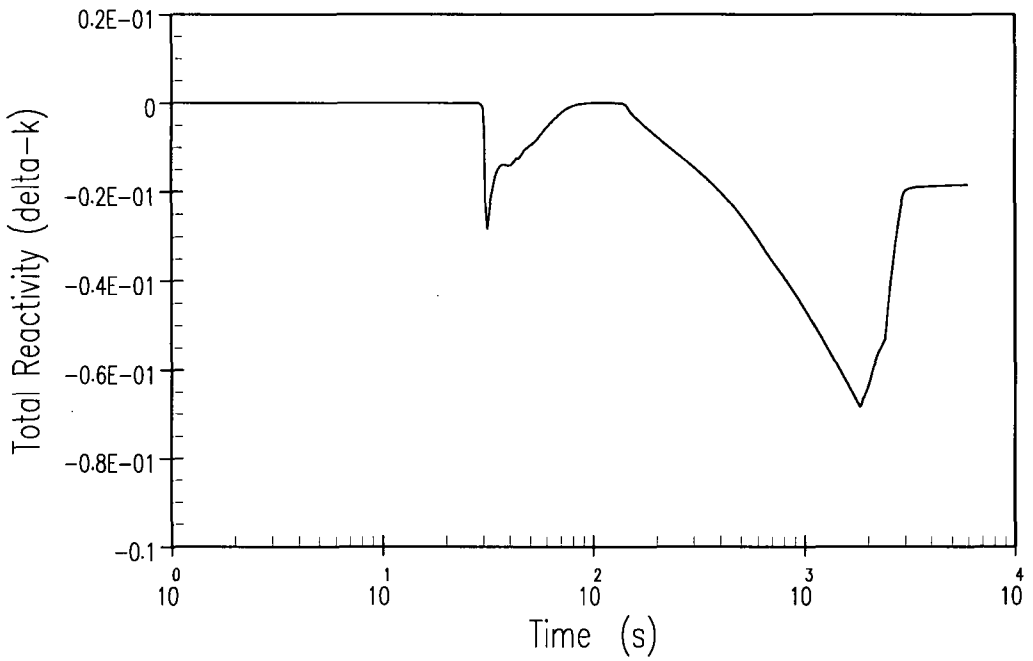
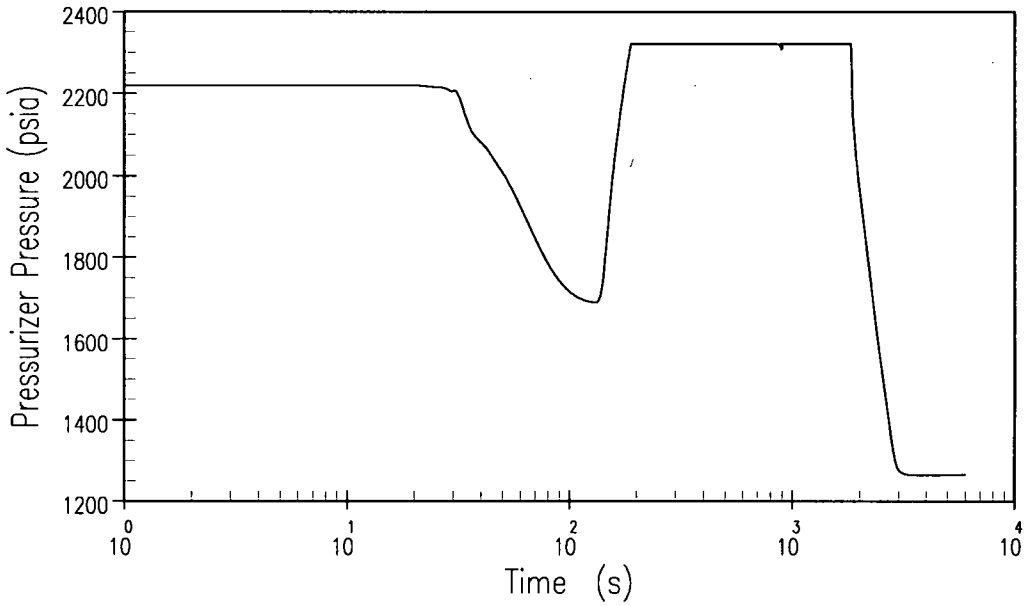


Figure 2.3.4-2 CPNPP Unit 1 – Feedline Break with Offsite Power – Total Reactivity Versus Time



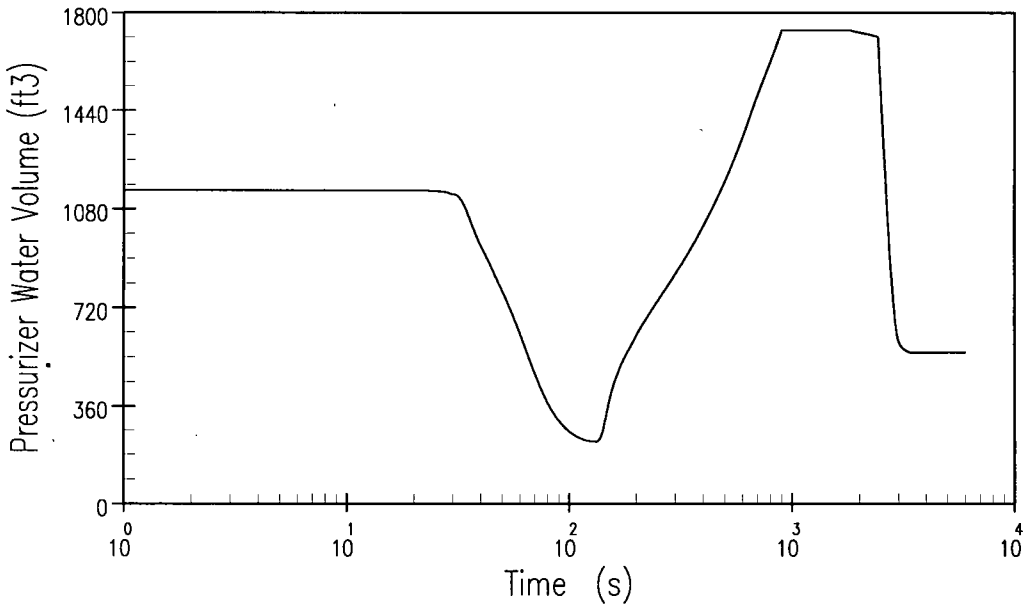
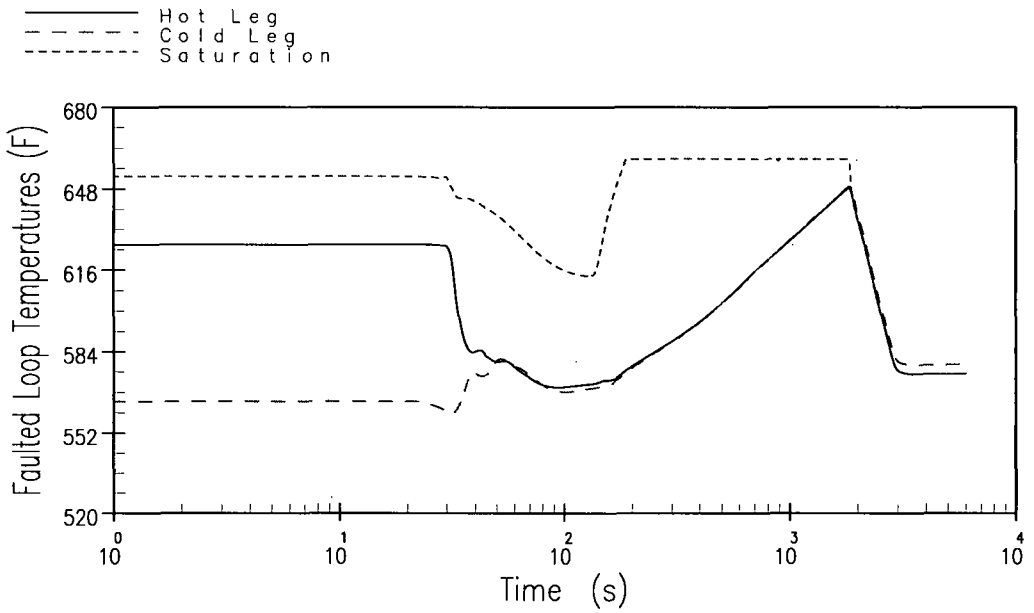


Figure 2.3.4-3 CPNPP Unit 1 – Feedline Break with Offsite Power – Pressurizer Pressure and Water Volume Versus Time



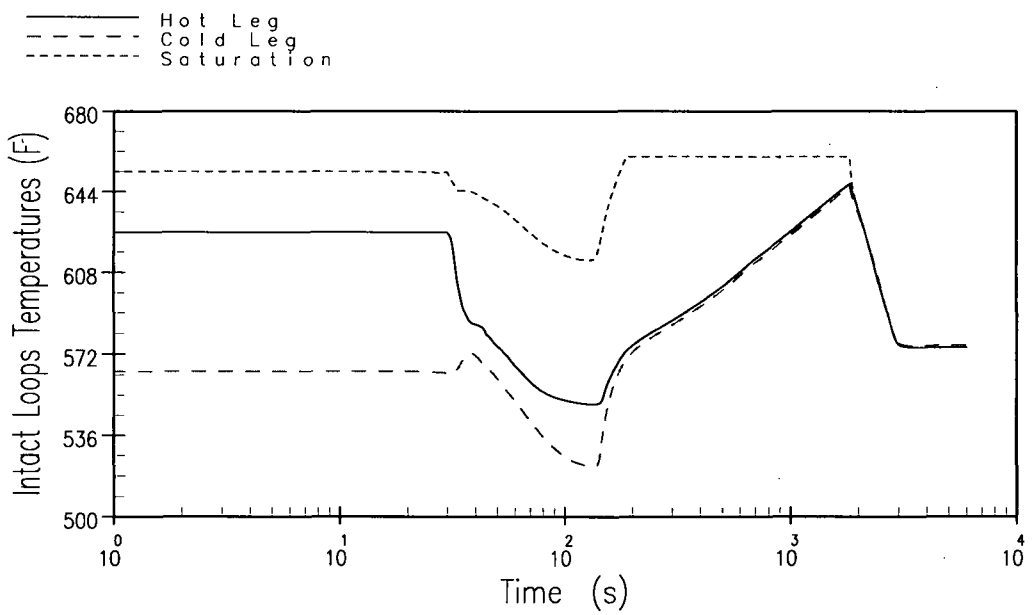
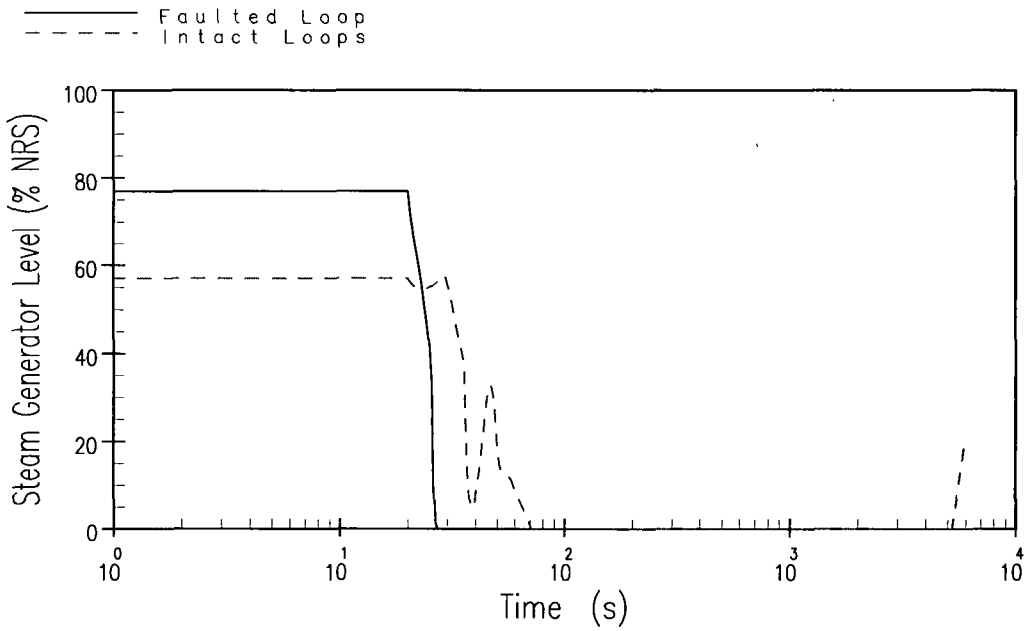


Figure 2.3.4-4 CPNPP Unit 1 – Feedline Break with Offsite Power – Reactor Coolant Temperatures Versus Time for the Faulted and Intact Loops



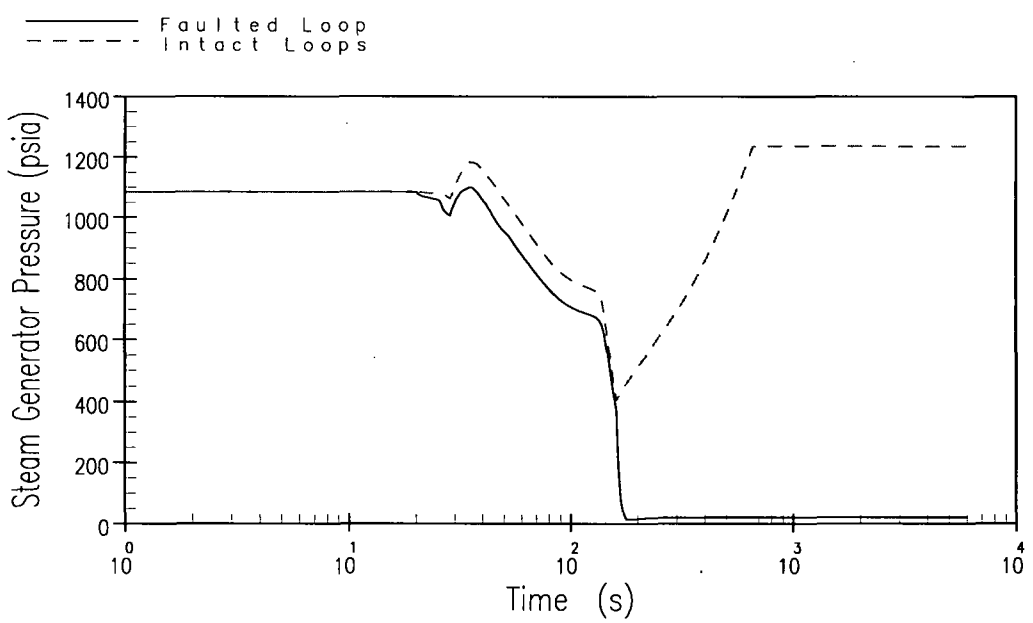


Figure 2.3.4-5 CPNPP Unit 1 – Feedline Break with Offsite Power – Steam Generator Level and Pressure Versus Time

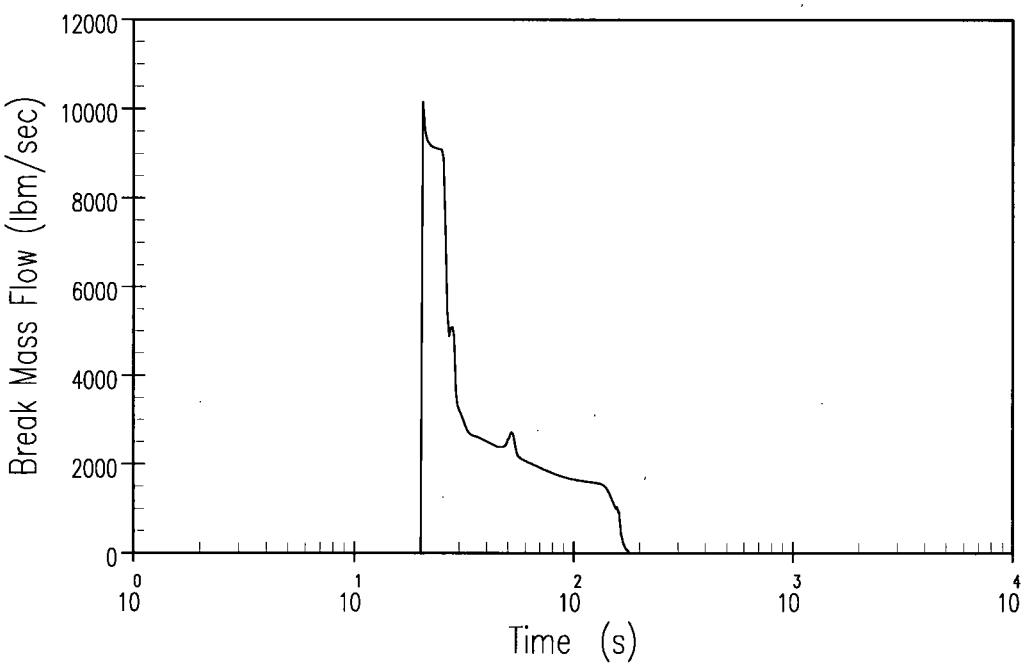
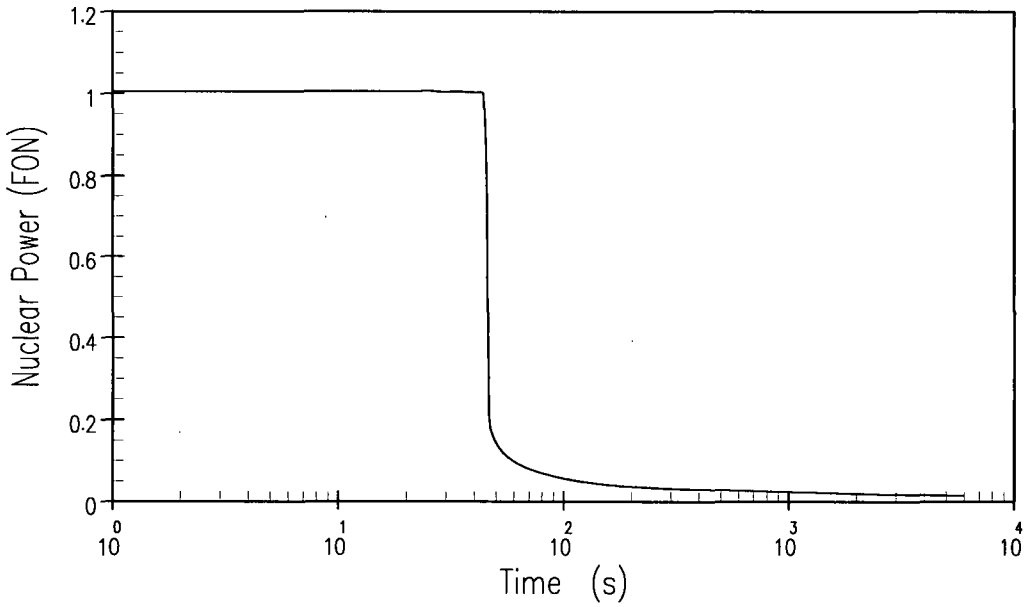


Figure 2.3.4-6 CPNPP Unit 1 – Feedline Break with Offsite Power – Feedline Break Flow Versus Time



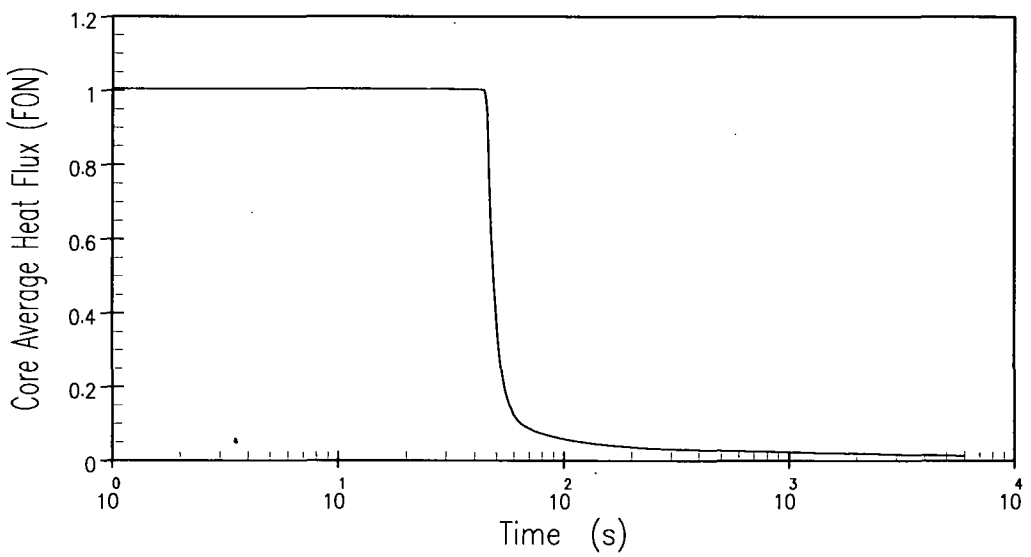


Figure 2.3.4-7 CPNPP Unit 2 – Feedline Break with Offsite Power – Nuclear Power and Core Average Heat Flux Versus Time

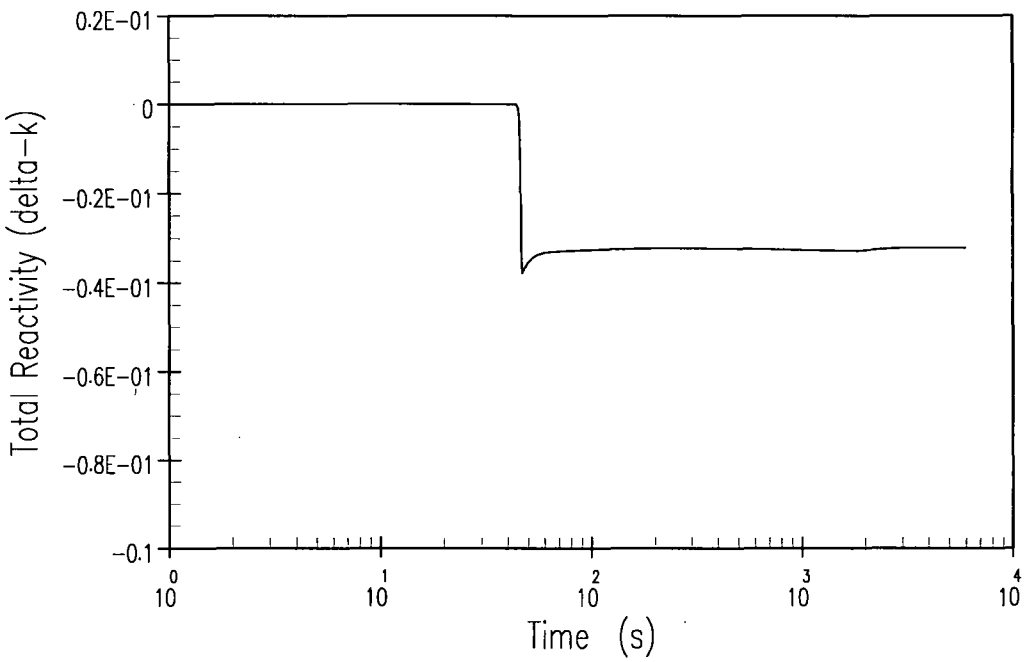
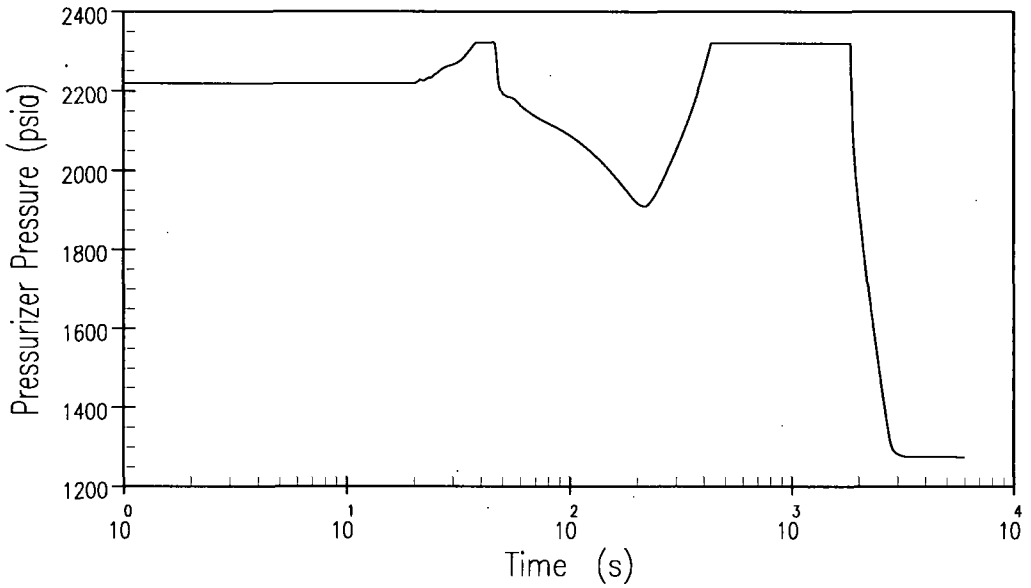


Figure 2.3.4-8 CPNPP Unit 2 – Feedline Break with Offsite Power – Total Reactivity Versus Time



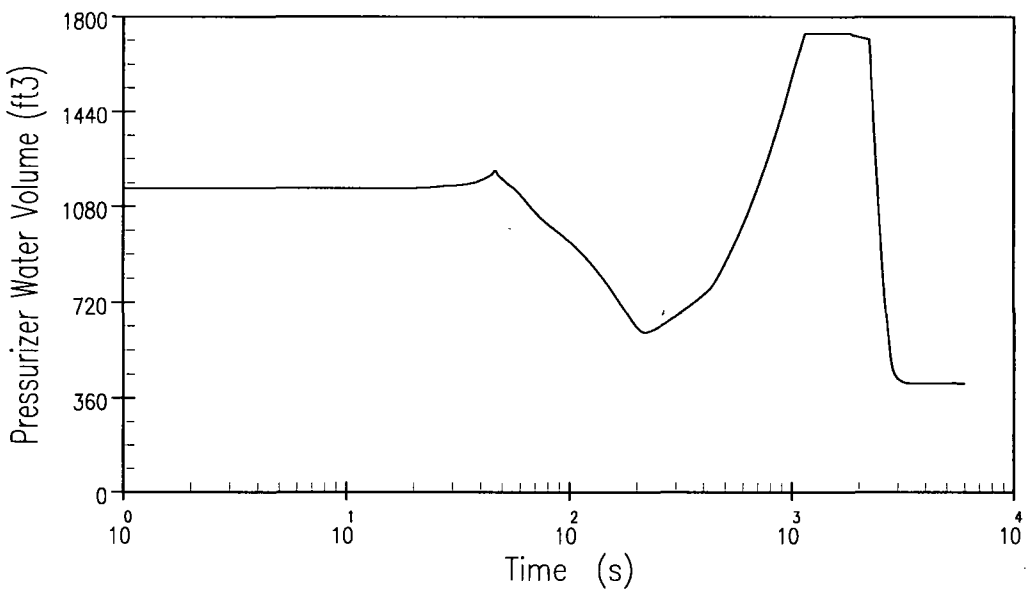
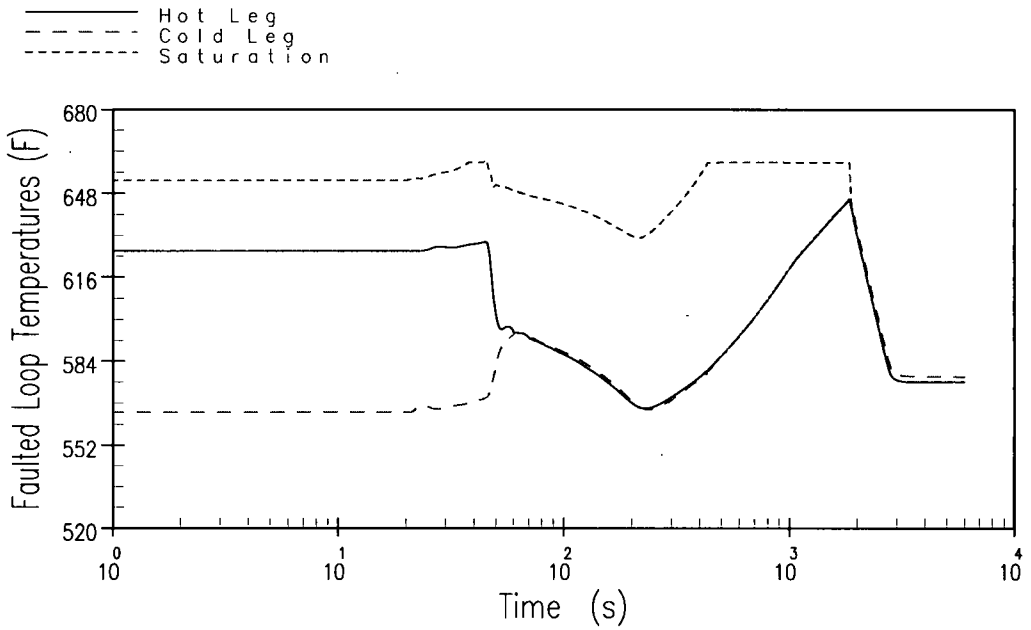


Figure 2.3.4-9 CPNPP Unit 2 – Feedline Break with Offsite Power – Pressurizer Pressure and Water Volume Versus Time



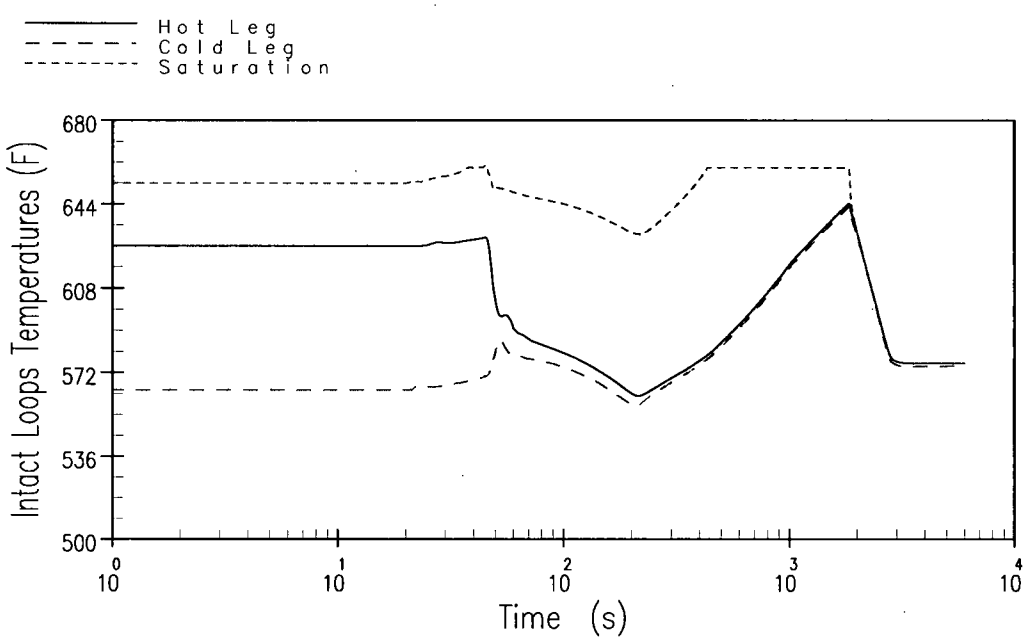
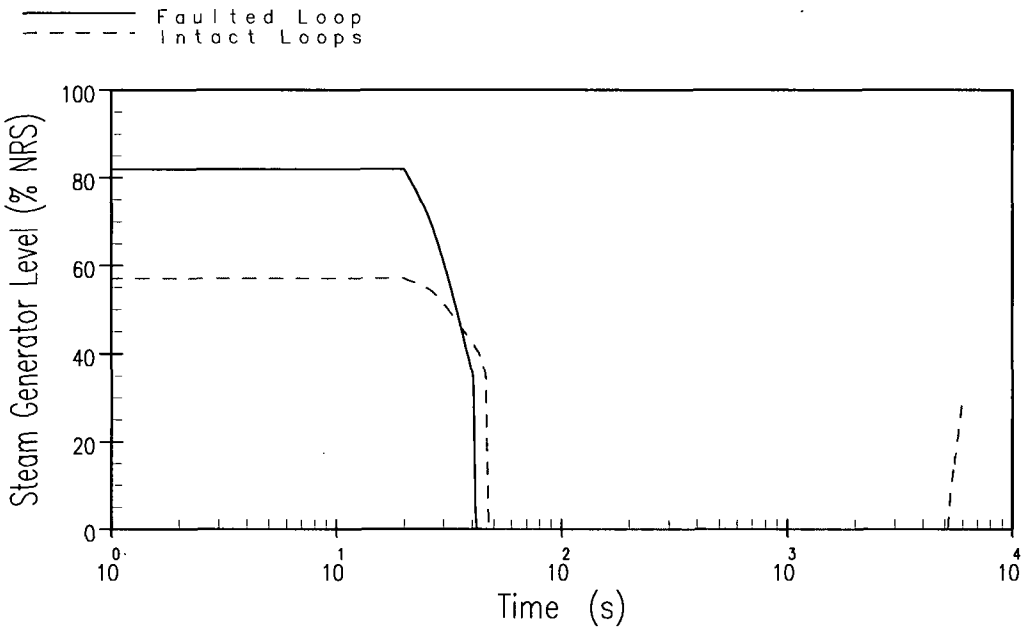


Figure 2.3.4-10 CPNPP Unit 2 – Feedline Break with Offsite Power – Reactor Coolant Temperatures Versus Time for the Faulted and Intact Loops



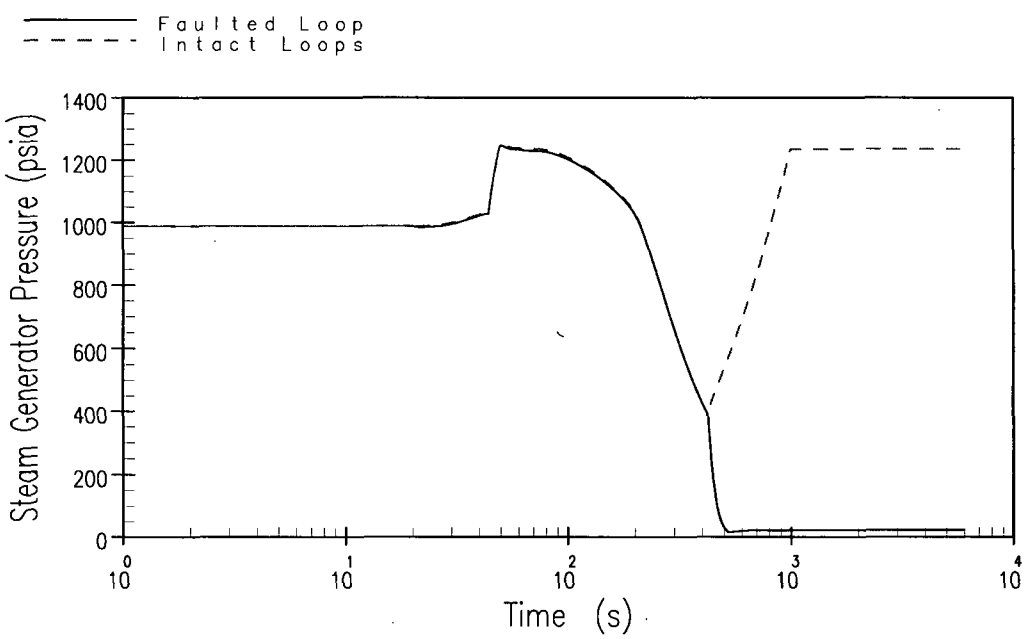


Figure 2.3.4-11 CPNPP Unit 2 – Feedline Break with Offsite Power – Steam Generator Level and Pressure Versus Time

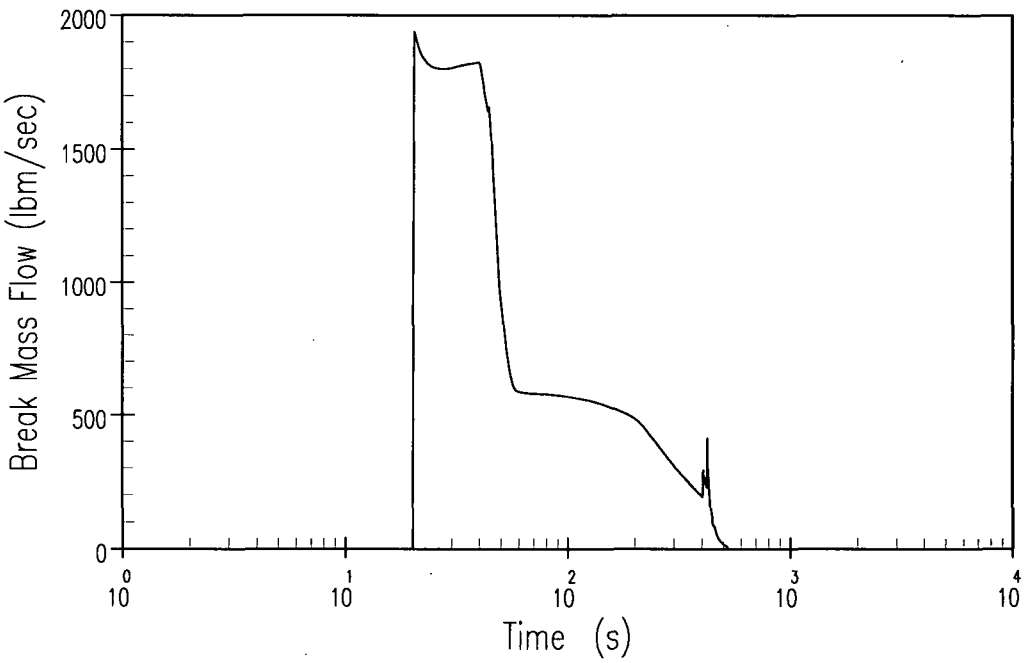


Figure 2.3.4-12 CPNPP Unit 2 – Feedline Break with Offsite Power – Feedline Break Flow Versus Time

2.4 DECREASE IN REACTOR COOLANT SYSTEM FLOW

2.4.1 Loss of Forced Reactor Coolant Flow

2.4.1.1 Technical Evaluation

The specific acceptance criteria for this event are as follows:

- The DNBR remains above the 95/95 DNBR limit at all times during the transient. Demonstrating that the DNBR limit is met satisfies the requirements of GDC-10.
- Primary and secondary pressures remain below 110 percent of their respective design pressures at all times during the transient. Demonstrating that the primary and secondary pressure limits are met satisfies the requirements of GDC-15.
- GDC-26 requires reliable control of reactivity changes to ensure that specified acceptable fuel design limits are not exceeded, including anticipated operational occurrences. This is accomplished by ensuring that appropriate margin for malfunctions, such as stuck RCCAs, are accounted for in the safety analysis assumptions. Demonstrating that the fuel design limits (that is, DNBR) are met satisfies the requirements of GDC-26.

The discussion below demonstrates that all applicable acceptance criteria are met for this event at CPNPP Units 1 and 2 at uprated conditions.

2.4.1.1.1 Introduction

A loss of forced reactor coolant flow accident (FSAR Sections 15.3.1 and 15.3.2) can result from a mechanical or electrical failure in an RCP, from an interruption in the power supplying one or more of these pumps, or from a reduction in RCP motor supply frequency. If the reactor is at power at the time of the event, the immediate effect from the loss of forced coolant flow is a rapid increase in the coolant temperature. This increase in coolant temperature could result in DNB, with subsequent fuel damage, if the reactor is not promptly tripped.

The following signals provide protection against a loss of forced reactor coolant flow incident:

- Low reactor coolant loop flow reactor trip
- Undervoltage on RCP power supply busses reactor trip
- Underfrequency on RCP power supply busses reactor trip

The reactor trip on low reactor coolant loop flow provides primary protection against partial loss-of-flow conditions. This function is generated by two-out-of-three low-flow signals in any reactor coolant loop. Above Permissive P-8, low flow in any loop will actuate a reactor trip. Between approximately 10-percent power (Permissive P-7) and the power level corresponding to Permissive P-8, low flow in two loops will actuate a reactor trip. Reactor trip on low flow is blocked below Permissive P-7 since there is insufficient heat production to be concerned about DNB.

The reactor trip on RCP undervoltage is provided to protect against conditions that can cause a loss of voltage to all RCPs, that is, loss of offsite power. An undervoltage reactor trip serves as an anticipatory backup to the low reactor coolant loop flow trip. The undervoltage trip function is blocked below approximately 10-percent power (Permissive P-7).

The RCP underfrequency reactor trip is provided to trip the reactor for an underfrequency condition resulting from frequency disturbances on the power grid. The RCP underfrequency reactor trip function is blocked below Permissive P-7. This trip function also serves as an anticipatory backup to the low reactor coolant loop flow trip.

2.4.1.1.2 Input Parameters, Assumptions, and Acceptance Criteria

This accident was analyzed using the RTDP (Reference 1). Initial core power was assumed to be at its nominal value consistent with steady-state, full-power operation. The RCS pressure and vessel average temperature were assumed to be at their nominal values. Minimum measured flow was also assumed. Uncertainties in initial conditions were accounted for in the DNBR limit value as described in the RTDP.

A conservatively large absolute value of the Doppler-only power coefficient was used. The analysis also assumed a conservative MTC of 0 pcm/°F at HFP conditions. This resulted in the maximum core power and hot spot heat flux during the initial part of the transient when the minimum DNBR is reached.

Engineered safety systems (such as safety injection) are not required to function. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

A partial loss of forced reactor coolant flow incident is classified as a Condition II event as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. A complete loss of forced reactor coolant flow incident is classified by the ANS as a Condition III event. However, for conservatism, the incident was analyzed to Condition II criteria. The immediate effect from a complete loss of forced reactor coolant flow is a rapid increase in the reactor coolant temperature and subsequent increase in RCS pressure. The following three items identify the acceptance criteria associated with the analysis of the loss of flow events:

The critical heat flux is not to be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.

- Pressures in the RCS and MSS are maintained below 110 percent of their respective design pressures.

- The peak linear heat generation rate does not exceed a value that would cause fuel centerline melt.

2.4.1.1.3 Description of Analyses and Evaluations

With each being applicable to both CPNPP Units 1 and 2 the following loss of forced reactor coolant flow cases were analyzed:

- Loss of power to one RCP (partial loss of flow)
- Loss of power to all RCPs (complete loss of flow)
- 5 Hz/second frequency decay of the RCPs power supply (complete loss of flow)

The transients were analyzed with two computer codes. First, the RETRAN computer code (Reference 2) was used to calculate the loop and core flows during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE computer code (Reference 3) was then used to calculate the heat flux and DNBR based on the nuclear power and RCS temperature (enthalpy), pressure, and flow from the output of the RETRAN transient run. The DNBR transients presented represent the minimum of the typical or thimble cell for the fuel.

2.4.1.1.4 Results

The partial loss of flow case resulted in a low reactor coolant loop flow reactor trip signal and the complete loss of flow case resulted in an undervoltage reactor trip signal. The frequency decay complete loss of flow case resulted in an underfrequency reactor trip signal. The VIPRE (Reference 3) analysis for these scenarios confirmed that the minimum DNBR acceptance criterion was met. Fuel cladding damage criteria were not challenged in any of the loss of forced reactor coolant flow cases since the DNB criterion was met.

The analyses of the loss of flow events also demonstrated that the peak RCS and MSS pressures were well below their respective limits.

The most limiting of these cases in terms of the minimum calculated DNBR was the complete loss of flow undervoltage case. The transient results for each case are presented in Figures 2.4.1-1 through 2.4.1-21. The sequence of events for each case is presented in Table 2.4.1-1. Numerical results for the analyses are shown in Table 2.4.1-2.

The analysis demonstrates that, for the aforementioned loss of flow cases, the DNBR did not decrease below the safety analysis limit value at any time during the transients. Therefore, no fuel or cladding damage is predicted. Also, the peak RCS and MSS pressures remained below their respective limits at all times. All applicable acceptance criteria were therefore met.

The protection features identified in subsection 2.4.1.1.1 provide mitigation for the loss of forced reactor coolant flow transients such that the above criteria are satisfied. Furthermore, the results and conclusions of the loss of flow analysis will be confirmed on a cycle-specific basis as part of the normal reload safety evaluation process.

2.4.1.2 Conclusion

The analyses of the decrease in reactor coolant flow event have been reviewed and it is concluded that the analyses have adequately accounted for plant operations at the proposed uprated power level and were performed using acceptable analytical models. The review further concludes that the evaluation has demonstrated that the reactor protection and safety systems will continue to ensure that the specified acceptable fuel design limits and the RCS and MSS pressure limits will not be exceeded as a result of this event. Based on this, it is concluded that the plant will continue to meet the requirements of GDCs -10, -15, and -26.

2.4.1.3 References

1. WCAP-11397, "Revised Thermal Design Procedure," April 1989.

2. WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

3. WCAP-14565, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," October 1999.

Table 2.4.1-1 Time Sequence of Events – Loss of Forced Reactor Coolant Flow		
Case	**Event**	**Time (sec)**
Loss of Power to One RCP	Flow Coastdown Begins	0.0
	Reactor Coolant Low-Flow Trip Setpoint Reached	1.4
	Rods Begin to Drop	2.4
	Minimum DNBR Occurs	3.2
Loss of Power to All RCPs	Flow Coastdown Begins	0.0
	Rods Begin to Drop(1)	1.5
	Minimum DNBR Occurs	3.1
5 Hz/sec Frequency Decay of the RCPs Power Supply	Frequency Decay Begins	0.0
	Underfrequency Trip Setpoint Reached	0.6
	Rods Begin to Drop	1.2
	Minimum DNBR Occurs	3.0

Note:

1. Undervoltage reactor trip is assumed to occur 1.5 seconds following loss of bus voltage

Table 2.4.1-2 Results – Loss of Forced Reactor Coolant Flow		
	Analysis Value	**Limit Value**
Minimum DNBR – Loss of Power to One RCP	2.173	1.61
Minimum DNBR – Loss of Power to All RCPs	1.901	1.61
Minimum DNBR – Frequency Decay of the RCPs Power Supply	1.921	1.61

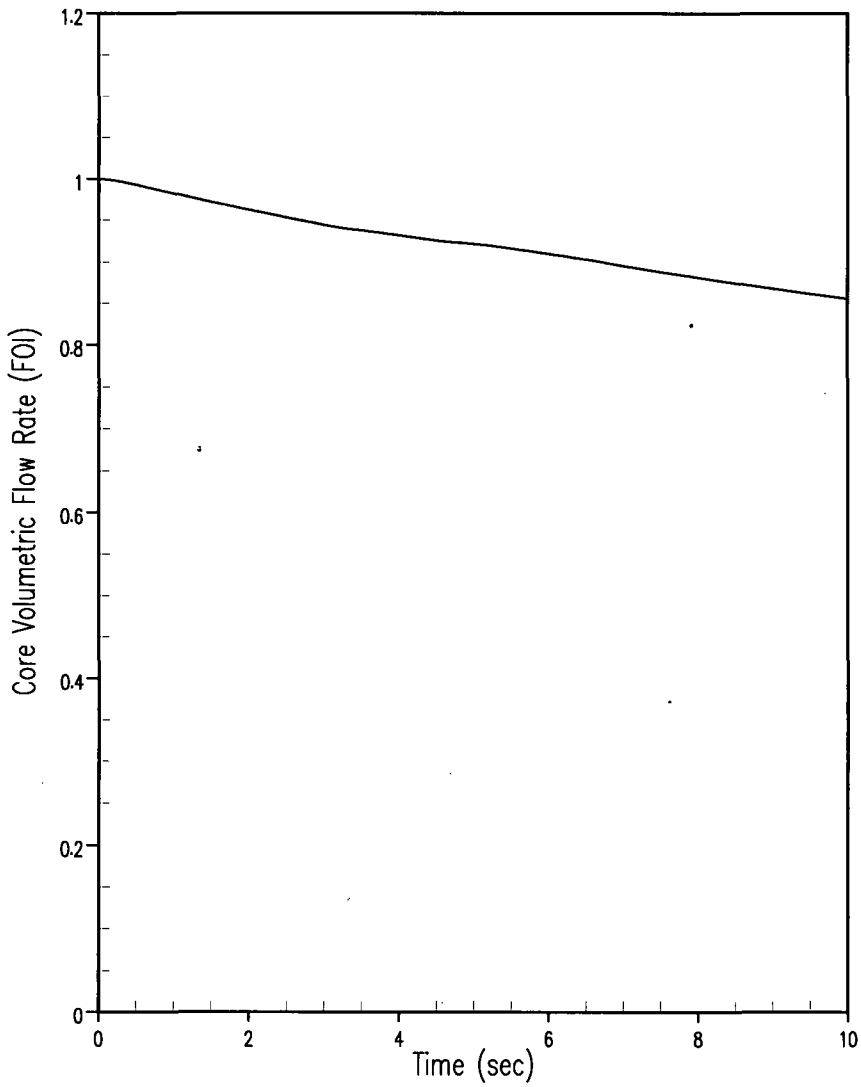


Figure 2.4.1-1 Partial Loss of Flow Core Volumetric Flow Rate Versus Time

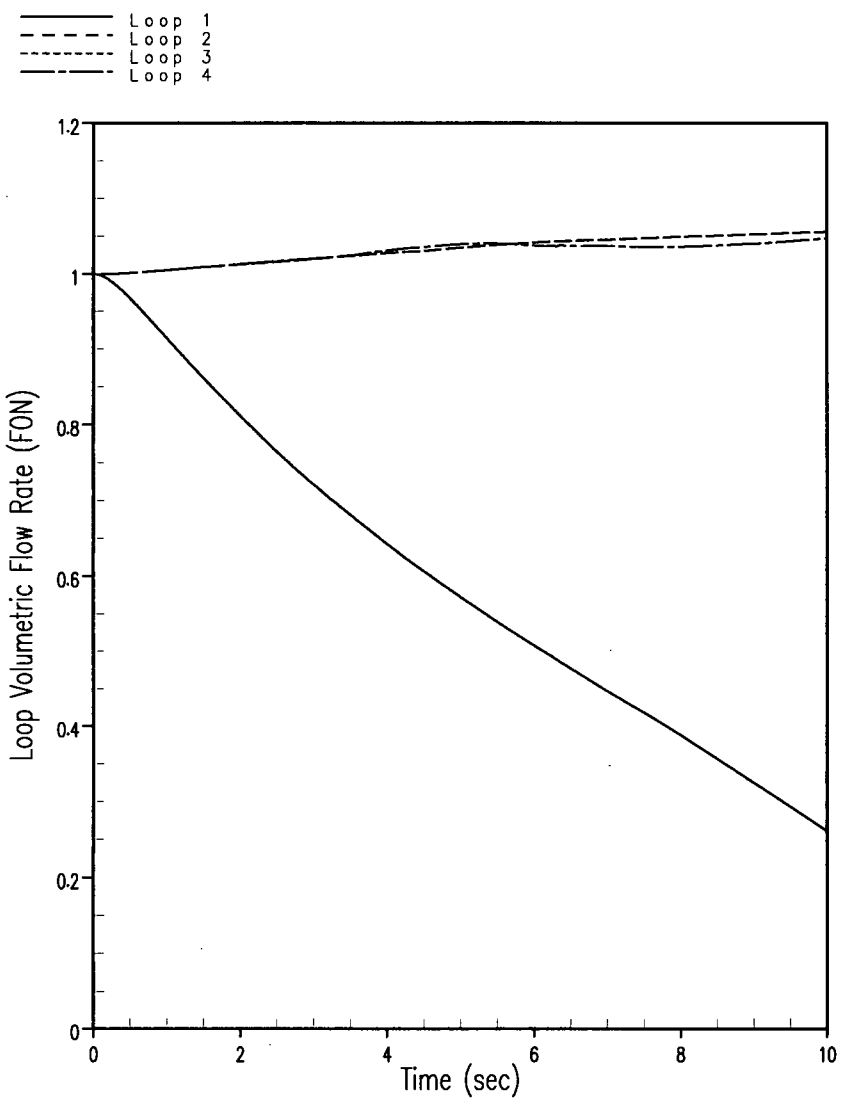


Figure 2.4.1-2 Partial Loss of Flow Loop Volumetric Flow Rate Versus Time

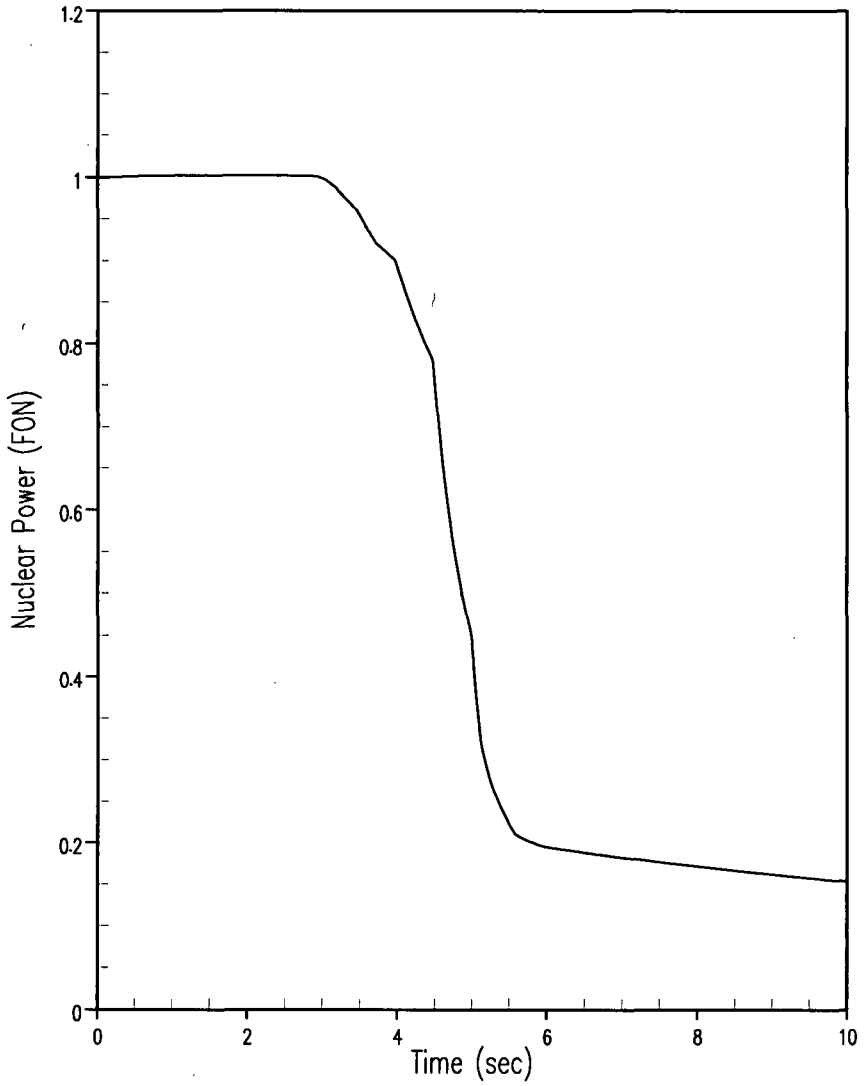


Figure 2.4.1-3 Partial Loss of Flow Nuclear Power Versus Time

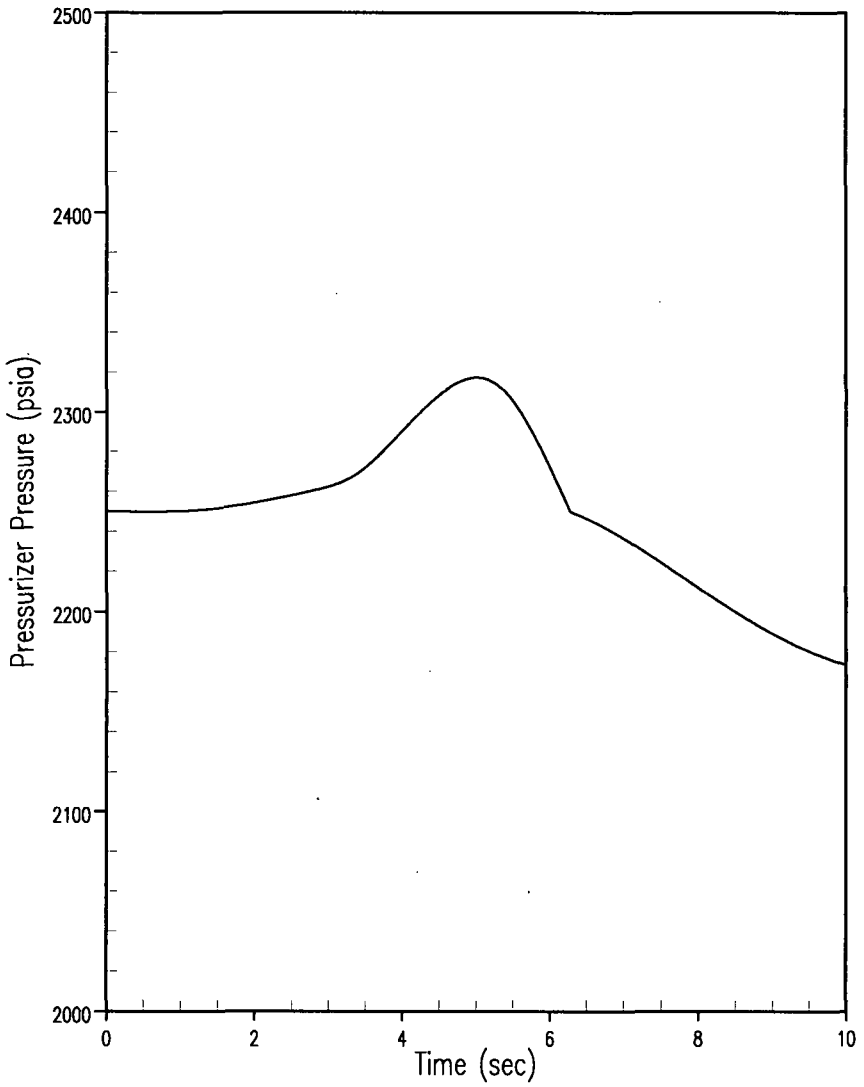


Figure 2.4.1-4 Partial Loss of Flow Pressurizer Pressure Versus Time

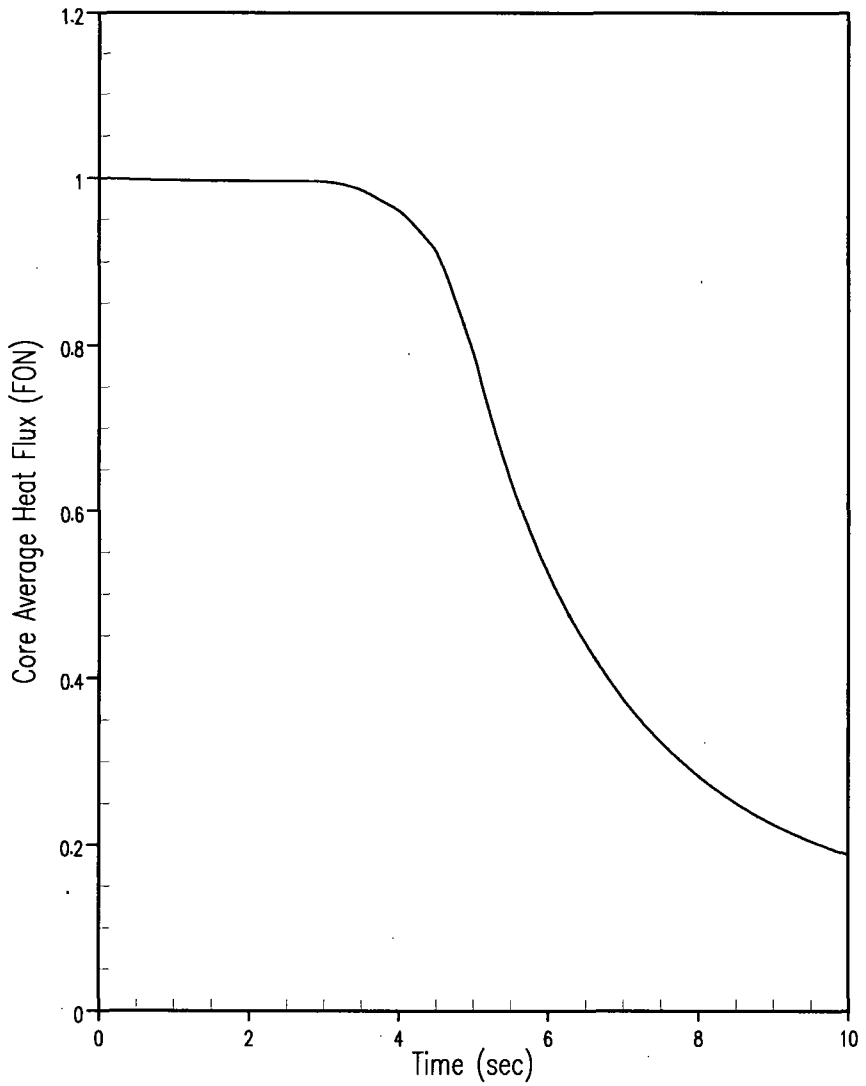


Figure 2.4.1-5 Partial Loss of Flow Core Average Heat Flux Versus Time

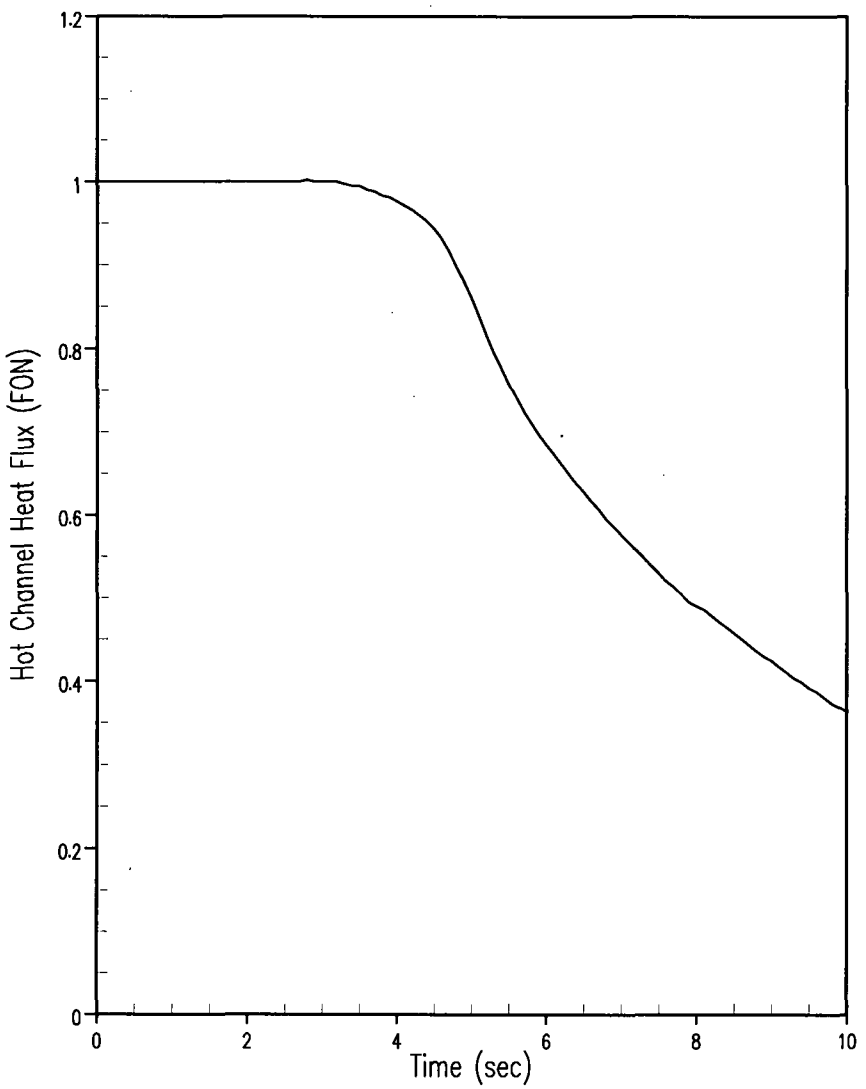


Figure 2.4.1-6 Partial Loss of Flow Hot Channel Heat Versus Time

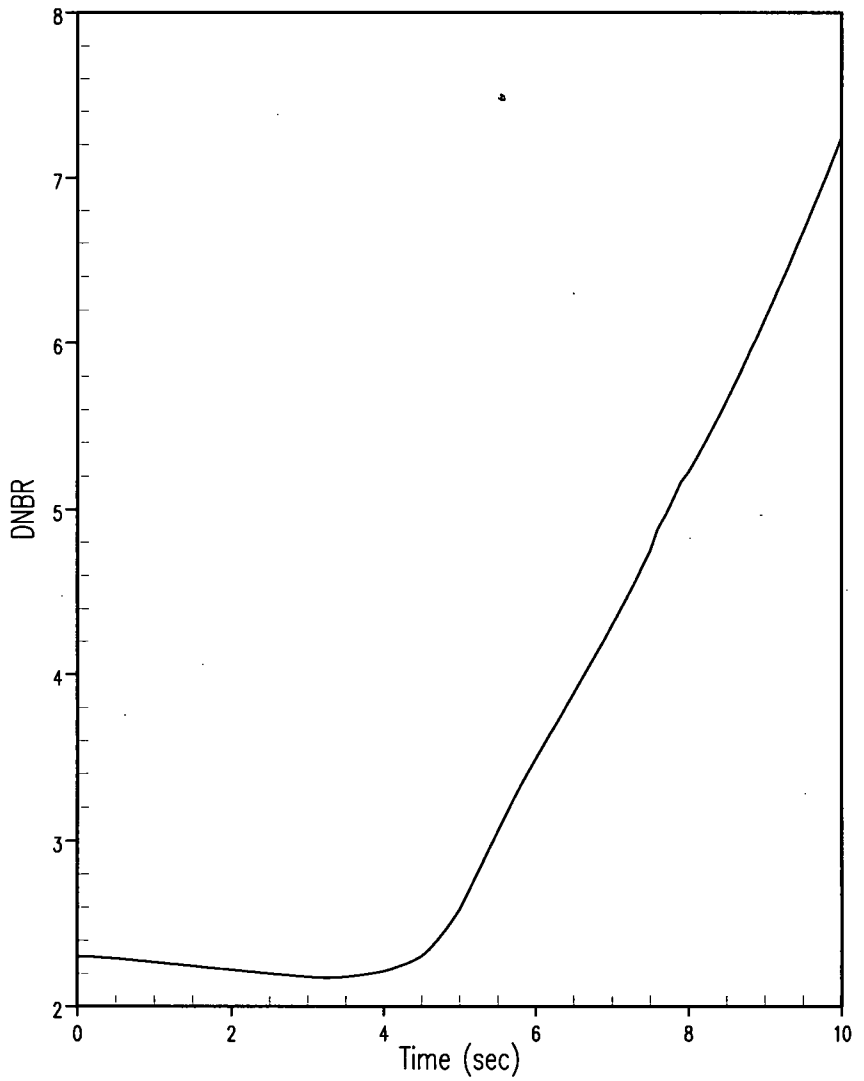


Figure 2.4.1-7 Partial Loss of Flow DNBR Versus Time

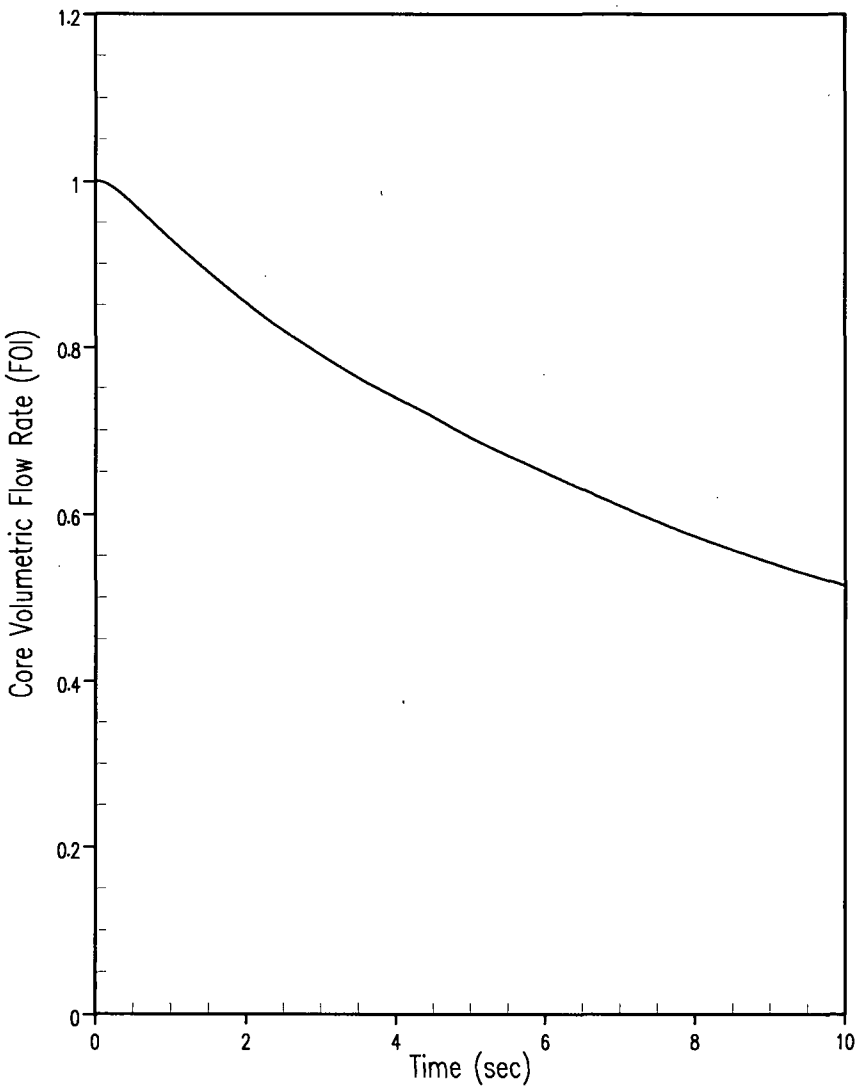


Figure 2.4.1-8 Complete Loss of Flow Undervoltage Core Volumetric Flow Rate Versus Time

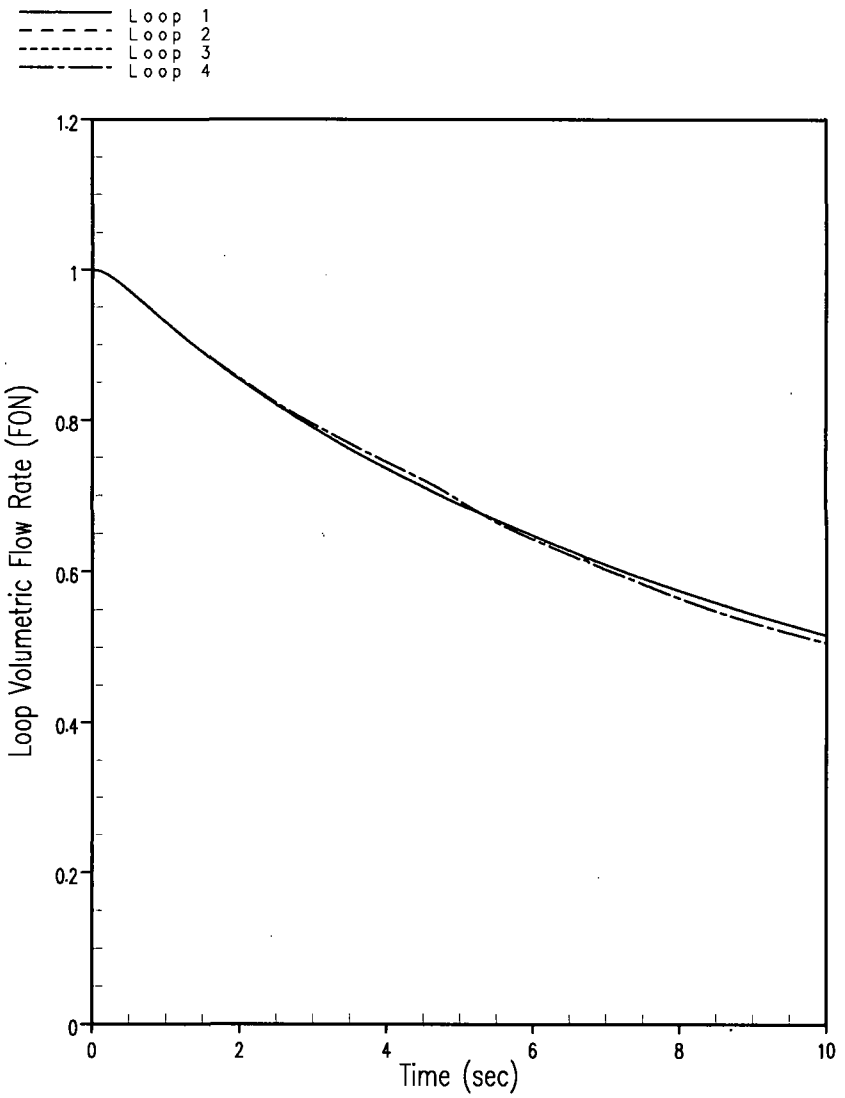


Figure 2.4.1-9 Complete Loss of Flow Undervoltage Loop Volumetric Flow Rate Versus Time

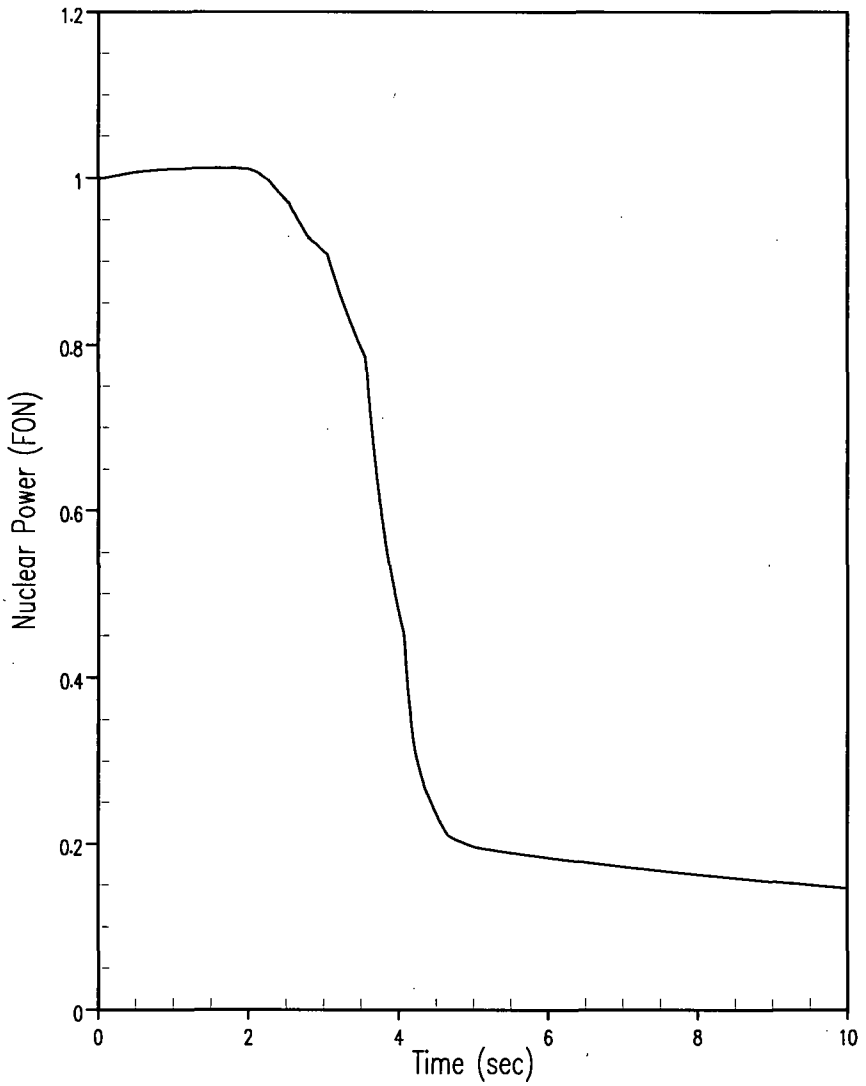


Figure 2.4.1-10 Complete Loss of Flow Undervoltage Nuclear Power Versus Time

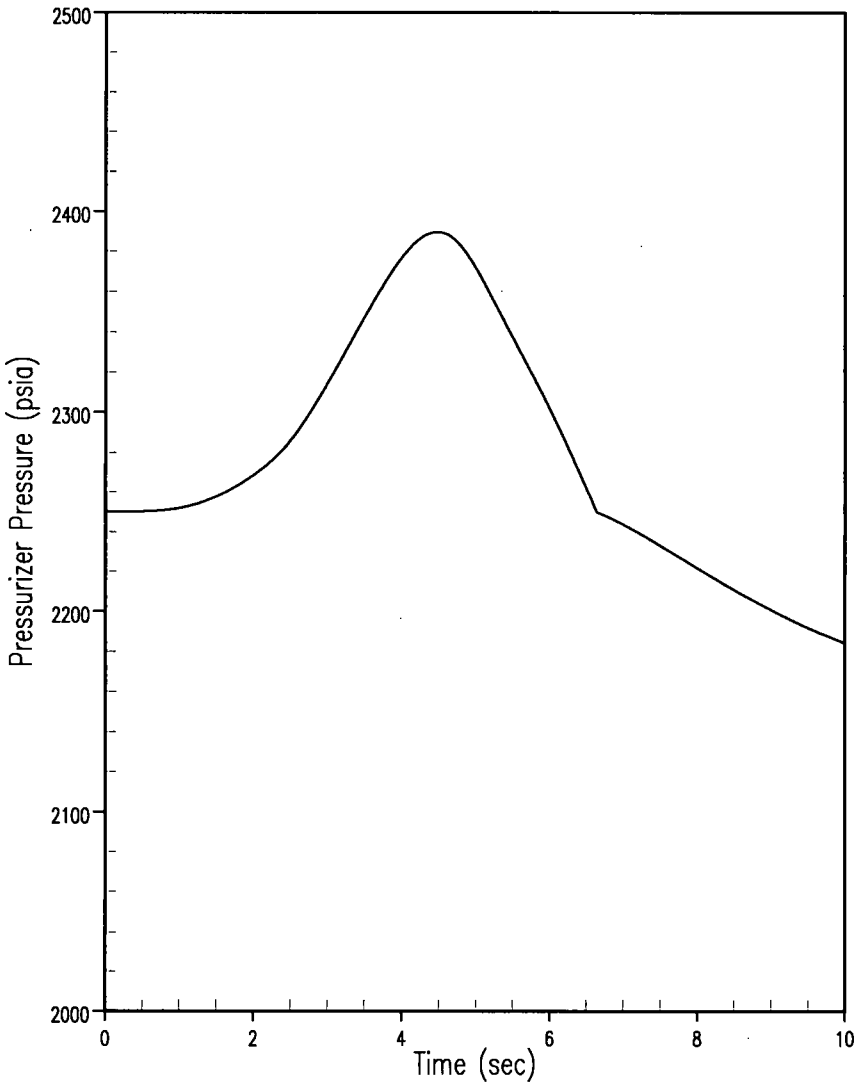


Figure 2.4.1-11 Complete Loss of Flow Undervoltage Pressurizer Pressure Versus Time

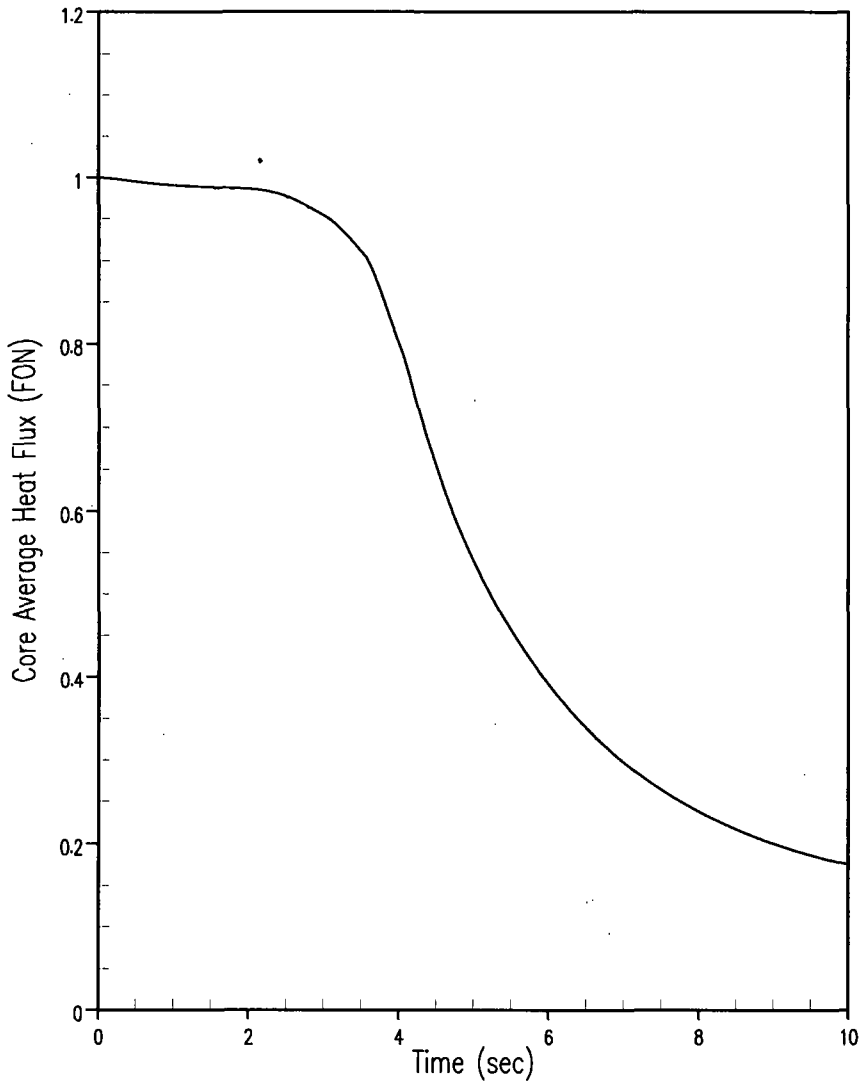


Figure 2.4.1-12 Complete Loss of Flow Undervoltage Core Average Heat Flux Versus Time

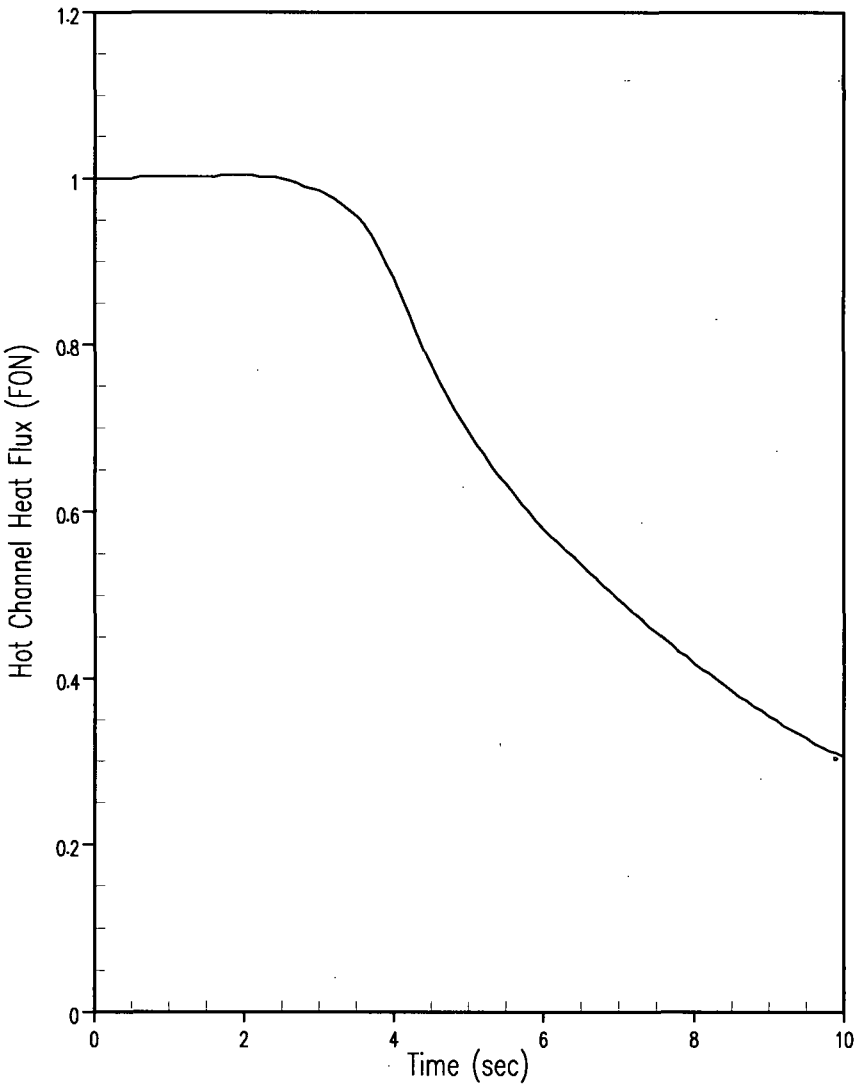


Figure 2.4.1-13 Complete Loss of Flow Undervoltage Hot Channel Heat Flux Versus Time

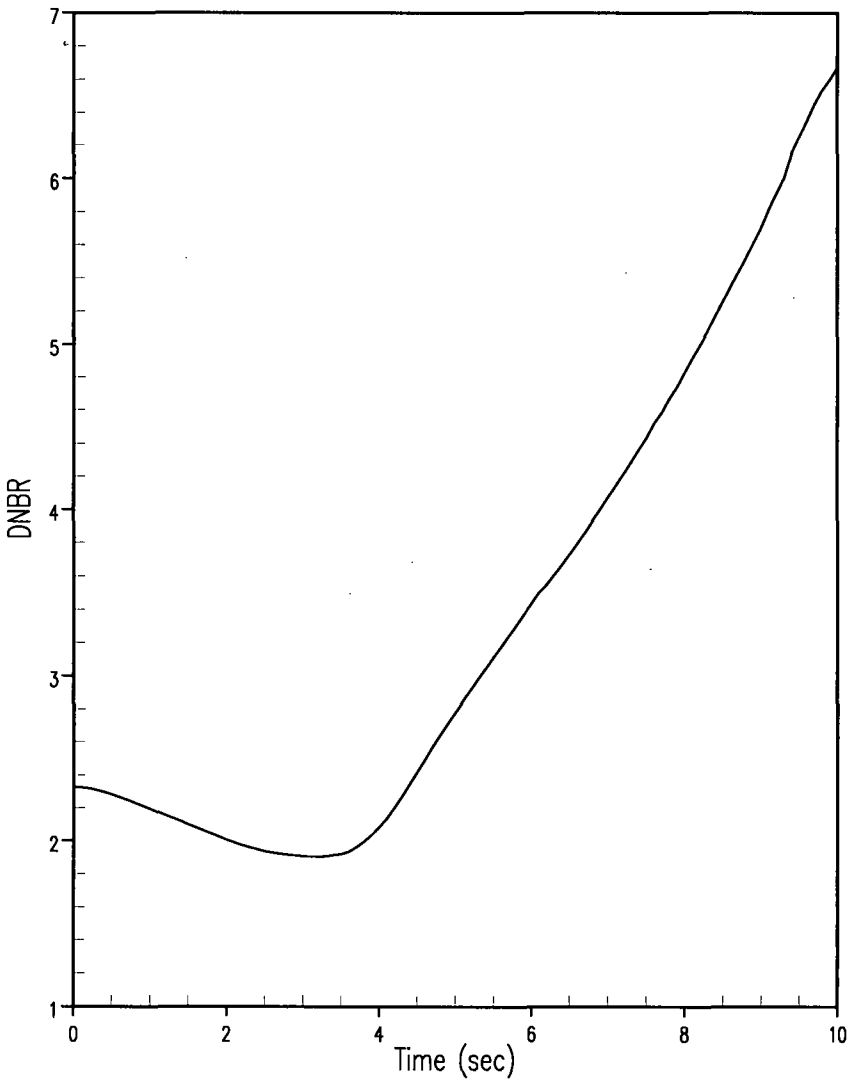


Figure 2.4.1-14 Complete Loss of Flow Undervoltage DNBR Versus Time

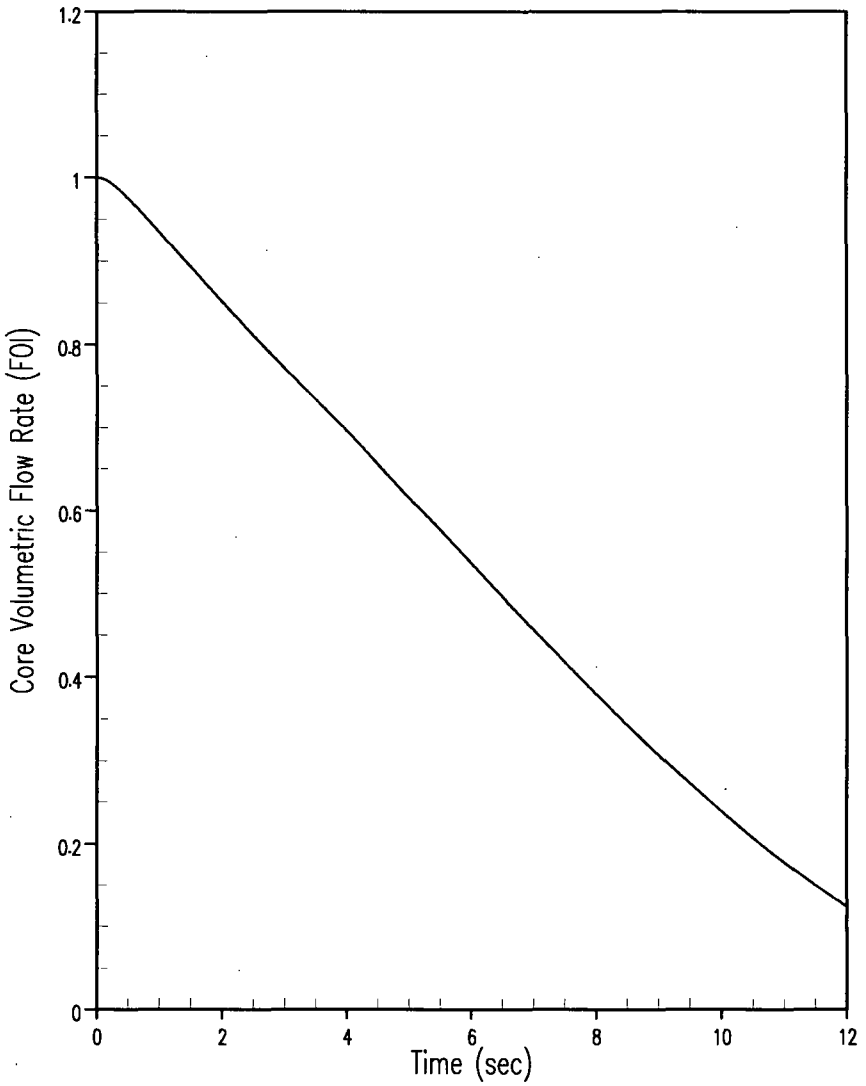


Figure 2.4.1-15 Complete Loss of Flow Frequency Decay Core Volumetric Flow Rate Versus Time

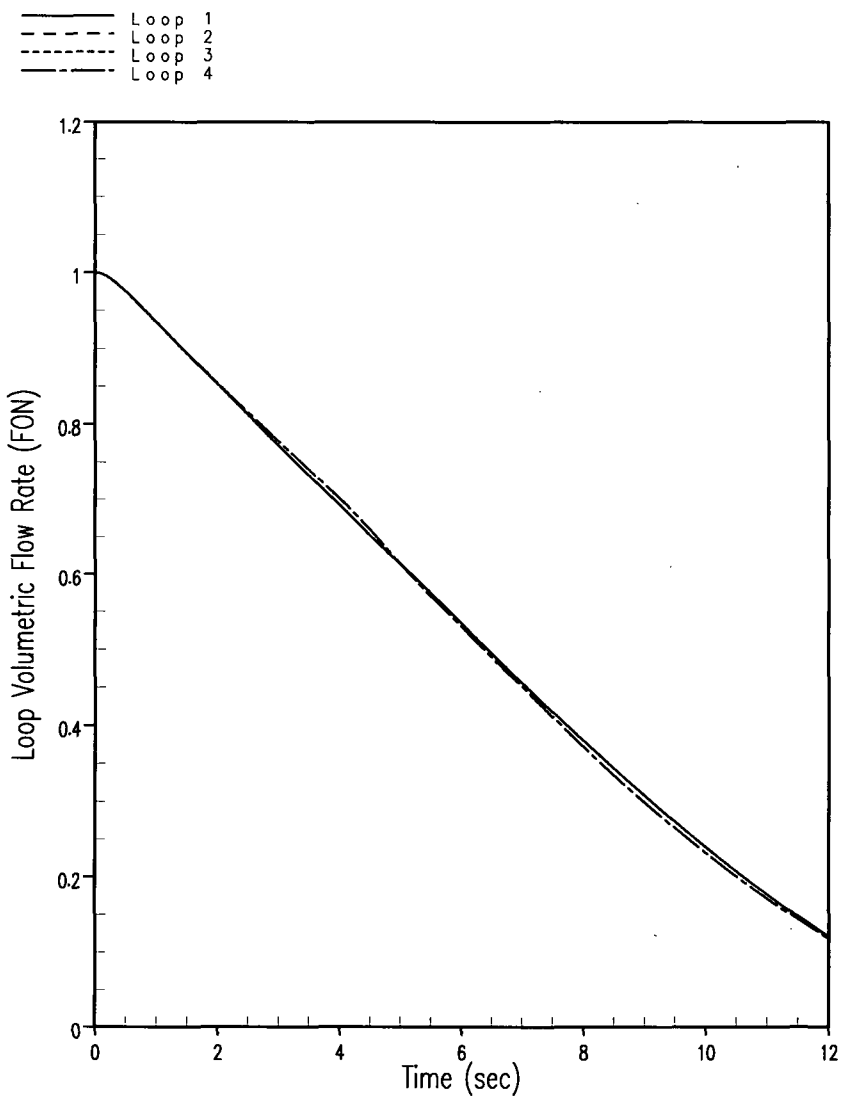


Figure 2.4.1-16 Complete Loss of Flow Frequency Decay Loop Volumetric Flow Rate Versus Time

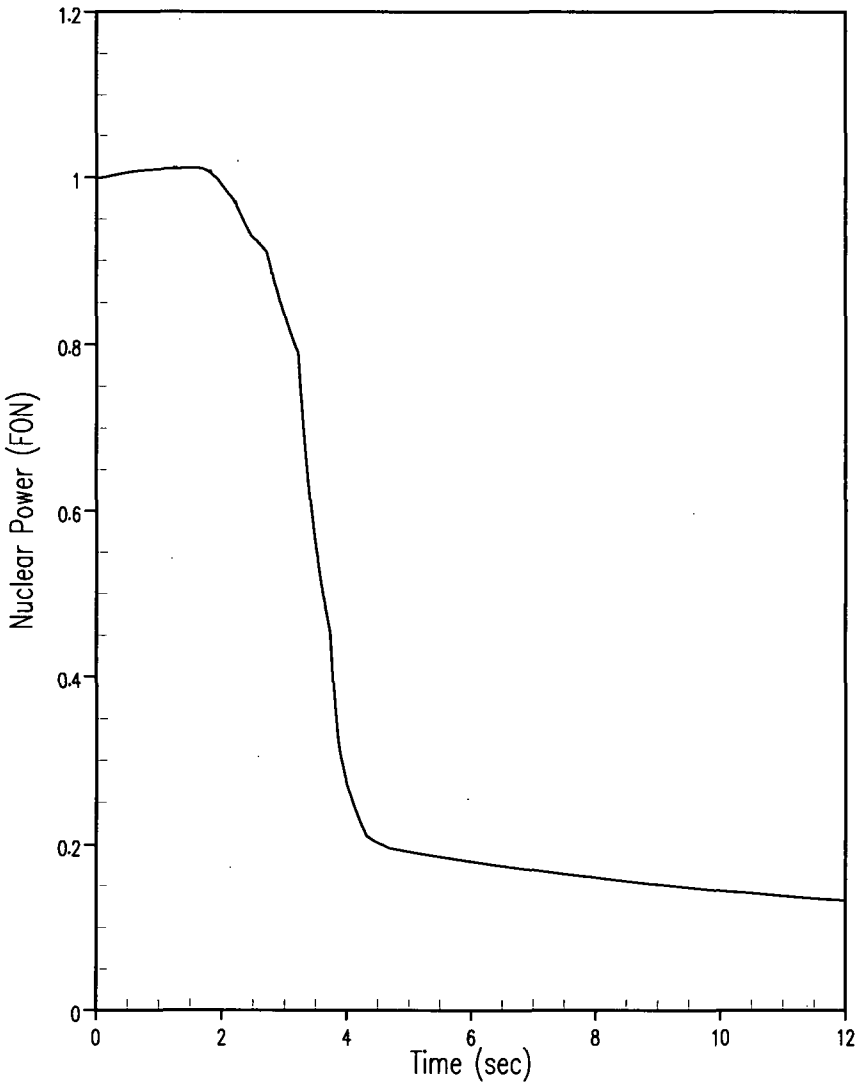


Figure 2.4.1-17 Complete Loss of Flow Frequency Decay Nuclear Power Versus Time

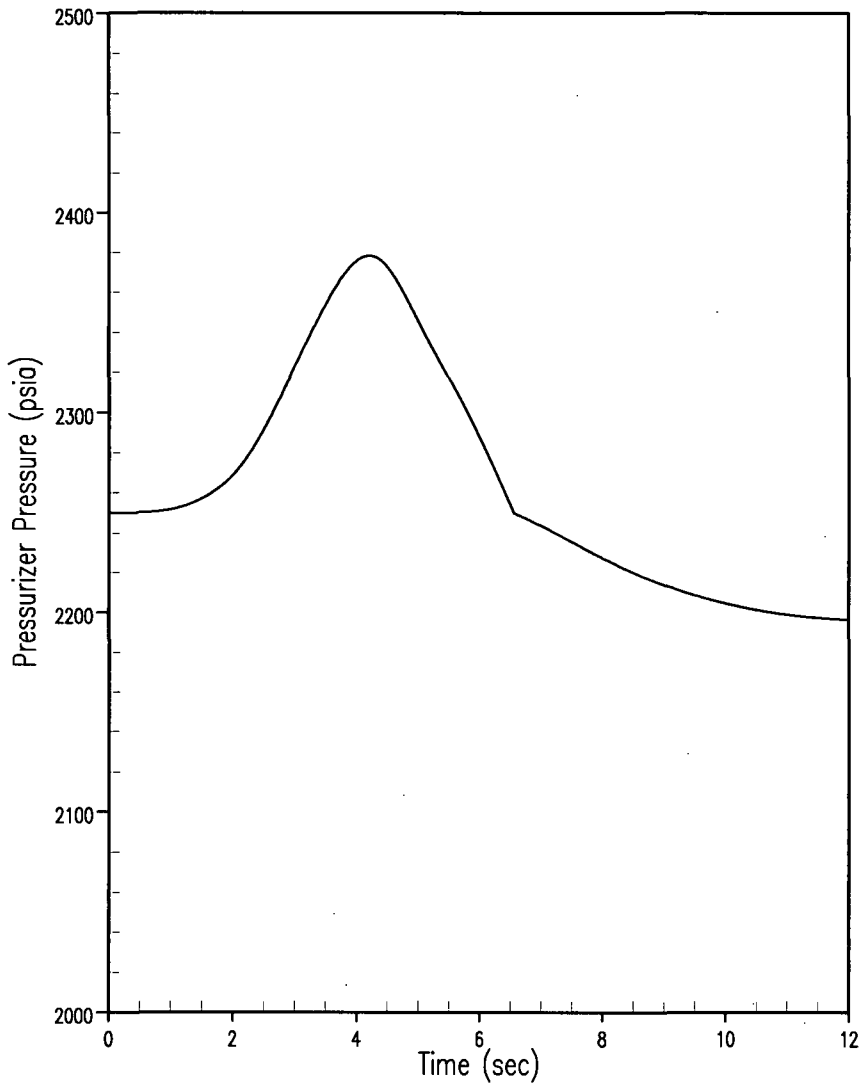


Figure 2.4.1-18 Complete Loss of Flow Frequency Decay Pressurizer Pressure Versus Time

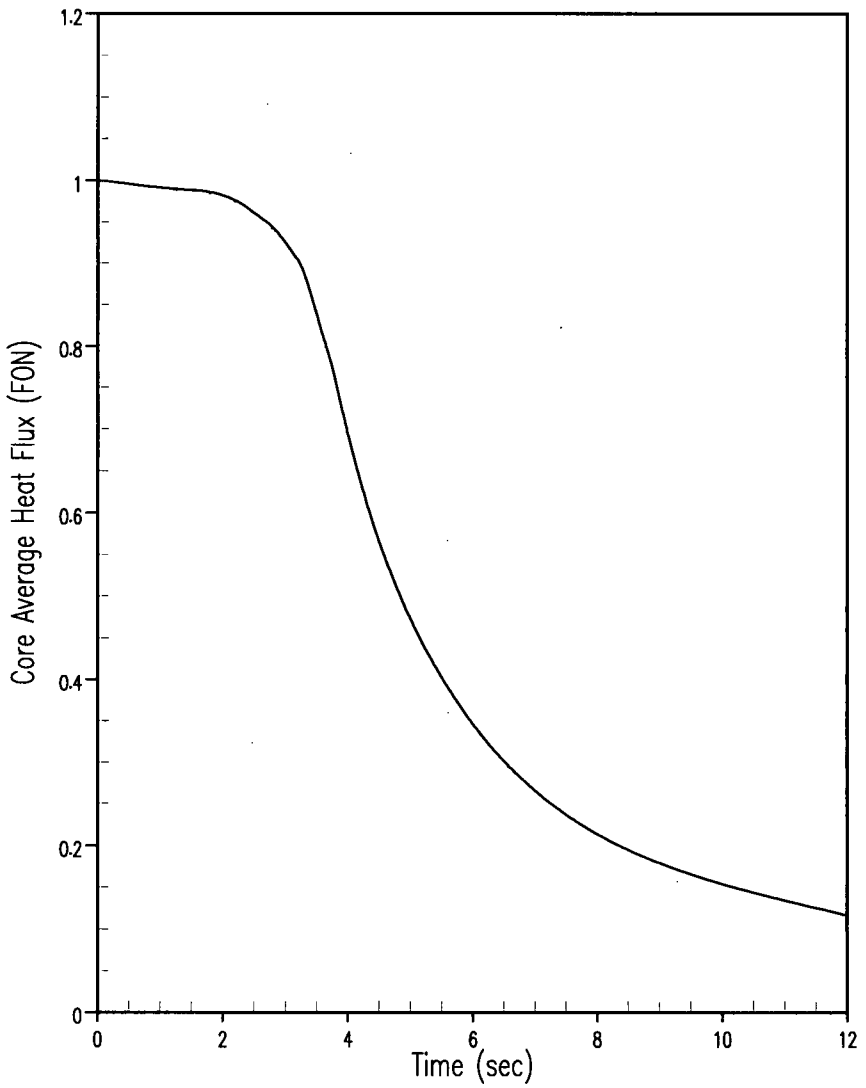


Figure 2.4.1-19 Complete Loss of Flow Frequency Decay Core Average Heat Flux Versus Time

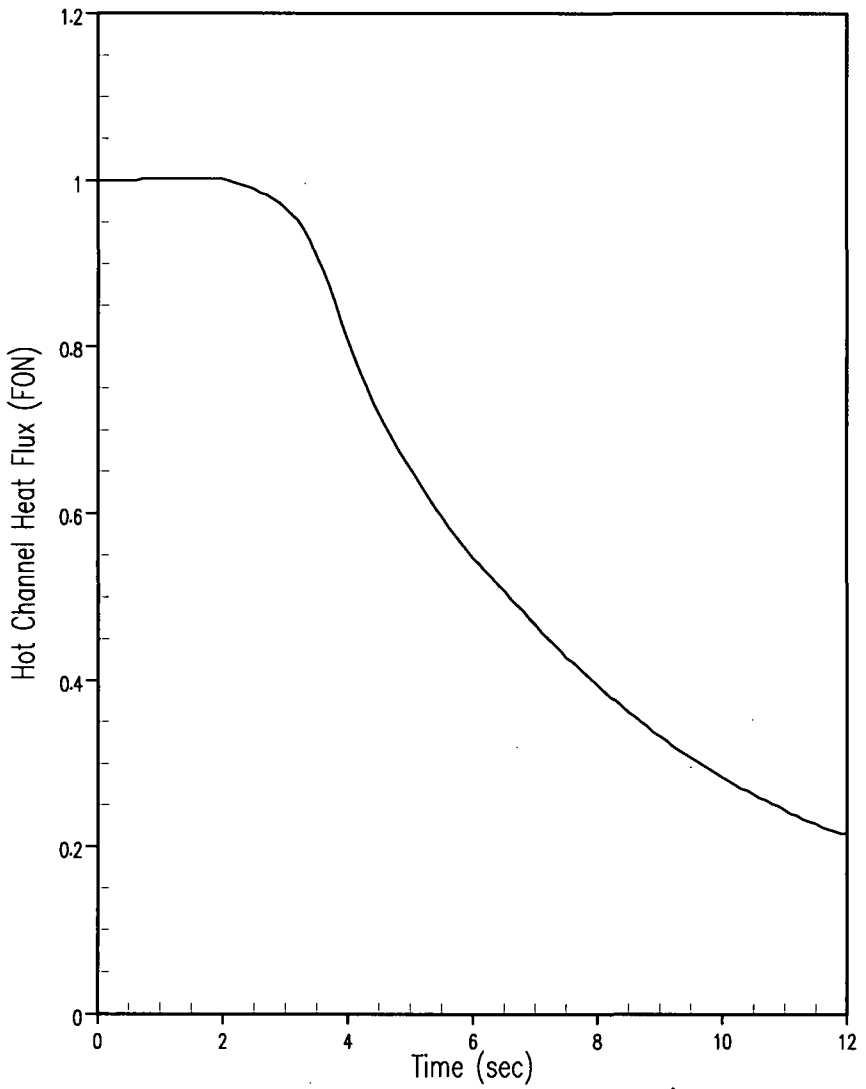


Figure 2.4.1-20 Complete Loss of Flow Frequency Decay Hot Channel Heat Flux Versus Time

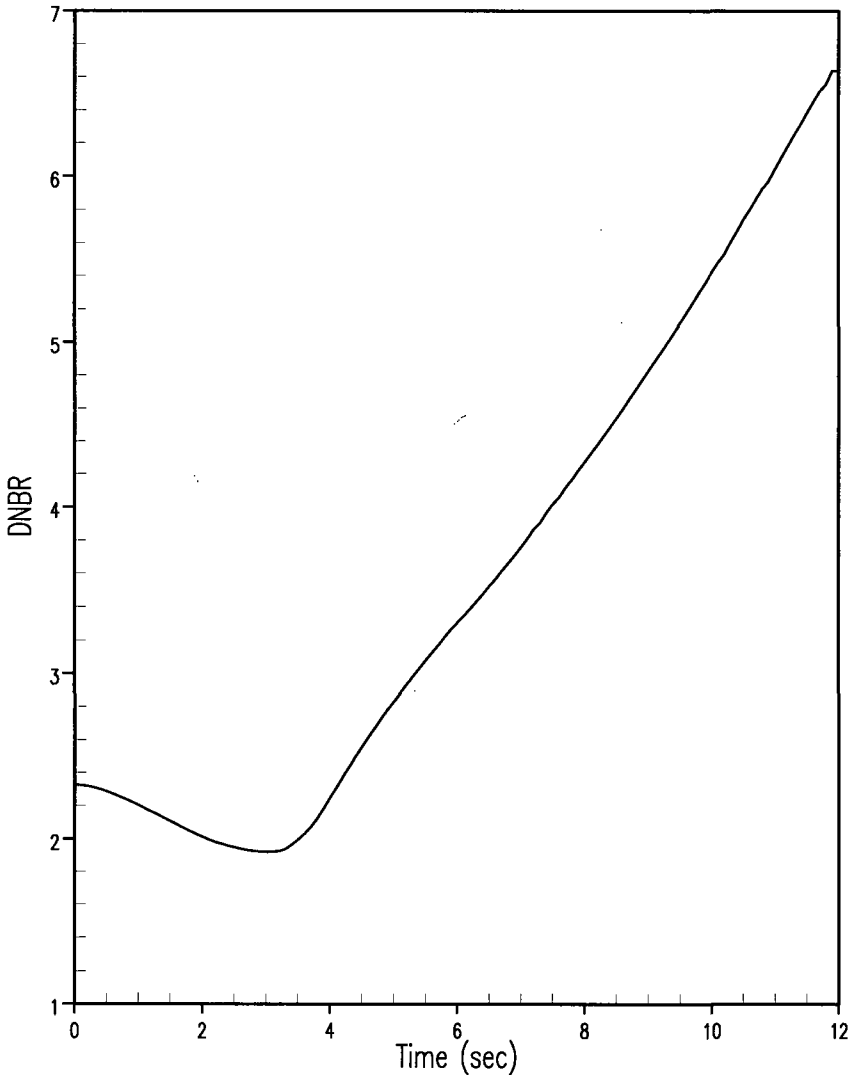


Figure 2.4.1-21 Complete Loss of Flow Frequency DNBR Versus Time

2.4.2 Reactor Coolant Pump Rotor Seizure and RCP Shaft Break

2.4.2.1 Technical Evaluation

The specific acceptance criteria for this event are as follows:

- The peak cladding temperature must remain below 2,700°F and the maximum zirconium-water reaction must remain below 16 percent. Appropriate margin for malfunctions, such as stuck rods, were accounted for in the safety analysis assumptions. Demonstrating that these limits are met satisfies the requirements of GDC-27 and GDC-28.

- Pressures in the RCS are to be maintained less than that which would cause stresses to exceed the faulted condition stress limits for very low probability events such as locked rotor. Demonstrating that this limit is met satisfies the requirements of GDC-28.

- The total percentage of rods-in-DNB should be less than that analyzed in the dose analysis. The specific limit for the uprate analysis is 10 percent. Demonstrating that this limit is met satisfies the requirements of GDC-27 and GDC-28.

The discussion below demonstrates that all applicable acceptance criteria were met for this event at CPNPP Units 1 and 2 at uprated conditions.

2.4.2.1.1 Introduction

The event postulated is an instantaneous seizure of an RCP rotor or the sudden break of the shaft of the RCP (FSAR Sections 15.3.3 and 15.3.4). Flow through the affected reactor coolant loop is rapidly reduced, leading to initiation of a reactor trip on a low reactor coolant flow signal.

Following initiation of the reactor trip, heat stored in the fuel rods continues to be transferred to the coolant causing the coolant to expand. At the same time, heat transfer to the shell side of the steam generators is reduced; first because the reduced flow results in a decreased tube-side film heat transfer coefficient, and second because the temperature differential between the reactor coolant in the tubes and the shell-side fluid is decreased. The rapid expansion of the coolant in the reactor core causes an insurge into the pressurizer and a pressure increase throughout the RCS. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the PORVs, and opens the PSVs, in that sequence. The PORVs are designed for reliable operation and are expected to function properly during the event. However, for conservatism, their pressure-reducing effect, as well as the pressure-reducing effect of the pressurizer spray, were not included in the analysis.

The consequences of a locked rotor (that is, an instantaneous seizure of a pump shaft) are very similar to those of a pump shaft break. The initial rate of the reduction in coolant flow is slightly greater for the locked rotor event. However, with a broken shaft, the impeller could conceivably be free to spin in the reverse direction. The effect of reverse spinning is a reduced core flow when compared to the locked rotor scenario. The analysis considers only one scenario; it

represents the most limiting combination of conditions for the locked rotor and pump shaft break events.

2.4.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

There were two locked rotor cases analyzed, with each being applicable to both CPNPP Units 1 and 2: one for peak RCS pressure and peak cladding temperature (PCT) concerns and a second to determine the percentage of rods-in-DNB. The case evaluating peak RCS pressure and PCT assumed one locked rotor and shaft break with all reactor coolant loops in operation. The first case made assumptions designed to maximize the RCS pressure and cladding temperature transients. It was done using the Standard Thermal Design Procedure (STDP). Initial core power, reactor coolant temperature, and pressure were assumed to be at their maximum values consistent with full-power conditions, including allowances for calibration and instrument errors. This assumption resulted in a conservative calculation of the coolant insurge into the pressurizer, which in turn resulted in a maximum calculated peak RCS pressure.

The second case was run to confirm that the percentage of rods-in-DNB is less than that assumed in the radiological analysis. As in the peak RCS pressure/PCT case, one locked rotor and shaft break was assumed with all reactor coolant loops in operation. Initial core power was assumed to be at its nominal value consistent with steady-state, full-power operation. The RCS pressure and vessel average temperature were assumed to be at their nominal values. Minimum measured flow was also assumed. Uncertainties in initial conditions were accounted for in the DNBR limit value as described in the RTDP (Reference 1).

A zero MTC and a conservatively large (absolute value) Doppler-only power coefficient were assumed in the analysis. The negative reactivity from control rod insertion/scram was based on 4.0-percent $\Delta k/k$ trip reactivity from HFP.

Engineered safety systems (such as safety injection) are not required to function. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

The RCP locked rotor/shaft break accident is classified as a Condition IV event as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. An RCP locked rotor/shaft break results in a rapid reduction in forced reactor coolant loop flow that increases the reactor coolant temperature and subsequently causes the fuel cladding temperature and RCS pressure to increase. The following items summarize the criteria associated with this event:

- Fuel cladding damage, including melting, due to increased reactor coolant temperatures must be prevented. This is precluded by demonstrating that the maximum cladding temperature at the core hot spot remains below 2,700°F, and the zirconium-water reaction at the core hot spot is less than 16 percent by weight.

- Pressures in the RCS are to be maintained below 110 percent of the design pressure.

- The total percentage of rods-in-DNB is less than that analyzed in the dose analysis. The specific limit for the uprate analysis is 10 percent.

2.4.2.1.3 Description of Analyses and Evaluations

The locked-rotor transient was analyzed with two primary computer codes. First, the RETRAN computer code (Reference 2) was used to calculate the loop and core flows during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE code (Reference 3) was then used to calculate the PCT using the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN.

For the peak RCS pressure evaluation, the initial pressure was conservatively estimated to be 30 psi above the nominal pressure of 2,250 psia. This was to allow for initial condition uncertainties in the pressurizer pressure measurement and control channels. This was done to obtain the highest possible rise in the coolant pressure during the transient. The pressure response reported in Table 2.4.2-2 corresponds to the location in the RCS that has the maximum pressure, that is, in the lower plenum of the reactor vessel.

No credit was taken for the pressure-reducing effect of the pressurizer PORVs, pressurizer spray, or steam dump. Although these systems are expected to function and would result in a lower peak pressure, an additional degree of conservatism was provided by not including their effect. The PSV model included a +2-percent valve opening tolerance above the nominal setpoint of 2,485 psig plus a 1-percent set pressure shift due to the water-filled pressurizer loop seals.

The film boiling coefficient was calculated in the VIPRE code (Reference 3) using the Bishop-Sandberg-Tong film boiling correlation. The fluid properties were evaluated at film temperature. The program calculated the film coefficient at every time step based upon the actual heat transfer conditions at the time. The nuclear power, system pressure, bulk density, and RCS flow rate as a function of time were based on the RETRAN results.

The magnitude and time dependence of the heat transfer coefficient between the fuel and cladding (gap coefficient) has a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between the pellet and cladding. Based on investigations on the effect of the gap coefficient upon the maximum cladding temperature during the transient, the gap coefficient was assumed to increase from a steady-state value consistent with the initial fuel temperature to approximately 10,000 Btu/hr-ft^2-°F at the initiation of the transient. Therefore, the large amount of energy stored in the fuel because of the small initial value was released to the cladding at the initiation of the transient.

The zirconium-steam reaction can become significant above 1,800°F (cladding temperature). The Baker-Just parabolic rate equation was used to define the rate of zirconium-steam reaction. The effect of the zirconium-steam reaction was included in the calculation of the PCT temperature transient.

2.4.2.1.4 Results

With respect to the peak RCS pressure, PCT, and zirconium-steam reaction, the analysis demonstrated that all applicable acceptance criteria were met for CPNPP Units 1 and 2. The calculated sequence of events is presented in Table 2.4.2-1 for the locked rotor/shaft break event. The results of the calculations (peak pressure, PCT, and zirconium-steam reaction) are summarized in Table 2.4.2-2. The transient results for the peak pressure/PCT case are provided in Figures 2.4.2-1 through 2.4.2-6 while the transient results for the rods-in-DNB case are provided in Figures 2.4.2-7 through 2.4.2-12.

The analysis performed for the uprate demonstrated that, for the locked rotor event, the PCT calculated for the hot spot during the worst transient remained considerably less than 2,700°F, and the amount of zirconium-water reaction was small. Under such conditions, the core would remain in place and intact with no loss of core cooling capability.

The analysis also confirmed that the peak RCS pressure reached during the transient was less than the acceptance limit, and thereby, the integrity of the primary coolant system was demonstrated. The total number of rods-in-DNB was less than 10 percent. The low reactor coolant flow reactor trip function provided mitigation for the locked rotor/shaft break transient such that the above criteria were satisfied. Furthermore, the results and conclusions of this analysis will be confirmed on a cycle-specific basis as part of the normal reload safety evaluation process.

2.4.2.2 Conclusion

The analyses of the sudden decrease in core coolant flow events have been reviewed and it is concluded that the analyses have adequately accounted for plant operation at the proposed uprated power level and were performed using acceptable analytical models. The review further concludes that the evaluation has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCS pressure limit will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of propagating fracture of the reactor coolant pressure boundary is minimized, and adequate core cooling will be provided. Based on this, it is concluded that the plant will continue to meet the requirements of GDCs -27, -28, and -31.

2.4.2.3 References

1. WCAP-11397, "Revised Thermal Design Procedure," April 1989.

2. WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

3. WCAP-14565, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," October 1999.

Table 2.4.2-1 Time Sequence of Events – Single RCP Locked Rotor/Shaft Break		
Case	**Event**	**Time (sec)**
Locked Rotor (LR) – Overpressurization/Peak Cladding Temperature	Loop 1 RCP Rotor Seizes	0.0
	Reactor Coolant Low-Flow Trip Setpoint Reached	0.04
	Rods Begin to Drop	1.04
	Remaining Pumps Lose Power and Begin to Coast Down	1.04
	Maximum Cladding Temperature Occurs	3.65
	Maximum RCS Pressure Occurs	4.94
LR – Rods-in-DNB	Loop 1 RCP Rotor Seizes	0.0
	Reactor Coolant Low-Flow Trip Setpoint Reached	0.04
	Rods Begin to Drop	1.04
	Remaining Pumps Lose Power and Begin to Coast Down	1.04
	Minimum DNBR Occurs	2.70

Table 2.4.2-2 Results – Single RCP Locked Rotor/Shaft Break		
Criteria	**Analysis Value**	**Limit**
Peak Cladding Temperature at Core Hot Spot, °F	1,723.6	2,700.
Maximum Zirconium-Water Reaction at Core Hot Spot, %	0.22	16.0
Maximum RCS Pressure, psia	2,574.5	2,748.2
Total number of rods-in-DNB, %	< 10%	10%

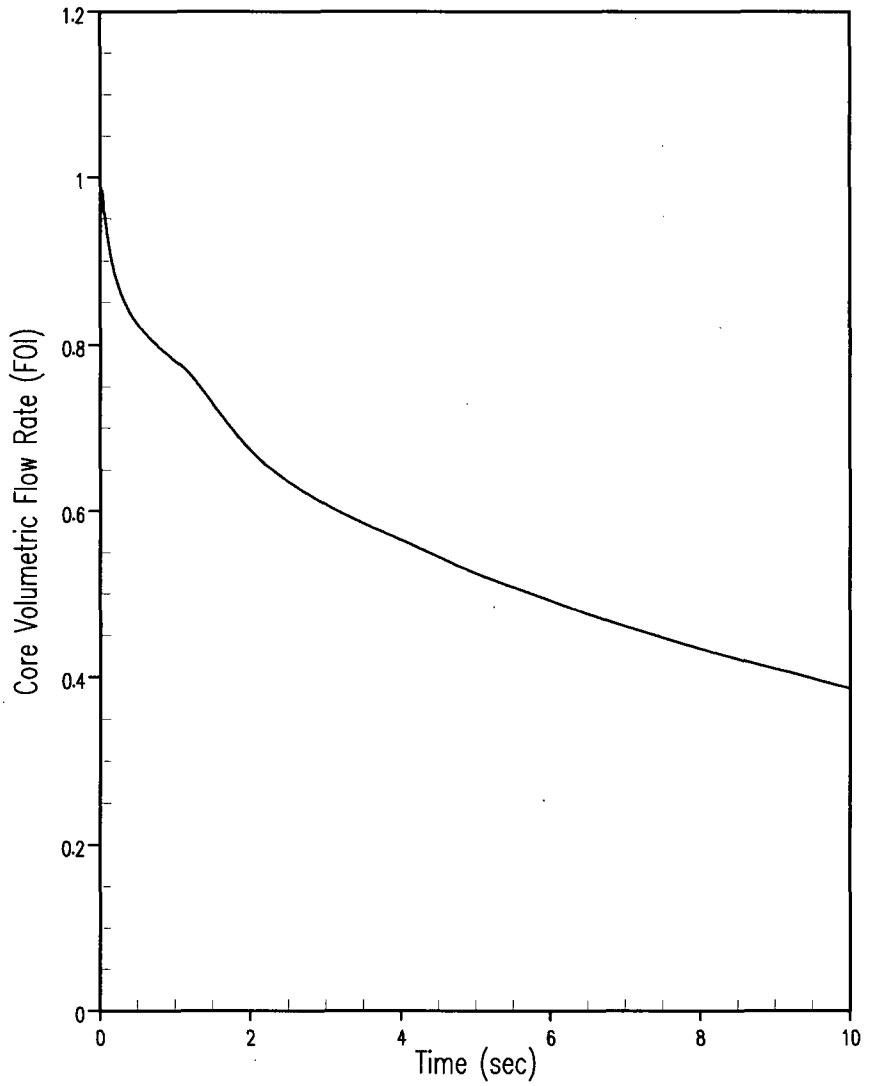


Figure 2.4.2-1 RCP Locked Rotor/Shaft Break Overpresurization/Peak Clad Temperature Core Volumetric Flow Rate Versus Time

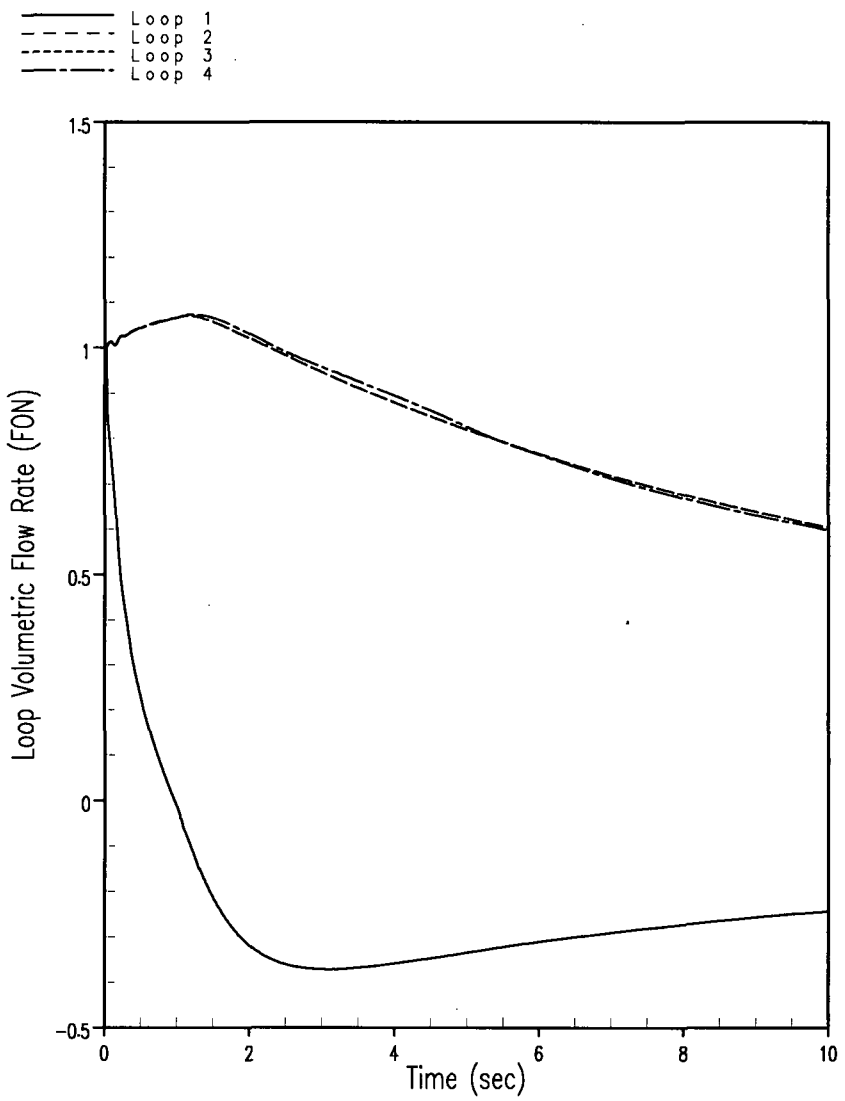


Figure 2.4.2-2 RCP Locked Rotor/Shaft Break Overpresurization/Peak Clad Temperature Loop Volumetric Flow Rate Versus Time

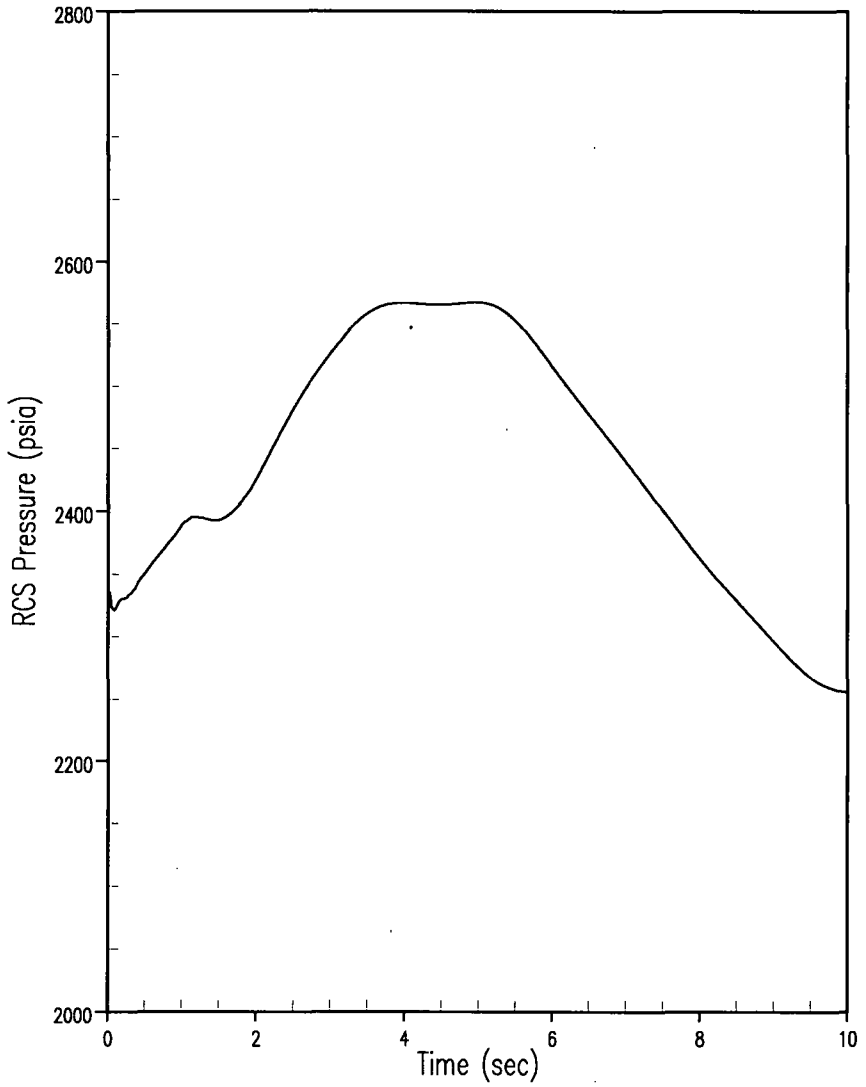


Figure 2.4.2-3 RCP Locked Rotor/Shaft Break Overpresurization/Peak Clad Temperature RCS Pressure Versus Time

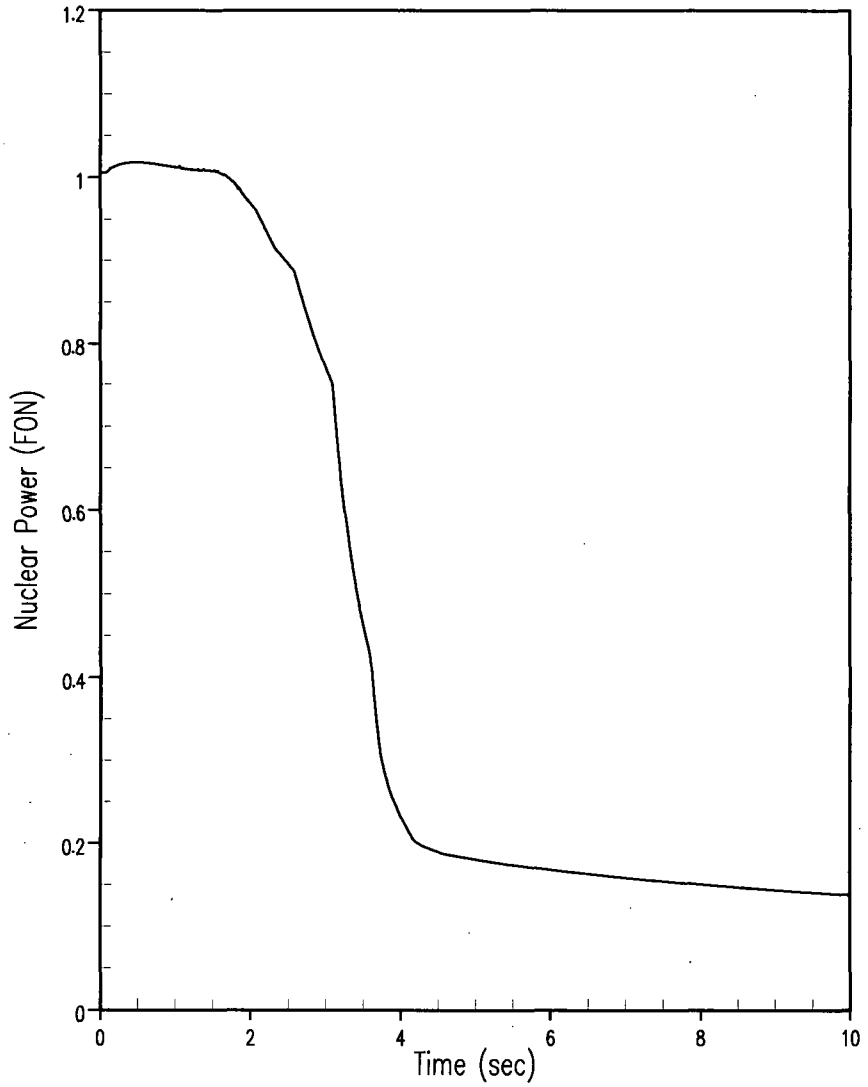


Figure 2.4.2-4 RCP Locked Rotor/Shaft Break Overpresurization/Peak Clad Temperature Nuclear Power Versus Time

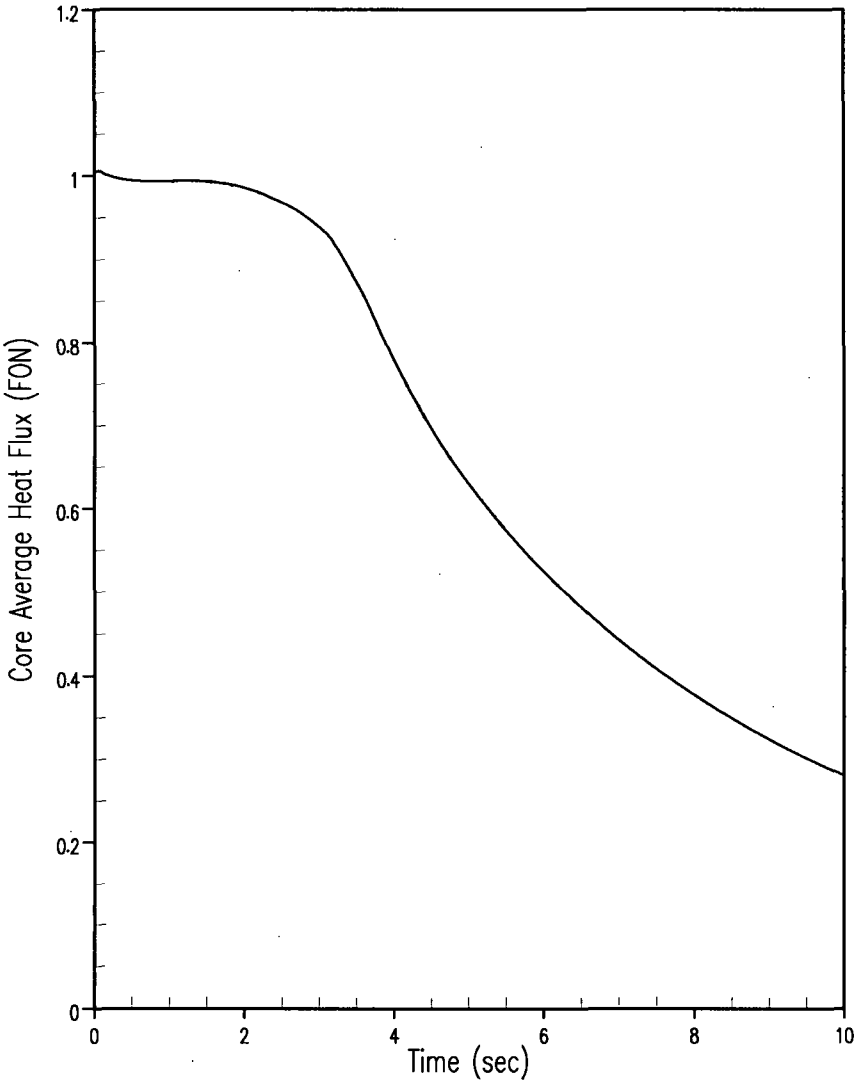


Figure 2.4.2-5 RCP Locked Rotor/Shaft Break Overpresurization/Peak Clad Temperature Core Average Heat Flux Versus Time

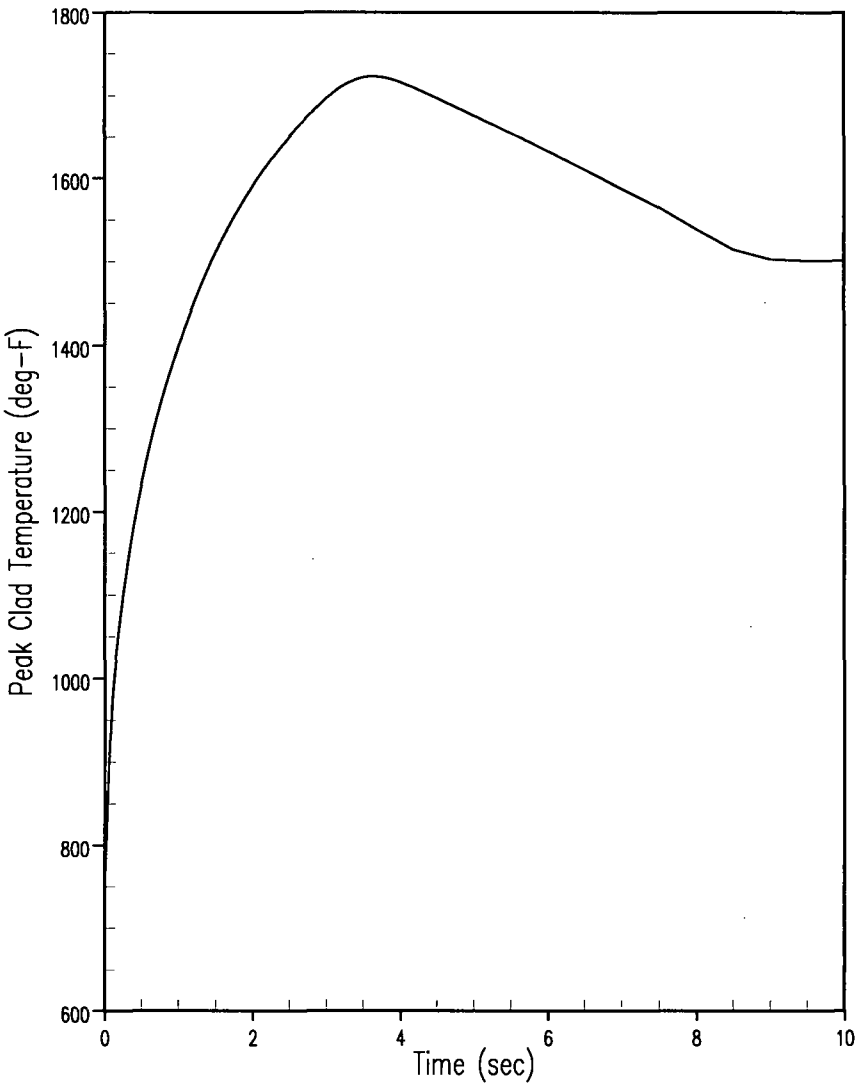


Figure 2.4.2-6 RCP Locked Rotor/Shaft Break Overpresurization/Peak Clad Temperature Clad Inner Temperature Versus Time

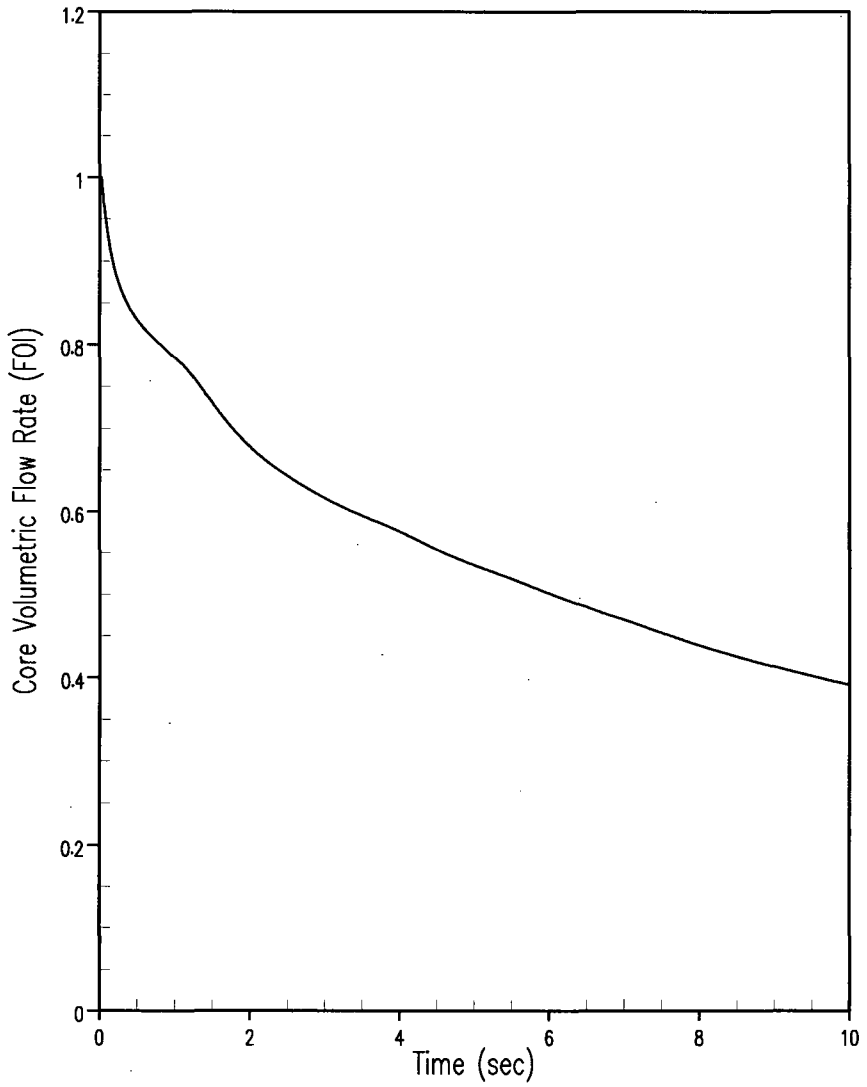


Figure 2.4.2-7 RCP Locked Rotor/Shaft Break Rods-in-DNB Core Volumetric Flow Rate Versus Time

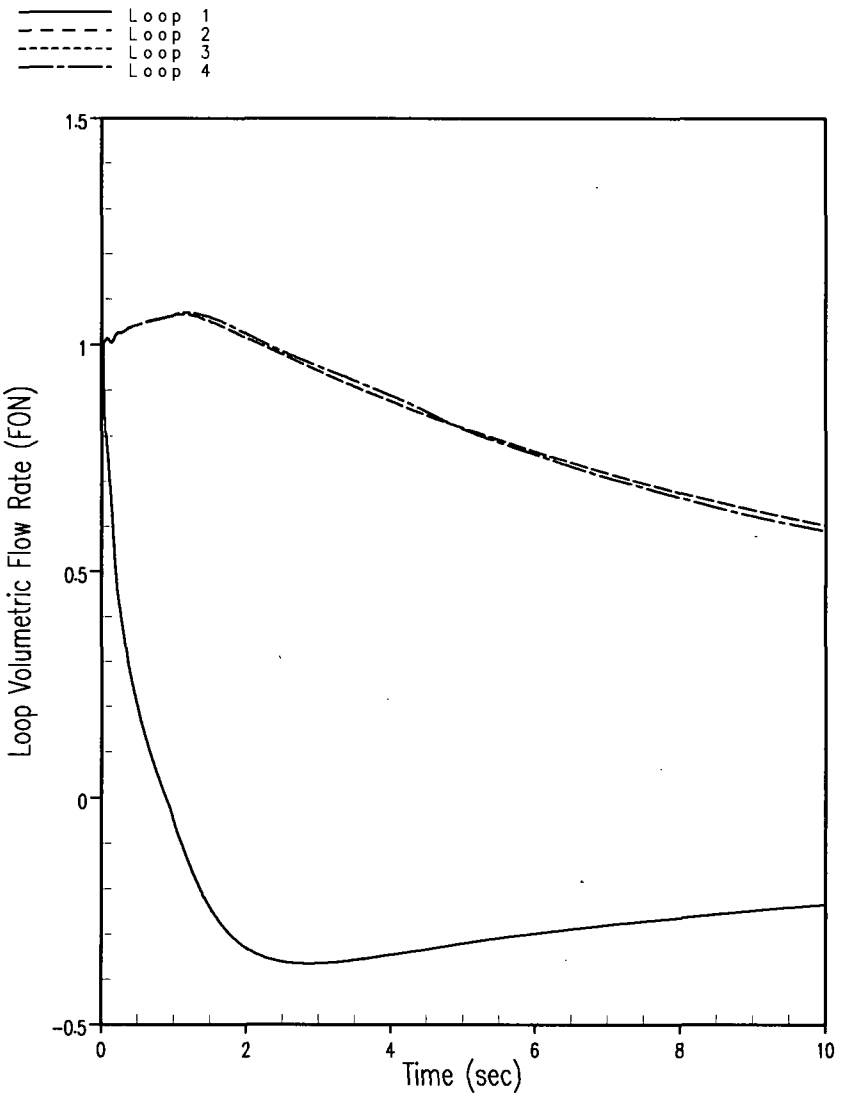


Figure 2.4.2-8 RCP Locked Rotor/Shaft Break Rods-in-DNB Loop Volumetric Flow Rate Versus Time

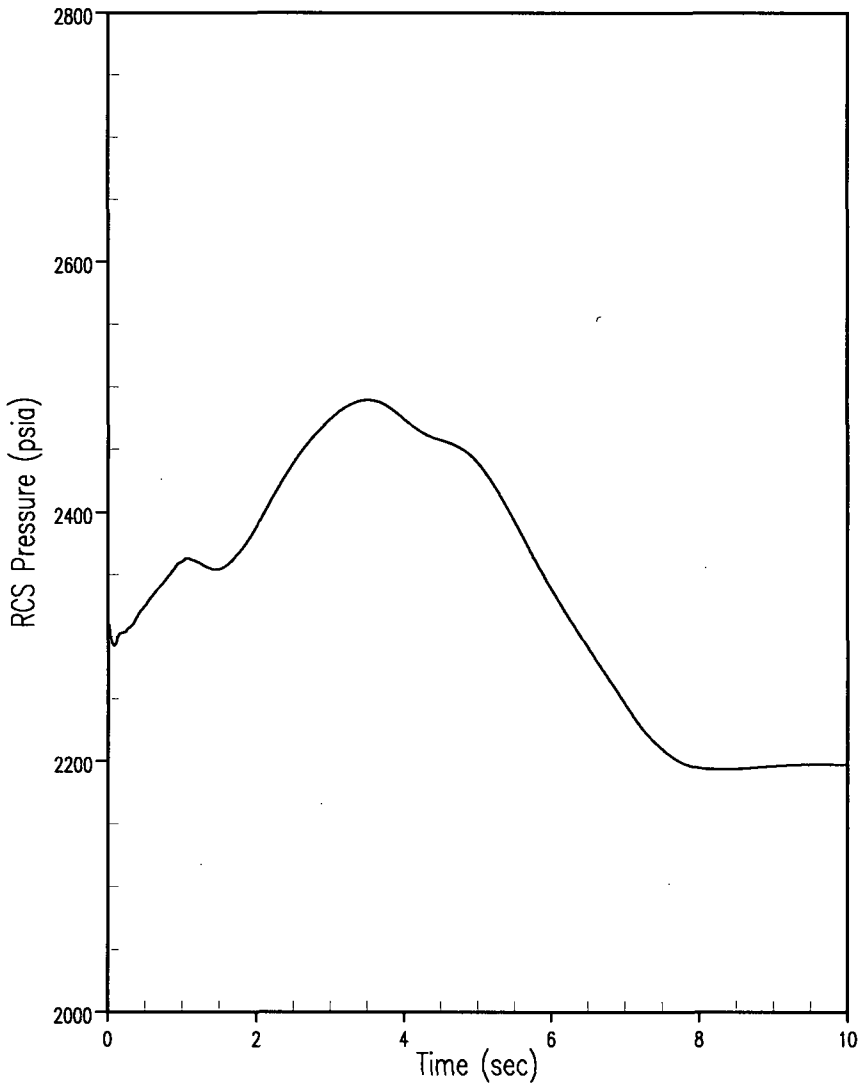


Figure 2.4.2-9 RCP Locked Rotor/Shaft Break Rods-in-DNB RCS Pressure Versus Time

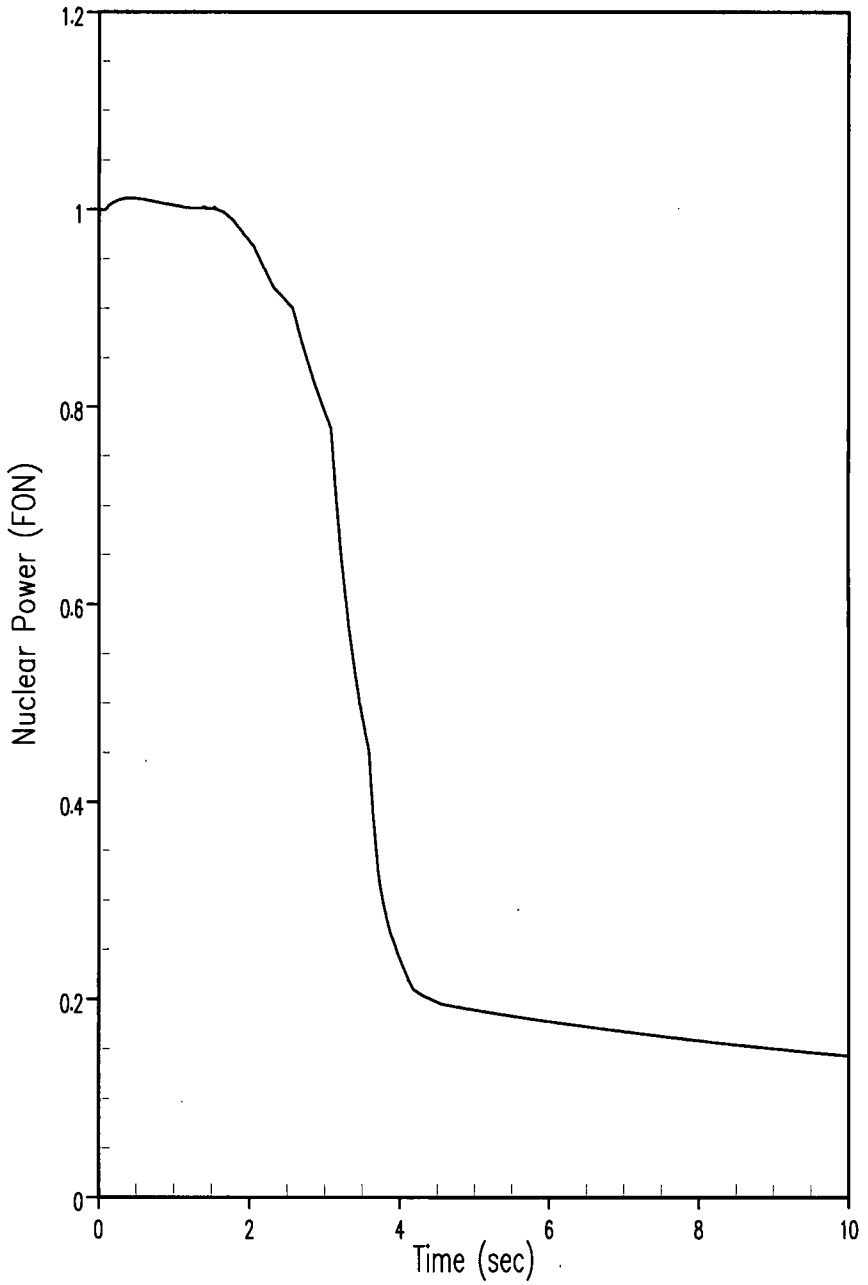


Figure 2.4.2-10 RCP Locked Rotor/Shaft Break Rods-in-DNB Nuclear Power Versus Time

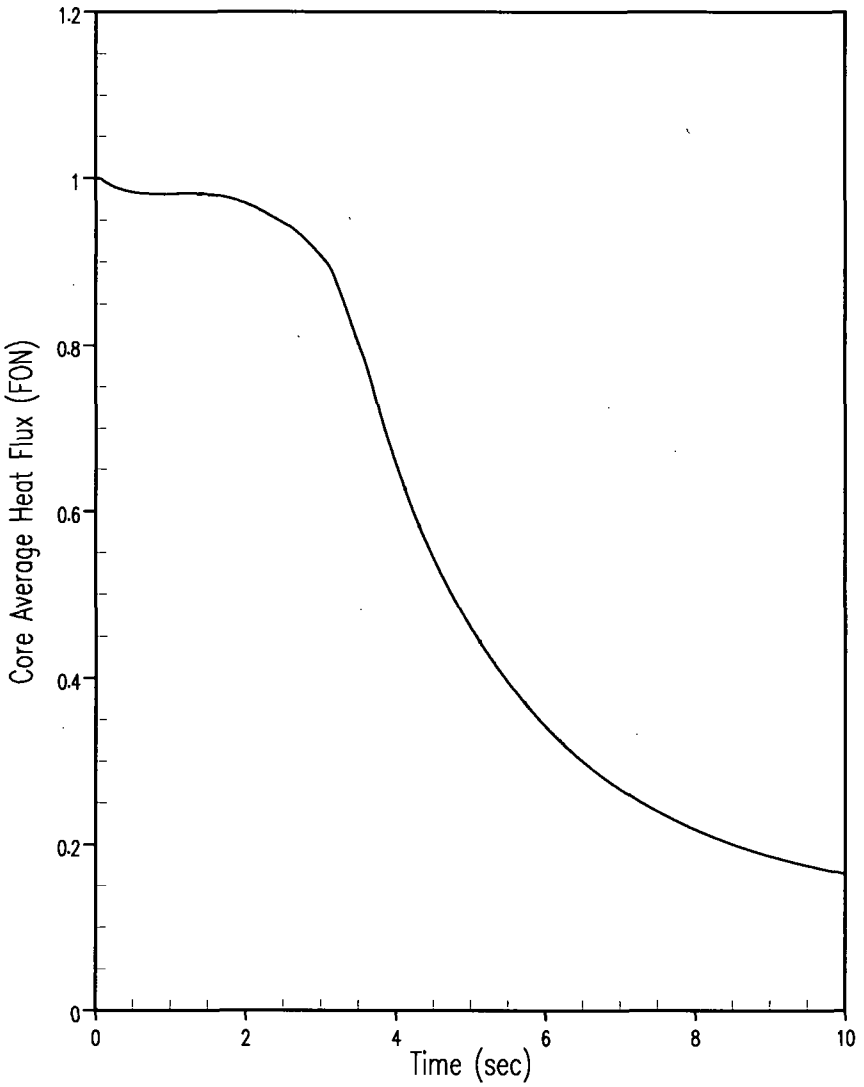


Figure 2.4.2-11 RCP Locked Rotor/Shaft Break Rods-in-DNB Core Average Heat Flux Versus Time

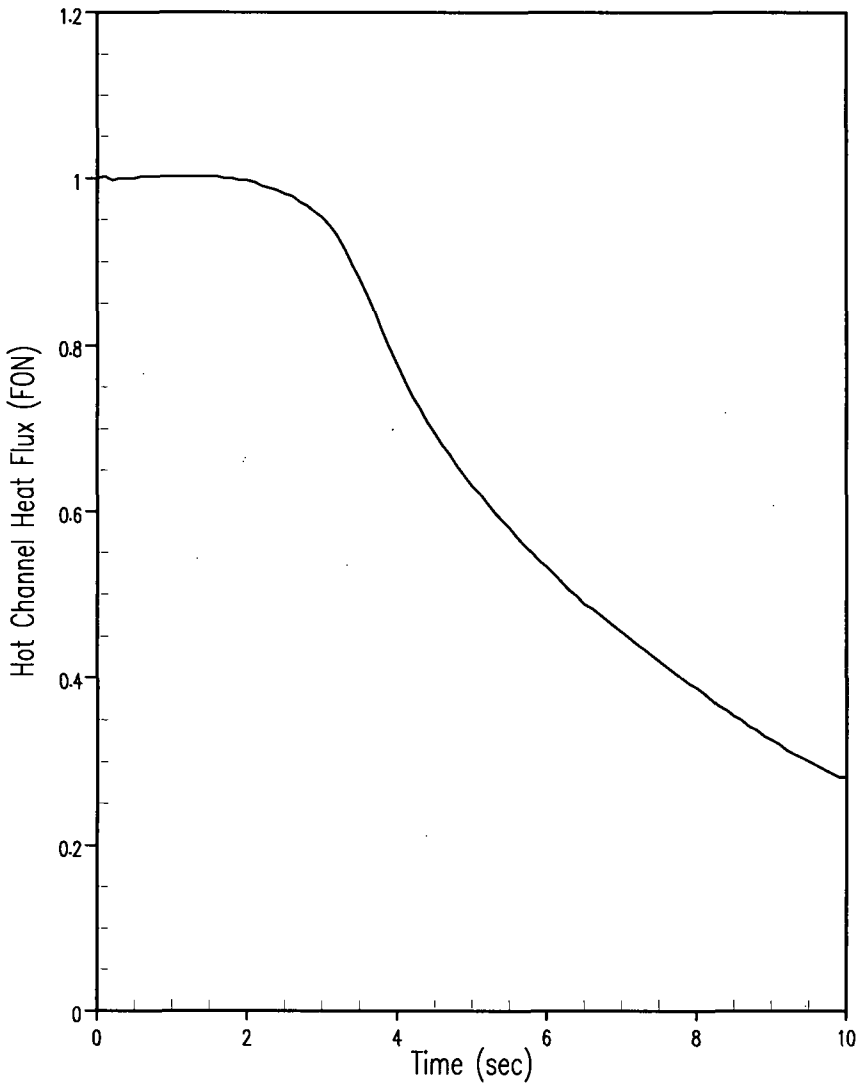


Figure 2.4.2-12 RCP Locked Rotor/Shaft Break Rods-in-DNB Hot Channel Heat Flux Versus Time

2.5 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

2.5.1 Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low-Power Startup Condition

2.5.1.1 Technical Evaluation

2.5.1.1.1 Introduction

An uncontrolled RCCA withdrawal incident is defined as an uncontrolled addition of reactivity to the reactor core by withdrawal of RCCAs resulting in a power excursion. While the probability of a transient of this type is extremely low, such a transient could be caused by a malfunction of the reactor control rod drive system. This could occur with the reactor either subcritical or at power. The "at power" occurrence is discussed in subsection 2.5.2. The uncontrolled RCCA withdrawal from a subcritical condition is classified as a Condition II event, a fault of moderate frequency, as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973.

Reactivity is added at a prescribed and controlled rate in bringing the reactor from a shutdown condition to a low-power level during startup by RCCA withdrawal or by reducing the core boron concentration. RCCA motion can cause much faster changes in reactivity than can result from changing boron concentration.

The rods are physically prevented from withdrawing in other than their respective banks. Power supplied to the rod banks is controlled such that no more than two banks can be withdrawn at any time. The control rod drive mechanism (CRDM) is of the magnetic latch type and the coil actuation is sequenced to provide variable speed rod travel. The maximum reactivity insertion rate is analyzed in the detailed plant analysis assuming the simultaneous withdrawal of the combination of the two rod banks with the maximum combined worth at maximum speed.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast flux increase terminated by the reactivity feedback effect of the negative Doppler coefficient. This self-limitation of the initial power increase results from a fast negative fuel temperature feedback (Doppler effect) and is of prime importance during a startup transient since it limits the power to an acceptable level prior to protection system action. After the initial power increase, the nuclear power is momentarily reduced and then, if the incident is not terminated by a reactor trip, the nuclear power increases again, but at a much slower rate.

Should a continuous RCCA withdrawal be initiated, the transient will be terminated by one of the following automatic protective functions:

- Source range neutron flux reactor trip – actuated when either of two independent source range channels indicates a flux level above a pre-selected, manually adjustable setpoint. This trip function may be manually bypassed only after an intermediate range neutron flux channels indicates a flux level above the source range cutoff power level. It is

automatically reinstated when both intermediate channels indicate a flux level below the source range cutoff power level.

- Intermediate range neutron flux reactor trip – actuated when either of two independent intermediate range channels indicates a flux level above a pre-selected, manually adjustable setpoint. This trip function may be manually bypassed when two of the four power range channels are reading above approximately 10 percent of full power and is automatically reinstated when three of the four channels indicate a power level below this value.

- Power range neutron flux reactor trip (low setting) – actuated when two of the four power range channels indicate a power level above approximately 25 percent of full power. This trip function may be manually bypassed when two of the four power range channels indicate a power level above approximately 10 percent of full power. This trip function is automatically reinstated when three of the four channels indicate a power level below 10-percent power.

- Power range neutron flux reactor trip (high setting) – actuated when two out of the four power range channels indicate a power level above approximately 110.8 percent of full power. This trip function is always active.

- High nuclear flux rate reactor trip – actuated when the positive rate of change of neutron flux on two out of four nuclear power range channels indicates a rate above the preset setpoint of approximately 6.3 percent in 2 seconds. This trip function is always active.

In addition, control rod stops on high intermediate range flux level (one out of two) and high power range flux level (one out of four) serve to discontinue rod withdrawal and prevent the need to actuate the intermediate range flux level trip and the power range flux level trip, respectively. This analysis credits the power range neutron flux trip (low setting) to initiate the reactor trip.

2.5.1.1.2 Input Parameters, Assumptions, and Acceptance Criteria

The accident analysis uses the Standard Thermal Design Procedure (STDP) methodology since the conditions resulting from the transient are outside the range of applicability of the RTDP methodology. To obtain conservative results for the analysis of the uncontrolled RCCA bank withdrawal from subcritical event, the following input parameters and initial conditions are modeled:

1. The magnitude of the nuclear power peak reached during the initial part of the transient, for any given reactivity insertion rate, is strongly dependent on the Doppler-only power defect. Therefore, a conservatively low absolute value is used (1,000 pcm) to maximize the nuclear power transient.

A most-positive moderator temperature coefficient (+5 pcm/°F) is used since this yields the maximum rate of power increase. The contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time constant between the fuel and moderator is much longer than the nuclear flux response time constant. However, after the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient.

The analysis assumes the reactor to be at hot-zero-power conditions with a nominal no-load temperature of 557°F. This assumption is more conservative than that of a lower initial system temperature (that is, shutdown conditions). The higher initial system temperature yields a larger fuel-to-moderator heat transfer coefficient, a larger specific heat of the moderator and fuel, and a less-negative (smaller absolute magnitude) Doppler defect. The less-negative Doppler defect reduces the Doppler feedback effect, thereby increasing the neutron flux peak. The high neutron flux peak combined with a high fuel specific heat and larger heat transfer coefficient yields a larger peak heat flux.

The analysis assumes the initial effective multiplication factor (K_{eff}) to be 1.0 since it maximizes the peak neutron flux and results in the most severe nuclear power transient.

Reactor trip is assumed on power range high neutron flux (low setting). A conservative combination of instrumentation error, setpoint error, delay for trip signal actuation, and delay for control rod assembly release is modeled. The analysis assumes a 10-percent uncertainty in the power range flux trip setpoint (low setting), raising it from the nominal value of 25 percent of full power to 35 percent of full power. A delay time of 0.5 seconds is assumed for trip signal actuation and control rod assembly release. No credit is taken for the source range or intermediate range protection. During the transient, the rise in nuclear power is so rapid that the effect of errors in the trip setpoint on the actual time at which the rods release is negligible. In addition, the total reactor trip reactivity is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position.

The maximum positive reactivity insertion rate assumed is greater than that for the simultaneous withdrawal of the two sequential control banks having the greatest combined worth at the maximum rod withdrawal speed. The assumed reactivity insertion rate is 75 pcm/sec, which is based on a rod worth of 100 pcm/inch and a maximum rod speed of 72 steps per minute.

The DNB analysis assumes the most limiting axial and radial power shapes possible during the fuel cycle associated with having the two highest combined worth banks in their highest worth position.

The analysis assumes the initial power level to be below the power level expected for any shutdown condition (10^{-9} fraction of nominal power). The combination of highest reactivity insertion rate and low initial power produces the highest peak heat flux.

The analysis assumes two of the four reactor coolant pumps to be in operation. This is conservative with respect to the DNB transient.

This accident analysis uses the STDP methodology. The use of the STDP stipulates that the RCS flow rates will be based on a fraction of the thermal design flow for two pumps operating. Since the event is analyzed from hot-zero power, the steady-state non-RTDP uncertainties are not considered in defining the initial conditions.

The uncontrolled RCCA bank withdrawal from subcritical event is considered an ANS Condition II event, a fault of moderate frequency, and is analyzed to show that the core and reactor coolant system are not adversely affected by the event. This is demonstrated by showing that the DNB design basis is not violated and subsequently that there is little likelihood of core damage. It must also be shown that the peak hot spot fuel centerline temperature remains within the acceptable limit (4,800°F), although for this event, the heatup is relatively non-limiting.

2.5.1.1.3 Description of Analyses and Evaluations

The analysis of the uncontrolled RCCA bank withdrawal from subcritical conditions is performed in three stages. First, a spatial neutron kinetics computer code, TWINKLE (Reference 1), is used to calculate the core average nuclear power transient, including the various core feedback effects, that is, Doppler and moderator reactivity. Next, the FACTRAN computer code (Reference 2) uses the average nuclear power calculated by TWINKLE and performs a fuel rod transient heat transfer calculation to determine the core average heat flux and hot spot fuel temperature transients. Finally, the core average heat flux calculated by FACTRAN is used in the VIPRE computer code (Reference 3) for transient DNBR calculations.

2.5.1.1.4 Results

The analysis shows that all applicable acceptance criteria are met for CPNPP Units 1 and 2. The minimum DNBR never goes below the limit value and the peak fuel centerline temperature is 2,304°F. The peak temperatures are well below the minimum temperature where fuel melting would be expected (4,800°F).

Figure 2.5.1-1 shows the nuclear power transient, Figure 2.5.1-2 shows the core average heat flux transient, and Figure 2.5.1-3 shows the inner cladding and fuel average temperature transient at the hot spot.

The time sequence of events for both cases is presented in Table 2.5.1-1.

In the event of an RCCA withdrawal event from subcritical conditions, the core and the reactor coolant system are not adversely affected since the combination of thermal power and coolant temperature results in a minimum DNBR greater than the safety analysis limit value. Furthermore, since the maximum fuel temperatures predicted to occur during this event are much less than those required for fuel melting to occur, no fuel damage is predicted as a result of this transient. Cladding damage is also precluded.

2.5.1.2 Conclusions

Luminant Power has reviewed the analyses of the uncontrolled RCCA withdrawal from a subcritical or low-power startup condition and concludes that the analyses have adequately accounted for the changes in core design necessary for plant operation at the power level. It is also concluded that the analyses were performed using acceptable analytical models. Luminant Power further concluded that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the specified acceptable fuel design limits are not exceeded. Based on this, it is concluded that the plant will continue to meet the requirements of GDCs -10, -20, and -25.

2.5.1.3 References

1. WCAP-7979, "TWINKLE - A Multi-dimensional Neutron Kinetics Computer Code," January 1975

2. WCAP-7908, "FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," December 1989.

3. WCAP-14565, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," October 1999.

Table 2.5.1-1 Time Sequence of Events – Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition	
Event	**Time (seconds)**
Initiation of Uncontrolled Rod Withdrawal	0.0
Power Range High Neutron Flux Low Setpoint is Reached	9.82
Peak Nuclear Power Occurs	9.95
Rod Motion Begins	10.32
Peak Heat Flux Occurs (0.3336)	12.075
Minimum DNBR Occurs (1.616)	12.075
Peak Average Cladding Temperature Occurs (680°F)	12.60
Peak Average Fuel Temperature Occurs (1,884°F)	12.75

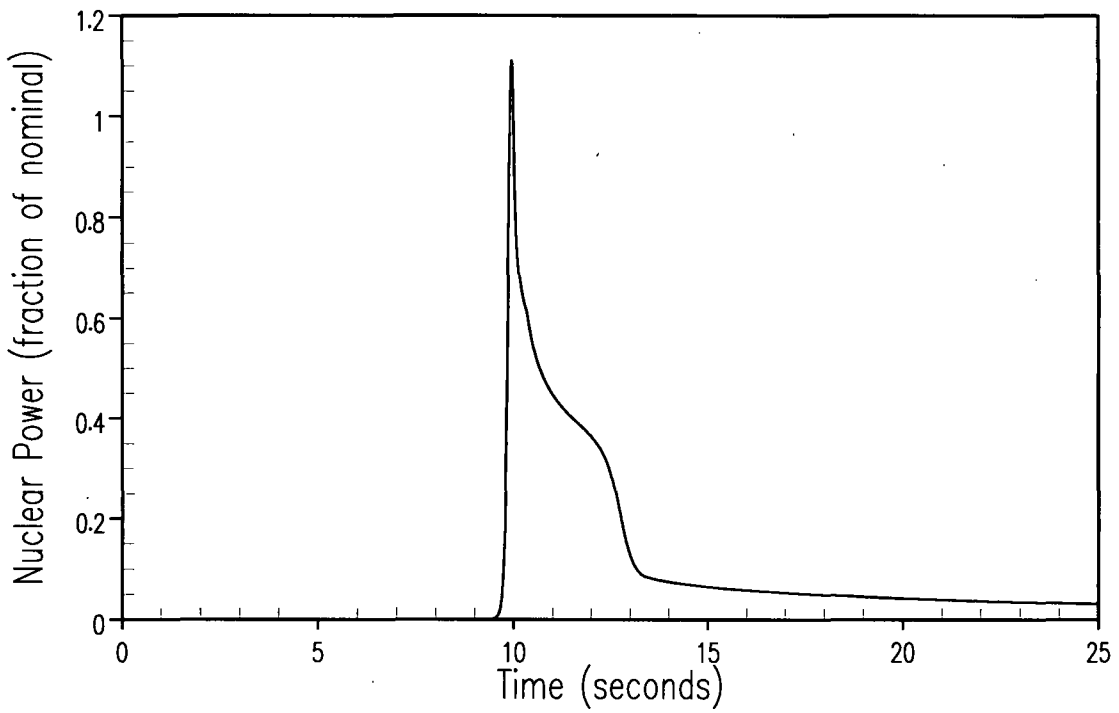


Figure 2.5.1-1 Rod Withdrawal from Subcritical Nuclear Power Versus Time

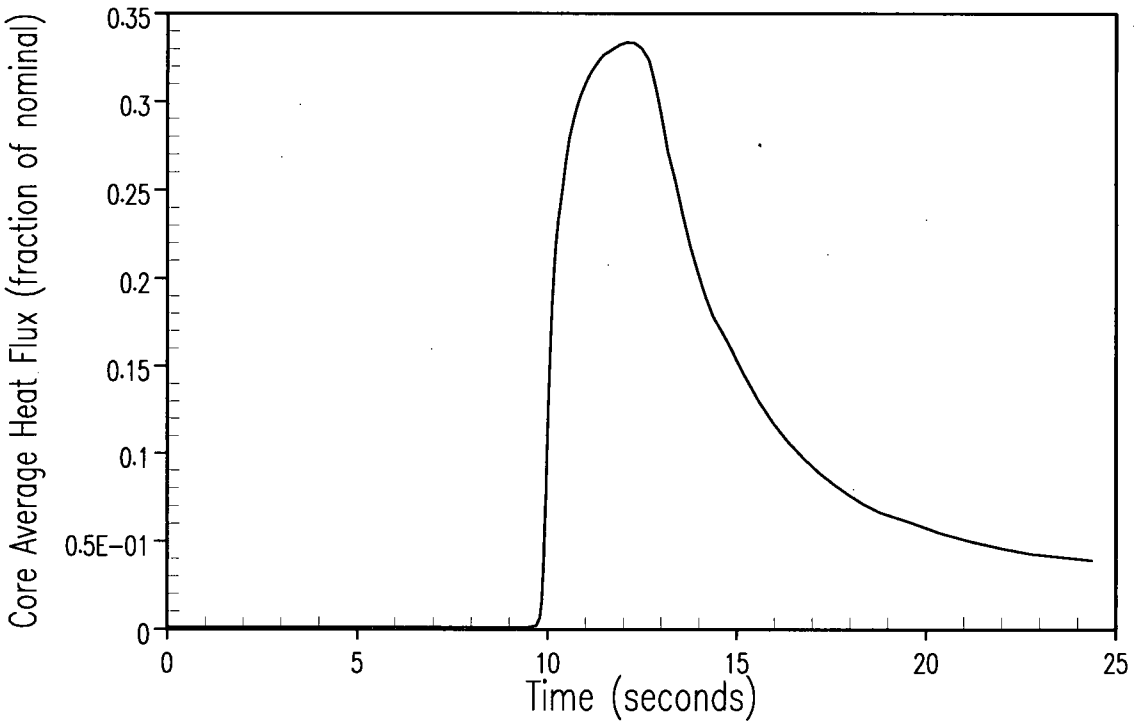


Figure 2.5.1-2 Rod Withdrawal from Subcritical Core Average Heat Flux Versus Time

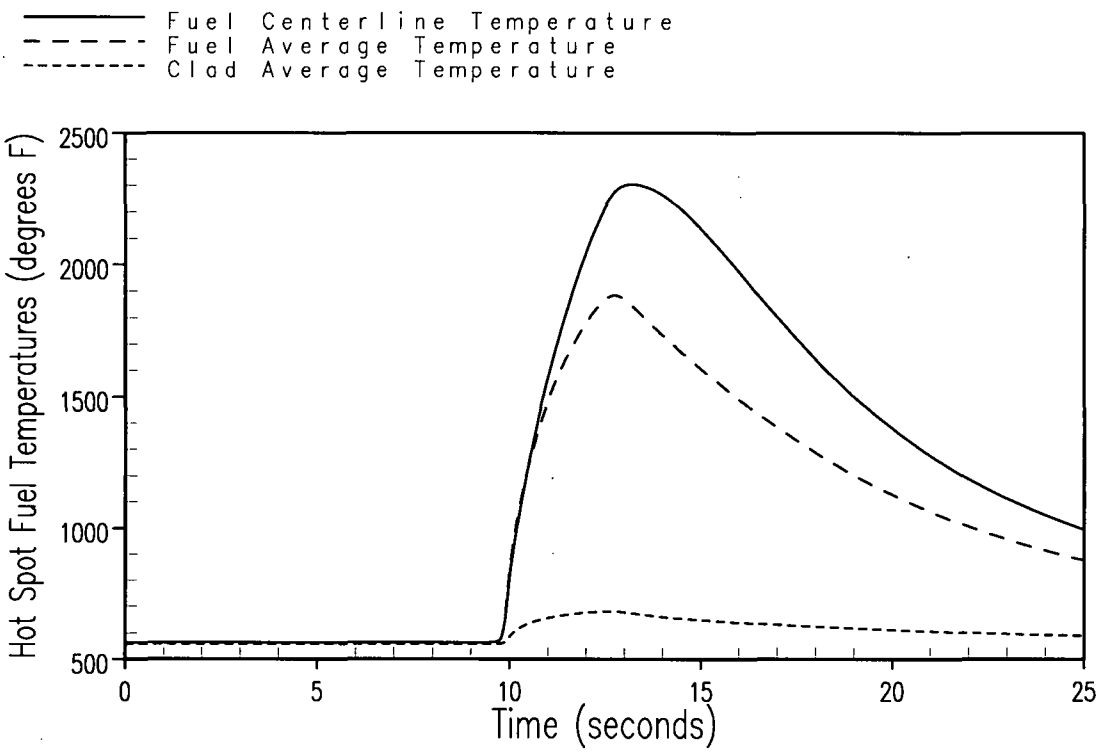


Figure 2.5.1-3 Rod Withdrawal from Subcritical Hot Spot Fuel Temperatures Versus Time

2.5.2 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power

2.5.2.1 Technical Evaluation

2.5.2.1.1 Introduction

An uncontrolled RCCA bank withdrawal at power that causes an increase in core heat flux can result from faulty operator action or a malfunction in the rod control system. Immediately following the initiation of the accident, the steam generator heat removal rate lags behind the core power generation rate until the steam generator pressure reaches the setpoint of the steam generator relief or safety valves. This imbalance between heat removal and heat generation rate causes the reactor coolant temperature to rise. Unless terminated, the power mismatch and resultant coolant temperature rise could eventually result in a violation of the DNBR safety analysis limit and/or fuel centerline melt. Therefore, to avoid core damage, the reactor protection system is designed to automatically terminate any such transient before the DNBR falls below the safety analysis limit value, or the fuel rod linear heat generation rate (kW/ft) limit is exceeded.

The automatic features of the reactor protection system that prevent core damage in an RCCA bank withdrawal incident at power include the following:

- Power range high neutron flux instrumentation actuates a reactor trip on neutron flux if two-out-of-four channels exceed an overpower setpoint.
- Reactor trip actuates if any two-out-of-four channels exceed the high positive neutron flux rate setpoint.
- Reactor trip actuates if any two-out-of-four N-16 channels exceed an overtemperature N-16 setpoint. This setpoint is automatically varied with axial power distribution, coolant average temperature, and coolant average pressure to protect against violating the DNBR safety analysis limit.
- Reactor trip actuates if any two-out-of-four N-16 channels exceed an overpower N-16 setpoint.
- Main steam safety valves (MSSVs) can open for this event and provide an additional heat sink.
- A high pressurizer pressure reactor trip actuated from any two-out-of-four pressure channels which is set at a fixed point. This set pressure is less than the set pressure for the pressurizer safety valves.
- A high pressurizer water level reactor trip actuated from any two-out-of-three channels which is set at a fixed point, when the reactor power is above approximately 10 percent (Permissive 7).

2.5.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

A number of cases were analyzed assuming a range of reactivity insertion rates for both minimum and maximum reactivity feedback conditions at various power levels. The cases presented below are representative for this event.

For an uncontrolled RCCA bank withdrawal at power accident, the analysis assumed the following conservative assumptions:

- This accident was analyzed with the Revised Thermal Design Procedure (RTDP) (Reference 1). Initial reactor power, RCS pressure, and RCS temperature were assumed to be at their nominal values. Minimum measured flow was modeled. Uncertainties in initial conditions were included in the DNBR safety analysis limit as described in the RTDP.

- For reactivity coefficients, two cases were analyzed.

  - Minimum reactivity feedback; A least negative or positive value of the moderator temperature coefficient of reactivity is assumed corresponding to the beginning of core life. A conservatively small (in absolute magnitude) value of the Doppler coefficient is assumed.

  - Maximum reactivity feedback; A conservatively large positive moderator density coefficient and a large (in absolute magnitude) negative Doppler coefficient are assumed.

- The reactor trip on high neutron flux was assumed to be actuated at a conservative value of 118.0 percent of nominal full power. The N-16 trips included all adverse instrumentation and setpoint errors, while the delays for the trip signal actuation were assumed at their maximum values.

- The RCCA trip insertion characteristic was based on the assumption that the highest-worth RCCA was stuck in its fully withdrawn position.

- A range of reactivity insertion rates was examined. The maximum-positive reactivity insertion rate was greater than that which would be obtained from the simultaneous withdrawal of the two control rod banks having the maximum combined worth at a conservative speed (45 inches/minute, which corresponds to 72 steps/minute).

- To be conservative with respect to DNB, the pressurizer sprays and relief valves were assumed operational since they limit the reactor coolant pressure increase.

- Power levels of 10, 60, and 100 percent of the nuclear steam supply system (NSSS) power of 3,628 MWt were considered.

Based on its frequency of occurrence, the uncontrolled RCCA bank withdrawal at-power accident is considered a Condition II event as defined by the ANS. The following items summarize the main acceptance criteria associated with this event:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the safety analysis limit value at any time during the transient.

- Pressure in the RCS and main steam system (MSS) should be maintained below 110 percent of the design pressures.

The protection features presented in Licensing Report (LR) subsection 2.5.2.1.1 provide mitigation of the uncontrolled RCCA bank withdrawal at-power transient such that the above criteria are satisfied.

Also, a conservative generic evaluation that is applicable to CPNPP has shown that the positive flux rate and high pressurizer pressure functions provide a timely reactor trip that precludes RCS overpressurization in instances where the power range high neutron flux or the overtemperature N-16 trip occur too late to provide the necessary protection. This evaluation confirms that the RCS pressure limit is met.

2.5.2.1.3 Description of Analyses and Evaluations

The purpose of this analysis was to demonstrate the manner in which the protection functions described above actuate for various combinations of reactivity insertion rates and initial conditions. Insertion rate and initial conditions determined which trip function actuated first.

The uncontrolled RCCA bank withdrawal at-power event was analyzed with the RETRAN computer code (Reference 2). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and MSSVs. The code computes pertinent plant variables including temperatures, pressures, power level, and the DNBR (based on a conservative partial derivative approximation of the DNB core limit lines).

2.5.2.1.4 Results

Figures 2.5.2-1 through 2.5.2-3 (Unit 1) and Figures 2.5.2-10 through 2.5.2-12 (Unit 2) show the transient response for a rapid uncontrolled RCCA bank withdrawal incident (110 pcm/sec) starting from 100 percent power with minimum reactivity feedback. The neutron flux level in the core rises rapidly while the core heat flux and coolant system temperature lag behind due to the thermal capacity of the fuel and coolant system fluid. Reactor trip on high neutron flux occurs shortly after the start of the accident prior to a significant increase in the heat flux and water temperature with resultant minimum DNB ratios that remain well above the safety analysis limit value throughout the transient.

The transient response for a slow uncontrolled RCCA bank withdrawal (1 pcm/sec) from 100 percent power with minimum feedback is shown in Figures 2.5.2-4 through 2.5.2-6 (Unit 1)

and Figures 2.5.2-13 through 2.5.2-15 (Unit 2). With a lower insertion rate the power increase rate is slower, the rate of rise of the average coolant temperature is slower and the system lags and delays become less significant. A reactor trip on overtemperature N-16 occurs after a longer period of time than for a rapid RCCA bank withdrawal. Again, the minimum DNBR remain greater than the safety analysis limit value.

Figure 2.5.2-7 (Unit 1) and Figure 2.5.2-16 (Unit 2) show the minimum DNBR as a function of reactivity insertion rate from 100 percent power for both minimum and maximum reactivity feedback conditions. It can be seen that the high neutron flux and overtemperature N-16 reactor trip functions provided DNB protection over the analyzed range of reactivity insertion rates and the minimum DNBR is never less than the safety analysis limit value.

Figures 2.5.2-8, 2.5.2-9 (Unit 1), 2.5.2-17 and 2.5.2-18 (Unit 2) show the minimum DNBR as a function of reactivity insertion rate for RCCA bank withdrawal incidents starting at 60- and 10-percent power, respectively. The results are similar to the 100-percent power case. However, as the initial power level is decreased, the range over which the overtemperature N-16 trip is effective is increased.

A calculated sequence of events for two cases is shown in Table 2.5.2-1. With the reactor tripped, the plant eventually returns to a stable condition. The plant could subsequently be cooled down further by following normal plant shutdown procedures. The limiting results of the uncontrolled RCCA bank withdrawal at power analysis are shown in Table 2.5.2-2.

The high neutron flux and overtemperature N-16 reactor trip functions provided adequate protection over the entire range of possible reactivity insertion rates. The results show that the DNB design basis is met and the peak kW/ft is less than the limit. The peak pressures in the RCS and MSS do not exceed 110 percent of their respective design pressures.

Therefore, the results of the analysis show that an uncontrolled RCCA bank withdrawal at-power does not adversely affect the core, the RCS, or the MSS.

2.5.1.2 Conclusions

This review of the uncontrolled RCCA bank withdrawal at-power event analysis demonstrates that TXU Power has adequately accounted for the changes in core design required for plant operation at the proposed uprated power level. This analysis was performed using acceptable analytical models. This analysis has also demonstrated that the reactor protection and safety systems will continue to ensure that the specified acceptable fuel design limits are not exceeded. Based on this, it can be concluded that the plant will continue to meet the requirements of GDCs -10, -20, and -25 following implementation of the proposed uprated power level. Therefore, the uprated power level is acceptable with respect to the uncontrolled RCCA bank withdrawal at power event.

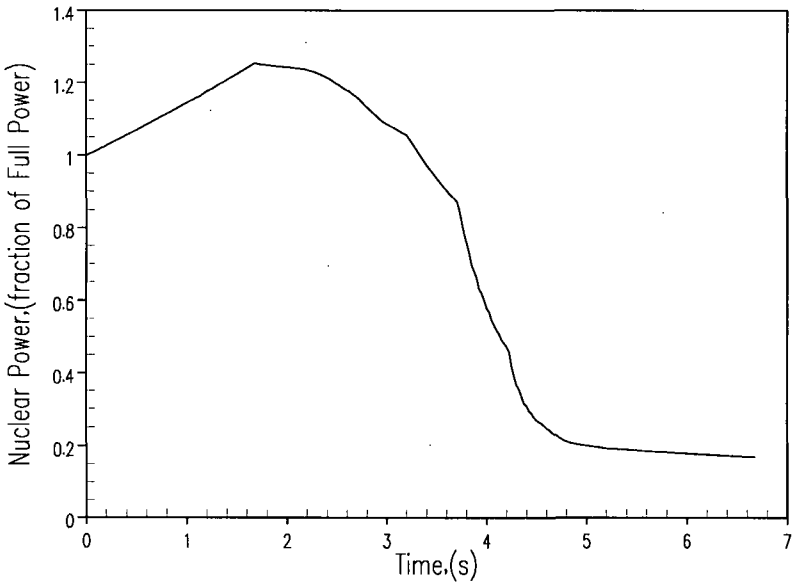
2.5.1.3 References

1. WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), "Revised Thermal Design Procedure," April 1989.

2. WCAP-14882-P-A (Proprietary), WCAP-15234-A (Non-Proprietary), "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April and May 1999 respectively.

Table 2.5.2-1 Time Sequence of Events – Uncontrolled RCCA Bank Withdrawal at Power			
Case	Event	Time (sec)	
		Unit 1	Unit 2
100% Power, Minimum Feedback, Rapid RCCA Bank Withdrawal (110 pcm/sec)	Initiation of Uncontrolled RCCA Bank Withdrawal	0.00	0.00
	Power Range High Neutron Flux – High Setpoint Reached	1.67	1.68
	Reactor Trip	3.67	3.68
	Minimum DNBR Occurs	2.58	2.56
100% Power, Minimum Feedback, Slow RCCA Bank Withdrawal (1 pcm/sec)	Initiation of Uncontrolled RCCA Bank Withdrawal	0.00	0.00
	Overtemperature N-16 Setpoint Reached	94.09	90.82
	Reactor Trip	96.09	92.82
	Minimum DNBR Occurs	94.00	91.00

Table 2.5.2-2 Uncontrolled RCCA Bank Withdrawal at Power – Limiting Results				
	Limiting value		Safety Analysis Limit	Case
	Unit 1	Unit 2		
Minimum DNBR	1.689	1.726	1.61	10% power, maximum feedback, 80 pcm/sec reactivity insertion rate (Unit 1) 100% power, maximum feedback, 37 pcm/sec reactivity insertion rate (Unit 2)
Peak Core Heat Flux (fon)	1.162	1.163	1.18	100% power, minimum feedback, 5 pcm/sec (Unit 1) 100% power, maximum feedback 37 pcm/sec (Unit 2)
Peak Secondary System Pressure (psia)	1,275.34	1,272.45	1,318.5	10% power, minimum feedback 14 pcm/sec (Unit 1) 10% power, minimum feedback, 7 pcm/sec (Unit 2)



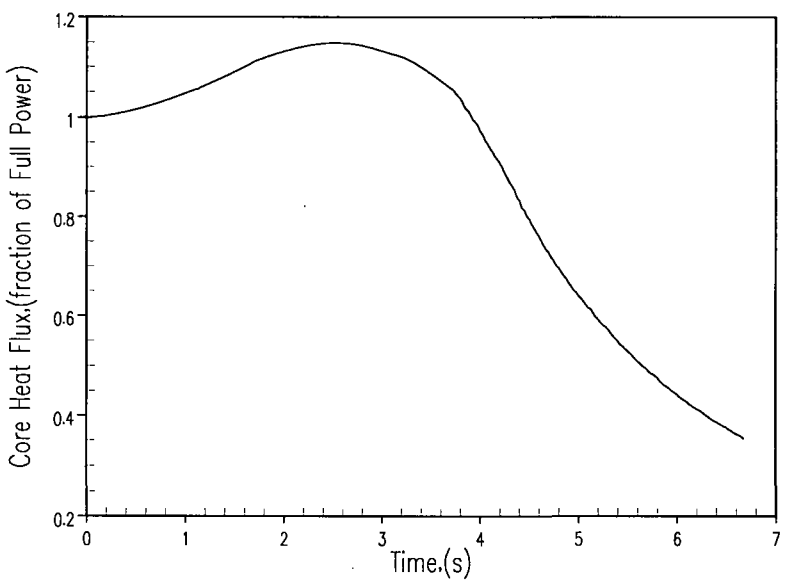
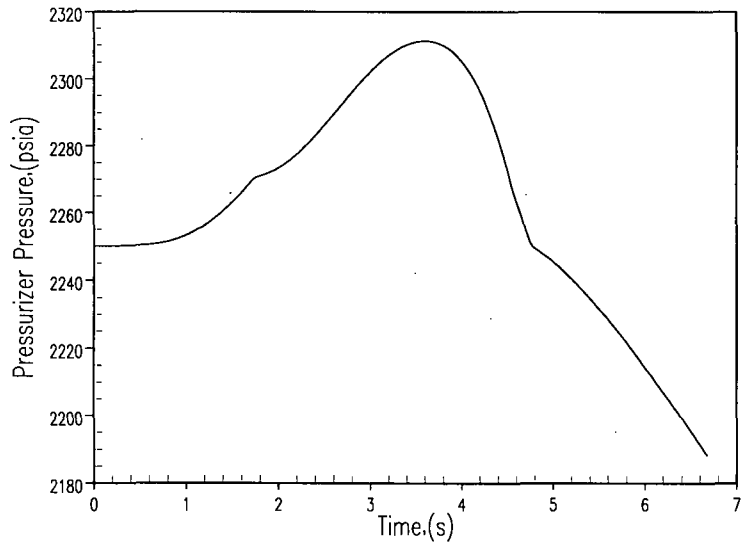


Figure 2.5.2-1 Bank Withdrawal at Power – Unit 1, Minimum Reactivity Feedback – 100% Power – 110 pcm/sec – Nuclear Power and Core Heat Flux Versus Time



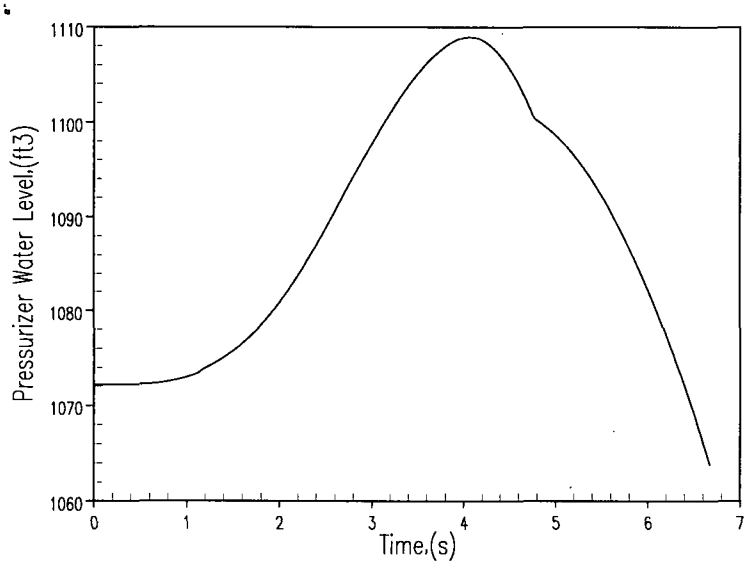


Figure 2.5.2-2 Bank Withdrawal at Power – Unit 1, Minimum Reactivity Feedback – 100% Power – 110 pcm/sec – Pressurizer Pressure and Water Volume Versus Time

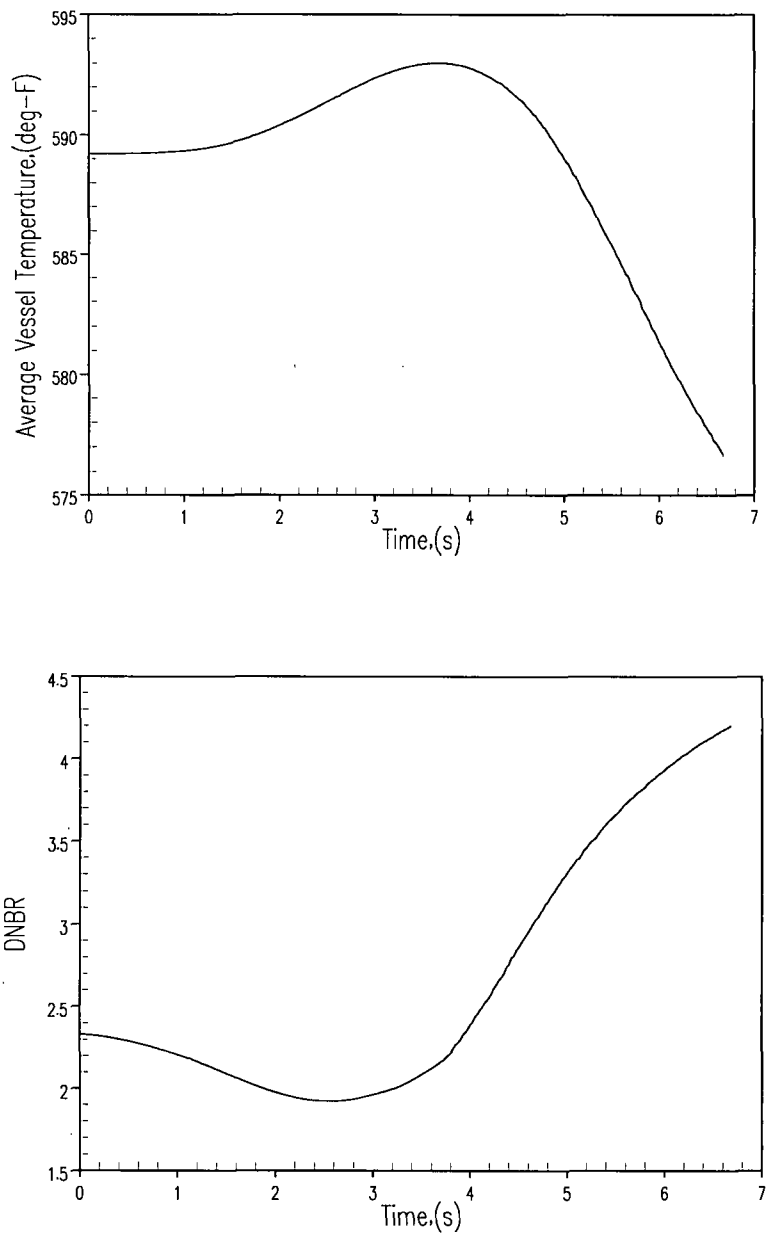


Figure 2.5.2-3 Bank Withdrawal at Power – Unit 1, Minimum Reactivity Feedback – 100% Power – 110 pcm/sec – Vessel Average Temperature and DNBR Versus Time

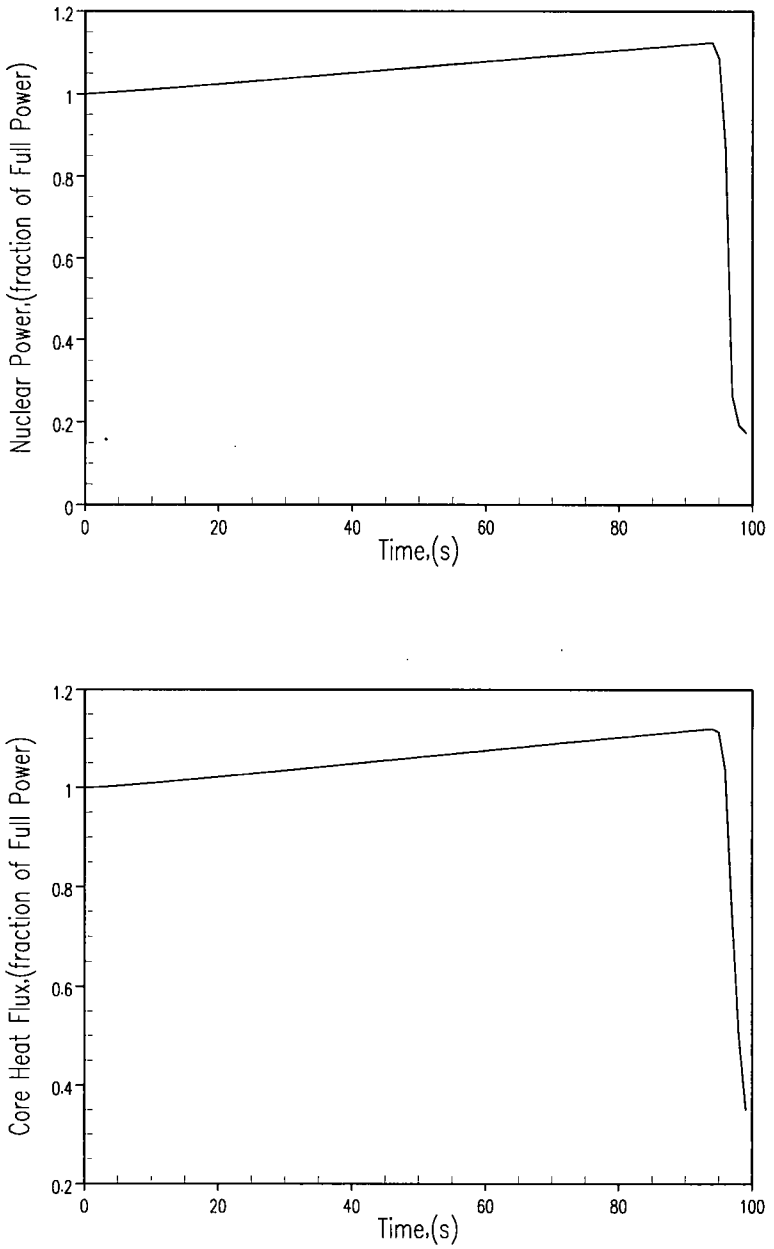
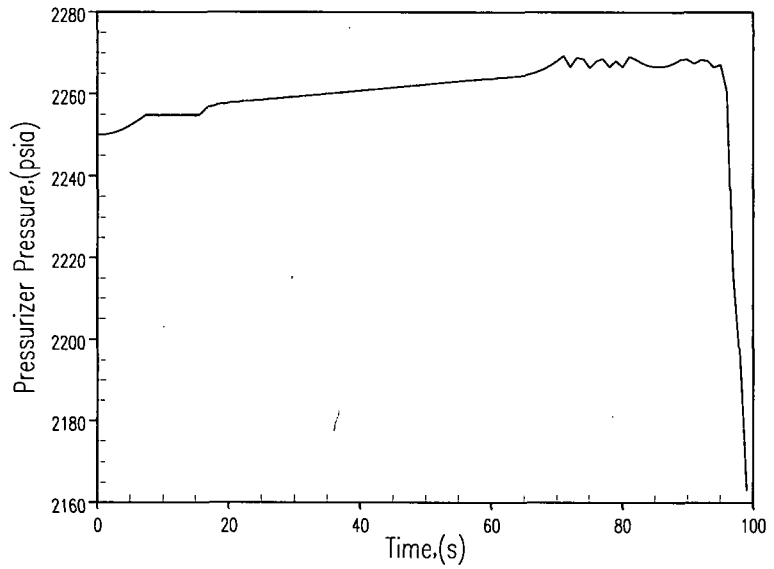


Figure 2.5.2-4 Bank Withdrawal at Power – Unit 1, Minimum Reactivity Feedback – 100% Power – 1 pcm/sec – Nuclear Power and Core Heat Flux Versus Time



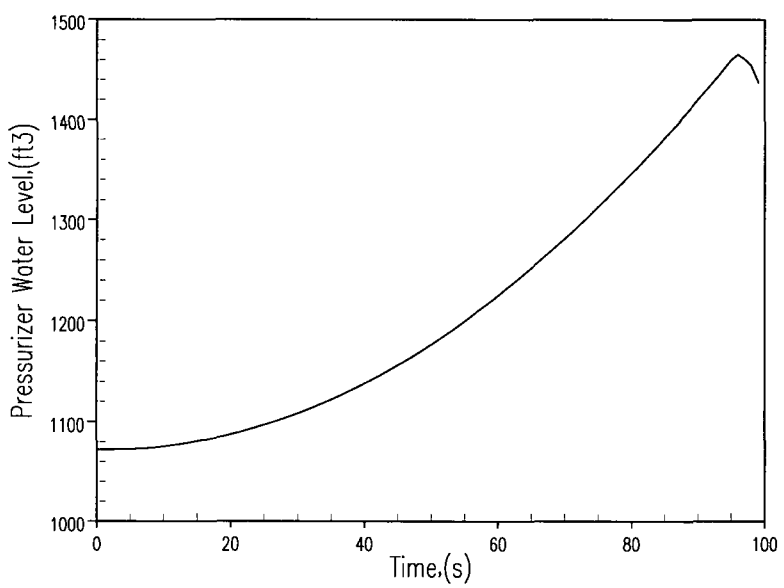
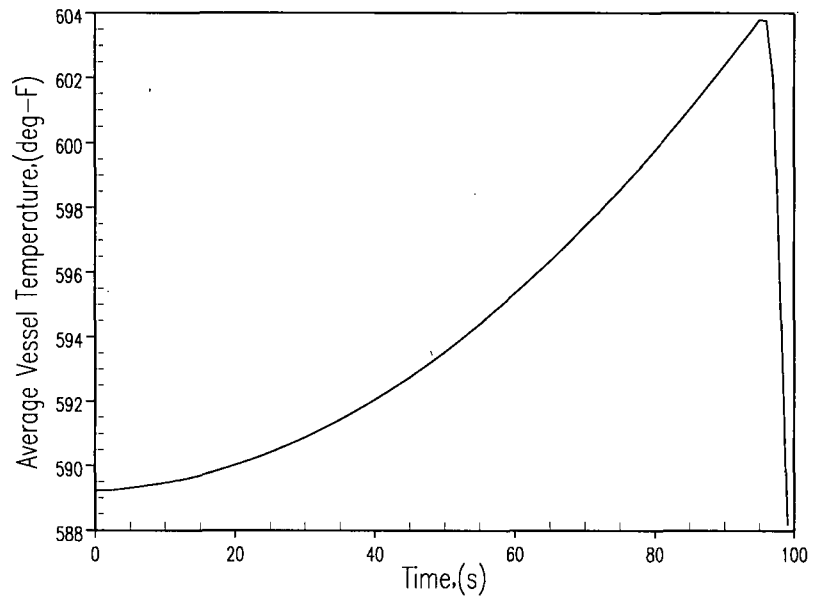


Figure 2.5.2-5 Bank Withdrawal at Power – Unit 1, Minimum Reactivity Feedback – 100% Power – 1 pcm/sec – Pressurizer Pressure and Water Volume Versus Time



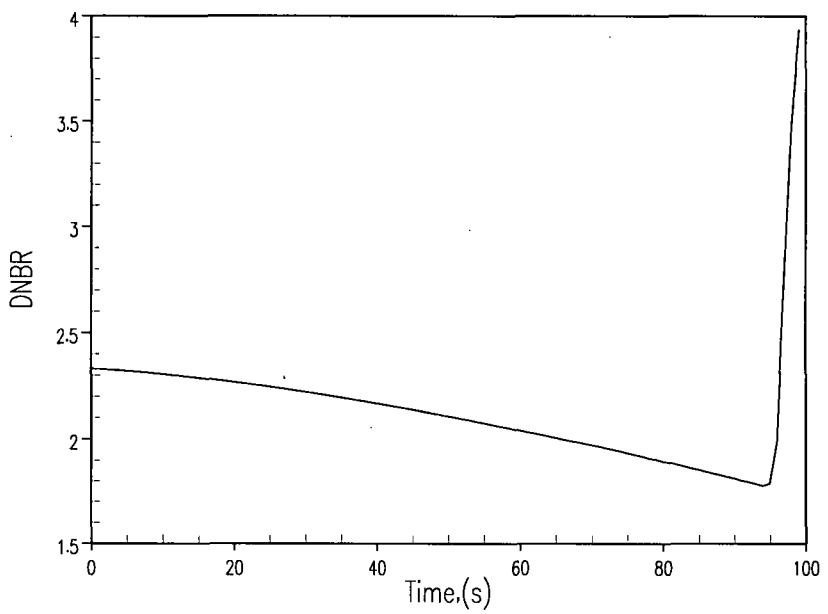


Figure 2.5.2-6 Bank Withdrawal at Power – Unit 1, Minimum Reactivity Feedback – 100% Power – 1 pcm/sec – Vessel Average Temperature and DNBR Versus Time

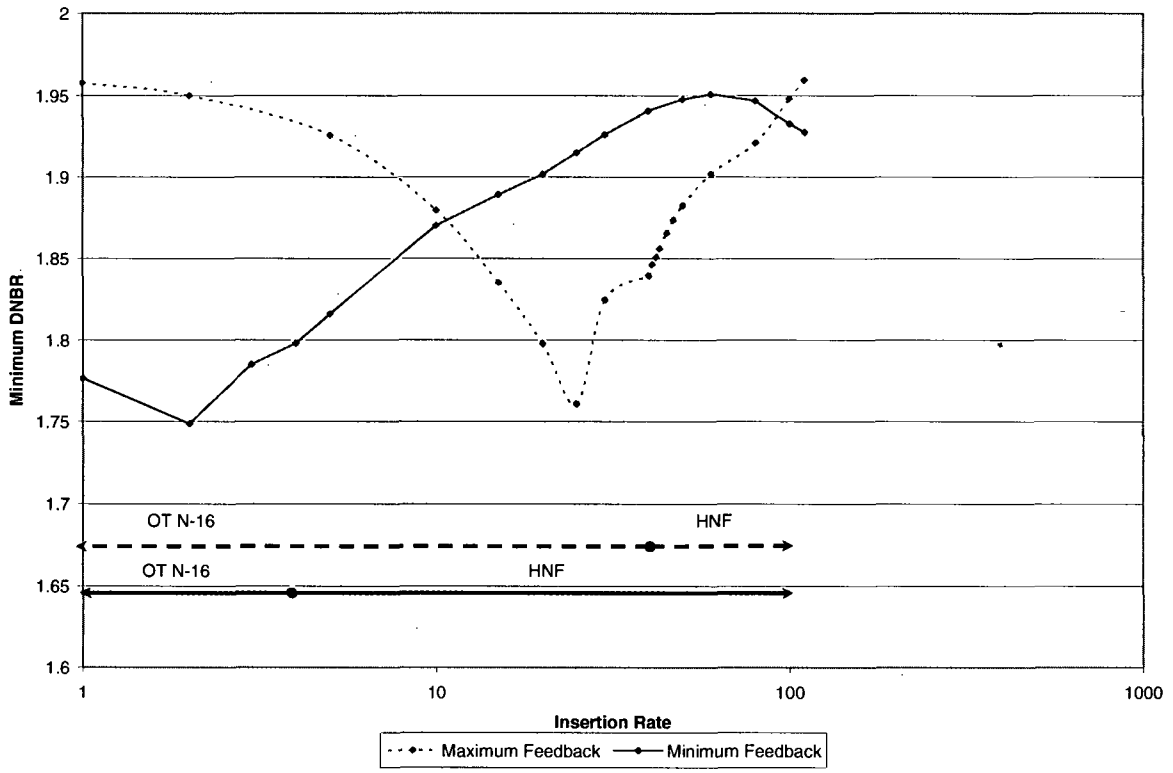


Figure 2.5.2-7 Bank Withdrawal at Power – Unit 1, 100% Power – Minimum DNBR Versus Reactivity Insertion Rate

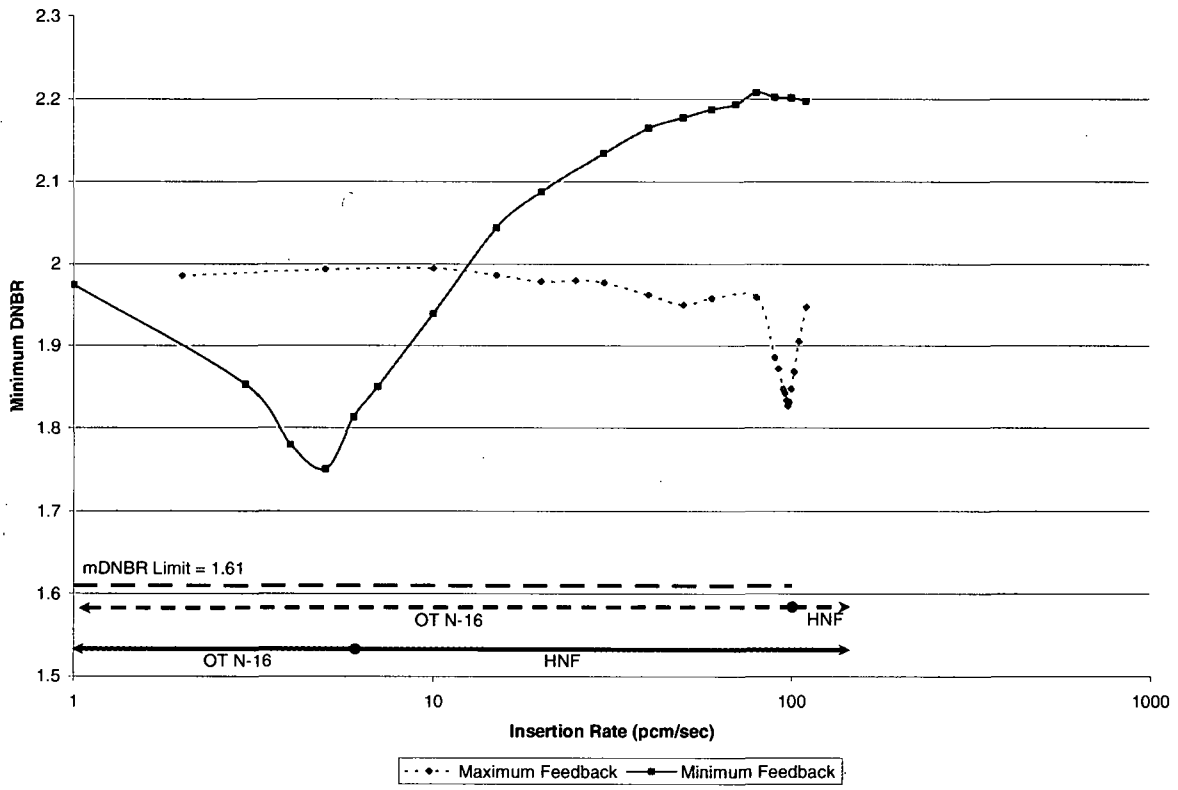


Figure 2.5.2-8 Bank Withdrawal at Power – Unit 1, 60% Power – Minimum DNBR Versus Reactivity Insertion Rate

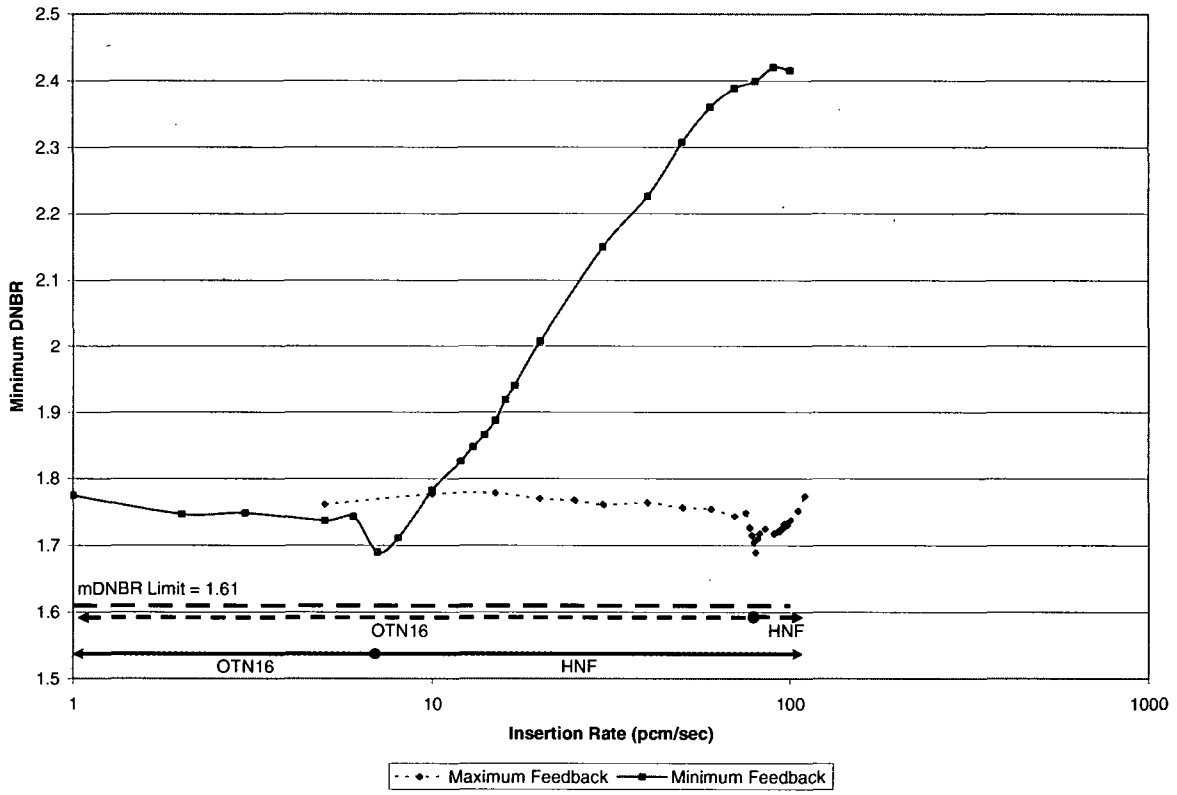


Figure 2.5.2-9 Bank Withdrawal at Power – Unit 1, 10% Power – Minimum DNBR Versus Reactivity Insertion Rate

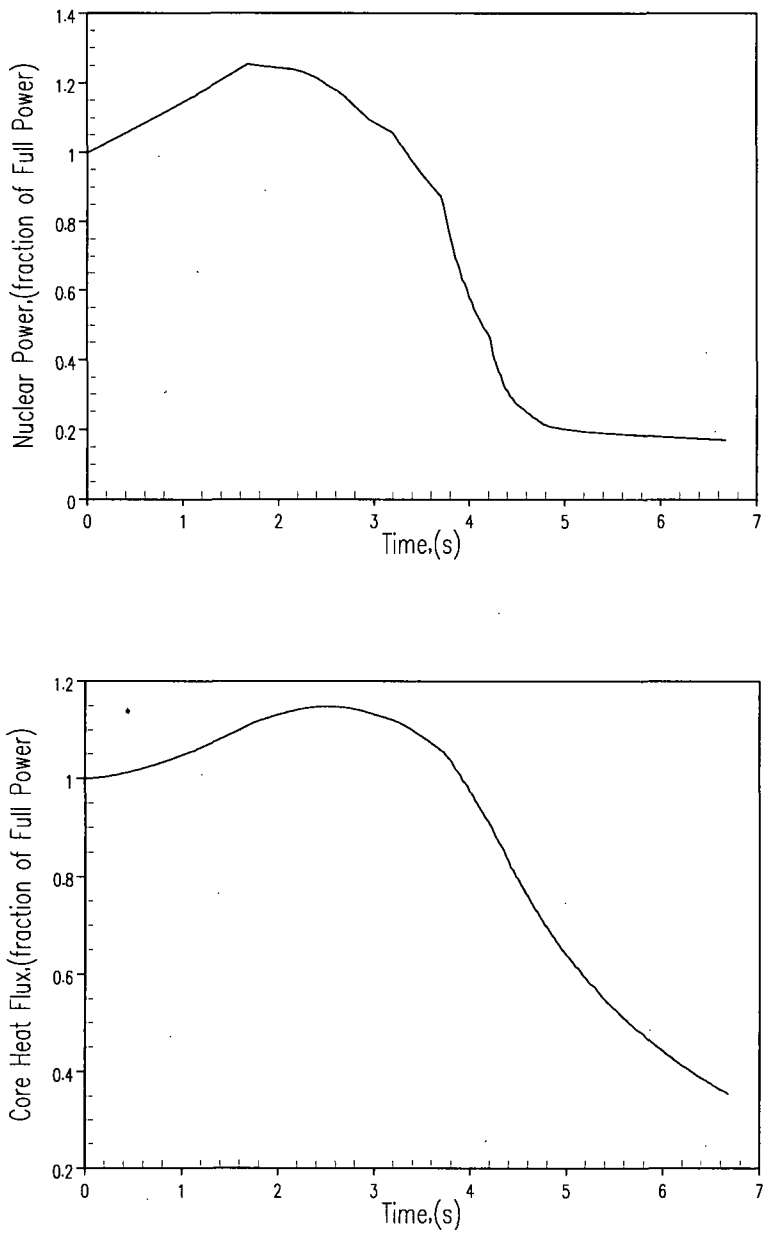
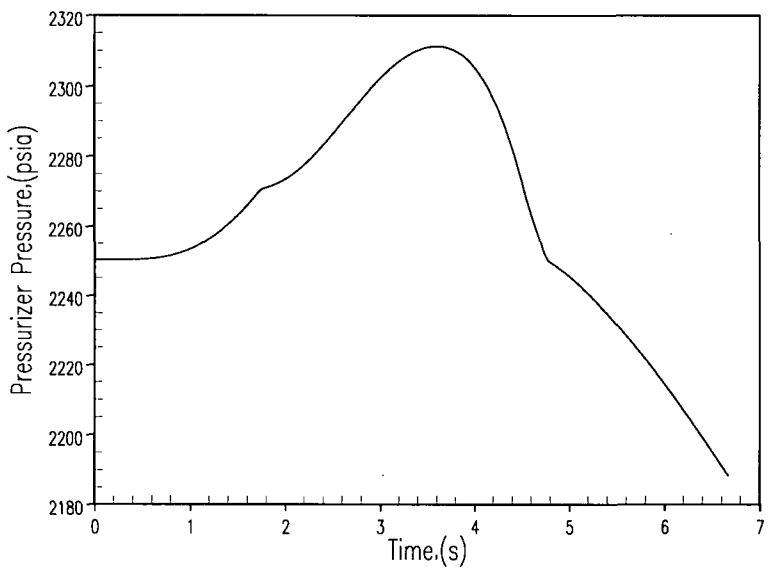


Figure 2.5.2-10 Bank Withdrawal at Power – Unit 2, Minimum Reactivity Feedback – 100% Power – 110 pcm/sec – Nuclear Power and Core Heat Flux Versus Time



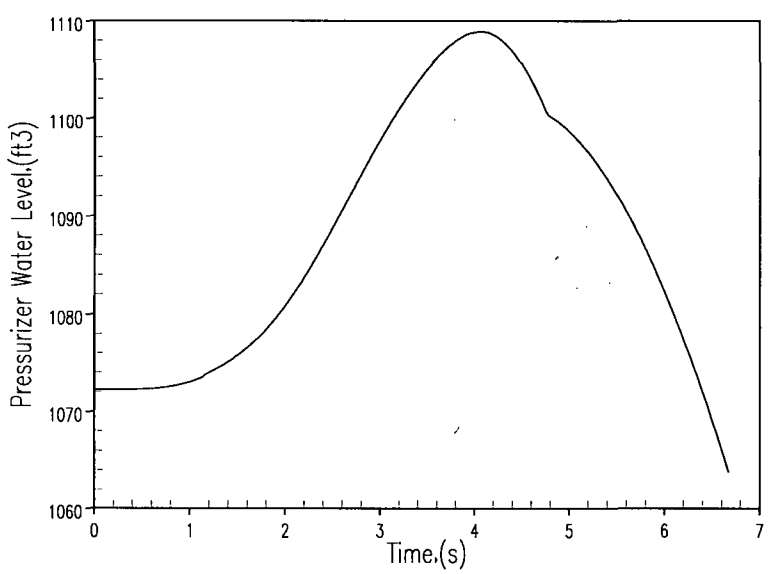
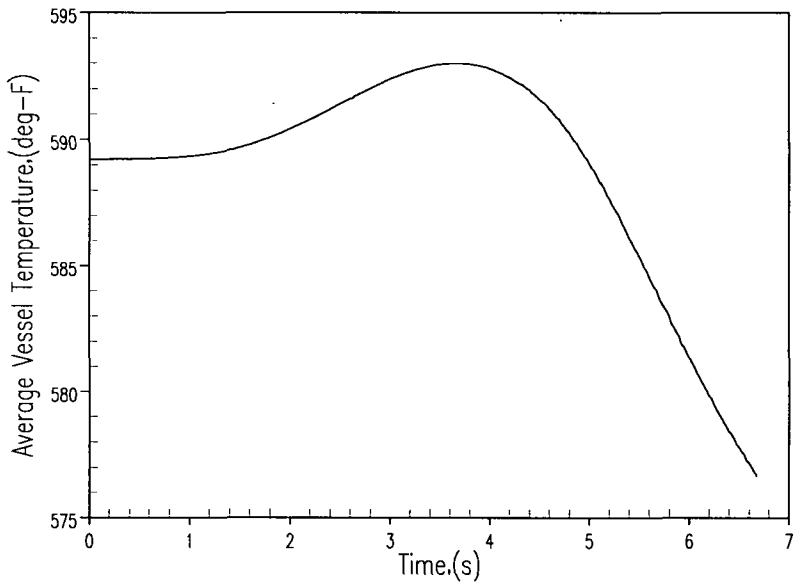


Figure 2.5.2-11 Bank Withdrawal at Power – Unit 2, Minimum Reactivity Feedback – 100% Power – 110 pcm/sec – Pressurizer Pressure and Water Volume Versus Time



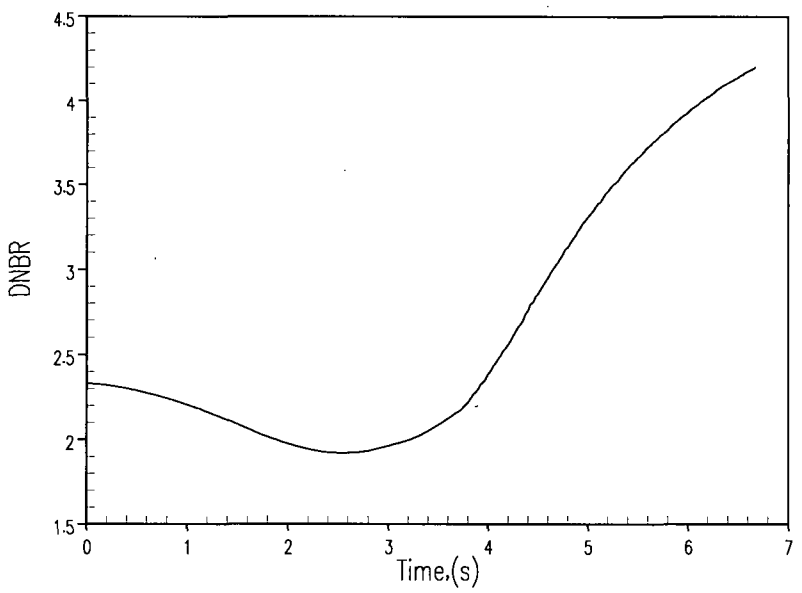


Figure 2.5.2-12 Bank Withdrawal at Power – Unit 2, Minimum Reactivity Feedback – 100% Power – 110 pcm/sec – Vessel Average Temperature and DNBR Versus Time

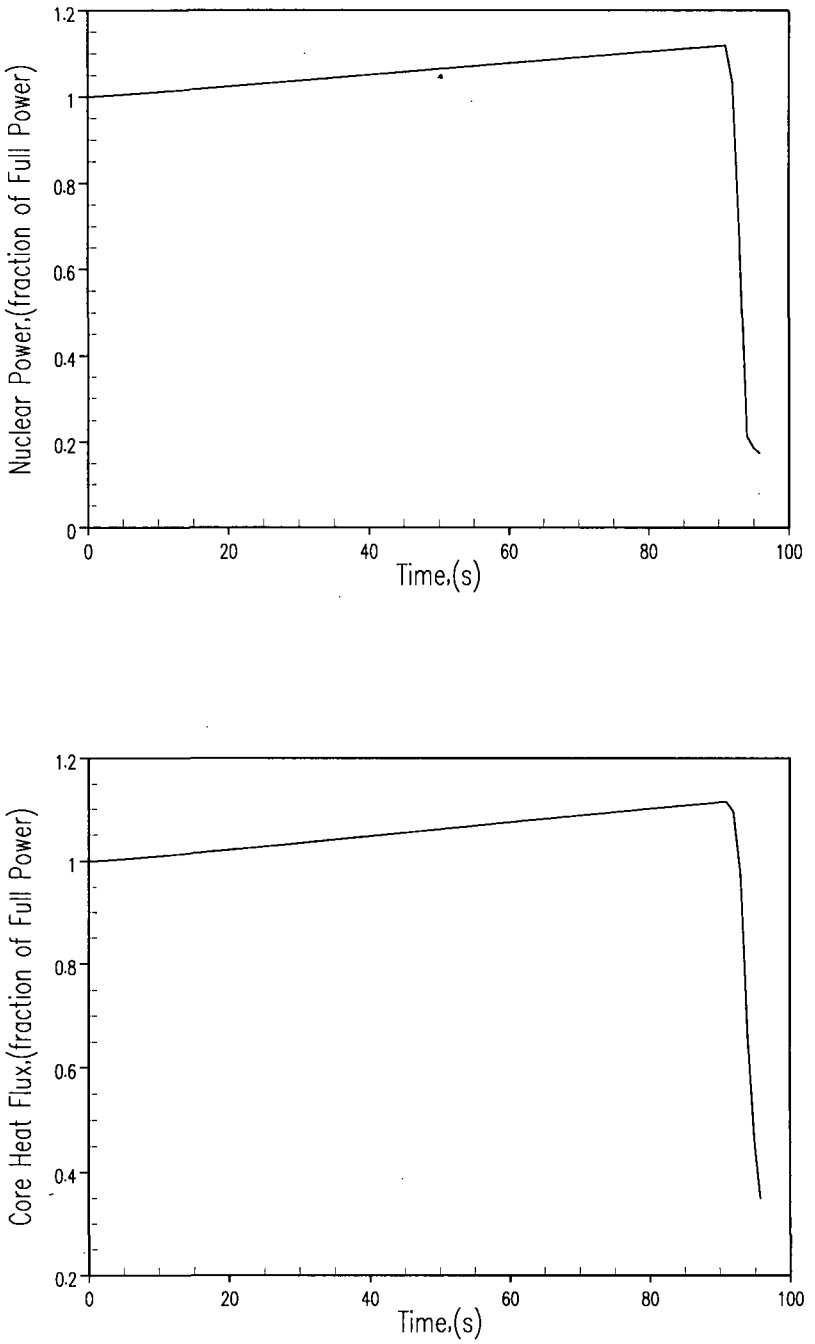
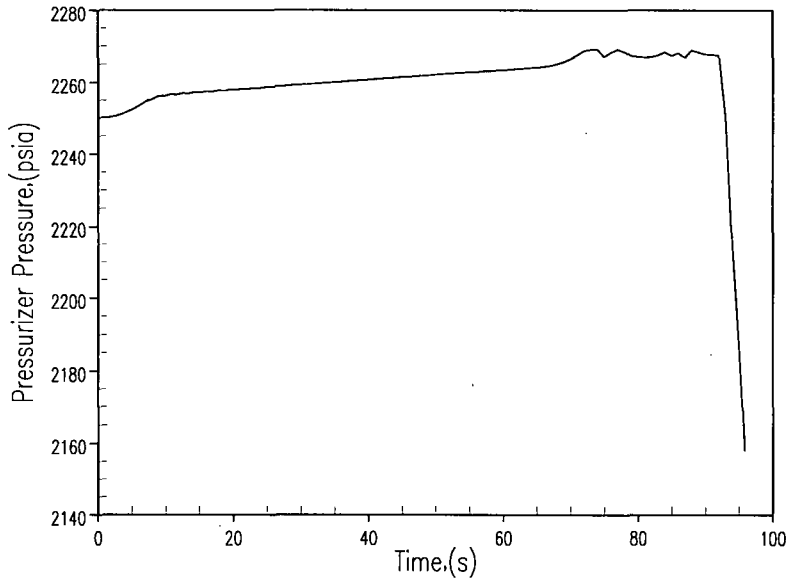


Figure 2.5.2-13 Bank Withdrawal at Power – Unit 2, Minimum Reactivity Feedback – 100% Power – 1 pcm/sec – Nuclear Power and Core Heat Flux Versus Time



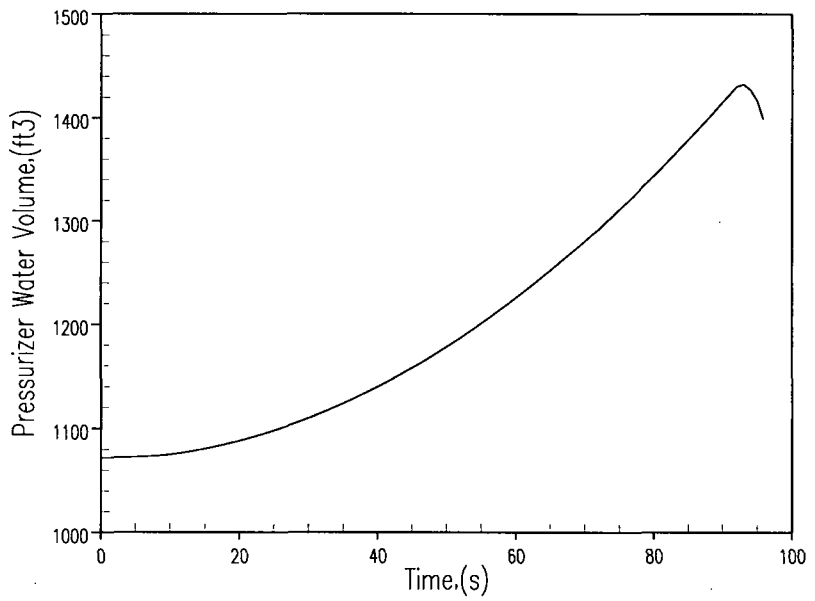
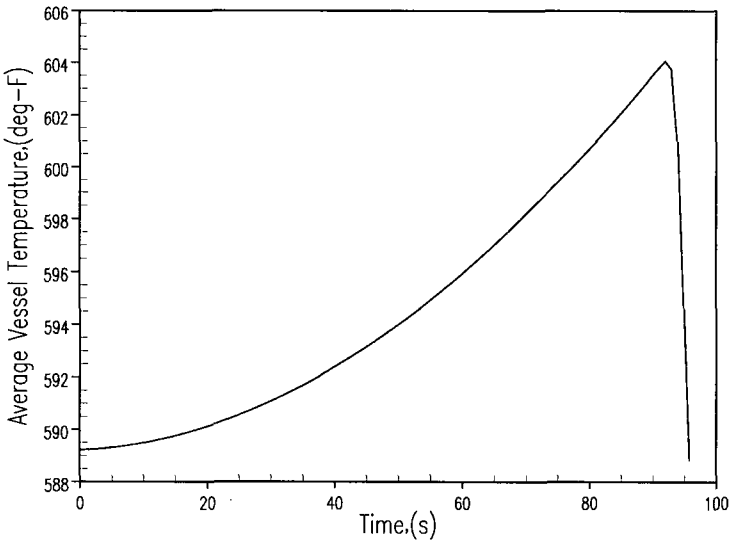


Figure 2.5.2-14 Bank Withdrawal at Power – Unit 2, Minimum Reactivity Feedback – 100% Power – 1 pcm/sec – Pressurizer Pressure and Water Volume Versus Time



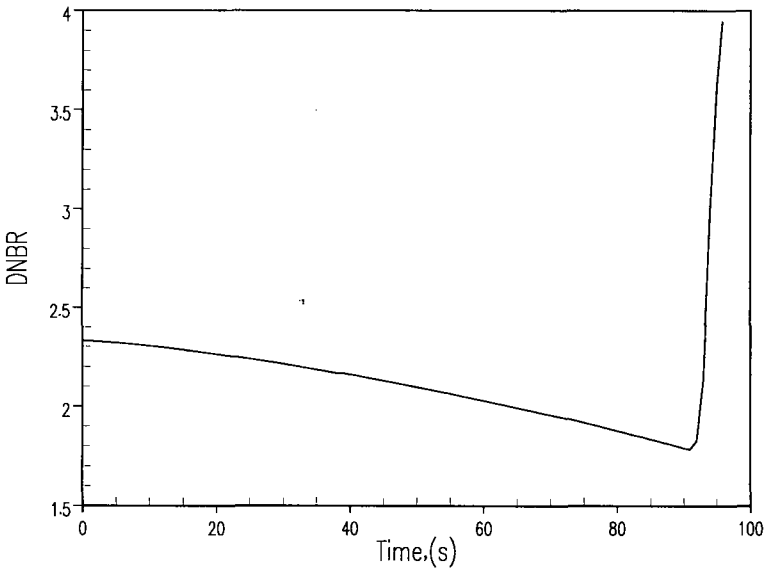


Figure 2.5.2-15 Bank Withdrawal at Power – Unit 2, Minimum Reactivity Feedback – 100% Power – 1 pcm/sec – Vessel Average Temperature and DNBR Versus Time

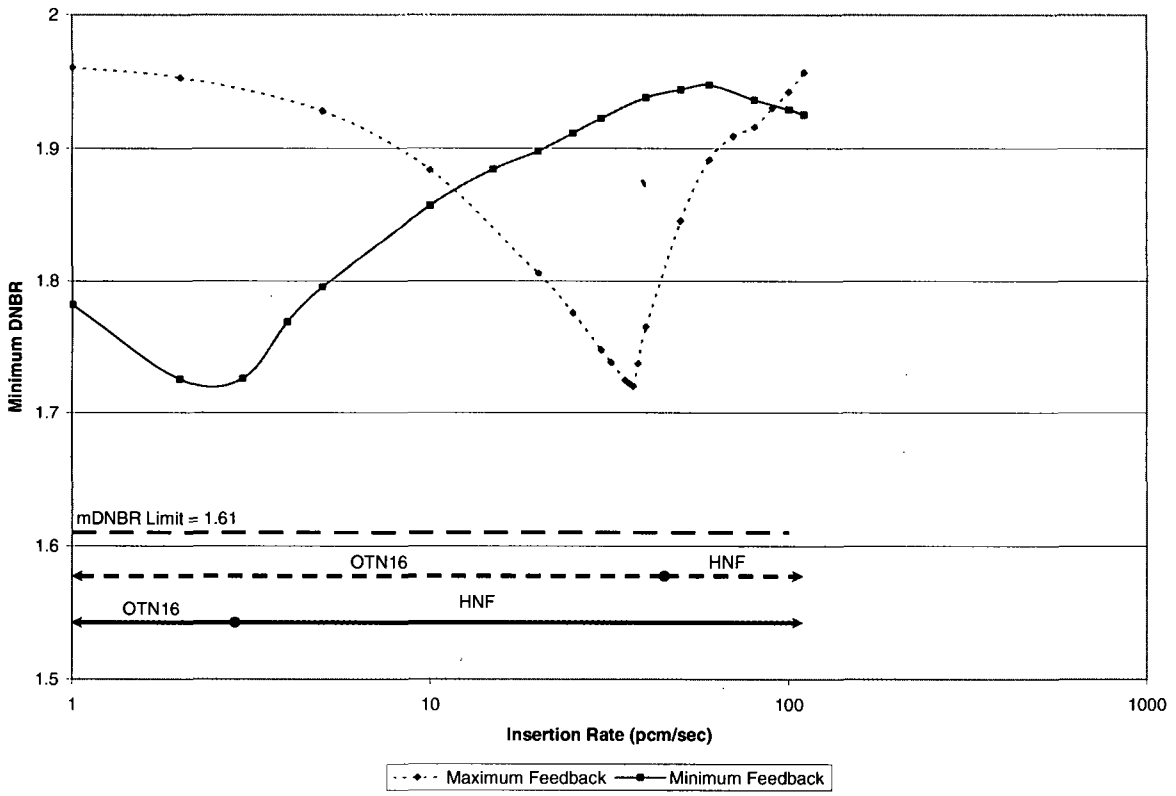


Figure 2.5.2-16 Bank Withdrawal at Power – Unit 2, 100% Power – Minimum DNBR Versus Reactivity Insertion Rate

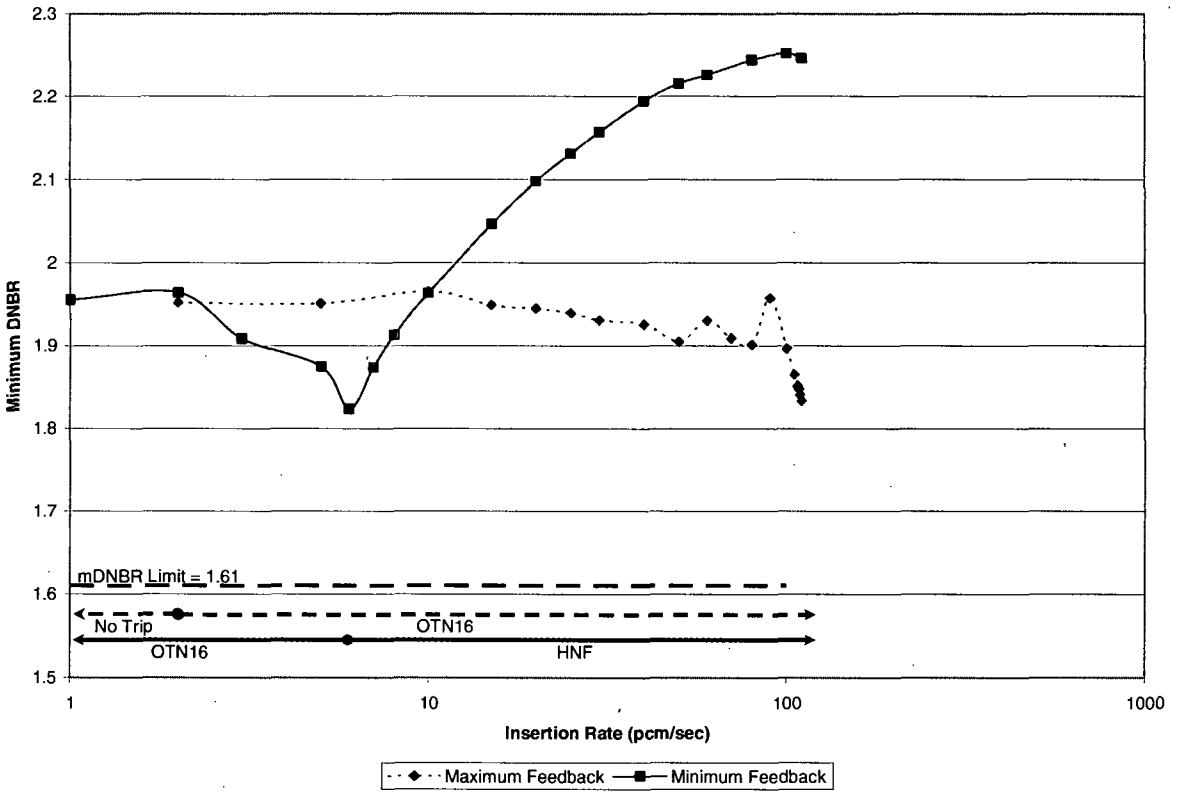


Figure 2.5.2-17 Bank Withdrawal at Power – Unit 2, 60% Power – Minimum DNBR Versus Reactivity Insertion Rate

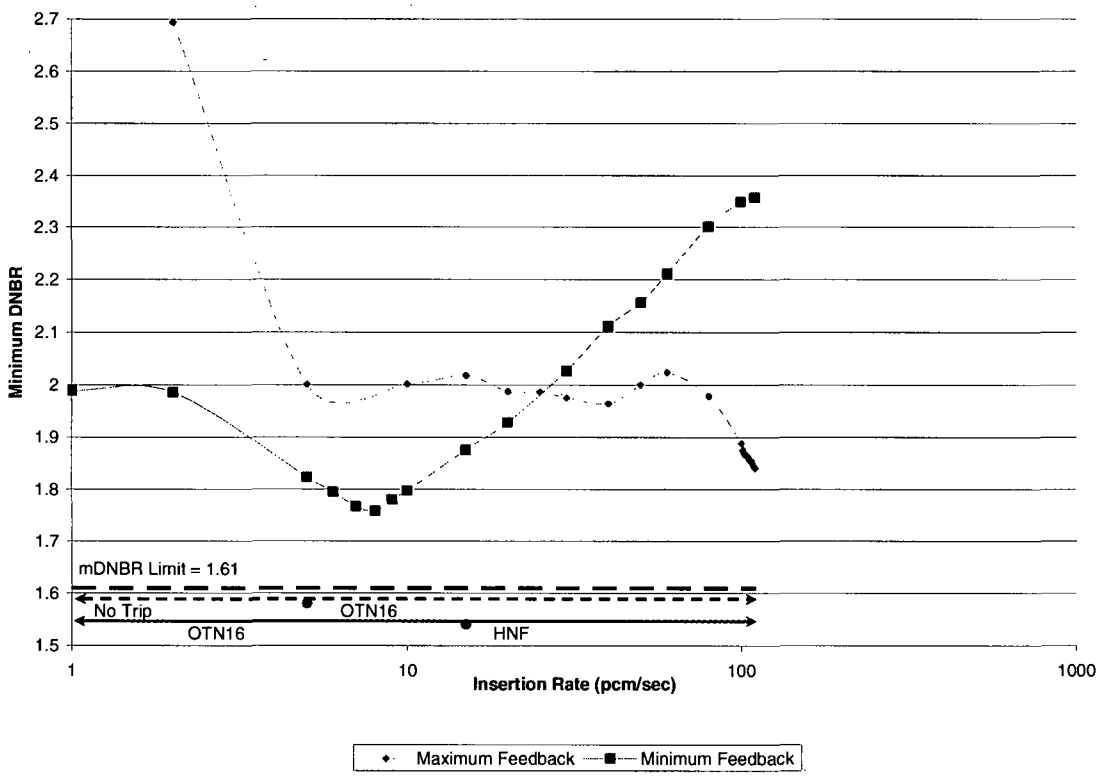


Figure 2.5.2-18 Bank Withdrawal at Power – Unit 2, 10% Power – Minimum DNBR Versus Reactivity Insertion Rate

2.5.3 Control Rod Misoperation

2.5.3.1 Technical Evaluation

The specific acceptance criteria applied for this event are as follows:

- The DNBR should remain above the 95/95 DNBR limit at all times during the transient. Demonstrating that the DNBR limit is met satisfies the requirements of GDC-10.

- Per GDC-20, the protection system should be designed to automatically initiate the operation of appropriate systems, including the reactivity control systems, to ensure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and to sense accident conditions and initiate the operation of safety-related systems and components. For this event, protection is provided via the overtemperature N-16 trip, but only for the most limiting cases. The nonlimiting cases considered do not require protection.

- GDC-25 requires that the protection system is designed to ensure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods. Demonstrating that the fuel design limits (that is, DNBR) are met satisfies the requirements of GDC-25.

The following discussion demonstrates that all applicable acceptance criteria are met for this event at CPNPP Units 1 and 2 at uprate conditions.

2.5.3.1.1 Introduction

The RCCA misalignment events include the following:

- One or more dropped RCCAs from the same group
- A dropped RCCA bank
- A statically misaligned RCCA
- Withdrawal of a single RCCA

Each RCCA has a position indicator channel that displays the position of the assembly. The displays of assembly positions are grouped for the operator's convenience. Fully inserted assemblies are further indicated by a rod at bottom signal, which actuates an alarm and a Control Room annunciator. Group demand position is also indicated.

Full-length RCCAs are moved in preselected banks, and the banks are moved in the same preselected sequence. Each control bank of RCCAs is divided into two groups. The rods comprising a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. A definite schedule of actuation (or deactuation of the stationary gripper, movable gripper, and lift coils of a mechanism) is required to withdraw the RCCA attached to the mechanism.

Since the stationary gripper, moveable gripper, and lift coils associated with the four RCCAs of a rod group are driven in parallel, any single failure which would cause rod withdrawal would affect a minimum of one group. Mechanical failures are in the direction of insertion, or immobility.

A dropped RCCA or RCCA bank is detected by one or more of the following:

- Sudden drop in the core power level as seen by the nuclear instrumentation system
- Asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples
- Rod at bottom signal
- Rod deviation alarm
- Rod position indication

Dropping of a full-length RCCA is assumed to be initiated by a single electrical or mechanical failure that causes any number and combination of rods from the same group of a given control bank to drop to the bottom of the core. The resulting negative reactivity insertion causes nuclear power to rapidly decrease. An increase in the hot channel factor can occur due to the skewed power distribution representative of a dropped rod configuration. For this event, it must be shown that the DNB design basis is met for the combination of power, hot channel factor, and other system conditions which exist following a dropped rod.

Misaligned assemblies are detected by:

- Asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples
- Rod deviation alarm
- Rod position indicators

For CPNPP Units 1 and 2, rod position is displayed in 6-step increments with an accuracy of +4 steps. Deviation of any RCCA from its group by twice this distance (12 steps) will not cause power distributions worse than the design limits. The deviation alarm alerts the operator to rod deviation with respect to the group position in excess of 6 steps. If the rod deviation alarm is not operable, the operator is required to take action per the Technical Requirements Manual.

If one or more rod position indicator channels should be out of service, detailed operating instructions shall be followed to assure the alignment of the non-indicated RCCAs. The operator is also required to take action per the Technical Specifications.

In the extremely unlikely event of simultaneous electrical failures that could result in single RCCA withdrawal, rod deviation and rod control urgent failure would both be displayed on the plant annunciator, and the rod position indicators would indicate the relative positions of the assemblies in the bank. The urgent failure alarm also inhibits automatic rod motion in the group in which it occurs. Withdrawal of a single RCCA by operator action, whether deliberate or by a combination of errors, would result in activation of the same alarm and the same visual indications. Withdrawal of a single RCCA results in both positive reactivity insertion tending to increase core power, and an increase in local power density in the core area associated with the RCCA. Automatic protection for this event is provided by the overtemperature N-16 reactor trip, although due to the increase in local power density it is not possible in all cases to provide assurance that the core safety limits will not be violated.

2.5.3.1.2 Input Parameters, Assumptions, and Acceptance Criteria

The dropped RCCA, dropped RCCA bank, and statically misaligned RCCA events are classified as Condition II events (faults of moderate frequency) as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. The single RCCA withdrawal incident is classified as an ANS Condition III event, as discussed below.

No single electrical or mechanical failure in the rod control system could cause the accidental withdrawal of a single RCCA from the inserted bank at full-power operation. The operator could deliberately withdraw a single RCCA in the control bank since this feature is necessary in order to retrieve an assembly should one be accidentally dropped. The event analyzed must result from multiple wiring failures or multiple deliberate operator actions and subsequent and repeated operator disregard of event indication. The probability of such a combination of conditions is so low that the limiting consequences may include slight fuel damage. Thus, consistent with the philosophy and format of ANSI N18.2, the event is classified as a Condition III event. By definition "Condition III occurrences include incidents, any one of which may occur during the lifetime of a particular plant," and "shall not cause more than a small fraction of fuel elements in the reactor to be damaged."

Refer to Tables 2.1-1 and 2.1-6 in Section 2.1 for detailed acceptance criteria and initial conditions used in the dropped RCCA/dropped RCCA bank analysis. For the statically misaligned RCCA and single RCCA withdrawal events, see the analysis descriptions and results in subsections 2.5.3.1.3 and 2.5.3.1.4 for details of the inputs and acceptance criteria.

2.5.3.1.3 Description of Analyses and Evaluations

One or More Dropped RCCAs from the Same Group

The LOFTRAN computer code calculates transient system responses for the evaluation of a dropped RCCA event. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and MSSVs. The code computes pertinent plant variables including temperatures, pressures, and power levels.

Transient RCS statepoints (temperature, pressure, and power) are calculated by LOFTRAN. Nuclear models are used to obtain a hot-channel factor consistent with the primary-system conditions and reactor power. By incorporating the primary conditions from the transient analysis and the hot-channel factor from the nuclear analysis, it is shown that the DNB design basis is met using dropped rod limit lines developed with the VIPRE code (Reference 1). The transient response analysis, nuclear peaking factor analysis, and performance of the DNB design basis confirmation are performed in accordance with the approved methodology described in Reference 2.

Dropped RCCA Bank

A dropped RCCA bank results in a symmetric power change in the core. Assumptions made in the methodology (Reference 2) for the dropped RCCA(s) analysis provide a bounding analysis for the dropped RCCA bank.

Statically Misaligned RCCA

Steady-state power distributions are analyzed using the appropriate nuclear physics computer codes. The peaking factors are then compared to peaking factor limits developed using the VIPRE code, which are based on meeting the DNBR design criterion. The following cases are examined in the analysis assuming the reactor is at full power: the worst rod withdrawn with bank D inserted at the insertion limit, the worst rod dropped with bank D inserted at the insertion limit, and the worst rod dropped with all other rods out. It is assumed that the incident occurs at the time in the cycle with maximum predicted peaking factors. This assures a conservative $F_{\Delta H}$ for the misaligned RCCA configuration.

Single RCCA Withdrawal

Power distributions within the core are calculated. The peaking factors are then used by VIPRE to calculate the DNBR for the event. The case of the worst rod withdrawn from bank D inserted at the insertion limit, with the reactor initially at full power, was analyzed. This incident is assumed to occur at beginning-of-life since this condition results in a minimum value of moderator temperature coefficient. This assumption maximizes the power rise and minimizes the tendency of increased moderator temperature to flatten the power distribution.

2.5.3.1.4 Control Rod Misalignment Results

One or More Dropped RCCAs

Single or multiple dropped RCCAs within the same group result in a negative reactivity insertion. The core is not adversely affected during this period since power is decreasing rapidly. Either reactivity feedback or control bank withdrawal will re-establish power.

For a dropped RCCA event in the automatic rod control mode, the rod control system detects the drop in power and initiates control bank withdrawal. Power overshoot may occur due to this

action by the automatic rod controller after which the control system will insert the control bank to restore nominal power. In all cases, the minimum DNBR remains above the limit value.

Following a dropped rod event in manual rod control, the plant will establish a new equilibrium condition. The equilibrium process without control system interaction is monotonic, thus removing power overshoot as a concern, and establishing the automatic rod control mode of operation as the limiting case.

Dropped RCCA Bank

A dropped RCCA bank results in a large negative reactivity insertion. Due to the relatively large worth of the dropped bank, and if the turbine load is constant, a reactor trip may occur on low pressurizer pressure due to the mismatch between the reactor power and the turbine power. The core is not adversely affected during this period, since power is decreasing rapidly. In the event a reactor trip does not occur, the initial power reduction from a dropped RCCA bank is large and the power return due to reactivity feedback and control bank withdrawal is far less than seen from one or more dropped RCCAs from the same group. In either instance, the minimum DNBR remains above the limit value.

Following plant stabilization, the operator may manually retrieve the RCCA(s) by following approved operating procedures.

Statically Misaligned RCCA

The most severe misalignment situations with respect to DNBR at significant power levels arise from cases in which one RCCA is fully inserted, or where bank D is fully inserted with one RCCA fully withdrawn. Multiple independent alarms, including a bank insertion limit alarm, alert the operator well before the postulated conditions are approached. The bank can be inserted to its insertion limit with any one assembly fully withdrawn without the DNBR falling below the limit value.

The insertion limits in the Technical Specifications may vary from time to time depending on a number of limiting criteria. It is preferable, therefore, to analyze the misaligned RCCA case at full power for a control bank insertion position that is as deep as allowed by the DNBR and power peaking factor limits. The full power insertion limits on control bank D must then be chosen to be above that position and will usually be dictated by other criteria. Detailed results will vary from cycle to cycle depending on fuel arrangements.

For this RCCA misalignment, with bank D inserted to its full-power insertion limit and one RCCA fully withdrawn, the DNBR does not fall below the limit value. This case is analyzed assuming the initial reactor power, and RCS pressure and temperature are at their nominal values including uncertainties, but with the increased radial peaking factor associated with the misaligned RCCA.

DNB calculations have not been performed specifically for RCCAs missing from other banks. However, power shape calculations have been done as required for the RCCA ejection analysis.

Inspection of the power shapes shows that the DNB and peak kW/ft situation is less severe than the bank D case discussed above assuming insertion limits on the other banks equivalent to a bank D full-in insertion limit.

For RCCA misalignments with one RCCA fully inserted, the DNBR does not fall below the limit value. This case is analyzed assuming the initial reactor power, and RCS pressure and temperature are at their nominal values including uncertainties, but with the increased radial peaking factor associated with the misaligned RCCA.

DNB does not occur for the RCCA misalignment incident and thus the ability of the primary coolant to remove heat from the fuel rod is not reduced. The peak fuel temperature corresponds to a linear heat generation rate based on the radial peaking factor penalty associated with the misaligned RCCA and the design axial power distribution. The resulting linear heat generation is well below that which would cause fuel melting.

Following the identification of an RCCA group misalignment condition, the operator is required to take action per the plant Technical Specifications and operating instructions.

Single RCCA Withdrawal

For the single rod withdrawal event, two cases have been considered as follows:

1. If the reactor is in the manual control mode, continuous withdrawal of a single RCCA results in both an increase in core power and coolant temperature, and an increase in the local hot channel factor in the area of the withdrawing RCCA. In terms of the overall system response, this case is similar to those presented for the uncontrolled RCCA bank withdrawal at power event. However, the increased local power peaking in the area of the withdrawn RCCA results in lower minimum DNBRs than for the withdrawn bank cases. Depending on initial bank insertion and location of the withdrawn RCCA, automatic reactor trip may not occur sufficiently fast enough to prevent the minimum DNBR from falling below the limit value. Evaluation of this case at the power and coolant conditions at which the overtemperature N-16 trip would be expected to trip the plant shows that an upper limit for the number of fuel rods with a DNBR less than the limit value is 5 percent of the total rods in the core.

If the reactor is in the automatic control mode, the multiple failures that result in the withdrawal of a single RCCA will result in the immobility of the other RCCAs in the controlling bank. The transient will then proceed in the same manner as Case (1) described above.

For such cases as above, a reactor trip will ultimately ensue, although not sufficiently fast enough in all cases to prevent a minimum DNBR in the core of less than the limit value. Following reactor trip, normal shutdown procedures are followed. No single failure of the reactor trip system will negate the protection functions required for the single RCCA withdrawal accident, or adversely affect the consequences of the accident.

2.5.3.1.5 Results

The evaluation of the dropped rod event using the methodology in Reference 2, encompassing all possible dropped RCCA or RCCA bank worths delineated in Reference 2, concluded that the minimum DNBR remains above the safety analysis limit value for CPNPP Units 1 and 2. For all cases of any single RCCA fully inserted, or bank D inserted to the rod insertion limit and any single RCCA in that bank fully withdrawn (static misalignment), the minimum DNBR remains above the limit value for CPNPP Units 1 and 2. Therefore, the DNB design criterion is met and the RCCA misalignments do not result in core damage given implementation of the TM and SPU programs. For the case of the accidental withdrawal of a single RCCA, with the reactor in the automatic or manual control mode and initially operating at full power with bank D at the insertion limit, an upper bound of the number of fuel rods experiencing DNB is 5 percent of the total number of fuel rods in the core for CPNPP Units 1 and 2.

2.5.3.2 Conclusion

Luminant Power has reviewed the analyses of control rod misalignment events and concluded that the analyses have adequately accounted for the changes in core design required for plant operation at the uprate power level. It is also concluded that the analyses were performed using acceptable analytical models. Luminant Power further concluded that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the specified acceptable fuel design limits will not be exceeded during normal or anticipated operational transients. Based on this, it is concluded that the plant will continue to meet the requirements of GDCs -10, -20, and -25.

2.5.3.3 References

1. WCAP-14565, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," October 1999.

2. WCAP-11394, "Methodology for the Analysis of the Dropped Rod Event," January 1990.

2.5.4 Startup of an Inactive Loop at an Incorrect Temperature

2.5.4.1 Technical Evaluation

If the plant is operating with one pump out of service, there would be reverse flow through the inactive loop due to the pressure difference across the reactor vessel. The cold leg temperature in an inactive loop is identical to the cold leg temperature of the active loops (the reactor core inlet temperature). If the reactor is operated at power, and assuming the secondary side of the steam generator in the inactive loop is not isolated, there would be a temperature drop across the steam generator in the inactive loop and, with the reverse flow, the hot leg temperature of the inactive loop would be lower than the reactor core inlet temperature.

As indicated in the previous section, the event is precluded by the CPNPP Technical Specifications, which will not change for the uprate. Therefore, a detailed analysis of this event is not required.

2.5.4.2 Conclusion

The evaluation of the inactive loop startup event was reviewed, and it is concluded that the plant will continue to meet the requirements of GDCs-10, -15, -20, -26, and -28.

2.5.5 Chemical and Volume Control System Malfunction Resulting in a Decrease in Boron Concentration in the Reactor Coolant

2.5.5.1 Technical Evaluation

The specific acceptance criterion applied for the boron dilution events is that adequate operator action time is available prior to a complete loss of shutdown margin. For boron dilution events in Modes 1 through 5, there must be at least 15 minutes from operator notification (that is, first alarm) until shutdown margin is lost. For CPNPP Units 1 and 2, a boron dilution event cannot occur during Mode 6 (Refueling) due to administrative controls which isolate the RCS from the potential sources of unborated water. Additionally, for conditions when no reactor coolant pump is in operation, all dilution sources are isolated or under administrative control. Hence, a boron dilution event cannot occur during Mode 5 (Cold Shutdown), or Mode 4 (Hot Shutdown) once operation on the residual heat removal system (RHRS) begins. This is consistent with inadvertent boron dilution event analysis methodology approved by the NRC for CPNPP Units 1 and 2 (Reference 1). With shutdown margin maintained, there is no return to critical and no violation of the 95/95 DNBR limit (GDC-10), as well as no violation of the primary and secondary pressures limits (GDC-15). Furthermore, since a return to critical is precluded and fuel design limits are not exceeded, the requirements of GDC-26 are satisfied.

For Modes 1 and 2, the boron dilution analysis is performed to ensure that adequate time is available from alarm to total loss of shutdown margin for the operator to identify and terminate the dilution. For Modes 3 through 5, the boron dilution event is analyzed to generate operating guidelines that, when met, ensure that there is adequate time from alarm to total loss of shutdown margin for the operator to identify and terminate the dilution.

The discussion below demonstrates that all applicable acceptance criteria are met for this event at CPNPP Units 1 and 2 in operating Modes 1 through 5.

2.5.5.1.1 Introduction

Reactivity can be added to the core by feeding primary-grade water into the RCS via the reactor makeup portion of the CVCS. Boron dilution is a manual operation under strict administrative controls with procedures calling for a limit on the rate and duration of dilution. A boric acid blend system is provided to permit the operator to match the boron concentration of the reactor coolant makeup water during normal charging to the RCS boron concentration. As discussed below, the CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value that, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

2.5.5.1.2 Input Parameters, Assumptions, and Acceptance Criteria

The opening of the primary water makeup control valves provides makeup to the CVCS and subsequently to the RCS, which can dilute the reactor coolant. Inadvertent dilution from this source can be readily terminated by closing the control valve. In order for makeup water to be added to the RCS at pressure, at least one charging pump must be running in addition to a primary makeup water pump.

The limiting dilution flow path is identified as the lowest resistance flow path for an unintentional dilution. The boron dilution analysis excludes deliberate dilution operations from considerations. During intentional boron dilution operations, the plant operators are keenly aware of and continuously monitor the dilution process in progress for any sign of deviation or malfunction, such that the possibility of an undetected malfunction is considered remote. This is a standard assumption in the boron dilution analysis methodology. Thus, the limiting boron dilution flow path does not include either the normal dilute or the alternative dilute flow paths (these paths are used only for deliberate dilution operations). The limiting boron dilution flow path is the makeup flow path of the reactor makeup water system (RMWS) used in normal boration/blend operations.

The principal means of causing an inadvertent boron dilution are the opening of the primary water makeup control valve and failure of the blend system, either by controller or mechanical failure. The CVCS and the RMWS are designed to limit, even under various postulated failure modes, the potential rate of dilution to values that will allow sufficient time for operator response to terminate the dilution. An inadvertent dilution from the RMWS may be terminated by closing the primary water makeup control valve. All expected sources of dilution may be terminated by closing isolation valves in the CVCS. The lost shutdown margin may be regained by the opening of isolation valves to the refueling water storage tank (RWST), thus allowing the addition of borated water to the RCS.

The rate at which unborated water can be added to the RCS is limited by the design of the CVCS and RMWS. The maximum (limiting) boron dilution flow rate is 157.5 gpm for Modes 1 through 5.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of the pumps in the CVCS. Alarms are actuated to warn the operator when boric acid or makeup water flow rates deviate from preset values as a result of system malfunction.

A CVCS malfunction is classified as an ANS Condition II event, a fault of moderate frequency as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. Criteria established for Condition II events are as follows:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the RCS and MSS should be maintained below 110 percent of the design pressures.
- Fuel temperature and fuel cladding strain limits should not be exceeded. The peak linear heat generation rate should not exceed a value that would cause fuel centerline melt.

This event is analyzed to show that there is sufficient time for mitigation of an inadvertent boron dilution prior to the complete loss of shutdown margin. A complete loss of plant shutdown margin results in a return of the core to the critical condition causing an increase in the RCS temperature and heat flux. This could violate the safety analysis limit DNBR value and challenge the fuel and fuel cladding integrity. A complete loss of plant shutdown margin could also result in a return of the core to the critical condition causing an increase in RCS pressure. This could challenge the pressure design limit for the RCS.

If the shutdown margin is shown not to be lost, the condition of the plant at any point in the transient is within the bounds of those calculated for other Condition II transients. By showing that the above criteria are met for those Condition II events, it can be concluded that they are also met for the boron dilution event. Operator action is relied upon to preclude a complete loss of plant shutdown margin.

2.5.5.1.3 Description of Analyses and Evaluations

Dilution During Mode 6 – An analysis is not performed for an uncontrolled boron dilution accident during refueling. In this mode, the event is prevented by administrative control of valves in the possible dilution paths.

Dilution During Mode 5 – Typically, the plant is maintained in the cold shutdown mode when RCS ambient temperatures are required. Occasionally, reduced RCS inventory may be necessary. Mode 5 can also be a transition mode to either refueling (Mode 6) or hot shutdown (Mode 4). Through the cycle, the plant may enter Mode 5 if reduced temperatures are required in containment or as the result of a Technical Specification action statement. The plant is maintained in Mode 5 at the beginning of each cycle for startup testing of certain systems.

During this mode of operation, the control banks are fully inserted. The following conditions are assumed for an uncontrolled boron dilution during cold shutdown.

- The assumed dilution flow (157.5 gpm) is the maximum flow from the RMWS assuming multiple simultaneous failures of control valves.

- The active RCS water volume for CPNPP Unit 1 is 9,903.7 ft^3. The active RCS water volume for CPNPP Unit 2 is 8,593.1 ft^3. The difference in the active RCS water volume between the two units is due to the different steam generator designs (CPNPP Unit 1 has Δ76 steam generators installed; CPNPP Unit 2 still uses Model D-5 steam generators). These active volumes assume at least one reactor coolant pump is operation, with the volume of the pressurizer and surge line excluded to assure that conservative estimates are made. Additionally, since no consideration is given to mixing in the reactor vessel upper head region, the volumes for the upper head and the downcomer from the top of the cold legs to the bottom of the upper head spray nozzles are also removed.

- When no reactor coolant pump is in operation, all dilution sources are isolated or under administrative control. This is consistent with inadvertent boron dilution event analysis methodology approved by the NRC for CPNPP Units 1 and 2.

- The volume control tank (VCT) high water level alarm alerts the operators that a boron dilution may be in progress. This is consistent with inadvertent boron dilution event analysis methodology approved by the NRC for CPNPP Units 1 and 2.

- A minimum ratio of initial boron concentration at the most reactive burnup to the maximum critical boron concentration is determined at the upper core average operating temperature limit and the ambient temperature assumed for Mode 5.

Dilution During Mode 5 Drained – The RCS water level can be dropped to the mid-plane of the hot leg for maintenance work that requires the steam generators to be drained. When the water level is drained down to the mid-plane of the hot leg from a filled and vented condition in cold shutdown, an uncontrolled boron dilution accident is prevented by administrative controls which isolate the RCS from the potential source of unborated water. Nevertheless, an analysis has been performed for a Mode 5 drained case.

The conditions assumed for an uncontrolled boron dilution during cold shutdown with the water level drained to the mid-plane of the hot leg are identical to those for the uncontrolled boron dilution during cold shutdown, except that the minimum water volume in the RCS is reduced to 4,513 ft^3 for both CPNPP Units 1 and 2. This active volume assumes at least one reactor coolant pump in operation, with the volumes of the pressurizer, the surge line, the steam generators, the upper head and the downcomer from the top of the cold legs to the bottom of the upper head spray nozzles excluded and the hot leg volumes reduced to assure that a conservative estimate is made.

Dilution During Mode 4 – In Mode 4, the plant is being taken from a short-term mode of operation, cold shutdown (Mode 5), to a long-term mode of operation, hot standby (Mode 3). Typically, the plant is maintained in the hot shutdown mode to achieve plant heatup before entering Mode 3. The plant is maintained in Mode 4 at the beginning of each cycle for startup testing of certain systems. Throughout the cycle, the plant will enter Mode 4 if reduced temperatures are required in containment or as a result of a Technical Specification action statement. During this mode of operation, the control banks are fully inserted. In Mode 4, the primary coolant forced flow which provides mixing can be provided by either the RHRS or a reactor coolant pump, depending on system pressure. The following conditions are assumed for an uncontrolled boron dilution during hot shutdown:

- The assumed dilution flow (157.5 gpm) is the maximum flow from the RMWS assuming multiple, simultaneous failures of control valves.

- The active RCS water volume for CPNPP Unit 1 is 9,903.7 ft^3. The active RCS water volume for CPNPP Unit 2 is 8,593.1 ft^3. The difference in the active RCS water volume between the two units is due to the different steam generator designs (CPNPP Unit 1 has Δ76 steam generators installed; CPNPP Unit 2 still uses Model D-5 steam generators). These active volumes assume at least one reactor coolant pump is operation, with the volume of the pressurizer and surge line excluded to assure that conservative estimates are made. Additionally, since no consideration is given to mixing in the reactor vessel upper head region, the volumes for the upper head and the downcomer from the top of the cold legs to the bottom of the upper head spray nozzles are also removed.

- When no reactor coolant pump is in operation, all dilution sources are isolated or under administrative control. This is consistent with inadvertent boron dilution event analysis methodology approved by the NRC for CPNPP Units 1 and 2 (Reference 1).

- The VCT high water level alarm alerts the operators that a boron dilution may be in progress. This is consistent with inadvertent boron dilution event analysis methodology approved by the NRC for CPNPP Units 1 and 2.

- A minimum ratio of initial boron concentration at the most reactive burnup to the maximum critical boron concentration is determined at both the upper and lower core average operating temperature limits for Mode 4.

Dilution During Mode 3 – During this mode, rod control is in manual and the rods can be either withdrawn or inserted. In Mode 3, all reactor coolant pumps may not be in operation. In an effort to balance the heat loss through the RCS and the heat removal of the steam generators, one or more of the pumps may be off to decrease heat input into the system. In the approach to Mode 2, the operator must manually withdraw the control rods and may initiate a limited dilution according to shutdown margin requirements, but not simultaneously. If the shutdown or control banks are withdrawn, the dilution scenario is similar to the Mode 2 analysis where the failure to block the source range trip results in a reactor trip and immediate shutdown of the reactor. The dilution scenario is more limiting if the control rods are not withdrawn and the reactor is shut

down by boron to the Technical Specifications' minimum requirement for Mode 3. The following conditions are assumed for an uncontrolled boron dilution during hot standby:

- The assumed dilution flow (157.5 gpm) is the maximum flow from the RMWS assuming multiple, simultaneous failures of control valves.

- The active RCS water volume for CPNPP Unit 1 is 9,903.7 ft^3. The active RCS water volume for CPNPP Unit 2 is 8,593.1 ft^3. The difference in the active RCS water volume between the two units is due to the different steam generator designs (CPNPP Unit 1 has Δ76 steam generators installed; CPNPP Unit 2 still uses Model D-5 steam generators). These active volumes assume at least one reactor coolant pump is operation, with the volume of the pressurizer and surge line excluded to assure that conservative estimates are made. Additionally, since no consideration is given to mixing in the reactor vessel upper head region, the volumes for the upper head and the downcomer from the top of the cold legs to the bottom of the upper head spray nozzles are also removed.

- The VCT high water level alarm alerts the operators that a boron dilution may be in progress. This is consistent with inadvertent boron dilution event analysis methodology approved by the NRC for CPNPP Units 1 and 2.

- A minimum ratio of initial boron concentration at the most reactive burnup to the maximum critical boron concentration is determined at both the upper and lower core average operating temperature limits for Mode 3.

Dilution During Mode 2 – In this mode, the plant is being taken from one long-term mode of operation (Mode 3) to another (Mode 1). The plant is maintained in the startup mode only for the purpose of startup testing at the beginning of each cycle. All normal actions required to change power level, either up or down, require operator initiation. Assumed conditions at startup require the reactor to have available at least 1.30 percent Δk shutdown margin. The following conditions are assumed for an uncontrolled boron dilution during startup:

- The assumed dilution flow (157.5 gpm) is the maximum flow from the RMWS assuming multiple, simultaneous failures of control valves.

- Conservative estimates of the minimum active RCS water volume are made by excluding the pressurizer and surge line. For CPNPP Unit 1, the active RCS water volume is 11,071.5 ft^3. For CPNPP Unit 2, the active RCS water volume is 9,761.9 ft^3. The difference in Mode 2 active RCS water volume between the two units is due to the different steam generator designs (CPNPP Unit 1 has Δ76 steam generators installed; CPNPP Unit 2 still uses Model D-5 steam generators).

- The reactor trip on source range high flux level alerts the operators that a boron dilution may be in progress.

- The initial boron concentration is assumed to be 2,100 ppm, which is a conservative maximum value for the critical concentration at the condition of hot zero power, with the rods at the insertion limits, and no xenon.

- The critical boron concentration following reactor trip is assumed to be 1,800 ppm, corresponding to hot zero power, all rods inserted (minus the most reactive RCCA), no xenon conditions. The 300 ppm change from the initial condition noted above is a conservative minimum value.

Mode 2 is a transitory operational mode in which the operator intentionally dilutes and withdraws control rods to take the plant critical. During this mode, the plant is in manual control with the operator required to maintain a high awareness of the plant status. For a normal approach to criticality, the operator must manually initiate a limited dilution and withdraw the control rods, a process that takes several hours. The Technical Specifications require that the shutdown margin be determined prior to approaching criticality and to be above the minimum requirement by verifying that the predicted position of the rods is within the rod insertion limits. This ensures that the reactor did not go critical with the control rods below the insertion limits. Once critical, the power escalation must be sufficiently slow to allow the operator to manually block the source range reactor trip (nominally at 10^5 cps) after reaching permissive P-6. Too fast of a power escalation (due to an unknown dilution) would result in reaching P-6 unexpectedly, leaving insufficient time to manually block the source range reactor trip. Failure to perform this manual action results in a reactor trip and immediate shutdown of the reactor.

However, in the event of an unplanned approach to criticality or dilution during power escalation while in Mode 2, the plant status is such that minimal impact will result. The plant will slowly escalate in power to a reactor trip on the power range neutron flux low setpoint. After reactor trip, more than 15 minutes is available for operator action prior to return to criticality. Mode 2 results are summarized in Table 2.5.5-1.

Dilution During Mode 1 – In this mode, the plant can be operated in either automatic or manual rod control. With the reactor in manual control and no operator action taken to terminate the transient, the power and temperature rise will cause the reactor to reach the power range high neutron flux trip setpoint or the overtemperature N-16 trip setpoint, resulting in a reactor trip. In this case, the boron dilution transient up to the time of trip is essentially equivalent to an uncontrolled RCCA bank withdrawal at power. Following reactor trip, there is at least 15 minutes prior to criticality. This is sufficient time for the operator to determine the cause of dilution and isolate the reactor makeup water source before the available shutdown margin is lost.

With the reactor in automatic rod control, the power and temperature increase from the boron dilution results in insertion of the control rods and a decrease in the available shutdown margin. As the dilution and rod insertion continue, the rod insertion limit alarms (low and low-low settings) and axial flux difference alarm alert the operator at least 15 minutes prior to criticality that a dilution is in progress and that the Technical Specification requirement for shutdown margin may be challenged. This is sufficient time to determine the cause of dilution and isolate the reactor makeup water source before the available shutdown margin is lost.

The effective reactivity addition rate is primarily a function of the dilution rate, boron concentration, and boron worth. The following conditions are assumed for an uncontrolled boron dilution during full power:

- The assumed dilution flow (157.5 gpm) is the maximum flow from the RMWS assuming multiple, simultaneous failures of control valves.

- Conservative estimates of the minimum active RCS water volume are made by excluding the pressurizer and surge line. For CPNPP Unit 1, the active RCS water volume is 11,071.5 ft^3. For CPNPP Unit 2, the active RCS water volume is 9,761.9 ft^3. The difference in Mode 1 active RCS water volume between the two units is due to the different steam generator designs (CPNPP Unit 1 has Δ76 steam generators installed; CPNPP Unit 2 still uses Model D-5 steam generators).

- The reactor trip on high flux level or the overtemperature N-16 alerts the operators that a boron dilution may be in progress.

- The initial boron concentration is assumed to be 2,100 ppm, which is a conservative maximum value for the initial concentration at the condition of hot full power, with the rods at the insertion limits, and no xenon.

- The critical boron concentration following reactor trip is assumed to be 1,800 ppm, corresponding to the hot zero power, all rods inserted (minus the most reactive RCCA), no xenon condition. The 300 ppm change from the initial condition noted above is a conservative minimum value.

- A 1.3-percent minimum shutdown margin is assumed in the analysis.

- Bounding boron worths of -15 and -5 pcm/ppm are conservatively considered. The larger absolute value maximizes the reactivity insertion rate, while the smaller absolute value minimizes the reactivity insertion rate thereby delaying the time to reach the reactor trip setpoint.

2.5.5.1.4 Results

The boron dilution analysis demonstrated that all applicable acceptance criteria are met for CPNPP Units 1 and 2. This means that operator action to terminate the dilution flow within 15 minutes from operator notification from Modes 1, 2, 3, 4 and 5 precludes a complete loss of shutdown margin. The results of the boron dilution analysis are provided in Table 2.5.5-1.

No analysis is presented for Mode 6 operation since dilution during refueling is precluded by administrative controls.

If an unintentional dilution of boron in the RCS does occur, numerous alarms and indications are available to alert the operator to the condition. The maximum reactivity addition due to the dilution is slow enough to allow the operator sufficient time to determine the cause of the

addition and take corrective action before shutdown margin is lost. The acceptance criteria as specified in subsection 2.5.5.1.2 are met.

2.5.5.2 Conclusion

A review of the analyses of the decrease in boron concentration in the reactor coolant due to a CVCS malfunction has been conducted. It is concluded that the analyses have adequately accounted for plant operation at the proposed uprated power level and were performed using acceptable analytical models. It is further concluded that the analyses demonstrate that the reactor protection and safety systems will continue to ensure that the specified acceptable fuel design limits and the RCPB pressure limits will not be exceeded as a result of the decrease in boron concentration events. Based on this, Luminant Power has concluded that CPNPP Units 1 and 2 will continue to meet the requirements of GDCs -10, -15, and -26.

2.5.5.3 References

1. RXE-94-001-A, "Safety Analysis of the Postulated Inadvertent Boron Dilution Event in Modes 3, 4, and 5," February 1994.

Table 2.5.5-1 CVCS Malfunction Boron Dilution Event Results		
Operating Mode	**Available Operator Action Time (minutes)**	**Limit (minutes)**
Mode 1 – Manual Rod Control	Unit 1: 54.6 Unit 2: 48.2	15
Mode 1 – Automatic Rod Control	Unit 1: 56.5 Unit 2: 49.8	15
Mode 2	Unit 1: 59.5 Unit 2: 52.5	15
Mode 3	The maximum critical boron concentration is controlled as a function of the plant initial boron concentration to meet a minimum operator action time of 15 minutes	15
Mode 4		15
Mode 5 – Drained		15
Mode 5 – Filled		15
Mode 6	N/A(1)	

Note:

1. No analysis is presented for Mode 6 operation since boron dilution during refueling is precluded by the Technical Specifications requirements.

2.5.6 Spectrum of Rod Ejection Accidents

2.5.6.1 Technical Evaluation

The criterion applied to ensure the core remains in a coolable geometry following a rod ejection incident is that the average fuel pellet enthalpy at the hot spot must remain less than 200 cal/gm (360 Btu/lbm). The use of the initial conditions presented in Table 2.5.6-1 resulted in conservative calculations of the fuel pellet enthalpy. The results of the licensing basis analyses demonstrated that the fuel pellet enthalpy does not exceed 360 Btu/lbm for any of the rod ejection cases analyzed.

Overpressurization of the RCS during a rod ejection event is generically addressed in WCAP-7588, Revision 1-A (Reference 1)

Another applicable acceptance criterion is that fuel melting must be limited to less than the innermost 10 percent of the fuel pellet at the hot spot, even if the average fuel pellet enthalpy at the hot spot is less than the limit of 360 Btu/lbm. Conservative fuel melt temperatures of 4,900° and 4,800°F were assumed for the hot spot for the beginning-of-life (BOL) and end-of-life (EOL) cases, respectively. These fuel melting temperatures correspond to a specific burnup limit at the hot spot. The peak UO_2 burnup at the hot spot is based on the assembly with the maximum post-ejection F_Q, which is typically a fresh fuel assembly. Therefore, the fuel melting temperatures represent bounding values for the assumed UO_2 burnup at the hot spot. The maximum burnup at the hot spot at BOL and EOL is confirmed to be below these values as part of the reload process. This assumption does not affect the maximum licensed fuel burnup limit. The results of the licensing basis rod ejection analyses demonstrated that the amount of fuel melting was limited to less than 10 percent of the fuel pellet at the hot spot for each of the rod ejection cases.

2.5.6.1.1 Introduction

This accident is defined as a mechanical failure of a CRDM pressure housing resulting in the ejection of the RCCA and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage. The resultant core thermal power excursion is limited by the Doppler reactivity effect of the increased fuel temperature and terminated by reactor trip actuated by high nuclear power signals.

A failure of a CRDM housing sufficient to allow a control rod to be rapidly ejected from the core is not considered credible for the following reasons:

- Each full-length CRDM housing is completely assembled and shop tested at 4,100 psig.
- The mechanism housings are individually hydrotested after they are attached to the head adapters in the reactor vessel head and checked during the hydrotest of the completed RCS.

- Stress levels in the mechanism are not affected by anticipated system transients at power or by the thermal movement of the coolant loops. Moments induced by the design earthquake can be accepted within the allowable primary working stress ranges specified in the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, for Class I components.

- The latch mechanism housing and rod travel housing are each a single length of forged type-304 stainless steel. This material exhibits excellent notch toughness at all temperatures that will be encountered.

A significant amount of margin of strength in the elastic range, together with the large energy absorption capability in the plastic range, gives additional assurance that the gross failure of the housing will not occur. The joints between the latch mechanism housing and rod housing are threaded joints reinforced by canopy-type rod welds.

In general, the reactor is operated with the RCCAs inserted only far enough to permit load follow. Reactivity changes caused by the core depletion are compensated by boron changes. Furthermore, the location and grouping of control rod banks are selected during the nuclear design to lessen the severity of an RCCA ejection accident. Therefore, if an RCCA is ejected from its normal position during full-power operation, only a minor reactivity excursion, at worst, could be expected to occur. The position of all of the RCCAs is continuously indicated in the Control Room. An alarm will occur if a bank of RCCAs approaches its insertion limit or if one control rod assembly deviates from its bank. There are low and low-low level insertion alarm circuits for each bank. The control rod position monitoring and alarm systems are described in WCAP-7588 (Reference 1).

2.5.6.1.2 Input Parameters, Assumptions, and Acceptance Criteria

Input parameters for the analysis were conservatively selected on the basis of values calculated for this type of core. The most important parameters are discussed below. Table 2.5.6-1 presents the parameters used in this analysis.

Ejected Rod Worths and Hot Channel Factors

The values for the ejected rod worths and hot channel factors were calculated using either 3-D static methods or a synthesis of 1-D and 2-D calculations. Standard nuclear design codes were used in the analysis. No credit was taken for the flux-flattening effects of reactivity feedback. The calculation was performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. The analysis assumed adverse xenon distributions to provide worst-case results.

Appropriate margins were added to the ejected rod worth and hot channel factors to account for any calculational uncertainties.

Delayed Neutron Fraction, β_{eff}

Calculations of the effective delayed neutron fraction (β_{eff}) typically yield values of approximately 0.75 percent at BOL and 0.40 percent at EOL. The ejected rod accident is sensitive to βeff if the ejected rod worth is equal to or greater than βeff, as in the zero-power transients. In order to allow for future fuel cycle flexibility, conservative estimates of βeff of 0.55 percent at beginning of cycle and 0.44 percent at end of cycle were used in the analysis.

Reactivity Weighting Factor

The largest temperature rises, and therefore the largest reactivity feedbacks, occur in channels where the power is higher than average. Since the weight of a region is dependent on flux, these regions have high weights. This means that the reactivity feedback is larger than that indicated by a simple channel analysis. Physics calculations have been carried out for temperature changes with a flat temperature distribution, and with a large number of axial and radial temperature distributions.

Reactivity changes were compared and effective weighting factors determined. These weighting factors take the form of multipliers which, when applied to single-channel feedbacks, correct them to effective whole-core feedbacks for the appropriate flux shape. In this analysis, a 1-D (axial) spatial kinetics method was employed. Therefore, axial weighting is not necessary if the initial condition is made to match the ejected rod configuration. In addition, no weighting was applied to the moderator feedback. A conservative radial weighting factor was applied to the transient fuel temperature to obtain an effective fuel temperature as a function of time accounting for the missing spatial dimension. These weighting factors have also been shown to be conservative compared to 3-D analysis.

Moderator and Doppler Coefficient

The critical boron concentrations at BOL and EOL were adjusted in the nuclear code in order to obtain moderator density coefficient curves that were conservative when compared to the actual design conditions for the plant. As discussed above, no weighting factor was applied to these results. The MTCs that were modeled are +5 pcm/°F at zero-power nominal T_{avg} and 0 pcm/°F at full-power T_{avg} for the BOL cases. For the EOL cases the applicable zero-power MTC was -16.817 pcm/°F and the full-power MTC was -22.920 pcm/°F.

The Doppler reactivity defect as a function of power level was adjusted in the nuclear code to a conservative design value using a Doppler weighting factor of 1.0. The Doppler weighting factor was increased under accident conditions, as discussed above.

Heat Transfer Data

The FACTRAN code (Reference 3), used to determine the hot spot transient, contains standard curves of thermal conductivity versus fuel temperature. During the transient, the peak centerline fuel temperature is nearly independent of the gap conductance. The cladding temperature is, however, strongly dependent on the gap conductance and is highest for high gap conductance.

For conservatism, a low initial gap heat transfer coefficient was used at the beginning of the transient to maximize the initial fuel temperature, and a high gap heat transfer coefficient value of 10,000 Btu/hr-ft^2 was used for the remainder of the transient to maximize the cladding temperature. This high gap heat transfer coefficient corresponds to a negligible gap resistance, and a further increase would have essentially no effect on the rate of heat transfer.

Coolant Mass Flow Rates

When the core is operating at full power, all four coolant pumps are always operational. For zero power conditions, the system was conservatively assumed to be operating with two pumps. The principal effect of operating at reduced flow is to reduce the film boiling heat transfer coefficient. This resulted in higher peak cladding temperatures, but did not affect the peak centerline fuel temperature. Reduced flow also lowers the critical heat flux. However, since DNB was always assumed at the hot spot, and since the heat flux rose very rapidly during the transient, this produced only second-order changes in the cladding and centerline fuel temperatures.

Trip Reactivity Insertion

The trip reactivity insertion was assumed to be 4.0 percent Δk from HFP and 2.0 percent Δk from HZP, including the effect of one stuck RCCA. These values were also reduced by the ejected rod reactivity. The shutdown reactivity was simulated by dropping a rod of the required worth into the core. The start of rod motion occurred 0.5 seconds after reaching the power range high neutron flux trip setpoint. It was assumed that insertion to dashpot did not occur until 2.7 seconds after the rods began to fall. The time delay to full insertion, combined with the 0.5 second trip delay, conservatively delayed insertion of shutdown reactivity into the core.

Due to the extremely low probability of an RCCA ejection accident, this event is classified as a Condition IV event as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. As such, some fuel damage is considered an acceptable consequence.

The real physical limits of this accident are that the rod ejection event and any consequential damage to either the core or the RCS must not prevent long-term core cooling. More specific and restrictive criteria are applied to ensure that there is no fuel dispersal in the coolant and that gross lattice distortion or severe shock waves do not occur. In view of the above experimental results and the conclusions of WCAP-7588, Revision 1-A (Reference 1), the applied criteria are:

- Average fuel pellet enthalpy at the hot spot must remain below 200 cal/gm for irradiated fuel. This bounds non-irradiated fuel which has a slightly higher enthalpy limit.

- Peak reactor coolant pressure must be less than that which could cause RCS stresses to exceed the faulted-condition stress limits (Note: the peak pressure aspects of the rod ejection transient are addressed generically in Reference 1).

- Fuel melting is limited to less than the innermost 10 percent of the pellet volume at the hot spot even if the average fuel pellet enthalpy at the hot spot is below the 200 cal/gm fuel enthalpy limit.

2.5.6.1.3 Description of Analyses and Evaluations

This section describes the models used in the analysis of the rod ejection accident. Only the initial few seconds of the power transient are discussed, since the long-term considerations are the same as those for a small LOCA.

The calculation of the RCCA ejection transient was performed in two stages: first an average core channel calculation, and then a hot spot calculation. The average core calculation used spatial neutron-kinetics methods to determine the average power generation with time including the various total core feedback effects, that is, Doppler reactivity and moderator reactivity. Enthalpy and temperature transients at the hot spot were then determined by multiplying the average core energy generation by the hot channel factor and performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback was conservatively assumed to continue throughout the transient. A detailed discussion of the method of analysis can be found in Reference 1.

Average Core

The spatial-kinetics computer code TWINKLE (Reference 3) was used for the average core transient analysis. This code solves the two-group neutron diffusion theory kinetic equation in one, two, or three spatial dimensions (rectangular coordinates) for six delayed neutron groups and up to 2,000 spatial points. The computer code includes a detailed, multi-region, transient fuel-clad-coolant heat transfer model for calculation of pointwise Doppler and moderator feedback effects. This analysis used the code as a 1-D axial kinetics code since it allows a more realistic representation of the spatial effects of axial moderator feedback and RCCA movement. However, since the radial dimension was missing, it was still necessary to employ very conservative methods (described below) of calculating the ejected rod worth and hot channel factor.

Hot Spot Analysis

In the hot spot analysis, the initial heat flux is equal to the nominal heat flux times the design hot channel factor. During the transient, the heat flux hot channel factor is linearly increased to the transient value in 0.1 second, the time for full ejection of the rod. Therefore, the assumption is made that the hot spot before and after ejection are coincident. This is very conservative since the peak after ejection will occur in or adjacent to the assembly with the ejected rod, and prior to ejection the power in this region will necessarily be depressed.

The average core energy addition, calculated as described above, was multiplied by the appropriate hot channel factors. The hot spot analysis used the detailed fuel and cladding transient heat transfer computer code FACTRAN (Reference 2). This computer code calculates the transient temperature distribution in a cross section of a metal clad UO_2 fuel rod, and the

heat flux at the surface of the rod, using the nuclear power versus time and local coolant conditions as input. The zirconium-water reaction is explicitly represented, and all material properties are represented as functions of temperature. A parabolic radial power distribution was assumed within the fuel rod.

FACTRAN uses the Dittus-Boelter or Jens-Lottes correlation to determine the film heat transfer before DNB, and the Bishop-Sandberg-Tong correlation (Reference 4) to determine the film boiling coefficient after DNB. The Bishop-Sandberg-Tong correlation was conservatively used assuming zero bulk fluid quality. The DNB heat flux was not calculated. Instead, the code was forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient could be calculated by the code. However, it was adjusted to force the full-power, steady-state temperature distribution to agree with fuel heat transfer design codes.

Reactor Protection

The protection for this accident, as explicitly modeled in the analysis, is provided by the power range high neutron flux trip (high and low settings). The power range high neutron flux positive rate trip complements the high and low flux trip functions to ensure that the criteria are met for rod ejection from partial power.

2.5.6.1.4 Spectrum of Rod Ejection Accidents Results

The results of the analyses performed for the rod ejection event, which cover BOL and EOL conditions at hot full power and HZP for both CPNPP Units 1 and 2, are discussed below.

Beginning of Cycle, Zero Power

The worst ejected rod worth and hot channel factor were conservatively calculated to be 0.75-percent Δk and 11.0-percent Δk, respectively. The peak hot spot average fuel pellet enthalpy reached 205.7 Btu/lbm (114.3 cal/gm). The peak fuel centerline temperature never reached the BOL melt temperature of 4,900°F. Therefore, no fuel melting is predicted.

Beginning of Cycle, Full Power

Control bank D was assumed to be inserted to its insertion limit. The worst ejected rod worth and hot channel factor were conservatively calculated to be 0.24-percent Δk and 5.5-percent Δk, respectively. The peak hot spot average fuel pellet enthalpy reached 290.9 Btu/lbm (161.6 cal/gm). The peak fuel centerline temperature reached the BOL melt temperature of 4,900°F. However, fuel melting remained well below the limiting criterion of 10 percent of total pellet volume at the hot spot.

End of Cycle, Zero Power

The worst ejected rod worth and hot channel factor were conservatively calculated to be 0.84-percent Δk and 26.0-percent Δk, respectively. The peak hot spot average fuel pellet

enthalpy reached 250.0 Btu/lbm (138.9 cal/gm). The peak fuel centerline temperature never reached the EOL melt temperature of 4,800°F. Therefore, no fuel melting is predicted.

End of Cycle, Full Power

Control bank D was assumed to be inserted to its insertion limit. The ejected rod worth and hot channel factors were conservatively calculated to be 0.25-percent Δk and 6.0-percent Δk, respectively. The peak hot spot average fuel pellet enthalpy reached 283.5 Btu/lbm (157.5 cal/gm). The peak fuel centerline temperature reached the EOL melting temperature of 4,800°F. However, fuel melting remained well below the limiting criterion of 10 percent of total pellet volume at the hot spot.

A summary of the parameters used in the rod ejection analyses, and the analyses results, are presented in Table 2.5.6-1. The sequence of events for all four cases is presented in Table 2.5.6-2. Figure 2.5.6-1 shows the plot results for the BOL/HZP case and Figure 2.5.6-2 shows the BOL/HFP plot results. The EOL/HZP and EOL/HFP plot results are presented in Figures 2.5.6-3 and 2.5.6-4, respectively.

A detailed calculation of the pressure surge for an ejected rod worth of 1 dollar at BOL HFP indicates that the peak pressure did not exceed that which would cause the reactor pressure vessel stress to exceed the faulted condition stress limits (Reference 1). Since the severity of the present analysis did not exceed the worst-case analysis, the accident for this plant will not result in an excessive pressure rise or further adverse effects on the RCS.

2.5.6.1.5 Results

Despite the conservative assumptions, the analyses indicate that the described fuel and cladding limits were not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure did not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no danger of further consequential damage to the RCS. Generic analyses demonstrated that the fission product release as a result of fuel rods entering DNB was limited to less than 10 percent of the fuel rods in the core.

The results and conclusions of the analyses performed for the rupture of a CRDM housing RCCA ejection support operation up to the uprated reactor core power of 3,612 MWt.

2.5.6.2 Conclusion

The Luminant Power review of the analyses of the rod ejection accident concludes that the analyses have adequately accounted for plant operation at the uprated power level and were performed using acceptable analytical models. It is further concluded that appropriate reactor protection and safety systems will prevent postulated reactivity accidents that could result in damage to the RCPB greater than limited local yielding, or cause sufficient damage that would significantly impair the capability to cool the core. Based on this, it has been concluded that the plant will continue to meet the requirements of GDC-28.

2.5.6.3 References

1. WCAP-7588, Rev. 1-A, "An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Special Kinetics Methods," January 1975.

2. WCAP-7908, "FACTRAN, A FORTRAN IV Code for Thermal Transients in a UO_2 Fuel Rod," December 1989.

3. WCAP-7979, "TWINKLE, A Multi-Dimensional Neutron Kinetics Computer Code," January 1975.

4. ASME 65-HT-31, "Forced Convection Heat Transfer at High Pressure After the Critical Heat Flux," August 1965.

Table 2.5.6-1 Parameters and Results of the Limiting RCCA Ejection Analyses				
	Beginning of Cycle	**Beginning of Cycle**	**End of Cycle**	**End of Cycle**
Initial Reactor Core Power Level (MWt)	3,634	0	3,634	0
Ejected Rod Worth (% Δk)	0.24	0.75	0.25	0.84
Delayed Neutron Fraction (%)	0.55	0.55	0.44	0.44
Feedback Reactivity Weighting	1.2927	2.0079	1.3549	3.7649
Trip Reactivity (%Δk)	4.0	2.0	4.0	2.0
FQ Before Rod Ejection	2.50	--	2.50	--
FQ After Rod Ejection	5.5	11.0	6.0	26.0
Number of Operational Pumps	4	2	4	2
Maximum Fuel Pellet Average Temperature (°F)	3,754	2,797	3,674	3,304
Maximum Fuel Centerline Temperature (°F)	4,913	3,270	4,825	3,756
Maximum Cladding Average Temperature (°F)	2,121	2,085	2,073	2,503
Maximum Fuel Stored Energy (cal/gm)	161.6	114.3	157.5	138.9
Maximum Fuel Melt at the Hot Spot (%)	0.04	0.00	0.23	0.00

Table 2.5.6-2 Time Sequence of Events – RCCA Ejection		
Event	Time (sec)	
	BOL HFP	EOL HFP
Initiation of Rod Ejection	0.0	0.0
Power Range High Neutron Flux Setpoint Reached	0.05	0.04
Peak Nuclear Power Occurs	0.13	0.13
Rods Begin to Fall	0.55	0.54
Peak Fuel Average Temperature Occurs	2.25	2.25
Peak Cladding Temperature Occurs	2.30	2.31
	BOL HZP	EOL HZP
Initiation of Rod Ejection	0.0	0.0
Power Range High Neutron Flux Setpoint Reached	0.31	0.19
Peak Nuclear Power Occurs	0.38	0.23
Rods Begin to Fall	0.81	0.69
Peak Fuel Average Temperature Occurs	2.52	1.81
Peak Cladding Temperature Occurs	2.38	1.58

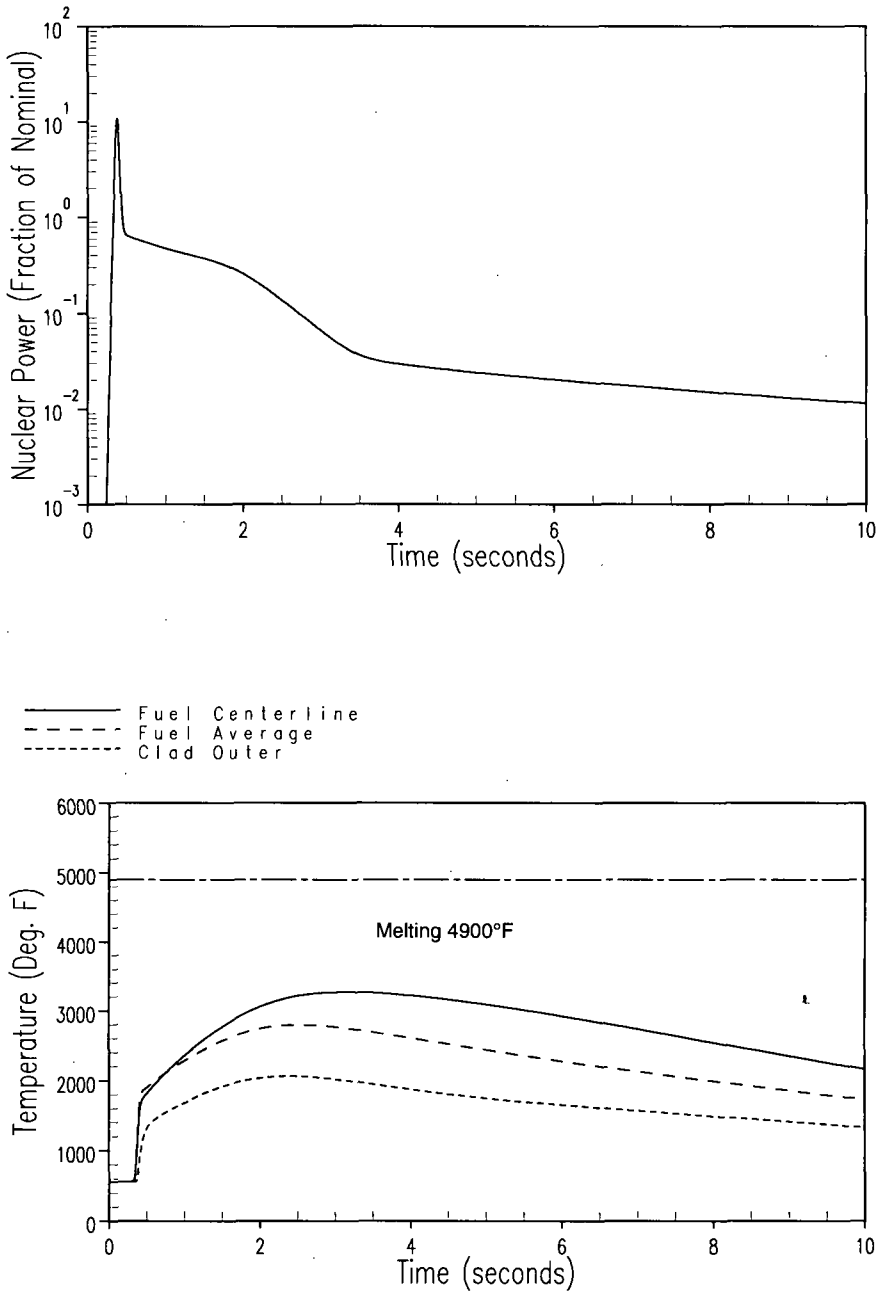
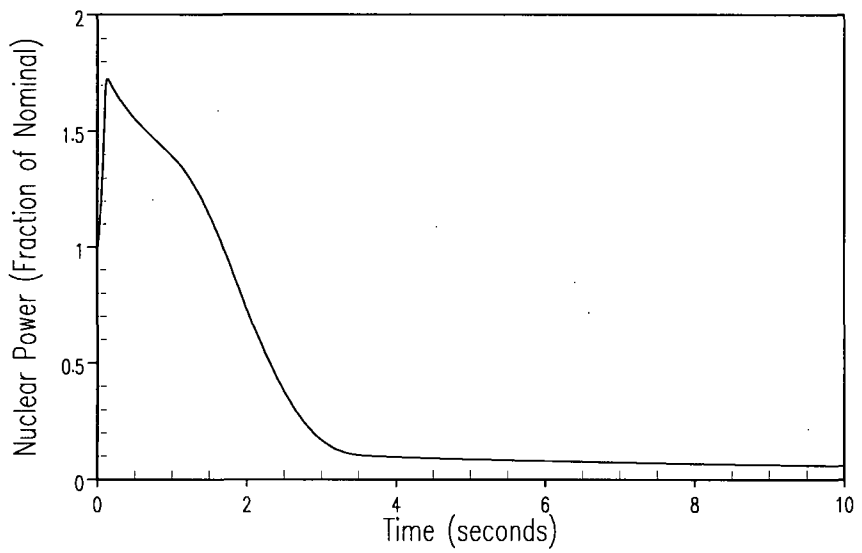


Figure 2.5.6-1 Rod Ejection – BOL/HZP Case



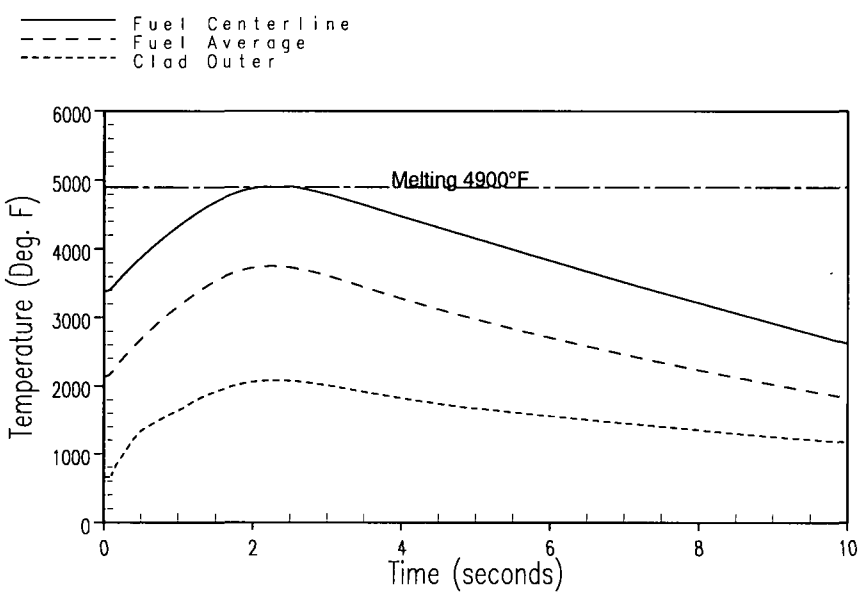
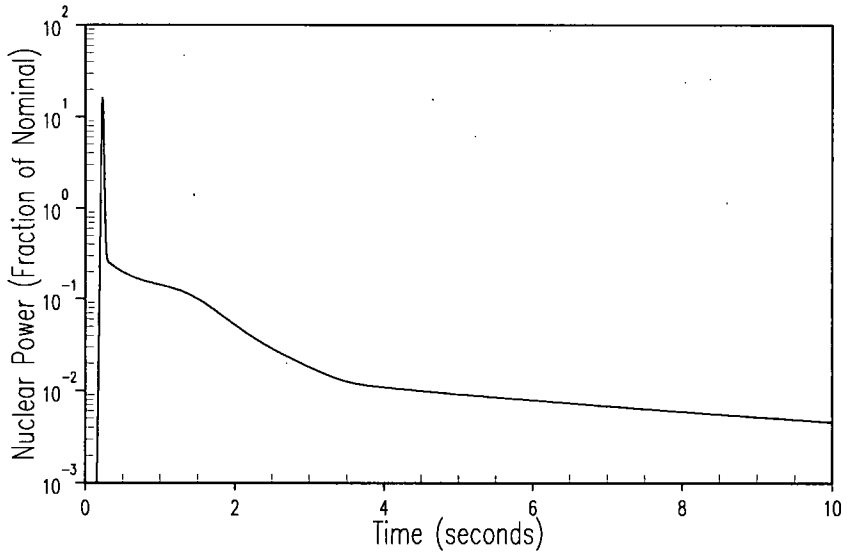


Figure 2.5.6-2 Rod Ejection – BOL/HFP Case



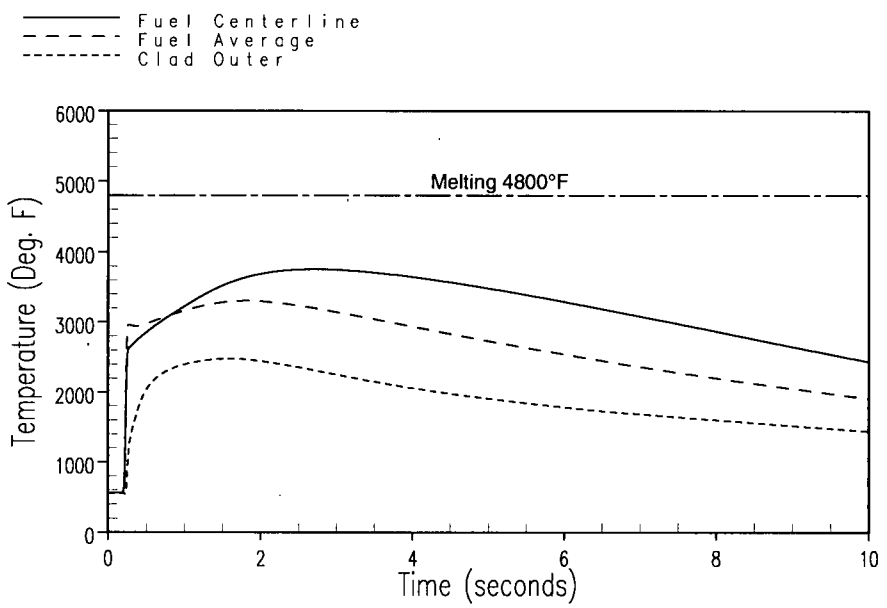
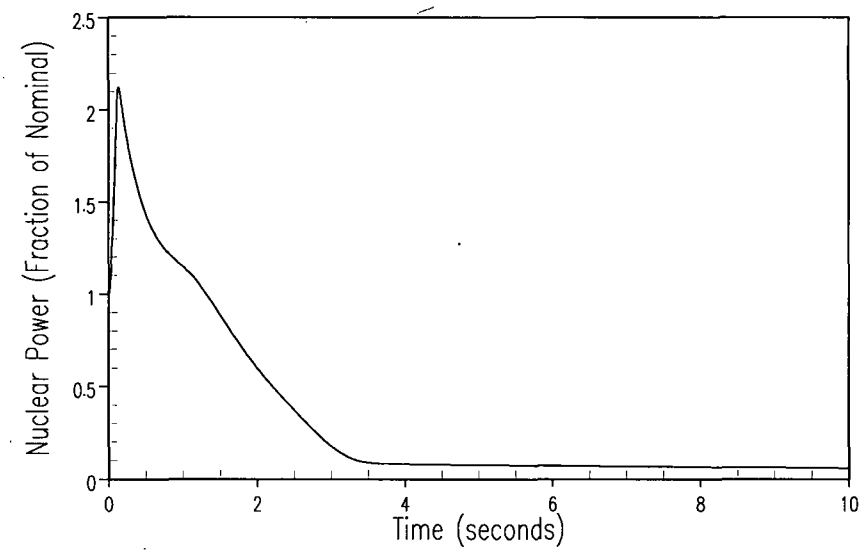


Figure 2.5.6-3 Rod Ejection – EOL/HZP Case



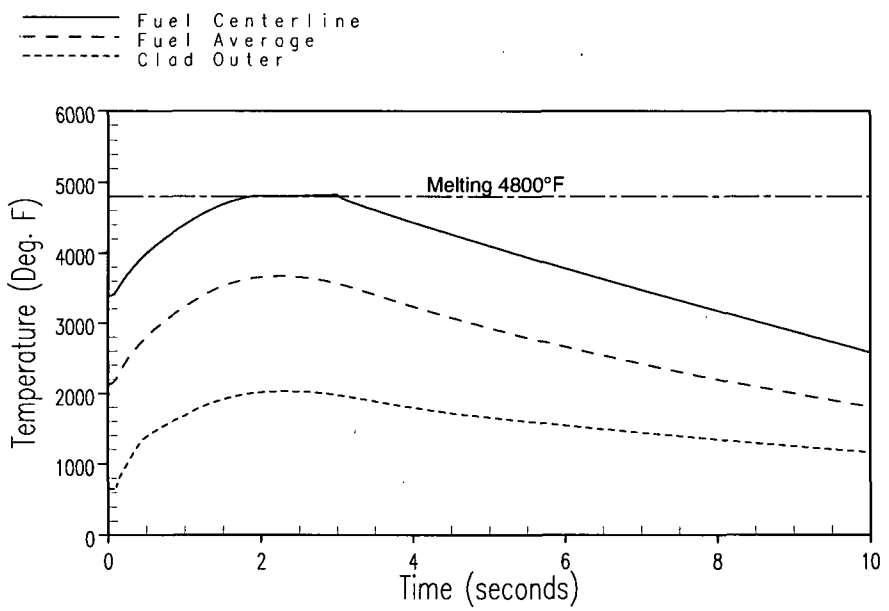


Figure 2.5.6-4 Rod Ejection – EOL/HFP Case

2.6 INADVERTENT OPERATION OF ECCS AND CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTION THAT INCREASES IN REACTOR COOLANT INVENTORY

2.6.1 Technical Evaluation

The following events, which could result in an increase in reactor coolant inventory for a PWR are presented in this section:

1. Inadvertent operation of the ECCS during power operation
2. CVCS malfunction that increases reactor coolant inventory

2.6.1.1 Inadvertent Operation of the Emergency Core Cooling System During Power Operation

2.6.1.1.1 Introduction

An inadvertent actuation of the ECCS at power event results in an increase in RCS inventory leading to the potential filling of the pressurizer. Operator error or a spurious electrical actuating signal could cause the event.

Following the actuation signal, the SI system is actuated, which results in borated water being pumped into the cold leg of each RCS loop. Normally, an SI actuation signal results in an immediate automatic reactor trip, which in turn generates a turbine trip. However, even without an immediate reactor trip, the reactor will experience a negative reactivity excursion as a result of the injected borated water. This negative reactivity results in a decrease in reactor power.

In manual rod control, the primary-to-secondary system power mismatch causes a drop in coolant temperature and a contraction of the reactor coolant. Assuming an immediate reactor trip signal is not received, the RCS responds with a decrease in pressurizer pressure and water level and the turbine load will decrease due to the effect of reduced steam pressure once the turbine throttle valves are fully open. The decrease in RCS pressure results in an increase in SI flow associated with the SI pump performance characteristics.

In automatic rod control, RCCA withdrawal may compensate for the above effects as the control system responds to maintain programmed T_{avg}. Once the rods have been fully withdrawn, the event continues as described for operation in manual rod control.

The inadvertent ECCS actuation at power event is performed to demonstrate that sufficient time is available for the appropriate operator actions to be taken to preclude a pressurizer water-solid condition (and avoid actuation of the pressurizer relief and safety valves). In the design-basis analysis of the inadvertent ECCS transient, operator actions that are credited for the mitigation of the transient are the control of T_{avg} by manually dumping steam through steam generator atmospheric relief valves (ARVs), securing ECCS flow and ultimately, the manual control of the Pressurizer Pressure and Level Control System.

2.6.1.1.2 Input Parameters, Assumptions, and Acceptance Criteria

The following assumptions were made in the inadvertent ECCS analyses:

- An initial NSSS power of 3,628 MWt plus 0.6-percent power uncertainty was assumed.
- A range of the full-power reactor vessel average coolant temperature (T_{avg}) of 585.4° to 589.2°F was considered in the analysis.
- The initial pressurizer water level is assumed to be 65-percent level span (the programmed full-power value of 60 percent plus 5-percent span uncertainty). A high initial pressurizer water level minimizes the initial margin to a water-solid pressurizer condition.
- The initial pressurizer pressure is assumed to be 2,220 psia (the nominal value of 2,250 psia minus 30 psi uncertainty). A lower initial RCS pressure allows a higher ECCS flow.
- The pressurizer heaters and sprays are assumed to function because their operation generates a more limiting condition with respect to filling the pressurizer.
- An immediate reactor trip on the SI actuation signal and a turbine trip derived from the reactor trip are assumed because this limits the primary-to-secondary heat transfer rate, thus minimizing the magnitude of the initial reactor coolant shrinkage.
- The first operator action assumed is the initiation of an RCS cooldown a no-load temperature of 557°F. This is modeled by the opening of three of the four steam generator atmospheric relief valves within 7 minutes and 30 seconds after the event initiation to control T_{avg} to the no-load temperature of 557°F. (The valves' stroke times are included in the analysis.).
- The operators are then assumed to secure ECCS within 13 minutes after the event initiation.

Based on its frequency of occurrence, the inadvertent ECCS accident is considered a Condition II event as defined by the ANS. The following items summarize the acceptance criteria associated with this event:

- Fuel cladding integrity is maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR safety analysis limit.
- Pressures in the RCS and MSS are maintained below 110 percent of the design pressures.
- An incident of moderate frequency does not generate a more serious plant condition without other faults occurring independently.

With respect to the overpressure evaluation, the inadvertent ECCS actuation at power event is bounded by the loss of load/turbine trip (LOL/TT) event, discussed in subsection 2.3.1, in which assumptions are made to conservatively maximize the RCS and MSS pressure transients. For the inadvertent ECCS actuation at power event, turbine trip occurs following reactor trip, whereas for the LOL/TT event, the turbine trip is the initiating fault. Therefore, the primary-to-secondary power mismatch and resultant RCS and MSS heatup and pressurization transients are always more severe for the LOL/TT event. For this reason, it is not necessary to calculate the maximum RCS or MSS pressures for the inadvertent ECCS actuation at power event.

This event is non-limiting with respect to DNB since the conditions resulting from injecting borated water into the RCS are beneficial with respect to DNB. Depending on the control systems in operation, core power and RCS temperatures either remain near the initial nominal conditions or decrease during this event. The RCS flow remains constant throughout the event. A decrease in RCS pressure is the only condition that may occur which would adversely affect DNB. However, for the decrease in RCS pressure that may occur, the effects are more than offset by significant reduction in the power and temperature. The net effect is a DNBR that remains near the initial DNBR or increases throughout the event.

The major concern from an inadvertent ECCS actuation at power event is the potential to violate the ANS Condition II acceptance criterion where an incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently. The pressurizer water volume increases for this event as a result of the continuous safety injection flow. Operator actions are required to initiate the opening of the ARVs, and to control filling of the pressurizer, thus demonstrating that this ANS Condition II event does not propagate to a more serious plant condition. This event is analyzed to demonstrate that sufficient time is available for the appropriate operator actions to be taken to preclude a pressurizer water-solid condition.

2.6.1.1.3 Description of Analyses and Evaluations

The inadvertent ECCS at power event was analyzed using the RETRAN computer code (Reference 1). The RETRAN computer code is a digital computer code, developed to simulate transient behavior in light water reactor systems. The main features of the code include a point kinetics and one-dimensional kinetics model, one-dimensional homogeneous equilibrium mixture thermal-hydraulic model, control system models, two-phase natural convection heat transfer correlations and non-equilibrium pressurizer model. The code computes pertinent plant variables including temperatures, pressures and power level.

2.6.1.1.4 Results

Table 2.6-1 presents the sequence of events for the Unit 1 analysis; Table 2.6-2 presents the sequence of events for the Unit 2 analysis. Figures 2.6-1 through 2.6-3 show the transient behavior of the most pertinent plant parameters for Unit 1; Figures 2.6-4 through 2.6-6 show the transient behavior of the most pertinent plant parameters for Unit 2. Reactor trip occurs at the event initiation followed by a rapid cooldown of the RCS. The initial coolant contraction results in a short-term reduction in pressurizer pressure and water level. The combination of the RCS heatup, due to residual RCS heat generation, and ECCS injected flow causes an increase in the rate of pressurizer filling. At 7 minutes and 30 seconds (after event initiation), the first operator action is assumed to cool the RCS to a no-load temperature of 557°F. This is modeled by the opening of three of the four ARVs to control T_{avg} to the no-load temperature of 557°F. This results in a cooldown of the secondary side, and a subsequent cooldown of the primary side resulting in a shrink of the RCS fluid. At 13 minutes (after event initiation), it is assumed operators effectively control the pressurizer from filling. This is modeled by terminating all sources of safety injection flow coincident with turning off the pressurizer heaters.

2.6.1.2 Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory

An increase in reactor coolant inventory that results from the addition of cold, unborated water to the RCS is analyzed in subsection 2.5.5, CVCS malfunction that results in a decrease in boron concentration in the reactor coolant. The analysis of the inadvertent operation of the ECCS during power operation (Section 2.6) bounds the CVCS malfunction that results in an increase in reactor coolant inventory.

2.6.2 Conclusion

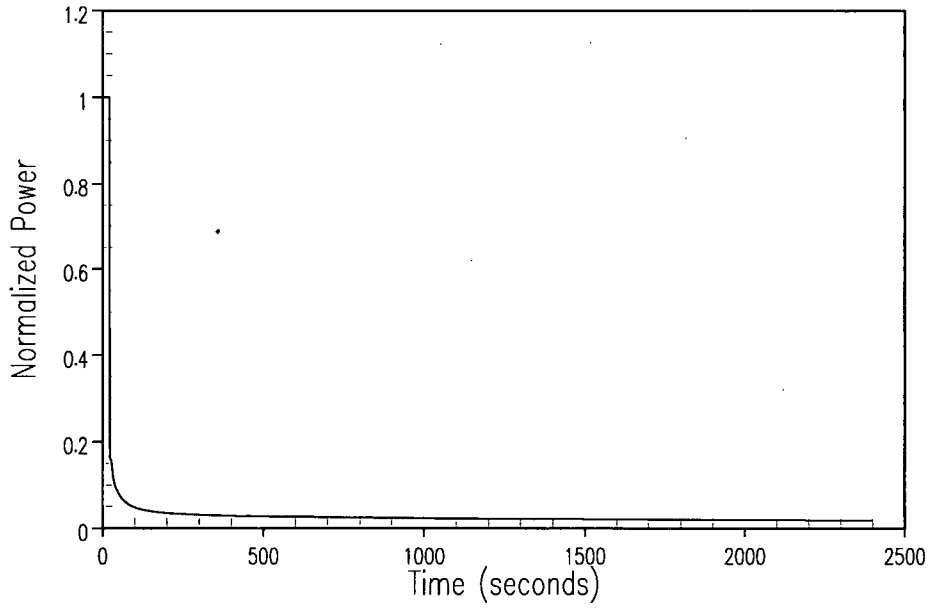
The analysis of the inadvertent ECCS at power event has been reviewed and Luminant Power has concluded that the analyses have adequately accounted for operation of the plant at the uprated power level and were performed using acceptable analytical models. The evaluation demonstrates that the reactor protection and safety systems will ensure that the specified acceptable fuel design limits are met and the reactor coolant pressure boundary pressure limits will not be exceeded as a result of the inadvertent ECCS event. Based on this, it is concluded that the plant will continue to meet the requirements of GDCs -10, -15, and -26.

2.6.3 References

1. WCAP-14882 and WCAP-15234, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999 and May 1999, respectively.

Table 2.6-1 Time Sequence of Events – Unit 1 Inadvertent ECCS	
Event	**Time into Transient (seconds)**
Inadvertent SI Actuation	0.0
Reactor Trip due to SI Actuation	0.0
Turbine Trip from Reactor Trip	0.0
MSSV Actuation	58.1
Operator initiates action to control T_{avg} to no-load temperature of 557°F (modeled by opening 3 of 4 ARVs)	450.0
Maximum Pressurizer Water Volume Reached	468.0
ARVs Are Fully Opened (model)	490.0
SI Injection Terminated (Operator Action) and Heaters Turned Off (modeled)	780.0
End of Transient	2,380.0

Table 2.6-2 Time Sequence of Events – Unit 2 Inadvertent ECCS	
Event	**Time into Transient (seconds)**
Inadvertent SI Actuation	0.0
Reactor Trip due to SI Actuation	0.0
Turbine Trip from Reactor Trip	0.0
MSSV Actuation	80.1
Operator initiates action to control T_{avg} to no-load temperature of 557°F (modeled by opening 3 of 4 ARVs)	450.0
ARVs Are Fully Opened	490.0
SI Injection Terminated (Operator Action) and Heaters Turned Off (modeled)	780.0
Maximum Pressurizer Water Volume Reached	788.0
End of Transient	2,380.0



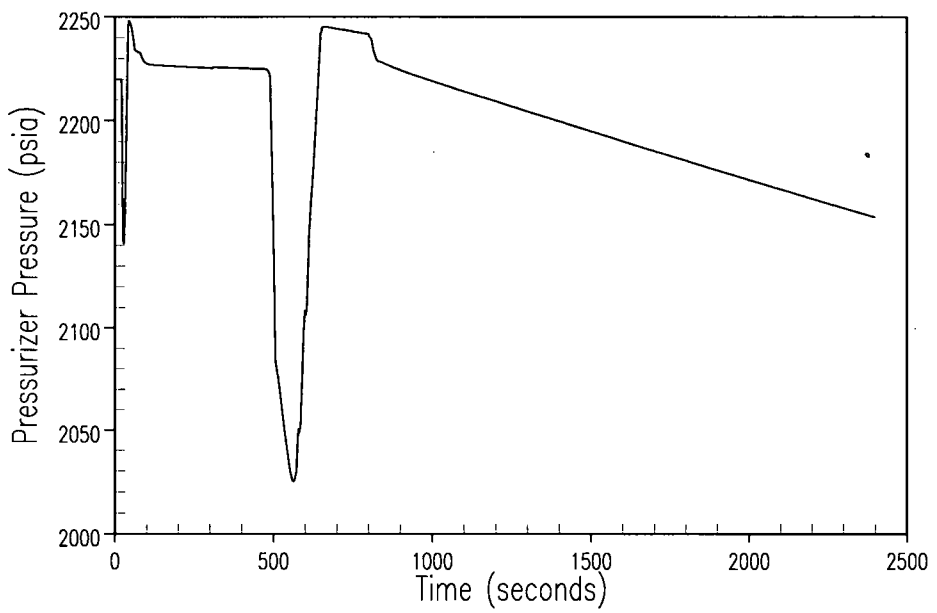
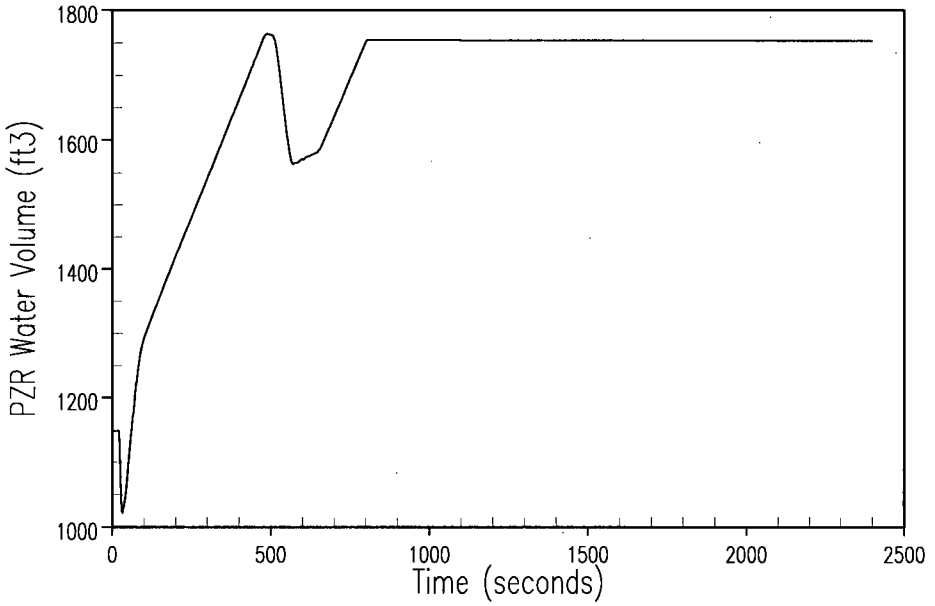


Figure 2.6-1 Unit 1 Inadvertent ECCS Power and Pressurizer Pressure Versus Time



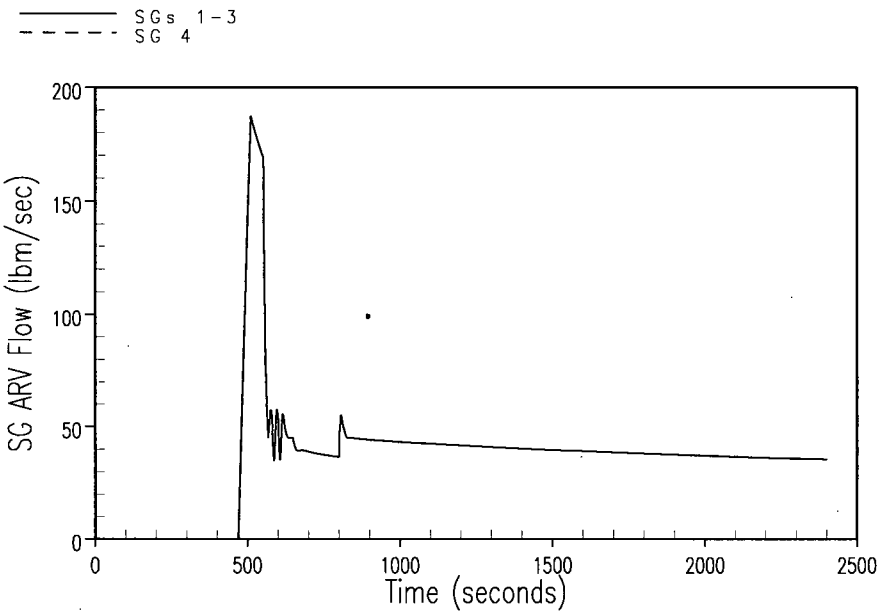
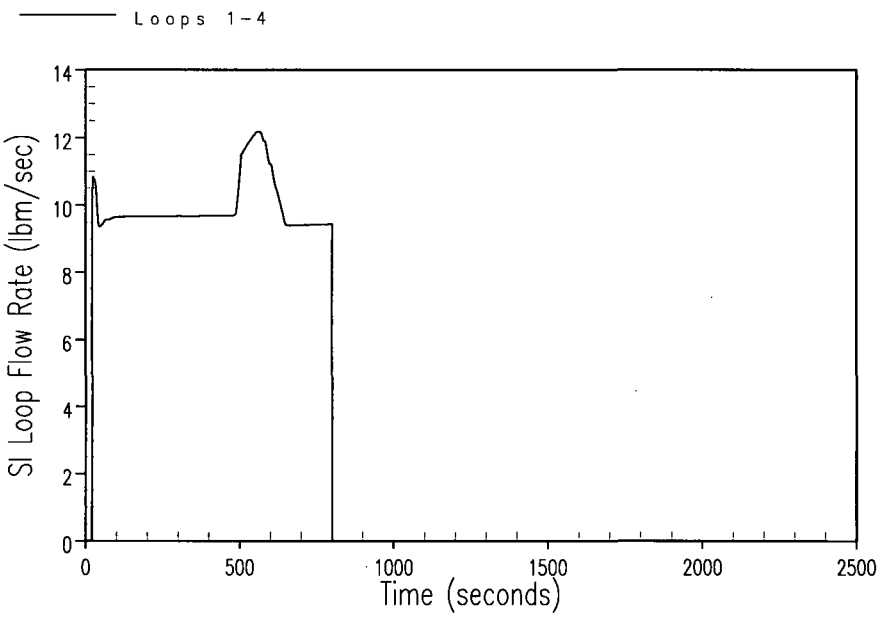


Figure 2.6-2 Unit 1 Inadvertent ECCS Pressurizer Volume and ARV Flow Rate Versus Time



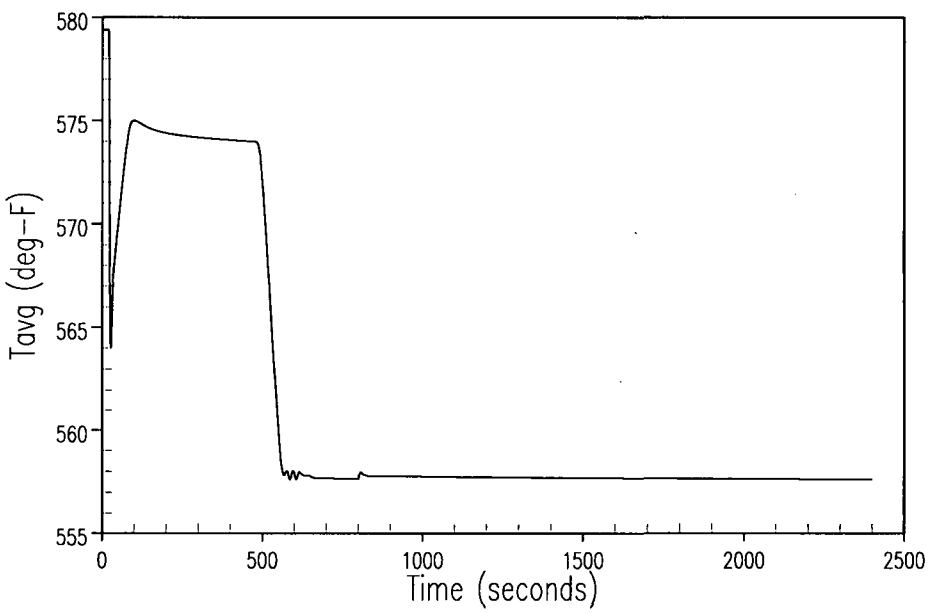
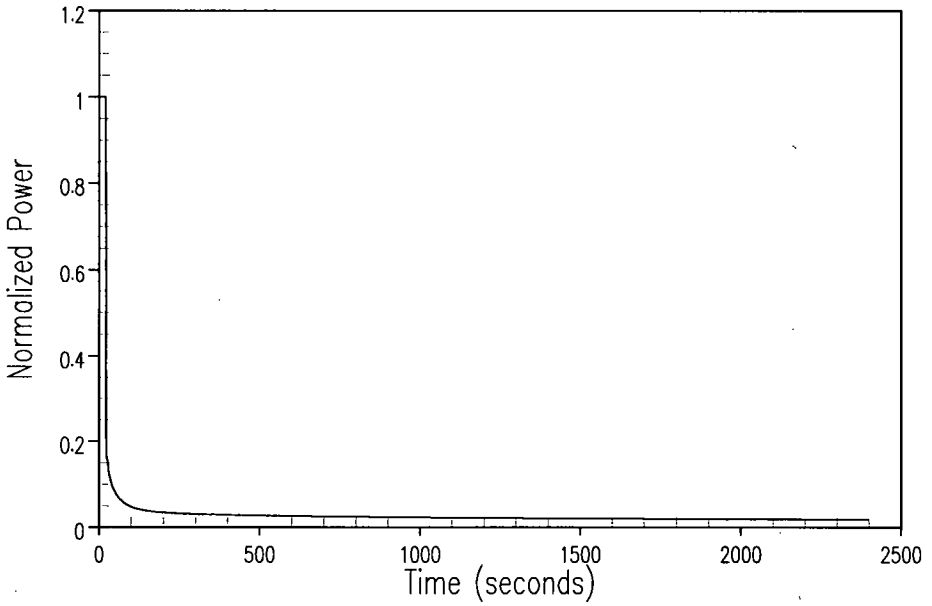


Figure 2.6-3 Unit 1 Inadvertent ECCS SI Flow Rates and RCS Average Temperature Versus Time



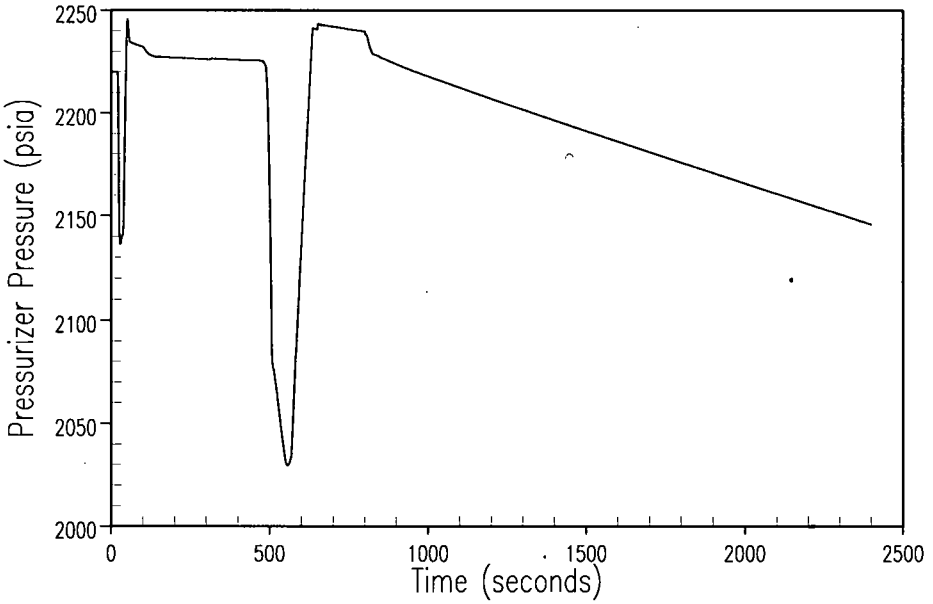
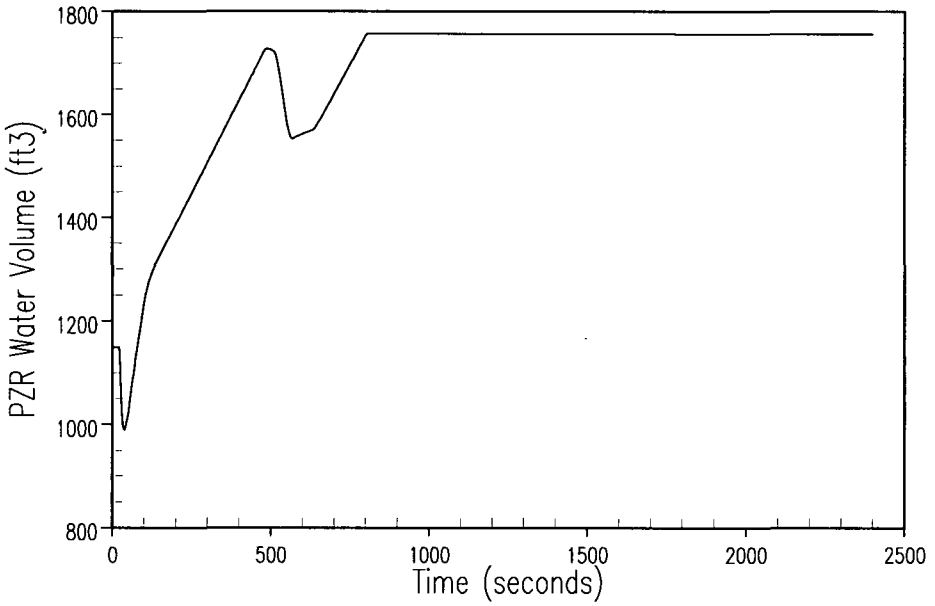


Figure 2.6-4 Unit 2 Inadvertent ECCS Power and Pressurizer Pressure Versus Time



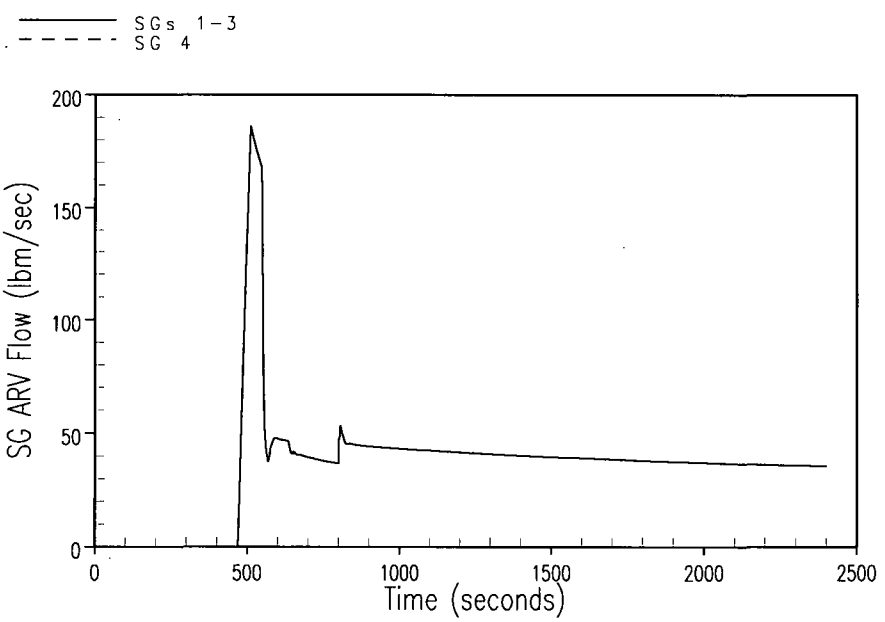
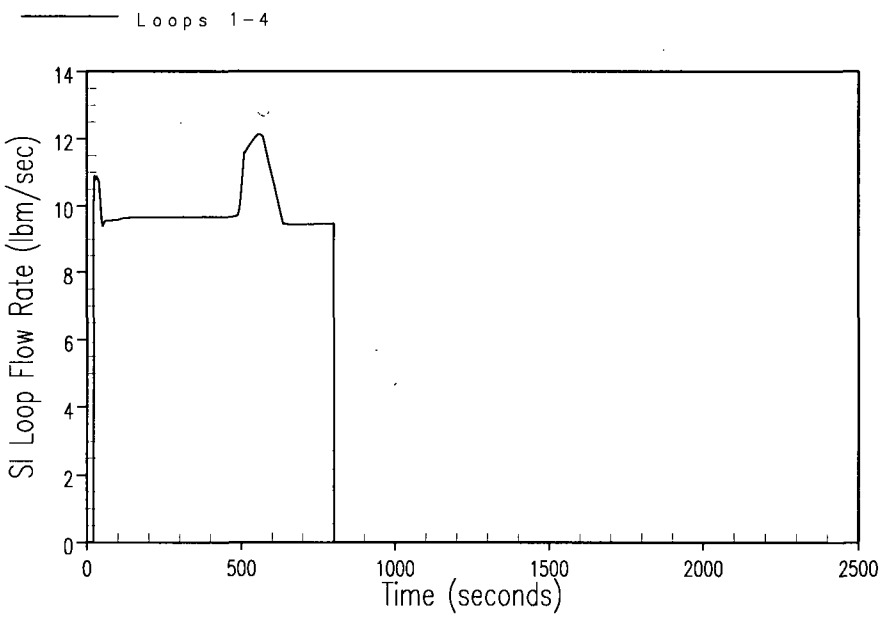


Figure 2.6-5 Unit 2 Inadvertent ECCS Pressurizer Volume and ARV Flow Rate Versus Time



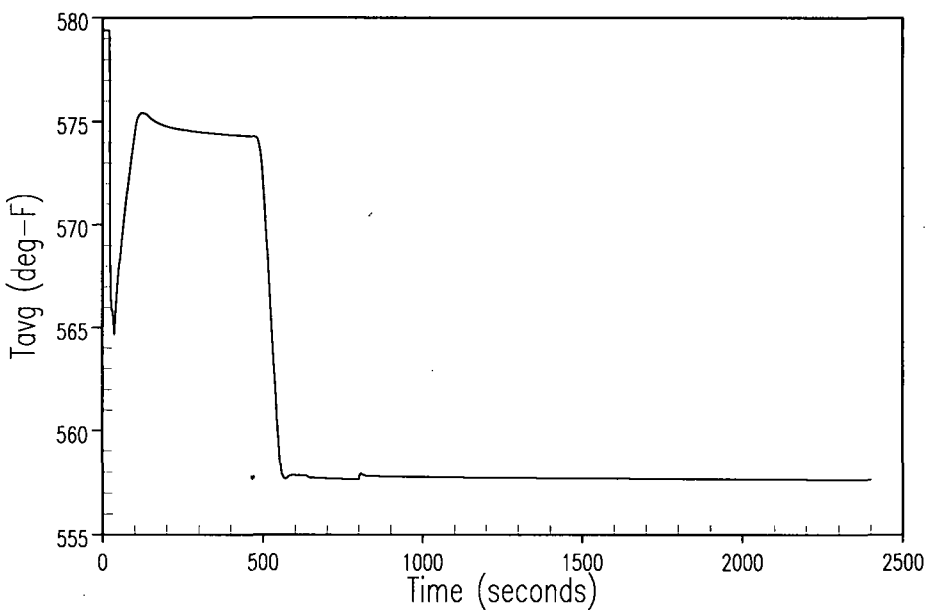


Figure 2.6-6 Unit 2 Inadvertent ECCS SI Flow Rates and RCS Average Temperature Versus Time

2.7 DECREASE IN REACTOR COOLANT INVENTORY

2.7.1 Inadvertent Pressurizer Pressure Relief Valve Opening

2.7.1.1 Technical Evaluation

2.7.1.1.1 Introduction

An accidental depressurization of the RCS could occur as a result of an inadvertent opening of a pressurizer relief valve. To conservatively bound this scenario, the Westinghouse methodology models the failure of a pressurizer safety valve since a safety valve is sized to relieve approximately twice the steam flow of a pressurizer PORV and will allow a much more rapid depressurization upon opening. The depressurization resulting from an open safety valve is also much more rapid than would occur from the accidental actuation of pressurizer spray. Therefore, the failure of a pressurizer safety valve yields the most severe core conditions resulting from an accidental depressurization of the RCS. It should be noted that a stuck-open pressurizer safety valve is not an event of moderate frequency as a control system failure would be. A stuck-open safety valve is considered to be a small-break LOCA during which the RCS cannot be isolated, whereas the failure of a PORV can be overridden by the closure of the PORV block valve. Nonetheless, the results of this analysis are shown to comply with the acceptance criteria for an event of moderate frequency.

Initially, the event results in a rapidly decreasing RCS pressure, which could reach hot leg saturation conditions without reactor protection system intervention. If saturated conditions are reached, the rate of depressurization is slowed considerably. However, the pressure continues to decrease throughout the event. The power remains essentially constant throughout the initial stages of the transient.

The reactor may be tripped by the following reactor trip system signals:

- Low pressurizer pressure
- Overtemperature N-16

2.7.1.1.2 Input Parameters, Assumptions, and Acceptance Criteria

To produce conservative results in calculating the DNBR during the transient, the following assumptions were made:

- The accident was analyzed using the RTDP (Reference 1). Initial core power, pressurizer pressure, and RCS temperature were assumed to be at their nominal values, consistent with steady-state full-power operation. Reactor coolant minimum measured flow was modeled. Uncertainties in initial conditions were included in the DNBR safety analysis limit as described in Reference 1. The initial core power level assumed is 3,612 MWt.

- A zero moderator coefficient of reactivity was assumed. This is conservative for beginning-of-life (BOL) operation in order to provide a conservatively low amount of negative reactivity feedback due to changes in moderator temperature.

- A small (absolute value) Doppler coefficient of reactivity is assumed, such that the resultant amount of negative feedback is conservatively low in order to maximize any power increase due to moderator feedback.

- The spatial effect of voids resulting from local or subcooled boiling was not considered in the analysis with respect to reactivity feedback or core power shape. In fact, it should be noted that the power peaking factors were kept constant at their design values, while the void formation and resulting core feedback effects would result in considerable flattening of the power distribution. Although this would significantly increase the calculated DNBR, no credit was taken for this effect.

- The analysis performed assumes that the rod control system is in automatic. However, no rod motion occurs during the transient because the conditions do not change enough to demand any rod motion from the rod control system. Therefore, the transient results are identical with or without automatic rod control.

Based on its frequency of occurrence, the accidental depressurization of the RCS accident is considered a Condition II event as defined by the American Nuclear Society's "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI N18.2-1973. The following items summarize the acceptance criteria associated with this event:

- The critical heat flux should not be exceeded. This was met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.

- Pressure in the reactor coolant and main steam systems should be maintained below 110 percent of the design pressures. Note that since this event is a depressurization event, these limits are not challenged. Both primary and secondary pressures decrease for the entire duration of the event.

2.7.1.1.3 Description of Analyses and Evaluations

The purpose of this analysis was to demonstrate that the reactor trip system functions and mitigates the consequences of the RCS depressurization event. This analysis is concerned with the transient from initiation through just past the time of reactor trip. With respect to long-term post-accident recovery, it is assumed that operators follow approved plant procedures to bring the plant to a safe post-accident condition.

The accident was analyzed by using the detailed digital computer code RETRAN (Reference 2). This code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

2.7.1.1.4 Results

The system response to an inadvertent opening of a pressurizer safety valve is shown in Figures 2.7.1-1 through 2.7.1-8. Figures 2.7.1-1 and 2.7.1-2 illustrate the nuclear power transients following the depressurization for Unit 1 and Unit 2, respectively. Nuclear power remains essentially unchanged until the reactor trip occurs on low pressurizer pressure. The pressurizer pressure transients are illustrated in Figures 2.7.1-3 (Unit 1) and 2.7.1-4 (Unit 2). Pressure decreases continuously throughout the transient. However, pressure decreases more rapidly after core heat generation is reduced via the reactor trip. Illustrated in Figures 2.7.1-5 (Unit 1) and 2.7.1-6 (Unit 2) are the loop average temperature transients. The loop average temperature decreases slowly until the reactor trip occurs. The DNBR decreases initially, but increases rapidly following the reactor trip as demonstrated in Figures 2.7.1-7 (Unit 1) and 2.7.1-8 (Unit 2). The DNBR remains above the limit value of 1.61 throughout the transient.

The calculated sequences of events for both units are shown in Table 2.7.1-1. The calculated minimum DNBR values are provided in Table 2.7.1-2.

The results of the analysis show that the low pressurizer pressure reactor trip system function provides adequate protection against the RCS depressurization event since the minimum DNBR remains above the safety analysis limit throughout the transient. Therefore, no cladding damage or release of fission products to the RCS is predicted for this event.

The results of the analysis performed for the accidental depressurization of the RCS for the core power level of 3,612 MWt support the implementation of the TM and SPU at CPNPP.

2.7.1.2 Conclusion

The analysis of the inadvertent opening of a pressurizer pressure relief valve event has been reviewed and Luminant Power has concluded that the analysis has adequately accounted for plant operation at the uprated power level and was performed using acceptable analytical models. It is further concluded that the evaluation has demonstrated that the reactor protection and safety systems will continue to ensure that the specified acceptable fuel design limits and the reactor coolant pressure boundary pressure limits will not be exceeded as a result of this event. Based on this, it is concluded that the plant will continue to meet the current licensing basis requirements with respect to GDCs -10, -15, and -26.

2.7.1.3 References

1. WCAP-11397, "Revised Thermal Design Procedure," April 1989.

2. WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

Table 2.7.1-1 Time Sequence of Events – Accidental Depressurization of the RCS		
Event	**Time (seconds) (Unit 1)**	**Time (seconds) (Unit 2)**
Inadvertent Opening of One Pressurizer Safety Valve	0.0	0.0
Low Pressurizer Pressure Reactor Trip Setpoint Reached	42.8	42.4
Rods Begin to Drop	44.8	44.4
Minimum DNBR Occurs	45.5	45.0

Table 2.7.1-2 Results - Accidental Depressurization of the RCS		
Minimum DNBR (Unit 1)	**Minimum DNBR (Unit 2)**	**DNBR Safety Analysis Limit**
1.923	1.921	1.61

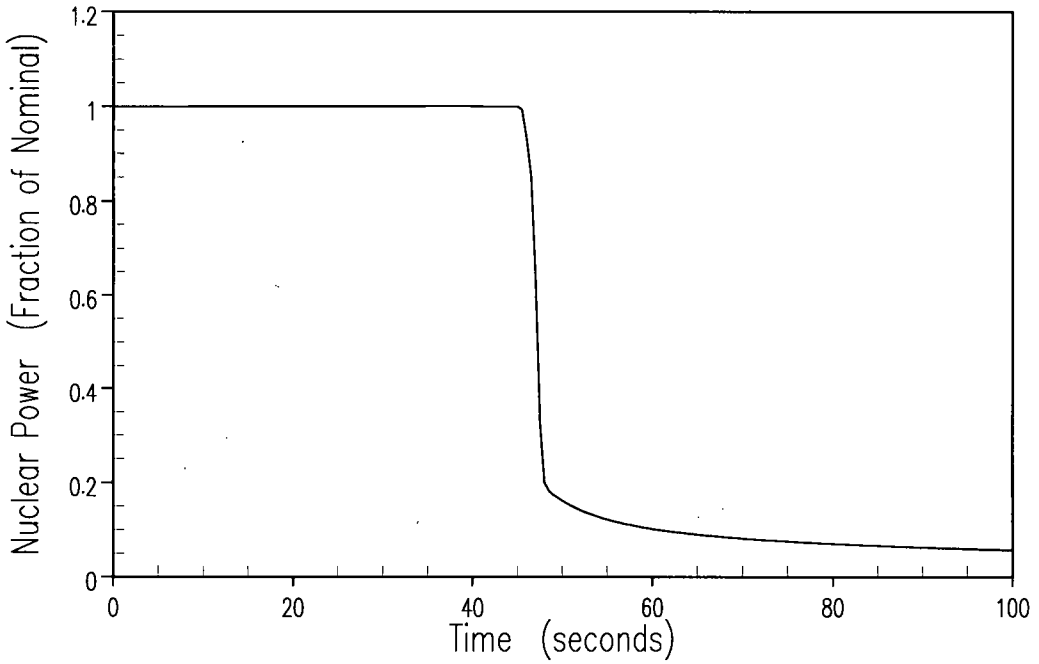


Figure 2.7.1-1 RCS Depressurization Nuclear Power Versus Time (Unit 1)

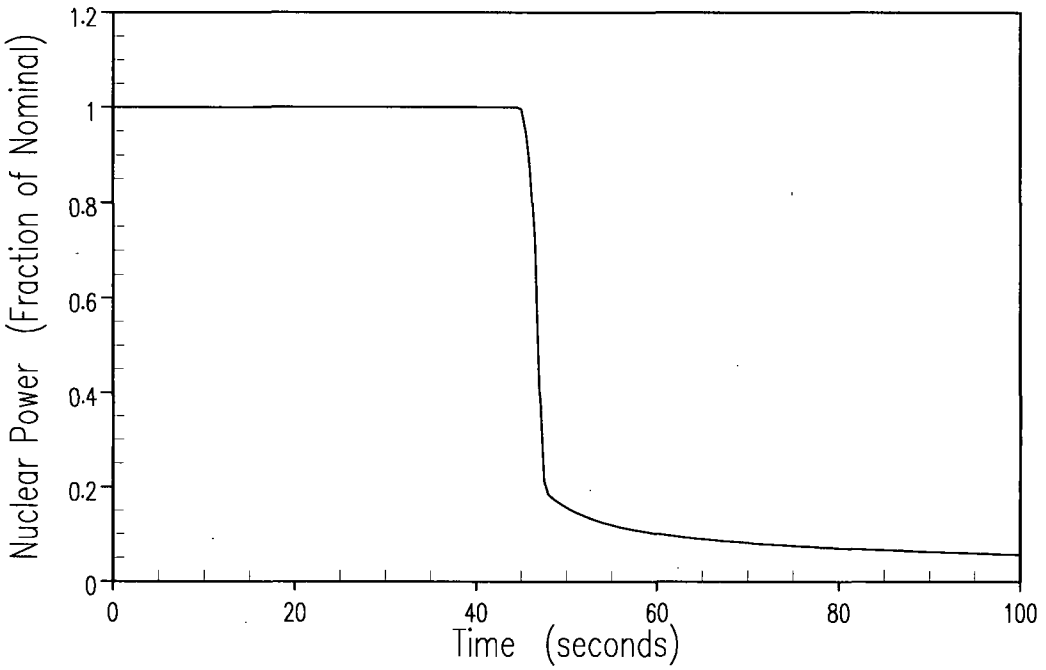


Figure 2.7.1-2 RCS Depressurization Nuclear Power Versus Time (Unit 2)

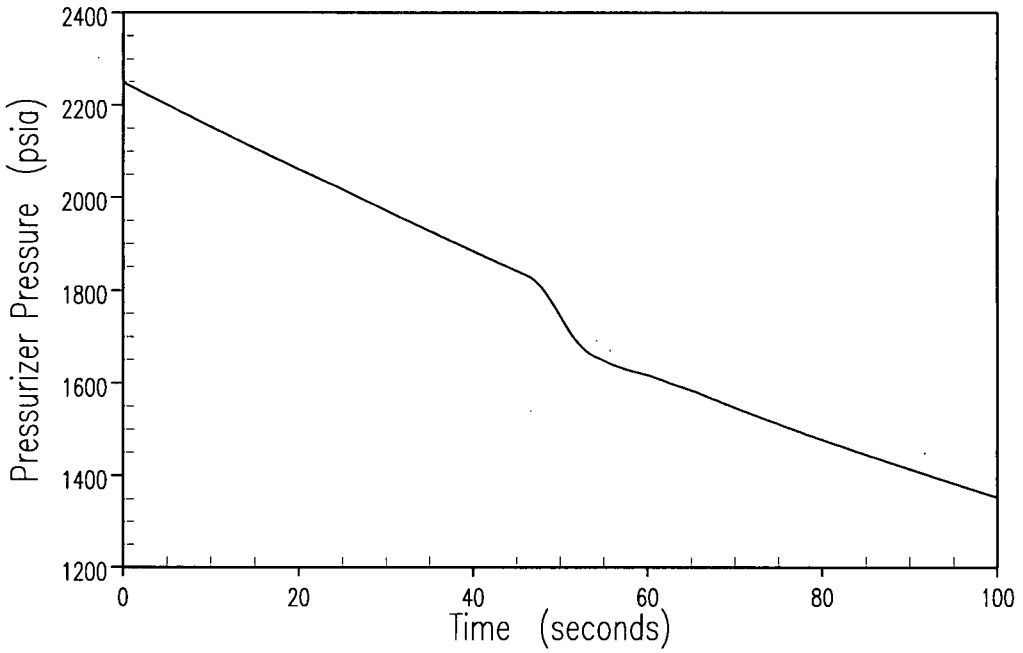


Figure 2.7.1-3 RCS Depressurization Pressurizer Pressure Versus Time (Unit 1)

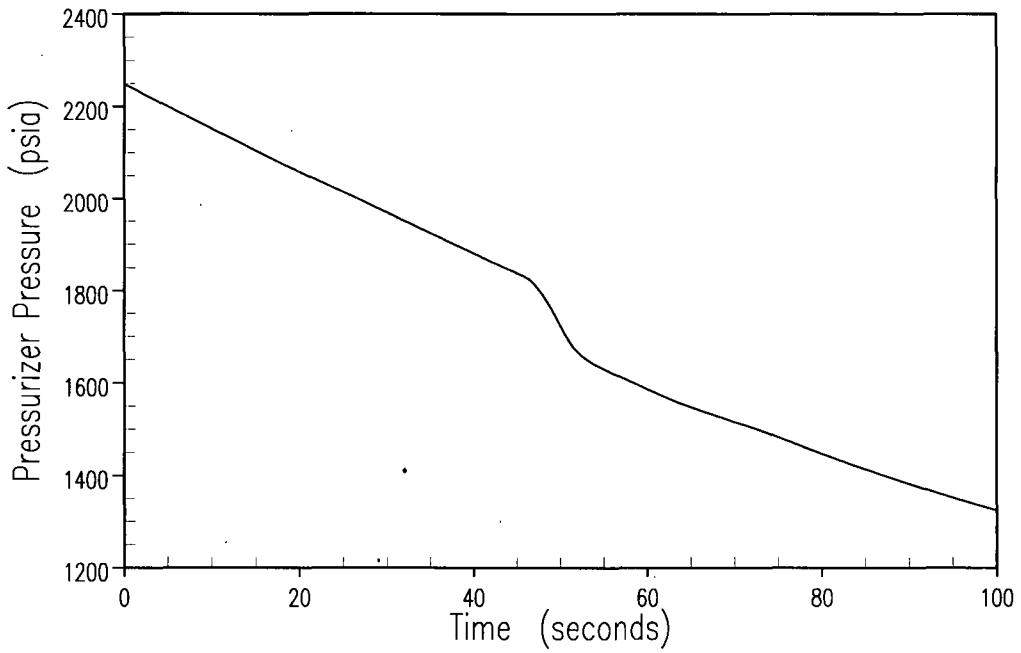


Figure 2.7.1-4 RCS Depressurization Pressurizer Pressure Versus Time (Unit 2)

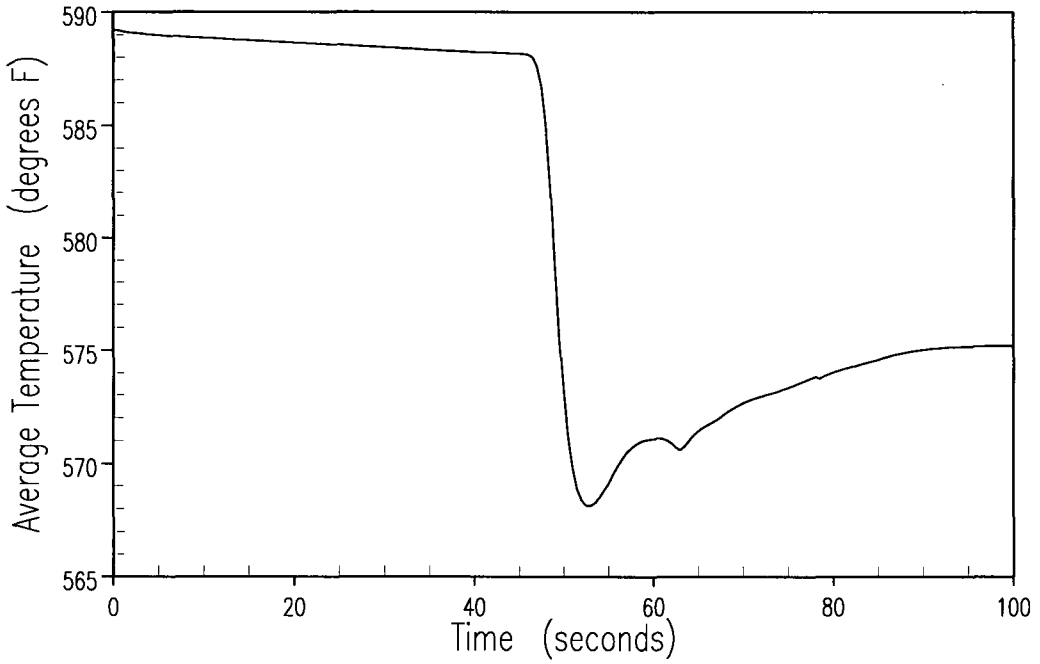


Figure 2.7.1-5 RCS Depressurization Indicated Loop Average Temperature Versus Time (Unit 1)

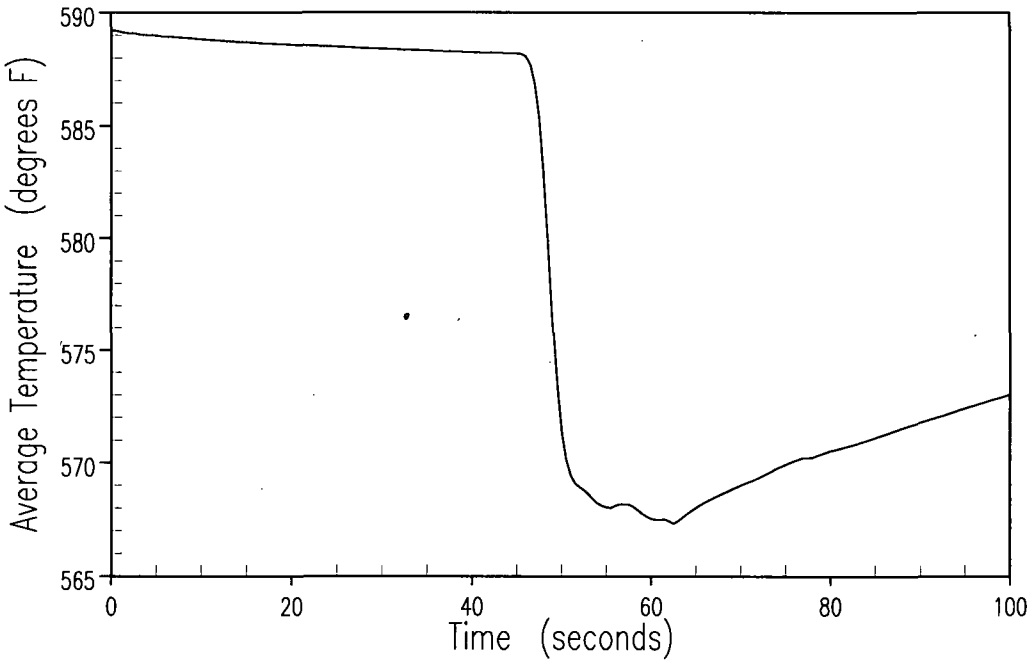


Figure 2.7.1-6 RCS Depressurization Indicated Loop Average Temperature Versus Time (Unit 2)

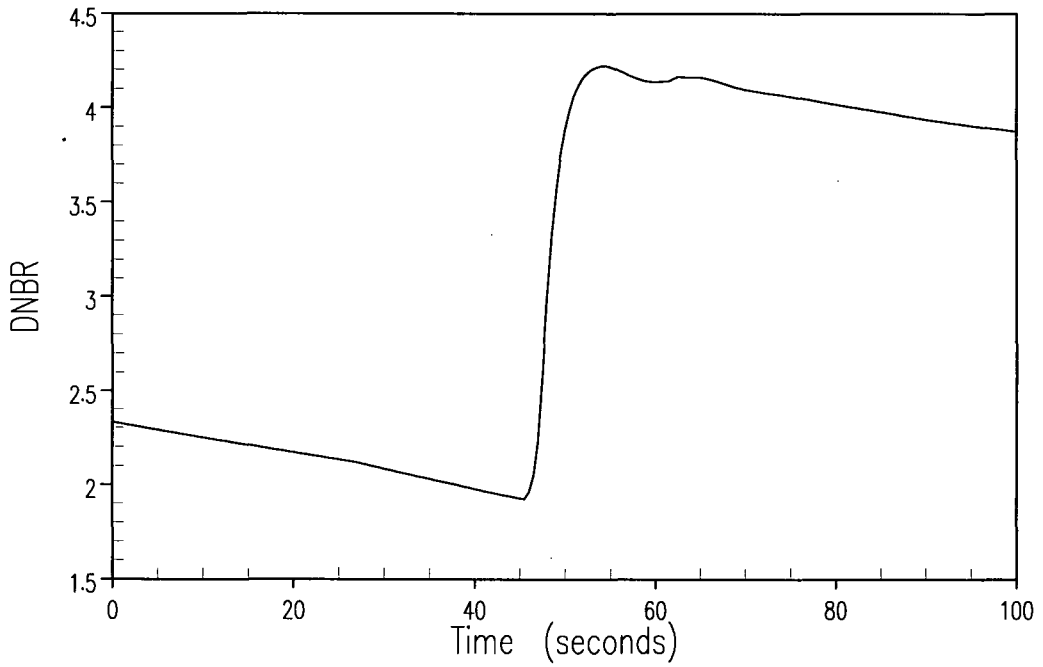


Figure 2.7.1-7 RCS Depressurization DNBR Versus Time (Unit 1)

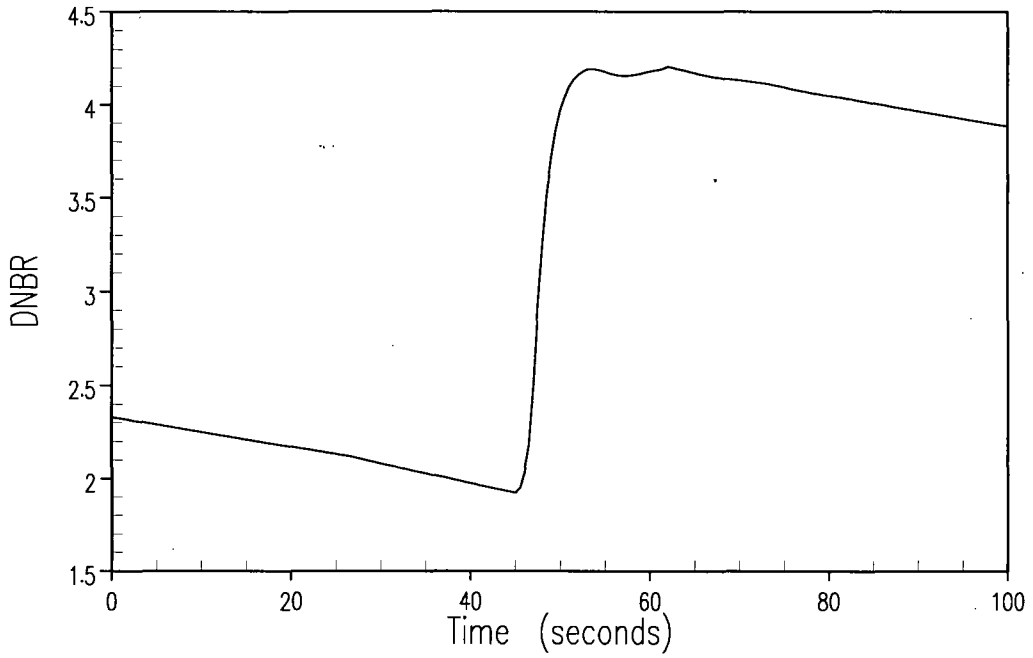


Figure 2.7.1-8 RCS Depressurization DNBR Versus Time (Unit 2)

2.7.2 Steam Generator Tube Rupture

2.7.2.1 Technical Evaluation

The evaluation of the design basis steam generator tube rupture (SGTR) event demonstrated that the current design is acceptable to support the uprate operation.

2.7.2.1.1 Introduction

The SGTR analysis is described in the FSAR, Section 15.6.3. The SGTR accident analysis included analyses performed to demonstrate margin-to-overfill and analyses to ensure that possible radiological dose consequences are within allowable guidelines. The dose analysis required that thermal-hydraulic calculations be performed to determine the amount of reactor coolant discharged to the ruptured steam generator, and the amounts of steam released from the steam generators. The effects of limiting single failures and the times for required operator actions were explicitly included in the analyses. Only the results of the limiting margin-to-overfill and mass-release cases are discussed in the FSAR.

The uprate analyses were performed using the methodology developed in WCAP-10698 and its supplement (References 2 and 3), but with the RETRAN-02 computer code (Reference 4).

The analysis included an analyzed NSSS power level of 3,628 MWt, and a full-power T_{avg} operating range from 574.2° to 589.2°F and up to 10-percent steam generator tube plugging as well as a main feedwater temperature range from 390° to 450.3°F. All cases were analyzed with a loss-of-offsite power.

Note that in order to demonstrate margin to overfill, Unit 1 is limited to a minimum T_{avg} of 580.0°F. A lower T_{avg} would result in overfilling the ruptured steam generator. Unit 2 demonstrated margin to overfill with a T_{avg} of 574.2°F.

The margin-to-overfill transient was analyzed until the ruptured steam generator secondary-side and RCS pressures equalized, at which time the ruptured tube flow was considered to be terminated. The margin-to-overfill analysis examined both CPNPP units, including unit-specific single failures and operating conditions. Only the results of the limiting margin-to-overfill case are presented.

The mass-release case determines the primary-to-secondary break flows and steam releases for the SGTR radiological consequences analysis. This case is analyzed through tube rupture flow isolation and cooldown to RHRS in-service conditions to obtain the total steam releases from the intact and ruptured steam generators. (At this point the plant proceeds to Mode 5 (cold shutdown) conditions using the RHRS without additional steam release.) The mass release analysis considered both CPNPP units. It was determined that Unit 1 bounds Unit 2 for the purposes of the mass release analysis. Only the results of the limiting mass release case are presented.

2.7.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

Design Basis Accident

The accident modeled is a double-ended break of one steam generator tube located at the top of the tubesheet on the outlet-cold-leg-side of the steam generator. The location of the break on the cold side of the steam generator results in higher primary-to-secondary leakage than a break on the hot side of the steam generator. However, the break flow flashing fraction was conservatively calculated for use in the radiological consequences analysis assuming that all of the break flow came from the hot leg side of the steam generator. The combination of these conservative assumptions regarding the break location results in a conservative calculation of the radiological consequences. It was also assumed that loss-of-offsite power occurred at the time of reactor trip, and the highest worth control assembly was assumed to be stuck in its fully withdrawn position at reactor trip. Due to the assumed loss-of-offsite power, the condenser was not available for steam releases once the reactor was tripped. Consequently, after reactor trip, steam was released to the atmosphere through the steam generator ARVs.

Single Failure Considerations

The effects of single failures in margin-to-overfill and mass-release analyses were investigated in WCAP-10698 and its Supplement 1 (References 2 and 3). The limiting single failures for CPNPP SGTR analyses are described below.

The limiting single failure for margin-to-overfill considerations for Unit 1 is an ARV on one intact steam generator failing to open. The limiting single failure for margin-to-overfill considerations for Unit 2 is the failure of a DC bus, resulting in a failure to open two ARVs on intact steam generators. The failure of the ARVs on intact steam generators requires the RCS cooldown to be performed with fewer steam generators, resulting in a longer cooldown and delayed break flow termination.

The limiting single failure for the mass-release analysis for the CPNPP units is the ARV failing to close on the ruptured steam generator (Reference 3). Failure of this ARV causes an uncontrolled release directly to the atmosphere and the uncontrolled depressurization of the ruptured steam generator resulting in increased primary-to-secondary flow. Pressure in the ruptured steam generator remains less than the RCS until the failed ARV is isolated and recovery actions are completed.

Operator Actions Assumed

Important operator actions in the CPNPP emergency operating procedures (EOPs) were explicitly modeled in the analysis. These actions were intended to terminate flow though the SGTR before proceeding to long-term cooldown. The operator actions modeled in the uprate analysis and the associated times were consistent with or conservative compared to those currently incorporated in the analyses presented in FSAR Section 15.6.3. These action times consisted of two components: initiation times (for the operator to start actions) and plant/system response times (for the plant conditions to reach performance objectives such as temperature,

pressure, flow, etc., required by the recovery action). The latter times were determined from the thermal-hydraulic transient analyses of the SGTR accident. The operator action times are summarized in Table 2.7.2-1.

The operator actions that were modeled include:

- Control excessive auxiliary feedwater (AFW) flow to the ruptured steam generators.

  In the analysis, this function is modeled by assuming the operators isolate the TDAFW flow at 3 minutes past reactor trip. The TDAFW flow is isolated consistent with CPNPP procedure EOP-0.0A/(B), "Reactor Trip or Safety Injection," which calls for throttling the AFW flow to steam generators with levels above just-on-span.

- Identifying the ruptured steam generator.

  Several means are available to the operator to identify a ruptured steam generator. The predominant indications are an unexpected rapid increase in the ruptured steam generator's narrow-range level following the reactor trip, high radiation from a steam generator blowdown radiation monitor, or high radiation from a steam line radiation monitor. The analysis modeled a loss-of-offsite power concurrent with reactor trip. This results in the unavailability of the radiation monitors post-trip, leaving only the ruptured steam generator level increase as a means of identifying the ruptured steam generator.

- Isolating the steam flow from the ruptured steam generator and throttling auxiliary feedwater flow to the ruptured steam generator.

  Isolating the ruptured steam generator minimizes radiological releases and reduces the possibility of overfilling by minimizing the accumulation of feedwater. This action also enables the operator to establish a pressure differential between the ruptured and intact steam generators as a necessary step toward terminating primary-to-secondary flow. It was assumed that the ruptured steam generator would be isolated when the level in the steam generator reached between being just on span and 50 percent on the narrow-range instrument (modeled as 44-percent narrow-range level for Unit 1 and 30-percent narrow-range level for Unit 2), or after an operator action time of 13 minutes, whichever was longer.

- Cooling down the RCS by dumping steam from the intact steam generators.

  The RCS is cooled down as rapidly as possible to a temperature less than the saturation temperature corresponding to the ruptured steam generator's pressure. The cooldown is performed using the intact steam generators' ARVs since neither the steam dump valves nor the condenser were available following the assumed loss-of-offsite power. The cooldown continues until RCS subcooling at the ruptured steam generator pressure is 20°F, plus an allowance of 25°F for instrument uncertainty.

- Depressurizing the RCS after cooldown to minimize break flow and restore pressurizer level.

  After the RCS cooldown, safety injection is terminated since it is the principal contributor to tube rupture flow. Depressurizing the RCS is required to ensure an adequate RCS inventory and reliable pressurizer level indication prior to stopping injection. Since offsite power was assumed to be lost at the time of reactor trip, the reactor coolant pumps were not running, and thus normal pressurizer spray was not available. It was assumed that the operator depressurized the RCS using a pressurizer PORV. The operator continues to depressurize until any of the following is satisfied:

  - RCS pressure is less than the ruptured steam generator pressure and pressurizer level is greater than 13 percent
  - Pressurizer level is greater than 75 percent
  - RCS subcooling is less than the 25°F allowance for subcooling instrument uncertainty

- Terminating safety injection to prevent re-pressurization of the RCS and terminate primary to secondary flow.

  Safety injection is terminated when all of the following are satisfied:

  - The RCS pressure stabilizes or starts to increase.
  - The RCS subcooling is greater than the 25°F allowance for subcooling instrument uncertainty.
  - Secondary heat sink is available.
  - The pressurizer level is greater than 13 percent.

Following termination of tube rupture flow, the operator is required to perform additional actions to bring the plant to Mode 5 (cold-shutdown) conditions. The operator actions are defined in the CPNPP EOPs. Only two of the actions were explicitly considered in the analysis.

The operator is required to cool the RCS to the RHRS in-service temperature by feeding and steaming the intact steam generators. The SGTR long-term mass-release analysis assumed the operator performs this action by dumping steam to the atmosphere via the ARVs. Although other preferable cooldown methods (such as steam dump to the condenser to minimize activity releases) are identified in the CPNPP EOPs, steam dump to the atmosphere was necessary because offsite power was assumed to be lost at the time of reactor trip, causing the condenser to be unavailable.

Cooldown and depressurization of the ruptured steam generator is performed after the RCS is cooled to the RHRS in-service temperature. With a loss-of-offsite power, the operator releases steam from the ruptured steam generator to the atmosphere. (This method is conservative for radiological calculations since it maximizes the activity released from the plant.) The operator maintains equal pressure between the RCS and ruptured steam generator secondary side using the PORV as needed until the RHRS is brought online.

Explicit operator action times were not defined since cooldown can proceed more gradually after tube rupture flow is terminated.

Input Parameters and Initial Conditions

Parameters and initial conditions common to the margin-to-overfill and mass release analyses were:

- Both units were at 100.6-percent rated thermal power. Both units were operating within the T_{avg} window, which ranged from 574.2° to 589.2°F. The mass release analysis modeled the high T_{avg} since that maximized secondary steam releases. The margin-to-overfill analysis modeled the low T_{avg} as that minimized secondary steam releases and maximized the mass flow rate through the break. Note that, in order to demonstrate margin to overfill, Unit 1 is limited to a minimum T_{avg} of 580.0°F. A lower T_{avg} would result in overfilling the ruptured steam generator. Unit 2 demonstrated margin to overfill with a T_{avg} of 574.2°F. Other initial conditions are summarized in Table 2.7.2-2.

- Reactor trip occurred when the overtemperature N-16 setpoint was reached. No reactor trip delay was assumed since it maximized the secondary-side inventory in the ruptured steam generator and steam releases from all steam generators. It was also assumed that loss-of-offsite power occurred at the time of reactor trip.

- The turbine automatically tripped following a reactor trip. Zero delay was assumed since it minimized the steam flow to the turbine, and maximized the secondary-side water inventory in the ruptured steam generator and steam releases from all steam generators.

- The condenser was unavailable for steam dump following reactor trip due to the assumed loss-of-offsite power. All subsequent steam relief was through the ARVs, and MSSV, if needed.

- A low ARV setpoint of 1,140 psia was used since control at lower steam generator pressures caused a greater primary-to-secondary side pressure differential and tube rupture flow.

- Maximum safeguards safety injection flows were modeled. This assumption conservatively increased the break flow through the ruptured tube.

- Auxiliary feedwater was automatically started following reactor trip and loss-of-offsite power.

- Operation of charging and letdown systems and pressurizer heaters were not credited. Operating these systems delays the reactor trip, which reduces the severity of the analyzed transient.

- Conservatively high decay heat rates were used. The increased heat input resulted in greater tube rupture flow after reactor trip due to the longer time needed for removing heat and depressurizing the RCS.

For the margin-to-overfill cases:

- The initial water mass in the steam generators corresponded to the nominal steam generator level plus uncertainty. For Unit 1, the initial water mass corresponded to a level of 77 percent on the narrow-range level, which corresponded to a nominal level of 67-percent plus 10-percent uncertainty. For Unit 2, the initial water mass corresponded to a level of 82 percent on the narrow-range level, which corresponded to a nominal level of 64-percent plus 18-percent uncertainty. A higher initial mass in the ruptured steam generator is conservative with respect to reducing the margin to overfill. (The total fluid mass shown in Table 2.7.2-2 corresponds to the mass in the Unit 1 steam generators at T_{avg} of 580.0°F at full power, with 10-percent tube plugging and a feedwater temperature of 390°F.)

- The turbine runback on overtemperature N-16 at a rate of 10-percent power per minute prior to reactor trip was simulated but not credited for delaying reactor trip, for a maximum of 3 minutes. Turbine runback increased the secondary water mass with reduced load, because the feedwater controller attempts to maintain steam generator level as power decreased before the trip.

- The maximum available AFW flow was modeled to maximize the mass of water in the ruptured steam generator at the time of isolation. The intact steam generators received the minimum AFW flow. This increased the steam releases from the intact steam generators, which decreased the steam release from the ruptured steam generator.

For the mass release analyses:

- A turbine runback was not assumed since it delays reactor trip and increases secondary mass. An earlier reactor trip results in greater steam releases to the atmosphere from all steam generators.

- The steam generator water mass corresponded to 57 percent on the narrow-range level. This mass represented the full-power, nominal steam generator water level with a -10-percent instrument uncertainty applied. A lower initial mass in the ruptured steam generator increases the predicted offsite doses. (The value shown in Table 2.7.2-2 corresponds to T_{avg} at 589.2°F with 0-percent tube plugging and feedwater temperature of 450.3°F.)

- The minimum AFW flow, distributed equally, was modeled to maximize the steam releases.

Acceptance Criteria

No regulatory acceptance criteria were used for the margin-to-overfill and mass release analyses. Both analyses were performed using conservative assumptions to demonstrate the ability of the operator to limit the system transient and establish parameters for providing a bounding radiological consequence assessment.

In order to demonstrate that water release from the ruptured steam generator did not have to be considered in the radiological consequences assessment, the margin-to-overfill analysis was performed to demonstrate that the secondary side of the ruptured steam generator did not completely fill with water. The available secondary side volume of a single CPNPP Unit 1 steam generator is 5,328 ft^3. The available secondary-side volume of a single Unit 2 steam generator is 5,955 ft^3. Margin-to-overfill was demonstrated, provided the transient calculated steam generator secondary side water volume was less than 5,328 ft^3 for Unit 1 and less than 5,955 ft^3 for Unit 2.

2.7.2.1.3 Description of Analyses and Evaluations

The margin-to-overfill analyses were performed using the methodology in WCAP-10698 (Reference 2) with plant-specific parameters. The ruptured steam generator's secondary-side water volume was calculated as a function of time to demonstrate that overfill did not occur. The analysis was performed from the start of the rupture until break flow was terminated at equalization of primary-and-secondary pressures. The methodology included the explicit modeling of operator actions in the CPNPP EOPs required for mitigation of the SGTR accident.

The mass release analyses were performed using the methodology in WCAP-10698 and its Supplement 1 (References 2 and 3). The plant response, the integrated primary-to-secondary break flow, and the steam releases to the condenser and to the atmosphere up to the time the tube rupture flow was terminated were all calculated using RETRAN-02 results. When calculating the amount of break flow that flashed to steam, 100 percent of the break flow was assumed to come from the hot leg side of the break.

The steam release from the time of tube rupture flow termination until 2 hours, and from 2 to 11 hours, were determined from mass-and-energy balances using the RCS's and intact steam generators' conditions. Following termination of the tube rupture flow, the intact steam generators' ARVs were assumed to cool down the plant at less than the maximum allowable rate of 100°F/hour to an RHRS in-service temperature of 350°F.

The ruptured steam generator was assumed to be depressurized to the RHRS in-service pressure of 365 psia immediately after the RCS cooldown. The amount of steam released was determined from mass-and-energy balances. No changes in thermodynamic conditions were assumed from termination of the tube rupture flow until depressurization was started since the ruptured steam generator was isolated. Steam releases from all steam generators are considered terminated when a single train of residual heat removal (RHR) is able to remove decay heat. This is assumed to occur at a conservatively long value of 11 hours.

2.7.2.1.4 SGTR Results

Only the results for the limiting margin-to-overfill and mass release cases were presented.

SGTR Margin-to-Overfill Transient Analysis

Results are presented for the worst-case margin-to-overfill analysis. The worst case, considering both units, the range of T_{avg}, and the range of tube plugging was Unit 1—10-percent tube plugging with a T_{avg} of 580.0°F. The analysis showed that 580.0°F was the lowest temperature to demonstrating margin to overfill for Unit 1. (Unit 2 demonstrated margin to overfill at a T_{avg} of 574.2°F.) The sequence of events is summarized in Table 2.7.2-3 and Figures 2.7.2-1 to 2.7.2-7 show primary- and secondary-side responses until the SGTR flow was terminated.

To ensure proper initialization of the RETRAN-02 model, 100 seconds of steady-state operation were modeled prior to initiating the break, and all times listed include this 100 seconds. Once the break was initiated, the reactor coolant flow to the secondary side through the ruptured tube immediately caused the pressurizer level and pressure to decrease, as shown in Figures 2.7.2-1 and 2.7.2-2. The continued decrease in pressurizer pressure caused the overtemperature N-16 setpoint to be reached at 287 seconds, followed by immediate reactor and turbine trips. The reactor coolant pumps tripped due to the assumed loss-of-offsite power at the time of reactor trip. Immediately following reactor trip, the temperature differential across the hot and cold legs decreased as core power decayed. The temperature differential then increased as shown in Figure 2.7.2-4 as the pumps coasted down and natural circulation flow developed.

With the steam dump valves closed after trip (due to the loss-of-condenser vacuum resulting from the assumed loss-of-offsite power at the time of reactor trip), the secondary-side pressures in all steam generators increased rapidly to the ARV setpoint as shown in Figure 2.7.2-3. The pressurizer level and pressure dropped more rapidly, and safety injection was actuated via the low-pressurizer pressure setpoint at 300 seconds (see Figures 2.7.2-1 and 2.7.2-2 and Table 2.7.2-3).

Turbine-driven auxiliary feedwater flow was isolated at 3 minutes past reactor trip (Table 2.7.2-1) at 467 seconds. The operator isolated the ruptured steam generator by isolating steam flow and throttling the remaining motor-driven auxiliary feedwater flow at 13 minutes after break initiation (see Table 2.7.2-3). The operator actions were assumed at 13 minutes after break initiation since the ruptured steam generator's narrow-range level had previously returned to greater than 44 percent. After AFW isolation, the increase in fluid mass in the ruptured steam generator (shown in Figure 2.7.2-6) was due to the ruptured tube flow.

There was a 5-minute operator delay time before initiating the cooldown (see Table 2.7.2-1) at 1,180 seconds (See Table 2.7.2-3). The ARV on one intact steam generator was assumed to fail closed at the start of the cooldown. The cooldown was then completed with the ARVs on the remaining two intact steam generators. The subsequent reduction in the available intact steam generators' pressure is shown in Figure 2.7.2-3, and the resulting cooldown of the RCS temperature is shown in Figure 2.7.2-4. The pressurizer level and pressure also decreased

during this cooldown, as shown in Figures 2.7.2-1 and 2.7.2-2. The cooldown was continued until RCS subcooling at the ruptured steam generator pressure was 20°F, plus an allowance of 25°F for instrument uncertainty. The cooldown was completed at 1,980 seconds (see Table 2.7.2-3).

The available intact steam generators' ARVs were later re-opened to dump steam and maintain an adequate RCS subcooling margin. When the ARVs were opened, the increased energy transfer from the primary to the secondary side also aided in the depressurization of the RCS to the ruptured steam generator's pressure (see Figures 2.7.2-2 and 2.7.2-3).

The operator began to depressurize the RCS using the pressurizer PORV at 2,100 seconds after a 2-minute delay (see Table 2.7.2-1). Depressurization was terminated at 2,180 seconds when the RCS subcooling was reduced below the 25°F allowance for instrument uncertainty. The depressurization reduced pressurizer pressure and the break flow and increased safety injection flow to refill the pressurizer, as shown in Figures 2.7.2-1 and 2.7.2-2.

A 2-minute delay was imposed prior to termination of safety injection flow (see Table 2.7.2-1). Safety injection was terminated in the analysis at that time because the safety injection termination criteria were satisfied. The RCS pressure was allowed to increase to 50 psi above the ruptured steam generator pressure to ensure that the RCS pressure was increasing when safety injection was terminated. The operator terminated safety injection at 2,300 seconds because the safety injection termination criteria were satisfied and the RCS pressure began to decrease, as shown in Figure 2.7.2-2. The primary-to-secondary flow continued until the RCS and ruptured steam generator pressures equalized at approximately 3,045 seconds.

The primary-to-secondary break flow rate and water volume in the ruptured steam generator are shown in Figure 2.7.2-5 and 2.7.2-7, respectively. Figure 2.7.2-7 shows a bounding value of 23 ft^3 margin-to-overfill relative to the steam generator's total volume of 5,328 ft^3. For Unit 2 the margin-to-overfill is 185 ft^3. Therefore, it was concluded that overfill of the ruptured steam generator would not occur for a design basis SGTR for CPNPP.

SGTR Mass Release Transient Analysis

The maximum mass release occurred for Unit 1 with a steam generator tube plugging level of 0 percent, and with the reactor initially operating with a T_{avg} at 589.2°F. The sequence of events is summarized in Table 2.7.2-4, and the primary- and secondary-side responses appear in Figures 2.7.2-8 to 2.7.2-19. Total mass releases for use in the dose analyses are summarized in Table 2.7.2-5.

The mass release and margin-to-overfill results were similar until 13 minutes from break initiation. The mass release transient modeled a low initial secondary inventory and minimum AFW flow with actuation delayed conservatively. As a result, the ruptured steam generator level did not reach 44 percent until 1,077 seconds. Isolating the ruptured steam generator was therefore delayed until 1,077 seconds, consistent with Table 2.7.2-1. At 1,077 seconds, the ruptured steam generator's ARV was assumed to fail open. Steam releases from the ruptured steam generator are shown in Figure 2.7.2-16. The failure of the ARV caused the steam

generator to rapidly depressurize, and the primary-to-secondary flow through the ruptured tube to increase (see Figures 2.7.2-10 and 2.7.2-13). The ruptured steam generator's depressurization caused the RCS pressure and temperature to decrease. The operator identified and locally closed the block valve for the failed ARV after 36 minutes (see Table 2.7.2-1). The depressurization of the ruptured steam generator stopped at 3,237 seconds, and its pressure began to increase, as shown in Figure 2.7.2-10.

There was a 5-minute operator action delay time imposed prior to initiating cooldown after the failed ARV's block valve was closed (see Table 2.7.2-1). The cooldown was performed using the intact steam generators' ARVs to dump steam to the atmosphere, and continued until the RCS subcooling at the ruptured steam generator pressure at the start of cooldown was 20°F, plus an allowance of 25°F for instrument uncertainty. Because of the lower pressure in the ruptured steam generator when the cooldown was initiated, the RCS had to be cooled to a lower temperature to satisfy the cooldown criterion. The net effect was that the cooldown period was longer, relative to the overfill case. The cooldown was completed at 5,082 seconds. The reductions in the intact steam generators' pressure and the RCS temperature during the cooldown period are shown in Figures 2.7.2-10, 2.7.2-11, and 2.7.2-12, respectively. The intact steam generators' ARVs were later reopened (see Figure 2.7.2-17) to maintain RCS temperature and subcooling margin.

The RCS depressurization began later than the limiting margin-to-overfill case. After a 2-minute delay (see Table 2.7.2-1), the operator used the pressurizer PORV to depressurize, starting at 5,202 seconds. Depressurization was terminated at 5,358 seconds, when the RCS pressure was less than the ruptured steam generator's pressure and the pressurizers level was above 13 percent. During depressurization, safety injection flow refilled the pressurizer while break flow was reduced, as shown in Figures 2.7.2-8 and 2.7.2-13, respectively.

At this point, a 2-minute operator delay (see Table 2.7.2-1) was assumed before shutting down safety injection at 5,478 seconds. Like the overfill analysis, safety injection was terminated after that 2 minutes because the criteria were satisfied. The RCS pressure began to decrease, as shown in Figure 2.7.2-9. Figure 2.7.2-13 shows that the primary-to-secondary flow continued until the RCS and ruptured steam generator pressures equalized at 7,156 seconds. Figures 2.7.2-18 and 2.7.2-19 show the transient ruptured steam generator water volume and mass. The peak ruptured steam generator water volume is well below the available volume of 5,328 ft^3.

The integrated flashing break flow was 25,482 lbm. Figures 2.7.2-14 and 2.7.2-15 show the flashing fraction and integrated flashed break flows, respectively.

Following termination of the tube rupture flow, the RCS was cooled down using the intact steam generators. The steam releases are presented in Table 2.7.2-5. Since the condenser was in service until reactor trip, any radioactivity released to the atmosphere before reactor trip was through the condenser air ejector. After reactor trip, the releases were assumed to be via the ARVs. Table 2.7.2-5 indicates that 215,400 lbm of steam was released to the atmosphere from the ruptured steam generator within the first 2 hours (that is, the ruptured steam generator was isolated within this interval). After 2 hours, 20,400 lbm of steam was released to the

atmosphere from the ruptured steam generator, when it was depressurized after the RCS was cooled to the RHRS in-service temperature. A total of 307,900 lbm of reactor coolant flowed through the tube rupture before break flow was terminated.

The analysis performed to calculate the mass transfer data for input to the radiological consequences analysis has been completed and data tabulated for the limiting case.

2.7.2.2 Conclusion

Luminant Power has reviewed the analysis of the SGTR accident and concludes that the analysis has adequately accounted for the plant operation at the uprate power level and was performed using acceptable analytical methods and approved computer codes. Luminant Power further concludes that the assumptions used in this analysis are conservative and that the event does not result in an overfill of the ruptured steam generator. Therefore, Luminant Power finds the uprate acceptable with respect to the SGTR event.

2.7.2.3 References

1. RXE-88-101, "Design Basis Analysis of a Postulated Steam Generator Tube Rupture Event for Comanche Peak Steam Electric Station," Unit 1, March 1988.

2. WCAP-10698, "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill," August 1987.

3. WCAP-10698 Supplement 1, "Evaluation of Offsite Radiation Doses for a Steam Generator Tube Rupture Accident," March 1986.

4. WCAP-14882, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999.

Table 2.7.2-1 Operator Action Times For Design Basis SGTR Analysis	
Action	**Time**
Isolate TDAFW Flow to all Steam Generators	3 minutes from reactor trip
Identify and Isolate Ruptured Steam Generator	Maximum of 13 minutes past break initiation or the calculated time to reach the midpoint of just-on-span and 50% span. For Unit 1, this is 44% span. For Unit 2, this is 30% span.
Identify and Isolate the Failed-Open ARV (mass release analysis only)	36 minutes from the time of ARV failure
Operator Action Time to Initiate Cooldown	5 minutes from complete ruptured steam generator isolation
Cooldown	Calculated time for RCS cooldown
Operator Action Time to Initiate Depressurization	2 minutes from end of cooldown
Depressurization	Calculated time for RCS depressurization
Operator Action time to Initiate Safety Injection Termination	Maximum of 2 minutes from end of depressurization or time to satisfy safety injection termination criteria
Pressure Equalization	Calculated time for equalization of RCS and ruptured steam generator pressures

Table 2.7.2-2 Plant Parameters Used in SGTR Analysis		
	SGTR Overfill Analysis	**SGTR Dose Analysis**
Initial RCS pressure (psia)	2,280	2,220
Initial Steam Generator Water Mass (lbm)	117,500	71,000
Reactor Trip Delay (sec)	0.0	0.0
Turbine Trip Delay	0.0	0.0
Pressurizer Pressure Setpoint for Safety Injection (psia)	2,000	2,000
Steam Generator Atmospheric Relief Valve Setpoint (psia)	1,140	1,140
Safety Injection System Pump Delay (sec)	0.0	0.0
AFW Delay (sec)	0.0	60 sec from safety injection
AFW Flow Ruptured steam generator Intact steam generators	 Maximum Minimum	 Minimum Minimum
AFW Temperature (°F)	100	100
Decay Heat	120% ANS	120% ANS
Safety Injection Flow	Maximum safeguards	Maximum safeguards
ARV Capacity Ruptured steam generator (1,200 psia reference pressure) Intact steam generators (1,200 psia reference pressure)	 750,000 lbm/hr 750,000 lbm/hr	 968,800 lbm/hr 750,000 lbm/hr

Table 2.7.2-3 Sequence of Events for Margin-to-Overfill Analysis	
Event	**Time (seconds)**
SGTR	100
Reactor Trip	287
AFW Initiated	287
Safety Injection	300
TDAFW to all Steam Generators Isolated	467
Ruptured Steam Generator Isolated	880
RCS Cooldown Initiated	1,180
RCS Cooldown Target Temperature Reached	1,980
Pressurizer PORV Opened	2,100
Pressurizer PORV Closed	2,180
Safety Injection Terminated	2,300
Break Flow Terminated	3,045

Table 2.7.2-4 Sequence of Events for Input to Radiological Consequences Analysis	
Event	**Time (seconds)**
SGTR	100
Reactor Trip	277
Safety Injection	287
AFW Initiated	347
TDAFW to All Steam Generators Isolated	457
Ruptured Steam Generator Isolated	1,077
Ruptured Steam Generator ARV Fails Open	1,077
Ruptured Steam Generator ARV Isolated	3,237
RCS Cooldown Initiated	3,537
Break Flow Flashing Terminated	3,958
RCS Cooldown Target Temperature Reached	5,082
Pressurizer PORV Opened	5,202
Pressurizer PORV Closed	5,358
Safety Injection Terminated	5,478
Break Flow Terminated	7,156

Table 2.7.2-5

Mass Releases
Total Mass Flow (Pounds)

	Time Period			
	Start of Event to Time of Reactor Trip[1,2]	**Time of Reactor Trip to Time at Which Break Flow is Terminated[1]**	**Time at Which Break Flow is Terminated to 2 Hours**	**2 Hours to Time at Which RCS Reaches RHR In-Service Conditions[1]**
Ruptured Steam Generator – Condenser – Atmosphere	 314,500 0	 0 215,400	 0 0	 0 20,400
Intact Steam Generators – Condenser – Atmosphere	 937,700 0.0	 0 365,600	 0 33,100	 0 1,302,800
Total Break Flow	9,400	298,500	0	0
Flashed Break Flow	1,390	24,092	0	0

Notes:

1. The break is initiated at 100 seconds. Reactor trip occurs at 277 seconds; break flow stops flashing at 3,958 seconds; break flow is terminated at 7,156 seconds; RHR conditions are reached at 11 hours.
2. Pre-trip releases to condenser and feedwater flows include 100 seconds steady-state operation prior to initiation of the break.

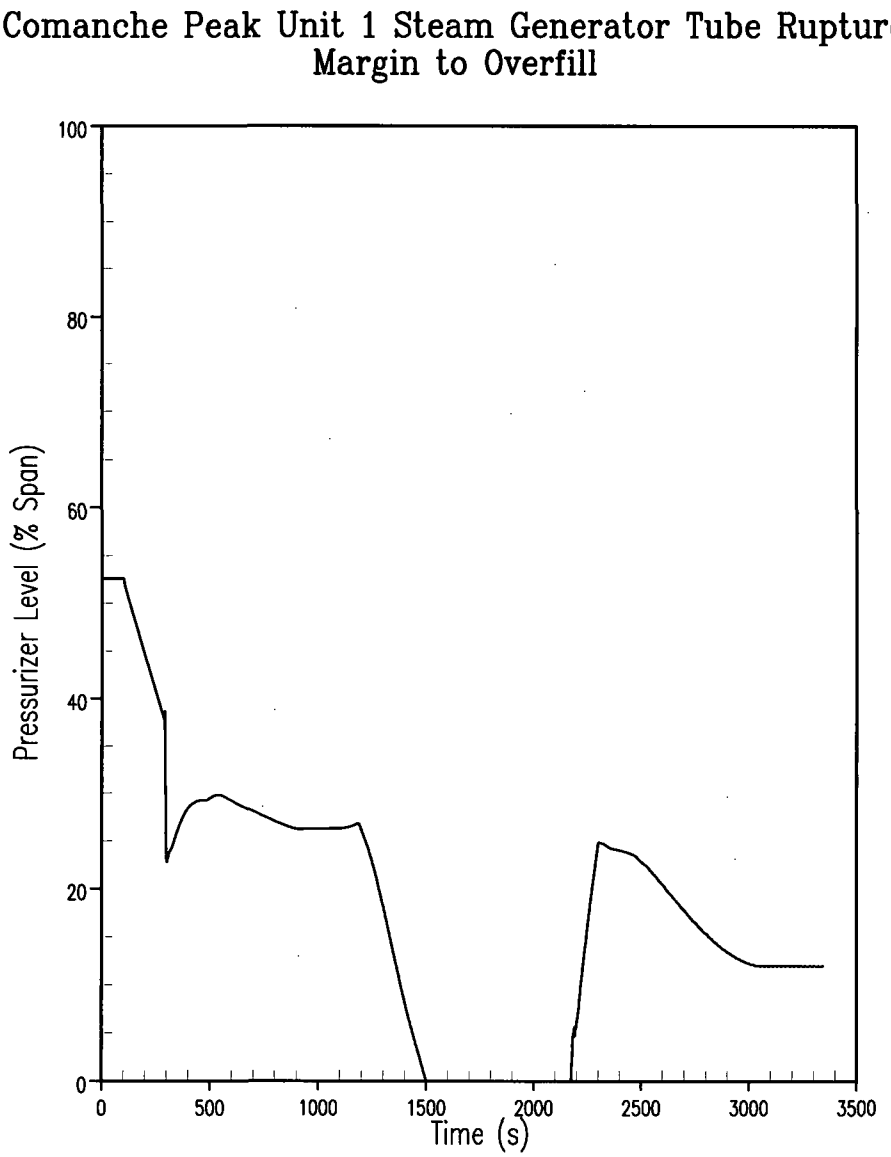


Figure 2.7.2-1 SGTR (Overfill), Pressurizer Level Versus Time

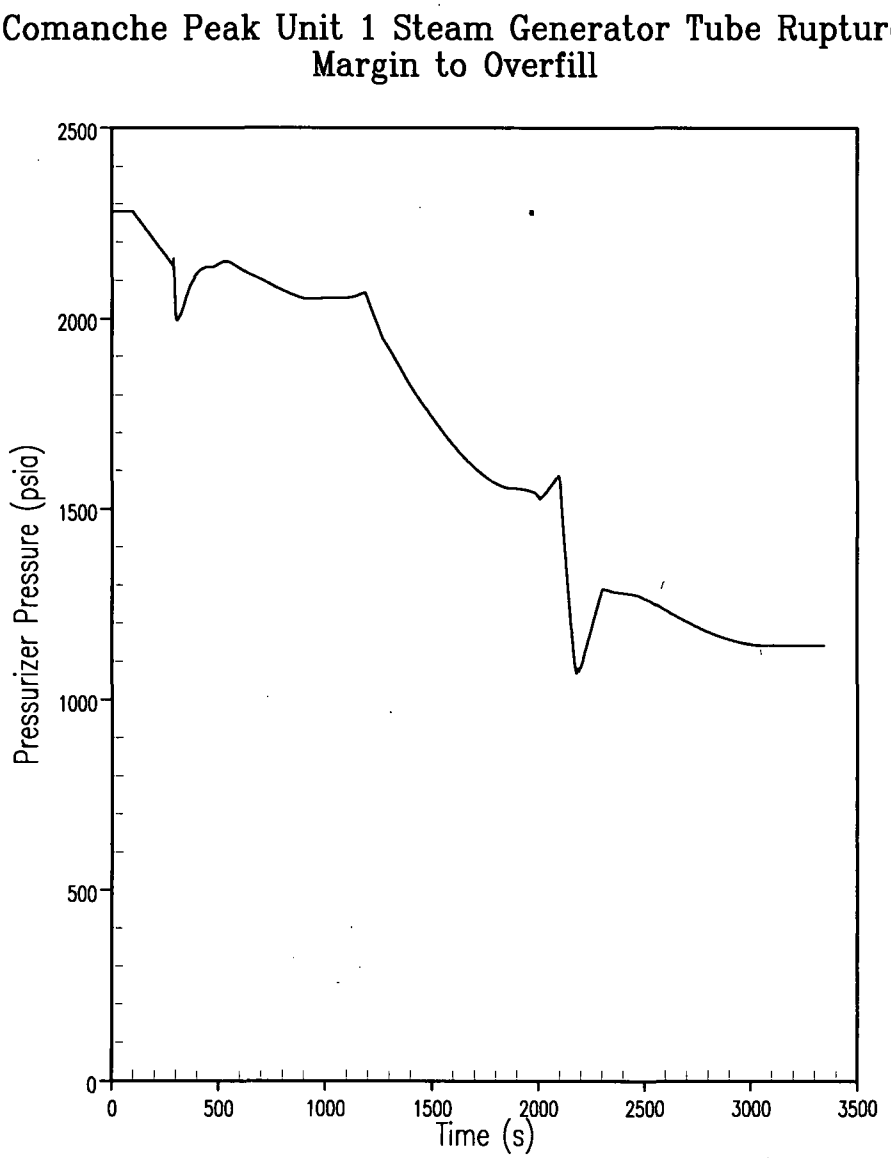


Figure 2.7.2-2 SGTR (Overfill), Pressurizer Pressure Versus Time

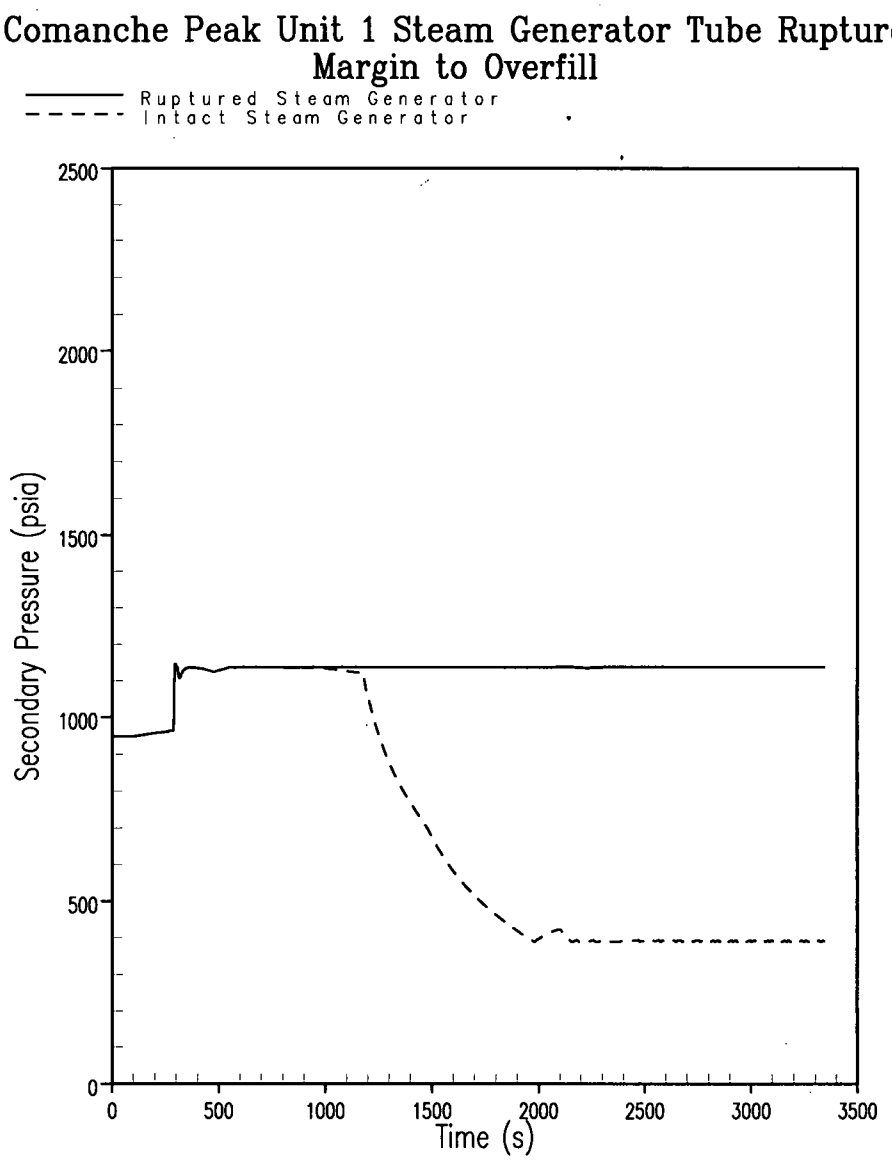


Figure 2.7.2-3 SGTR (Overfill), Secondary Pressure Versus Time

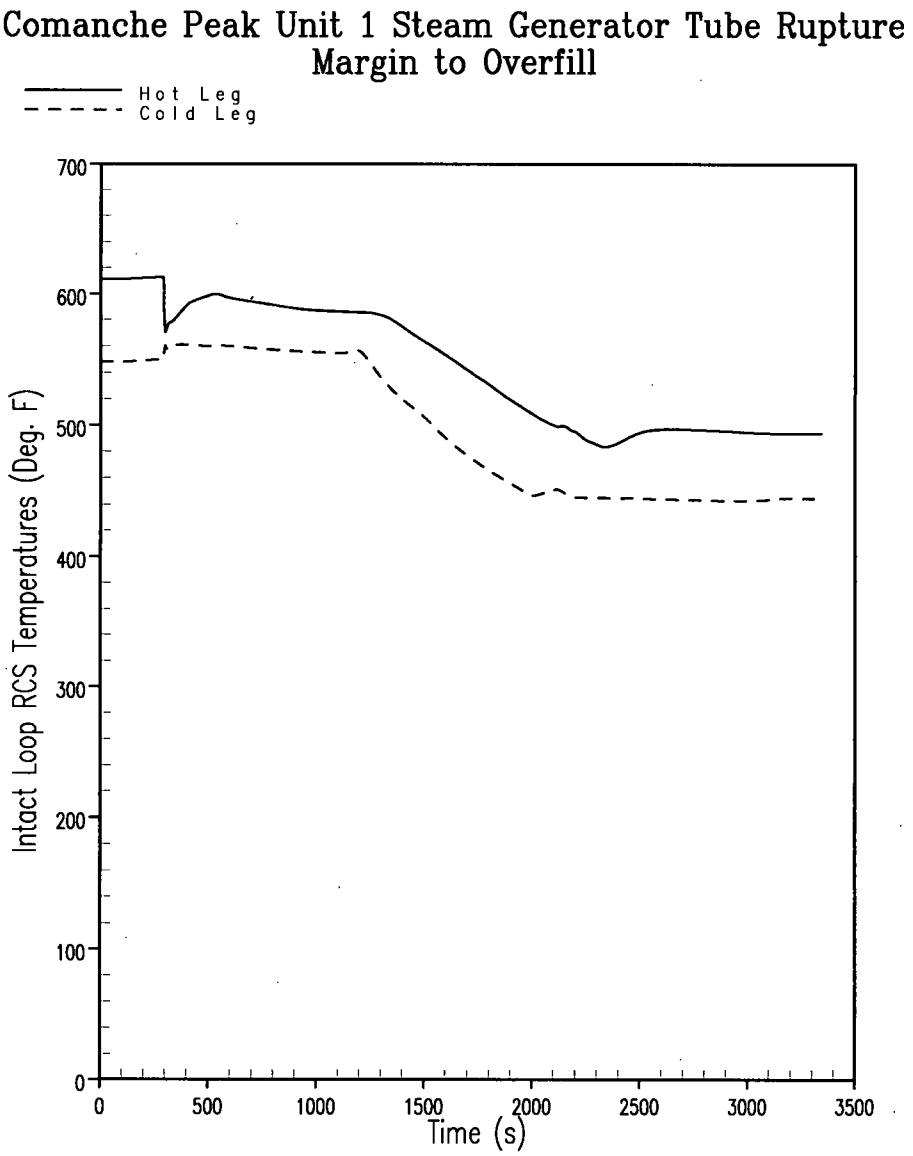


Figure 2.7.2-4 SGTR (Overfill), Intact Loop RCS Temperatures Versus Time

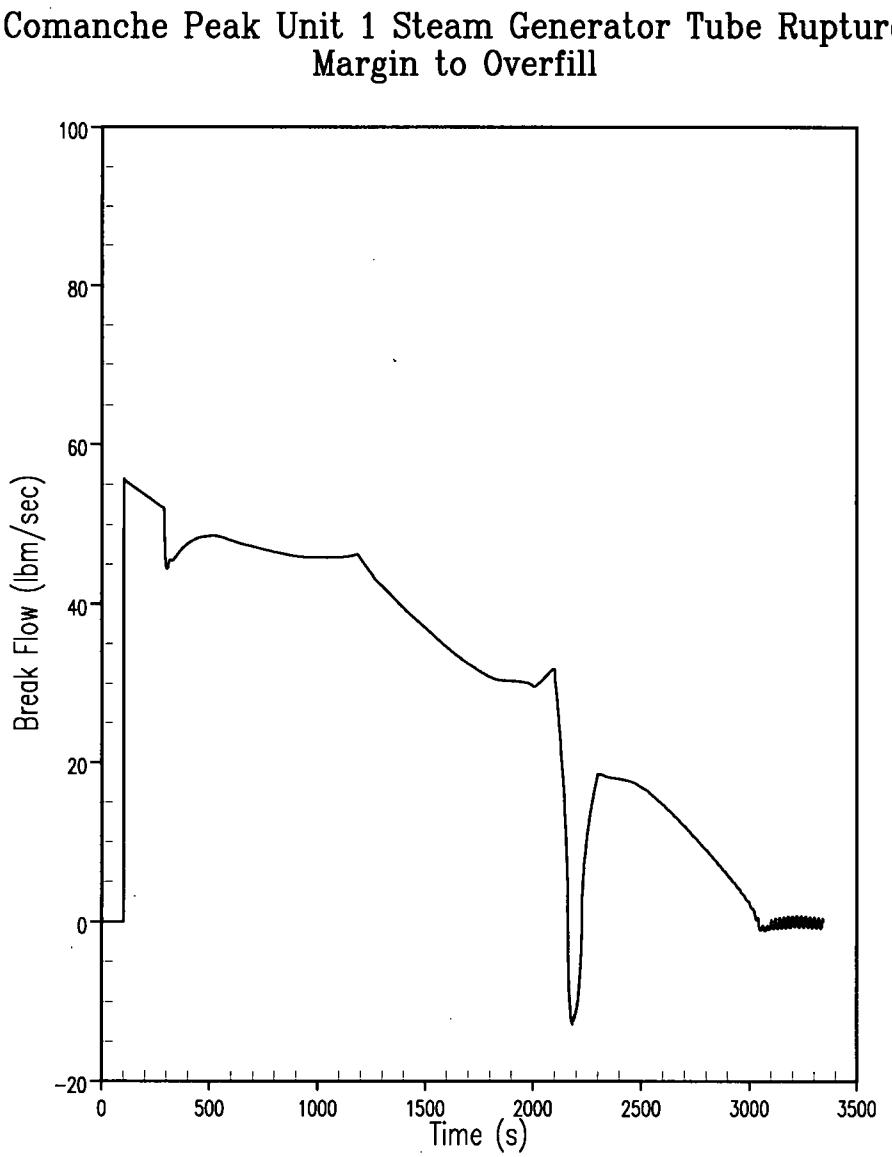


Figure 2.7.2-5 SGTR (Overfill), Break Flow Versus Time

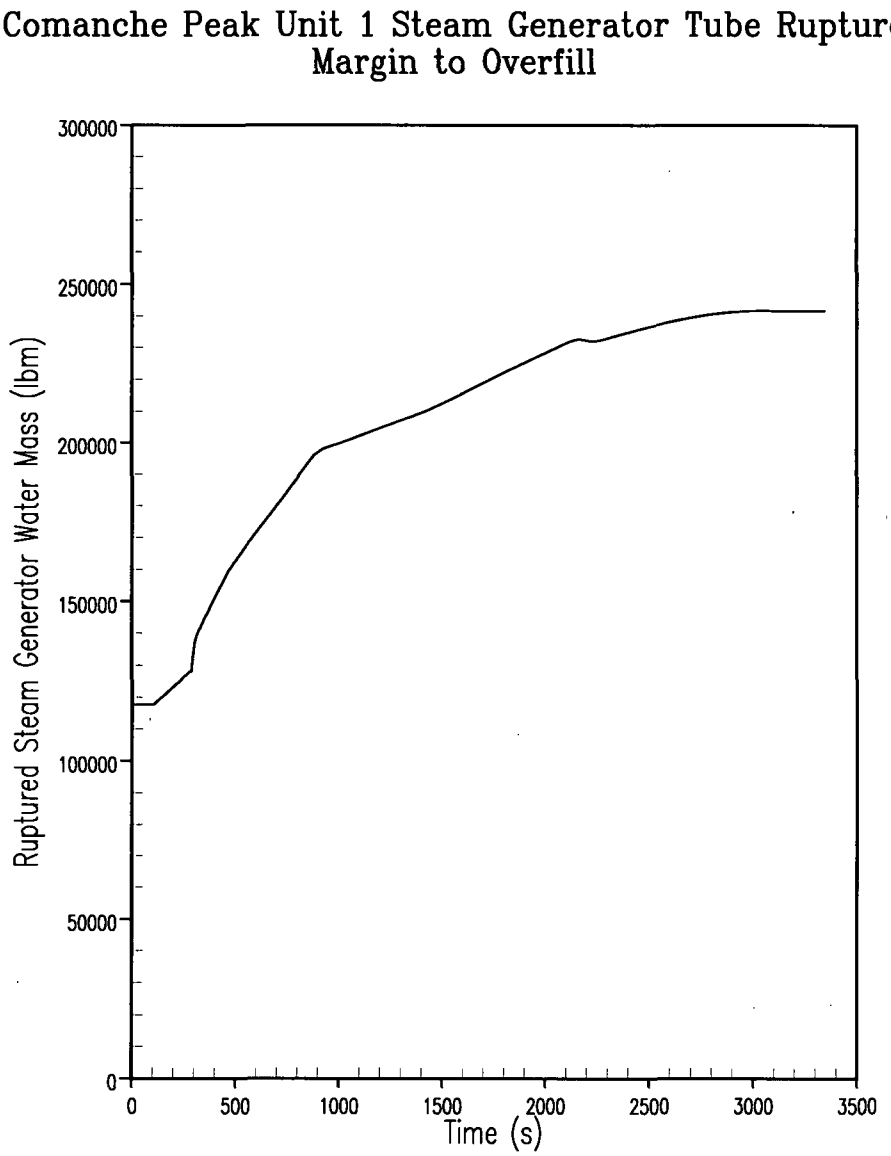


Figure 2.7.2-6 SGTR (Overfill), Ruptured Steam Generator Fluid Mass Versus Time

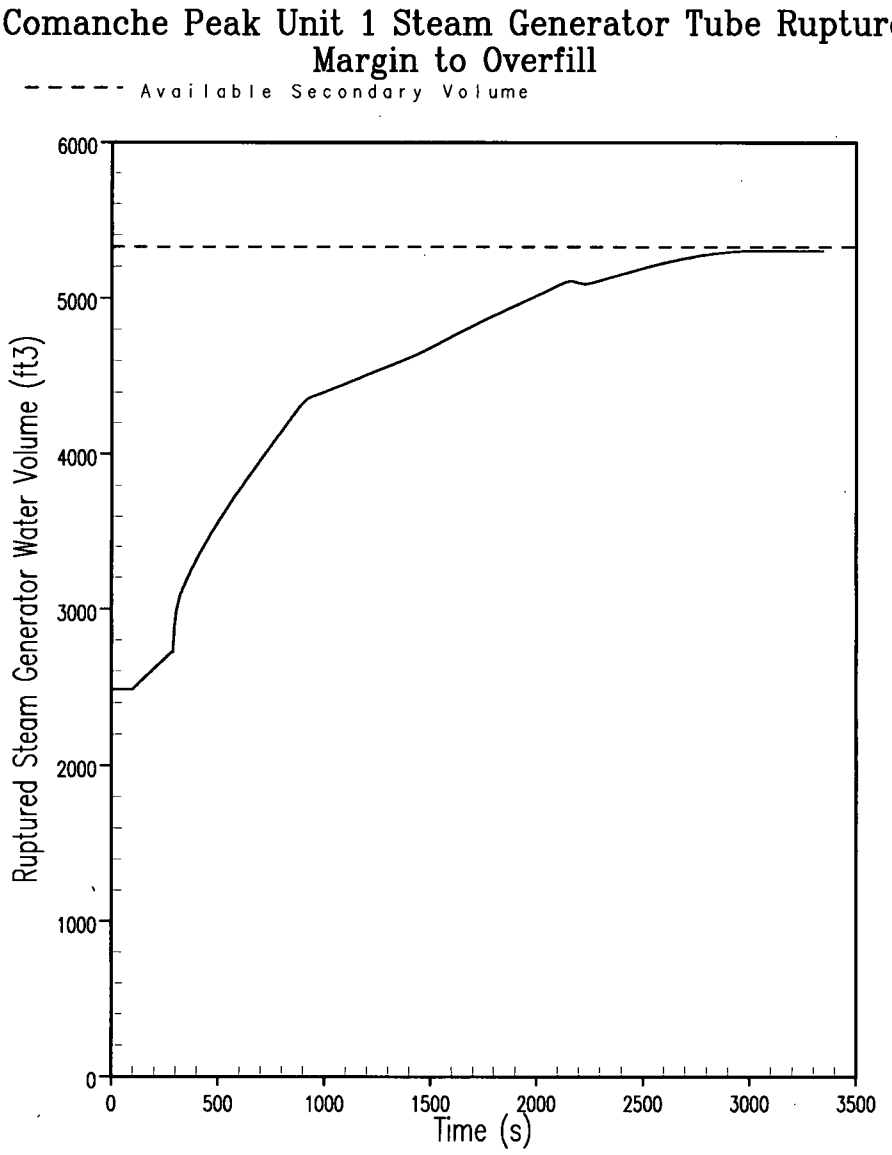


Figure 2.7.2-7 SGTR (Overfill), Ruptured Steam Generator Water Volume Versus Time

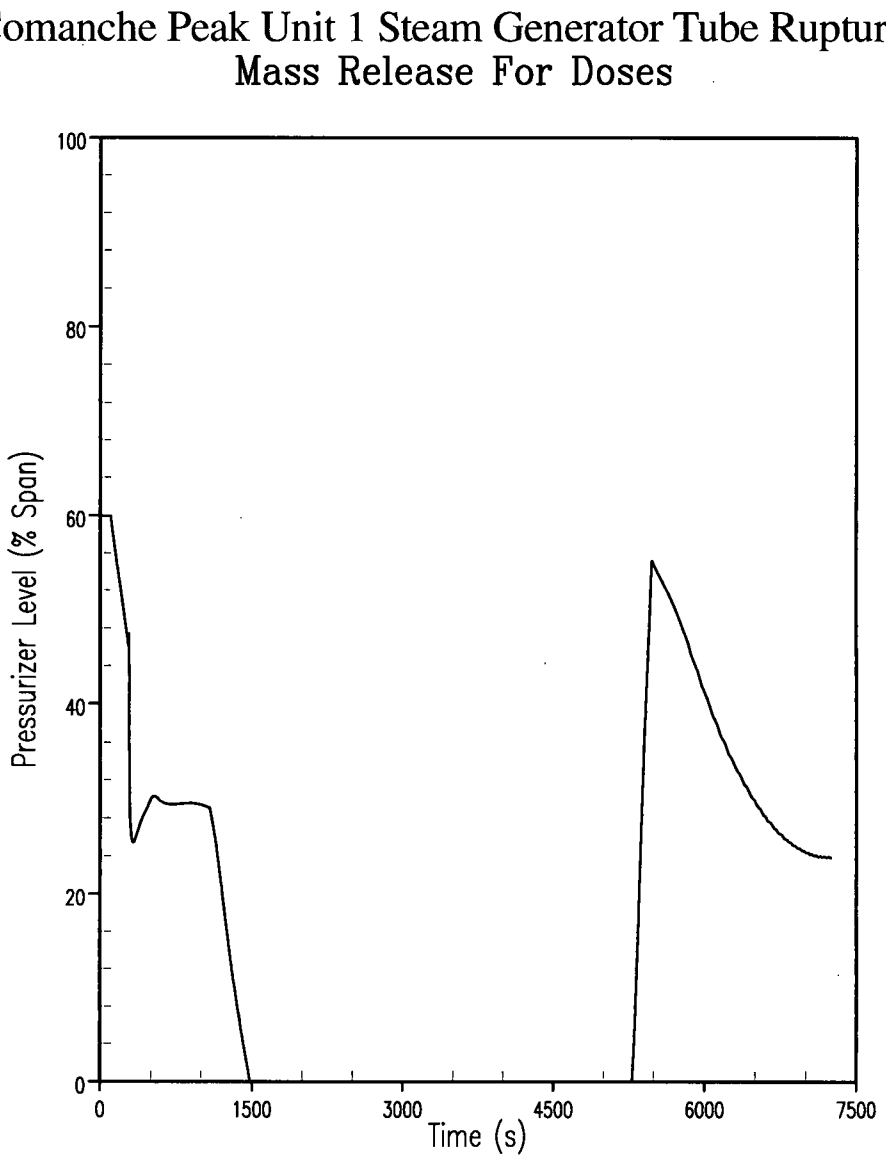


Figure 2.7.2-8 SGTR (Mass Release), Pressurizer Level Versus Time

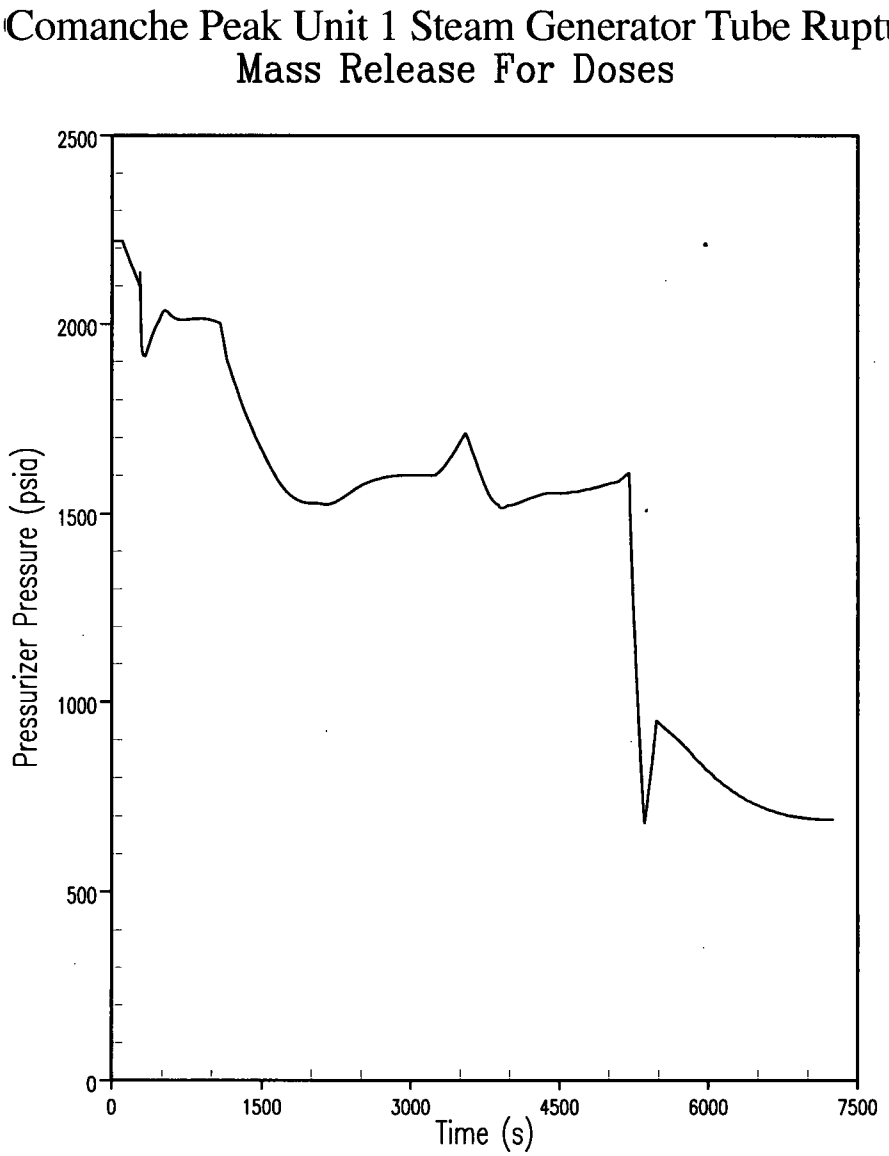


Figure 2.7.2-9 SGTR (Mass Release), Pressurizer Pressure Versus Time

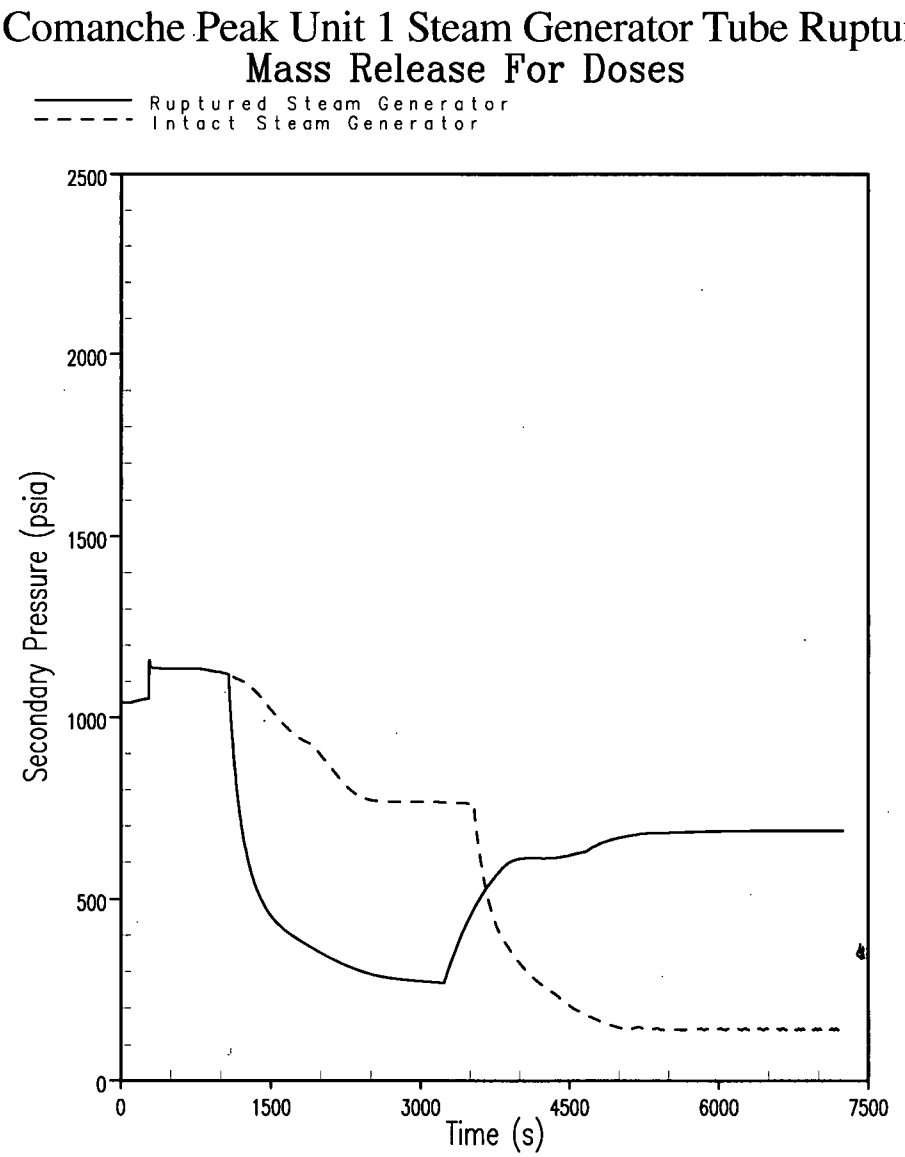


Figure 2.7.2-10 SGTR (Mass Release), Secondary Pressure Versus Time

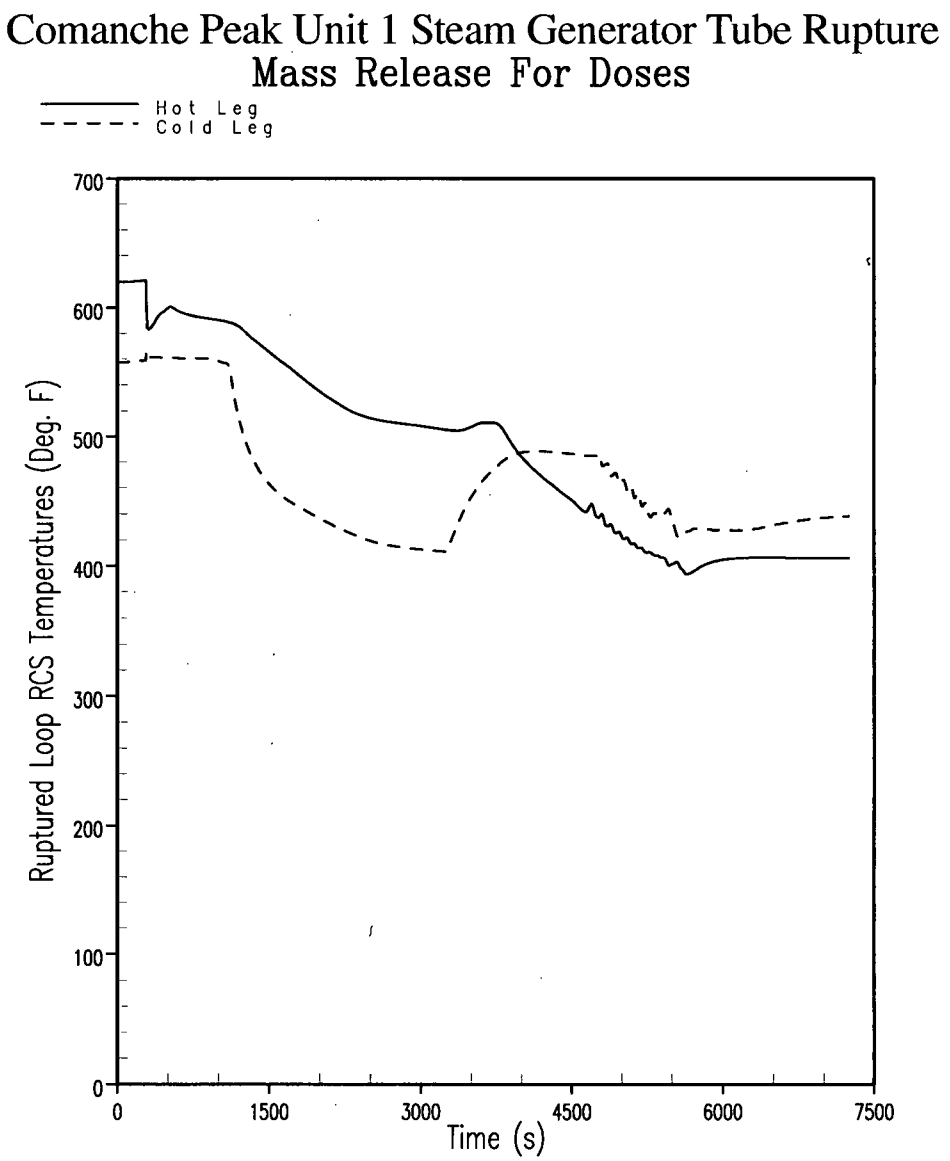


Figure 2.7.2-11 SGTR (Mass Release), Ruptured Loop RCS Temperatures Versus Time

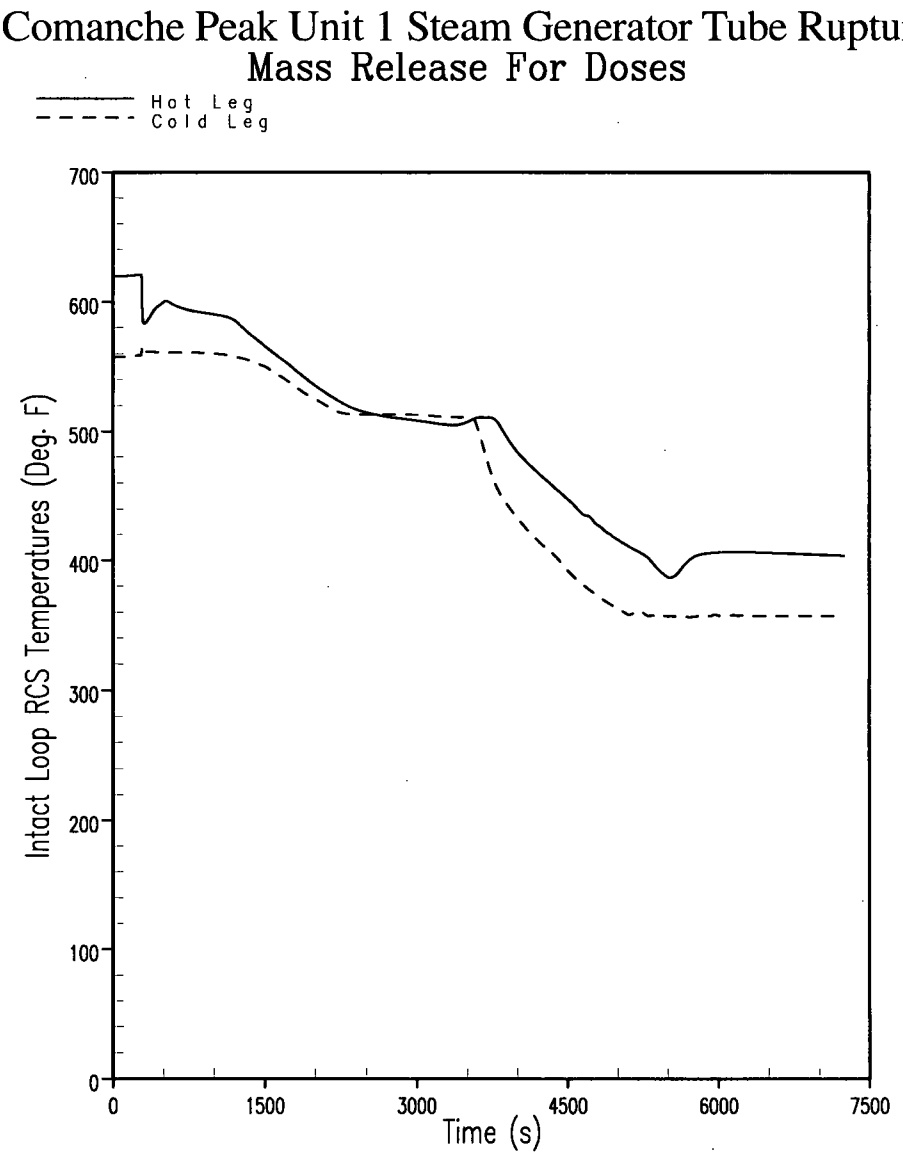


Figure 2.7.2-12 SGTR (Mass Release), Intact Loop RCS Temperatures Versus Time

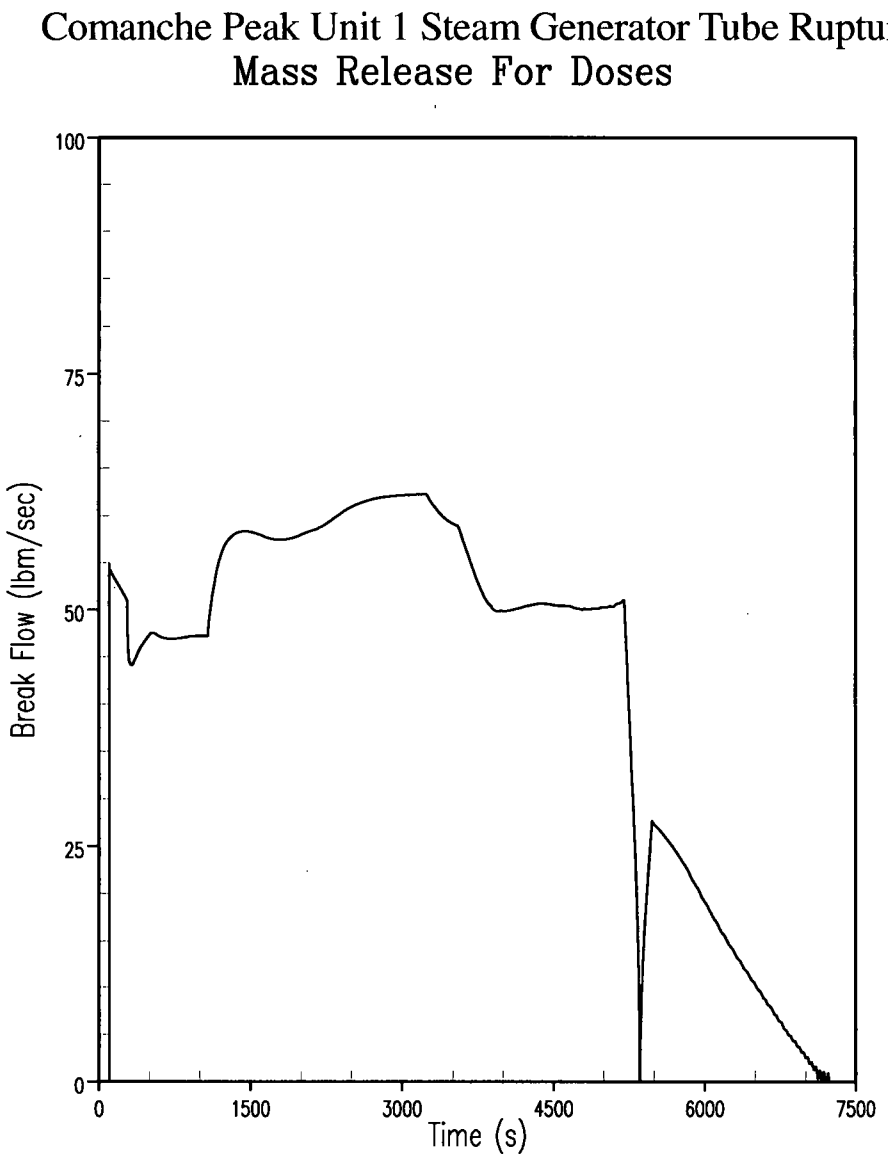


Figure 2.7.2-13 SGTR (Mass Release), Break Flow Versus Time

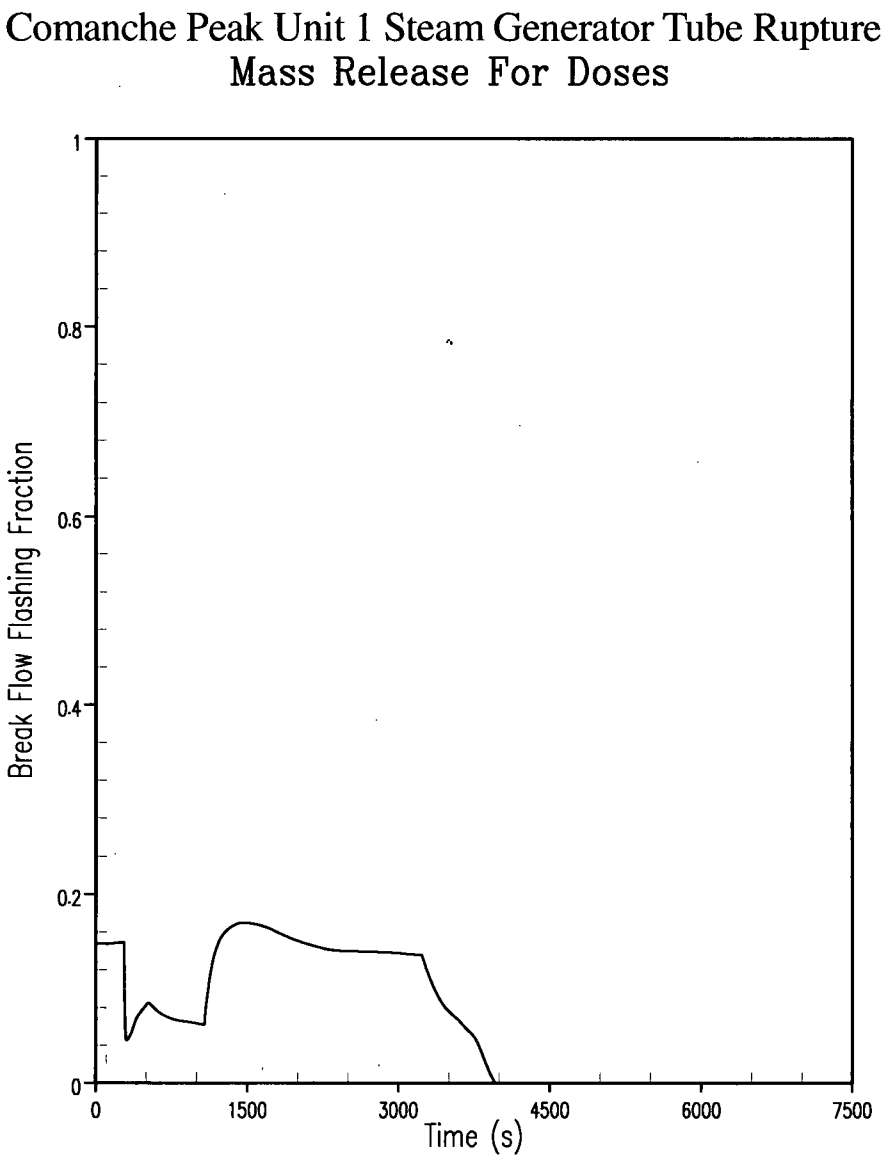


Figure 2.7.2-14 SGTR (Mass Release), Break Flow Flashing Fraction Versus Time

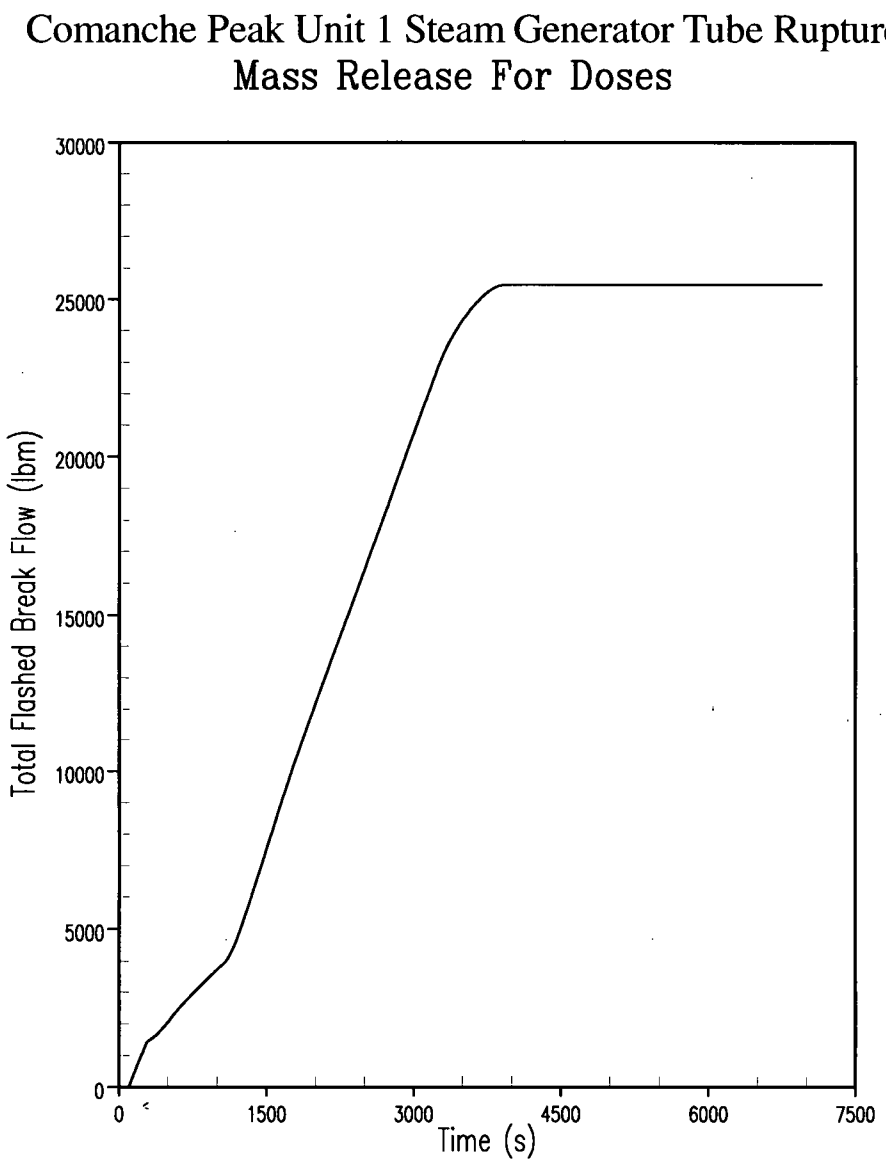


Figure 2.7.2-15 SGTR (Mass Release), Total Flashed Break Flow Versus Time

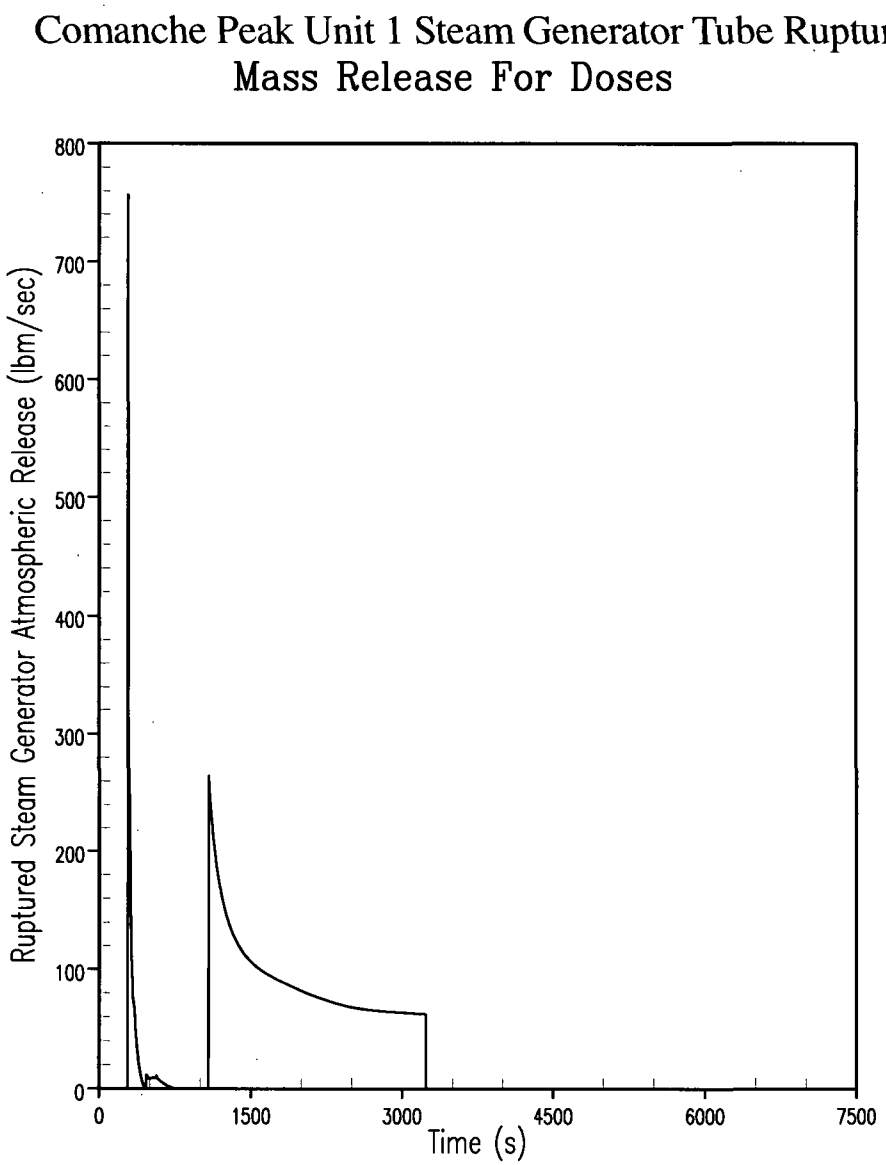


Figure 2.7.2-16 SGTR (Mass Release), Ruptured Steam Generator Mass Release Rate to the Atmosphere Versus Time

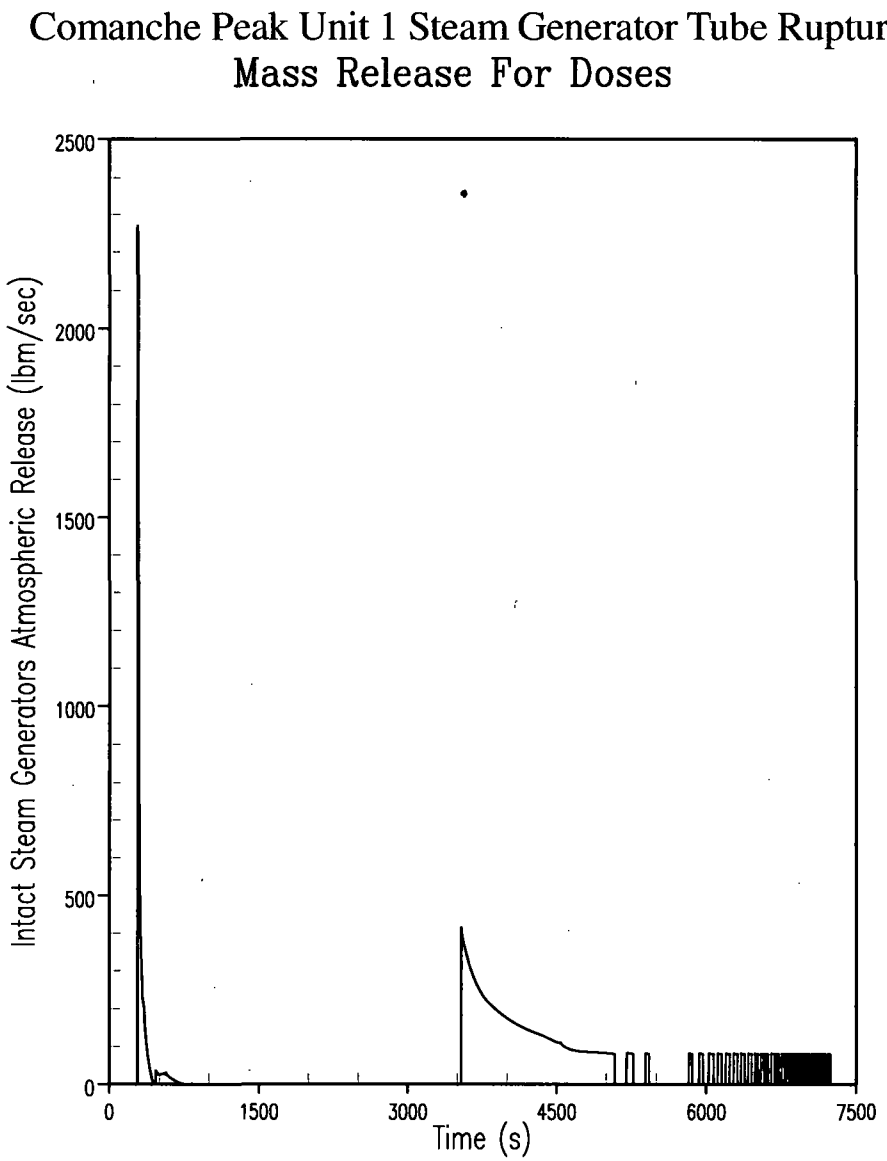


Figure 2.7.2-17 SGTR (Mass Release), Intact Steam Generator Mass Release Rate to the Atmosphere Versus Time

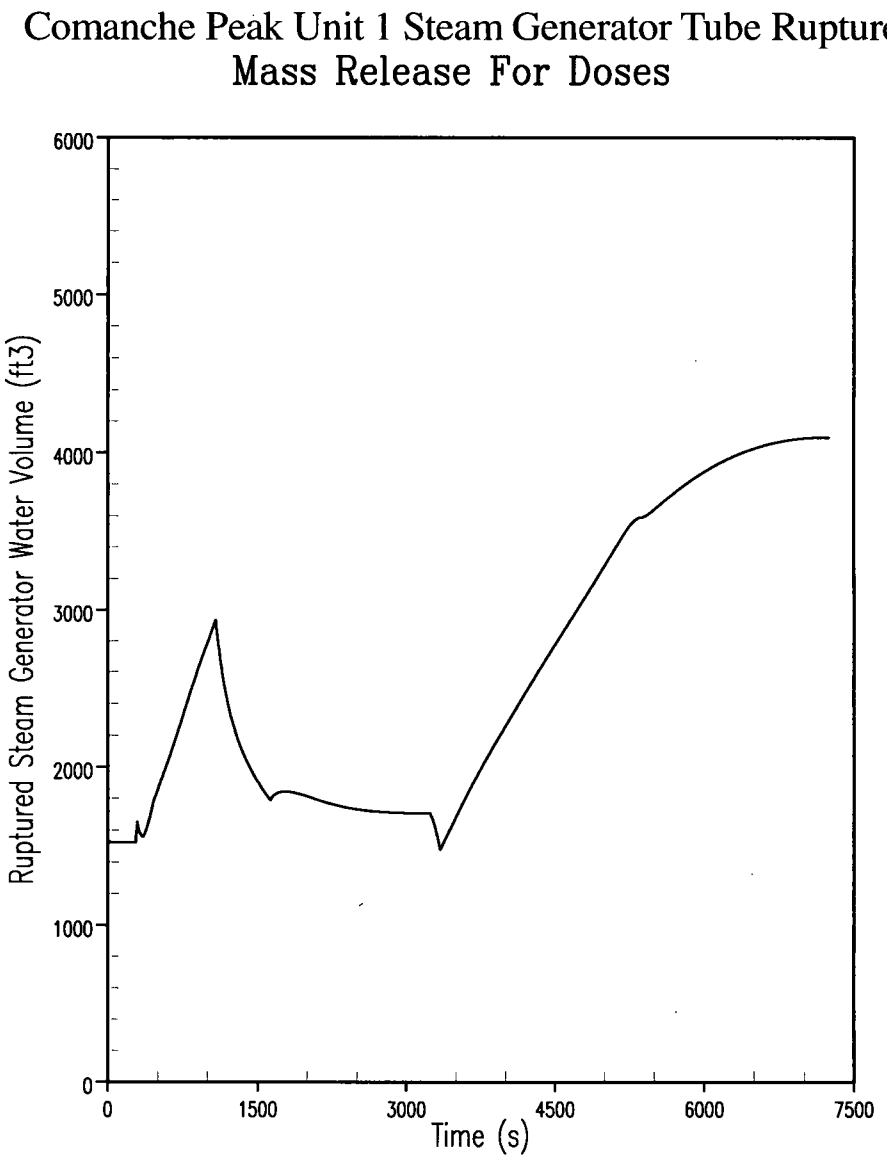


Figure 2.7.2-18 SGTR (Mass Release), Ruptured Steam Generator Water Volume Versus Time

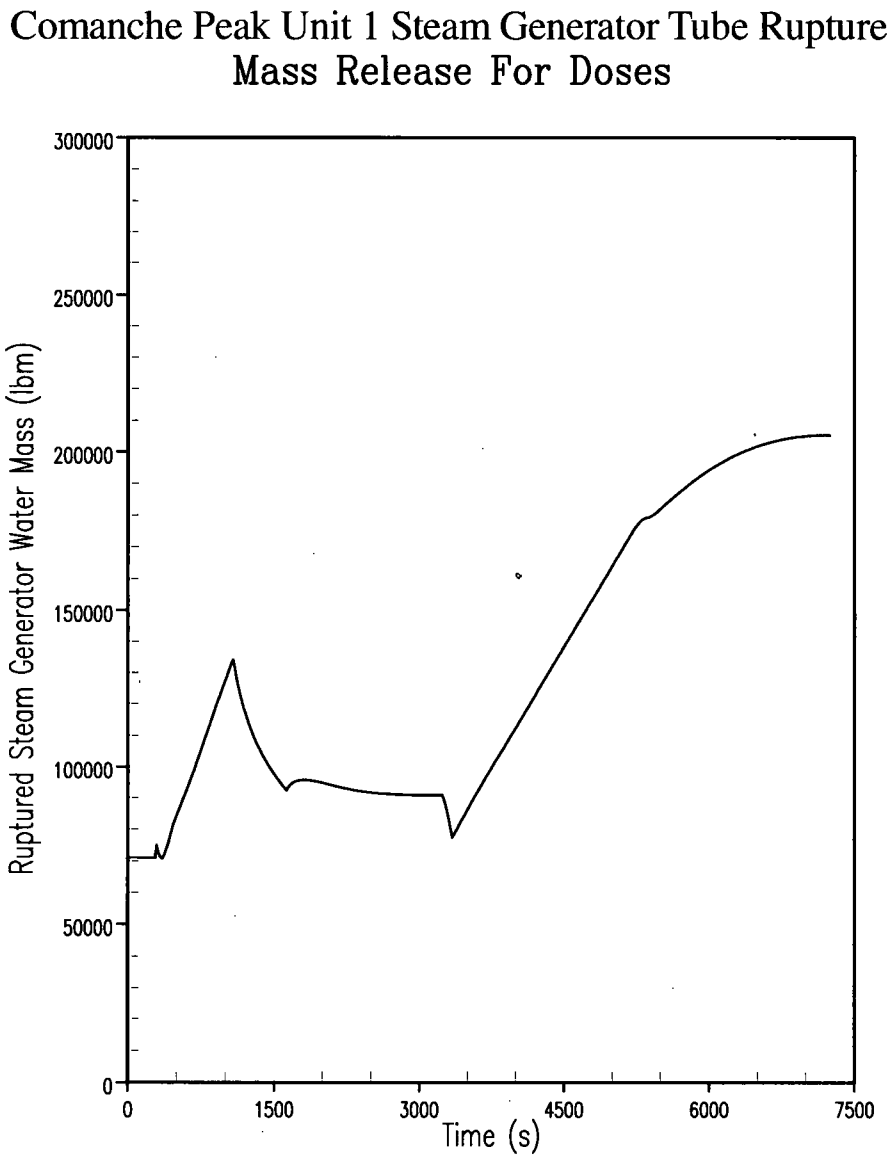


Figure 2.7.2-19 SGTR (Mass Release), Ruptured Steam Generator Water Mass Versus Time

2.7.3 Emergency Core Cooling System and Loss-of-Coolant Accidents

2.7.3.1 Large-Break LOCA

This section discusses the large-break best-estimate LOCA (BELOCA) analysis to support the TM and SPU programs for CPNPP.

2.7.3.1.1 Introduction

The LBLOCA is described in subsection 2.7.3.1.3 for a major rupture of the RCPB. A major rupture (large break) is defined as a breach in the RCPB with a total cross-sectional area greater than 1.0 ft^2.

A best-estimate LOCA analysis has been completed for the CPNPP Units 1 and 2. This license amendment request for CPNPP requests approval to apply the Westinghouse BELOCA analysis methodology.

Westinghouse recently underwent a program to revise the statistical approach used to develop the PCT and oxidation results at the 95th percentile. This method is still based on the Code Qualification Document (CQD) technology (Reference 1) and follows the steps in the Code Scaling, Applicability, and Uncertainty (CSAU) methodology (Reference 2). However, the uncertainty analysis (Element 3 in CSAU) is replaced by a technique based on order statistics. The Automated Statistical TReatment of Uncertainty Method (ASTRUM) methodology replaces the response surface technique with a statistical sampling method where the uncertainty parameters are simultaneously sampled for each case. The approved ASTRUM evaluation model is documented in WCAP-16009 (Reference 3).

Report subsections 2.7.3.1.2 through 2.7.3.1.4 summarize the application of the Westinghouse ASTRUM BELOCA evaluation model to the CPNPP analysis of the BELOCA event. The analysis was performed in compliance with all the NRC conditions and limitations as identified in WCAP-16009 (Reference 3). Luminant Power and its vendor, Westinghouse Electric Company LLC, continue to have ongoing processes that ensure that LOCA analysis input values conservatively bound the as-operated plant values for those parameters.

2.7.3.1.2 Input Parameters, Assumptions, and Acceptance Criteria

Table 2.7.3.1-1 lists the major plant parameter assumptions used in an as-approved ASTRUM BELOCA analysis. The major plant parameter assumptions for CPNPP Unit 1 and 2 are included in the safety analysis transition submittal to the NRC. The acceptance criteria are discussed in subsection 2.7.3.1.4.

2.7.3.1.3 Description of Analyses

Westinghouse developed an uncertainty methodology called ASTRUM (Reference 3). This method is based on the CQD methodology (Reference 1) and follows the steps in the CSAU methodology (Reference 2). However, the uncertainty analysis (Element 3 in the CSAU) is

replaced by a technique based on order statistics. The ASTRUM methodology replaces the response surface technique with a statistical sampling method where the uncertainty parameters are simultaneously sampled for each case. The ASTRUM methodology has received NRC approval for referencing in licensing calculations in WCAP-16009 (Reference 3). The ASTRUM methodology remains applicable to three- and four-loop PWRs, as well as 2-loop Westinghouse plants with upper plenum injection.

The three 10 CFR 50.46 criteria (PCT, LMO, and core-wide oxidation (CWO)) are satisfied by running a sufficient number of WCOBRA/TRAC calculations (sample size).

This analysis is in accordance with the applicability limits and usage conditions defined in Section 13.3 of WCAP-16009 (Reference 3), as applicable to the ASTRUM methodology. Section 13.3 of WCAP-16009 (Reference 3) was found to acceptably disposition each of the identified conditions and limitations related to WCOBRA/TRAC and the CQD uncertainty approach per Section 4.0 of the ASTRUM Final Safety Evaluation Report.

2.7.3.1.4 Results

The description of the limiting PCT, LMO, and CWO transients and the results for the CPNPP ASTRUM analyses are included in the safety analysis transition submittal to the NRC (TXX-07107 and TXX-07108).

10 CFR 50.46 Requirements

It must be demonstrated that there is a high level of probability that the limits set forth in 10 CFR 50.46 are met. The demonstration that these limits are met is as follows:

(b)(1) The limiting PCT corresponds to a bounding estimate of the 95th percentile PCT at the 95-percent confidence level. The resulting PCT for the limiting CPNPP case confirms that 10 CFR 50.46 acceptance criterion (b)(1), i.e., "Peak Clad Temperature less than 2,200°F," is demonstrated.

(b)(2) The maximum cladding oxidation corresponds to a bounding estimate of the 95th percentile LMO at the 95-percent confidence level. The resulting LMO (considering both transient and pre-transient oxidation) for the limiting CPNPP case confirms that 10 CFR 50.46 acceptance criterion (b)(2), i.e., "Local Maximum Oxidation of the cladding less than 17 percent," is demonstrated.

(b)(3) The limiting CWO corresponds to a bounding estimate of the 95th percentile CWO at the 95-percent confidence level. The resulting CWO for the limiting CPNPP case confirms that 10 CFR 50.46 acceptance criterion (b)(3), i.e., "Core-Wide Oxidation less than 1 percent," is demonstrated.

(b)(4) 10 CFR 50.46 acceptance criterion (b)(4) requires that the calculated changes in core geometry are such that the core remains amenable to cooling. This criterion has historically been satisfied by adherence to criteria (b)(1) and (b)(2), and by

assuring that fuel deformation due to combined LOCA and seismic loads is specifically addressed. It has been demonstrated that the PCT and maximum cladding oxidation limits remain in effect for best-estimate LOCA applications. The approved methodology (Reference 1) specifies that effects of LOCA and seismic loads on core geometry do not need to be considered unless grid crushing extends beyond the 44 assemblies in the low-power channel. This situation is not calculated to occur for CPNPP. Therefore, acceptance criterion (b)(4) is satisfied.

(b)(5) 10 CFR 50.46 acceptance criterion (b)(5) requires that long-term core cooling be provided following the successful initial operation of the ECCS. Long-term cooling is dependent on the demonstration of continued delivery of cooling water to the core. The actions, automatic or manual, that are currently in place at these plants to maintain long-term cooling remain unchanged with the application of the ASTRUM methodology (Reference 3).

2.7.3.1.5 References

1. WCAP-12945, Volume 1, Revision 2 and Volumes 2 through 5, Revision 1, and WCAP-14747, "Code Qualification Document for Best-Estimate LOCA Analysis," 1998.

2. "Qualifying Reactor Safety Margins: Application of Code Scaling Applicability and Uncertainty (CSAU) Evaluation Methodology to a Large Break Loss-of-Coolant-Accident," 1989.

3. WCAP-16009, "Realistic Large Break LOCA Evaluation Methodology using the Automated Statistical Treatment of Uncertainty Method (ASTRUM)," 2005.

4. "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors," 10 CFR 50.46 and Appendix K of 10 CFR 50, Federal Register, Volume 39, Number 3, January 4, 1974.

5. Information Report from W. J. Dircks to the Commissioners, "Emergency Core Cooling System Analysis Methods," SECY-83-472, November 17, 1983.

6. "Best-Estimate Calculations of Emergency Core Cooling System Performance," Regulatory Guide 1.157, USNRC, May 1989.

Table 2.7.3.1-1 Major Plant Parameter Assumptions Used in Best-Estimate LBLOCA ASTRUM Analysis	
Parameter	**Bias**
Plant Physical Description	
• Steam Generator Tube Plugging	Maximum
Plant Initial Operating Conditions	
• Reactor Power	Maximum (nominal + uncertainties)
• Peaking Factors	Max F_Q Max $F_{\Delta H}$
• Axial Power Distribution	PBOT/PMID Envelop
Fluid Conditions	
• T_{avg}	Nominal ± uncertainties
• Pressurizer Pressure	Nominal ± uncertainties
• Reactor Coolant Flow	Nominal
• Accumulator Temperature	Nominal ± uncertainties
• Accumulator Pressure	Nominal ± uncertainties
• Accumulator Water Volume	Nominal ± uncertainties
• Accumulator Boron Concentration	Minimum
Accident Boundary Conditions	
• Single Failure Assumptions	Loss of one ECCS train
• Safety Injection Flow	Minimum
• Safety Injection Temperature	Nominal ± uncertainties
• Safety Injection Initiation Delay Time	Maximum delay with offsite power Maximum delay without offsite power
• Containment Pressure	Minimum

2.7.3.2 Small-Break LOCA

2.7.3.2.1 Introduction

A LOCA is defined as a rupture of the RCS piping or of any line connected to the system. The small-break LOCA (SBLOCA) includes all postulated pipe ruptures with a total cross-sectional area less than 1.0 ft^2. The SBLOCAs analyzed in this section are for those breaks beyond the capability of a single charging pump resulting in the actuation of the ECCS. The analysis was

performed to demonstrate conformance with the 10 CFR 50.46 requirements for the conditions associated with the CPNPP Units 1 and 2 TM and SPU programs.

2.7.3.2.2 Input Parameters, Assumptions and Acceptance Criteria

Table 2.7.3.2-1 lists the key input parameters and assumptions used in a NOTRUMP-EM SBLOCA analysis. The key input parameters and assumptions for CPNPP are included in the Safety Analysis Transition submittal to the NRC.

The acceptance criteria for the SBLOCA analysis are specified in 10 CFR 50.46, as follows:

1. The calculated maximum fuel element cladding temperature shall not exceed 2,200°F.

2. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

3. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

4. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

5. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core. (Note that this criterion is not addressed as part of the short-term SBLOCA analysis; the post-LOCA long term cooling analysis addresses this acceptance criterion.)

2.7.3.2.3 Description of Analyses

The SBLOCA analysis was performed for the CPNPP Unit 1 and 2 TM and SPU programs using the 1985 Westinghouse SBLOCA Evaluation Model with NOTRUMP (NOTRUMP-EM) (References 1 – 3), including NRC approved changes to the methodology as described in References 4 and 5. Westinghouse obtained generic NRC approval of the NOTRUMP computer code's modeling capabilities and solution techniques (Reference 1) and the use of the NOTRUMP computer code for licensing applications (Reference 2) in 1985. NRC approval of additional modeling details (Reference 3), such as limiting break location was obtained in 1986. The NOTRUMP-EM was later revised (Reference 4) and granted generic NRC approval for an improved condensation model and related changes in safety injection modeling assumptions for safety injection to the RCS cold legs. Most recently, the NRC generically approved updates to the NOTRUMP-EM to include the ability to model annular fuel pellets (Reference 5) in the fuel rod heatup calculations.

2.7.3.2.4 Results

The results for the CPNPP NOTRUMP-EM SBLOCA analysis are included in the Safety Analysis Transition submittal to the NRC (TXX-07107 and TXX-07108).

2.7.3.2.5 References

1. WCAP-10079, "NOTRUMP - A Nodal Transient Small Break and General Network Code," August 1985.

2. WCAP-10054, "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," August 1985.

3. WCAP-11145, "Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study with the NOTRUMP Code," October 1986.

4. WCAP-10054, Addendum 2, Revision 1, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," July 1997.

5. WCAP-14710, "1-D Heat Conduction Model for Annular Fuel Pellets," May 1998.

6. LTR-NRC-06-44, "Transmittal of LTR-NRC-06-44 NP-Attachment, 'Response to NRC Request for Additional Information on the Analyzed Break Spectrum for the Small Break Loss of Coolant Accident (SBLOCA) NOTRUMP Evaluation Model (NOTRUMP EM), Revision 1'," July 2006.

Table 2.7.3.2-1 Key Plant Parameters and Assumptions Used in Appendix K SBLOCA NOTRUMP-EM Analysis	
Parameter	**Bias**
A. Core Parameters	
Analyzed Core Power Level	Maximum (Nominal + Uncertainties)
Total Core Peaking Factor, F_Q	Maximum
Hot Channel Enthalpy Rise Factor, $F_{\Delta H}$	Maximum
Hot Assembly Average Rod Power, P_{HA}	Maximum
Axial Offset	Maximum
B. Reactor Coolant System	
Pressurizer Pressure	Maximum (Nominal + Uncertainties)(1)
C. Reactor Protection System	
Reactor Trip Setpoint	Minimum
E. Steam Generators	
Steam Generator Tube Plugging	Maximum(1)
F. Safety Injection (SI)	
Limiting Single Failure	Loss of one Emergency Diesel Generator
SI Water Temperature	Maximum
SI Delay Time	Maximum
Safety Injection Flow Rates	Minimum
G. Accumulators	
Water/Gas Temperature	Maximum
Cover Gas Pressure	Minimum

Notes:

1. These parameters are analyzed at the maximum value, but are generally inconsequential to SBLOCA analysis results.

2.7.3.3 Post-LOCA Subcriticality

2.7.3.3.1 Technical Evaluation

Input Parameters, Assumptions, and Acceptance Criteria

The input parameters and assumptions used in the sump boron calculations are given in Table 2.7.3.3-1.

The sump boron concentration calculational model is based on the following assumptions:

- The calculation of the sump mixed mean boron concentration assumes minimum mass and minimum boron concentrations for significant boron sources and maximum mass and minimum boron concentration for significant dilution sources.
- Boron is mixed uniformly in the sump. The post-LOCA sump inventory is made up of constituents that are equally likely to return to the containment sump; that is, selective holdup in containment is neglected.
- The sump mixed mean boron concentration is calculated as a function of the pre-trip RCS conditions.

There are no specific acceptance criteria when calculating the post-LOCA sump boron concentration. However, the resulting sump boron concentration, which is calculated as a function of the pre-LOCA RCS boron concentration, is reviewed for each cycle-specific core design to confirm that adequate boron exists to maintain subcriticality in the long-term post-LOCA.

Description of Analyses and Evaluations

With respect to post-LOCA criticality, a post-LOCA subcriticality boron limit curve was developed for the TM and SPU plant conditions. Provided that the cycle-specific maximum critical boron concentration remains below the post-LOCA sump boron concentration limit curve (for all rods out, no Xenon, 68 – 212°F), the core will remain subcritical post-LOCA, and decay heat can be removed for the extended period required by the remaining long-lived radioactivity.

Results

A post-LOCA subcriticality boron limit curve was developed for the TM and SPU plant conditions. The CPNPP TM and SPU post-LOCA subcriticality boron limit curve is shown in Figure 2.7.3.3-1.

2.7.3.3.2 Conclusion

Cycle-specific reload safety evaluations will ensure that the core will remain subcritical post-LOCA, thus addressing the GDC-27 requirement that the capability to cool the core is maintained.

2.7.3.3.3 References

1. WCAP-8339, "Westinghouse Emergency Core Cooling System Evaluation Model - Summary," June 1974.

2. WCAP-9272, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

Table 2.7.3.3-1 CPNPP Units 1 and 2 TM and SPU Input Parameters	
Parameter	**TM and SPU Value**
RWST Boron Concentration, Minimum (ppm)	2,400
Accumulator Boron Concentration, Minimum (ppm)	2,300
RWST Volume, Assumed Minimum (gallons)	440,300

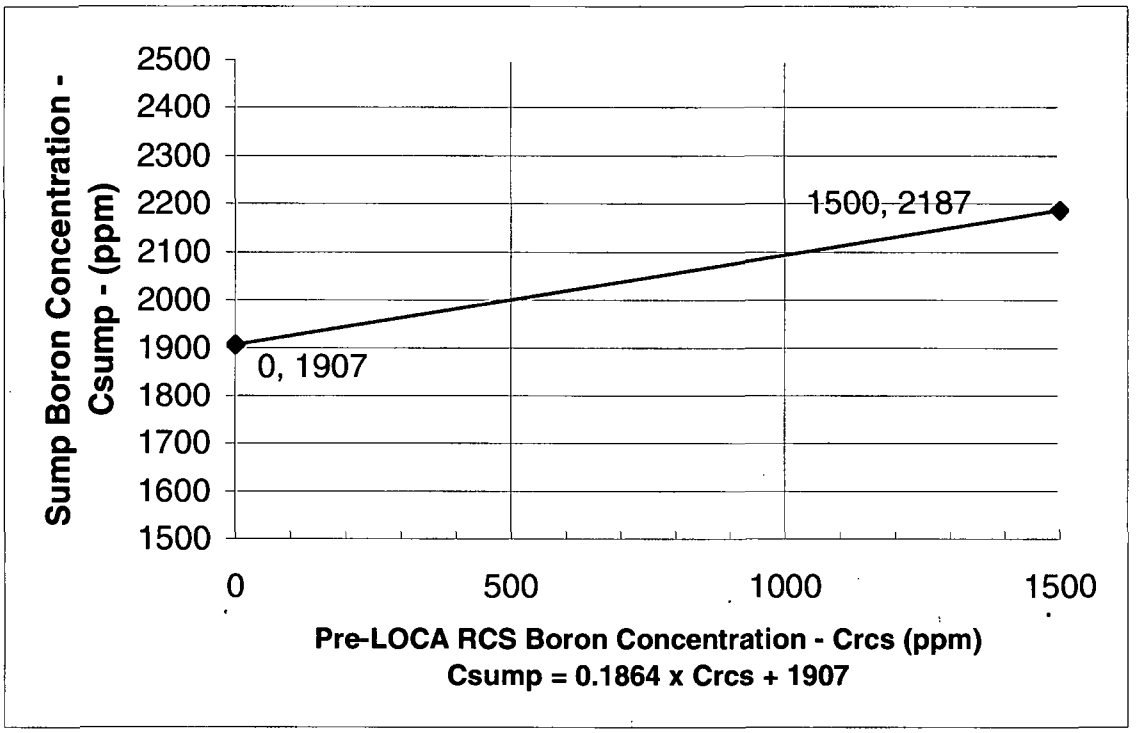


Figure 2.7.3.3-1 CPNPP TM and SPU Post-LOCA Subcriticality Boron Limit Curve

2.7.3.4 Post-LOCA Long-Term Cooling

2.7.3.4.1 Technical Evaluation

Input Parameters, Assumptions, and Acceptance Criteria

The major inputs to the boric acid precipitation calculation include core power assumptions and assumptions for boron concentrations and water volume/masses for significant contributors to the containment sump. The input parameters used in the CPNPP TM and SPU boric acid precipitation calculations are given in Table 2.7.3.4-1.

The boric acid precipitation calculation model is based on the following assumptions and meets NRC guidance as presented in Reference 3 and is consistent with the interim methodology reported in Reference 4.

- The boric acid concentration in the core region is computed over time with consideration of the effect of core voiding on liquid mixing volume. Voiding is calculated using the Modified Yeh Correlation described in Reference 1.

- The core mixing volume used in the calculations considered the potential negative effects of loop pressure drop.

- The boric acid concentration limit is the experimentally determined boric acid solubility limit as reported in Reference 2 and summarized in Table 2.7.3.4-2 and Figure 2.7.3.4-1. For large breaks and large small breaks, the effect of containment or RCS pressure above atmospheric pressure is not credited and the boric acid solubility limit at 218°F (boiling point of saturated boric acid solution at atmospheric conditions) is assumed. For breaks where RCS depressurization is not complete or breaks where the RCS might be at elevated pressures at hot leg switchover time, the solubility limit associated with the saturation temperature of water at the associated elevated pressure is credited.

- The liquid mixing volume used in the calculation includes 50 percent of the lower plenum volume and is consistent with the results of the Mitsubishi Heavy Industries (MHI) BACCHUS PWR vessel mixing tests summarized in Reference 7.

- For SBLOCA scenarios, the analysis does not assume a specific start time for cooldown/depressurization emergency procedures, nor does it assume depressurization to some minimum pressure at hot leg switchover time. Nevertheless, for the purpose of defining expected scenarios, it is anticipated that operators begin cooldown/depressurization within one hour of the initiation of the event.

- The effect of containment sump pH additives on increasing the boric acid solubility limit is not credited.

- The boric acid concentration of the makeup containment sump water during recirculation is a calculated sump mixed mean boron concentration. The calculation of the sump mixed mean boron concentration assumes maximum mass and maximum boron concentrations for significant boron sources, and minimum mass and maximum boron concentrations for significant dilution sources.

- ECCS flow and enthalpy changes that may occur during the switchover from injection mode to sump recirculation are not part of the long-term cooling analysis scope and were considered in the SBLOCA analysis.

In addition to the above assumptions, NRC requirements pertaining to the decay heat generation rate for both boric acid accumulation and decay heat removal (which is based on the 1971 ANS Standard for an infinite operating time with 20-percent uncertainty) is utilized as an input to prepare the boric acid precipitation calculation. The assumed core power includes a multiplier to address instrument uncertainty as identified by Section 1.A of 10 CFR 50, Appendix K.

The acceptance criteria for the long-term cooling analysis are demonstrated by the ability to keep the core cool after a LOCA and calculating a hot leg switchover (HLSO) time with methods, plant design assumptions, and operating parameters are consistent with the interim methodology reported in Reference 4. The FSAR, Technical Specifications, and EOPs have been revised to support the maximum time to establish simultaneous hot leg and cold leg injection.

ECCS recirculation flows are evaluated by comparing minimum safety injection pump flows to the flows necessary to dilute the core and replace core boiloff, thus keeping the core quenched.

Description of Analyses and Evaluations

There are two aspects to a long-term cooling analysis – the potential for boric acid precipitation to occur and decay heat removal. The purpose of the boric acid precipitation analysis is to demonstrate that the maximum boric acid concentration in the core remains below the solubility limit, thereby preventing the precipitation of boric acid in the core. If boric acid were to precipitate in the core region, the precipitate might prevent water from remaining in contact with the fuel cladding and, consequently, result in the core temperature not being maintained at an acceptably low value. The boric acid precipitation analysis determines the appropriate time for switching some or all ECCS recirculation flow to the hot leg and verifies that there is sufficient dilution flow through the core to dilute the core and prevent boric acid buildup.

Prior to sump recirculation, core cooling is addressed by the LBLOCA analysis that demonstrates core reflood and stable and sustained quench, and by the SBLOCA analysis that demonstrates core recovery. After an SBLOCA, RCS refill, depressurization and entry into shutdown cooling, or depressurization and indefinite sump recirculation occurs. With the switch to sump recirculation, long-term cooling is addressed by demonstrating that the core remains covered with two-phase mixture in the long term, thereby ensuring that the core temperature is maintained at an acceptably low value. Paragraph (b)(5) of 10 CFR 50.46 is satisfied when the

fuel in the core is quenched, the switch from injection to recirculation phases is complete, and the recirculation flow is large enough to match the boiloff rate. Prior to hot leg recirculation, the ECCS recirculation flow must be sufficient to remove decay heat. ECCS pump availability and specific flow path alignments may reduce ECCS recirculation flow as compared to the flows available during the injection phase. After the switch to hot leg recirculation, core flow sufficient to dilute the core or prevent boric acid buildup, by definition, exceeds core boiloff and therefore provides core cooling.

The long-term cooling analysis described here supports the Post-LOCA Boric Acid Precipitation Analysis Logic presented in Table 2.7.3.4-3. The flowchart in Figure 2.7.3.4-2 shows the applicability of the calculations to the specific post-LOCA scenarios.

Large-Break LOCAs

Large breaks (double-ended guillotine down to approximately 1.0 ft^2) rapidly depressurize to very near containment pressure with no operator action. The 14.7 psia boric acid precipitation calculation models this scenario and calculates the boric acid buildup for the limiting condition of a cold leg break. Dilution and core cooling flows are confirmed for 14.7 psia RCS backpressure. After hot leg switchover, the hot leg injected flow provides immediate core dilution for a cold leg break. If the break is in the hot leg, injected ECCS flow to the cold leg is sufficient to prevent the buildup of boric acid in the core after switchover to hot leg recirculation. Therefore, after hot leg switchover, simultaneous hot leg and cold leg injection prevents boric acid precipitation in the long term.

Large breaks that lead to rapid RWST draindown represent the limiting case for recirculation flow requirements. At the start of sump recirculation, ECCS flows are evaluated.

Large Small-Break LOCAs

Large small breaks (approximately 0.1 - 1.0 ft^2) depressurize to relatively low pressures (before the potential for boric acid precipitation) with no operator action. The 120 psia boric acid precipitation calculation models this scenario and calculates the boric acid buildup for the limiting condition of a cold leg break. The 120 psia calculations consider less core voiding, a lower h_{fg} (heat of vaporization), and do not credit SI subcooling to reduce core boiloff. After hot leg switchover, as with large breaks, the hot leg injected flow provides core dilution for cold leg breaks and cold leg injected flow prevents buildup of boric acid in the core for hot leg breaks. Dilution and decay heat removal flows are confirmed as adequate at 120 psia RCS backpressure. Core dilution flow provides effective core cooling.

Small-Break LOCAs

For small breaks (approximately 0.005 - 0.1 ft^2), emergency procedures instruct operators to take action to depressurize and cool down the RCS. Although this depressurization and cooldown process typically begins within one hour after the event, the long-term cooling analysis makes no specific assumptions regarding time to depressurize. Depressurization to 120 psia (the threshold for boric acid precipitation concerns) may occur before or after hot leg

switchover time. In either case, the boric acid buildup at hot leg switchover time is conservatively represented by that calculated for the 120 psia RCS backpressure scenario since this calculation takes no credit for SI subcooling, nor any beneficial effects of the operator action (such as reduced net core boiloff due to condensation in the steam generators). If 120 psia is reached before hot leg switchover time, the core dilution flow after hot leg switchover, which is confirmed as adequate for 120 psia backpressure, provides effective core dilution. If at hot leg switchover time, the 120 psia has not been reached, boric acid precipitation does not occur so long as the RCS remains above this pressure since water and boric acid are miscible at the saturation temperature for these pressures. Even if the RCS pressure is above 120 psia at 24 hours after the LOCA with no core dilution flow, the total boric acid in the core is well below the saturation capacity at the corresponding saturation temperature. Furthermore, if after 24 hours with no dilution flow, the RCS is at saturation and depressurized at the maximum cooldown rate, the core is diluted prior to reaching the boric acid precipitation point. If subcooled core conditions are reached either before or after hot leg switchover, boric acid precipitation is not a concern since there is no net boiling in the core. If subcooled core entry conditions are not reached, the operators continue to depressurize the RCS under controlled conditions. Sump recirculation continues, decay heat in the core decreases, and core dilution flow prevents the buildup of boric acid. Eventually, subcooled core conditions are reached, the system is put into RHR or it remains in indefinite recirculation cooling.

Very Small-Break LOCAs

For very small breaks (less than approximately 0.005 ft^2), emergency procedures instruct operators to take action to depressurize the RCS. Because the break is small, subcooled conditions are reached prior to depressurization to 120 psia (the threshold for boric acid precipitation concerns). Natural circulation, if lost, is quickly restored. While in natural circulation, boric acid precipitation is not a concern because the core region is not stagnant. When subcooled conditions occur, net core boiling ceases and boric acid does not accumulate. Eventually, subcooled core conditions will be reached, the system will be put into RHR or continued natural circulation and sump recirculation will keep the boric acid from accumulating in the core. It is important to note that CPNPP is designed so that high pressure SI provides hot leg recirculation flow. As such, it is not necessary to depressurize the RCS to get effective dilution flow.

Results

To address LBLOCAs, CPNPP TM and SPU post-LOCA boric acid buildup calculations for 14.7 psia were performed. These calculations support a 3-hour switchover time to initiate simultaneous hot leg and cold leg SI injection. Note the boric acid concentration is below the boric acid solubility limit for this scenario up to a 7-hour switchover time. Figure 2.7.3.4-3 shows the buildup of boric acid versus time and the boric acid solubility limit used for this scenario. Although the boric acid buildup calculations for this scenario apply to RCS pressures of up to 30 psia, the boric acid solubility above the atmospheric boiling point of a saturated boric acid and water solution is not credited. Figure 2.7.3.4-3 also shows the dilution effect of the hot leg injected flow after simultaneous hot leg and cold leg is established.

To address SBLOCAs, CPNPP TM and SPU post-LOCA boric acid precipitation calculations for 120 psia were performed. These calculations show that there is considerable margin to the boric acid solubility limit for this scenario at the 3-hour switchover time. The 120 psia calculations consider less core voiding, a lower heat of vaporization (h_{fg}), and do not credit SI subcooling to reduce core boiloff. Since the boric acid buildup calculations for this scenario apply to RCS pressures of 30 to 120 psia, the boric acid solubility for the saturation temperature of water at 30 psia was credited. Figure 2.7.3.4-4 shows the buildup of boric acid versus time and the solubility limit appropriate for this scenario. Figure 2.7.3.4-4 also shows the dilution effect of the hot leg injected flow after simultaneous hot leg and cold leg is established.

In the unlikely event that the RCS pressure remains above 120 psia at hot leg switchover time while at saturated conditions, boric acid precipitation does not occur since the total boric acid in the core is well below the saturation capacity at the elevated pressure saturation temperature. In order to demonstrate the effectiveness of hot leg dilution flow for this scenario, calculations were performed for a hypothetical condition where there would be no hot leg dilution flow for 24 hours. Figure 2.7.3.4-5 shows the boric acid concentration in the core with the RCS at 120 psia for 24 hours assuming no steam generator heat removal, no dilution flow, and no benefit of reduced steaming due to SI subcooling. At 24 hours, the boric acid concentration is still below the boric acid solubility limit at the saturation temperature at 120 psia. Figure 2.7.3.4-5 also shows that if hot leg flow is established at 24 hours and the RCS is at saturation and is then cooled (with corresponding depressurization) at a cooldown rate of 100°F/hr, boric acid precipitation does not occur. The resulting hot leg dilution flow maintains the boric acid concentration in the core well below the solubility limit, even as the solubility limit is reduced due to the RCS cooldown. For CPNPP, hot leg dilution flow is provided by the SI pumps which would, in fact, provide dilution flow at RCS pressures well above 120 psia.

Calculations were performed to support an early switchover to hot leg or simultaneous injection. Two aspects of early switchover were considered – the hot leg entrainment threshold and core cooling. If switchover occurs too early, injected SI in the hot legs might be carried around the loops and might not be available for core cooling and dilution. Entrainment threshold calculations similar to those reported in Reference 5 demonstrated that significant hot leg entrainment would not occur after 75 minutes. Calculations showed that either hot leg or cold leg flows are sufficient to provide core cooling flow at 3 hours after the LOCA.

Assessments were made of the effect of loop pressure drop and downcomer boiling on the core mixing volume by performing calculations similar to those reported to the NRC in References 5 and 6. For CPNPP, the total loop pressure drop loss coefficient with and without locked RCP rotor is approximately 1.3E-08 ft/gpm^2 and 7.1E-08 ft/gpm^2, respectively. In all cases, the core region mixing volume assumed in the boric acid buildup calculation was found to be conservatively small in relation to the collapsed liquid volume that would be based on loop pressure drop and available downcomer head.

The effect of the refilling of the pump suction leg loop seals (due to a break at the top of the cold leg pipe) was also assessed by performing calculations similar to those reported to the NRC in References 5 and 6. For CPNPP, the bottom elevation of the loop seal piping is approximately 6.34 feet below the top of the active fuel. While the simultaneous complete closure of all four

loop seals would depress the core mixture to slightly below that associated with the core mixing volume, the expected duration of the depression would be brief. Brief core mixture level depressions would have the benefit of promoting mixing between the core region and lower plenum by cycling liquid back and forth between the core region, lower plenum, and downcomer.

An assessment was made of the effect of boric acid plate-out in the steam generators by performing calculations similar to those reported to the NRC in Reference 6. These calculations show that, with 10-percent entrainment for 1.5 hours, the total boric acid mass entrained would deposit a coating of approximately 0.002 inches over 10 feet of steam generator tubes. This coating would not significantly increase loop resistance or depress the core mixture level.

An assessment was made concerning the potential for boric acid precipitation at the hot leg injection point or at colder regions of the vessel. A simplified demonstration calculation showed that the mixing of injected SI with the highly borated solution in the reactor vessel would not initiate boric acid precipitation at the injection point. This calculation ignored temperature and boric acid gradients and assumed effective mixing with no differentiation between different mixing mechanisms such as diffusion (thermal or molecular) and density-driven convection within the vessel. The assessment also concluded that the heating of the injected water as it travels to the core region (either from the downcomer or hot leg) and the expected density-driven mixing mechanisms in the vessel would make it unlikely that significant temperature or boric acid gradients would exist. These conclusions were consistent with those reported to the NRC in Reference 6.

2.7.3.4.2 Conclusions

In summary, the CPNPP TM and SPU post-LOCA boric acid precipitation calculations used conservative methodology to initiate switchover to hot leg recirculation. SI flow to the hot leg provides effective core dilution thus precluding boric acid precipitation in the core. This realignment addresses the requirements of 10 CFR 50.46 (b) (4) coolable geometry and 10 CFR 50.46 (b) (5) long-term cooling. ECCS flows during sump recirculation were shown to be sufficient to remove decay heat after a LOCA for TM and SPU plant conditions, provided the ECCS realignment to provide SI flow to the hot legs occurs no sooner than 3 hours following the event. This addresses the requirements of 10 CFR 50.46 (b) (5) long-term cooling. Since the long-term core cooling analyses for the TM and SPU show that no changes to the CPNPP ECCS are required, GDC-35 requirements continue to be met.

2.7.3.4.3 References

1. H. C. Yeh, "Modification of Void Fraction Calculation," Proceedings of the Fourth International Topical Meeting on Nuclear Thermal-Hydraulics, Operations and Safety, Volume 1, Taipei, Taiwan, June 6, 1988.

2. P. Cohen, Water Coolant Technology of Power Reactors, Chapter 6, "Chemical Shim Control and pH Effect," ANS-USEC Monograph, 1980 (Originally published in 1969).

3. Letter dated August 1, 2005 from R. A. Gramm, U. S. Nuclear Regulatory Commission to J. A. Gresham, Westinghouse Electric Company, "Suspension of NRC Approval for Use of Westinghouse Topical Report CENPD-254-P, 'Post LOCA Long Term Cooling Model' Due to Discovery of Non-conservative Modeling Assumptions During Calculations Audit".

4. Letter dated October 3, 2006 from Sean E. Peters, Project Manager, Special Projects Branch, Division of Policy and Rulemaking, Office of Nuclear Reactor Regulation, NRC to Stacey L. Rosenberg, Chief, Special Projects Branch, Division of Policy and Rulemaking, Office of Nuclear Reactor Regulation, NRC, "Summary of August 23, 2006 Meeting With The Pressurized Water Reactor Owners Group to Discuss the Status of Program to Establish Consistent Criteria For Post Loss-Of-Coolant (LOCA) Calculations."

5. Letter L-05-112, FirstEnergy Nuclear Operating Company to USNRC, "Responses to a Request for Additional Information in Support of License Amendment Request Nos. 302 and 173," July 08, 2005.

6. Letter L-05-169, FirstEnergy Nuclear Operating Company to USNRC, "Responses to a Request for Additional Information (RAI dated September 30, 2005) in Support of License Amendment Request Nos. 302 and 173," November 21, 2005.

7. WCAP-16317, "Review and Evaluation of MHI BACCHUS PWR Vessel Mixing Tests," November 2004.

Table 2.7.3.4-1 CPNPP Post-LOCA Long-Term Cooling Analysis Input Parameters	
Parameter	**TM and SPU Value**
Analyzed Core Power (MWt)	3,612
Analyzed Core Power Uncertainty (percent)	0.6
Decay Heat Standard	1971 ANS, Infinite Operation, plus 20% (10 CFR 50 Appendix K)
H_3BO_3 Solubility Limit (weight percent)	See Table 2.7.3.4-2
RWST Boron Concentration, Maximum (ppm)	2,600
RWST Volume, Maximum (gallons)	506,368
RWST Temperature, Minimum (°F)	40
Accumulator Boron Concentration, Maximum (ppm)	2,600
Accumulator Tank Volume, Maximum (gallons)	6,597 per tank
Accumulator Tank Temperature, Minimum (°F)	60

Table 2.7.3.4-2 Boric Acid Solution Solubility Limit		
Temperature, °F	**Pressure, psia**	**Solubility g H_3BO_3/100 g of Solution in H_2O**
P = Atmospheric Pressure		
32	14.7	2.70
41	14.7	3.14
50	14.7	3.51
59	14.7	4.17
68	14.7	4.65
77	14.7	5.43
86	14.7	6.34
95	14.7	7.19
104	14.7	8.17
113	14.7	9.32
122	14.7	10.23
131	14.7	11.54
140	14.7	12.97
149	14.7	14.42
158	14.7	15.75
167	14.7	17.41
176	14.7	19.06
185	14.7	21.01
194	14.7	23.27
203	14.7	25.22
212	14.7	27.53
217.9	14.7	29.27
$P = P_{SAT}$		
226.0	19.3	31.47
242.8	26.3	36.69
260.1	35.5	42.34
277.3	47.1	48.81
289.9	57.5	54.79
304.7	71.9	62.22
318.9	88.3	70.67
339.8 = Congruent Melting of H_3BO_3		

Table 2.7.3.4-3

Post-LOCA Boric Acid Precipitation Analysis Logic

APPROXIMATE BREAK SIZE (FT^2)	SCENARIO	ANALYSIS
DEG 1.0	Large Breaks Large breaks will rapidly depressurize to very near containment pressure.	Represented by 14.7 psia boric acid buildup calculation. Dilution flows confirmed for 14.7 psia RCS backpressure.
0.1	Large Small Breaks Large small breaks will depressurize to below 120 psia without operator action.	Represented by 120 psia boric acid buildup calculation. Dilution flows are confirmed at 120 psia RCS backpressure.
0.005	Small Breaks Emergency procedures will instruct operators to take action to depressurize RCS. Eventually the system will be put into RHR or it will remain in indefinite recirculation cooling.	Credit operator action to depressurize the RCS. If the 120 psia is reached before HLSO time, the 120 psia boric acid buildup calculation applies. If 120 psia is not reached before HLSO time, credit higher boric acid solubility limit. If core subcooling conditions are reached, boric acid precipitation is not a concern since there will be no net boiling in the core.
0.001	Very Small Breaks Emergency procedures will instruct operators to take action to depressurize RCS. Subcooled conditions will be reached prior to depressurization to 120 psia (the threshold for boric acid precipitation concerns). Eventually, the system will be put in RHR or it will remain in indefinite recirculation cooling.	Natural circulation, if lost, will be quickly restored. While in natural circulation, boric acid precipitation is not a concern because the core region will not be stagnant.
0.0	Leaks Charging System has make-up capacity.	

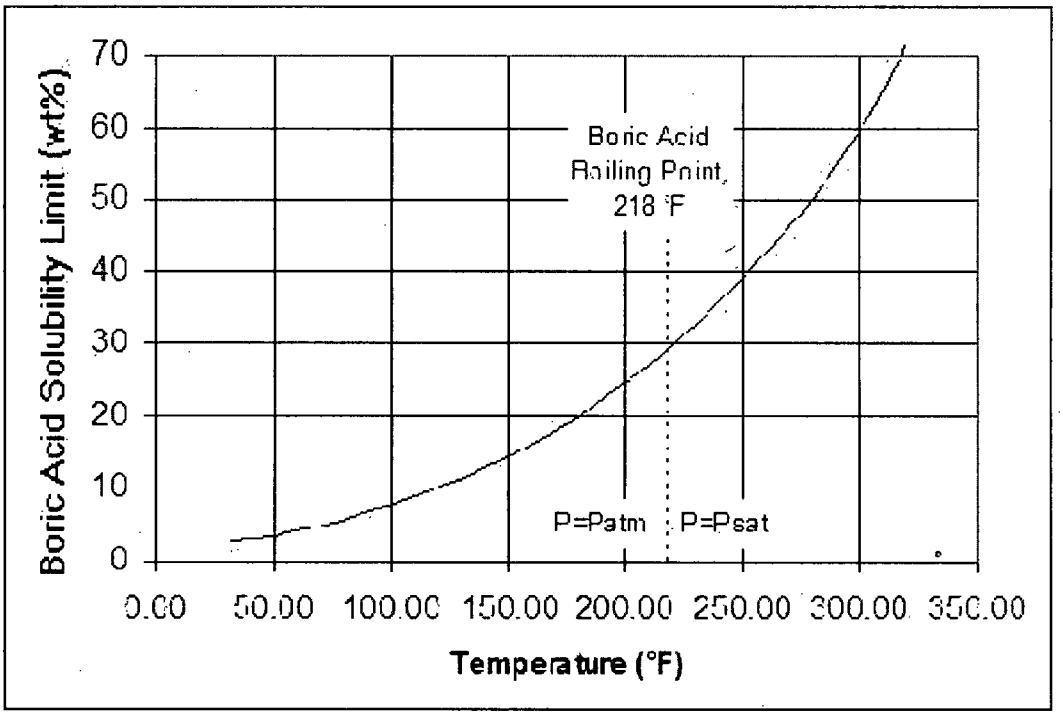


Figure 2.7.3.4-1 Boric Acid Solubility Limit

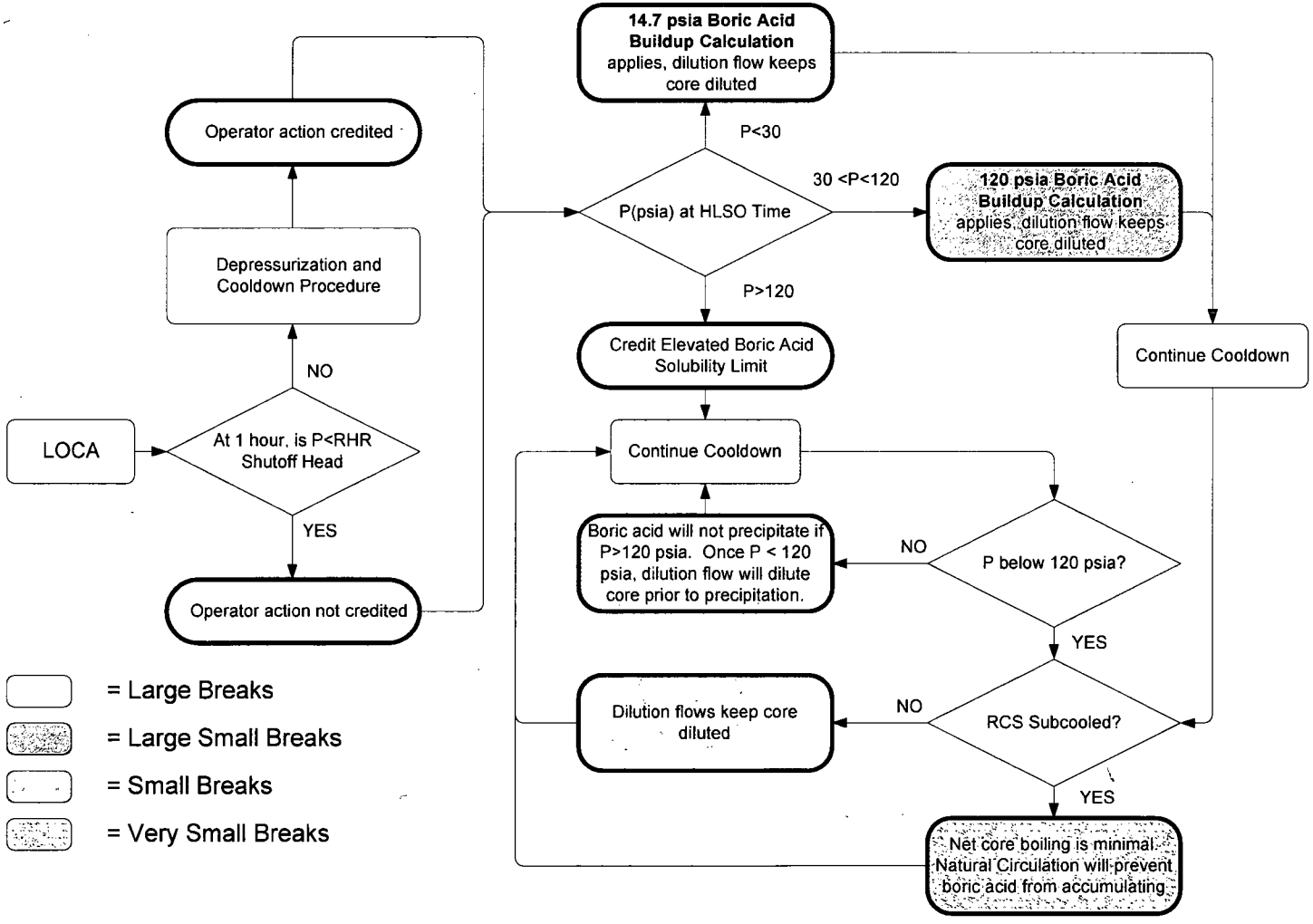


Figure 2.7.3.4-2 Post-LOCA Boric Acid Precipitation Analysis Logic

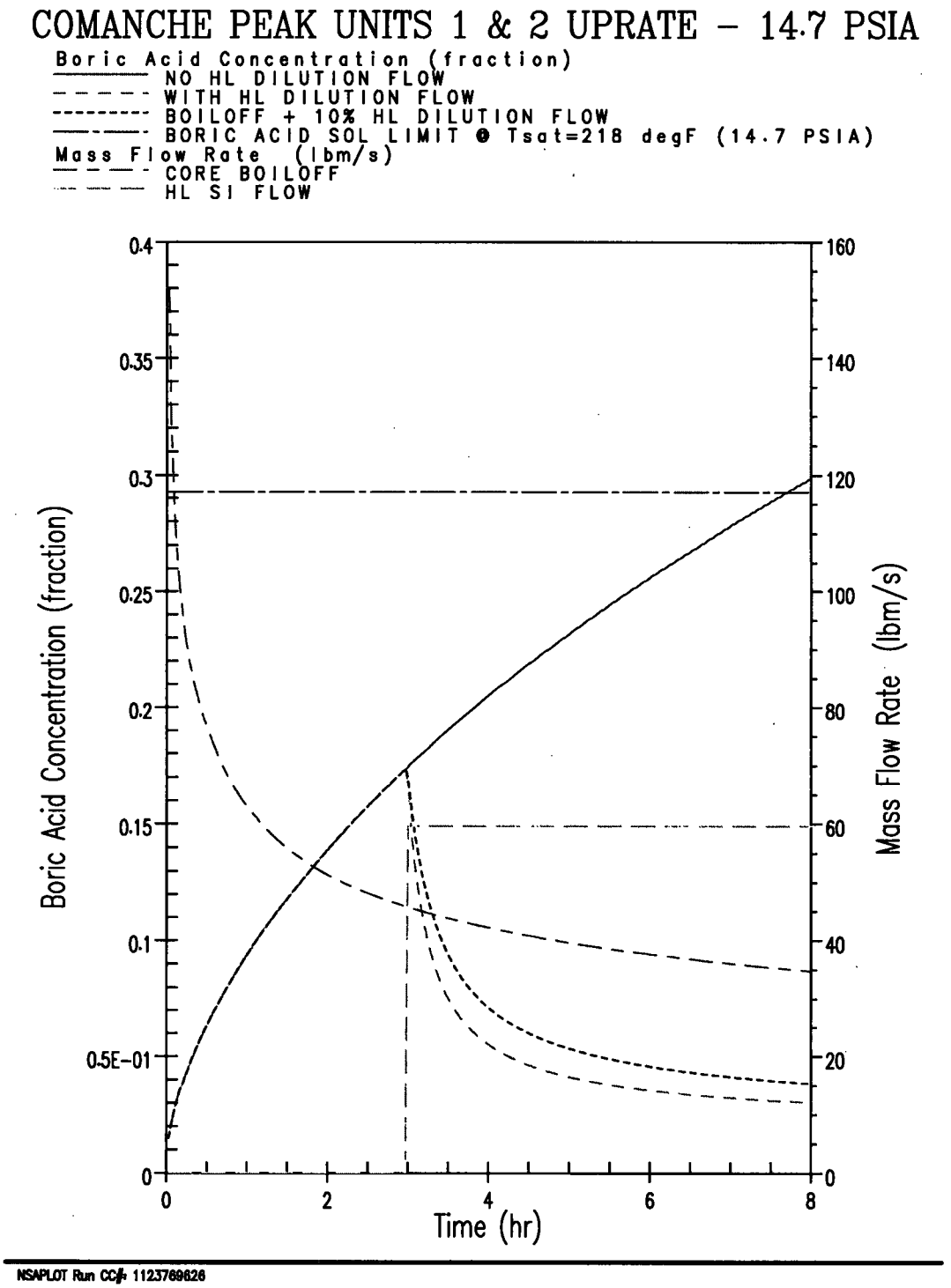


Figure 2.7.3.4-3 Boiloff, SI, and Core Dilution Rate at a 3-Hour HLSO Time at 14.7 psia

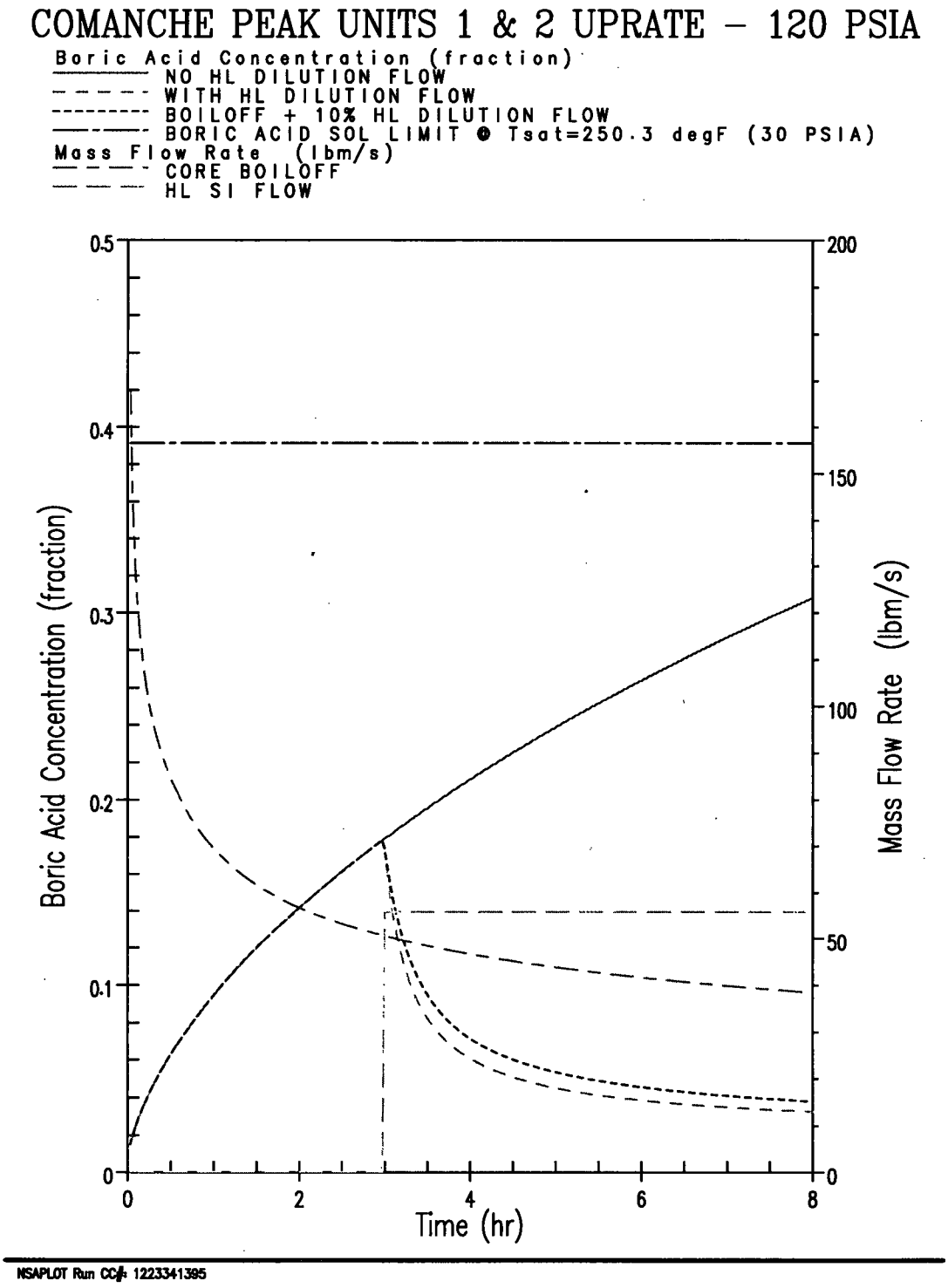


Figure 2.7.3.4-4 Boiloff, SI, and Core Dilution Rate at a 3-Hour HLSO Time at 120 psia

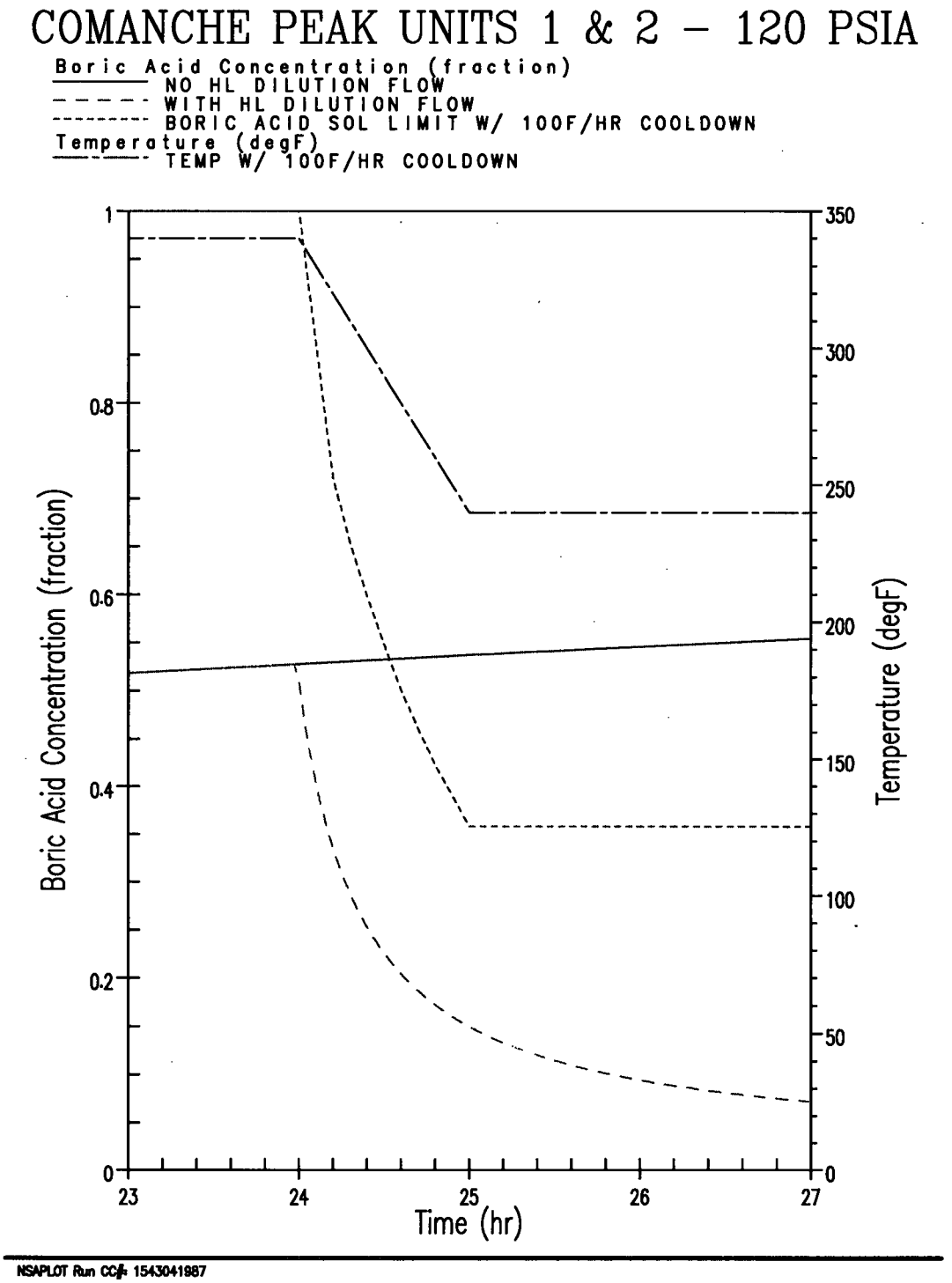


Figure 2.7.3.4-5 Demonstration of Core Dilution at 24 hours

2.7.3.5 LOCA Forces

2.7.3.5.1 Technical Evaluation

Input Parameters, Assumptions, and Acceptance Criteria

To conservatively calculate LOCA hydraulic forces for CPNPP Units 1 and 2, the following operating conditions were considered in establishing the limiting temperature and pressures:

- Initial RCS conditions associated with a minimum thermal design flow of 95,700 gpm per loop
- Uprated core power of 3,612 MWt (analyzed nuclear steam supply system [NSSS] power of 3,628 MWt)
- A nominal RCS HFP vessel T_{avg} range of 574.2° to 589.2°F (This provides an RCS T_{cold} range of 542.2° to 558.0°F.)
- An RCS temperature uncertainty of ±6.0°F
- A feedwater temperature range of 390.0° to 450.3°F
- A nominal RCS pressure of 2,250 psia
- A pressurizer pressure uncertainty of ±30 psi

Based on these conditions, the LOCA hydraulic forces on the vessel and steam generator were generated at a minimum T_{cold} of 536.2°F, including uncertainty, and a pressurizer pressure of 2,280 psia, including uncertainty. In order to accommodate the NSSS RCS loop piping structural analyses for the CPNPP Units 1 and 2 TM and SPU programs, the LOCA hydraulic forces on the RCS piping were generated at the minimum T_{cold} of 536.2°F; along with two higher T_{cold} values of 546.7° and 552.0°F, including uncertainty; and a pressurizer pressure of 2,280 psia, including uncertainty.

The LOCA hydraulic forcing functions and loads that occur as a result of a postulated LOCA are calculated assuming a limiting break location and break area. The NRC's revision to GDC-4 allowed the main coolant piping breaks to be "excluded from the design basis when analyses reviewed and approved by the commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for piping." This exemption is generally referred to as "leak before break." The analysis presented in WCAP-10527 (Reference 3) is technical justification for eliminating primary loop pipe ruptures from the design basis for CPNPP Units 1 and 2. The analyses presented in References 4 through 9 provide technical justification for eliminating accumulator, pressurizer surge, and residual heat removal branch line ruptures from the design basis for CPNPP Units 1 and 2. Thus, the primary loop piping breaks and larger branch lines did not need to be considered when generating CPNPP Unit 1 and 2 LOCA hydraulic forces. The breaks that were considered

were the 6-inch SI line connection to the cold leg and the 4-inch pressurizer spray line connection on the hot leg.

Description of Analyses and Evaluations

LOCA hydraulic forces were generated with a focus on the component of interest (such as loop, vessel, or steam generator) using the advanced beam model version of MULTIFLEX 3.0 (Reference 1), and assuming a conservative break opening time of 1 millisecond.

Generally, this improved modeling results in lower, more realistic, but still conservative hydraulic forces on the core barrel.

The MULTIFLEX computer code calculated the thermal-hydraulic transient within the RCS and considered subcooled, transition, and early two-phase (saturated) blowdown regimes. The code used the method of characteristics to solve the conservation laws, assuming 1-D flow and a homogeneous liquid-vapor mixture. The RCS was divided into subregions, in which each subregion was regarded as an equivalent pipe. A complex network of these equivalent pipes was used to represent the entire primary RCS.

For the reactor pressure vessel (RPV) and specific vessel internal components, the MULTIFLEX code generated the LOCA thermal-hydraulic transient that was input to the LATFORC and FORCE2 post-processing codes (Reference 10). These codes, in turn, were used to calculate the actual forces on the various components.

These forcing functions for horizontal and vertical LOCA hydraulic forces, combined with seismic, thermal, and flow-induced vibration loads as applicable, were used in the structural analyses to determine the resultant mechanical loads on the vessel and vessel internal components.

The loop forces analysis used the THRUST post-processing code to generate X, Y, and Z directional component forces during a LOCA blowdown. RCS pressure, density, and mass flux were calculated by the MULTIFLEX code and were used as inputs to the THRUST code. The THRUST code is described in WCAP-8252 (Reference 11).

The steam generator forces analysis utilizes the hydraulic transient time-history data, which is extracted directly from the MULTIFLEX computer code output. This analysis is performed to qualify the steam generators for duty using loads associated with the uprated power conditions.

Results

All LOCA hydraulic forces analyses for the CPNPP Units 1 and 2 TM and SPU programs were performed directly at the analyzed NSSS power level of 3,628 MWt, using models specific to the CPNPP Units 1 and 2 NSSS design. The analyses of the forces acting on the RPV and vessel internals, fuel, loop piping, and steam generator were performed. The results of the LOCA hydraulic forces analyses were then used as input to the calculations for component qualification.

Discussion of Margin Change

As previously mentioned, the LOCA forces are used as input to the various structural analyses, so margin quantification would be appropriately derived from the calculations for the specific component. Qualitatively speaking, margin in the forces analyses is realized by analyzing smaller diameter lines, because larger diameter lines would yield higher forces.

2.7.3.5.2 Conclusions

Luminant Power has reviewed the analyses of the LOCA events and the ECCS, and has concluded that the analyses have adequately accounted for plant operation at the proposed power level and that the analyses were performed using acceptable analytical models. Luminant Power further concluded that the evaluation has demonstrated that the reactor protection system and the ECCS will continue to ensure that the peak cladding temperature, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling will remain within acceptable limits. Based on this, Luminant Power concluded that the plant will continue to meet the CPNPP current licensing basis requirements with respect to GDC-4, -27, -35, and 10 CFR 50.46.

2.7.3.5.3 References

1. WCAP-9735, Rev. 2, and WCAP-9736, Rev. 1, "MULTIFLEX 3.0 A FORTRAN IV Computer Program for Analyzing Thermal-Hydraulic- Structural System Dynamics Advanced Beam Model," February 1998.

2. WCAP-15029 and WCAP-15030, "Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions," January 1999.

3. WCAP-10527 and WCAP-10528, "Technical Basis for Eliminating Large Primary Loop Pipe Rupture as a Structural Design Basis for Comanche Peak Units 1 and 2," April 1984.

4. WCAP-12267 and WCAP-12268, "Technical Bases for Eliminating Rupture of the Accumulator Injection Nozzles as a Structural Design Basis for Comanche Peak Unit 1," May 1989.

5. WCAP-12247 and WCAP-12248, "Evaluation of Thermal Stratification for the Comanche Peak Unit 1 Pressurizer Surge Line," April 1989.

6. WCAP-12258 and WCAP-12259, "Evaluation of Thermal Stratification for the Comanche Peak Unit 1 Residual Heat Removal Lines," April 1989.

7. WCAP-13167 and WCAP-13168, "Technical Justification for Eliminating 10 Inch Accumulator Lines Rupture as the Structural Design Basis for the Comanche Peak Nuclear Plant Unit 2," January 1992.

8. WCAP-13100 and WCAP-13101, "Technical Justification for Eliminating Pressurizer Surge Line Rupture from the Structural Design Basis for Comanche Peak Unit 2," December 1991.

9. WCAP-13165 and WCAP-13166, "Technical Justification for Eliminating Residual Heat Removal Lines Rupture as the Structural Design Basis for Comanche Peak Nuclear Power Plant – Unit 2," December 1991.

10. WCAP-8708 and WCAP-8709, "MULTIFLEX A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," September 1977.

11. WCAP-8252, Rev. 1, "Documentation of Selected Westinghouse Structural Analysis Computer Codes," May 1977.

2.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM

2.8.1 Technical Evaluation

2.8.1.1 Introduction

As noted above, the final ATWS Rule, 10 CFR 50.62(c)(1) (Reference 1), requires the incorporation of a diverse (from the reactor trip system) actuation of the AFW system and turbine trip for Westinghouse-designed plants. The installation of the NRC-approved AMSAC satisfies this final ATWS Rule. However, it must also be demonstrated that the deterministic ATWS analyses that form the basis for this rule and the AMSAC design remain valid for the plant. This is typically done by confirming that the analyses documented in NS-TMA-2182 (Reference 2) remain valid or by performing new deterministic analyses for the proposed plant state.

To address the uprate program for CPNPP, the LOL and LONF ATWS events were re-analyzed to ensure that the analytical basis for the final ATWS rule continues to be met. The LOL and LONF ATWS events are the two most limiting RCS overpressure transients reported in NS-TMA-2182 (Reference 2). The approach taken was to demonstrate that the ATWS unfavorable exposure time (UET) is less than 5 percent of an operating cycle. UET is the duration of a given cycle for which the core reactivity feedback is insufficient to preclude the RCS pressure from exceeding the Service Level C pressure limit of 3,200 psig following an ATWS event. The objective is to show that the ATWS pressure limit of 3,200 psig is met for at least 95 percent of the cycle, and therefore the analytical basis for the final ATWS rule continues to be met.

The UET approach has been previously approved by the NRC per Reference 3. The analysis must show that the UET, given the cycle design (including MTC), will be less than 5 percent. This 5-percent requirement for the UET is equivalent to the probability level in the reference analyses for the ATWS rule analytical basis (Reference 2). In those analyses, the NRC required that all parameters be best-estimate values with the exception of the MTC initial condition, which is to be at a full-power value that is bounding for at least 95 percent of a given cycle. The UET approach provides a similar level of assurance for the effectiveness of the reactivity feedback.

To determine UET, the reactivity conditions of the core and plant conditions under consideration must be compared to the ATWS analysis conditions that lead to a peak RCS pressure at the ATWS pressure limit of 3,200 psig. The variable conditions of significance to the resulting peak RCS pressure following the LONF and LOL ATWS events are total reactivity feedback (primarily MTC), primary-side pressure relief capacity, and AFW capacity. For a given primary-side pressure relief configuration and AFW capacity, reactivity feedback (MTC) can be adjusted in the ATWS analysis until the peak RCS pressure during the specific ATWS event equals 3,200 psig. At these specific reactivity feedback conditions, the change in power with increasing temperature represents what is defined as the critical power trajectory (CPT) (or heatup/ shutdown characteristics) for the specific plant configuration. The heatup/shutdown

characteristics of a given core at various times in the cycle can then be compared to the CPT to establish UET for the given core at the specific plant configuration conditions.

2.8.1.2 Input Parameters, Assumptions, and Acceptance Criteria

The ATWS analyses performed for the TM and SPU programs showed that the results obtained for CPNPP Unit 1 with Westinghouse Δ76 steam generators are more limiting than those obtained for Unit 2 with D-5 steam generators and, therefore, may be conservatively applied to CPNPP Unit 2. As such, only the Unit 1 inputs, assumptions, and results are reported.

The primary input to the LOL and LONF ATWS analysis for the CPNPP Units 1 and 2 TM and SPU programs was the four-loop reference LOL and LONF ATWS models from the analyses supporting NS-TMA-2182. The following analysis assumptions were used:

- The nominal and initial conditions were updated to the NSSS design parameters for 3,628 MWt.
- The steam generator data was revised to reflect the Westinghouse Δ76 steam generator for the Unit 1 analyses.
- Consistent with the analysis basis for the Final ATWS Rule (NS-TMA-2182):
  - Thermal design flow (TDF) is assumed, no uncertainties are applied to the initial power, RCS average temperature or RCS pressure.
  - Zero-percent steam generator tube plugging (SGTP) is assumed. Zero-percent SGTP is more limiting (that is, results in a higher peak RCS pressure) for ATWS events.
  - Control rod insertion was not assumed.
  - 100-percent pressurizer power-operated relief valve capacity was assumed.
  - The AMSAC actuation setpoint is not directly assumed in the ATWS analyses. Turbine trip and AFW actuation are modeled to occur at generic times after event initiation, consistent with NS-TMA-2182.
- A CPNPP best-estimate AFW flow of 2,148 gpm was assumed.
- The reactivity feedback (MTC) was adjusted until the peak RCS pressure during the specific ATWS event equaled 3,200 psig.

To remain compliant with the basis of the final ATWS rule (10 CFR 50.62), the UET calculated for the ATWS reference conditions (no control rod insertion, nominal AFW flow, and unblocked pressurizer power-relief valves) must be less than 5 percent for a given cycle.

2.8.1.3 Description of Analyses and Evaluations

ATWS CPTs were generated for the two pressure-limiting ATWS events. The ATWS CPTs were generated based on the four-loop reference LOL and LONF ATWS models from the analyses supporting NS-TMA-2182. The models were revised to incorporate the uprated power conditions reflecting an NSSS power level of 3,628 MWt, the Unit 1 Westinghouse Δ76 steam generators (the Unit 1 Model Δ76 steam generators were determined to be limiting compared to the Unit 2 Model D-5 steam generators), and plant-specific, best-estimate AFW flow. The CPTs were then used to determine the ATWS UET.

2.8.1.4 Results

CPT curves were calculated for CPNPP Unit 1 with Westinghouse Δ76 steam generators at an uprated NSSS power level of 3,628 MWt. These critical power trajectory curves for the LOL and LONF ATWS transients are shown in Figures 2.8-1 and 2.8-2, respectively.

The results of this analysis may be conservatively applied to CPNPP Unit 2 with Model D-5 steam generators since the results obtained for the Model Δ76 SGs are more limiting than those obtained for the Model D-5 steam generators.

To remain compliant with the basis of the final ATWS rule (10 CFR 50.62), the UET must be less than 5 percent for a given cycle, or equivalently, the ATWS pressure limit of 3,200 psig must be met for 95 percent of the cycle. The UET is met for the anticipated operating conditions with a representative core design and will be checked on a cycle-specific basis. Therefore, the basis of the final ATWS rule (10 CFR 50.62) is met for the CPNPP Units 1 and 2 TM and SPU programs.

2.8.2 Conclusion

The information related to ATWS has been reviewed and it was concluded that it has adequately accounted for the proposed CPNPP Units 1 and 2 TM and SPU programs effects on ATWS. The evaluation has demonstrated that the AMSAC continues to meet the requirements of 10 CFR 50.62. The evaluation has shown that the plant is not required by 10 CFR 50.62 to have a diverse scram system. Additionally, the evaluation has shown that the UET, for the anticipated operating conditions with a representative core design, will be less than five percent, or equivalently, that the ATWS pressure limit of 3,200 psig will be met for at least 95 percent of the cycle. The UET will continue to be checked on a cycle-specific basis. Therefore, the proposed uprate is acceptable with respect to ATWS.

2.8.3 References

1. 10 CFR 50.62 and Supplementary Information Package, "Requirements for Reduction of Risk from ATWS Events for Light Water-Cooled Nuclear Power Plants."

2. NS-TMA-2182, "Anticipated Transients Without Scram for Westinghouse Plants," December 1979.

3. NRC letter to D. L. Farrar (ComEd), "Issuance of Amendments (TAC NOs. M89092, M89093, M89072, and M89091)," July 27, 1995.

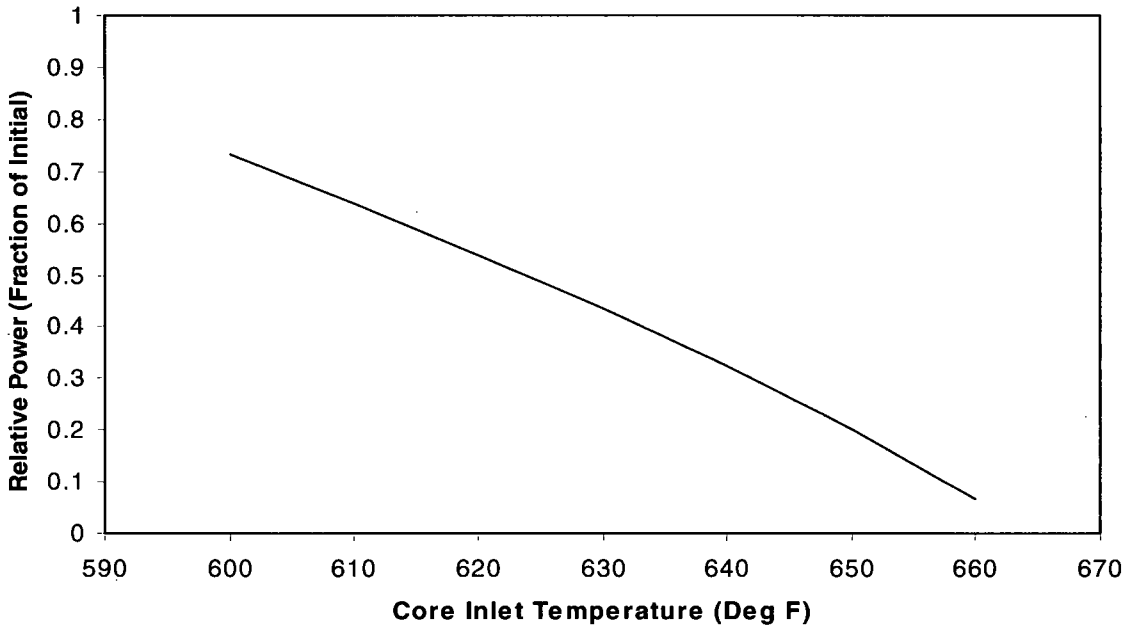


Figure 2.8-1 **Critical Power Trajectory for Loss of Load ATWS at Uprated NSSS Power Conditions (3,628 MWt)**

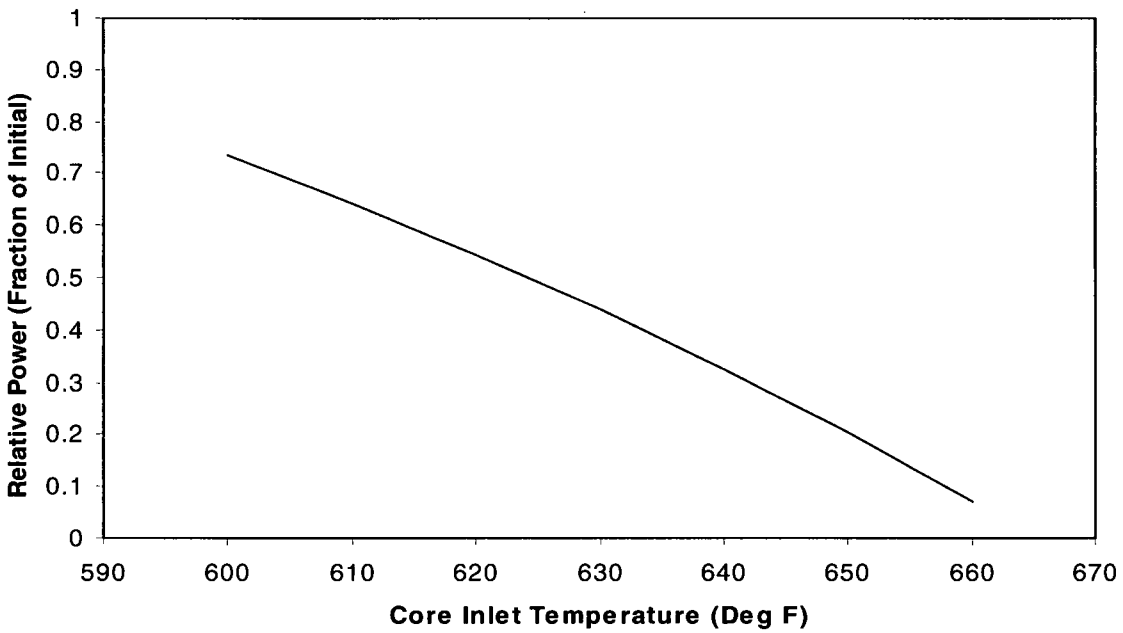


Figure 2.8-2 **Critical Power Trajectory for Loss of Normal Feedwater ATWS at Uprated NSSS Power Conditions (3,628 MWt)**