15.2 DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

A number of transients and accidents have been postulated which could result in a reduction of the capacity of the secondary system to remove heat generated in the reactor coolant system. Detailed analyses are presented in this section for the following events which have been identified as more limiting than the others:

- Steam pressure regulator malfunction or failure that results in decreasing steamflow.
- Loss of external electrical load.
- Turbine trip.
- Inadvertent closure of main steam isolation valves.
- Loss of condenser vacuum and other events resulting in turbine trip.
- Loss of nonemergency ac power to the station auxiliaries.
- Loss of normal feedwater flow.
- Feedwater system pipe break.

All of the accidents in this section have been analyzed. It has been determined that the most severe radiological consequences will result from the loss of ac power accident discussed in subsection 15.2.6. Therefore, the radiological consequences are only reported for that limiting case.

15.2.1 STEAM PRESSURE REGULATOR MALFUNCTION OR FAILURE THAT RESULTS IN DECREASING STEAMFLOW

There are no steam pressure regulators in the VEGP units whose failure or malfunction could cause a steamflow transient.

15.2.2 LOSS OF EXTERNAL ELECTRICAL LOAD

15.2.2.1 Identification of Causes and Accident Description

A major load loss on the plant can result from loss of external electrical load due to some electrical system disturbance. Offsite ac power remains available to operate plant components, such as the reactor coolant pumps; as a result, the onsite emergency diesel generators are not required to function for this event. Following the loss of generator load, an immediate fast closure of the turbine control valves will occur. The automatic turbine bypass system would accommodate the excess steam generation. Reactor coolant temperatures and pressure do not significantly increase if the turbine bypass system and pressurizer pressure control system are functioning properly. If the condenser is not available, the excess steam generation is relieved to the atmosphere. Additionally, main feedwater flow is lost if the condenser is not available. For this situation, feedwater flow is maintained by the auxiliary feedwater system.

For a loss of external electrical load without subsequent turbine trip, no direct reactor trip signal would be generated, and the plant would be expected to trip from the reactor protection system if a safety limit were approached. A continued steam load of approximately 5 percent would exist after total loss of external electrical load, because of the steam demand of plant auxiliaries.

In the event that a safety limit is approached, protection would be provided by high pressurizer pressure, high pressurizer water level, low-low steam generator water level, and overtemperature ΔT trip. Voltage and frequency relays associated with the reactor coolant pump provide no additional safety function for this event. Following a complete loss of external load, the maximum turbine overspeed would be approximately 8 to 9 percent, resulting in an overfrequency of less than 6 Hz. This resulting overfrequency is not expected to damage the voltage and frequency sensors in any way. Any degradation in their performance could be ascertained at that time. Any increased frequency to the reactor coolant pump motors will result in slightly increased flowrate and subsequent additional margin to safety limits. For postulated loss of load and subsequent turbine-generator overspeed, any overfrequency condition is not seen by other safety-related pump motors, reactor protection system equipment, or other safety-related loads. Safety-related loads are alternately supplied from offsite power or from emergency diesels. Reactor protection system equipment is supplied from the 120-V-ac instrument power supply system, which, in turn, is supplied from the inverters; the inverters are supplied from a dc bus energized from batteries or by a rectified ac voltage from safety-related buses.

In the event that the steam dump valves fail to open following a large loss of load, the steam generator safety valves may lift, and the reactor may be tripped by the high pressurizer pressure signal, the high pressurizer water level signal, or the overtemperature ΔT signal. The steam generator shell side pressure and reactor coolant temperature will increase rapidly. The pressurizer safety valves and steam generator safety valves are, however, sized to protect the reactor coolant system (RCS) and steam generator against overpressure for all load losses, without assuming the operation of the turbine bypass system, pressurizer spray, pressurizer power-operated relief valves, automatic rod cluster control assembly control, or direct reactor trip on turbine trip.

The steam generator safety valve capacity is sized to remove the steam flow at the engineered safety features rating (105 percent of steam flow at rated power) from the steam generator, without exceeding 110 percent of the steam system design pressure. The pressurizer safety valve capacity is sized to accommodate a complete loss of heat sink with the plant initially operating at the maximum calculated turbine load along with operation of the steam generator safety valves. The pressurizer safety valves are then able to relieve sufficient steam to maintain the RCS pressure within 110 percent of the RCS design pressure.

A more complete discussion of overpressure protection can be found in reference 1.

A loss of external load is classified as an American Nuclear Society Condition II event, fault of moderate frequency.

A loss-of-external-load event results in a nuclear steam supply system transient that is bounded by the turbine trip event analyzed in subsection 15.2.3. Therefore, a detailed transient analysis is not presented for the loss-of-external-load event.

The primary side transient is caused by a decrease in heat transfer capability from primary to secondary due to a rapid termination of steam flow to the turbine, accompanied by an automatic reduction of feedwater flow. (Should feedwater flow not be reduced, a larger heat sink would be available and the transient would be less severe.) Termination of steam flow to the turbine following a loss of external load occurs due to automatic fast closure of the turbine control valves in approximately 0.3 s. Following a turbine trip event, termination of steam flow occurs via turbine stop valve closure, which occurs in approximately 0.1 s. Therefore, the transient in primary pressure, temperature, and water volume will be less severe for the loss of external load than for the turbine trip due to a slightly slower loss of heat transfer capability.

The protection available to mitigate the consequences of a loss of external load is the same as that for a turbine trip, as listed in table 15.0.8-1.

15.2.2.2 Analysis of Effects and Consequences

Refer to paragraph 15.2.3.2 for the method used to analyze the limiting transient (turbine trip) in this grouping of events. The results of the turbine trip event analysis bound those expected for the loss of external load, as discussed in paragraph 15.2.2.1.

Plant systems and equipment which may be required to function to mitigate the effects of a complete loss of load are discussed in subsection 15.0.8 and listed in table 15.0.8-1.

The reactor protection system may be required to function to terminate core heat input and to prevent departure from nucleate boiling. Depending on the magnitude of the load loss, pressurizer safety valves and/or steam generator safety valves may be required to open to maintain system pressures below allowable limits. No single active failure will prevent operation of any system required to function. Normal reactor control systems and engineered safety systems are not required to function. The auxiliary feedwater system may, however, be automatically actuated following a loss of main feedwater; this will further mitigate the effects of the transient.

15.2.2.3 Conclusions

Based on results obtained for the turbine trip event and considerations described in paragraph 15.2.2.1, the applicable acceptance criteria for a loss-of-external-load event are met. (See subsection 15.2.3.)

15.2.2.4 Reference

1. Cooper, L., Miselis, V., and Starek, R. M., "Overpressure Protection for Westinghouse Pressurized Water Reactors," WCAP-7769, Revision 1, June, 1972. (Also letter NS-CE-622, C. Eicheldinger (Westinghouse) to D. B. Vassallo (NRC), additional information on WCAP-7769, Revision 1, April 16, 1975.)

15.2.3 TURBINE TRIP

15.2.3.1 Identification of Causes and Accident Description

For a turbine trip event, the reactor trips directly (unless below approximately 40-percent power) from a signal derived from the turbine stop emergency trip fluid pressure and turbine stop valves. The turbine stop valves close rapidly (typically in 0.1 s) on loss of trip fluid pressure actuated by one of several possible turbine trip signals. Turbine trip initiation signals include:

- Generator trip.
- Low condenser vacuum.
- Loss of lubricating oil.
- Turbine thrust bearing failure.
- Turbine overspeed.
- Manual trip.

Upon initiation of stop valve closure, steam flow to the turbine stops abruptly. Sensors on the stop valve detect the turbine trip and initiate turbine bypass through steam dump valves and, if above 40-percent power, a reactor trip. The loss of steam flow results in an almost immediate rise in secondary system temperature and pressure with a resultant increase in primary system temperature and pressure. A slightly more severe transient than the loss of electrical load event occurs for the turbine trip event due to a more rapid loss of steam flow caused by the more rapid valve closure.

The automatic turbine bypass system would accommodate up to 40 percent of rated steam flow. Reactor coolant temperatures and pressure do not increase significantly if the turbine bypass system and pressurizer pressure control system are functioning properly. If the condenser was not available, the excess steam generation would be relieved to the atmosphere, and main feedwater flow would be lost. For this situation, feedwater flow would be maintained by the auxiliary feedwater system to ensure adequate residual and decay heat removal capability. Should the turbine bypass system fail to operate, the steam generator safety valves may lift to provide pressure control. See paragraph 15.2.2.1 for a further discussion of the transient.

A turbine trip is classified as an American Nuclear Society Condition II event, fault of moderate frequency.

A turbine trip is more limiting than loss of external load, loss of condenser vacuum, and other events which result in a turbine trip. As such, this event has been analyzed in detail. Results and discussion of the analysis are presented in paragraph 15.2.3.2.

15.2.3.2 Analysis of Effects and Consequences

15.2.3.2.1 Method of Analysis

In this analysis, evaluation of the behavior of the units is for a complete loss of steam load from nominal full power, with a turbine trip not causing a direct reactor trip. This demonstrates the adequacy of the pressure-relieving devices and the core protection margins. This assumption delays reactor trip until conditions in the RCS result in a trip due to other signals. Thus, the analysis models a worst-case transient. In addition, no credit is taken for the turbine bypass system. Main feedwater flow terminates at the time of turbine trip with no credit taken for auxiliary feedwater (except for long-term recovery) to mitigate the consequences of the transient.

The analysis of the turbine trip transients employs the detailed digital computer program LOFTRAN (reference 1). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. LOFTRAN computes pertinent plant variables, including temperatures, pressures, and power level.

The analysis of this accident uses RTDP methodology. Plant characteristics and initial conditions are shown in tables 15.0.3-2 and 15.0.3-3.

The following summarizes the major assumptions used in the analysis:

A. Initial Operating Conditions

The analysis assumes nominal values of core power, reactor coolant average temperature, and nominal reactor coolant average pressure. The limit-DNBR includes uncertainties in initial conditions as described in chapter 4. Previous studies have shown that the peak pressurizer pressure reached for the turbine trip event is insensitive to the initial conditions of temperature and pressure, and the peak pressurizer pressure is only slightly sensitive to the initial power condition. Therefore, the use of these initial conditions is appropriate for this event.

B. Moderator and Doppler Coefficients of Reactivity

The analysis of the turbine trip is with both maximum and minimum reactivity feedback. With maximum feedback, the analysis assumes a large negative moderator temperature coefficient and the most-negative Doppler-only power coefficient. With minimum feedback, the analysis assumes the most positive moderator temperature coefficient and the least-negative Doppler-only power coefficient.

C. Rod Control

It is conservative to assume that the reactor is in manual rod control with respect to the maximum pressures attained. If the reactor were in automatic rod control, the control rod banks would move before the trip and reduce the severity of the transient.

D. Steam Release

No credit is taken for the operation of the steam dump system or steam generator power-operated relief valves. The steam generator safety valves are operable. The steam generator pressure rises to the safety valve setpoint where steam release through the safety valves limits secondary steam pressure at the setpoint value.

E. Pressurizer Spray and Power-Operated Relief Valves

The following analyses are the two cases for both the minimum and maximum reactivity feedback cases examined:

1. The loss of load event is analyzed with full credit taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Safety valves are also operable. This case minimizes the increase in primary pressure which is conservative for the DNBR transient.

2. The loss of load event is analyzed with no credit taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Safety valves are operable. This case maximizes the pressure increase which is conservative for the RCS overpressurization transient. In this case, the pressurizer safety valves

begin to open at 2550 psia. The effects of the pressurizer safety valve loop seals are accounted for by modeling a 1-percent set pressure shift and assuming no steam flow until the valve loop seals are purged.

F. Feedwater Flow

The analysis assumes main feedwater flow to the steam generators to be lost at the time of turbine trip. No credit is taken for auxiliary feedwater flow since the plant will reach a stabilized condition before auxiliary feedwater initiation is normally assumed to occur; however, the auxiliary feedwater pumps would start on a trip of the main feedwater pumps. The auxiliary feedwater flow would remove core decay heat following plant stabilization.

G. Reactor Trip

Reactor trip actuates by the first reactor protection system trip setpoint reached, with no credit taken for direct reactor trip on turbine trip. Trip signals are expected due to high pressurizer pressure, OTΔT, high pressurizer water level, and low-low steam generator water level.

Plant systems and equipment which may be required to function to mitigate the effects of a turbine trip event are discussed in subsection 15.0.8 and listed in table 15.0.8-1.

The reactor protection system may be required to function following a turbine trip. Pressurizer safety valves and/or steam generator safety valves may be required to open to maintain system pressures below allowable limits. No single active failure will prevent operation of any system required to function. Normal RCS and engineered safety systems are not required to function. However, cases are analyzed both with and without the operation of pressurizer spray and power-operated relief valves to ensure that the worst case is presented.

15.2.3.2.2 Results

The transient responses for a turbine trip from nominal full power operation are shown for the following four cases: two cases with minimum reactivity feedback and two cases with maximum reactivity feedback (figures 15.2.3-1 through 15.2.3-8).

Figures 15.2.3-1 and 15.2.3-2 show the transient responses for the turbine trip event with minimum reactivity feedback, assuming full credit for the pressurizer spray and pressurizer power-operated relief valves. No credit is taken for the turbine bypass through the steam dumps. The reactor trips on overtemperature ΔT. The minimum DNBR remains well above the limit value. The pressurizer safety valves and steam generator safety valves prevent overpressurization in the primary and secondary systems, respectively.

Figures 15.2.3-3 and 15.2.3-4 show the responses for the turbine trip event with maximum reactivity feedback. All other plant parameters are the same as the above. The DNBR increases throughout the transient and never drops below its initial value. The pressurizer power-operated relief valves and steam generator safety valves prevent overpressurization in the primary and secondary systems, respectively. The reactor trips on low-low steam generator water level. The pressurizer safety valves do not actuate for this case.

The turbine trip accident was also studied assuming the plant to be initially operating at nominal full power with no credit taken for the pressurizer spray, pressurizer power-operated relief valves, or turbine bypass system. The reactor trips on the high pressurizer pressure signal. Figures 15.2.3-5 and 15.2.3-6 show the transient responses with minimum reactivity feedback. The neutron flux remains constant at nominal full power until the reactor trips. The DNBR never goes below its initial value throughout the transient. In this case the pressurizer safety valves and steam generator safety valves actuate to maintain the RCS and main steam system pressure below 110 percent of their respective design values.

Figures 15.2.3-7 and 15.2.3-8 show the transients with maximum reactivity feedback, with the other assumptions being the same as in the preceding case. The reactor trips on the high pressurizer pressure signal and the DNBR increases throughout the transient. The pressurizer safety valves and steam generator safety valves actuate to limit primary and secondary system pressures, respectively.

The calculated sequence of events for the turbine trip event is shown in table 15.2.3-1.

Reference 2 presents additional results of analysis for a complete loss of heat sink, including loss of main feedwater. This analysis shows the overpressure protection that is afforded by the pressurizer and steam generator safety valves.

15.2.3.3 Conclusions

Results of the analyses, including those in reference 2, show that the plant design is such that a turbine trip without a direct reactor trip presents no hazard to the integrity of the RCS or the main steam system. Pressure-relieving devices incorporated in the two systems are adequate to limit the maximum pressures to within the design limits.

The analyses show that the DNBR will not decrease below the limit value at any time during the transient. Thus, the DNB design basis, as described in section 4.4, is met.

15.2.3.4 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-Proprietary), April 1984.
2. Cooper, L., Miselis, V., and Starek, R. M., "Overpressure Protection for Westinghouse Pressurized Water Reactors," WCAP-7769, Revision 1, June 1972. (Also letter NS-CE-622, C. Eicheldinger (Westinghouse) to D. B. Vassallo (NRC), additional information on WCAP-7769, Revision 1, April 16, 1975.)

15.2.4 INADVERTENT CLOSURE OF MAIN STEAM ISOLATION VALVES

Inadvertent closure of the main steam isolation valves would result in a turbine trip with no credit taken for the turbine bypass system. Turbine trips are discussed in subsection 15.2.3.

15.2.5 LOSS OF CONDENSER VACUUM AND OTHER EVENTS RESULTING IN TURBINE TRIP

Loss of condenser vacuum is one of the events that can cause a turbine trip. Turbine trip-initiating events are described in subsection 15.2.3. A loss of condenser vacuum would preclude the use of steam dump to the condenser; however, since steam dump is assumed to be unavailable in the turbine trip analysis, no additional adverse effects would result if the turbine trip were caused by loss of condenser vacuum. Therefore, the analysis results and conclusions contained in subsection 15.2.3 apply to the loss of the condenser vacuum. In addition, analyses for the other possible causes of a turbine trip, as listed in paragraph 15.2.3.1, are covered by subsection 15.2.3. Possible overfrequency effects due to a turbine overspeed condition are discussed in paragraph 15.2.2.1 and are not a concern for this type of event.

15.2.6 LOSS OF NONEMERGENCY AC POWER TO THE PLANT AUXILIARIES

15.2.6.1 Identification of Causes and Accident Description

A complete loss of nonemergency ac power may result in the loss of all power to the plant auxiliaries; i.e., the reactor coolant 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 plant or by a loss of the onsite ac distribution system.

This transient is more severe than the turbine trip event analyzed in subsection 15.2.3 because for this case the decrease in heat removal by the secondary system is accompanied by a flow coastdown which further reduces the capacity of the primary coolant to remove heat from the core. The reactor will trip:

- Due to turbine trip.
- Upon reaching one of the trip setpoints in the primary and secondary systems as a result of the flow coastdown and decrease in secondary heat removal.
- Due to the loss of power to the control rod drive mechanisms as a result of the loss of power to the plant.

Following a loss of ac power with turbine and reactor trips, the sequence described below will occur:

A. Plant vital instruments are supplied from emergency dc power sources.

B. As the steam system pressure rises following the trip, the steam generator power-operated relief valves may be automatically opened to the atmosphere. The condenser is assumed not to be available for turbine bypass. If the steam flowrate through the power-operated relief valves is not available, the steam generator safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

C. As the no-load temperature is approached, the steam generator power-operated relief valves (or safety valves, if the power-operated relief valves are not available) are used to dissipate the residual decay heat and to maintain the plant at the hot shutdown condition.

D. The standby diesel generators, started on loss of voltage on the plant emergency buses, begin to supply plant vital loads.

The auxiliary feedwater system is started automatically, as follows:

- Two motor-driven auxiliary feedwater pumps are started on any of the following:
  - Low-low level in any steam generator.
  - Any safety injection signal.
  - Loss of offsite power.
  - Manual actuation.

- The turbine-driven auxiliary feedwater pump is started on any of the following:
  - Low-low level in any two steam generators.
  - Loss of offsite power.
  - Manual actuation.

The motor-driven auxiliary feedwater pumps are supplied power by the diesels, and the turbine-driven pump utilizes steam from the secondary system. Both types of pumps are designed to supply rated flow within 1 min of the initiating signal, even if a loss of all nonemergency ac power occurs simultaneously with loss of normal feedwater. The auxiliary feedwater turbine exhausts the secondary steam to the atmosphere. The auxiliary feedwater pumps take suction from the two condensate storage tanks for delivery to the steam generators.

Upon the loss of power to the reactor coolant pumps, coolant flow necessary for core cooling and the removal of residual heat is maintained by natural circulation in the reactor coolant loops.

A loss of nonemergency ac power to the plant auxiliaries is classified as an American Nuclear Society Condition II event, fault of moderate frequency. This event is more limiting with respect to RCS heatup than the turbine-trip-initiated decrease in secondary heat removal without loss of ac power, which was analyzed in subsection 15.2.3. However, a loss of ac power to the plant auxiliaries, as postulated above, could also result in a loss of normal feedwater if the condensate pumps lose their power supply.

Following the reactor coolant pump coastdown caused by the loss of ac power, the natural circulation capability of the reactor coolant system (RCS) will remove residual and decay heat from the core, aided by auxiliary feedwater in the secondary system. An analysis is presented here to show that the natural circulation flow in the RCS following a loss of ac power event is sufficient to remove residual heat from the core.

The plant systems and equipment available to mitigate the consequences of a loss of ac power event are discussed in subsection 15.0.8 and listed in table 15.0.8-1.

15.2.6.2 Analysis of Effects and Consequences

15.2.6.2.1 Method of Analysis

A detailed analysis using the LOFTRAN code(1) is performed to simulate the system transient following a plant blackout. The simulation describes the plant thermal kinetics and RCS, including the natural circulation, pressurizer, steam generators, and feedwater system. The digital program computes pertinent variables, including the steam generator level, pressurizer water level, and reactor coolant average temperature.

The assumptions used in the analysis are as follows:

A. The plant is initially operating at 100.3 percent of the uprated power, 3653 MWt (includes +0.3% power uncertainty and 17MWt for the reactor coolant pump heat), with initial reactor coolant temperature 6°F above the nominal value and the pressurizer pressure 50 psi above the nominal value.

B. Core residual heat generation is based on the 1979 version of ANS 5.1(2). ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates.

C. The auxiliary feedwater system is actuated by the low-low steam generator water level signal. The auxiliary feedwater system is assumed to supply a minimum of 510 gal/min from each motor-driven pump with each pump supplying flow to two steam generators. Therefore, a total minimum auxiliary feedwater flow rate of 1020 gal/min is supplied by both motor-driven pumps split equally to the four steam generators.

D. The auxiliary feedwater system reliability concerns resulting from the Three Mile Island accident are addressed assuming one motor-driven pump is available, supplying a minimum of 510 gal/min split equally to two steam generators. Better-estimate conditions are modeled for this scenario, where plant operating parameters are set to their nominal values, with no consideration of uncertainties.

E. Secondary system steam relief is achieved through the steam generator safety valves.

F. The pressurizer relief valves, safety valves, sprays, and heaters are assumed to function to maximize the peak pressurizer water volume.

G. The high-head charging pumps, which are initiated on a loss of offsite power signal, are not assumed to function for this event as their operation is a benefit with respect to long term core decay heat removal. Note, however, that charging pump actuation following a loss of offsite power will increase the reactor coolant inventory if the letdown isolation valve fails closed due to a subsequent loss of instrument air. This scenario was examined to determine if the operators have sufficient time to unblock the pressurizer power-operated relief valves to preclude water relief through the pressurizer safety valves.

The assumptions used in the analysis are similar to the loss of normal feedwater flow incident (subsection 15.2.7) except that power is assumed to be lost to the reactor coolant pumps at the time of reactor trip.

Plant characteristics and initial conditions are further discussed in subsection 15.0.3.

15.2.6.2.2 Results

The transient response of the RCS following a loss of ac power is shown in figures 15.2.6-1 and 15.2.6-2. The calculated sequence of events for this event is listed in table 15.2.3-1.

The LOFTRAN code results show that the natural circulation flow and the auxiliary feedwater flow rates are sufficient to provide adequate core decay heat removal following reactor trip and reactor coolant pump coastdown.

A separate case was run to address the auxiliary feedwater system reliability concerns resulting from the Three Mile Island accident. This case did not result in the filling of the pressurizer, which confirms the reliability of the auxiliary feedwater system.

A separate case was run with charging pumps initiated on a loss of offsite power signal. This case did not result in the filling of the pressurizer prior to 10 minutes following the initiation of the event. Thus, there is sufficient time available for the operator to unblock the pressurizer power-operated relief valves and thus preclude water relief through the pressurizer safety valves. This case is analyzed similar to the inadvertent emergency core cooling system (ECCS) at power event, discussed in subsection 15.6.1, where operator action is required to unblock the pressurizer power-operated relief valves thereby precluding water relief through the pressurizer safety valves.

15.2.6.3 Radiological Consequences

The evaluation of the radiological consequences of a postulated loss of nonemergency ac power assumes that the reactor has been operating with a small percent of defective fuel and leaking steam generator tubes for sufficient time to establish equilibrium concentrations of radionuclides in the reactor coolant and in the secondary coolant.

Following the loss of nonemergency ac power, radionuclides are carried by the primary coolant to the steam generator via leaking tubes and are released to the environment via the steam line safety or power-operated relief valves.

15.2.6.3.1 Analytical Assumptions

The major assumptions and parameters used in the analysis are itemized in table 15.2.6-1. The following is a more detailed discussion of the source term.

15.2.6.3.1.1 Source Term Calculation. The concentration of nuclides in the primary and secondary system, prior to the accident, are determined as follows:

A. The iodine concentrations in the reactor coolant will be based upon preaccident and accident initiated iodine spikes.

   1. Accident Initiated Spike

      The reactor trip associated with the loss of nonemergency ac power creates an iodine spike in the primary system which increases the iodine release rate from the fuel to the primary coolant to a value 500 times greater than the release rate corresponding to the maximum equilibrium primary system iodine concentration of 1 μCi/g of dose equivalent (DE) I-131. The elevated appearance rates are assumed to return to normal once the reactor coolant iodine level increases to 100 μCi/g DE I-131.

   2. Preaccident Spike

      A reactor transient has occurred prior to the loss of nonemergency ac power and has raised the primary coolant iodine concentration to 60 μCi/g of DE I-131.

B. The noble gas concentrations in the primary coolant are based on 1-percent defective fuel.

C. The secondary coolant activity is based on DE of 0.1 μCi/g of I-131.

15.2.6.3.1.2 Mathematical Models Used in the Analysis. Mathematical models used in the analysis are described in the following sections:

A. The mathematical models used to analyze the activity released during the course of the accident are described in appendix 15A.

B. The atmospheric dispersion factors used in the analysis were calculated based on the onsite meteorological measurement programs described in subsection 2.3.3.

C. The thyroid inhalation and total-body gamma immersion doses to a receptor at the exclusion area boundary and outer boundary of the low population zone were analyzed using the models described in appendix 15A.

15.2.6.3.1.3 Identification of Leakage Pathways and Resultant Leakage Activity. Radionuclides carried from the primary coolant to the steam generators via leaking tubes are released to the environment via the steam line safety or power-operated relief valves. Iodines are assumed to mix with the secondary coolant and partition between the generator liquid and steam before release to the environment. Noble gases are assumed to be directly released.

All activity is released to the environment with no consideration given to radioactive decay or cloud depletion by ground deposition during transport to the exclusion area boundary and low population zone. Hence, the resultant radiological consequences represent the most conservative estimate of the potential integrated dose due to the postulated loss of nonemergency ac power.

15.2.6.3.2 Identification of Uncertainties and Conservative Elements in the Analysis

A. The initial reactor coolant iodine activity is based on the technical specification limit of 1.0 μCi/g of DE I-131 which is significantly greater than the activities associated with normal operating conditions.

B. The preaccident iodine spike activity based on 60 μCi/g and the accident initiated spike iodine appearance rate multiplier of 500 are much greater than expected for typical plant operation.

C. The noble gas activities are based on 1 percent defective fuel which cannot exist simultaneously with 1.0-μCi/g I-131. For iodines, 1 percent defects would be approximately three times the technical specification limit.

D. A 1-gal/min steam generator primary-to-secondary leakage is assumed, which is significantly greater than that anticipated during normal operation.

E. The meteorological conditions which may be present at the site during the course of the accident are uncertain. However, it is highly unlikely that the assumed meteorological conditions would be present during the course of the accident for any extended period of time. Therefore, the radiological consequences evaluated, based on the meteorological conditions assumed, are conservative.

15.2.6.3.3 Conclusions

15.2.6.3.3.1 Filter Loadings. No filter serves to limit the release of radioactivity in this accident. There is no significant activity buildup on any filters as a consequence of a loss of nonemergency ac power.

15.2.6.3.3.2 Doses to Receptor at Exclusion Area Boundary and Low Population Zone Outer Boundary. The potential radiological consequences resulting from the occurrence of a postulated loss of nonemergency ac power have been conservatively analyzed using the assumptions and models described. The total-body gamma dose due to immersion from direct radiation and the thyroid dose due to inhalation have been analyzed for the 0- to 2-h dose at the exclusion area boundary and for the duration of the accident (0 to 20 h) at the low population zone outer boundary. The results are presented in table 15.2.6-2. The resultant doses are well within the guidelines of 10 CFR 100.

15.2.6.4 Conclusions

Results of the analysis show that for the loss of nonemergency ac power to plant auxiliaries event all safety criteria are met. Auxiliary feedwater capacity is sufficient to prevent water relief through the pressurizer relief and safety valves. The analysis demonstrates that sufficient long-term RCS heat removal capability exists via natural circulation and auxiliary feedwater following reactor coolant pump coastdown to prevent fuel or clad damage and assures that the RCS is not overpressurized.

15.2.6.5 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (proprietary), WCAP-7907-A (nonproprietary), April 1984.
2. "American National Standard for Decay Heat Power in Light Water Reactors," ANSI/ANS-5.1-1979, August 1979.

15.2.7 LOSS OF NORMAL FEEDWATER FLOW

15.2.7.1 Identification of Causes and Accident Description

A loss of normal feedwater (from pump failures, valve malfunctions, or loss of offsite ac power) results in a reduction in the capability of the secondary system to remove the heat generated in the reactor core. If an alternative supply of feedwater were not supplied to the plant, core residual heat following reactor trip would heat the primary system water to the point where water relief from the pressurizer would occur, resulting in a substantial loss of water from the reactor coolant system (RCS). Since the plant is tripped well before the steam generator heat transfer capability is reduced, the primary system variables never approach a departure from nucleate boiling condition.

A small secondary system break could affect normal feedwater flow control causing low steam generator levels prior to protective actions for the break. This scenario is addressed by the assumptions made for the feedwater system pipe break (subsection 15.2.8).

The following occur upon loss of normal feedwater (assuming main feedwater pump failures or valve malfunctions):

A. As the steam system pressure rises following the trip, the steam generator power-operated relief valves are automatically opened to the atmosphere. The condenser is assumed to be unavailable for turbine bypass. If the steam flow path through the power-operated relief valves is not available, the steam generator safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

B. As the no-load temperature is approached, the steam generator power-operated relief valves (or safety valves, if the power-operated relief valves are not available) are used to dissipate the residual decay heat and to maintain the plant at the hot shutdown condition.

A loss of normal feedwater is classified as an American Nuclear Society Condition II event, fault of moderate frequency.

The reactor trip on low-low water level in any steam generator provides the necessary protection against a loss of normal feedwater.

The auxiliary feedwater system is started automatically, as discussed in paragraph 15.2.6.1. The turbine-driven auxiliary feedwater pump utilizes steam from the secondary system and exhausts it to the atmosphere. The motor-driven auxiliary feedwater pumps are supplied power by the diesel generators. The auxiliary feedwater pumps take suction directly from the condensate storage tank for delivery to the steam generators.

An analysis of the system transient is presented below to show that following a loss of normal feedwater the auxiliary feedwater system is capable of removing the stored and residual decay heat, thus preventing either overpressurization of the RCS or loss of water from the reactor coolant system, and returning the plant to a safe condition.

15.2.7.2 Analysis of Effects and Consequences

15.2.7.2.1 Method of Analysis

A detailed analysis using the LOFTRAN code(1) is performed to obtain the plant transient following a loss of normal feedwater. The simulation describes the plant thermal kinetics, RCS (including the natural circulation), pressurizer, steam generators, and feedwater system. The digital program computes pertinent variables, including the steam generator level, pressurizer water level, and reactor coolant average temperature.

The assumptions used in the analysis are as follows:

A. The plant is initially operating at 100.3 percent of the uprated full power, design rating, 3653 MWt (includes +0.3% power uncertainty and 17 MWt for the reactor coolant pump heat).

B. Core residual heat generation is based on the 1979 version of ANS 5.1(2). ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates.

C. Reactor trip occurs on steam generator low-low level.

D. The worst single failure in the auxiliary feedwater system occurs. The auxiliary feedwater system is assumed to supply a total of 510 gal/min from each motor-driven pump with each pump supplying flow to two steam generators. Therefore, a total minimum auxiliary feedwater flow rate of 1020 gal/min is supplied by both motor-driven pumps split equally to the four steam generators.

E. The auxiliary feedwater system reliability concerns resulting from the Three Mile Island accident are addressed assuming one motor-driven pump is available, supplying a minimum of 510 gal/min split equally to two steam generators. Better-estimate conditions are modeled for this scenario, where plant operating parameters are set to their nominal values, with no consideration of uncertainties.

F. The auxiliary feedwater system is actuated by the low-low steam generator water level signal.

G. Secondary system steam relief is achieved through the steam generator safety valves.

H. The initial reactor coolant average temperature is 6°F higher than the nominal value, and initial pressurizer pressure is 50 psi higher than nominal.

The loss of normal feedwater analysis is performed to demonstrate the adequacy of the reactor protection and engineered safeguards systems (e.g., the auxiliary feedwater system) in removing long-term decay heat and preventing excessive heatup of the RCS with possible resultant RCS overpressurization or loss of RCS water.

As such, the assumptions used in this analysis minimize the energy removal capability of the system and maximize the possibility of water relief from the coolant system by maximizing the coolant system expansion.

For the loss of normal feedwater transient, the reactor coolant volumetric flow remains at its normal value, and the reactor trips via the low-low steam generator level trip. The reactor coolant pumps may be manually tripped at some later time to reduce heat addition to the RCS. However, the pumps are not assumed to trip in the analysis.

An additional assumption made for the loss of normal feedwater evaluation is that the pressurizer relief valves, safety valves, sprays, and heaters are assumed to function to maximize the peak pressurizer water volume. Operation of the valves, if required, maintains peak RCS pressure below 110 percent of RCS design pressure throughout the transient.

Plant characteristics and initial conditions are further discussed in subsection 15.0.3.

Plant systems and equipment which are necessary to mitigate the effects of a loss of normal feedwater accident are discussed in subsection 15.0.8 and listed in table 15.0.8-1. Normal reactor control systems are not required to function. The reactor protection system is required to function following a loss of normal feedwater, as analyzed here. The auxiliary feedwater system is required to deliver a minimum auxiliary feedwater flow rate. No single active failure will prevent operation of any system to perform its required function. A discussion of anticipated transients without scram considerations is presented in section 15.8.

15.2.7.2.2 Results

Figures 15.2.7-1 and 15.2.7-2 show the significant plant parameters following a loss of normal feedwater.

Following the reactor and turbine trip from full load, the water level in the steam generators will fall due to the reduction of steam generator void fraction, and because steam flow through the safety valves continues to dissipate the stored and generated heat. One minute following the initiation of the low-low level trip, both motor-driven auxiliary feedwater pumps are automatically started, reducing the rate of water inventory decrease in the four steam generators.

The capacity of the auxiliary feedwater pumps is such that the water level in the steam generators is sufficient to dissipate core residual heat without water relief from the RCS safety valves.

The calculated sequence of events for this accident is listed in table 15.2.3-1. As shown in figures 15.2.7-1 and 15.2.7-2, the plant slowly approaches a stabilized condition following reactor trip and auxiliary feedwater initiation. Plant procedures may be followed to further cool down the plant.

A separate case was run to address the auxiliary feedwater system reliability concerns resulting form the Three Mile Island accident. This case did not result in the filling of the pressurizer, which confirms the reliability of the auxiliary feedwater system.

15.2.7.3 Conclusions

Results of the analysis show that a loss of normal feedwater does not adversely affect the core, the RCS, or the steam system. The auxiliary feedwater capacity is such that reactor coolant water is not relieved from the pressurizer relief or safety valves.

15.2.7.4 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (proprietary), WCAP-7907-A (nonproprietary), April 1984.
2. "American National Standard for Decay Heat Power in Light Water Reactors," ANSI/ANS-5.1-1979, August 1979.

15.2.8 FEEDWATER SYSTEM PIPE BREAK

15.2.8.1 Identification of Causes and Accident Description

A major feedwater line rupture is defined as a break in a feedwater line 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 feedwater line between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. A break in this location could preclude the subsequent addition of auxiliary feedwater to the affected steam generator. Furthermore, due to the piping system design the feed break piping may cause a safety injection branch line to break which decreases the safety injection flow delivered to the core. (A break upstream of the feedwater line check valve would affect the plant only as a loss of feedwater. This case is covered by the evaluation in subsections 15.2.6 and 15.2.7.)

Depending upon the size of the break and the plant operating conditions at the time of the break, the break could cause either a reactor coolant system (RCS) cooldown (by excessive energy discharge through the break) or an RCS heatup. Potential RCS cooldown resulting from a secondary pipe rupture is evaluated in subsection 15.1.5. Therefore, only the RCS heatup effects are evaluated for a feedwater line rupture.

A feedwater line rupture reduces the ability to remove heat generated by the core from the RCS for the following reasons:

A. Feedwater flow to the steam generators is reduced. Since feedwater is subcooled, its loss may cause reactor coolant temperatures to increase prior to reactor trip.

B. Fluid in the steam generator may be discharged through the break and would then not be available for decay heat removal after trip.

C. The break may be large enough to prevent the addition of any main feedwater after trip.

An auxiliary feedwater system functions to ensure the availability of adequate feedwater so that:

A. No substantial overpressurization of the RCS occurs (less than 110 percent of design pressures).

B. Sufficient liquid in the RCS is maintained so that the core remains in place and geometrically intact with no loss of core cooling capability.

A major feedwater line rupture is classified as an American Nuclear Society Condition IV event.

The severity of the feedwater line rupture transient depends on a number of system parameters, including break size, initial reactor power, and the functioning of various control and safety systems. Sensitivity studies presented in reference 1 illustrate that the most limiting feedwater line rupture is a double-ended rupture of the largest feedwater line. The main feedwater control system is assumed to malfunction due to an adverse environment. The water levels in all steam generators are assumed to decrease equally until the low-low steam generator level reactor trip setpoint is reached. After reactor trip, a double-ended rupture of the largest feedwater line is assumed. These assumptions conservatively bound the most limiting feedwater line rupture that can occur. Analyses have been performed at full power, with and without loss of offsite power. For the case without offsite power available, the power is assumed to be lost at the time of reactor trip. This is more conservative than the case where power is lost at the initiation of the event. These cases are analyzed below.

The following provides the protection for a main feedwater line rupture:

A. A reactor trip on any of the following conditions:

   1. High pressurizer pressure.
   2. Overtemperature ΔT.
   3. Low-low steam generator water level in any steam generator.
   4. Low pressurizer pressure.
   5. High pressurizer level.
   6. Safety injection signals from either of the following:
      - Two out of three low steam line pressure in any steam generator.
      - Two out of three high containment pressure (high-1).

   Refer to chapter 7 for a description of the actuation system.

B. The auxiliary feedwater system provides an assured source of feedwater to the steam generators for decay heat removal. Refer to subsection 10.4.9 for a description of the auxiliary feedwater system.

15.2.8.2 Analysis of Effects and Consequences

15.2.8.2.1 Method of Analysis

A detailed analysis using the LOFTRAN code (reference 2) is performed in order to determine the plant transient following a feedwater line rupture. The code describes the plant thermal kinetics, RCS (including natural circulation), pressurizer, steam generators, and feedwater system and computes pertinent variables, including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

The cases analyzed assume a double-ended rupture of the largest feedwater pipe at full power. Major assumptions used in the analysis are as follows:

A. The plant is initially operating at 102 percent of the engineered safety features design rating.

B. Initial reactor coolant average temperature is 6.0°F above the nominal value, and the initial pressurizer pressure is 50 psi below its nominal value.

C. The pressurizer power-operated relief valves and the safety relief valves are assumed to be operable. No credit is taken for pressurizer spray.

D. Initial pressurizer level is at the nominal programmed value plus 10 percent error; a conservative initial steam generator water level is assumed in all steam generators.

E. No credit is taken for the high pressurizer pressure, low pressurizer pressure, high pressurizer level, and overtemperature ΔT reactor trips.

F. Main feedwater to all steam generators is assumed to stop at the time the break occurs. (All main feedwater spills out through the break.) As a result, the water level in all four steam generators begins to drop.

G. A double-ended break area of 0.89 ft^2 is assumed at the time of reactor trip. This maximizes the blowdown discharge rate following the time of trip, which maximizes the resultant heatup of the reactor coolant.

H. A conservative feedwater line break discharge quality is assumed at the time the reactor trip occurs. This minimizes the heat removal capability of the affected steam generator.

I. Reactor trip is assumed to be initiated when the low-low level setpoint is reached on the ruptured steam generator.

J. The auxiliary feedwater system is actuated by the low-low steam generator water level signal. The auxiliary feedwater system is assumed to supply a minimum of 510 gal/min to three unaffected steam generators, including allowance for possible spillage through the main feedwater line break. A 60-s delay was assumed following the low-low level signal to allow time for startup of the standby diesel generators and the auxiliary feedwater pumps. An additional 223 s were assumed before the feedwater lines were purged and the relatively cold auxiliary feedwater entered the unaffected steam generators.

K. No credit is taken for heat energy deposited in RCS metal during the RCS heatup.

L. No credit is taken for charging or letdown.

M. Steam generator heat transfer area is assumed to decrease as the shell-side liquid inventory decreases.

N. Conservative core residual heat generation is assumed based upon long-term operation at the initial power level preceding the trip (reference 3).

O. No credit is taken for the following potential protection logic signals to mitigate the consequences of the accident:

  1. High pressurizer pressure.
  2. Overtemperature ΔT.
  3. High pressurizer level.
  4. High containment pressure.

Receipt of a low-low steam generator water level signal in at least one steam generator starts the motor-driven auxiliary feedwater pumps, which in turn initiate auxiliary feedwater flow to the steam generators. The turbine-driven auxiliary feedwater pump is initiated if the low-low steam generator water level signal is reached in at least two steam generators. Similarly, receipt of a low steam line pressure signal in at least one steam line initiates a steam line isolation signal which closes all main steam line isolation valves. This signal also gives a safety injection (SI) signal which initiates flow of cold borated water into the RCS. The amount of SI flow is a function of RCS pressure.

Emergency operating procedures following a feedwater system pipe rupture require the following actions to be taken by the reactor operator:

A. Isolate main and auxiliary feedwater flow spilling from the ruptured feedwater line.

B. Stop all but one high-head SI charging pump if the SI termination criteria are met.

Isolating auxiliary feedwater flow spilling through the break allows additional auxiliary feedwater flow to be diverted to the intact steam generators; however, no credit for this operator action is explicitly modeled in the analysis.

Subsequent to recovery of level in the intact steam generators, the high-head SI pumps will be turned off and plant operating procedures will be followed in cooling the plant to hot shutdown conditions.

Plant characteristics and initial conditions are further discussed in subsection 15.0.3.

No reactor control systems are assumed to function other than a conservative assumption that the pressurizer PORVs are operable. The reactor protection system is required to function following a feedwater line rupture as analyzed here. No single active failure will prevent operation of this system.

The engineered safety systems assumed to function are the auxiliary feedwater system and the SI system. For the auxiliary feedwater system, the worst case configuration has been used; i.e., only three intact steam generators receive auxiliary feedwater following the break. Most of the flow from the motor-driven auxiliary feedwater pump feeding the affected steam generator was assumed to spill through the break. The turbine-driven auxiliary feedwater pump has been assumed to fail. The total flow from the two motor-driven auxiliary feedwater pumps is assumed to be a minimum of 510 gal/min divided among the three intact steam generators.

For the case without offsite power, there will be a flow coastdown until flow in the loops reaches the natural circulation value. The natural circulation capability of the RCS has been shown (in subsection 15.2.6) to be sufficient to remove core decay heat following reactor trip for the loss of ac power transient. Pump coastdown characteristics are demonstrated in subsections 15.3.1 and 15.3.2 for single and multiple reactor coolant pump trips, respectively.

A detailed description and analysis of the SI system is provided in section 6.3. The auxiliary feedwater system is described in subsection 10.4.9.

15.2.8.2.2 Results

Calculated plant parameters following a major feedwater line rupture are shown in figures 15.2.8-1 through 15.2.8-8. Results for the case with offsite power available are presented in figures 15.2.8-1 through 15.2.8-4. Results for the case where offsite power is lost are presented in figures 15.2.8-5 through 15.2.8-8. The calculated sequence of events for both cases analyzed is listed in table 15.2.3-1.

The system response following the feedwater line rupture is similar for both cases analyzed. Results presented in figures 15.2.8-2 and 15.2.8-4 (with offsite power available) and figures 15.2.8-6 and 15.2.8-8 (without offsite power) show that pressures in the RCS and main steam system remain below 110 percent of the respective design pressures. Pressurizer pressure decreases after reactor trip of low-low steam generator level (66 s). Pressurizer pressure decreases due to the loss of heat input, until the SI system is actuated on low steam line pressure in the ruptured loop. Coolant expansion occurs due to reduced heat transfer capability in the steam generators; the pressurizer PORVs are conservatively assumed to open, which prevents pressurizer pressure from increasing beyond the PORV setpoint. The addition of the SI flow aids in cooling down the primary and helps to ensure that sufficient fluid exists to keep the core covered with water.

Figure 15.2.8-2 shows that the minimum volume in the pressurizer is reached at approximately 150 s; however, the results of LOFTRAN show that the core remains covered at all times and that no boiling occurs in the reactor coolant loops.

The major difference between the two cases analyzed can be seen in the plots of hot and cold leg temperatures, figure 15.2.8-3 (with offsite power available) and figure 15.2.8-7 (without offsite power). It is apparent that for the initial transient (150 s) the case without offsite power results in higher temperatures in the hot leg. For longer times, however, the case with offsite power results in a more severe rise in temperature. The pressurizer fills more rapidly for the case with power due to the increased coolant expansion resulting from the pump heat addition; however, water is not relieved for the case without offsite power. As previously stated, the core cooling capability is maintained.

15.2.8.3 Conclusions

Results of the analyses show that for the postulated feedwater line rupture, the assumed auxiliary feedwater system capacity is adequate to remove decay heat, to prevent overpressurizing the RCS, and to maintain the core cooling capability. Radioactivity doses from the postulated feedwater lines rupture are less than those previously presented for the postulated steam line break. All applicable acceptance criteria are therefore met.

15.2.8.4 References

1. Lang, G. E., and Cunningham, J. P., "Report on the Consequences of a Postulated Main Feedline Rupture," WCAP-9230 (proprietary) and WCAP-9231 (nonproprietary), January 1978.
2. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP 7907-P-A (proprietary), WCAP-7907-A (nonproprietary), April 1984.
3. "American National Standard for Decay Heat Power in Light Water Reactor," ANSI/ANS-5.1-1979, August 1979.

TABLE 15.2.3-1 (SHEET 1 OF 5)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

	Accident	Event	Time (s)
I.	Turbine Trip		
	A. With pressurizer control (minimum reactivity feedback)	Turbine trip; loss of main feedwater flow	0.0
		Initiation of steam release from steam generator safety valves	7.1
		Peak pressurizer pressure occurs	8.4
		Overtemperature ΔT reactor trip point reached	8.9
		Rods begin to drop	10.9
		Minimum DNBR occurs	12.1
	B. With pressurizer control (maximum reactivity feedback)	Turbine trip; loss of main feedwater flow	0.0
		Initiation of steam release from steam generator safety valves	7.1
		Peak pressurizer pressure occurs	7.1
		Low-low steam generator water level reactor trip setpoint reached	40.9
		Rods begin to drop	42.9
		Minimum DNBR occurs	[a]

TABLE 15.2.3-1 (SHEET 2 OF 5)

Accident	Event	Time (s)
I. Turbine Trip		
C. Without pressurizer control (minimum reactivity feedback)	Turbine trip; loss of main feedwater flow	0.0
	High pressurizer pressure reactor trip point reached	4.5
	Rods begin to drop	6.5
	Initiation of steam release from steam generator safety valves	7.0
	Peak pressurizer pressure occurs	8.6
	Minimum DNBR occurs	(a)
D. Without pressurizer control (maximum reactivity feedback)	Turbine trip; loss of main feedwater flow	0.0
	High pressurizer pressure reactor trip point reached	4.5
	Rods begin to drop	6.5
	Initiation of steam release from steam generator safety valves	7.0
	Peak pressurizer pressure occurs	7.4
	Minimum DNBR occurs	(a)
II. Loss of nonemergency ac power to the station auxiliaries	Main feedwater flow stops	10.0
	Low-low steam generator water level trip setpoint reached	56.5

TABLE 15.2.3-1 (SHEET 3 OF 5)

	Accident	Event	Time (s)
II.	Loss of nonemergency ac power to the station auxiliaries (continued)	Rods begin to drop	58.5
		Reactor coolant pumps begin coasting down	60.5
		Peak pressurizer volume occurs	62.4
		Auxiliary feedwater initiated	131.5
		Core decay heat decreases to the auxiliary feedwater heat removal capacity	≃450.0
III.	Loss of normal feedwater flow	Main feedwater flow stops	10.0
		Low-low steam generator water level reactor trip setpoint reached	56.5
		Rods begin to drop	58.5
		Peak pressurizer volume occurs	62.0
		Auxiliary feedwater initiated	116.5
		Core decay heat plus pump decreases to auxiliary feedwater heat removal capacity	≃400

TABLE 15.2.3-1 (SHEET 4 OF 5)

Accident	Event	Time (s)
IV. Feedwater system pipe break		
A. With offsite power available	Feedwater control system fails	10.0
	Pressurizer relief valve setpoint reached	25.5
	Low-low steam generator level reactor trip setpoint reached in all steam generator	66.5
	Rods begin to drop and feedline rupture occurs	68.5
	Steam generator safety valve setpoint reached in intact steam generators	70.0
	Low steam line pressure setpoint reached in affected steam generator	110.0
	All main steam line isolation valves close	120.0
	Auxiliary feedwater is delivered to intact steam generators	126.5
	Core decay heat decreases to auxiliary feedwater heat removal capacity	≃2500
B. Without offsite power	Feedwater control system	10.0
	Pressurizer relief valve setpoint reached	25.5

TABLE 15.2.3-1 (SHEET 5 OF 5)

Accident		Event	Time (s)
B	Without offsite power (continued)	Low-low steam generator level reactor trip setpoint reached in affected steam generator	66.5
		Rods begin to drop; power lost to the reactor coolant pumps, feedline rupture occurs	68.5
		Steam generator safety valve setpoint reached in intact steam generators	70.0
		Low steam line pressure setpoint reached in affected steam generator	101.0
		All main steam line isolation valves close	111.0
		Auxiliary feedwater is delivered to intact steam generators	126.5
		Core decay heat decreases to auxiliary feedwater heat removal capacity	$\simeq$1000

---

a. DNBR does not decrease below its initial value.

TABLE 15.2.6-1 (SHEET 1 OF 2)

PARAMETERS USED IN EVALUATING RADIOLOGICAL CONSEQUENCES OF LOSS OF NONEMERGENCY ac POWER[(a)]

I. Source Data

A.	Core power level (MWt)	3636
	Total steam generator tube leakage (gal/min)	1
	Reactor coolant iodine activity	
	1. Accident initiated spike	Initial activity equal to the DE of 1.0 µCi/g of I-131 with an iodine spike that increases the rate of iodine release into the reactor coolant by a factor of 500. See table 15A-7.
	2. Preaccident spike	An assumed preaccident iodine spike which has resulted in the DE of 60 µCi/g of I-131 in the reactor coolant. See table 15A-6.
D.	Gap activity released to reactor coolant from failed fuel	None
E.	Reactor coolant noble gas activity	Based on 1 percent defective fuel. See table 15A-4.
F.	Secondary system initial activity	DE of 0.1 µCi/g of I-131.
G.	Secondary coolant mass, four generators (g)	1.9 x 108
H.	Reactor coolant mass (g)	2.3 x 10^8
I.	Offsite power	Lost after trip
J.	Primary-to-secondary leakage duration (h)	20
K.	Species of iodine	100 percent elemental

TABLE 15.2.6-1 (SHEET 2 OF 2)

II.	Atmospheric Dispersion Factors	See table 15A-2.
III.	Activity Release Data	
	A. Primary-to-secondary leak rate(gal/min)(b)	1.0
	B. Steam released (lb)	
	0 to 2 h	555,000
	2 to 8 h	1,365,000
	8 to 20 h(c)	2,730,000
	C. Iodine partition factor	0.01

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a. Power is lost at 10 s.

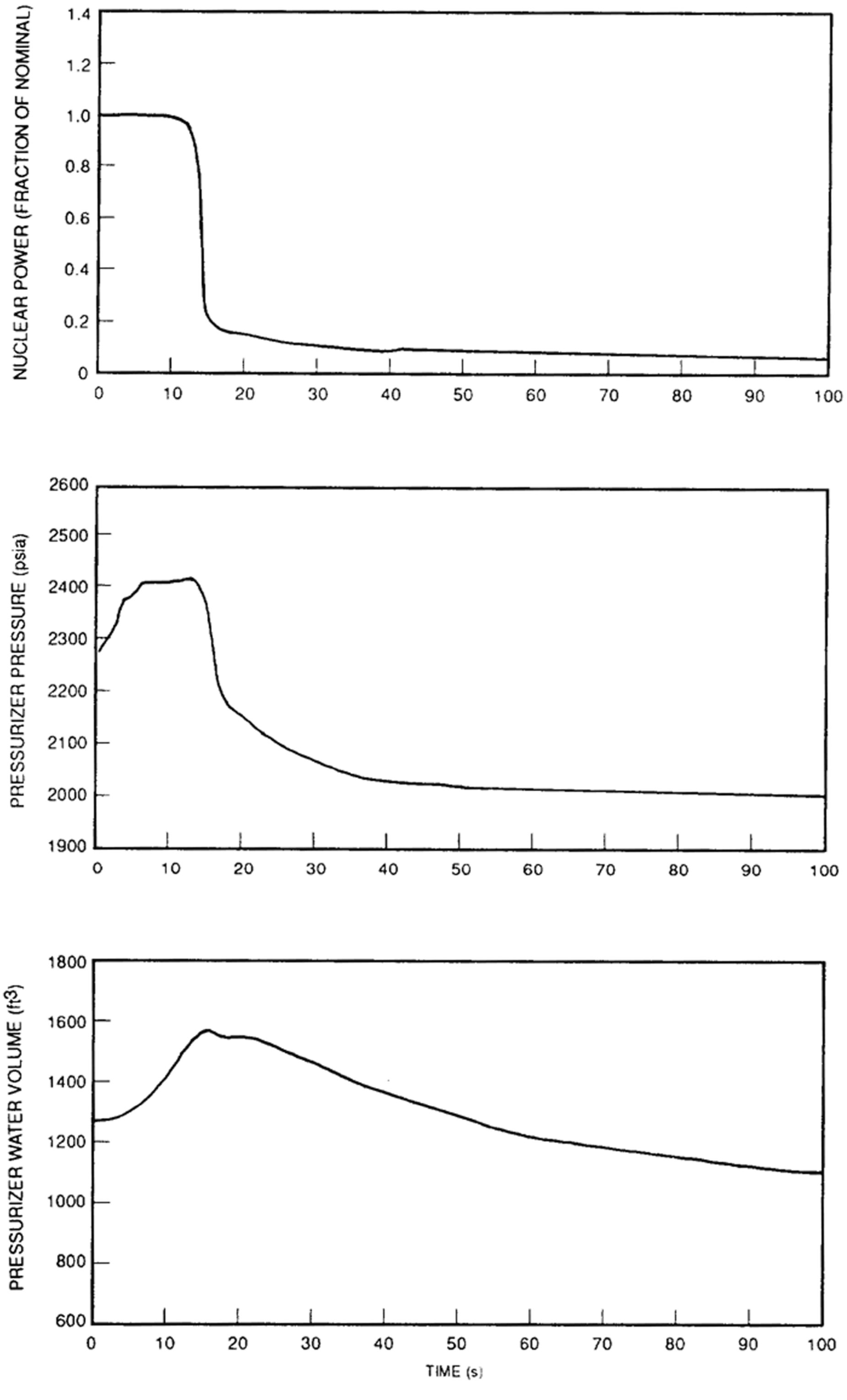
b. Based on water at 62.4 lb/ft^3.

c. The evaluation has included the impact of a longer time required to cool the plant resulting from the deletion of the RHR suction valve thermal relief (as specified by PS-06-1981). The 20-hour assumption is consistent with the evaluation provided by Westinghouse Electric Corporation when the RHR change was first evaluated.

TABLE 15.2.6-2

RADIOLOGICAL CONSEQUENCES OF LOSS OF NONEMERGENCY ac POWER

	Doses (rem)
Case 1 - Accident Initiated Iodine Spike	
Exclusion area boundary (0 to 2 h)	
Thyroid	< 0.1
Whole Body	< 0.2
Low population zone outer boundary (0 to 20 h)	
Thyroid	< 0.1
Whole Body	0.1
Case 2 - Preaccident Iodine Spike	
Exclusion area boundary (0 to 2 h)	
Thyroid	< 0.1
Whole Body	< 0.1
Low population zone outer boundary (0 to 20 h)	
Thyroid	0.1
Whole Body	< 0.1
Both Cases - Whole Body Gamma	
Exclusive area bounding (0 to 2 h)	< 0.1
Low population zone outer boundary (8 h)	< 0.1



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TURBINE TRIP ACCIDENT WITH PRESSURIZER SPRAY AND POWER–OPERATED RELIEF VALVES, MINIMUM MODERATOR FEEDBACK

FIGURE 15.2.3–1

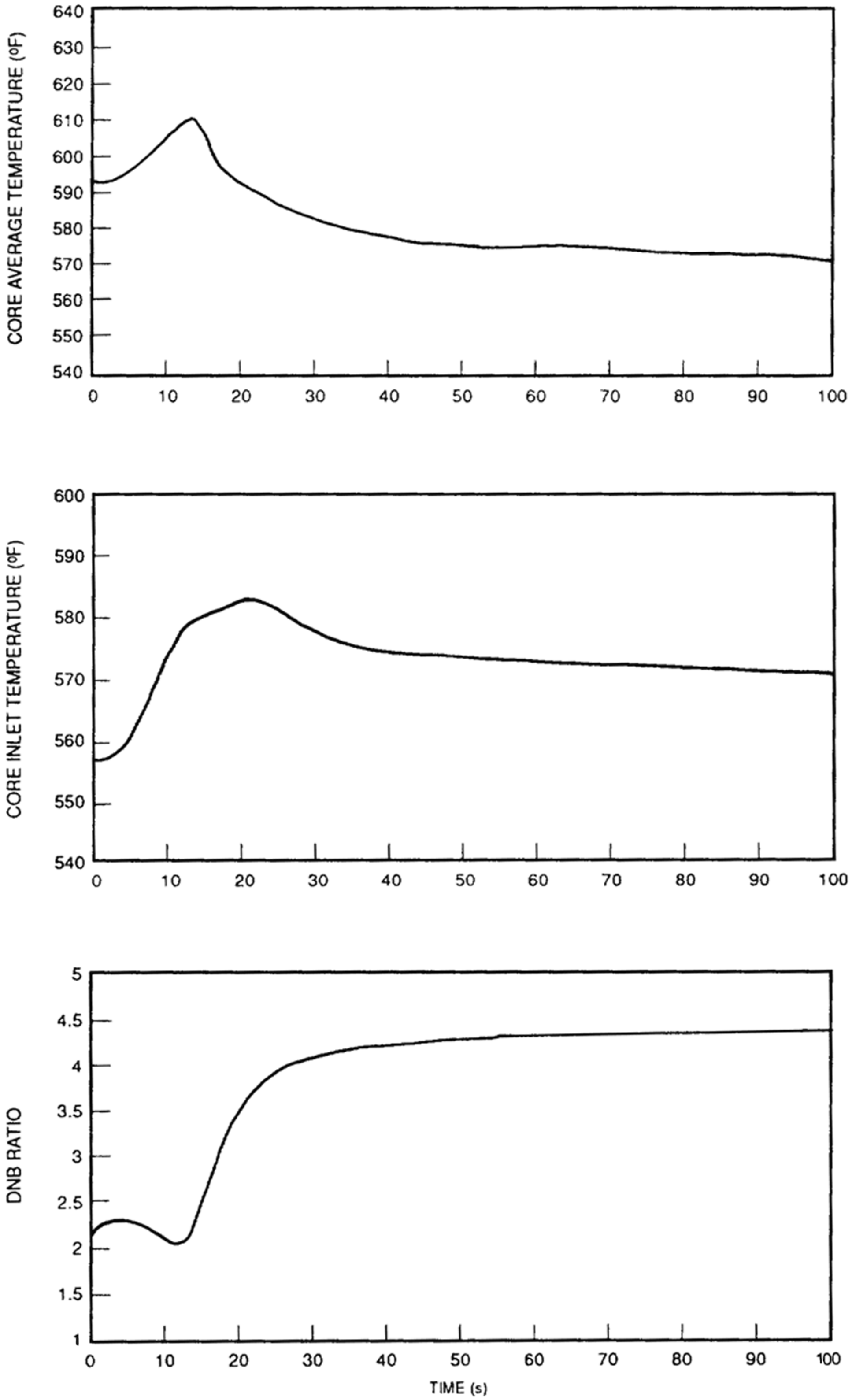

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FIGURE 15.2.3–2

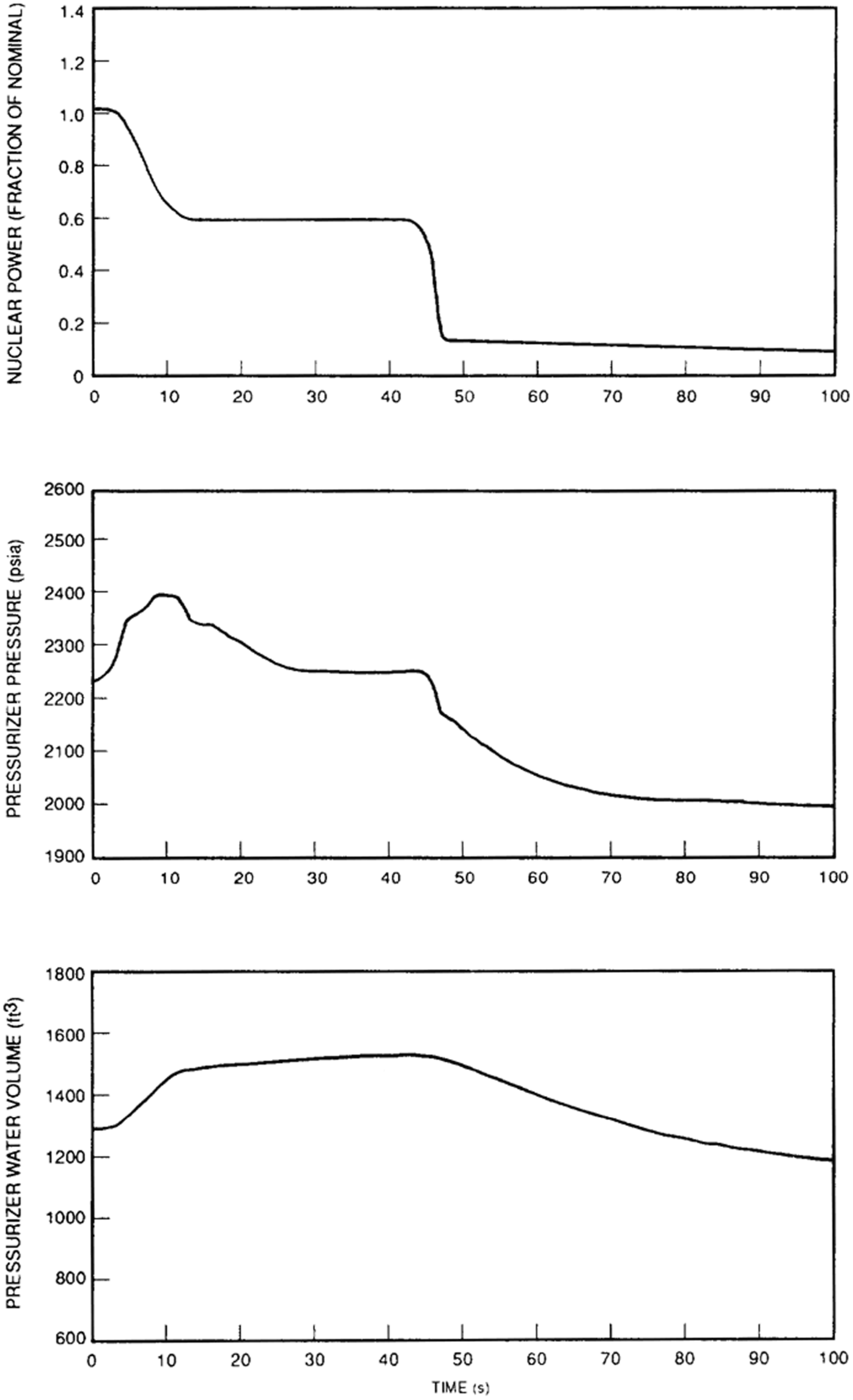

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FIGURE 15.2.3–3

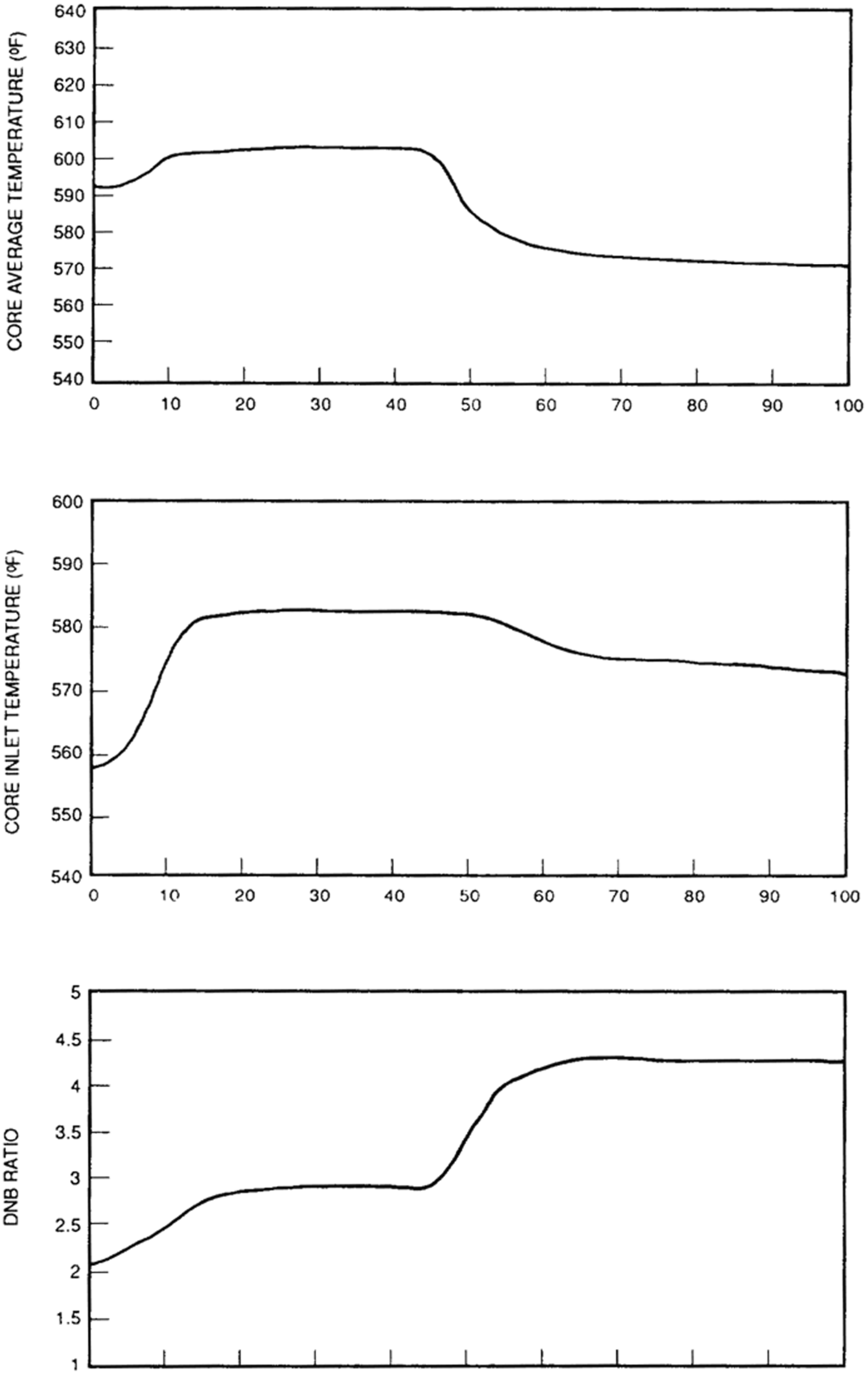

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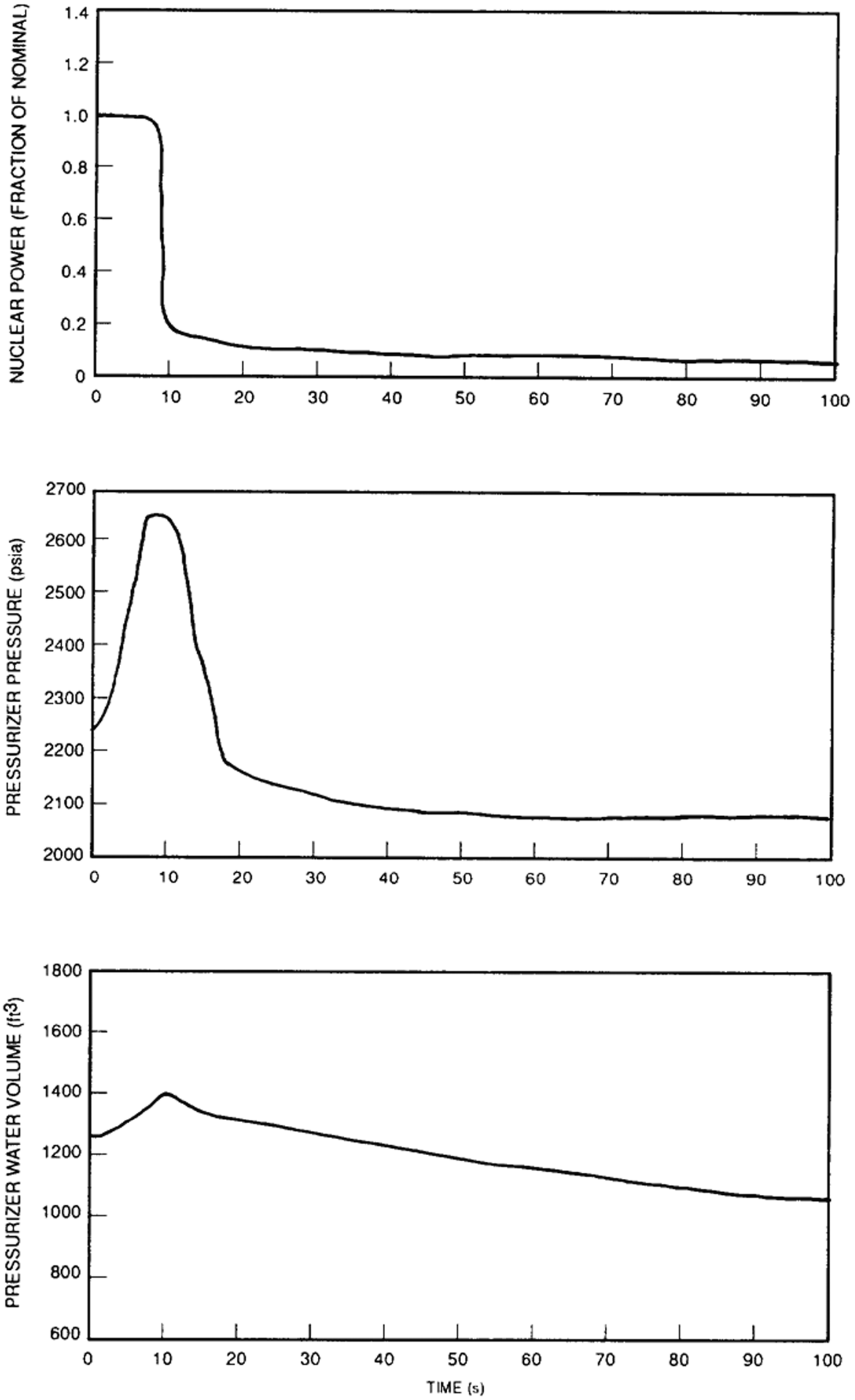
FIGURE 15.2.3–4



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TURBINE TRIP ACCIDENT WITHOUT PRESSURIZER SPRAY AND POWER–OPERATED RELIEF VALVES, MINIMUM MODERATOR FEEDBACK

FIGURE 15.2.3–5

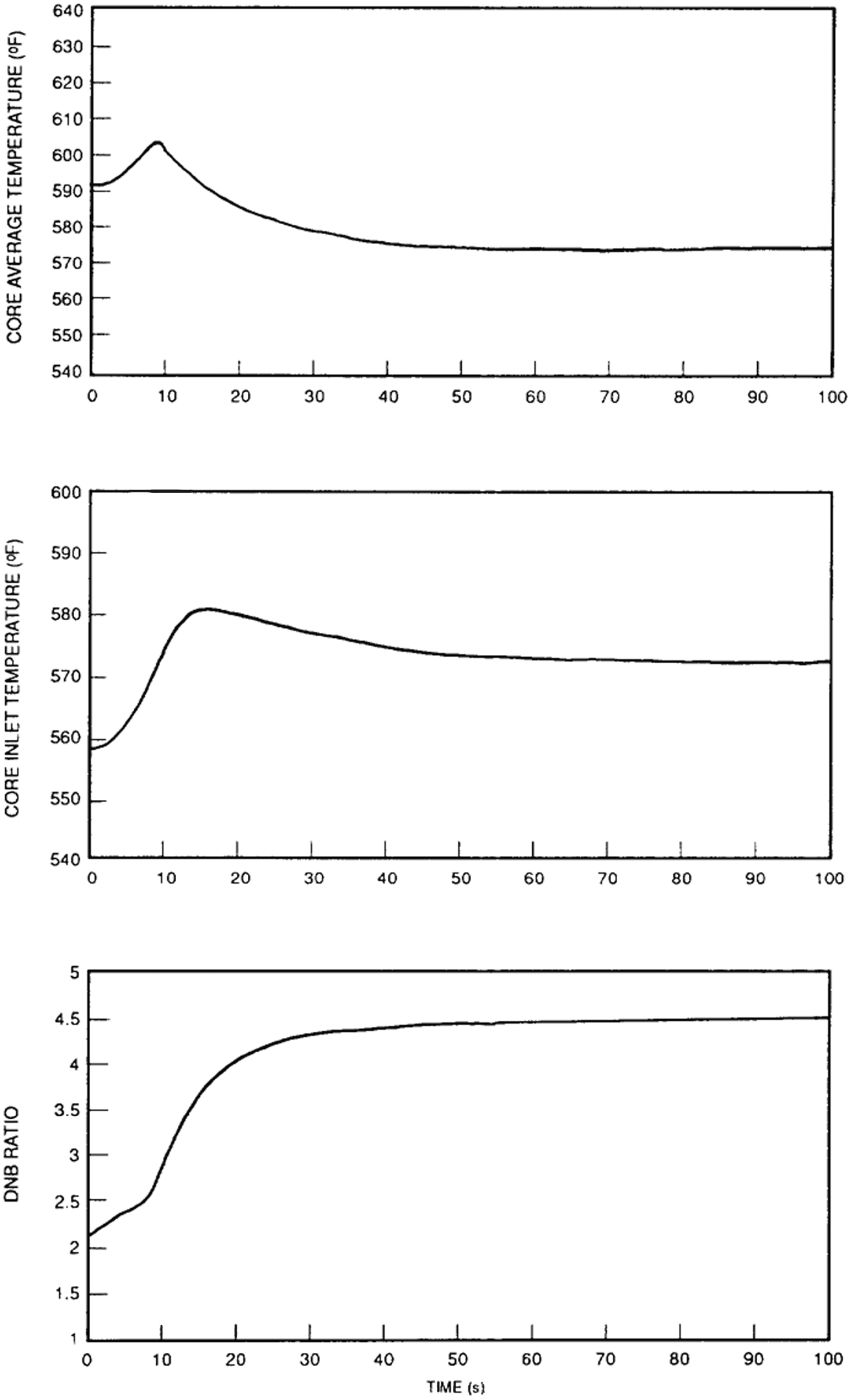

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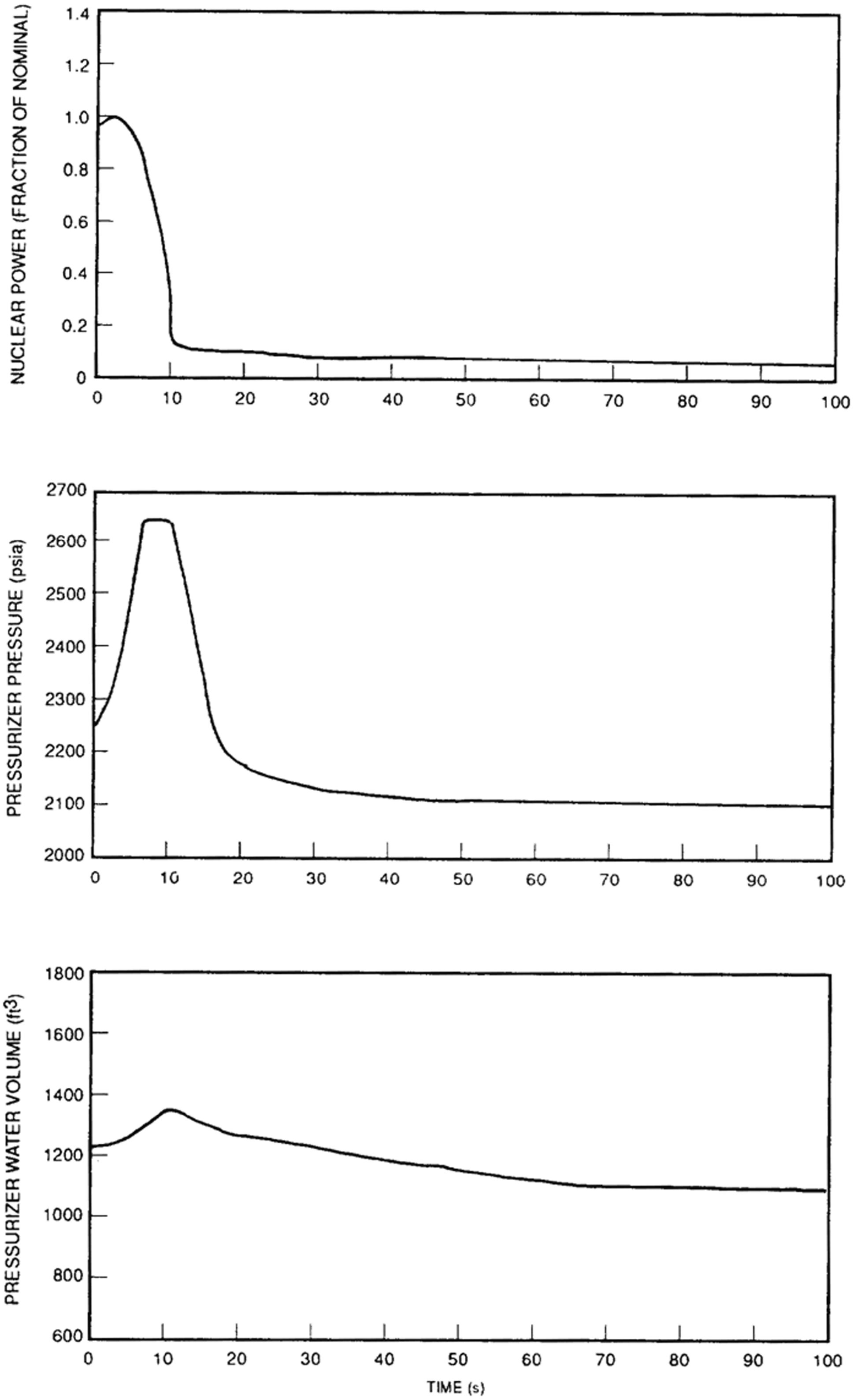
FIGURE 15.2.3–6



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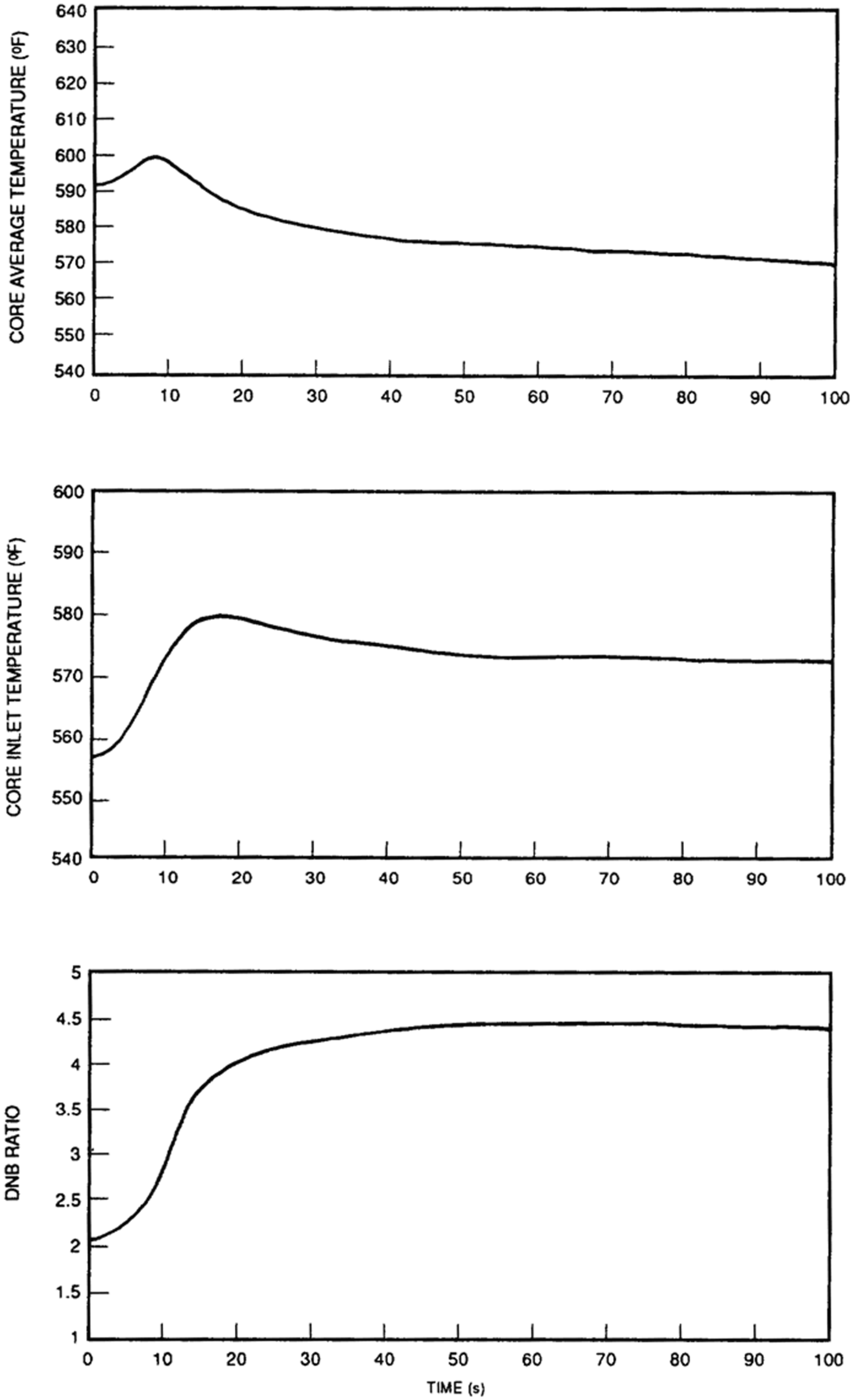
TURBINE TRIP ACCIDENT WITHOUT PRESSURIZER SPRAY AND POWER–OPERATED RELIEF VALVES, MAXIMUM MODERATOR FEEDBACK

FIGURE 15.2.3–7



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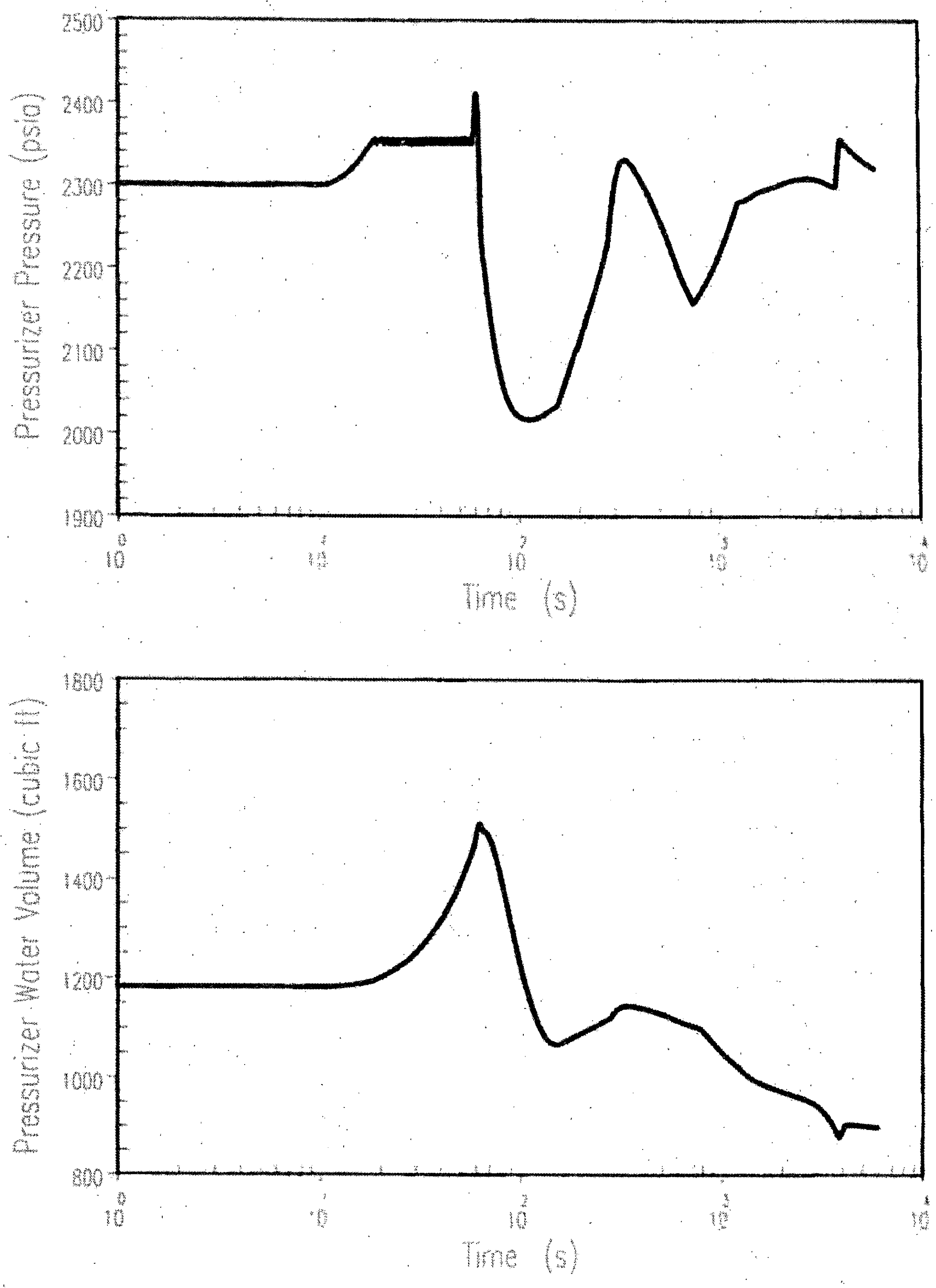
TURBINE TRIP ACCIDENT WITHOUT PRESSURIZER SPRAY AND POWER–OPERATED RELIEF VALVES, MAXIMUM MODERATOR FEEDBACK

FIGURE 15.2.3–8



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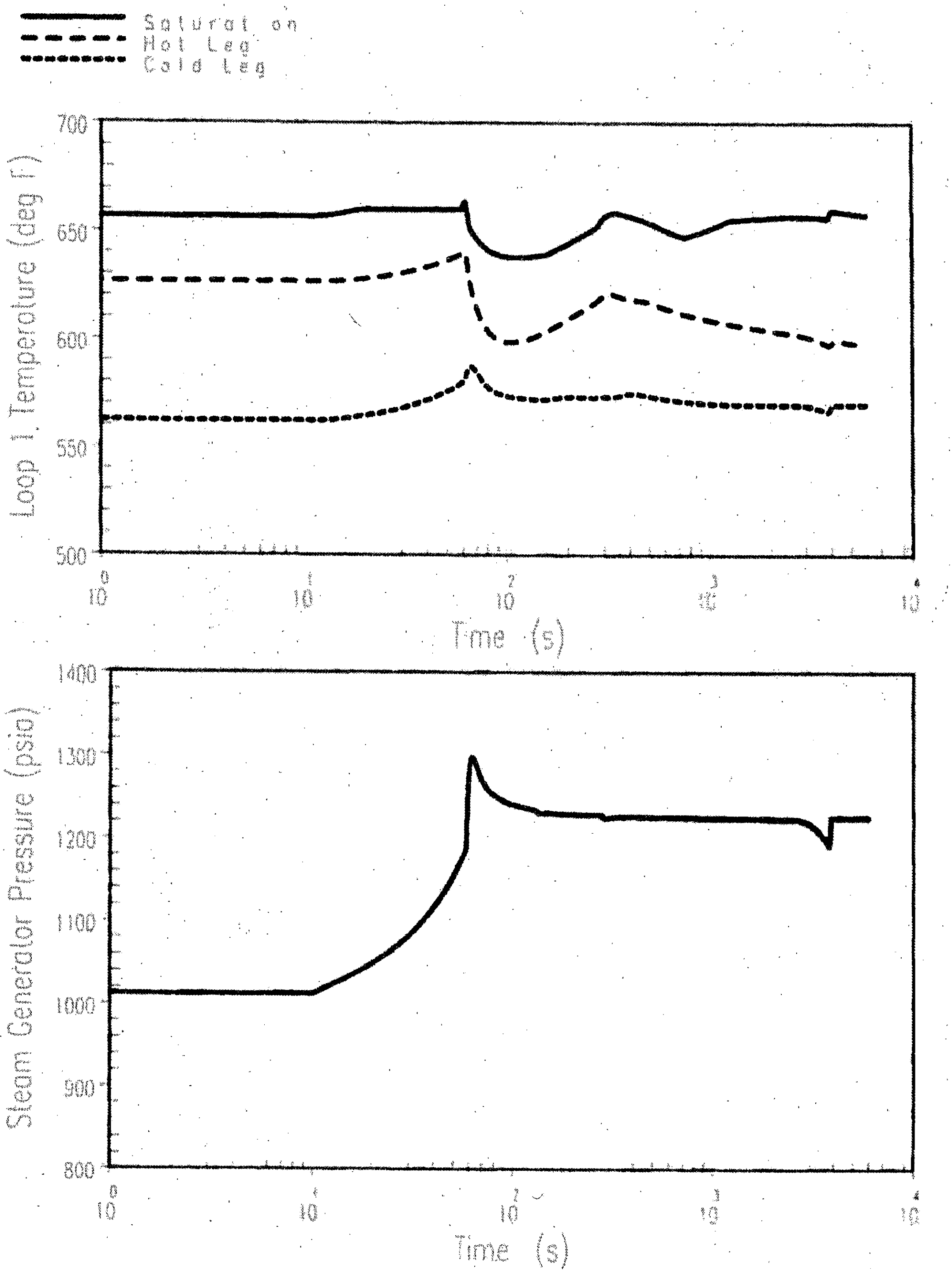
PRESSURIZER PRESSURE AND WATER VOLUME TRANSIENTS FOR LOSS OF OFFSITE POWER

FIGURE 15.2.6–1



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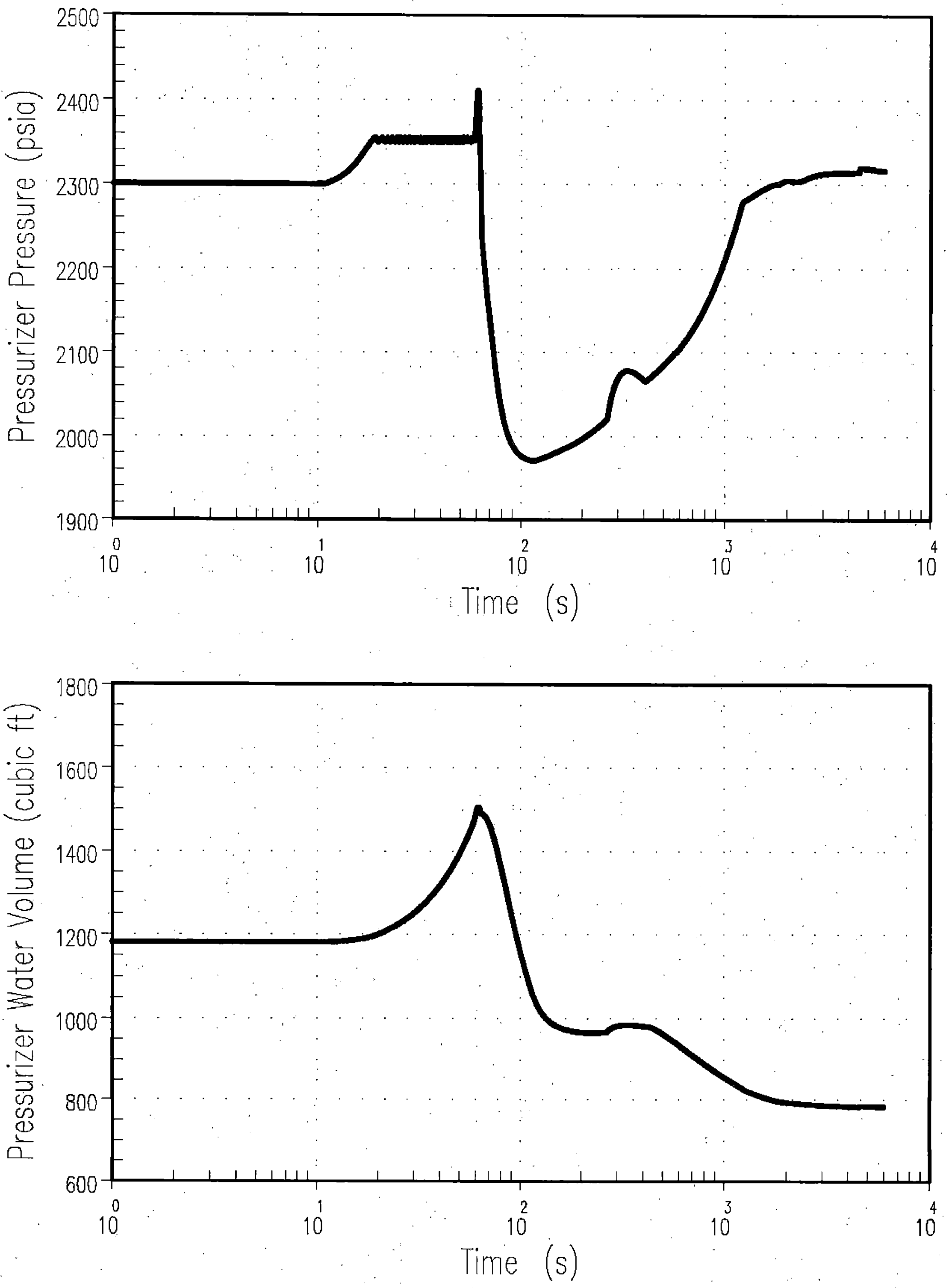
LOOP TEMPERATURE AND STEAM GENERATOR PRESSURE TRANSIENTS FOR LOSS OF OFFSITE POWER

FIGURE 15.2.6–2



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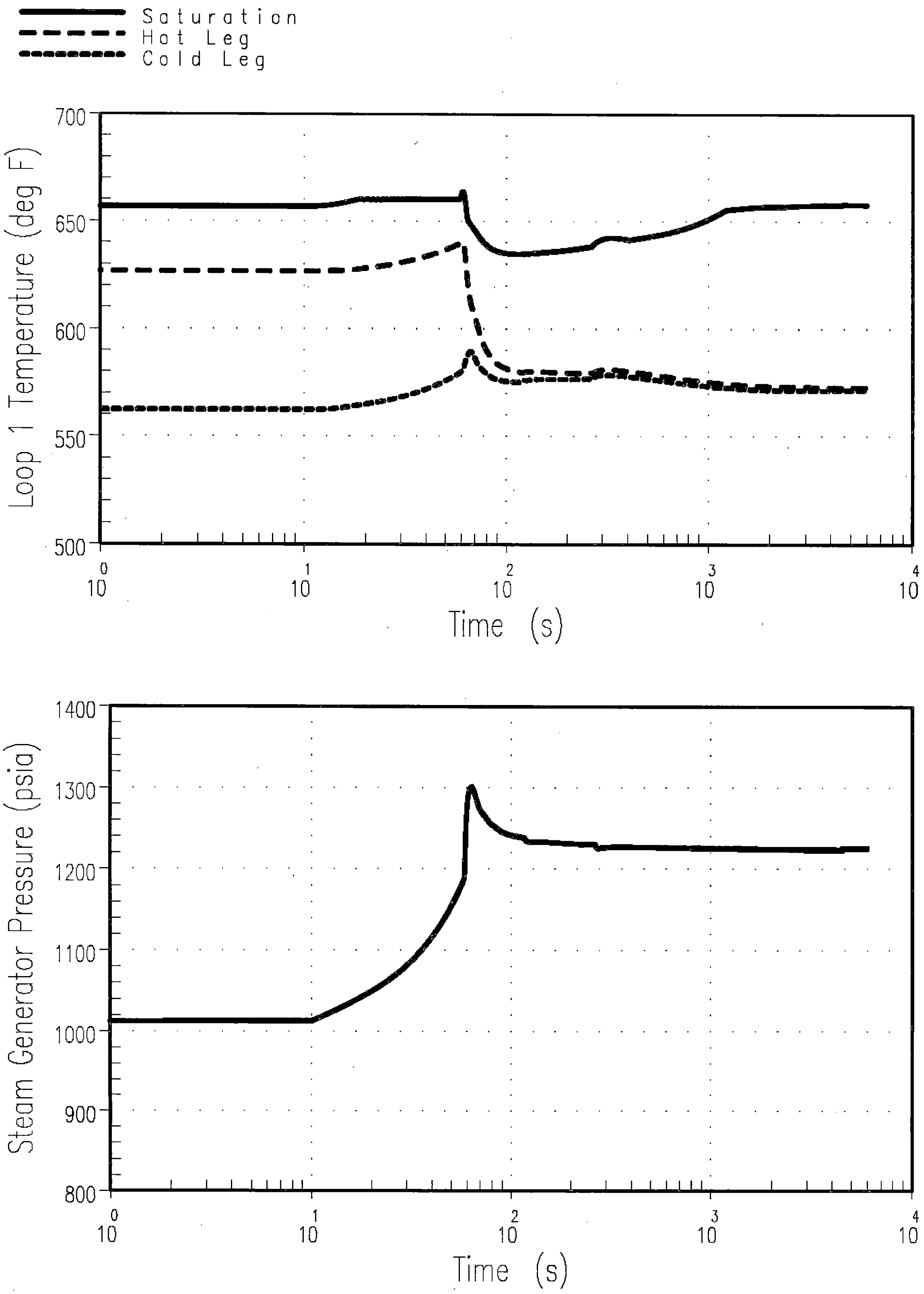
PRESSURIZER PRESSURE AND WATER VOLUME TRANSIENTS FOR LOSS OF NORMAL FEEDWATER

FIGURE 15.2.7–1



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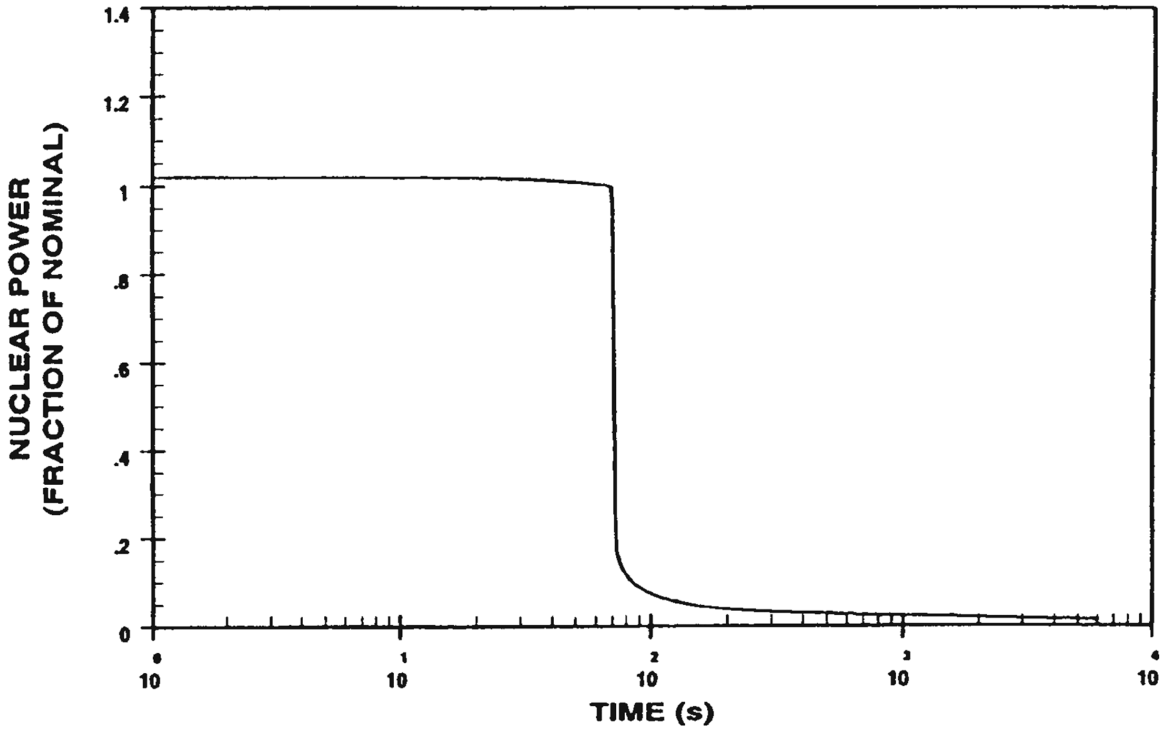
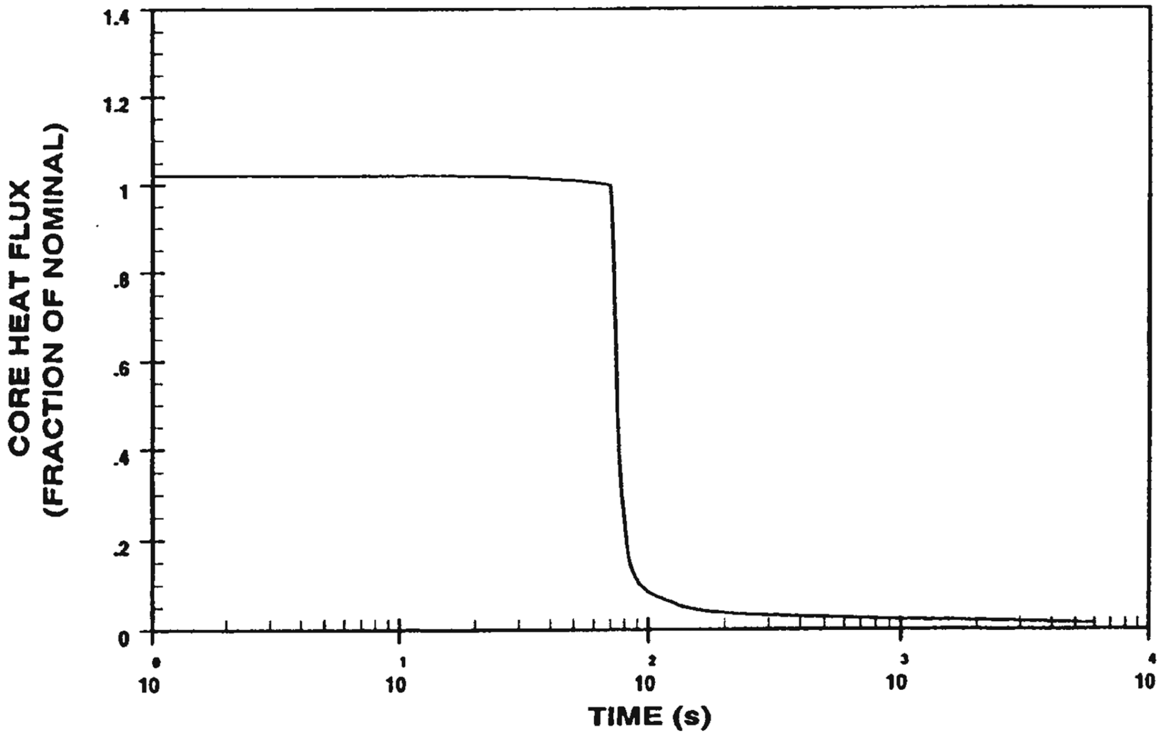
LOOP TEMPERATURE AND STEAM GENERATOR PRESSURE TRANSIENTS FOR LOSS OF NORMAL FEEDWATER

FIGURE 15.2.7–2





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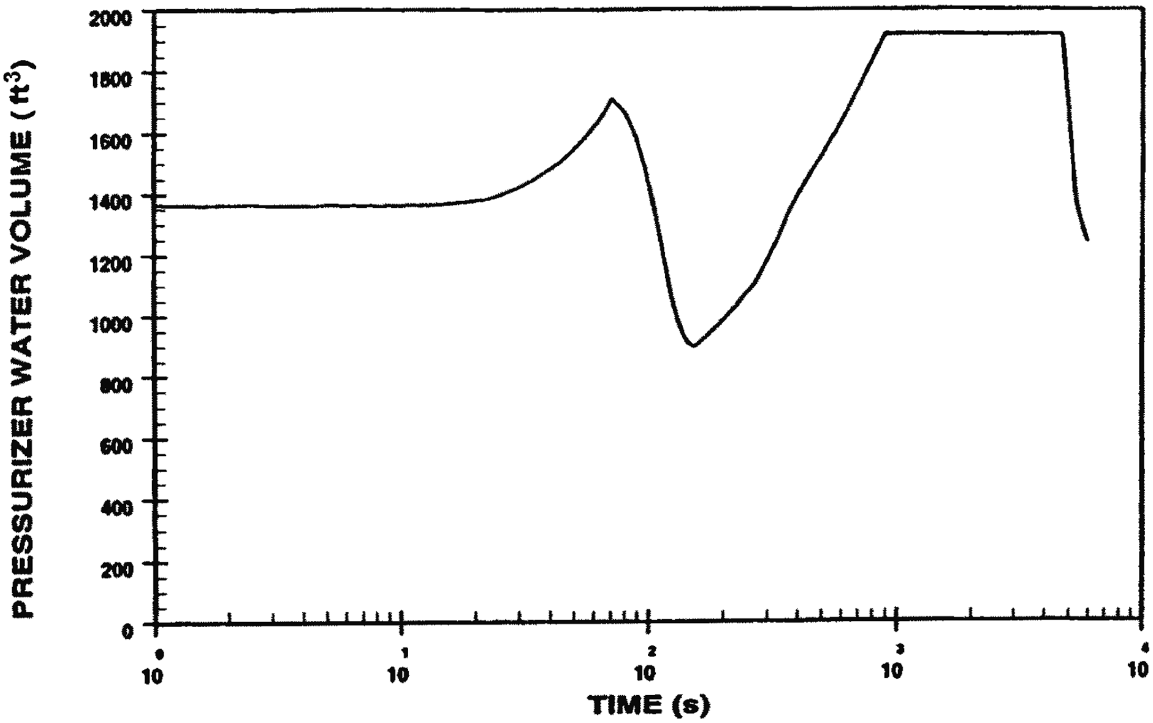
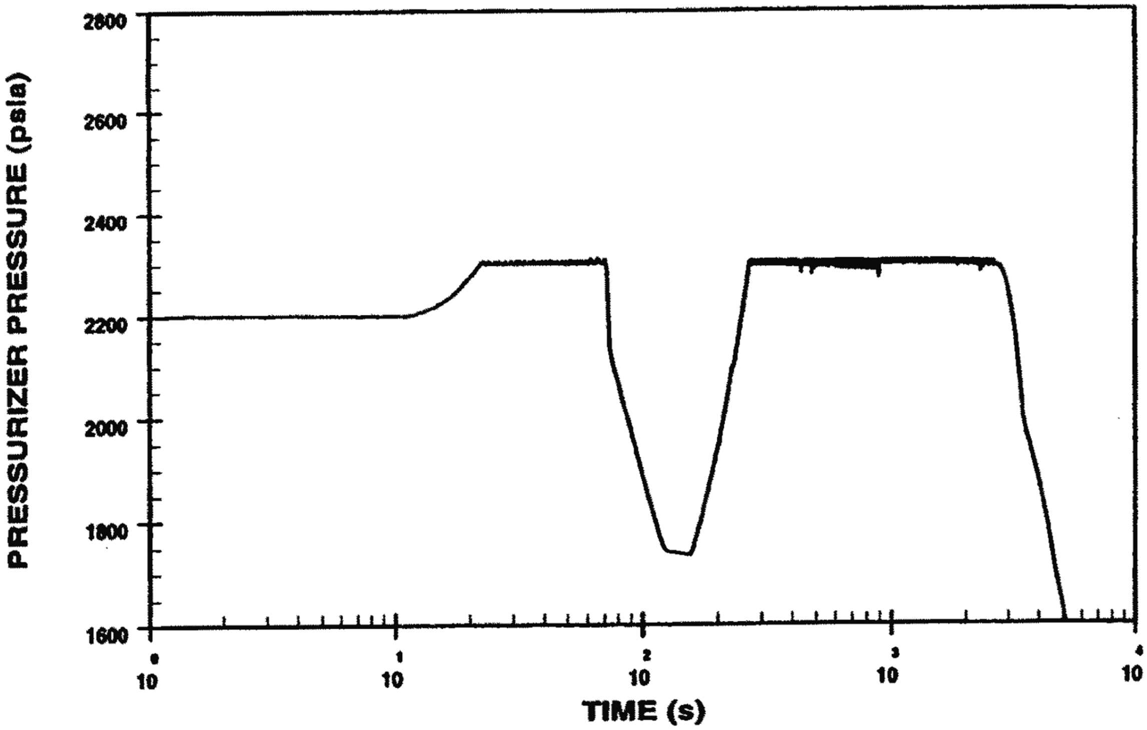
NUCLEAR POWER TRANSIENT AND CORE HEAT FLUX TRANSIENT FOR MAIN FEEDLINE RUPTURE WITH OFFSITE POWER AVAILABLE

FIGURE 15.2.8–1





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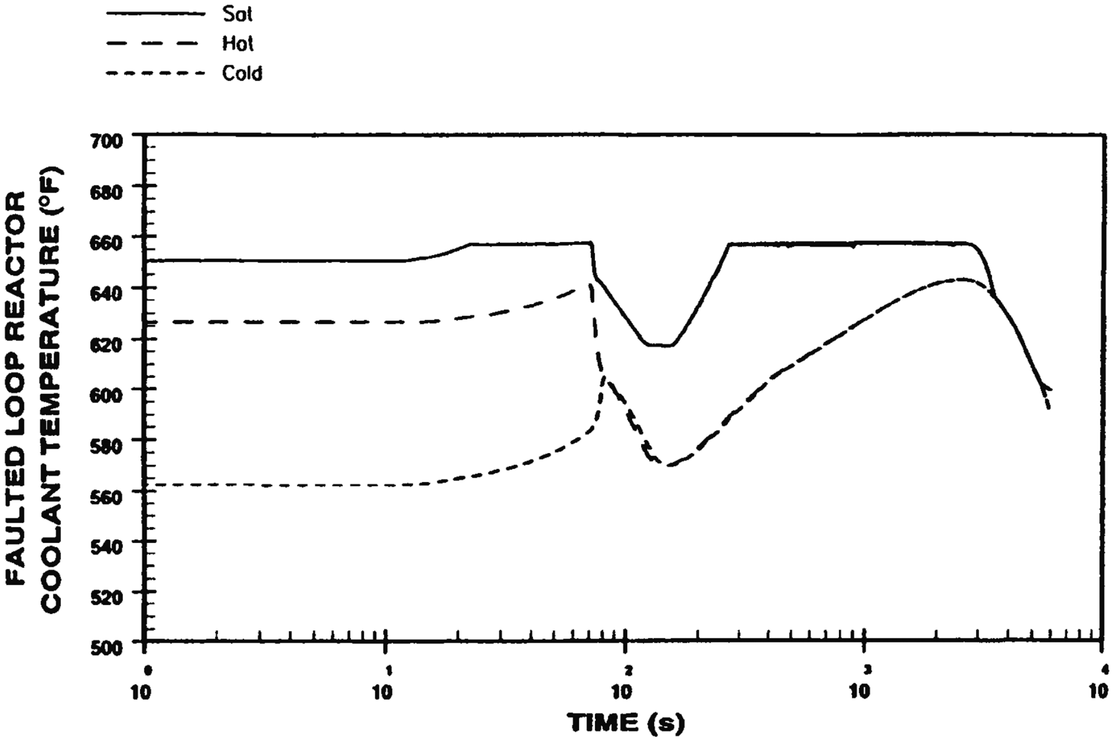
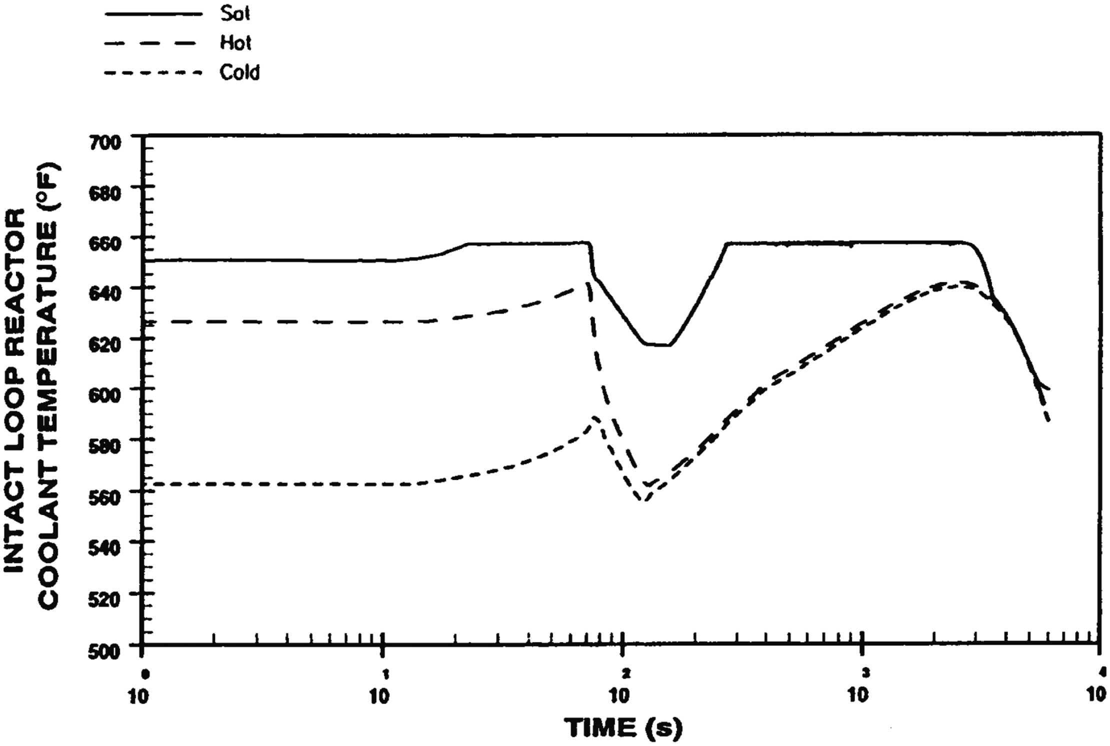
PRESSURIZER PRESSURE AND WATER VOLUME TRANSIENTS FOR MAIN FEEDLINE RUPTURE WITH OFFSITE POWER AVAILABLE

FIGURE 15.2.8–2





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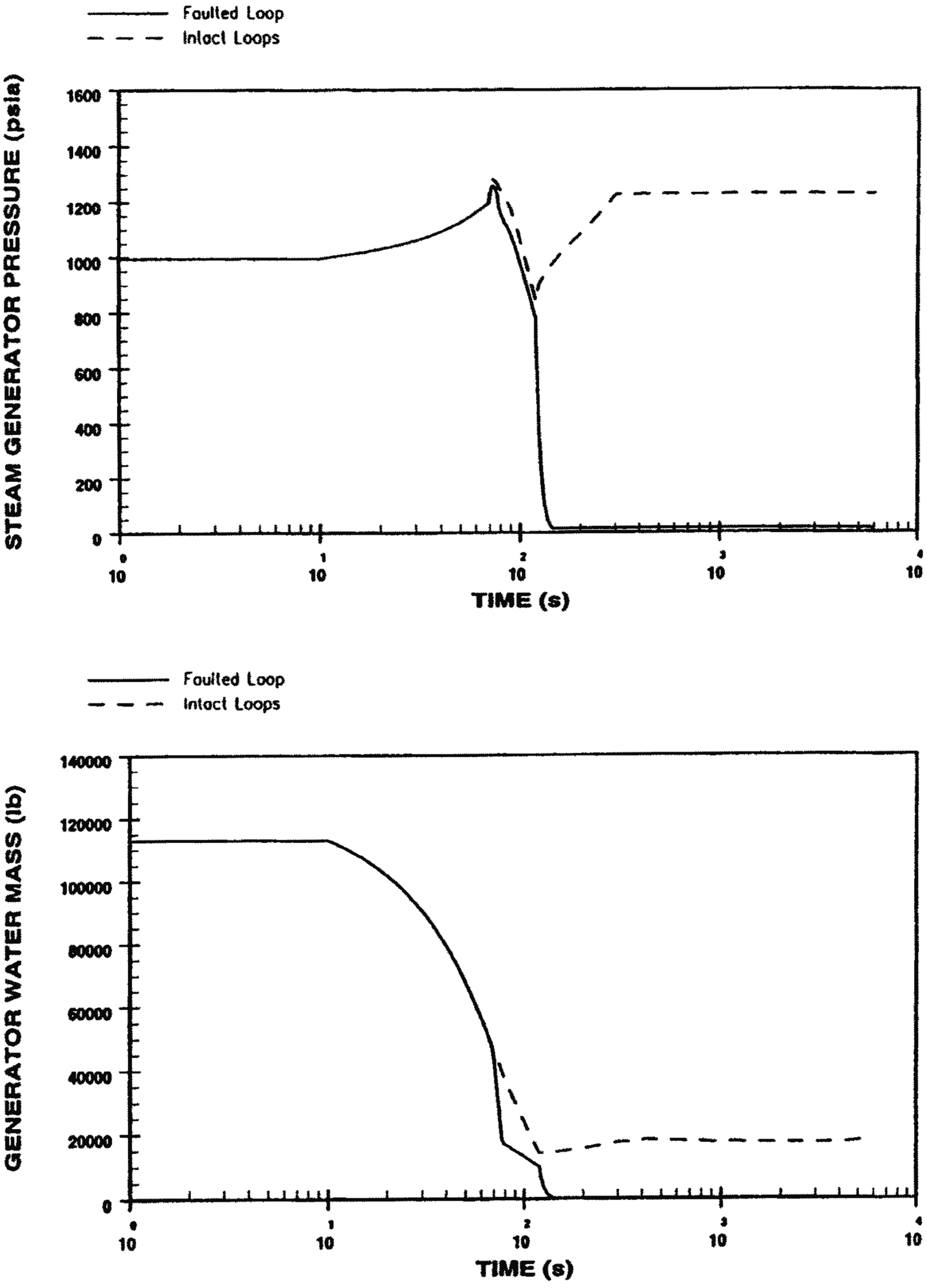
REACTOR COOLANT TEMPERATURE TRANSIENTS FOR THE FAULTED AND INTACT LOOPS FOR MAIN FEEDLINE RUPTURE WITH OFFSITE POWER AVAILABLE

FIGURE 15.2.8–3



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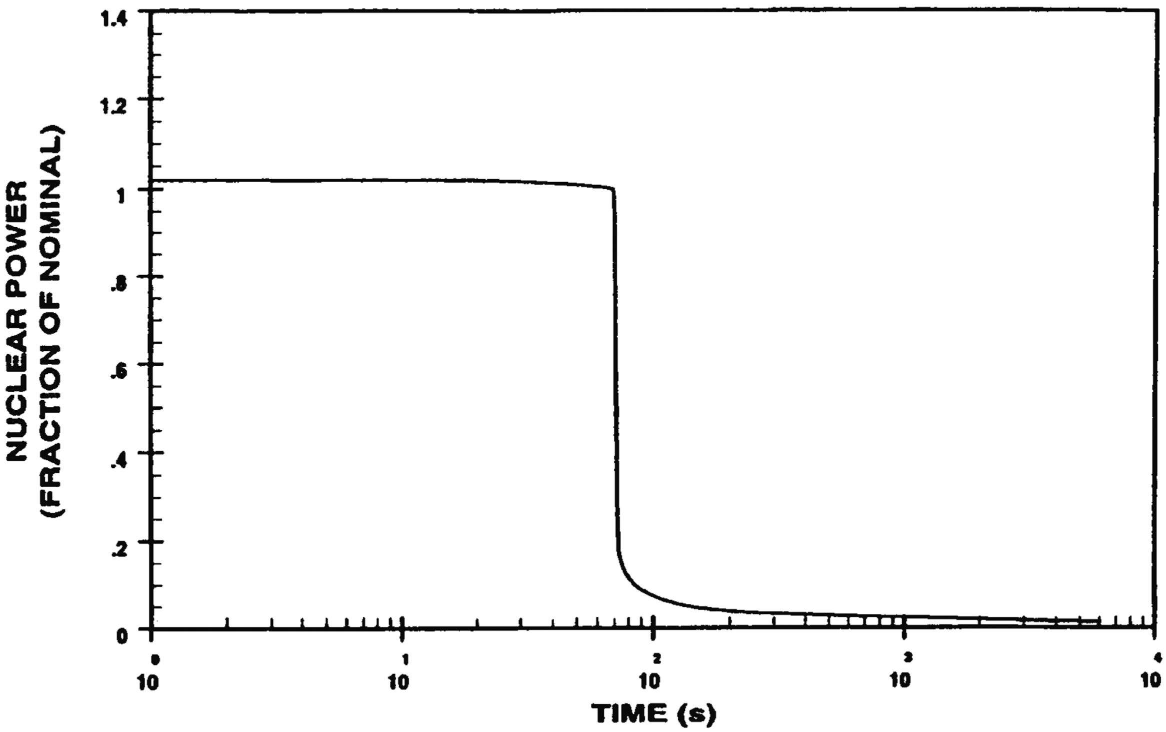
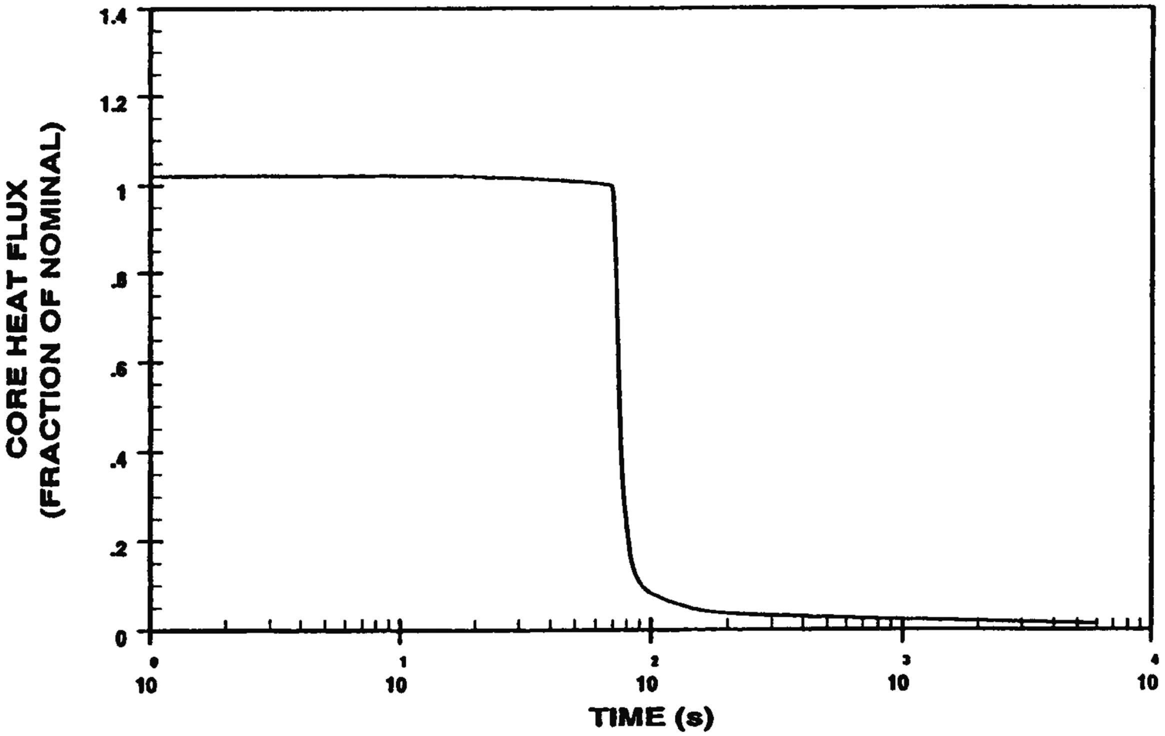
STEAM GENERATOR PRESSURE AND WATER MASS TRANSIENTS FOR MAIN FEEDLINE RUPTURE WITH OFFSITE POWER AVAILABLE

FIGURE 15.2.8–4





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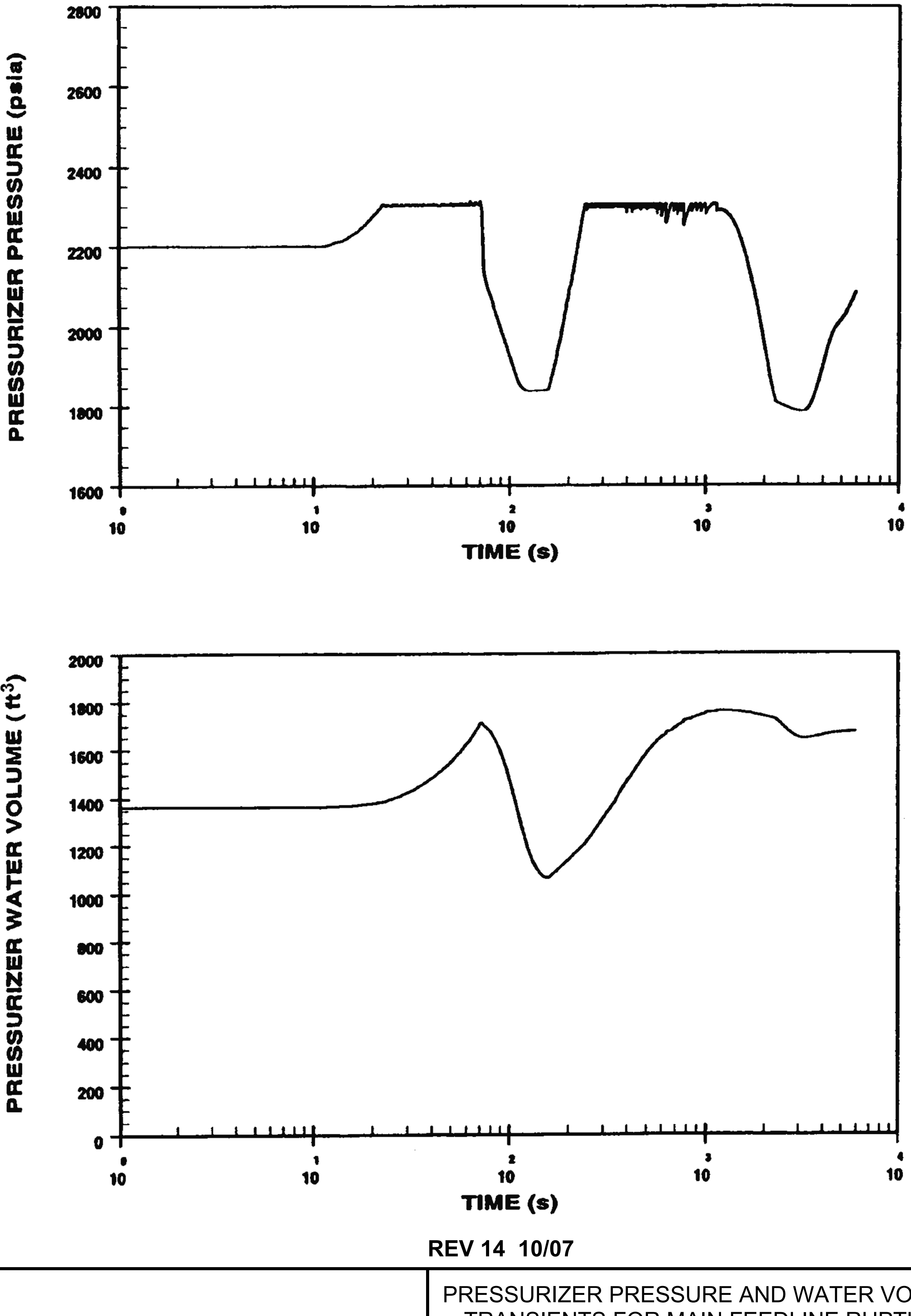
NUCLEAR POWER AND CORE HEAT FLUX TRANSIENTS FOR MAIN FEEDLINE RUPTURE WITHOUT OFFSITE POWER AVAILABLE

FIGURE 15.2.8–5



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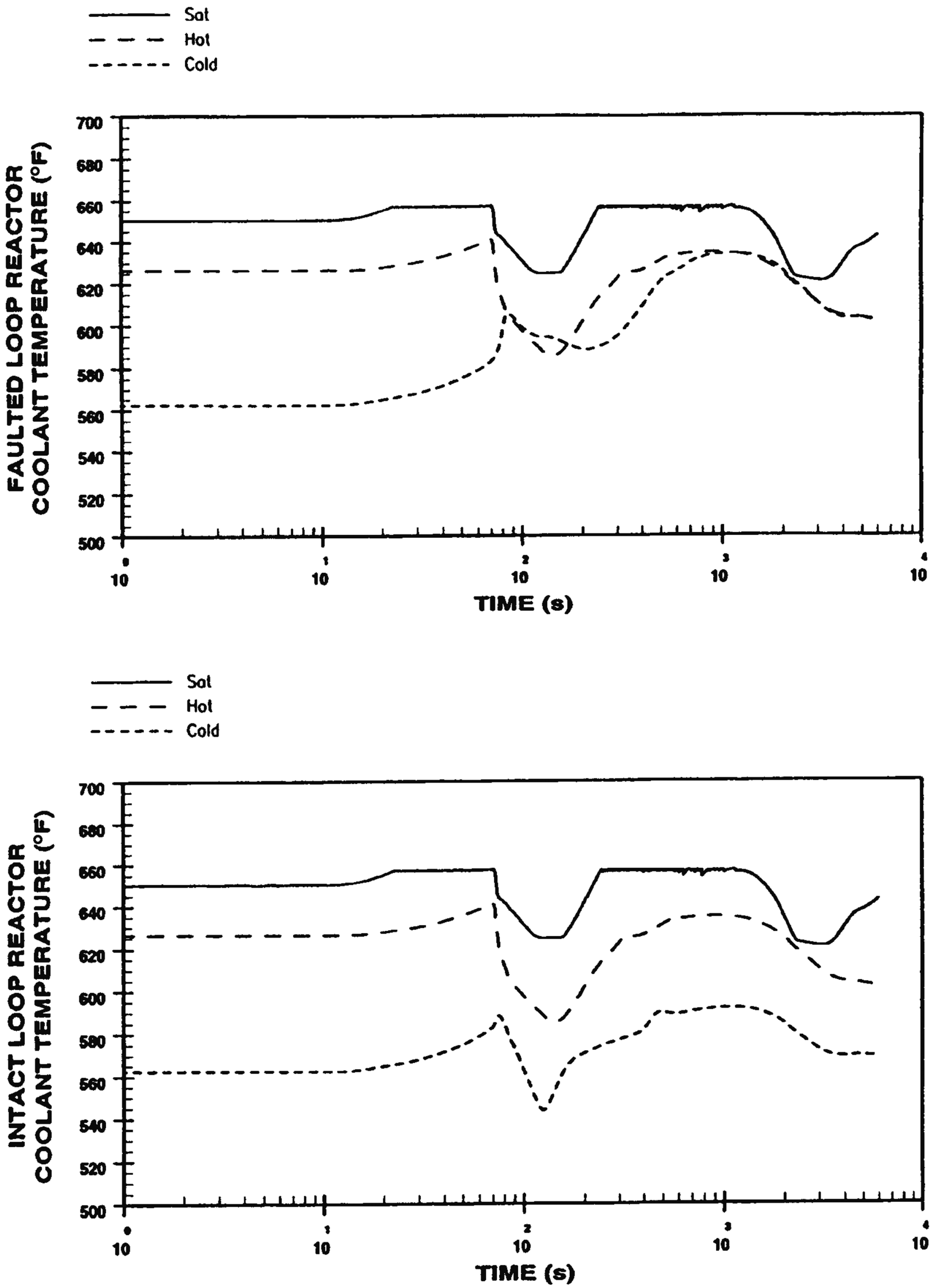
PRESSURIZER PRESSURE AND WATER VOLUME
TRANSIENTS FOR MAIN FEEDLINE RUPTURE
WITHOUT OFFSITE POWER AVAILABLE

FIGURE 15.2.8–6



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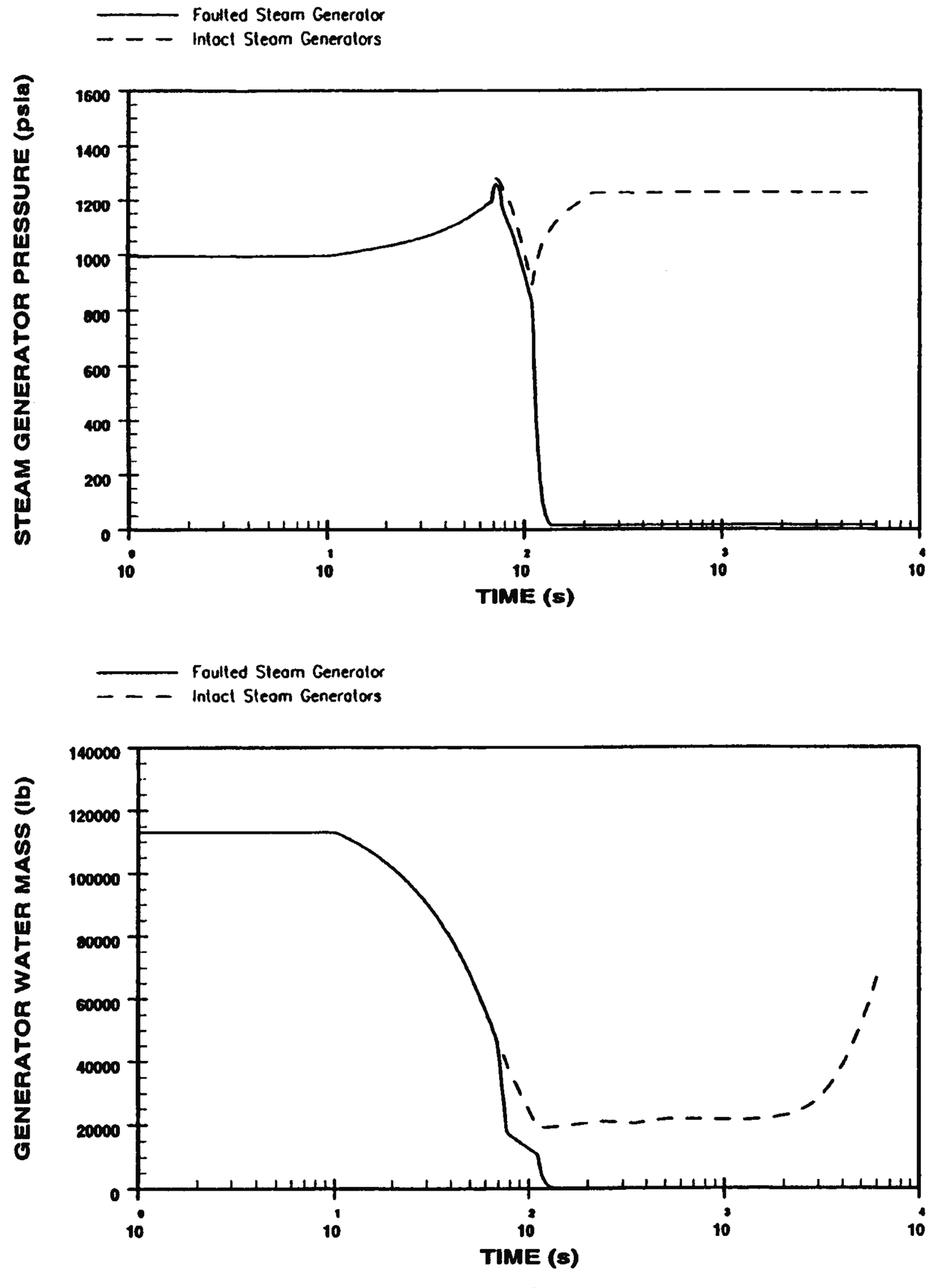
REACTOR COOLANT TEMPERATURE
TRANSIENTS FOR THE FAULTED AND INTACT
LOOPS FOR MAIN FEEDLINE RUPTURE
WITHOUT OFFSITE POWER AVAILABLE

FIGURE 15.2.8–7



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UNIT 1 AND UNIT 2

STEAM GENERATOR PRESSURE AND STEAM GENERATOR WATER MASS TRANSIENTS FOR MAIN FEEDLINE RUPTURE WITHOUT OFFSITE POWER AVAILABLE

FIGURE 15.2.8–8

15.3 DECREASE IN REACTOR COOLANT SYSTEM FLOWRATE

A number of faults which could result in a decrease in the reactor coolant system flowrate are postulated. These events are discussed in this section. Detailed analyses are presented for the most limiting of the following flow decrease events:

A. Partial loss of forced reactor coolant flow.

B. Complete loss of forced reactor coolant flow.

C. Reactor coolant pump shaft seizure (locked rotor).

D. Reactor coolant pump shaft break.

All of the accidents in this section have been analyzed. It has been determined that the most severe radiological consequences will result from the reactor coolant pump shaft seizure accident discussed in subsection 15.3.3. Therefore, doses are reported only for that limiting case.

15.3.1 PARTIAL LOSS OF FORCED REACTOR COOLANT FLOW

15.3.1.1 Identification of Causes and Accident Description

A partial loss-of-forced-reactor-coolant flow accident can result from a mechanical or electrical failure in an RCP or from a fault in the power supply to the pump or pumps supplied by an RCP bus. If the reactor is at power at the time of the accident, the immediate effect of the loss-of-forced-reactor-coolant flow is a rapid increase in the coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor does not trip promptly.

Two buses connected to the generators supply power to the pumps. When a generator trip occurs, the buses are automatically transferred to a transformer supplied from external power lines, and the pumps continue to operate. Following any turbine trip where there are no electrical faults which require tripping the generator from the network, the generator remains connected to the network for approximately 30 seconds. The RCPs remain connected to the generator, thus ensuring full flow for approximately 30 seconds after the reactor trip before any transfer is made.

The low primary coolant flow reactor trip signal, which actuates in any reactor coolant loop by two out of three low-flow signals, provides the necessary protection against this event. 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 any two loops will actuate a reactor trip. Above permissive P-7, two or more RCP circuit breakers from the same bus will open which will actuate the corresponding undervoltage relays. This results in a reactor trip which serves as backup to the flow trip.

This is an ANS Condition II incident.

15.3.1.2 Analysis of Effects and Consequences

15.3.1.2.1 Method of Analysis

This analysis examines partial loss-of-forced-reactor-coolant flow involving loss of two pumps with four loops in operation.

This analysis uses three digital computer codes. First the LOFTRAN code (reference 1) calculates the loop and core flow 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 FACTRAN code (reference 2) then calculates the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the VIPRE-01 code (section 4.4) calculates the DNBR during the transient based on the heat flux from FACTRAN and flow from LOFTRAN. The DNBR transients presented represent the minimum of the typical or thimble fuel assembly cell.

This analysis employs RTDP methodology; therefore, the initial conditions assume nominal values of power, reactor coolant average temperature, and RCS average pressure. (See tables 15.0.3-2 and 15.0.3-3.) The limit DNBR includes uncertainties in the initial conditions.

This analysis assumes a conservatively large absolute value of the Doppler-only power coefficient. (See figure 15.0.4-1.) This is equivalent to a total integrated Doppler reactivity from 0 to 100 percent power of 0.016 Δk.

The analysis assumes the most positive moderator temperature coefficient (minimum moderator density coefficient) since this results in the maximum core power during the initial part of the transient when the transient reaches minimum DNBR. (See figure 15.0.4-2.)

These analyses use the curve of trip reactivity insertion versus time (figure 15.0.5-3).

The basis for the flow coastdown analysis is a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, and the pump characteristics and is based on high estimates of system pressure losses.

Plant systems and equipment which are necessary to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in table 15.0.8-1. No single active failure in any of these systems or equipment will adversely affect the consequences of the accident.

15.3.1.2.2 Results

Figures 15.3.1-1 through 15.3.1-4 show the transient response for the loss of power to two RCPs with four loops in operation. The reactor trips on the low-flow signal. Figure 15.3.1-4 shows the DNBR to be always greater than the safety analysis limit value for the most limiting fuel assembly cell.

Since DNB does not occur, the ability of the primary coolant to remove heat from the fuel rod is not significantly reduced. Thus, the average fuel and clad temperature do not increase significantly above their respective initial values.

The time sequence of events is shown in table 15.3.1-1 for the partial loss of flow event.

The affected reactor coolant pumps will continue to coast down, and the core flow will reach a new equilibrium value. With the reactor tripped, a stable plant condition will eventually be attained. Normal plant shutdown may then proceed.

15.3.1.3 Conclusions

The analysis shows that the minimum DNBR always remains above the limit value during the transient. Thus, all applicable acceptance criteria are met.

15.3.1.4 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Nonproprietary), April 1984.
2. Hargrove, H. G., "FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," WCAP-7908-A, December 1989.

15.3.2 COMPLETE LOSS OF FORCED REACTOR COOLANT FLOW

15.3.2.1 Identification of Causes and Accident Description

A loss-of-forced-reactor-coolant flow may result from a simultaneous loss of electrical power to all RCPs. If the reactor is at power at the time of the accident, the immediate effect of a loss-of-forced-coolant flow is a rapid increase in the coolant temperature. This increase could result in DNB with subsequent adverse effects to the fuel if the reactor does not trip promptly. The reactor trip together with flow sustained by the inertia of the pump impeller will be sufficient to prevent RCS overpressurization and the DNBR from exceeding the limit values.

Two buses connected to the generators supply power to the pumps. When a generator trip occurs, the buses are automatically transferred to a transformer supplied from external power lines, and the pumps continue to operate. Following any turbine trip where there are no electrical faults which require tripping the generator from the network, the generator remains connected to the network for approximately 30 seconds. The RCPs remain connected to the generator, thus ensuring full flow for approximately 30 seconds after the reactor trip before any transfer is made.

The trip systems available to mitigate the consequences of this accident are the following:

- Reactor coolant pump power supply bus undervoltage or underfrequency.
- Low reactor coolant loop flow.

The reactor trip on reactor coolant pump undervoltage is provided to protect against conditions which can cause a loss of voltage to all reactor coolant pumps; i.e., station blackout. This function is blocked below approximately 10-percent power (permissive P7).

The reactor trip on reactor coolant pump underfrequency is provided to trip the reactor for an underfrequency condition, resulting from frequency disturbances on the power grid. Reference 1 provides analyses of grid frequency disturbances and the resulting nuclear steam supply system protection requirements which are applicable to the VEGP units.

The reactor trip on low primary coolant loop flow is provided to protect against loss-of-flow conditions which affect only one reactor coolant loop. This function is generated by two out of three low flow signals per reactor coolant loop. Above permissive P8, low flow in any loop will actuate a reactor trip. Between approximately 10-percent power (permissive P7) and the power level corresponding to permissive P8, low flow in any two loops will actuate a reactor trip. If the maximum grid frequency decay rate is less than approximately 2.5 Hz/s, this trip function will protect the core from underfrequency events. This effect is fully described in reference 1.

This is an ANS Condition III incident.

15.3.2.2 Analysis of Effects and Consequences

15.3.2.2.1 Method of Analysis

The method of analysis and the assumptions made regarding initial operating conditions and reactivity coefficients are identical to those discussed in subsection 15.3.1, except that following the loss of power supply to all pumps at power, a reactor trip actuates by either RCP power supply undervoltage or underfrequency.

15.3.2.2.2 Results

Figures 15.3.2-1 through 15.3.2-4 show the transient response for the loss of power to all RCPs with four loops in operation. The reactor trips on the undervoltage signal. Figure 15.3.2-4 shows the DNBR to be always greater than the safety analysis limit value for the most limiting fuel assembly cell.

Since DNB does not occur, the ability of the primary coolant to remove heat from the fuel rod is not significantly reduced. Thus, the average fuel and clad temperature do not increase significantly above their respective initial values.

The RCPs will continue to coast down, and natural circulation flow will eventually be established as demonstrated in subsection 15.2.6. With the reactor tripped, a stable plant condition will be attained. Normal plant shutdown may then proceed.

Besides the complete loss-of-forced-reactor-coolant flow (loss of power to four pumps), an underfrequency event with a frequency decay rate of 5 Hz/sec was also analyzed. For this event, the reactor trip occurs on an underfrequency signal. The DNBR analysis of the underfrequency event verified that the DNBR remains above the safety analysis limit value.

The time sequence of events in shown in table 15.3.1-1 for the complete loss-of-forced-reactor-coolant flow.

15.3.2.3 Conclusions

The analysis shows that the minimum DNBR always remains above the limit value during the transient. Thus, the analysis does not predict any adverse fuel effects or clad rupture and all applicable acceptance criteria are met. The design basis for the DNBR is described in section 4.4.

15.3.2.4 Reference

1. Baldwin, M. S., et al., "An Evaluation of Loss of Flow Accidents Caused by Power System Frequency Transients in Westinghouse PWRs," WCAP-8424, Revision 1, May 975.

15.3.3 REACTOR COOLANT PUMP SHAFT SEIZURE (LOCKED ROTOR)

15.3.3.1 Identification of Causes and Accident Description

For the instantaneous seizure of an RCP rotor, flow through the affected reactor coolant loop is rapidly reduced, leading to a reactor trip on a low flow signal. Following the trip, heat stored in the fuel rods continues to be transferred into the core coolant, causing the coolant to expand. At the same time, heat transfer to the shell side of the steam generator reduces, first because the reduced flow results in a decreased tube side film coefficient and then because the reactor coolant in the tubes cools down while the shell side temperature increases (turbine steam flow reduces to zero upon plant trip). The rapid expansion of the coolant in the reactor core, combined with the reduced heat transfer in the steam generator, causes an insurge into the pressurizer and a pressure increase throughout the RCS. The insurge into the pressurizer causes a pressure increase, which in turn actuates the automatic spray system, opens the power-operated relief valves, and opens the pressurizer safety valves in that sequence. The power-operated relief valves are safety grade and would be expected to function properly during an accident; however, for conservatism, the analysis does not use the pressure-reducing effect of the power-operated relief valves and the pressure-reducing effect of the spray.

The analysis of the locked rotor event demonstrates that overpressurization of the RCS does not occur and that the core remains in a coolable geometry.

This is an ANS Condition IV incident.

15.3.3.2 Analysis of Effects and Consequences

15.3.3.2.1 Method of Analysis

The analysis of this transient uses two digital computer codes. The LOFTRAN code (reference 1) calculates: 1) the resulting loop and core flow transients following the pump seizure; 2) the time of reactor trip based on the loop flow transients; 3) the nuclear power following reactor trip; and 4) the peak RCS pressure. The thermal behavior of the fuel located at the core hot spot is investigated using the FACTRAN code (reference 2) based on the core flow and the nuclear power calculated by LOFTRAN.

At the beginning of the postulated locked rotor accident (at the time the shaft in one of the RCPs is assumed to seize), the plant is assumed to be in operation under the most adverse steady-state operating conditions; i.e., maximum guaranteed steady-state thermal power, maximum steady-state pressure, and maximum steady-state coolant average temperature.

The plant characteristics and the initial conditions are shown in table 15.0.3-2 and table 15.0.3-3. The analysis evaluates the transient with and without offsite power available.

For the case without offsite power available, power is lost to the unaffected pumps 2 s after reactor trip. (Note: Grid stability analyses show that the grid will remain stable and that offsite power will not be lost because of a unit trip from 100-percent power. The 2-s delay is a conservative assumption based on grid stability analyses.)

For the peak pressure evaluation, the initial pressure is conservatively estimated as 50 psi above nominal pressure (2250 psia) to allow for errors in the pressurizer pressure measurement and control channels. This is done to obtain the highest possible rise in the coolant pressure during the transient. To obtain the maximum pressure in the primary side, conservatively high loop pressure drops are added to the calculated pressurizer pressure.

Plant systems and equipment which are available to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in table 15.0.8-1. No single active failure in any of these systems or equipment will adversely affect the consequences of the accident.

15.3.3.2.2 Evaluation of the Pressure Transient

After pump seizure, the neutron flux is rapidly reduced by control rod insertion due to reactor trip on low coolant flow in the affected loop. Rod motion begins 1 second after the flow in the affected loop reaches 87 percent of nominal flow. No credit is taken for the pressure reducing effect of the pressurizer relief valves, pressurizer spray, steam dump, or controlled feedwater flow after plant trip. Although these components will operate and will result in a lower peak RCS pressure, ignoring their effect provides an additional degree of conservatism.

The analysis conservatively bounds the pressurizer safety valves opening at 2500 psia and achieving rated flow at 2575 psia.

15.3.3.2.3 Evaluation of Departure from Nucleate Boiling (DNB) in the Core During the Accident

Because DNB occurs in the core for this accident, there is an evaluation of the consequences with respect to fuel rod thermal transients. Results obtained from analyses of this "hot spot" condition represent the upper limit with respect to clad temperature and zirconium-water reaction.

In the evaluation, the rod power at the hot spot is conservatively assumed to be 2.55 times the average rod power (i.e., $F_Q = 2.55$) at the initial core power level.

A second evaluation is performed for this transient to determine what percentage, if any, of the fuel rods are expected to experience DNB during the transient. For this evaluation, core conditions are generated with the LOFTRAN and FACTRAN computer codes and a detailed DNB analysis is performed with the VIPRE-01 computer code. Results from the VIPRE-01 calculation are then used to determine the percentage of fuel rods which experience DNB. Table 15.0.3-2 presents the initial conditions assumed for the rods-in-DNB evaluation.

15.3.3.2.4 Film Boiling Coefficient

To model the effect of DNB occurring, the FACTRAN code calculates the film boiling coefficient using the Bishop-Sandberg-Tong film boiling correlation. Fluid properties are evaluated at film temperature (average between wall and bulk temperatures). The program calculates the film coefficient at every time step based upon the actual heat transfer conditions at the time. The neutron flux, system pressure, bulk density, and mass flowrate as a function of time are program inputs.

This analysis uses the initial values of the pressure and the bulk density throughout the transient since they are the most conservative with respect to clad temperature response. For conservatism, the analysis assumes DNB to start at the beginning of the accident to maximize the fuel rod thermal transient.

15.3.3.2.5 Fuel Clad Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and clad (gap coefficient) have a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat transferred between pellet and clad. Based on investigations of the effect of the gap coefficient upon the maximum clad temperature during the transient, the analysis assumes the gap coefficient to increase from a steady-state value consistent with initial fuel temperature to 10,000 Btu/h-ft^2-°F at the initiation of the transient. Thus, the large amount of energy stored in the fuel because of the small initial value releases to the clad at the initiation of the transient.

15.3.3.2.6 Zirconium-Steam Reaction

The zirconium-steam reaction can become significant above 1800°F (clad temperature). In order to take this phenomenon into account, the models (reference 4) introduced the following correlation which defines the rate of the zirconium-steam reaction.

$$\frac{d(w^2)}{dt} = 33.3 \times 10^6 \times e^{-[(45{,}000.)/(1.986\ T)]}$$

where:

w = amount reacted, mg/cm^2.

t = time, s.

T = temperature, °F.

The reaction heat is 1510 cal/g.

The effect of zirconium-steam reaction is included in the calculation of the hot spot clad temperature transient.

15.3.3.2.7 Results

The transient results for the locked rotor accident are shown in figures 15.3.3-1 through 15.3.3-4. Table 15.3.3-1 also summarizes the results of the locked rotor calculations. The peak RCS pressure reached during the transient is less than that which would cause stresses to exceed the faulted condition stress limits of the American Society of Mechanical Engineers Code, Section III. Also, the peak clad temperature is less than 2700°F (ZIRLO®) and the more restrictive limit of 2375°F (associated with Optimized ZIRLO™ cladding). Note that the clad temperature was conservatively calculated assuming DNB occurs at the initiation of the transient. These results represent the most limiting conditions of the locked rotor event or RCP shaft break.

The calculated sequence of events for the locked rotor event is shown in table 15.3.1-1. Figure 15.3.3-1 shows that the core flow rapidly reaches a new equilibrium value (for the case with offsite power available). With the reactor tripped, a stable plant condition will eventually be attained. Normal plant shutdown may then proceed.

15.3.3.3 Radiological Consequences

The evaluation of the radiological consequences of a postulated seizure of a reactor coolant pump rotor; i.e., locked rotor accident (LRA), assumes that the reactor has been operating with a small percent of defective fuel and leaking steam generator tubes for sufficient time to establish equilibrium concentrations of radionuclides in the reactor coolant and in the secondary coolant.

As a result of the accident, a fraction of the fuel rods will undergo DNB and will release gap inventory to the reactor coolant. Radionuclides carried by the primary coolant to the steam generator via leaking tubes are released to the environment via the steam line safety or power-operated relief valves.

15.3.3.3.1 Analytical Assumptions

The major assumptions and parameters used in the analysis are itemized in table 15.3.3-2. The following is a more detailed discussion of the source term.

15.3.3.3.1.1 Source Term Calculations. The concentration of nuclides in the primary and secondary system prior to and following the LRA are determined as follows:

A. The iodine activity in the reactor coolant prior to the accident is based upon an iodine spike which has raised the reactor coolant concentration to 60 μCi/g of dose equivalent (DE) I-131.

B. The noble gas concentrations in the reactor coolant are based upon 1-percent defective fuel.

C. Following the LRA, 5 percent of the fuel rods in the core undergo DNB. Hence, 5 percent of the core iodine and noble gas gap inventory is released to the reactor coolant.

D. The secondary coolant iodine activity is based on the DE of 0.1 μCi/g of I-131.

15.3.3.3.1.2 Mathematical Models Used in the Analysis. Mathematical models used in the analysis are described in the following sections:

A. The mathematical models used to analyze the activity released during the course of the accident are described in appendix 15A.

B. The atmospheric dispersion factors used in the analysis were calculated based on the onsite meteorological measurement programs described in subsection .3.3.

C. The thyroid inhalation dose and total-body gamma immersion doses to a receptor at the exclusion area boundary and outer boundary of the low population zone were analyzed using the models described in appendix 15A.

15.3.3.3.1.3 Identification of Leakage Pathways and Resultant Leakage Activity. Radionuclides carried from the primary coolant to the steam generators via leaking tubes are released to the environment via the steam line safety or power-operated relief valves. Iodines are assumed to mix with the secondary coolant and partition between the generator liquid and steam before release to the environment. Noble gases are assumed to be directly released.

All activity is released to the environment with no consideration given to radioactive decay or to cloud depletion by ground deposition during transport to the exclusion area boundary and low population zone. Hence, the resultant radiological consequences represent the most conservative estimate of the potential intergrated dose due to the postulated LRA.

15.3.3.3.2 Identification of Uncertainties and Conservative Elements in the Analysis

A. The initial reactor coolant iodine activity is based on the technical specification limit of 1.0 μCi/g of DE I-I3I which is further increased by a large preaccident iodine spike to 60 μCi/g resulting in equivalent concentrations many times greater than the reactor coolant activities based on 0.12-percent defective fuel and expected iodine spiking values associated with normal operating conditions.

B. The noble gas activities are based on 1-percent defective fuel which cannot exist simultaneously with 1.0-μCi/g I-131. For iodines, 1-percent defects would be approximately three times the technical specification limit.

C. The fraction of failed fuel is assumed to be equal to the fraction of fuel rods experiencing DNB without consideration given to the extent of the zirc-water reaction. Based on experimental data(3) no oxidation related fuel rod clad failure is predicted.

D. A 1-gal/min steam generator primary-to-secondary leakage is assumed, which is significantly greater than that anticipated during normal operation.

E. The meteorological conditions which may be present at the site during the course of the accident are uncertain. However, it is highly unlikely that the assumed meteorological conditions would be present during the course of the accident for any extended period of time. Therefore, the radiological consequences evaluated, based on the meteorological conditions assumed, are conservative.

15.3.3.3.3 Conclusions

15.3.3.3.3.1 Filter Loadings. The only engineered safety feature filtration system considered in the analysis which limits the consequences of the LRA is the control room filtration system.

Integrated activity on the control room filters have been evaluated for the more limiting loss-of-coolant accident (LOCA) analysis, as discussed in paragraph 15.6.5.4.6. Since the control room filters are capable of accommodating the potential design basis LOCA fission product iodine loadings, there will be sufficient capacity to accommodate any fission product loading due to a postulated LRA.

15.3.3.3.3.2 Doses to Receptor at the Exclusion Area Boundary and Low Population Zone Outer Boundary. The potential radiological consequences resulting from the occurrence of a postulated LRA have been conservatively analyzed using assumptions and models described.

The total-body gamma dose due to immersion from direct radiation and the thyroid dose due to inhalation have been analyzed for the 0- to 2-h dose at the exclusion area boundary and for the duration of the accident (0 to 20 h) at the low population zone outer boundary. The results are listed in table 15.3.3-3. The resultant doses are well within the guideline values of 10 CFR 100.

15.3.3.4 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Nonproprietary), April 1984.
2. Hargrove, H. G., "FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," WCAP-7908-A, December 1989.
3. Van Houten, R., "Fuel Rod Failure as a Consequence of Departure from Nucleate Boiling or Dryout," NUREG-0562, June 1979.
4. Baker, L. and Just, L., "Studies of Metal Water Reactions of High Temperatures, III Experimental and Theoretical Studies of the Zirconium-Water Reacton, ANL-6548, Argonne National Laboratory, May 1962.

15.3.4 REACTOR COOLANT PUMP SHAFT BREAK

15.3.4.1 Identification of Causes and Accident Description

The accident is postulated as an instantaneous failure of a reactor coolant pump shaft, as discussed in section 5.4. Flow through the affected reactor coolant loop is rapidly reduced, though the initial rate of reduction of coolant flow is greater for the reactor coolant pump rotor seizure event. Reactor trip is initiated on a low-flow signal in the affected loop.

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 coefficient; second, because the reactor coolant in the tubes cools down while the shell-side temperature increases. (Turbine steam flow is reduced to zero upon plant trip.) The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam generators, causes an insurge into the pressurizer and a pressure increase throughout the reactor coolant system. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the power-operated relief valves, and opens the pressurizer safety valves, in that sequence. The two power-operated relief valves are designed for reliable operation and would be expected to function properly during the accident. However, for conservatism, their pressure-reducing effect, as well as the pressure-reducing effect of the spray, is not included in the analysis.

This is an ANS Condition IV incident.

15.3.4.2 Conclusion

The consequences of a locked rotor (subsection 15.3.3) represent the most limiting event with respect to the locked rotor or the pump shaft break. With a failed shaft, the impeller could conceivably be free to spin in a reverse direction as opposed to being fixed in position as assumed in the locked-rotor analysis. However, the net effect on core flow is negligible, resulting in only a slight decrease in the end point (steady-state) core flow. For both the shaft break and locked-rotor incidents, reactor trip occurs very early in the transient. In addition, the locked-rotor analysis conservatively assumes that departure from nucleate boiling occurs at the beginning of the transient.

TABLE 15.3.1-1 (SHEET 1 OF 2)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN A DECREASE IN REACTOR COOLANT SYSTEM FLOWRATE

Accident	Event	Time (s)
Partial loss of forced reactor coolant flow		
Loss of two pumps with four loops in operation	Coastdown begins	0.0
	Low-flow reactor trip	1.4
	Rods begin to drop	2.4
	Minimum DNBR occurs	3.6
Complete loss of forced reactor coolant flow		
Loss of four pumps with four loops in operation	All operating pumps lose power and begin coasting down	0.0
	Reactor coolant pump undervoltage trip point reached	0.0
	Rods begin to drop	1.5
	Minimum DNBR occurs	3.2
Reactor coolant pump shaft seizure (locked rotor)		
One locked rotor with four loops in operation with offsite power available	Rotor on one pump locks	0.0
	Low-flow trip point reached	0.0
	Rods begin to drop	1.0

TABLE 15.3.1-1 (SHEET 2 OF 2)

Accident	Event	Time (s)
	Maximum reactor coolant system pressure occurs	3.3
	Maximum clad average temperature occurs	3.5
One locked rotor with four loops in operation without offsite power available	Rotor on one pump locks	0.0
	Low-flow trip point reached	0.0
	Rods begin to drop	1.0
	Maximum reactor coolant system pressure occurs	3.4
	Maximum clad average temperature occurs	3.6

TABLE 15.3.3-1

SUMMARY OF RESULTS FOR LOCKED ROTOR TRANSIENTS (FOUR LOOPS OPERATING INITIALLY)

	With Offsite Power Available	Without Offsite Power Available
Maximum RCS pressure (psia)	2669	2669
Maximum clad average temperature, core hot spot (°F)	2048	2054
Zr-H_2O reaction, core hot spot (percent by weight)	0.6	0.7

TABLE 15.3.3-2 (SHEET 1 OF 2)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A LOCKED ROTOR ACCIDENT

I.	Source Data		
	A.	Core power level (MWt)	3636
	B.	Total steam generator tube leakage (gal/min)	1
	C.	Reactor coolant iodine activity prior to accident	An assumed preaccident iodine spike, which has resulted in the DE of 60 μCi/g of I-131 in the reactor coolant. See table 15A-6.
	D.	Gap activity released to reactor coolant from failed fuel	5 percent. See table 15A-3.
	E.	Reactor coolant noble gas activity	Based on 1-percent defective fuel. See table 15A-4.
	F.	Secondary system initial activity	DE of 0.1 μCi/g of I-131.
	G.	Reactor coolant mass (g)	2.3×10^8
	H.	Secondary coolant mass, 4 generators (g)	1.9×10^8
	I.	Offsite power	Lost after trip
	J.	Primary-to-secondary leakage duration (h)	20
	K.	Species of iodine	100-percent elemental
II.		Atmospheric Dispersion Factors	See table 15A-2.

TABLE 15.3.3-2 (SHEET 2 OF 2)

III.	Activity Release Data		
A.	Primary-to-secondary leak-rate (gal/min)[a]	1.0	
B.	Steam Released (lb)		
	0 to 2 h		555,000
	2 to 8 h		1,365,000
	8 to 20 h		2,730,000
C.	Iodine partition factor	100	

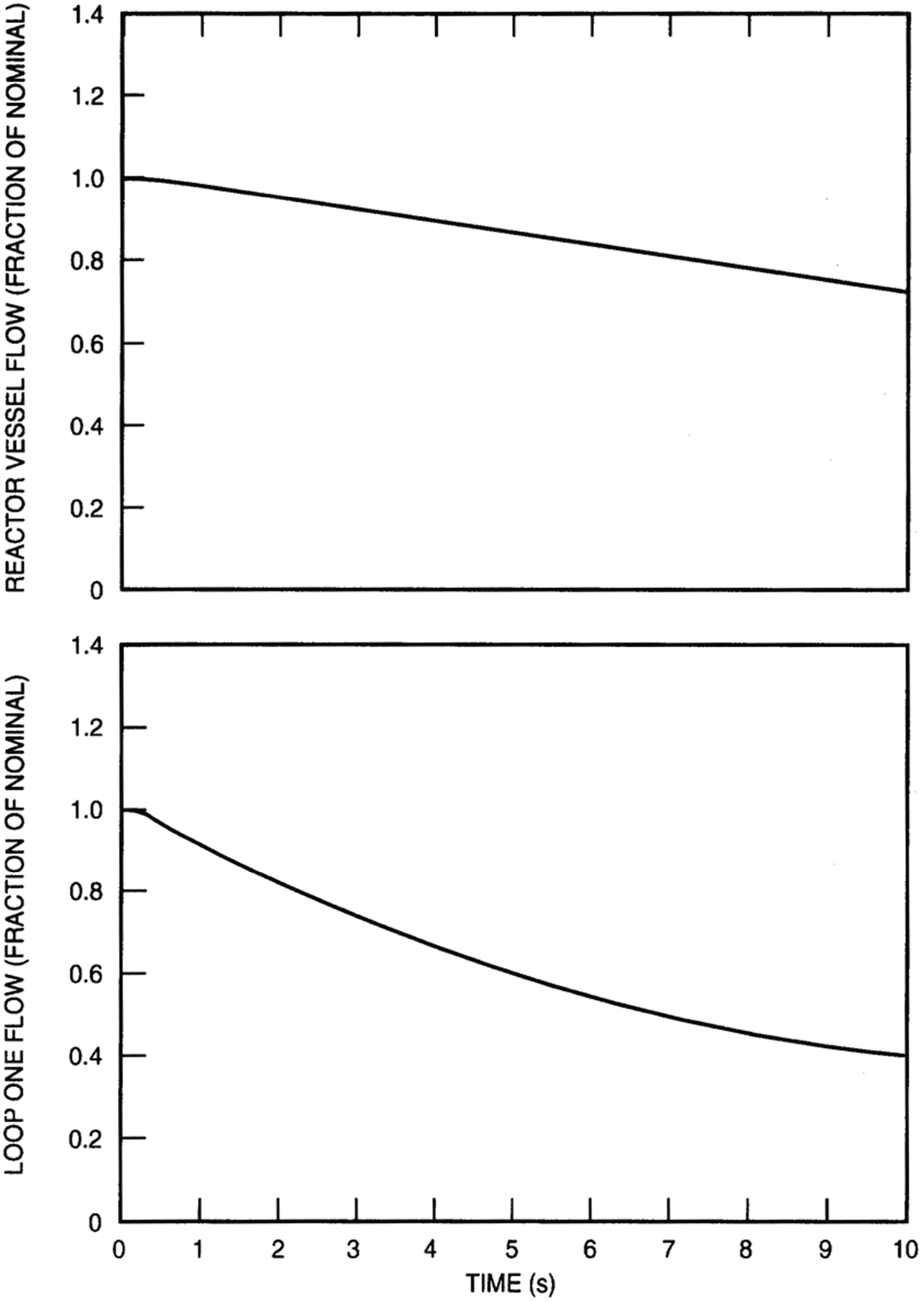
---

[a] Based on water at 62.4 lb/ft^3.

TABLE 15.3.3-3

RADIOLOGICAL CONSEQUENCES OF A LOCKED ROTOR ACCIDENT

	Doses (rem)
Exclusion Area Boundary (0 to 2 h)	
Thyroid	0.6
Whole-body gamma	0.1
Lower Population Zone Outer Boundary (20 h)	
Thyroid	4.2
Whole-body gamma	0.1



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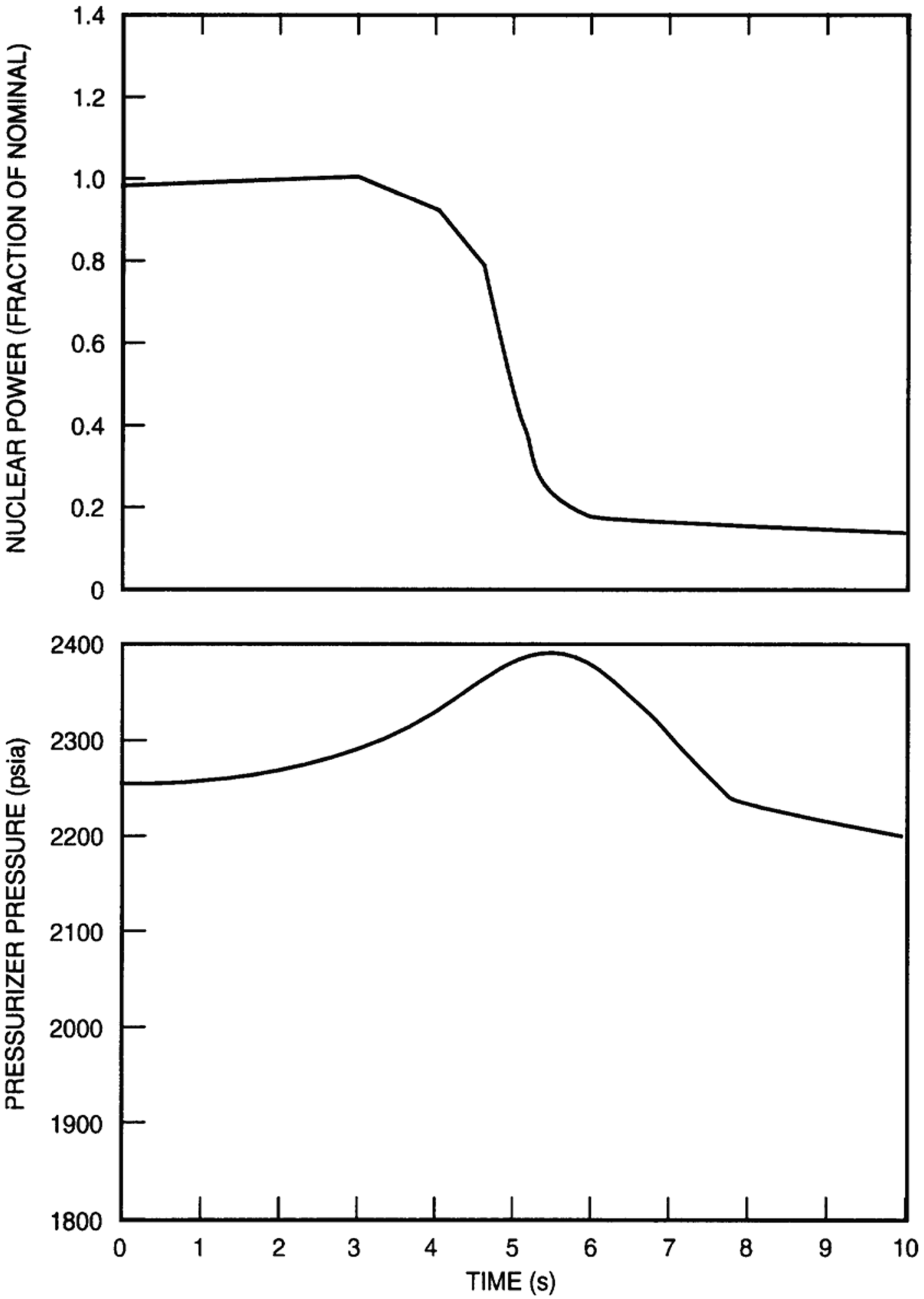
FLOW TRANSIENTS FOR FOUR LOOPS IN OPERATION, TWO PUMPS COASTING DOWN

FIGURE 15.3.1–1



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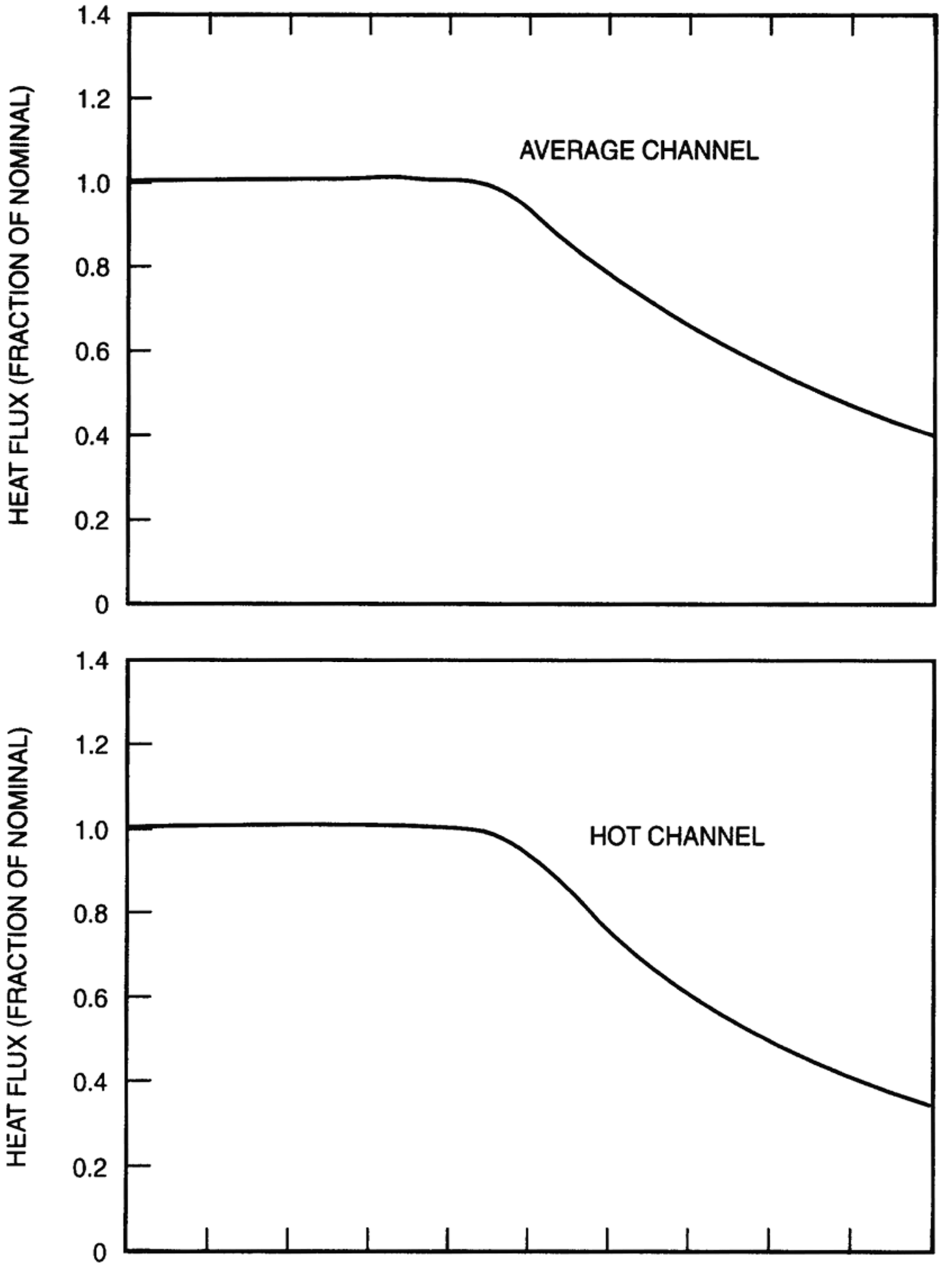
NUCLEAR POWER AND PRESSURIZER PRESSURE TRANSIENTS FOR FOUR LOOPS IN OPERATION, TWO PUMPS COASTING DOWN

FIGURE 15.3.1–2



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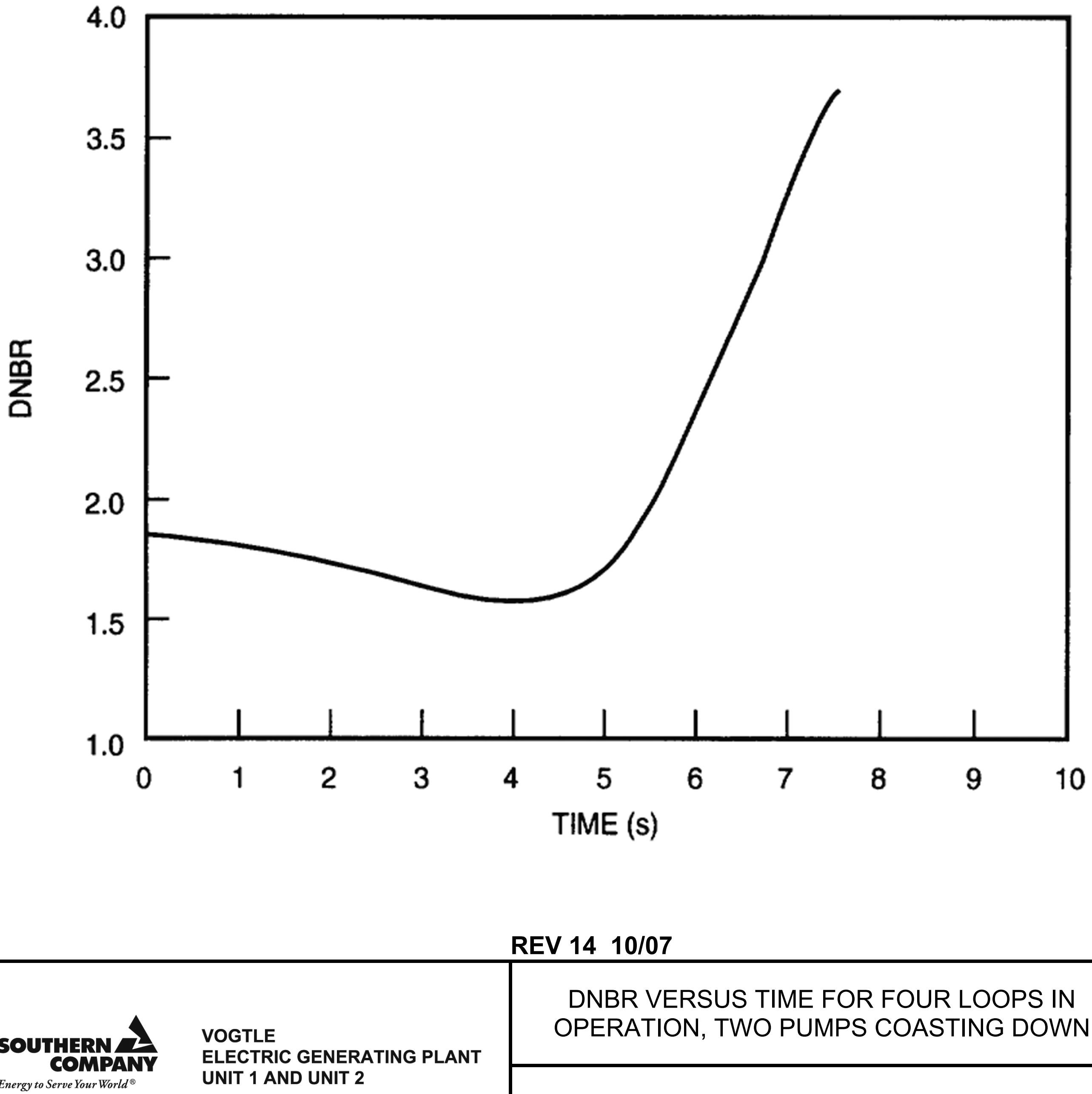
AVERAGE AND HOT CHANNEL HEAT FLUX TRANSIENTS FOR FOUR LOOPS IN OPERATION, TWO PUMPS COASTING DOWN

FIGURE 15.3.1–3



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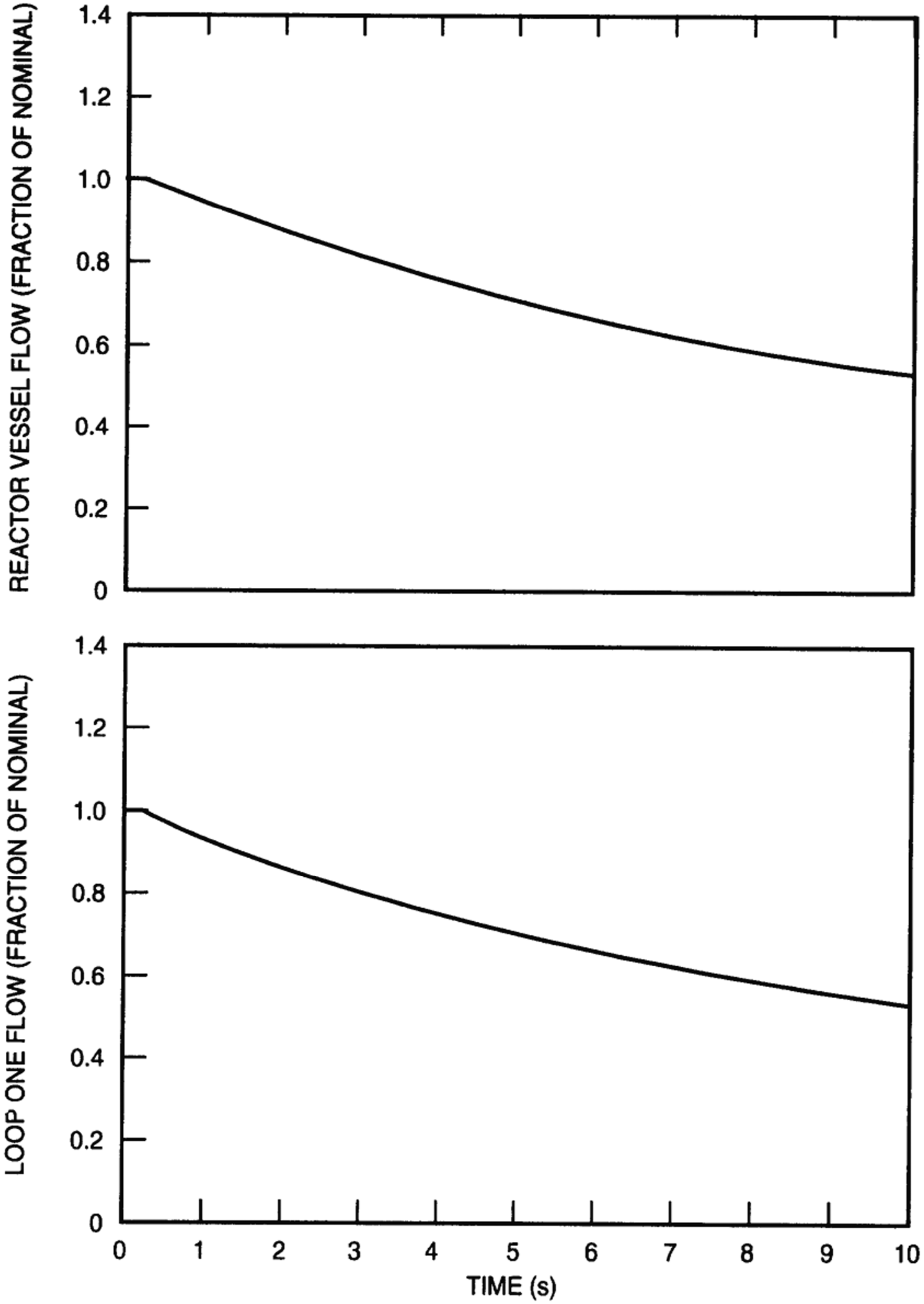
DNBR VERSUS TIME FOR FOUR LOOPS IN OPERATION, TWO PUMPS COASTING DOWN

FIGURE 15.3.1–4



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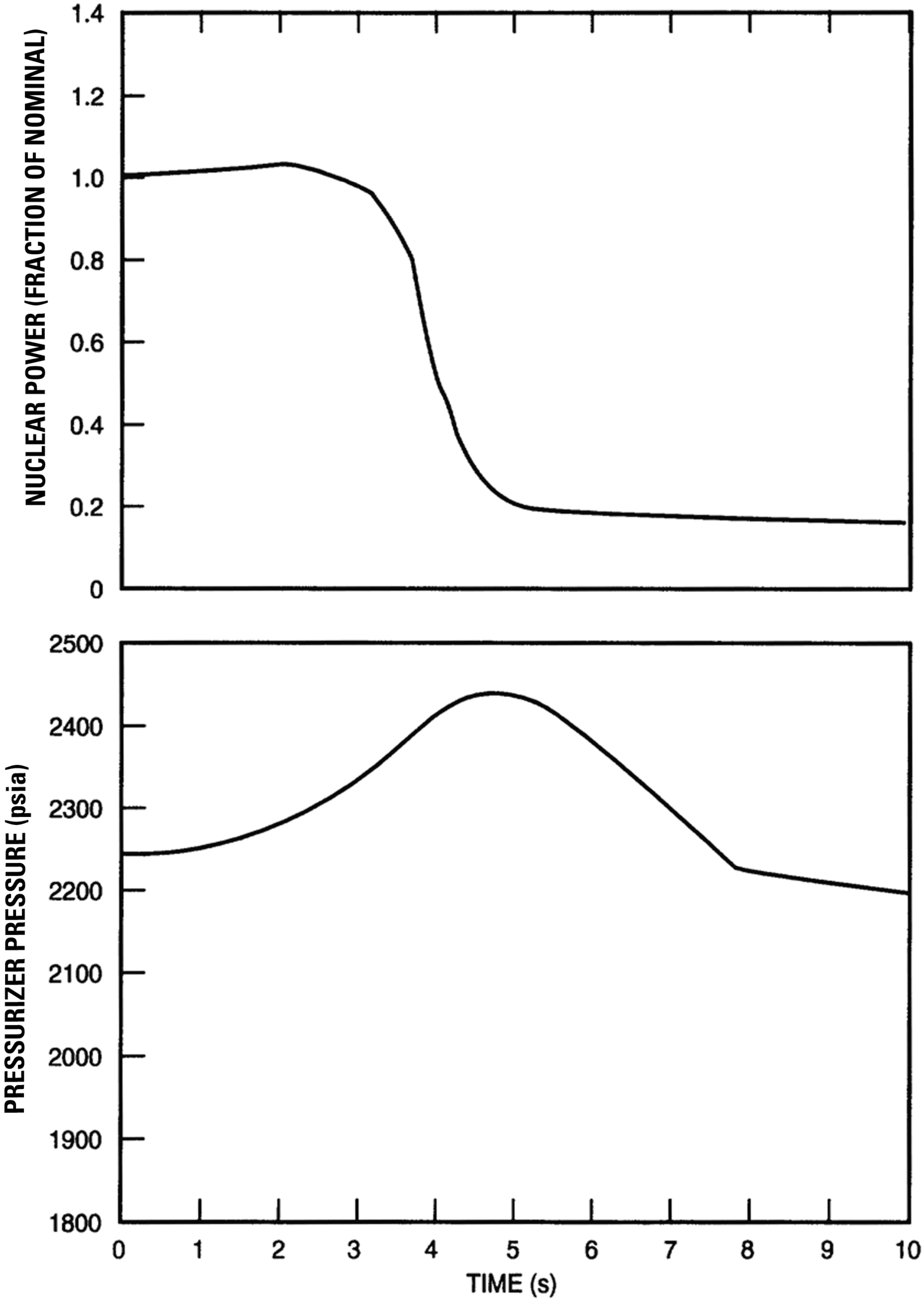
FLOW TRANSIENTS FOR FOUR LOOPS IN OPERATION, FOUR PUMPS COASTING DOWN

FIGURE 15.3.2–1



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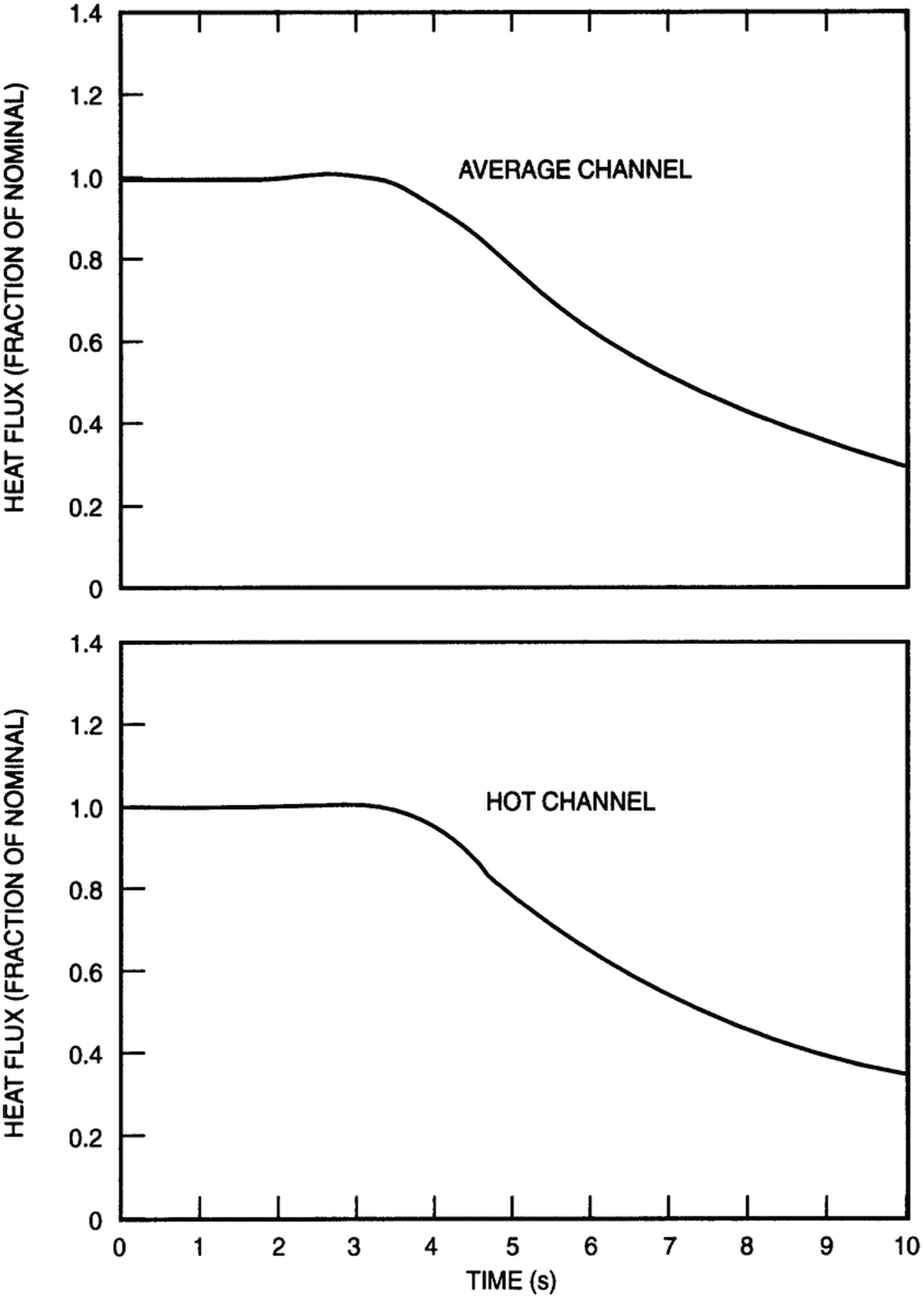
NUCLEAR POWER AND PRESSURIZER PRESSURE TRANSIENTS FOR FOUR LOOPS IN OPERATION, FOUR PUMPS COASTING DOWN

FIGURE 15.3.2–2



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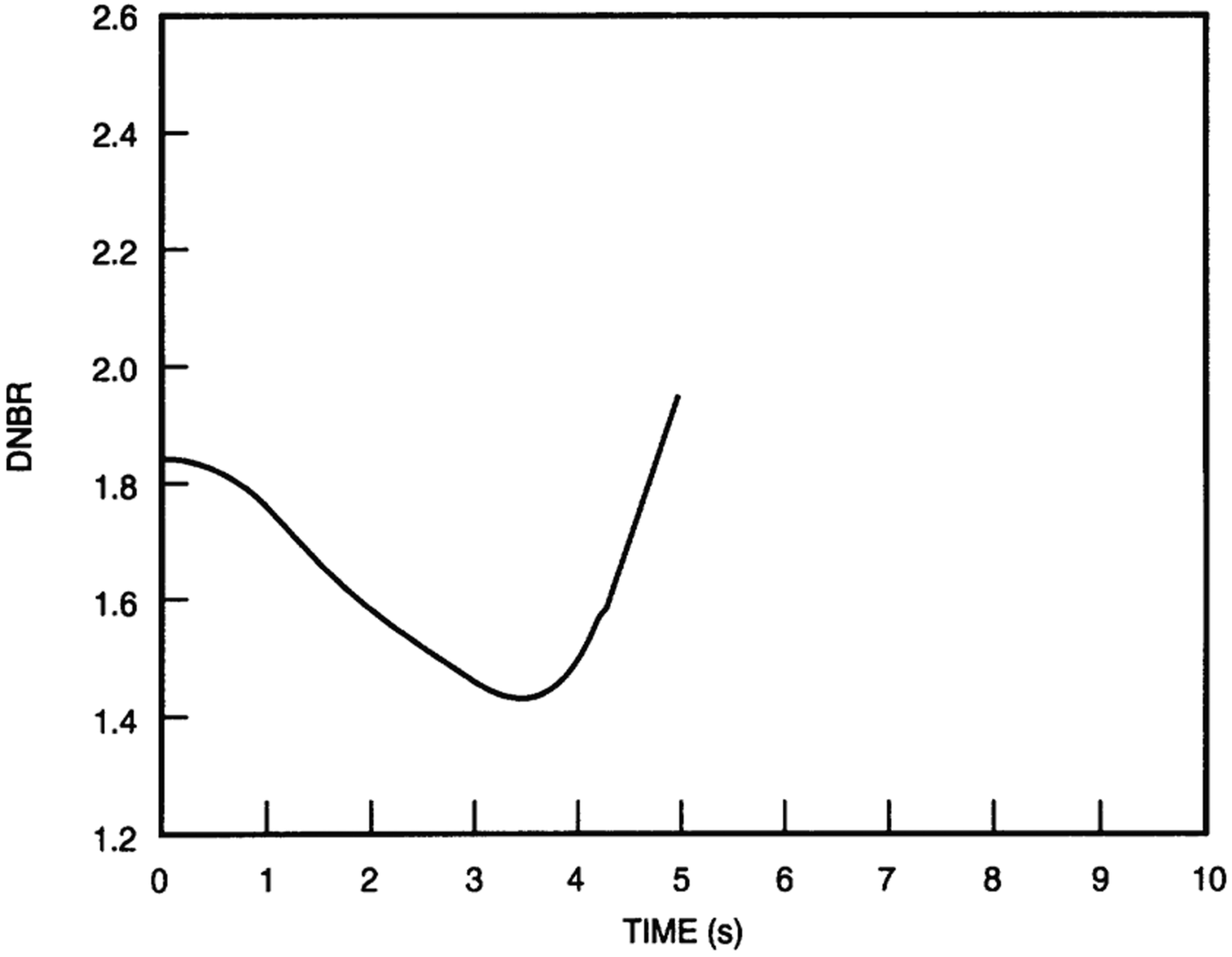
AVERAGE AND HOT CHANNEL HEAT FLUX TRANSIENTS FOR FOUR LOOPS IN OPERATION, FOUR PUMPS COASTING DOWN

FIGURE 15.3.2–3



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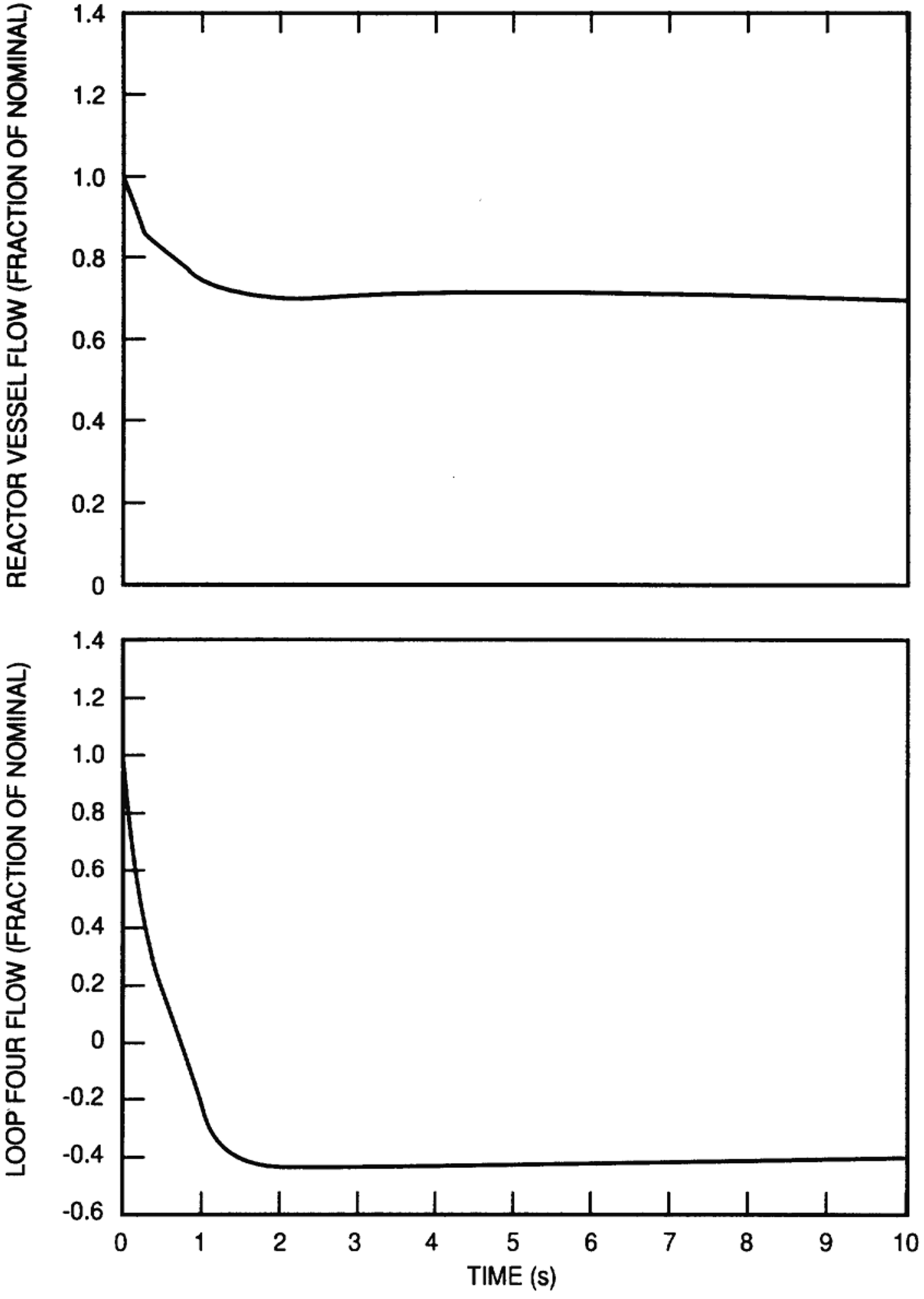
DNBR VERSUS TIME FOR FOUR LOOPS IN OPERATION, FOUR PUMPS COASTING DOWN

FIGURE 15.3.2–4



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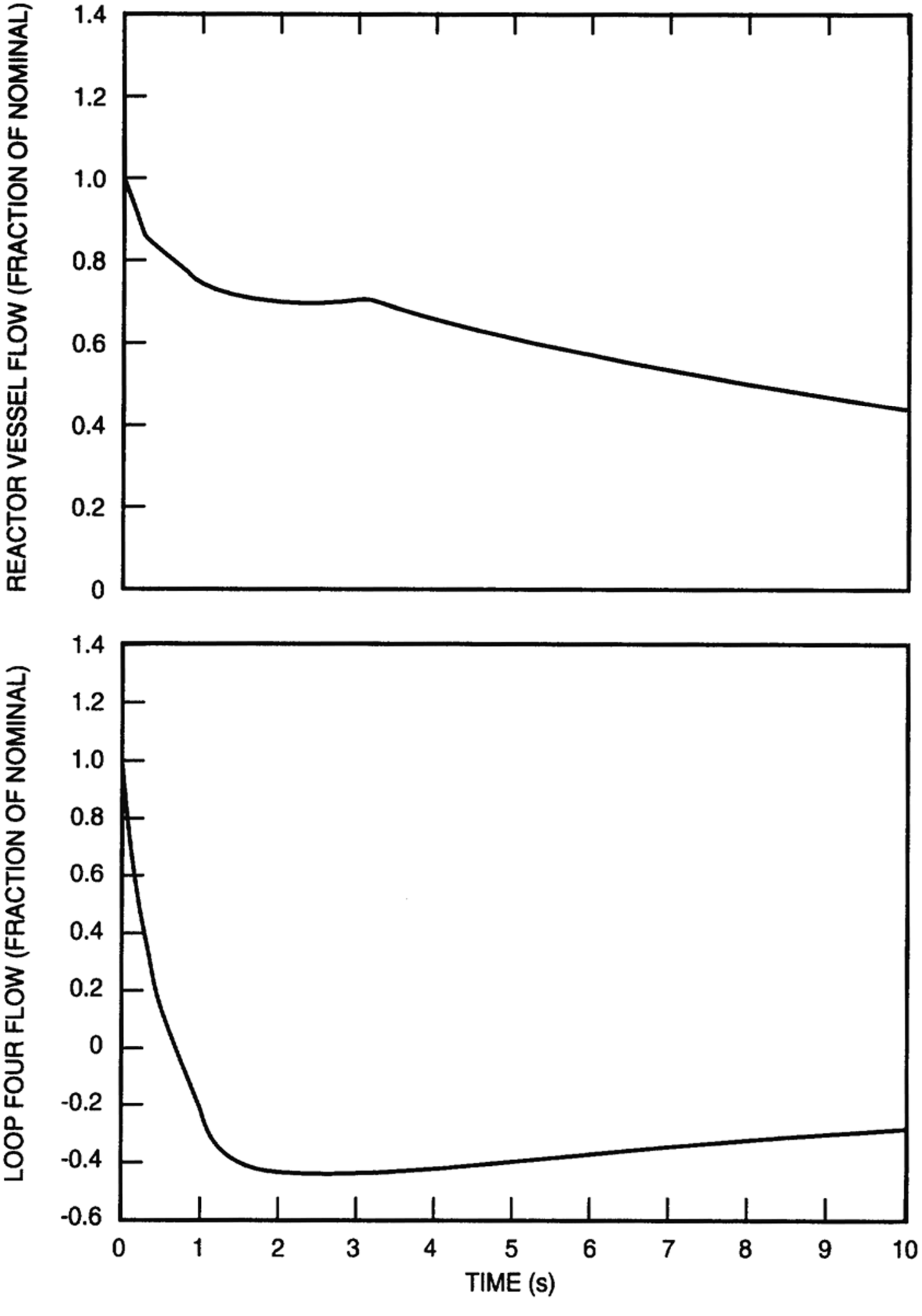
FLOW TRANSIENTS FOR FOUR LOOPS IN OPERATION, (ONE LOCKED ROTOR WITH OFFSITE POWER AVAILABLE)

FIGURE 15.3.3–1 (SHEET 1 OF 2)



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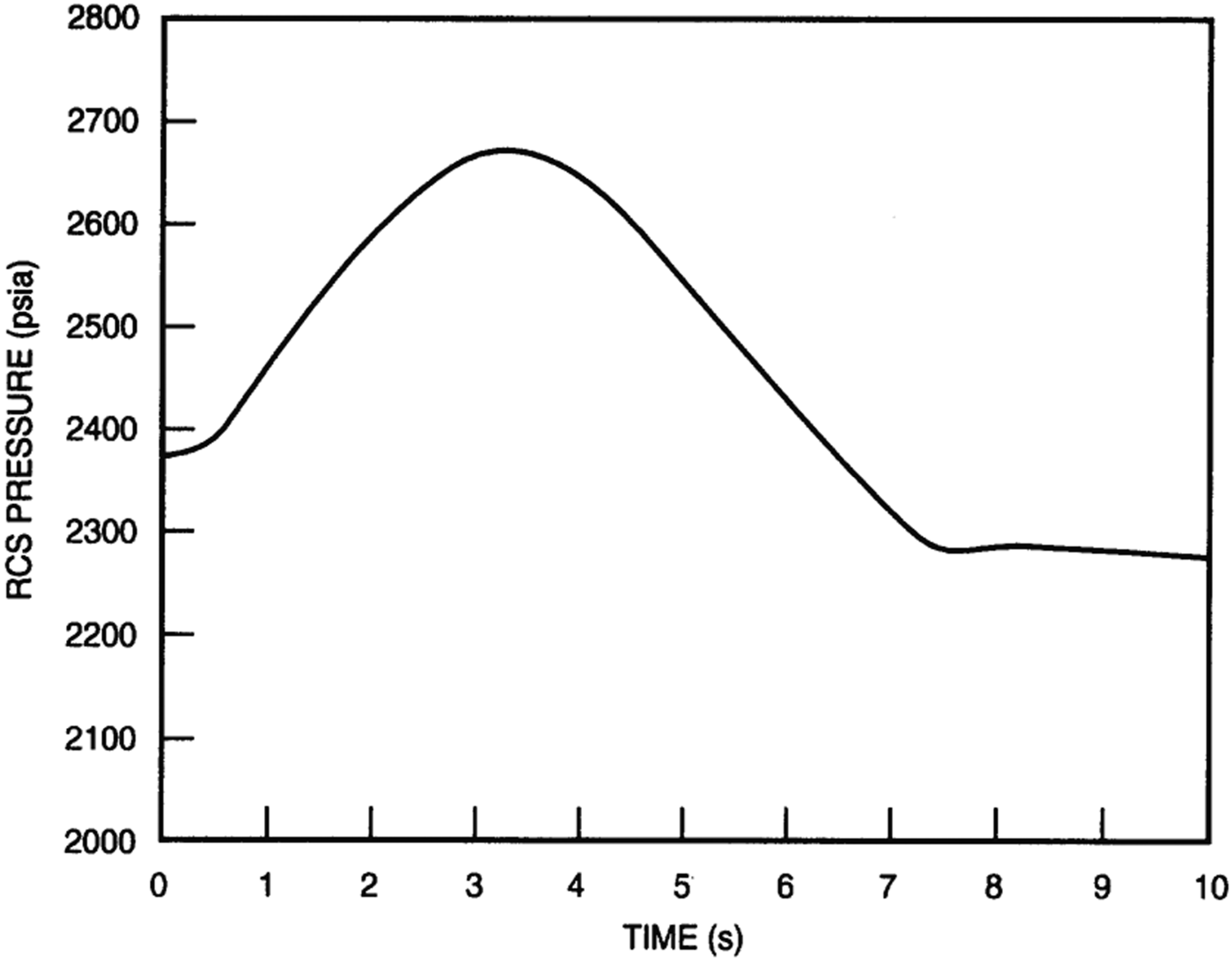
FLOW TRANSIENTS FOR FOUR LOOPS IN OPERATION, (ONE LOCKED ROTOR WITHOUT OFFSITE POWER AVAILABLE)

FIGURE 15.3.3–1 (SHEET 2 OF 2)



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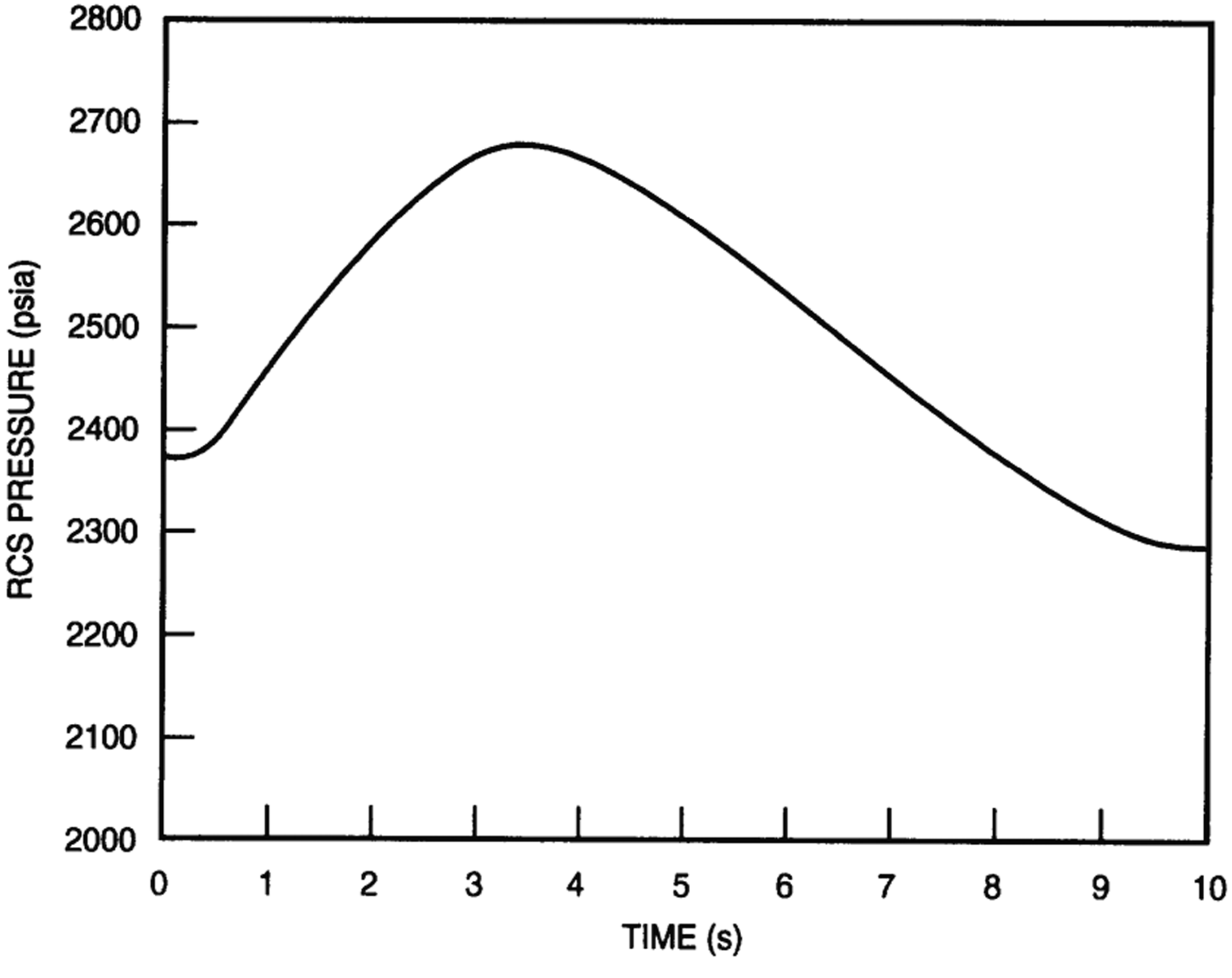
PEAK REACTOR COOLANT PRESSURE FOR FOUR LOOPS OPERATION (ONE LOCKED ROTOR WITH OFFSITE POWER AVAILABLE)

FIGURE 15.3.3–2 (SHEET 1 OF 2)



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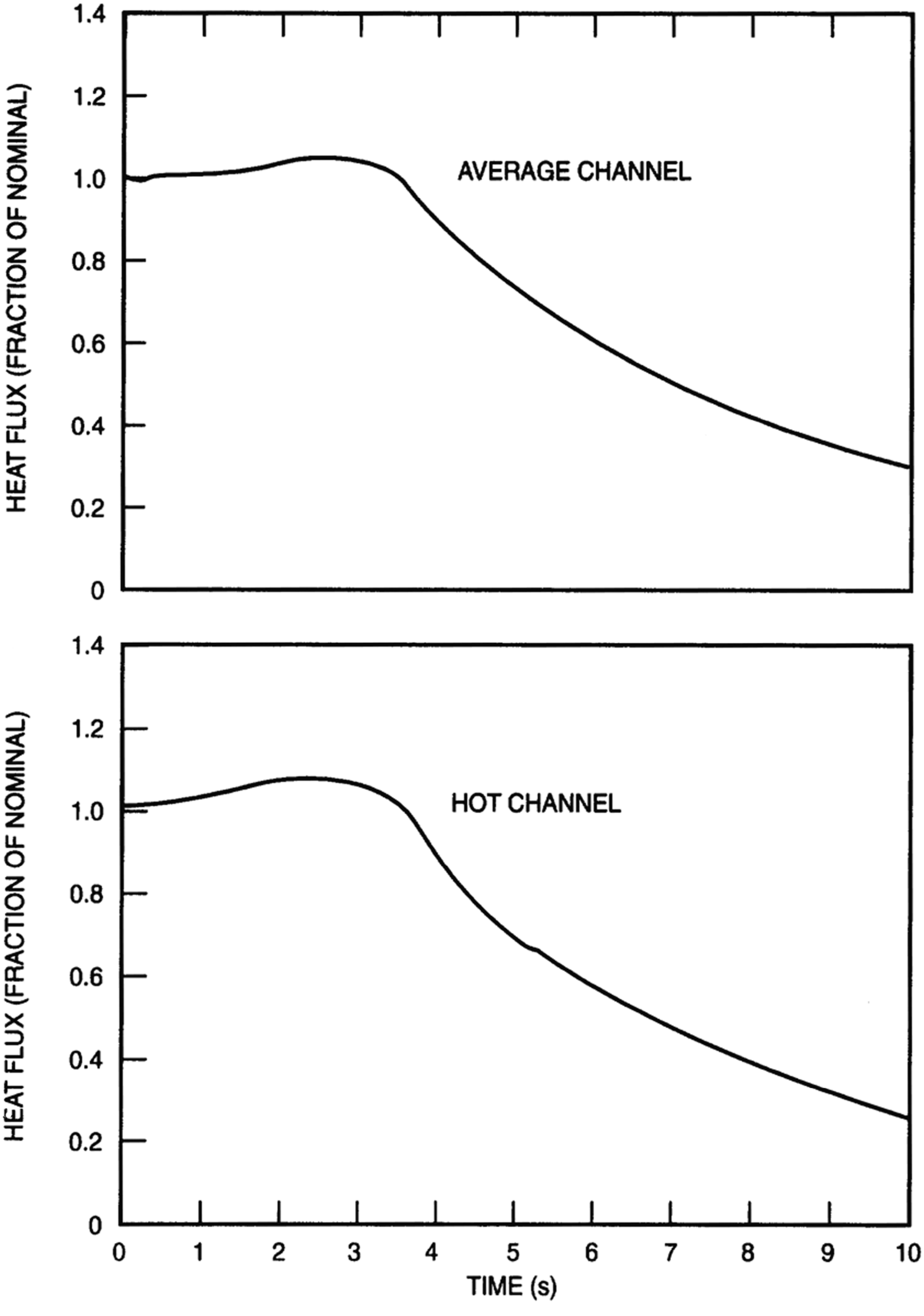
PEAK REACTOR COOLANT PRESSURE FOR FOUR LOOPS IN OPERATION (ONE LOCKED ROTOR WITHOUT OFFSITE POWER AVAILABLE

FIGURE 15.3.3–2 (SHEET 2 OF 2)



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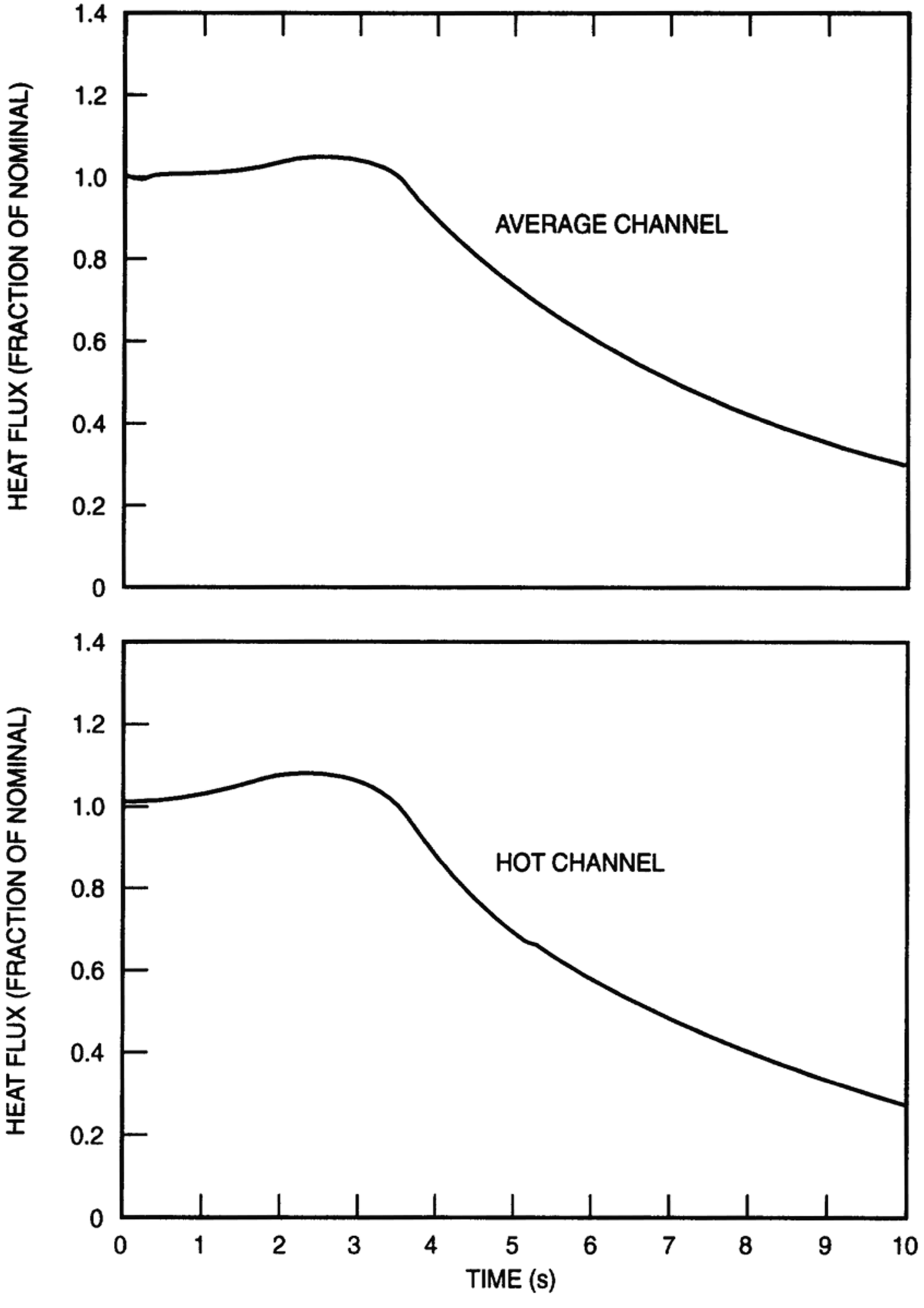
AVERAGE AND HOT CHANNEL HEAT FLUX TRANSIENTS FOR FOUR LOOPS IN OPERATION (ONE LOCKED ROTOR WITH OFFSITE POWER AVAILABLE)

FIGURE 15.3.3–3 (SHEET 1 OF 2)



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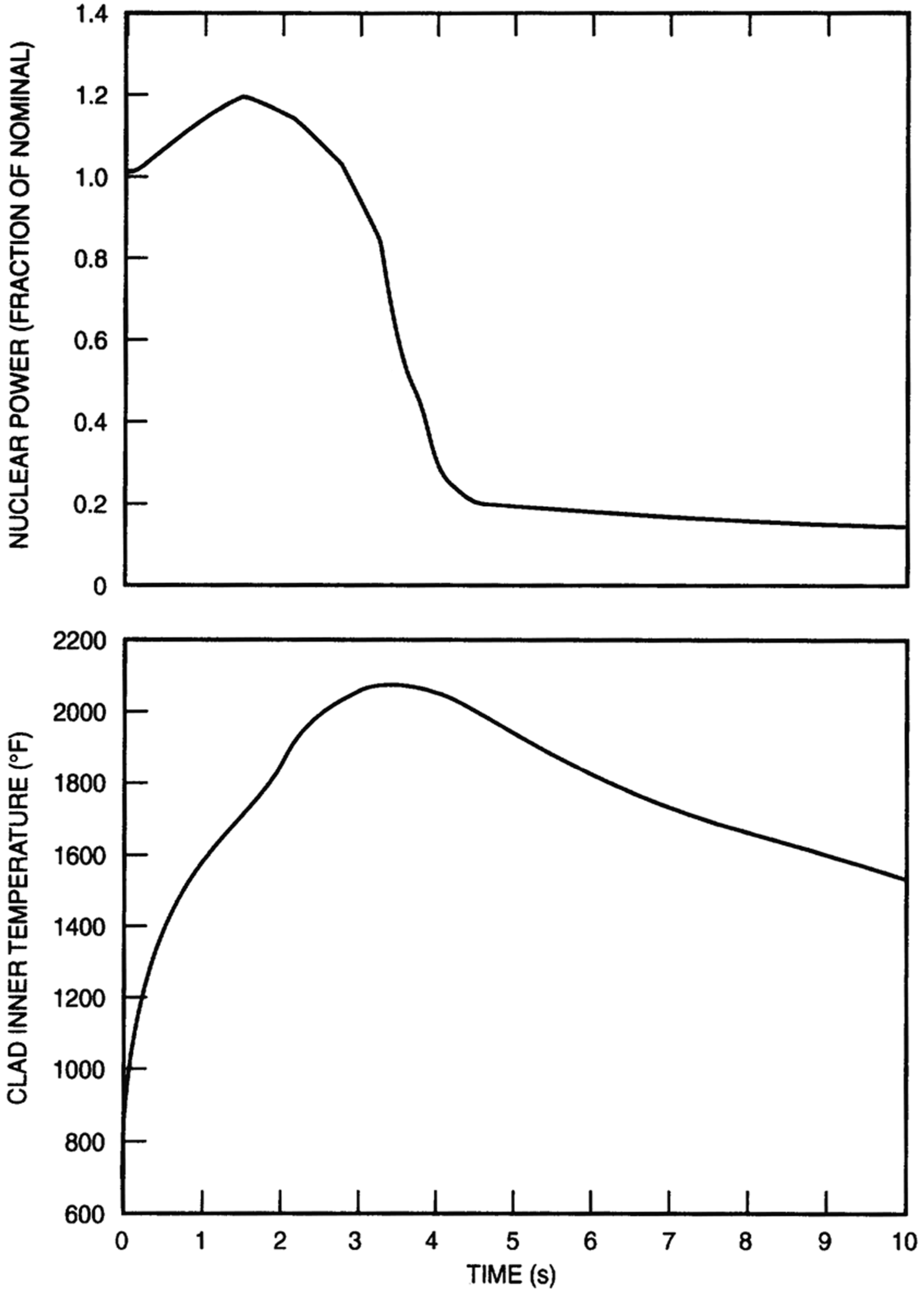
AVERAGE AND HOT CHANNEL HEAT FLUX TRANSIENTS FOR FOUR LOOPS IN OPERATION (ONE LOCKED ROTOR WITHOUT OFFSITE POWER AVAILABLE)

FIGURE 15.3.3–3 (SHEET 2 OF 2)



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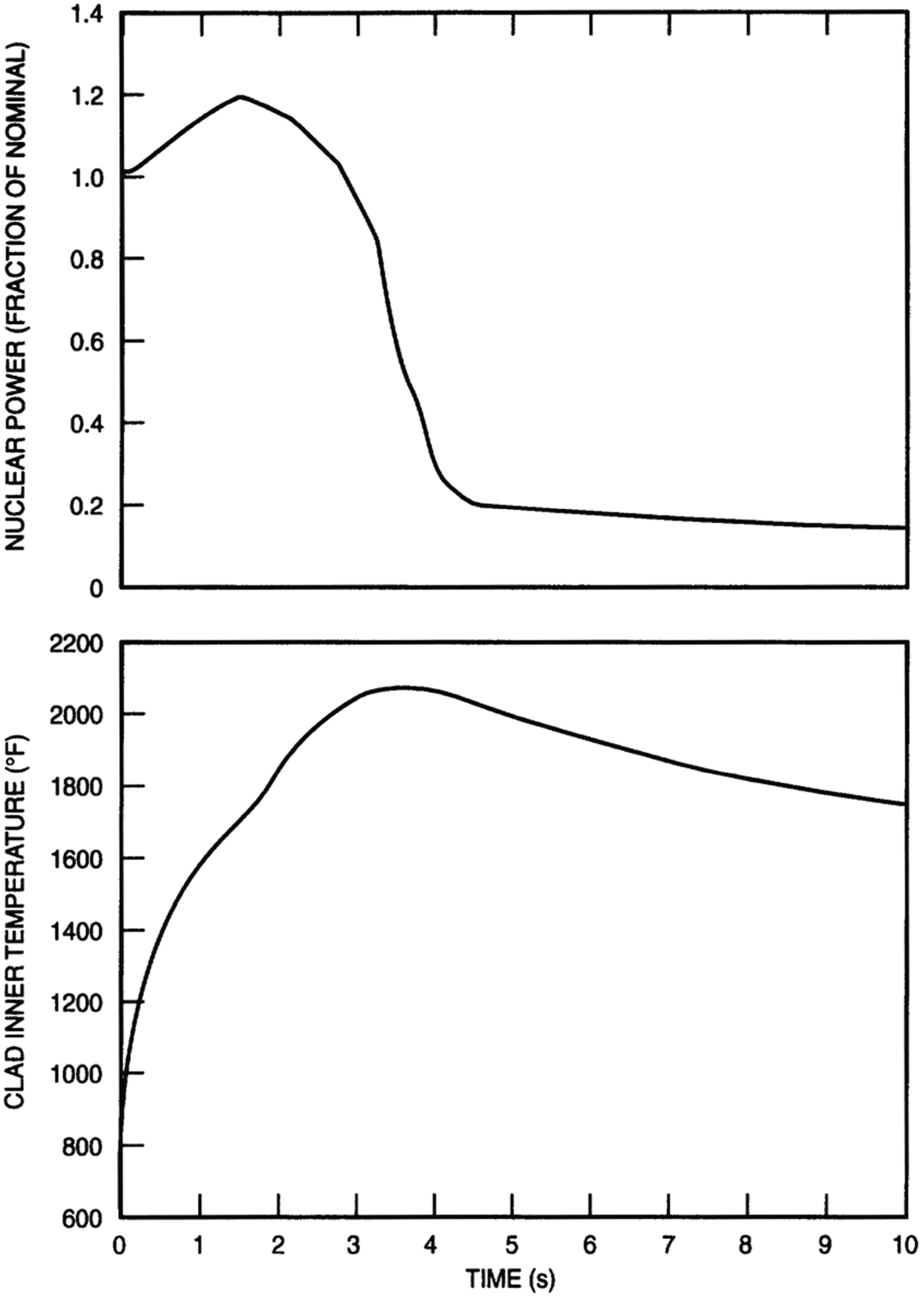
NUCLEAR POWER AND MAXIMUM CLAD TEMPERATURE AT HOT SPOT TRANSIENTS FOR FOUR LOOPS IN OPERATION (ONE LOCKED ROTOR WITH OFFSITE POWER AVAILABLE)

FIGURE 15.3.3–4 (SHEET 1 OF 2)



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NUCLEAR POWER AND MAXIMUM CLAD TEMPERATURE AT HOT SPOT TRANSIENTS FOR FOUR LOOPS IN OPERATION (ONE LOCKED ROTOR WITHOUT OFFSITE POWER AVAILABLE)

FIGURE 15.3.3–4 (SHEET 2 OF 2)

15.4 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

Several postulated faults can result in reactivity and power distribution anomalies. Control rod motion, control rod ejection, boron concentration changes, or addition of cold water to the RCS results in reactivity changes. Control rod motion, control rod misalignment, control rod ejection, or fuel assembly mislocation results in power distribution changes. This section discusses these events. Detailed analyses are presented for the most limiting of these events.

This section presents the following incidents:

- Uncontrolled rod cluster control assembly (RCCA) bank withdrawal from a subcritical or low-power startup condition.
- Uncontrolled RCCA bank withdrawal at power.
- RCCA misalignment.
- Startup of an inactive reactor coolant pump at an incorrect temperature.
- A malfunction or failure of the flow controller in a boiling water reactor recirculation loop that results in an increased reactor coolant flowrate (not applicable to VEGP).
- Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant.
- Inadvertent loading and operation of a fuel assembly in an improper position.
- Spectrum of RCCA ejection accidents.
- Steamline break with coincidental RCCA bank withdrawal at power.

All of the accidents in this section have been analyzed. The most severe radiological consequences result from the complete rupture of a control rod drive mechanism housing provided in subsection 15.4.8; therefore, radiological consequences are reported only for that limiting case.

15.4.1 UNCONTROLLED ROD CLUSTER CONTROL ASSEMBLY BANK WITHDRAWAL FROM A SUBCRITICAL OR LOW-POWER STARTUP CONDITION

15.4.1.1 Identification of Causes and Accident Description

An RCCA withdrawal incident is an uncontrolled addition of reactivity to the reactor core caused by withdrawal of RCCA banks resulting in a power excursion. While the occurrence of a transient of this type is highly unlikely, a malfunction of the control rod drive system can cause such a transient. This could occur with the reactor either subcritical, low power startup, or at power. Subsection 15.4.2 discusses the "at power" case.

RCCA bank withdrawal adds reactivity at a prescribed and controlled rate to bring the reactor from a subcritical condition to a low power level during startup. Although the initial startup procedure uses the method of boron dilution, the normal startup is with RCCA bank withdrawal. RCCA bank motion can cause much faster changes in reactivity than can be made by changing boron concentration.

The control rod drive mechanisms wire into preselected banks which remain unchanged during the core life. The circuit design is such that RCCAs cannot be withdrawn in other than their proper withdrawal sequence. Control of the power supplied to the rod banks is such that no more than two banks can be withdrawn at any time. The RCCA drive mechanism is the magnetic latch type, and the coil actuation sequencing provides variable speed travel. The analysis of the maximum reactivity insertion rate includes the assumption of the simultaneous withdrawal of the two sequential banks having the maximum combined worth at maximum speed.

The neutron flux response to a continuous reactivity insertion is characterized by a fast rise terminated by the reactivity feedback effect of the negative Doppler coefficient. This self-limitation of the power excursion is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a continuous control rod assembly withdrawal initiate, the transient will terminate by the following reactor trip functions:

- Source range high neutron flux reactor trip is actuated when either of two independent source range channels indicates a flux level above a preselected, manually adjustable setpoint. This trip function may be manually bypassed when the intermediate range flux channel indicates a flux level above the source range cutoff level. It is automatically reinstated when both intermediate range channels indicate a flux level below a specified setpoint.

- Intermediate range high neutron reactor flux trip is actuated when either of two independent intermediate range channels indicates a flux level above a preselected, 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/flux level and is automatically reinstated when three of the four power range channels indicate a power/flux level below this setpoint.

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

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

- High neutron flux rate reactor trip is 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. It is always active.

In addition, control rod stops on high intermediate range flux (one out of two) and high power range flux (one out of four) serve to cease rod withdrawal and prevent the need to actuate the intermediate range flux trip and the power range flux trip, respectively.

This is an ANS Condition II incident.

15.4.1.2 Analysis of Effects and Consequences

15.4.1.2.1 Method of Analysis

The following three stages comprise the analysis of the uncontrolled RCCA bank withdrawal from subcritical accident: first, an average core nuclear power transient calculation; then, an average core heat transfer calculation; and finally, the DNBR calculation. The spatial neutron kinetics computer code TWINKLE (reference 1) performs the average core calculation to determine the average power generation with time including the various total core feedback effects; i.e., Doppler reactivity and moderator reactivity. FACTRAN (reference 2) performs a fuel rod transient heat transfer calculation to determine the average heat flux and temperature transients. The average heat flux is next used in VIPRE-01 (section 4.4) for transient DNBR calculations.

In order to give conservative results for a startup incident, the following additional assumptions are made concerning the initial reactor conditions:

A. Since the magnitude of the neutron flux peak reached during the initial part of the transient for any given rate of reactivity insertion is strongly dependent on the Doppler power reactivity coefficient, the analysis employs a conservatively low value for Doppler power defect (-998 pcm).

B. 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 the moderator is much longer than the neutron flux response time constant; however, after the initial neutron flux peak, the moderator temperature reactivity coefficient affects the succeeding rate of power increase. The analysis assumes a moderator temperature coefficient which is +7 pcm/°F at the zero power nominal temperature.

C. The analysis assumes the reactor to be at hot zero power (557°F). This assumption is more conservative than that of a lower initial system temperature. The higher initial system temperature yields a larger fuel-to-water heat transfer coefficient, a larger fuel-specific heat, and a less-negative (smaller absolute magnitude) Doppler coefficient; these reduce the Doppler feedback effect, thereby increasing the neutron flux peak. The high neutron flux peak combined with a high fuel specific eat 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 this results in the maximum neutron flux peak.

D. The most adverse combination of instrumentation error, setpoint error, delay for trip signal actuation, and delay for control rod assembly release is taken into account. The analysis assumes a 10-percent increase in the power range flux trip setpoint, raising it from the nominal value of 25 percent to a value of 35 percent and not taking any credit for the source and intermediate range protection. Figure 15.4.1-1 shows that the rise in nuclear flux is so rapid that the effect of error in the trip setpoint on the actual time at which the rods release is negligible. Besides the above, the assumption that the highest worth control rod assembly is stuck in its fully withdrawn position is the basis of the rate of negative reactivity insertion corresponding to the reactor trip.

E. 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 maximum speed (45 in./min).

F. The DNB analysis assumes the most limiting axial and radial power shapes associated with having the two highest combined worth banks in their high-worth position.

G. 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.

H. The analysis assumes two RCPs to be in operation (Mode 3 Technical Specification allowed operation). This is conservative with respect to the DNB transient.

The accident analysis employs the STDP with the initial conditions shown in tables 15.0.3-2 and 5.0.3-3.

Plant systems and equipment which are available to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in table 15.0.8-1. No single active failure in any of these systems or components will adversely affect the consequences of the accident.

15.4.1.2.2 Results

Figures 15.4.1-1 through 15.4.1-3 show the transient behavior for the uncontrolled RCCA bank withdrawal incident, with the accident terminated by reactor trip at 35 percent of nominal power. The reactivity insertion rate used is greater than that calculated for the two highest worth sequential control banks, both assumed to be in their highest incremental worth region.

Figure 15.4.1-1 shows the average neutron flux transient.

The energy release and the fuel temperature increases are relatively small. The thermal flux response, of interest for DNB considerations, is shown on figure 15.4.1-2. The beneficial effect of the inherent thermal lag in the fuel is evidenced by a peak heat flux much less than the full-power nominal value. There is margin to DNB during the transient. Figure 15.4.1-3 shows the response of the hot spot average fuel and clad inner temperatures. The minimum DNBR at all times remains above the limiting value.

The calculated sequence of events for this accident is shown on table 15.4.1-1. With the reactor tripped, the plant returns to a stable condition. The plant may subsequently be cooled down further by following normal plant shutdown procedures.

15.4.1.3 Conclusions

In the event of an RCCA withdrawal accident from the subcritical condition, the core and the RCS are not adversely affected, since the combination of thermal power and the coolant temperature results in a DNBR greater than the limiting value. The DNBR design basis is described in section 4.4; applicable acceptance criteria have been met.

15.4.1.4 References

1. Risher, D. H., Jr., and Barry, R. F., "TWINKLE--A Multi-Dimensional Neutron Kinetics Computer Code," WCAP-7979-P-A (Proprietary) and WCAP-8028-A (Nonproprietary), January 1975.
2. Hargrove, H. G., "FACTRAN--A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," WCAP-7908-A, December 1989.

15.4.2 UNCONTROLLED ROD CLUSTER CONTROL ASSEMBLY BANK WITHDRAWAL AT POWER

15.4.2.1 Identification of Causes and Accident Description

An uncontrolled RCCA withdrawal at power results in an increase in core heat flux. Since the heat extraction from the steam generator lags behind the core power generation until the steam generator pressure reaches the relief or safety valve setpoint, there is a net increase in the reactor coolant temperature. Unless terminated by manual or automatic action, the power mismatch and resultant coolant temperature rise could eventually result in DNB; therefore, to avert damage to the fuel clad the reactor protection system is designed to terminate any such transient before DNBR falls below the safety analysis limit.

The automatic features of the reactor protection system which prevent core damage in an RCCA bank withdrawal incident at power include the following:

- Power range neutron flux instrumentation actuates a reactor trip on high neutron flux if two out of four channels exceed an overpower setpoint.
- Reactor trip actuates if any two out of four ΔT channels exceed an OTΔT setpoint. This setpoint is automatically varied with axial power distribution, coolant average temperature, and coolant average pressure to protect against DNB.
- Reactor trip actuates if any two out of four ΔT channels exceed an OPΔT setpoint. This setpoint is automatically varied with coolant average temperature so that the allowable heat generation rate (kW/ft) is not exceeded.
- A high pressurizer pressure reactor trip, actuated from any two out of four pressure channels, is set at a fixed point. This set pressure is less than the set pressure for the pressurizer safety valves.
- Any two out of three level channels when the reactor power is above approximately 10 percent (permissive P-7) will actuate a high pressurizer water level reactor trip.
- Power range neutron flux instrumentation actuates a reactor trip if two out of four channels exceed a specified positive flux rate. (This trip is credited for the RCS overpressure limit. It is not credited in the reactor core protection analyses.)

Besides the above listed reactor trips, there are the following RCCA withdrawal blocks:

- High neutron flux (one out of four).

- OPΔT (two out of four).
- OTΔT (two out of four).

The manner in which the combination of OPΔT and OTΔT trips provide protection over the full range of RCS conditions is described in chapter 7. Figure 15.0.6-1 presents allowable reactor coolant loop average temperature and ΔT for the design power distribution and flow as a function of primary coolant pressure. The boundaries of operation defined by the OPΔT and OTΔT trip are represented as "protection lines" on this diagram. The protection lines are drawn to include all adverse instrumentation and setpoint errors so that under nominal conditions trip would occur well within the area bounded by these lines. The utility of this diagram is in the fact that the limit imposed by any given DNBR can be represented as a line. The DNB lines represent the locus of conditions for which the DNBR equals the safety analysis limit. All points below and to the left of a DNB line for a given pressure have a DNBR greater than the safety analysis limit. The diagram shows that DNB is prevented for all cases if the area enclosed with the maximum protection lines is not traversed by the applicable DNBR line at any point.

The area of permissible operation (power, pressure, and temperature) is bounded by the combination of reactor trips:

- High neutron flux (fixed setpoint).
- High pressure (fixed setpoint).
- Low pressure (fixed setpoint).
- OPΔT and OTΔT (variable setpoints).

The purpose of this analysis is to demonstrate the manner in which the above protective systems function for various reactivity insertion rates from different initial conditions to prevent fuel damage. Reactivity insertion rates and initial conditions influence which protection function actuates first.

Reference 3 documents that a conservative analysis has been performed, assuming the reactor trip listed in table 15.0.6-1, that ensures that the RCS overpressure limit will not be exceeded for an uncontrolled rod withdrawal during power operation.

This is an ANS Condition II incident.

15.4.2.2 Analysis of Effects and Consequences

15.4.2.2.1 Method of Analysis

This transient is analyzed by the LOFTRAN code (reference 1). 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. The core limits as illustrated in figure 15.0.6-1 are used as input to LOFTRAN to determine the minimum DNBR during the transient.

The analysis of this accident uses the RTDP described in reference 2. Subsection 15.0.3 discusses the plant characteristics and initial conditions. For an uncontrolled RCCA bank withdrawal at power accident, the analysis assumes the following conservative assumptions:

A. Nominal values form the basis of the initial reactor power, pressure, and RCS temperature assumption. The limit DNBR includes uncertainties in initial conditions as described in reference 2.

B. Reactivity coefficients -- two cases analyzed:

  1. A +7 pcm/°F moderator temperature coefficient of reactivity and a least-negative Doppler-only power coefficient form the basis of the beginning-of-life minimum reactivity feedback assumption.

  2. A conservatively large positive moderator density coefficient (corresponding to a large negative moderator temperature coefficient) and a most-negative Doppler-only power coefficient form the basis of the end-of-life maximum reactivity feedback assumption.

C. A conservative value of 118 percent of nominal full core power actuates the reactor trip on high neutron flux. The ΔT trips include all adverse instrumentation and setpoint errors while maximum values form the basis of the delays for the trip signal actuation assumption.

D. The assumption that the highest worth assembly is stuck in its fully withdrawn position forms the basis of the RCCA trip insertion characteristic.

E. The analysis examines a range of reactivity insertion rates. The maximum positive reactivity insertion rate is greater than that for the simultaneous withdrawal of the two control banks having the maximum combined worth at maximum speed assuming normal overlap.

The effect of RCCA movement on the axial core power distribution is accounted for by causing a decrease in OTΔT trip setpoint proportional to a decrease in margin to DNB.

Plant systems and equipment which are available to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in table 15.0.8-1. No single active failure in any of these systems or equipment will adversely offset the consequences of the accident. A discussion of anticipated transients without trip considerations is presented in section 15.8.

15.4.2.2.2 Results

Figures 15.4.2-1 through 15.4.2-3 show the transient response for a rapid RCCA bank withdrawal incident starting from full power with minimum feedback. Reactor trip on high neutron flux occurs shortly after the start of the accident. Because of the rapid reactor trip with respect to the thermal time constants of the plant, small changes in T_{avg} and pressure result, and the margin to DNB is maintained.

The transient response for a slow RCCA withdrawal from full power with minimum feedback is shown in figures 15.4.2-4 through 15.4.2-6. Reactor trip on OTΔT occurs after a longer period and the rise in temperature and pressure is consequently larger than for rapid RCCA bank withdrawal. Again, the minimum DNBR is greater than the safety analysis limit.

Figure 15.4.2-7 shows the minimum DNBR as a function of reactivity insertion rate from initial full-power operation for both minimum and maximum reactivity feedback. It can be seen that the two reactor trip functions (high neutron flux and OTΔT functions) provide DNB protection over the whole range of reactivity insertion rates. The minimum DNBR is always greater than the safety analysis limit.

Figures 15.4.2-8 and 15.4.2-9 show the minimum DNBR as a function of reactivity insertion rate for RCCA 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 decreases, the range over which the OTΔT trip is effective is increased. In neither case does the DNBR fall below the safety analysis limit.

The shape of the curves of minimum DNBR versus reactivity insertion rate in the referenced figures is due both to reactor core and coolant system transient response and to protection system action initiating a reactor trip.

Referring to figure 15.4.2-8, for example, it is noted that:

A. For high reactivity insertion rates; i.e., between approximately 1.5×10^{-4} Δk/s and 1.0×10^{-3} Δk/s, reactor trip is initiated by the high neutron flux trip for the minimum reactivity feedback cases. The neutron flux level in the core rises rapidly for these insertion rates while core heat flux and coolant system temperature lag behind due to the thermal capacity of the fuel and coolant system fluid. Thus, the reactor is tripped prior to significant increase in heat flux or water temperature with resultant high minimum DNBRs during the transient. As reactivity insertion rate decreases, core heat flux and coolant temperatures can remain more nearly in equilibrium with the neutron flux; minimum DNBR during the transient thus decreases with decreasing insertion rate.

B. The OTΔT reactor trip circuit initiates a reactor trip when measured coolant loop ΔT exceeds a setpoint based on measured RCS average temperature and pressure. This trip circuit is described in detail in chapter 7; however, it is important in this context to note that the average temperature contribution to the circuit is lead-lag compensated to decrease the effect of the thermal capacity of the RCS in response to power increases.

C. With further decrease in reactivity insertion rate, the OTΔT and high neutron flux trips become equally effective in terminating the transient; e.g., at approximately 1.5×10^{-4} Δk/s reactivity insertion rate. For reactivity insertion rates between approximately 1×10^{-4} Δk/s and approximately 2×10^{-5} Δk/s, the effectiveness of the OTΔT trip increases (in terms of increased minimum DNBR) due to the fact that with lower insertion rates the power increase rate is slower, the rate of rise of average coolant temperature is slower, and the system lags and delays become less significant.

D. Referring to figure 15.4.2-9, it is shown that for reactivity insertion rates less than approximately 5×10^{-5} Δk/s, the rise in the reactor coolant temperature is sufficiently high so that the steam generator safety valve setpoint is reached prior to trip in the minimum feedback case. Opening of these valves, which act as an additional heat load of the RCS, sharply decreases the rate of increase of RCS average temperature. This decrease in rate of increase of the average coolant system temperature during the transient is accentuated by the lead-lag compensation, causing the OTΔT trip setpoint to be reached later, with resulting lower minimum DNBRs.

For transients initiated from higher power levels (for example, see figure 15.4.2-7) this effect, described in item D above, which results in the sharp peak in minimum DNBR at approximately

3×10^{-5} Δk/s, does not occur since the steam generator safety valves are never actuated prior to trip.

Figures 15.4.2-7, 15.4.2-8, and 15.4.2-9 illustrate minimum DNBR calculated for minimum and maximum reactivity feedback.

Since the RCCA withdrawal at power incident is an overpower transient, the fuel temperatures rise during the transient until after reactor trip occurs. For high reactivity insertion rates, the overpower transient is fast with respect to the fuel rod thermal time constant and the core heat flux lags behind the neutron flux response. Due to this lag, the peak core heat flux does not exceed 118 percent of its nominal value; i.e., the high neutron flux trip setpoint assumed in the analysis. Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak fuel temperature will still remain below the fuel melting temperature.

For slow reactivity insertion rates, the core heat flux remains more nearly in equilibrium with the neutron flux. The overpower transient is terminated by the OTΔT reactor trip before a DNB condition is reached. The peak heat flux again is maintained below 118 percent of its nominal value. Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak fuel centerline temperature will remain below the fuel melting temperature.

The reactor is tripped sufficiently fast during the RCCA bank withdrawal at power transient to ensure that the ability of the primary coolant to remove heat from the fuel rods is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

The calculated sequence of events for this accident is shown on table 15.4.1-1. With the reactor tripped, the plant eventually returns to a stable condition. The plant may subsequently be cooled down further by following normal plant shutdown procedures.

15.4.2.3 Conclusions

The high neutron flux and OTΔT trip channels provide adequate protection over the entire range of possible reactivity insertion rates; i.e., the minimum value of DNBR is always larger than the limiting value.

15.4.2.4 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Nonproprietary), April 1984.
2. Friedland, A. J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary), April 1989.
3. Westinghouse letter (GP-18572 dated October 14, 2009, “Transmittal of Results and Recommendations Regarding Rod Withdrawal at Power RCS Overpressurization.”

15.4.3 ROD CLUSTER CONTROL ASSEMBLY MISALIGNMENT (SYSTEM MALFUNCTION OR OPERATOR ERROR)

15.4.3.1 Identification of Causes and Accident Description

RCCA misoperation accidents include the following:

- One or more dropped RCCAs within the same group.
- A dropped RCCA bank.
- Statically misaligned RCCA.
- Withdrawal of a single RCCA.

Each RCCA has a position indicator channel which displays the position of the assembly in a display grouping that is convenient to the operator. Fully inserted assemblies are also indicated by a rod at bottom signal which actuates a local alarm and a control room annunciator. Group demand position is also indicated.

RCCAs move in preselected banks, and the banks move in the same preselected sequence. Each bank of RCCAs consists of 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) withdraws the RCCA attached to the mechanism. Mechanical failures are in the direction of insertion or immobility.

The dropped RCCAs, dropped RCCA bank, and statically misaligned RCCA events are classified as ANS Condition II incidents (incidents of moderate frequency) as defined in subsection 15.0.1. 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 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 (probability for single random failure is on the order of 10^{-6}/h (paragraph 7.7.2.2)) or multiple significant operator errors and subsequent and repeated operator disregard of event indication. The probability of such a combination of conditions is considered low such that the limiting consequences may include slight fuel damage.

Thus, consistent with the philosophy and format of American National Standards Institute 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 . . . ."

This selection of criteria is in accordance with General Design Criterion (GDC) 25, which states, "The protection system shall be designed to assure 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." (Emphases have been added.) It has been shown that single failures resulting in RCCA bank withdrawals do not violate specified fuel design limits. Moreover, no single malfunction can result in the withdrawal of a single RCCA.

Thus, it is concluded that criteria established for the single rod withdrawal at power are appropriate and in accordance with GDC 25.

The following indicators detect one or more dropped RCCAs, RCCA group, or RCCA bank:

- 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.

The following indicators detect misaligned RCCAs:

- Asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples.
- Rod deviation alarm.
- Rod position indicators.

The resolution of the rod position indicator channel is ±5 percent of span (±7.5 in.). Deviation of any RCCA from its group by twice this distance (10 percent of span or 15 in.) 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 5 percent of span. If the rod deviation alarm is not operable, the Technical Specifications require the operator to take action.

If one or more rod position indicator channel is out of service, the operator must follow detailed operating instructions to ensure the alignment of the nonindicated RCCAs. The operator is also required to take action, as required by the Technical Specifications.

In the unlikely event of simultaneous electrical failures which could result in single RCCA withdrawal, the plant annunciator will display both the rod deviation and rod control urgent failure; and the rod position indicators will indicate the relative positions of the RCCAs 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 indication. The OTΔT reactor trip provides automatic protection for this event, although due to the increase in local power density, it is not possible to always provide assurance that the core safety limits will not be exceeded.

Plant systems and equipment which are available to mitigate the effects of the various control rod misoperations are discussed in subsection 15.0.8 and listed in table 15.0.8-1. No single active failure in any of these systems or equipment will adversely affect the consequences of the accident.

15.4.3.2 Analysis of Effects and Consequences

15.4.3.2.1 Dropped RCCAs, Dropped RCCA Bank, and Statically Misaligned RCCA

15.4.3.2.1.1 Method of Analysis.

A. One or More Dropped RCCAs From the Same Group

The LOFTRAN computer code (reference 2) calculates the transient system response for the evaluation of the dropped RCCA event. The 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.

Calculated statepoints and nuclear models form the basis used to obtain a hot channel factor consistent with the primary system conditions and reactor power. By incorporating the primary conditions from the transient and the hot channel factor from the nuclear analysis, the DNB design basis is shown to be met using the VIPRE-01 code. The transient response analysis, nuclear peaking factor analysis, and performance of the DNB design basis confirmation are in accordance with the methodology described in reference 1. Note that the analysis does not take credit for the negative flux rate reactor trip.

B. Dropped RCCA Bank

A dropped RCCA bank results in a symmetric power change in the core. As discussed in reference 1, assumptions made for the dropped RCCA(s) analysis provide a bounding analysis for the dropped RCCA bank.

C. Statically Misaligned RCCA

Table 4.1-2 described the computer codes used in the analysis of steady-state power distributions. The peaking factors are then used as input to the VIPRE-01 code to calculate the DNBR. The analysis examines the case of the worst rod withdrawn from bank D inserted at the insertion limit with the reactor initially at full power. The analysis assumes this incident to occur at beginning of life since this results in the 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.

D. Single RCCA Withdrawal at Full Power

Table 4.1-2 describes the computer codes used in the calculation of power distributions within the core. The peaking factors are then used in the DNB evaluation for the event. The plant's analysis is for the case of the worst withdrawn rod from D bank inserted at the insertion limit, with the reactor initially at full power. The analysis assumes the transient to occur at beginning of life since this results in the 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.

15.4.3.2.1.2 Results.

A. 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. Power may be reestablished either by reactivity feedback or control bank withdrawal.

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.

For a dropped RCCA event in the automatic rod control mode (insertion and withdrawal), 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. Figures 15.4.3-1 and 15.4.3-2 show a typical transient response to a dropped RCCA (or RCCAs) in automatic control. Uncertainties in the initial condition are included in the DNB evaluation as described in reference 1. In all cases, the minimum DNBR remains above the limit value.

Following plant stabilization, the operator may manually retrieve the RCCA by following approved operating procedures.

B. Dropped RCCA Bank

A dropped RCCA bank results in a negative reactivity insertion greater than 500 pcm. The core is not adversely affected during the insertion period, since power is decreasing rapidly. The transient will proceed as described in part A; however, the return to power will be less due to the greater worth of the entire bank. The power transient for a dropped RCCA bank is symmetric. Following plant stabilization, normal procedures are followed.

C. 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 transient approaches the postulated conditions. 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 Core Operating Limits Report (COLR) may vary from time to time depending on several limiting criteria. The full-power insertion limits on control bank D must be chosen to be above that position which meets the minimum DNBR and peaking factors. The full power insertion limit is usually 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, DNBR does not fall below the limit value. The analysis of this case assumes that the initial reactor power, pressure, and RCS temperature are at their nominal values, with the increased radial peaking factor associated with the misaligned RCCA.

For RCCA misalignments with one RCCA fully inserted, the DNBR does not fall below the limit value. The analysis of this case assumes that initial reactor power, pressure, and RCS temperatures are at their nominal values, with the increased radial peaking factor associated with the misaligned RCCA.

DNB does not occur for the RCCA misalignment incident, thus there is no reduction in the ability of the primary coolant to remove heat from the fuel rod. 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 rate is well below that which would cause fuel melting.

After identifying an RCCA group misalignment condition, the operator must take action as required by the plant Technical Specifications and operating instructions.

D. The analysis of the single rod withdrawal event considers the following two events:

  1. If the reactor is in the manual rod 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. Depending on initial bank insertion and location of the withdrawn RCCA, automatic reactor trip may not occur quickly 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 OTΔT trip would trip the plant shows that an upper limit for the number of rods with a DNBR less than the limit value is 5 percent.
  2. If the reactor is in the automatic rod control mode, the multiple failures that result in the withdrawal of a single RCCA cause 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 quickly 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.

15.4.3.3 **Conclusions**

For cases of dropped RCCAs or dropped banks, the DNBR remains greater than the limit value; therefore, the DNB design criterion is met.

For all cases of any RCCA fully inserted, or bank D inserted to its rod insertion limits with any single RCCA in that bank fully withdrawn (static misalignment), the DNBR remains greater than the limit value.

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 DNBR is 5 percent of the total fuel rods in the core.

15.4.3.4 References

1. Haessler, R. L., et al., "Methodology For the Analysis of the Dropped Rod Event," WCAP-11394-P-A (Proprietary) and WCAP-11395-A (Nonproprietary), January 1990.
2. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Nonproprietary), April 1984.

15.4.4 STARTUP OF AN INACTIVE REACTOR COOLANT PUMP AT AN INCORRECT TEMPERATURE

15.4.4.1 Identification of Causes and Accident Description

Technical Specification 3.4.4 does not permit VEGP Units 1 and 2 operation in Modes 1 and 2 with less than four loops operating; however, this analysis assumes approximately 75-percent power in Mode 1 in order to bound Mode 3 operation where the Technical Specifications permit operation with less than four loops.

If the plant operates with one reactor coolant pump (RCP) out of service, there is reverse flow through the inactive loop due to the pressure difference across the reactor vessel. The cold leg temperature of the inactive loop is identical to the cold leg temperature of the active loops. If the reactor is operated at power, and assuming there is no isolation of the secondary side of the steam generator in the inactive loop, there is a temperature drop across the steam generator in the inactive loop and, with the reverse flow, the hot leg temperature of the inactive loop is lower than the reactor core inlet temperature.

Administrative procedures require that the unit be brought to a load of less than 25 percent of full power prior to starting the pump in an inactive loop in order to bring the inactive loop hot leg temperature closer to the core inlet temperature. Starting an idle RCP without bringing the inactive loop hot leg temperature close to the core inlet temperature would result in the injection of cold water into the core, which would cause a reactivity insertion and subsequent power increase.

If the startup of an inactive RCP accident occurs, the transient terminates automatically by a reactor trip on low coolant loop flow when the power range neutron flux (two out of four channels) exceeds the P-8 setpoint, which has been previously reset for three-loop operation.

This is an ANS Condition II incident.

15.4.4.2 Analysis of Effects and Consequences

15.4.4.2.1 Method of Analysis

The analysis of this transient uses three digital computer codes. The LOFTRAN code (reference 1) calculates the loop and core flow, nuclear power, and core pressure and temperature transients following the startup of an idle pump. FACTRAN (reference 2) calculates the core heat flux transient based on core flow and nuclear power from LOFTRAN. The THINC code is then used to calculate the DNBR during the transient based on system conditions calculated by LOFTRAN and heat fluxes calculated by FACTRAN.

Subsection 15.0.3 discusses plant characteristics and initial conditions. In order to obtain conservative results for the startup of an inactive pump accident, the following assumptions are made (this analysis employed STDP):

A. Initial conditions of maximum core power and reactor coolant average temperatures and minimum reactor coolant pressure resulting in minimum initial margin to DNB. These values are consistent with maximum steady-state power level that would be permitted with three loops in operation. The high initial power gives the greatest temperature difference between the core inlet temperature and the inactive loop hot leg temperature.

B. Following initiation of startup of the idle pump, the inactive loop flow reverses and accelerates to its nominal full-flow value in approximately 9 s.

C. The analysis assumes a conservatively large negative moderator temperature coefficient.

D. The analysis assumes a least-negative Doppler-only power coefficient.

E. The initial reactor coolant loop flows are at the appropriate values for one pump out of service.

F. The reactor trip occurs on low coolant flow when the power range neutron flux exceeds the P-8 setpoint. The P-8 setpoint is conservatively assumed to be 84 percent of rated power, which corresponds to the nominal setpoint plus 9 percent for nuclear instrumentation errors.

Plant systems and equipment which are available to mitigate the effects of the accident are discussed in subsection 15.0.8 and listed in table 15.0.8-1. No single active failure in any of these systems or equipment will adversely affect the consequences of the accident.

15.4.4.2.2 Results

The results following the startup of an idle pump with the above listed assumptions are shown in figures 15.4.4-1 through 15.4.4-5. These curves show that during the first part of the transient, the increase in core flow with cooler water results in an increase in nuclear power and a decrease in the core average temperature. The minimum DNBR during the transient is greater than the safety analysis limit values.

Reactivity addition for the inactive loop startup accident is due to the decrease in core water temperature. During the transient, this decrease is due both to the increase in reactor coolant flow and, as the inactive loop flow reverses, to the colder water entering the core from the hot leg side of the steam generator in the inactive loop. Thus, the reactivity insertion rate for this transient changes with time. The resultant core nuclear power transient, computed with consideration of both moderator and Doppler reactivity feedback effects, is shown in figure 15.4.4-1. The calculated sequence of events for this accident is shown in table 15.4.1-1. The transient results illustrated in figures 15.4.4-1 through 15.4.4-5 indicate that a stabilized plant condition, with the reactor tripped, is rapidly approached. By following normal shutdown procedures, the plant can subsequently achieve cooldown.

15.4.4.3 Conclusions

The transient results show that the core is not adversely affected. There is considerable margin to the safety analysis limit DNBRs; thus, the DNB design basis as described in section 4.4 is met.

15.4.4.4 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A, (Proprietary) and WCAP-7907-A (Nonproprietary), April 1984.
2. Hargrove, H. G., "FACTRAN--A FORTRAN-IV Code for Thermal Transients in UO_2 Fuel Rod," WCAP-7908-A, December 1989.

15.4.5 A MALFUNCTION OR FAILURE OF THE FLOW CONTROLLER IN A BOILING WATER REACTOR LOOP THAT RESULTS IN AN INCREASED REACTOR COOLANT FLOWRATE

This subsection is not applicable to the VEGP.

15.4.6 CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTION THAT RESULTS IN A DECREASE IN THE BORON CONCENTRATION IN THE REACTOR COOLANT

15.4.6.1 Identification of Causes and Accident Description

Feeding primary grade water into the RCS via the reactor makeup portion of the chemical and volume control (CVCS) adds reactivity to the core. 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 permits the operator to match the boron concentration of reactor coolant makeup water during normal charging to that in the RCS. Even under various postulated failure modes, the design of the CVCS limits the potential rate of dilution to a value which gives the operator sufficient time to correct the situation in a safe and orderly manner.

The opening of the primary water makeup control valve supplies water to the RCS which can dilute the reactor coolant. Inadvertent dilution can be readily terminated by closing one of the valves in the makeup pathway. In order to add makeup water to the RCS at pressure, at least one charging pump in addition to the primary makeup water pumps must be running. Normally, only one primary water supply pump is operating while the other is on standby.

The boric acid from the boric acid tank blends with primary grade water at the mixing tee, and the preset flowrates of boric acid and primary grade water on the control board determine the composition.

Information on the status of reactor coolant makeup is continuously available to the operator. Lights on the control board indicate the operating condition of pumps in the CVCS. Alarms actuate to warn the operator if boric acid or demineralized water flowrates deviate from preset values as a result of system malfunction.

This is an ANS Condition II incident.

15.4.6.2 Analysis of Effects and Consequences

15.4.6.2.1 Method of Analysis

To cover all phases of the plant operation, this analysis considers boron dilution during refueling, cold shutdown, hot shutdown, hot standby, startup, and power operation. The analysis assumes conservative values for the critical parameters; i.e., high RCS critical boron concentrations, most negative boron worths, minimum shutdown margins, and small RCS volumes. These result in conservative calculations of the time available for the operator to determine the cause of the addition and take corrective action before shutdown margin is lost.

A. Dilution During Refueling

This analysis evaluates boron dilution events during refueling (Mode 6). During refueling, a very small amount of unborated chemical solution is allowed to enter the RCS for water chemistry quality control. The dilution flow path is provided by opening CVCS valves 176 and 177. The maximum flowrate possible through this flow path is less than 3.5 gal/min which is approximately 3.0 percent of the limiting flowrate considered in the analysis for Modes 3, 4, and 5a. At all other times during Mode 6, valves 176 and 177 will be locked closed. Any other chemical makeup solution which is required during refueling will be borated water supplied from the refueling water storage tank by the RHR pumps.

Valves 175 and 183 in the CVCS will be locked closed or isolated by removal of control air or electrical supply during refueling operations (Mode 6). These valves will block additional flow paths which could allow unborated chemical makeup water in excess of 3.5 gal/min to reach the RCS.

B. Dilution During Cold Shutdown, Hot Shutdown, and Hot Standby

This analysis evaluates boron dilution events during cold shutdown with the RCS in the "loops filled" condition (Mode 5a), cold shutdown with the RCS in the "loop not filled" condition (midloop operation, Mode 5b), hot shutdown (Mode 4), and hot standby (Mode 3). Failure modes and effects analysis, human error analysis, and event tree analysis were used to identify credible boron dilution initiators and to evaluate the plant response to these events. For the initiators identified, time intervals from alarm to loss of shutdown margin were calculated to determine the length of time available for operator response. These calculations depended on dilution flowrates, boron concentrations, and reactor coolant system volumes specific to the event and mode of operation. The technique modeled realistic plant conditions and responses, including both mechanical failure and human errors.

The analysis identified four events considered to be the most likely initiators:

1. Demineralizer outlet isolation valve open during resin flushing.
2. Valve 226 open following BTRS demineralizer flushing operation.
3. Failure to secure chemical addition.
4. Boric acid flow control valve (FV-110A) fails closed during makeup.

Initiator 4 was found to be the most limiting event for Modes 3, 4, and 5a. For Mode 5b, initiator 3 was considered to allow the addition of small amounts of unborated chemical solution into the RCS for water chemistry control. The maximum flowrate possible through this flow path is approximately 3 percent of that associated with the limiting flow path for Modes 3, 4, and 5a. The parameters used in the calculation of time available for operator response are listed in table 15.4.6-1. Conservative values of boron worth (pcm/ppm), as a function of RCS boron concentration, were assumed in the analysis.

Since the active volumes considered are so small in Mode 5b, it was determined that the same valves locked closed in refueling (valves 175 and 183, and, except when required for small chemical additions, valves 176 and 177) would need to be locked closed in Mode 5b. (See paragraph A.)

C. Dilution During Full Power Operation, Including Startup. For the dilution during startup (Mode 2), the analysis assumes an initial maximum critical boron concentration of 2100 ppm based on the rods being inserted to the insertion limits. The analysis assumes the minimum change in the boron concentration from this initial condition to a hot zero power critical condition to be 300 ppm. The analysis also assumes full rod insertion to occur due to reactor trip, minus the most reactive stuck rod. The analysis assumes the dilution flow to be the combined capacity of the two primary water makeup pumps (approximately 242 gal/min) and a minimum RCS water volume of 9583 ft^3. This volume corresponds to the active volume of the RCS minus the pressurizer and accounts for 10-percent steam generator tube plugging.

During power operation (mode 1), the plant operates under either manual or automatic rod control. While the plant is in manual control, the analysis assumes the dilution flow to be a maximum of 242 gal/min, which is the combined capacity of the two primary water makeup pumps. While in automatic control, the maximum letdown flow (approximately 130 gal/min) limits the dilution flow. The analysis assumes an initial maximum critical boron concentration, corresponding to the rods inserted to the insertion limits at hot full power, of 2100 ppm. The analysis also assumes the minimum change in the boron concentration from this initial condition to a hot zero power critical condition to be 300 ppm. The analysis assumes full rod insertion to occur due to reactor trip, minus the most reactive stuck rod. The analysis uses a minimum water volume of 9583 ft^3 in the RCS, corresponding to the active volume of the RCS minus the pressurizer volume and accounts for 10-percent tube plugging.

No single active failure in any plant systems or equipment will adversely affect the consequences of the accident.

15.4.6.2.2 Results

The calculated sequence of events is shown in table 15.4.1-1.

A. Dilution During Refueling

Since the maximum flowrate associated with the available dilution flow paths in mode 6 is very small, the total time from initiation of event to the eventual complete loss of shutdown margin is significantly large compared to the minimum required operator action time. Therefore, a considerable amount of time is available for the operator to initiate and terminate procedures for RCS water chemistry adjustments before potential loss of shutdown becomes a concern. Additionally, assuming the availability of one high flux at shutdown (HFAS) alarm set at not more than 2.3 times background, it is shown that the technical specification shutdown margin requirement for mode 6 is sufficient to ensure that the operator has 30 minutes from the time of alarm to terminate the dilution before shutdown margin is lost.

B. Dilution During Cold Shutdown, Hot Shutdown, and Hot Standby

For dilution during cold shutdown, hot shutdown, and hot standby, the Core Operating Limits Report (COLR) provides the required shutdown margin as a function of RCS boron concentration. The specified shutdown margin ensures that the operator has 15 min from the time of the HFAS alarm to the total loss of shutdown margin due to initiator 4, which is the limiting case for Modes 3, 4, and 5a. Since the maximum flowrate associated with the available dilution flow paths in Mode 5b is very small, the total time from initiation of event to the eventual complete loss of shutdown margin is significantly large compared to the minimum required operator action time of 15 minutes.

C. Dilution During Full Power Operation, Including Startup

In the event of an unplanned approach to criticality or dilution during power escalation while in the startup mode, the operator is alerted to an unplanned dilution by a reactor trip at the power range neutron flux high, low setpoint. After reactor trip there are at least 15 minutes for operator action prior to loss of shutdown margin.

During full power operation with the reactor in manual control, the operator is alerted to an uncontrolled dilution by an OTΔT reactor trip. At least 15 minutes are available after the trip for operator action prior to loss of shutdown margin.

During full power operation with the reactor in automatic control, the operator is alerted to an uncontrolled reactivity insertion by the rod insertion limit alarms. At least 15 minutes are available for operator action from the low-low rod insertion limit alarm until a loss of shutdown margin occurs.

15.4.6.3 Conclusions

The results presented above show that adequate time is available for the operator to manually terminate the source of dilution flow. Following termination of the dilution flow, the operator can initiate boration to establish adequate shutdown margin.

15.4.7 INADVERTENT LOADING AND OPERATION OF A FUEL ASSEMBLY IN AN IMPROPER POSITION

15.4.7.1 Identification of Causes and Accident Description

Fuel- and core-loading errors such as can arise from the inadvertent loading of one or more fuel assemblies into improper positions, loading a fuel rod during manufacture with one or more pellets of the wrong enrichment, or loading a full fuel assembly during manufacture with pellets of the wrong enrichment, will lead to increased heat fluxes if the error results in placing fuel in core positions calling for fuel of lesser enrichment. Also included among possible core-loading errors is the inadvertent loading of one or more fuel assemblies requiring burnable poison rods into a new core without burnable poison rods.

Any error in enrichment, beyond the normal manufacturing tolerances, can cause power shapes which are more peaked than those calculated with the correct enrichments. There is a 5-percent uncertainty margin included in the design value of power peaking factor assumed in the analysis of Condition I and Condition II transients. The in-core system of movable flux detectors which is used to verify power shapes at the start of life is capable of revealing any assembly enrichment error or loading error which causes power shapes to be peaked in excess of the design value.

To reduce the probability of core loading errors, each fuel assembly is marked with an identification number and loaded in accordance with a core-loading diagram. During core loading, the identification number will be checked before each assembly is moved into the core. Serial numbers read during fuel movement are subsequently recorded on the loading diagram as a further check on proper placing after the loading is completed.

The power distortion due to any combination of misplaced fuel assemblies would significantly raise peaking factors and would be readily observable with in-core flux monitors. In addition to the flux monitors, thermocouples are located at the outlet of about one-third of the fuel assemblies in the core. There is a high probability that these thermocouples would also indicate any abnormally high coolant temperature rise. In-core flux measurements are taken during the startup subsequent to every refueling operation.

This event is classified as an American Nuclear Society Condition III incident (an infrequent fault) as defined in subsection 15.0.1.

15.4.7.2 Analysis of Effects and Consequences

15.4.7.2.1 Method of Analysis

Steady-state power distributions in the x-y plane of the core are calculated using the TURTLE code(1) based on macroscopic cross section calculated by the LEOPARD code.(2) A discrete representation is used wherein each individual fuel rod is described by a mesh interval. Representative power distributions in the x-y plane for a correctly loaded core assembly are also given in chapter 4.

For each core loading error case analyzed, the percent deviations from detector readings for a normally loaded core are shown in all in-core detector locations. (See figures 15.4.7-1 through 15.4.7-5.)

15.4.7.2.2 Results

The following core loading error cases have been analyzed:

Case A:

Case in which a region 1 assembly is interchanged with a region 3 assembly. The particular case considered was the interchange to two adjacent assemblies near the periphery of the core. (See figure 15.4.7-1.)

Case B:

Case in which a region 1 assembly is interchanged with a neighboring region 2 fuel assembly. Two analyses have been performed for this case. (See figures 15.4.7-2 and 15.4.7-3.)

In Case B-1, the interchange is assumed to take place with the burnable poison rods transferred with the region 2 assembly mistakenly loaded into region 1.

In Case B-2, the interchange is assumed to take place closer to core center and with burnable poison rods located in the correct region 2 position but in a region 1 assembly mistakenly loaded in the region 2 position.

Case C:

Enrichment error: Case in which a region 2 fuel assembly is loaded in the core central position. (See figure 15.4.7-4.)

Case D:

Case in which a region 2 fuel assembly instead of a region 1 assembly is loaded near the core periphery. (See figure 15.4.7-5.)

15.4.7.3 Conclusions

Fuel assembly enrichment errors would be prevented by administrative procedures implemented in fabrication.

In the event that a single pin or pellet has a higher enrichment than the nominal value, the consequences in terms of reduced departure from nucleate boiling ratio and increased fuel and clad temperatures will be limited to the incorrectly loaded pin or pins and perhaps the immediately adjacent pins.

Fuel assembly loading errors are prevented by administrative procedures implemented during core loading. In the unlikely event that a loading error occurs, analyses in this section confirm that resulting power distribution effects will either be readily detected by the in-core movable detector system or will cause a sufficiently small perturbation to be acceptable within the uncertainties allowed between nominal and design power shapes.

15.4.7.4 References

1. Barry, R. F., and Altomore, A., "The TURTLE 24.0 Diffusion Depletion Code," WCAP-7213-P-A (Proprietary) and WCAP-7758-A (Nonproprietary), February 1975.
2. Barry, R. F., "LEOPARD - A Spectrum Dependent Non-Spacial Depletion Code for the IBM-7094," WCAP-3269-26, September 1963.

15.4.8 SPECTRUM OF ROD CLUSTER CONTROL ASSEMBLY EJECTION ACCIDENTS

15.4.8.1 Identification of Causes and Accident Description

This accident is defined as the mechanical failure of a control rod mechanism pressure housing, resulting in the ejection of a rod cluster control assembly (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.

15.4.8.1.1 Design Precautions and Protection

Certain features in the VEGP reactors are intended to preclude the possibility of a rod ejection accident or to limit the consequences if the accident occurs. These include a sound, conservative mechanical design of the rod housings, together with a thorough quality control (testing) program during assembly, and a nuclear design which lessens the potential ejection worth of RCCAs and minimizes the number of assemblies inserted at high-power levels.

15.4.8.1.1.1 Mechanical Design. The mechanical design is discussed in section 4.6. Mechanical design and quality control procedures intended to preclude the possibility of an RCCA drive mechanism housing failure are listed below:

A. Each control rod drive mechanism housing is completely assembled and shop tested at 4100 psi.

B. 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 reactor coolant system (RCS).

C. 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 range specified by the American Society of Mechanical Engineers Code, Section III, for Class 1 components.

D. 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 which will be encountered.

A significant margin of strength in the elastic range together with the large energy absorption capability in the plastic range gives additional assurance that gross failure of the housing will not occur. The joints between the latch mechanism housing and head adapter, and between the latch mechanism housing and rod travel housing, are threaded joints reinforced by canopy-type rod welds which are subject to periodic inspections.

15.4.8.1.1.2 Nuclear Design. Even if a rupture of an RCCA drive mechanism housing is postulated, the operation utilizing chemical shim is such that the severity of an ejected RCCA is inherently limited. In general, the reactor is operated with the RCCA inserted only far enough to permit load follow. Reactivity changes caused by core depletion and xenon transients are compensated for by boron changes. Further, the location and grouping of control RCCA banks are selected during the nuclear design to lessen the severity of an RCCA ejection accident. Therefore, should an RCCA be ejected from its normal position during full-power operation, only a minor reactivity excursion, at worst, could be expected to occur.

However, it may be occasionally desirable to operate with larger than normal insertions. For this reason, a rod insertion limit is defined as a function of power level. Operation with the RCCAs above this limit guarantees adequate shutdown capability and acceptable power distribution. The position of all RCCAs is continuously indicated in the control room. An alarm will occur if a bank of RCCAs approaches its insertion limit or if one RCCA deviates from its bank. Procedures require action per the Technical Specifications if shutdown or control RCCA banks are below insertion limits.

15.4.8.1.1.3 Reactor Protection. The reactor protection in the event of a rod ejection accident has been described in reference 1. The protection for this accident is provided by high neutron flux trip (high and low setting) and high rate of neutron flux increase trip. These protection functions are described in detail in section 7.2.

15.4.8.1.1.4 Effects on Adjacent Housings. Disregarding the remote possibility of the occurrence of an RCCA mechanism housing failure, investigations have shown that failure of a housing due to either longitudinal or circumferential cracking would not cause damage to adjacent housings. The control rod drive mechanism is described in paragraph 3.9.4.1.1.

15.4.8.1.1.5 Effects of Rod Travel Housing Longitudinal Failures. If a longitudinal failure of the rod travel housing should occur, the region of the position indicator assembly opposite the break would be stressed by the reactor coolant pressure of 2250 psia. The most probable leakage path would be provided by the radial deformation of the position indicator coil assembly, resulting in the growth of axial flow passages between the rod travel housing and the hollow tube along which the coil assemblies are mounted.

If failure of the position indicator coil assembly should occur, the resulting free radial jet from the failed housing could cause it to bend and contact adjacent rod housings. If the adjacent housings were on the periphery, they might bend outward from their bases. The housing material is quite ductile; plastic hinging without cracking would be expected. Housings adjacent to a failed housing, in locations other than the periphery, would not be bent because of the rigidity of multiple adjacent housings.

15.4.8.1.1.6 Effect of Rod Travel Housing Circumferential Failures. If circumferential failure of a rod travel housing should occur, the broken-off section of the housing would be ejected vertically because the driving force is vertical and the position indicator coil assembly and the drive shaft would tend to guide the broken-off piece upwards during its travel. Travel is limited by the missile shield, thereby limiting the projectile acceleration. When the projectile reached the missile shield, it would partially penetrate the shield and dissipate its kinetic energy. The water jet from the break would continue to push the broken-off piece against the missile shield.

If the broken-off piece of the rod travel housing were short enough to clear the break when fully ejected, it would rebound after impact with the missile shield. The top end plates of the position indicator coil assemblies would prevent the broken piece from directly hitting the rod travel housing of a second drive mechanism. Even if a direct hit by the rebounding piece were to occur, the low kinetic energy of the rebounding projectile would not be expected to cause significant damage (sufficient to cause failure of an adjacent housing).

15.4.8.1.1.7 Possible Consequences. From the above discussion, the probability of damage to an adjacent housing must be considered remote. However, even if damage is postulated, it would not be expected to lead to a more severe transient since RCCAs are inserted in the core in symmetric patterns, and control rods immediately adjacent to worst ejected rods are not in the core when the reactor is critical. Damage to an adjacent housing could, at worst, cause that RCCA not to fall on receiving a trip signal; however, this is already taken into account in the analysis by assuming a stuck rod adjacent to the ejected rod.

15.4.8.1.1.8 Summary. The considerations given above lead to the conclusion that failure of a control rod housing, due either to longitudinal or circumferential cracking, would not cause damage to adjacent housings that would increase severity of the initial accident.

15.4.8.1.2 Limiting Criteria

This event is classified as an American Nuclear Society (ANS) Condition IV incident. See subsection 15.0.1 for a discussion of ANS classifications. Due to the extremely low probability of an RCCA ejection accident, some fuel damage would be considered an acceptable consequence.

Comprehensive studies of the threshold of fuel failure and of the threshold of significant conversion of the fuel thermal energy to mechanical energy have been carried out as part of the SPERT project by the Idaho Nuclear Corporation.(2) Extensive tests of UO_2 zirconium-clad fuel rods representative of those in pressurized water reactor-type cores such as VEGP have demonstrated failure thresholds in the range of 240 to 257 cal/g. However, other rods of a slightly different design have exhibited failure as low as 225 cal/g. These results differ significantly from the TREAT(3) results, which indicated a failure threshold of 280 cal/g. Limited results have indicated that this threshold decreases by about 10 percent with fuel burnup. The clad failure mechanism appears to be melting for zero burnup rods and brittle fracture for irradiated rods. Also important is the conversion ratio of thermal to mechanical energy. This ratio becomes marginally detectable above 300 cal/g for unirradiated rods and 200 cal/g for irradiated rods; catastrophic failure (large fuel dispersal, large pressure rise), even for irradiated rods, did not occur below 300 cal/g.

In view of the above experimental results and conformance with Regulatory Guide 1.77 (subsection 1.9.77), criteria are applied to ensure that there is little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These limiting criteria are as follows (reference 9):

A. Average fuel pellet enthalpy at the hot spot will be below 200 cal/g for unirradiated fuel and irradiated fuel.

B. Peak reactor coolant pressure will be less than that which could cause stresses to exceed the faulted condition stress limits.

C. Fuel melting will be limited to less than 10 percent of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits of criterion A, above.

15.4.8.2 Analysis of Effects and Consequences

A. Method of Analysis

The calculation of the RCCA ejection transient is performed in two stages, first an average core channel calculation and then, a hot region calculation. The average core calculation is performed using spatial neutron kinetics methods to determine the average power generation with time including the various total core feedback effects; i.e., Doppler reactivity and moderator reactivity. Enthalpy and temperature transients at the hot spot are 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 is conservatively assumed to persist throughout the transient.

A detailed discussion of the method of analysis can be found in reference 1.

B. Average Core Analysis

The spatial kinetics computer code, TWINKLE,(4) is used for the average core transient analysis. This code uses cross sections generated by LEOPARD(5) to solve 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 2000 spatial points. The computer code includes a detailed multiregion, transient fuel clad coolant heat transfer model for calculation of pointwise Doppler and moderator feedback effects. In this analysis, the code is used as a one-dimensional 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 is missing, it is still necessary to employ conservative methods (described below) of calculating the ejected rod worth and hot channel factor. Further description of TWINKLE appears in subsection 15.0.11.

C. Hot Spot Analysis

In the hot spot analysis, the initial heat flux is equal to the nominal volume multiplied by the design hot channel factor. During the transient, the heat flux hot channel factor is linearly increased to the transient value in 0.1 s, the time for full ejection of the rod. Therefore, the assumption is made that the hot spots before and after ejection are coincident. This is 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 be depressed due to the inserted rod.

The hot spot analysis is performed using the detailed fuel and clad transient heat transfer computer code, FACTRAN.(6) 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 as input the nuclear power versus time and the local coolant conditions. The zirconium-water reaction is explicitly represented, and all material properties are represented as functions of temperature. A conservative radial power distribution is used within the fuel rod.

FACTRAN uses the Dittus-Boelter or Jens-Lottes correlation to determine the film heat transfer before departure from nucleate boiling (DNB) and the Bishop-Sandburg-Tong correlation(7) to determine the film boiling coefficient after DNB. The Bishop-Sandburg-Tong correlation is conservatively used, assuming zero-bulk fluid quality. The departure from nucleate boiling ratio is not calculated; instead, the code is forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient can be calculated by the code; however, it is adjusted in order to force the full-power, steady-state temperature distribution to agree with the fuel heat transfer design codes. Further description of FACTRAN appears in subsection 15.0.11.

D. System Overpressure Analysis

Because safety limits for fuel damage specified earlier are not exceeded, there is little likelihood of fuel dispersal into the coolant. The pressure surge may therefore be calculated on the basis of conventional heat transfer from the fuel and prompt heat absorption by the coolant.

The pressure surge is calculated by first performing the fuel heat transfer calculation to determine the average and hot spot heat flux versus time. Using this heat flux data, a core thermal-hydraulic calculation is conducted to determine the volume surge. Finally, the volume surge is simulated using the LOFTRAN computer code. This code calculates the pressure transient taking into account fluid transport in the RCS and heat transfer to the steam generators. No credit is taken for the possible pressure reduction caused by the assumed failure of the control rod pressure housing.

15.4.8.2.1 Calculation of Basic Parameters

Input parameters for the analysis are conservatively selected on the basis of values calculated for this type of core. The more important parameters are discussed below. Table 15.4.8-1 presents the parameters used in this analysis.

15.4.8.2.1.1 Ejected Rod Worths and Hot Channel Factors. The values for ejected rod worths and hot channel factors are calculated using either three-dimensional static methods or by a synthesis method employing one-dimensional and two-dimensional calculations. Standard nuclear design codes are used in the analysis. No credit is taken for the flux flattening effects of reactivity feedback. The calculation is performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. Adverse xenon distributions are considered in the calculation.

Appropriate margins are added to the ejected rod worth and hot channel factors to account for any calculational uncertainties, including an allowance for nuclear peaking due to densification.

Power distributions before and after ejection for a worst case can be found in reference 1. During initial plant startup physics testing, ejected rod worths and power distributions are measured in the zero-power and part power configurations and compared to values used in the analysis. Experience shows that the ejected rod worth and power peaking factors are consistently overpredicted in the analysis.

15.4.8.2.1.2 Reactivity Feedback Weighting Factors. The largest temperature rises and hence 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 performed 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, since a one-dimensional (axial) spatial kinetics method is employed, axial weighting is not necessary if the initial condition is made to match the ejected rod configuration. In addition, no weighting is applied to the moderator feedback. A conservative radial weighting factor is 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 three-dimensional analysis.(1)

15.4.8.2.1.3 Moderator and Doppler Coefficient. The critical boron concentrations at the beginning of life and end of life are adjusted in the nuclear code in order to obtain moderator density coefficient curves which are conservative compared to actual design conditions for the plant. As discussed above, no weighting factor is applied to these results.

The Doppler reactivity defect is determined as a function of power level using a one-dimensional, steady-state computer code with a Doppler weighting factor of 1.0. The Doppler defect used is given in subsection 15.0.4. The Doppler weighting factor will increase under accident conditions, as discussed above.

15.4.8.2.1.4 Delayed Neutron Fraction, β_{eff}. Calculations of the effective delayed neutron fraction (β_{eff}) typically yield values no less than 0.70 percent at beginning of life and 0.50 percent at end of life for the first cycle. The accident is sensitive to β_{eff} if the ejected rod worth is equal to or greater than β_{eff} as in zero-power transients. To allow for future cycles, the analysis used conservative β_{eff} estimates of 0.54 percent at beginning-of-life hot zero power, 0.57 percent at beginning-of-life hot full power, and 0.46 percent for both end-of-life cases.

15.4.8.2.1.5 Trip Reactivity Insertion. The trip reactivity insertion assumed is given in table 15.4.8-1 and includes the effect of one stuck RCCA adjacent to the ejected rod. These values are 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 s after the high neutron flux trip point was reached. This delay is assumed to consist of 0.2 s for the instrument channel to produce a signal, 0.15 s for the trip breaker to open, and 0.15 s for the coil to release the rods. A curve of trip rod insertion versus time was used which assumed that insertion to the dashpot does not occur until 3.3 s after the start of fall. The choice of such a conservative insertion rate means that there is over 1 s after the trip point is reached before significant shutdown reactivity is inserted into the core. This is particularly important conservatism for hot full-power (HFP) accidents.

The minimum design shutdown margin available for this plant at hot zero power (HZP) may be reached only at end of life in the equilibrium cycle. This value includes an allowance for the worst stuck rod, adverse xenon distribution, conservative Doppler and moderator defects, and an allowance for calculational uncertainties. Physics calculations for this plant have shown that the effect of two stuck RCCAs (one of which is the worst ejected rod) is to reduce the shutdown by about an additional 1-percent □k/k. Therefore, following a reactor trip resulting from an RCCA ejection accident, the reactor will be subcritical when the core returns to HZP.

Depressurization calculations have been performed for a typical four-loop plant, assuming the maximum possible size break (2.75-in. diameter) located in the reactor pressure vessel head. The results show a rapid pressure drop and a decrease in system water mass due to the break. The safety injection system is actuated on low pressurizer pressure within 1 min after the break. The RCS pressure continues to drop and reaches saturation (1200 psi) in about 2 to 3 min. Due to the large thermal inertia of primary and secondary systems, there has been no significant decrease in the RCS temperature below no-load by this time, and the depressurization itself has caused an increase in shutdown margin by about 0.2-percent Δk due to the pressure coefficient. The cooldown transient could not absorb the available shutdown margin until more than 10 min after the break. The addition of borated (2400 ppm) safety injection flow starting 1 min after the break is much more than sufficient to ensure that the core remains subcritical during the cooldown.

15.4.8.2.1.6 Reactor Protection. As discussed in paragraph 15.4.8.1.1.3, reactor protection for a rod ejection is provided by high neutron flux trip (high and low setting) and high positive rate of neutron flux increase trip; however, the analysis only models the high neutron flux trip. These protection functions are part of the reactor trip system. No single failure of the reactor trip system will negate the protection functions required for the rod ejection accident or adversely affect the consequences of the accident.

No single active failure in any plant systems or equipment will adversely affect the consequences of the accident.

15.4.8.2.1.7 Results. Cases are presented for both beginning and end of life at zero and full power.

A. 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/k and 5.5, respectively. The peak hot spot fuel centerline temperature reached melting at 4900°F. However, melting was restricted to less than 10 percent of the pellet volume at the hot spot.

B. Beginning of Cycle, Zero Power

For this condition, control bank D was assumed to be fully inserted and banks B and C were at their insertion limits. The worst ejected rod is located in control bank D and has a worth of 0.75-percent Δk/k and a hot channel factor of 11.0. The fuel center temperature was 3985°F.

C. 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/k and 6.0, respectively.

The peak hot spot fuel centerline temperature reached melting at 4800°F. However, melting was restricted to less than 10 percent of the pellet volume at the hot spot.

D. End of Cycle, Zero Power

The ejected rod worth and hot channel factor for this case were obtained assuming control bank D to be fully inserted with banks C and B at their insertion limits. The results were 0.84-percent Δk/k and 26.0, respectively. The fuel centerline temperature was 3891°F. The Doppler weighting factor for this case is significantly higher than for the other cases due to the very large transient hot channel factor.

For all four cases analyzed, average fuel pellet enthalpy at the hot spot remained below 200 cal/g.

A summary of the cases presented above is given in table 15.4.8-1. The nuclear power and hot spot fuel and clad temperature transients for the worst cases are presented in figures 15.4.8-1 through 15.4.8-4.

The calculated sequence of events for the worst case rod ejection accidents, as shown in figures 15.4.8-1 through 15.4.8-4, is presented in table 15.4.8-1. For all cases, reactor trip occurs early in the transient after the nuclear power excursion is terminated by Doppler feedback. As discussed previously in paragraph 15.4.8.2.1, the reactor remains subcritical following reactor trip.

The ejection of an RCCA constitutes a break in the RCS, located in the reactor pressure vessel head. The effects and consequences of loss-of-coolant accidents (LOCAs) are discussed in subsection 15.6.5. Following the RCCA ejection, the operator would follow the same emergency instructions as for any other LOCA to recover from the event.

15.4.8.2.1.8 Fission Product Release. It is assumed that fission products are released from the gaps of all rods entering DNB. In all cases considered, less than 10 percent of the rods entered DNB based on a detailed three-dimensional THINC analysis.(1) Although limited fuel melting at the hot spot was predicted for the full-power cases, in practice, melting is not expected since the analysis conservatively assumed that the hot spots before and after ejection were coincident.

15.4.8.2.1.9 Pressure Surge. A detailed calculation of the pressure surge for an ejection worth of one dollar at beginning of life, hot full power, indicates that the peak pressure does not exceed that which would cause stress to exceed the faulted condition stress limits.(2) Since the severity of the present analysis does not exceed the worst-case analysis, the accident for this plant will not result in an excessive pressure rise or further damage to the RCS.

15.4.8.2.1.10 Lattice Deformations. A large temperature gradient will exist in the region of the hot spot. Since the fuel rods are free to move in the vertical direction, differential expansion between separate rods cannot produce distortion. However, the temperature gradients across individual rods may produce a differential expansion tending to bow the midpoint of the rods toward the hotter side of the rod. Calculations have indicated that this bowing would result in a negative reactivity effect at the hot spot since Westinghouse cores are undermoderated, and bowing will tend to increase the undermoderation at the hot spot. In practice, no significant bowing is anticipated, since the structural rigidity of the core is more than sufficient to withstand the forces produced. Boiling in the hot spot region would produce a net flow away from that region. However, the heat from the fuel is released to the water relatively slowly, and it is considered inconceivable that crossflow will be sufficient to produce sufficient lattice forces. Even if massive and rapid boiling, sufficient to distort the lattice, is hypothetically postulated, the large void fraction in the hot spot region would produce a reduction in the total core moderator to fuel ratio and a large reduction in this ratio at the hot spot. The net effect would therefore be a negative feedback. It can be concluded that no conceivable mechanism exists for a net positive feedback resulting from lattice deformation. In fact, a small negative feedback may result. The effect is conservatively ignored in the analysis.

15.4.8.3 Radiological Consequences

The evaluation of the radiological consequences of a postulated control rod ejection accident assumes that the reactor has been operating with a small percent of defective fuel and leaking generator tubes for sufficient time to establish equilibrium concentrations of radionuclides in the reactor coolant and in the secondary coolant.

As a result of the accident, a fraction of the fuel rods will undergo DNB and will release gap inventory to the reactor coolant. Additionally, a small fraction of fuel is assumed to melt and release core inventory to the reactor coolant. Radionuclides carried by the primary coolant to the steam generators via leaking tubes are released to the environment via the steam line safety or power-operated relief valves. Radionuclides released to the containment via the spill from the reactor vessel head are released to the environment via containment leakage.

15.4.8.3.1 Analytical Assumptions

The major assumptions and parameters used in the analysis are itemized in table 15.4.8-2. The following is a more detailed discussion of the source term.

15.4.8.3.1.1 Source Term Calculations. The concentration of nuclides in the primary and secondary system prior to and following the rod ejection accident are determined as follows:

A. The iodine activity in the reactor coolant prior to the accident is based upon an iodine spike which has raised the reactor coolant concentration to 60 µCi/g of dose equivalent (DE) I-131.

B. The noble gas concentrations in the reactor coolant are based upon 1-percent defective fuel.

C. Following the rod ejection accident, 10 percent of the fuel rods in the core undergo DNB. Hence, 10 percent of the core iodine and noble gas gap inventory is released to the reactor coolant. In addition, 0.25 percent of the fuel in the core is assumed to melt and release 0.00125 of the core iodines and 0.0025 of the core noble gases to the reactor coolant.

D. The secondary coolant iodine activity is based on the DE of 0.1 µCi/g of I-131.

15.4.8.3.1.2 Mathematical Models Used in the Analysis. Mathematical models used in the analysis are described in the following sections:

A. The mathematical models used to analyze the activity released during the course of the accident are described in appendix 15A.

B. The atmospheric dispersion factors used in the analysis were calculated based on the onsite meteorological measurement programs described in subsection 2.3.3.

C. The thyroid inhalation dose and total-body gamma immersion doses to a receptor at the exclusion area boundary and outer boundary of the low population zone were analyzed using the models described in appendix 15A.

15.4.8.3.1.3 Identification of Leakage Pathways and Resultant Leakage Activity. Radionuclides carried from the primary coolant to the steam generators via leaking tubes are released to the environment via the steam line safety or power-operated relief valves. Iodines are assumed to mix with the secondary coolant and partition between the generator liquid and steam before release to the environment. Noble gases are assumed to be directly released.

Forty-five percent of the iodines and one hundred percent of the noble gases carried by the primary coolant spill are released to the containment vapor space and are leaked to the environment at the containment design leak rate. For the iodine release, 39 percent of the break flow is assumed to initially flash to vapor and 10 percent of the nonflashed portion is assumed to become airborne; i.e., 0.39 + 10 percent of 0.61 for a total of 0.45.

All activity is released to the environment with no consideration given to radioactive decay or to cloud depletion by ground deposition during transport to the exclusion area boundary and low population zone. Hence, the resultant radiological consequences represent the most conservative estimate of the potential integrated dose due to the postulated rod ejection accident.

15.4.8.3.2 Identification of Uncertainties and Conservative Elements in the Analysis

A. The initial reactor coolant iodine activity is based on the technical specification limit of 1.0 μCi/g of DE I-131 which is further increased by a large preaccident iodine spike to 60 μCi/g, resulting in equivalent concentrations many times greater than the reactor coolant activities based on 0.12-percent defective fuel and expected iodine spiking values associated with normal operating conditions.

B. The noble gas activities are based on 1-percent defective fuel which cannot exist simultaneously with 1.0-μCi/g I-131. For iodines, 1-percent defects would be approximately three times the technical specification limit.

C. The fraction of failed fuel is assumed to be equal to the fraction of fuel rods experiencing DNB, without consideration given to the extent of the zirc-water reaction. Based on experimental data(8) no oxidation related fuel rod clad failure is predicted. Likewise, the small amount of melted fuel assumed (0.25 percent) is not predicted.

D. A 1-gal/min steam generator primary-to-secondary leakage is assumed, which is significantly greater than that anticipated during normal operation.

E. The meteorological conditions which may be present at the site during the course of the accident are uncertain. However, it is highly unlikely that the assumed meteorological conditions would be present during the course of the accident for any extended period of time. Therefore, the radiological consequences evaluated, based on the meteorological conditions assumed, are conservative.

15.4.8.3.3 Conclusions

15.4.8.3.3.1 Filter Loadings. The only engineered safety feature filtration system considered in the analysis which limits the consequences of the rod ejection accident is the control room filtration system.

Integrated activity on the control room filters have been evaluated for the more limiting LOCA analysis as discussed in paragraph 15.6.5.4.6. Since the control room filters are capable of accommodating the potential design basis LOCA fission product iodine loadings, there will be sufficient capacity to accommodate any fission product loading due to a postulated rod ejection accident.

15.4.8.3.3.2 Dose to Receptor at the Exclusion Area Boundary and Low Population Zone Outer Boundary. The potential radiological consequences resulting from the occurrence of a postulated rod ejection accident have been conservatively analyzed using assumptions and models described. The total-body gamma dose due to immersion from direct radiation and the thyroid dose due to inhalation have been analyzed for the 0- to 2-h dose at the exclusion area boundary and for the duration of the accident (0 to 30 days) at the low population zone outer boundary. The results are listed in table 15.4.8-3. The resultant doses are well within the guideline values of 10 CFR 100.

15.4.8.4 References

1. Risher, D. H., Jr., "An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Spatial Kinetics Methods," WCAP-7588, Revision 1A, January 1975.
2. Taxelius, T. G., ed, "Annual Report-Spert Project, October 1968, September 1969," Idaho Nuclear Corporation, IN-1370, June 1970.
3. Liimataninen, R. C., and Testa, F. J., "Studies in TREAT of Zircaloy-2-Clad, UO_2-Core Simulated Fuel Elements," ANL-7225, January-June 1966, p 177, November 1966.
4. Risher, D. H., Jr., and Barry, R. F., "TWINKLE--A Multi- Dimensional Neutron Kinetics Computer Code," WCAP-7979-P-A (Proprietary) and WCAP-8028-A (Nonproprietary), January 1975.
5. Barry, R. F., "LEOPARD--A Spectrum Dependent or Non-Spacial Depletion Code for the IBM-7904," WCAP-3269-26, September 1963.
6. Hargrove, H. G., "FACTRAN-A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," WCAP-7908-A, December 1989.
7. Bishop, A. A., Sandburg, R. O., and Tong, L. S., "Forced Convection Heat Transfer at High Pressure After the Critical Heat Flux," ASME 65-HT-31, August 1965.
8. Van Houten, R., "Fuel Rod Failure as a Consequence of Departure from Nucleate Boiling or Dryout," NUREG-0562, June 1979.
9. Johnson, V. J., "Use of 2700°F PCT Acceptance Limit in Non-LOCA Accidents," NS-NRC-89-3466, October 23, 1989.

15.4.9 STEAMLINE BREAK WITH COINCIDENTAL ROD CLUSTER CONTROL ASSEMBLY WITHDRAWAL AT POWER

The automatic rod withdrawal capability of the rod control system is disabled for Vogtle Unit 1 and Unit 2. Physically disabling the automatic rod withdrawal capability eliminates the possibility that a steam line break event will result in a consequential and coincidental rod withdrawal. The analysis presented in this section is retained for historical purposes.

15.4.9.1 Introduction

The coincidental and consequential occurrence of an uncontrolled RCCA bank withdrawal at power following steamline break event is one of four potential interaction scenarios resulting from adverse environmental conditions (either inside or outside of containment) following a high energy line break; these scenarios are identified in "IE Information Notice 79-22." The premise of this concern is that during a high energy line break (such as steamline rupture), certain sensors used in the control systems could be exposed to an adverse environment. If the equipment is not qualified for the adverse environment, a control system malfunction might occur.

The automatic rod control system is one of the control systems that could malfunction. The rod control system relies on the measurement of T_{avg}, nuclear power, and turbine impulse pressure to determine if control rod motion is required. A small steamline rupture may occur outside containment near the turbine impulse pressure transmitters or inside containment in the vicinity of the excore detectors, thus exposing equipment used in the rod control system to an adverse environment. If this equipment is not properly qualified for these conditions, a consequential RCCA withdrawal following a steamline rupture may occur.

The steamline break affects the rod control system (via either an inside containment break near the excore detectors or an outside containment break near the turbine impulse transmitters) and causes the control rods to withdraw following the initiation of the transient. This causes an increase in reactor power and core heat flux to the point at which an OPΔT trip setpoint is reached. This trip terminates the most adverse part of the transient. The steamline break causes increased heat removal and subsequent decrease in primary pressure simultaneous with the increase in reactor power. Secondary pressure also decreases until the low steamline pressure setpoint is reached, initiating steamline isolation and safety injection actuation.

Because of the lower RCS pressure coincident with the increase in reactor power, the consequences at the point of peak heat flux may be more adverse than the RCCA bank withdrawal at power transient analyzed in the FSAR.

The most limiting part of this transient pertinent to this study is immediately before reactor trip (i.e., rod motion). The most limiting case is that for the largest steamline break that trips on OPΔT prior to reaching a reactor trip on a safety injection signal (e.g., low steamline pressure). Therefore, the analysis assumes the largest steamline break size for which a low steamline pressure signal will not occur prior to the OPΔT reactor trip, and the analysis terminates 5 seconds after reactor trip. "Steam System Piping Failure" presented in subsection 15.1.5 bounds the return to power following reactor trip and steamline isolation. If the low steamline pressure setpoint is reached, a reactor trip on safety injection actuation would result and terminate the event. Therefore, like the analysis performed for "Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power" (subsection 15.4.2), to demonstrate protection by the ΔT trips, only the applicable range of these trips needs to be considered. Also note that no credit is taken in the steamline break with coincident rod withdrawal at power analysis for a reactor trip via the high neutron flux overpower protection signal, since this trip function may be inoperable due to adverse environmental conditions associated with a steamline break inside containment.

The performance of the analysis for a steamline break with coincident withdrawal of the control rods due to an adverse environment demonstrates that the corresponding minimum DNBR does not decrease below the appropriate safety analysis limit DNBR value, and no fuel or clad damage occurs. Additionally, no system overpressurization is expected since the steamline break results in an RCS depressurization as described above.

This is an ANS Condition III/IV incident.

15.4.9.2 Analysis of Effects and Consequences

15.4.9.2.1 Method of Analysis

The analysis of this transient uses the LOFTRAN computer code (reference 1). The following assumptions were made for this transient:

A. The analysis employs RTDP methodology in determining initial conditions of maximum core power, reactor coolant average temperature, and minimum reactor coolant pressure.

B. For end of life shutdown margin and equilibrium xenon conditions, the analysis assumes the most reactive RCCA stuck in its fully withdrawn position for conditions following reactor trip.

C. The analysis uses a negative moderator coefficient corresponding to the end of life unrodded core. This maximizes the reactivity insertion caused by the cooldown during the steamline break.

D. The analysis assumes the reactor trip setpoint on OPΔT at a conservative value. The ΔT trip includes all adverse instrumentation and setpoint errors; the delays for trip actuation are at the maximum values.

E. The analysis bases the RCCA trip insertion characteristic on the assumption that the highest worth assembly is stuck in its fully withdrawn position.

F. A spectrum of break sizes are analyzed. The limiting break is the largest break size for which a low steam line pressure signal will not occur and a reactor trip occurs on OPΔT.

G. The calculation of the steam flow during a steamline break uses the Moody Curve for f L/D = 0.

H. A conservatively large reactivity insertion rate is used.

No single active failure in any plant systems or equipment will adversely affect the consequences of the accident.

15.4.9.2.2 Results

The minimum DNBR occurred with beginning of life reactivity coefficients and a 0.7 ft break area. The calculated sequence of events for the limiting case is shown in table 15.4.1-1.

Figures 15.4.9-1, 15.4.9-2 and 15.4.9-3 show transient conditions following the steam line rupture with coincident RCCA bank withdrawal.

The steamline break affects the turbine impulse transmitters and causes the control rods to withdraw at the initiation of the transient. This causes an increase in reactor power and core heat flux to the point at which the OPΔT trip setpoint is reached. The reactor trip terminates the most adverse part of the transient. The steamline break causes increased heat removal and subsequent decrease in primary pressure simultaneous with the increase in reactor power. If the transient extends beyond post-reactor trip, secondary pressure will decrease until the low steamline pressure setpoint is reached, initiating steamline isolation and safety injection actuation.

The analysis of the steamline break with coincident RCCA bank withdrawal demonstrates that the DNBR limit is met. The most limiting part of this transient pertinent to this study was immediately before reactor trip (i.e., rod motion). The transient for the steamline break presented in subsection 15.1.5 bounds the return to power following reactor trip and steamline isolation. The other FSAR steamline break analysis assumed a larger break size and initial conditions corresponding to no-load temperatures (i.e., less stored energy in the RCS and reactor fuel). The DNBR is always greater than the limit value. Figure 15.4.9-3 shows the DNBR as a function of time for this transient.

15.4.9.3 Conclusions

The analysis demonstrates that the DNBR does not decrease below the limit value and no fuel or clad damage occurs. Additionally, no system overpressurization will occur; thus, all applicable safety criteria are met. As stated in the results, the large steamline break analysis presented in subsection 15.1.5 bounds the return to power following a reactor trip and steamline isolation; therefore, there is adequate protection to ensure plant safety for this transient.

15.4.9.4 Reference

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (proprietary), and WCAP-7907-A (nonproprietary), April 1984.

TABLE 15.4.1-1 (SHEET 1 OF 4)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN REACTIVITY AND POWER DISTRIBUTION ANOMALIES

Accident	Event	Time Delays (s)
Uncontrolled RCCA bank withdrawal from a subcritical or low-power startup condition		
	Initiation of uncontrolled rod withdrawal from 10^{-9} fraction of nominal power	0.0
	Power range high neutron flux low setpoint reached	12.5
	Peak nuclear power occurs	12.7
	Rods begin to fall into core	13.0
	Minimum DNBR occurs	14.9
	Peak heat flux occurs	14.9
	Peak average clad temperature occurs	15.1
	Peak average fuel temperature occurs	15.4
Uncontrolled RCCA bank withdrawal at power (full power with minimum feedback)		
1. Case A	Initiation of uncontrolled RCCA withdrawal at a high-reactivity insertion rate (80 pcm/s)	0
	Power range high neutron flux high setpoint reached	1.4
	Rods begin to fall into core	1.9
	Minimum DNBR occurs	1.95

TABLE 15.4.1-1 (SHEET 2 OF 4)

Accident	Event	Time Delays (s)
2. Case B	Initiation of uncontrolled RCCA withdrawal at a small-reactivity insertion rate (2 pcm/s)	0
	OT∆T setpoint reached	34.0
	Rods begin to fall into core	36.0
	Minimum DNBR occurs	37.1
Startup of an inactive reactor coolant loop at an incorrect temperature		
	Initiation of pump startup	0.0
	Power reaches P-8 trip setpoint	3.5
	Rods begin to drop	4.0
	Minimum DNBR occurs	5.0
CVCS malfunction that results in a decrease in the boron concentration in the reactor coolant		
1. Dilution during startup	Power range - low setpoint reactor trip due to dilution	0
	Shutdown margin lost (if dilution continues after trip)	2010

TABLE 15.4.1-1 (SHEET 3 OF 4)

Accident	Event	Time Delays (s)
2. Dilution during full-power operation		
a. Automatic reactor control	Operation receives low-low rod insertion limit alarm due to dilution	0
	Shutdown margin lost	3560
b. Manual reactor control	Reactor trip on OTΔT due to dilution	0
	Shutdown margin is lost (if dilution continues after trip)	1860
RCCA ejection accident		
1. End of life, zero power	Initiation of rod ejection	0.0
	Power range high neutron flux low setpoint reached	0.22
	Peak nuclear power occurs	0.24
	Rods begin to fall into core	0.72
	Peak clad average temperature occurs	1.79
	Peak heat flux occurs	1.79
	Peak fuel average temperature occurs	1.98

TABLE 15.4.1-1 (SHEET 4 OF 4)

Accident	Event	Time Delays (s)
2. Beginning of life, full power	Initiation of rod injection	0.0
	Power range high neutron flux high setpoint reached	0.05
	Peak nuclear power occurs	0.13
	Rods begin to fall into core	0.55
	Peak fuel average temperature occurs	2.44
	Peak clad average temperature occurs	2.52
	Peak heat flux occurs	2.53
Steam line break with coincident rod withdrawal at power	Steam line ruptures, RCCA bank begins to withdraw	0.0
	OPΔT reactor trip setpoint reached	11.8
	Rods begin to fall	13.8
	Minimum DNBR occurs	14.6

TABLE 15.4.6-1

PARAMETERS

Dilution Flowrates:

Initiator	Flowrate (gal/min)
1	63
2	100
3	3.5
4	110

Volumes:

Mode	Volume (ft^3)	Volume (gal)
3, 4	9583	71,681
5a (loops filled)	4120	30,818
5b (loops not filled)	3460[(a)]	25,880
6 (loops not filled)	3460[(a)]	25,880

---

a. This volume corresponds with the reactor vessel coolant level at the mid-plane of the nozzles.

TABLE 15.4.8-1

PARAMETERS USED IN THE ANALYSIS OF THE ROD CLUSTER CONTROL ASSEMBLY EJECTION ACCIDENT

Time in Life	HZP Beginning	HZP Beginning	HZP End	HZP End
Power level (%)	0	102	0	102
Ejected rod worth (% Δk)	0.75	0.24	0.84	0.25
Delayed neutron fraction (%)	0.54	0.57	0.46	0.46
Doppler feedback reactivity weighting	1.744	1.30	3.55	1.30
Trip reactivity (%Δk)	2.0	4.0	2.0	4.0
F_Q before rod ejection	--	2.55	--	2.55
F_Q after rod ejection	11.0	5.5	26.0	6.0
Number of operational pumps	2	4	2	4
Maximum fuel pellet average temperature at the hot spot (°F)	3425	4091	3412	3970
Maximum fuel center temperature at the hot spot (°F)	3985	>4900	3891	>4800
Maximum fuel stored energy at the hot spot (cal/g)	144.9	179.2	144.2	172.7
Percent of fuel melted at the hot spot	0	<10	0	<10

TABLE 15.4.8-2 (SHEET 1 OF 2)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A CONTROL ROD EJECTION ACCIDENT

I.	Source Data	
A.	Core power level (MWt)	3636
B.	Total steam generator tube leakage (gal/min)	1
C.	Reactor coolant iodine activity prior to accident	An assumed preaccident iodine spike, which has resulted in the DE of 60 µCi/g of I-131 in the reactor coolant. See table 15A-6.
D.	Gap activity released to reactor coolant from failed fuel	10 percent See table 15A-3.
E.	Melted fuel	0.25 percent of core (0.00125 of core iodines, 0.0025 of core noble gases)
F.	Reactor coolant noble gas activity	Based on 1 percent defective fuel. See table 15A-4.
G.	Secondary system initial activity	DE of 0.1 µCi/g of I-131.
H.	Reactor coolant mass (g)	2.3 x 10^8
I.	Secondary coolant mass, 4 generators (g)	1.9 x 10^8
J.	Offsite power	Lost after trip
II.	Atmospheric Dispersion Factors	See table 15A-2.

TABLE 15.4.8-2 (SHEET 2 OF 2)

III. Activity Release Data	
A. Containment	
1. Leak rate (percent/day)	0.2
2. Mass of primary coolant discharged to containment (lb)	
0 to 1600 s	9.3×10^4
1600 to 4700 s	3.4×10^5
4700 to 10000 s	6.9×10^5
3. Fraction of activity carried by reactor coolant spill that is assumed to be airborne	
Iodines	0.45
Noble gases	1.0
B. Steam generators	
1. Primary-to-secondary leak rate (gal/min)(a)	1.0
2. Mass of steam released (lb)	
0 - 214 s	4.9×10^4
3. Iodine partition factor	100

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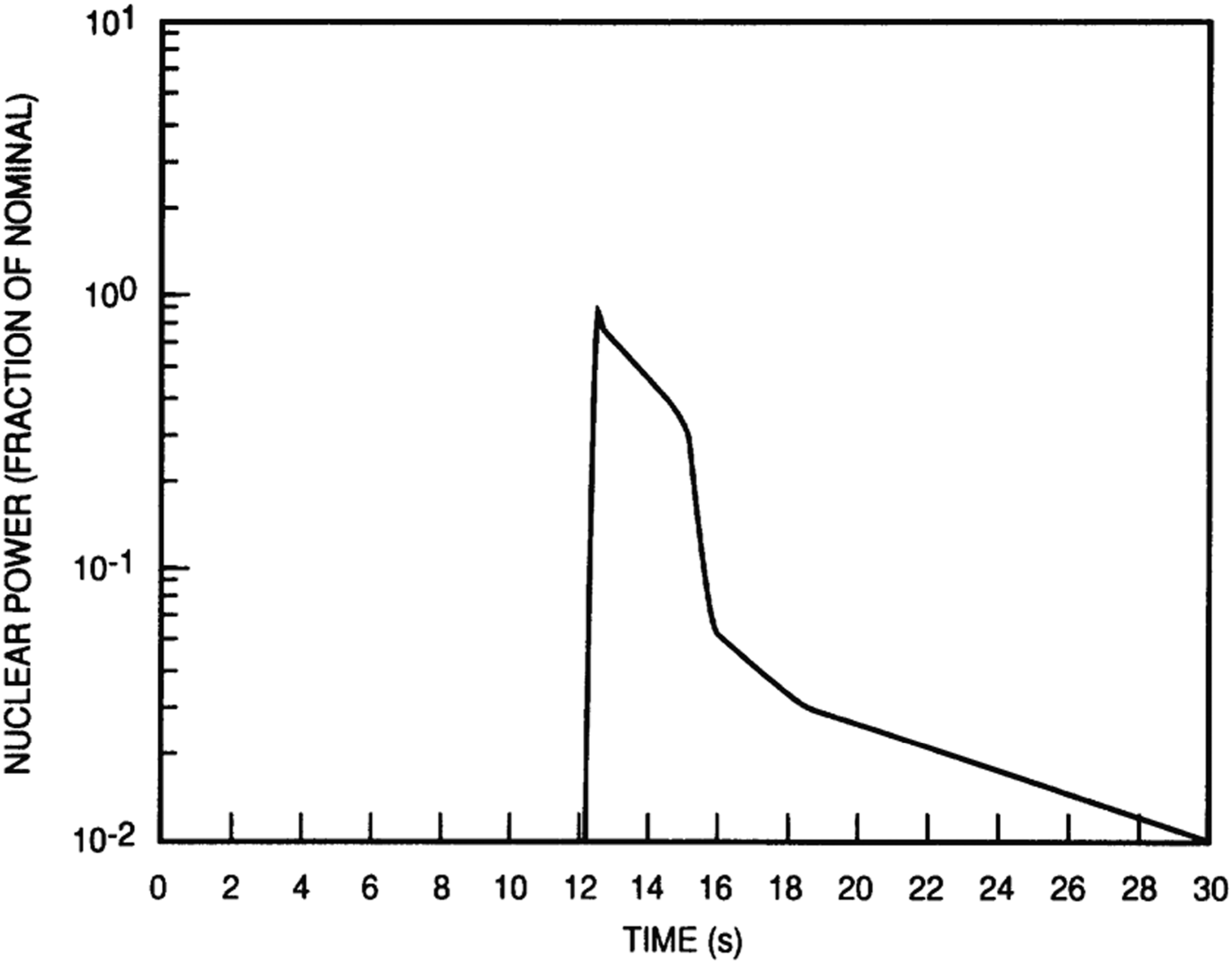
a. Based on water at 62.4 lb/ft^3.

TABLE 15.4.8-3

RADIOLOGICAL CONSEQUENCES OF A CONTROL ROD EJECTION ACCIDENT

	Doses (rem)
Exclusion Area Boundary (0 to 2 h)	
Thyroid	9.6
Whole-body gamma	0.2
Low Population Zone Outer Boundary (30 days)	
Thyroid	23
Whole-body gamma	0.1



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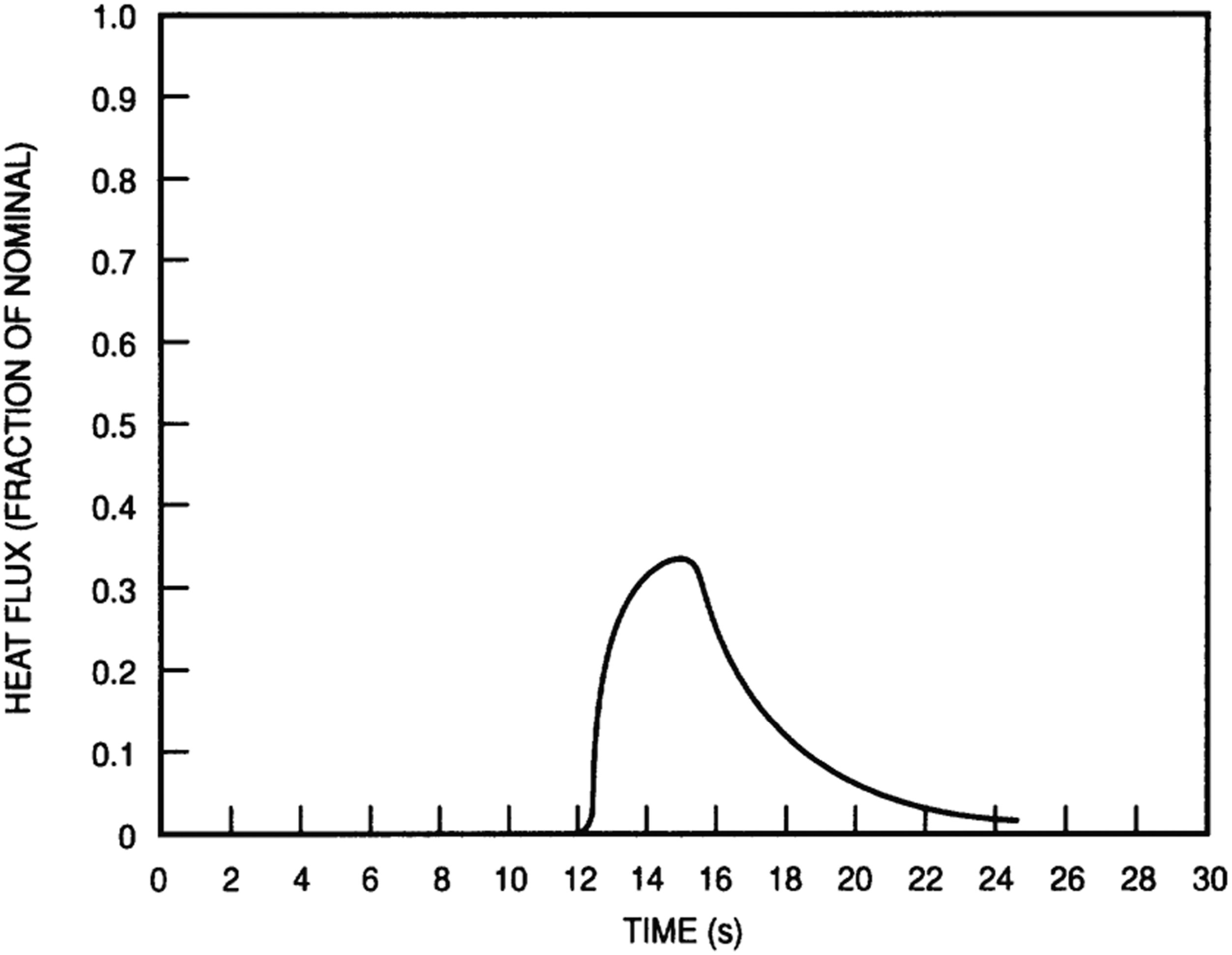
UNIT 1 AND UNIT 2

NEUTRON FLUX TRANSIENT FOR UNCONTROLLED ROD WITHDRAWAL FROM A SUBCRITICAL CONDITION

FIGURE 15.4.1–1



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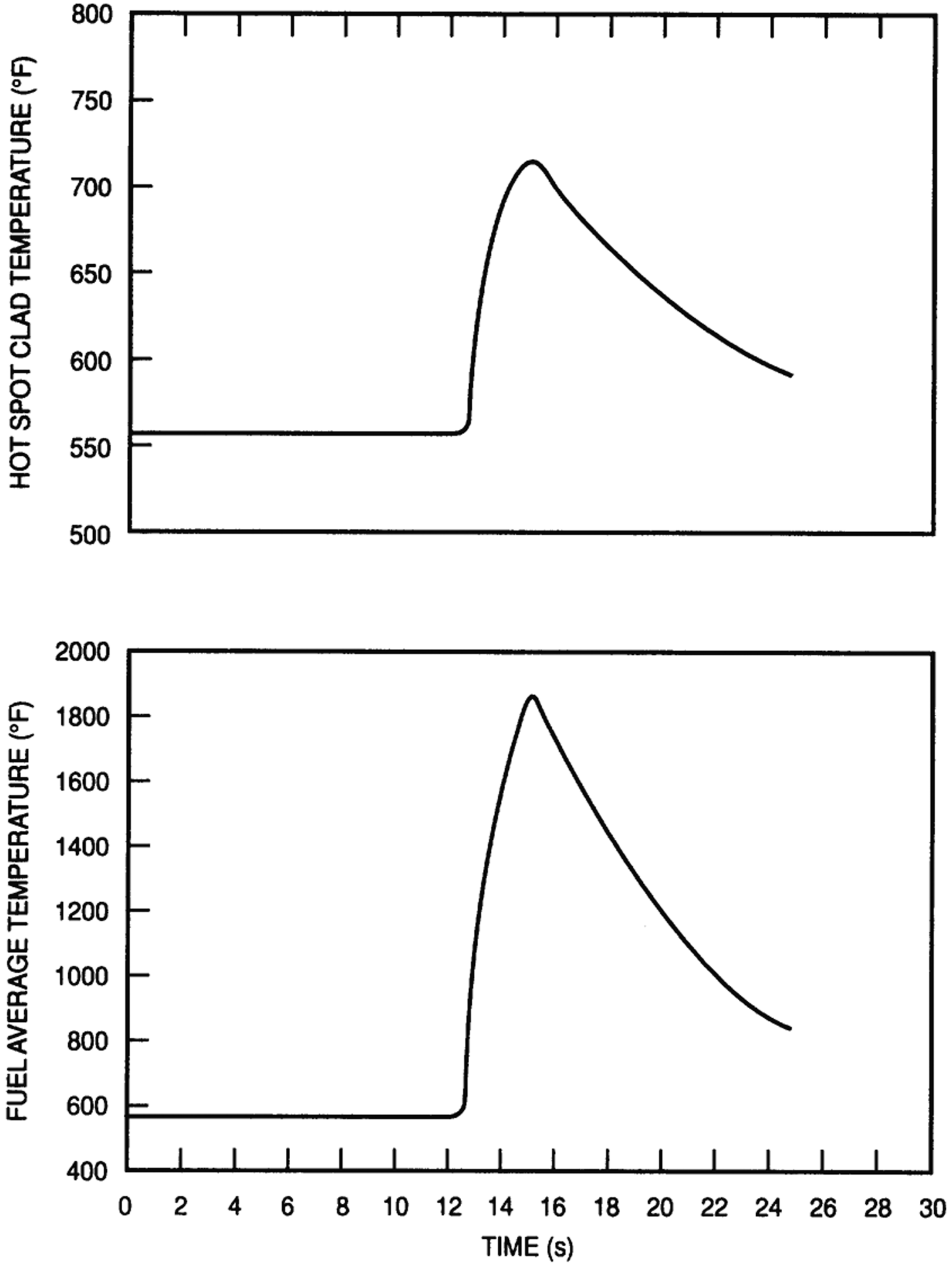
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

THERMAL FLUX TRANSIENT FOR
UNCONTROLLED ROD WITHDRAWAL FROM
A SUBCRITICAL CONDITION

FIGURE 15.4.1–2



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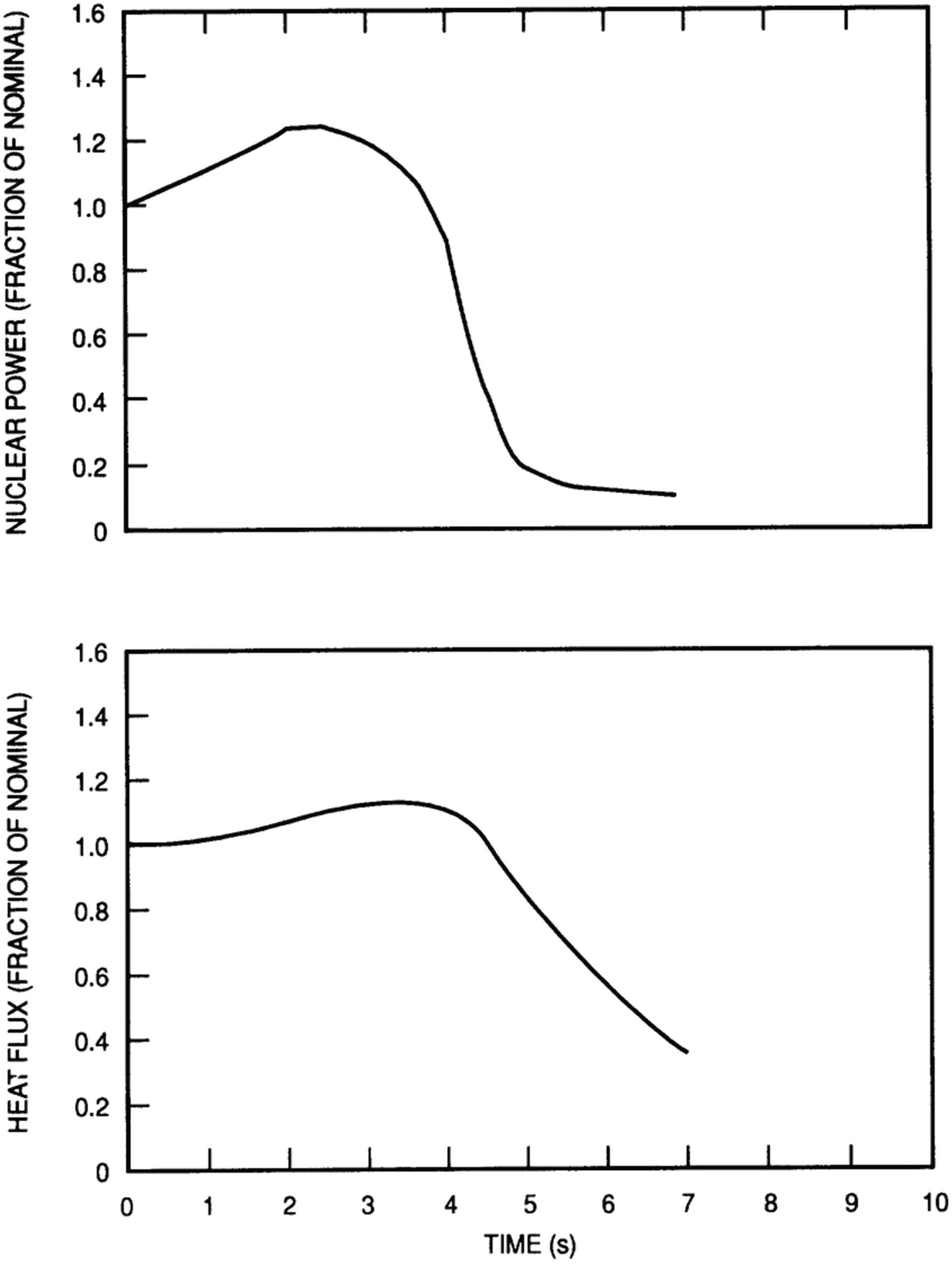
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

FUEL AND CLAD TEMPERATURE FOR UNCONTROLLED ROD WITHDRAWAL FROM A SUBCRITICAL CONDITION

FIGURE 15.4.1–3



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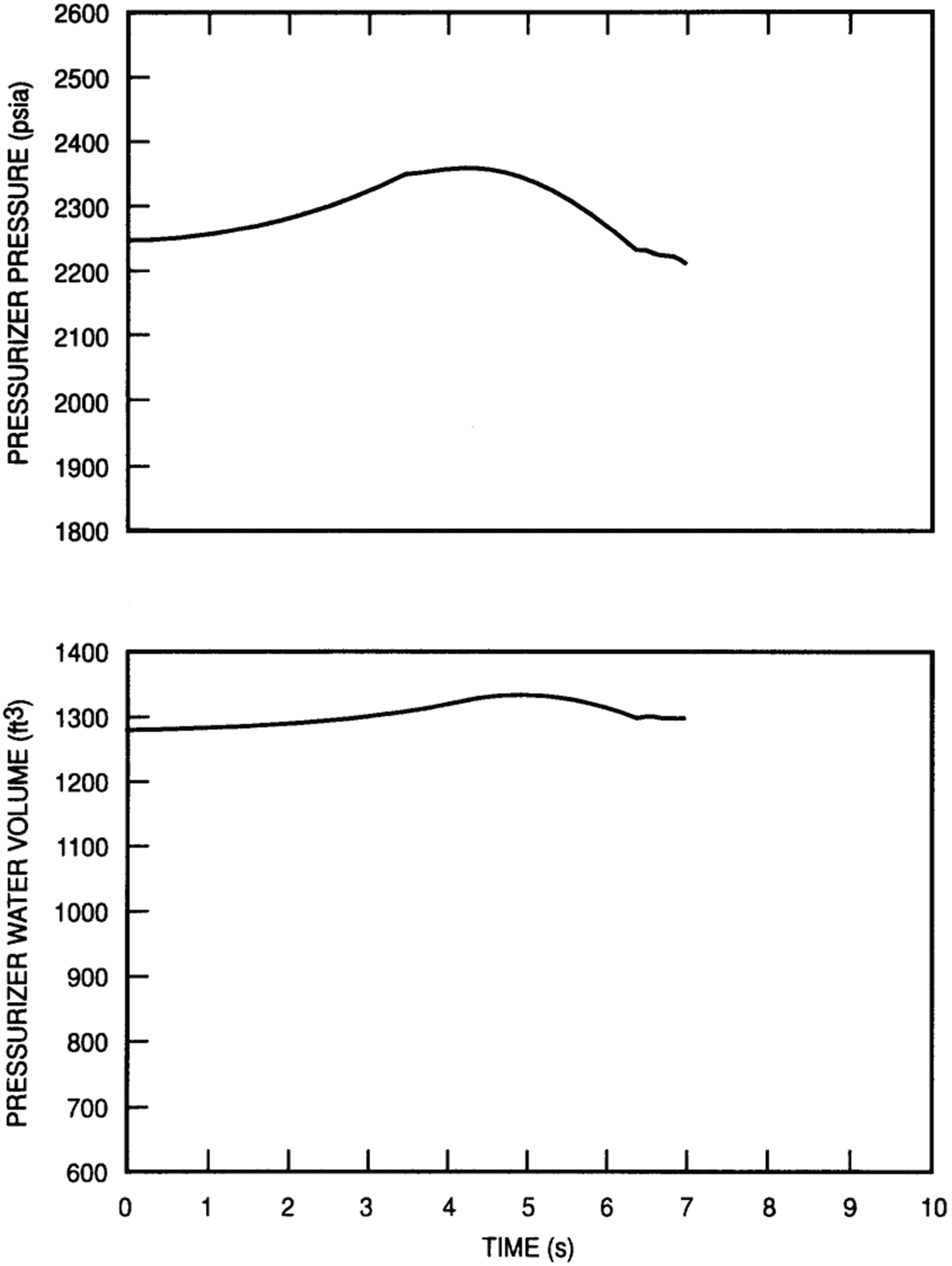
UNCONTROLLED RCCA BANK WITHDRAWAL FROM FULL POWER WITH MINIMUM REACTIVITY FEEDBACK (80 pcm/s WITHDRAWAL RATE)

FIGURE 15.4.2–1



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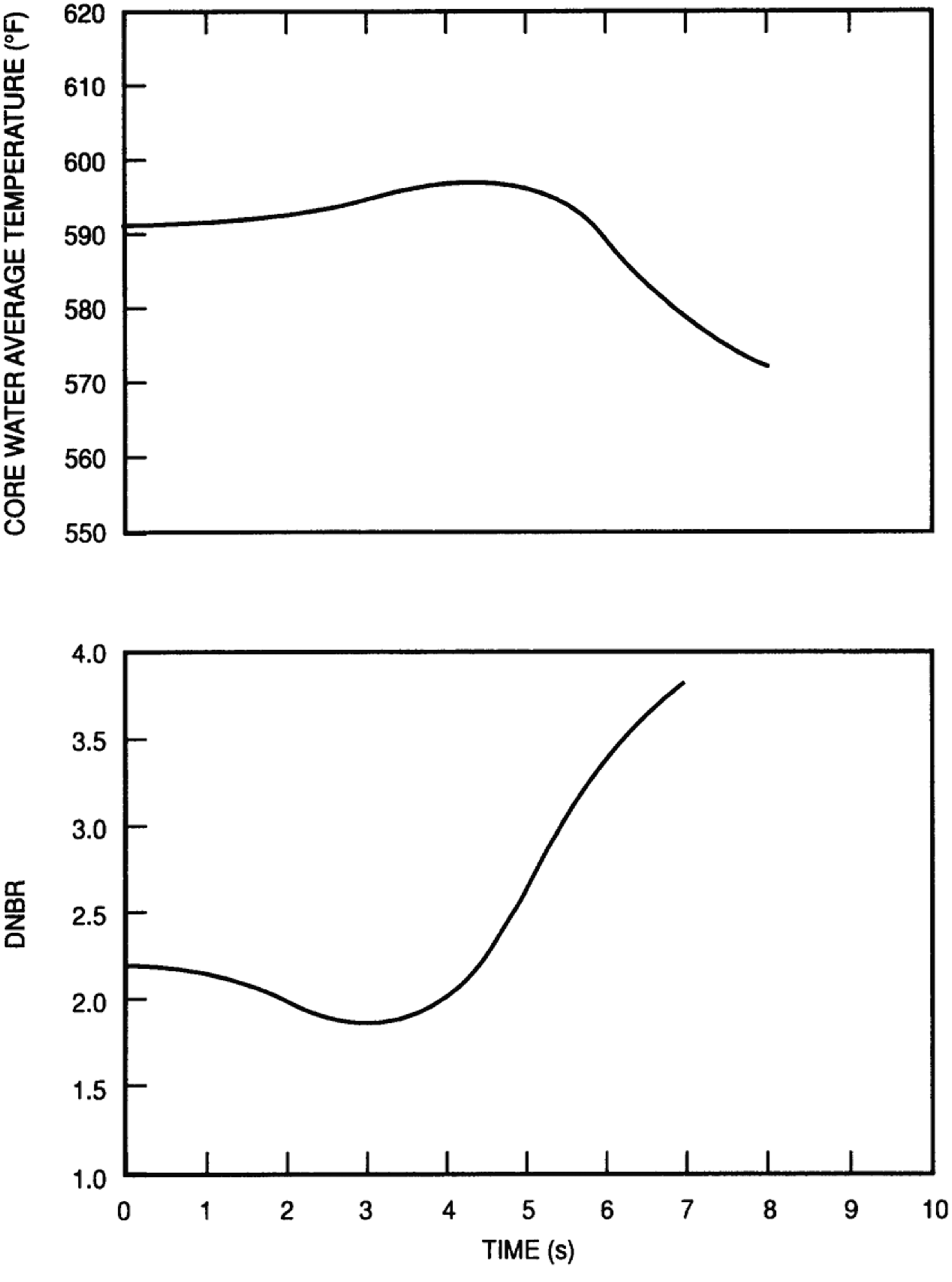
UNCONTROLLED RCCA BANK WITHDRAWAL FROM FULL POWER WITH MINIMUM REACTIVITY FEEDBACK (80 pcm/s WITHDRAWAL RATE)

FIGURE 15.4.2–2



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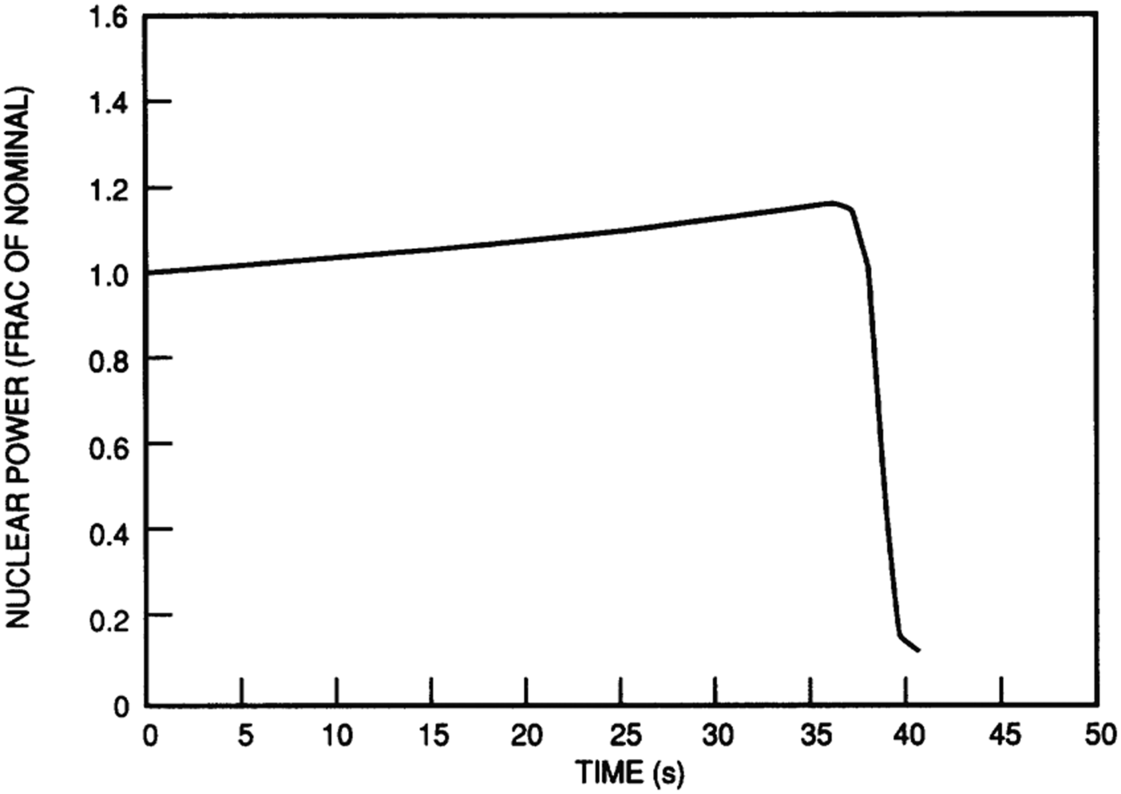
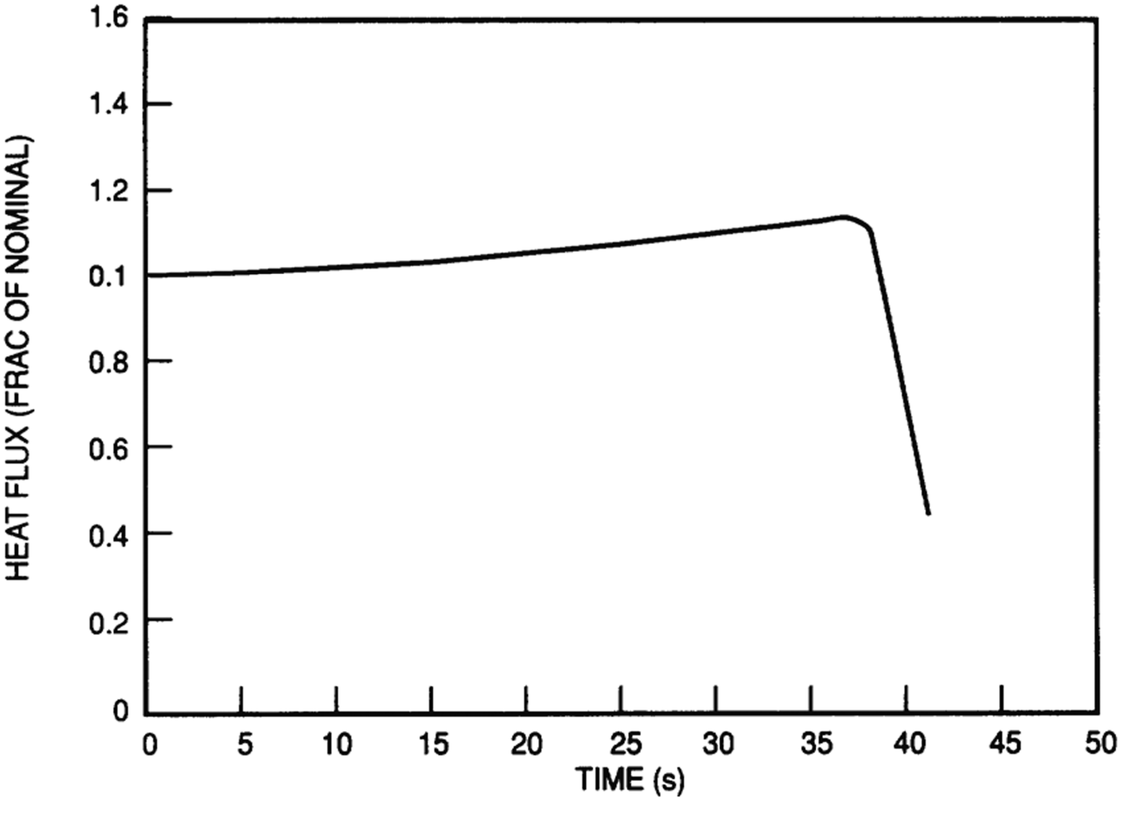
UNIT 1 AND UNIT 2

UNCONTROLLED RCCA BANK WITHDRAWAL FROM FULL POWER WITH MINIMUM REACTIVITY FEEDBACK (80 pcm/s WITHDRAWAL RATE)

FIGURE 15.4.2–3





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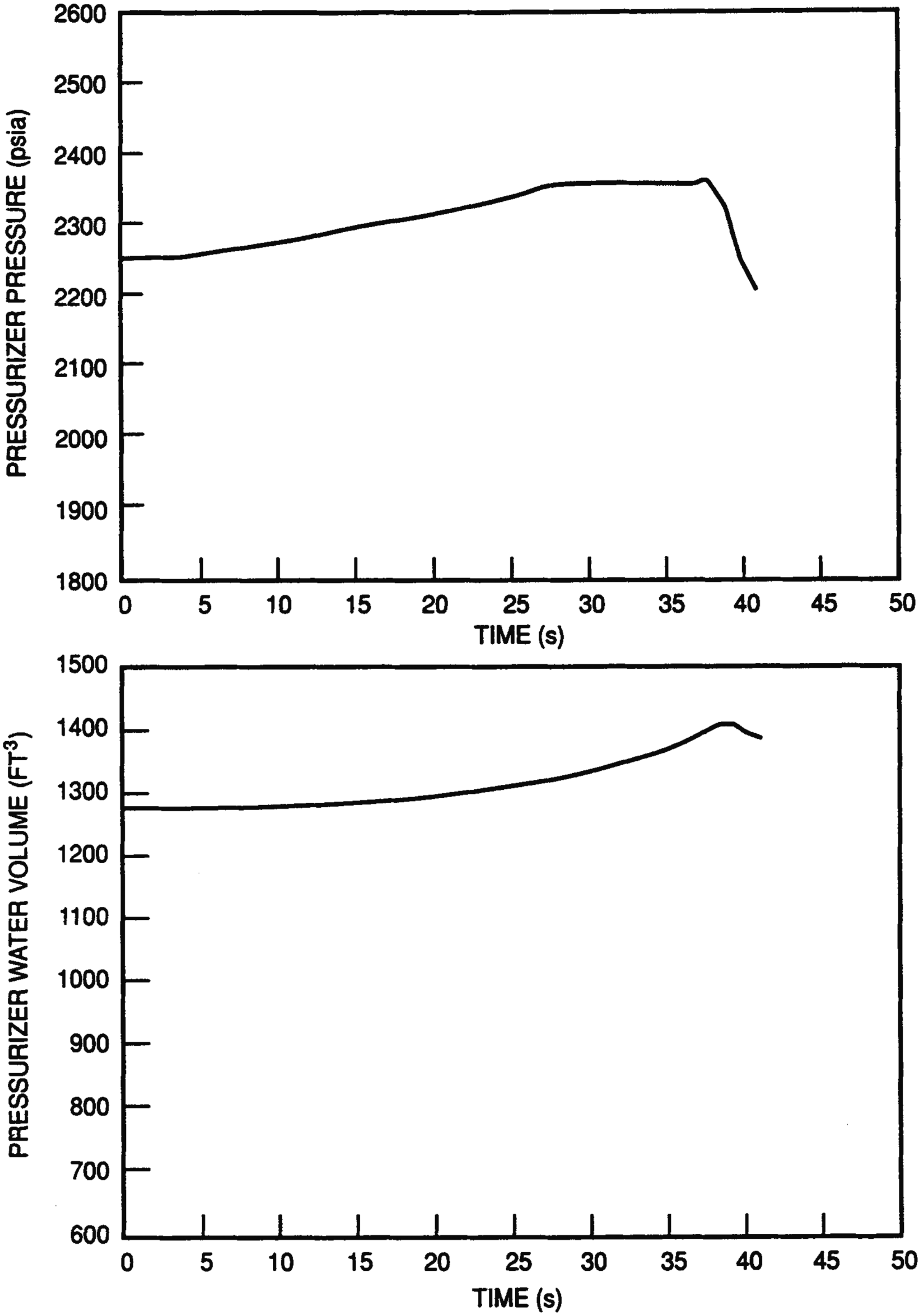
UNCONTROLLED RCCA BANK WITHDRAWAL FROM FULL POWER WITH MINIMUM REACTIVITY FEEDBACK (2 pcm/s WITHDRAWAL RATE)

FIGURE 15.4.2–4



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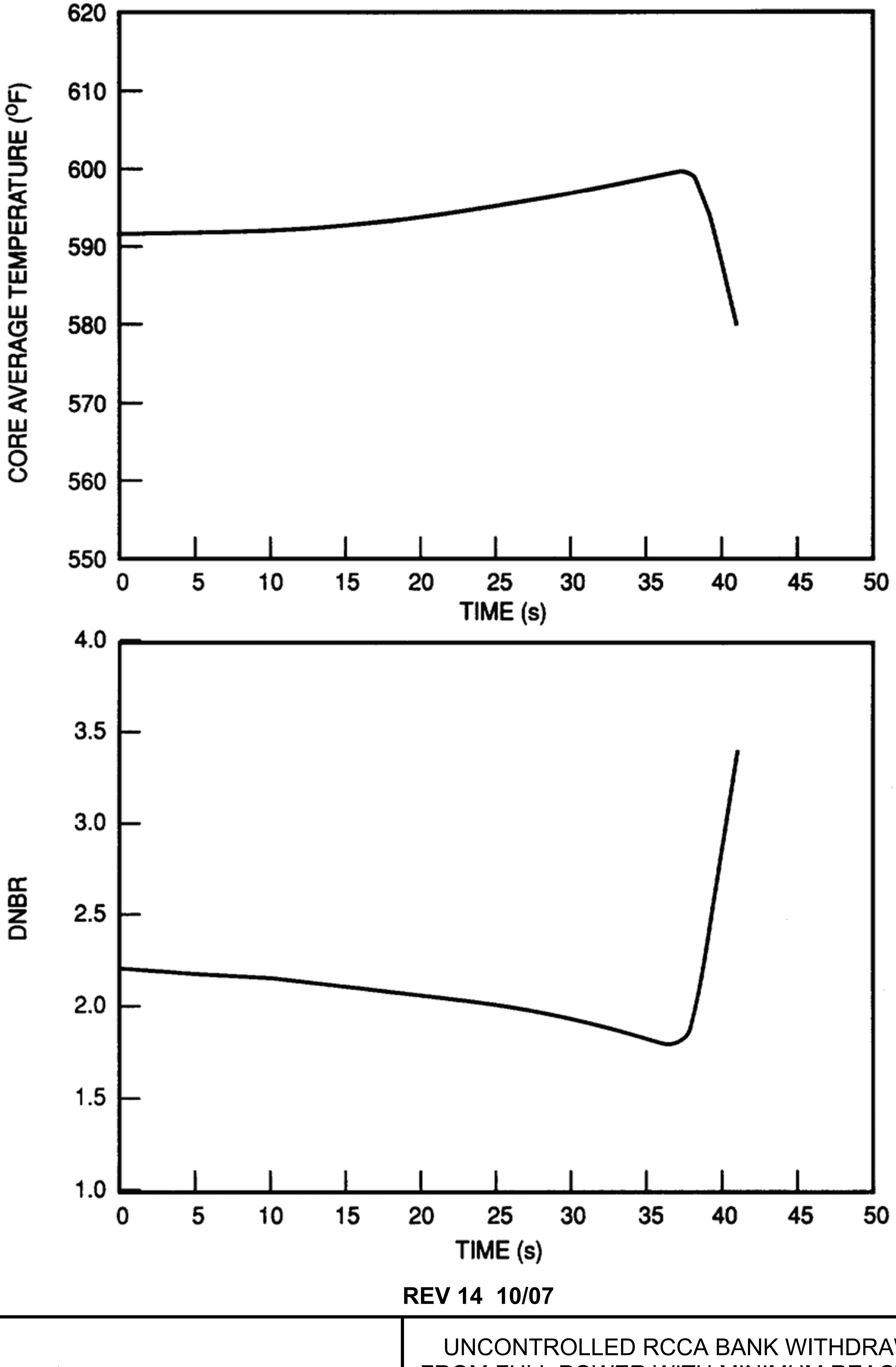
UNCONTROLLED RCCA BANK WITHDRAWAL FROM FULL POWER WITH MINIMUM REACTIVITY FEEDBACK (2 pcm/s WITHDRAWAL RATE)

FIGURE 15.4.2–5



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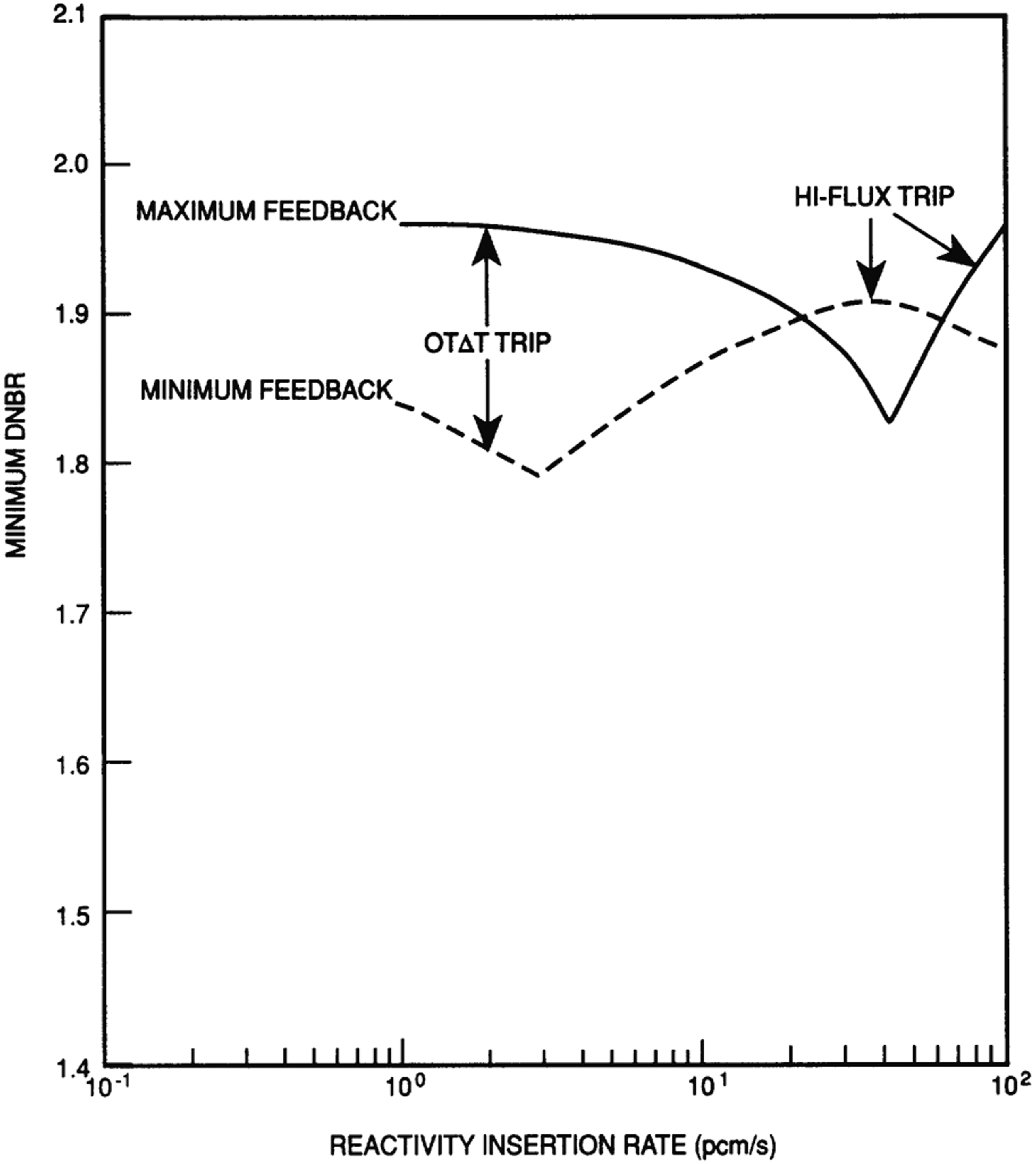
UNCONTROLLED RCCA BANK WITHDRAWAL
FROM FULL POWER WITH MINIMUM REACTIVITY
FEEDBACK (2 pcm/s WITHDRAWAL RATE)

FIGURE 15.4.2–6



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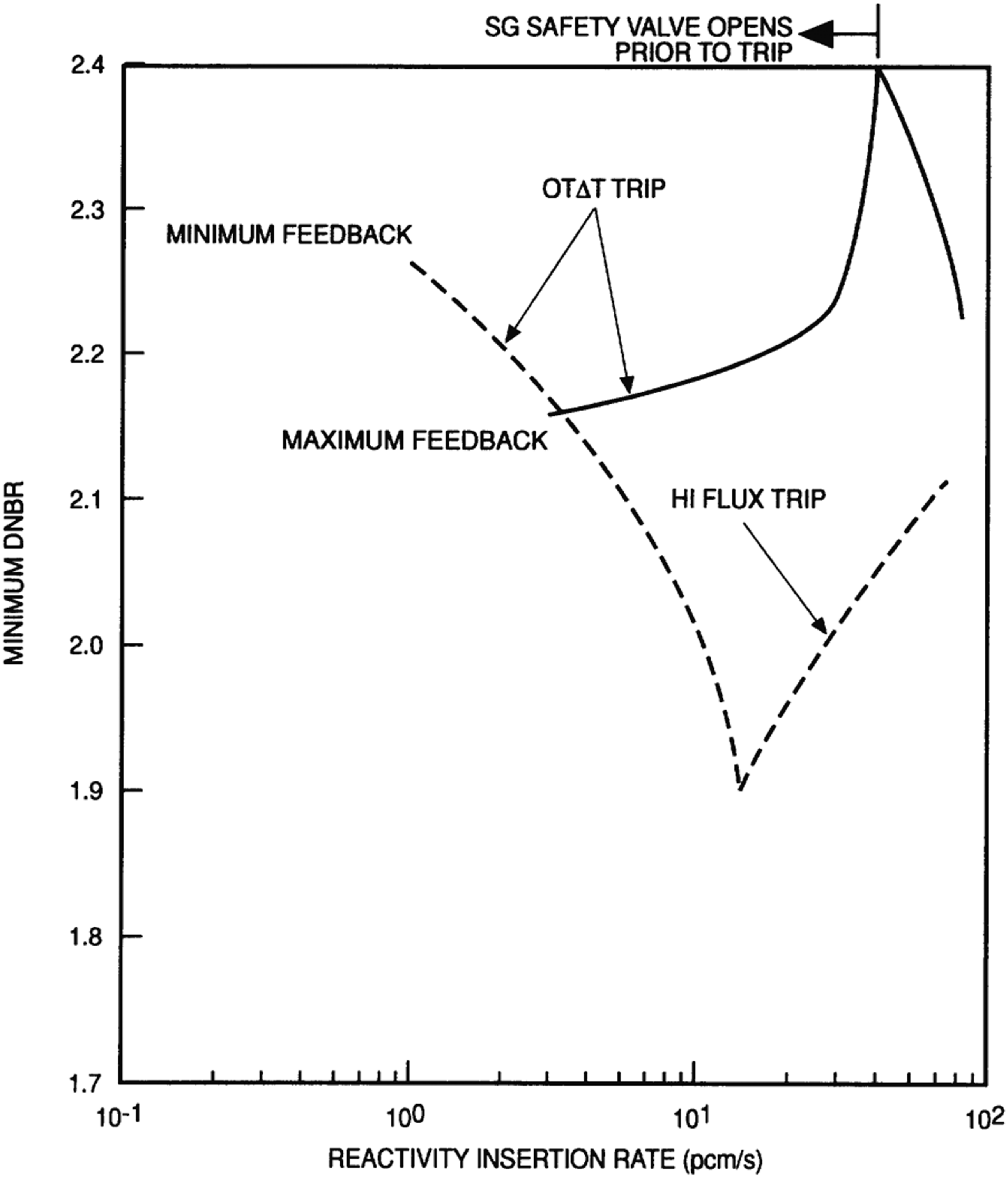
MINIMUM DNBR VS. REACTIVITY INSERTION RATE FOR ROD WITHDRAWAL AT 100 PERCENT POWER

FIGURE 15.4.2–7



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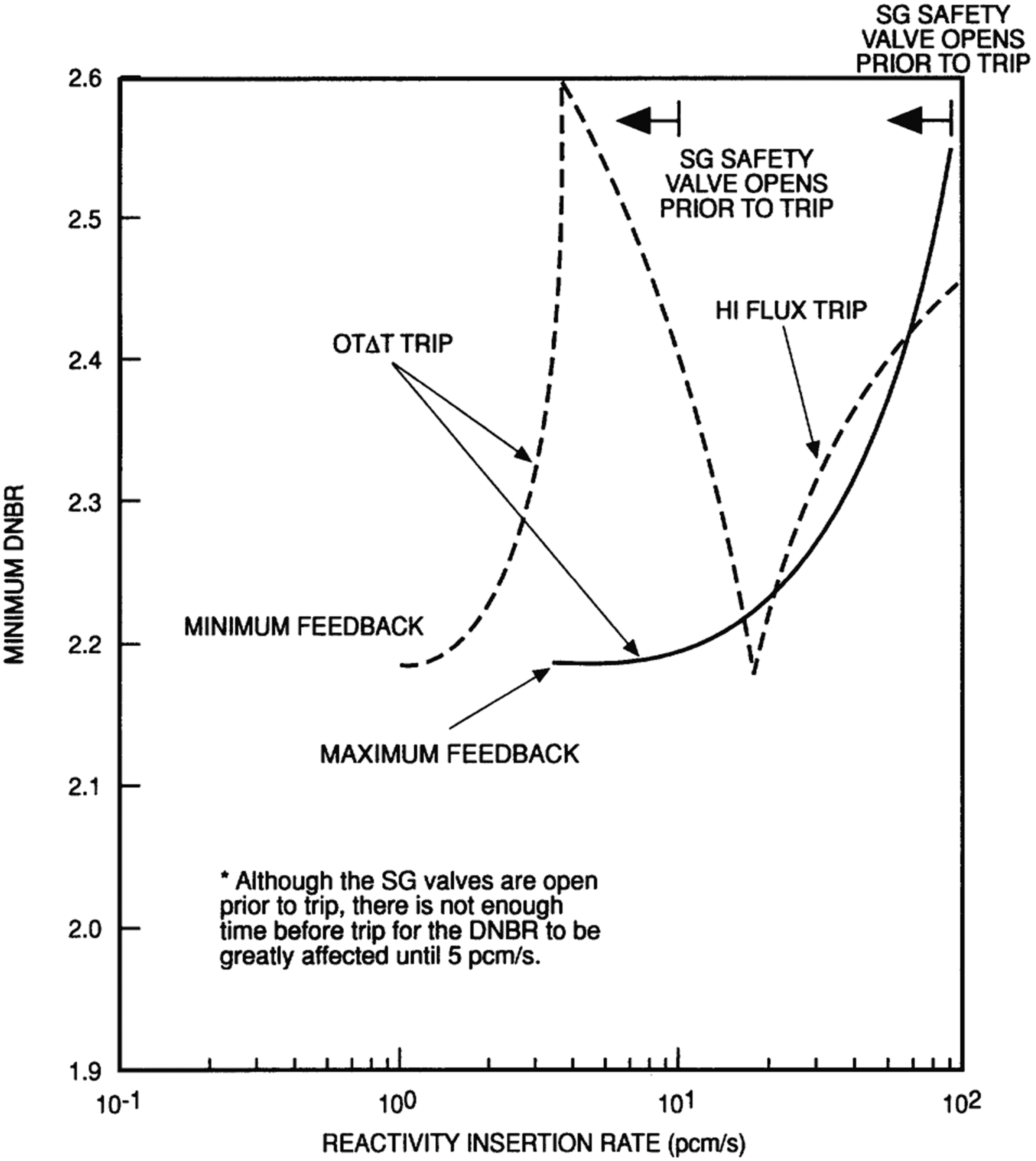
MINIMUM DNBR VS. REACTIVITY INSERTION RATE FOR ROD WITHDRAWAL FORM 60 PERCENT POWER

FIGURE 15.4.2–8



* Although the SG valves are open prior to trip, there is not enough time before trip for the DNBR to be greatly affected until 5 pcm/s.

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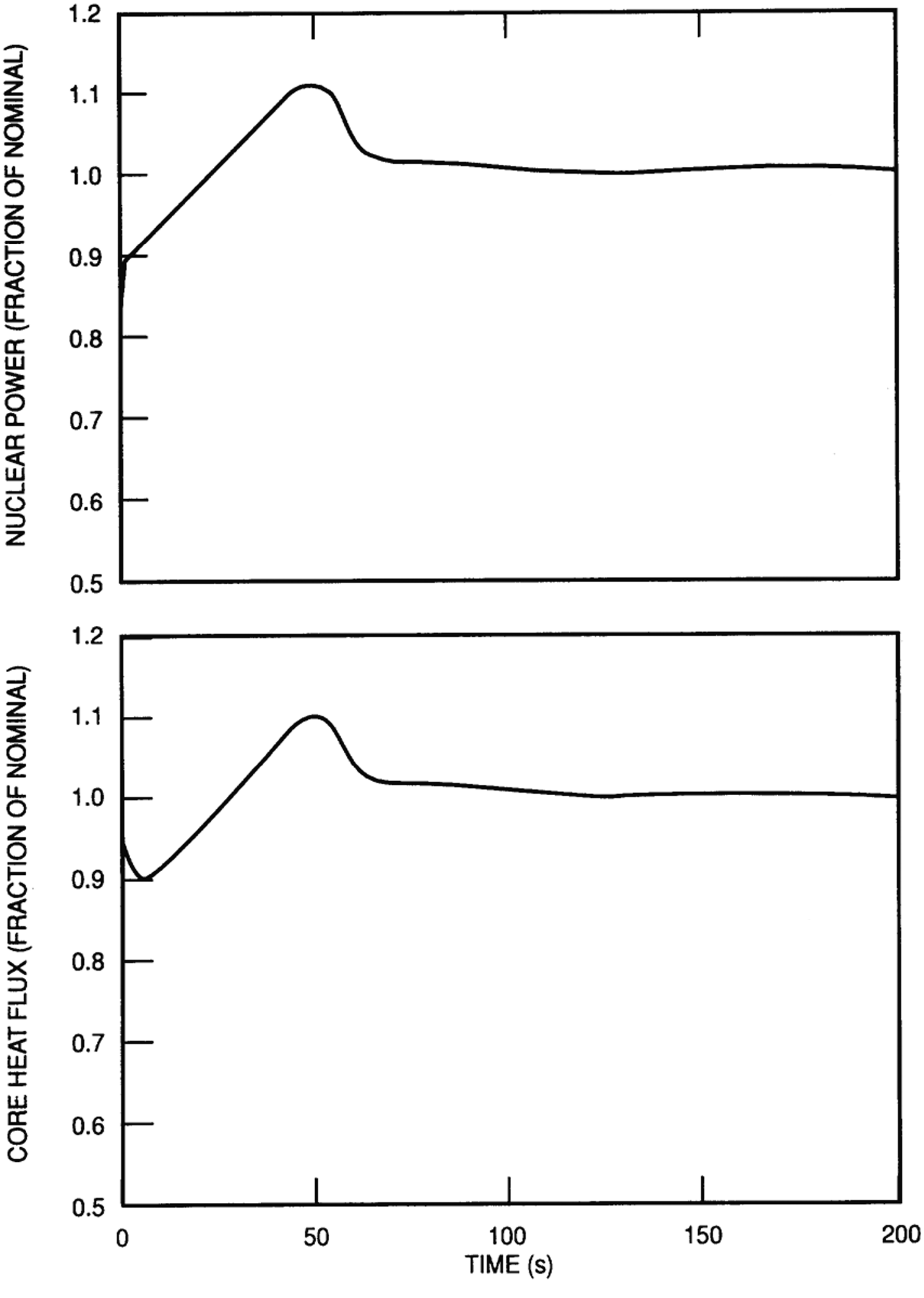
MINIMUM DNBR VS. REACTIVITY INSERTION RATE FOR ROD WITHDRAWAL FROM 10 PERCENT POWER

FIGURE 15.4.2–9



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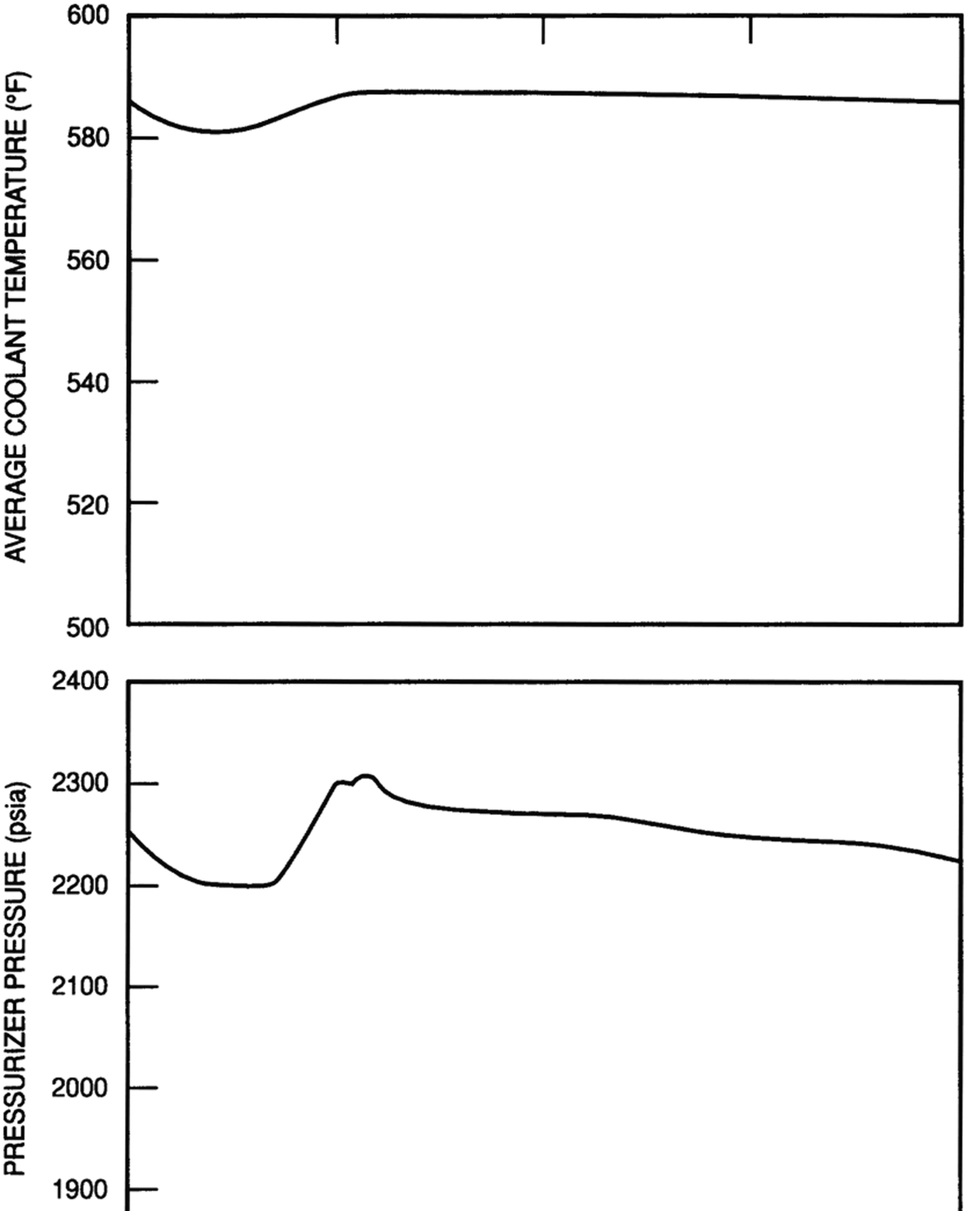
UNIT 1 AND UNIT 2

NUCLEAR POWER TRANSIENT AND CORE HEAT FLUX TRANSIENT FOR DROPPED RCCA

FIGURE 15.4.3–1



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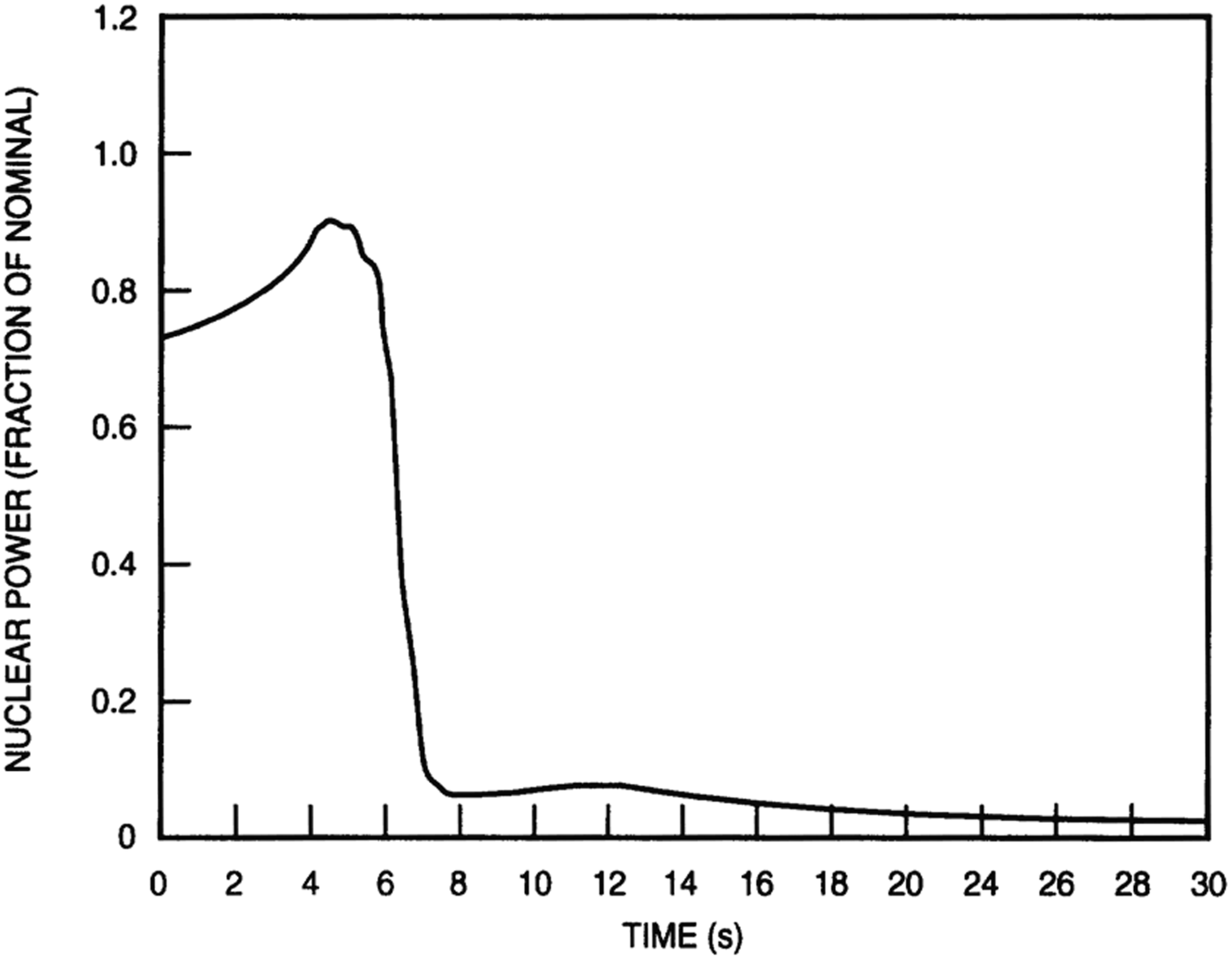
UNIT 1 AND UNIT 2

PRESSURIZER PRESSURE TRANSIENT AND CORE AVERAGE TEMPERATURE TRANSIENT FOR DROPPED RCCA

FIGURE 15.4.3–2



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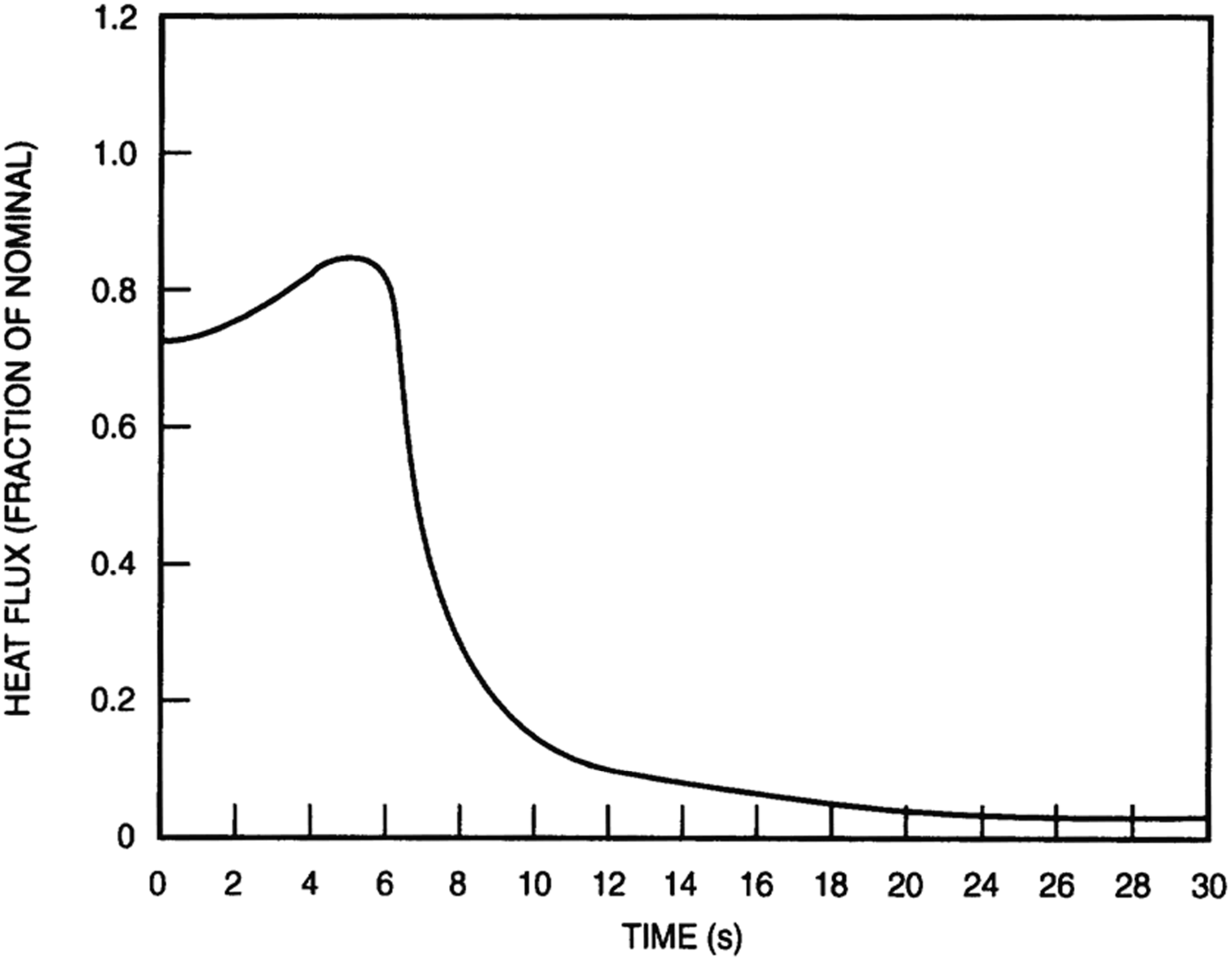
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

IMPROPER STARTUP OF AN INACTIVE REACTOR COOLANT PUMP

FIGURE 15.4.4–1



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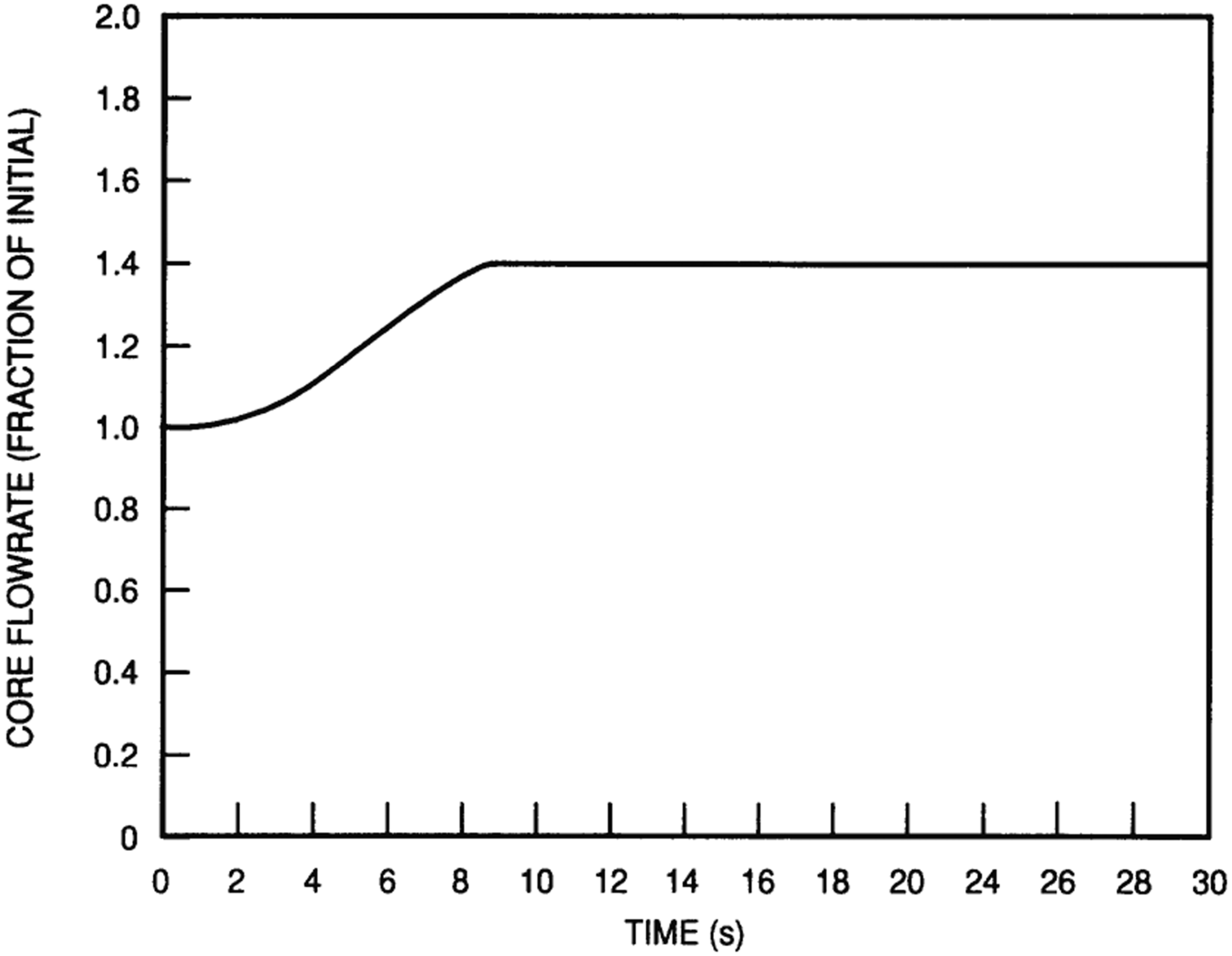
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

IMPROPER STARTUP OF AN INACTIVE
REACTOR COOLANT PUMP

FIGURE 15.4.4–2



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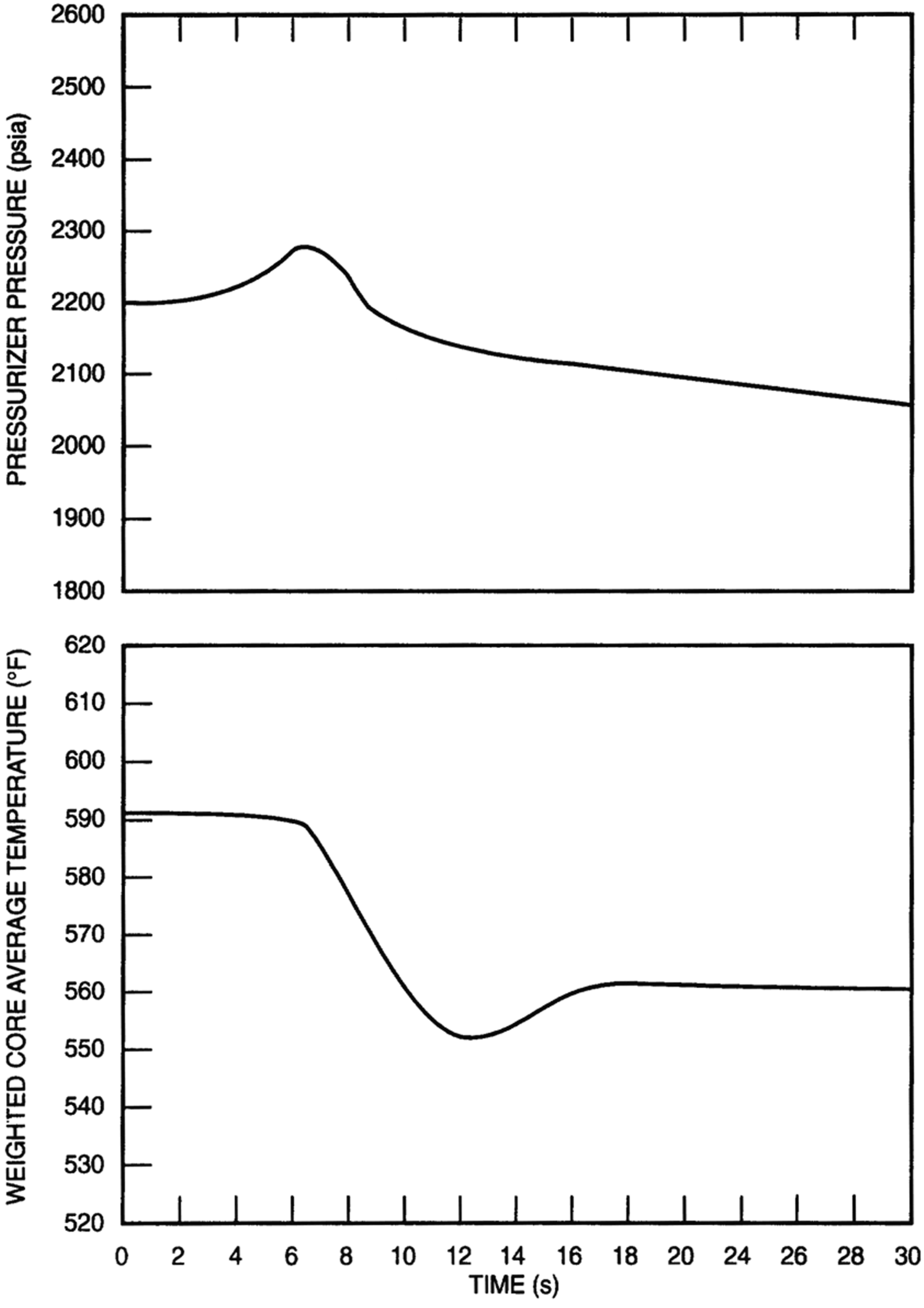
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

IMPROPER STARTUP OF AN INACTIVE REACTOR COOLANT PUMP

FIGURE 15.4.4–3



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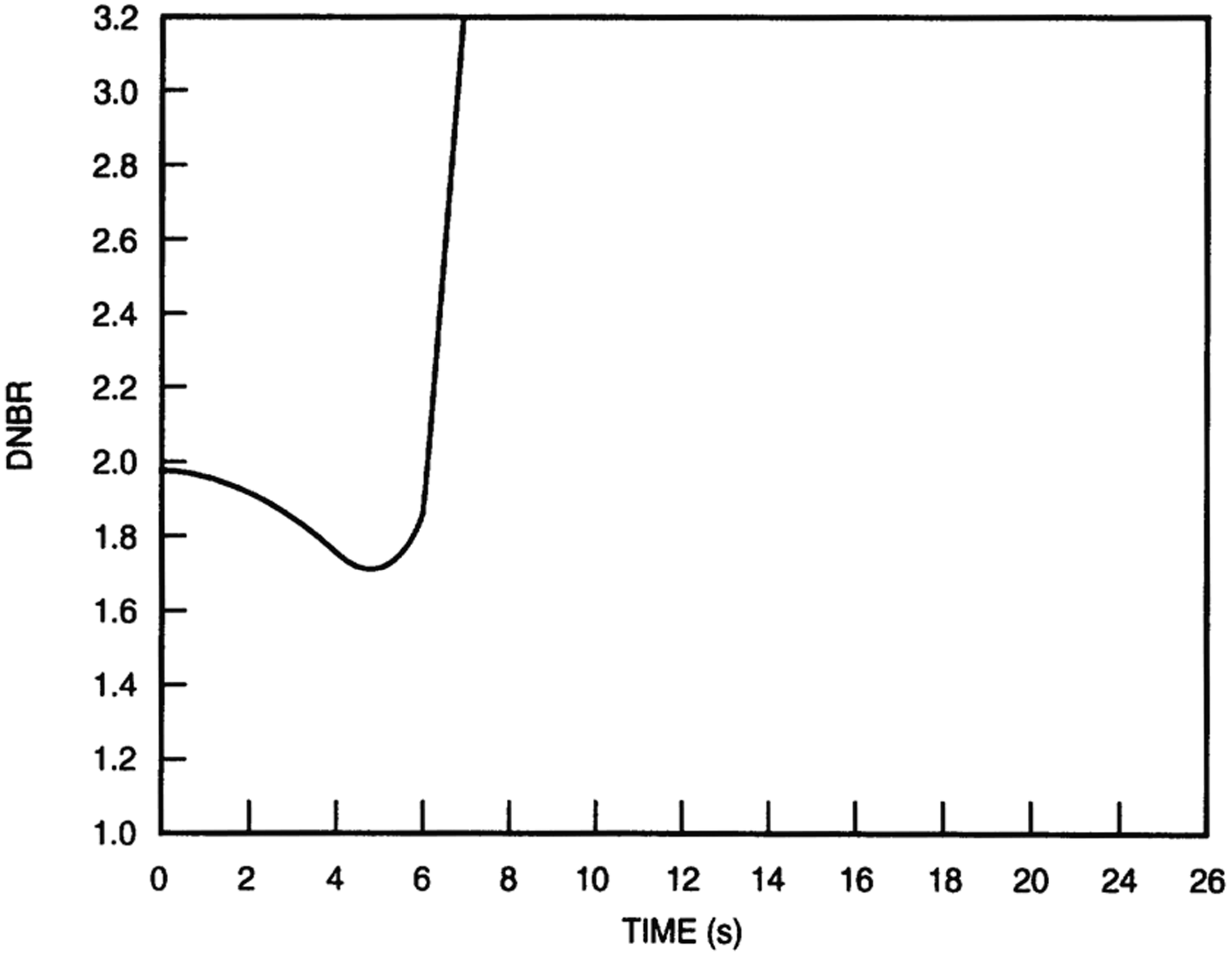
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

IMPROPER STARTUP OF AN INACTIVE REACTOR COOLANT PUMP

FIGURE 15.4.4–4



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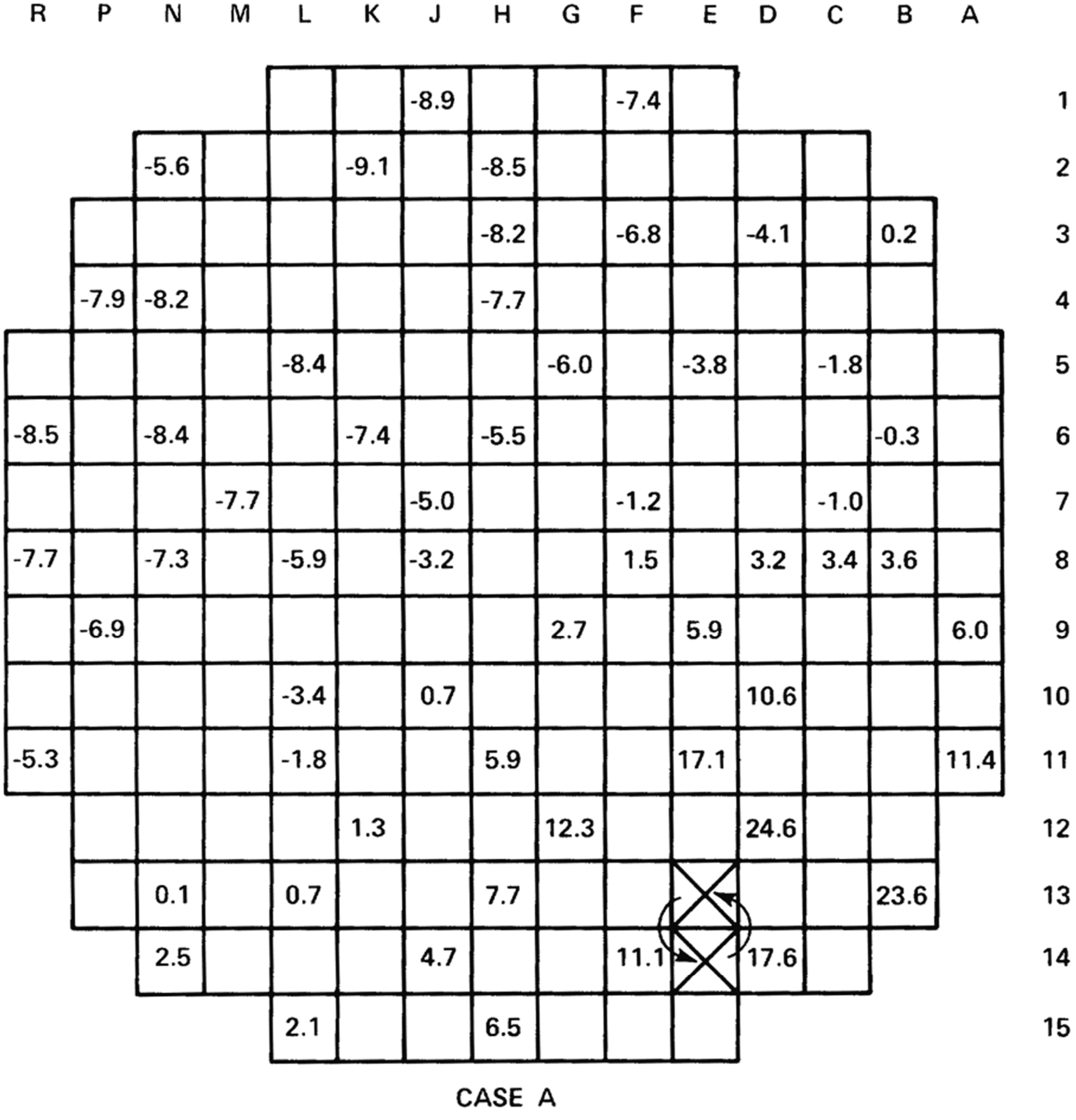
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

IMPROPER STARTUP OF AN INACTIVE REACTOR COOLANT PUMP

FIGURE 15.4.4–5



	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							-8.9			-7.4					
2			-5.6			-9.1		-8.5							
3								-8.2		-6.8		-4.1		0.2	
4		-7.9	-8.2					-7.7							
5					-8.4				-6.0		-3.8		-1.8		
6	-8.5		-8.4			-7.4		-5.5						-0.3	
7				-7.7			-5.0			-1.2			-1.0		
8	-7.7		-7.3		-5.9		-3.2			1.5		3.2	3.4	3.6	
9		-6.9							2.7		5.9				6.0
10					-3.4		0.7					10.6			
11	-5.3				-1.8			5.9			17.1				11.4
12						1.3			12.3			24.6			
13			0.1		0.7			7.7						23.6	
14			2.5				4.7			11.1		17.6			
15					2.1			6.5							

CASE A

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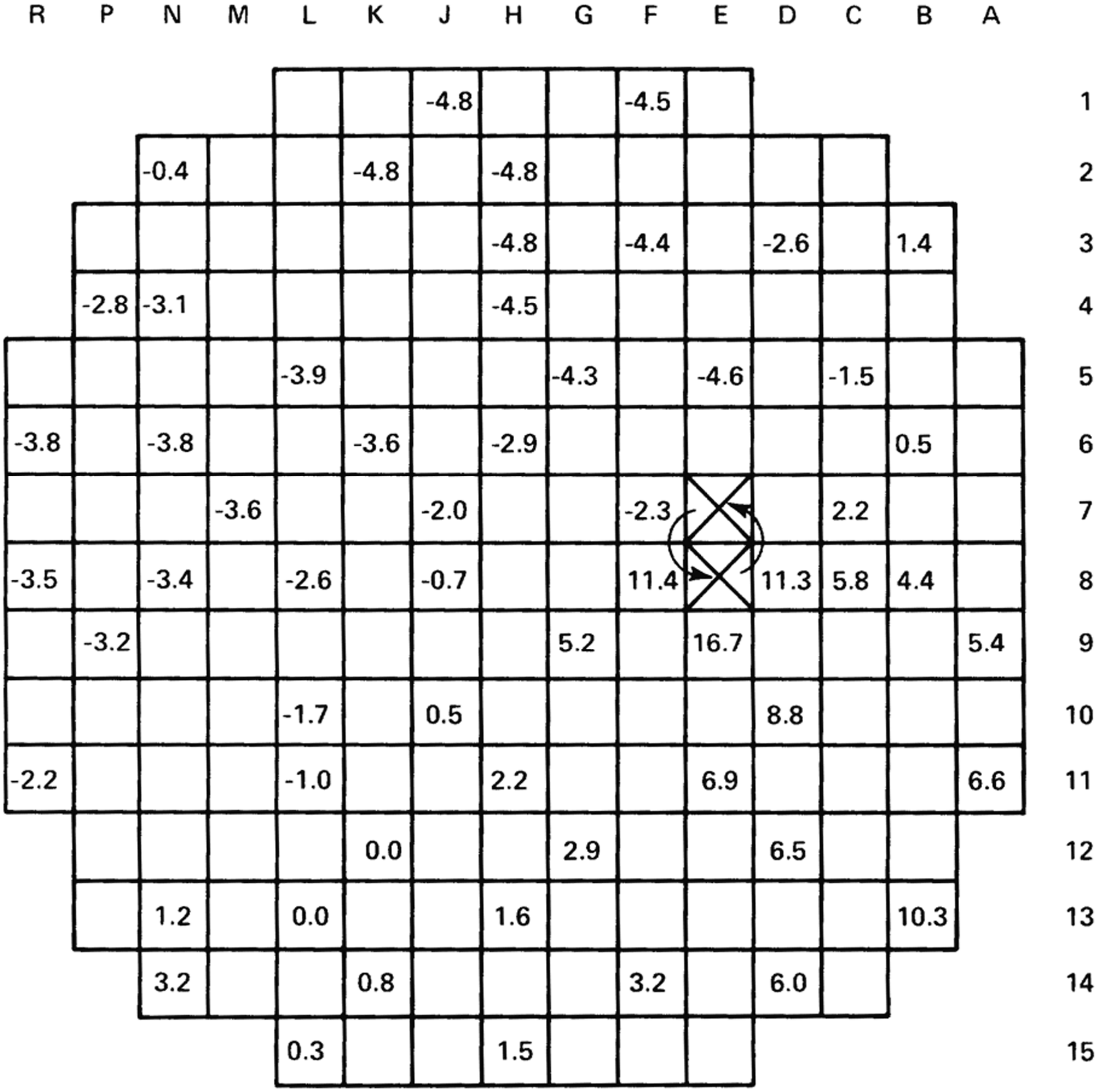
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

REPRESENTATIVE % CHANGE IN LOCAL ASSY. AVG. POWER FOR INTERCHANGE BETWEEN REGION 1 AND REGION 3 ASSY.

FIGURE 15.4.7–1



	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							-4.8			-4.5					
2			-0.4			-4.8		-4.8							
3								-4.8		-4.4		-2.6		1.4	
4		-2.8	-3.1					-4.5							
5					-3.9				-4.3		-4.6		-1.5		
6	-3.8		-3.8			-3.6		-2.9						0.5	
7				-3.6			-2.0			-2.3			2.2		
8	-3.5		-3.4		-2.6		-0.7			11.4		11.3	5.8	4.4	
9		-3.2							5.2		16.7				5.4
10					-1.7		0.5					8.8			
11	-2.2				-1.0			2.2			6.9				6.6
12						0.0			2.9			6.5			
13			1.2		0.0			1.6						10.3	
14			3.2			0.8				3.2		6.0			
15					0.3			1.5							

CASE B-1

REV 14 10/07

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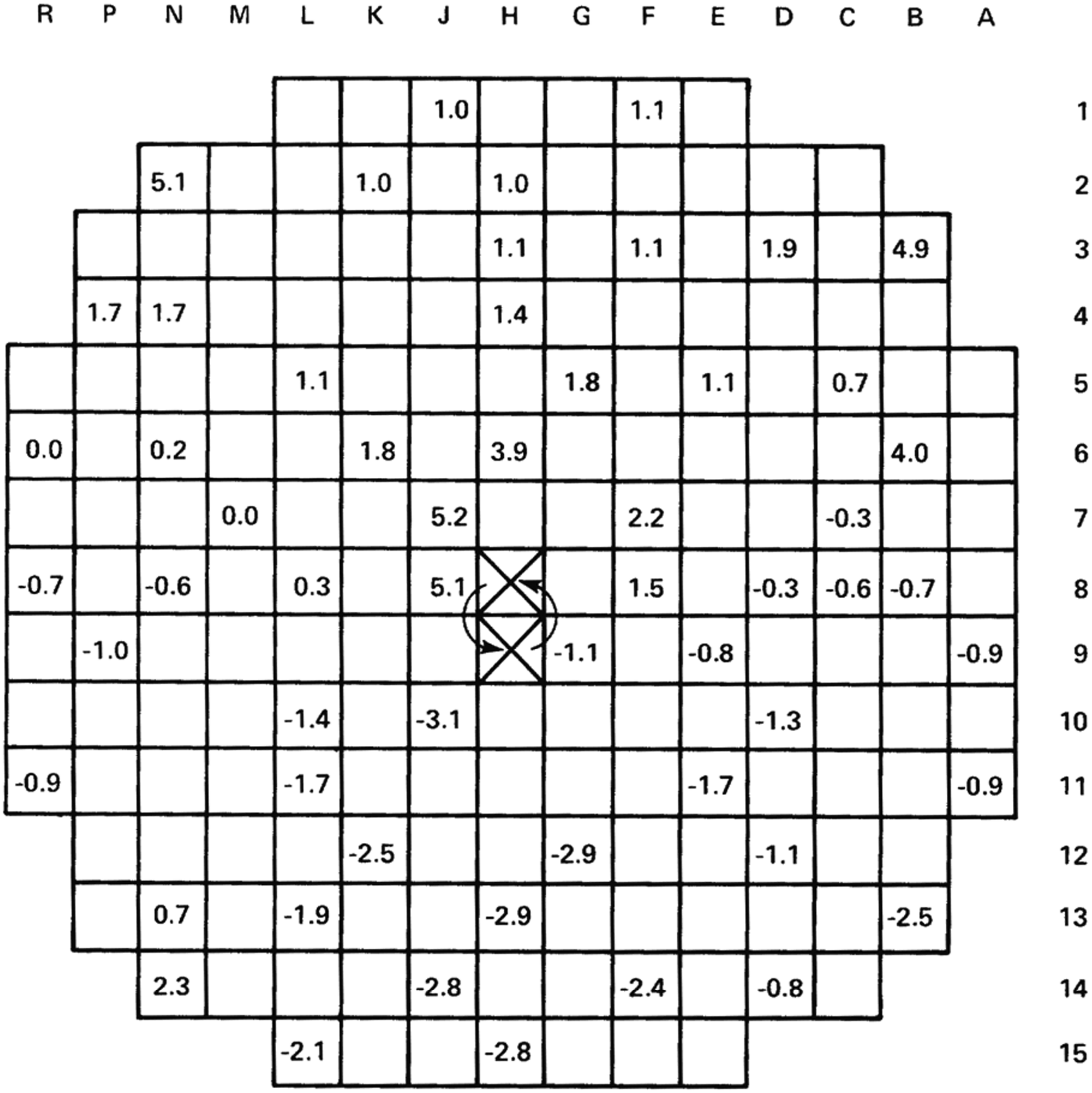
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

REPRESENTATIVE % CHANGE IN LOCAL ASSY. AVG. POWER FOR INTERCHANGE BETWEEN REGION 1 AND REGION 2 ASSY. WITH BP RODS RETAINED BY THE REGION 2 ASSY.

FIGURE 15.4.7–2



	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							1.0			1.1					
2			5.1			1.0		1.0							
3								1.1		1.1		1.9		4.9	
4		1.7	1.7					1.4							
5					1.1				1.8		1.1		0.7		
6	0.0		0.2			1.8		3.9						4.0	
7				0.0			5.2			2.2			-0.3		
8	-0.7		-0.6		0.3		5.1			1.5		-0.3	-0.6	-0.7	
9		-1.0							-1.1		-0.8				-0.9
10					-1.4		-3.1					-1.3			
11	-0.9				-1.7						-1.7				-0.9
12						-2.5			-2.9			-1.1			
13			0.7		-1.9			-2.9						-2.5	
14			2.3				-2.8			-2.4		-0.8			
15					-2.1			-2.8							

CASE B-2

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UNIT 1 AND UNIT 2

REPRESENTATIVE % CHANGE IN LOCAL ASSY. AVG. POWER FOR INTERCHANGE BETWEEN REGION 1 AND REGION 2 ASSY. WITH THE BP RODS TRANFERRED TO REGION 1 ASSY.

FIGURE 15.4.7–3

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							-2.2			-2.1					
2			2.0			-2.0		-2.1							
3								-1.5		-1.6		-1.0		2.0	
4		-0.9	-1.0					-0.4							
5					-0.4				1.2		-0.5		-1.4		
6	-2.1		-1.6			2.3		5.7						-2.0	
7				-3.2			9.7			4.4			-1.7		
8	-2.3		-1.6		1.8		13.6	☒		5.6		-0.4	-1.6	-2.1	
9		-2.2							9.7		1.1				-2.2
10					0.3		4.5					-0.9			
11	-1.9				-0.4			1.8			-0.5				-1.9
12						-0.9			-0.6			-1.1			
13			0.4		-1.4			-1.5						2.0	
14			2.0				-2.1			-2.0		-0.9			
15					-1.9			-2.2							

CASE C

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UNIT 1 AND UNIT 2

REPRESENTATIVE % CHANGE IN LOCAL ASSY. AVG. POWER FOR ENRICHMENT ERROR (REGION 2 ASSY. LOADED INTO CORE CENTRAL POSITION)

FIGURE 15.4.7–4

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							-11			-14					
2			0.4			-9.2		-12							
3								-12		-14		-15		-13	
4		3.2	1.2					-11							
5					-1.5				-12		-15		-16		
6	9.8		7.1			-1.6		-8.0						-16	
7				9.2			-2.3			-12			-14		
8	20.0		17.8		10.8		0.8			-10		-14	-15	-16	
9		27.2							-5.5		-11				-15
10					20.7		5.8					-12			
11	42.0		☒		23.6			1.9			-8.6				-13
12						14.0			-1.7			-8.9			
13			38.6		20.4			2.8						-7.0	
14			35.9				7.0			-3.3		-6.3			
15					15.3			2.9							

CASE D

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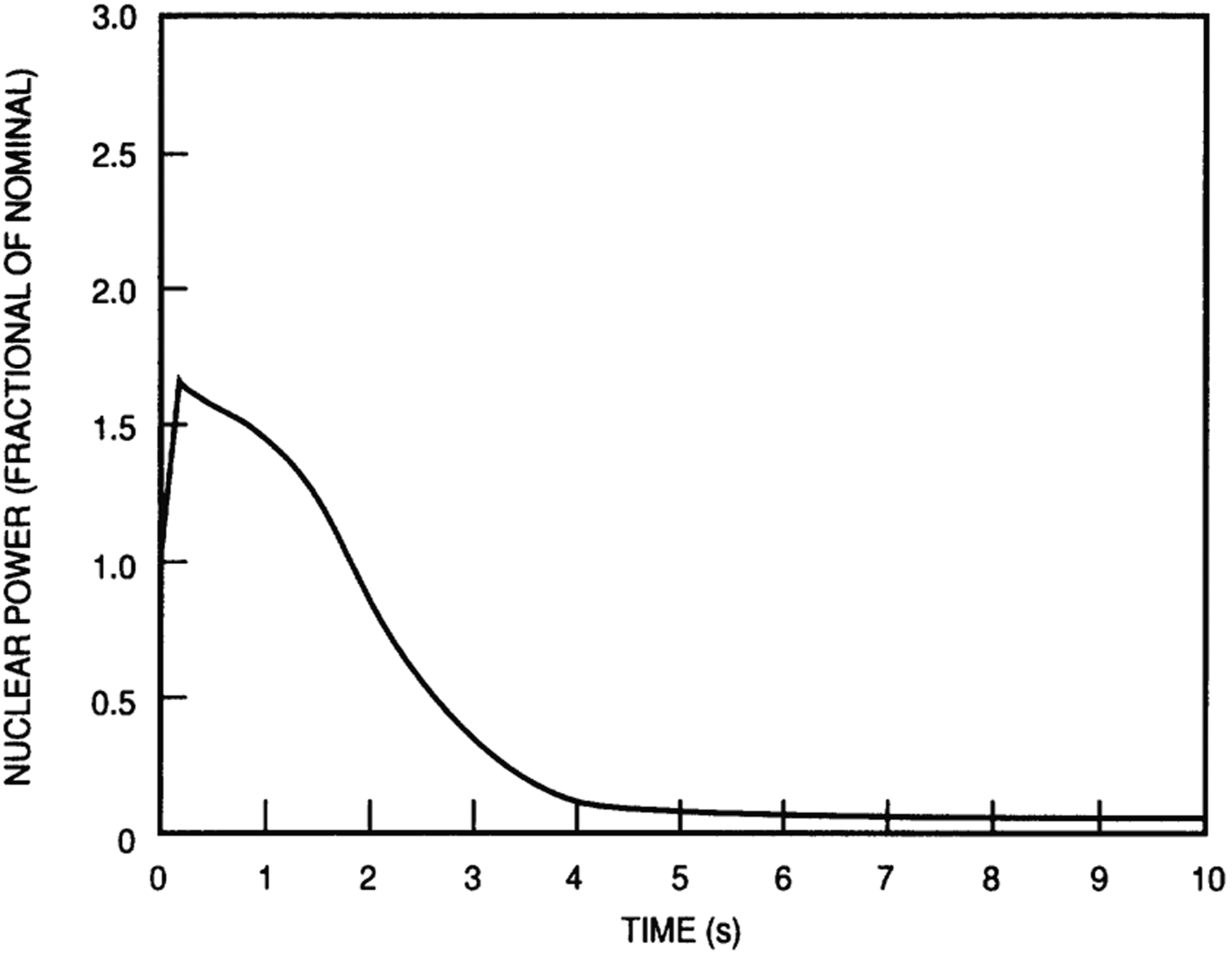
UNIT 1 AND UNIT 2

REPRESENTATIVE % CHANGE IN LOCAL ASSY. AVG. POWER FOR LOADING REGION 2 ASSY. INTO REGION 1 POSITION NEAR CORE PERIPHERY

FIGURE 15.4.7–5



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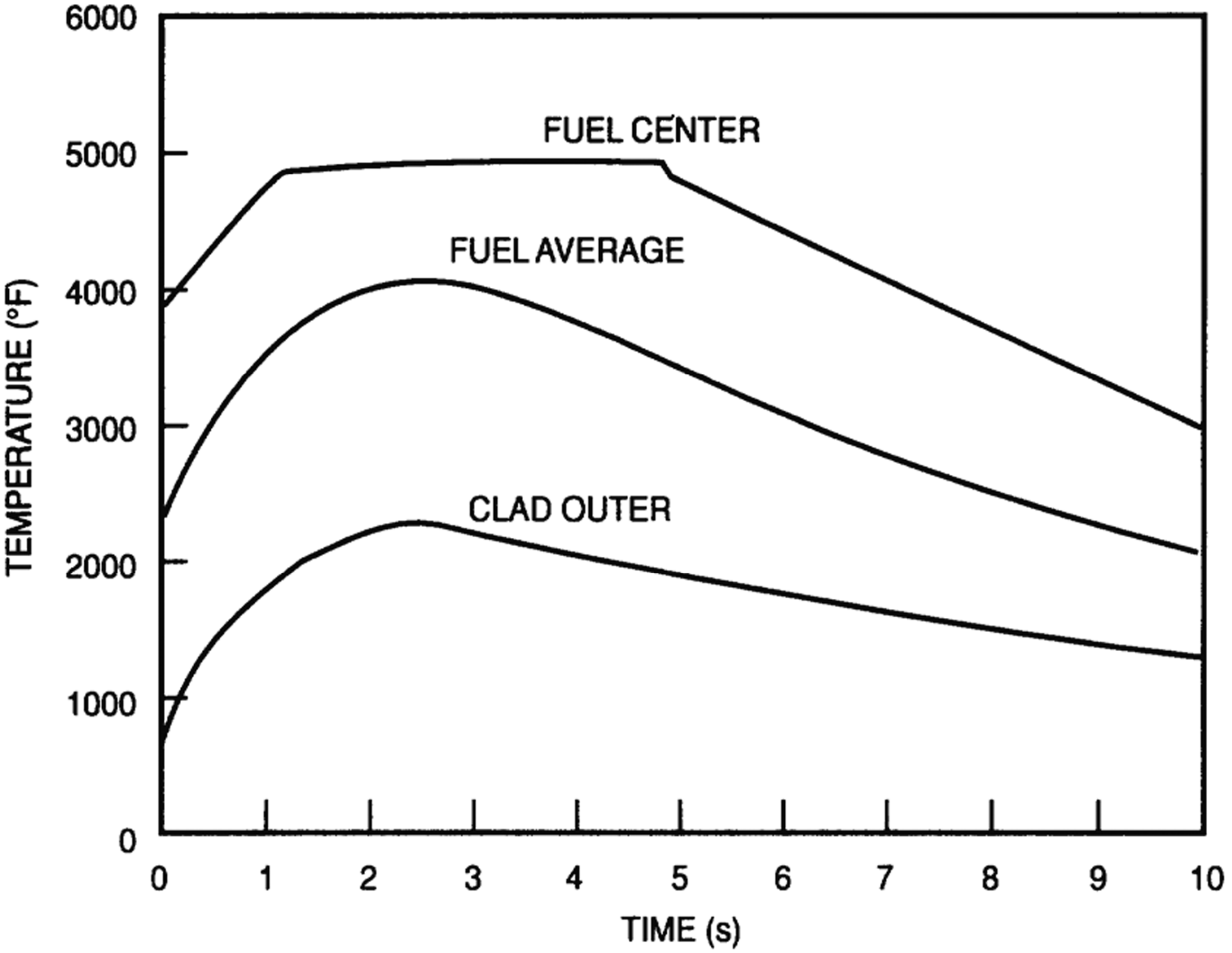
UNIT 1 AND UNIT 2

NUCLEAR POWER TRANSIENT
BOL FULL POWER

FIGURE 15.4.8–1



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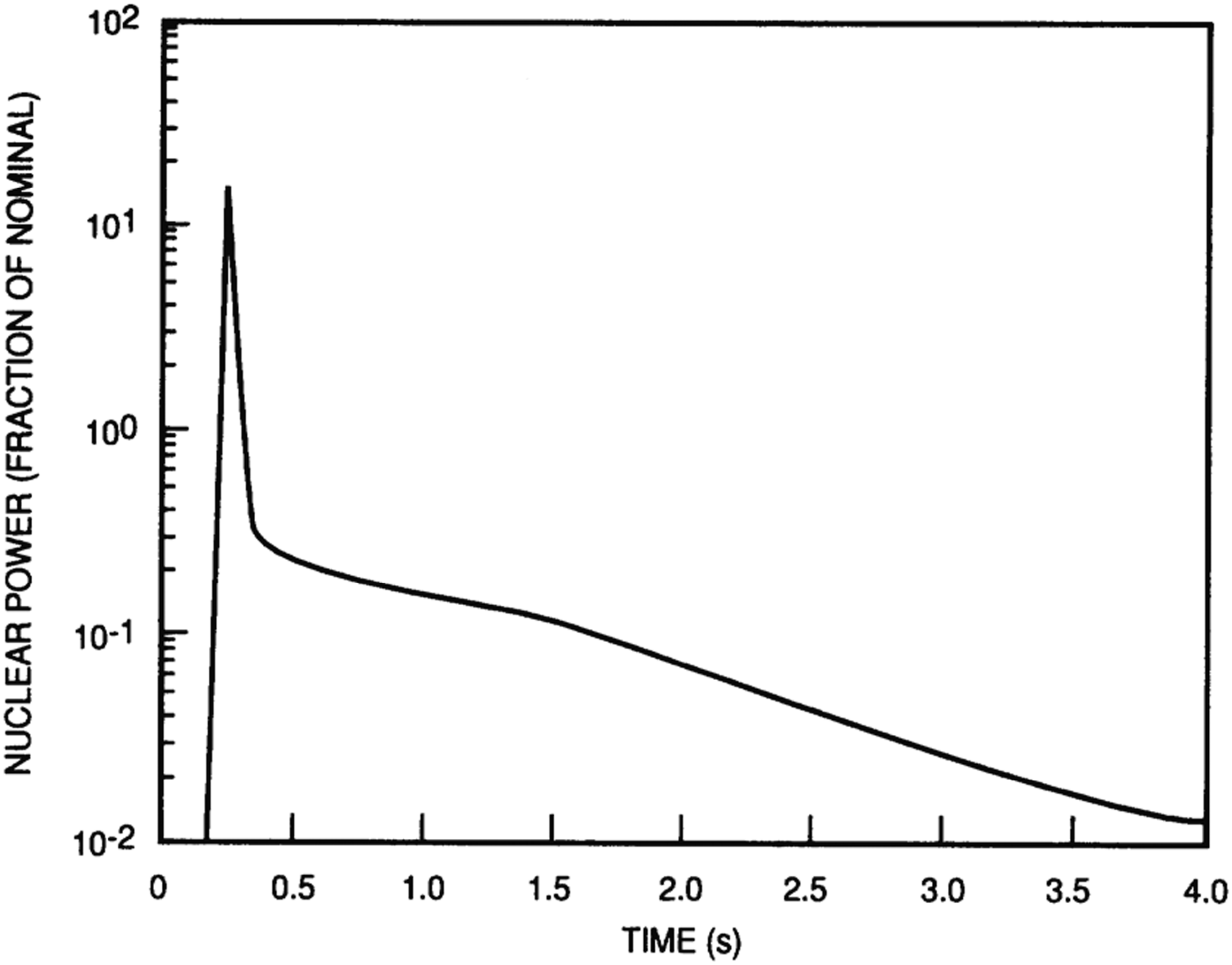
UNIT 1 AND UNIT 2

HOT SPOT FUEL AND CLAD TEMPERATURE VS. TIME BOL FULL POWER

FIGURE 15.4.8–2



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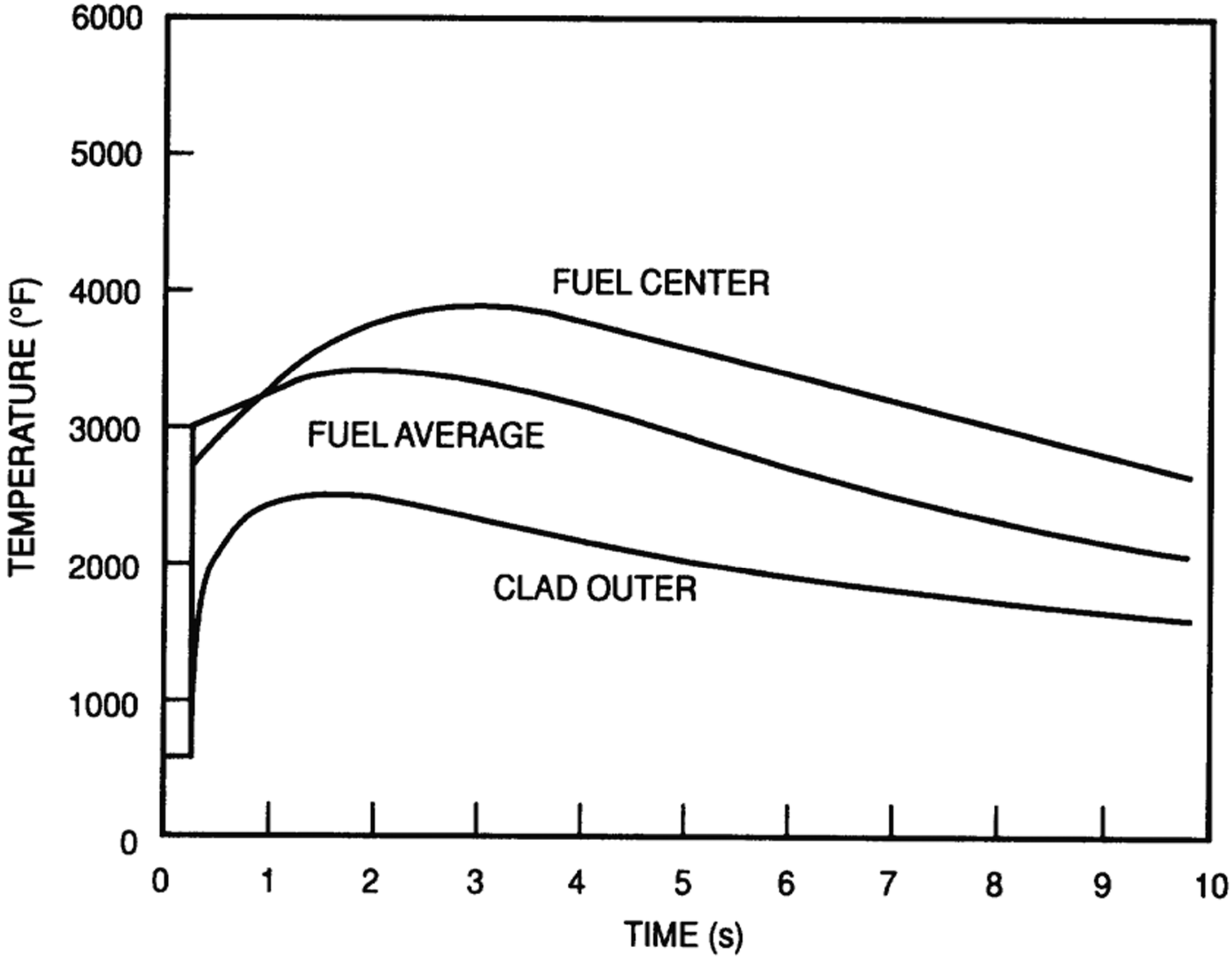
UNIT 1 AND UNIT 2

NUCLEAR POWER TRANSIENT
EOL ZERO POWER

FIGURE 15.4.8–3



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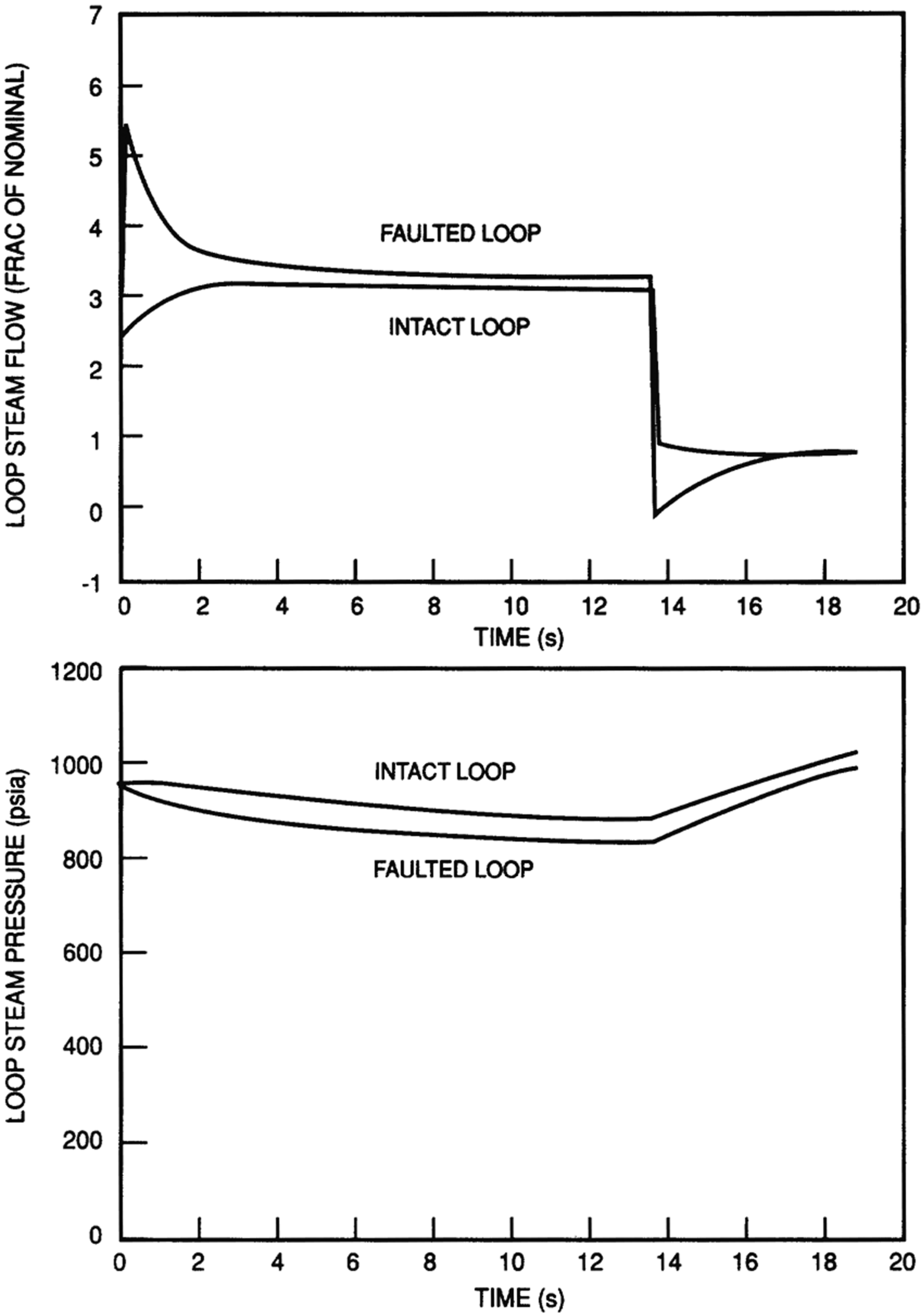
UNIT 1 AND UNIT 2

HOT SPOT FUEL AND CLAD TEMPERATURE VS. TIME EOL ZERO POWER

FIGURE 15.4.8–4



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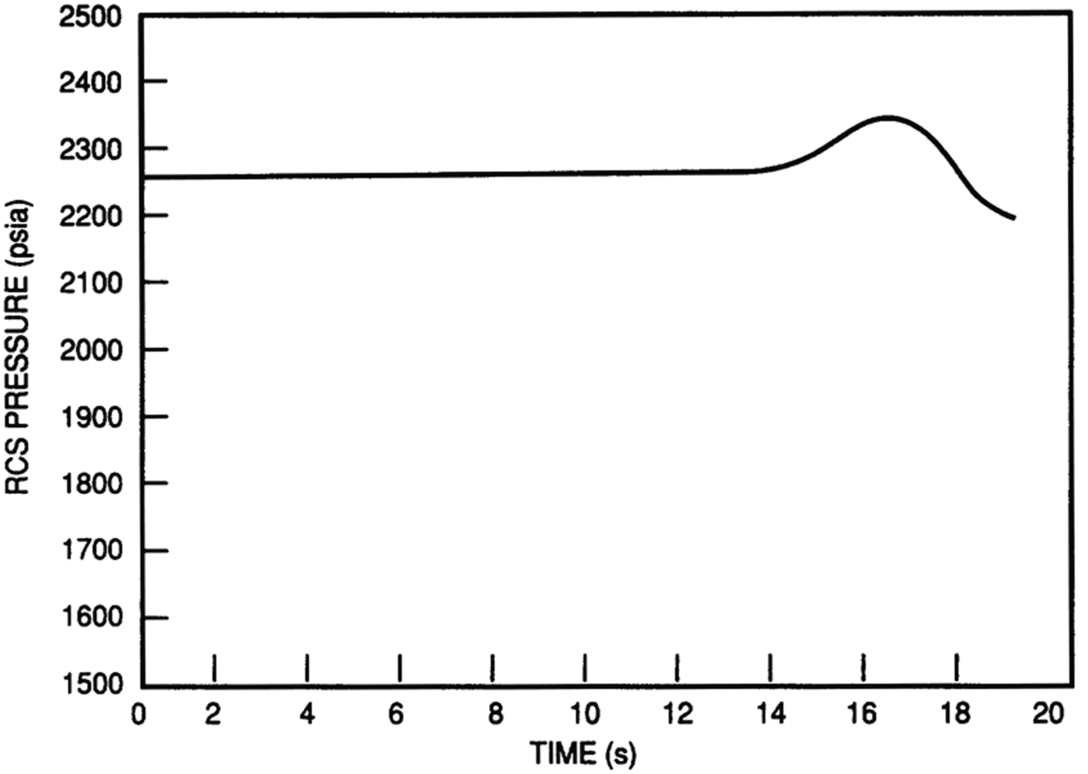
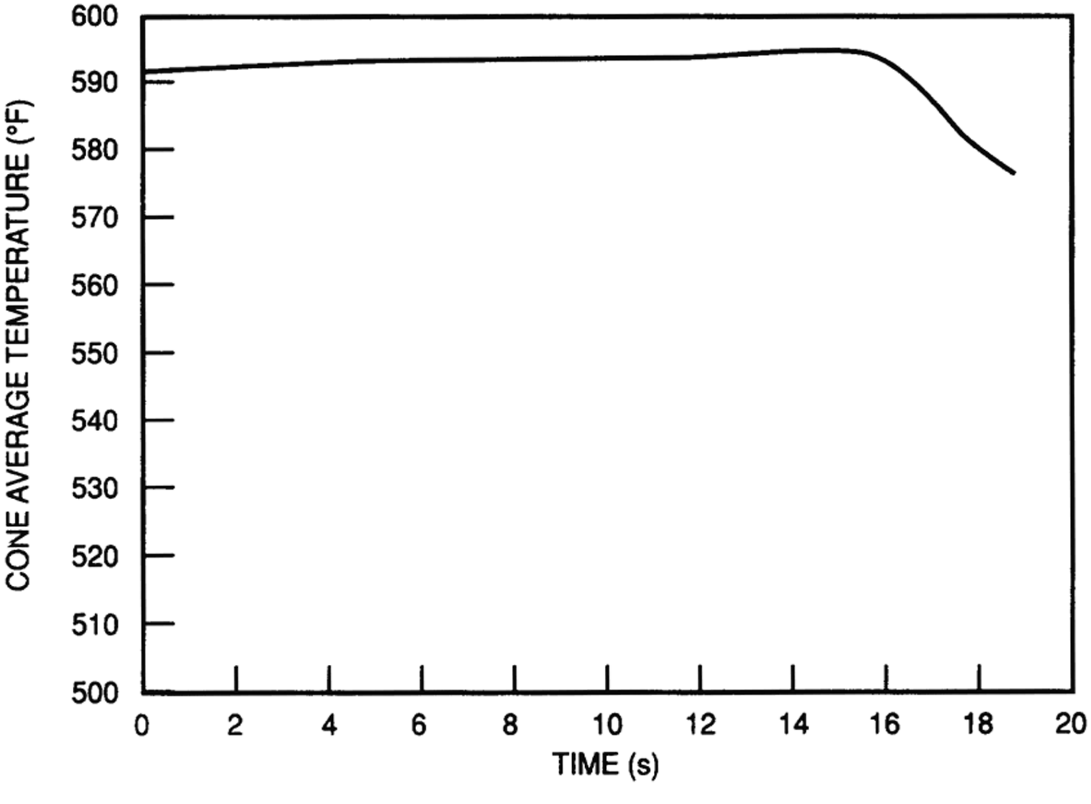
UNIT 1 AND UNIT 2

STEAM LINE BREAK COINCIDENT WITH CONTROL ROD WITHDRAWAL: STEAM FLOW AND STEAM PRESSURE

FIGURE 15.4.9–1





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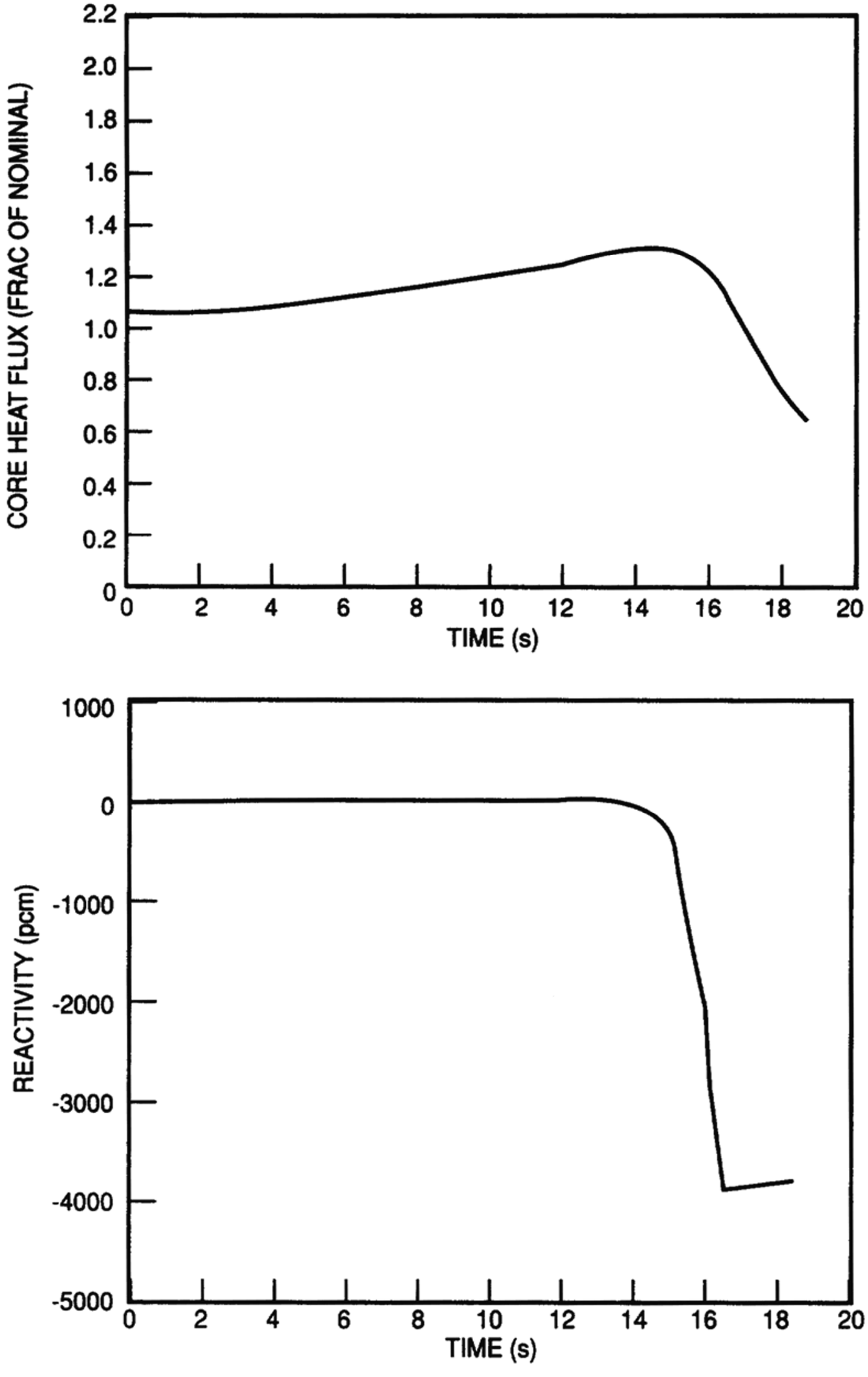
UNIT 1 AND UNIT 2

STEAM LINE BREAK COINCIDENT WITH CONTROL ROD WITHDRAWAL: RCS PRESSURE AND CORE AVERAGE TEMPERATURE

FIGURE 15.4.9–2



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UNIT 1 AND UNIT 2

STEAM LINE BREAK COINCIDENT WITH CONTROL ROD WITHDRAWAL: CORE HEAT FLUX AND REACTIVITY

FIGURE 15.4.9–3

15.5 INCREASE IN REACTOR COOLANT INVENTORY

Discussion and analysis of the following events which cause an increase in reactor coolant inventory are presented in this section:

A. Inadvertent operation of the emergency core cooling system (ECCS) during power operation.

B. Chemical and volume control system (CVCS) malfunction that increases reactor coolant inventory.

C. A number of boiling water reactor (BWR) transients (not applicable to VEGP).

15.5.1 INADVERTENT OPERATION OF THE EMERGENCY CORE COOLING SYSTEM DURING POWER OPERATION

15.5.1.1 Identification of Causes and Accident Description

Inadvertent operation of the Emergency Core Cooling System (ECCS) at power could be caused by operator error, test sequence error, or a false electrical actuation signal. A spurious signal initiated after the logic circuitry in one solid-state protection system train for any of the following engineered safety feature (ESF) functions could cause this incident by actuating the ESF equipment associated with the affected train.

A. High containment pressure.

B. Low pressurizer pressure.

C. Low steam line pressure.

Following the actuation signal, the suction of the coolant charging pumps diverts from the volume control tank to the refueling water storage tank. Simultaneously, the valves isolating the injection header from the charging pumps open and the normal charging line isolation valves close. The charging pumps force the borated water from the RWST through the pump discharge header, the injection line, and into the cold leg of each loop. The safety injection (SI) pumps also start automatically but provide no flow when the reactor coolant system (RCS) is at normal pressure. The passive accumulator tank safety injection and low head system are available. However, they do not provide flow when the reactor coolant system (RCS) is at normal pressure.

A SI signal normally results in a direct reactor trip and a turbine trip. However, any single fault that actuates the ECCS will not necessarily produce a reactor trip. If an SI signal generates a reactor trip, the operator should determine if the signal is spurious. If the SI signal is determined to be spurious, the operator should terminate SI and maintain the plant in the hot standby condition as determined by appropriate recovery procedures. If repair of the ESF actuation system instrumentation is necessary, future plant operation will be in accordance with the Technical Specifications.

If the reactor protection system does not produce an immediate trip as a result of the spurious SI signal, the reactor experiences a negative reactivity addition due to the injected boron, which causes a decrease in reactor power. The power mismatch causes a drop in T_{avg} and consequent coolant shrinkage. The pressurizer pressure and water level decrease. Load decreases due to the effect of reduced steam pressure on load after the turbine throttle valve is fully open. If automatic rod control is used, these effects will lessen until the rods have moved out of the core. The transient is eventually terminated by the reactor protection system low pressurizer pressure trip or by manual trip.

The time to trip is affected by initial operating conditions. These initial conditions include the core burnup history which affects initial boron concentration, rate of change of boron concentration, and Doppler and moderator coefficients.

15.5.1.2 Analysis of Effects and Consequences

15.5.1.2.1 Method of Analysis

Inadvertent operation of the ECCS is analyzed using the LOFTRAN(1) computer code. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, feedwater system, steam generator, steam generator safety valves, and the effect of the SI system. The code computes pertinent plant variables including temperatures, pressures, and power level.

Inadvertent operation of the ECCS at power is classified as a Condition II event, a fault of moderate frequency. The criteria established for Condition II events include the following:

A. Pressure in the reactor coolant and main steam systems should be maintained below 110 percent of the design values.

B. Fuel cladding integrity shall be maintained by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains above the 95/95 DNBR limit for PWRs.

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

To address criterion C, the analysis historically used the more restrictive criterion that a water-solid pressurizer condition be precluded when the pressurizer is at or above the set pressure of the pressurizer safety valves (PSVs). This addressed any concerns regarding subcooled water relief through the plant PSVs. The current analysis conservatively predicts the minimum time to reaching a pressurizer water solid condition and the resulting water relief characteristics (if applicable). An evaluation of the PSV operability for temporary water relief under the specific conditions of this transient was performed. The evaluation demonstrated that a more serious plant condition will not result following an inadvertent ECCS actuation by confirming that the RCS pressure boundary remains intact for the post-transient plant shutdown.

The inadvertent ECCS actuation at power event is analyzed to determine both the minimum DNBR value and maximum pressurizer volume (or minimum time to a pressurizer water-solid condition and subsequent water relief). The most limiting case with respect to DNB is a minimum reactivity feedback condition with the plant assumed to be in manual rod control. Because of the power and temperature reduction during the transient, operating conditions do not approach the core limits.

For maximizing the potential for pressurizer filling, the most limiting case is a maximum reactivity feedback condition with an immediate reactor trip, and subsequent turbine trip, on the initiating SI signal. The transient results are presented for each case.

The analysis assumptions are as follows:

A. Initial Operating Conditions

The DNB case is analyzed with the Revised Thermal Design Procedure as described in WCAP-11397-P-A (reference 2). Initial reactor power, RCS pressure, and temperature are assumed to be at the nominal full power values. Uncertainties in initial conditions are included in the limit DNBR as described in reference 2. VEGP has a vessel average temperature window from 570°F to 588.4°F; therefore, cases at each end of this window are analyzed for pressurizer filling. The initial conditions for these cases assume maximum uncertainties on power (+2 percent), vessel average temperature (-5°F), and pressurizer pressure (-50 psia).

B. Moderator and Doppler Coefficients of Reactivity

The minimum feedback case (DNB) assumes a positive (+7 pcm/°F) moderator temperature coefficient and a low absolute value Doppler power coefficient at beginning of life (BOL). The maximum feedback case (pressurizer filling) assumes a large (absolute value) negative moderator temperature coefficient and a most-negative Doppler power coefficient.

C. Reactor Control

For the DNB case (without direct reactor trip on SI) the reactor is assumed to be in manual rod control.

D. Pressurizer Pressure Control

For the DNB case, the pressurizer heaters are inoperable. This assumption yields a higher rate of pressurizer decrease. The pressurizer spray portion of the pressurizer pressure control system is assumed available in order to minimize the RCS pressure. The PORVs are also assumed operable. PORVs reduce RCS pressure which is conservative for DNB analyses.

For the pressurizer filling cases, the following pressurizer pressure control system assumptions are made:

- Normal operation of the pressurizer spray is assumed. Spray actuates as a result of the pressure increase. Spray is assumed to be fully effective in condensing steam and thus maintaining a lower pressure until the water level increases to the point where the spray nozzle is submerged (i.e., when the pressurizer is nearly filled). This maximizes the ECCS injection flow.
- Operation of the pressurizer heaters minimizes the time to fill the pressurizer and subsequent water relief through the PSV(s). This is important since the maximum number of water relief cycles supported in the valve operability evaluation is four. Operation of the heaters, however, increases the temperature of the water that is relieved. Colder water relief temperatures are more limiting with respect to valve operability. Therefore, to ensure that both criteria are conservatively addressed, cases have been analyzed assuming both normal heater operation and no heater operation.
- PORVs are not assumed as an automatic pressure control system for the pressurizer filling case. Automatic actuation of the PORVs would directly mitigate the event consequences by preventing water relief through the PSVs. Operator action to make one PORV available following an acceptable

delay is credited in the analysis to mitigate the event. Should the PORVs fail due to water relief, the block valves would be available to isolate the RCS.

E. ECCS Injection

The inadvertent ECCS analysis models a maximum ECCS flow rate that bounds operation at the original design which included a positive displacement pump and the plant configuration with the replacement centrifugal pump. Safety injection (SI) is actuated at time zero, with flow injected to the RCS from two high-head centrifugal charging pumps plus the normal charging pump. Both high- head charging and SI pumps automatically start on an SI signal, and the associated alternate minimum flow protection lines receive a signal to open at high RCS back pressures. The failure of the normal charging pump to be stripped from the bus was taken as the single failure since it results in higher flow rates than the failure to open one safety-related miniflow path. The analysis also assumes zero injection line purge volume for calculation simplicity; thus, the boration transient begins immediately in the analysis.

F. Turbine Load

For the DNB case (without direct reactor trip/turbine trip on SI), the turbine load remains constant until the governor drives the throttle valve wide open. After the throttle valve is full open, turbine load decreases as steam pressure drops.

G. Reactor Trip

Reactor trip is initiated by a low pressurizer pressure signal at 1935 psia for the DNB case. The pressurizer filling case assumes reactor trip on the initiating SI signal.

H. Decay Heat

Core residual heat generation is based on the 1979 version of ANS 5.1 (reference 3). 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 is assumed.

I. Pressurizer Safety Valves

The safety valves open at a pressure of 2425 psia which corresponds to a tolerance of -2 percent relative to the set pressure of 2475 psia. The valves are assumed to close at a pressure of 2300 psia, which corresponds to a blowdown of 5 percent below the opening pressure of 2425 psia.

J. Operator Actions

An operator action, to make one PORV available for water relief, was assumed at 590 seconds in the pressurizer fill case initialized from the low end of the vessel average window (570.7°F), and 625 seconds was assumed for the pressurizer fill case initialized from the high end of the vessel average window (588.4°F).

15.5.1.2.2 Results

The transient responses for the DNB and limiting pressurizer filling cases are shown in figure 15.5.1-1. Table 15.5.1-1 shows the calculated sequence of events.

For the DNB case, nuclear power starts decreasing immediately due to boron injection, but steam flow does not decrease until later in the transient when the turbine throttle valve is wide open. The mismatch between load and nuclear power causes T_{avg}, pressurizer water level, and pressurizer pressure to drop. The reactor trips and control rods start moving into the core when the pressurizer pressure reaches the pressurizer low pressure trip setpoint. The DNBR increases throughout the transient.

For the pressurizer filling case, reactor trip occurs at event initiation followed by a rapid initial cooldown of the RCS. 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 the pressure and level transients to rapidly turn around. Pressurizer water level then increases throughout the transient. For the cases with operation of the heaters, the number of PSV water relief cycles is four; whereas, for the cases without operation of the heaters, the number of PSV water relief cycles is three. The cases without operation of the heaters show a slightly lower minimum final water relief temperature which is a factor considered in determining the limiting PSV operability condition. However, although the minimum final water relief temperature of the cases with operation of the heaters is slightly higher, these cases are considered to be more limiting since the number of PSC water relief cycles is more.

In the case initialized from the low end of the vessel average window (570.7°F), the analysis assumes that at 590 seconds the operator manually opens a PORV. For the case initialized from the high end of the vessel average window (588.4°F), this operator action is assumed at 625 seconds. In each of these cases, once the PORV is fully open, the RCS begins to depressurize to below the pressure where the safety valves reseat.

15.5.1.3 Conclusions

Results of the analysis show that spurious ECCS operation without immediate reactor trip does not present any hazard to the integrity of the RCS with respect to DNBR. The minimum DNBR is never less than the initial value. Thus, there will be no cladding damage and no release of fission products to the RCS. If the reactor does not trip immediately, the low pressurizer pressure reactor trip will provide protection. This trips the turbine and prevents excess cooldown, which expedites recovery from the incident.

With respect to pressurizer filling, the pressurizer may reach a water-solid condition. However, the resulting potential water relief will not impair PSV operability. The RCS pressure boundary will therefore remain intact and the event will not generate a more serious plant condition.

15.5.1.4 Reference

1. Burnett, T.W.T., et al., "LOFTRAN Code Description," WCAP-7907-P-A, (proprietary), WCAP-7907-A (nonproprietary), April 1984.
2. Friedland, A.J. and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A, April 1989.
3. ANSI/ANS-5.1-1979, "Decay Heat Power in Light Water Reactors," August 29, 1979.

15.5.2 CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTION THAT INCREASES REACTOR COOLANT INVENTORY

An increase in reactor coolant inventory which results from the addition of cold, unborated water to the reactor coolant system (RCS) is analyzed in subsection 15.4.6, Chemical and Volume Control System Malfunction That Results in a Decrease in Boron Concentration in the Reactor Coolant. An increase in reactor coolant inventory which results from the injection of highly borated water into the RCS is analyzed in subsection 15.5.1, Inadvertent Operation of the Emergency Core Cooling System During Power Operation.

15.5.3 A NUMBER OF BOILING WATER REACTOR TRANSIENTS

This subsection is not applicable to the VEGP.

TABLE 15.5.1-1 (SHEET 1 OF 2)

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN AN INCREASE IN REACTOR COOLANT INVENTORY

(Accident: Inadvertent operation of ECCS during power operation)

Case	Event	Time(s)
DNBR case:	SI pumps begin injecting borated water	0.0
	Low pressurizer pressure reactor trip setpoint reached	45.5
	Rods begin to drop	47.5
	Minimum DNBR occurs	(a)

Pressurizer filling case:		Pressurizer Heaters	
		On	Off
A nominal $T_{AVG} = 570.7°F$	SI actuation, reactor trip	0.0	0.0
Operator action to manually open PORV at 590 s	Pressurizer fills with water	451.0	470.5
	PSV opens – cycle #1	482.0	504.5
	PSV closes – cycle #1	486.0	509.0
	PSV opens – cycle #2	516.0	537.5
	PSV closes – cycle #2	520.0	541.5
	PSV opens – cycle #3	547.0	569.0
	PSV closes – cycle #3	551.5	573.0
	PSV opens – cycle #3	579.5	N/A
	PSV closes – cycle #4	584.0	N/A
	Time of last PSV cycle (minimum final water relief temperature)	584.0 (631.5°F)	573.0 (628.4°F)
	Operator action to open PORV	590.0	590.0

TABLE 15.5.1-1 (SHEET 2 OF 2)

Accident	Event	Time(s)	
		Pressurizer Heaters	
		On	Off
A nominal T_{AVG} = 588.4°F	SI actuation, reactor trip	0.0	0.0
Operator action to manually open PORV at 625 s	Pressurizer fills with water	484.5	505.5
	PSV opens – cycle #1	520.5	543.0
	PSV closes – cycle #1	525.0	547.0
	PSV opens – cycle #2	555.0	578.5
	PSV closes – cycle #2	559.0	583.0
	PSV opens – cycle #3	589.5	611.5
	PSV closes – cycle #3	593.5	615.5
	PSV opens – cycle #4	620.5	N/A
	PSV closes – cycle #4	625.0	N/A
	Time of last PSV cycle (minimum final water relief temperature)	625.0 (634.5°F)	615.5 (631.7°F)
	Operator action to open PORV	625.0	625.0

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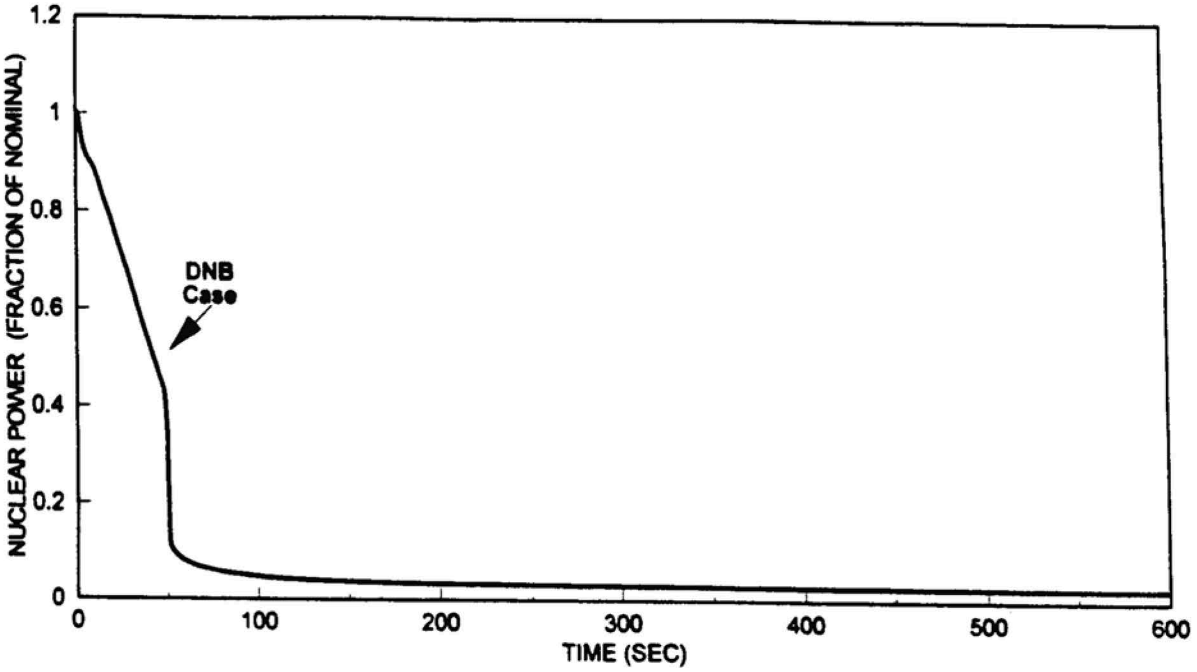
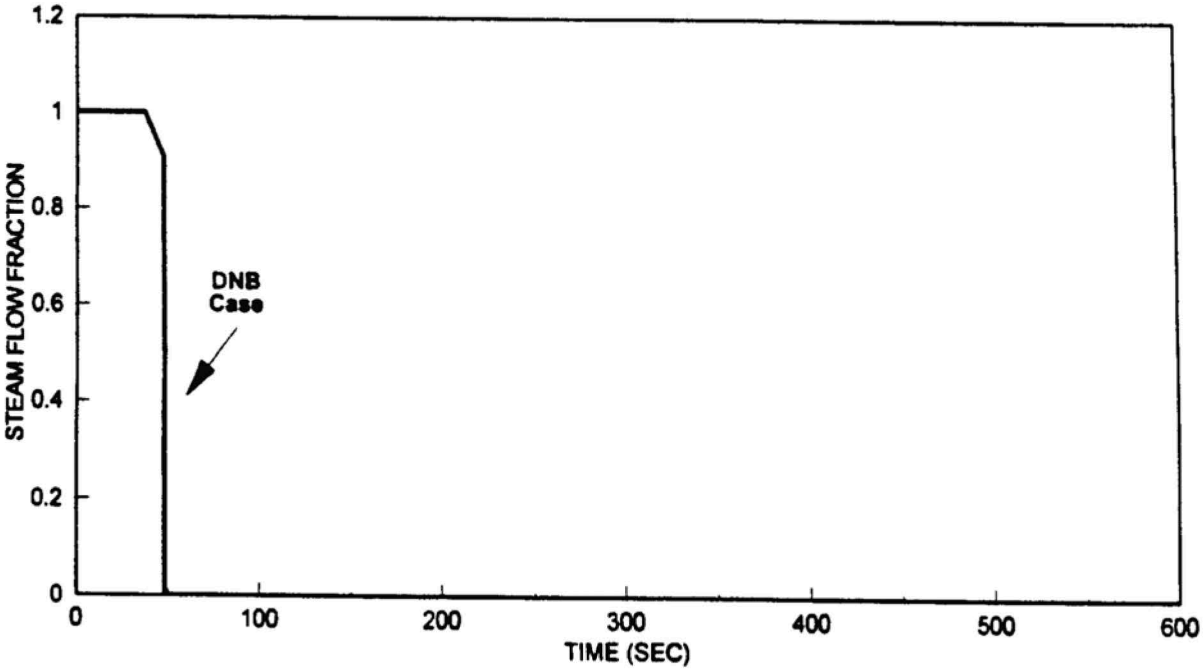
a. DNBR does not decrease below its initial value.





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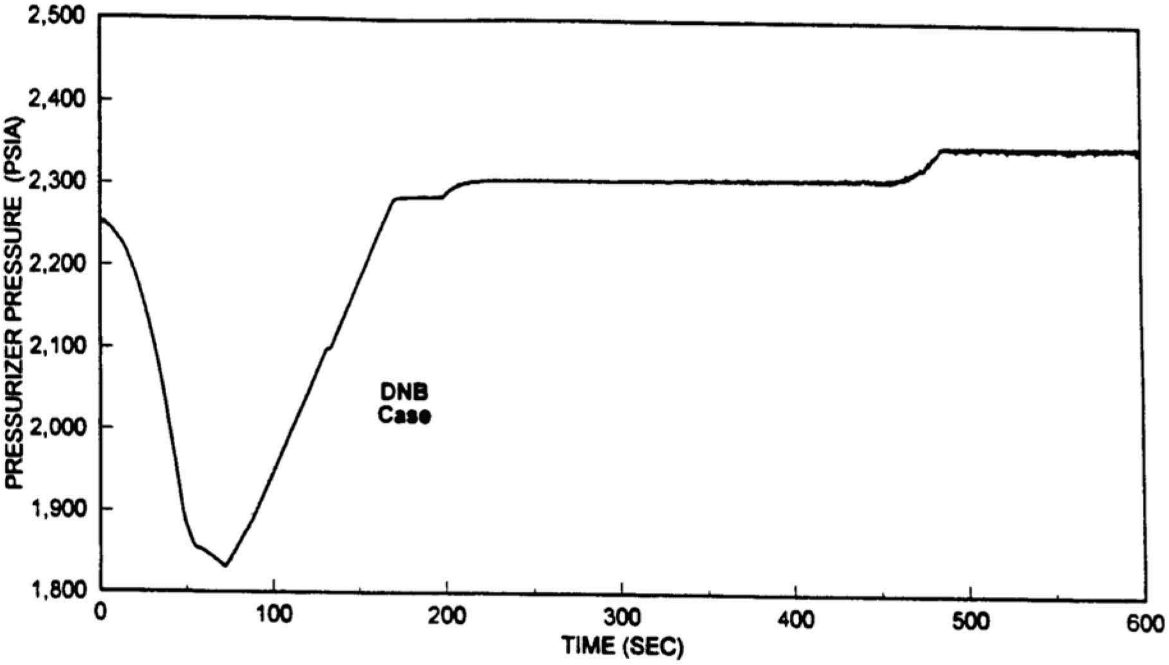
INADVERTENT OPERATION OF ECCS AT POWER

FIGURE 15.5.1-1 (SHEET 1 OF 9)



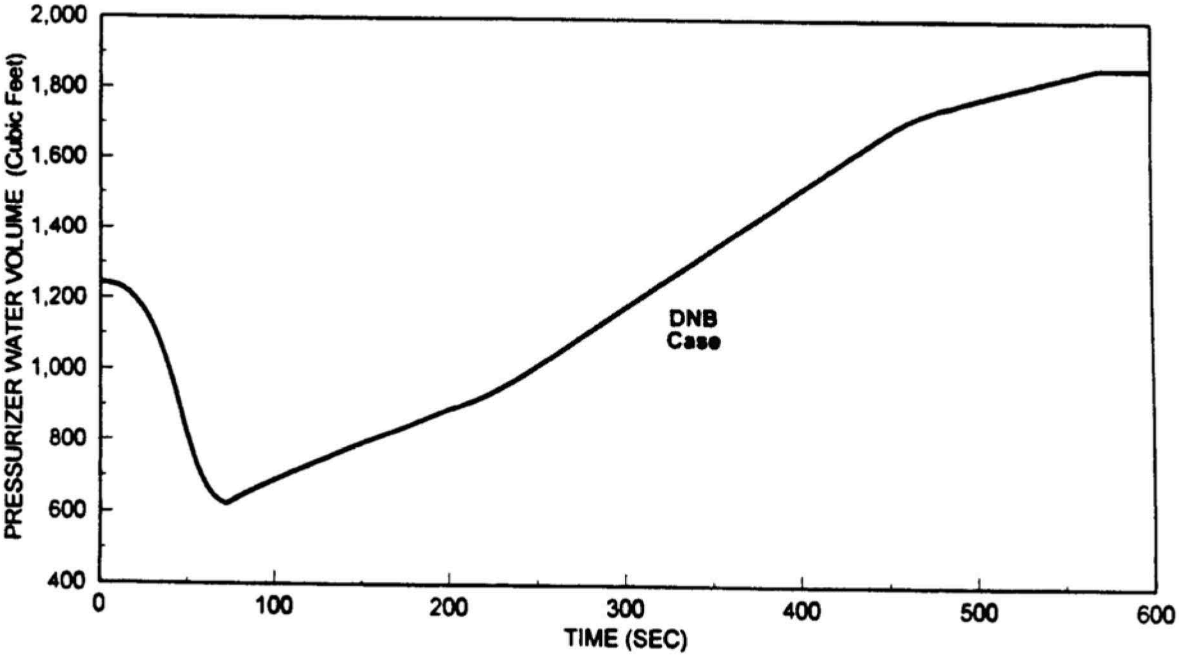


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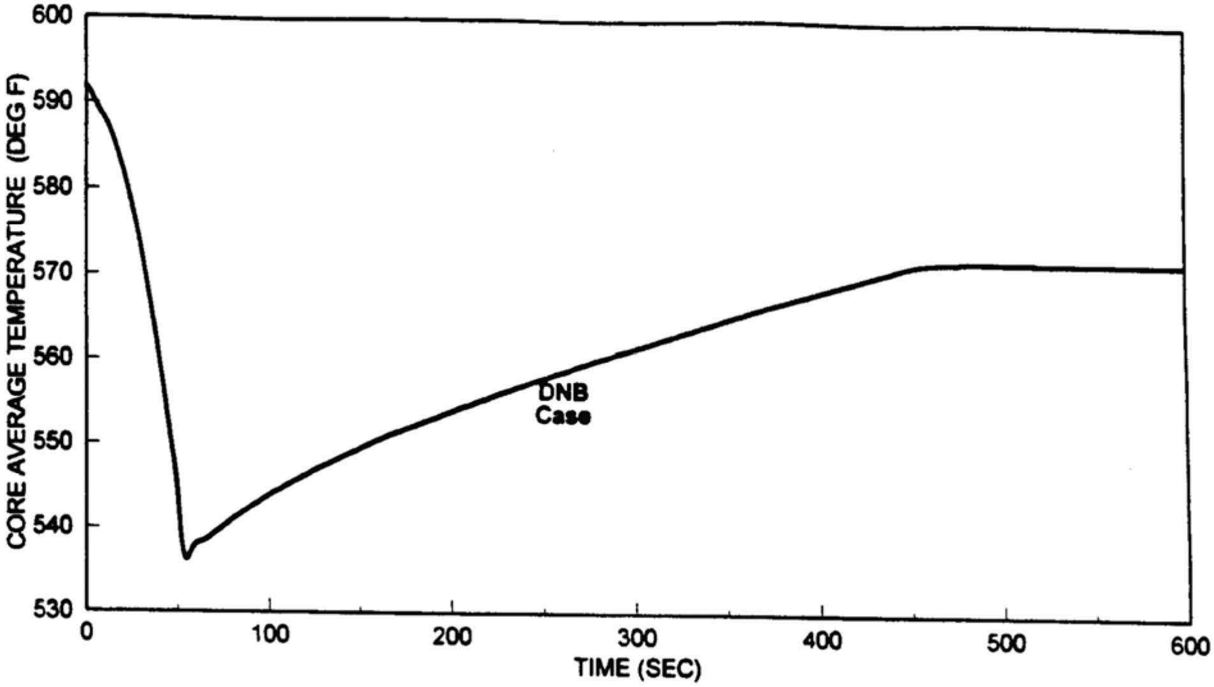
FIGURE 15.5.1-1 (SHEET 2 OF 9)



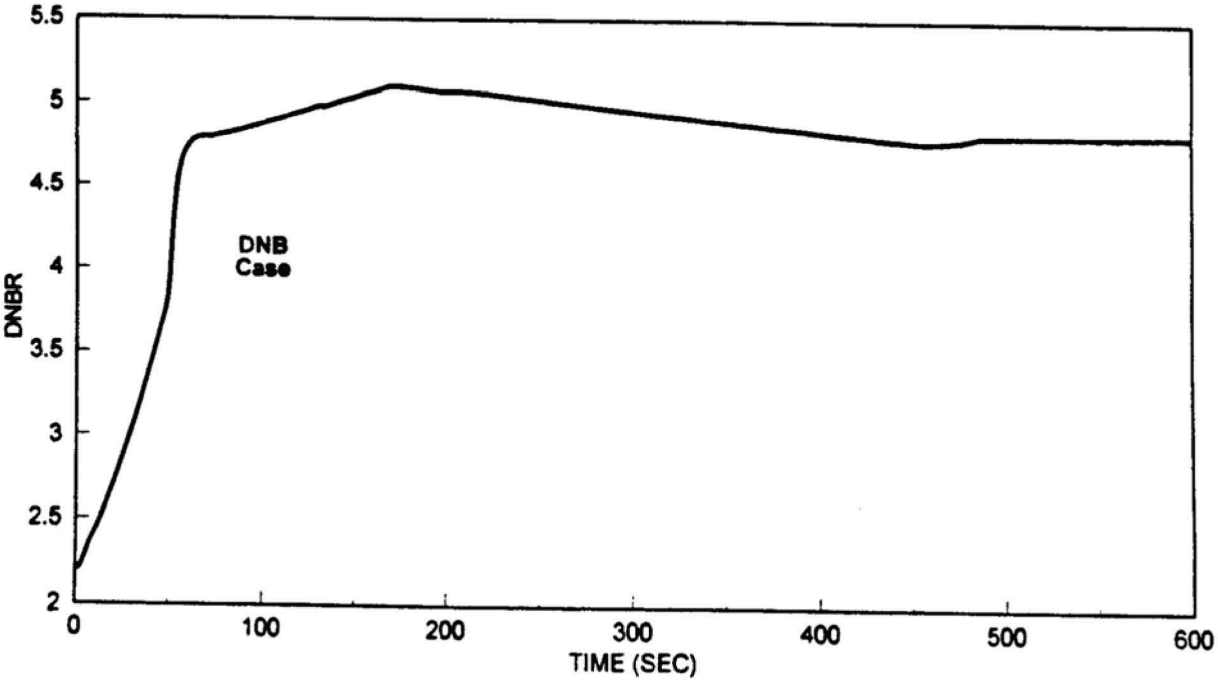


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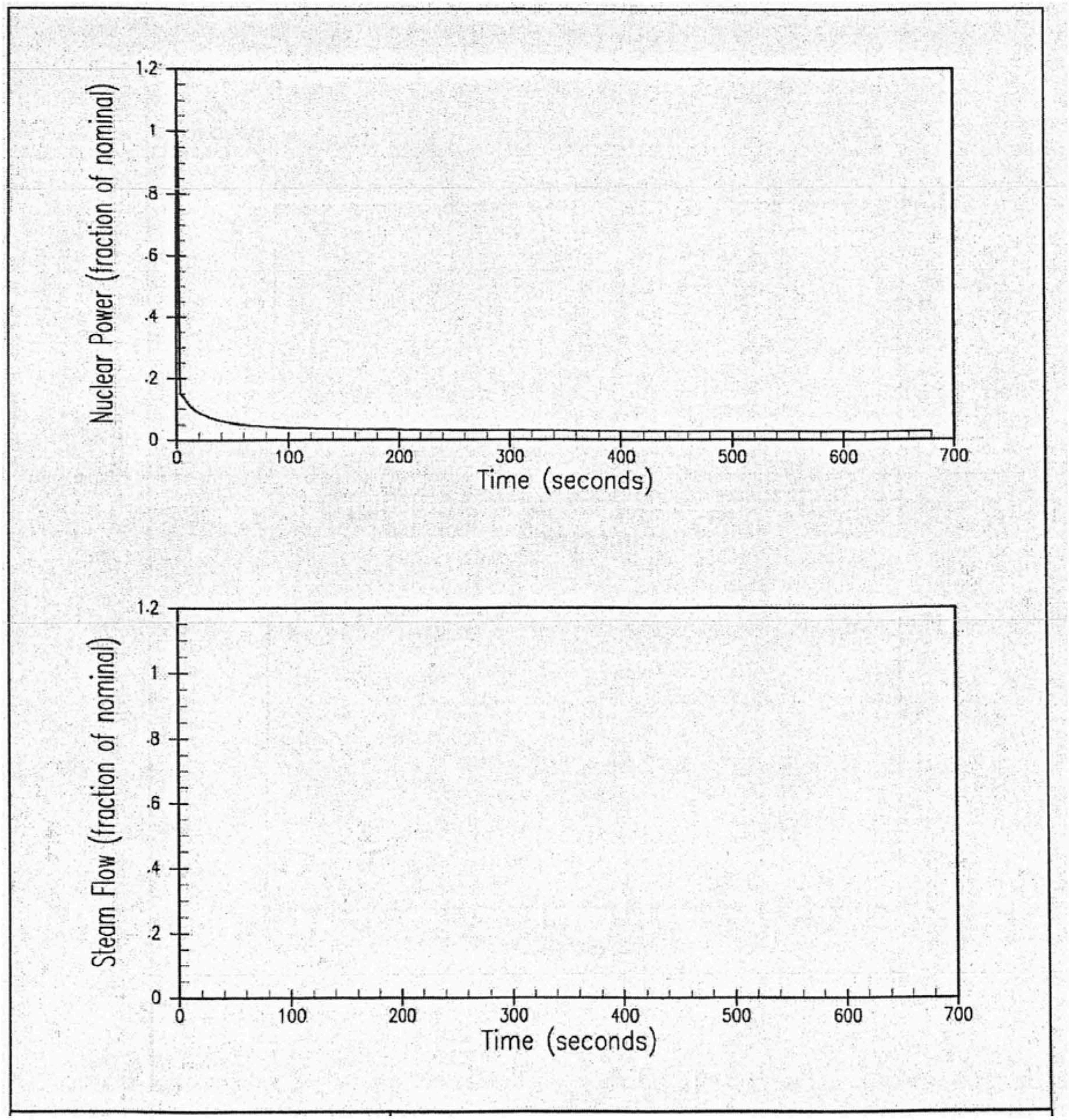
FIGURE 15.5.1-1 (SHEET 3 OF 9)



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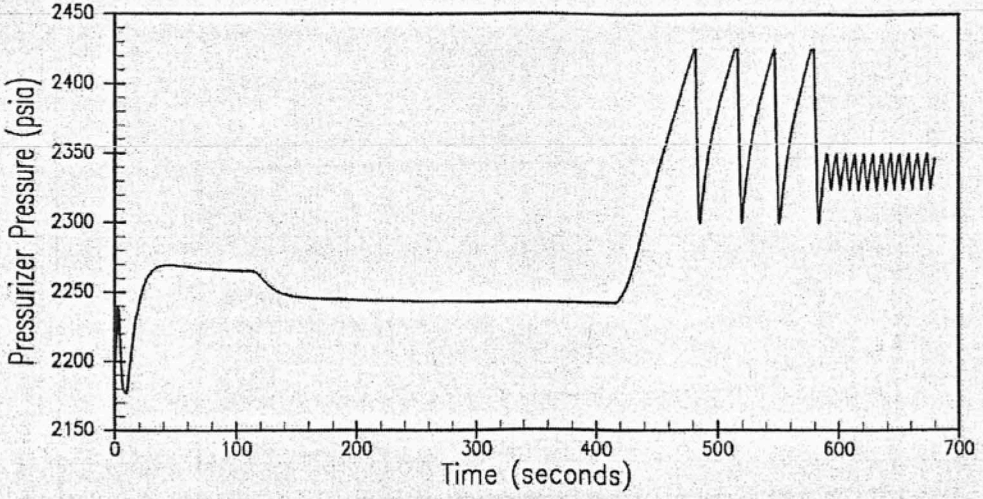
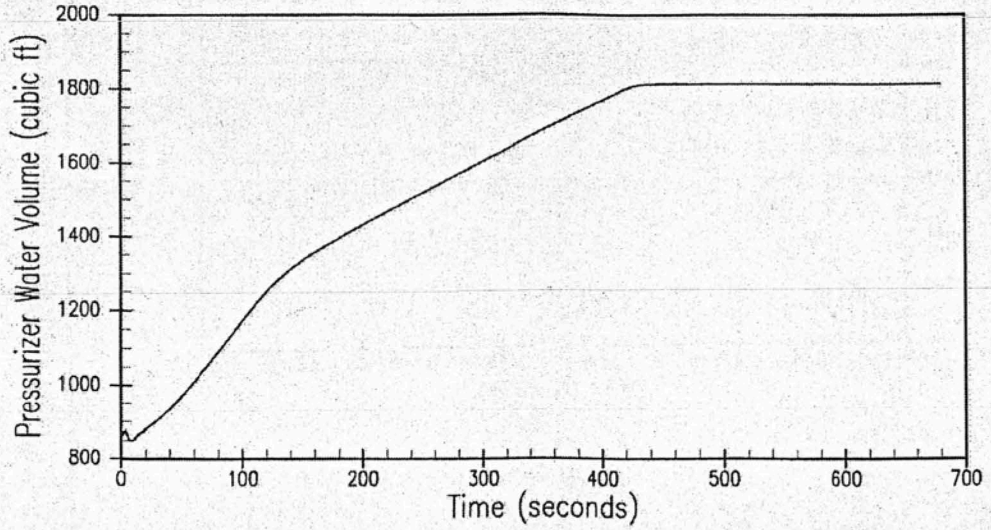
INADVERTENT OPERATION OF ECCS AT POWER - NUCLEAR POWER AND STEAM FLOW AS A FUNCTION OF TIME (T_{AVG}=570.7 °F, Pressurizer Heaters ON)

FIGURE 15.5.1-1 (SHEET 4 OF 9)





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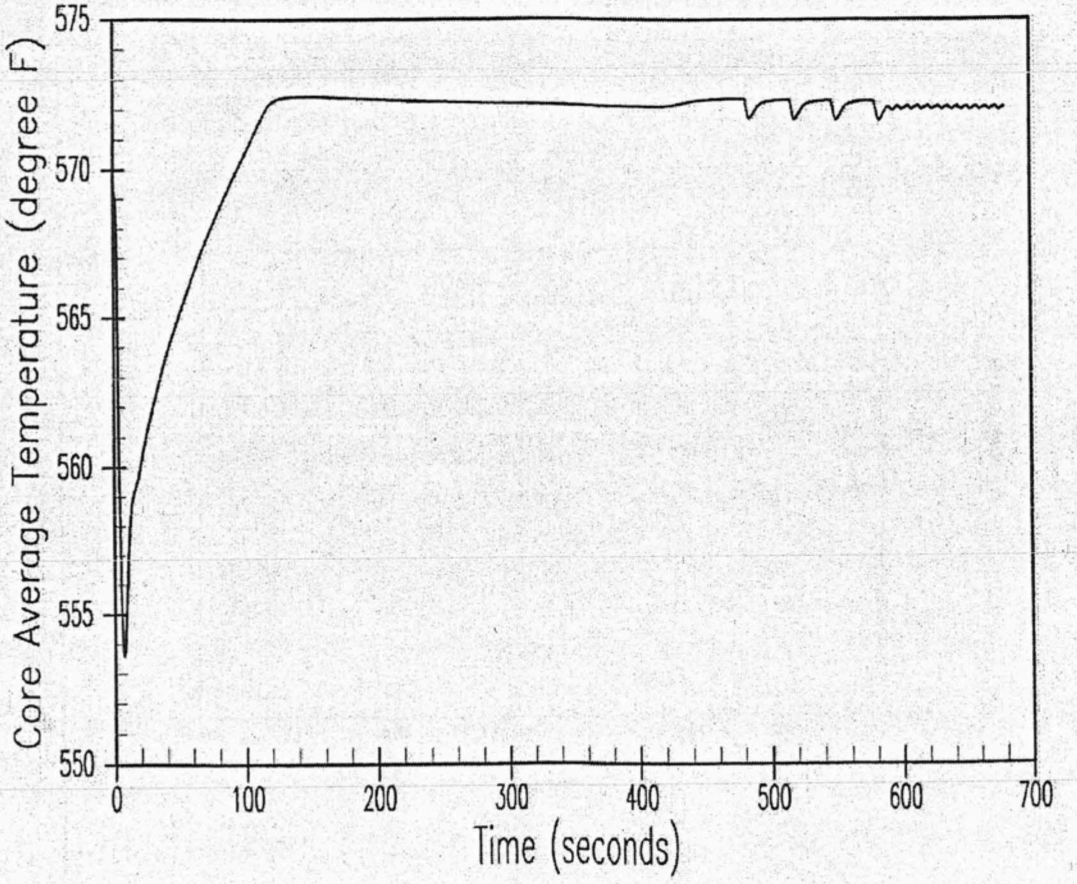
INADVERTENT OPERATION OF ECCS AT POWER - PRESSURIZER PRESSURE AND WATER VOLUME AS A FUNCTION OF TIME
(T_{AVG}=570.7 °F, Pressurizer Heaters ON)

FIGURE 15.5.1-1 (SHEET 5 OF 9)



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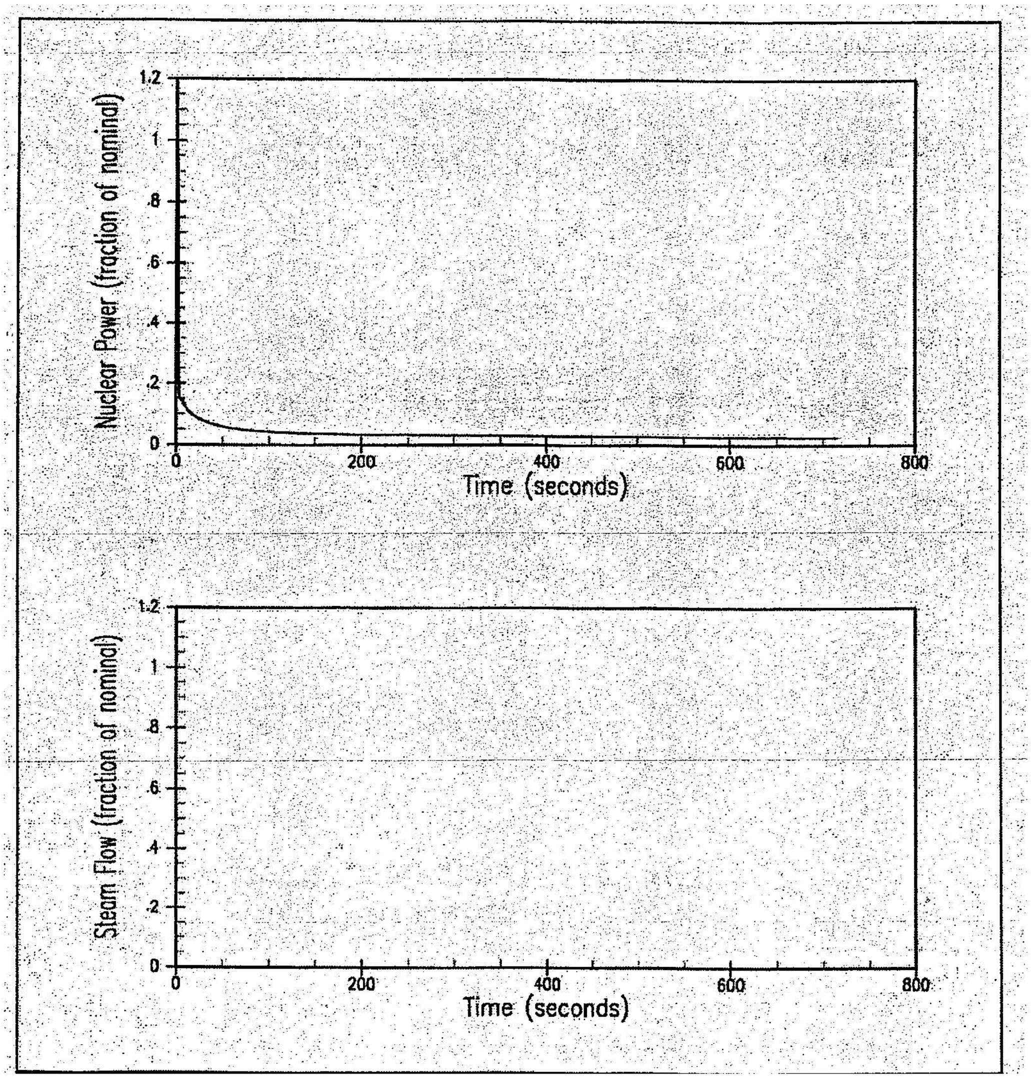
INADVERTENT OPERATION OF ECCS AT POWER - CORE AVERAGE TEMPERATURE AS A FUNCTION OF TIME
(T_{AVG}=570.7 °F, Pressurizer Heaters ON)

FIGURE 15.5.1-1 (SHEET 6 OF 9)



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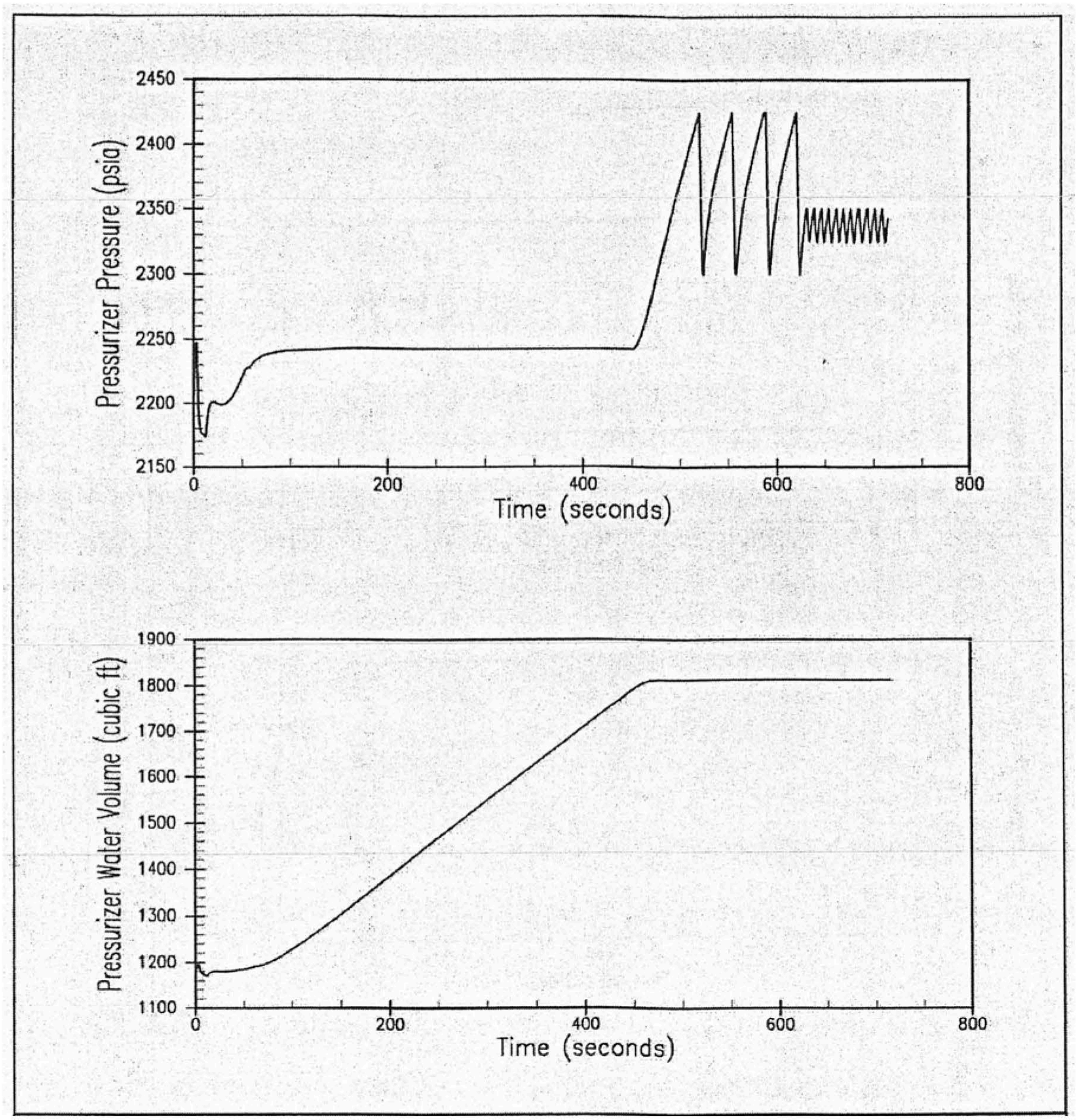
INADVERTENT OPERATION OF ECCS AT POWER - NUCLEAR POWER AND STEAM FLOW AS A FUNCTION OF TIME (T_{AVG}=588.4 °F, Pressurizer Heaters ON)

FIGURE 15.5.1-1 (SHEET 7 OF 9)



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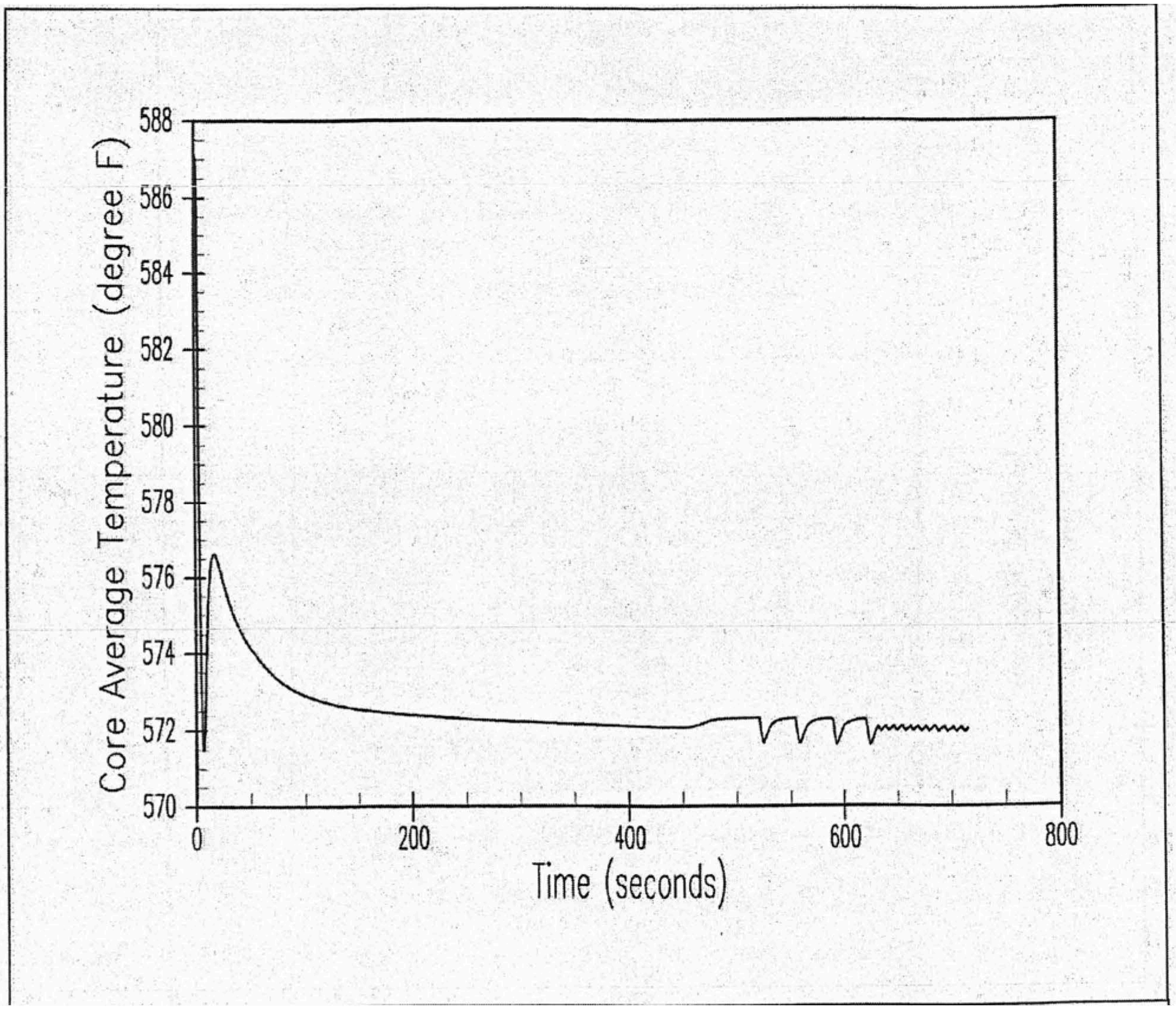
INADVERTENT OPERATION OF ECCS AT POWER - PRESSURIZER PRESSURE AND WATER VOLUME AS A FUNCTION OF TIME (T_{AVG}=588.4 °F, Pressurizer Heaters ON)

FIGURE 15.5.1-1 (SHEET 8 OF 9)



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INADVERTENT OPERATION OF ECCS AT POWER - CORE AVERAGE TEMPERATURE AS A FUNCTION OF TIME
(T_{AVG}=588.4 °F, Pressurizer Heaters ON)

FIGURE 15.5.1-1 (SHEET 9 OF 9)

15.6 DECREASE IN REACTOR COOLANT INVENTORY

Events which result in a decrease in reactor coolant inventory, as discussed in this section, are as follows:

A. Inadvertent opening of a pressurizer safety or relief valve.

B. Break in instrument line or other lines from reactor coolant pressure boundary that penetrate the containment.

C. Steam generator tube failure.

D. Spectrum of boiling water reactor (BWR) steam system piping failures outside of containment (not applicable to the VEGP).

E. Loss-of-coolant accident (LOCA) resulting from a spectrum of postulated piping breaks within the reactor coolant pressure boundary.

F. A number of BWR transients (not applicable to VEGP).

All of the applicable accidents in this category have been analyzed. It has been determined that the most severe radiological consequences will result from the major LOCA of subsection 15.6.5. Therefore, the LOCA is the design basis accident. The LOCA chemical and volume control system (CVCS) letdown line break outside the containment and the steam generator tube rupture accident have been analyzed radiologically. All other accidents in this section are bounded by these accidents.

15.6.1 INADVERTENT OPENING OF A PRESSURIZER SAFETY OR RELIEF VALVE

15.6.1.1 Identification of Causes and Accident Description

An accidental depressurization of the reactor coolant system (RCS) could occur as a result of an inadvertent opening of a pressurizer relief or safety valve. Since a pressurizer safety valve is sized to relieve approximately twice the steam flowrate of a relief valve and will therefore allow a much more rapid depressurization upon opening, the most severe core conditions resulting from an accidental depressurization of the RCS are associated with an inadvertent opening of a pressurizer safety valve. Initially the event results in a rapidly decreasing RCS pressure. The effect of the pressure decrease is to increase power via the moderator density feedback. The average coolant temperature remains approximately the same, but the pressurizer level increases until reactor trip.

The reactor may be tripped by the following reactor protection system signals:

- Overtemperature ∆T.
- Pressurizer low pressure.

This is an ANS Condition II incident.

15.6.1.2 Analysis of Effects and Consequences

15.6.1.2.1 Method of Analysis

The accidental depressurization transient is analyzed by employing the detailed digital computer code LOFTRAN.(1) The 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.

In order to produce conservative results in calculating the DNBR during the transient, the following assumptions are made:

A. Nominal values are assumed for the initial reactor power, pressure, and RCS temperatures. Uncertainties in initial conditions are included in the limit DNBR as described in reference 7. (See tables 15.0.3-2 and 15.0.3-3.)

B. A most positive moderator temperature coefficient is assumed. The spatial effect of voids resulting from local or subcooled boiling is not considered in the analysis with respect to reactivity feedback or core power shape.

C. A small (absolute value) Doppler coefficient of reactivity such that the resultant amount of negative feedback is conservatively low. This tends to maximize any power increase resulting from moderator reactivity feedback.

Plant systems and equipment which are necessary to mitigate the effects of RCS depressurization caused by an inadvertent safety valve opening are discussed in subsection 15.0.8 and listed in table 15.0.8-1.

Normal automatic rod control systems are not required to function. The reactor protection system functions to trip the reactor on the appropriate signal. No single active failure will prevent the reactor protection system from functioning properly.

15.6.1.2.2 Results

The system response to an inadvertent opening of a pressurizer safety valve is shown in figures 15.6.1-1 and 15.6.1-2. Figure 15.6.1-1 illustrates the nuclear power transient following the depressurization. Nuclear power increases slowly until reactor trip occurs on overtemperature delta T. The pressure decay transient and average temperature transient following the accident are given in figure 15.6.1-2. Pressure drops more rapidly while core heat generation is reduced via the trip and then slows once saturation temperature is reached in the hot leg. The DNBR decreases initially but increases rapidly following the trip, as shown in figure 15.6.1-1. The DNBR remains above its limit throughout the transient. The DNBR design basis is described in section 4.4.

The calculated sequence of events for the inadvertent opening of a pressurizer safety valve incident is shown in table 15.6.1-1.

15.6.1.3 Conclusion

The results of the analysis show that the pressurizer low pressure and the overtemperature WT reactor protection system signals provide adequate protection against the RCS depressurization event.

15.6.1.4 Reference

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (proprietary), WCAP-7907-A (nonproprietary), April 1984.

15.6.2 BREAK IN INSTRUMENT LINE OR OTHER LINES FROM REACTOR COOLANT PRESSURE BOUNDARY THAT PENETRATE CONTAINMENT

The reactor coolant system (RCS) wide-range pressure instrument lines penetrate the containment. In addition, there are the sample lines from the hot legs of reactor coolant loops 1 and 3, from the steam and liquid space of the pressurizer, and from the 3-in. chemical and volume control system (CVCS) letdown line penetrating the containment. The sample lines are provided with isolation valves on both sides of the containment wall and are designed in accordance with the requirements of General Design Criterion (GDC) 55.

A break in one of the RCS wide-range pressure instrument lines at a point outside the containment but before the hydraulic isolator combined with the failure of the instrument bellows would result in a nonisolable release of reactor coolant outside the containment. While the release would continue until the plant is shut down and the RCS is depressurized, the release rate never exceeds 0.106 lb/s.

The most severe pipe rupture outside containment, with regard to radioactivity release during normal plant operation, occurs in the CVCS. This would be a complete severance of the 3-in. letdown line just outside containment but between the outboard letdown isolation valve and letdown heat exchanger at rated power condition. (See drawings 1X4DB114, 1X4DB115, 1X4DB116-1, 1X4DB116-2, 1X4DB117, and 1X4DB118.) The occurrence of a complete severance of the letdown line would result in a loss of reactor coolant at the rate of about 21.3 lb/s. Since the release rate is within the capability of the reactor makeup system, it would not result in engineered safety features system actuation. Frequent operation of the automatic reactor makeup system in addition to the low pressurizer pressure deviation alarm will provide the operator some indication of the loss of reactor coolant. After the 30 min, the operator is assumed to isolate the letdown line.

15.6.2.1 Assumptions - Instrument Line Break

The major assumptions and parameters used in the analysis are provided in table 15.6.2-1 and summarized below:

A. The reactor coolant iodine activity is based on a pre-existing iodine spike of 60 -μCi/g dose equivalent I-131. (See table 15A-6.)

B. The noble gas activity in the reactor coolant is based on 1-percent fuel defects. (See table 15A-4.)

C. Reactor shutdown is assumed to be initiated 8 h after the break occurs.

D. One residual heat removal system train is assumed to be available. Time to cool the RCS to < 212°F is 24 h.

E. A total of 12,200 lb of reactor coolant is spilled (based on a release for 32 h).

F. All of the noble gases in the spilled reactor coolant are released to the environment.

G. The fraction of the spill assumed to flash is 58 percent. All of the iodine activity in the flashed fraction of the spill is assumed to be released. Ten percent of the iodine in the unflashed fraction is assumed to be released.

H. No credit is taken for mixing and holdup of the releases within the auxiliary building nor are the auxiliary building normal exhaust filters credited with reducing the release. That is, the release is modeled as being direct to the environment.

I. No credit is taken for ground deposition or decay in transit to the exclusion area boundary or outer boundary of the low population zone.

15.6.2.2 Assumptions - Letdown Line Break

The major assumptions and parameters used in the analysis are provided in table 15.6.2-2 and summarized below:

A. The reactor coolant iodine activity is based on a pre-existing iodine spike of 60-μCi/g dose equivalent I-131. (See table 15A-6.)

B. The noble gas activity in the reactor coolant is based on 1-percent fuel defects. (See table 15A-4.).

C. A total of 38,400 lb of reactor coolant is spilled (based on a release for 30 min).

D. All of the noble gases in the spilled reactor coolant are released to the environment.

E. The fraction of the spill assumed to flash is 8.6 percent. All of the iodine activity in the flashed fraction of the spill is assumed to be released. Ten percent of the iodine in the unflashed fraction is assumed to be released.

F. No credit is taken for mixing and holdup of the releases within the auxiliary building nor are the auxiliary building normal exhaust filters credited with reducing the release. That is, the release is modeled as being direct to the environment.

G. No credit is taken for ground deposition or decay in transit to the exclusion area boundary or outer boundary of the low population zone.

15.6.2.3 Mathematical Models Used in the Analysis

Mathematical models used in the analysis are described in the following sections:

A. The mathematical models used to analyze the activity released during the course of the accident are described in appendix 15A.

B. The atmospheric dispersion factors used in the analysis were calculated based on the onsite meteorological measurement program described in section 2.3 and are provided in table 15A-2.

C. The thyroid inhalation and total-body immersion doses to a receptor at the exclusion area boundary or outer boundary of the low population zone were analyzed using the models described in appendix 15A.

15.6.2.4 Identification of Leakage Pathways

The reactor coolant spilled in the auxiliary building will collect in the floor drain sumps. From there, it will be pumped to the radwaste treatment system. Therefore, the only release paths that present a radiological hazard involve the volatile fraction of spilled coolant.

Normally, gases released in the auxiliary building mix with the building atmosphere and are gradually exhausted through the filtered building ventilation system. The charcoal filters normally remove a very large fraction of the airborne iodine in the building atmosphere. However, the ventilation system is not designed to mitigate the consequences of an accident (e.g., it might not survive an earthquake) nor can the possibility of unplanned leakage from the auxiliary building be eliminated; hence, no credit is taken for these effects reducing the released activity.

15.6.2.5 Identification of Uncertainties and Conservatisms in the Analysis

The uncertainties and conservatisms in the assumptions used to evaluate the radiological consequences result principally from assumptions made involving the amount of the gaseous fission products available for release to the environment and the meteorology present at the site during the course of the accident. The most significant of these assumptions are:

A. The meteorological conditions assumed to be present at the site during the course of the accident are based on χ/Q values which are worse than those which will exist at the site 95 percent of the time. This condition results in the poorest values of atmospheric dispersion calculated for the exclusion area boundary and the low population zone outer boundary. Furthermore, no credit has been taken for the transit time required for activity to travel from the point of release to the exclusion area boundary and to the low population zone outer boundary. Hence, the radiological consequences evaluated under these conditions are conservative.

B. The concentrations of noble gases and iodines assumed in the reactor coolant is significantly greater than those expected during normal plant operation.

C. No credit is taken for deposition of airborne iodine.

15.6.2.6 Conclusions

The radiological consequences resulting from the occurrence of postulated line ruptures have been conservatively analyzed, using assumptions and models described in previous sections.

The thyroid inhalation and total-body immersion doses have been analyzed for the 0- to 2-h dose at the exclusion area boundary and for the duration of the accident at the low population zone outer boundary. The results are listed in table 15.6.2-3 for the instrument line break and in table 15.6.2-4 for the letdown line break. These doses do not exceed 10 percent of the guidelines values of 10 CFR 100.

15.6.3 STEAM GENERATOR TUBE FAILURE

15.6.3.1 Identification of Causes and Accident Description

The accident examined is the complete severance of a single steam generator tube. This event is considered an American Nuclear Society (ANS) Condition IV event, a limiting fault. (See subsection 15.0.1.) The accident is assumed to take place at full power with the reactor coolant contaminated with fission products corresponding to continuous operation with a limited number of defective fuel rods. The accident leads to an increase in contamination of the secondary system due to leakage of radioactive coolant from the reactor coolant system (RCS). In the event of a coincident loss of offsite power or failure of the condenser steam dump system, discharge of activity to the atmosphere takes place via the steam generator atmospheric relief valves (and safety valves if their setpoint is reached).

Complete severance of a steam generator tube is considered a somewhat conservative assumption since the Inconel-600 tube material is highly ductile. The more probable mode of tube failure would be one or more minor leaks of undetermined origin. Activity in the steam and power conversion system is subject to continual surveillance, and an accumulation of minor leaks which exceed the limits established in the Technical Specifications is not permitted during the unit operation.

The operator is expected to determine that a steam generator tube rupture has occurred, to identify and isolate the ruptured steam generator, and to complete the required recovery actions to stabilize the plant and terminate the primary to secondary break flow. These actions should be performed on a restricted time scale in order to minimize contamination of the secondary system and ensure termination of radioactive release to the atmosphere from the faulted unit. Consideration of the indications provided at the control board, together with the magnitude of the break flow, leads to the conclusion that the recovery procedure can be carried out on a time scale which ensures that break flow to the secondary system is terminated before water level in the affected steam generator rises into the main steam pipe. Sufficient indications and controls are provided to enable the operator to carry out these functions satisfactorily.

If normal operation of the various plant control system is assumed, the following sequence of events is initiated by a tube rupture.

A. Pressurizer low-pressure and low-level alarms are actuated and charging pump flow increases in an attempt to maintain pressurizer level. On the secondary side, steam flow/feedwater flow mismatch occurs, since feedwater flow to the affected steam generator is reduced as a result of primary coolant break flow to that unit.

B. The main steamline radiation monitors, the condenser air ejector radiation monitor, and/or the steam generator blowdown liquid monitor will alarm, indicating a sharp increase in radioactivity in the secondary system. The high radiation level alarm from the steam generator blowdown process monitor automatically isolates the system and terminates discharge. The high radiation level alarm from the air ejector monitor automatically diverts the air ejector and steam seal exhauster blower discharges through a filtration unit.

C. The decrease in RCS pressure due to continued loss of reactor coolant inventory leads to a reactor trip signal on low pressurizer pressure or OTΔT. Resultant plant cooldown following reactor trip leads to a rapid decrease in RCS pressure and pressurizer level, and a safety injection signal initiated by low pressurizer pressure follows soon after reactor trip. The safety injection signal automatically terminates normal feedwater supply and initiates auxiliary feedwater addition.

D. The reactor trip automatically trips the turbine, and if offsite power is available, the steam dump valves open, permitting steam dump to the condenser. In the event of a coincident loss of offsite power, the steam dump valves automatically close to protect the condenser. The steam generator pressure rapidly increases, resulting in steam discharge to the atmosphere through the steam generator atmospheric relief valves (and safety valves if their setpoint is reached).

E. Following reactor trip and safety injection actuation, the continued action of the auxiliary feedwater supply and borated safety injection flow (supplied from the refueling water storage tank) provides a heat sink which absorbs some of the decay heat. This reduces the amount of steam bypass to the condenser, or in the case of loss of offsite power, steam relief to the atmosphere.

F. Safety injection flow results in increasing RCS pressure and pressurizer water level, and the RCS pressure trends toward the equilibrium value where the safety injection flow rate equals the break flow rate.

In the event of a steam generator tube rupture (SGTR), the plant operators must diagnose the SGTR and perform the required recovery actions to stabilize the plant and terminate the primary to secondary leakage. The operator actions for SGTR recovery are provided in the Emergency Operating Procedures. The major operator actions include identification and isolation of the ruptured steam generator, cooldown and depressurization of the RCS to restore inventory, and termination of SI to stop primary to secondary leakage. These operator actions are described below.

1. Identify the ruptured steam generator.

   High secondary side activity, as indicated by the main steamline radiation monitors, the condenser air ejector radiation monitor, or steam generator blowdown radiation monitors, typically will provide the first indication of an SGTR event. The ruptured steam generator can be identified by an unexpected increase in steam generator narrow range level or a high radiation indication on the corresponding main steamline radiation monitor. For an SGTR that results in a reactor trip at high power, the steam generator water level will decrease due to void collapse but is expected to remain in the narrow range for all of the steam generators. The AFW flow will begin to refill the steam generators, distributing approximately equal flow to each of the steam generators. Since primary to secondary leakage adds additional liquid inventory to the ruptured steam generator, the water level will increase more rapidly in that steam generator. This response, as indicated by the steam generator water level instrumentation, provides confirmation of an SGTR event and also identifies the ruptured steam generator.

2. Isolate the ruptured steam generator from the intact steam generators and isolate feedwater to the ruptured steam generator.

   Once a tube rupture has been identified, recovery actions begin by isolating steam flow from and stopping feedwater flow to the ruptured steam generator. In addition to minimizing radiological releases, this also reduces the possibility of overfilling the ruptured steam generator with water by 1) minimizing the accumulation of feedwater flow and 2) enabling the operator to establish a pressure differential between the ruptured and intact steam generators as a necessary step toward terminating primary to secondary leakage.

3. Cool down the RCS using the intact steam generators.

   After isolation of the ruptured steam generator, the RCS is cooled as rapidly as possible to less than the saturation temperature corresponding to the ruptured steam generator pressure by dumping steam from only the intact steam generators. This ensures adequate subcooling in the RCS after depressurization to the ruptured steam generator pressure in subsequent actions. If offsite power is available, the normal steam dump system to the condenser can be used to perform this cooldown. However, if offsite power is lost, the RCS is cooled using the atmospheric relief valves (ARVs) on the intact steam generators.

4. Depressurize the RCS to restore reactor coolant inventory.

   When the cooldown is completed, SI flow will increase RCS pressure until break flow matches SI flow. Consequently, SI flow must be terminated to stop primary to secondary leakage. However, adequate reactor coolant inventory must first be assured. This includes both sufficient reactor coolant subcooling and pressurizer inventory to maintain a reliable pressurizer level indication after SI flow is stopped. Since leakage from the primary side will continue after SI flow is stopped until RCS and ruptured steam generator pressures equalize, an "excess" amount of inventory is needed to ensure pressurizer level remains on span. The "excess" amount required depends on RCS pressure and reduces to zero when RCS pressure equals the pressure in the ruptured steam generator.

   The RCS depressurization is performed using normal pressurizer spray if the rector coolant pumps (RCPs) are running. However, if offsite power is lost or the RCPs are not running for some other reason, normal pressurizer spray is not available. In this event, RCS depressurization can be performed using a pressurizer PORV or auxiliary pressurizer spray.

5. Terminate SI to stop primary to secondary leakage.

   The previous actions will have established adequate RCS subcooling, a secondary side heat sink, and sufficient reactor coolant inventory to ensure that SI flow is no longer needed. When these actions have been completed, SI flow must be stopped to terminate primary to secondary leakage. Primary to secondary leakage will continue after SI flow is stopped until RCS and ruptured steam generator pressures equalize. Charging flow, letdown, and pressurizer heaters will then be controlled to prevent repressurization of the RCS and reinitiation of leakage into the ruptured steam generator.

   Following SI termination, the plant conditions will be stabilized, the primary to secondary break flow will be terminated, and all immediate safety concerns will have been addressed. At this time, a series of operator actions are performed to prepare the plant for cool down to cold shutdown conditions. Subsequently, actions are performed to cool down and depressurize the RCS to cold shutdown conditions and to depressurize the ruptured steam generator.

15.6.3.2 Analysis of Effects and Consequences

An SGTR results in the leakage of contaminated reactor coolant into the secondary system and subsequent release of a portion of the activity to the atmosphere. Therefore, an analysis must be performed to assure that the offsite radiological consequences resulting from an SGTR are within the allowable guidelines. One of the major concerns for an SGTR is the possibility of steam generator overfill since this could potentially result in a significant increase in the offsite radiological consequences. Therefore, an analysis was performed to demonstrate margin to steam generator overfill (MTO) as documented in reference 11, assuming the limiting single failure relative to overfill. The analysis assumes that one of the steam generator atmospheric relief valves (ARVs) is out of service, as allowed by the Technical Specifications. The analysis was performed assuming one operable ARV was on the ruptured steam generator and the other two operable ARVs were on intact steam generators. The limiting single failure for the margin to overfill analysis results in the loss of control room (CR) control of the ARVs on the intact steam generators. Action outside the CR is required to open an intact steam generator ARV to perform the plant cooldown. The analysis assumed that a single intact steam generator ARV is used for the cooldown, and it is not opened until 12 minutes after the ruptured steam generator is isolated. The results of this analysis demonstrated that there is margin to steam generator overfill for VEGP. An analysis was also performed to determine the offsite radiological consequences as documented in reference 1, assuming the limiting single failure relative to offsite doses without steam generator overfill. Since steam generator overfill does not occur, the results of this analysis represent the limiting consequences for an SGTR for VEGP.

A thermal and hydraulic analysis was performed to determine the plant response for a design basis SGTR, and to determine the integrated primary to secondary break flow and the mass releases from the ruptured and intact steam generators to the condenser and to the atmosphere. This information was then used to calculate the quantity of radioactivity released to the environment and the resulting radiological consequences.

15.6.3.3 Thermal and Hydraulic Analysis

The plant response following an SGTR was analyzed with the LOFTTR2 (reference 1 and reference 11) program until the primary to secondary break flow is terminated. The reactor protection system and the automatic actuation of the engineered safeguards systems were modeled in the analysis. The major operator actions which are required to terminate the break flow for an SGTR were also simulated in the analysis.

Analysis Assumptions

The accident modeled is a double-ended break of one steam generator tube located at the top of the tube sheet on the outlet (cold leg) side of the steam generator. It was assumed that the reactor is operating at full power at the time of the accident and the secondary level was assumed to correspond to operation at the nominal steam generator level minus an allowance for uncertainties. It was also assumed that a loss of offsite power occurs 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.

Other important analysis assumptions include:

A. NSSS power = 3579 MWt* 1.02 (uncertainty) = 3653 MWt.

B. Average RCS temperature = 588.4°F for the dose consequence analysis. For the MTO analysis, the average RCS temperature = 570.7°F.

C. RCS pressure = 2250 psia - 50 psia (uncertainty) = 2200.

D. Thermal design flow = 374400 gal/min.

E. Pressurizer level = 60% (includes uncertainty) for dose consequence analysis and 40.3% for overall analysis.

F. SG tube plugging = 0% for dose consequence analysis and 10% for overfill analysis.

G. Auxiliary feed flow = 2110 gal/min for overfill analysis and 1600 gal/min for the dose analysis.

H. Auxiliary feed flow delay time = 90 seconds for dose analysis, 30 seconds for overfill analysis.

The limiting single failure for offsite doses was assumed to be the failure of the ARV on the ruptured steam generator. Failure of this ARV in the open position will cause an uncontrolled depressurization of the ruptured steam generator which will increase primary to secondary leakage and the mass release to the atmosphere. It was assumed that the ruptured steam generator ARV fails open when the ruptured steam generator is isolated, and that the ARV is isolated by locally closing the associated block valve.

The offsite radiological analysis also assumed that one of the intact steam generator ARVs was inoperable. The analysis assumed that only two of the three intact steam generator ARVs were available for the cooldown.

The major operator actions required for the recovery from an SGTR are discussed in paragraph 15.6.3.1, and these operator actions were simulated in the analysis. The operator action times used for the analysis were established in reference 2 and are presented in table 15.6.3-1. It is noted that the ARV on the ruptured steam generator was assumed to fail open at the time the ruptured steam generator was isolated. Before proceeding with the recovery operations, the failed-open ARV on the ruptured steam generator was assumed to be isolated by locally closing the associated block valve. It was assumed that the ruptured steam generator ARV is isolated at 16 minutes after the valve was assumed to fail open. After the ruptured steam generator ARV was isolated, an additional delay time of 12 minutes (table 15.6.3-1) was assumed for the operator action time to initiate the RCS cooldown.

Transient Description

The LOFTTR2 analysis results are described below. The sequence of events for this transient is presented in table 15.6.3-2.

Following the tube rupture, reactor coolant flows from the primary into the secondary side of the ruptured steam generator since the primary pressure is greater than the steam generator pressure. In response to this loss of reactor coolant, pressurizer level decreases as shown in figure 15.6.3-1. The RCS pressure also decreases as shown in figure 15.6.3-2, as the steam bubble in the pressurizer expands. As the RCS pressure decreases due to the continued primary to secondary leakage, automatic reactor trip occurs on an OTΔT trip signal.

After reactor trip, core power rapidly decreases to decay heat levels. The turbine stop valves close, and steam flow to the turbine is terminated. The steam dump system is designed to actuate following reactor trip to limit the increase in secondary pressure, but the steam dump valves remain closed due to the loss of condenser vacuum resulting from the assumed loss of offsite power at the time of reactor trip. Thus, the energy transfer from the primary system causes the secondary side pressure to increase rapidly after reactor trip until the steam generator ARVs (and safety valves if their setpoints are reached) lift to dissipate the energy, as shown in figures 15.6.3-3. The main feedwater flow will be terminated and AFW flow will be automatically initiated following reactor trip and the loss of offsite power.

The RCS pressure decreases more rapidly after reactor trip as energy transfer to the secondary shrinks the reactor coolant and the tube rupture break flow continues to deplete primary inventory. Pressurizer level also decreases more rapidly following reactor trip. The decrease in RCS inventory results in a low pressurizer pressure SI signal. After SI actuation, the SI flowrate exceeds the tube rupture break flowrate, and the pressurizer level begins to increase. This also results in an increase in the RCS pressure which trends toward the equilibrium value where the SI flowrate equals the break flowrate.

Since offsite power is assumed lost at reactor trip, the RCPs trip, and a gradual transition to natural circulation flow occurs. Immediately following reactor trip, the temperature differential across the core decreases as core power decays (see figures 15.6.3-4 and 15.6.3-5); however, the temperature differential subsequently increases as natural circulation flow develops. The cold leg temperatures trend toward the steam generator temperature as the fluid residence time in the tube region increase. The intact steam generator loop temperatures continue to slowly decrease due to the continued AFW flow until operator actions are taken to control the AFW flow to maintain the specified level in the intact steam generators. The ruptured steam generator loop temperatures also continue to slowly decrease until the ruptured steam generator was isolated and the ARV was assumed to fail open.

Major Operator Actions

1. Identify and Isolate the Ruptured Steam Generator

   The ruptured steam generator was assumed to be identified and the MSIV isolated at 20 minutes after the initiation of the SGTR or when the narrow range level recovers to 30 percent, whichever time is greater. Isolation of AFW flow to the ruptured steam generator takes place 4 minutes after event initiation. The ruptured steam generator ARV was assumed to fail open at the time of MSIV isolation, and the failure was simulated at 1202 seconds. The failure causes the ruptured steam generator to rapidly depressurize as shown in figure 15.6.3-3, which results in an increase in primary to secondary leakage. The depressurization of the ruptured steam generator increases the break flow and energy transfer from primary to secondary, which results in a decrease in the ruptured loop temperatures, as shown in figure 15.6.3-5. As noted previously, the intact steam generator loop temperatures also decrease, as shown in figure 15.6.3-4, until the AFW flow to the intact steam generators is throttled. After this time, the heat transfer to the intact steam generators decreases and the temperature differential across the intact steam generators decreases. The decrease in the RCS temperatures results in an initial decrease in the pressurizer level and RCS pressure. However, the increased SI flow subsequently causes the pressurizer level and RCS pressure to increase again, as shown in figures 15.6.3-1 and 15.6.3-2, respectively. It was assumed that the time required for the operator to identify that the ruptured steam generator ARV is open and to locally close the associated block valve is 16 minutes. Thus, at 2162 s the depressurization of the ruptured steam generator was terminated.

2. Cooldown the RCS to establish Subcooling Margin

   After the ruptured steam generator ARV block valve was closed, a 12-minute operator action time was imposed prior to initiation of cooldown. The depressurization of the ruptured steam generator affects the RCS cooldown target temperature since the temperature is dependent upon the pressure in the ruptured steam generator. Since offsite power was lost, the RCS was cooled by dumping steam to the atmosphere using the two available, intact steam generator ARVs. The cooldown was continued until RCS cooldown target was met. Because of the lower pressure in the ruptured steam generator, the associated temperature the RCS must be cooled to is also lower, which has the net effect of extending the time for cooldown. The cooldown was initiated at 2882 seconds and was completed at 3264 seconds.

The reduction in the intact steam generator pressures required to accomplish the cooldown is shown in figure 15.6.3-3, and the effect of the cooldown on the RCS temperature is shown in figure 15.6.3-4. The pressurizer level and RCS pressure also decrease during this cooldown process due to shrinkage of the reactor coolant, as shown in figures 15.6.3-1 and 15.6.3-2.

3. Depressurize to Restore Inventory

   After the RCS cooldown, a 5-min and 45-s operator action time was assumed prior to depressurization. The RCS was depressurized at 3612 s to assure adequate coolant inventory prior to terminating SI flow. With the RCPS stopped, normal pressurizer spray is not available and, thus, the RCS was depressurized by opening a pressurizer PORV. The depressurization was continued until any of the following conditions were satisfied: RCS pressure is less than the ruptured steam generator pressure and pressurized level is greater than 5 percent or RCS pressure is within 300 psi of the ruptured steam generator pressure and pressurizer level is greater than 50 percent, or pressurizer level is greater than 75 percent, or RCS subcooling is less than the 22 ºF allowance for subcooling uncertainty. The effect of the RCS depressurization on the RCS pressure and the differential pressure between the RCS and the ruptured steam generator is shown in figures 15.6.3-2 and 15.6.3-6. RCS depressurization reduces the break flow as shown in figure 15.6.3-7 and increases SI flow to refill the pressurizer as shown in figure 15.6.3-1.

4. Terminate SI to Stop Primary to Secondary Leakage

   The previous actions have established adequate RCS subcooling, verified a secondary side heat sink, and restored the reactor coolant inventory to ensure that SI flow is no longer needed. When these actions have been completed, the SI flow must be stopped to prevent repressurization of the RCS and to terminate primary to secondary leakage. The SI flow is terminated at this time if RCS subcooling is greater than the 22°F allowance for uncertainty, minimum AFW flow is available or at least one intact steam generator level is in the narrow range, the RCS pressure is increasing, and the pressurizer level is greater than the 5-percent allowance for uncertainty. To assure that the RCS pressure is increasing, SI was not terminated until the RCS pressure increases by at least 50 psi.

   After depressurization was completed, an operator action time of 3 minutes was assumed prior to SI termination. Since the above requirements are satisfied, SI termination was performed at this time. After SI termination, the RCS pressure decreases as shown in figure 15.6.3-2. The differential pressure between the RCS and the ruptured steam generator also decreases as shown in figure 15.6.3-6. Figure 15.6.3-7 shows that the primary to secondary leakage continues after the SI flow is stopped until the RCS and ruptured steam generator pressures equalize.

The ruptured steam generator water volume is shown in figure 15.6.3-8. It is noted that the water volume in the ruptured steam generator is significantly less than the total steam generator volume of 5837 ft^3 when the break flow is terminated. The mass of water in the ruptured steam generator is also shown as a function of time in figure 15.6.3-9.

Mass Releases

The mass releases were determined for use in evaluating the exclusion area boundary and low population zone radiation exposure. The steam releases from the ruptured and intact steam generators, the feedwater flows to the ruptured and intact steam generators, and primary to secondary break flow into the ruptured steam generator were determined for the period from accident initiation until 2 hours after the accident and from 2 to 20 hours after the accident. The releases for 0 to 2 hours were used to calculate the radiation doses at the exclusion area boundary for a 2-hour exposure, and the releases for 0 to 20 hours were used to calculate the radiation doses at the low population zone for the duration of the accident.

The operator actions for the SGTR recovery up to the termination of primary to secondary leakage were simulated in the LOFTTR2 analysis. Thus, the steam releases from the ruptured and intact steam generators, the feedwater flows to the ruptured and intact steam generators, and the primary to secondary leakage into the ruptured steam generator were determined from the LOFTTR2 results for the period from the initiation of the accident until the leakage is terminated.

Following the termination of leakage, it was assumed that the actions are taken to cool down the plant to cold shutdown conditions. The ARVs for the intact steam generators were assumed to be used to cool down the RCS to the RHR system operating temperature of 350°F, at the maximum allowable cooldown rate of 100°F/h. The steam releases and the feedwater flows for the intact steam generators for the period from leakage termination until 2 hours were determined from a mass and energy balance using the calculated RCS and intact steam generator conditions at the time of leakage termination and at 2 hours. The RCS cooldown was assumed to be continued after 2 hours until the RHR system in-service temperature of 350°F is reached. Depressurization of the ruptured steam generator was then assumed to be performed to the RHR in-service pressure of 350 psia via steam release from the ruptured steam generator ARV. The RCS pressure was also assumed to be reduced concurrently as the ruptured steam generator is depressurized. It was assumed that the continuation of the RCS cooldown and depressurization to RHR operating conditions are completed within 20 hours after the accident since there is ample time to complete the operations during this time period. The steam releases and feedwater flows from 2 to 20 hours were determined for the intact and ruptured steam generators from a mass and energy balance using the conditions at 2 hours and at the RHR system in-service conditions.

After 20 hours, it was assumed that further plant cooldown to cold shutdown as well as long-term cooling is provided by the RHR system. Therefore, the steam releases to the atmosphere were terminated after RHR in-service conditions were assumed to be reached at 20 hours.

For the time period from initiation of the accident until leakage termination, the releases were determined from the LOFTTR2 results for the time prior to reactor trip and following reactor trip. Since the condenser is in service until reactor trip, any radioactivity released to the atmosphere prior to reactor trip would be through the condenser air ejector. After reactor trip, the releases to the atmosphere were assumed to be via the steam generator ARVs. The mass release rates to the atmosphere from the LOFTTR2 analysis are presented in figures 15.6.3-10 and 15.6.3-11 for the ruptured and intact steam generators, respectively, for the time period until leakage termination. The mass releases calculated from the time of leakage termination until 2 hours and from 2 to 20 hours are also assumed to be released to the atmosphere via the steam generator ARVs. The mass releases for the SGTR event for the 0 to 2-hour and 2 to 20-hour time intervals are presented in table 15.6.3-3.

15.6.3.4 Offsite Radiation Dose Analysis

The evaluation of the radiological consequences of a steam generator tube rupture event assumes that the reactor has been operating at the maximum allowable Technical Specification limit for primary coolant activity and primary to secondary leakage for sufficient time to establish equilibrium concentrations of radionuclides in the reactor coolant and in the secondary coolant. Radionuclides from the primary coolant enter the steam generator via the ruptured tube and are released to the atmosphere through the steam generator PORVs (and safety valves) and via the condenser air ejector exhaust.

The quantity of radioactivity released to the environment, due to an SGTR, depends upon primary and secondary coolant activity, iodine spiking effects, primary to secondary break flow, break flow flashing fractions, attenuation of iodine carried by the flashed portion of the break flow, partitioning of iodine between the liquid and steam phases, the mass of fluid released from the generator, and liquid-vapor partitioning in the turbine condenser hot well. All of these parameters were conservatively evaluated in a manner consistent with the recommendations in Standard Review Plan 15.6.3.

1. Design Basis Analytical Assumptions

   The major assumptions and parameters used in the analysis are itemized in table 15.6.3-4.

2. Source Term Calculations

   The radionuclide concentrations in the primary and secondary system, prior to and following the SGTR, are determined as follows:

   a. The iodine concentrations in the reactor coolant will be based upon preaccident and accident-initiated iodine spikes.

      i. Accident-Initiated Spike - The initial primary coolant iodine concentration is 1 μCi/g of Dose Equivalent (D.E.) I-131. Following the primary system depressurization associated with the SGTR, an iodine spike is initiated in the primary system which increases the iodine release rate from the fuel to the coolant to a value 500 times greater than the release rate corresponding to the initial primary system iodine concentration.

      ii. Preaccident Spike - A reactor transient has occurred prior to the SGTR and has raised the primary coolant iodine concentration from 1 to 60 μCi/gram of D.E. I-131.

   b. The initial secondary coolant iodine concentration is 0.1 μCi/gram of D.E. I-131.

   c. The chemical form of iodine in the primary and secondary coolant is assumed to be elemental.

   d. The initial noble gas concentrations in the reactor coolant are based upon 1-percent fuel defects.

3. Dose Calculations

   The iodine transport model utilized in this analysis was proposed by Postma and Tam (reference 3). The model considers break flow flashing, steaming, and partitioning. The model assumes that a fraction of the iodine carried by the break flow becomes airborne immediately due to flashing and atomization. The fraction of primary coolant iodine which is not assumed to become airborne immediately mixes with the secondary water and is assumed to become airborne at a rate proportional to the steaming rate and the iodine partition coefficient. This analysis conservatively assumes an iodine partition coefficient of 100 between the steam generator liquid and steam phases. Droplet removal by the dryers is conservatively assumed to be negligible. The iodine transport model is illustrated in figure 15.6.3-12.

The offsite radiological analysis did not consider steam generator tube uncovery in the calculation, since the steam generator tube uncovery issue was investigated and closed by the Westinghouse Owners Group (WOG). Reference 7 documents the Westinghouse position on the issue that the affect of tube uncovery on the limiting SGTR transient is essentially negligible and need not be considered in the analysis. Reference 8 documents the NRC agreement on this issue.

The following assumptions and parameters were used to calculate the activity released to the atmosphere and the offsite doses following an SGTR.

a. The mass of reactor coolant discharged into the secondary system through the rupture and the mass of steam released from the ruptured and intact steam generators to the atmosphere are presented in table 15.6.3-3.

b. The time dependent fraction of rupture flow that flashes to steam and is immediately released to the environment is presented in figure 15.6.3-13. The break flow flashing fraction was conservatively calculated assuming that 100 percent of the break flow comes from the hot leg side of the steam generator, whereas the break flow actually comes from both the hot leg and the cold leg sides of the steam generator.

c. The total primary to secondary leak rate is assumed to be 1.0 gal/min as allowed by the Technical Specifications. The leak rate is assumed to be 0.70 gal/min to the three intact steam generators and 0.30 gal/min to the ruptured steam generator.

d. The iodine partition factor between the liquid and steam of the ruptured and intact steam generators is assumed to be 100.

e. No credit was taken for radioactive decay during release and transport, or for cloud depletion by ground deposition during transport to the site boundary or outer boundary of the low population zone.

f. Short-term atmospheric dispersion factors (χ/Qs) for accident analysis and breathing rates are provided in table 15.6.3-8 and table 15A-2. The breathing rates were obtained from NRC Regulatory Guide 1.4, (reference 4).

4. Offsite Thyroid Dose Calculation Model

Offsite thyroid doses are calculated using the equation:

$$D_{Th} = \sum_i \left[DCF_i \left(\sum_j (IAR)_{IJ} (BR)_j \left(\chi/Q \right)_j \right) \right]$$

where:

$(IAR)_{ij}$ = integrated activity of iodine nuclide i released during the time interval j in Ci[a]

$(BR)_j$ = breathing rate during time interval j in m^3/s (table 15.6.3-8)

$(\chi/Q)_j$ = atmospheric dispersion factor during time interval j in s/m^3 (table 15A-2)

$(DCF)_i$ = thyroid dose conversion factor via inhalation for iodine nuclide i in rem/Ci (table 15A-5)

D_{Th} = Thyroid dose via inhalation in rem

Offsite whole-body gamma doses are calculated using the equation:

$$D\gamma = \sum_i \left[DCF_{\gamma i} \left(\sum_j (IAR)_{ij} \left(\chi/Q \right)_j \right) \right]$$

where:

$(IAR)_{ij}$ = integrated activity of noble gas nuclide i released during time interval j in Ci[a]

$(\chi/Q)_j$ = atmospheric dispersion factor during time interval j in $seconds/m^3$

$DCF_{\gamma i}$ = whole body dose conversion factor via submersion for noble gas nuclide i in rem-m^3/Ci-sec (table 15.6.3-10)

$D\gamma$ = whole body gamma dose due to immersion in rem

Offsite beta-skin doses are calculated using the equation:

$$D\beta = \sum_i \left[DCF_{\beta i} \left(\sum_j (IAR)_{ij} \left(\chi/Q \right)_j \right) \right]$$

where:

$(IAR)_{ij}$ = integrated activity of noble gas nuclide i released during time interval j in Ci[a]

$\left(\chi/Q \right)_j$ = atmospheric dispersion factor during time interval j in $seconds/m^3$

$DCF_{\beta i}$ = beta skin dose conversion factor via submersion for noble gas nuclide i in rem-m^3/Ci-sec (table 15.6.3-10)

$D\beta$ = beta-skin dose due to immersion in rem

5. Results

Thyroid, whole-body gamma, and beta-skin doses at the Exclusion Area Boundary and Low Population Zone are presented in table 15.6.3-11. All doses are well within the allowable guidelines as specified by Standard Review Plan 15.6.3 and 10 CFR 100.

(a) No credit is taken for cloud depletion by ground deposition or by radioactive decay during transport to the exclusion area boundary or to the outer boundary of the low-population zone.

15.6.3.5 References

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8. Attachment to WOG-93-066, letter to Lawrence A. Walsh (Chairman WOG) from Robert C. Jones (NRC), "Westinghouse Owners Group - Steam Generator Tube Uncovery Issue," March 10, 1993.
9. Environmental Protection Agency, “Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion,” Federal Guidance Report 11, EPA 520/1-88-020, 1988.
10. Environmental Protection Agency, “External Exposure to Radionuclides in Air, Water, and Soil,” Federal Guidance Report 12, EPA 402-R-93-081, 1993.
11. Westinghouse Electric Company, “Vogtle Units 1 and 2 SGTR Margin to Overfill Report to Address NSAL-07-11, “LTR-CRA-16-132, Rev. 1, December 21, 2016, GP-19499.
12. Westinghouse Electric Company, “Report for Vogtle Units 1 and 2 Steam Generator Tube Rupture Input to Dose and Offsite Dose Analyses,” LTR-CRA-19-39, Rev. 0.
13. Southern Nuclear Operating Company, Inc., SA-19-001, memo from J. Douglass (Southern Nuclear) to K. W. Bonadio (W) dated February 28, 2019.

15.6.4 SPECTRUM OF BOILING WATER REACTOR STEAM SYSTEM PIPING FAILURES OUTSIDE OF CONTAINMENT

This subsection is not applicable to VEGP.

15.6.5 LOSS-OF-COOLANT ACCIDENTS

15.6.5.1 Identification of Causes and Frequency Classification

A loss-of-coolant accident (LOCA) is the result of a pipe rupture of the reactor coolant system (RCS) pressure boundary. For the analyses reported here, a major pipe break (large break) is defined as a rupture with a total cross-sectional area equal to or greater than 1.0 ft^2. This event is considered a limiting fault, an American Nuclear Society (ANS) Condition IV event, in that it is not expected to occur during the lifetime of the plant but is postulated as a conservative design basis.

For large-break LOCAs, the most limiting single failure is the loss of one train of emergency core cooling system (ECCS) injection. The large-break LOCA analyses assume both maximum containment safeguards (to analyze lowest containment pressure conditions) and minimum ECCS safeguards (to analyze the loss of one complete train of ECCS components), which results in the minimum delivered ECCS flow available to the RCS.

A minor pipe break (small break), as considered in this subsection, is defined as a rupture of the reactor coolant pressure boundary with a total cross-sectional area less than 1.0 ft^2, in which the normally operating charging system flow is not sufficient to sustain pressurizer level and pressure. This is considered a Condition III event in that it is an infrequent fault that may occur during the life of the plant.

For small-break LOCAs, the most limiting single active failure is of an emergency power train which results in loss of one complete train of ECCS components. The minimum delivered ECCS flow available to the RCS is based on this single failure.

The acceptance criteria for the LOCA described in 10 CFR 50.46(1) are met as follows:

A. The calculated maximum fuel element cladding temperature is below the requirement of 2200 °F.

B. The local oxidation of the cladding does not exceed 0.17 times the thickness before oxidation.

C. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam does not exceed 0.01 times the hypothetical amount that would be generated if all the fuel cladding metal, excluding the cladding surrounding the plenum volume, were to react.

D. Calculated changes in core geometry are such that the core remains amenable to cooling.

E. The core temperature is reduced and decay heat is removed for an extended period of time, as required by the long-lived radioactivity remaining in the core.

These criteria were established to provide a significant margin in ECCS performance following a LOCA. Reference 2 presents a recent study in regards to the probability of occurrence of RCS pipe ruptures.

In all cases, small breaks (less than 1.0 ft^2) yield results with more margin to the acceptance criteria limits than the limiting large break.

15.6.5.2 Sequence of Events and Systems Operations

Should a major break occur, depressurization of the RCS results in a pressure decrease in the pressurizer. Loss-of-offsite power (LOOP) is assumed coincident with the occurrence of the break. The reactor trip signal subsequently occurs when the pressurizer low-pressure trip setpoint is reached. A safety injection signal is generated when the appropriate setpoint is reached. These countermeasures will limit the consequences of the accident in two ways:

A. Reactor trip and borated water injection complement void formation in causing rapid reduction of power to a residual level corresponding to fission product decay heat. However, no credit is taken in the LOCA ECCS thermal analysis for boron content of the injection water. In addition, the insertion of control rods to shut down the reactor is neglected in the large-break ECCS thermal analysis.

B. Injection of borated water provides for heat transfer from the core and prevents excessive cladding temperatures.

In the present Westinghouse design, the large-break single failure is the loss of an entire train of ECCS components (i.e., one high head charging pump, one safety injection pump, and one low head pump).

The small-break single failure is the loss of one ECCS train. This means that for a small break, credit could be taken for one high head charging pump, one safety injection pump, and one low head pump, though low head flow was neglected in the small-break analysis for VEGP, since the transient is terminated before the cut-in pressure is reached.

The current design for both small and large breaks assumes that at least one train is available for delivery of water to the RCS. This means that one pump in each subsystem delivers to the primary loop.

For the large-break analysis, one ECCS train starts and delivers flow through the injection lines (one for each loop) with one branch injection line spilling to the containment backpressure. To minimize delivery to the reactor, the branch line chosen to spill is selected as the one with the minimum resistance.

For the small-break analysis, one ECCS train starts and delivers flow through the injection lines (one for each loop) with one branch injection line spilling to the RCS backpressure. To minimize delivery to the reactor, the branch line chosen to spill is the one with the minimum resistance.

15.6.5.2.1 Description of Large-Break LOCA Transient

The sequence of events following a large-break LOCA are presented in figure 15.6.5-1.

Before the break occurs, the unit is in an equilibrium condition; i.e., the heat generated in the core is being removed via the secondary system. During blowdown, heat from fission product decay, hot internals, and the vessel continues to be transferred to the reactor coolant. At the beginning of the blowdown phase, the entire RCS contains subcooled liquid which transfers heat from the core by forced convection with some fully developed nucleate boiling. Thereafter, the core heat transfer is based on local conditions with transition boiling and forced convection to steam as the major heat transfer mechanisms.

The heat transfer between the RCS and the secondary system may be in either direction depending on the relative temperatures. In the case of continued heat addition to the secondary system, the secondary system pressure increases and the main steam safety valves may actuate to limit the pressure. Makeup water to the secondary side is automatically provided by the auxiliary feedwater system. The safety injection signal actuates a feedwater isolation signal which isolates main feedwater flow by closing the main feedwater isolation valves and also initiates auxiliary feedwater flow by starting the auxiliary feedwater pumps. The secondary flow aids in the reduction of RCS pressure.

When the RCS depressurizes to 611.3 psia, the accumulators begin to inject borated water into the reactor coolant loops. Since LOOP is assumed, the reactor coolant pumps are assumed to trip at the inception of the accident. The effects of pump coastdown are included in the blowdown analysis.

The blowdown phase of the transient ends when the RCS pressure (initially assumed at 2300 psia) falls to a value approaching that of the containment atmosphere. Prior to or at the end of the blowdown, the mechanisms that are responsible for the emergency core cooling water bypassing the core are calculated not to be effective. At this time (end of bypass) refill of the reactor vessel lower plenum begins. Refill is complete when emergency core cooling water has filled the lower plenum of the reactor vessel which is bounded by the bottom of the fuel rods (bottom of core recovery time).

The reflood phase of the transient is defined as the time period lasting from the bottom of recovery until the reactor vessel is filled with water to the extent that the core temperature rise is terminated. From the latter stage of blowdown to early reflood, the safety injection accumulator tanks rapidly discharge borated cooling water into the RCS, contributing to the filling of the reactor vessel downcomer. The downcomer water elevation head provides the driving force required for the reflooding of the reactor core. The RHR (low head), safety injection (intermediate head), and high head charging pumps also aid the filling of the downcomer and subsequently supply water to maintain a full downcomer and complete the reflooding process.

Continued operation of the ECCS pumps supplies water during long-term cooling. By this time, core temperatures are reduced to long-term, steady-state levels associated with the dissipation of residual heat generation. After the water level of the refueling water storage tank (RWST) reaches a minimum allowable value, coolant for long-term cooling of the core is obtained by switching to the cold leg recirculation mode of operation, in which spilled borated water is drawn from the containment emergency sumps and returned to the RCS cold legs. The containment spray pumps are manually aligned to the containment emergency sumps and continue to operate to further reduce containment pressure.

Approximately 7.5 hours after initiation of the LOCA, the ECCS is realigned to supply water to the RCS hot legs to control the boric acid concentration in the reactor vessel.

15.6.5.2.2 Description of Small-Break LOCA Transient

As contrasted with the large break, the blowdown phase of the small break occurs over a longer time period. Thus, for the small-break LOCA there are only three characteristic stages; i.e., a gradual blowdown with a decrease in water level and a partial core uncovery, core recovery, and long-term recirculation.

Should a small break occur, depressurization of the RCS causes fluid to flow into the loops from the pressurizer resulting in a pressure and level decrease in the pressurizer. Reactor trip occurs when the low pressurizer pressure trip setpoint is reached. During the earlier part of the small-break transient, the effect of the break flow is not strong enough to overcome the flow maintained by the reactor coolant pumps through the core as they are coasting down following reactor trip. Due to the LOOP assumption, the reactor coolant pumps are assumed to be tripped coincident with reactor trip during the accident. Upward flow through the core is maintained. However, the core flow is not sufficient to prevent a partial core uncovery. The ECCS is actuated when the appropriate setpoint is reached and provides sufficient core flow to recover the core.

Before the break occurs the plant is in an equilibrium condition; i.e., the heat generated in the core is being removed via the secondary system. During blowdown, heat from fission product decay, hot internals, and the vessel continues to be transferred to the RCS. The heat transfer between the RCS and the secondary system may be in either direction depending on the relative temperatures. In the case of continued heat addition to the secondary, secondary system pressure increases and steam relief via the atmospheric relief and/or safety valves may occur. The auxiliary feedwater pumps provide makeup to the secondary side. The reactor trip signal isolates normal feedwater flow by closing the main feedwater isolation valves and initiates auxiliary feedwater flow by starting the auxiliary feedwater pumps. The secondary flow aids in the reduction of RCS pressure.

When the RCS depressurizes to approximately 611.3 psia, the cold leg accumulators begin to inject borated water into the reactor coolant loops. For some breaks, the vessel mixture level starts to increase with ECCS pumped injection before the accumulators come on. For the breaks that do reach the accumulator injection setpoint, the accumulation injection provides enough water to bring the mixture level up to the upper plenum region where it is maintained.

15.6.5.3 Core and System Performance

15.6.5.3.1 Mathematical Model

The requirements of an acceptable ECCS evaluation model are presented in Appendix K of 10 CFR 50.(1)

15.6.5.3.1.1 Large-Break LOCA Evaluation Model. The large break analysis was performed with the 1981 version of the Westinghouse ECCS evaluation model using BASH (reference 3), including the changes in the methodology for execution of the model which are described in references 4 and 5. The BASH evaluation model for dry containment plants includes the following main computer codes:

- SATAN - Blowdown thermal-hydraulics code;
- BASH - Refill and reflood thermal-hydraulics code;
- COCO - Containment backpressure code; and
- LOCBART - Rod temperature and blockage code.

A brief summary of each of these codes is presented in the following paragraphs.

SATAN (reference 6) is a one-dimensional nodal network code which models the thermal-hydraulic phenomena during the blowdown depressurization in the reactor core and RCS after a postulated large rupture of a primary coolant pipe. It was developed specifically as part of the evaluation model that meets 10 CFR 50 Appendix K requirements. The code provides blowdown thermal and hydraulic parameters that define the heat transfer boundary conditions in the LOCBART code, which is used to calculate the hot assembly and hot rod fuel cladding temperature transients during a LOCA. SATAN also provides mass and energy discharge rates from the RCS to containment for the COCO code, which is used for containment backpressure calculations.

Some specific features of the SATAN code include the use of a drift flux model and the use of a two-phase friction multiplier. In the core, a hot channel and an average channel flow calculation, effects of crossflow between channels, cladding swelling and rupture effects, and metal-water reaction effects are considered. In the rest of the primary loop, accumulator bypass effects and a two-phase pump model are included.

SATAN begins calculation of the transient at the time of the rupture. Calculations continue until the end of blowdown which is determined when the following two conditions are met:

1. Downflow of ECCS water into the reactor vessel lower plenum is established, and
2. The RCS pressure is equalized with the containment pressure.

When both of these conditions are met, SATAN will terminate and the refill phase calculations will begin.

The BASH code (reference 3) is used to calculate the refill and reflood portions of the large break LOCA transient. The REFILL module in the BASH code contains the thermal-hydraulic models that are used to describe the storage and transport of water from the ECCS injection points to the reactor vessel lower plenum. The only regions modeled in REFILL are the lumped intact loop cold legs, broken loop cold leg stub, reactor vessel downcomer, and lower plenum up to the bottom of the active fuel. The ECCS systems, including the accumulators, are also modeled. REFILL obtains the conditions from the SATAN tape at the end of blowdown which is used to initialize the refill portion of the transient. REFILL models the cold leg transit and fill, hot wall delay due to flashing of ECCS water in the downcomer, freefall of the water in the downcomer, and lower plenum fill. The refill stage of the LOCA ends when bottom-of-core recovery occurs. The time to bottom-of-core recovery is the total amount of time required for the ECCS to increase the water level in the reactor vessel lower plenum to the bottom of the active fuel.

When bottom-of-core recovery occurs, the reflood phase calculations in BASH begin. The BASH code consists of the BART code (reference 7) for core thermal-hydraulic and heat transfer calculations, and a modified version of the NOTRUMP code (reference 8) for the RCS transient response calculations. The BART computer code was developed primarily as a best-estimate design code for application to the reflood stage of LOCA analysis, and the basic features are described in reference 7. Some specific features of BART are as follows:

1. Conservation of mass and energy in liquid, vapor, and two-phase regions in the reactor core.
2. Radial conduction heat transfer within the fuel rod.
3. Heat exchange between rods and coolant in liquid, vapor, and two-phase regions in the core.
4. Quench-front propagation and heat release.
5. Thermal nonequilibrium and heat transfer between phases.

The loop models and equations are based on the equilibrium version of the NOTRUMP code, which is used for a variety of applications. The main code components are fluid nodes, metal nodes, flow links, and heat links. Physical problems are modeled by using the components to form a network of multiple fluid and metal nodes, appropriately interconnected by flow and heat links. The nodes provide for mass and energy storage; the links provide for mass, energy, and momentum transfer. Thermal-hydraulic effects in the RCS during core reflooding are modeled in the code. Flow correlations model the effects of pressure drop and phase separation. Heat transfer correlations represent all regimes from liquid convection, through nucleate and transition boiling, to stable film boiling or forced convection vaporization, and finally to steam forced convection.

BART, with numerical modifications and with changes to some of the physical models, was combined with the NOTRUMP code described above, creating BASH. BASH calculates the reflood rate which is input to LOCBART, which then calculates the hot assembly and hot rod thermal transient performance during reflood.

The BASH code is also used to provide the mass and energy discharge rates from the RCS to the containment during reflood, which are used in the COCO code for the containment backpressure calculations.

The COCO code (reference 9) models the containment behavior for dry containment plants during a large break LOCA transient. The code calculates the pressure and temperature transients inside the containment during the depressurization and post-blowdown phases following a LOCA.

A detailed examination is made of the nonlinear physical phenomena occurring within the containment during the transient. Transient conditions are determined for both the containment steam-air atmosphere and the containment sump water. Temperature gradients in and heat absorption by the containment structures are also considered. The code has the flexibility to analyze various safeguards systems, including internal and external sprays, containment venting and pump back, ventilation fan coolers, and a sump water recirculation system. In the current version of the BASH evaluation model, the COCO code is run interactively in the BASH code, to provide direct feedback between the containment and RCS during the refill and reflood phases of the transient.

The LOCBART code calculates fuel rod temperature profiles, cladding burst, and cladding oxidation during the accident sequence. LOCBART is a combination of the LOCTA-IV code (reference 10) and the BART code (reference 7). The heat transfer regimes which are analyzed by the LOCTA-IV code include single-phase convective cooling, nucleate boiling, transition boiling, stable film boiling, and heat transfer to steam using laminar or turbulent heat transfer film coefficients. The effects of fuel rod-to-coolant radiation and rod-to-rod radiation are considered within the program. Heat transfer coefficients are computed for each axial increment on the basis of local coolant flows, qualities, and temperatures.

After the blowdown phase of the accident, the ECCS delivers water to the RCS which ultimately fills the reactor vessel lower plenum. During this refill phase of the accident, only rod-to-rod radiation heat transfer is considered in LOCTA-IV. When the lower plenum is full, water begins to enter the core region, and the reflood phase of the accident begins. During the reflooding period, the core is cooled by a two-phase mixture that results from steam generation and droplets entrained leaving the flooded region of the core. In the two-phase period, the heat transfer coefficients are calculated by BART using rigorous mechanistic models. When the reflooding rate is less than 1 in./s, the heat transfer coefficient is calculated based on a steam cooling assumption.

During the blowdown and refill phases of a LOCA transient, the LOCTA-IV part of LOCBART is used to calculate the average fuel temperatures. The required mass flow, pressure, and enthalpy information to the fuel rod code during blowdown is provided by SATAN output. During refill, the rod-to-fluid heat transfer coefficient is conservatively assumed to be zero, which results in essentially adiabatic conditions. LOCBART also calculates the thermal-hydraulic conditions in the hot assembly during reflood using the flooding rate obtained from the BASH code. The complete LOCBART code is used to calculate the hot rod temperature during the blowdown, refill, and reflood phases.

15.6.5.3.1.2 Small-Break LOCA Evaluation Model. The small break analysis was performed with the Westinghouse ECCS evaluation model using NOTRUMP (references 8 and 16), including changes to the model and methodology as described in references 17 and 20. The NOTRUMP evaluation model includes the following computer codes:

- NOTRUMP - Thermal-hydraulic response of RCS during transient;

- SBLOCTA - Fuel rod/cladding heatup during transient.

A brief summary of each of these codes is presented in the following paragraphs.

The NOTRUMP computer code is a one-dimensional general thermal-hydraulic network code consisting of a number of features. Among these features are the calculation of thermal nonequilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flooding limitations, mixture level tracking logic in multiple-stacked fluid nodes, and regime-dependent heat transfer correlations. Heat transfer in the core is calculated based on LOCTA-IV code (reference 18) which considers heat transfer regimes, including single-phase convection to subcooled liquid, nucleate boiling, transition boiling, film boiling, and convection to superheated vapor in both laminar and turbulent flows. In addition, the NOTRUMP small break loss-of-coolant accident emergency core cooling system evaluation model (NOTRUMP SBLOCA ECCS EM) was developed to determine the RCS response to design basis small break LOCAs and to address the NRC concerns expressed in NUREG-0611.

The NOTRUMP model is generally made up of nodes (control volumes) and links (mass and energy transport). This model determines the thermal-hydraulic response of the RCS during the SBLOCA transient based upon initial operating conditions, core nuclear design parameters, and steam generator and reactor vessel characteristics, as well as ECCS performance and other plant specific parameters. Select RCS response boundary conditions are extracted from the NOTRUMP calculations and are used in the SBLOCTA fuel rod heatup code.

SBLOCTA is a small-break specific version of the LOCTA-IV code (reference 18). Peak cladding temperature (PCT) calculations are performed with the LOCTA-IV code using the NOTRUMP calculated core pressure, fuel rod power history, uncovered core steam flow, and mixture levels as boundary conditions. LOCTA-IV models the hot rod and the average hot assembly rod. As stated above, LOCTA-IV contains many heat transfer models; however, due to the relatively low velocities experienced in the core during the SBLOCA transient, heat transfer is basically limited to forced convection to super-heated vapor and rod-to-rod radiation. In addition to PCT, SBLOCTA also calculates maximum local and hot rod axial average ZrO_2 reaction.

15.6.5.3.2 Input Parameters and Initial Conditions

The large break LOCA analysis for Units 1 and 2 was performed for plant operation at 3565 MWt (plus 2% uncertainty, which bounds the current rated thermal power level of 3625.6 MWt) with 10% steam generator tube plugging. The analysis conditions are based on a total RCS thermal design flow of 93,600 gpm/loop which is consistent with 10% steam generator tube plugging. The analysis was performed with the upper head fluid temperature equal to the RCS cold leg fluid temperature, achieved by increasing the upper head cooling flow.

The effects of a combined LOCA/SSE event were explicitly accounted for in the large break LOCA analysis via an increase in the modeled steam generator tube plugging level. The steam generator tube plugging adder was conservatively assumed to be 2.5% (reference 15). The key parameters which were used in the large break LOCA analysis are summarized in table 15.6.5-1.

The small break LOCA analysis for Units 1 and 2 was also performed for plant operation at 3565 MWt (plus 2% uncertainty, which bounds the current rated thermal power level of 3625.6 MWt) with 10% steam generating tube plugging. The analysis conditions are based on a total RCS thermal design flow of 93,600 gpm/loop. A summary of the key parameters used in the small break LOCA analysis is presented in table 15.6.5-5.

The SBLOCA analysis imposed no restriction on the rate of return-to-power.

The integrated fuel burnable absorber (IFBA) fuel analysis was performed at 0 MWD/MTU, meaning the LBLOCA analysis imposes no restriction on the rate of return-to-power following an outage. Also, the analysis is considered to be insensitive to loop flow variations representative of normal plant operation.

The initial steady-state fuel pellet temperatures and the fuel rod internal pressures used in the LOCA analysis were generated with the PAD 4.0 Fuel Rod Design Code (reference 11), which was approved by the Nuclear Regulatory Commission.

Reference 23 concluded that the LOCA ZIRLO® models are acceptable for application to Optimized ZIRLO™ cladding in the large break and small break analyses, and that no additional calculations are necessary for evaluating the use of Optimized ZIRLO cladding provided plant specific ZIRLO calculations were previously performed. An exception to this is identified in the Safety Evaluation Report (SER) of reference 23 for plants licensed with the Westinghouse Appendix K LBLOCA code LOCBART with a blowdown or early reflood PCT; however, an evaluation performed for the implementation of Optimized ZIRLO cladding concluded that ZIRLO models are acceptable for application to Optimized ZIRLO cladding for Vogtle 1 and 2 and no additional calculations are necessary. Further, for the LBLOCA cases analyzed, PCT does not occur during blowdown or early reflood.

The bases used to select the numerical values that are input parameters to the analysis were conservatively determined from extensive sensitivity studies.(12)(13)(14) In addition, the requirements of 10 CFR 50 Appendix K (reference 1) regarding specific model features were met by selecting models which provide a significant overall conservatism in the analysis. The assumptions made pertain to the conditions of the reactor and associated safety system equipment at the time that the LOCA occurs and include such items as the core peaking factors, the containment pressure, and the performance of the ECCS. Decay heat generated throughout the transient is also conservatively calculated.

15.6.5.3.3 Results

15.6.5.3.3.1 Large-Break Results. Based on the results of the LOCA sensitivity studies (references 12, 13, and 14), the limiting large break was found to be the double-ended cold leg guillotine (DECLG). Therefore, only the DECLG break is considered in the large-break ECCS performance analysis. Calculations were performed for a range of Moody break discharge coefficients. The results of these calculations are summarized in table 15.6.5-2. (Note that the results in table 15.6.5-2 are obtained directly from the LOCBART output and are based on a T_{AVG} window of 573.0 °F to 588.4 °F. An evaluation was performed to extend the low T_{AVG} to 570.7 °F.) The time sequence of events for each case is summarized in table 15.6.5-3. Changes to the PCT subsequent to the ECCS model analysis are summarized in table 15.6.5-4.

The mass and energy release data for the break resulting in the highest calculated peak clad temperature are discussed in paragraph 6.2.1.5.

Figures 15.6.5-2 through 15.6.5-16 present the parameters of principal interest from the large-break ECCS analyses. For all cases, analyzed transients of the following parameters are presented in the following figures:

Figure	Parameter

Figure	Parameter
15.6.5-2	Cladding temperature at PCT and burst elevations
15.6.5-3	Core pressure during blowdown
15.6.5-4	Vessel liquid levels during reflood
15.6.5-5	Core inlet flooding rate during reflood
15.6.5-6	Normalized core power during blowdown
15.6.5-7	Containment pressure transient
15.6.5-8	Core inlet and outlet mass flow rate during blowdown
15.6.5-9	Cladding surface heat transfer coefficient at PCT and burst elevations
15.6.5-10	Vapor temperature at PCT and burst elevations
15.6.5-11	Break mass flow rate during blowdown
15.6.5-12	Break energy release rate during blowdown
15.6.5-13	Fluid quality at PCT and burst elevations
15.6.5-14	Fluid mass velocity at PCT and burst elevations
15.6.5-15	Intact loop accumulator mass flow rate during blowdown
15.6.5-16	Intact leg accumulator and SI mass flow rate during reflood

The peak cladding temperature calculated by LOCBART for a large break is 2061.6 °F for 156-IFBA, which is less than the acceptance limit of 2200 °F. The maximum local metal-water reaction is below the embrittlement limit of 17% as required by 10 CFR 50.46. The total core metal-water reaction is less than the 1% criterion of 10 CFR 50.46. The cladding temperature transient is terminated at a time when the core geometry is still amenable to cooling. As a result, the core temperature will continue to drop, and the ability to remove decay heat generated in the fuel for an extended period of time will be provided.

15.6.5.3.3.1.1 Additional Analyses and Safety Evaluations. An evaluation was performed to extend the large break LOCA analysis to support operation at PCWG T_{AVG} values between 570.7 °F and 573.0 °F with up to 10% tube plugging in any or all steam generators. This evaluation results in a PCT increase of about 0.5 °F, for an overall PCT value of 2062.1 °F with 156 IFBA. Note that the 156 IFBA PCT value is considered the "analysis-of-record" PCT value and will be reported as such on the 10 CFR 50.46 rack-up sheet.

The potential limited use of LOPAR fuel in future reloads will be evaluated on a cycle-specific basis.

15.6.5.3.3.2 Small-Break Results. Based on the results of the LOCA sensitivity studies (references 12 and 19), the limiting small break was found to be less than a 10-in. diameter rupture of the RCS cold leg. Therefore, a range of small-break is presented cases which established the limiting small break. The results of these analyses are summarized in tables 15.6.5-6 and 15.6.5-7. Changes to the PCT subsequent to the ECCS model analysis are summarized in table 15.6.5-8.

Figures 15.6.5-22 through 15.6.5-33 present the principal parameters of interest for the small-break ECCS analyses. The figures are as follows:

Figure	Parameter
15.6.5-22	2-in., Low T_{AVG} Reactor Coolant System Pressurizer Pressure
15.6.5-23	2-in., Low T_{AVG} Core Mixture Level 2 in.
15.6.5-24	3-in., Low T_{AVG} Reactor Coolant System Pressurizer Pressure
15.6.5-25	3-in., Low T_{AVG} Core Mixture Level
15.6.5-26	3-in., Low T_{AVG} Core Steam Flow Rate
15.6.5-27	3-in., Low T_{AVG} Pumped Safety Injection
15.6.5-28	3-in., Low T_{AVG} Peak Clad Temperature at 11.25 ft
15.6.5-29	3-in., Low T_{AVG} Hot Spot Fluid Temperature at 11.25 ft
15.6.5-30	3-in., Low T_{AVG} Hot Rod Heat Transfer Coefficient at 11.25 ft
15.6.5-31	4-in., Low T_{AVG} Reactor Coolant System Pressurizer Pressure
15.6.5-32	4-in., Low T_{AVG} Core Mixture Level
15.6.5-33	4-in., Low T_{AVG} Peak Clad Temperature at 10.75 ft

The PCT calculated for the small-break LOCA is 1138 °F. The maximum local metal-water reaction is below the acceptance criteria limit of 17%. The total core metal-water reaction is less than the 1 percent acceptance criteria. These results are below all acceptance criteria limits of 10 CFR 50.46.

15.6.5.3.3.2.1 Additional Analyses and Safety Evaluations. The potential use of LOPAR fuel in future reloads will be evaluated on a cycle-specific basis.

15.6.5.3.3.2.2 The impact on the SBLOCA analysis of installing a pressure breakdown orifice in the cold leg common header of the HHSI subsystem and one pressure breakdown orifice in each IHSI pump discharge line and replacing HIJSI branch line flow elements FE-924, FE-925, FE-926, and FE-927 with more restrictive flat plate orifices has been evaluated. The SBLOCA evaluation results arc bounded by the current SBLOCA AOR for Units 1 and 2.

15.6.5.4 Radiological Consequences

The results of the analyses presented in this section demonstrate that the radioactivity released to the environment by a LOCA does not result in doses exceeding the limits specified in 10 CFR 100. The dose calculations take into account radioactivity released to the environment by containment leakage of gases, by leakage of the recirculating sump solution, and by containment purge at the beginning of the accident. The results presented in this section are applicable to both initial and reload cycles and remain valid for both the VANTAGE 5 and LOPAR fuel assembly designs to 60,000 MWd/Mtu lead rod average burnups.

The major assumptions and parameters assumed in the analysis are itemized in tables 15.6.5-9 and 15A-1.

In the evaluation of a LOCA, the fission product release assumptions of Regulatory Guide 1.4 have been followed with some exceptions. Table 15.6.5-10 provides a comparison of the analysis to the recommendations of Regulatory Guide 1.4.

The mathematical models used to calculate the activity releases during the course of the accident and the resultant doses are described in appendix 15A.

15.6.5.4.1 Fission Product Release to the Containment

Following a postulated double-ended rupture of a reactor coolant pipe with subsequent blowdown, the ECCS limits the fuel clad temperature to well below the melting point and ensures that the reactor core remains intact and in a coolable geometry, thus minimizing the release of fission products to the containment. However, to demonstrate that the operation of a nuclear power plant does not represent an undue radiological hazard to the general public, a hypothetical accident involving a significant release of fission products to the containment is evaluated. It is assumed that, 20 s into the accident, 100 percent of the noble gases and 50 percent of the iodine equilibrium core fission product inventory are released to the containment atmosphere. The iodine and the noble gas activity are assumed to be immediately available for leakage from the containment.

15.6.5.4.2 Fission Product Release Due to Containment Leakage

Once the gaseous fission product activity is released to the containment atmosphere, it is subject to various mechanisms of removal which operate simultaneously to reduce the amount of activity in the containment atmosphere. The removal mechanisms include radioactive decay, containment sprays, deposition, and containment leakage. For the noble gas fission products, the only removal processes considered in the containment are radioactive decay and containment leakage. Credit for radioactive decay of fission products located within the containment is assumed throughout the course of the accident. Once the activity is released to the environment, no credit is taken for radioactive decay or deposition. The containment leakage to the environment is assumed to be direct and unfiltered.

The quantity of activity released through leakage from the containment was calculated with a two-volume model of the containment to represent sprayed and unsprayed regions of the containment. This model is discussed in appendix 15A.

Of the total free volume of the containment, part is covered by the containment spray, while some is not. The unsprayed fraction has been calculated as approximately 22 percent. The transfer rate between the sprayed and unsprayed regions is assumed to be limited to the forced convection induced by the fan cooler units. The number of units assumed in operation and the total mixing flow are presented in table 15.6.5-9. This assumed minimum flowrate conservatively neglects the effects of natural convection, spray-induced turbulence, steam condensation, and diffusion, although these effects are expected to enhance the mixing rate between the sprayed and unsprayed volumes.

For fission products other than iodine, the only removal processes considered are radioactive decay and leakage. Iodine is assumed to be removed not only by radioactive decay and leakage, but also by deposition and by the containment spray system. The effectiveness of the containment spray for the removal of the iodine in the containment atmosphere and the model used to determine the iodine removal efficiency are discussed in subsection 6.5.2. The iodine removal constants are given in table 15.6.5-9.

Credit for iodine removal by the containment spray system is taken, starting at the time spray is initiated and continuing until a decontamination factor of 21.4 for elemental iodine is achieved. Credit for particulate removal in the sprayed region is taken for the duration of the accident, with the removal rate reduced after a decontamination factor of 50 is achieved. Credit for deposition removal of elemental iodine is taken from accident initiation until a decontamination factor of 200 is achieved.

Release from the containment by containment leakage is assumed to be 0.2% per day for the first 24 h and 0.1% per day thereafter. The offsite doses at the site boundary and at the low population zone and the doses to control room personnel are given in table 15.6.5-11. The activity released due to containment leakage is given in table 15.6.5-12.

15.6.5.4.3 Fission Product Release Due to Containment Purge Operation

During normal power operation the containment purge system (described in section 6.2) is operating, venting the containment at 5000 ft^3/min. In the event of a LOCA, the purge system supply and exhaust isolation valves are assumed to close within 5 s of receiving a containment isolation signal as designed.

The containment airborne fission product inventory available for release is based on 100% of the total primary coolant iodine inventory assuming a preexisting iodine spike level of 60-µCi/g dose equivalent I-131 and 100% of the primary coolant noble gas inventory assuming the reactor has been operating with 1% fuel defects (i.e., defects in the cladding of fuel rods generating 1% of the core rated power). No credit is taken for removal of iodine by the purge filter train.

The offsite doses at the site boundary and at the low population zone and the doses to control room personnel are given in table 15.6.5-11. The activity released due to containment purge operation is given in table 15.6.5-12.

15.6.5.4.4 Radioactive Releases Resulting from Leakage from ECCS and Containment Spray Recirculation Lines

Subsequent to the injection phase of engineered safety features (ESF) system operation, the water in the containment recirculation sumps is recirculated by the residual heat removal, centrifugal charging, safety injection, and containment spray pumps. The radiological consequences of leakage from these systems is considered because the recirculated sump water contains a large fraction of the core iodines released as a result of the LOCA.

Because noble gases are assumed to be available for leakage from the containment atmosphere and are not readily entrained in water, the noble gases are not assumed to be part of the source term for this contribution to the total LOCA dose.

Since much of the radioiodine released during the LOCA would be retained by the containment sump water, it is conservatively assumed that 50 percent of the core iodine inventory is contained in the sump water to be recirculated through the external piping systems. Radioactive decay of this iodine is taken into account.

The fraction of the leakage that flashes to steam is assumed to carry 100% of the associated iodines into the air.

The recirculation flowpaths outside the containment are entirely within building areas served by the ESF ventilation system (subsection 6.5.1), which recirculates the air through charcoal filters to remove airborne iodine and maintains the areas at subatmospheric pressure to prevent the release of unfiltered air. A fraction of the recirculating air is discharged to the environment.

The offsite doses at the site boundary and at the low population zone and the doses to control room personnel are given in table 15.6.5-11. The activity released due to recirculation leakage is given in table 15.6.5-12.

15.6.5.4.5 Identification of Uncertainties and Conservatisms in the Analysis

The uncertainties and conservatisms in the assumptions used to evaluate the radiological consequences of a LOCA result principally from assumptions made involving the amount of the gaseous fission products available for release to the environment and the meteorology present at the site during the course of the accident. The most significant of these assumptions are:

A. The ECCS is designed to prevent fuel cladding damage that would release the fission products, contained in the fuel, to the reactor coolant. Severe degradation of the ECCS (simultaneous failure of redundant components) would be necessary to release the quantity of fission products assumed in the analysis.

B. The release of core fission products to the containment is assumed to occur after only 20 s from accident initiation.

C. The activity released to the containment atmosphere is assumed to leak to the environment at the containment leakage rate of 0.2 volume percent/day for the first 24 h and 0.1 volume percent/day thereafter. The initial containment leakage rate is based on the peak calculated internal containment pressure anticipated after a LOCA. The pressure within the containment actually decreases with time. Taking into account that the containment leak rate is a function of pressure, the calculated doses could be reduced significantly.

D. The meteorological conditions assumed to be present at the site during the course of the accident are based on x/Q values which are worse than those which will exist at the site 95% of the time. This condition results in the poorest values of atmospheric dispersion calculated for the exclusion area boundary and the low population zone outer boundary. Furthermore, no credit has been taken for the transit time required for activity to travel from the point of release to the exclusion area boundary and to the low population zone outer boundary. Hence, the radiological consequences evaluated under these conditions are conservative.

15.6.5.4.6 Conclusions

15.6.5.4.6.1 Filter Loadings. No recirculating or single-pass filters are used for fission product cleanup and control within the containment following a postulated LOCA. The only ESF filtration systems expected to be operating under post-LOCA conditions are the control room heating, ventilation, and air-conditioning (HVAC) system and the auxiliary building emergency exhaust filtration system.

Activity loadings on the control room charcoal adsorbers are based on the flowrate through the adsorber, the concentration of activity at the adsorber inlet, and the adsorber efficiency. Based on the radioactive iodine release assumptions previously described, the assumption that 50% of the core inventory of isotopes I-127 and I-129 is available for release from the containment atmosphere, and the assumption that the charcoal adsorber is 100% efficient, the calculated filter loadings are in accordance with Regulatory Guide 1.52, which limits the maximum loading to 2.5 mg of iodine/g of activated charcoal.

15.6.5.4.6.2 Doses to a Receptor at the Exclusion Area Boundary and Low Population Zone Outer Boundary. The potential radiological consequences resulting from the occurrence of the postulated LOCA have been conservatively analyzed, using assumptions and models described in previous sections.

The total-body immersion dose and the thyroid inhalation dose have been analyzed for the 0- to 2-h dose at the exclusion area boundary and for the duration of the accident at the low population zone. The results are listed in table 15.6.5-6. The resultant doses are within the guideline values of 10 CFR 100.

15.6.5.4.6.3 Doses to Control Room Personnel. Radiation doses to control room personnel following a postulated LOCA are based on the ventilation, cavity dilution, and dose model discussed in section 15A.3.

Control room personnel are subject to a total-body immersion dose and a thyroid inhalation dose. These doses have been analyzed and are provided in table 15.6.5-6. The operator will take appropriate action to ensure that the resultant doses are within the limits established by General Design Criterion 19.

15.6.5.5 References

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2. U.S. Nuclear Regulatory Commission 1975, "Reactor Safety Study – An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," WASH-1400, NUREG-75/014.
3. "The 1981 Version of the Westinghouse ECCS Evaluation Model Using the BASH Code," WCAP-10266-P-A, Revision 2 (Proprietary) and WCAP-11524-A, Revision 2 (Non-Proprietary), March 1987.
4. Westinghouse letter NTD-NRC-94-4143 from N. J. Liparulo to W. T. Russell (USNRC), “Change in Methodology for Execution of BASH Evaluation Model,” May 23, 1994.
5. Westinghouse letter NTD-NRC-95-4540 from N. J. Laparulo to W. T. Russell (USNRC), “Change in Methodology for Execution of BASH Evaluation Model,” August 29, 1995.
6. “SATAN VI Program: Comprehensive Space-Time Dependent Analysis of Loss-of-Coolant,” WCAP-8302 (Proprietary) and WCAP-8306 (Non-Proprietary), June 1974.
7. “BART-A1: A Computer Code for the Best Estimate Analysis of Reflood Transients,” WCAP-9561-P-A (Proprietary) and WCAP-9695-A (Non-Proprietary), March 1984.
8. “NOTRUMP: A Nodal Transient Small Break and General Network Code,” WCAP-10079-P-A (Proprietary) and WCAP-10080-A (Non-Proprietary), August 1985.

9. "Containment Pressure Analysis Code (COCO)," WCAP-8327, July 1974.

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14. “Westinghouse ECCS – Four Loop Plant (17 x 17) Sensitivity Studies,” WCAP-8565-P-A (Proprietary) and WCAP-8566-A (Non-Proprietary), July 1975.

15. “Steam Generator Tube Plugging Margin Analysis for the Alvin W. Vogtle Nos. 1 & 2 Nuclear Power Plants,” WCAP-10338, August 1983.

16. “Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code,” WCAP-10054-P-A, August 1985.

17. “Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model,” WCAP-10054-P-A, Addendum 2, Revision 1, July 1997.

18. “LOCTA-IV Program: Loss-of-Coolant Transient Analysis,” WCAP-8301, June 1974.

19. "Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study with the NOTRUMP Code,” WCAP-11145-P-A, October 1986.

20. “Model Changes to the Westinghouse Appendix K Small Break LOCA NOTRUMP Evaluation Model: 1988-1997,” WCAP-15085, July 1998.

21. Federal Guidance Report No. 11.

22. Federal Guidance Report No. 12.

23. Shah, H., “Optimized ZIRLO^{TM},” WCAP-12610-P-A & CENPD-404-P-A Addendum 1-A, July 2006.

TABLE 15.6.1-1

TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH CAUSE A DECREASE IN REACTOR COOLANT INVENTORY

Accident	Event	Time (s)
Inadvertent opening of a pressurizer safety valve	Pressurizer safety valve opens fully	0.0
	Overtemperature ΔT reactor trip setpoint reached	24.5
	Rods begin to drop	26.5
	Minimum DNBR occurs	27.0

TABLE 15.6.2-1

PARAMETERS USED TO EVALUATE THE CONSEQUENCES OF A BREAK IN AN RCS INSTRUMENT LINE OUTSIDE THE CONTAINMENT

Core power level (MWt)	3636
Fuel defect level (%)	1.0
Reactor coolant iodine spike (μCi/g dose equivalent I-131)	60
Reactor coolant radionuclide concentration (μCi/g)	
Iodines	Table 15A-6
Noble gases	Table 15A-4
Break flowrate (lbm/s)	0.106
Fraction of spill flashing	0.58
Fraction of iodine in the spill becoming airborne	
Flashed portion	1.0
Nonflashed portion	0.1
Time to recognize break and to initiate shutdown (h)	8
Time to cool reactor coolant to 212°F; one RHR train in operation (h)	24
Atmospheric dispersion factors	Table 15A-2
Dose conversion factors	Table 15A-5

TABLE 15.6.2-2

PARAMETERS USED TO EVALUATE THE CONSEQUENCES OF A LETDOWN LINE BREAK OUTSIDE THE CONTAINMENT

Core power level (MWt)	3636
Fuel defect level (%)	1.0
Reactor coolant iodine spike (μCi/g dose equivalent I-131)	60
Reactor coolant radionuclide concentration (μCi/g)	
Iodines	Table 15A-6
Noble gases	Table 15A-4
Break flowrate (lbm/s)	21.3
Fraction of spill flashing	0.086
Fraction of iodine in the spill becoming airborne	
Flashed portion	1.0
Nonflashed portion	0.1
Time to isolate letdown line (min)	30
Atmospheric dispersion factors	Table 15A-2
Dose conversion factors	Table 15A-5

TABLE 15.6.2-3

DOSES RESULTING FROM AN RCS INSTRUMENT LINE BREAK OUTSIDE CONTAINMENT

Doses	
Thyroid dose (rem)	
Site boundary	0.9
Low population zone	1.4
Whole-body dose (rem)	
Site boundary	< 0.1
Low population zone	< 0.1

TABLE 15.6.2-4

DOSES RESULTING FROM A LETDOWN LINE BREAK OUTSIDE CONTAINMENT

Doses	
Thyroid dose (rem)	
Site boundary	12.5
Low population zone	5.0
Whole-body dose (rem)	
Site boundary	< 0.1
Low population zone	< 0.1

TABLE 15.6.3-1

OPERATOR ACTION TIMES FOR DESIGN BASIS SGTR ANALYSIS

Action	Dose Analysis Time (min)	Margin to Overfill Analysis (ref. 11) Time (min)
Identify and isolate AFW flow to ruptured steam generator	4 minutes or LOFTTR2 calculated time to reach 9-percent narrow range level in the ruptured SG, whichever is longer[a]	6
Isolate ruptured steam generator	20 min or LOFTTR2 calculated time to recover to 30-percent narrow range level in the ruptured SG, whichever is longer[a]	15 min or LOFTTR2 calculated time to recover to 30-percent narrow range level in the ruptured SG, whichever is longer[a]
Operator action time to initiate cooldown	12	12
Cooldown	Calculated by LOFTTR2	Calculated by LOFTTR2
Operator action time to initiate depressurization	5.75	5.75
Depressurization	Calculated by LOFTTR2	Calculated by LOFTTR2
Operator action time to initiate SI termination	3	2
SI termination and pressure equalization	Calculated time for SI termination and equalization of RCS and ruptured SG pressures	Calculated time for SI termination and equalization of RCS and ruptured SG pressures

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a. Earlier AFW isolation time is conservative for the dose analysis. The AFW isolation time used in the dose analysis is not a Time Critical Operator Action.

TABLE 15.6.3-2

SEQUENCE OF EVENTS

Event	Time (s)
SG tube rupture	0
Reactor trip	49.7
SI actuated	113
AFW flow isolated to ruptured steam generator	240
Ruptured SG isolated	1200
Ruptured SG ARV fails open	1202
Ruptured SG ARV block valve closed	2162
RCS cooldown initiated	2882
RCS cooldown terminated	3264
RCS depressurization initiated	3612
RCS depressurization terminated	3666
SI terminated	3846
Break flow terminated	5502

TABLE 15.6.3-3

MASS RELEASES RESULTS TOTAL MASS FLOW (lb)

	0 - 2 h	2 - 20 h
Ruptured SG		
- Condenser	57,000	0
- Atmosphere	157,000	37,100
- Feedwater	70,300	0
Intact SGs		
- Condenser	169,900	0
- Atmosphere	526,600	2,495,600
- Feedwater	738,200	2,579,100
Break Flow	204,900	0

TABLE 15.6.3-4 (SHEET 1 OF 2)

PARAMETERS USED IN EVALUATING RADIOLOGICAL CONSEQUENCES

I.	Source Data	
A.	Core power level (MWt)	3636
B.	Total steam generator tube leakage, prior to accident (gal/min)	1.0
C.	Reactor coolant iodine activity:	
1.	Accident initiated spike	The initial RC iodine activities based on 1 μCi/gram of D.E. I-131 are presented in table 15A-6. The iodine appearance rates assumed for the accident initiated spike are presented in table 15A-7.
2.	Preaccident spike	Primary coolant iodine activities based on 60 μCi/gram of D.E. I-131 are presented in table 15A-6.
3.	Noble gas activity	The initial RC noble gas activities based on 1-percent fuel defects are presented in table 15A-4.
D.	Secondary system initial activity	Dose equivalent of 0.1 μCi/g of I-131, presented in table 15.6.3-5
E.	Reactor coolant mass, grams	2.53×10^8

TABLE 15.6.3-4 (SHEET 2 OF 2)

	F.		Initial steam generator mass (each), grams	4.2 x 10^7
	G.		Offsite power	Lost at time of reactor trip
	H.		Primary-to-secondary leakage duration for intact SG, h	20
	I.		Species of iodine	100-percent elemental
II.			Activity Release Data	
	A.		Ruptured steam generator	
		1.	Rupture flow	See table 15.6.3-3
		2.	Rupture flow flashing fraction	See figure 15.6.3-13
		3.	Iodine scrubbing efficiency	See figure 15.6.3-15
		4.	Total steam release, lb	See table 15.6.3-3
		5.	Iodine partition factor	100
	B.		Intact steam generators	
		1.	Total primary-to-secondary leakage, gal/min	0.7
		2.	Total steam release, lb	See table 15.6.3-3
		3.	Iodine partition factor	100
	C.		Condenser	
		1.	Iodine partition factor	100
	D.		Atmospheric Dispersion Factors	See table 15A-2

TABLE 15.6.3-5

IODINE SPECIFIC ACTIVITIES IN THE SECONDARY COOLANT BASED ON 0.1 μCi/gram OF D.E. I-131

Nuclide	Specific Activity (μ Ci/gm) Secondary Coolant 0.1 μCi/gm
I-131	0.074
I-132	0.075
I-133	0.141
I-134	0.018
I-135	0.069

TABLE 15.6.3-6

AND

TABLE 15.6.3-7

DELETED

TABLE 15.6.3-8

BREATHING RATES

Time (hours)	Breathing Rate (m^3/s) (ref. 4)
0-2	3.47×10^{-4}
2-8	3.47×10^{-4}
8-20	1.75×10^{-4}

TABLE 15.6.3-9

DELETED

TABLE 15.6.3-10

WHOLE BODY AND BETA SKIN DOSE CONVERSION FACTORS FOR NOBLE GASSES

(rem-m^3/Ci-sec) (ref. 10)

Nuclide	Conversion Factors	
	Whole Body	Beta Skin
Xe-131m	1.44×10^{-3}	1.78×10^{-2}
Xe-133m	5.07×10^{-3}	3.85×10^{-2}
Xe-133	5.77×10^{-3}	1.84×10^{-2}
Xe-135m	7.55×10^{-2}	1.10×10^{-1}
Xe-135	4.40×10^{-2}	1.15×10^{-1}
Xe-138	2.13×10^{-1}	3.96×10^{-1}
Kr-85m	2.77×10^{-2}	8.29×10^{-2}
Kr-85	4.40×10^{-4}	4.88×10^{-2}
Kr-87	1.52×10^{-1}	5.07×10^{-1}
Kr-88	3.77×10^{-1}	5.00×10^{-1}

TABLE 15.6.3-11

OFFSITE RADIATION DOSES

	Doses (rem) Calculated Value	Doses (rem) Allowable Guideline Value
1. Accident Initiated Iodine Spike		
Exclusion Area Boundary (0 - 2 h)		
Thyroid Dose	16.1	30
Low Population Zone (0 – 20 h)		
Thyroid Dose	6.9	30
2. Preaccident Iodine Spike		
Exclusion Area Boundary (0 - 2 h)		
Thyroid Dose	26.3	300
Low Population Zone (0 – 20 h)		
Thyroid Dose	10.8	300
3. Whole-Body Gamma and Beta-Skin Dose		
Exclusion Area Boundary (0 - 2 h)		
Whole-Body Gamma Dose	0.2	2.5
Beta-Skin Dose	0.3	not specified
Low Population Zone (0 – 20 h)		
Whole-Body Gamma Dose	0.1	2.5
Beta-Skin Dose	0.2	not specified

TABLE 15.6.5-1

SUMMARY OF LARGE BREAK LOCA ANALYSIS ASSUMPTIONS

Core power	3565 MWt
Calorimetric uncertainty	2%
Fuel type	17 x 17
Total core peaking factor, F_Q	2.50
Hot channel enthalpy rise factor, $F_{\Delta H}$	1.65
K(Z) limit	1.0 from 0 to 6 ft; 1.0 to 0.925 from 6 to 12 ft
Thermal design flow	93,600 gpm/loop
Nominal vessel average temperature	570.7 °F/588.4 °F[a]
Vessel average temperature uncertainty	±6 °F
Pressurizer pressure	2250 psia
Pressurizer pressure uncertainty	±50 psi
Steam generator tube plugging	10%
Accumulator water volume, nominal	900 ft^3/accumulator
Accumulator gas pressure, minimum	611.3 psia
Safety injection pumped flow	Figures 15.6.5-17 and 15.6.5-18
Containment parameters	Paragraph 6.2.1.5

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a. Note that the LOCBART calculations are based on a T_{AVG} window of 573.0°F to 588.4°F, and an evaluation was performed to support operation at T_{AVG} values between 570.7°F and 573.0°F with up to 10 percent steam generator tube plugging. See paragraph 15.6.5.3.3.1.1 for more information.

TABLE 15.6.5-2

LARGE BREAK LOCA RESULTS

	C_D=0.4 Low T_{AVG} MIN SI Cosine Shape non-IFBA	C_D=0.6 Low T_{AVG} MIN SI Cosine Shape non-IFBA	C_D=0.8 Low T_{AVG} MIN SI Cosine Shape non-IFBA	C_D=1.0 Low T_{AVG} MIN SI Cosine Shape non-IFBA	C_D=0.6 High T_{AVG} MIN SI Cosine Shape non-IFBA	C_D=0.6 Low T_{AVG} MAX SI Cosine Shape non-IFBA	C_D=0.6 Low T_{AVG} MIN SI 8.5' Shape non-IFBA	C_D=0.6 Low T_{AVG} MIN SI Cosine Shape 128-IFBA	C_D=0.6 Low T_{AVG} MIN SI Cosine Shape 156-IFBA
Peak Cladding Temperature (°F)	1887.2	1936.3	1909.2	1878.6	1932.9	1868.9	1919.7	2040.0	2061.6
Peak Cladding Temperature Time(s)	191.5	174.4	168.8	162.5	172.8	181.0	199.1	176.1	175.6
Peak Cladding Temperature Location (ft)	7.25	7.25.	7.25	7.25	7.25	7.25	9.0	7.25	7.25
Maximum Local Zr/H_2O Reaction (%)	<17.0	<17.0	<17.0	<17.0	<17.0	<17.0	<17.0	<17.0	<17.0
Maximum Local Zr/H_2O Location (ft)	7.25	7.25	7.25	7.25	5.25	7.25	9.0	7.25	7.25
Total Zr/H_2O Reaction (%)	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0
Hot Rod Burst Time(s)	71.11	43.85	39.97	42.77	41.35	43.85	48.48	43.85	51.62
Hot Rod Burst Loc. (ft)	6.25	5.75	5.50	5.50	5.25	5.75	8.25	5.75	5.50

TABLE 15.6.5-3

LARGE BREAK LOCA TIME SEQUENCE OF EVENTS

RESULTS (sec)	C_D=0.4 Low T_{AVG} MIN SI Cosine Shape non-IFBA	C_D=0.6 Low T_{AVG} MIN SI Cosine Shape non-IFBA	C_D=0.8 Low T_{AVG} MIN SI Cosine Shape non-IFBA	C_D=1.0 Low T_{AVG} MIN SI Cosine Shape non-IFBA	C_D=0.6 High T_{AVG} MIN SI Cosine Shape non-IFBA	C_D=0.6 Low T_{AVG} MAX SI Cosine Shape non-IFBA	C_D=0.6 Low T_{AVG} MIN SI 8.5’ Shape non-IFBA	C_D=0.6 Low T_{AVG} MIN SI Cosine Shape 128-IFBA	C_D=0.6 Low T_{AVG} MIN SI Cosine Shape 156-IFBA
Start	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reactor Trip Signal	0.44	0.43	0.42	0.42	0.49	0.43	0.43	0.43	0.43
Safety Injection Signal	2.6	2.0	1.8	1.6	2.0	2.0	2.0	2.0	2.0
Accumulator Injection	19.6	13.6	11.0	9.8	14.8	13.6	13.8	13.6	13.6
End of Blowdown	41.1	33.4	28.8	26.7	31.7	33.4	33.1	33.4	33.4
Start of Safety Injection	42.6	42.0	41.8	41.6	42.0	42.0	42.0	42.0	42.0
Bottom of Core Recovery	55.5	45.9	39.2	36.8	45.3	45.6	44.1	45.9	45.9
Accumulator Empty	61.7	54.7	51.0	49.0	54.4	55.4	54.6	54.7	54.7

TABLE 15.6.5-4

PEAK CLAD TEMPERATURE CHANGES FOR LARGE BREAK LOCA ANALYSIS (156 IFBA)

	Unit 1	Unit 2
Calculated PCT from ECCS Model Analysis (Analysis of Record)	2062.1 °F[(a)(b)(c)]	2062.1 °F[(a)(b)(c)]
Rebaseline of Limiting LOCBART Calculation	-22 °F[(d)]	-22 °F[(d)]
LOCBART Pellet Volumetric Heat Generation Rate Error Correction	18 °F[(d)]	18 °F[(d)]
PWROG TCD Evaluation - Rebaseline of AOR	22 °F[(e)]	22 °F[(e)]
Changes to Grid Blockage Ratio and Porosity	29 °F[(f)]	29 °F[(f)]
Total Resultant PCT	2109.1 °F	2109.1 °F

Notes:

(a) Includes 0.5 °F to address a reduction in low T_{AVG} from 573.0 °F to 570.7 °F.

(b) Includes additional metal mass allowance. Refer to table 6.2.1-72.

(c) Changes in assumed accumulator line resistance can affect plant testing acceptance criteria. The current PCT and test criteria are based on Westinghouse SECL-98-104, Revision 1.

(d) Per Westinghouse letter LTR-LIS-07-308, “10 CFR 50.46 Reporting Text for LOCBART Version 37.0 issues and Revised PCT Rackup Sheets for Vogtle Units 1 and 2,” May 2007.

(e) Per Westinghouse letter LTR-12-514, “Vogtle Units 1 and 2 10 CFR 50.46 Notification and Reporting for Fuel Pellet Thermal Conductivity Degradation and Peaking Factor Burndown,” September 20, 2012.

(f) Per Westinghouse letter LTR-LIS-13-408, “10 CFR 50.46 Report for the A. W. Vogtle Units 1 and 2 Evaluation of Changes to Grid Parameters Modeled in the BASH-EM Analysis,” October 2013.

TABLE 15.6.5-5

SUMMARY OF SMALL BREAK LOCA ANALYSIS ASSUMPTIONS

Core power	3565 MWt
Calorimetric uncertainty	2%
Fuel type	17 x 17
Total core peaking factor, F_Q	2.58
Hot channel enthalpy rise factor, $F_{\Delta H}$	1.7
K(Z) limit	1.0 from 0 to 6 ft; 1.0 to 0.925 from 6 to 12 ft
Thermal design flow	93,600 gmp/loop
Nominal vessel average temperature	570.7 °F/588.4 °F
Vessel average temperature uncertainty	±6 °F
Pressurizer pressure	2250 psia
Pressurizer pressure uncertainty	±50 psi
Steam generator tube plugging	10%
Accumulator water volume, nominal	900 ft^3/accumulator
Accumulator gas pressure, minimum	611.3 psia
Safety injection pumped flow	Figures 15.6.5-20 and 15.6.5-21
Power shape	Figure 15.6.5-22

TABLE 15.6.5-6

SMALL BREAK LOCA
LOW T_{AVG} NOTRUMP TRANSIENT RESULTS

Event Time (sec)	2 in.[(a)]	3 in.	4 in.
Break initiation	0	0	0
Reactor trip signal	35.5	14.9	8.58
S-signal	76.1	28.0	16.6
SI delivered	116.1	68.0	56.6
Loop seal clearing[(b)]	1090	473	280
Core uncovery	N/A	707	737
Accumulator injection	N/A	1888	945
RWST empty time	2537.7	2479.4	2441.8
PCT time	N/A	1665	973.4
Core recovery	N/A	2388	1567

---

a. Note that there was no core uncovery for the 2-in. break case.
b. Loop seal clearing is defined as break vapor flow > 1 lb/s.

TABLE 15.6.5-7

SMALL BREAK LOCA
LOW T_{AVG} BEGINNING OF LIFE (BOL) ROD HEATUP RESULTS

	2 in.[a]	3 in.	4 in.
PCT (°F)	N/A	1138	975
PCT time (s)	N/A	1665	973.4
PCT elevation (ft)	N/A	11.25	10.75
Burst time (s)	N/A	N/A	N/A
Burst elevation (ft)	N/A	N/A	N/A
Max. local ZrO_2 (%)	N/A	0.08	0.02
Max. local ZrO_2 elev (ft)	N/A	11.25	11.00
Core-Wide avg. ZrO_2 (%)	N/A	0.02	0.01

---

a. Note that there was no core uncovery for the 2-in. break case.

TABLE 15.6.5-8

PEAK CLAD TEMPERATURE CHANGES FOR SMALL BREAK LOCA ANALYSIS

	Unit 1	Unit 2
Calculated PCT from ECCS analysis (Analysis of Record)	1138.0 °F	1138.0 °F
Total Resultant PCT	1138.0 °F	1138.0 °F

TABLE 15.6.5-9 (SHEET 1 OF 4)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT

Source Data	
Core power level (MWt)	3636
Core activity released in the containment atmosphere after 20 s into the accident (%)	
Noble gas	100
Iodine	50
Core inventories	Table 15A-3
Iodine distribution (%)	
Elemental	91
Organic	4
Particulate	5
Atmospheric Dispersion Factors	Table 15A-2
Control Room Parameters	Tables 15A-1 and 15A-2
Containment Leakage of Activity	
Containment leak rate (volume %/day)	
0 to 24 h	0.2
1 to 30 days	0.1
Unfiltered containment leakage (%)	100
Deposition iodine removal constants elemental iodine only (h^{-1})	4.8 (DF ≤ 200)

TABLE 15.6.5-9 (SHEET 2 OF 4)

Credit for containment sprays	
Spray iodine removal constants (h^{-1})	
Elemental	$10^{(1)}$ (DF ≤ 21.4)
Organic	0.0
Particulate	4.2 (DF ≤ 50) 0.42 (DF > 50)
Duration of sprays (h)	2
Sprayed volume (%)	78
Unsprayed volume (%)	22
Number of fan coolers operating	2
Sprayed-unsprayed mixing rate (ft^3/min)	87,000
Containment volume (ft^3)	2.93×10^6

Activity released to containment atmosphere

Isotope	Curies
I-131	5.15×10^7
I-132	7.50×10^7
I-133	1.05×10^8
I-134	1.13×10^8
I-135	9.75×10^7
Xe-131m	7.13×10^5
Xe-133m	3.01×10^7
Xe-133	2.12×10^8
Xe-135m	4.18×10^7
Xe-135	4.65×10^7
Xe-138	1.69×10^8
Kr-85m	2.68×10^7
Kr-85	1.04×10^6
Kr-87	4.93×10^7
Kr-88	7.02×10^7

TABLE 15.6.5-9 (SHEET 3 OF 4)

Containment Purge of Activity

Purge flowrate (ft^3/min)	5000
Duration of purge, from accident initiation (s)	8.5
Reactor coolant iodine spike (μCi/g I-131 dose equivalent)	60
Reactor coolant activity airborne in the containment (%)	
Noble gas	100
Iodine	100

Activity released to the containment atmosphere from the reactor coolant

Isotope	Curies
I-131	1.12×10^4
I-132	1.14×10^4
I-133	2.14×10^4
I-134	2.73×10^3
I-135	1.05×10^4
Xe-131m	5.11×10^2
Xe-133m	4.45×10^3
Xe-133	6.48×10^4
Xe-135m	1.42×10^2
Xe-135	2.10×10^3
Xe-138	1.87×10^2
Kr-85m	5.16×10^2
Kr-85	2.12×10^3
Kr-87	3.24×10^2
Kr-88	9.31×10^2

TABLE 15.6.5-9 (SHEET 4 OF 4)

Recirculation Leakage Outside Containment

Leak rate (gal/min, measured at 70 °F)	2
Temperature of recirculating fluid (°F)	
0 to 0.5 h	No recirculation
0.5 to 2.0 h	240
2.0 to 720 h	< 212
Mass of water in the containment sump (lb)	6.77×10^6
Activity in the sump solution at time = 0	
Isotope	Curies
I-131	5.15×10^7
I-132	7.50×10^7
I-133	1.0×10^8
I-134	1.1×10^8
I-135	9.75×10^7
Volume of building served by the auxiliary building emergency ventilation system (ft^3)	525,000
Auxiliary building emergency ventilation system parameters (for each of two trains)	
Recirculation flow (ft^3/min)	13,950
Discharge flow (ft^3/min)	2970
Elemental iodine filter efficiency (%)	90

Notes:

(1) Calculated value is 22.5 h^{-1}.

TABLE 15.6.5-10 (SHEET 1 OF 7)

DESIGN COMPARISON TO THE REGULATORY POSITIONS OF REGULATORY GUIDE 1.4, ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT FOR PRESSURIZED WATER REACTORS, REVISION 2, JUNE 1974

Regulatory Guide 1.4 Position	Design
1. The assumptions related to the release of radioactive material from the fuel and containment are as follows:	
a. 25% of the equilibrium radioactive iodine inventory developed from maximum full-power operation of the core should be assumed to be immediately available for leakage from the primary reactor containment. 91% of this 25% is to be assumed to be in the form of elemental iodine; 5% of this 25% in the form of particulate iodine; and 4% of this 25% in the form of organic iodides.	Fifty percent of core inventory of iodine is assumed to be immediately available for leakage from the containment. The iodine is assumed to be 91% elemental, 5% particulate, and 4% organic. These assumptions are in accordance with Section 6.5.2 of NUREG-0800.
b. 100% of equilibrium radioactive noble gas inventory developed from maximum full-power operation of the core should be assumed to be immediately available for leakage from the reactor containment.	Conforms.
c. The effects of radiological decay during holdup in the containment or other buildings should be taken into account.	Conforms. Credit for radioactive decay is taken until the activity is assumed to be released.

TABLE 15.6.5-10 (SHEET 2 OF 7)

Regulatory Guide 1.4 Position	Design
d. The reduction in the amount of radioactive material available for leakage to the environment by containment sprays, recirculating filter systems, or other engineered safety features may be taken into account, but the amount of reduction in concentration of radioactive materials should be evaluated on an individual case basis.	Conforms.
e. The primary reactor containment should be assumed to leak at the leak rate incorporated or to be incorporated as a technical specification requirement at peak accident pressure for the first 24 h and at 50% of this leak rate for the remaining duration of the accident. Peak accident pressure is the maximum pressure defined in the Technical Specifications for containment leak testing.	Conforms.
2. Acceptable assumptions for atmospheric diffusion and dose conversion are:	
a. The 0- to 8-h ground level release concentrations may be reduced by a factor ranging from 1 to a maximum of 3 (see Figure 1) for additional dispersion produced by the turbulent wake of the reactor building in calculating potential exposures. The volumetric building wake correction, as defined in section 3.3.5.2 of Meteorology and Atomic Energy 1968, should be used only in the 0- to 8-h period; it is used with a shape factor of 1/2 and the minimum cross-sectional area of the reactor building only.	Short-term accident atmospheric dispersion factors were calculated based on site meteorological measurement program described in section 2.3. These factors are for ground level releases and are based on Regulatory Guide 1.145 methodology and represent the worst of the 5% site meteorology and the 0.5% worst sector meteorology.

TABLE 15.6.5-10 (SHEET 3 OF 7)

Regulatory Guide 1.4 Position	Design
b. No correction should be made for depletion of the effluent plume of radioactive iodine resulting from deposition on the ground or for the radiological decay of iodine in transit.	Same as response to 2a above.
c. For the first 8 h, the breathing rate of persons offsite should be assumed to be 3.47 x 10-4 m^3/s. From 8 to 24 h following the accident, the breathing rate should be assumed to be 1.75 x 10-4 m^3/s. After that, until the end of the accident, the breathing rate should be assumed to be 2.32 x 10-4 m^3/s. (These values were developed from the average daily breathing rate (2 x 107 cm^3/day) assumed in the report of ICRP, Committee II-1959.)	Conforms.
d. The iodine dose conversion factors are given in ICRP Publication 2, Report of Committee II, Permissible Dose for Internal Radiation, 1959.	The dose conversion factors provided in Federal Guidance Report 11 are used.
e. External whole body doses should be calculated using "infinite cloud" assumptions; i.e., the dimensions of the cloud are assumed to be large compared to the distance that the gamma rays and beta particles travel. "Such as a cloud would be considered an infinite cloud for a receptor at the center because any additional (gamma and) beta emitting material beyond the cloud dimensions would not alter the flux of (gamma rays and) beta particles to the receptor" (Meteorology and Atomic Energy, Section 7.4.1.1; editorial additions made so that gamma and beta emitting material could be considered). Under these conditions the rate of energy absorption per unit volume is equal	The dose conversion factors provided in Federal Guidance Report 12 are used.

TABLE 15.6.5-10 (SHEET 4 OF 7)

Regulatory Guide 1.4 Position | Design

to the rate of energy released per unit volume. For an infinite uniform cloud containing x curies of beta radioactivity per cubic meter, the beta dose in air at the cloud center is:

$${}_{\beta}D'_{\infty} + 0.457\,\overline{E}_{\beta\chi}$$

The surface body dose rate from beta emitters in the infinite cloud can be approximated as being one-half this amount (i .e.,

$${}_{\beta}D'_{\infty} + 0.23\,\overline{E}_{\beta\chi}\ )$$

For gamma emitting material, the dose rate in air at the cloud center is:

$${}_{\gamma}D'_{\infty} + 0.507\,\overline{E}_{\gamma\chi}$$

From a semi-infinite cloud, the gamma dose rate in air is:

$${}_{\gamma}D'_{\infty} + 0.25\,\overline{E}_{\gamma\chi}$$

where:

${}_{\beta}D'_{\infty}$ = Beta dose rate from an infinite cloud (rad/s).

${}_{\gamma}D'_{\infty}$ = Gamma dose rate from an infinite cloud (rad/s).

$\overline{E}_{\beta}$ = Average gamma energy per disintegration (MeV/dis).

$\overline{E}_{\gamma}$ = Average beta energy per disintegration (MeV/dis).

χ = Concentration of beta of gamma emitting isotope in the cloud (Ci/m^3).

TABLE 15.6.5-10 (SHEET 5 OF 7)

Regulatory Guide 1.4 Position	Design
f. The following specific assumptions are acceptable with respect to the radioactive cloud dose calculations:	
(1) The dose at any distance from the reactor should be calculated based on the maximum concentration in the plume at that distance, taking into account specific meteorological, topographical, and other characteristics which may affect the maximum plume concentration. These site-related characteristics must be evaluated on an individual case basis. In the case of beta radiation, the receptor is assumed to be exposed to an infinite cloud at the maximum ground level concentration at that distance from the reactor. In the case of gamma radiation, the receptor is assumed to be exposed to only one-half the cloud owing to the presence of the ground. The maximum cloud concentration always should be assumed to be at ground level.	See response to 2e above.
(2) The appropriate average beta and gamma energies emitted per disintegration, as given in the Table of Isotopes, Sixth Edition, by C. M. Lederer, J. M. Hollander, and I. Perlman; University of California, Berkeley, Lawrence Radiation Laboratory, should be used.	See response to 2e above.
g. The atmospheric diffusion model should be as follows:	
(1) The basic equation for atmospheric diffusion from a ground level point source is: $\chi/Q = \frac{1}{\pi\mu\sigma_y\sigma_z}$	Short-term accident atmospheric dispersion factors were calculated based on onsite meteorological measurement program described in section 2.3. These factors are for ground level releases and are based on Regulatory Guide1.145 methodology and represent the worst of the 5% site meteorology and the 0.5% worst sector meteorology.

TABLE 15.6.5-10 (SHEET 6 OF 7)

Regulatory Guide 1.4 Position	Design
where: χ = The short term average centerline value of ground level concentration (Ci/m^3). Q = Amount of material released (Ci/s) u = Windspeed (m/s). σ_y = The horizontal standard deviation of the plume (m). (See Figure V-1, page 48, Nuclear Safety, June 1961, Volume 2, Number 4, Use of Routine Meteorological Observations for Estimating Atmospheric Dispersion, F. A. Gifford, Jr.) σ_z = The vertical standard deviation of the plume (m). (See Figure V-2, page 48, Nuclear Safety, June 1961, Volume 2, Number 4, Use of Routine Meteorological Observations for Estimating Atmospheric Dispersion, F. A. Gifford, Jr.)	
(2) For time period of greater than 8 h the plume should be assumed to meander and spread uniformly over a 22.5° sector. The resultant equation is: $\chi/Q = \frac{2.032}{\sigma_x u_\chi}$ where: χ = Distance from point of release to the receptor; other variables are given in 2g (1).	See response to 2g(1) above.
(3) The atmospheric diffusion model2 for ground level release is based on the information below:	See response to 2g (1) above.

TABLE 15.6.5-10 (SHEET 7 OF 7)

Time Following Accident	Atmospheric Conditions
0 to 8 h	Pasquill type F, windspeed 1 m/s, uniform direction
8 to 24 h	Pasquill type F, windspeed 1 m/s, variable direction within a 22.5° sector
1 to 4 days	(a) 40% Pasquill type D, windspeed 3 m/s
	(b) 60% Pasquill type F, windspeed 2 m/s
	(c) wind direction variable within a 22.5° sector
4 to 30 days	(a) 33.3% Pasquill type C, windspeed 3 m/s
	(b) 33.3% Pasquill type D, windspeed 3 m/s
	(c) 33.3% Pasquill type F, windspeed 2 m/s
	(d) windspeed direction 33.3% frequency in a 22.5° sector

(4) Figures 2A and 2B give the ground level release atmospheric diffusion factor based on the parameters given in 2g(3).	See response to 2g (1) above.

TABLE 15.6.5-11 (SHEET 1 OF 2)

DOSES RESULTING FROM A LOSS-OF-COOLANT ACCIDENT

Site Boundary Dose (0 to 2 h)

Containment leakage	
Thyroid (rem)	74.4
Gamma body (rem)	1.9
Beta skin (rem)	4.1
Containment purge	
Thyroid (rem)	0.3
Gamma body (rem)	< 0.1
Beta skin (rem)	< 0.1
Recirculation leakage	
Thyroid (rem)	10.0
Gamma body (rem)	0.1
Beta skin (rem)	0.1
Total	
Thyroid (rem)	84.6
Gamma body (rem)	2.0
Beta skin (rem)	4.2

Low Population Zone (0 to 30 days)

Containment leakage	
Thyroid (rem)	88.1
Gamma body (rem)	1.3
Beta skin (rem)	3.1
Containment purge	
Thyroid (rem)	0.1
Gamma body (rem)	< 0.1
Beta skin (rem)	< 0.1
Recirculation leakage	
Thyroid (rem)	35.3
Gamma body	0.2
Beta skin	0.5
Total	
Thyroid (rem)	124
Gamma body (rem)	1.5
Beta skin (rem)	3.5

TABLE 15.6.5-11 (SHEET 2 OF 2)

Control Room (0 to 30 days)

Containment leakage	
Thyroid (rem)	20.6
Gamma body (rem)	0.6
Beta skin (rem)	13.6
Containment purge	
Thyroid (rem)	0.3
Gamma body (rem)	< 0.1
Beta skin (rem)	< 0.1
Recirculation leakage	
Thyroid (rem)	8.8
Gamma body (rem)	0.1
Beta skin (rem)	3.1
Total	
Thyroid (rem)	29.7
Gamma body (rem)	1.0(a)
Beta skin (rem)	16.7

(a) Includes contributions from inside and outside the control room.

TABLE 15.6.5-12

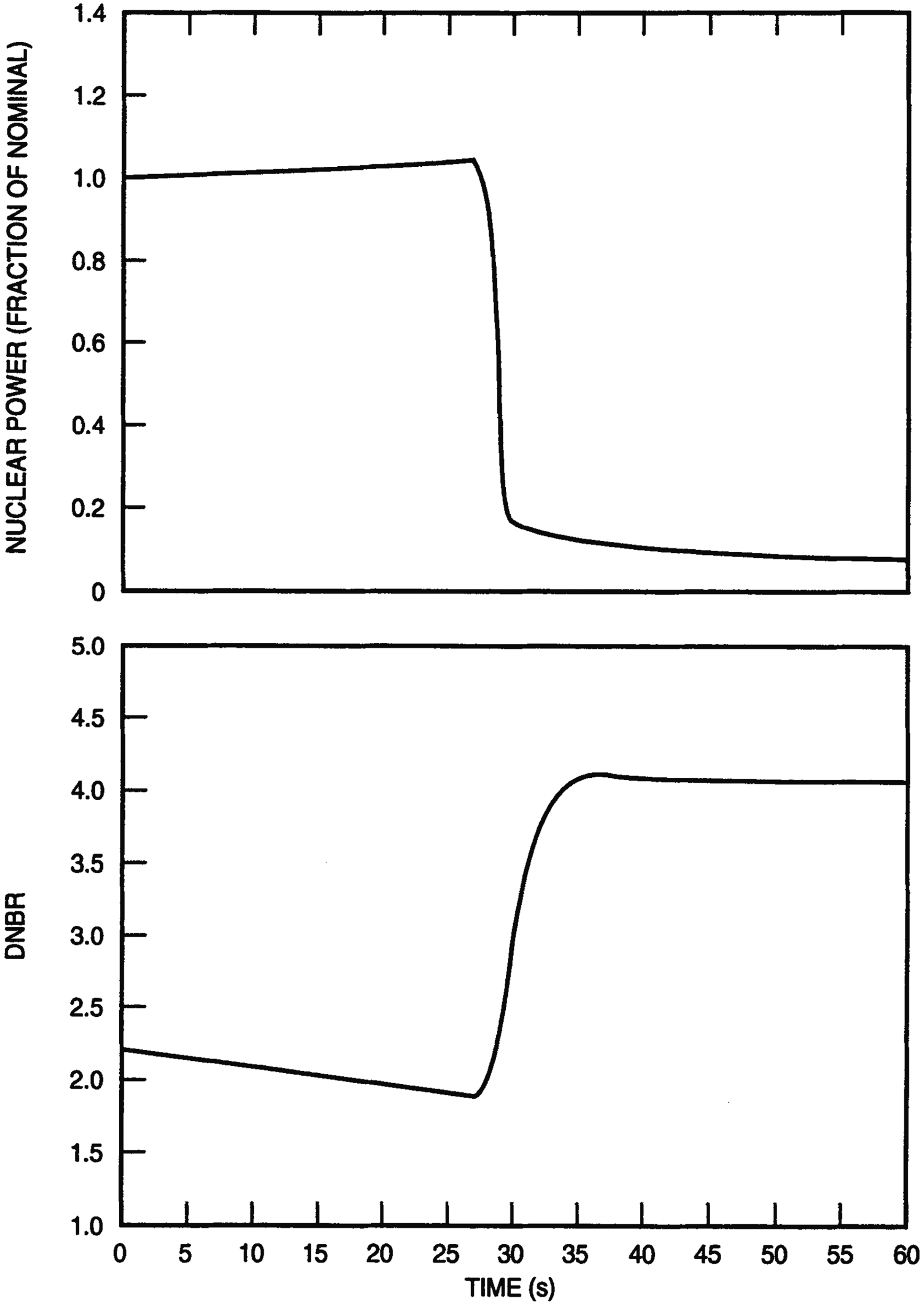
ACTIVITY RELEASES TO THE ENVIRONMENT DUE TO A LOSS-OF-COOLANT ACCIDENT (Ci)

0 to 2 h

Isotope	Containment Leakage	Containment Purge	Recirculation Leakage	Total
I-131	7.91×10^{2}	2.71	1.07×10^{2}	9.00×10^{2}
I-132	9.90×10^{2}	2.75	1.08×10^{2}	1.10×10^{3}
I-133	1.59×10^{3}	5.17	2.11×10^{2}	1.80×10^{3}
I-134	1.23×10^{3}	6.59×10^{-1}	9.30×10^{1}	1.33×10^{3}
I-135	1.42×10^{3}	2.54	1.79×10^{2}	1.60×10^{3}
Kr-85m	3.83×10^{3}	1.25×10^{-1}	NA	3.83×10^{3}
Kr-85	1.73×10^{2}	5.12×10^{-1}	NA	1.74×10^{2}
Kr-87	5.00×10^{3}	7.82×10^{-2}	NA	5.00×10^{3}
Kr-88	9.26×10^{3}	2.25×10^{-1}	NA	9.26×10^{3}
Xe-131m	1.19×10^{2}	1.24×10^{-1}	NA	1.19×10^{2}
Xe-133m	4.96×10^{3}	1.08	NA	4.96×10^{3}
Xe-133	3.51×10^{4}	1.57×10^{1}	NA	3.53×10^{4}
Xe-135m	3.18×10^{3}	3.54×10^{-2}	NA	5.85×10^{3}
Xe-135	8.38×10^{3}	5.08×10^{-1}	NA	1.00×10^{4}
Xe-138	4.79×10^{3}	4.50×10^{-2}	NA	4.79×10^{3}

2 to 720 h

I-131	2.62×10^{4}		1.83×10^{4}	4.45×10^{4}
I-132	5.04×10^{2}		1.88×10^{4}	6.92×10^{2}
I-133	8.35×10^{3}		4.13×10^{3}	1.25×10^{4}
I-134	1.10×10^{2}		4.08×10^{1}	1.51×10^{2}
I-135	2.67×10^{3}		1.05×10^{3}	3.72×10^{3}
Kr-85m	1.04×10^{4}		NA	1.04×10^{4}
Kr-85	3.15×10^{4}		NA	3.15×10^{4}
Kr-87	2.53×10^{3}		NA	2.53×10^{3}
Kr-88	1.48×10^{4}		NA	1.48×10^{4}
Xe-131m	1.46×10^{4}		1.33×10^{4}	2.78×10^{4}
Xe-133m	1.20×10^{5}		1.26×10^{4}	1.32×10^{5}
Xe-133	1.95×10^{6}		4.21×10^{5}	2.37×10^{6}
Xe-135m	9.63×10^{3}		1.69×10^{4}	2.66×10^{4}
Xe-135	1.02×10^{5}		1.28×10^{5}	2.30×10^{5}
Xe-138	1.36×10^{1}		NA	1.36×10^{1}



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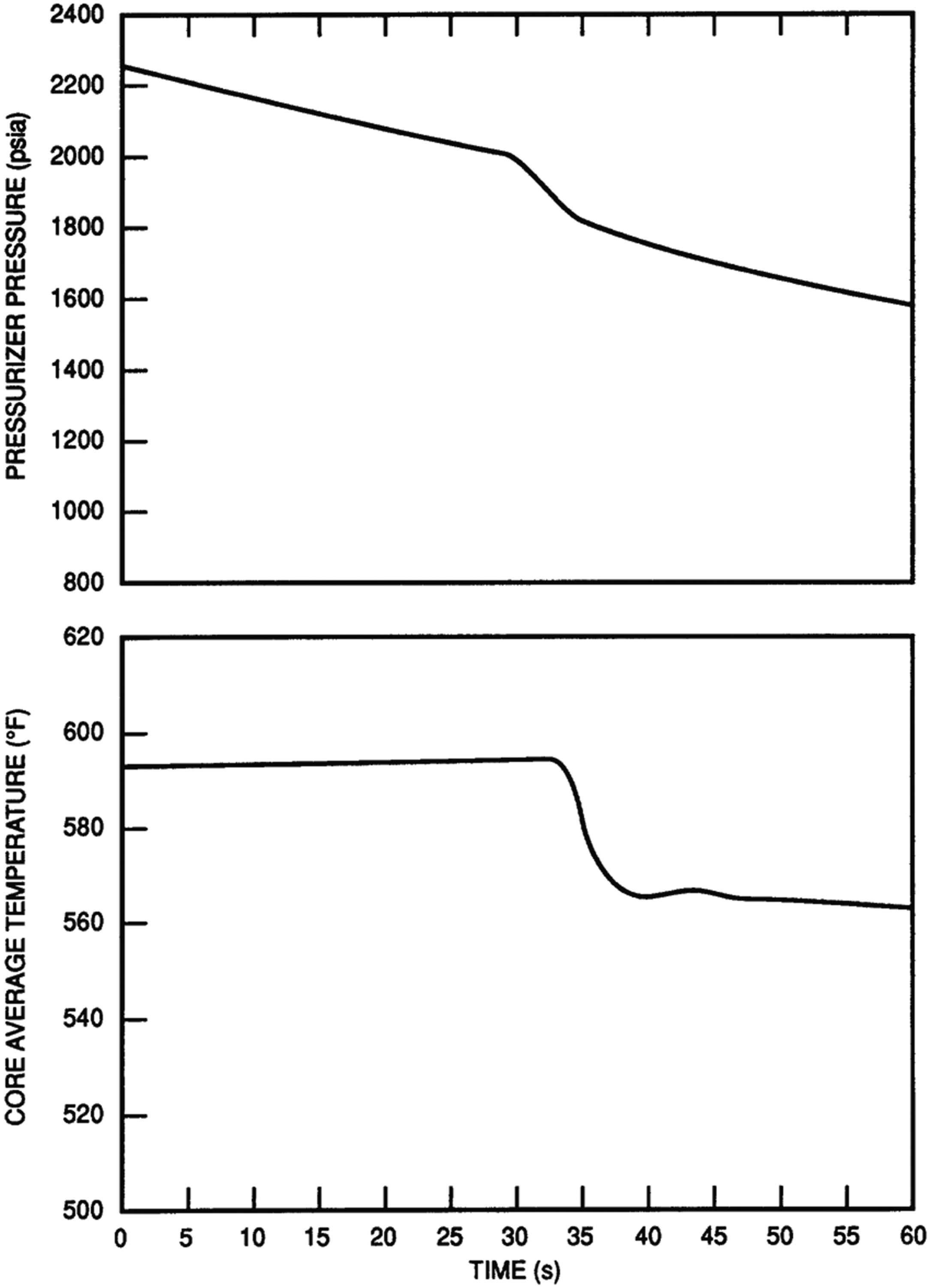
UNIT 1 AND UNIT 2

NUCLEAR POWER AND DNBR TRANSIENTS FOR INADVERTENT OPENING OF A PRESSURIZER SAFETY VALVE

FIGURE 15.6.1–1



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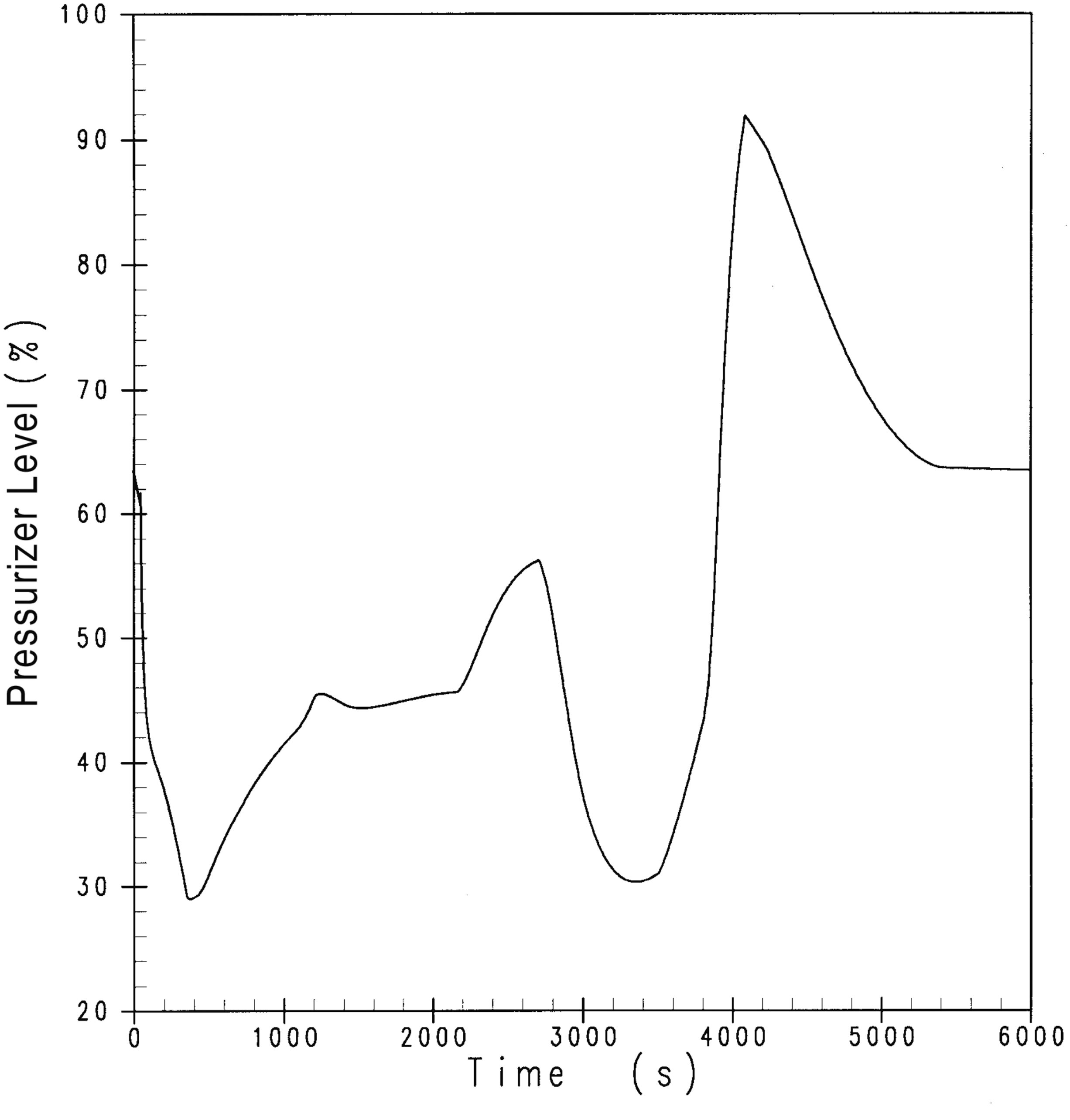
PRESSURIZER PRESSURE TRANSIENTS AND CORE AVERAGE TEMPERATURE TRANSIENT FOR INADVERTENT OPENING OF A PRESSURIZER SAFETY VALVE

FIGURE 15.6.1–2

STEAM GENERATOR TUBE RUPTURE
PRESSURIZER LEVEL



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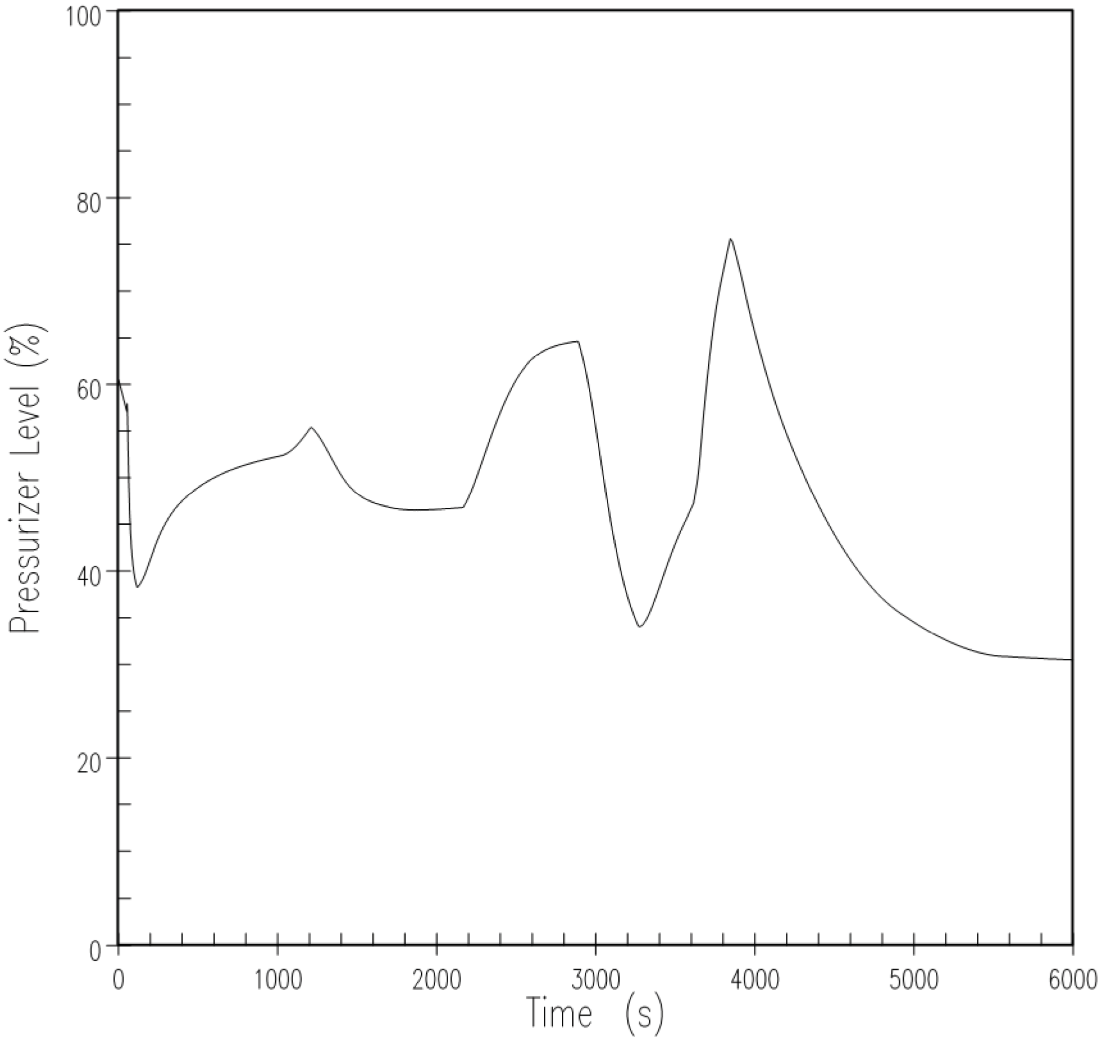
SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2**	PRESSURIZER LEVEL FIGURE 15.6.3-1

STEAM GENERATOR TUBE RUPTURE
PRESSURIZER LEVEL



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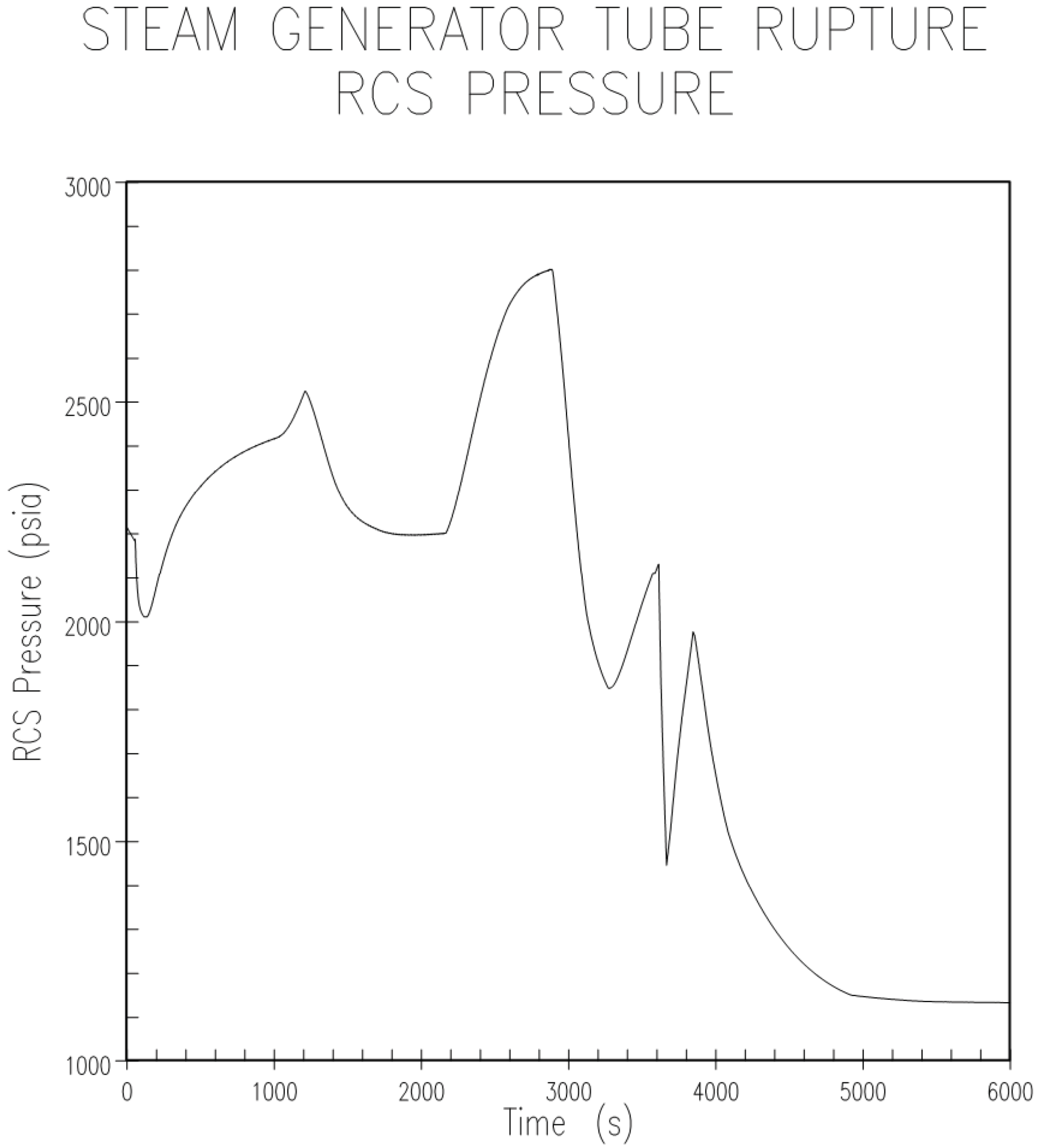
UNIT 1 AND UNIT 2

PRESSURIZER LEVEL

FIGURE 15.6.3-1



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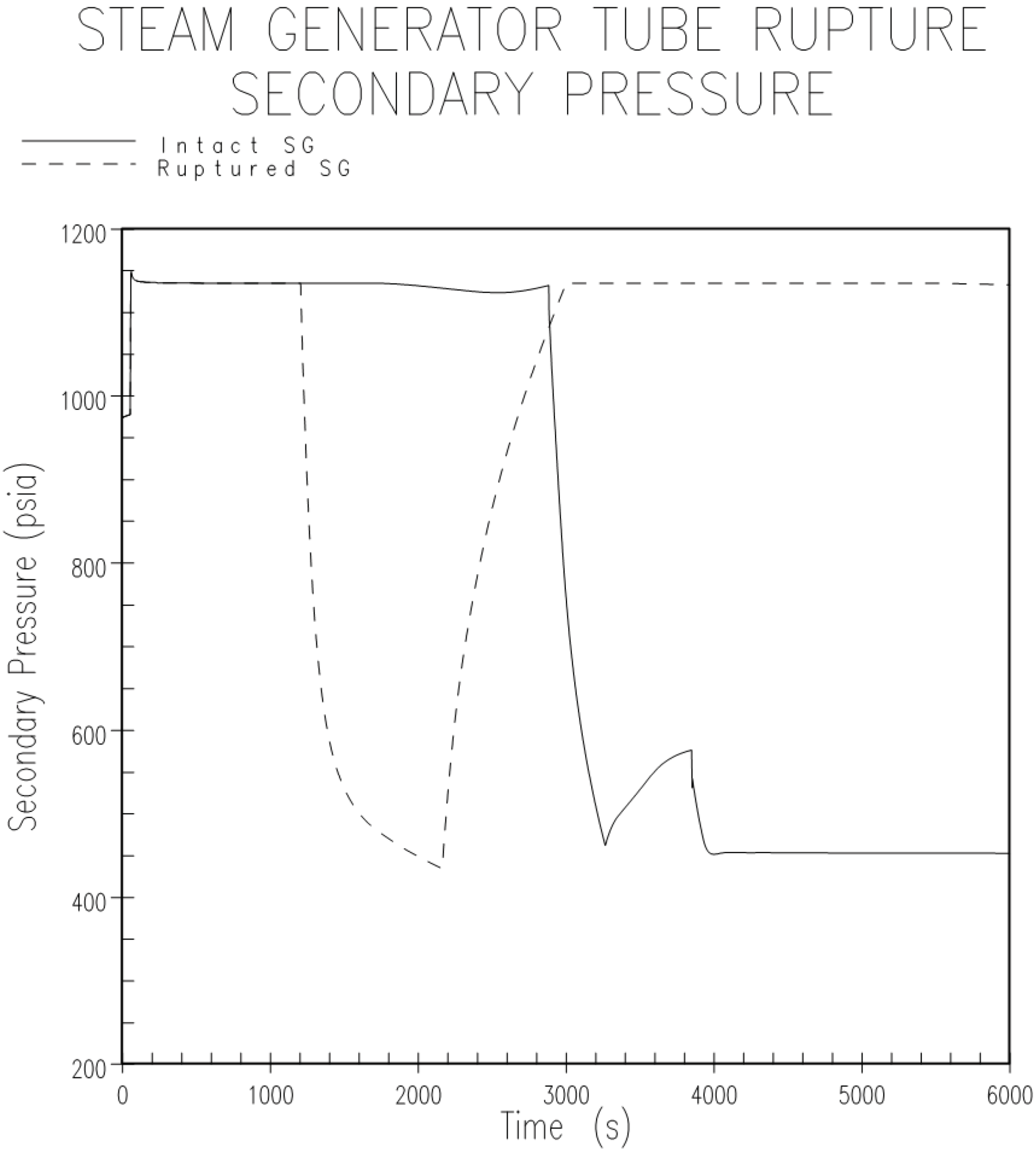
RCS PRESSURE

FIGURE 15.6.3-2



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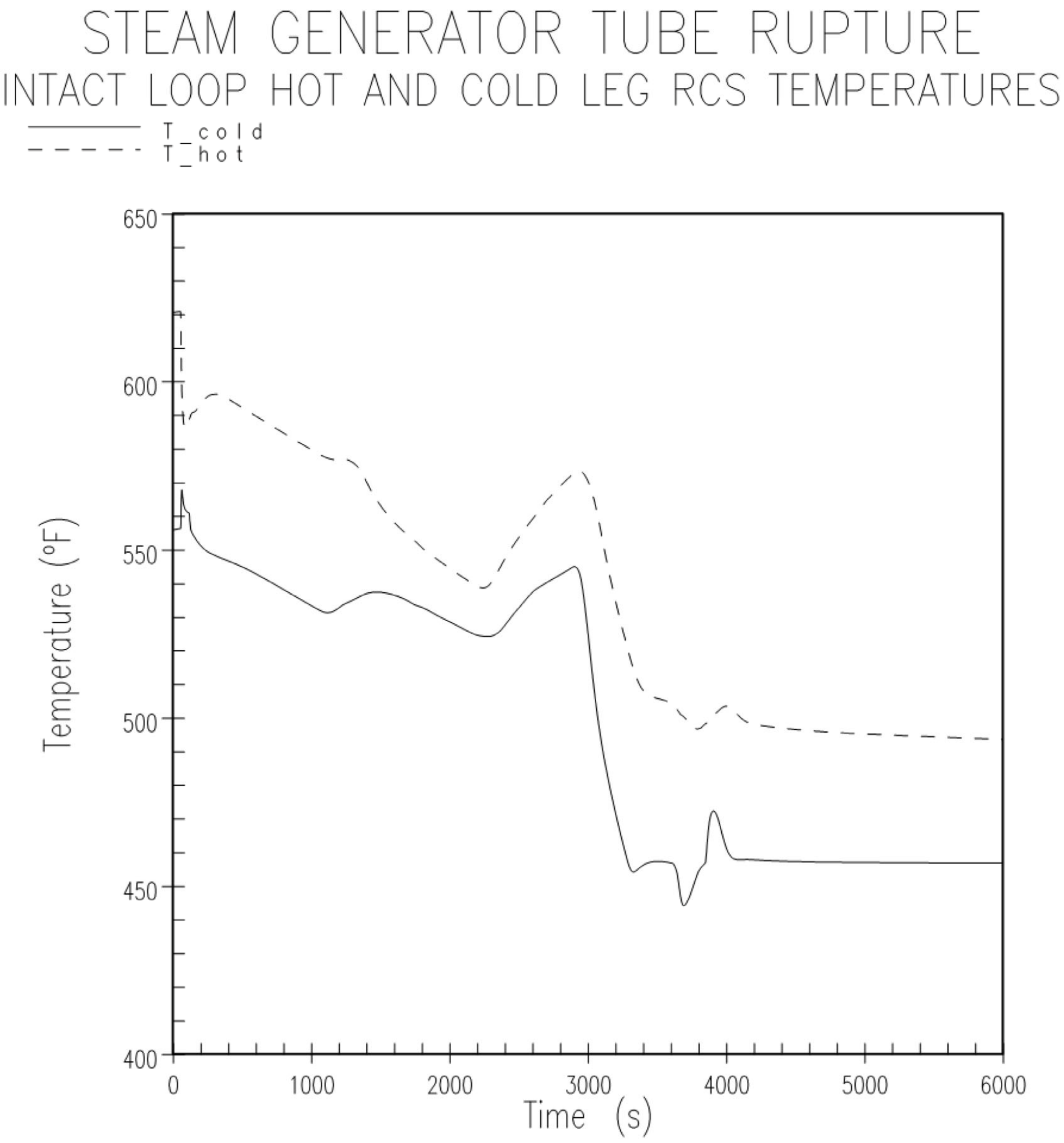
UNIT 1 AND UNIT 2

SECONDARY PRESSURE

FIGURE 15.6.3-3



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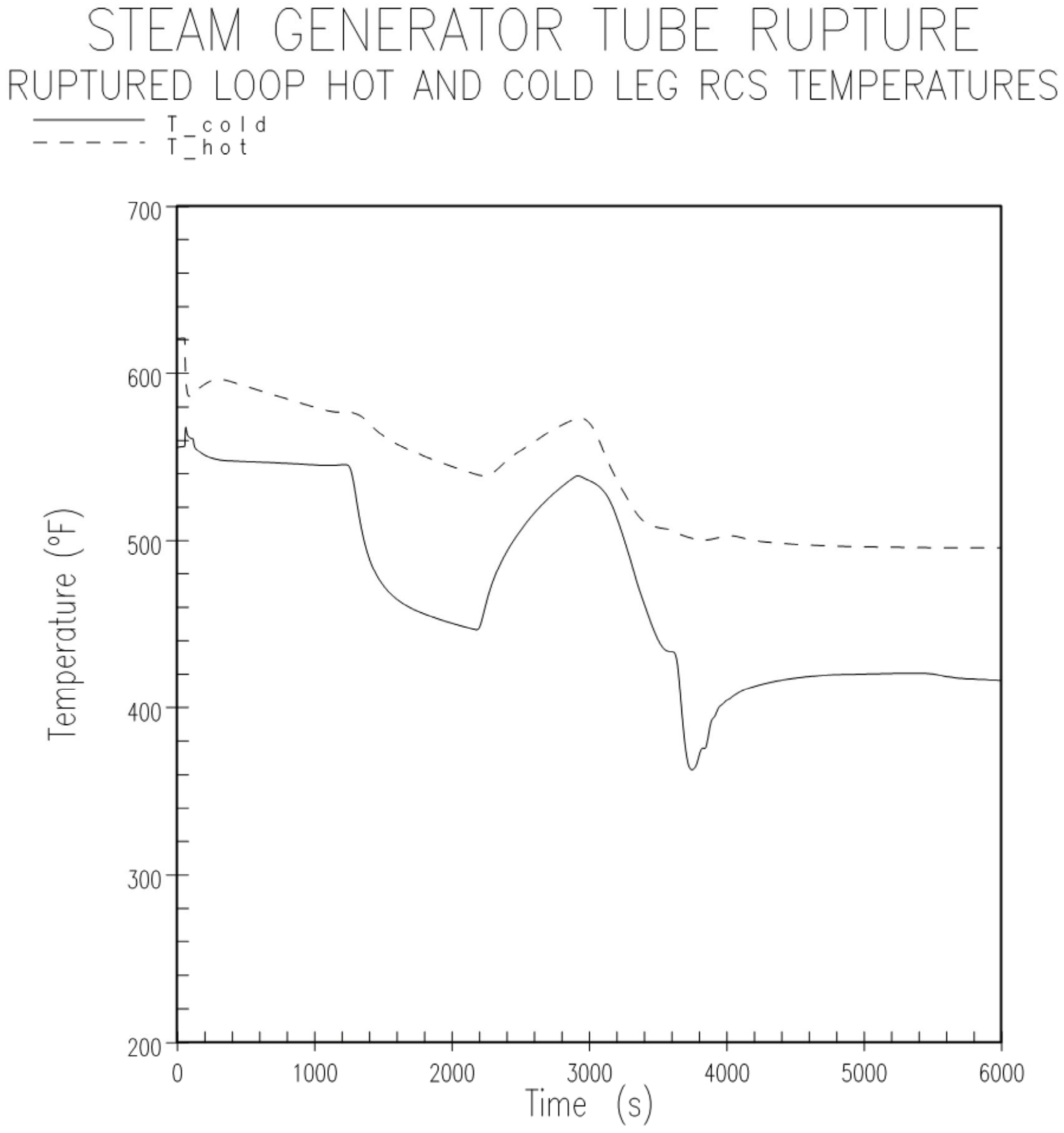
UNIT 1 AND UNIT 2

INTACT LOOP T_{HOT} AND T_{COLD}

FIGURE 15.6.3-4



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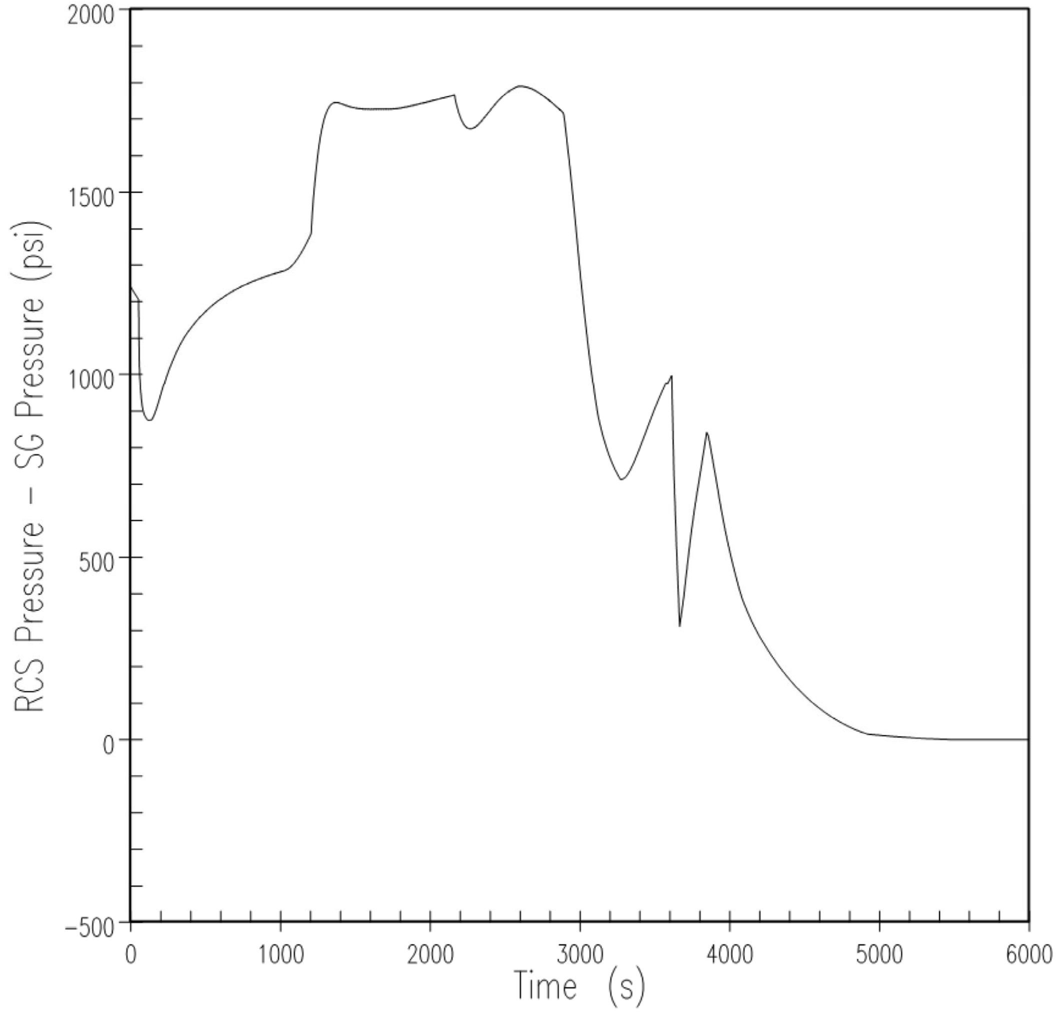
UNIT 1 AND UNIT 2

RUPTURED LOOP T_{HOT} AND T_{COLD}

FIGURE 15.6.3-5

STEAM GENERATOR TUBE RUPTURE
DIFFERENTIAL PRESSURE BETWEEN RCS AND RUPTURED SG



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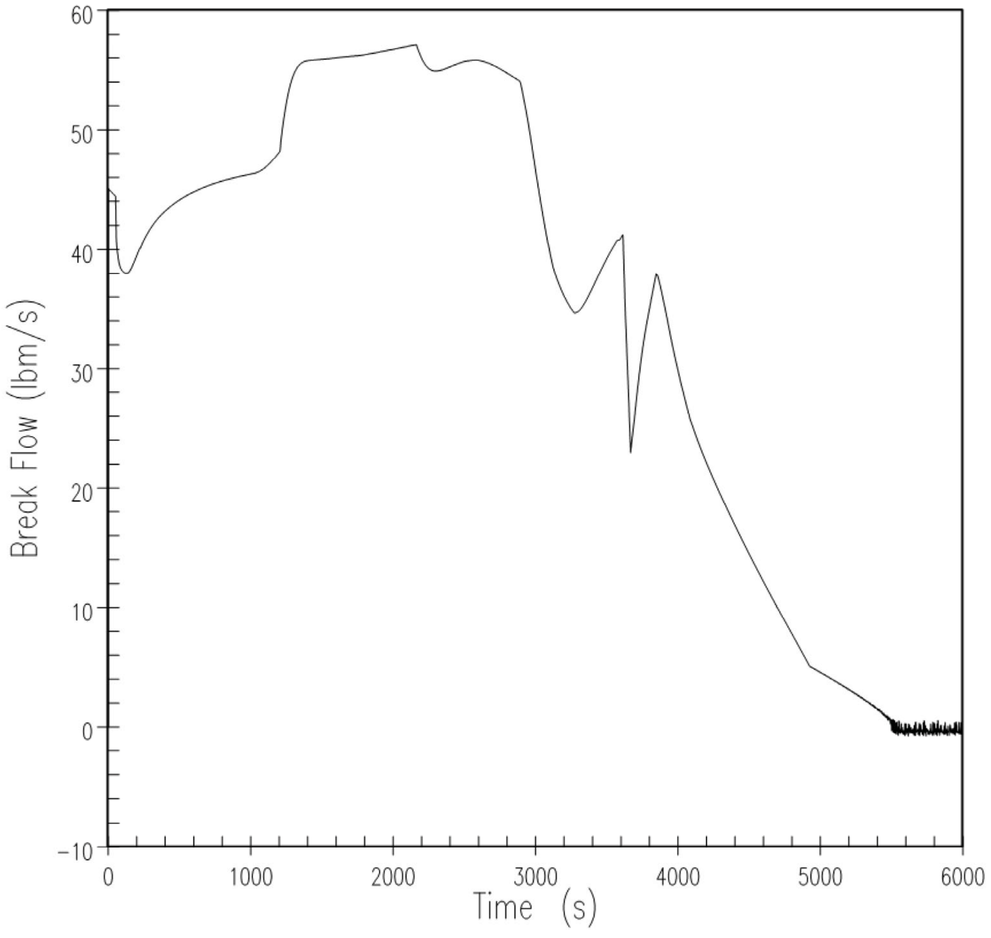
UNIT 1 AND UNIT 2

DIFFERENTIAL PRESSURE

FIGURE 15.6.3-6

STEAM GENERATOR TUBE RUPTURE
PRIMARY TO SECONDARY BREAK FLOW



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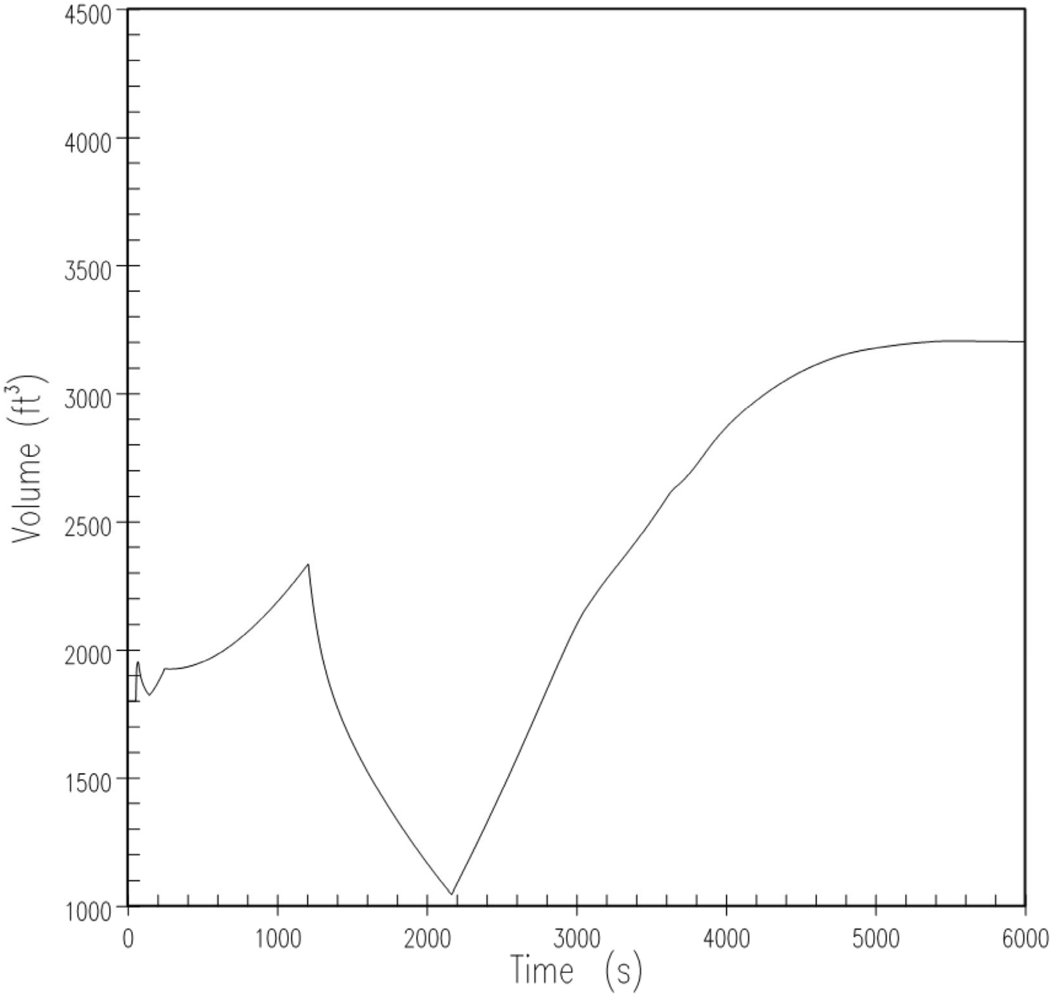
UNIT 1 AND UNIT 2

PRIMARY TO SECONDARY BREAK FLOW

FIGURE 15.6.3-7

STEAM GENERATOR TUBE RUPTURE
RUPTURED SG WATER VOLUME



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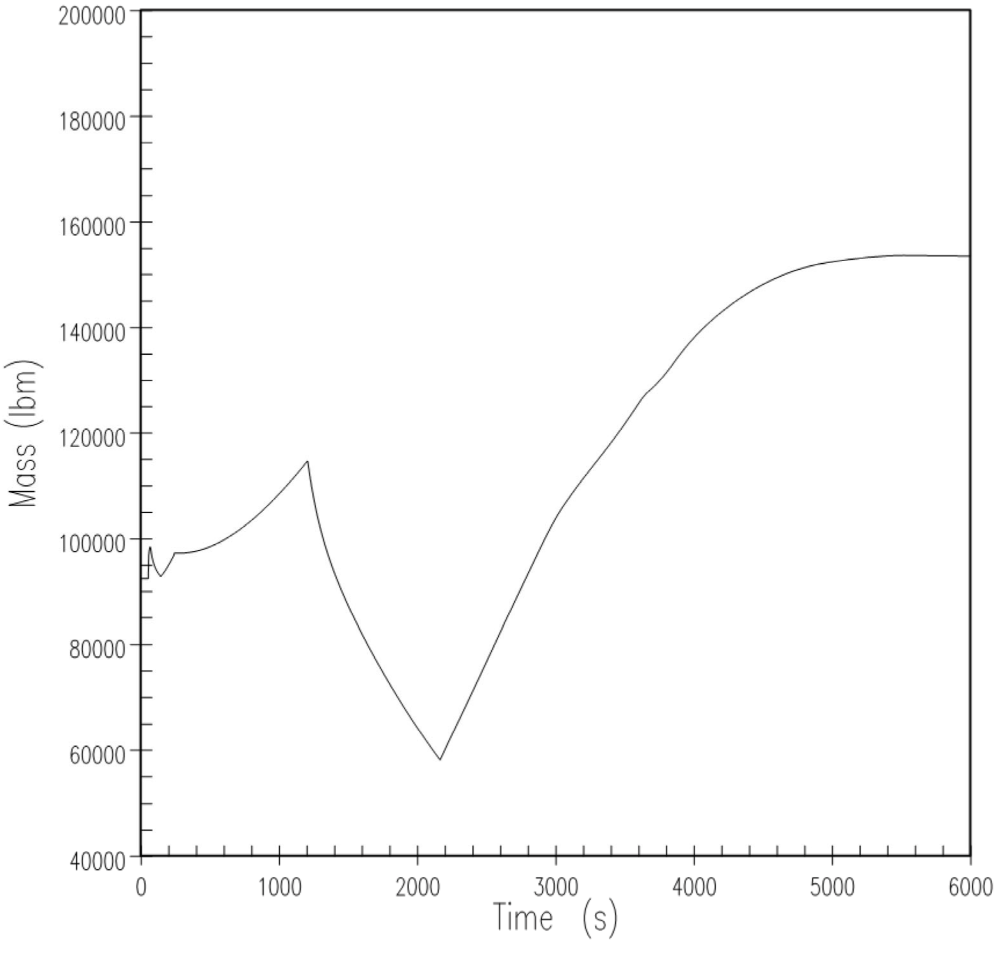
SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE** **ELECTRIC GENERATING PLANT** **UNIT 1 AND UNIT 2**	RUPTURED SG WATER VOLUME FIGURE 15.6.3-8

STEAM GENERATOR TUBE RUPTURE
RUPTURED SG WATER MASS



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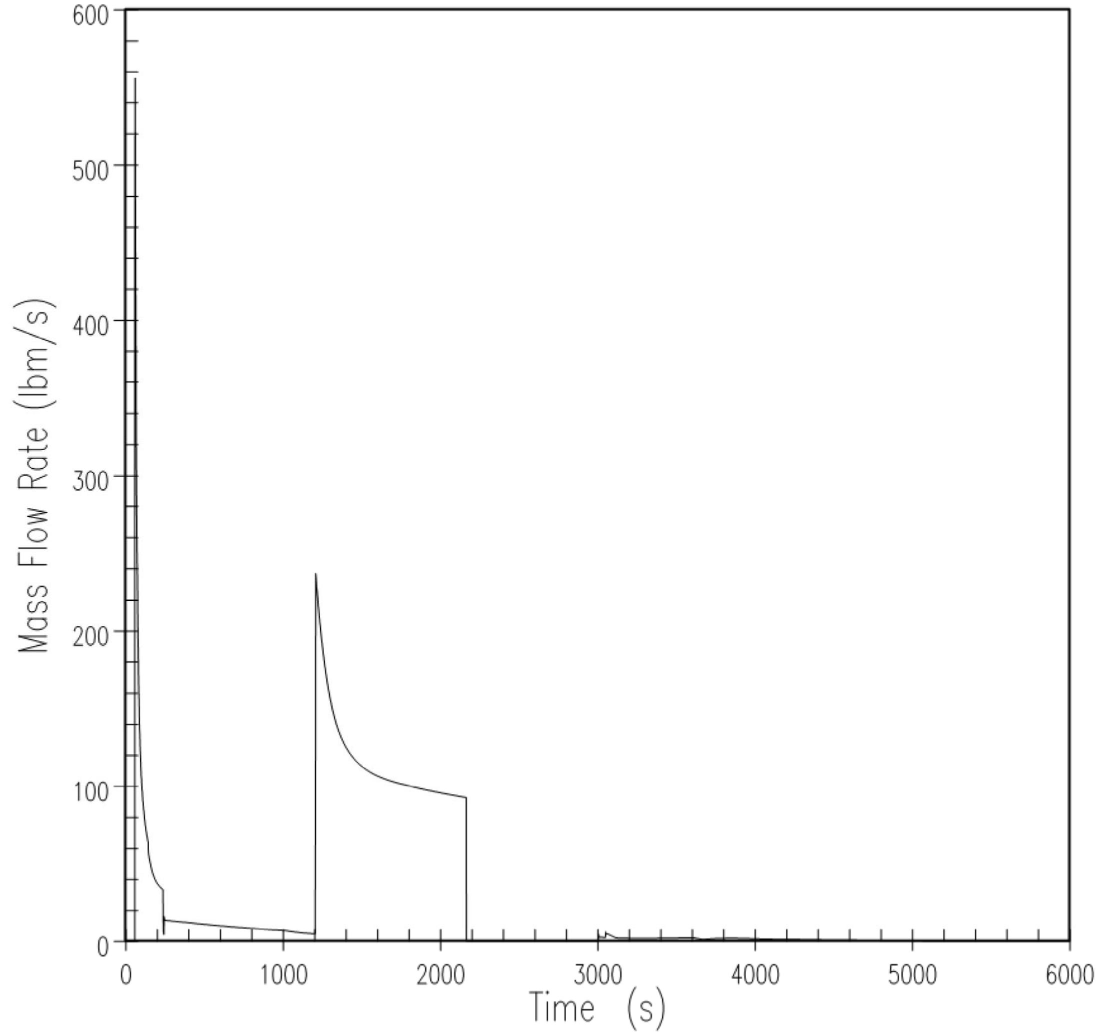
RUPTURED SG WATER MASS

FIGURE 15.6.3-9

STEAM GENERATOR TUBE RUPTURE
RUPTURED SG ATMOSPHERIC MASS RELEASES



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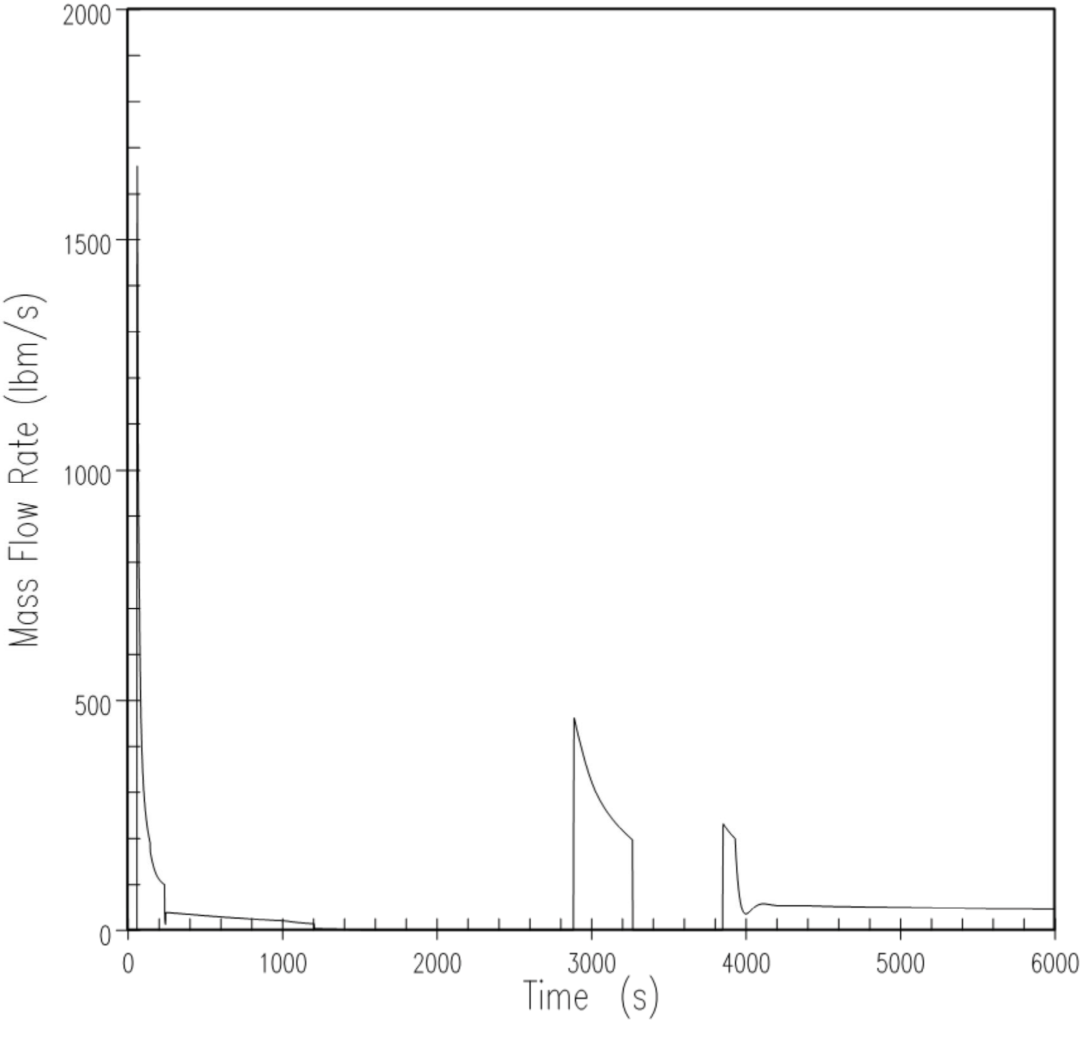
STEAM GENERATOR TUBE RUPTURE
INTACT SGS ATMOSPHERIC MASS RELEASES



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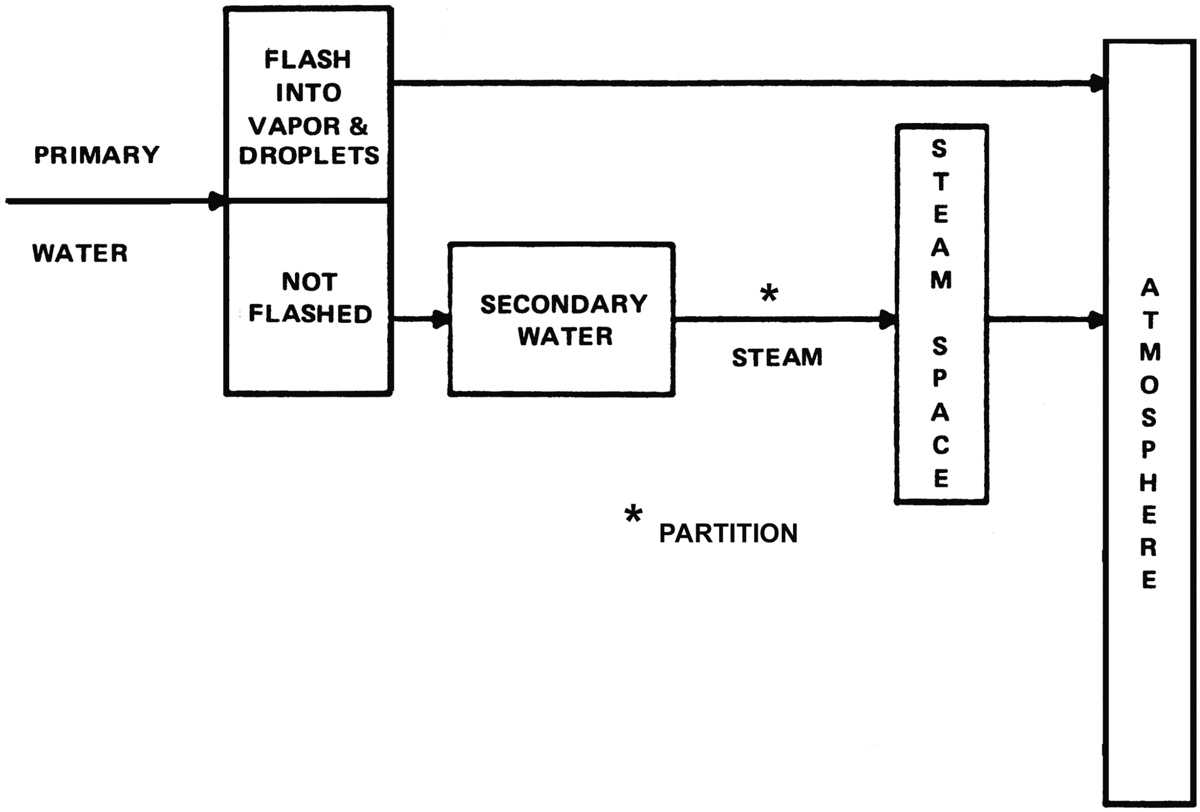
UNIT 1 AND UNIT 2

INTACT SG
ATMOSPHERIC MASS RELEASES

FIGURE 15.6.3-11


PRIMARY
WATER
FLASH INTO VAPOR & DROPLETS
NOT FLASHED
SECONDARY WATER
*
STEAM
STEAM SPACE
ATMOSPHERE
* PARTITION

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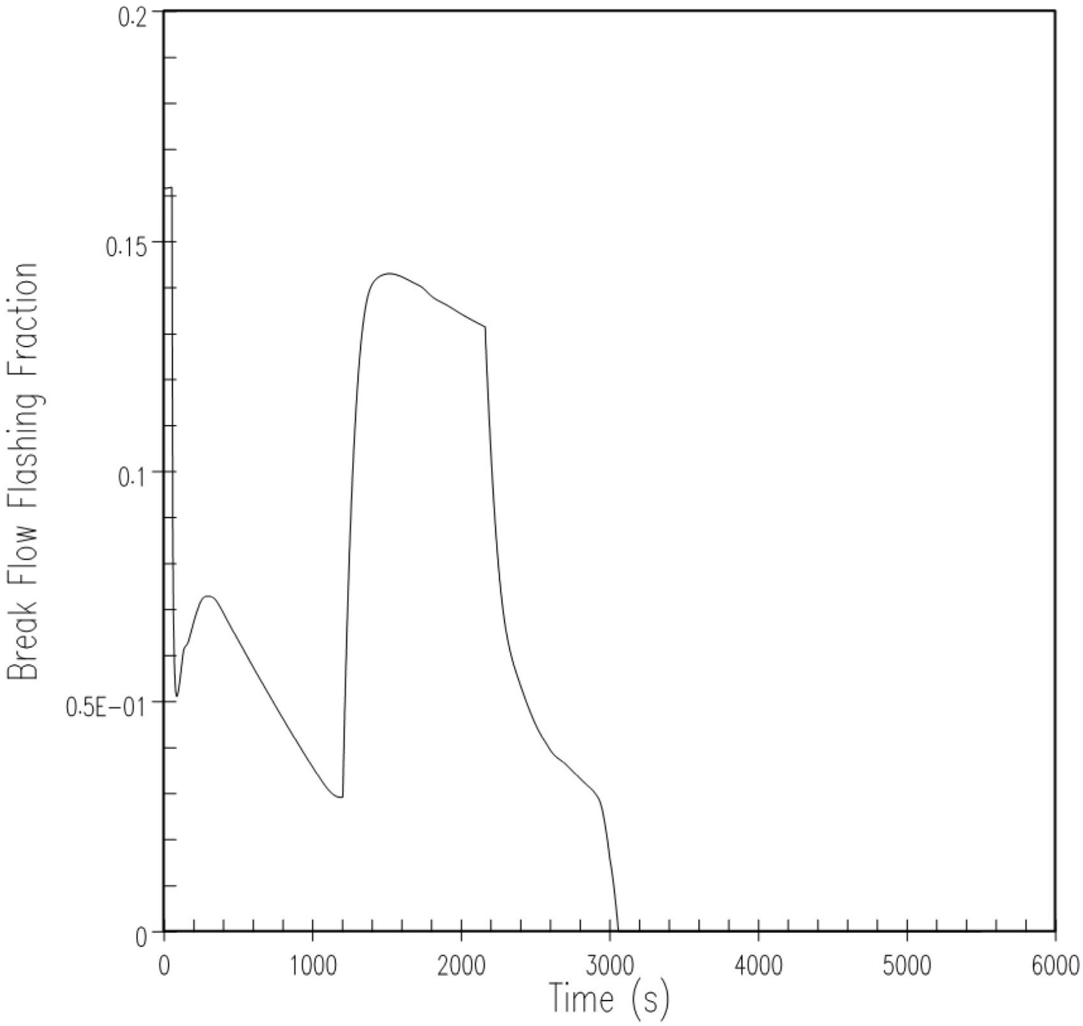
UNIT 1 AND UNIT 2

IODINE TRANSPORT MODEL

FIGURE 15.6.3-12

STEAM GENERATOR TUBE RUPTURE
BREAK FLOW FLASHING FRACTION



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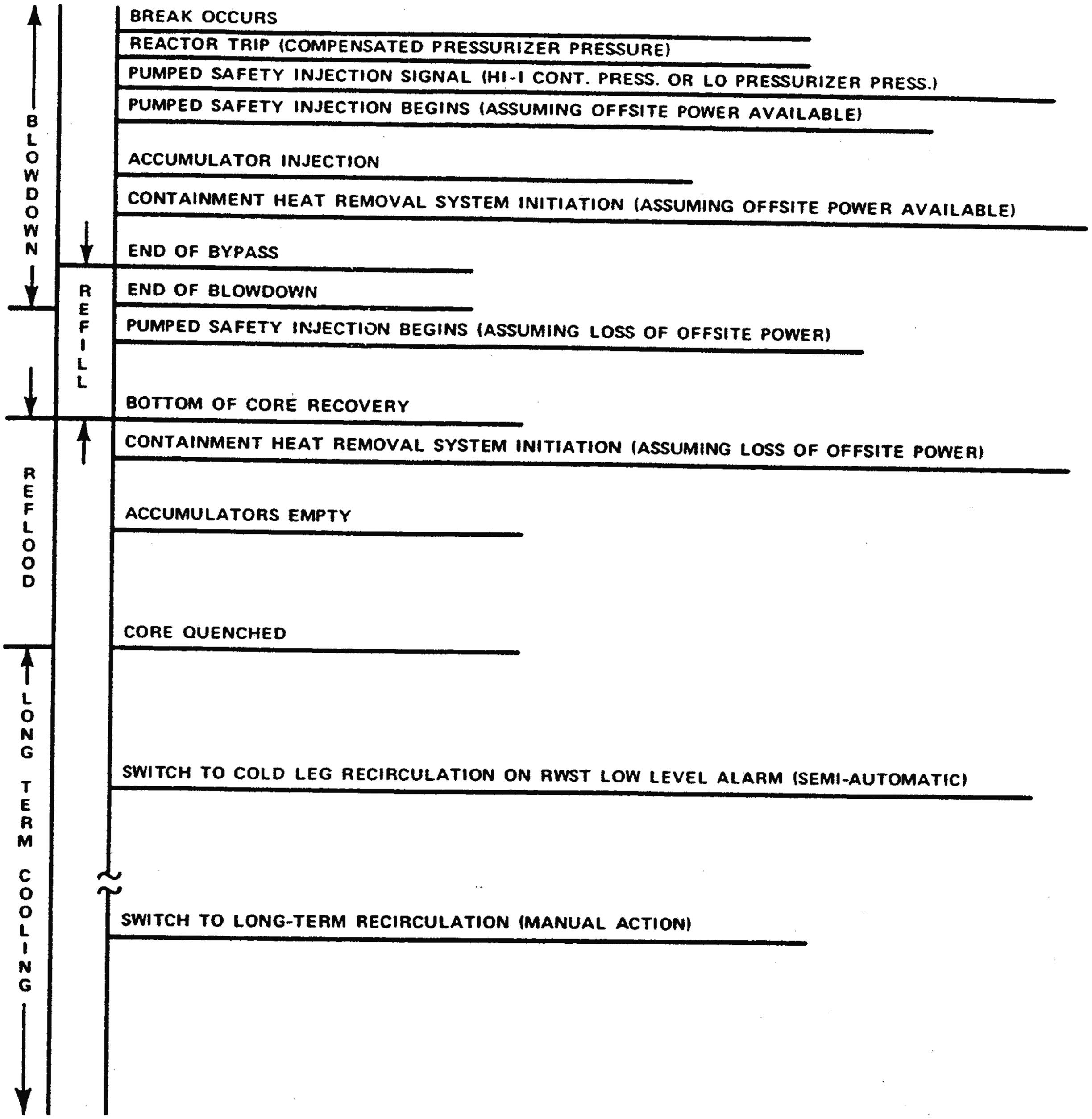
UNIT 1 AND UNIT 2

BREAK FLOW FLASHING FRACTION

FIGURE 15.6.3-13


BLOWDOWN
REFILL
REFLOOD
LONG TERM COOLING
BREAK OCCURS
REACTOR TRIP (COMPENSATED PRESSURIZER PRESSURE)
PUMPED SAFETY INJECTION SIGNAL (HI-I CONT. PRESS. OR LO PRESSURIZER PRESS.)
PUMPED SAFETY INJECTION BEGINS (ASSUMING OFFSITE POWER AVAILABLE)
ACCUMULATOR INJECTION
CONTAINMENT HEAT REMOVAL SYSTEM INITIATION (ASSUMING OFFSITE POWER AVAILABLE)
END OF BYPASS
END OF BLOWDOWN
PUMPED SAFETY INJECTION BEGINS (ASSUMING LOSS OF OFFSITE POWER)
BOTTOM OF CORE RECOVERY
CONTAINMENT HEAT REMOVAL SYSTEM INITIATION (ASSUMING LOSS OF OFFSITE POWER)
ACCUMULATORS EMPTY
CORE QUENCHED
SWITCH TO COLD LEG RECIRCULATION ON RWST LOW LEVEL ALARM (SEMI-AUTOMATIC)
SWITCH TO LONG-TERM RECIRCULATION (MANUAL ACTION)

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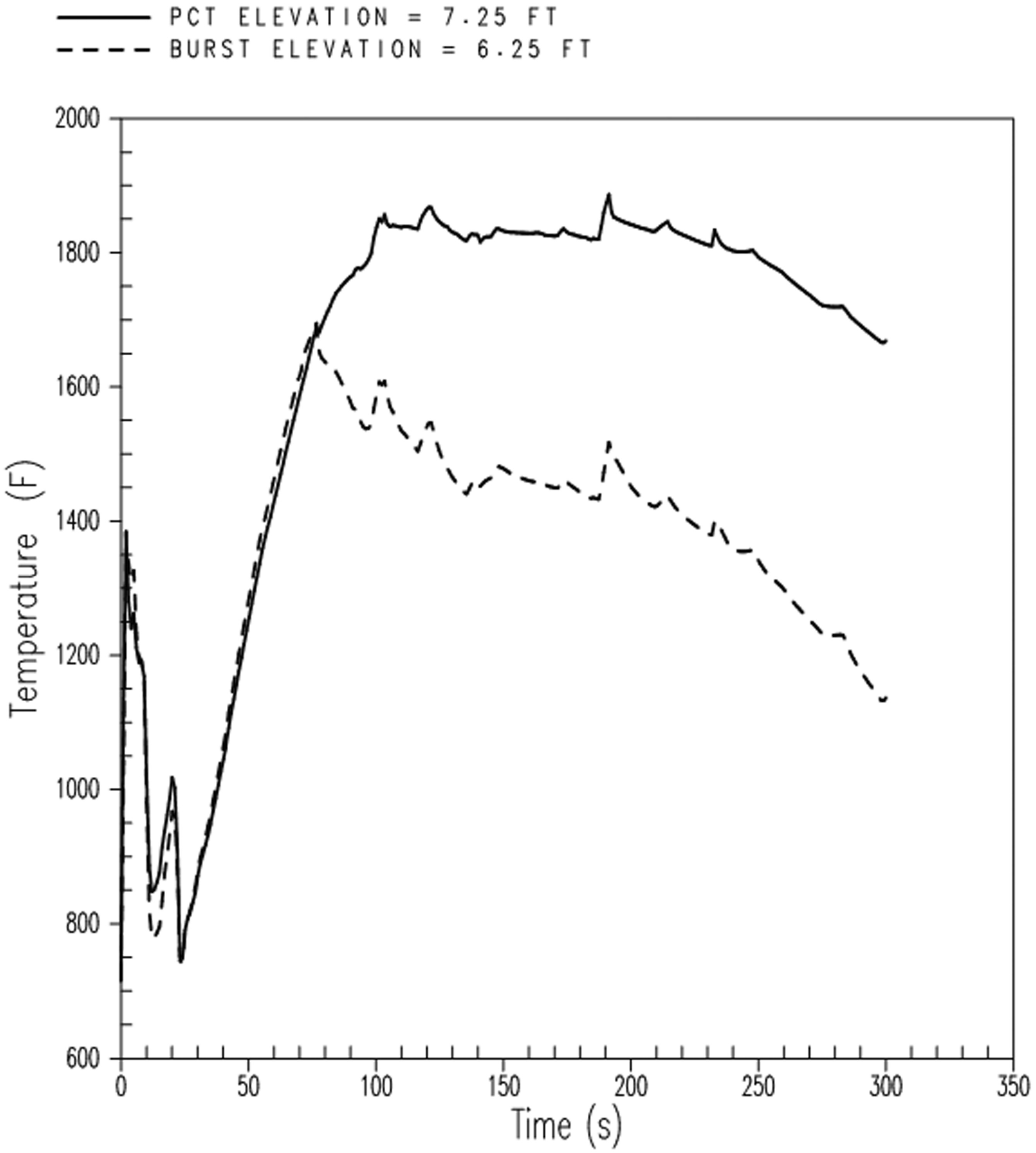
UNIT 1 AND UNIT 2

SEQUENCE OF EVENTS FOR LARGE BREAK LOCA ANALYSIS

FIGURE 15.6.5–1



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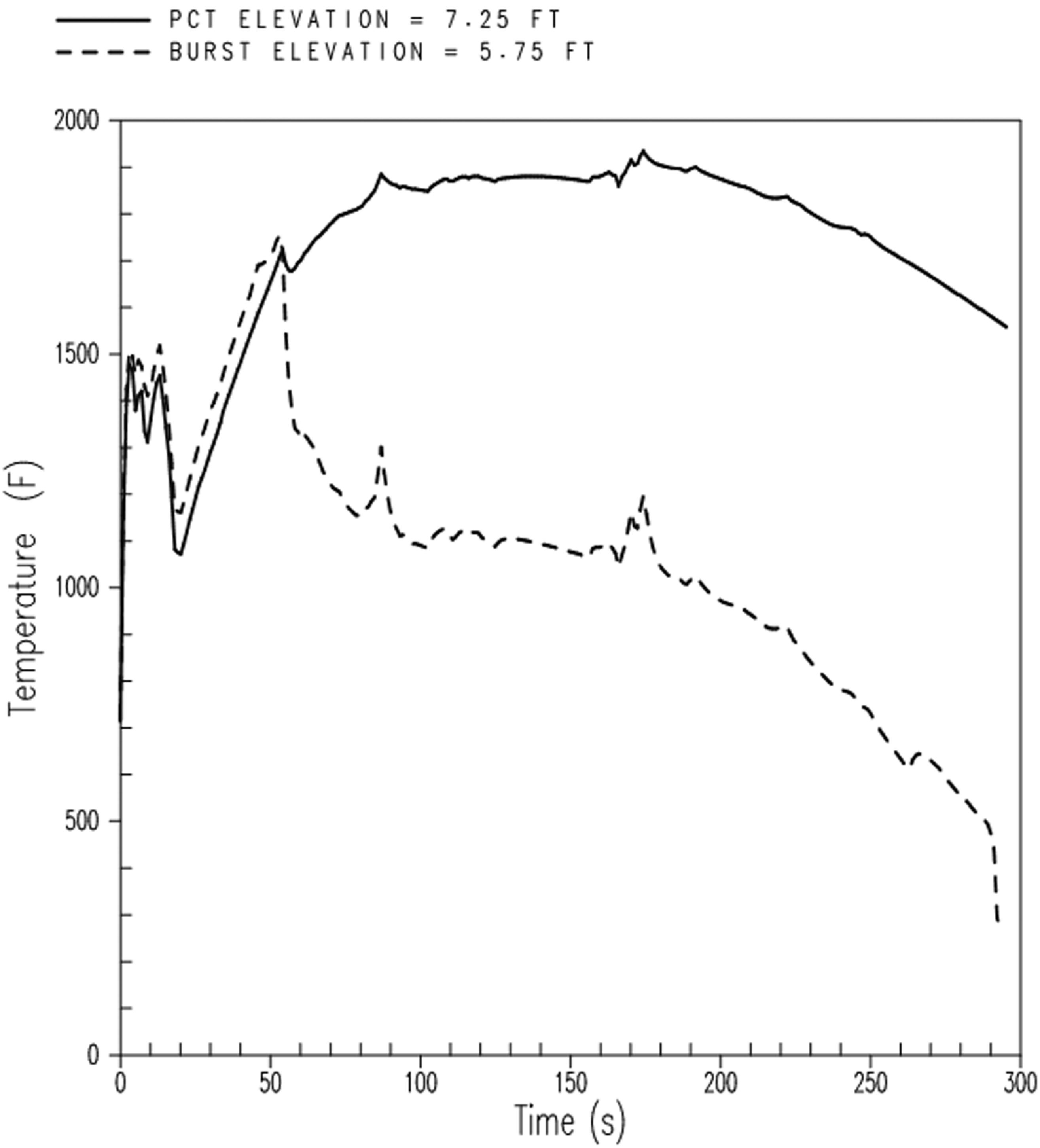
UNIT 1 AND UNIT 2

CLADDING TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–2 (SHEET 1 OF 9)



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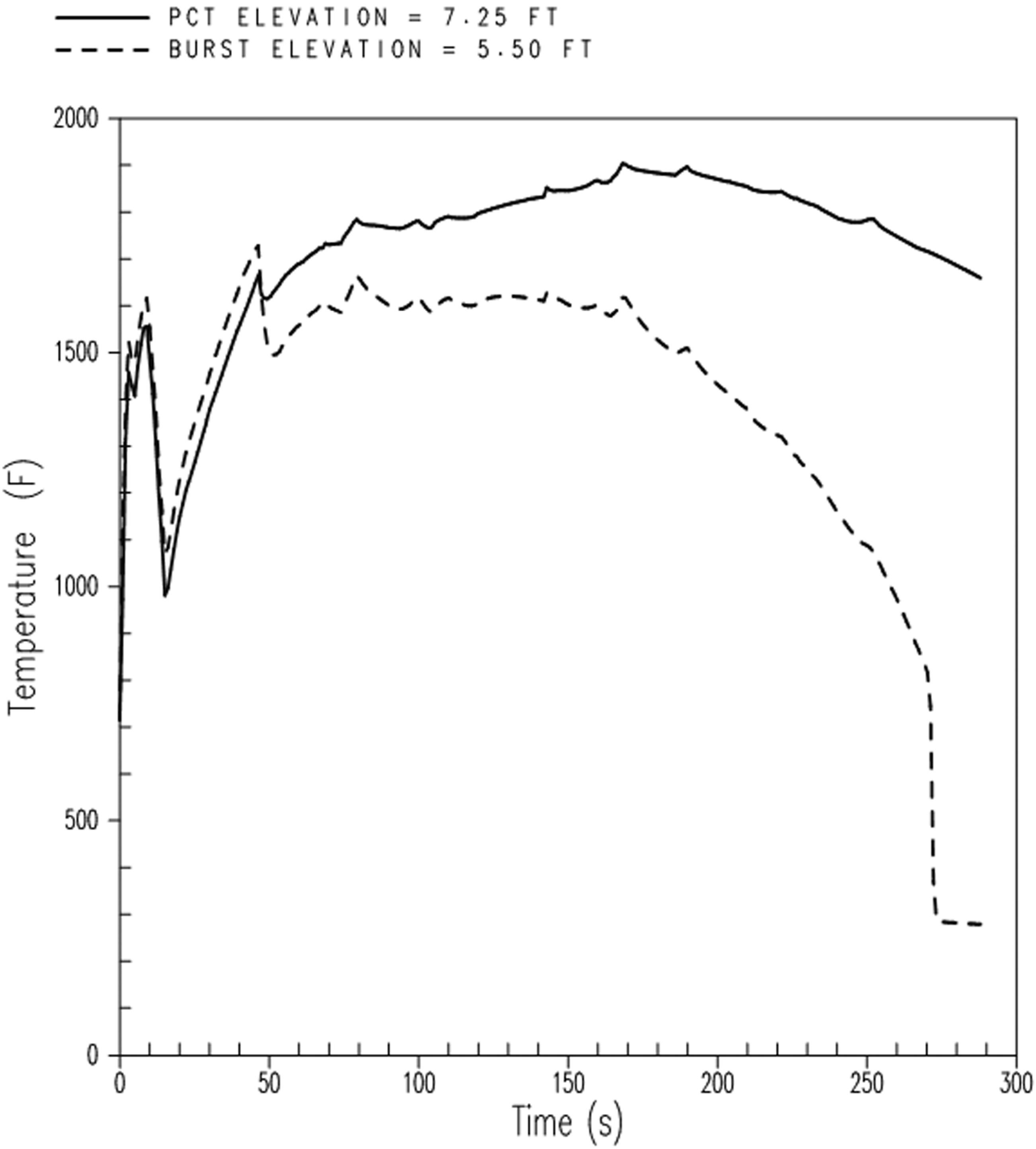
UNIT 1 AND UNIT 2

CLADDING TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–2 (SHEET 2 OF 9)



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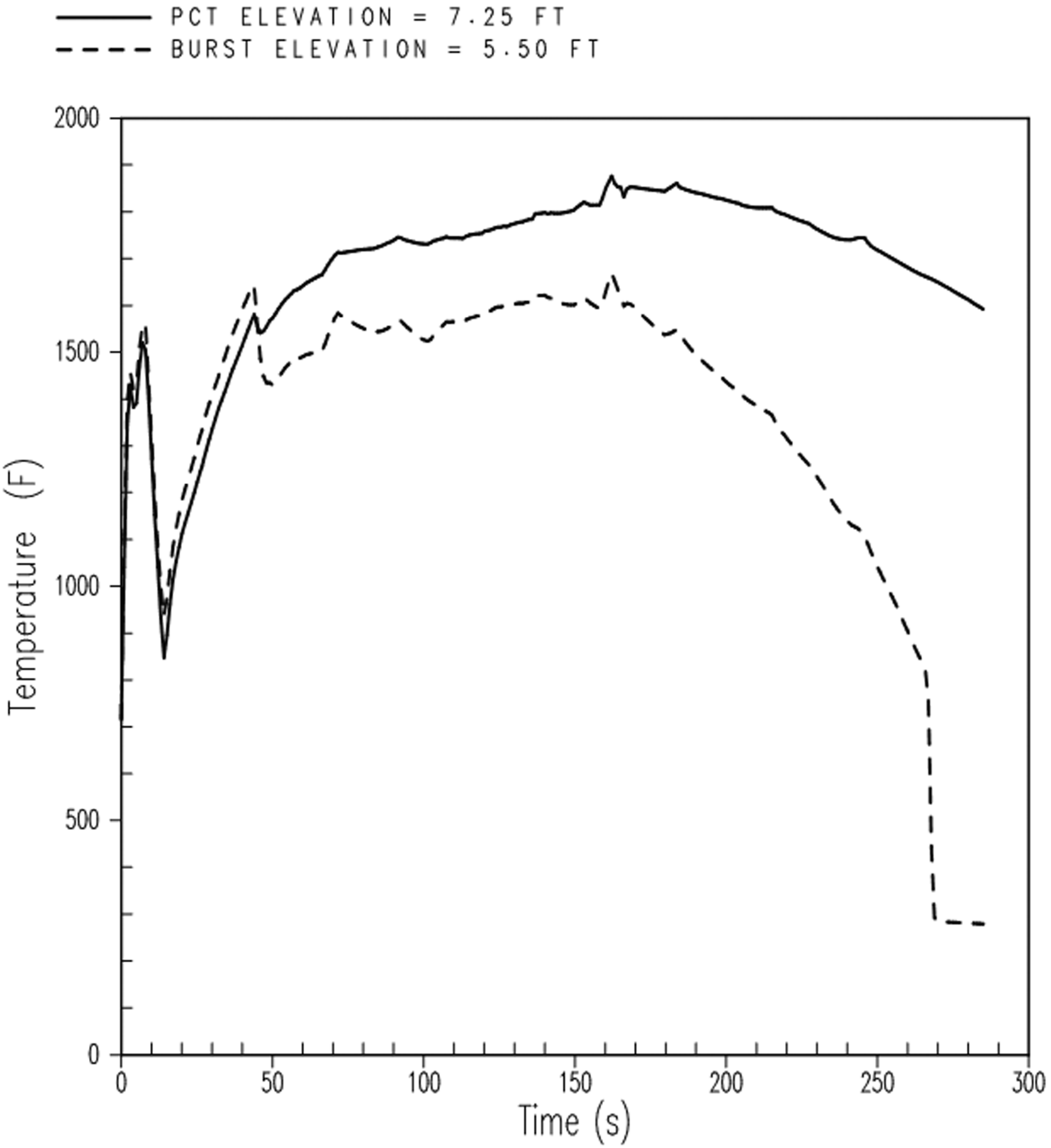
UNIT 1 AND UNIT 2

CLADDING TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–2 (SHEET 3 OF 9)



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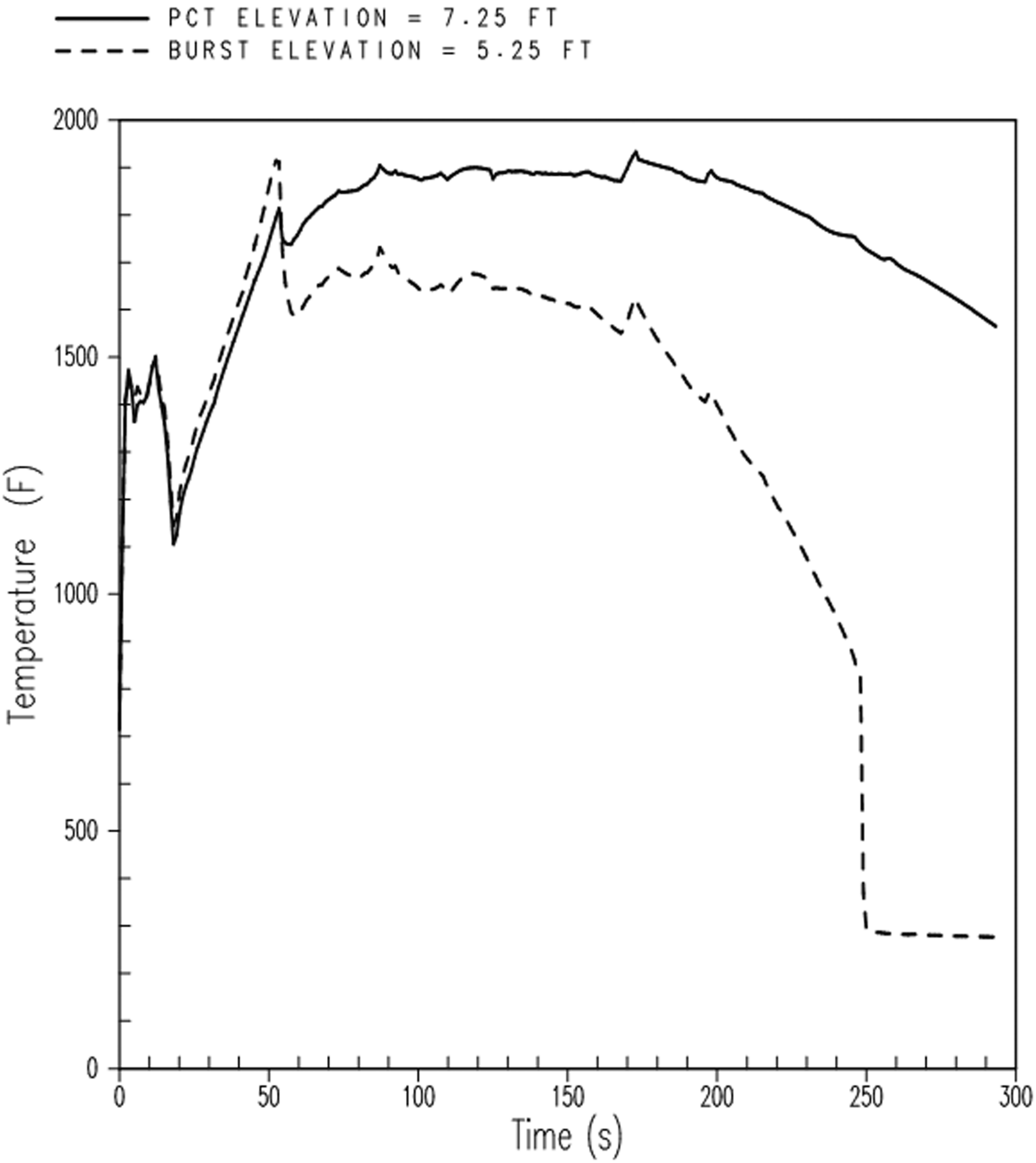
UNIT 1 AND UNIT 2

CLADDING TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 1.0, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–2 (SHEET 4 OF 9)



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CLADDING TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

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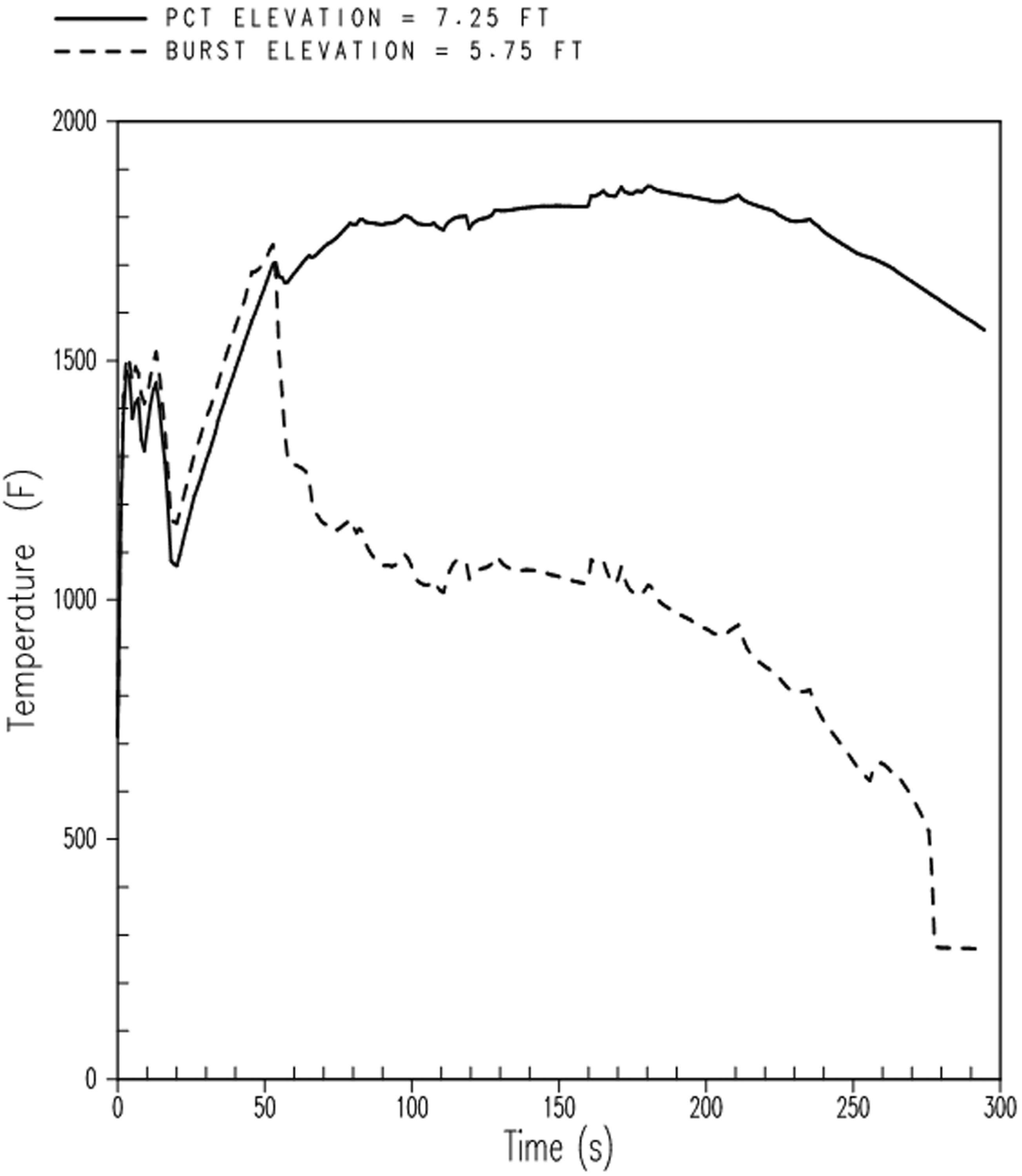
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

FIGURE 15.6.5–2 (SHEET 5 OF 9)



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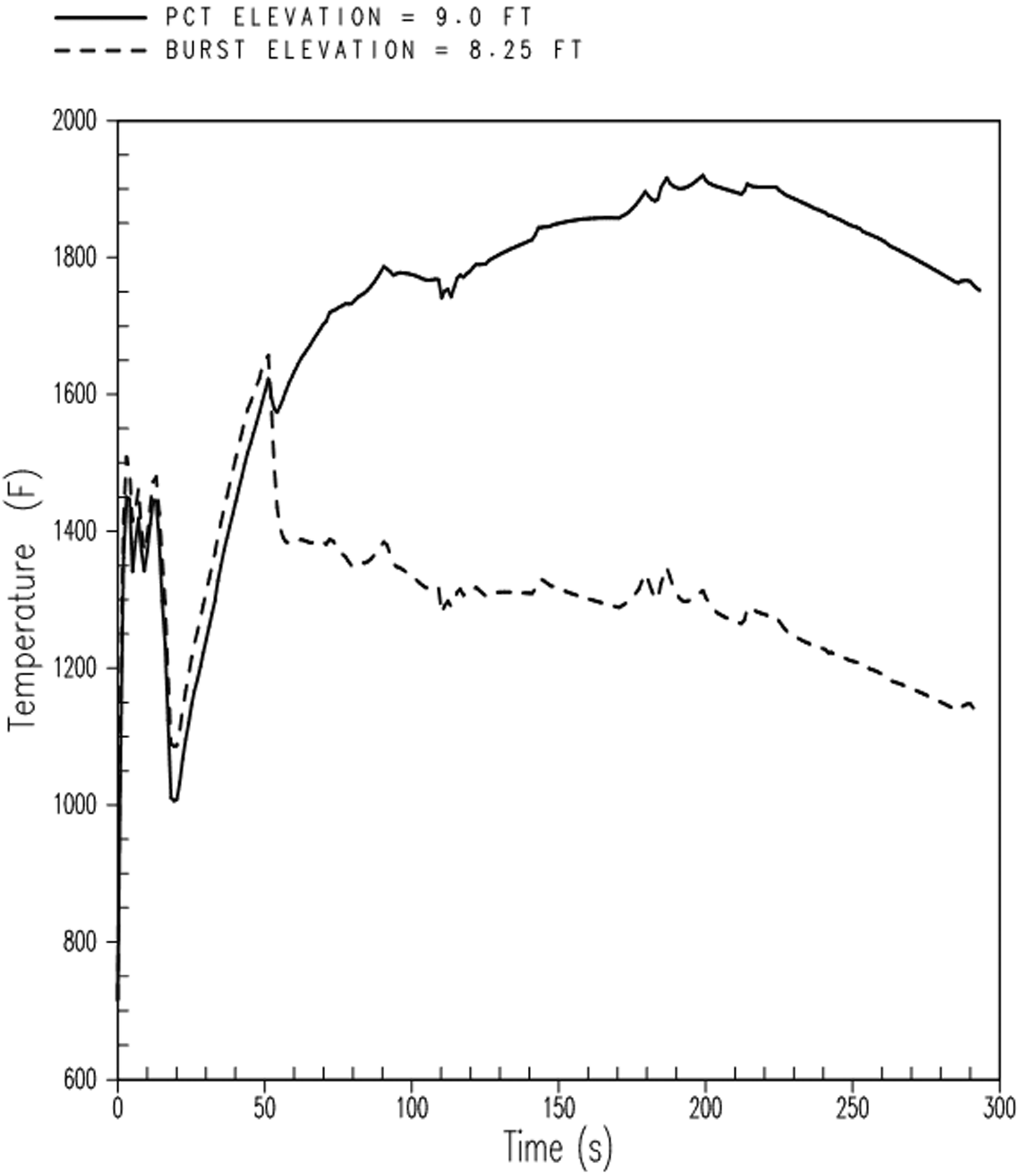
UNIT 1 AND UNIT 2

CLADDING TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–2 (SHEET 6 OF 9)



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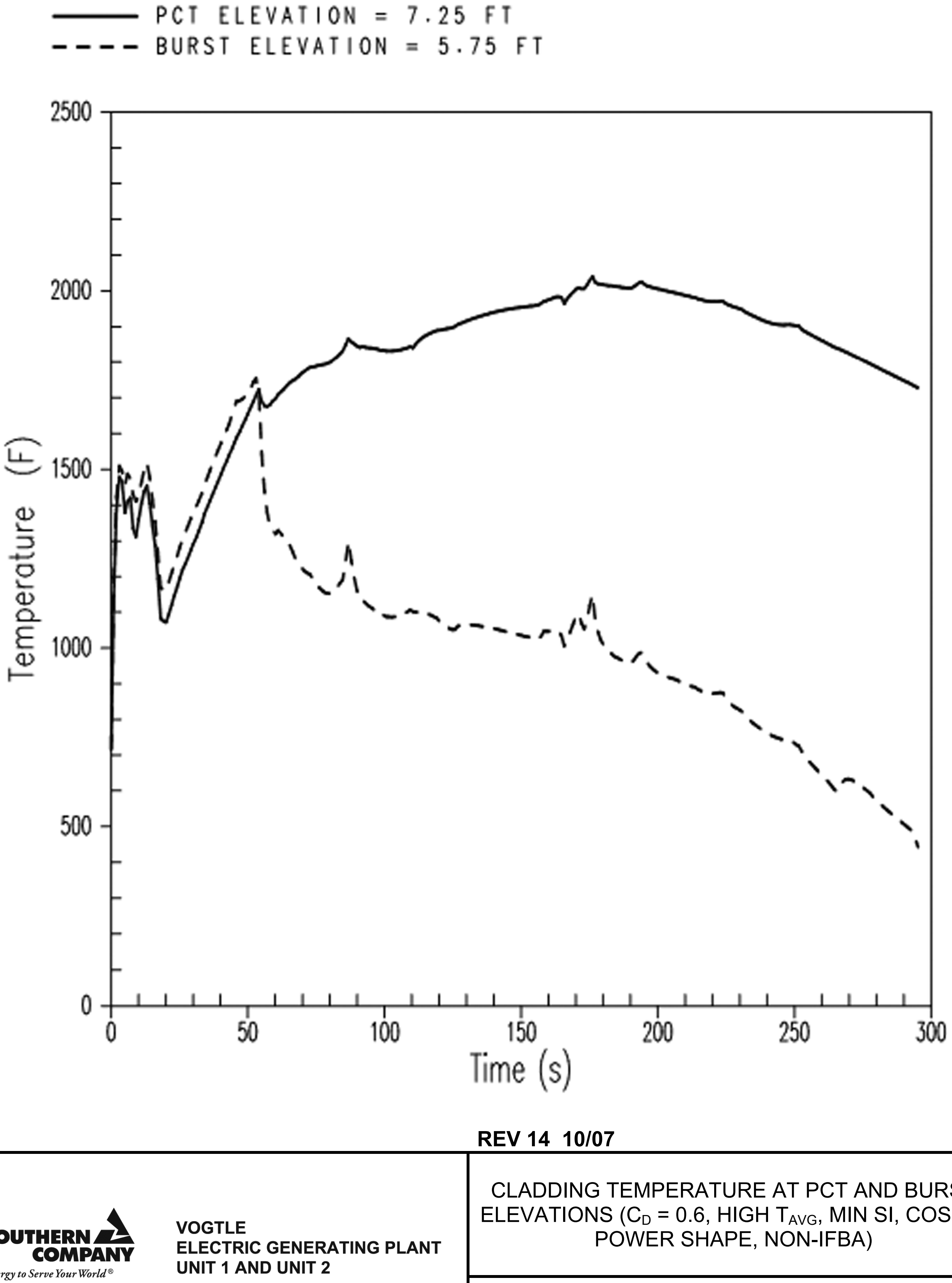
UNIT 1 AND UNIT 2

CLADDING TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–2 (SHEET 7 OF 9)



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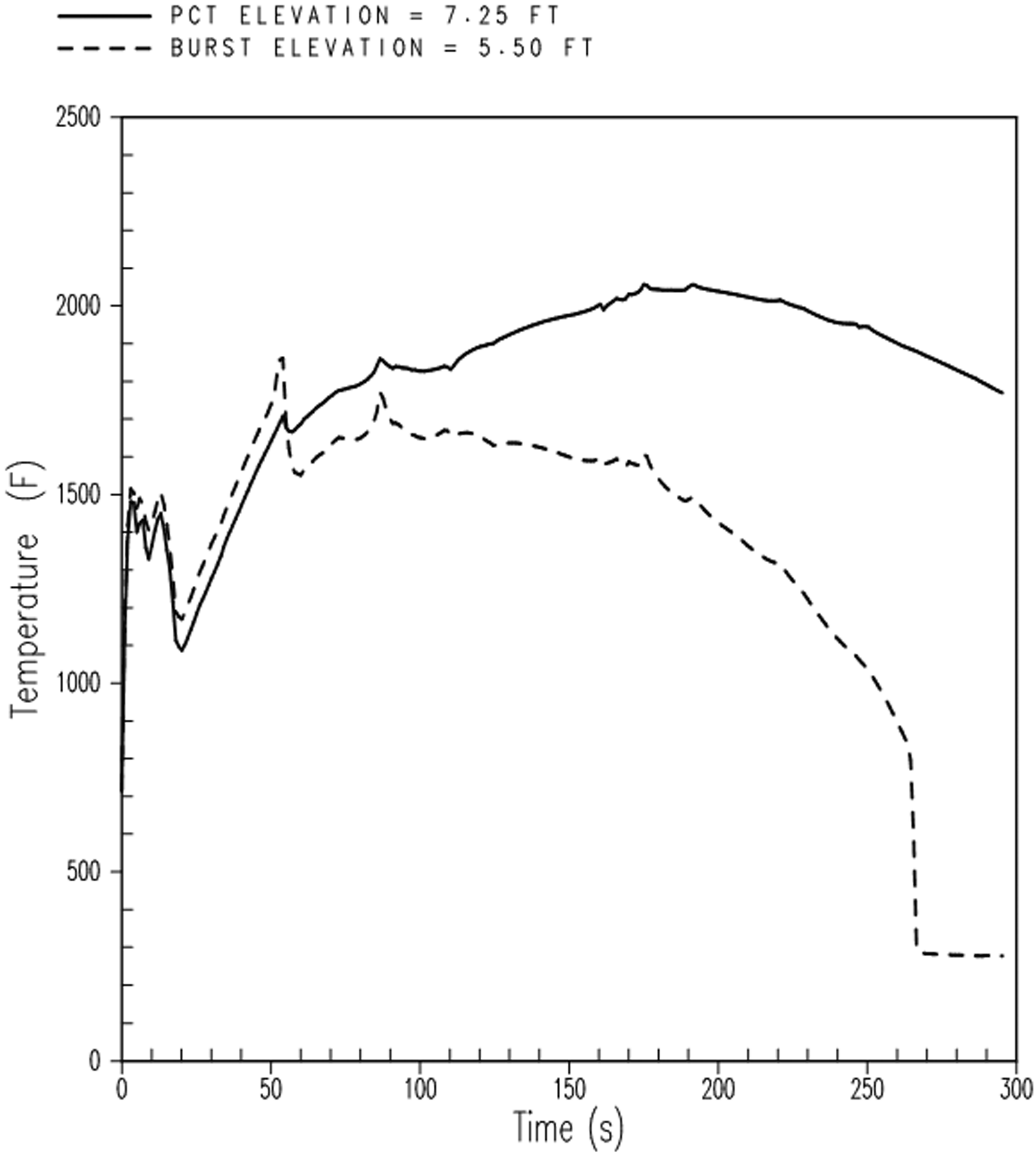
UNIT 1 AND UNIT 2

CLADDING TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–2 (SHEET 8 OF 9)



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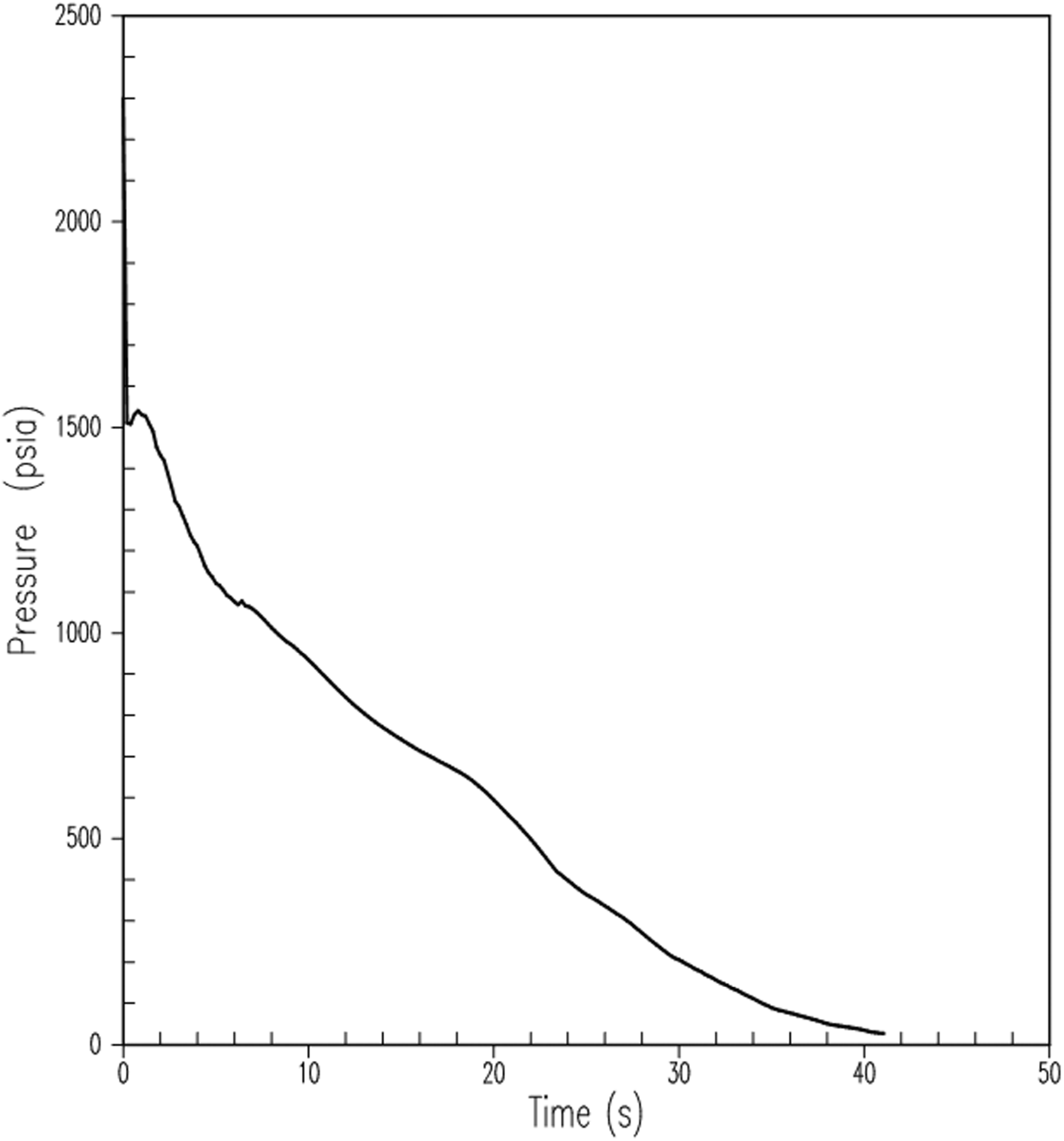
CLADDING TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–2 (SHEET 9 OF 9)



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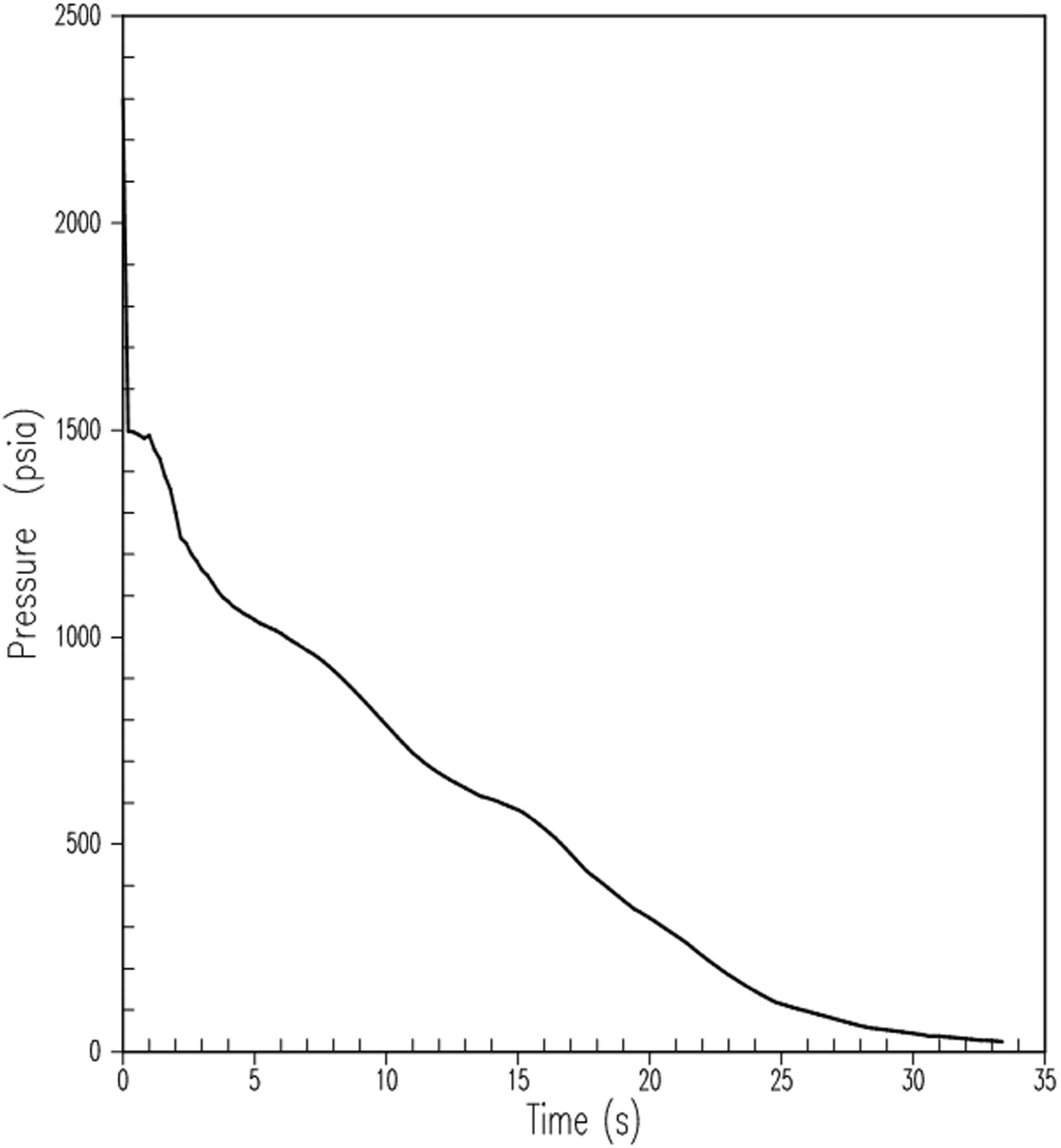
UNIT 1 AND UNIT 2

CORE PRESSURE DURING BLOWDOWN
(C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–3 (SHEET 1 OF 9)



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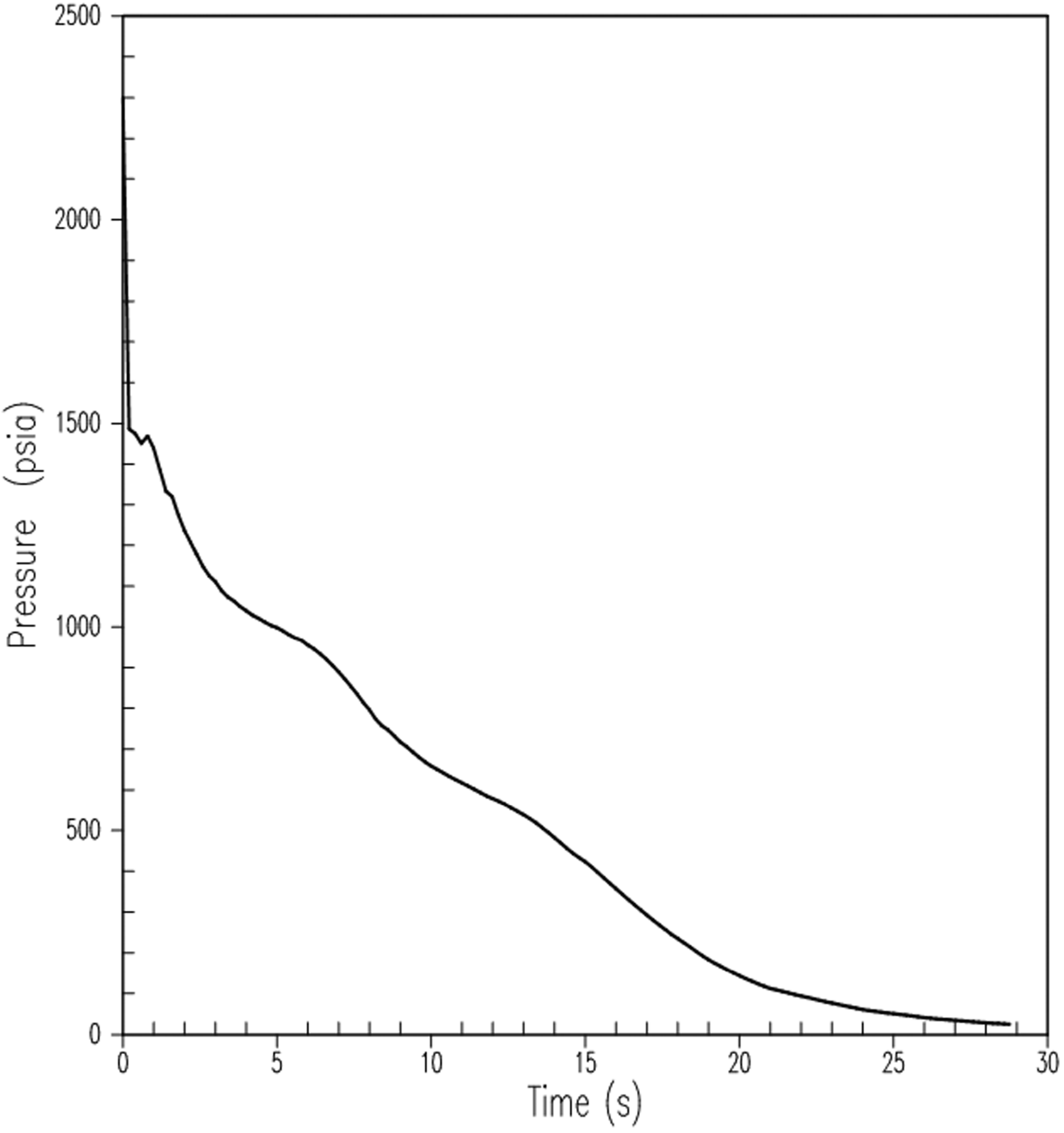
CORE PRESSURE DURING BLOWDOWN
(C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–3 (SHEET 2 OF 9)



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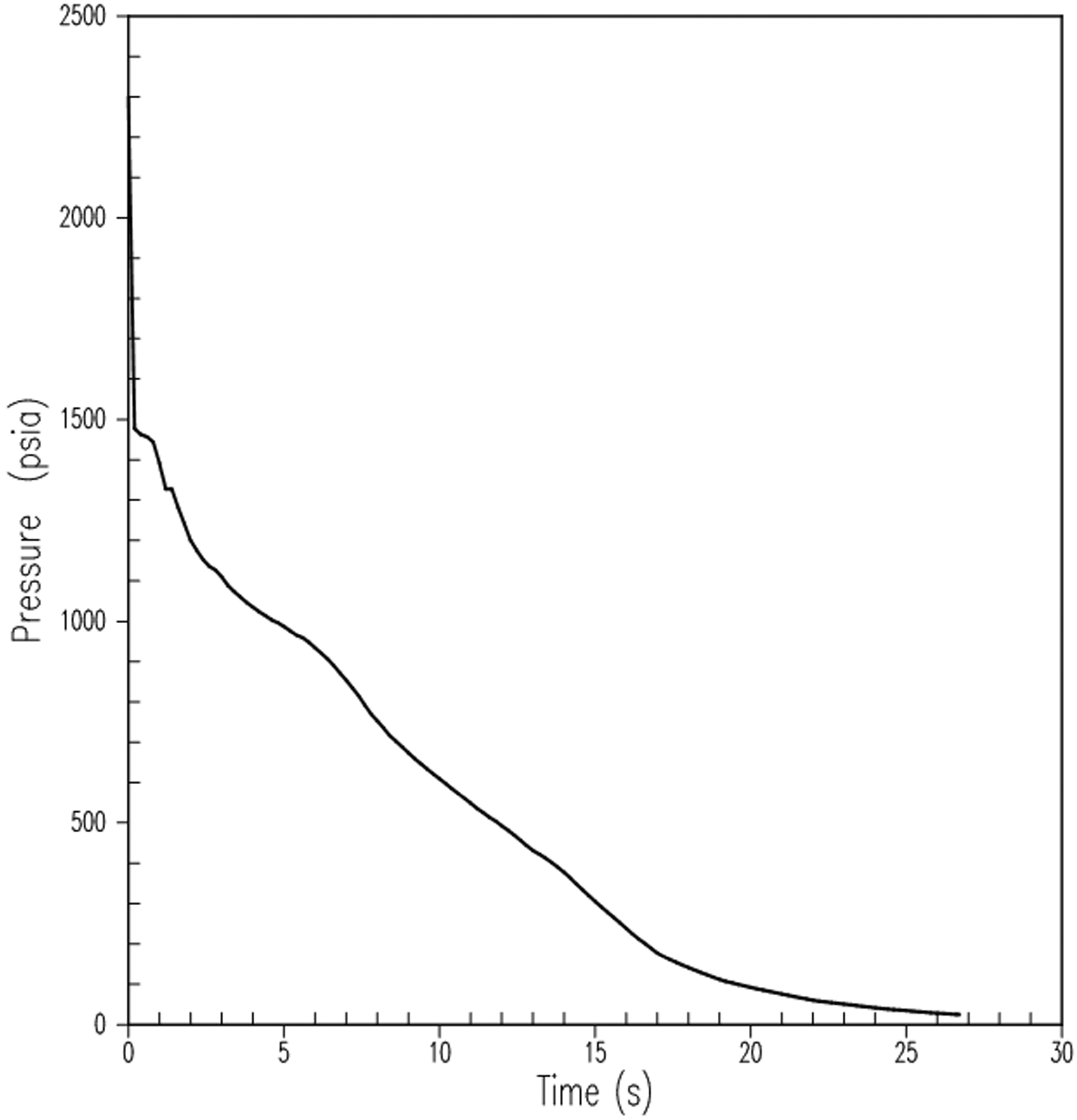
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE PRESSURE DURING BLOWDOWN
(C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–3 (SHEET 3 OF 9)



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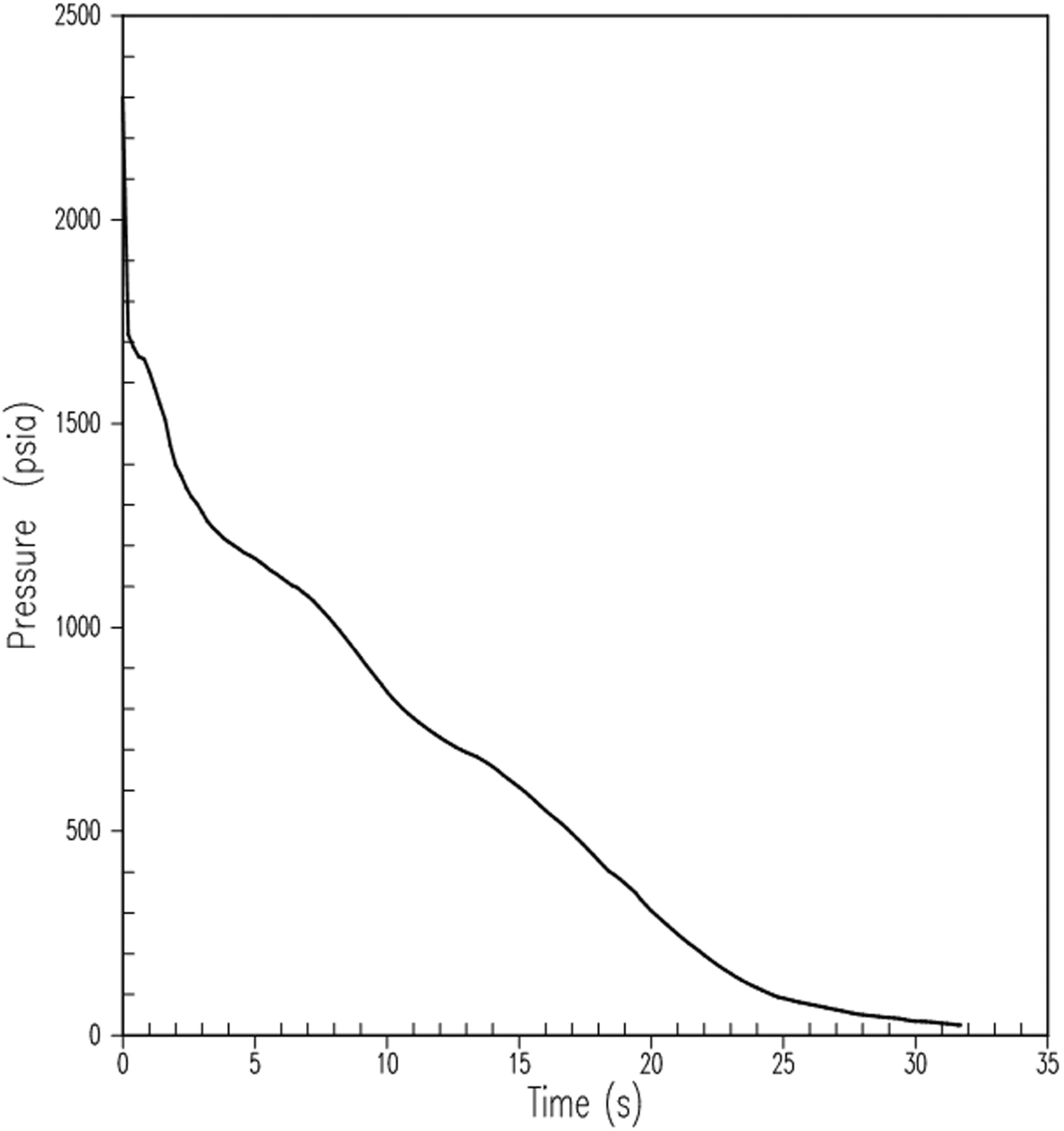
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE PRESSURE DURING BLOWDOWN
(C_D = 1.0, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–3 (SHEET 4 OF 9)



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UNIT 1 AND UNIT 2

CORE PRESSURE DURING BLOWDOWN
(C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–3 (SHEET 5 OF 9)

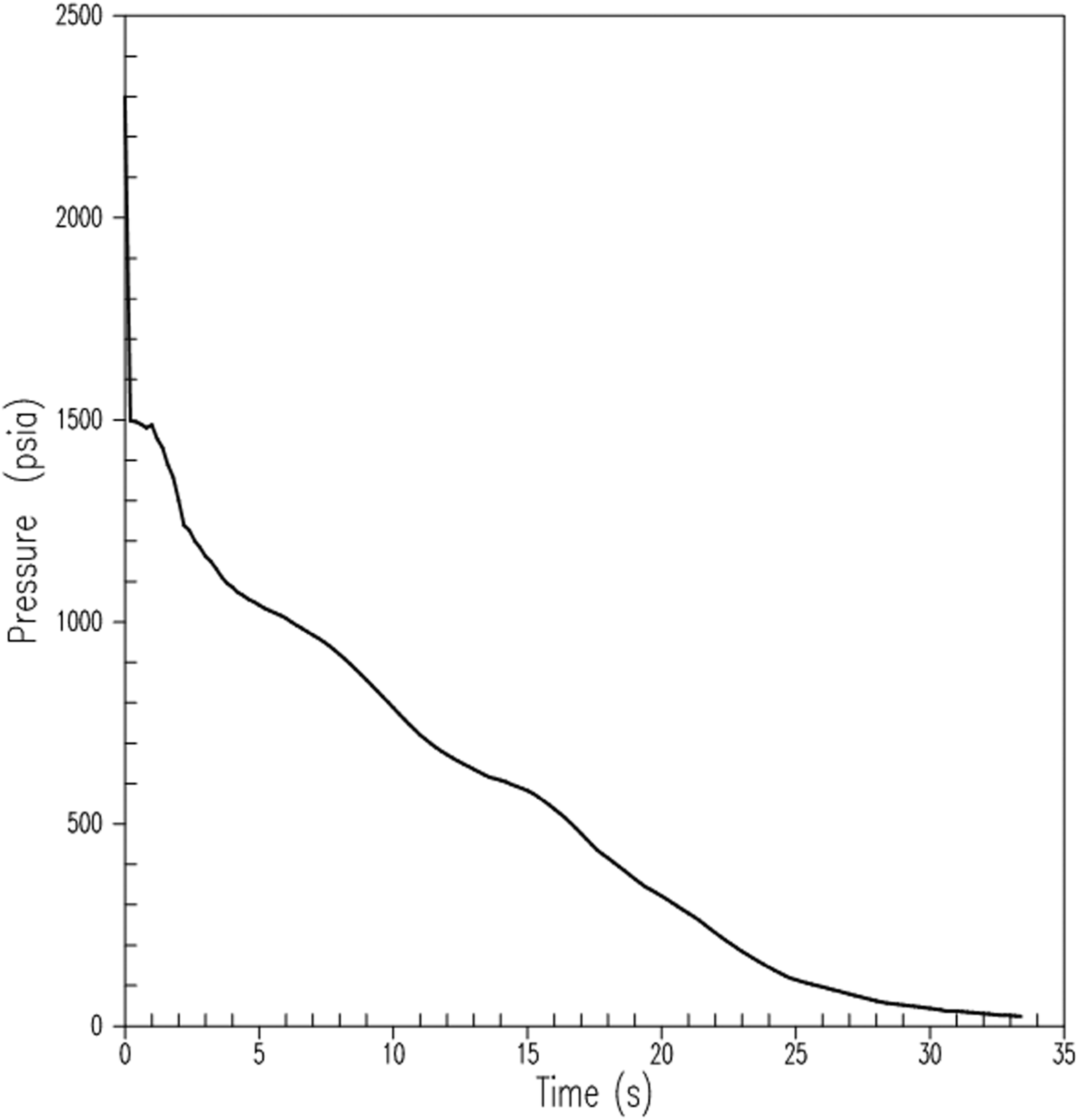

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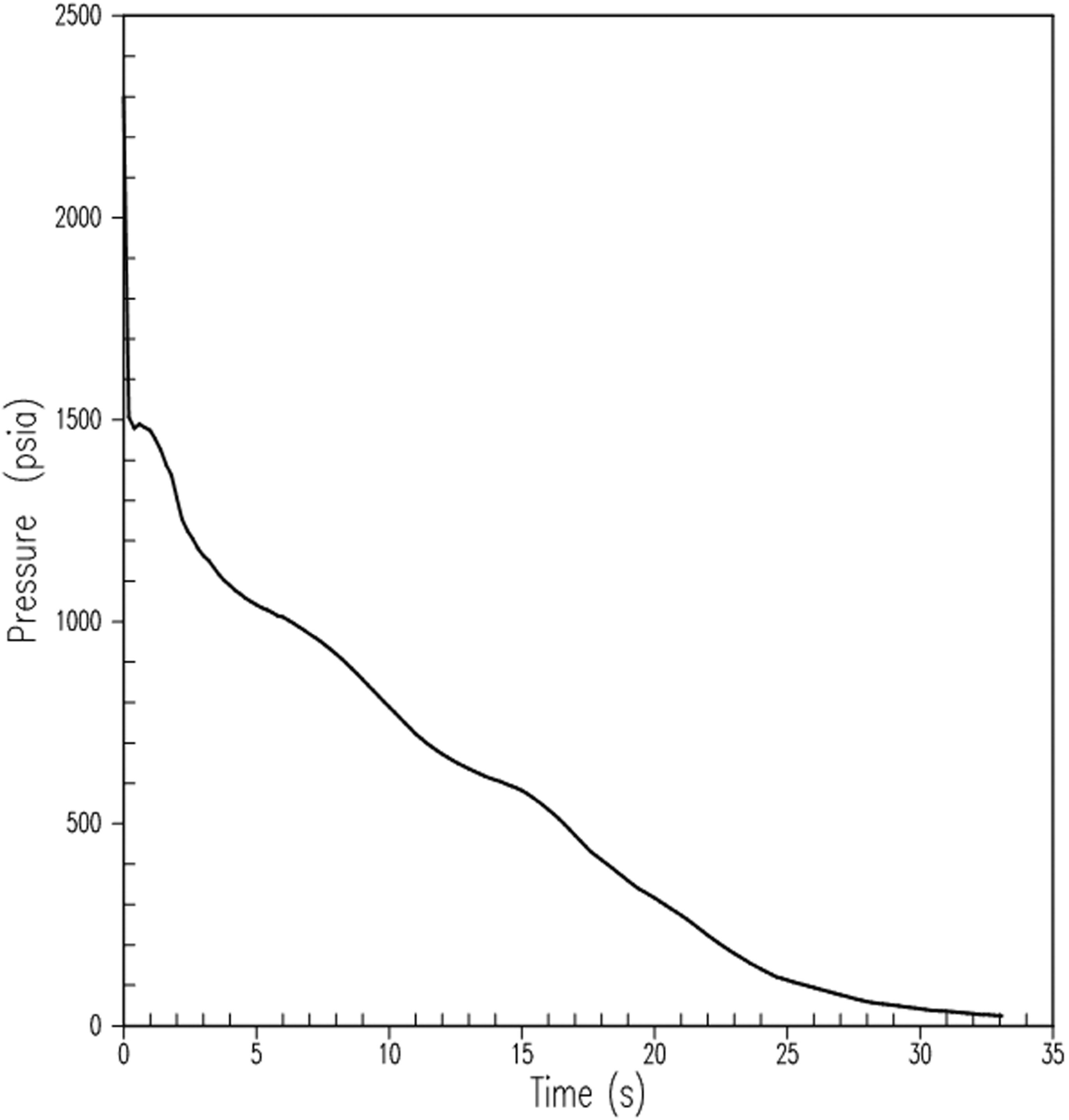
	FIGURE 15.6.5–3 (SHEET 6 OF 9)



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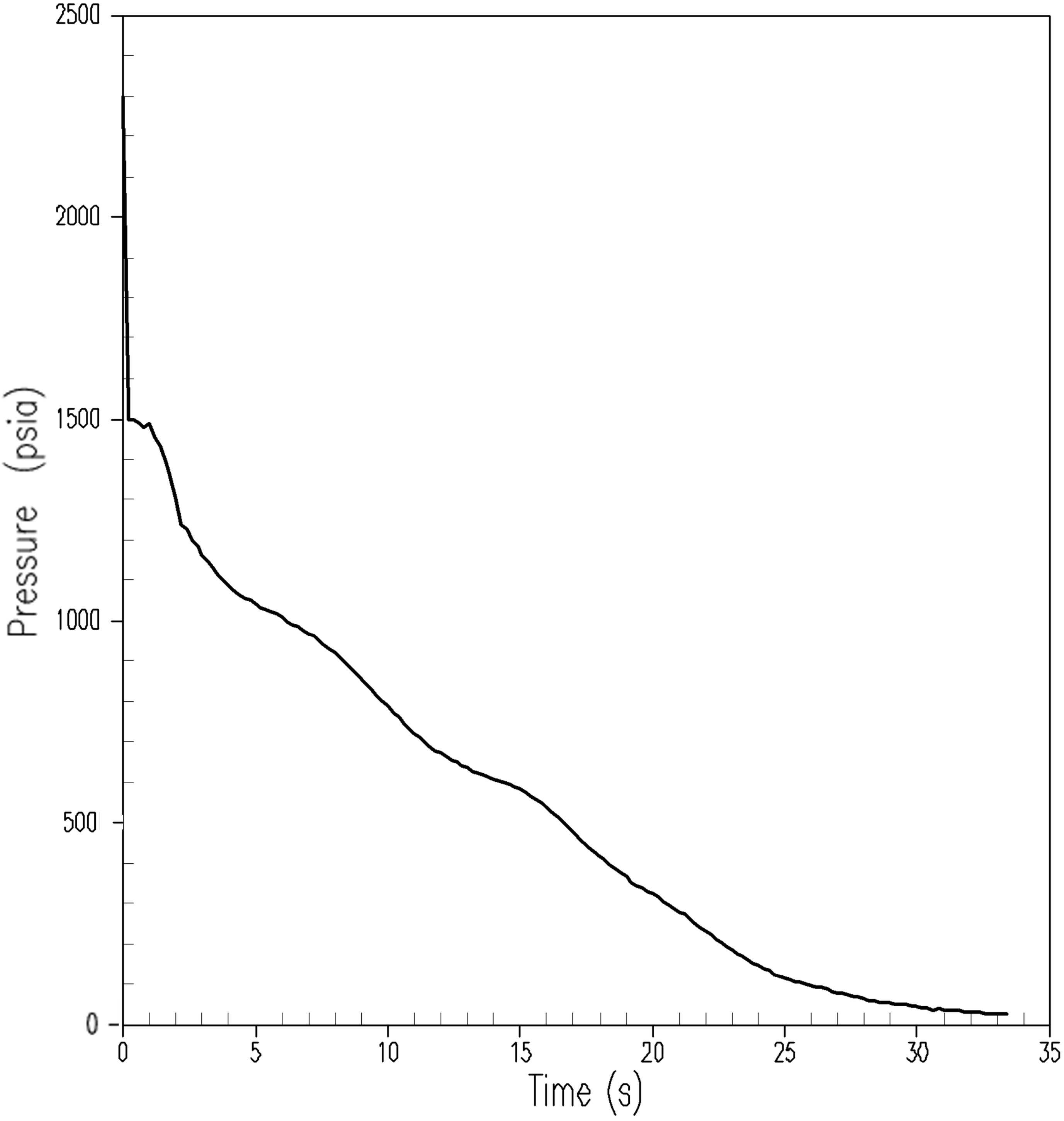
UNIT 1 AND UNIT 2

CORE PRESSURE DURING BLOWDOWN
(C_D = 0.6, LOW T_{AVG}, MIN SI, 8.5 FT POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–3 (SHEET 7 OF 9)



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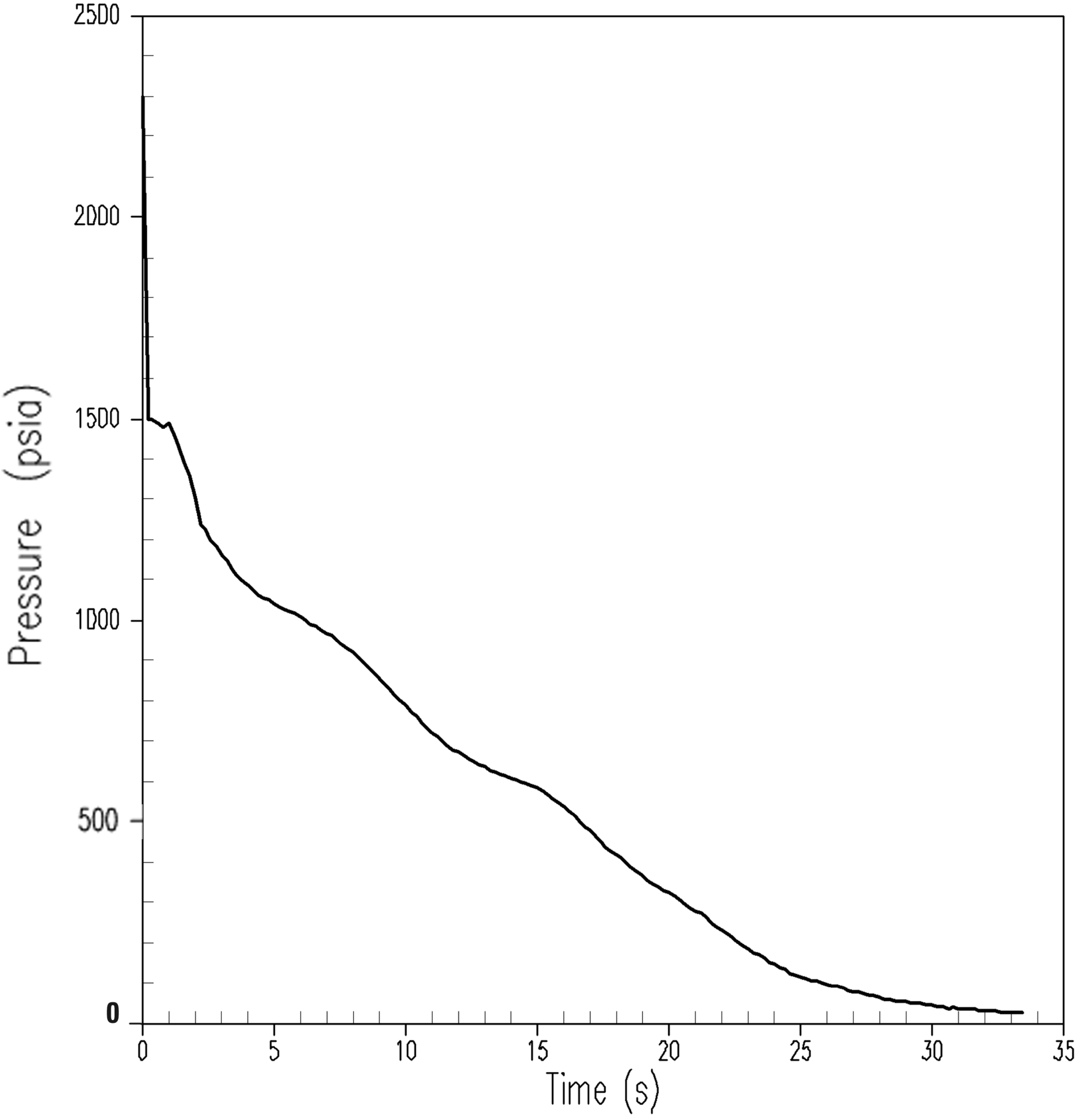
UNIT 1 AND UNIT 2

CORE PRESSURE DURING BLOWDOWN
(C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–3 (SHEET 8 OF 9)



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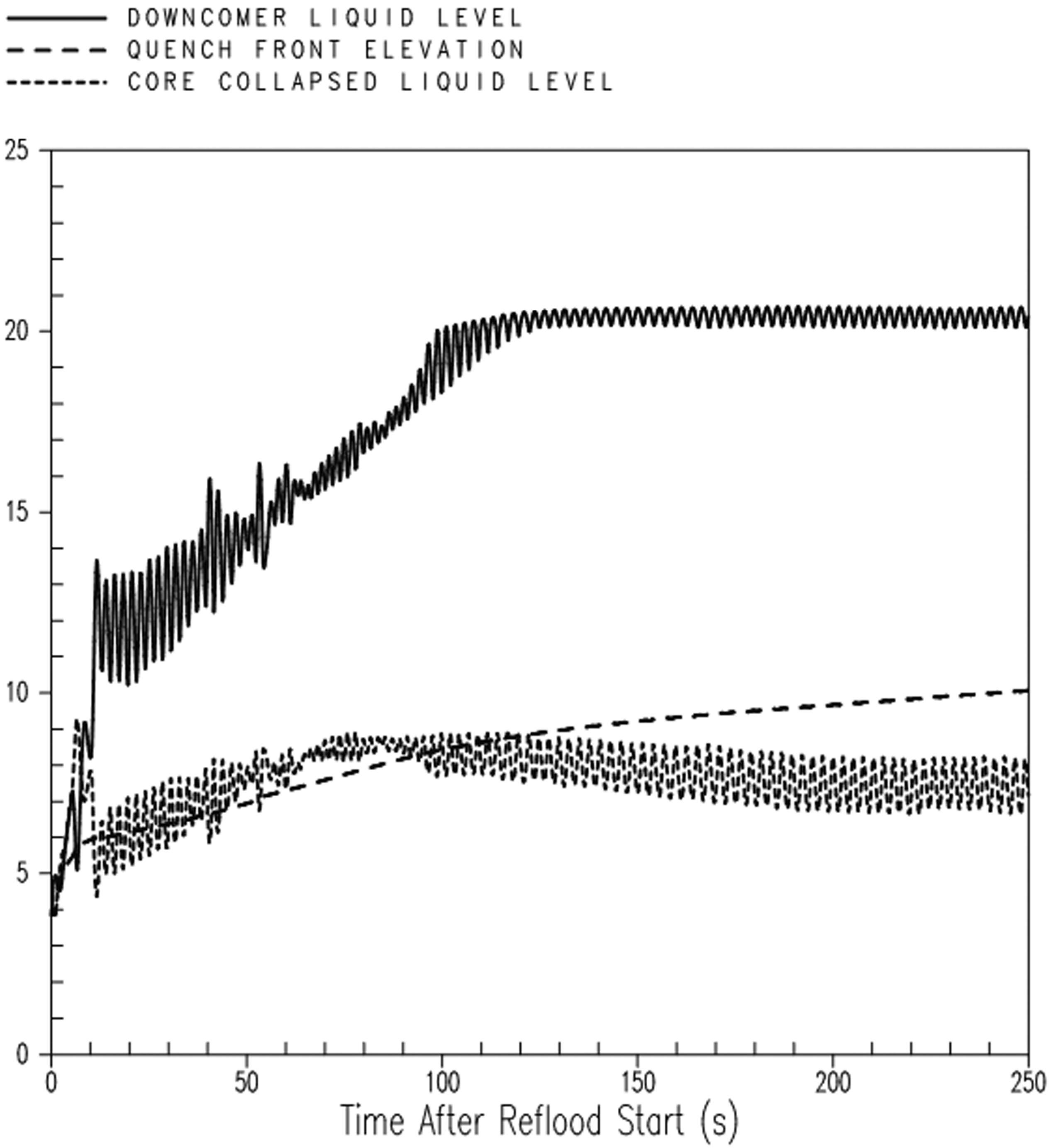
CORE PRESSURE DURING BLOWDOWN
(C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER
SHAPE, 156-IFBA)

FIGURE 15.6.5–3 (SHEET 9 OF 9)



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UNIT 1 AND UNIT 2

VESSEL LIQUID LEVELS DURING REFLOOD
(C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER
SHAPE, NON-IFBA)

FIGURE 15.6.5–4 (SHEET 1 OF 9)

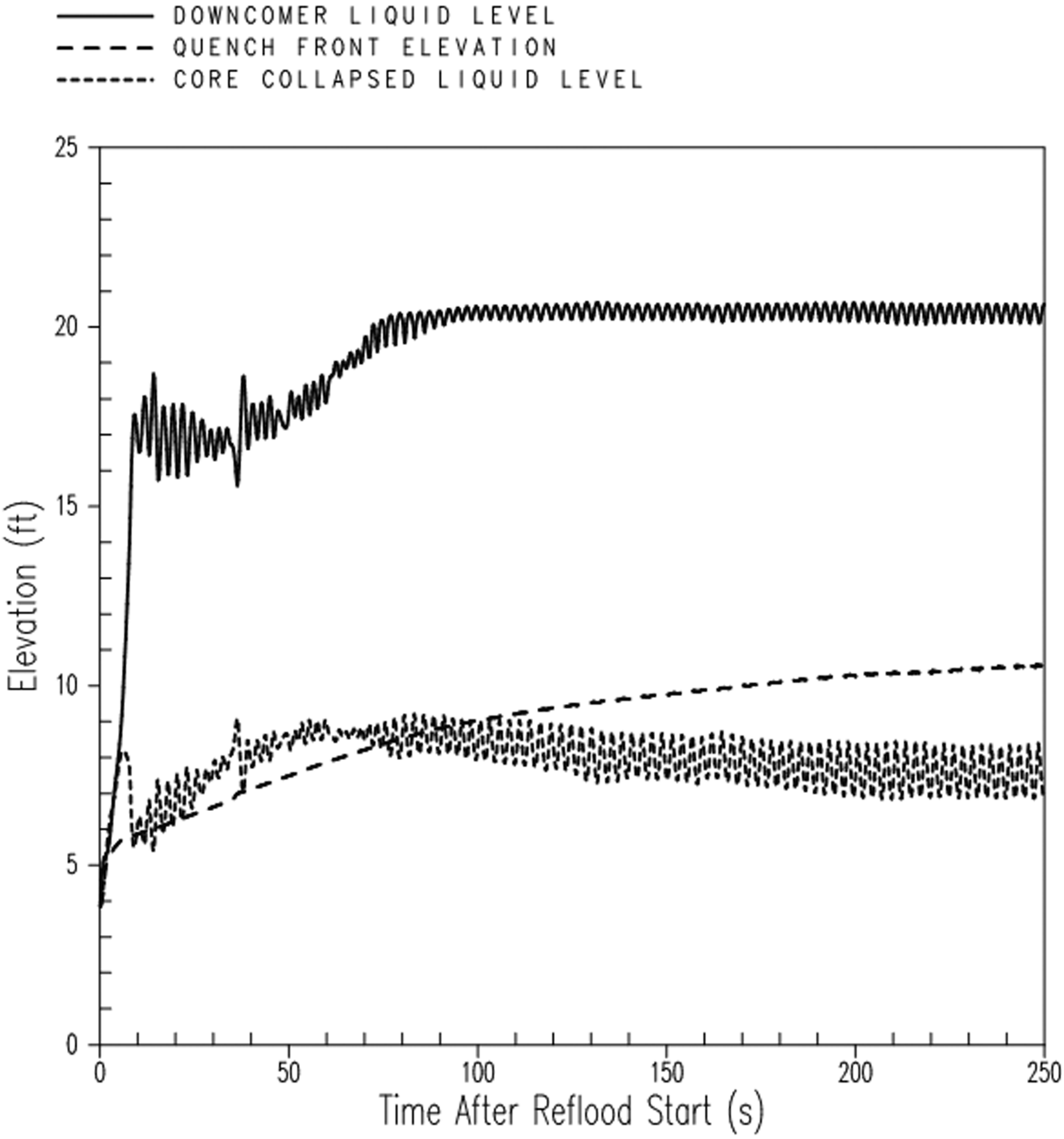

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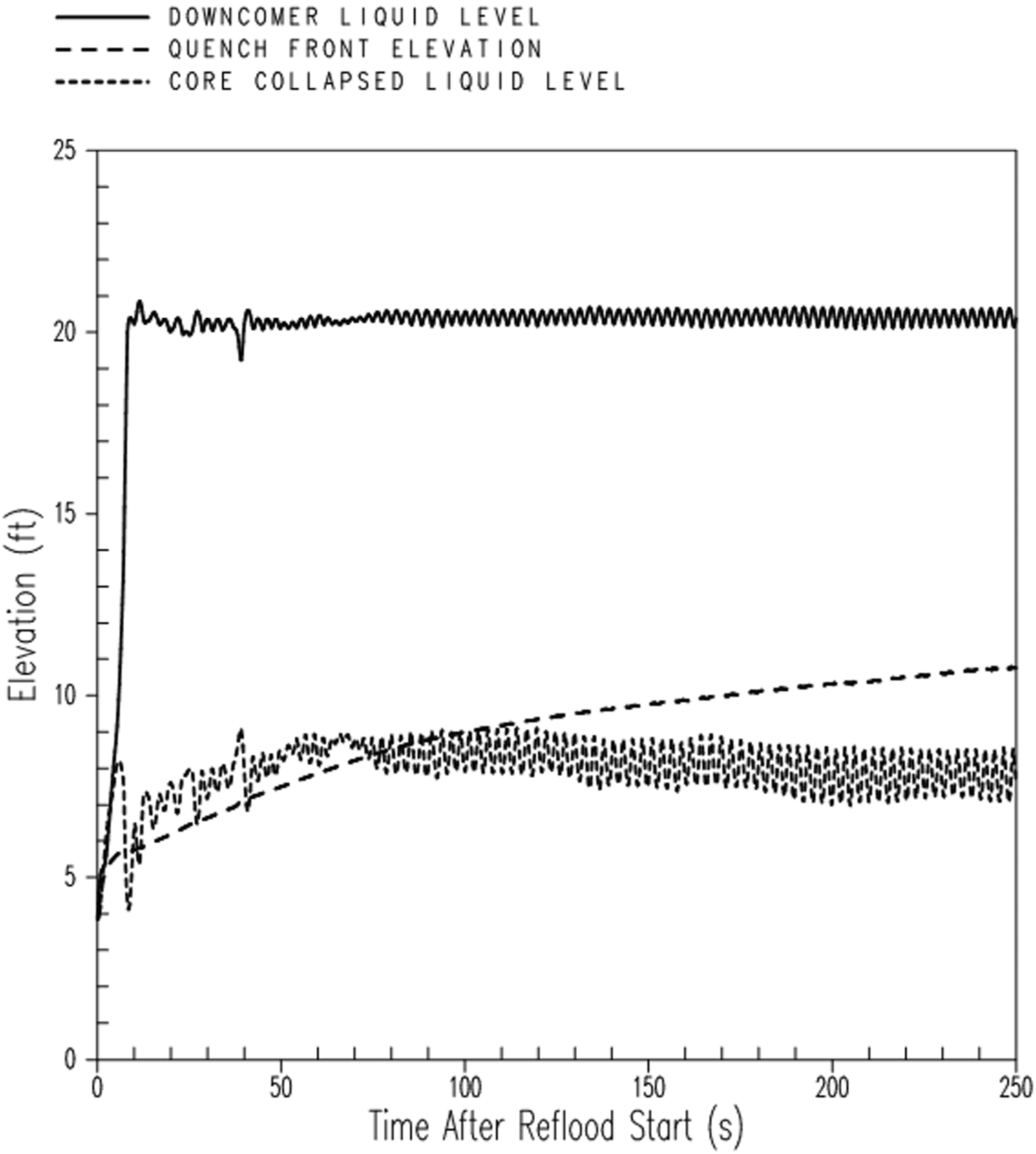
		FIGURE 15.6.5–4 (SHEET 2 OF 9)



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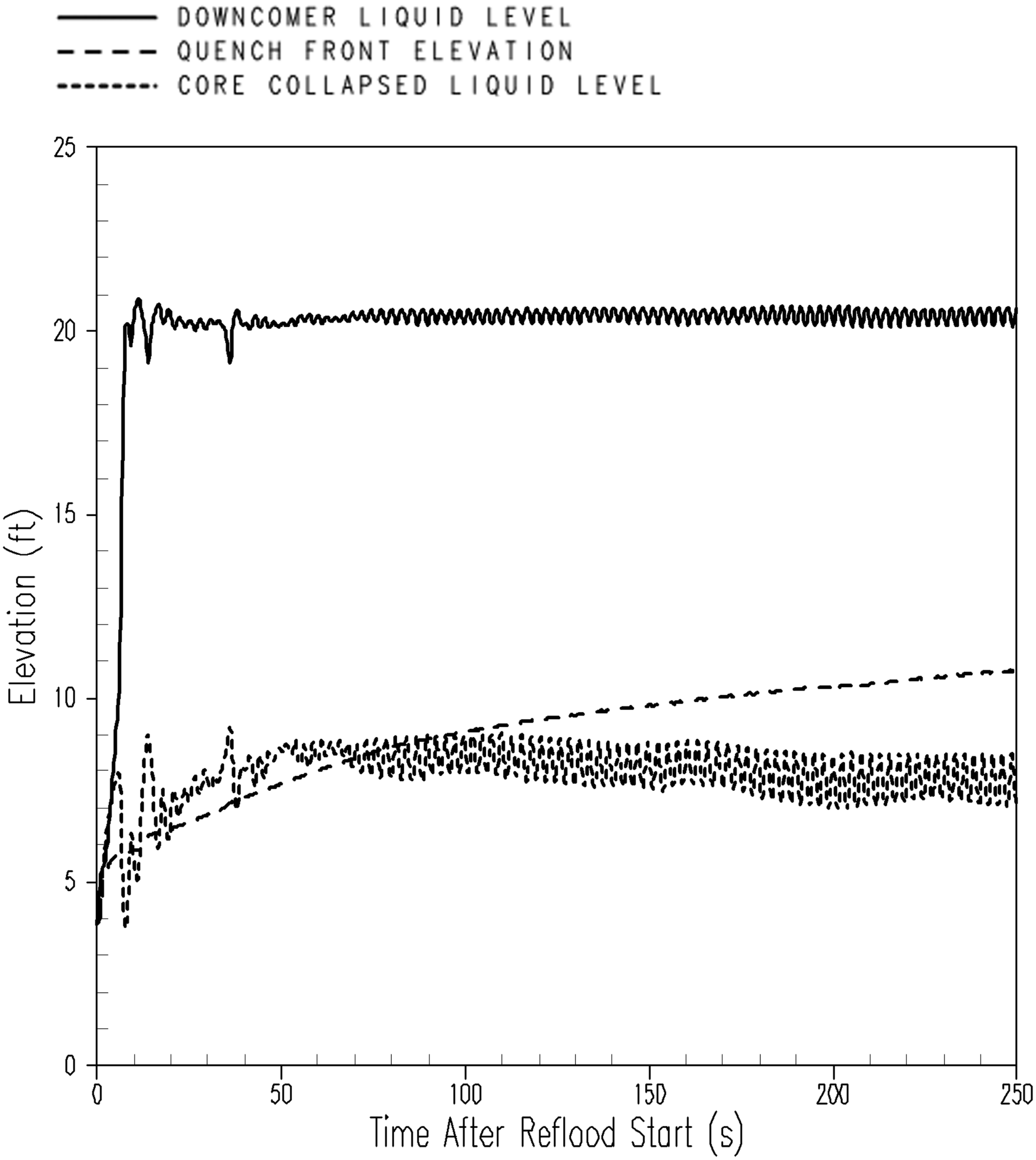
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

VESSEL LIQUID LEVELS DURING REFLOOD (C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–4 (SHEET 3 OF 9)



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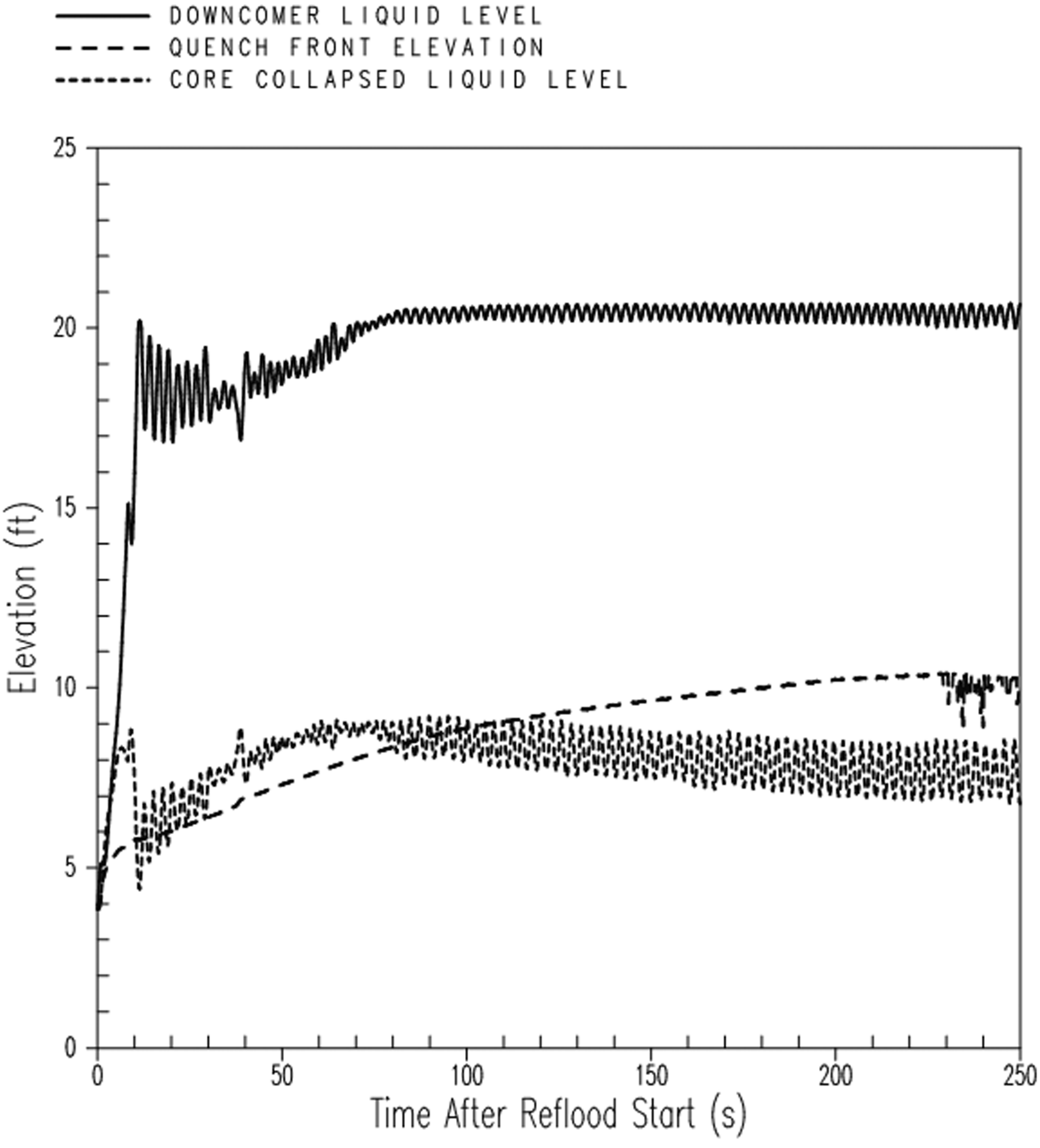
UNIT 1 AND UNIT 2

VESSEL LIQUID LEVELS DURING REFLOOD (C_D = 1.0, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–4 (SHEET 4 OF 9)



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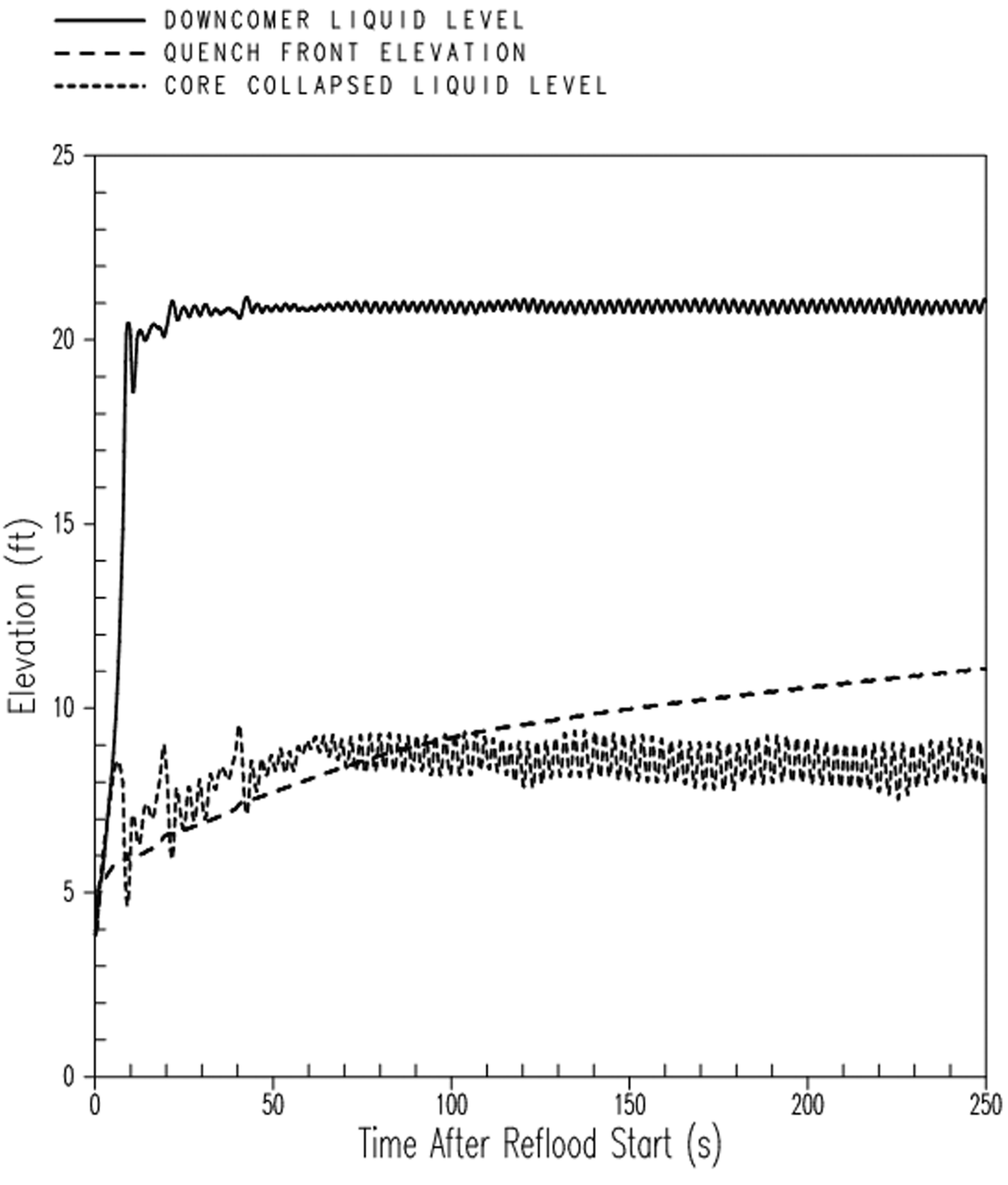
SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE** **ELECTRIC GENERATING PLANT** **UNIT 1 AND UNIT 2**	VESSEL LIQUID LEVELS DURING REFLOOD (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA) FIGURE 15.6.5–4 (SHEET 5 OF 9)



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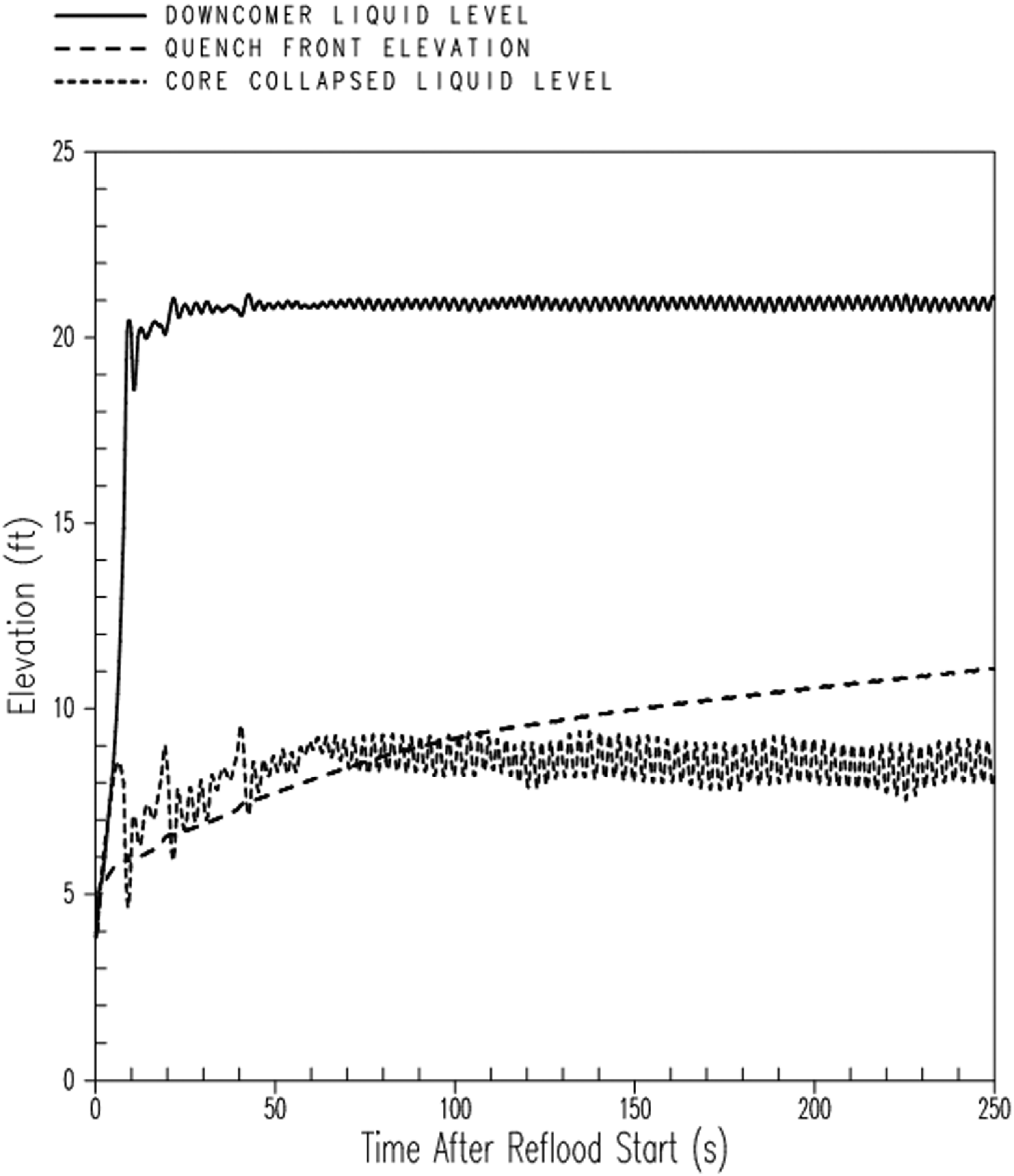
VESSEL LIQUID LEVELS DURING REFLOOD
(C_D = 0.6, LOW T_{AVG}, MAX SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–4 (SHEET 6 OF 9)



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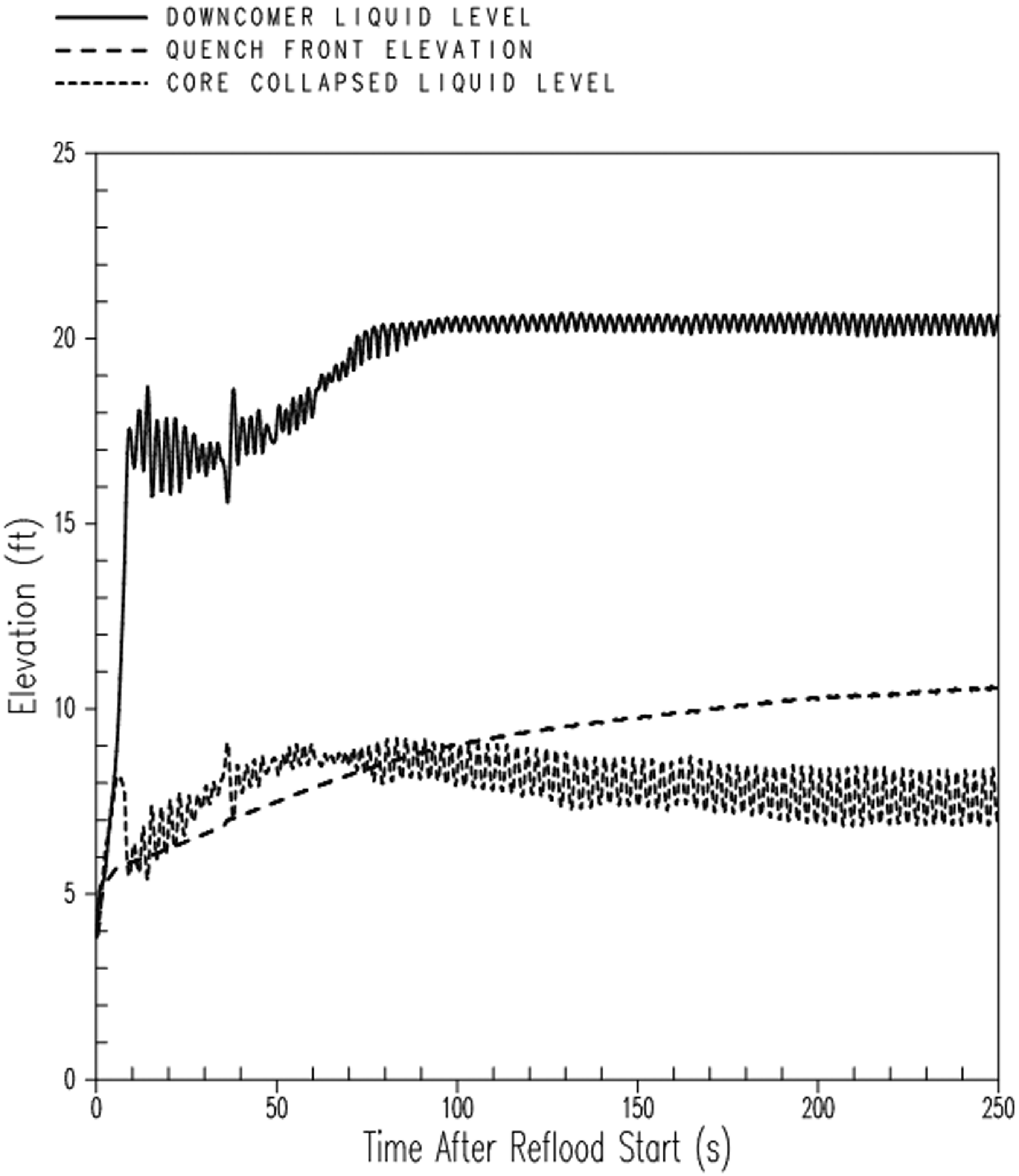

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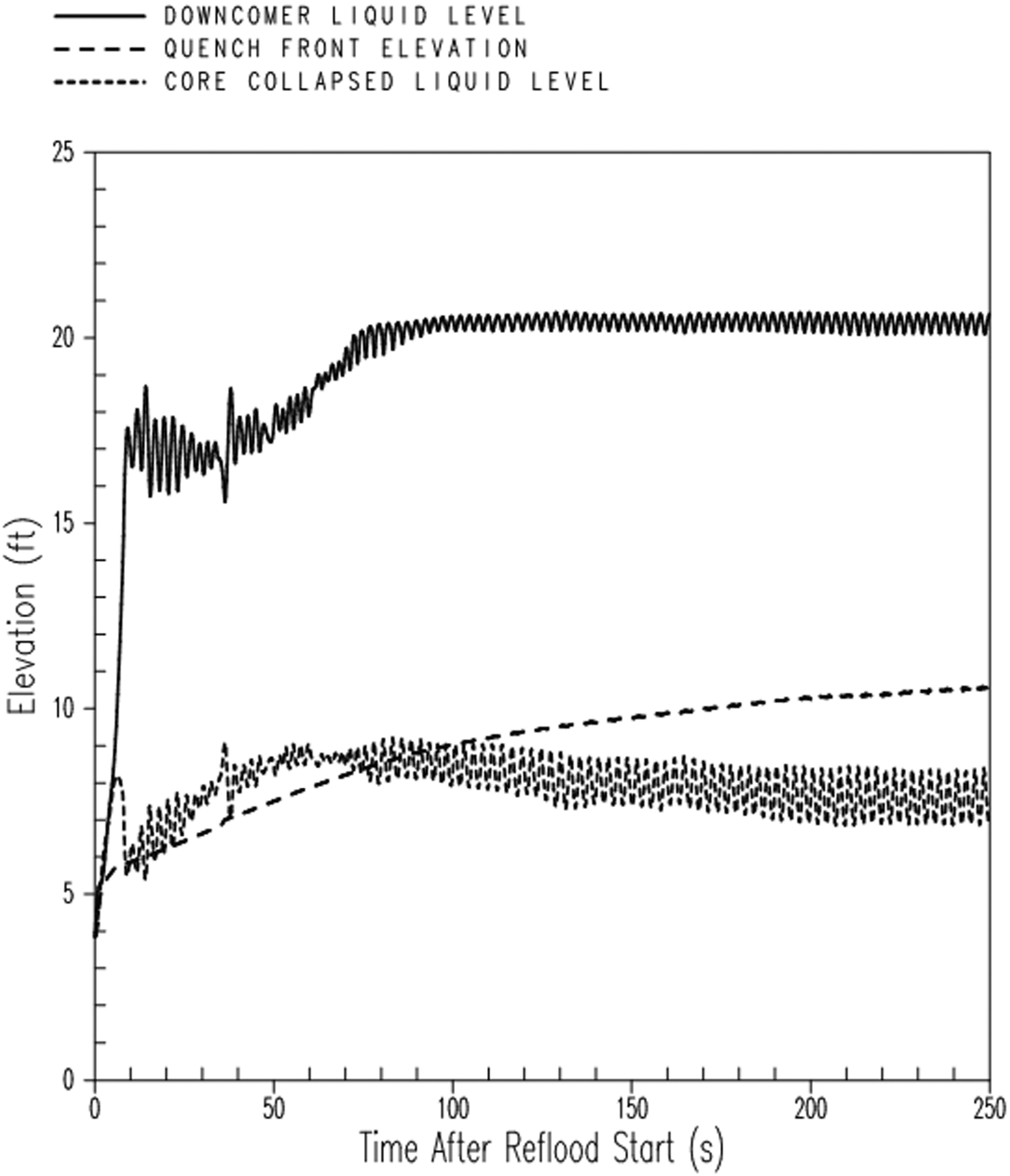
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

VESSEL LIQUID LEVELS DURING REFLOOD (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–4 (SHEET 8 OF 9)



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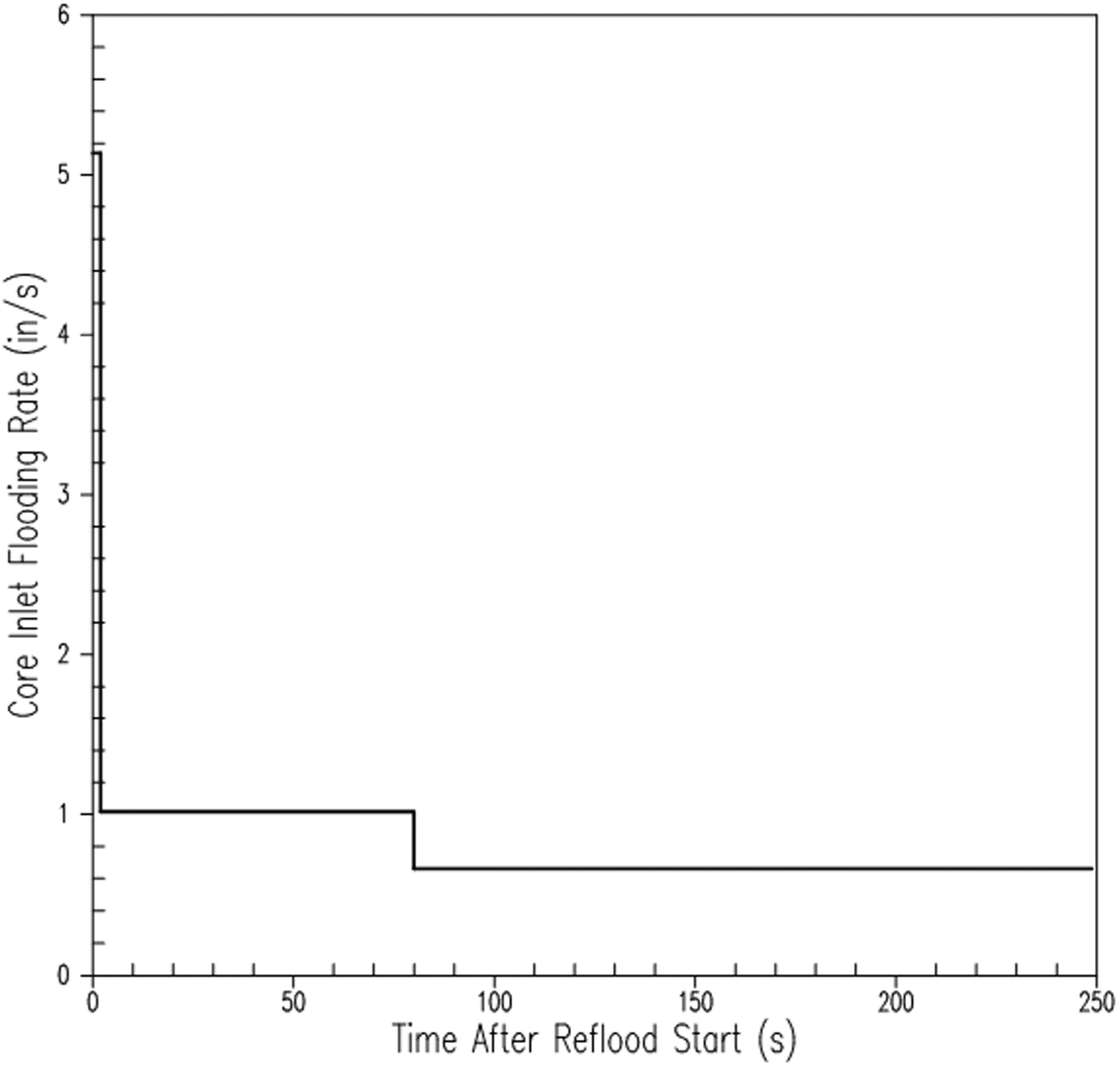
UNIT 1 AND UNIT 2

VESSEL LIQUID LEVELS DURING REFLOOD (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 156-IFBA)

FIGURE 15.6.5–4 (SHEET 9 OF 9)



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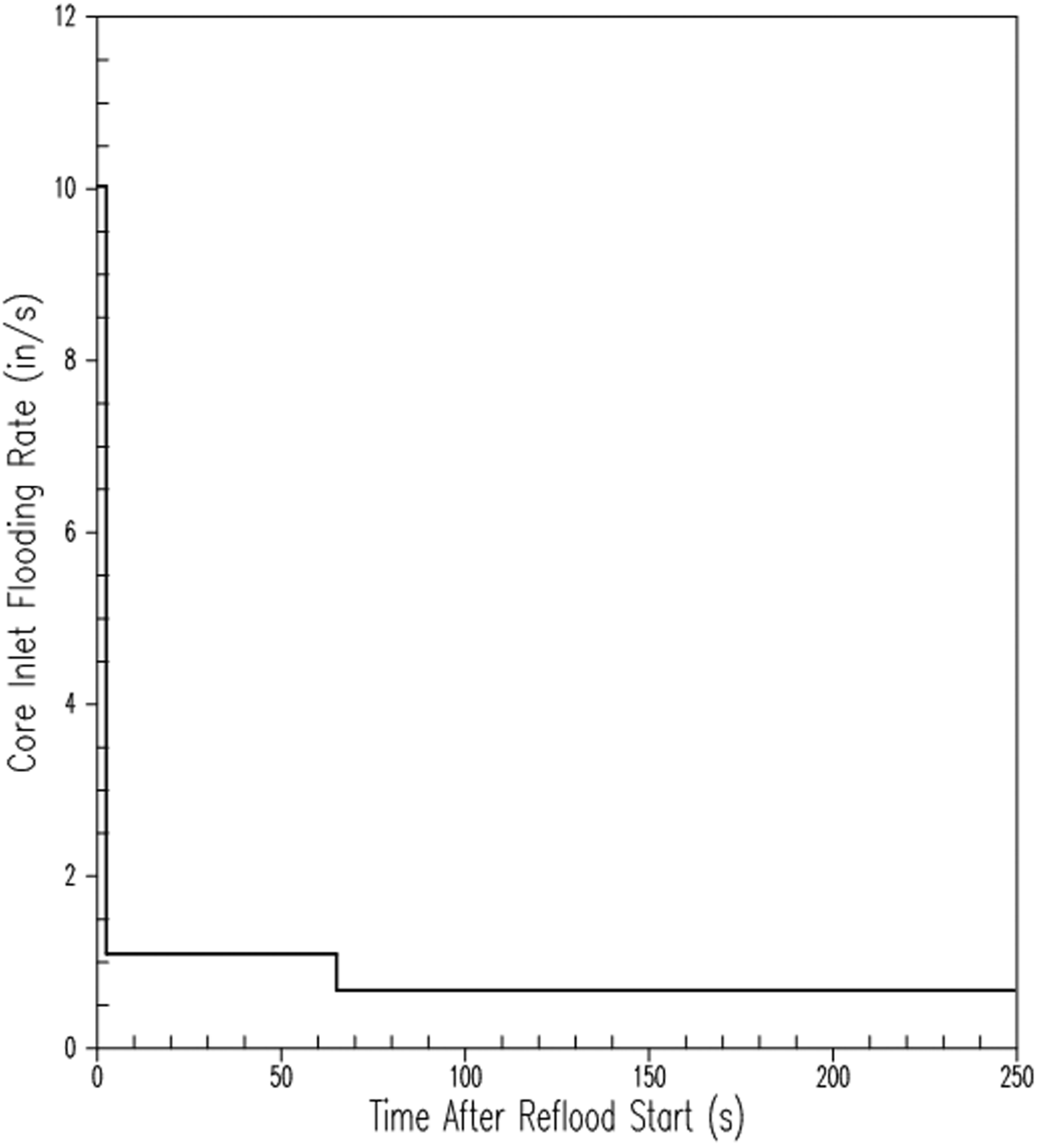
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET FLOODING RATE DURING REFLOOD (C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–5 (SHEET 1 OF 9)



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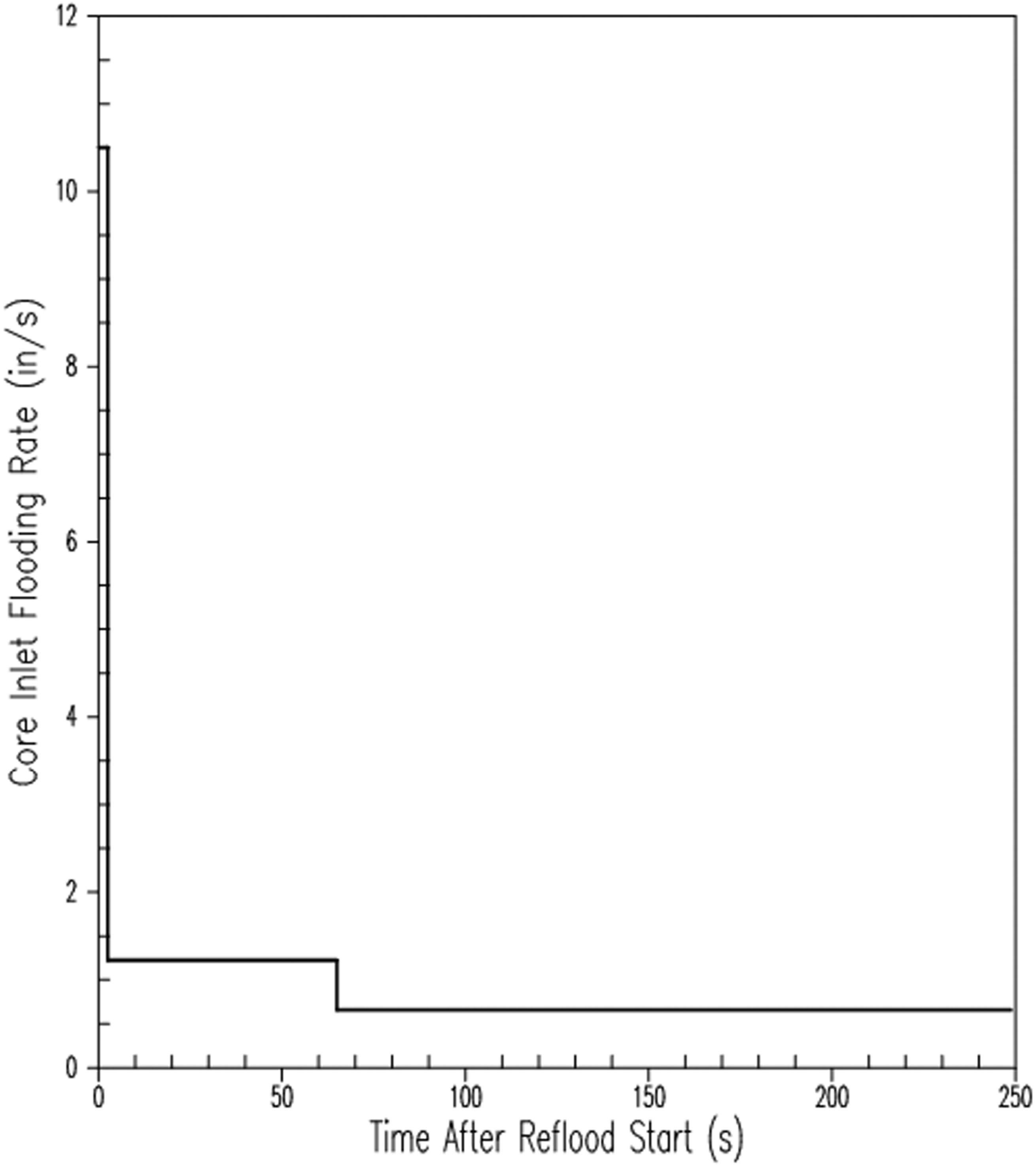
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET FLOODING RATE DURING REFLOOD (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–5 (SHEET 2 OF 9)



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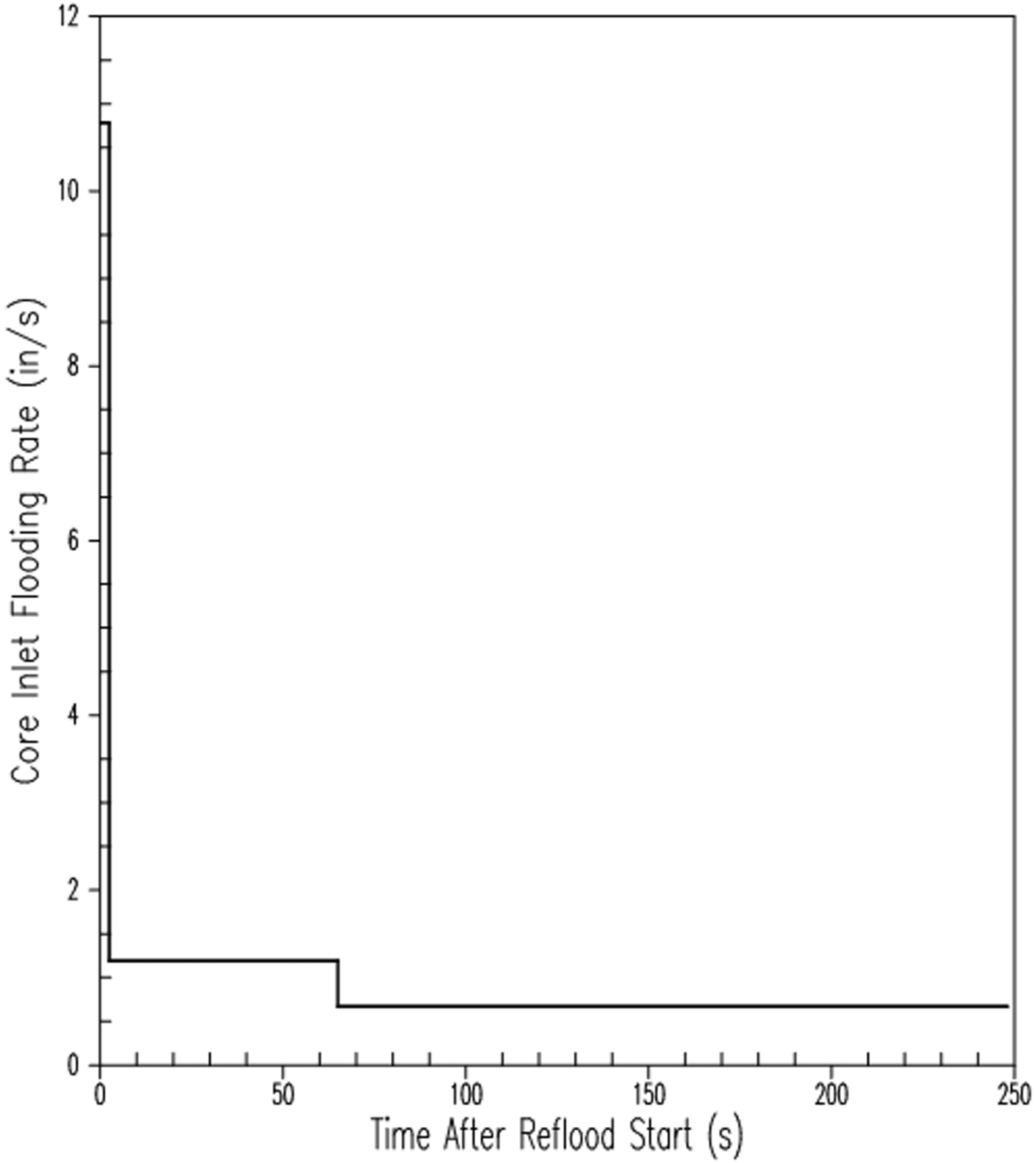
SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE** **ELECTRIC GENERATING PLANT** **UNIT 1 AND UNIT 2**	CORE INLET FLOODING RATE DURING REFLOOD (C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA) FIGURE 15.6.5–5 (SHEET 3 OF 9)



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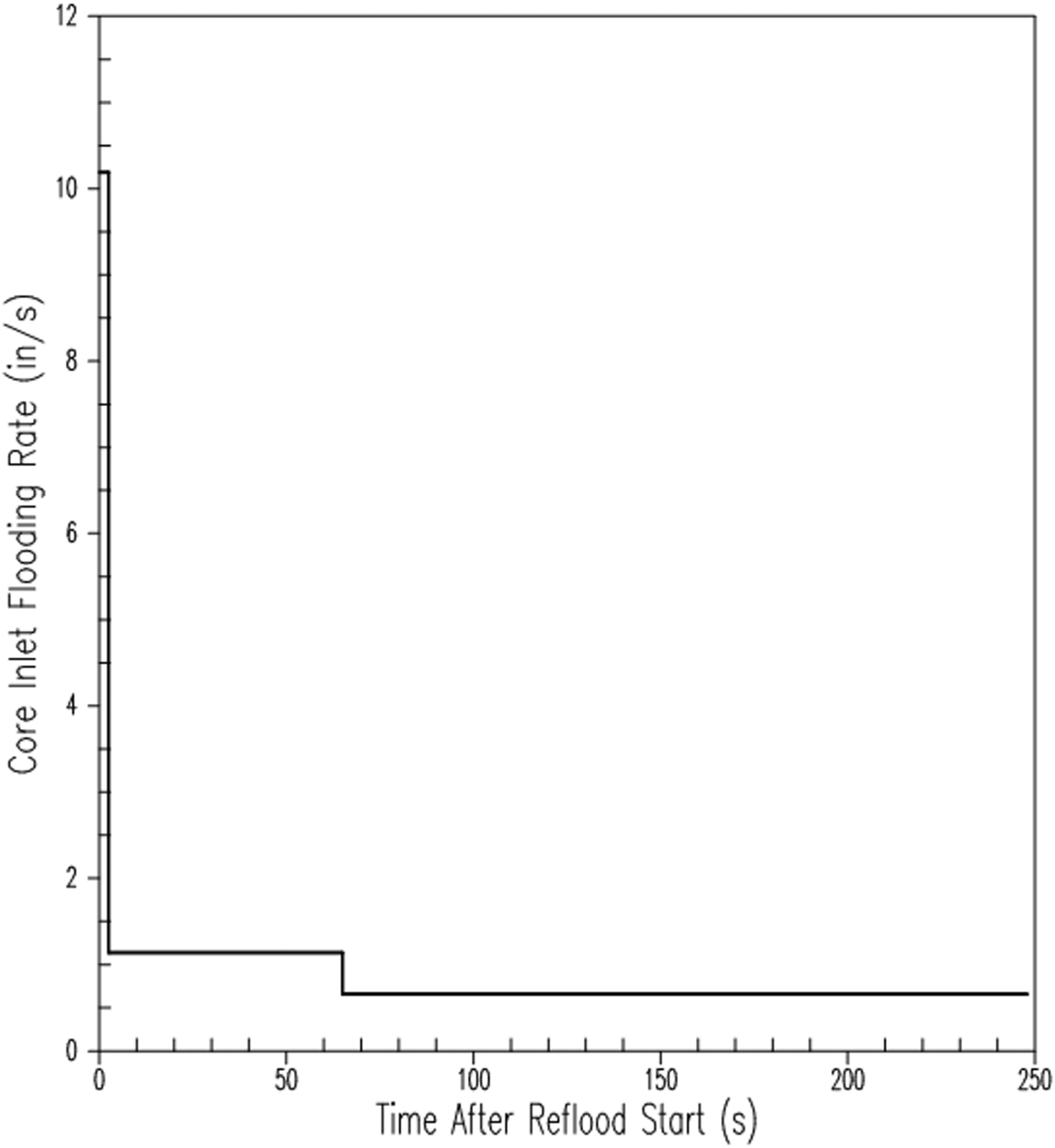
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET FLOODING RATE DURING REFLOOD (C_D = 1.0, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–5 (SHEET 4 OF 9)



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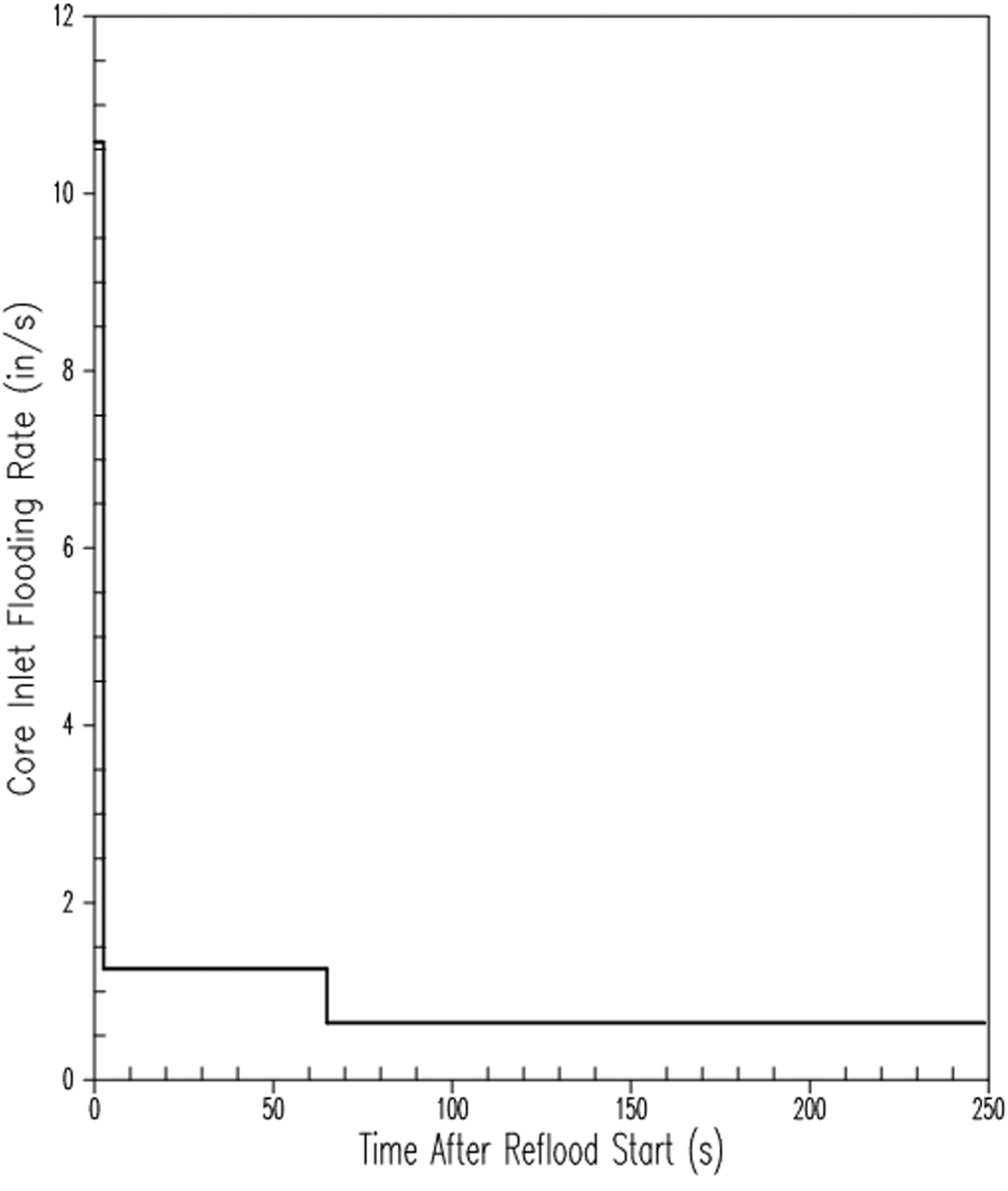
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET FLOODING RATE DURING REFLOOD (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–5 (SHEET 5 OF 9)



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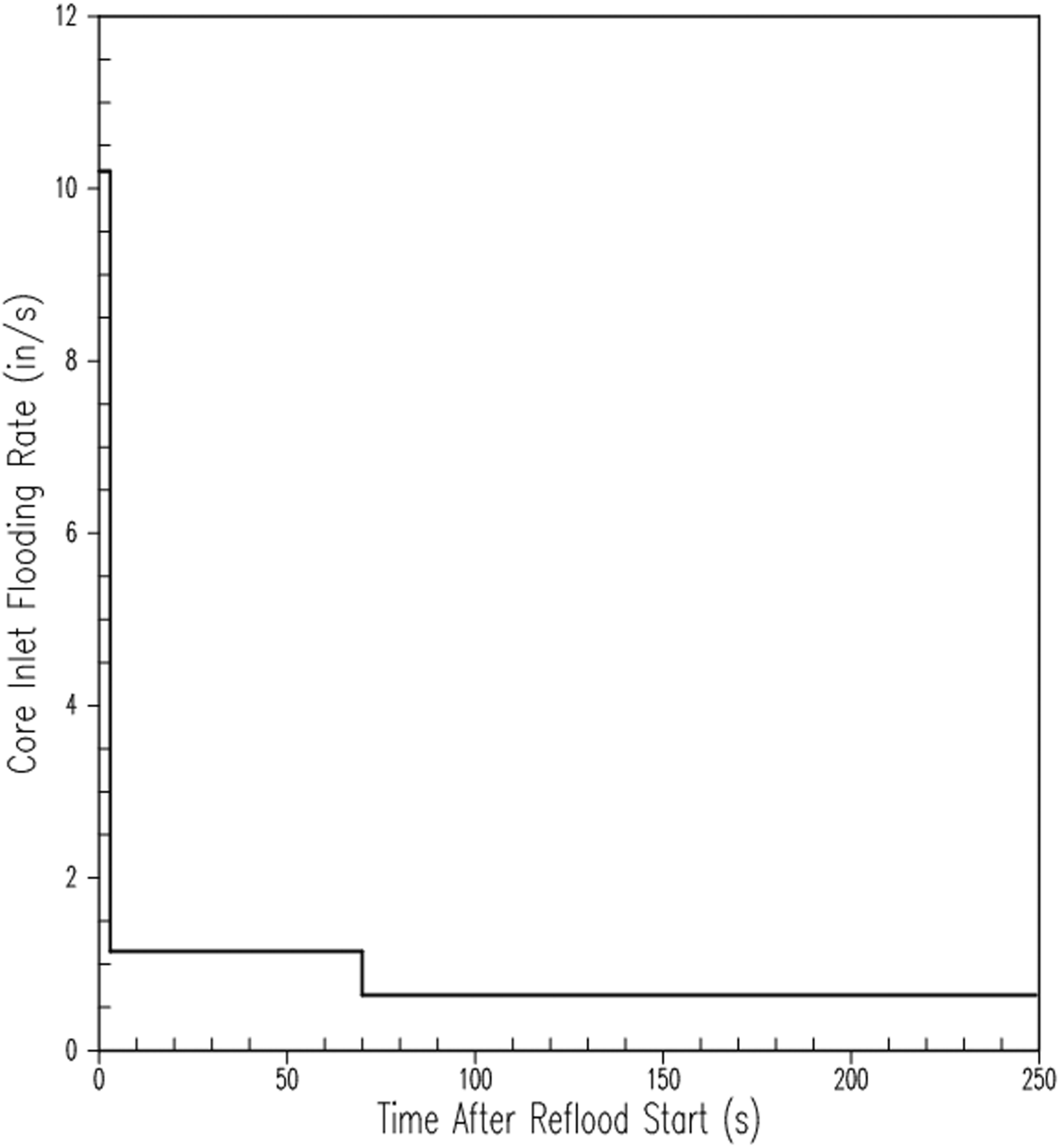
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET FLOODING RATE DURING REFLOOD (C_D = 0.6, LOW T_{AVG}, MAX SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–5 (SHEET 6 OF 9)



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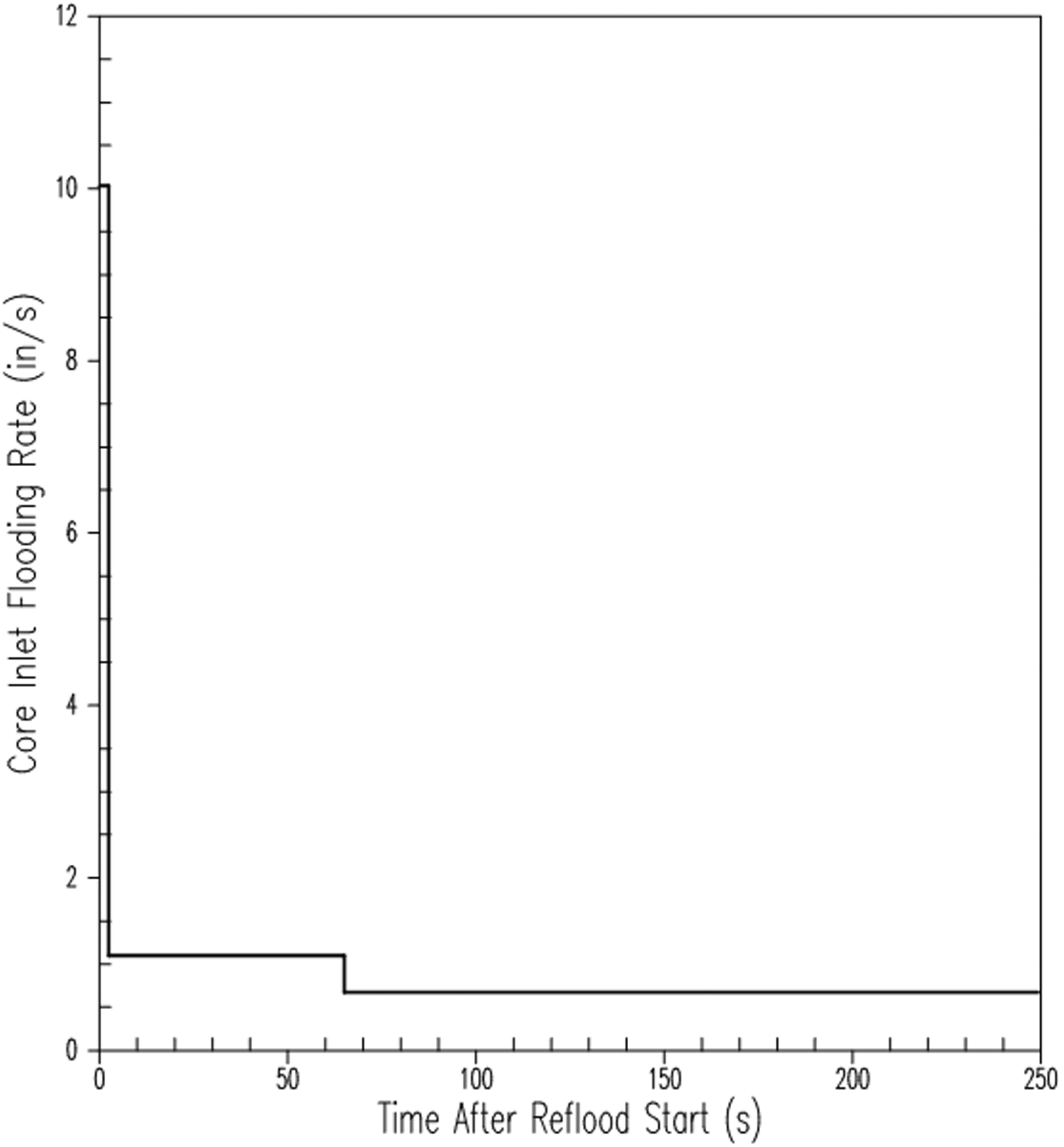
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET FLOODING RATE DURING REFLOOD (C_D = 0.6, LOW T_{AVG}, MIN SI, 8.5 FT POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–5 (SHEET 7 OF 9)



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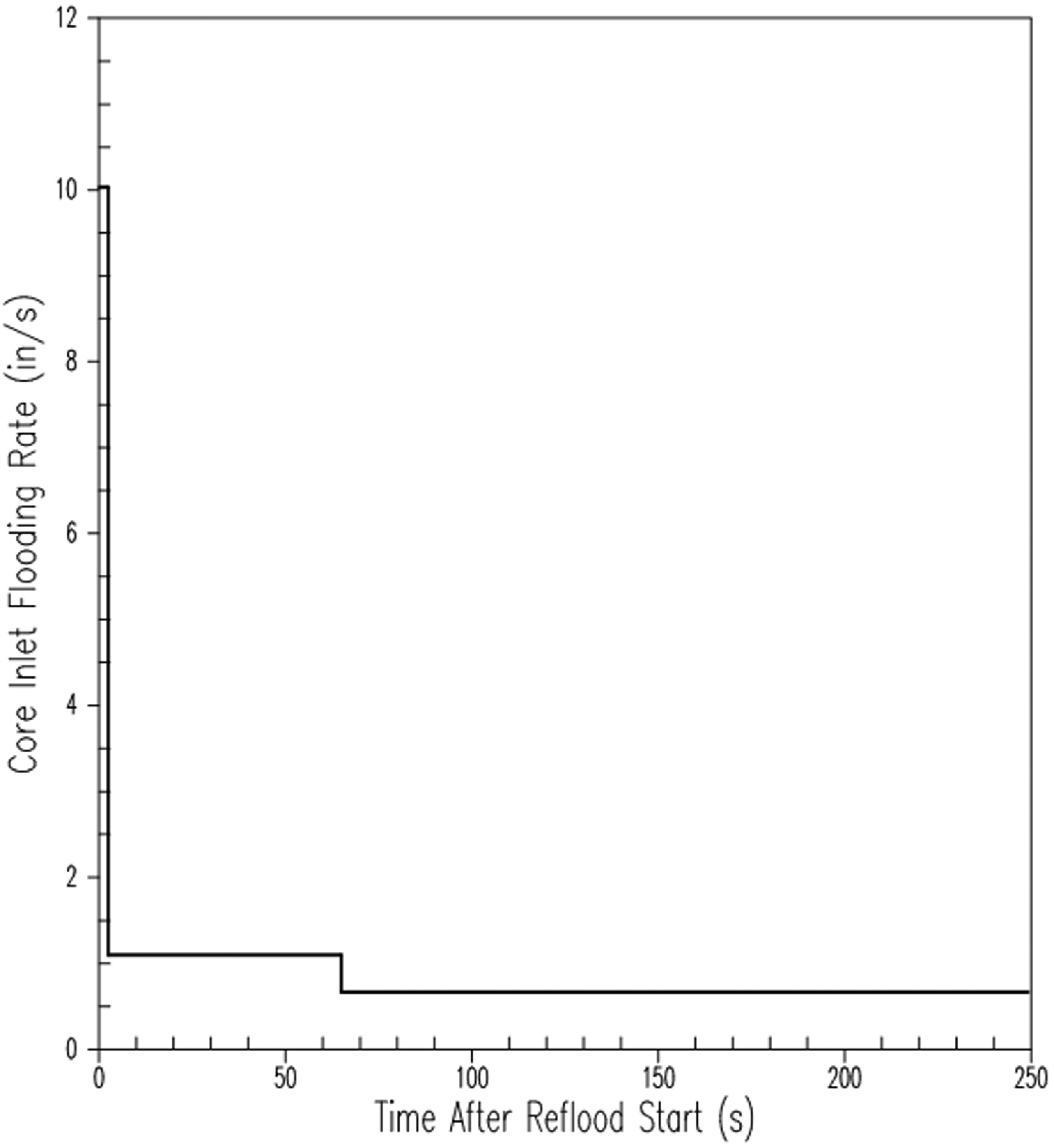
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET FLOODING RATE DURING REFLOOD (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–5 (SHEET 8 OF 9)



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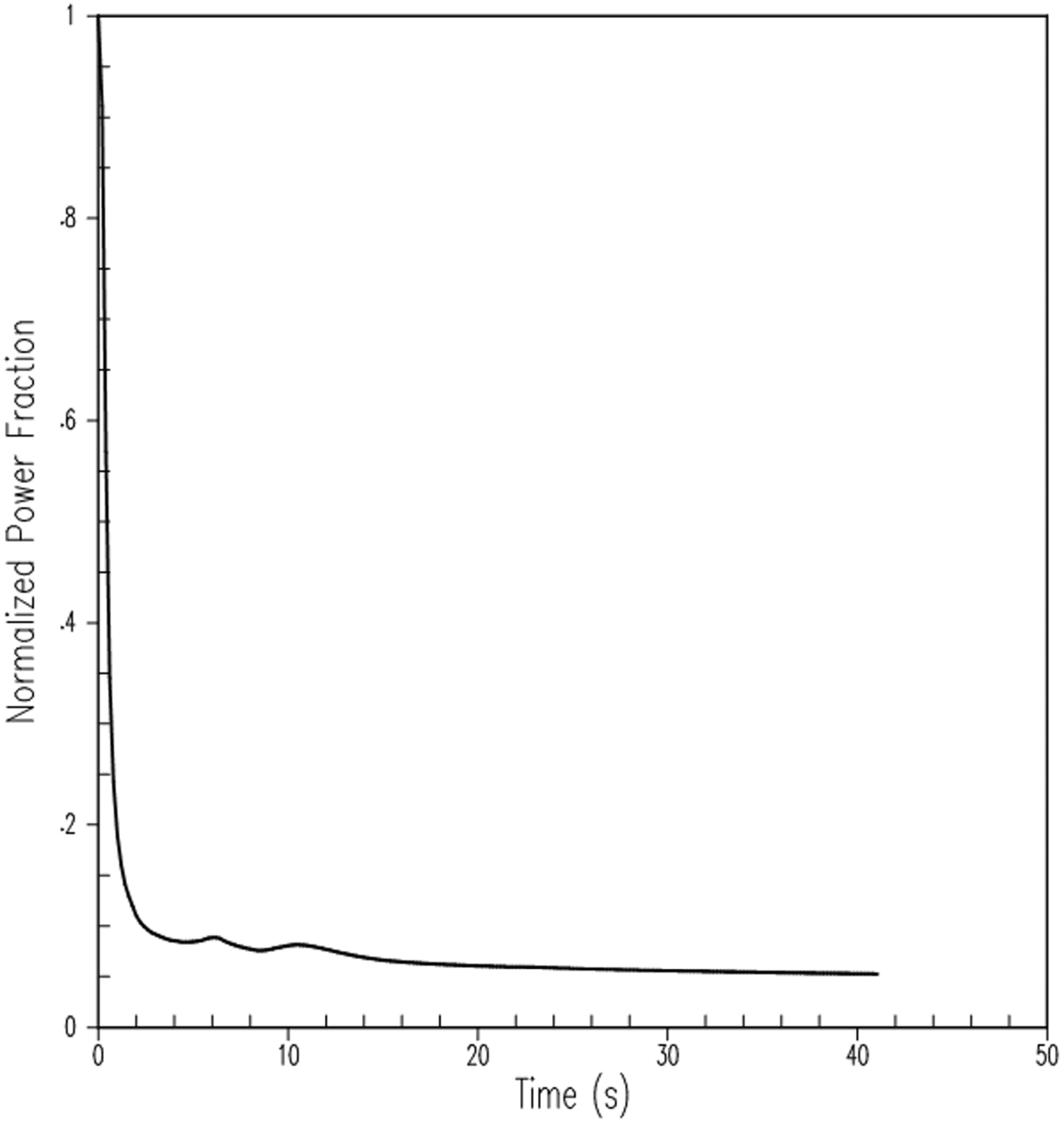
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET FLOODING RATE DURING REFLOOD (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 156-IFBA)

FIGURE 15.6.5–5 (SHEET 9 OF 9)



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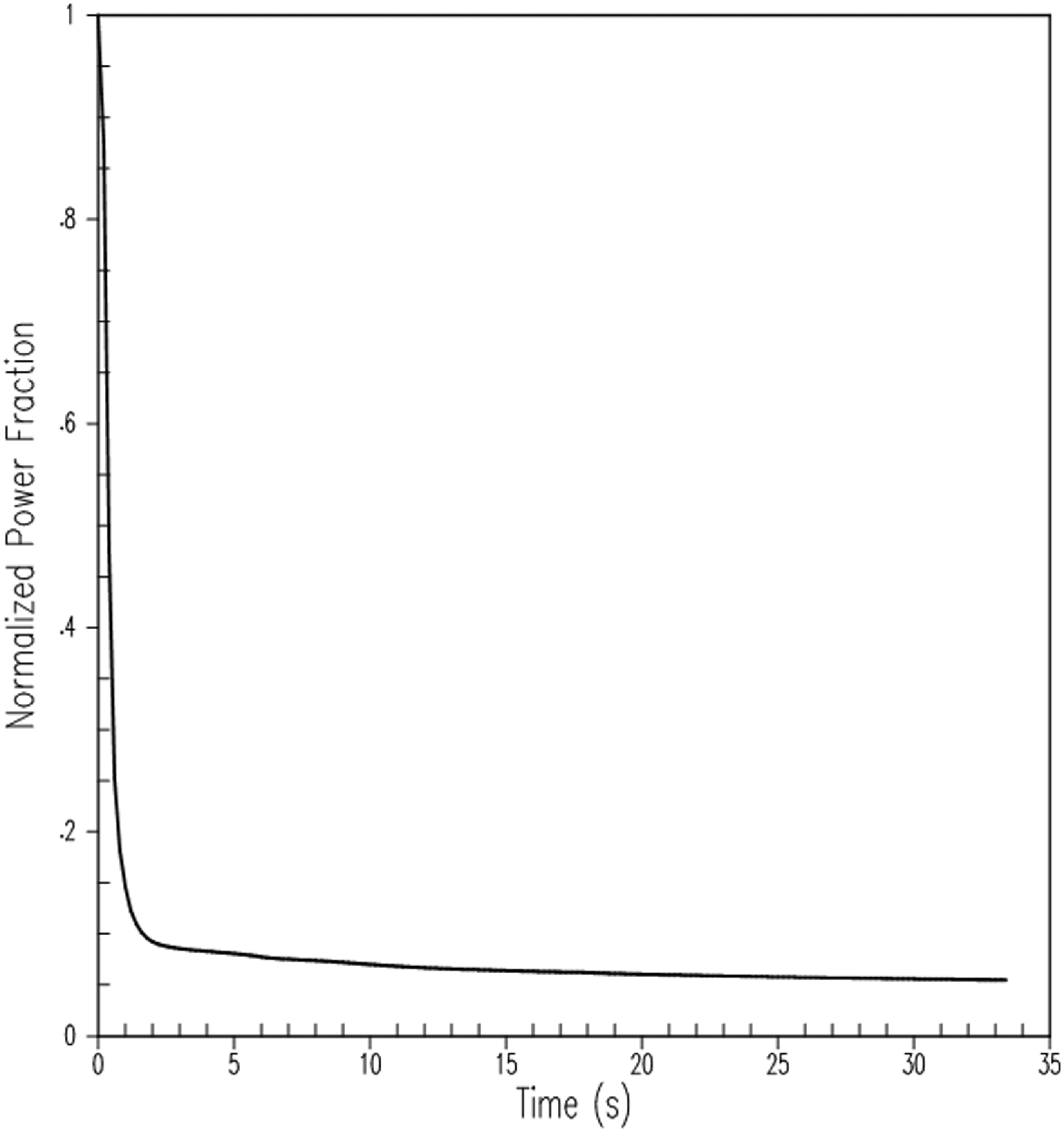
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

NORMALIZED CORE POWER DURING BLOWDOWN (C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–6 (SHEET 1 OF 9)



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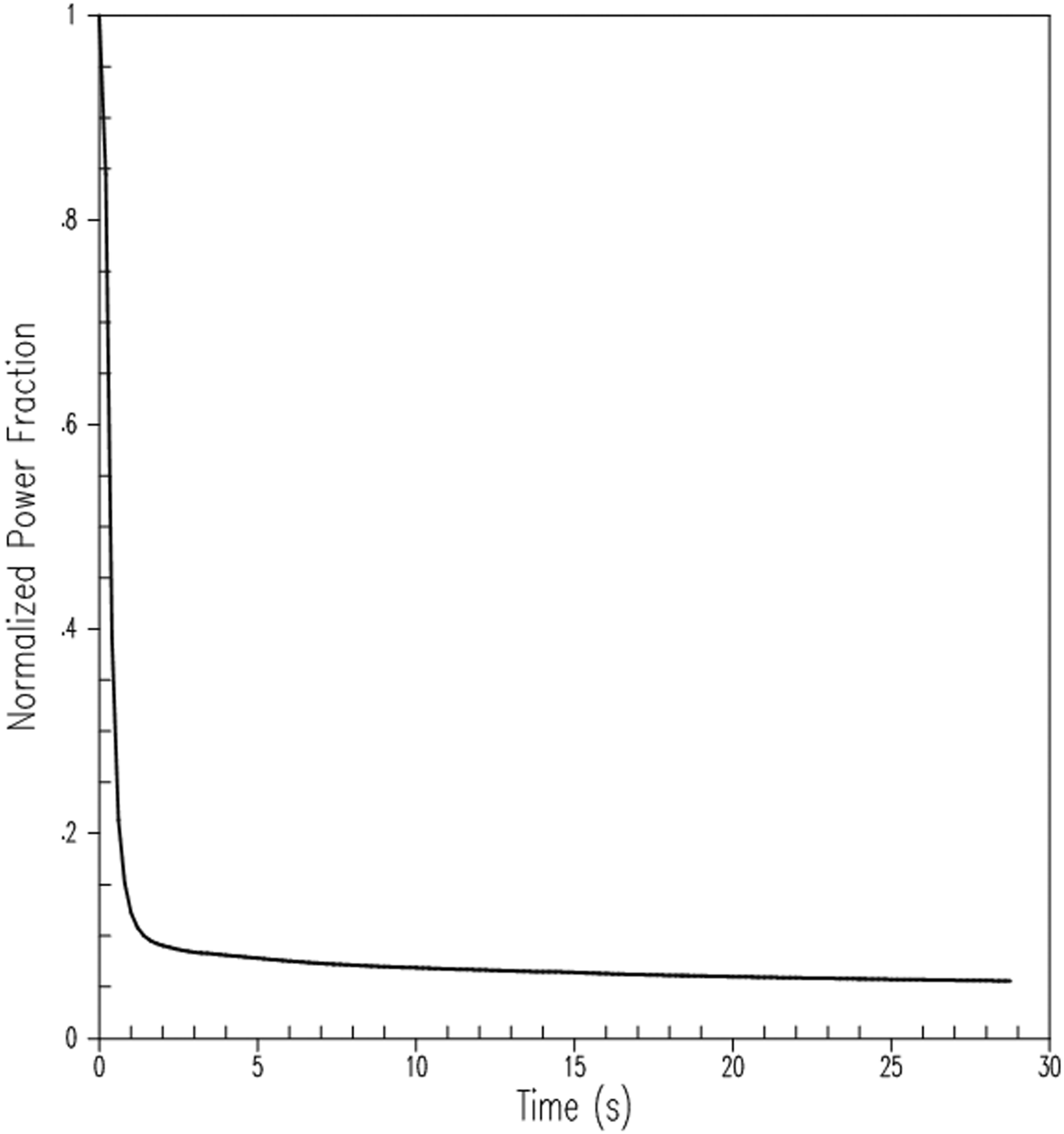
VOGTLE **ELECTRIC GENERATING PLANT** **UNIT 1 AND UNIT 2**	NORMALIZED CORE POWER DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)
	FIGURE 15.6.5–6 (SHEET 2 OF 9)



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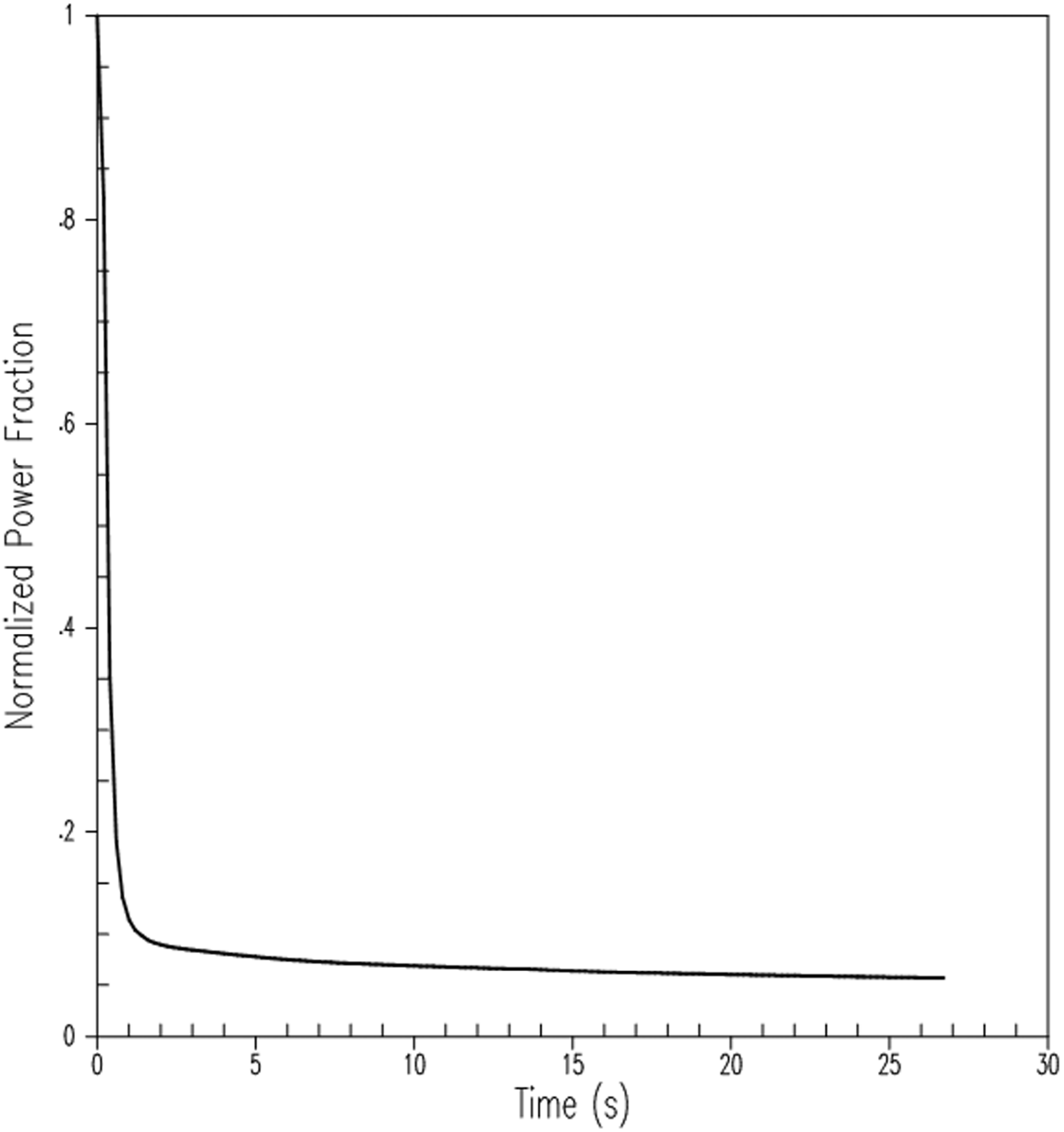
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

NORMALIZED CORE POWER DURING BLOWDOWN (C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–6 (SHEET 3 OF 9)



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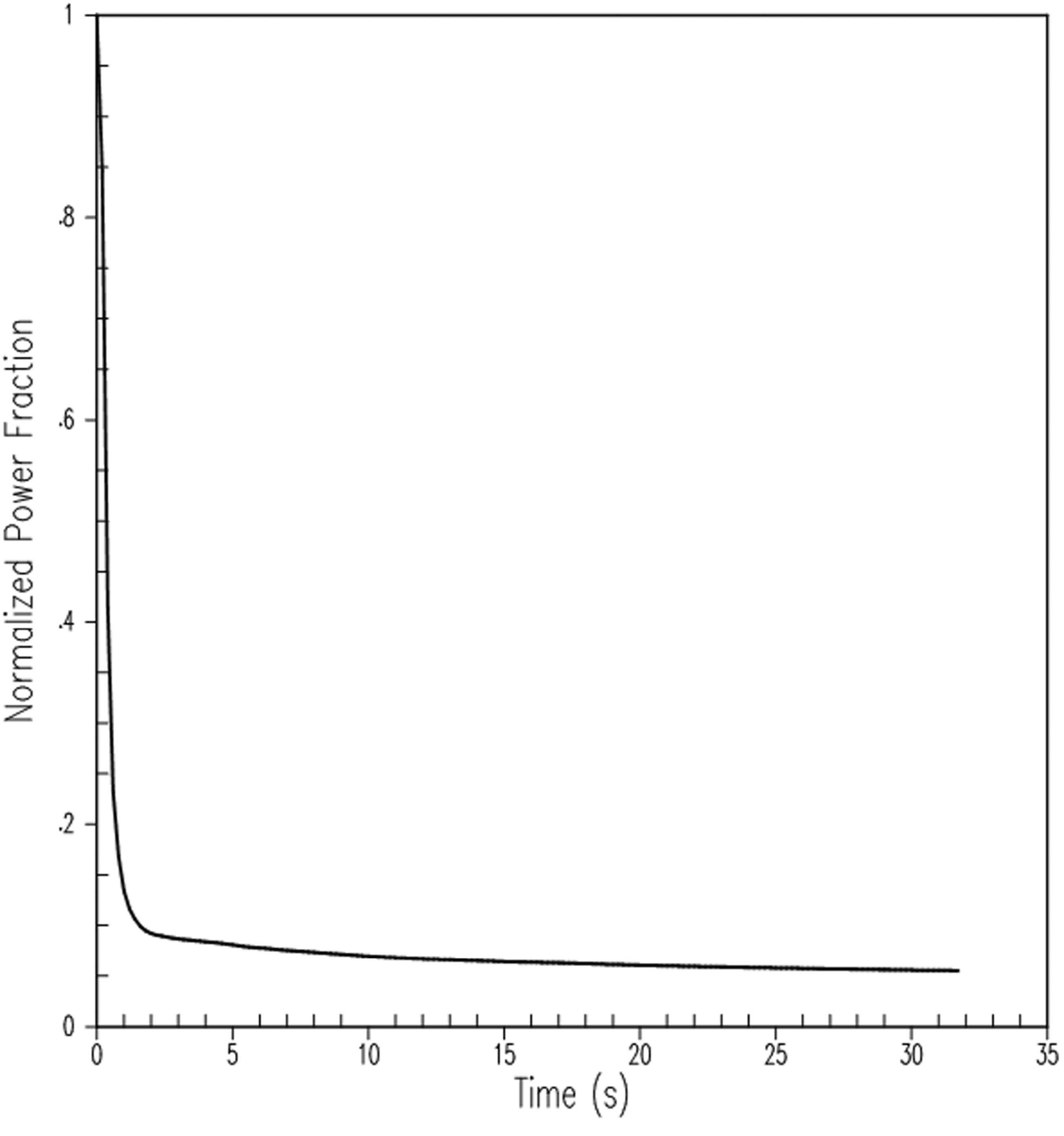
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

NORMALIZED CORE POWER DURING BLOWDOWN (C_D = 1.0, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–6 (SHEET 4 OF 9)



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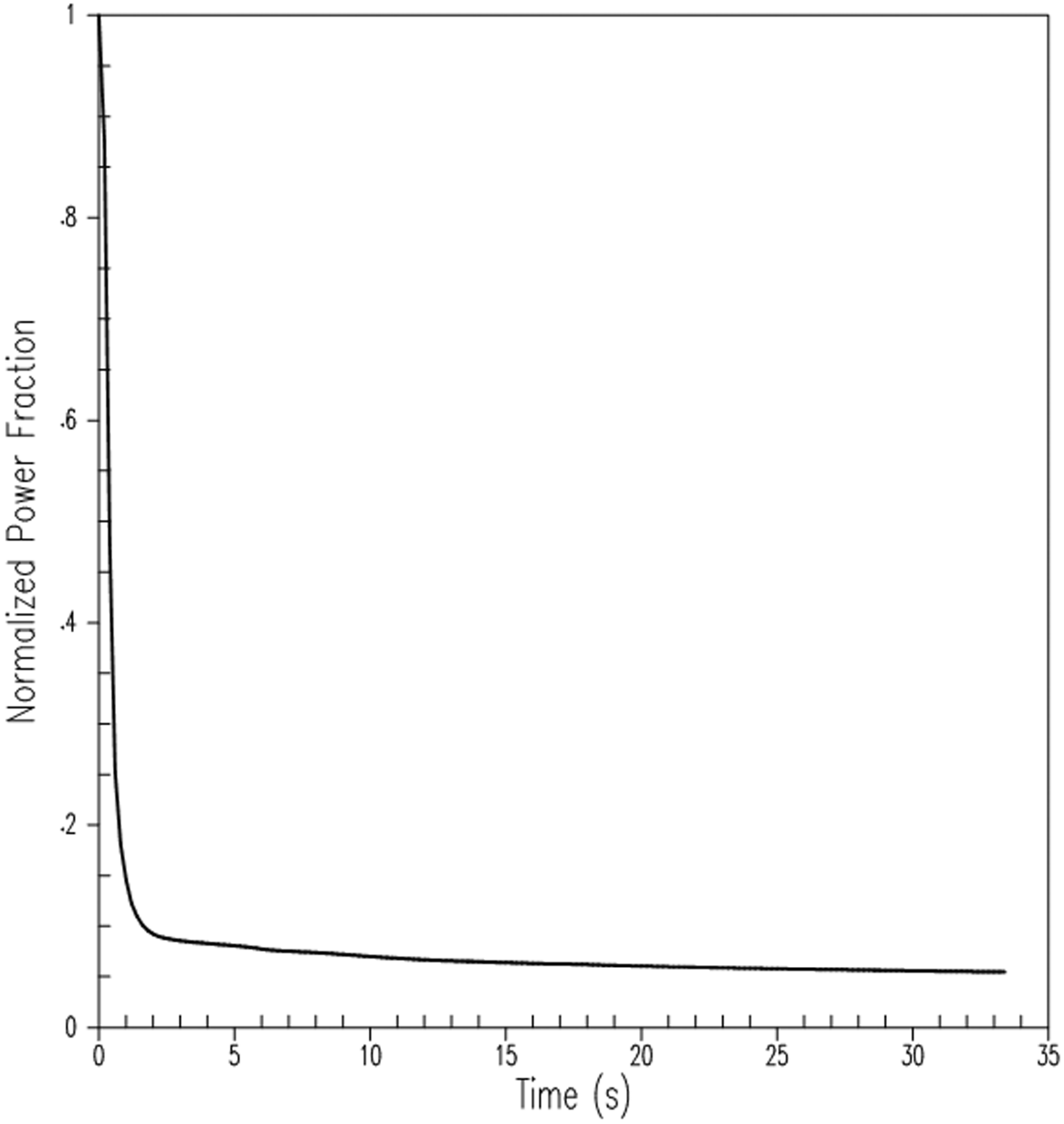
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

NORMALIZED CORE POWER DURING BLOWDOWN (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–6 (SHEET 5 OF 9)



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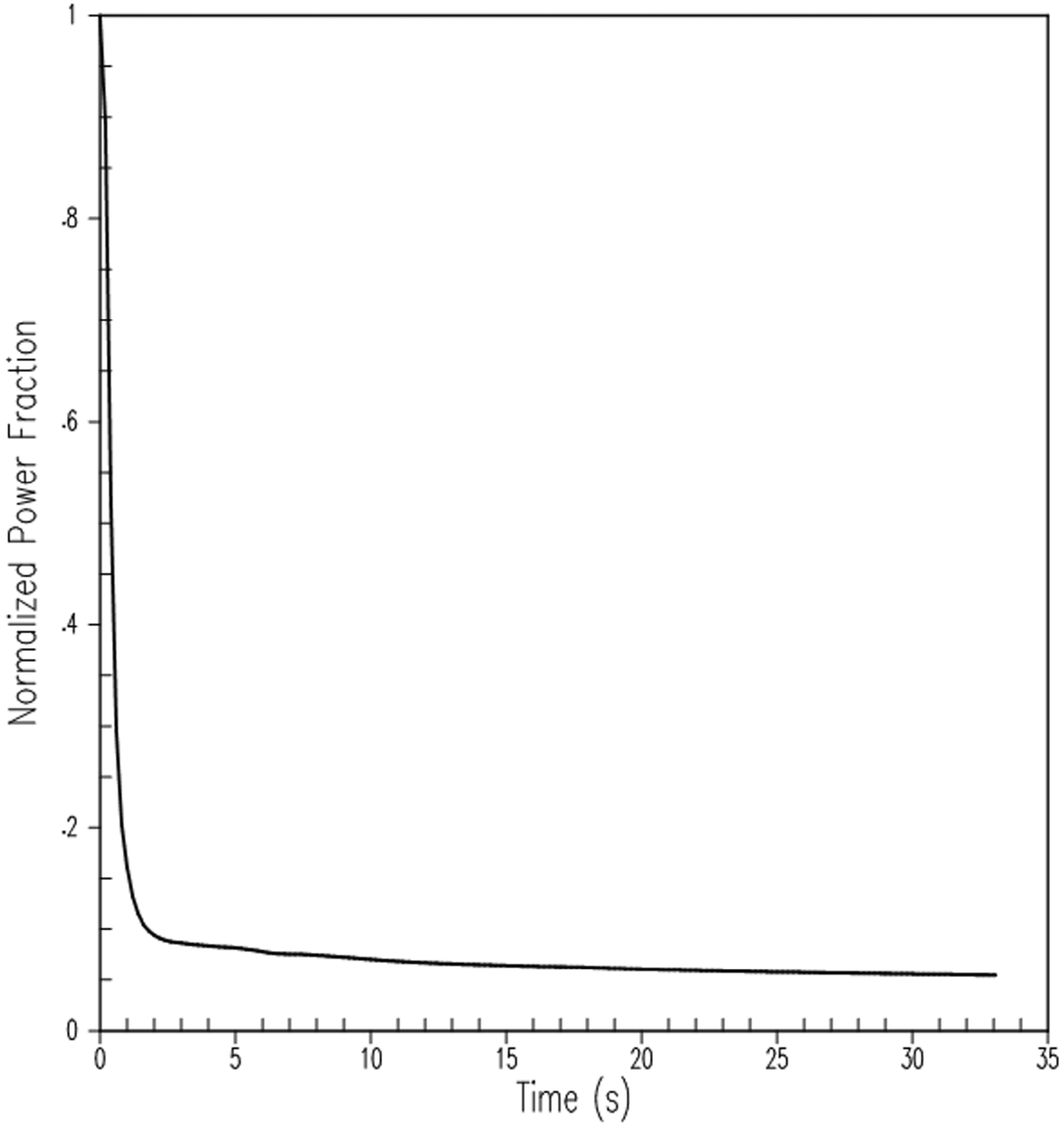
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

NORMALIZED CORE POWER DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MAX SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–6 (SHEET 6 OF 9)



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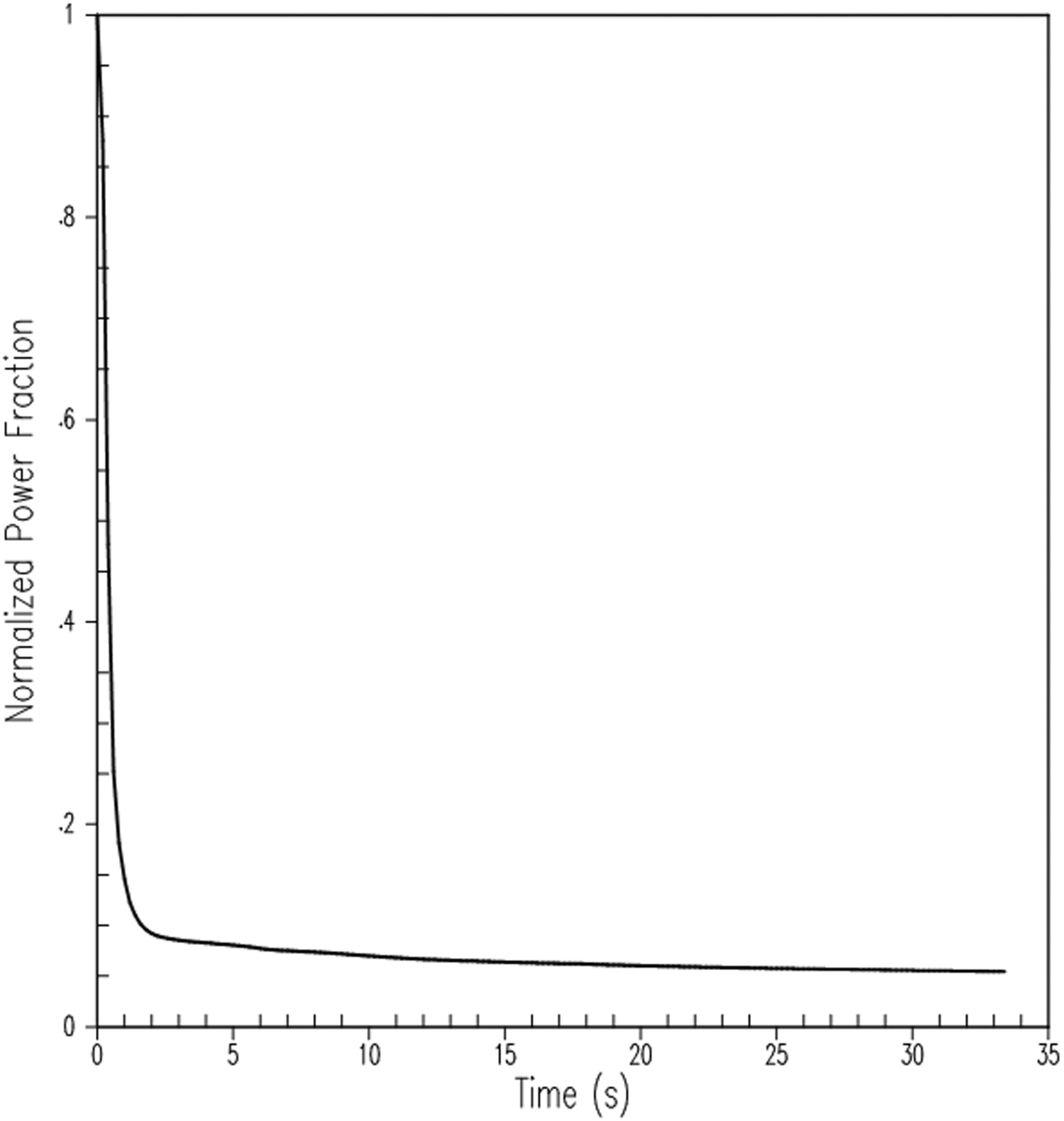
UNIT 1 AND UNIT 2

NORMALIZED CORE POWER DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MIN SI, 8.5 ft POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–6 (SHEET 7 OF 9)



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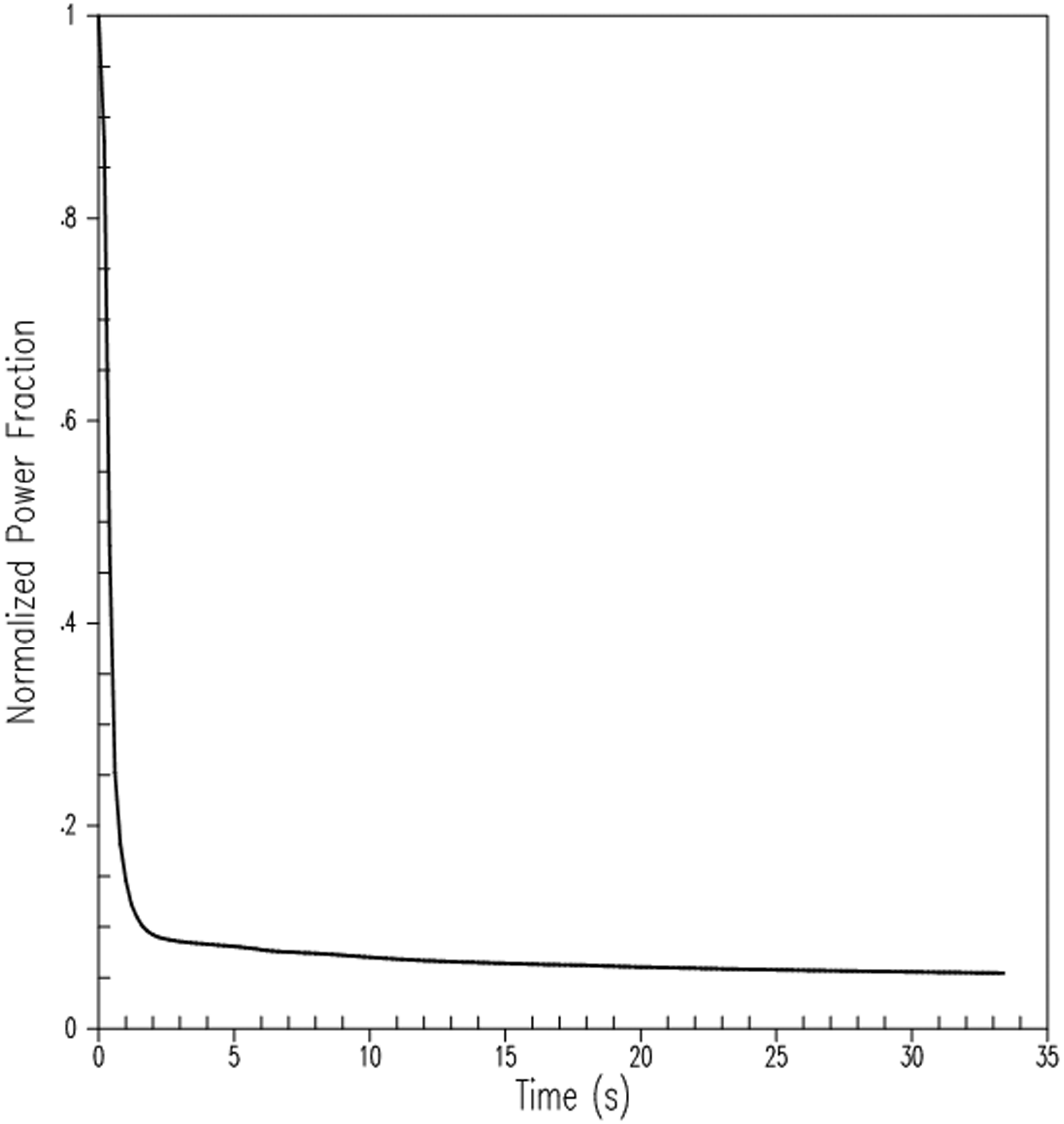
UNIT 1 AND UNIT 2

NORMALIZED CORE POWER DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–6 (SHEET 8 OF 9)



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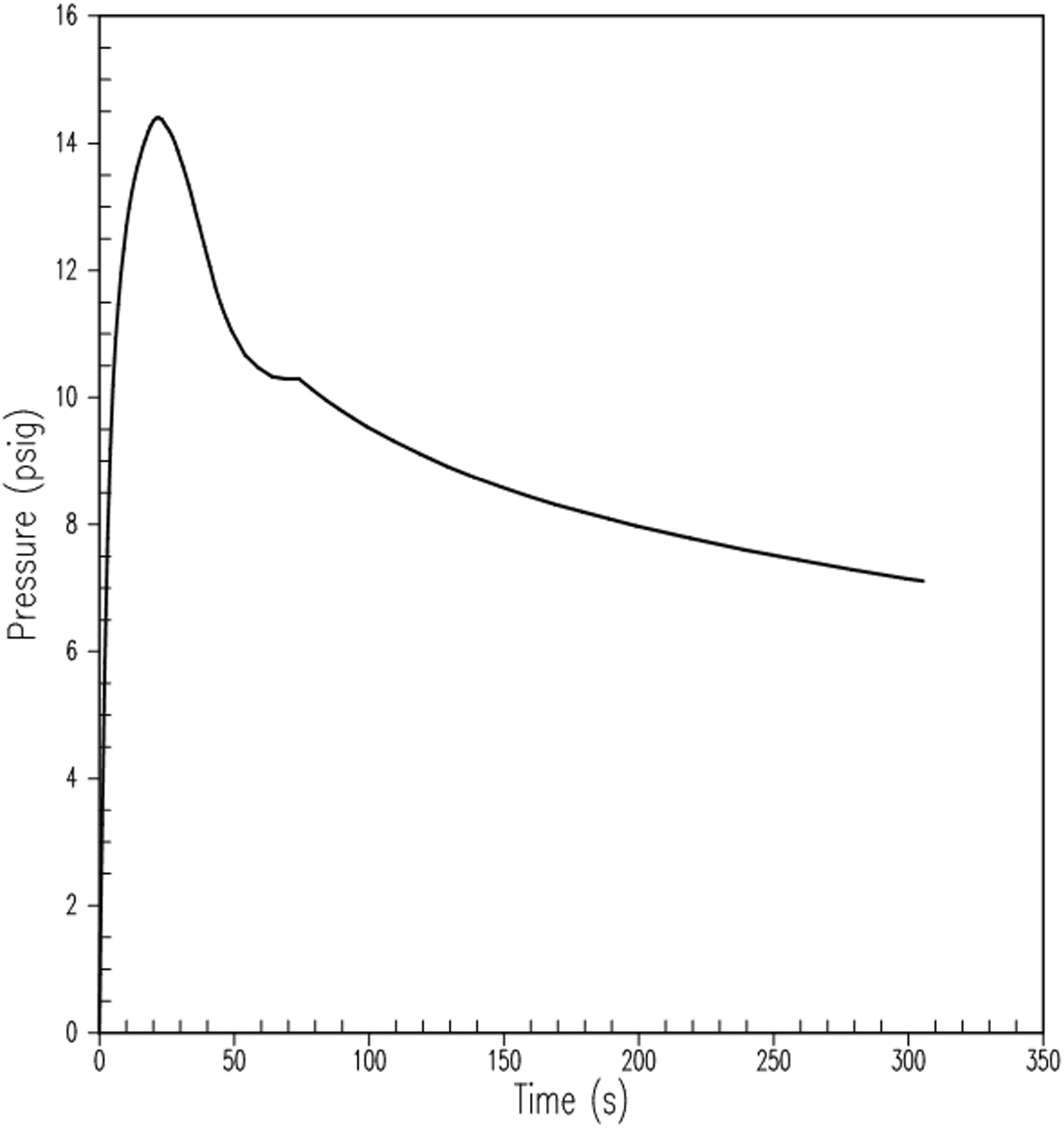
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

NORMALIZED CORE POWER DURING BLOWDOWN (CD = 0.6, LOW TAVG, MIN SI, COSINE POWER SHAPE, 156-IFBA)

FIGURE 15.6.5–6 (SHEET 9 OF 9)



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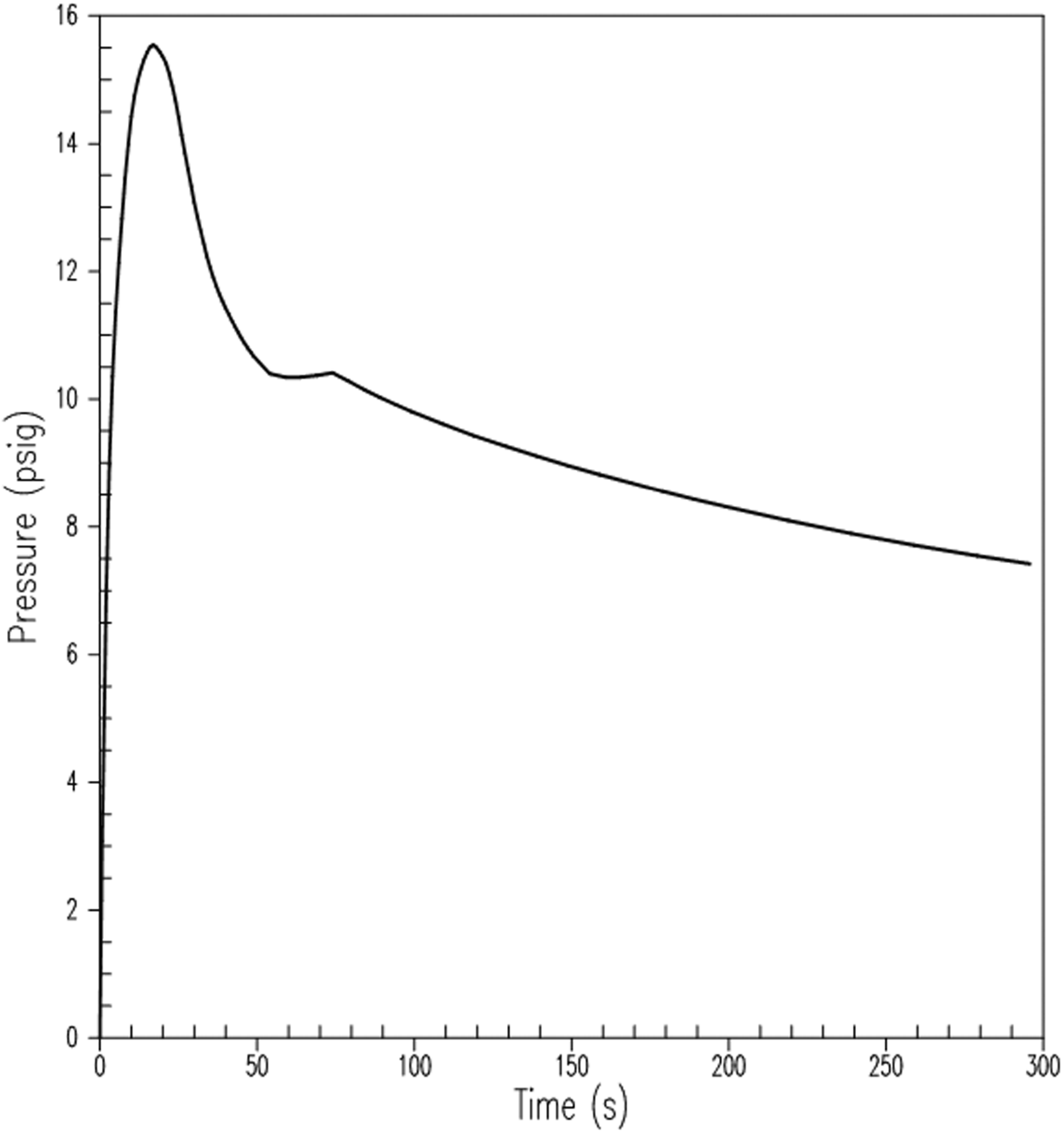
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTAINMENT PRESSURE
(C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–7 (SHEET 1 OF 9)



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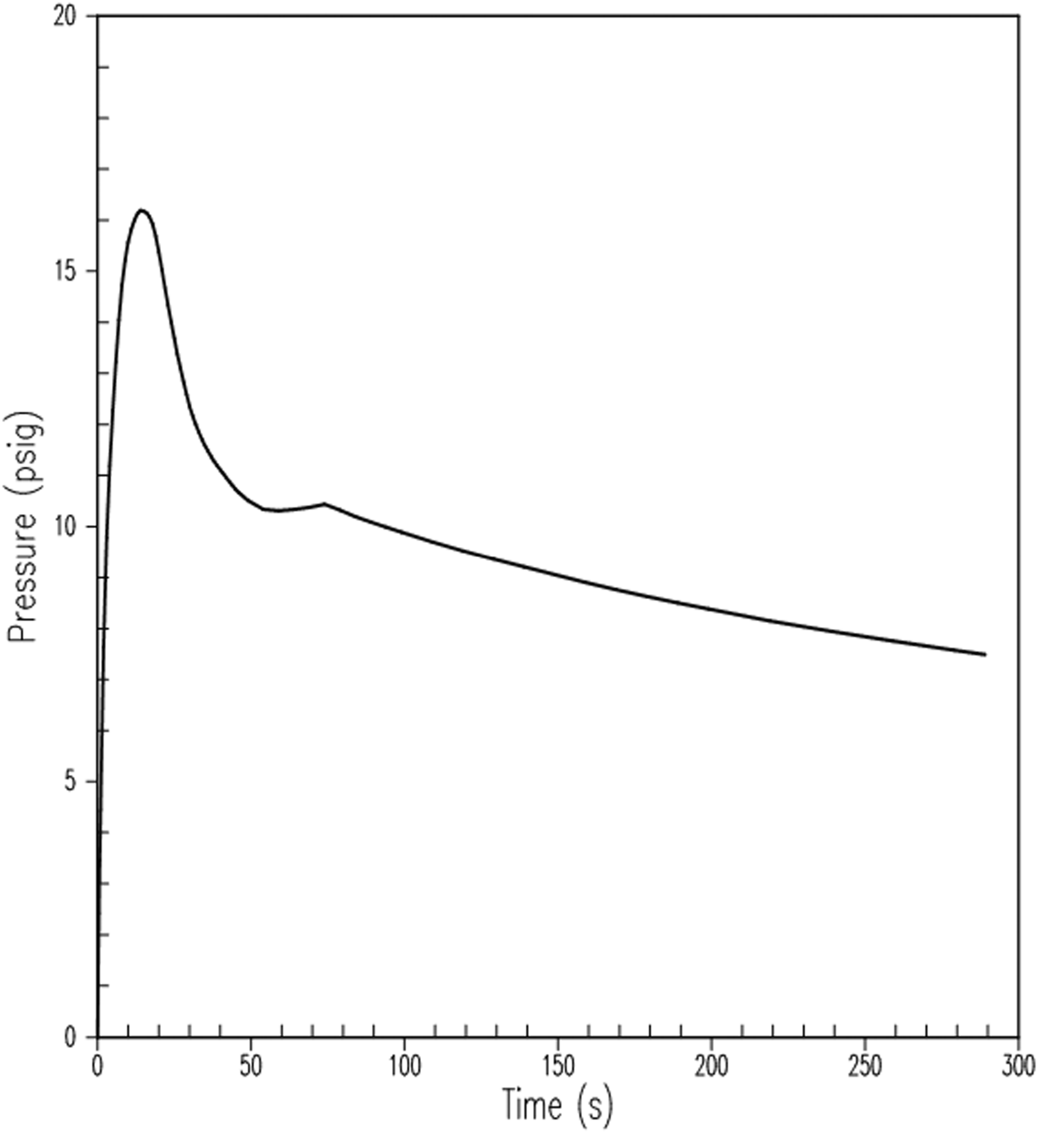
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTAINMENT PRESSURE
(C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–7 (SHEET 2 OF 9)



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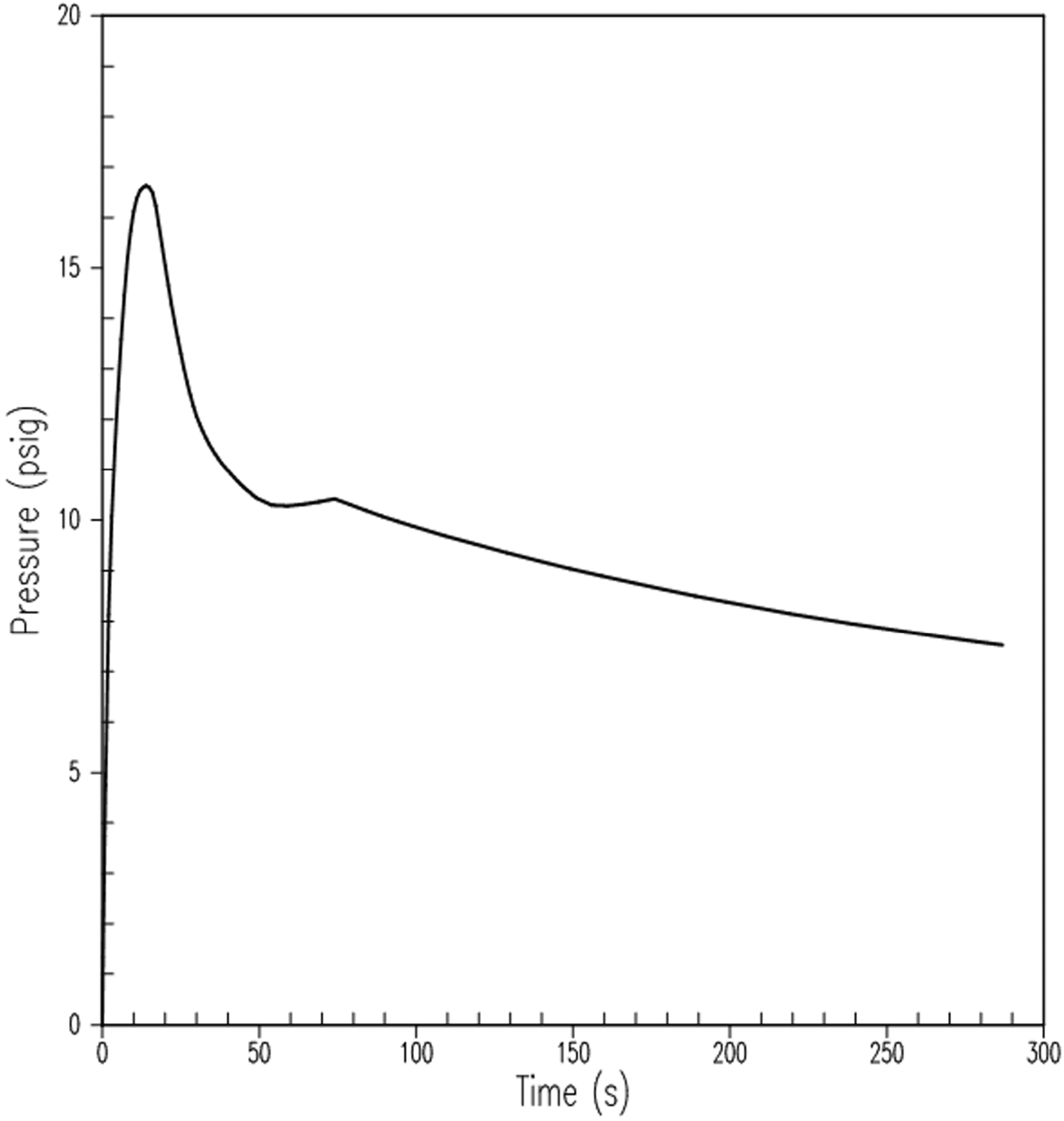
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTAINMENT PRESSURE
(C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–7 (SHEET 3 OF 9)



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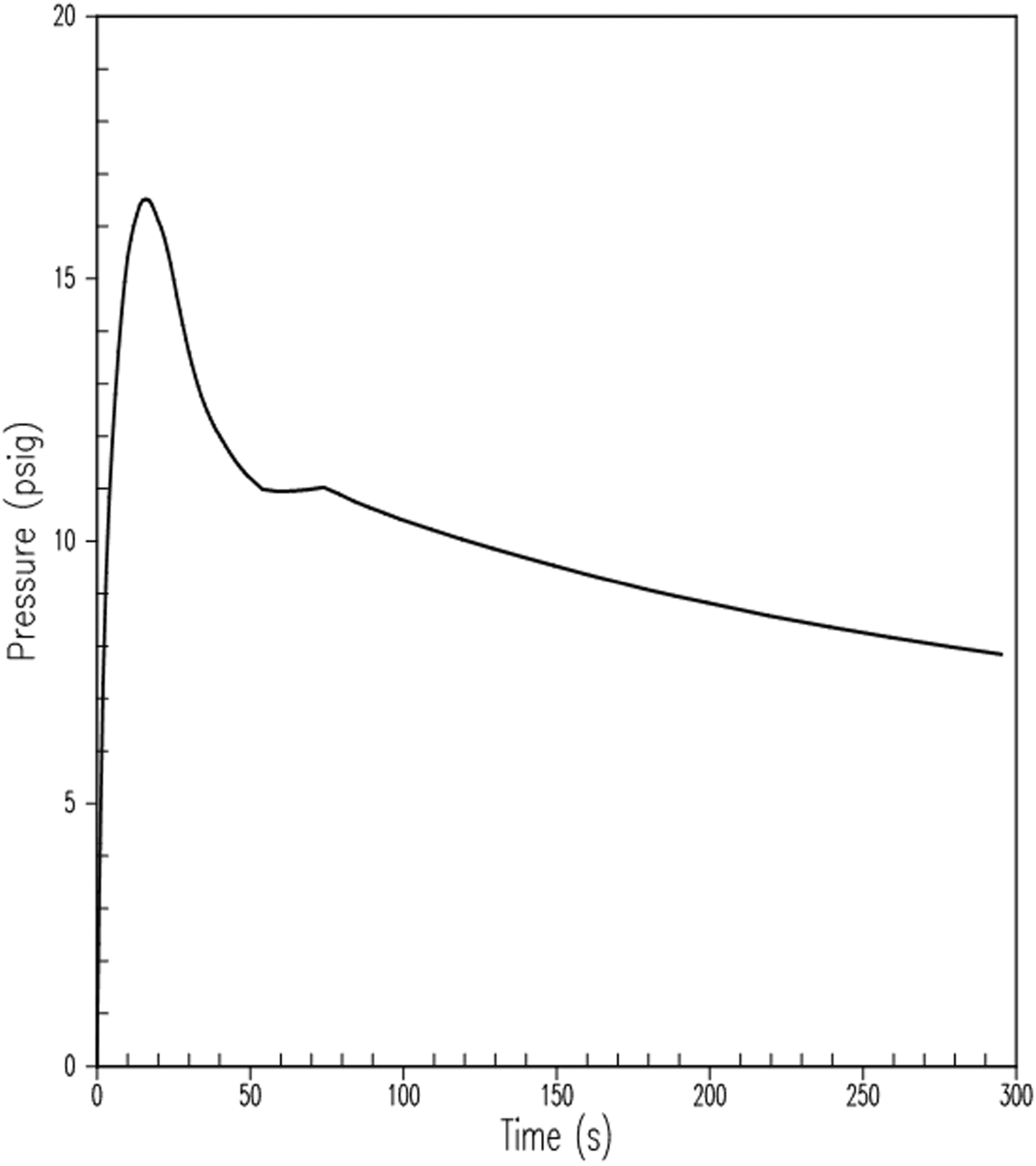
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTAINMENT PRESSURE
(C_D = 1.0, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–7 (SHEET 4 OF 9)



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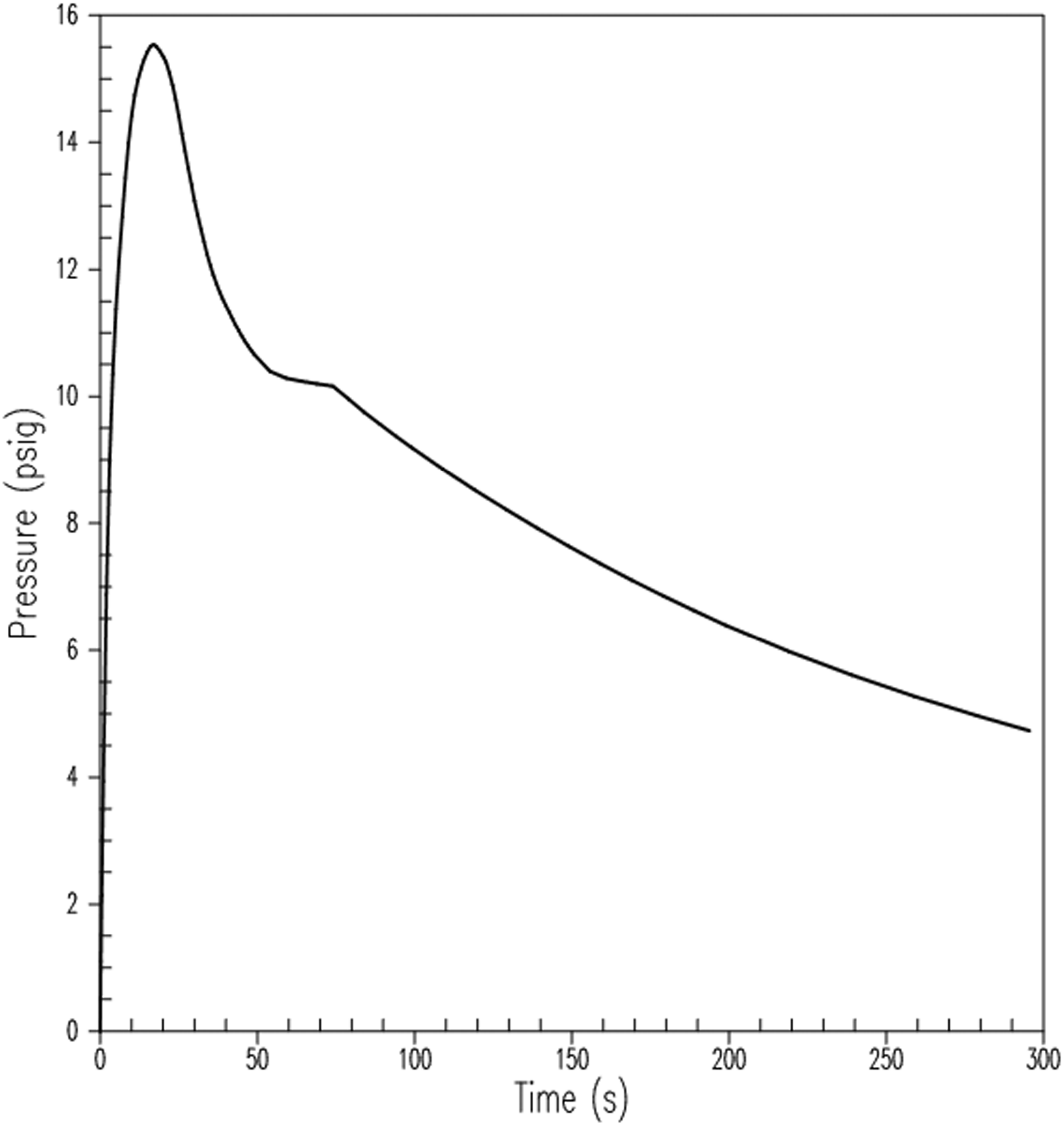
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTAINMENT PRESSURE
(C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–7 (SHEET 5 OF 9)



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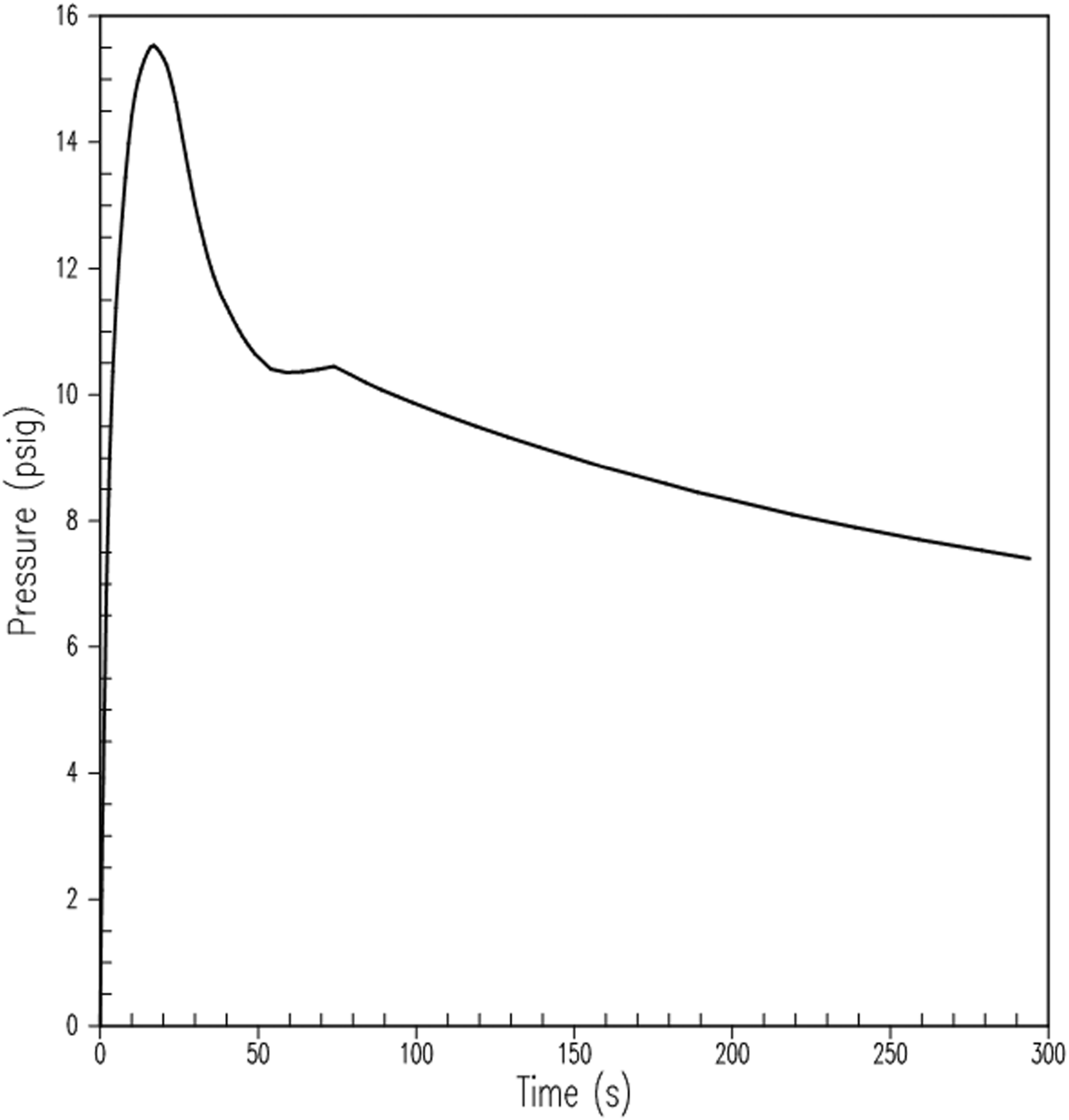
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTAINMENT PRESSURE
(C_D = 0.6, LOW T_{AVG}, MAX SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–7 (SHEET 6 OF 9)



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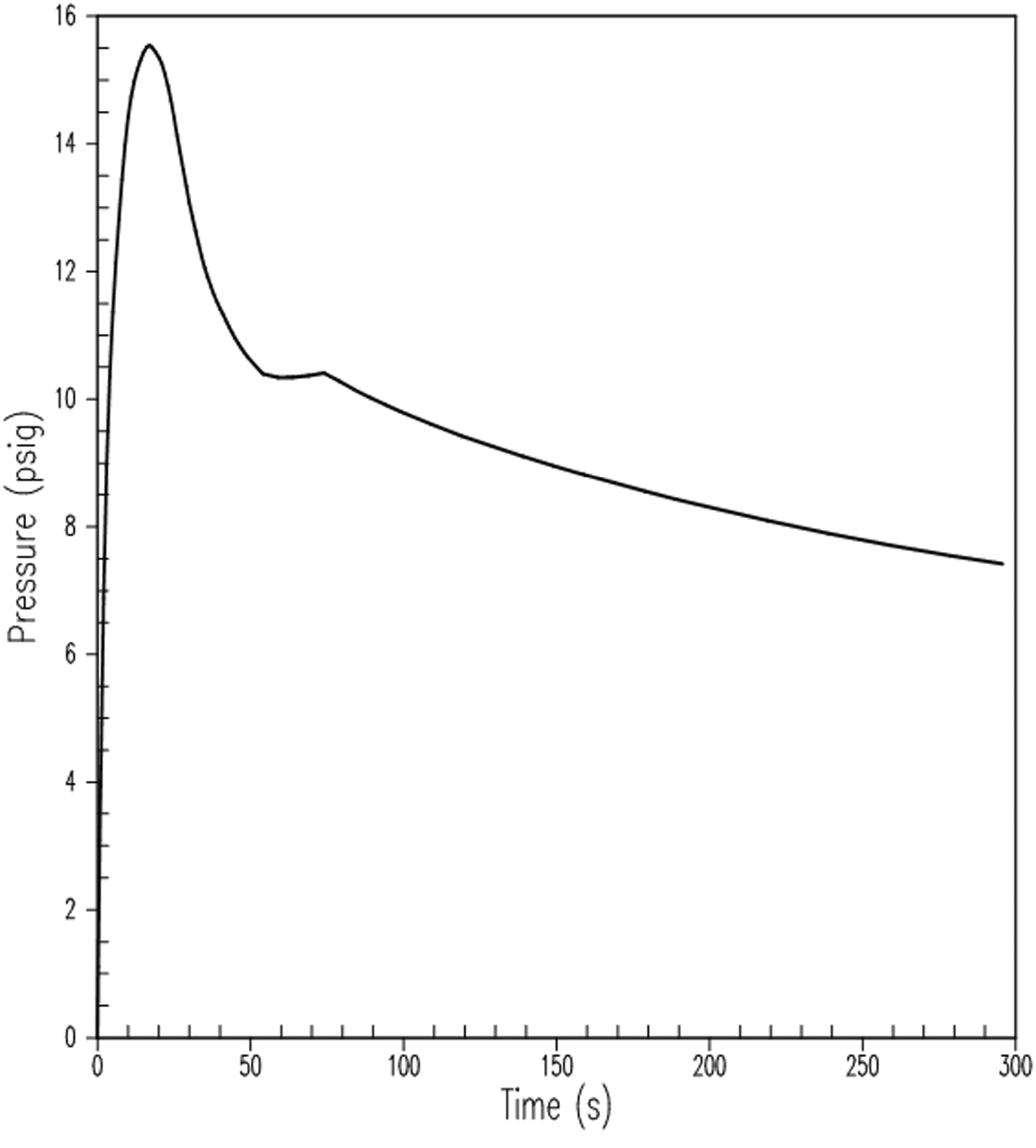
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTAINMENT PRESSURE
(C_D = 0.6, LOW T_{AVG}, MIN SI, 8.5 FT POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–7 (SHEET 7 OF 9)



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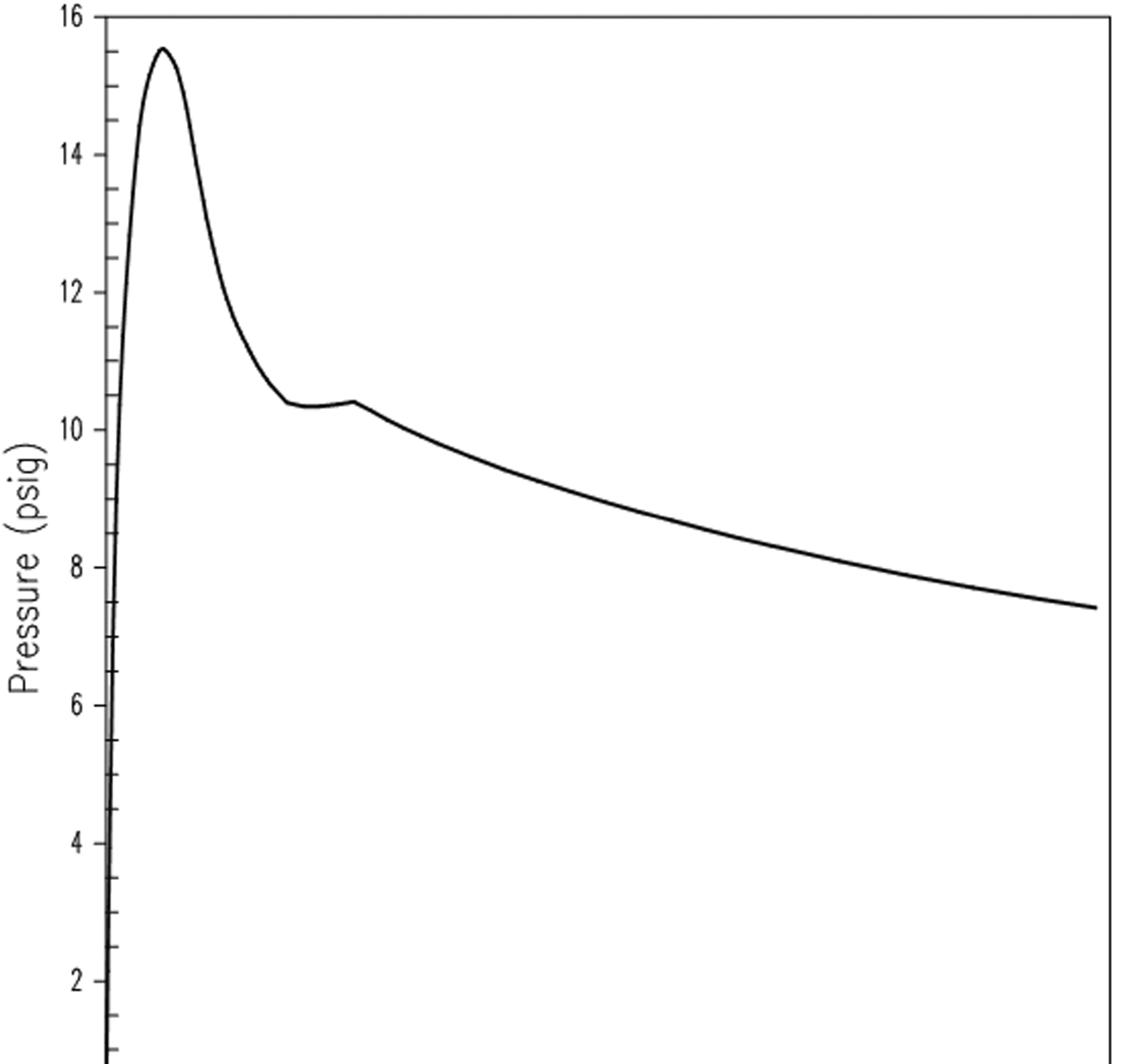
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTAINMENT PRESSURE
(C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–7 (SHEET 8 OF 9)



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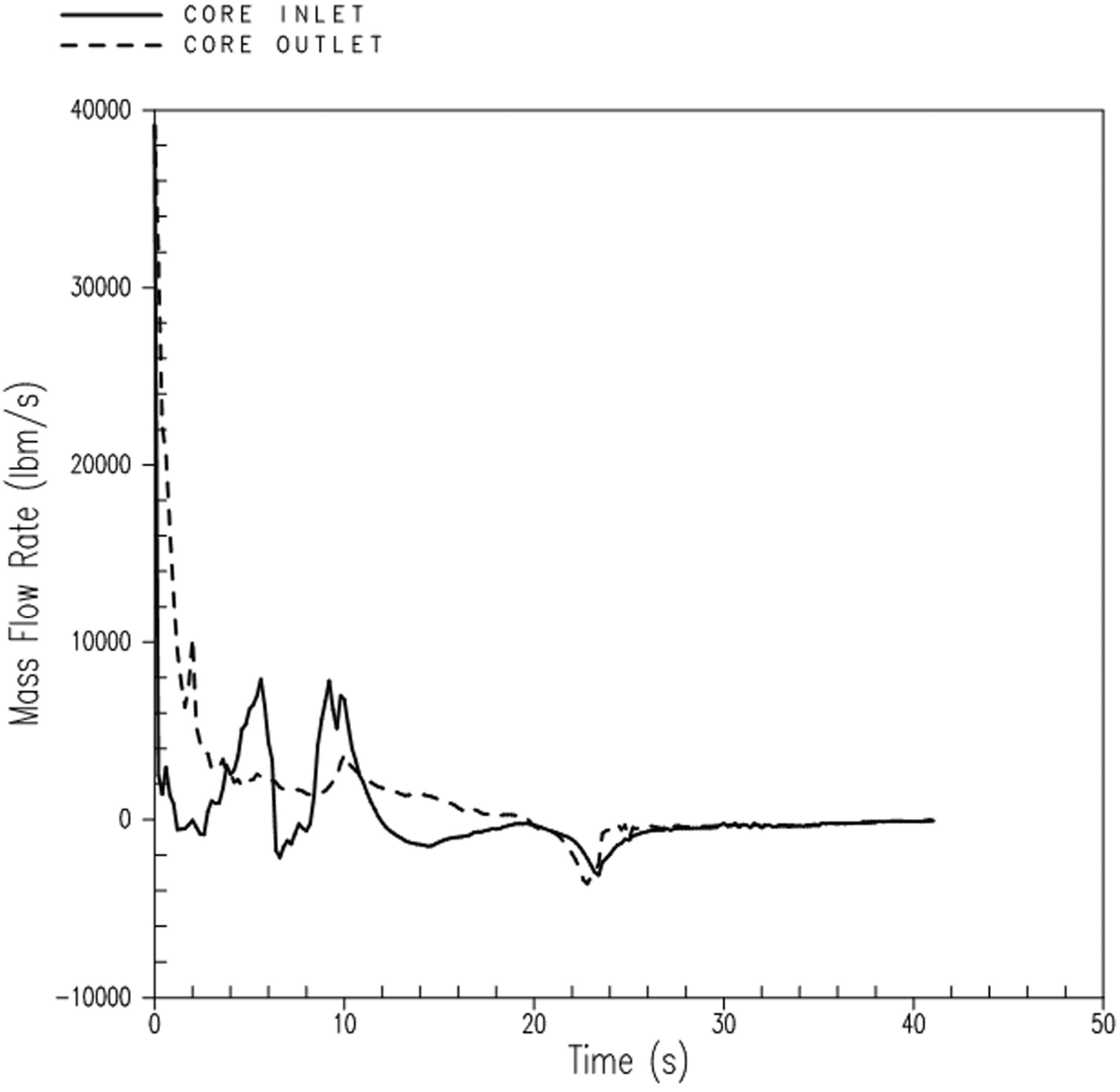
SOUTHERN COMPANY *Energy to Serve Your World®*	**VOGTLE** **ELECTRIC GENERATING PLANT** **UNIT 1 AND UNIT 2**	CONTAINMENT PRESSURE (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 156-IFBA) FIGURE 15.6.5–7 (SHEET 9 OF 9)



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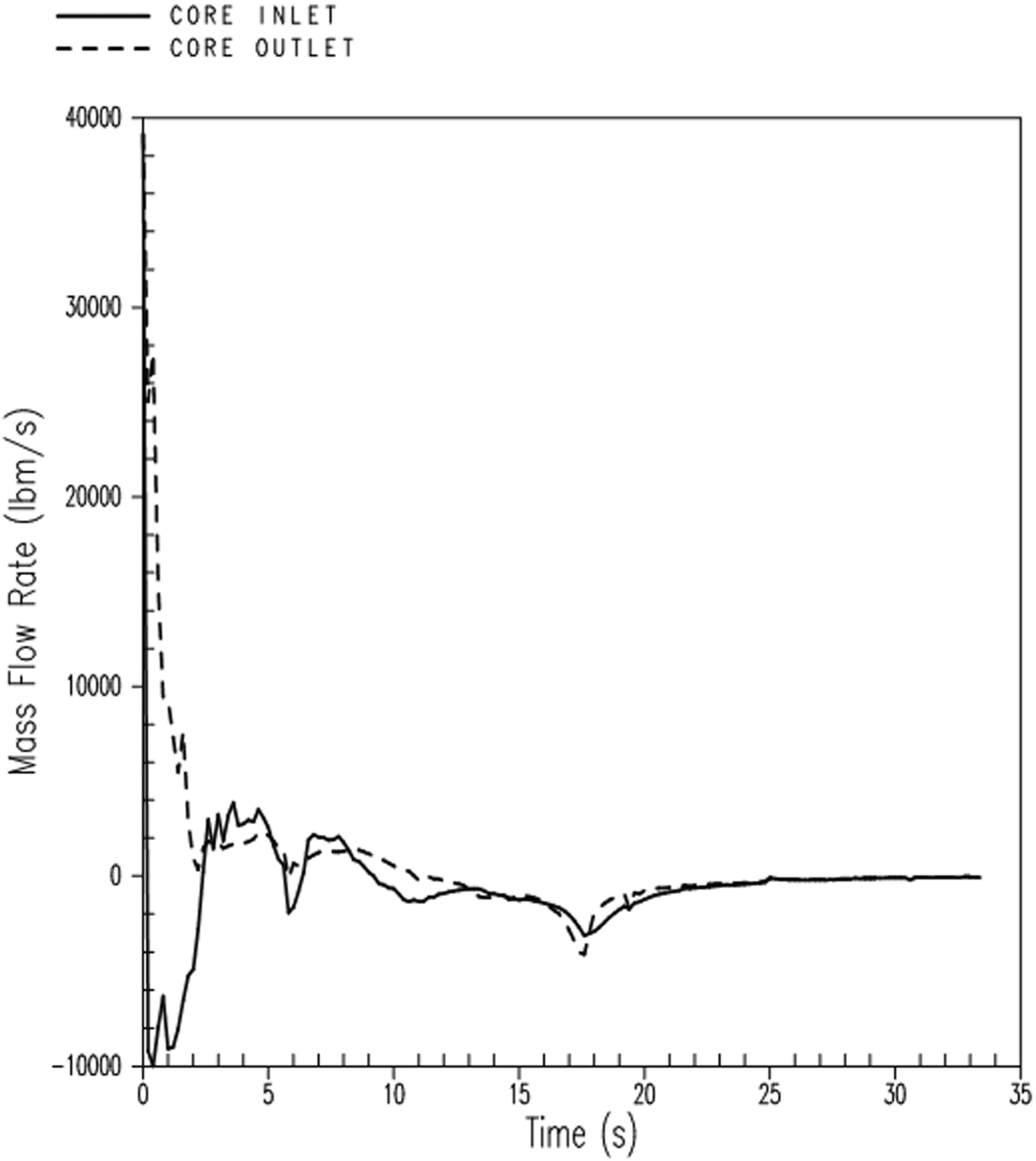
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET AND OUTLET MASS FLOW RATE DURING BLOWDOWN (CD = 0.4, LOW TAVG, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–8 (SHEET 1 OF 9)



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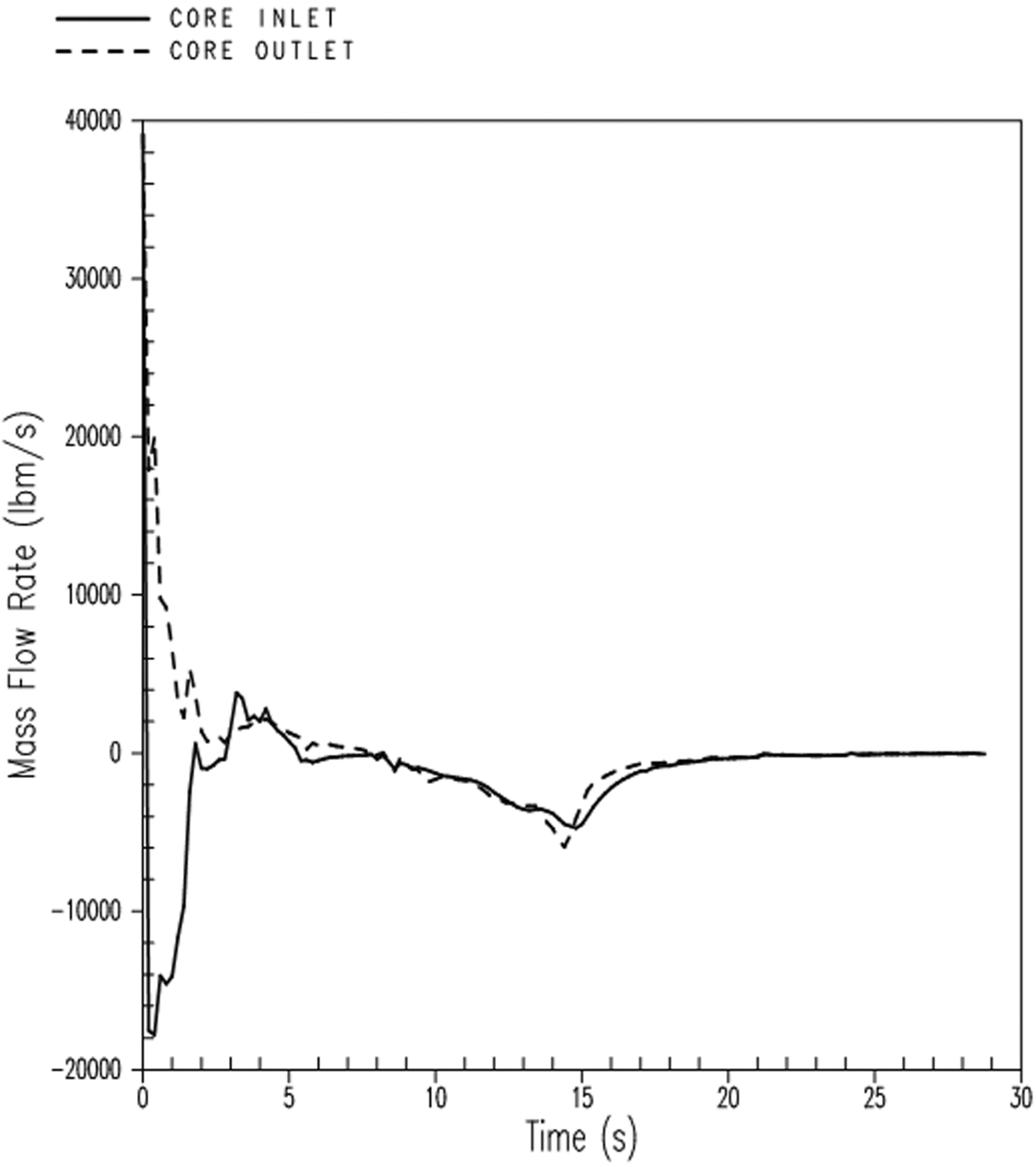
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET AND OUTLET MASS FLOW RATE DURING BLOWDOWN (CD = 0.6, LOW TAVG, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–8 (SHEET 2 OF 9)



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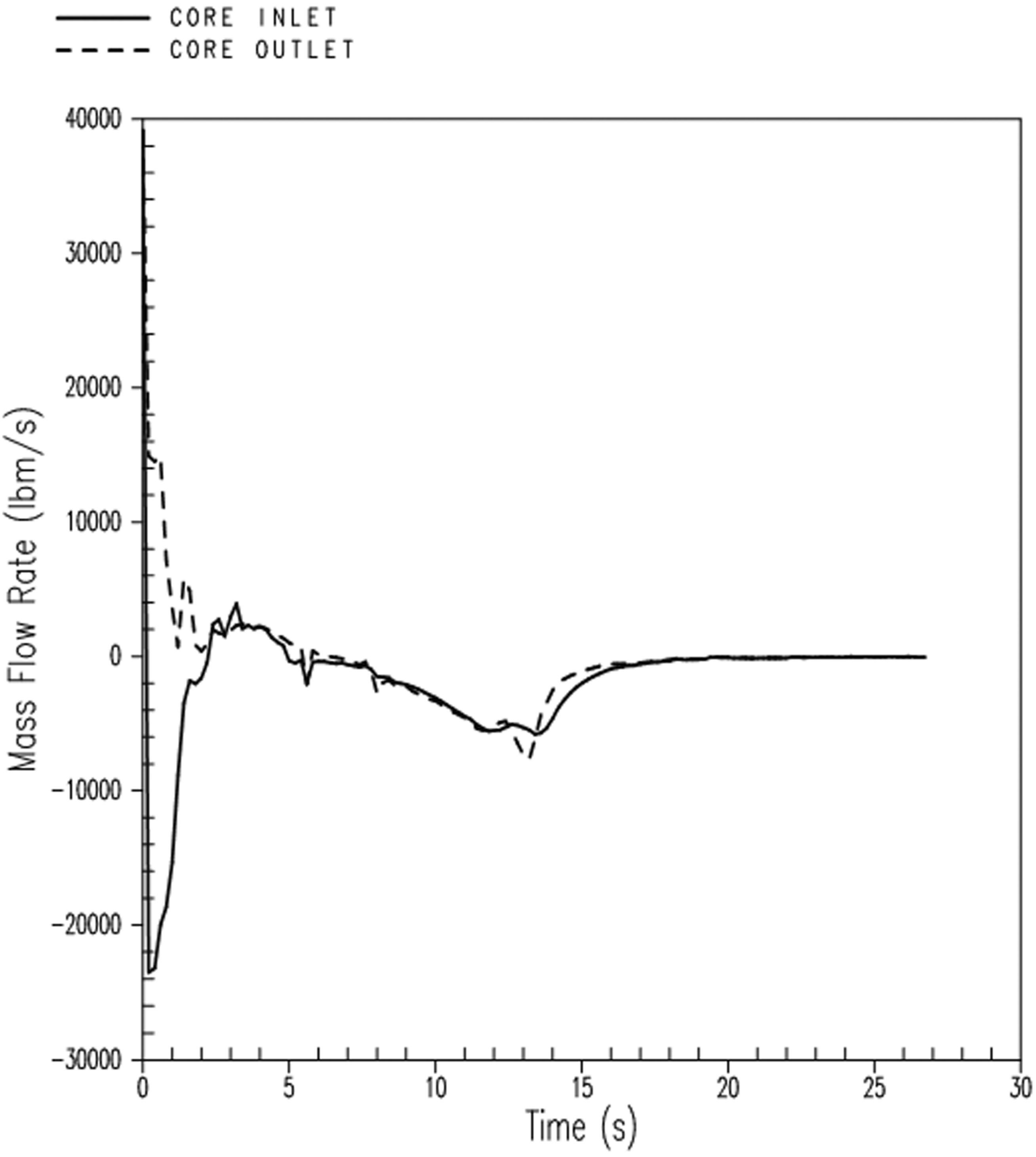
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET AND OUTLET MASS FLOW RATE DURING BLOWDOWN
(C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–8 (SHEET 3 OF 9)



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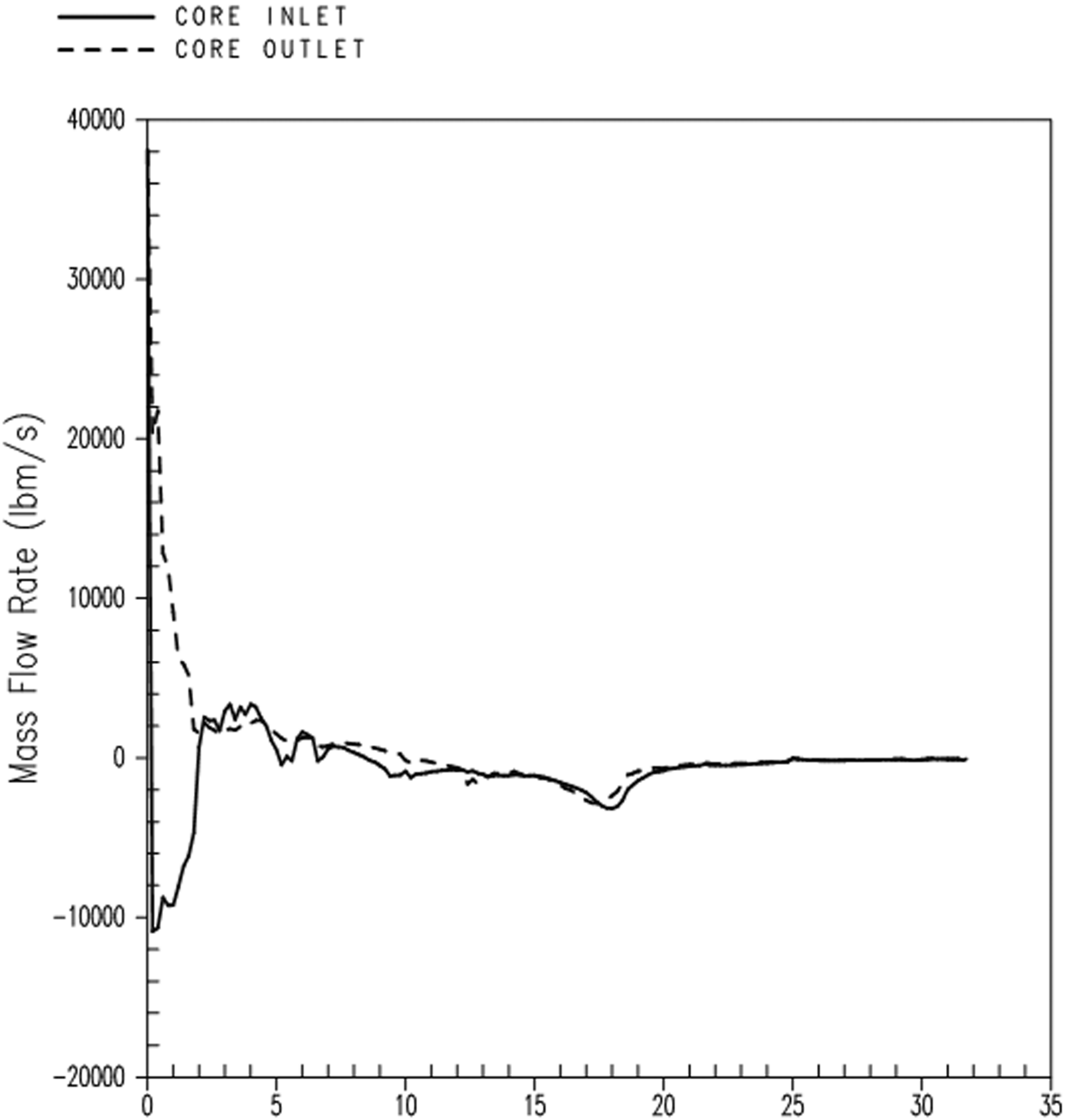
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET AND OUTLET MASS FLOW RATE DURING BLOWDOWN (C_D = 1.0, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–8 (SHEET 4 OF 9)



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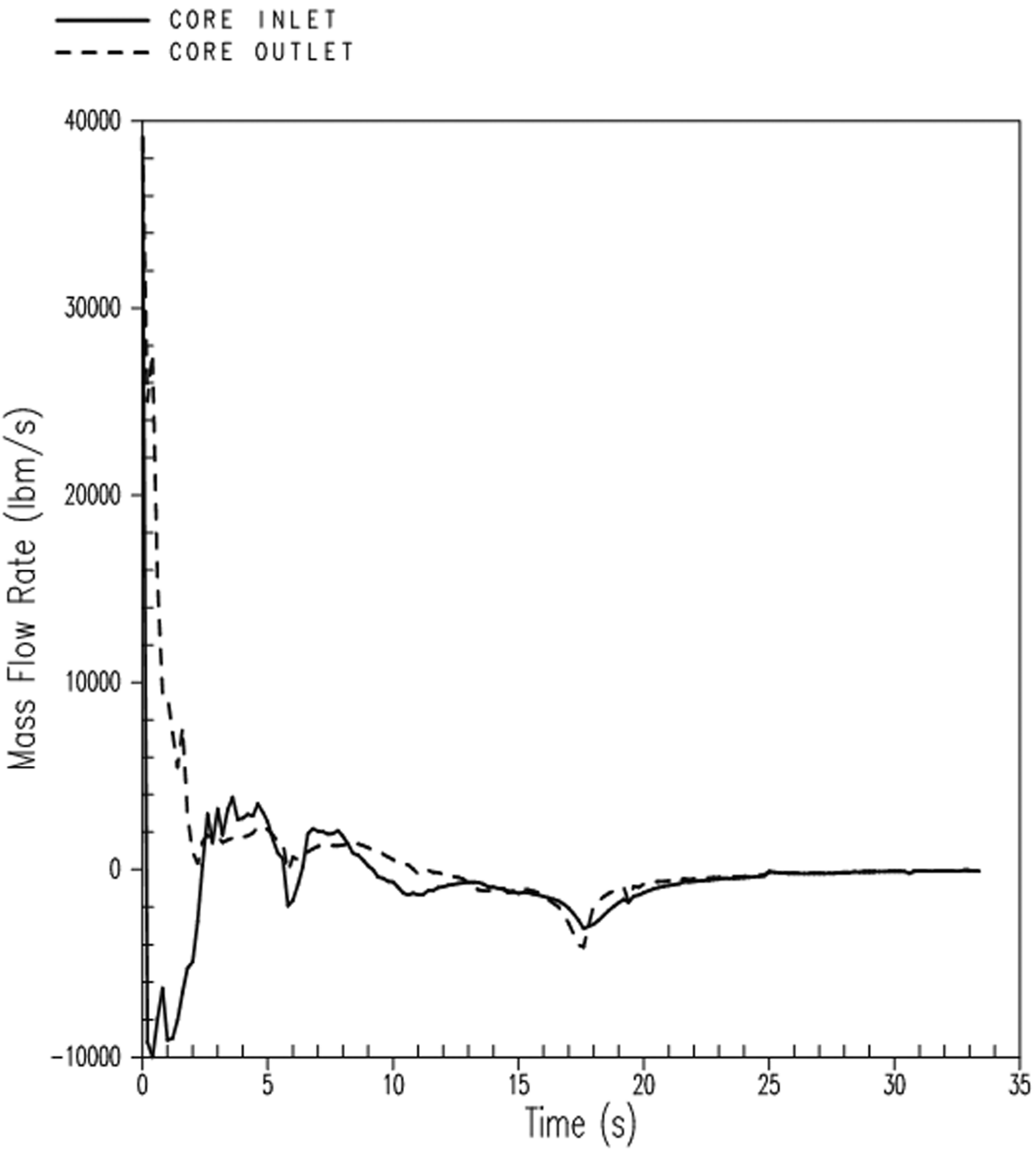
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET AND OUTLET MASS FLOW RATE DURING BLOWDOWN
(C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–8 (SHEET 5 OF 9)



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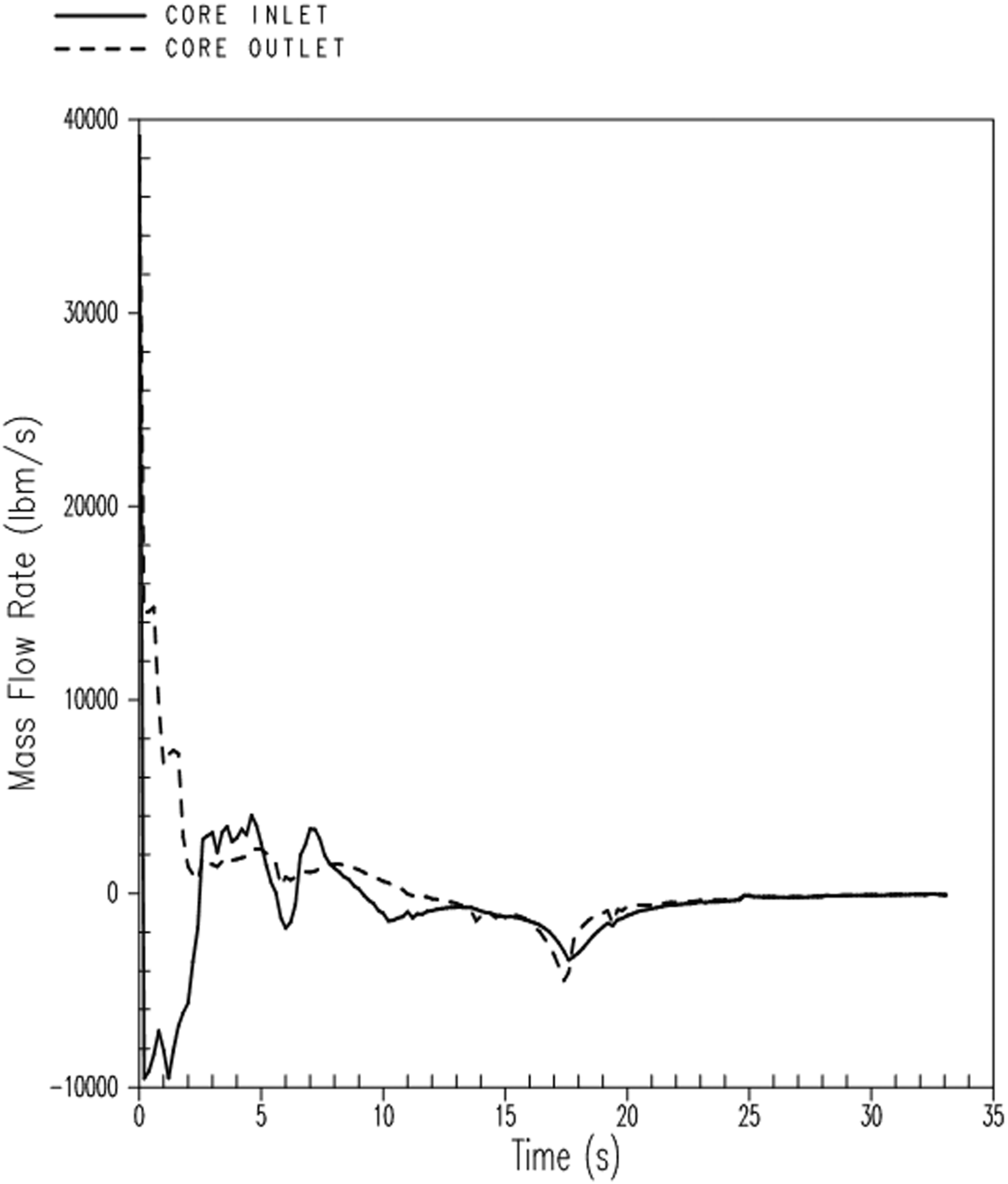
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET AND OUTLET MASS FLOW RATE DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MAX SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–8 (SHEET 6 OF 9)



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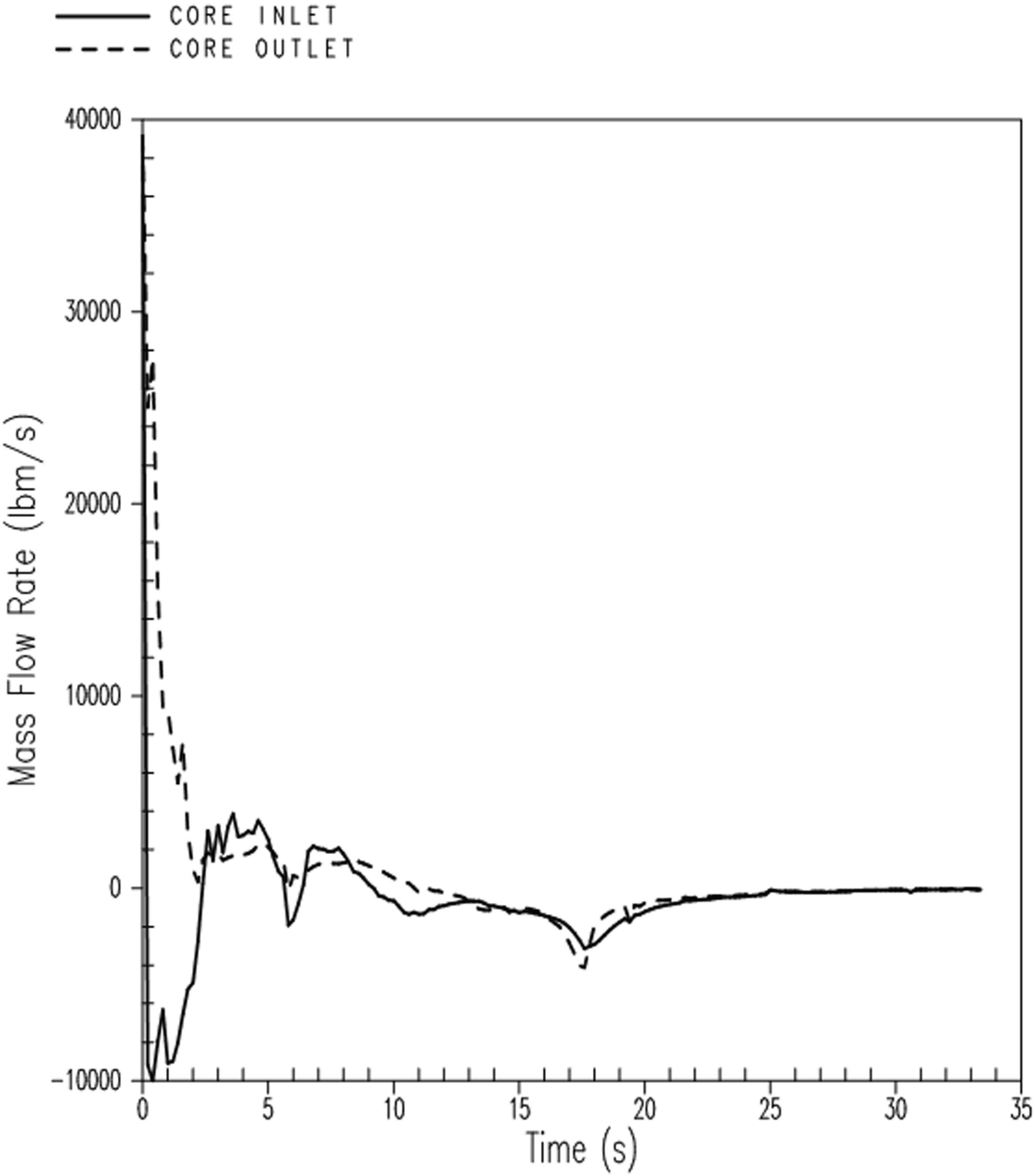
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET AND OUTLET MASS FLOW RATE DURING BLOWDOWN
(C_D = 0.6, LOW T_{AVG}, MIN SI, 8.5 FT POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–8 (SHEET 7 OF 9)



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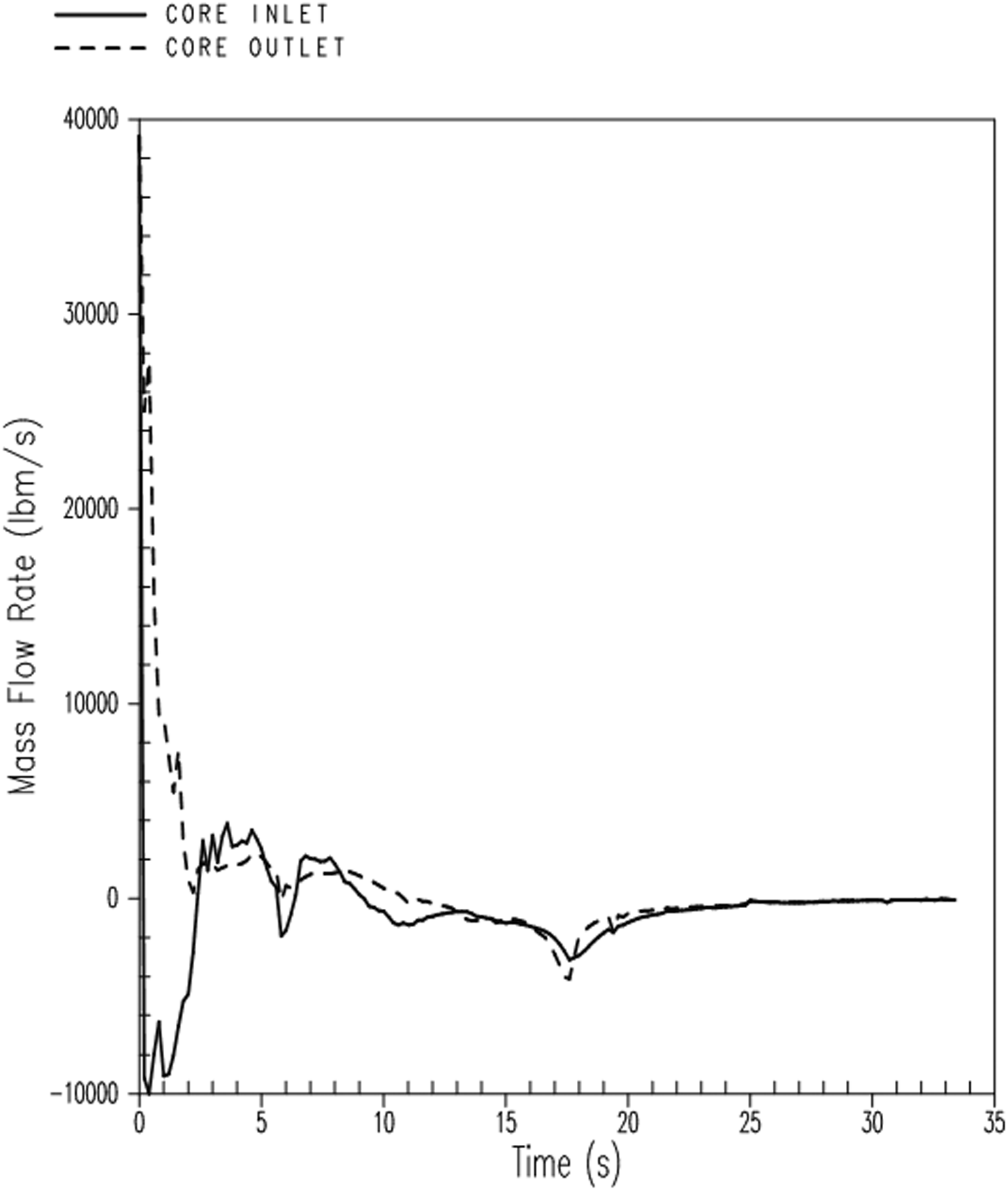
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET AND OUTLET MASS FLOW RATE DURING BLOWDOWN
(C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–8 (SHEET 8 OF 9)



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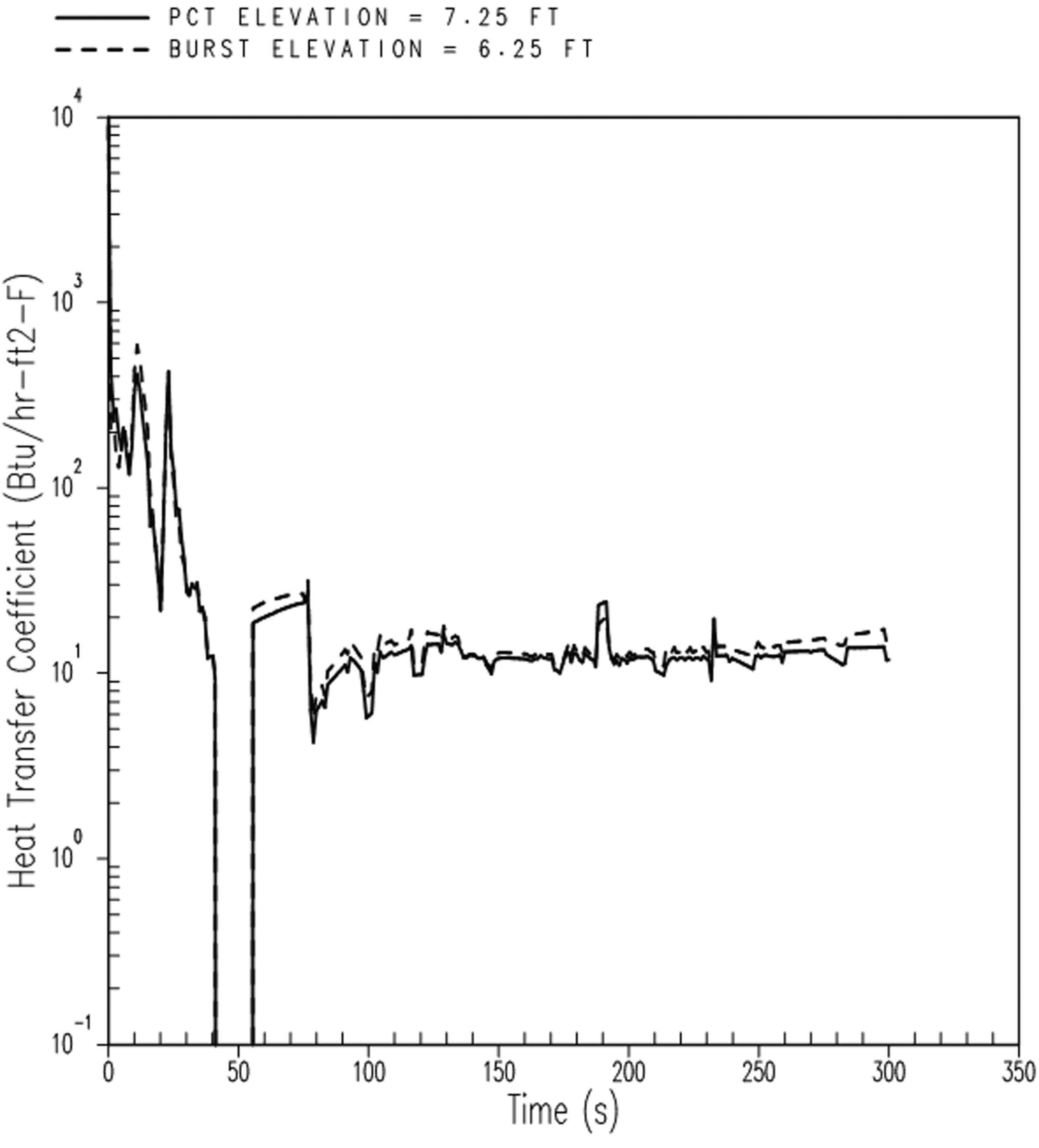
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE INLET AND OUTLET MASS FLOW RATE DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 156-IFBA)

FIGURE 15.6.5–8 (SHEET 9 OF 9)



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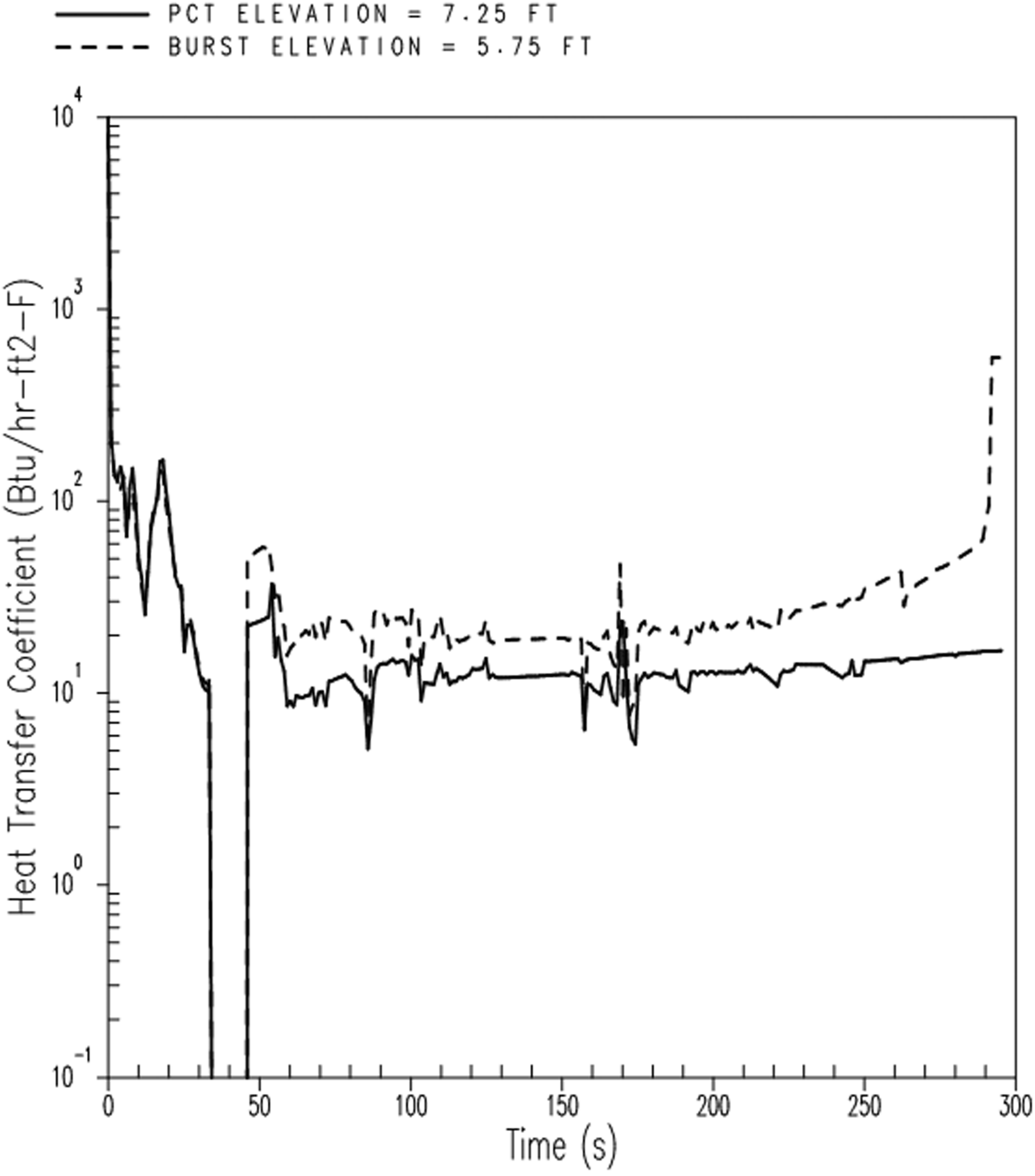
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CLADDING SURFACE HEAT TRANSFER COEFFICIENT AT PCT AND BURST ELEVATIONS (C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–9 (SHEET 1 OF 9)



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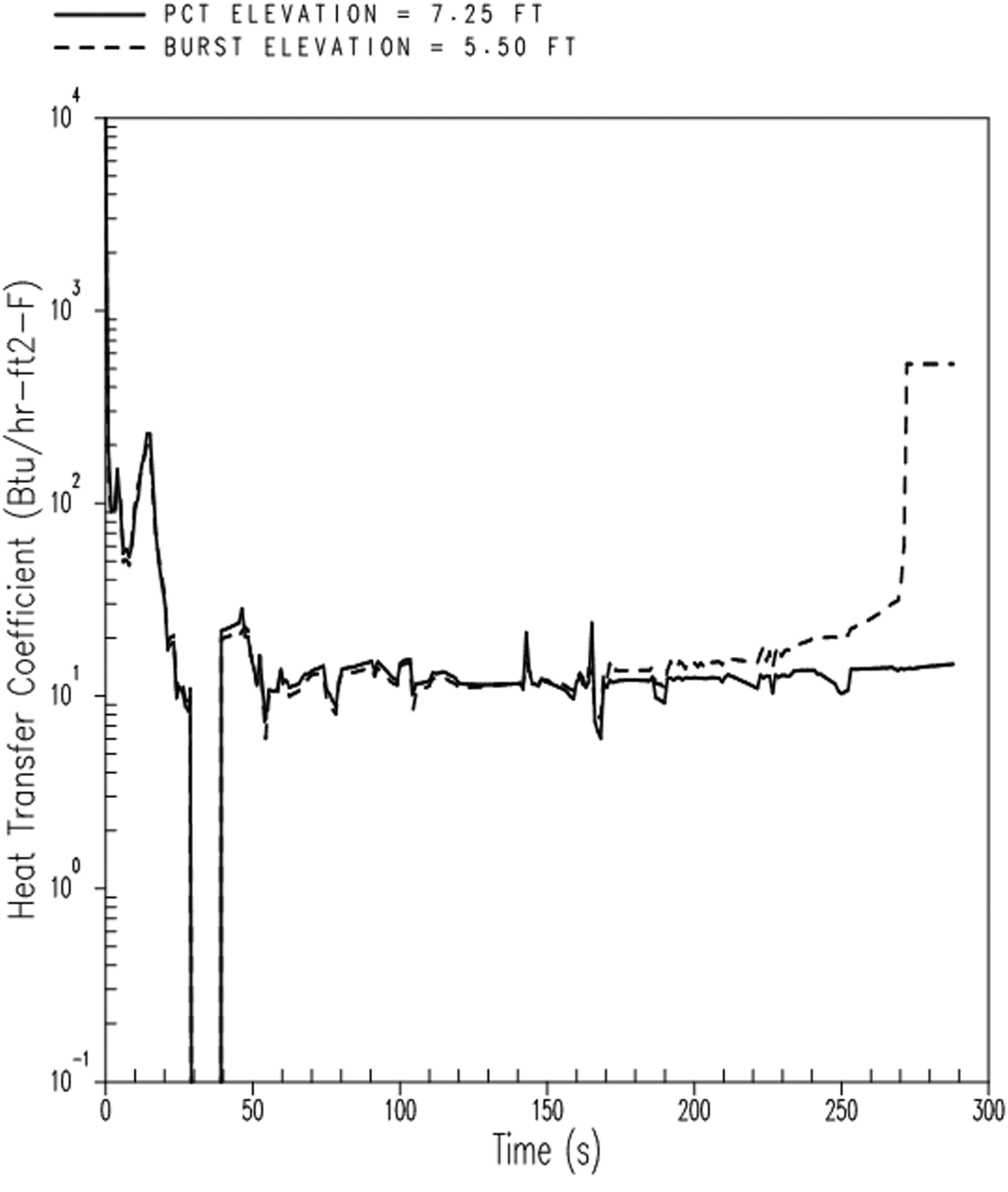
UNIT 1 AND UNIT 2

CLADDING SURFACE HEAT TRANSFER COEFFICIENT AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–9 (SHEET 2 OF 9)



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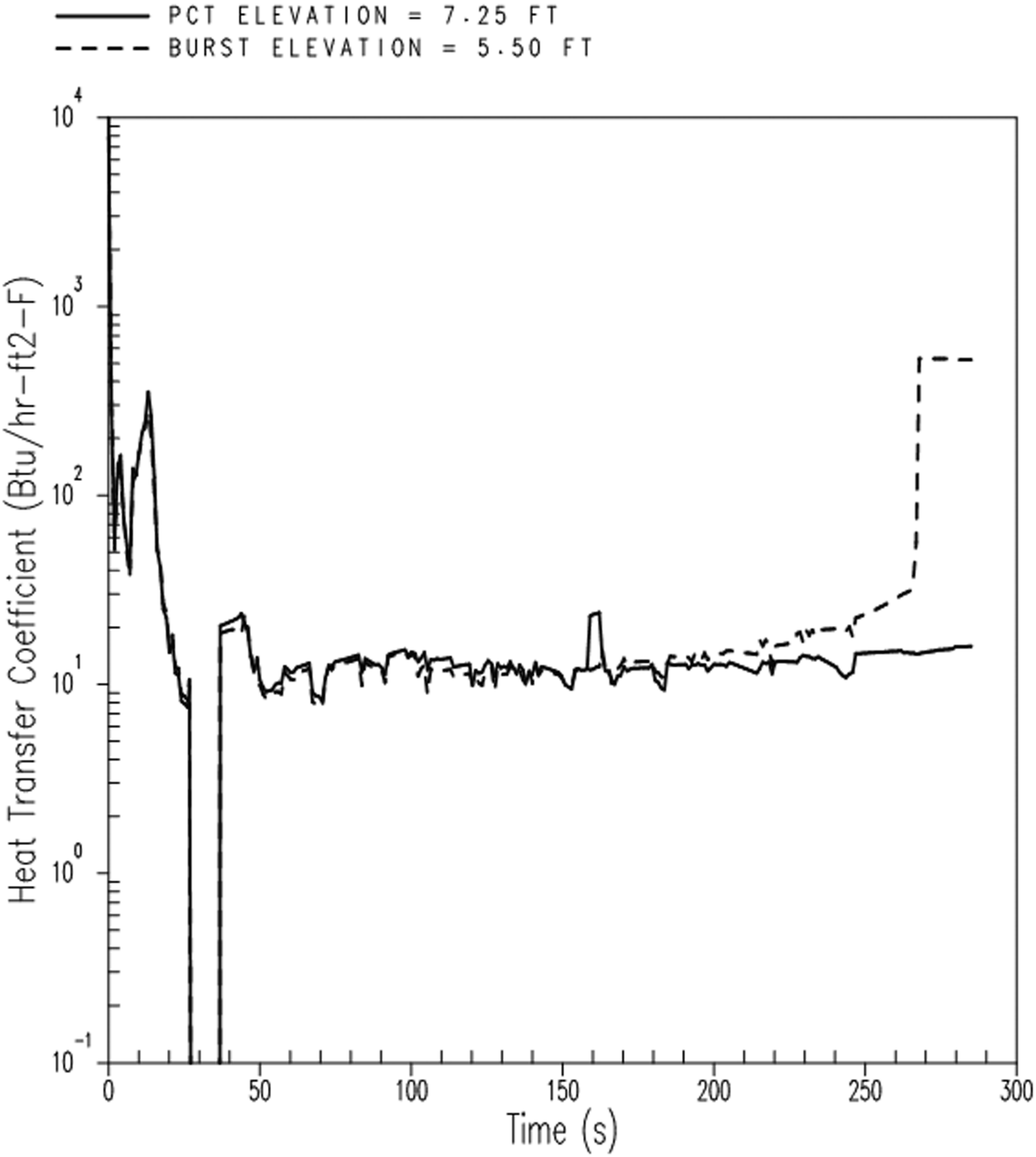
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CLADDING SURFACE HEAT TRANSFER COEFFICIENT AT PCT AND BURST ELEVATIONS (C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–9 (SHEET 3 OF 9)



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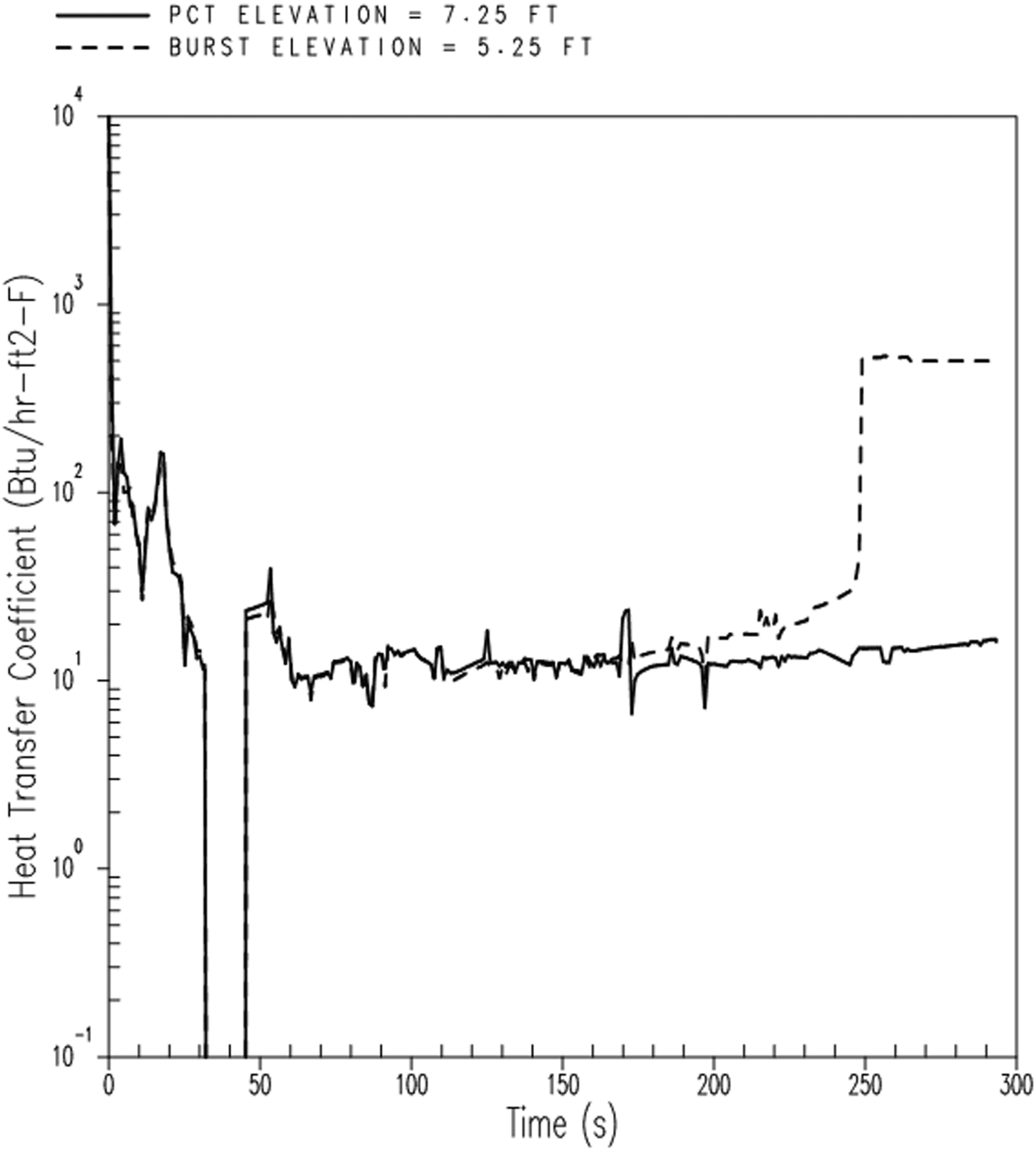
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CLADDING SURFACE HEAT TRANSFER COEFFICIENT AT PCT AND BURST ELEVATIONS (C_D = 1.0, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–9 (SHEET 4 OF 9)



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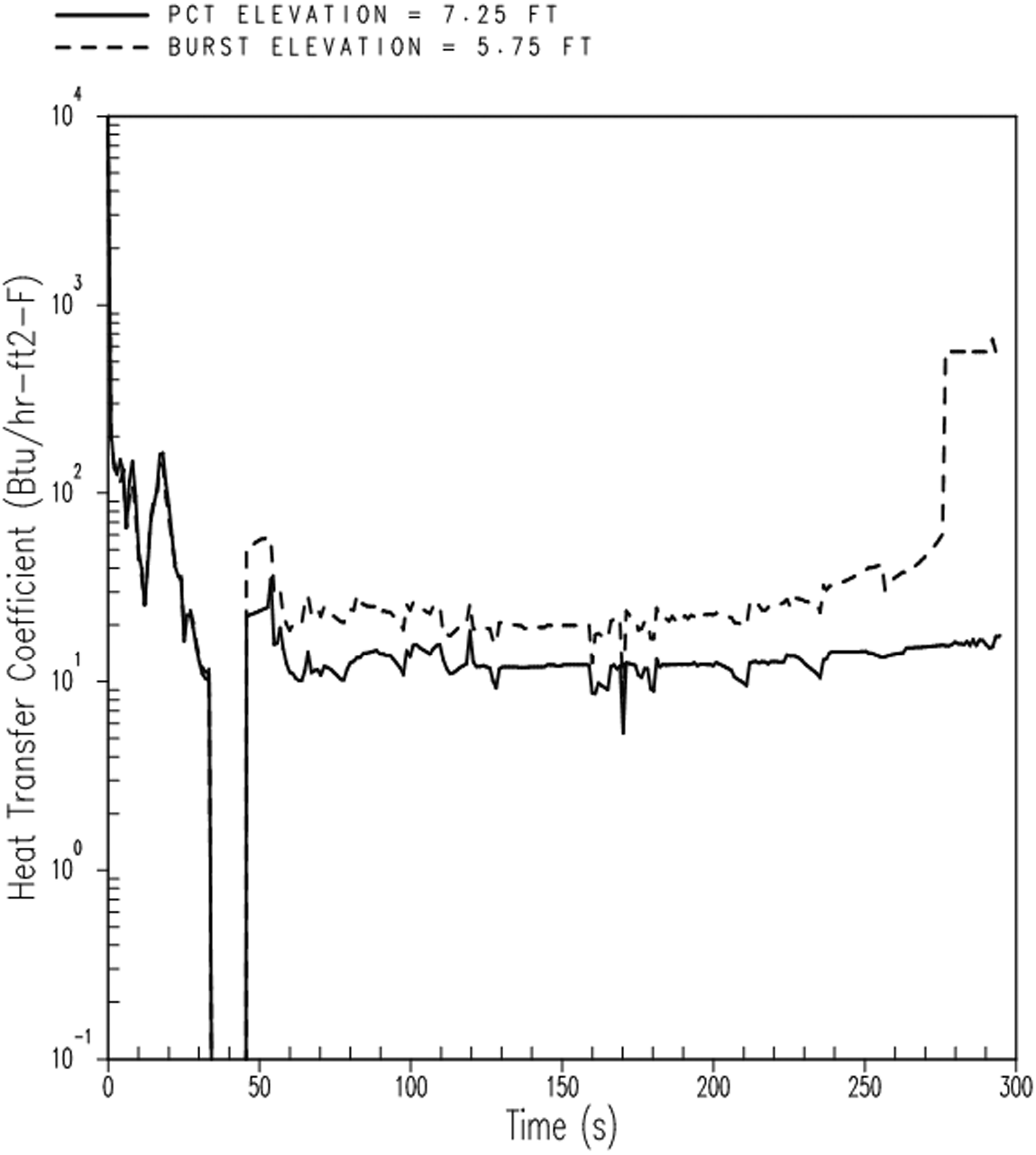
CLADDING SURFACE HEAT TRANSFER COEFFICIENT AT PCT AND BURST ELEVATIONS (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–9 (SHEET 5 OF 9)



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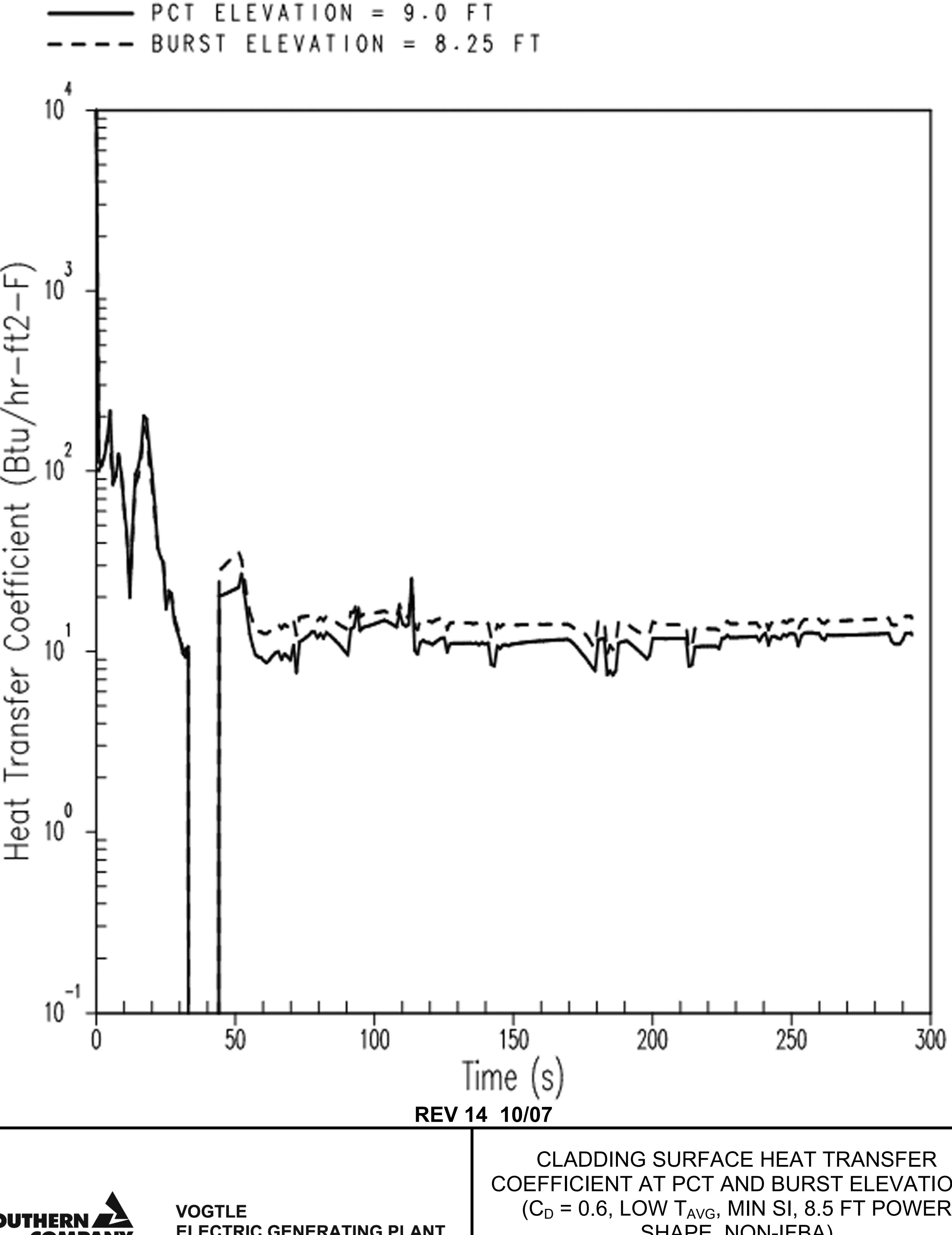
CLADDING SURFACE HEAT TRANSFER COEFFICIENT AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MAX SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–9 (SHEET 6 OF 9)



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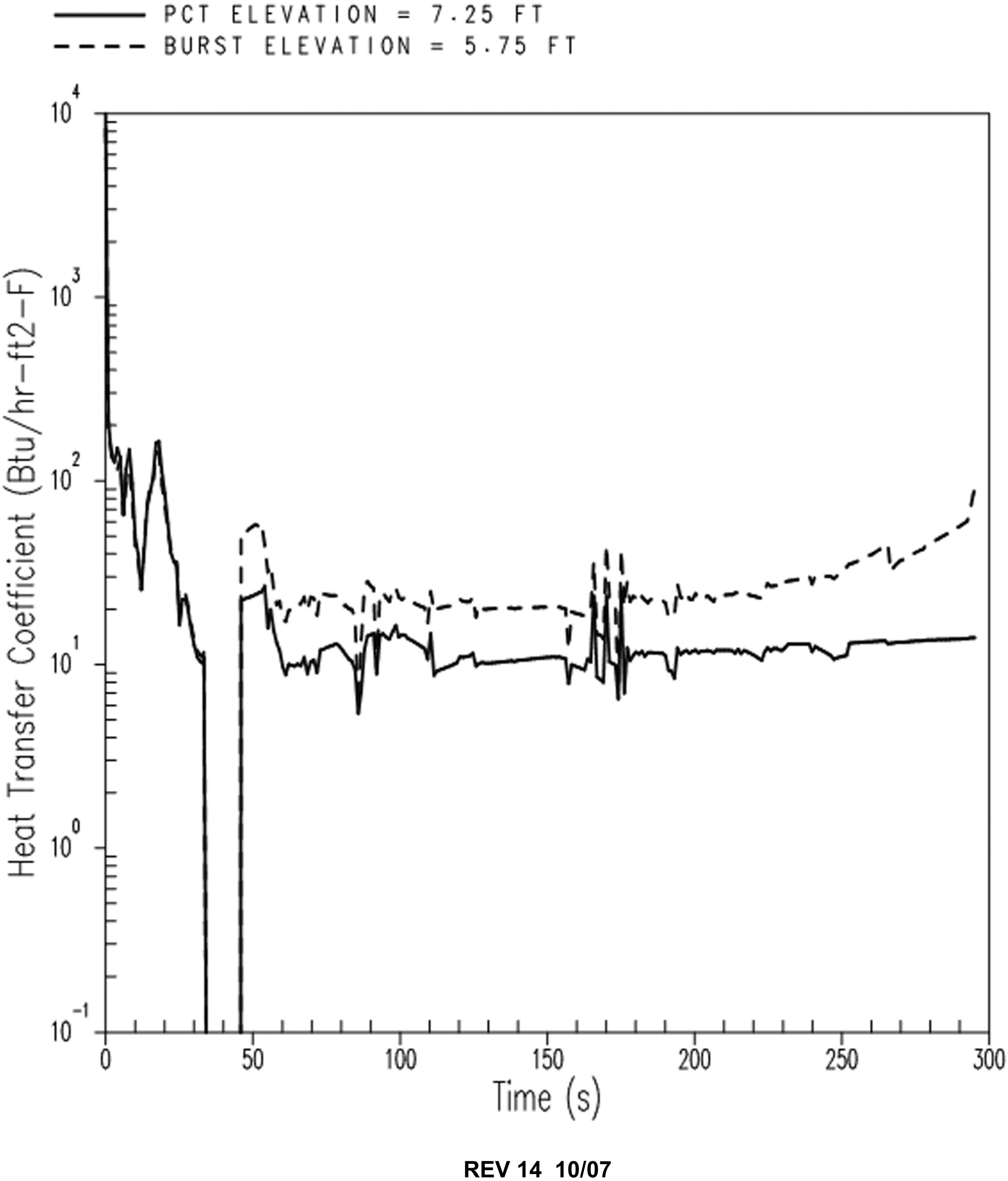
CLADDING SURFACE HEAT TRANSFER COEFFICIENT AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, 8.5 FT POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–9 (SHEET 7 OF 9)



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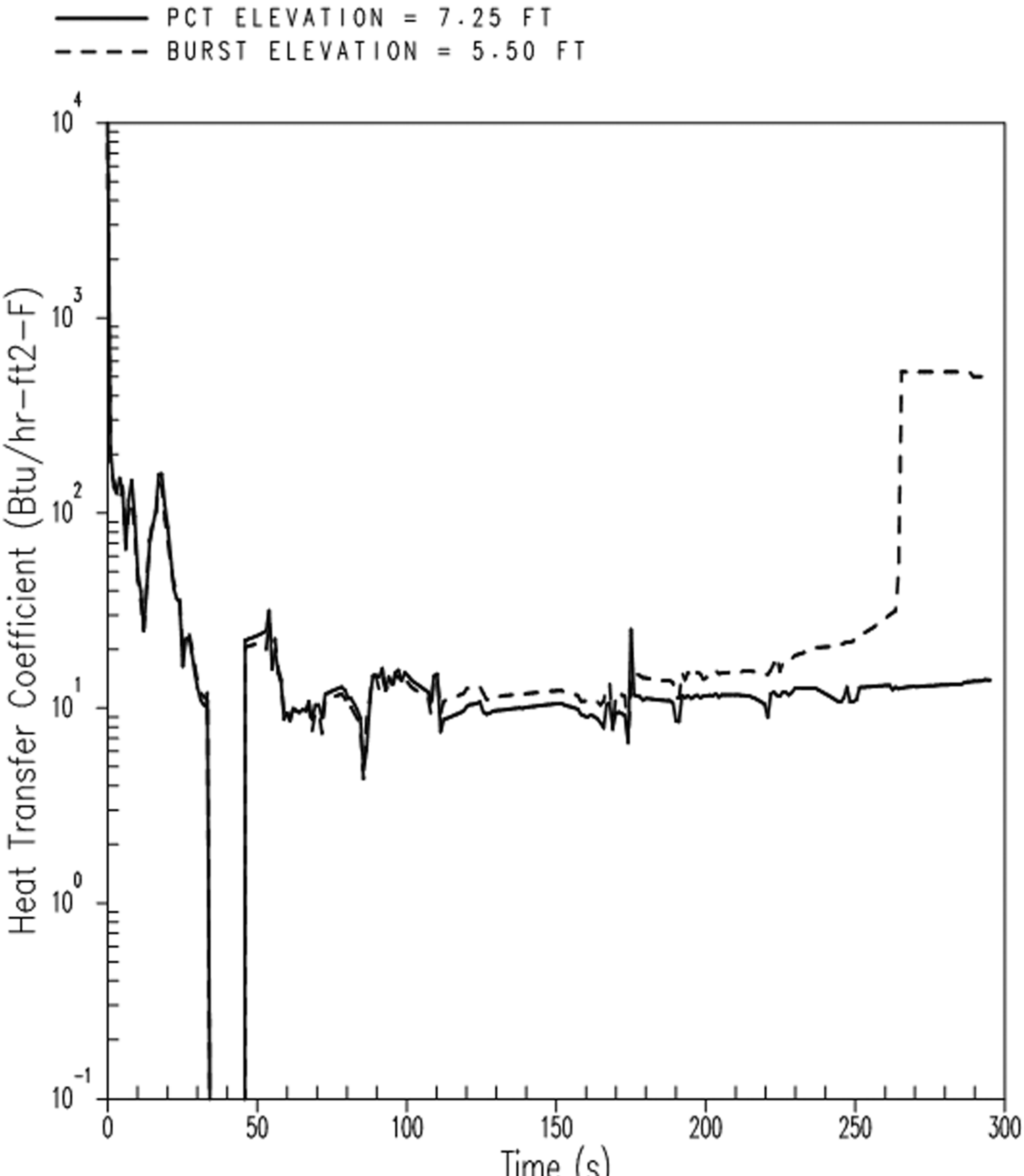
CLADDING SURFACE HEAT TRANSFER COEFFICIENT AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–9 (SHEET 8 OF 9)



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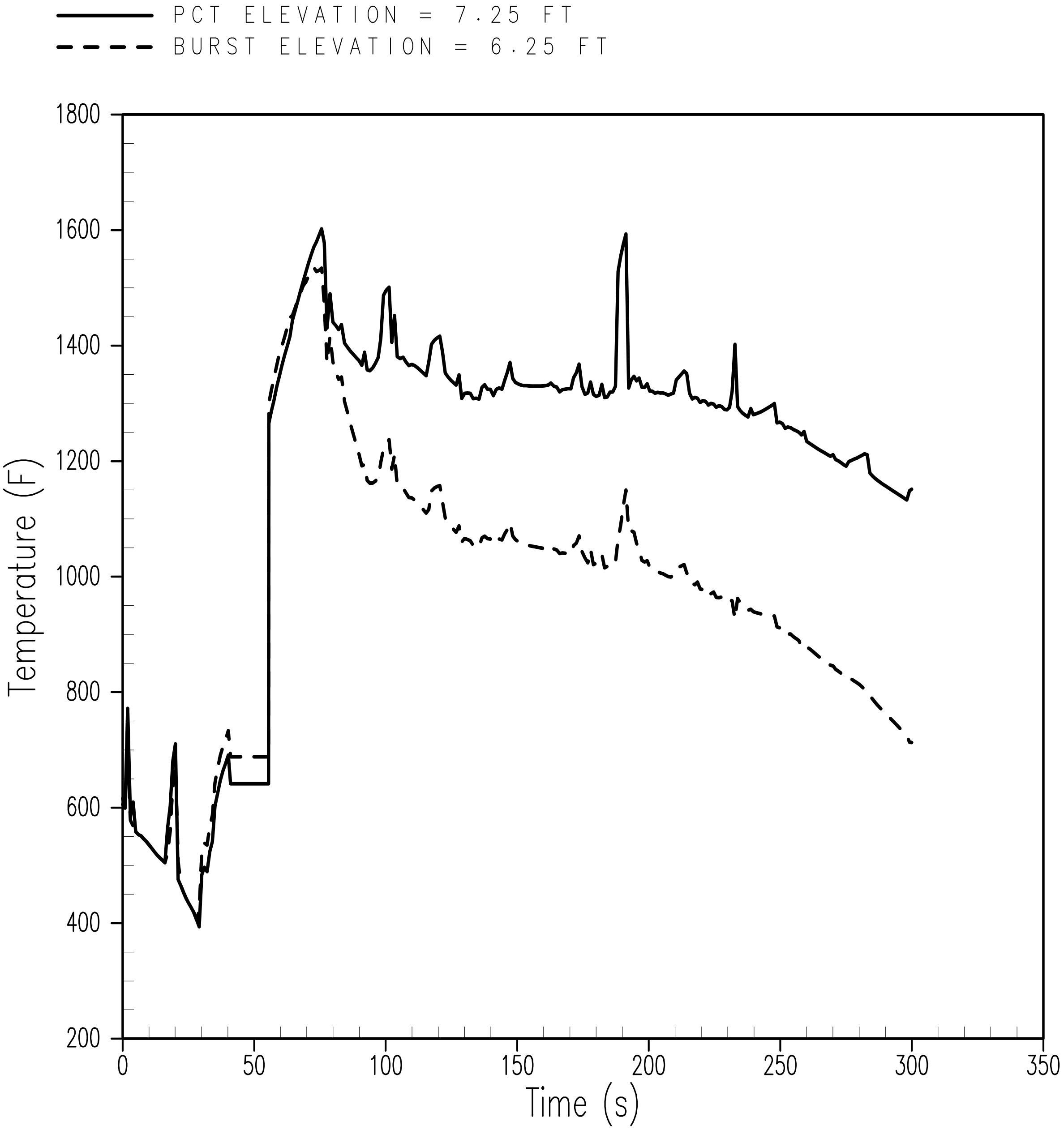
CLADDING SURFACE HEAT TRANSFER COEFFICIENT AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 156-IFBA)

FIGURE 15.6.5–9 (SHEET 9 OF 9)



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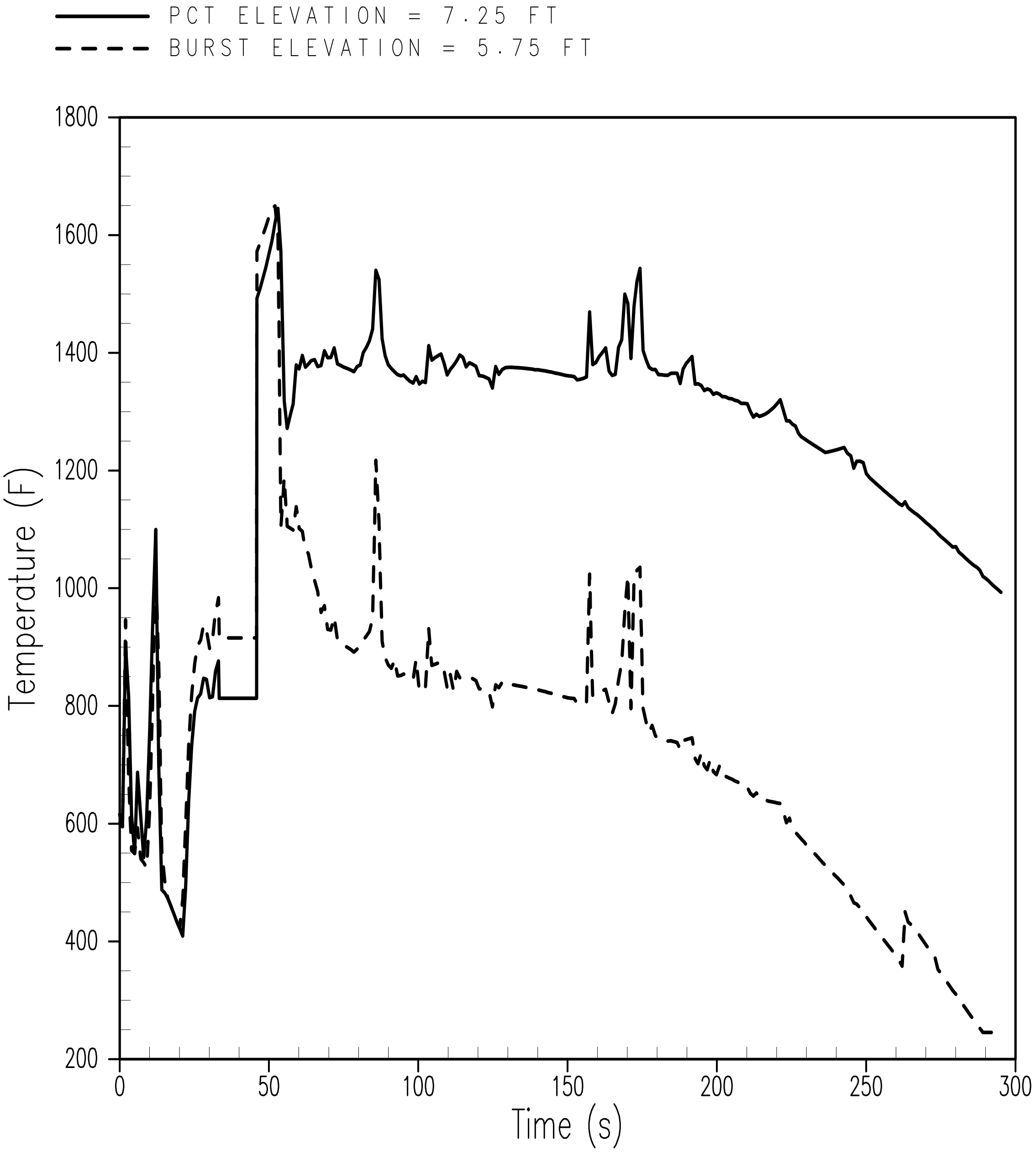
VAPOR TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–10 (SHEET 1 OF 9)



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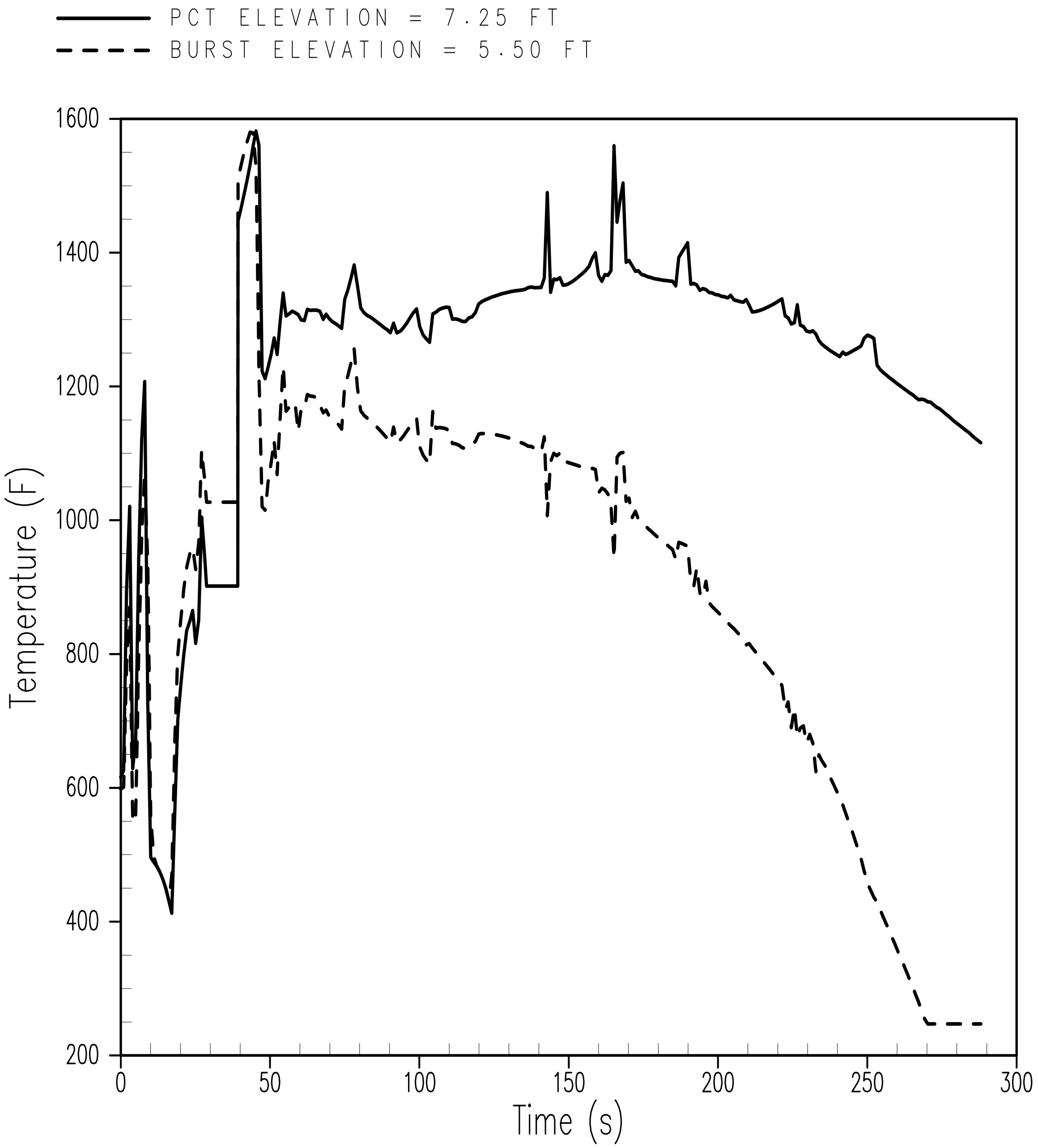
VAPOR TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–10 (SHEET 2 OF 9)



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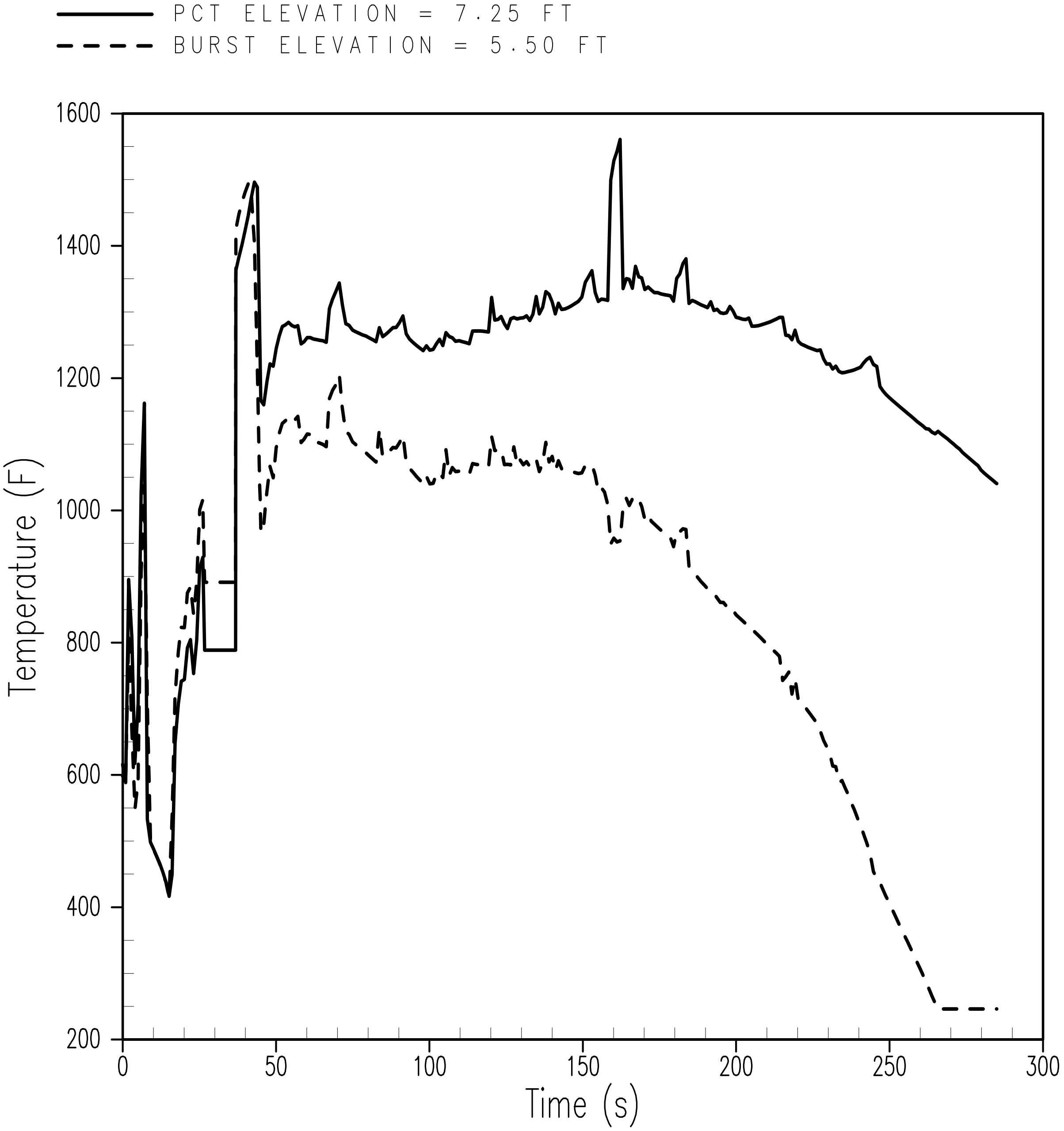
VAPOR TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–10 (SHEET 3 OF 9)



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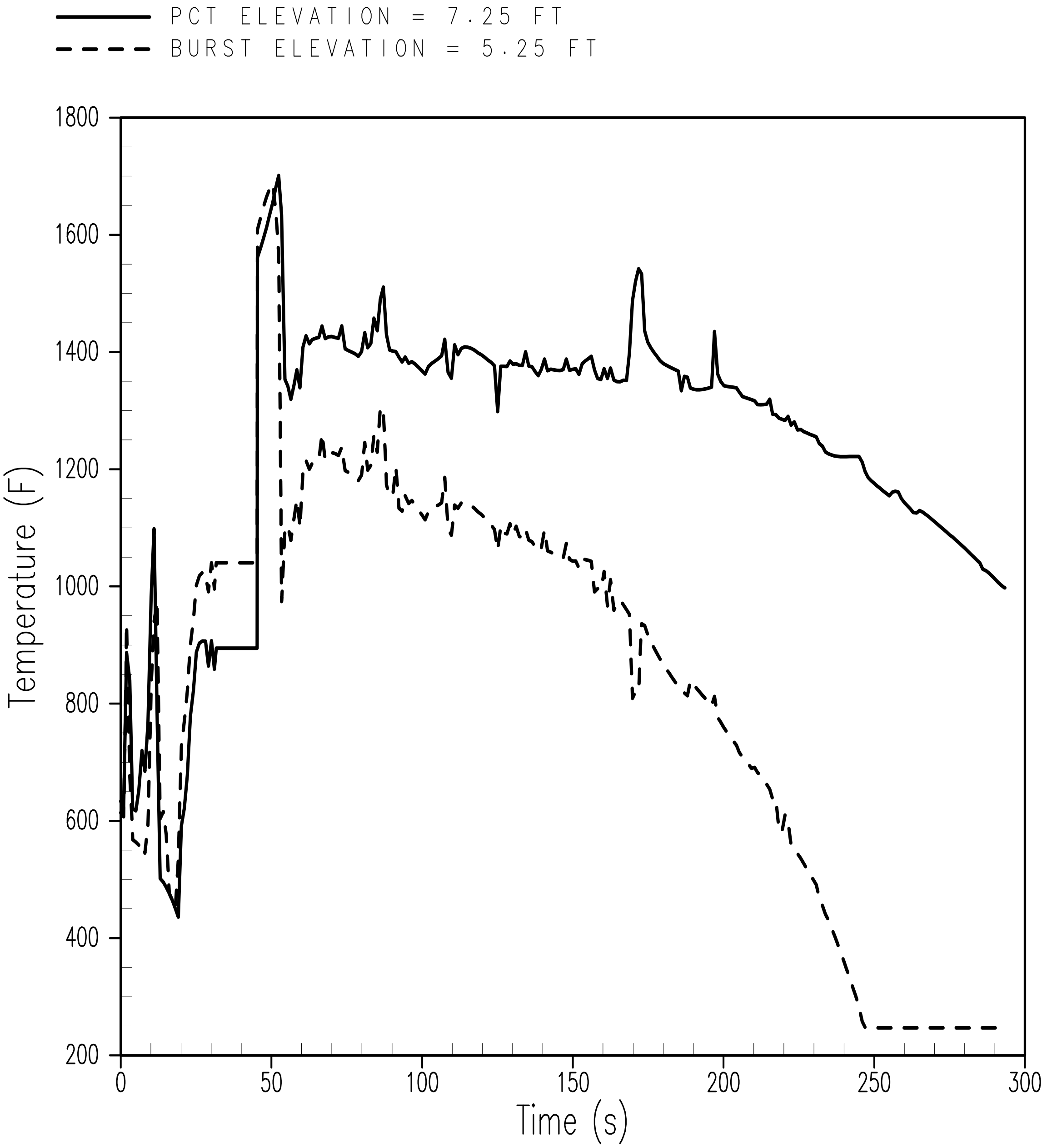
VAPOR TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 1.0, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–10 (SHEET 4 OF 9)



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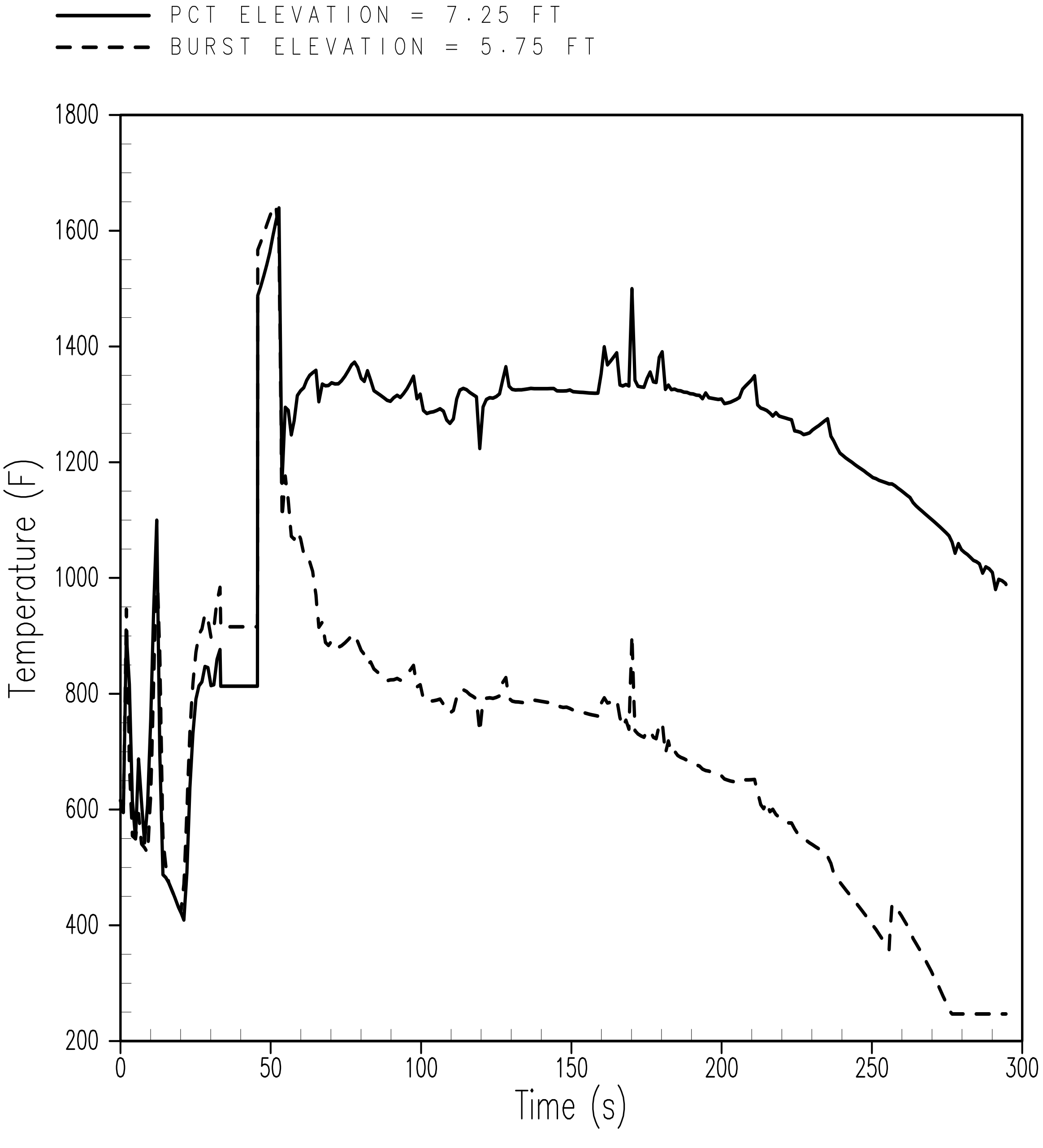
VAPOR TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–10 (SHEET 5 OF 9)



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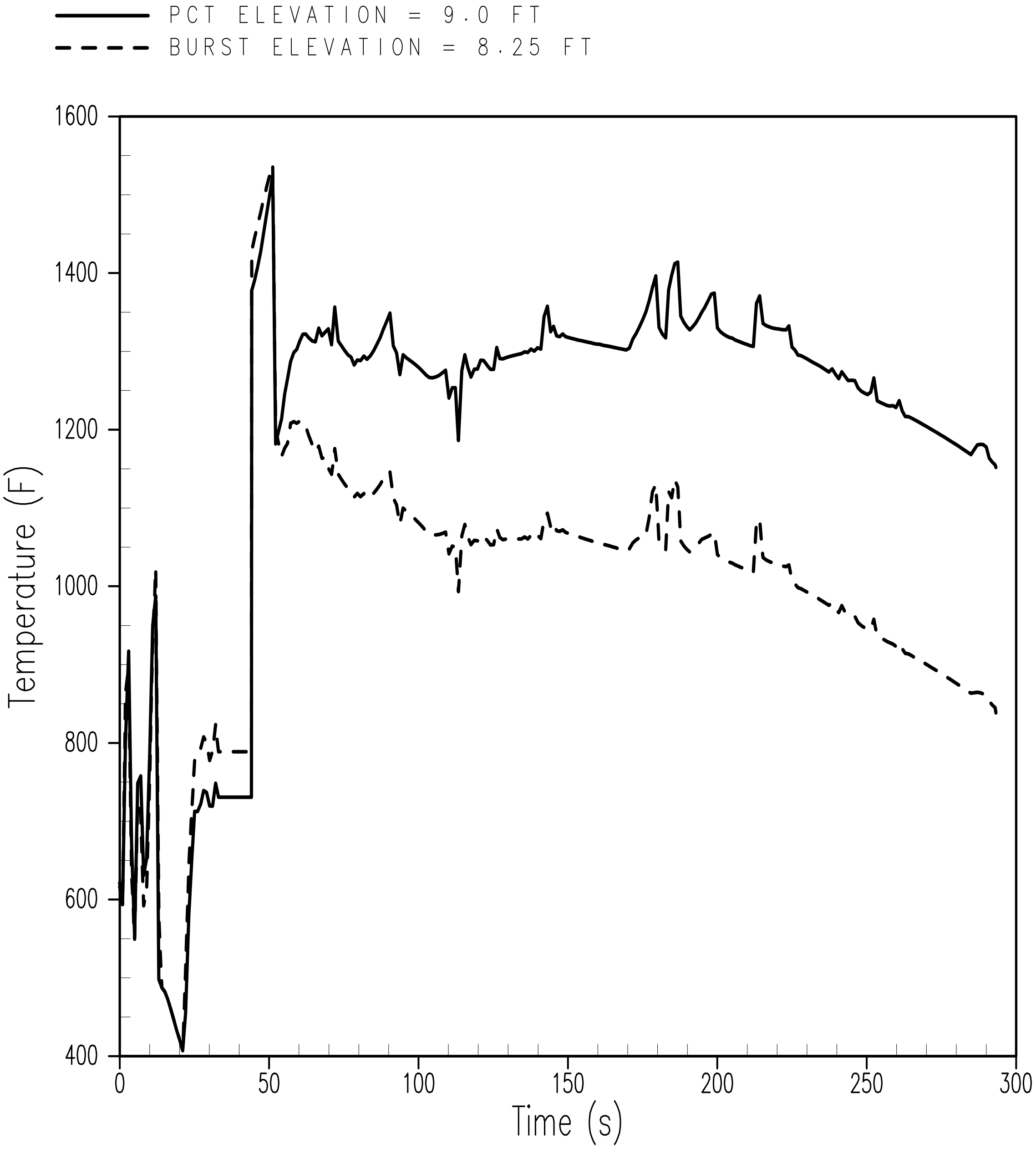
VAPOR TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MAX SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–10 (SHEET 6 OF 9)



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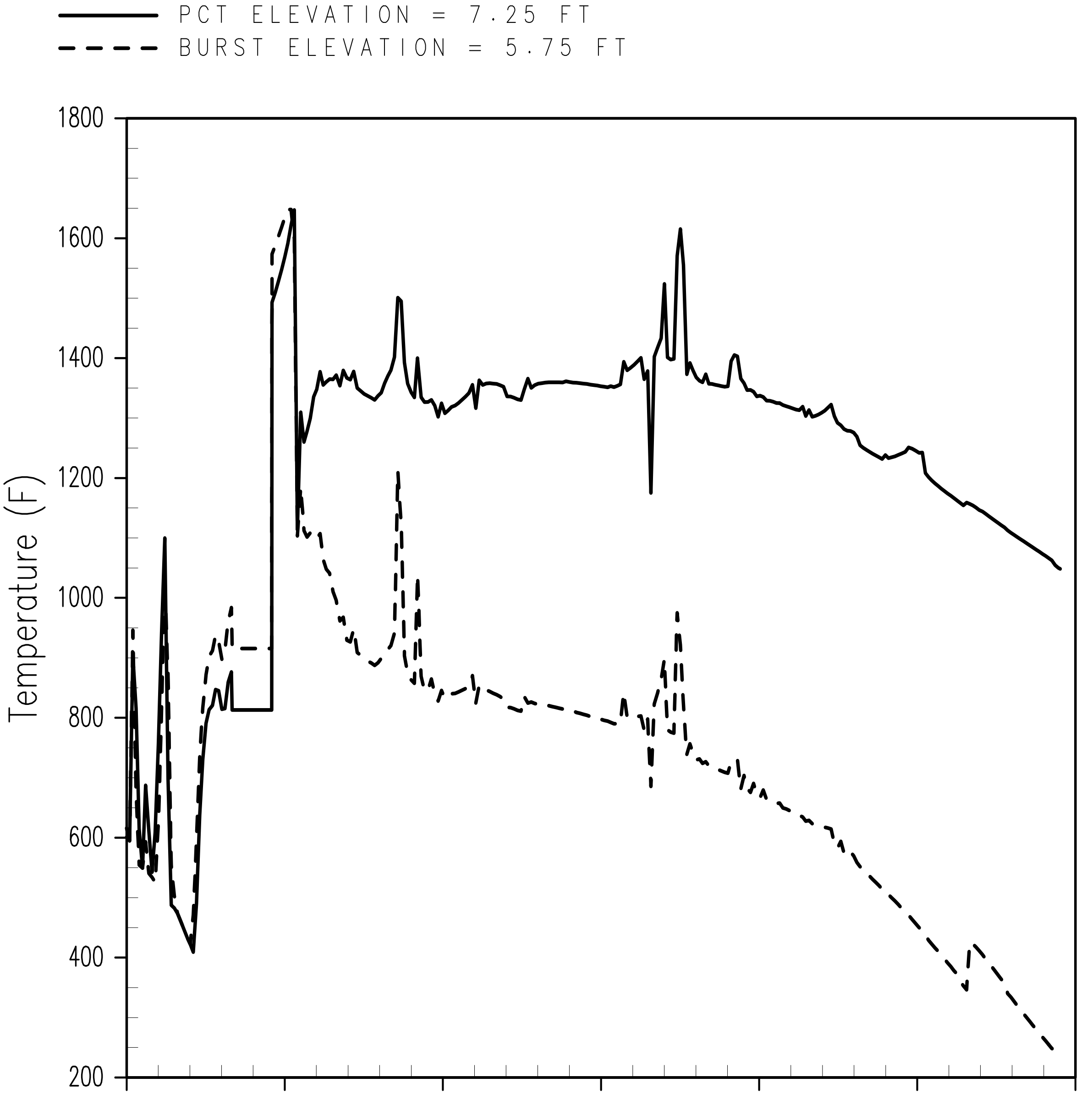
VAPOR TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, 8.5 FT POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–10 (SHEET 7 OF 9)



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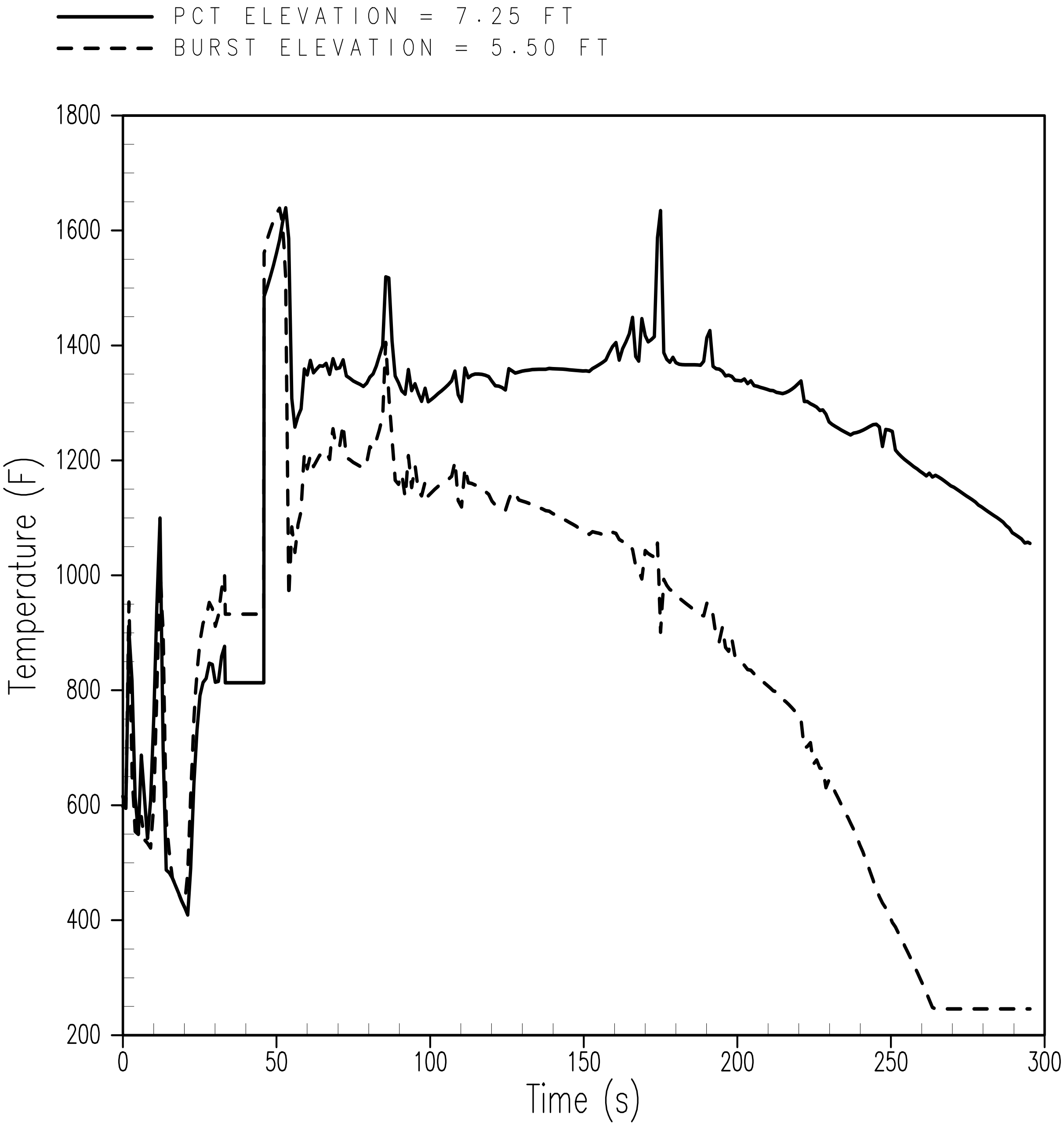
VAPOR TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–10 (SHEET 8 OF 9)



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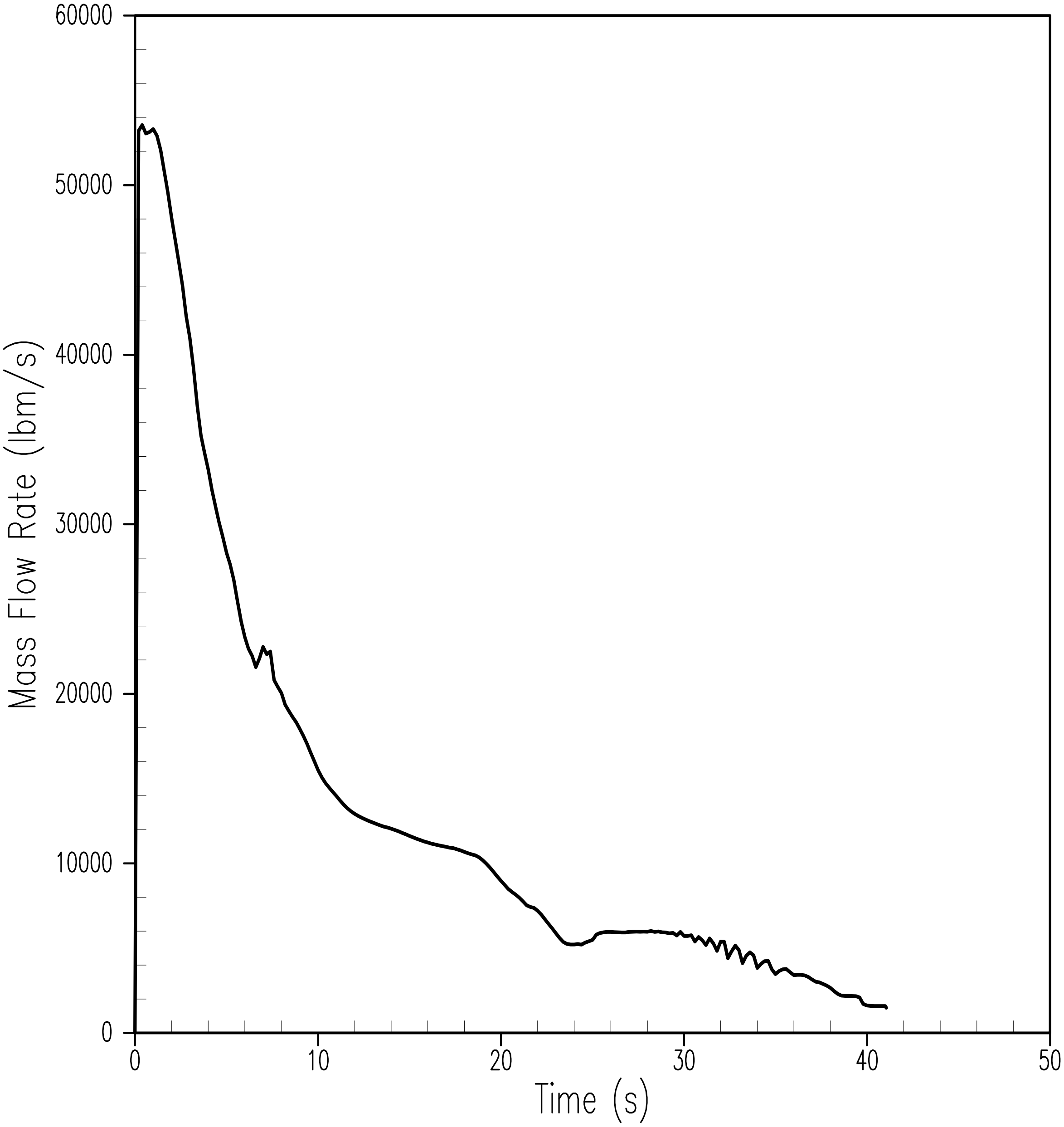
VAPOR TEMPERATURE AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 156-IFBA)

FIGURE 15.6.5–10 (SHEET 9 OF 9)



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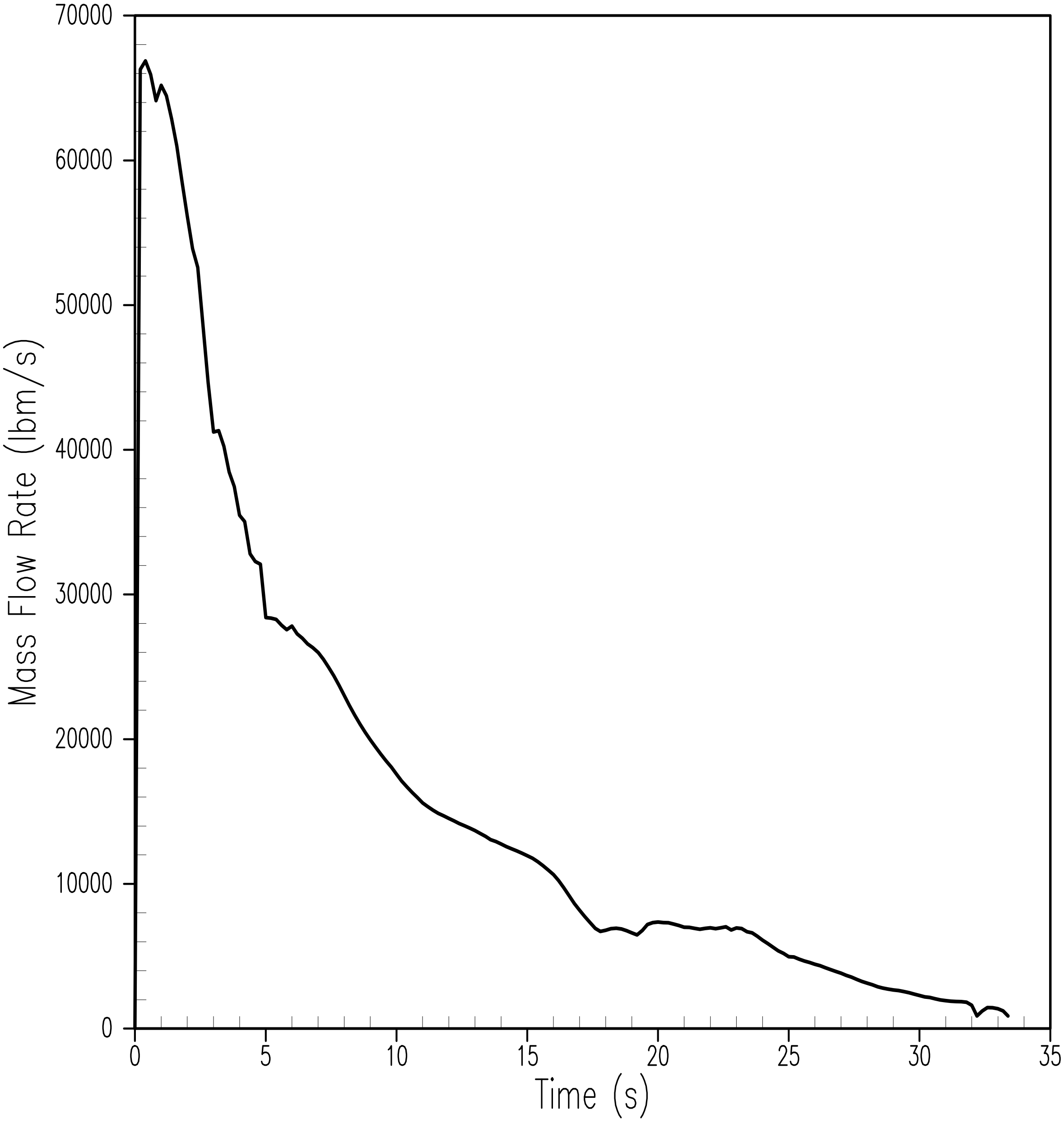
BREAK MASS FLOW RATE DURING BLOWDOWN (C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–11 (SHEET 1 OF 9)



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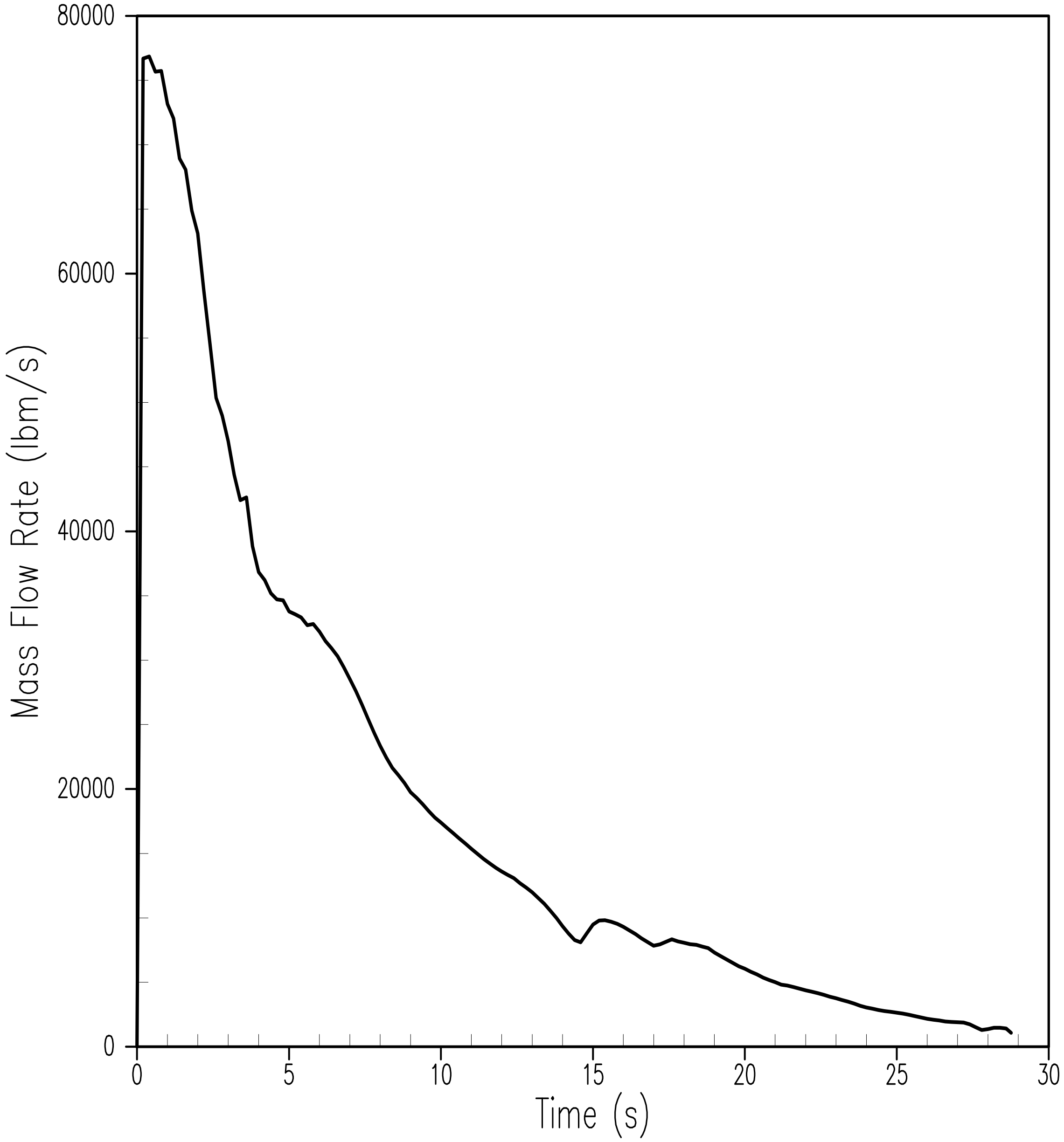
UNIT 1 AND UNIT 2

BREAK MASS FLOW RATE DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–11 (SHEET 2 OF 9)



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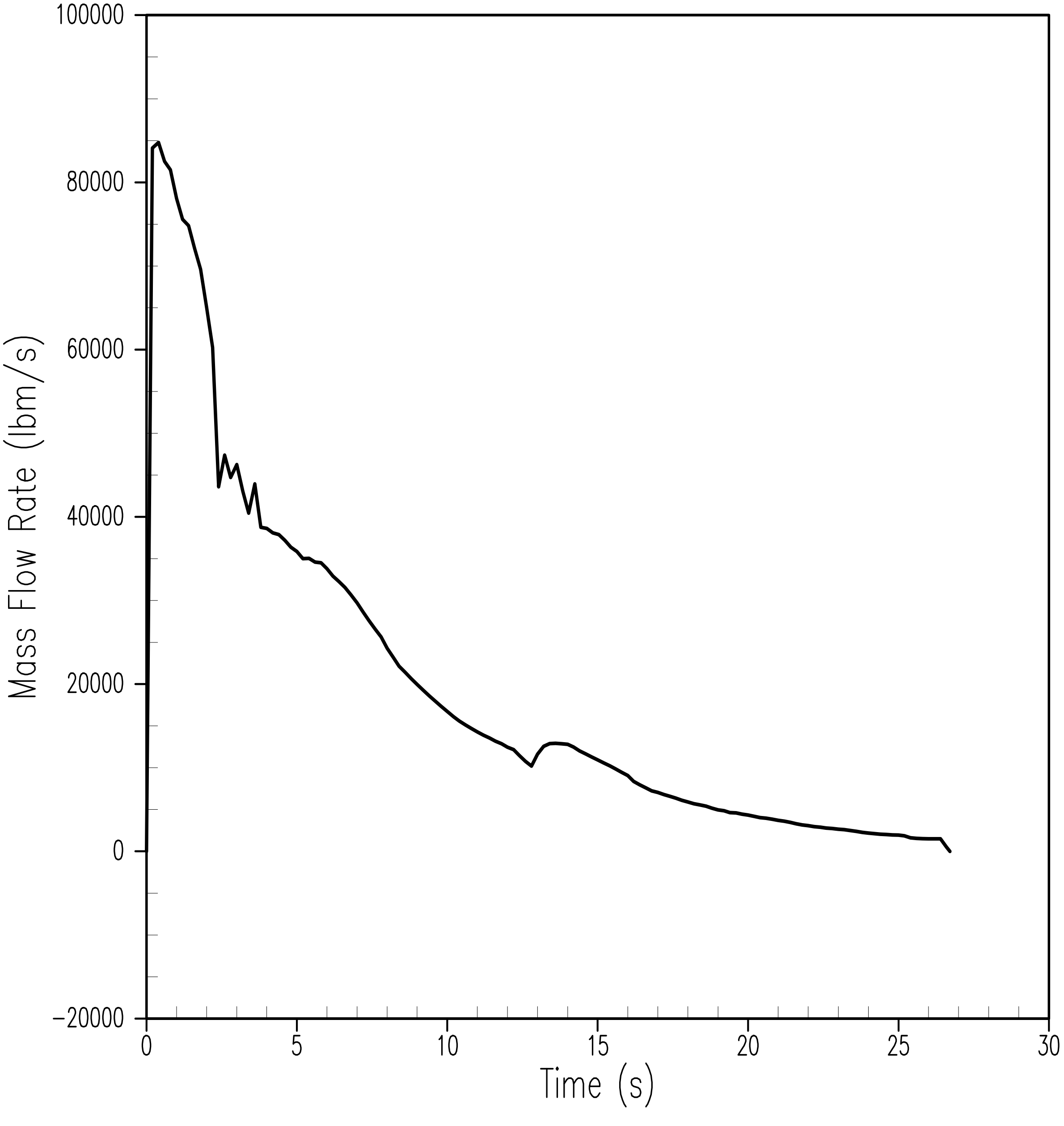
BREAK MASS FLOW RATE DURING BLOWDOWN (C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–11 (SHEET 3 OF 9)



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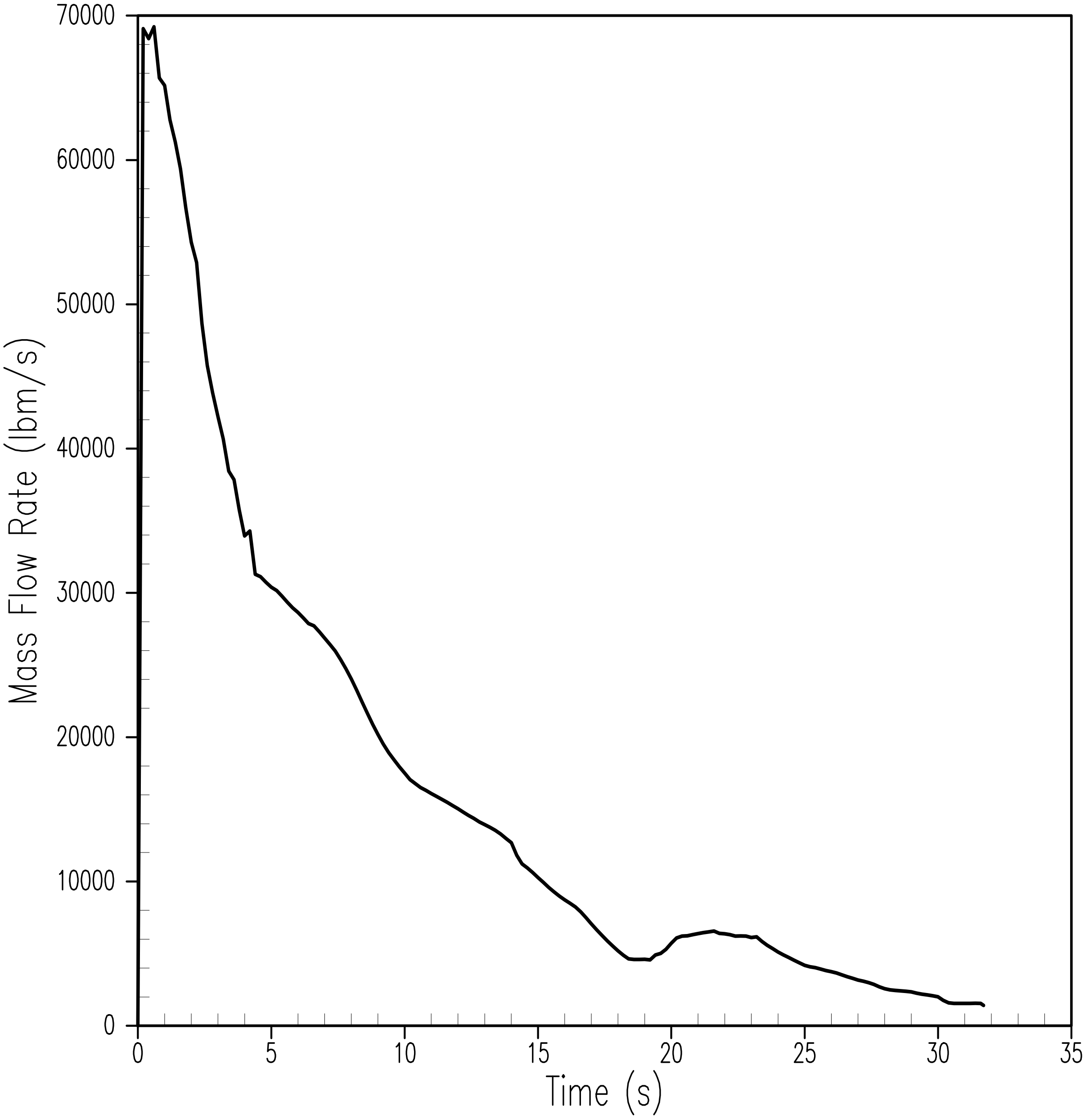
BREAK MASS FLOW RATE DURING BLOWDOWN (C_D = 1.0, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–11 (SHEET 4 OF 9)



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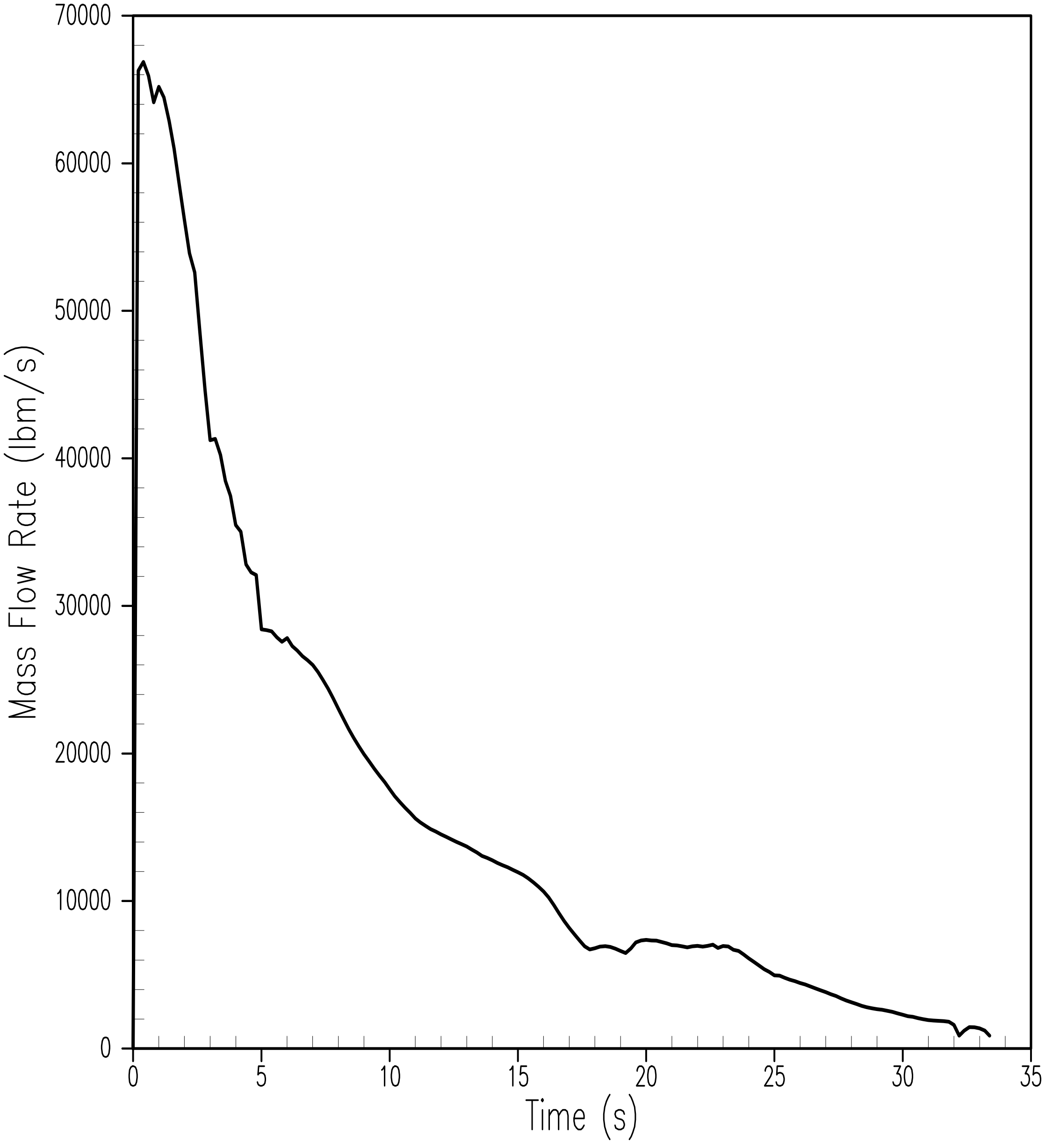
BREAK MASS FLOW RATE DURING BLOWDOWN (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–11 (SHEET 5 OF 9)



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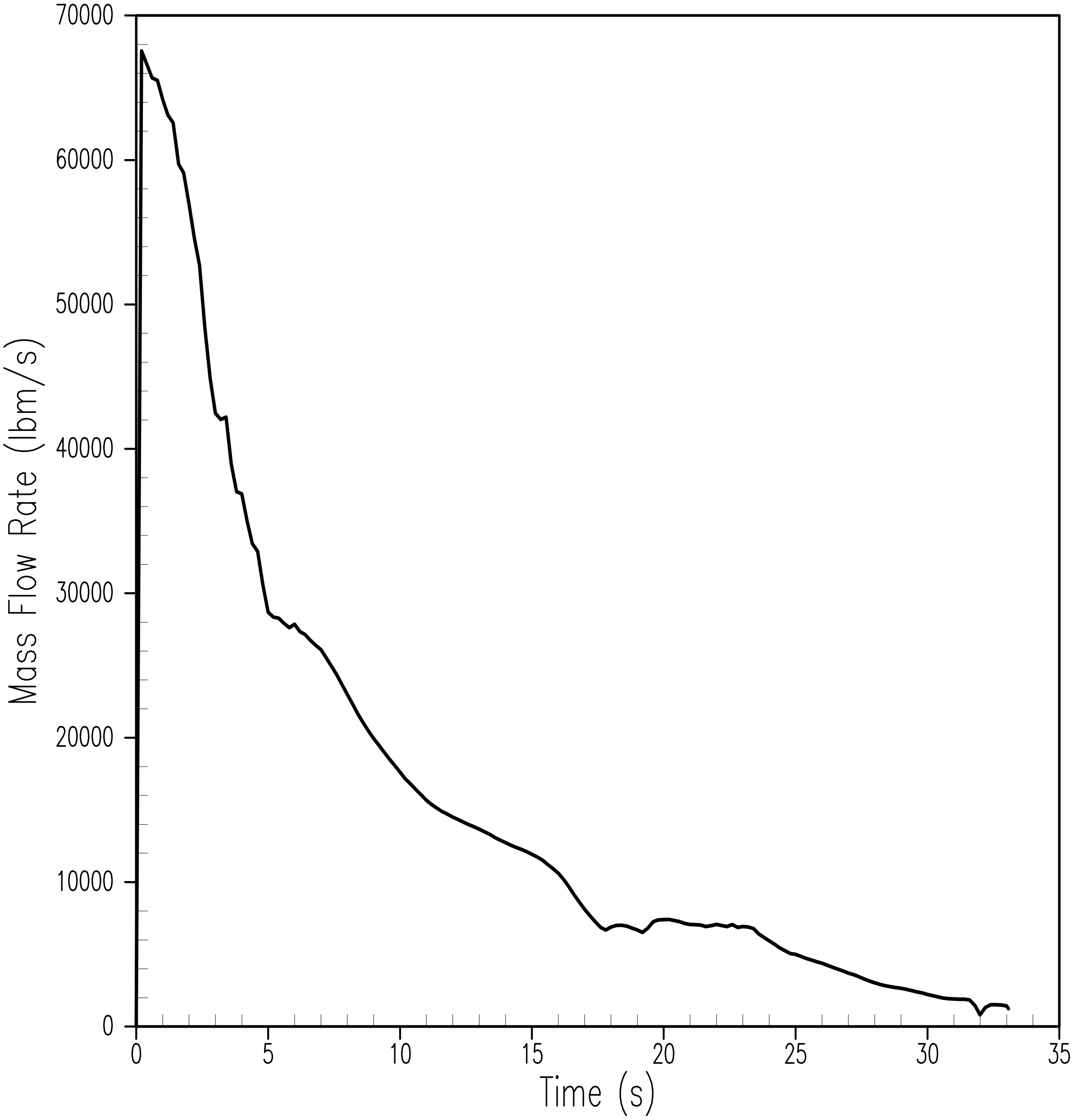
BREAK MASS FLOW RATE DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MAX SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–11 (SHEET 6 OF 9)



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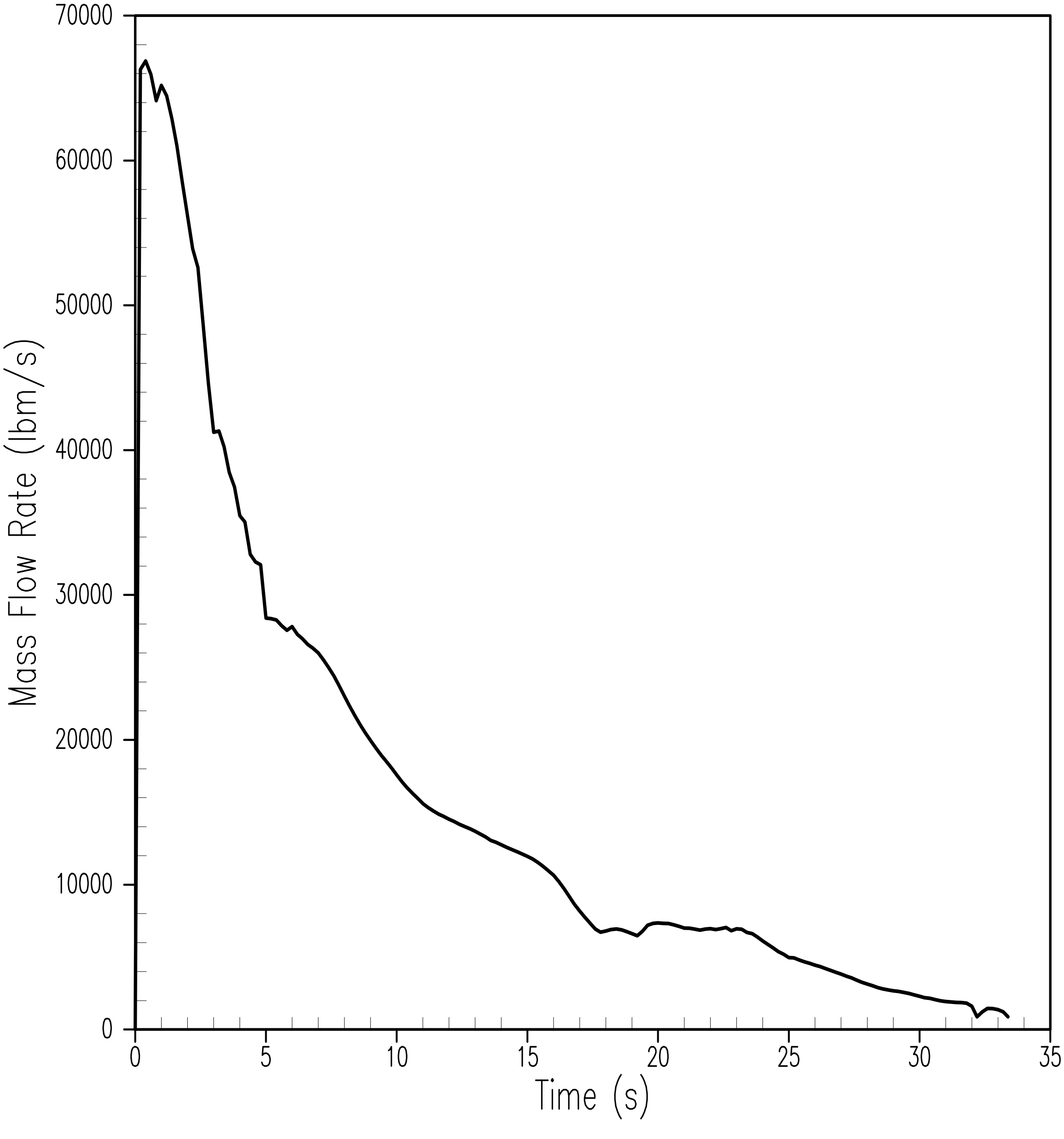
BREAK MASS FLOW RATE DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MIN SI, 8.5 FT POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–11 (SHEET 7 OF 9)



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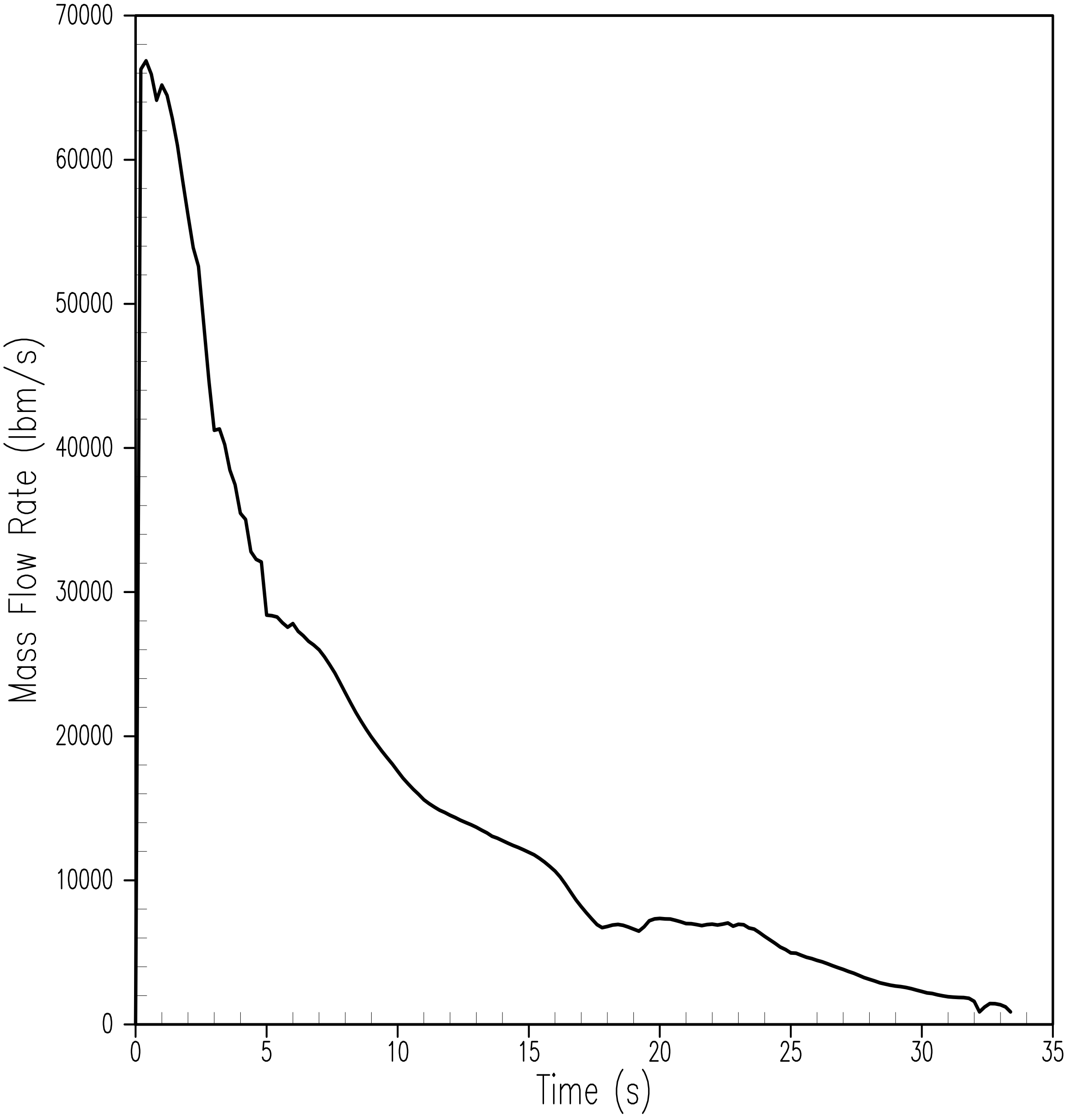
BREAK MASS FLOW RATE DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–11 (SHEET 8 OF 9)



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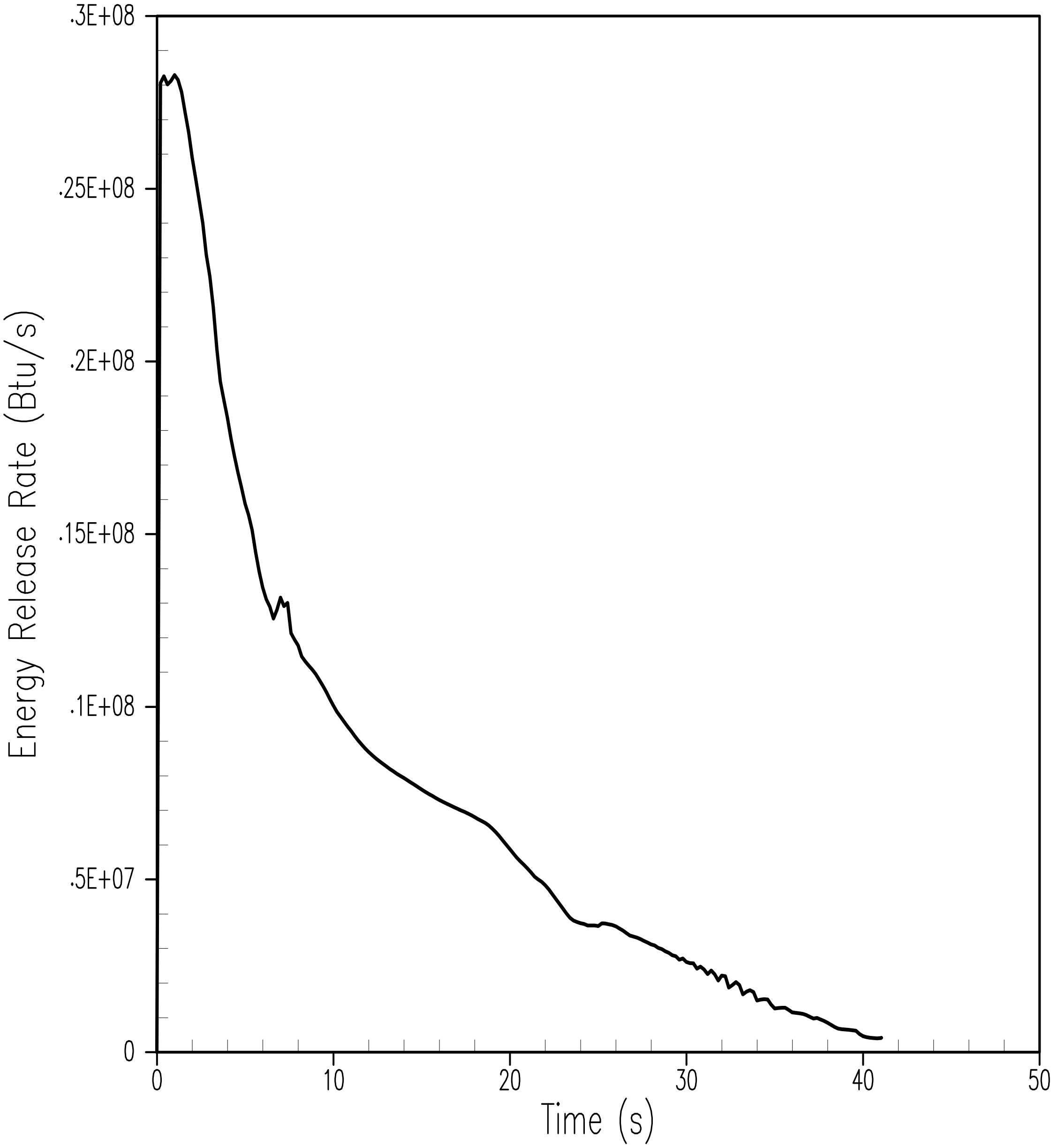
BREAK MASS FLOW RATE DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 156-IFBA)

FIGURE 15.6.5–11 (SHEET 9 OF 9)



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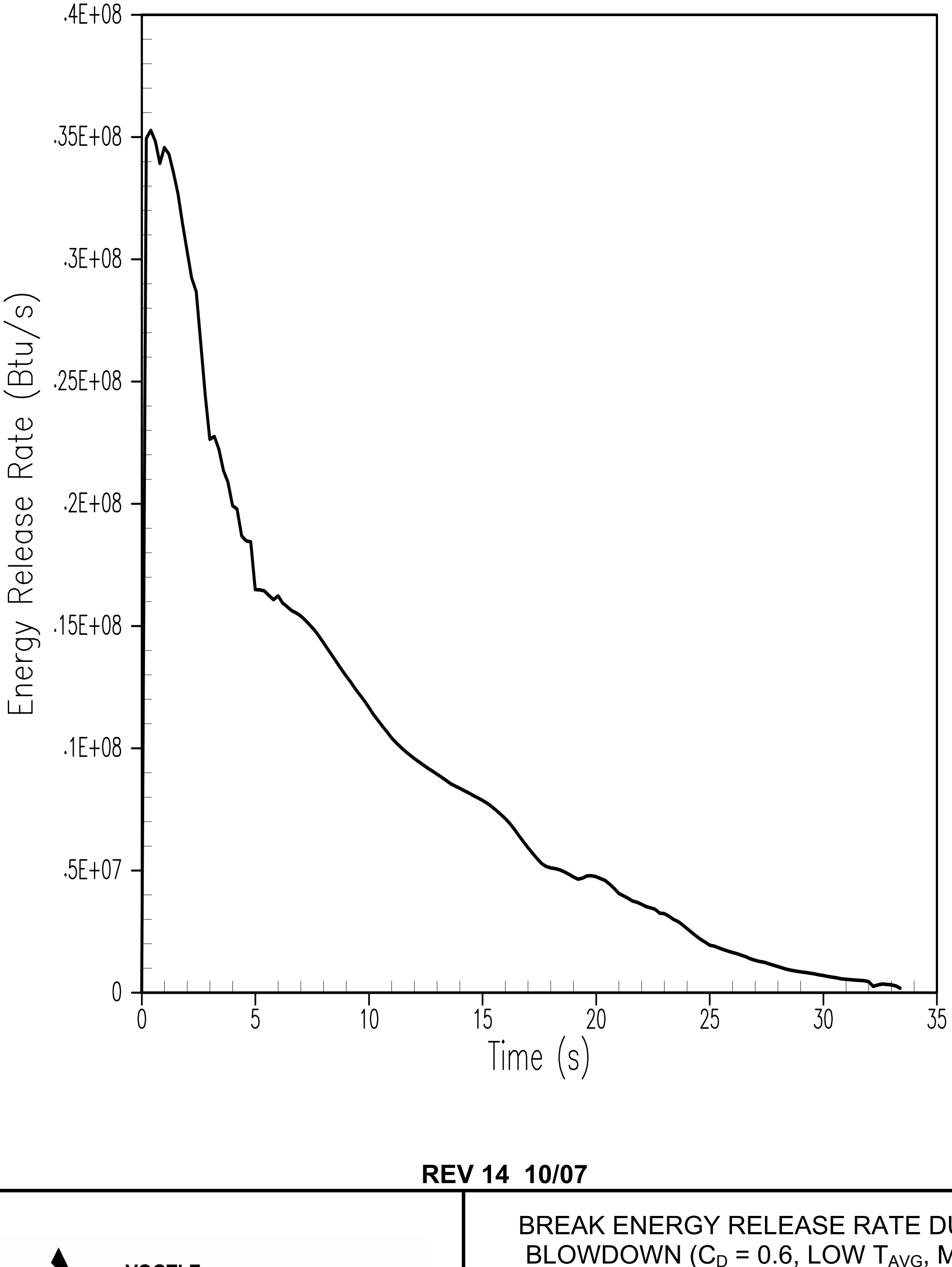
BREAK ENERGY RELEASE RATE DURING BLOWDOWN (C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–12 (SHEET 1 OF 9)



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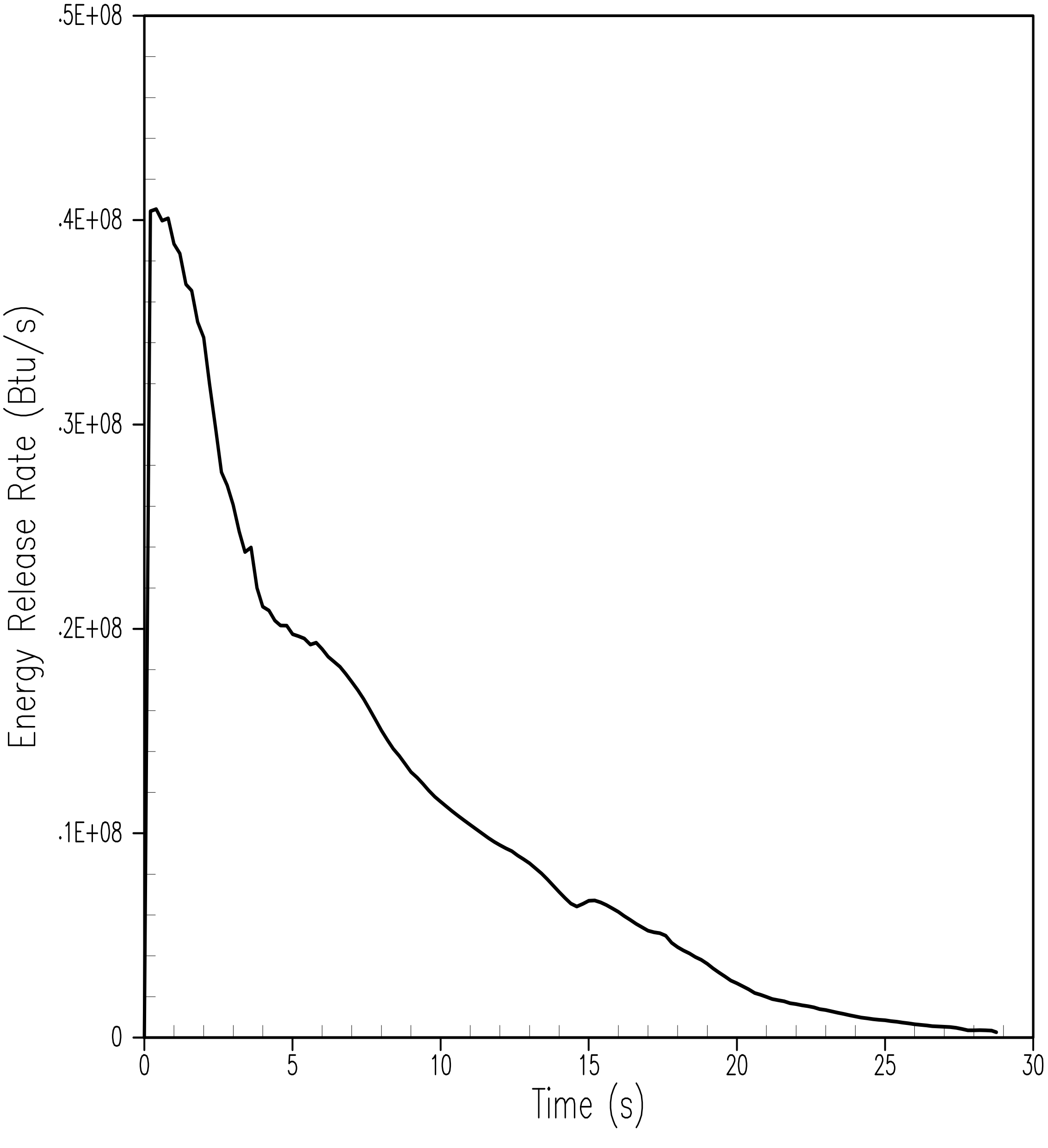
BREAK ENERGY RELEASE RATE DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–12 (SHEET 2 OF 9)



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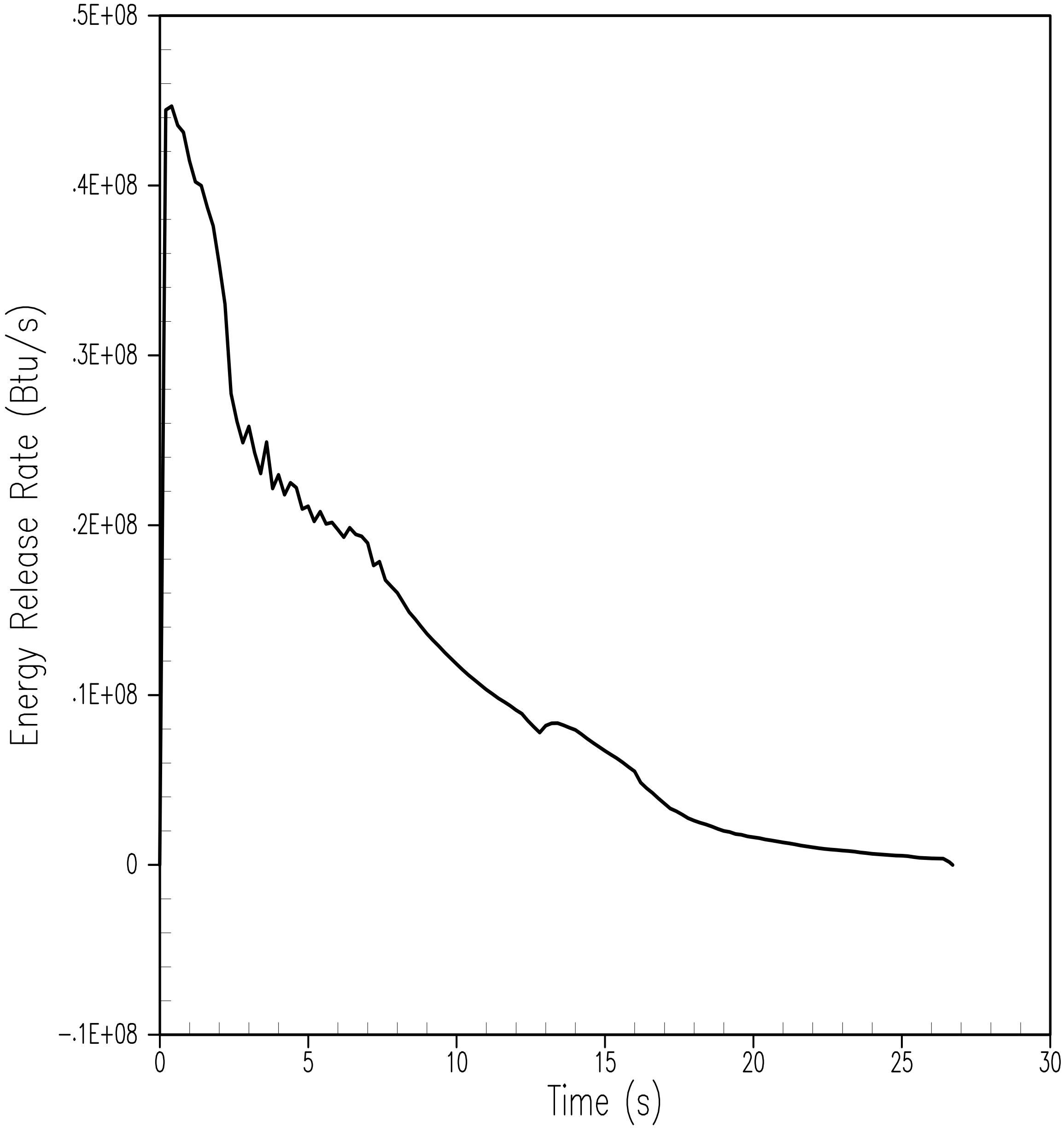
BREAK ENERGY RELEASE RATE DURING BLOWDOWN (C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–12 (SHEET 3 OF 9)



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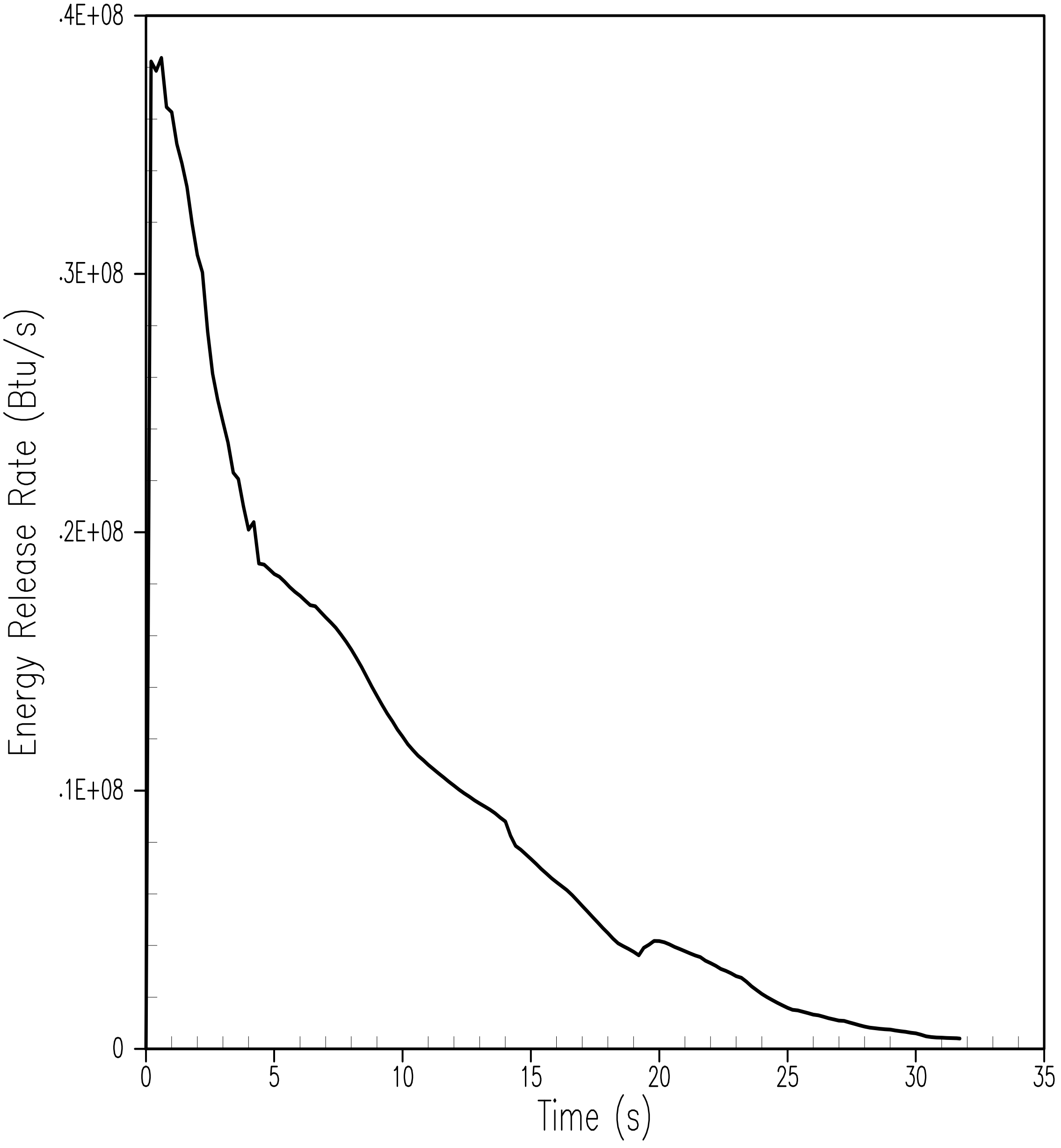
BREAK ENERGY RELEASE RATE DURING BLOWDOWN (C_D = 1.0, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–12 (SHEET 4 OF 9)



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BREAK ENERGY RELEASE RATE DURING BLOWDOWN (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–12 (SHEET 5 OF 9)

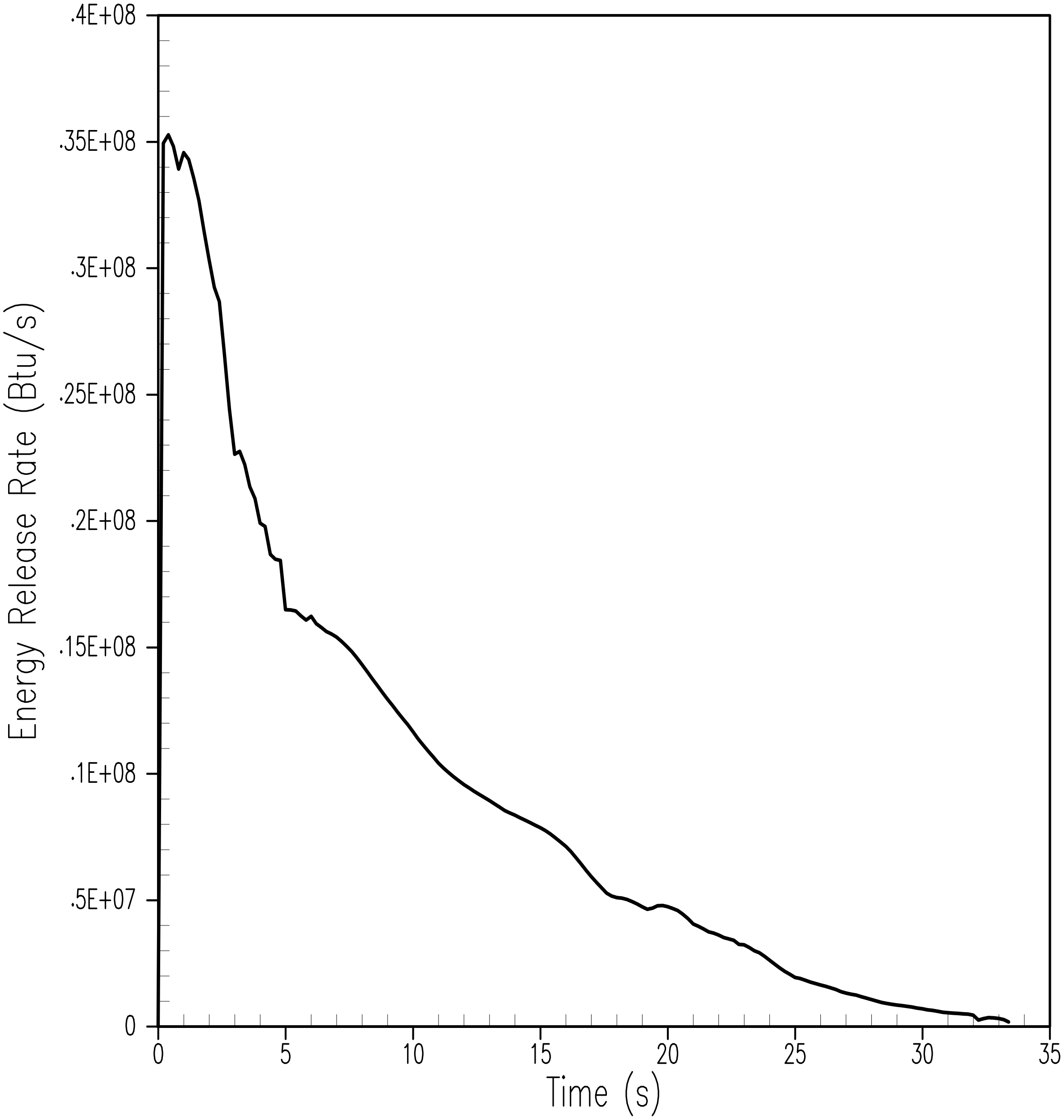

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FIGURE 15.6.5–12 (SHEET 6 OF 9)

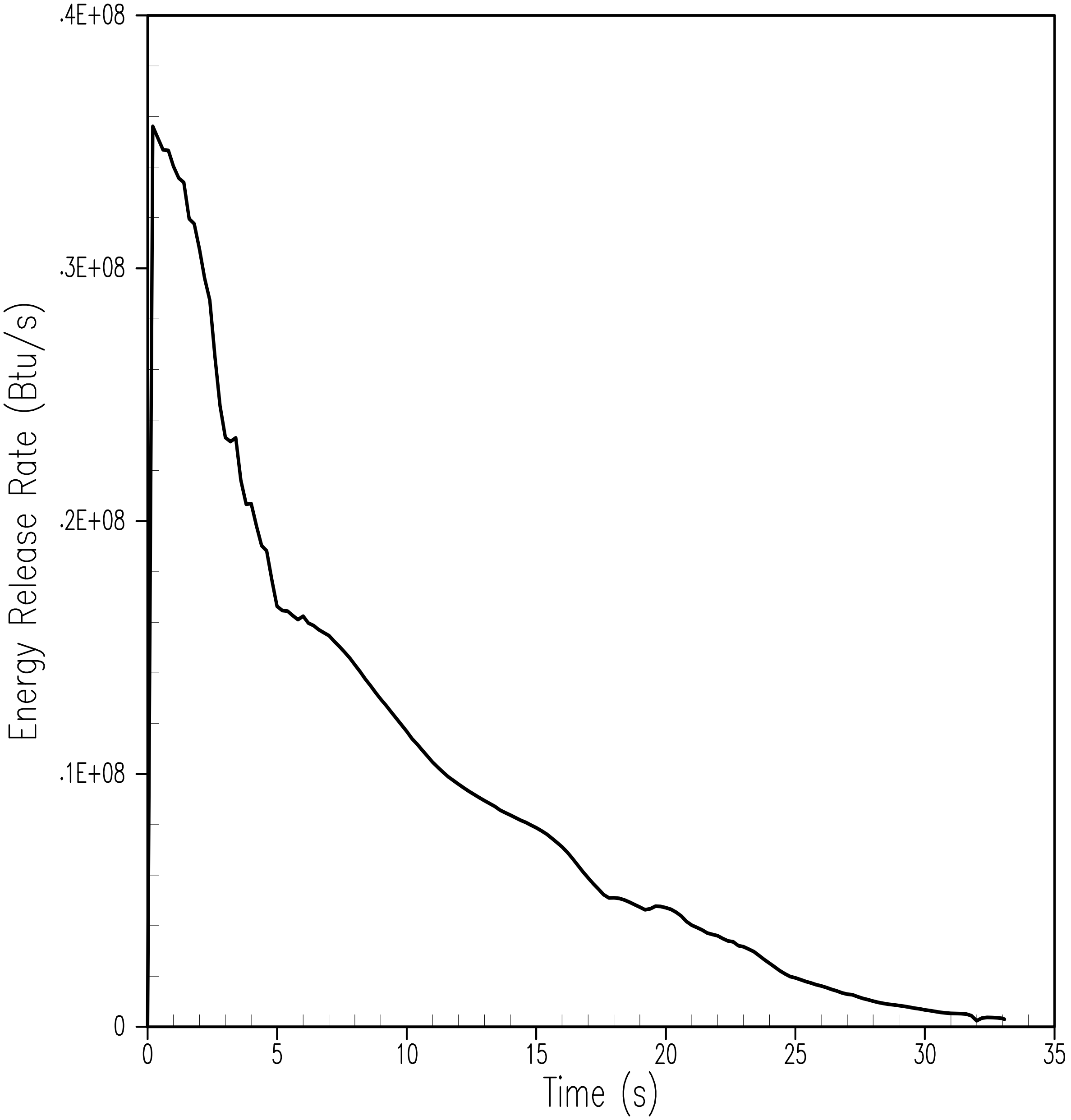

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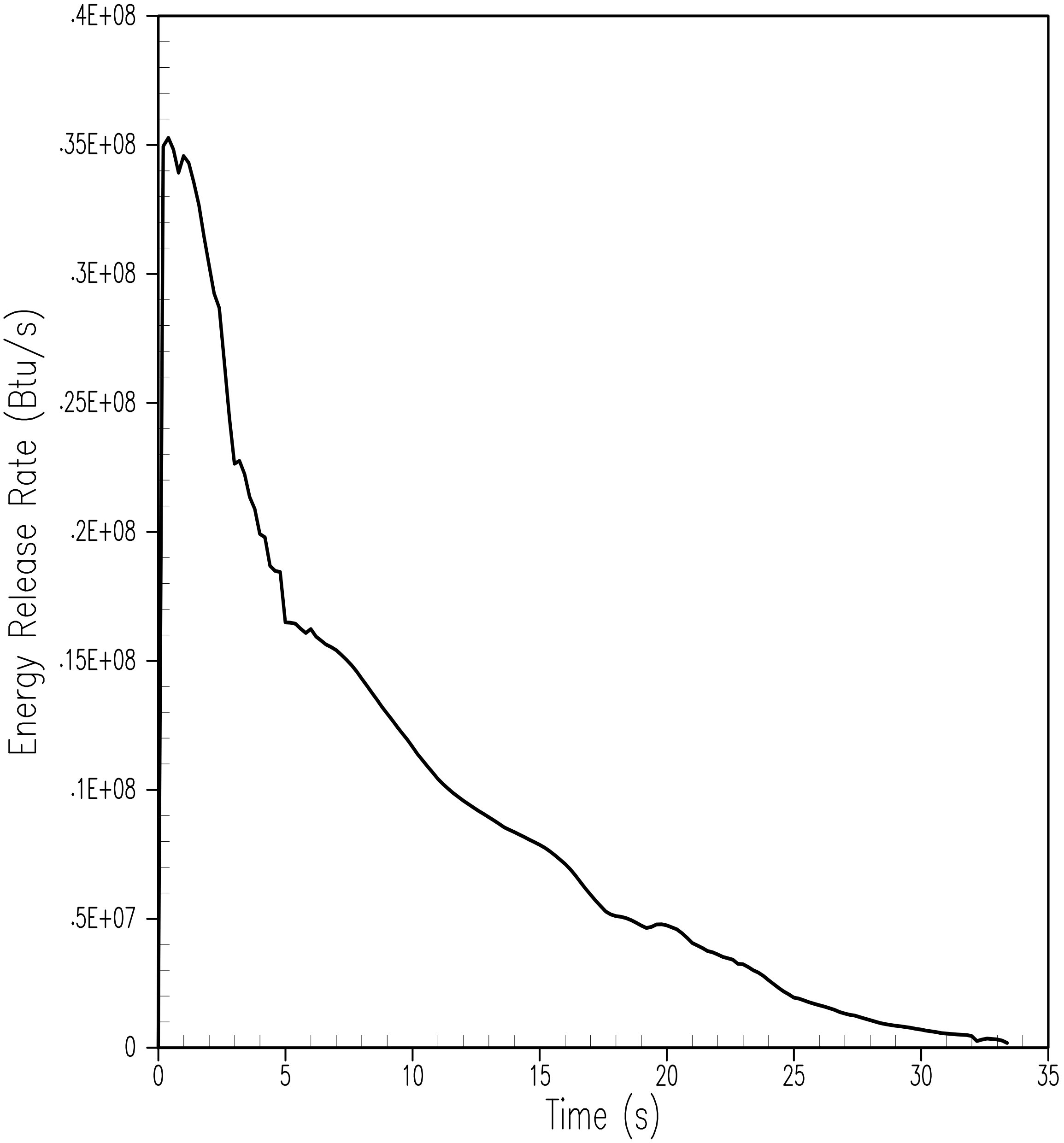
FIGURE 15.6.5–12 (SHEET 7 OF 9)



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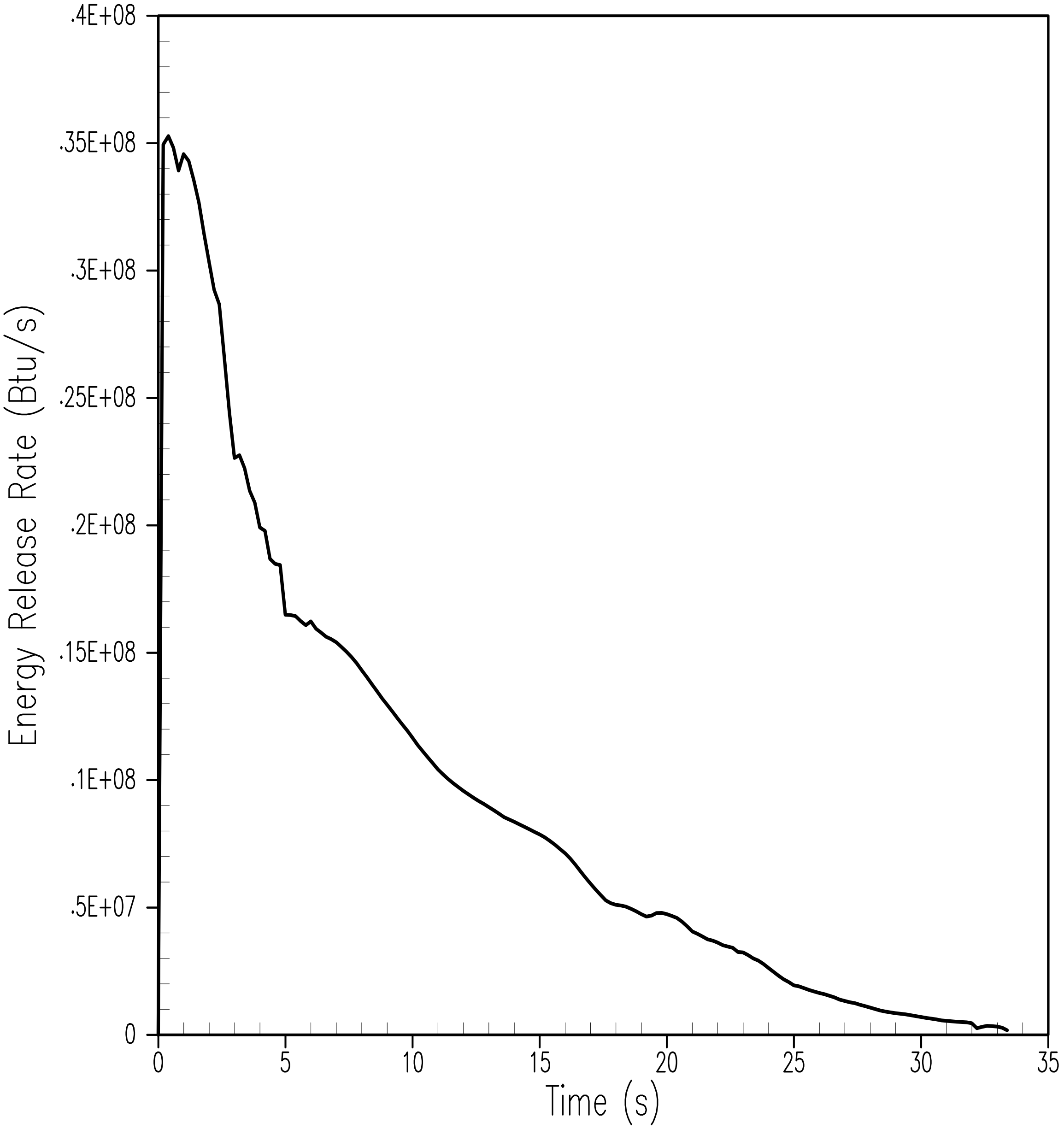
BREAK ENERGY RELEASE RATE DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–12 (SHEET 8 OF 9)



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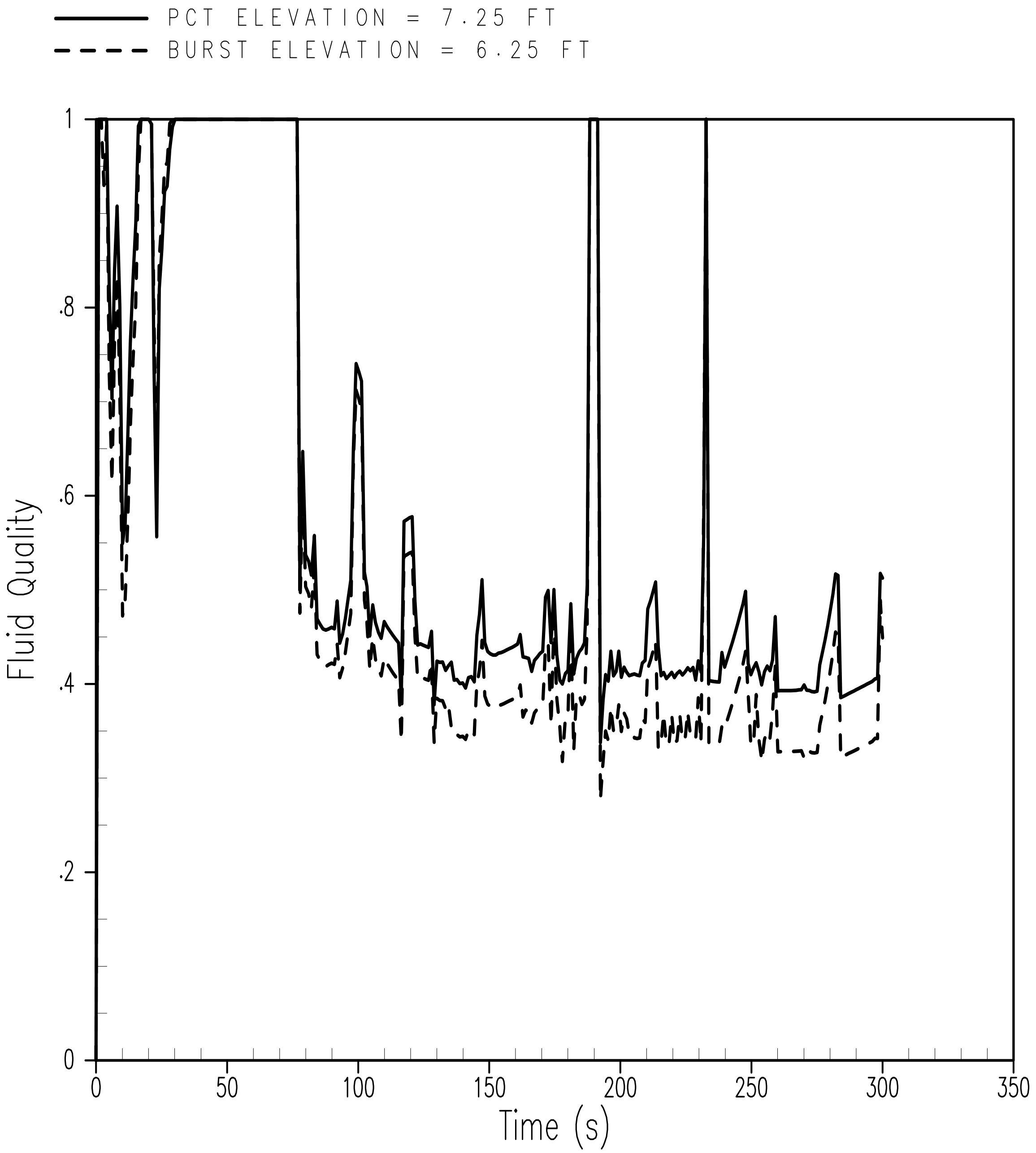
BREAK ENERGY RELEASE RATE DURING BLOWDOWN (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 156-IFBA)

FIGURE 15.6.5–12 (SHEET 9 OF 9)



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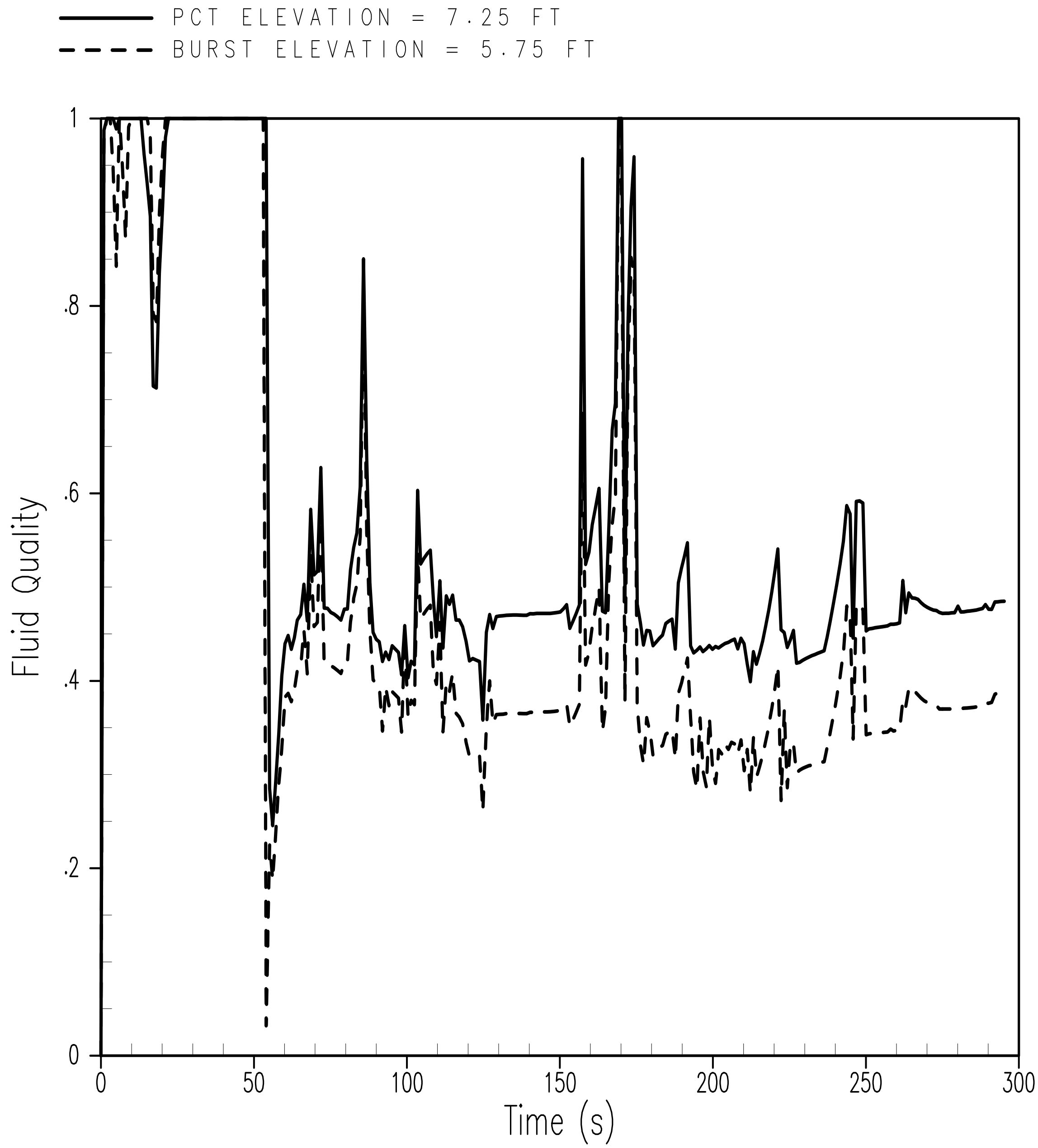
FLUID QUALITY AT PCT AND BURST ELEVATIONS (C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–13 (SHEET 1 OF 9)



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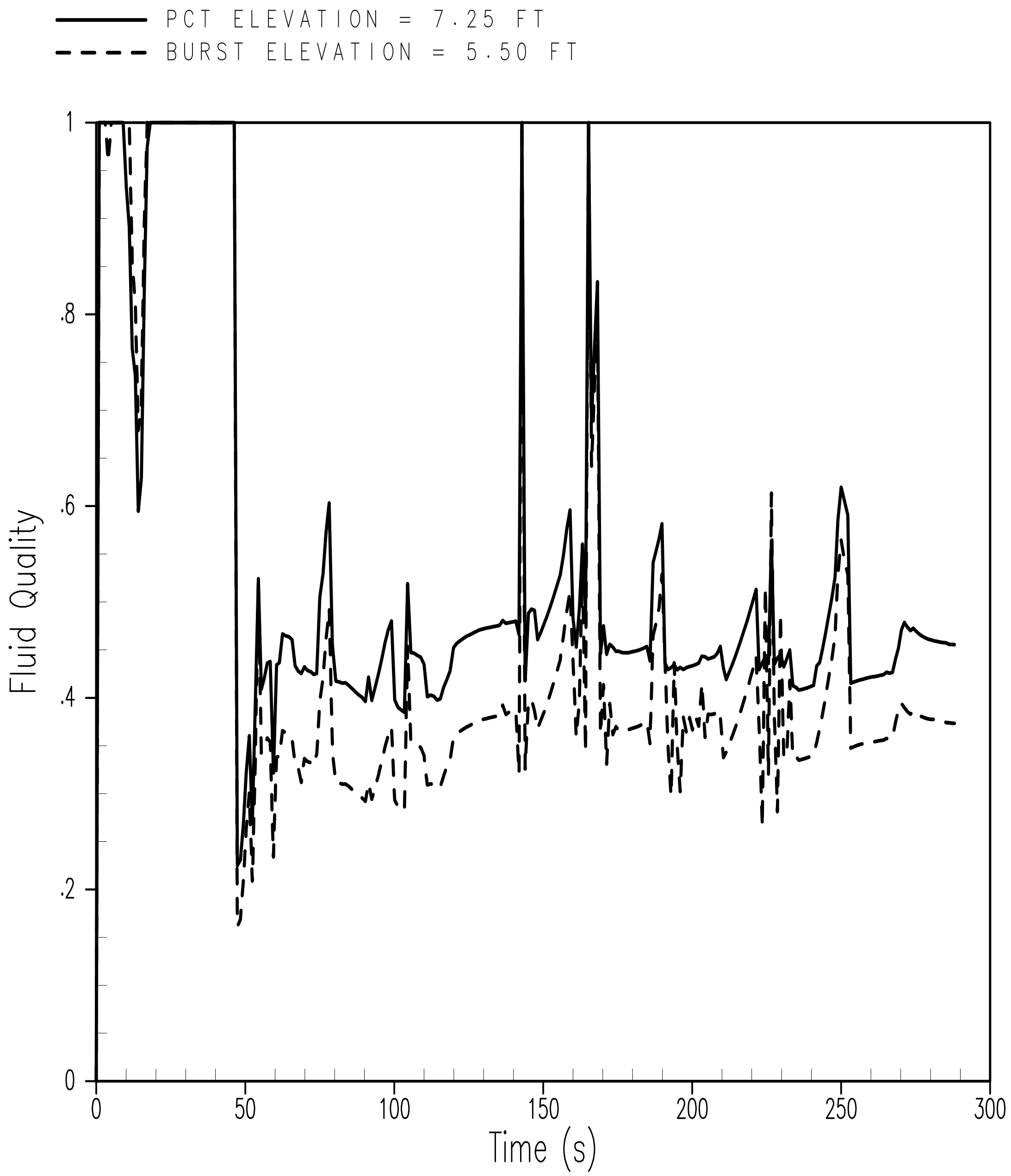
FLUID QUALITY AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–13 (SHEET 2 OF 9)



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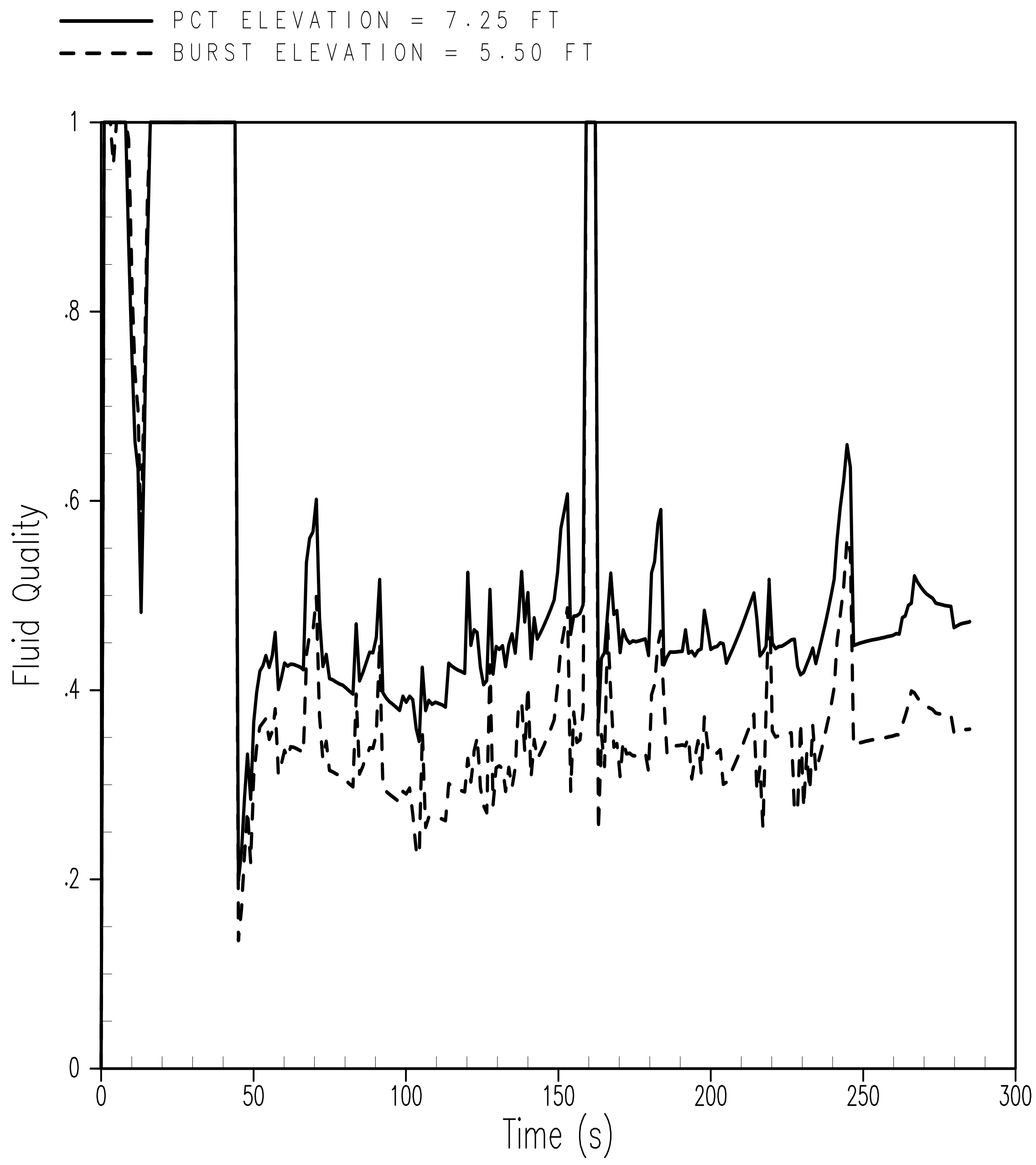
FLUID QUALITY AT PCT AND BURST ELEVATIONS (C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–13 (SHEET 3 OF 9)



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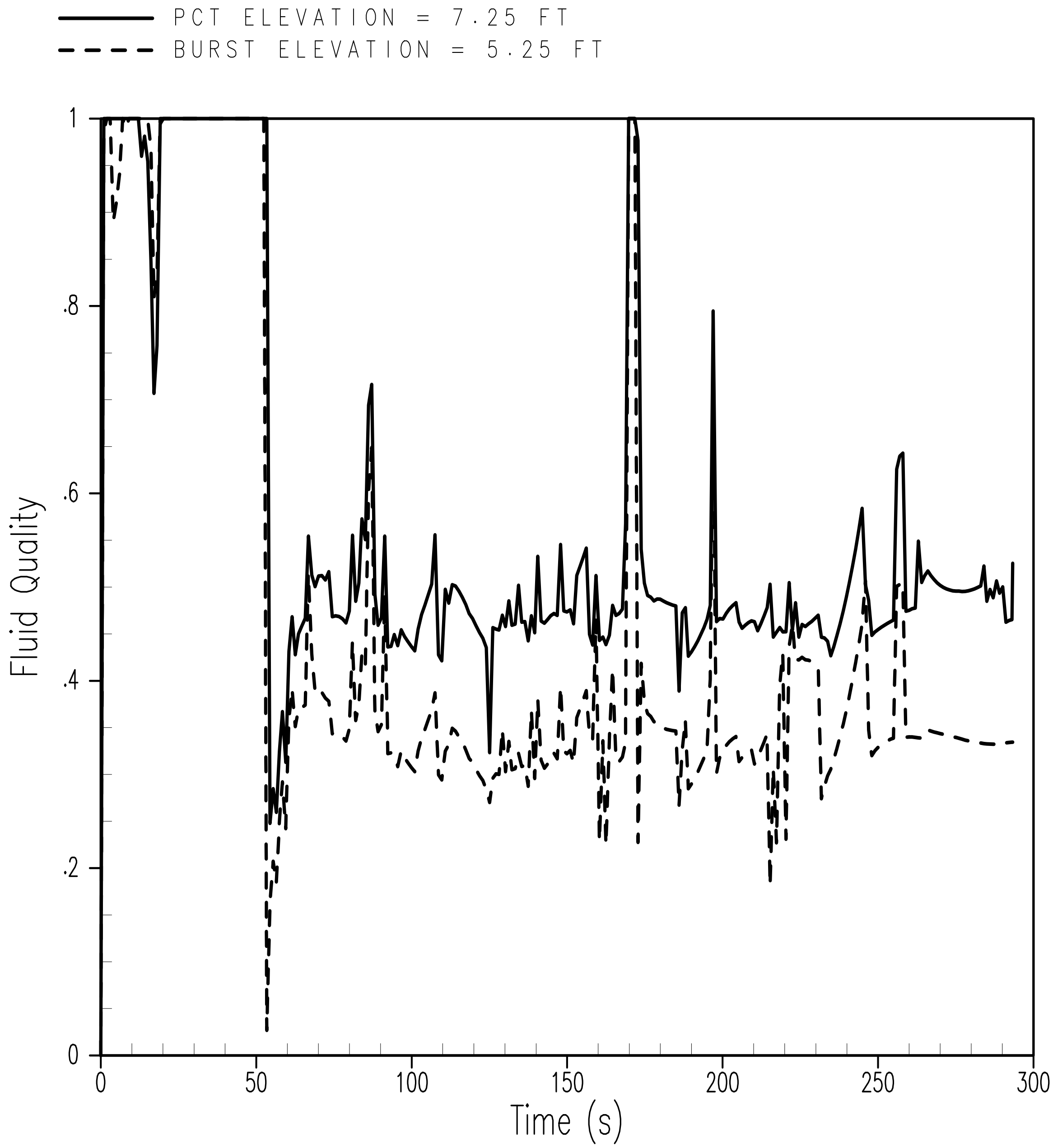
FLUID QUALITY AT PCT AND BURST ELEVATIONS (C_D = 1.0, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–13 (SHEET 4 OF 9)



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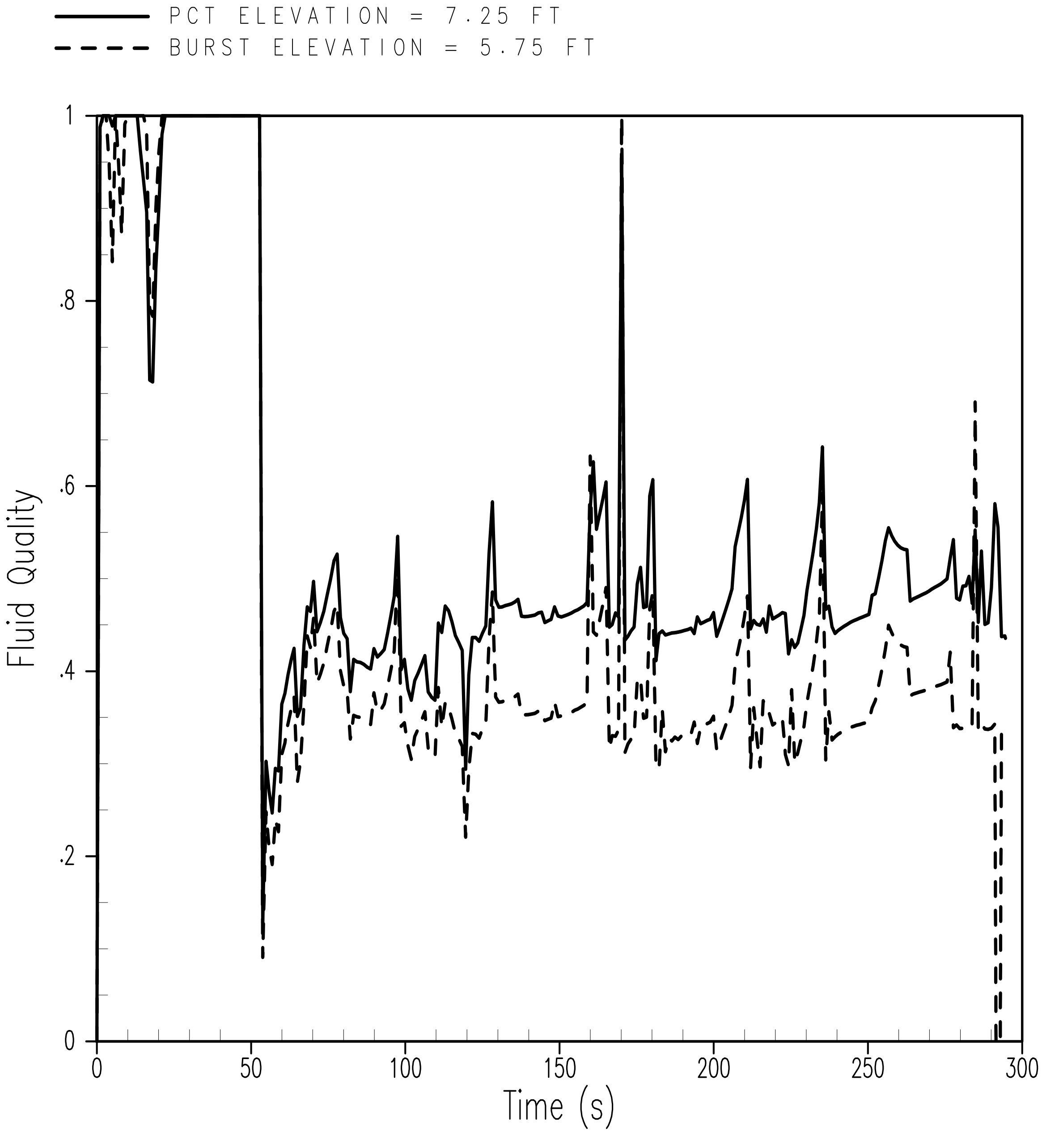
FLUID QUALITY AT PCT AND BURST ELEVATIONS (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–13 (SHEET 5 OF 9)



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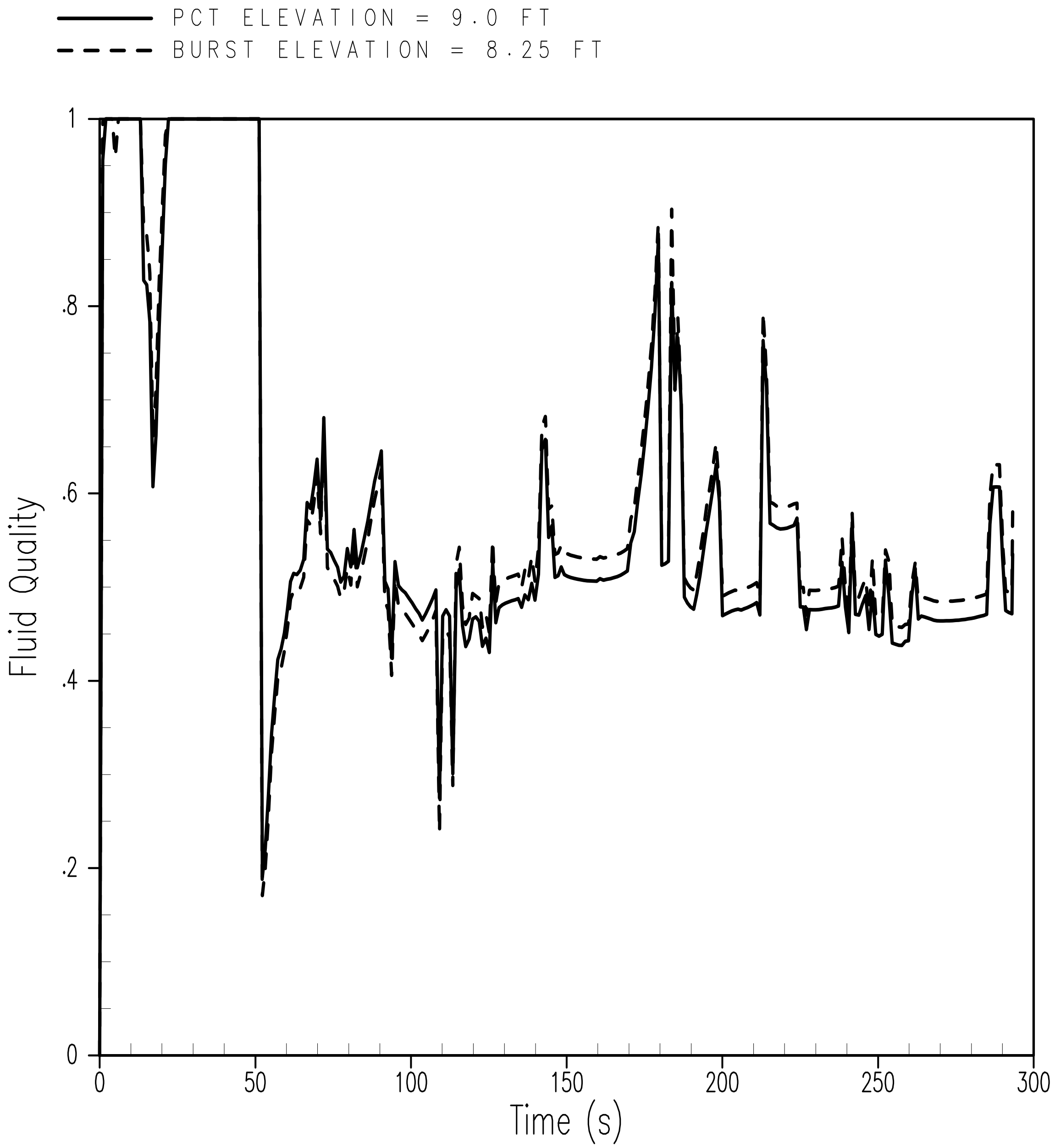
UNIT 1 AND UNIT 2

FLUID QUALITY AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MAX SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–13 (SHEET 6 OF 9)



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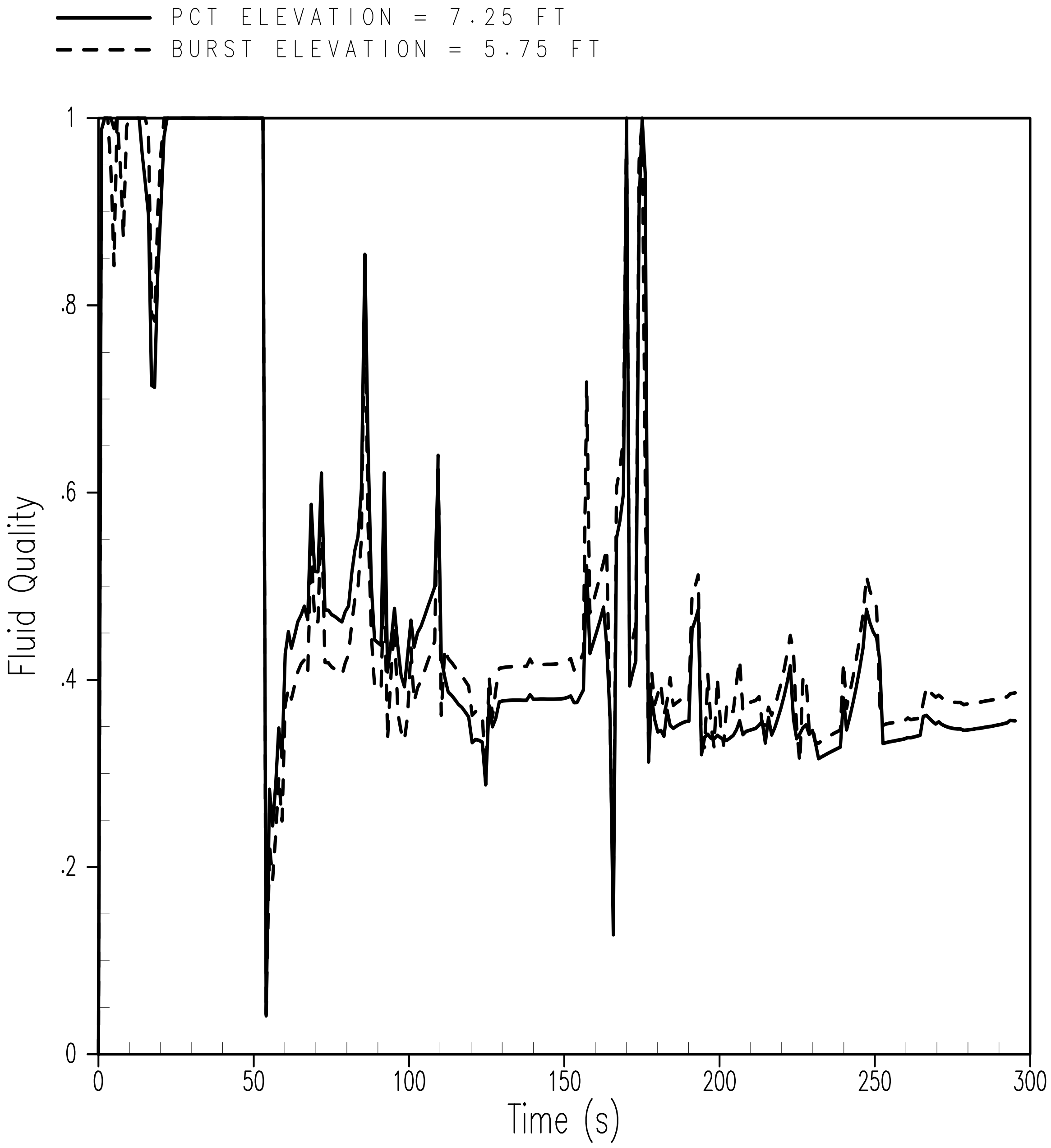
UNIT 1 AND UNIT 2

FLUID QUALITY AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, 8.5 FT POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–13 (SHEET 7 OF 9)



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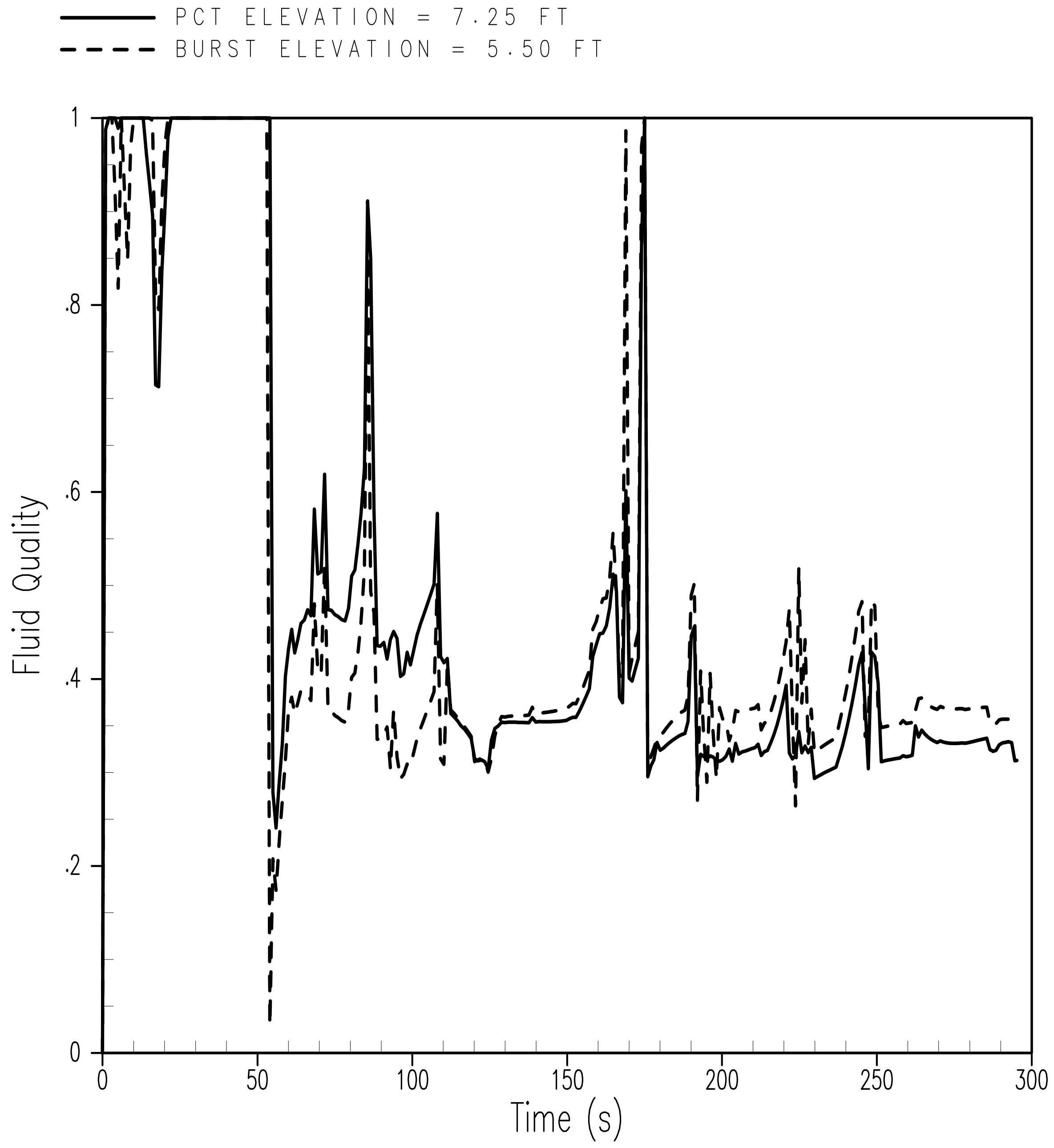
FLUID QUALITY AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–13 (SHEET 8 OF 9)



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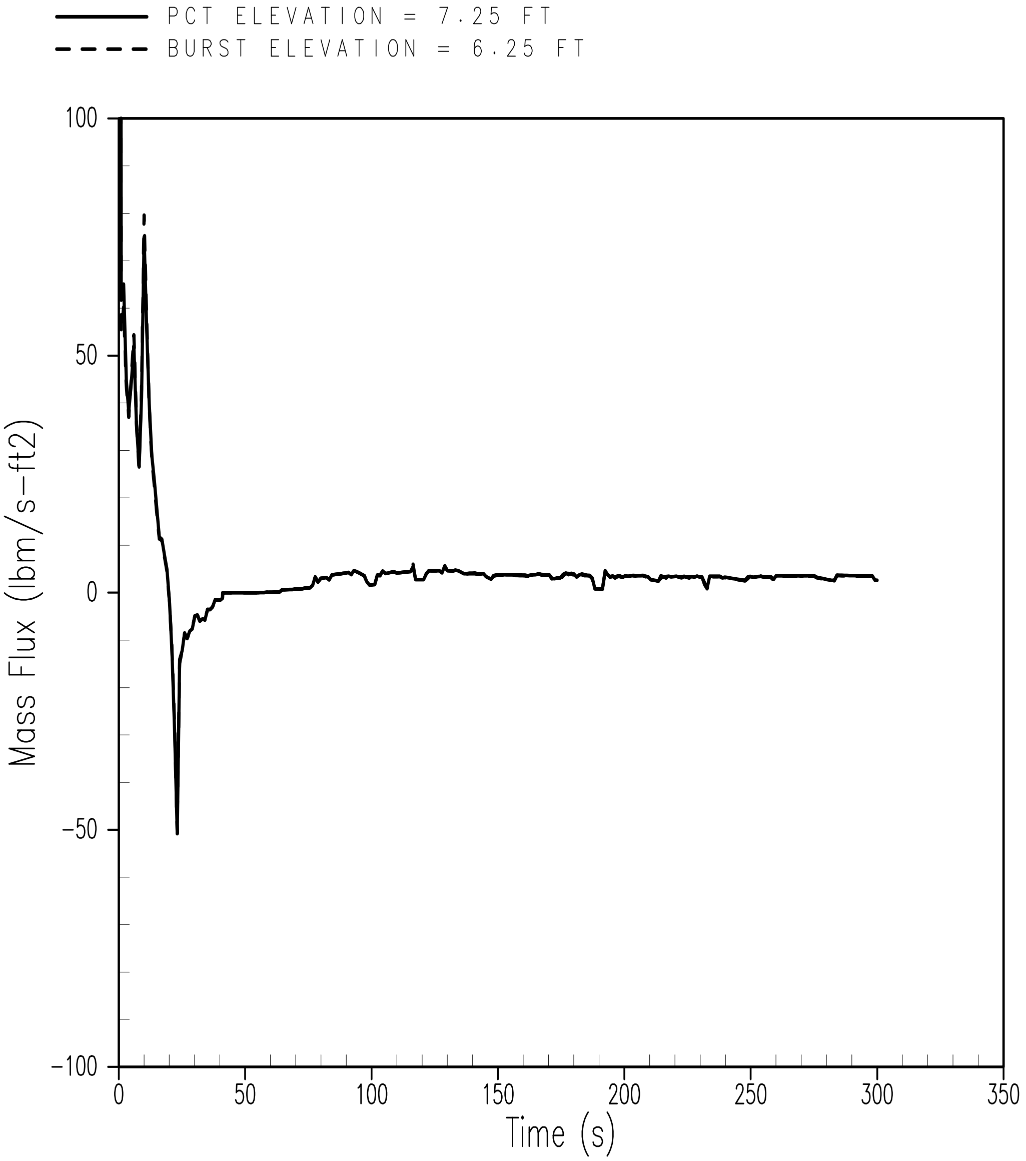
FLUID QUALITY AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 156-IFBA)

FIGURE 15.6.5–13 (SHEET 9 OF 9)



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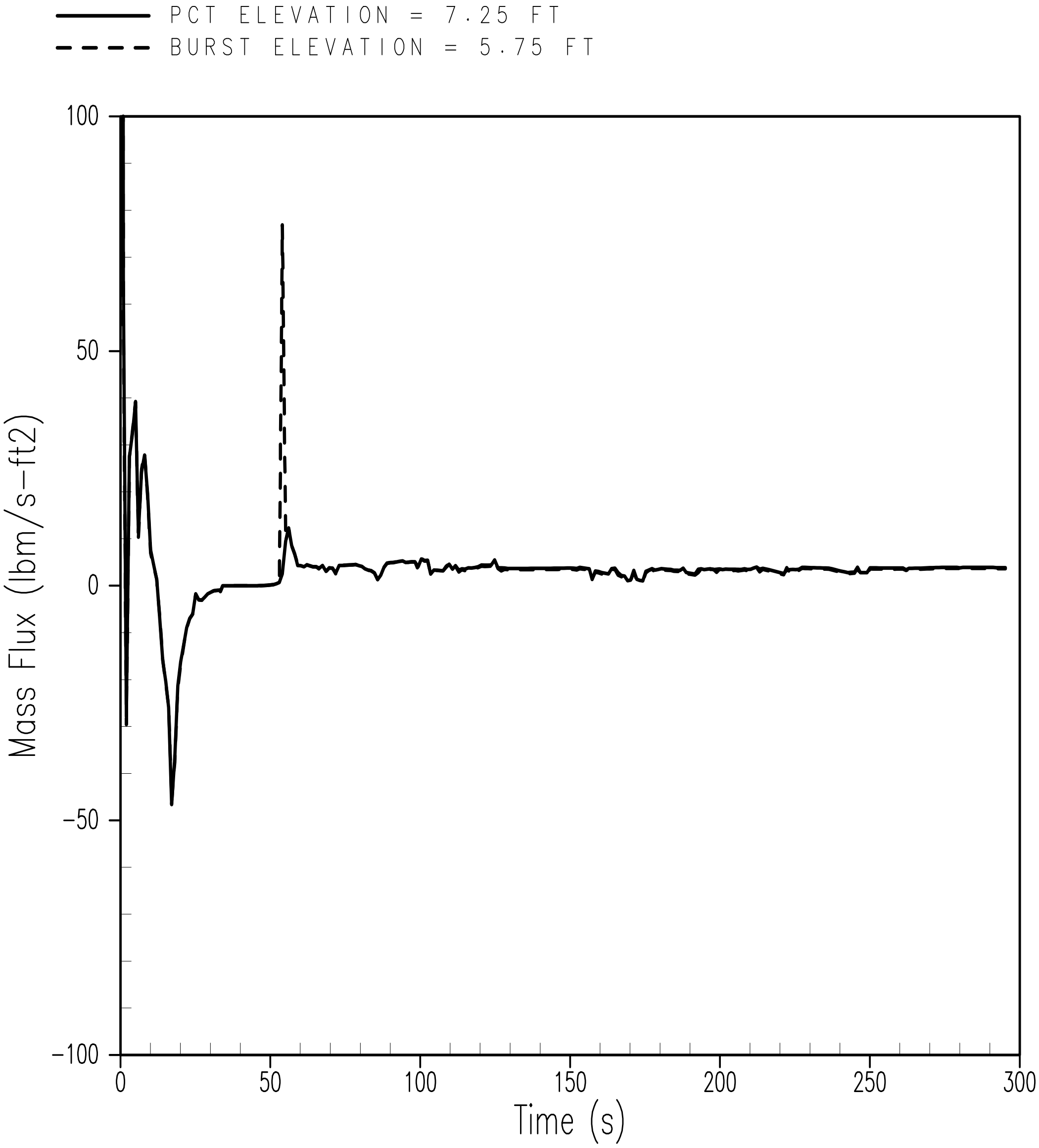
FLUID MASS VELOCITY AT PCT AND BURST ELEVATIONS (C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–14 (SHEET 1 OF 9)



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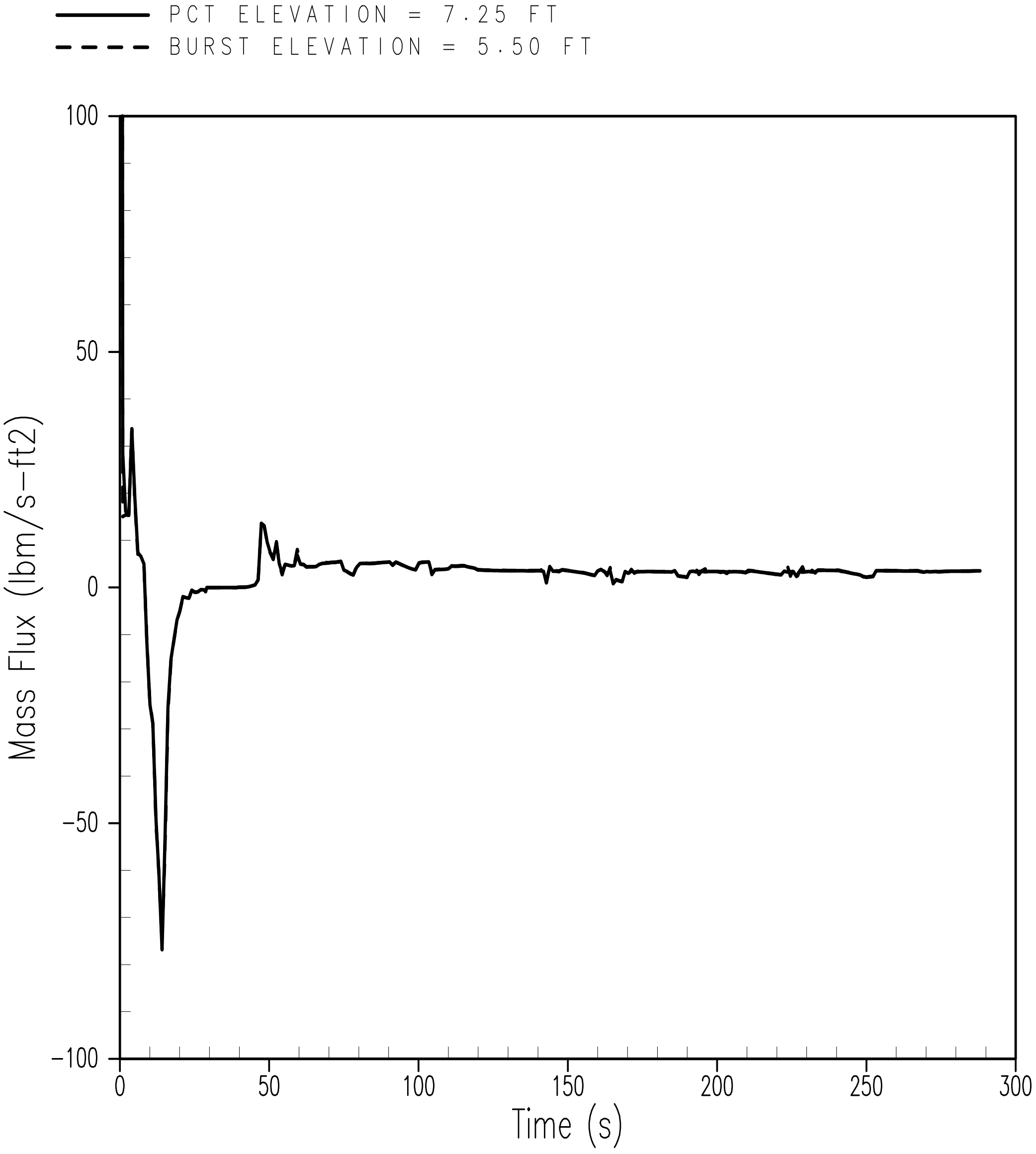
FLUID MASS VELOCITY AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–14 (SHEET 2 OF 9)



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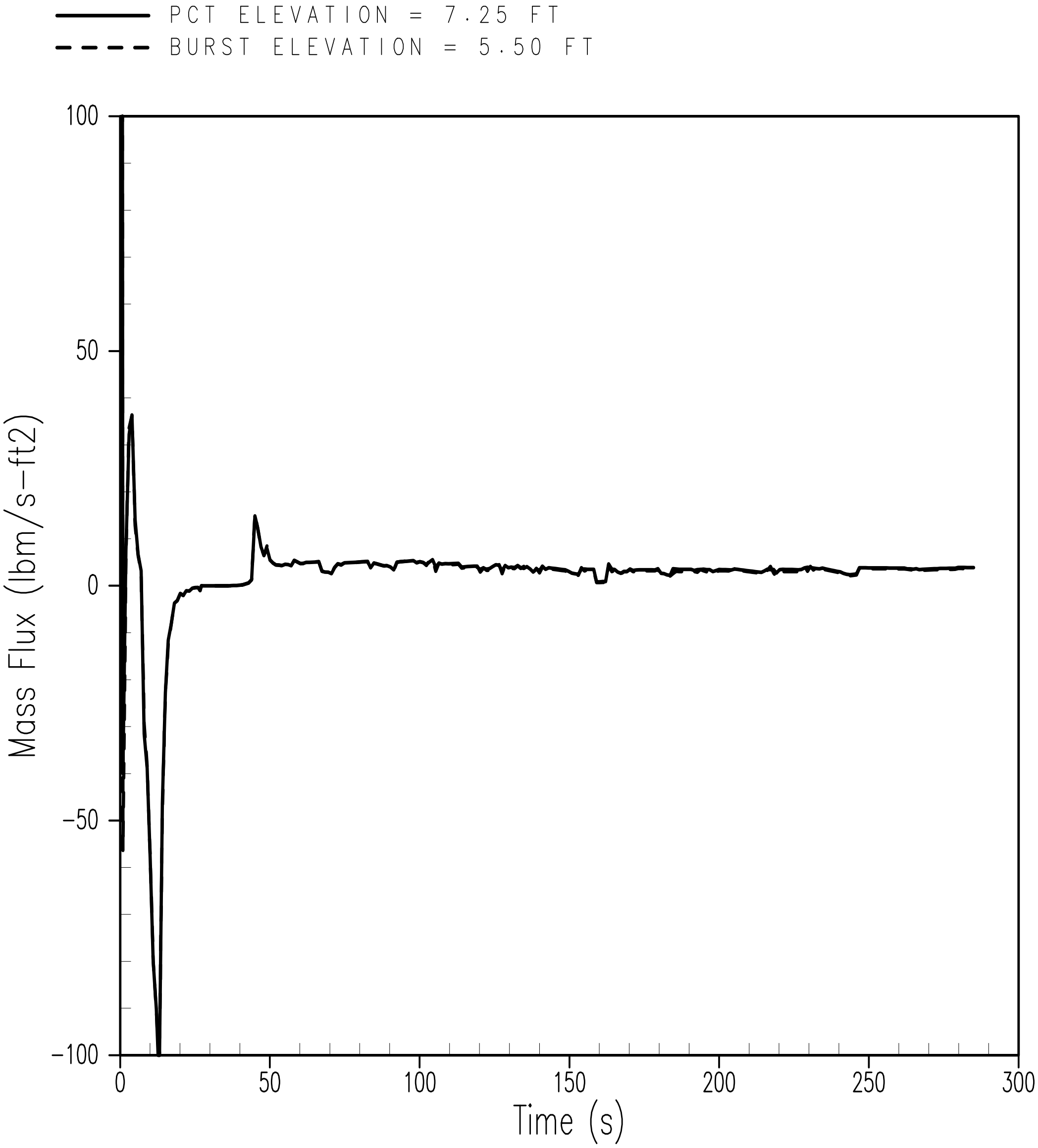
FLUID MASS VELOCITY AT PCT AND BURST ELEVATIONS (C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–14 (SHEET 3 OF 9)



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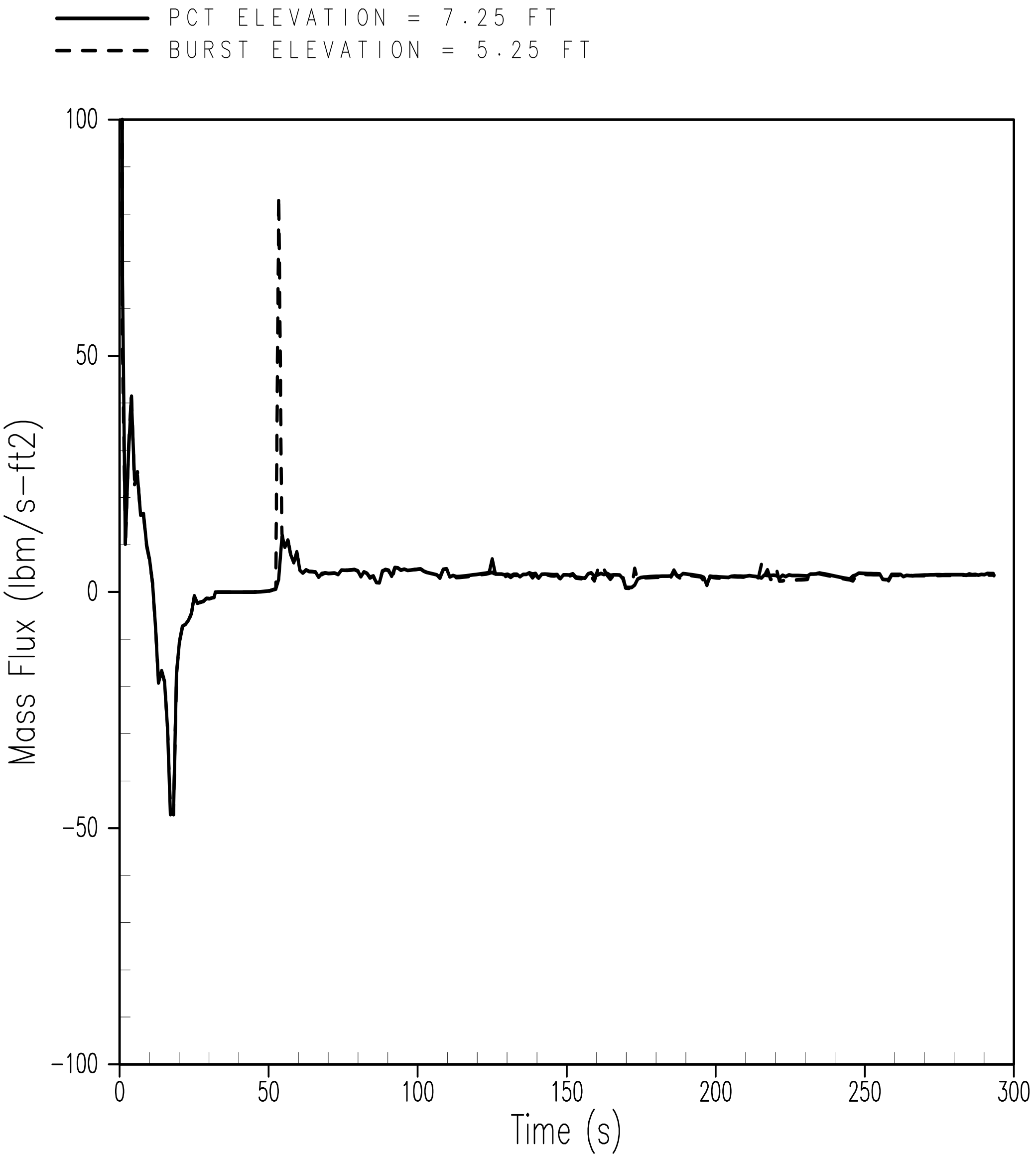
FLUID MASS VELOCITY AT PCT AND BURST ELEVATIONS (C_D = 1.0, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–14 (SHEET 4 OF 9)



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FLUID MASS VELOCITY AT PCT AND BURST ELEVATIONS (C_D = 0.6, HIGH T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–14 (SHEET 5 OF 9)

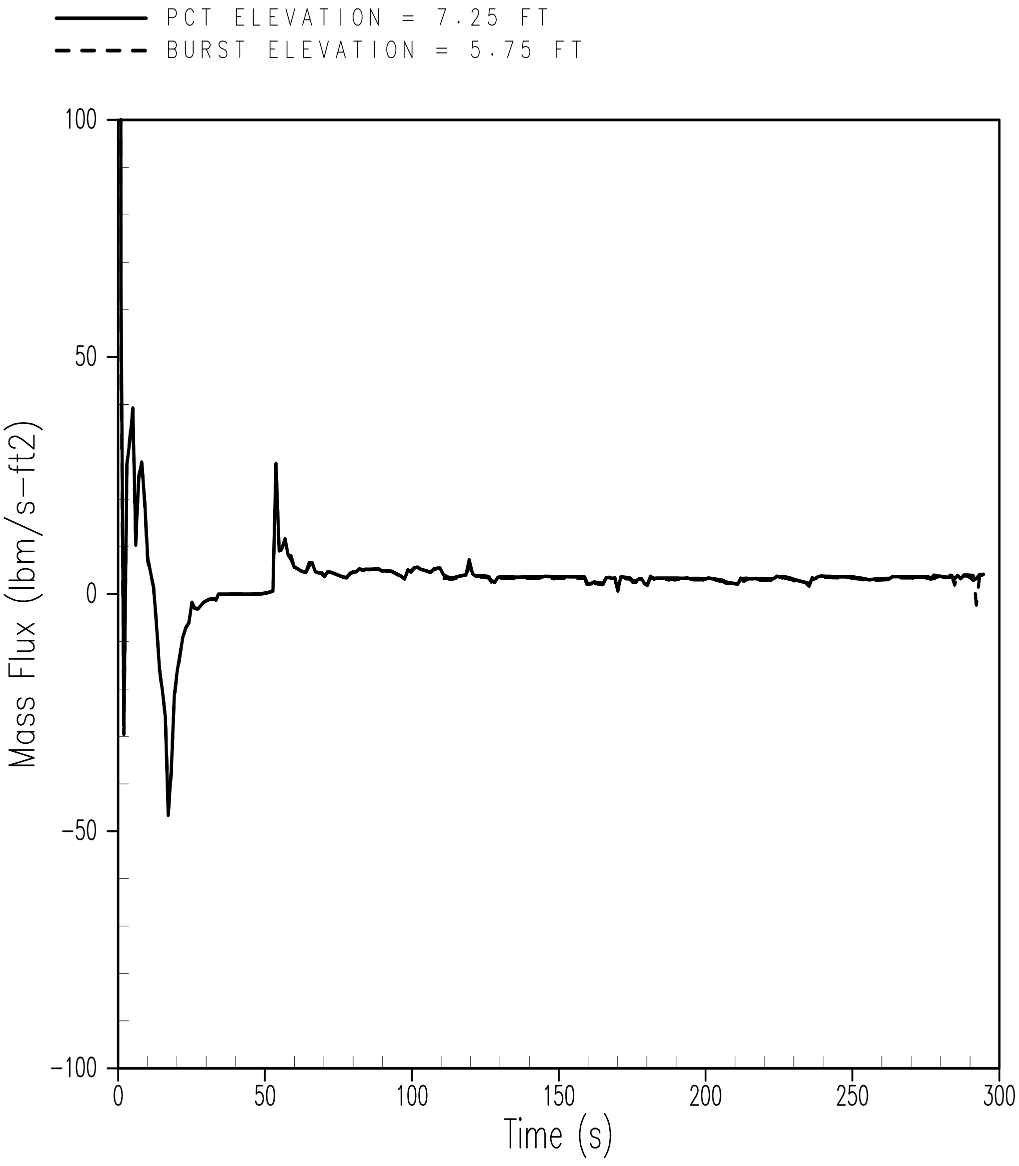

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FIGURE 15.6.5–14 (SHEET 6 OF 9)

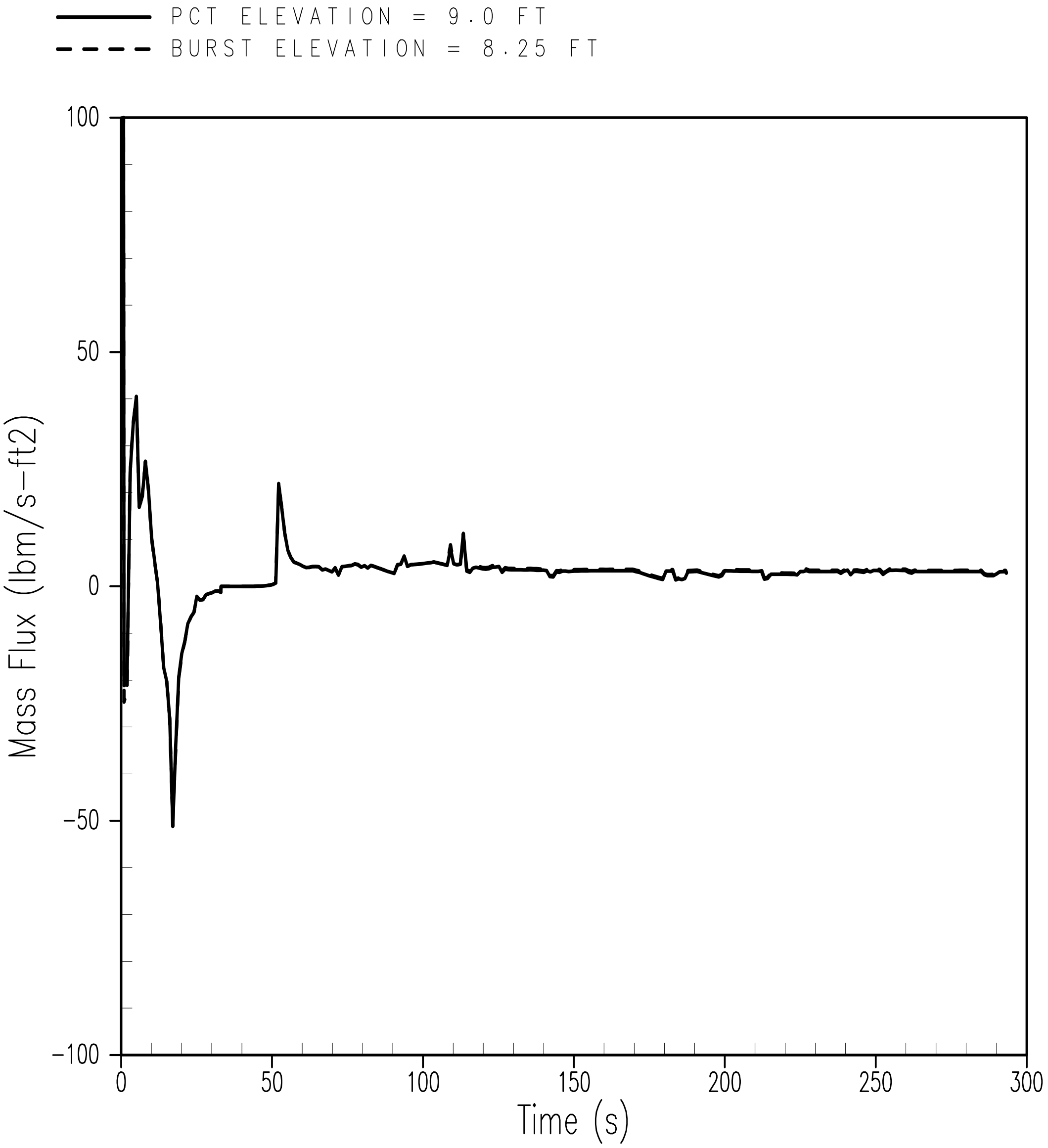

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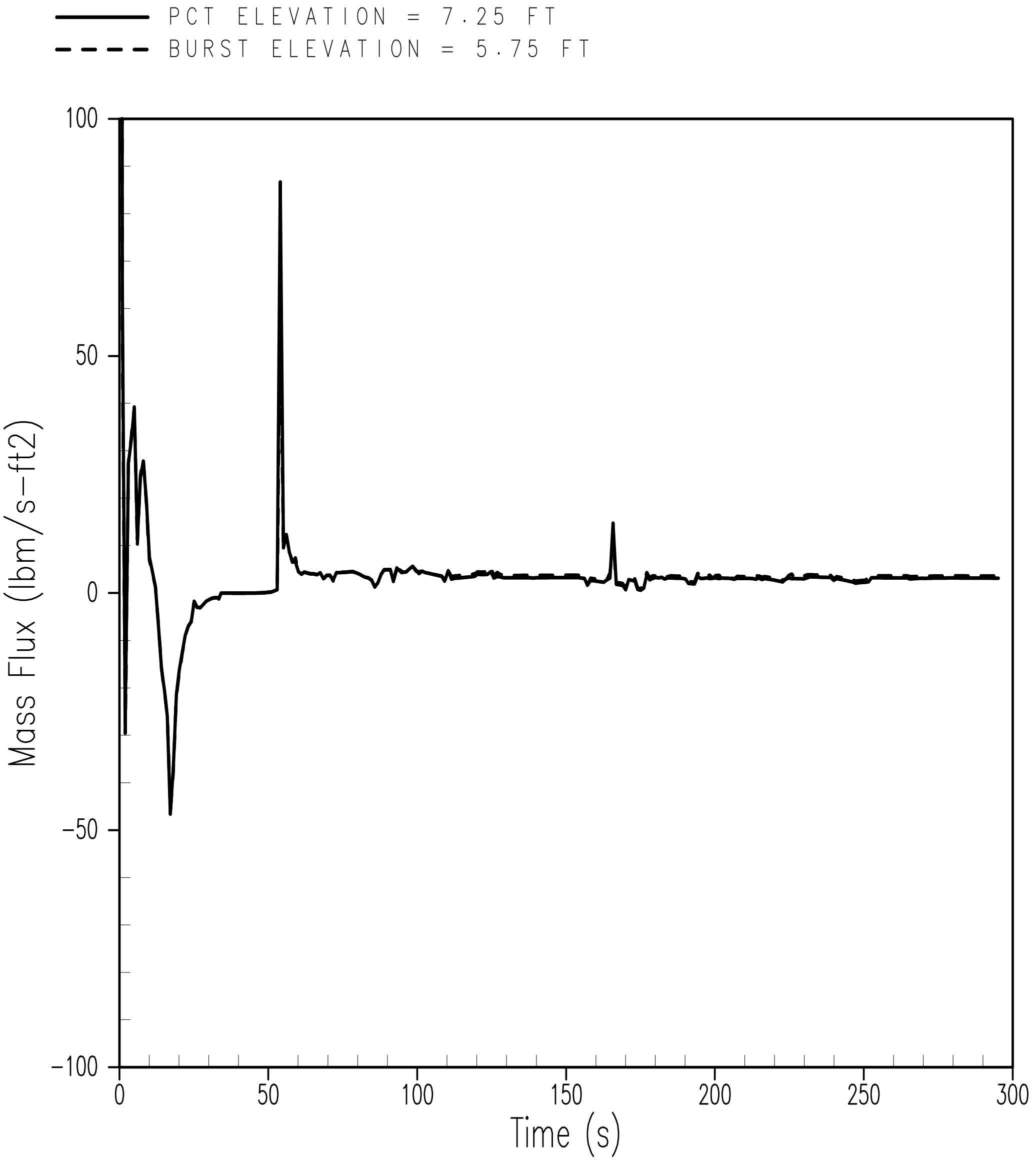
FIGURE 15.6.5–14 (SHEET 7 OF 9)



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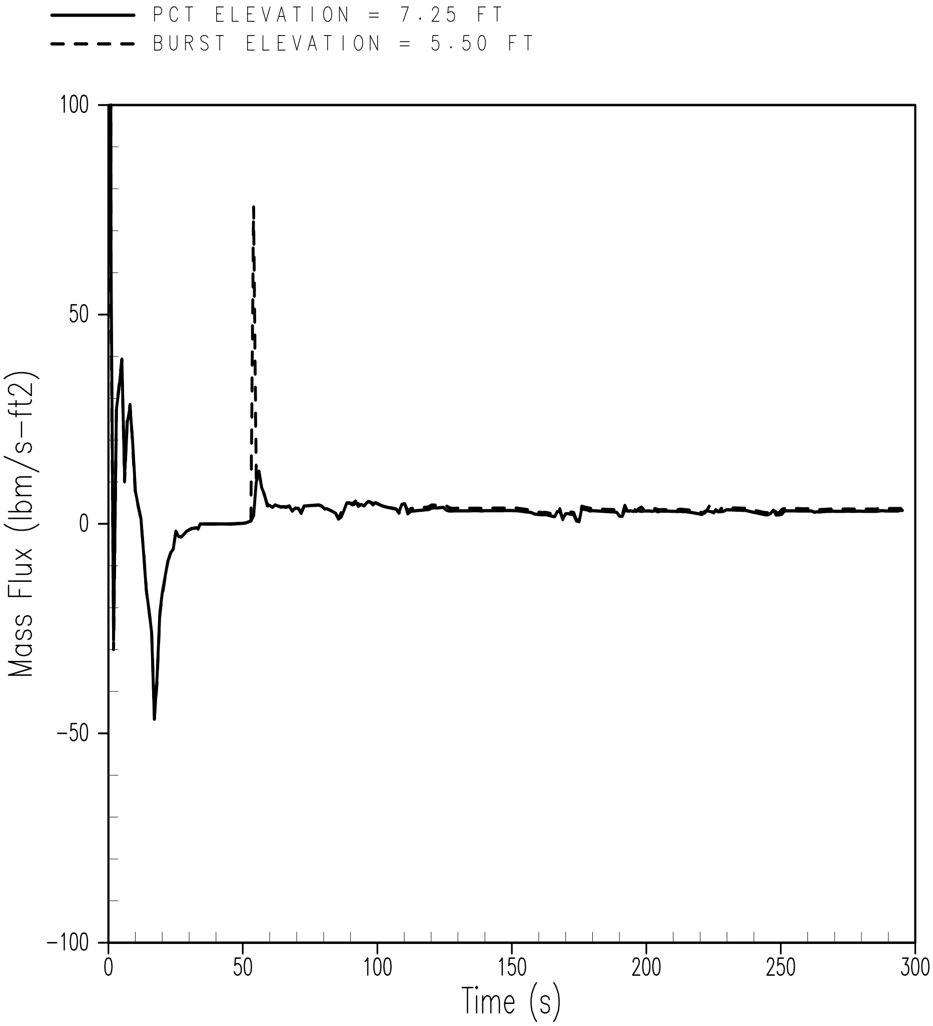
FLUID MASS VELOCITY AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–14 (SHEET 8 OF 9)



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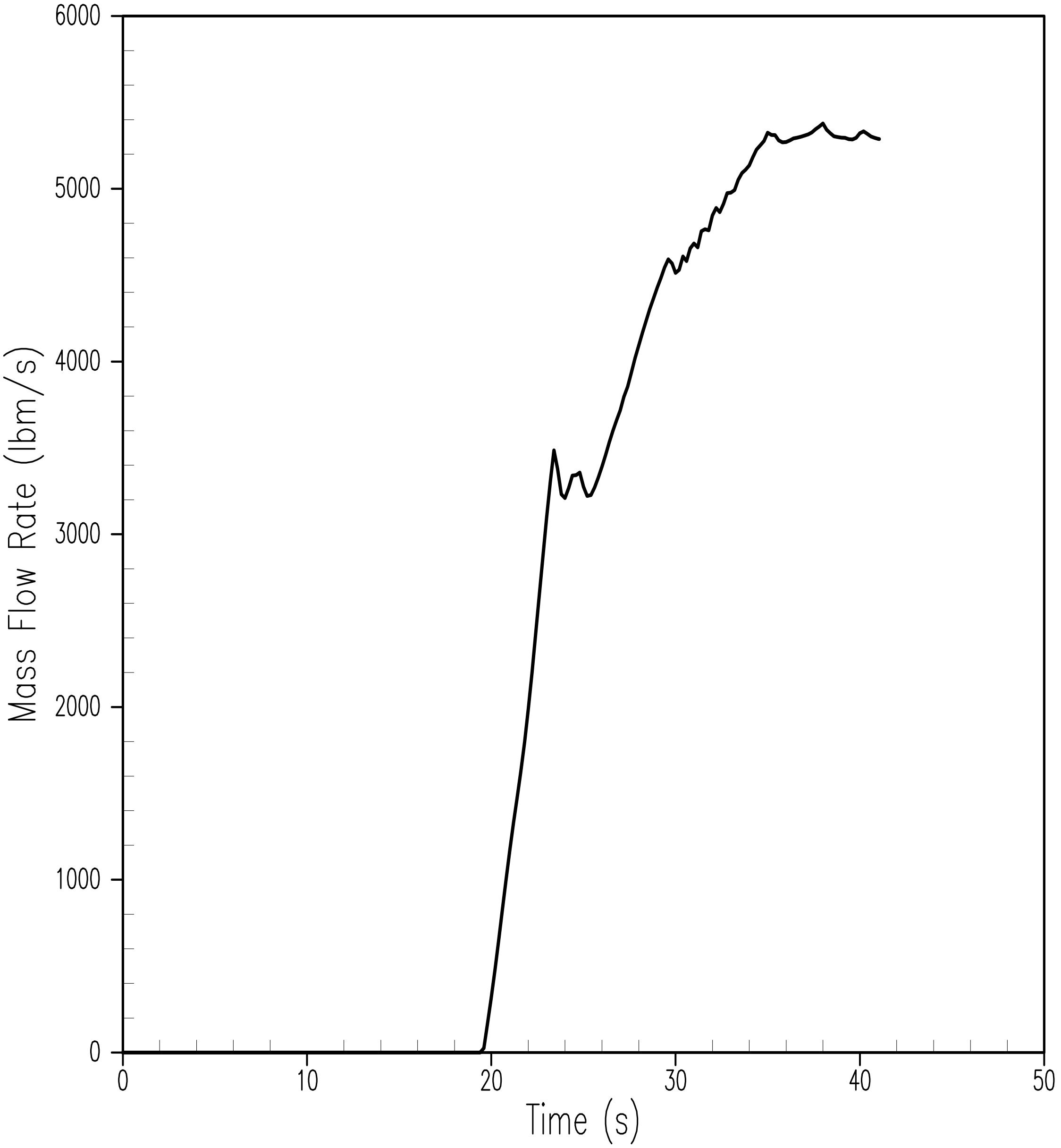
FLUID MASS VELOCITY AT PCT AND BURST ELEVATIONS (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 156-IFBA)

FIGURE 15.6.5–14 (SHEET 9 OF 9)



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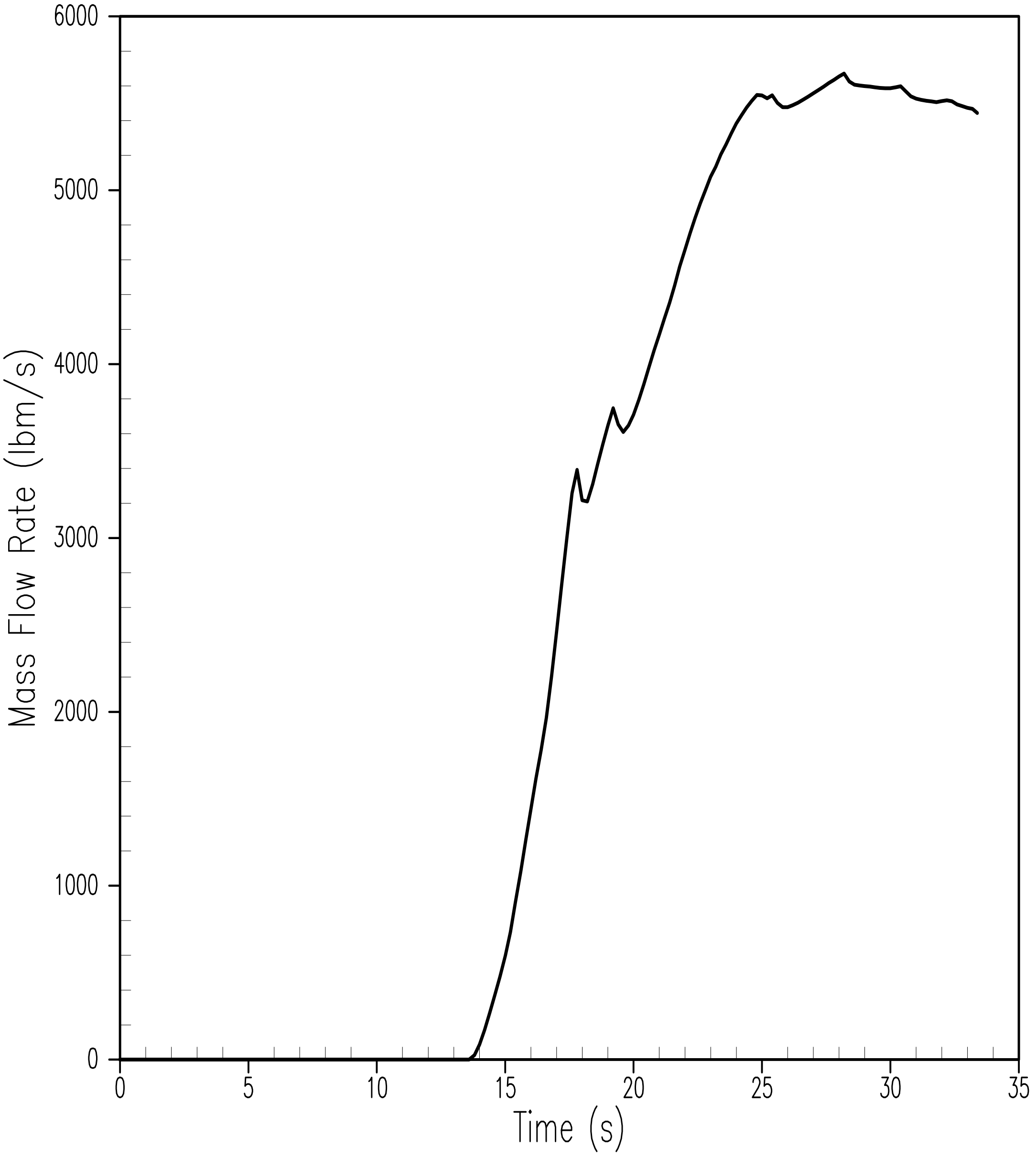
INTACT LOOP ACCUMULATOR MASS FLOW RATE DURING BLOWDOWN(C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–15 (SHEET 1 OF 9)



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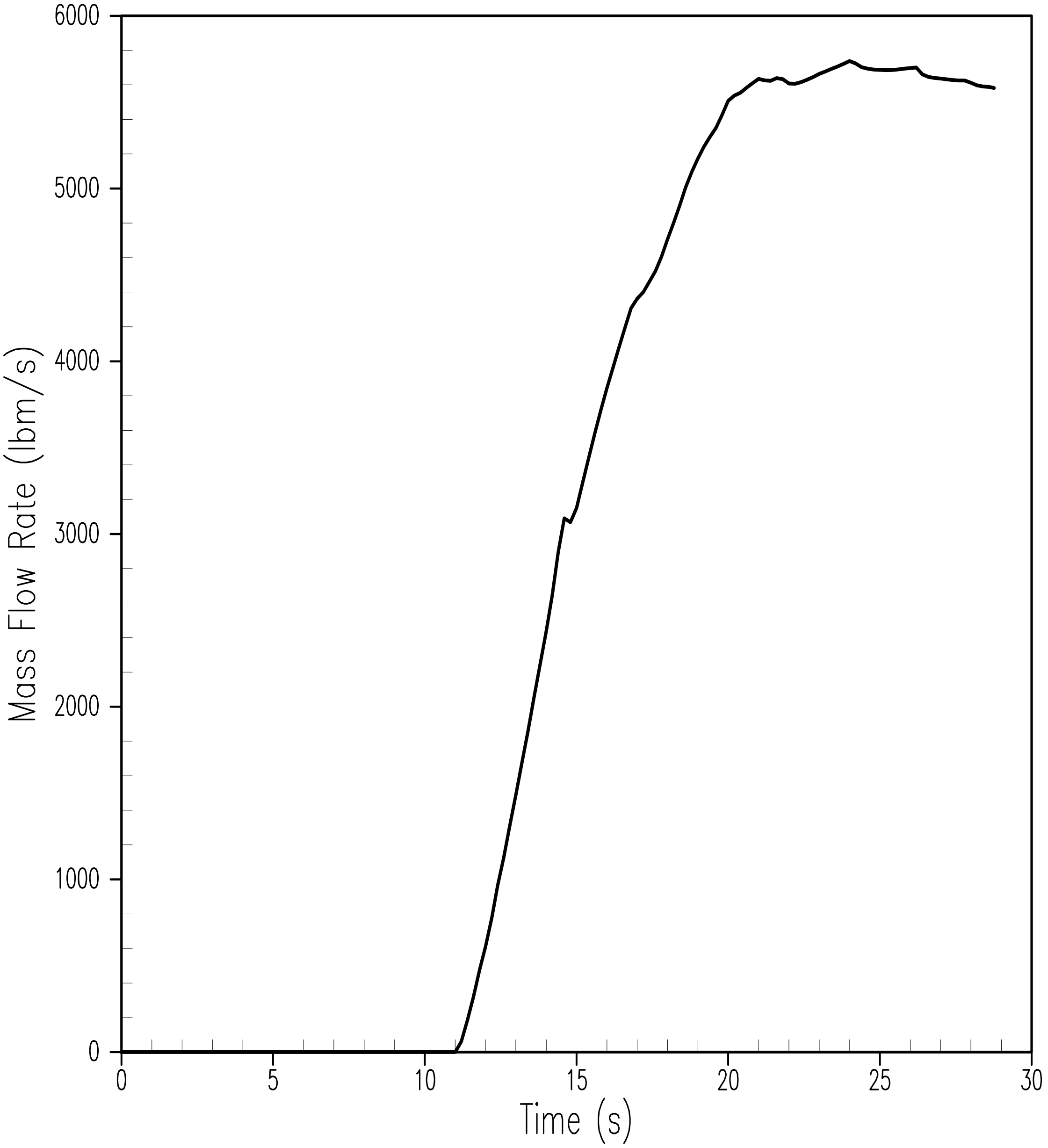
INTACT LOOP ACCUMULATOR MASS FLOW RATE DURING BLOWDOWN(C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–15 (SHEET 2 OF 9)



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INTACT LOOP ACCUMULATOR MASS FLOW RATE DURING BLOWDOWN(C_D = 0.8, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–15 (SHEET 3 OF 9)

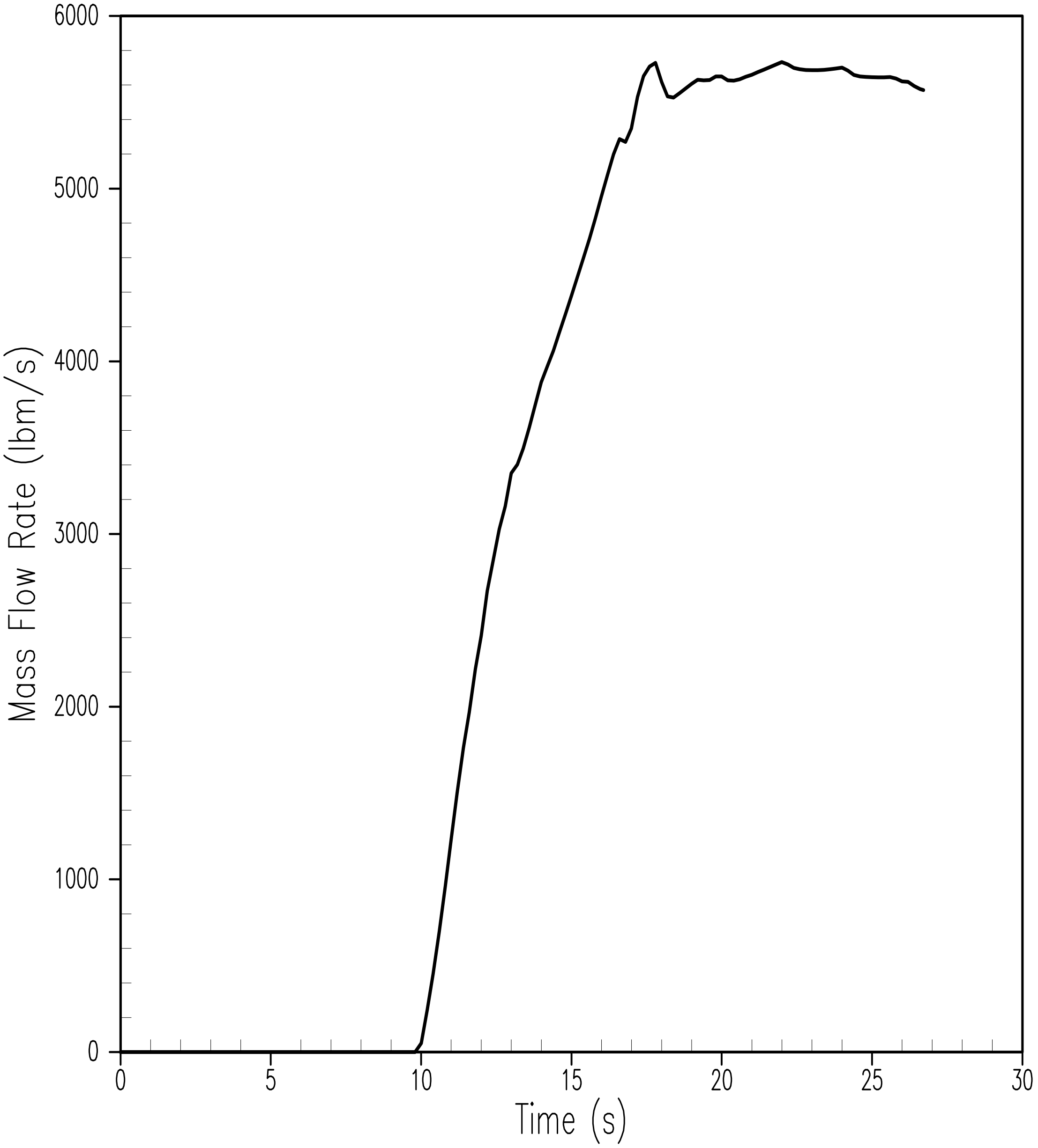

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FIGURE 15.6.5–15 (SHEET 4 OF 9)

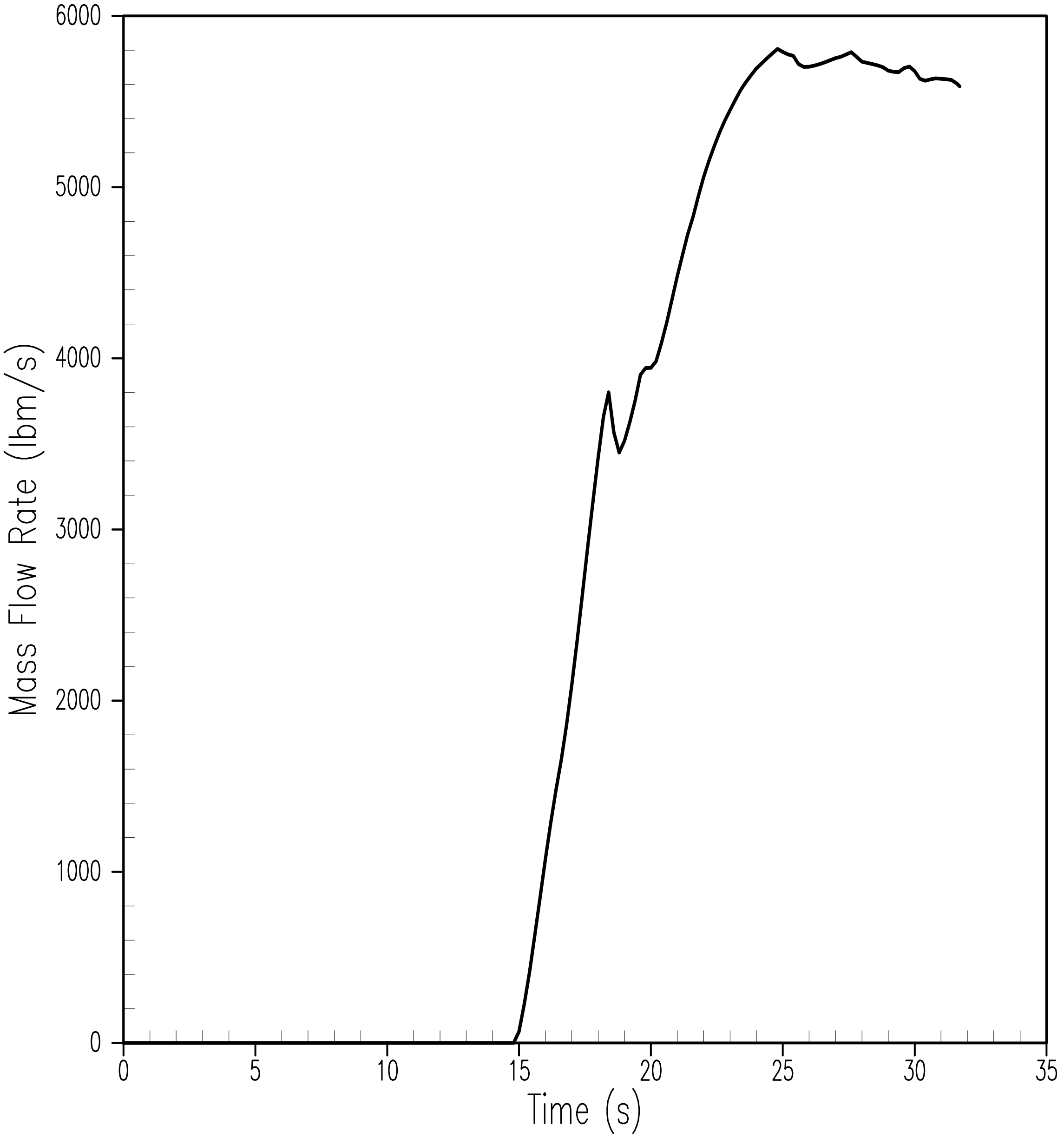

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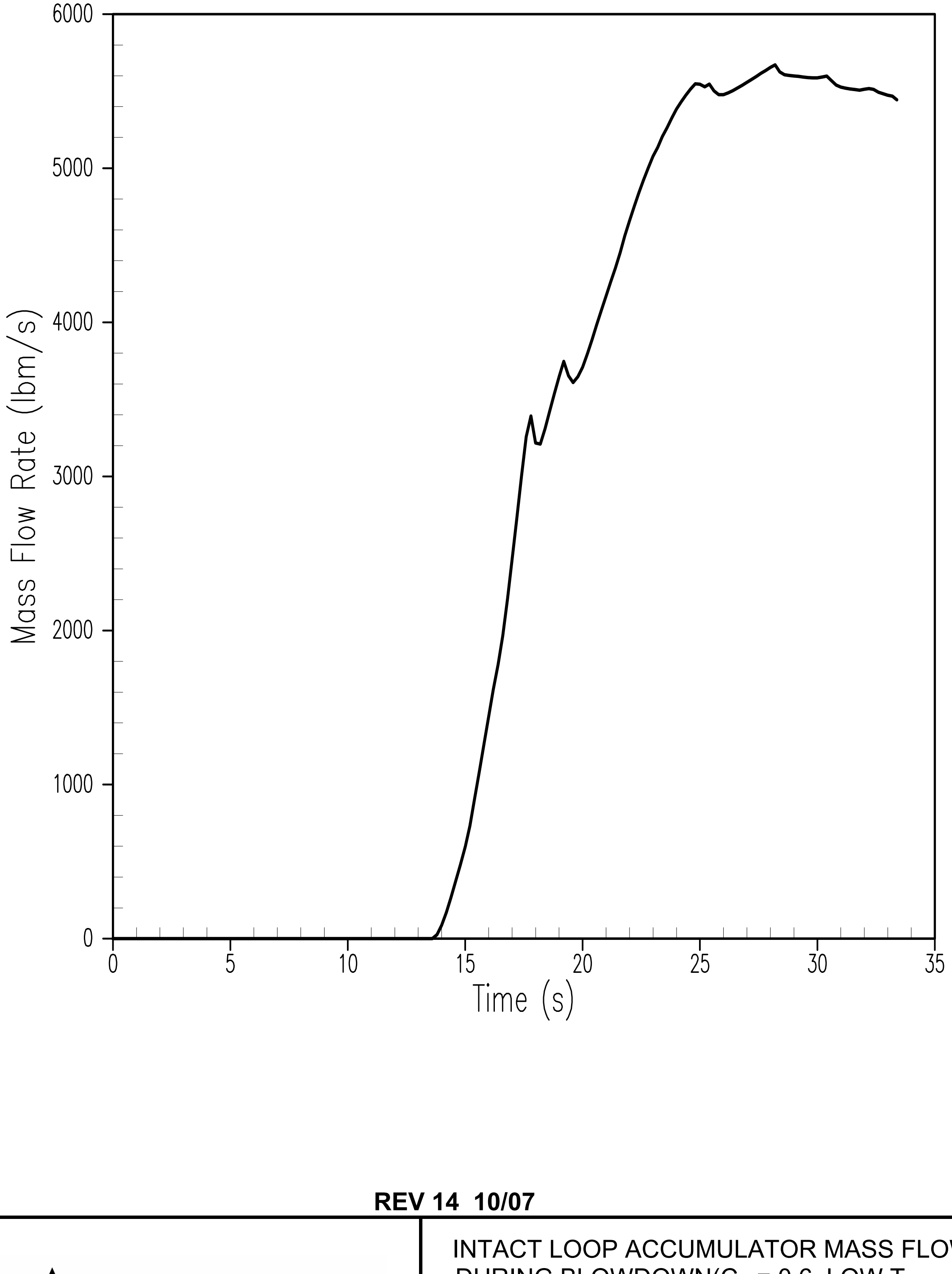
FIGURE 15.6.5–15 (SHEET 5 OF 9)



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INTACT LOOP ACCUMULATOR MASS FLOW RATE DURING BLOWDOWN(C_D = 0.6, LOW T_{AVG}, MAX SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–15 (SHEET 6 OF 9)

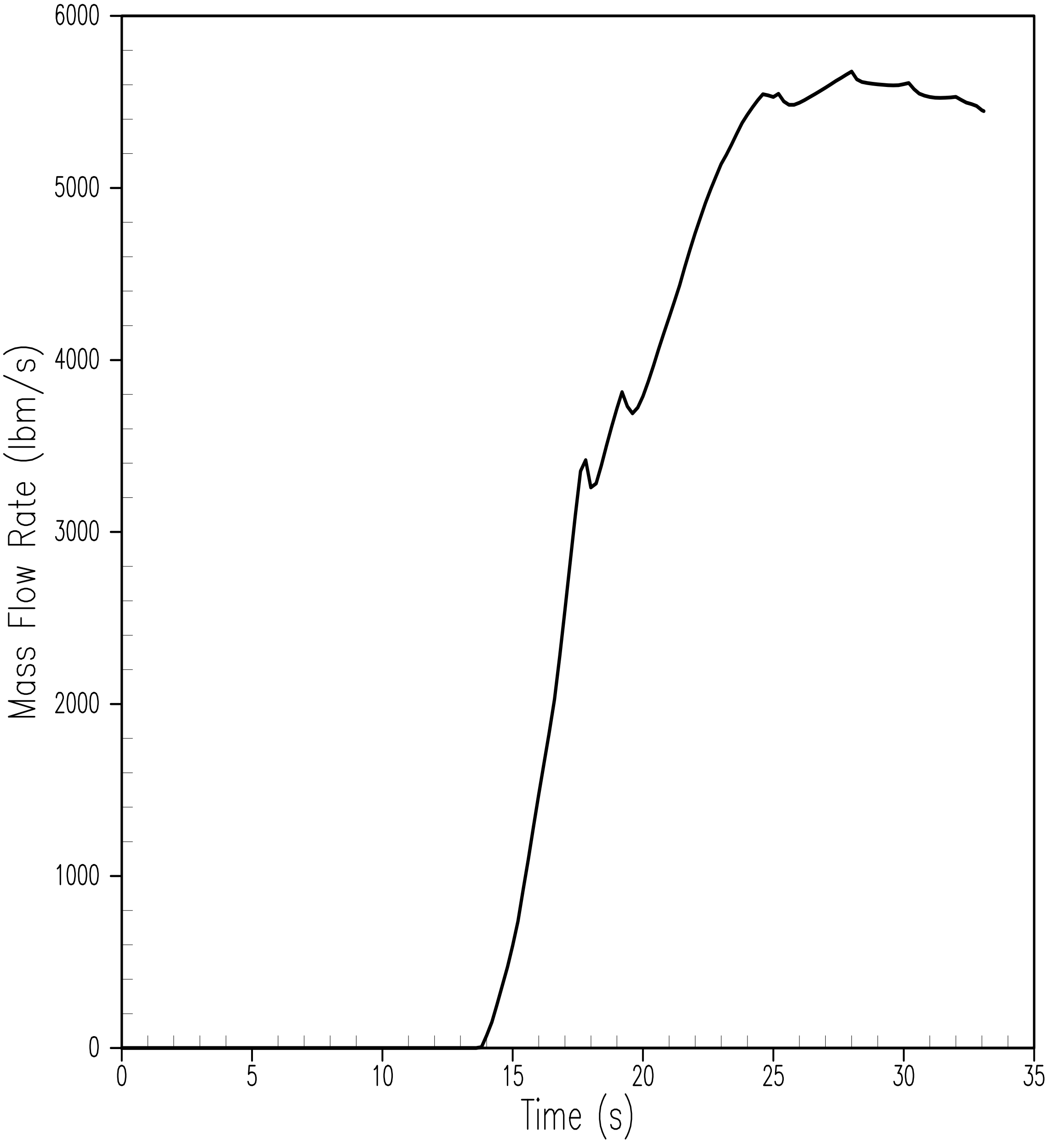

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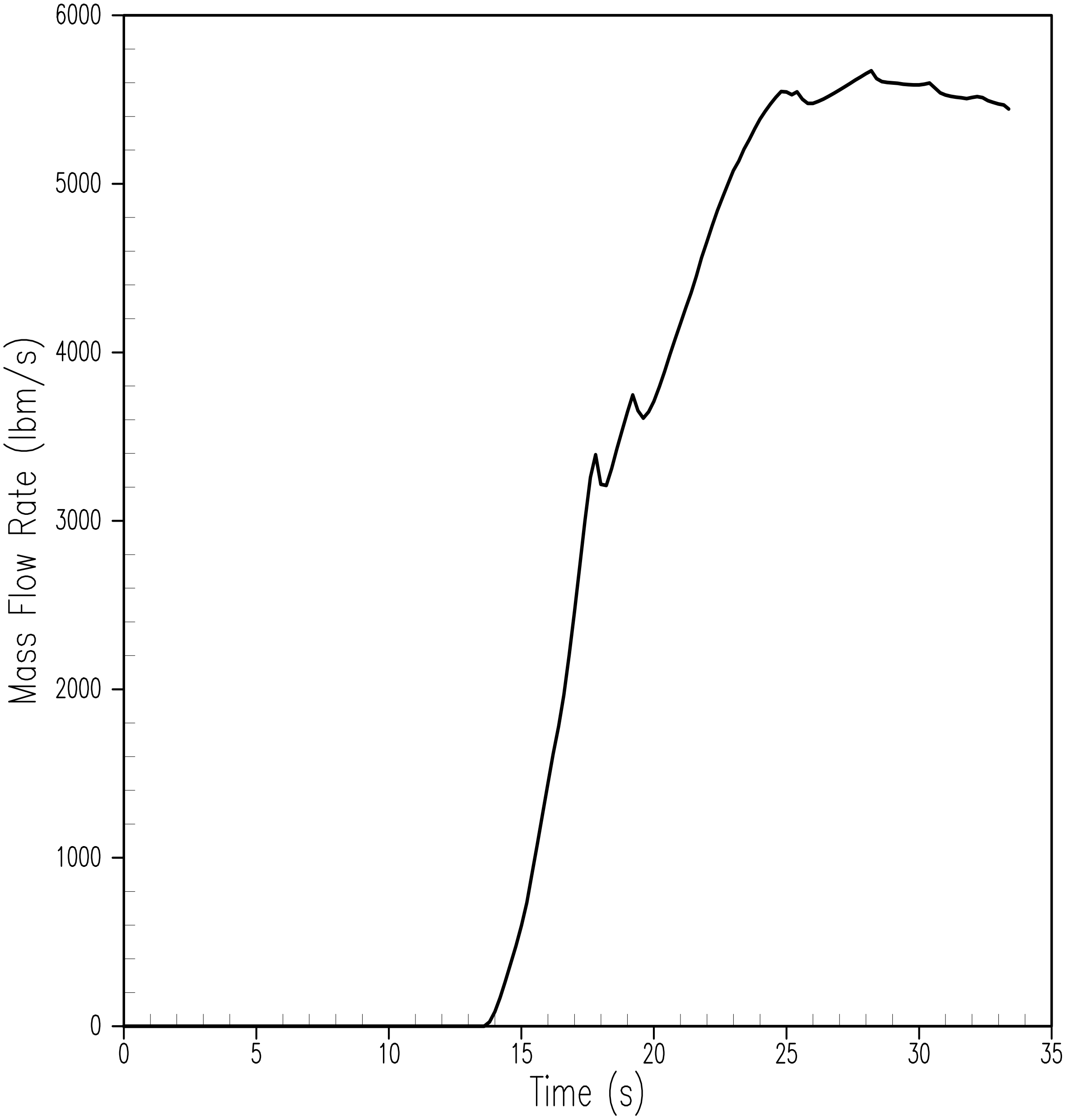
FIGURE 15.6.5–15 (SHEET 7 OF 9)



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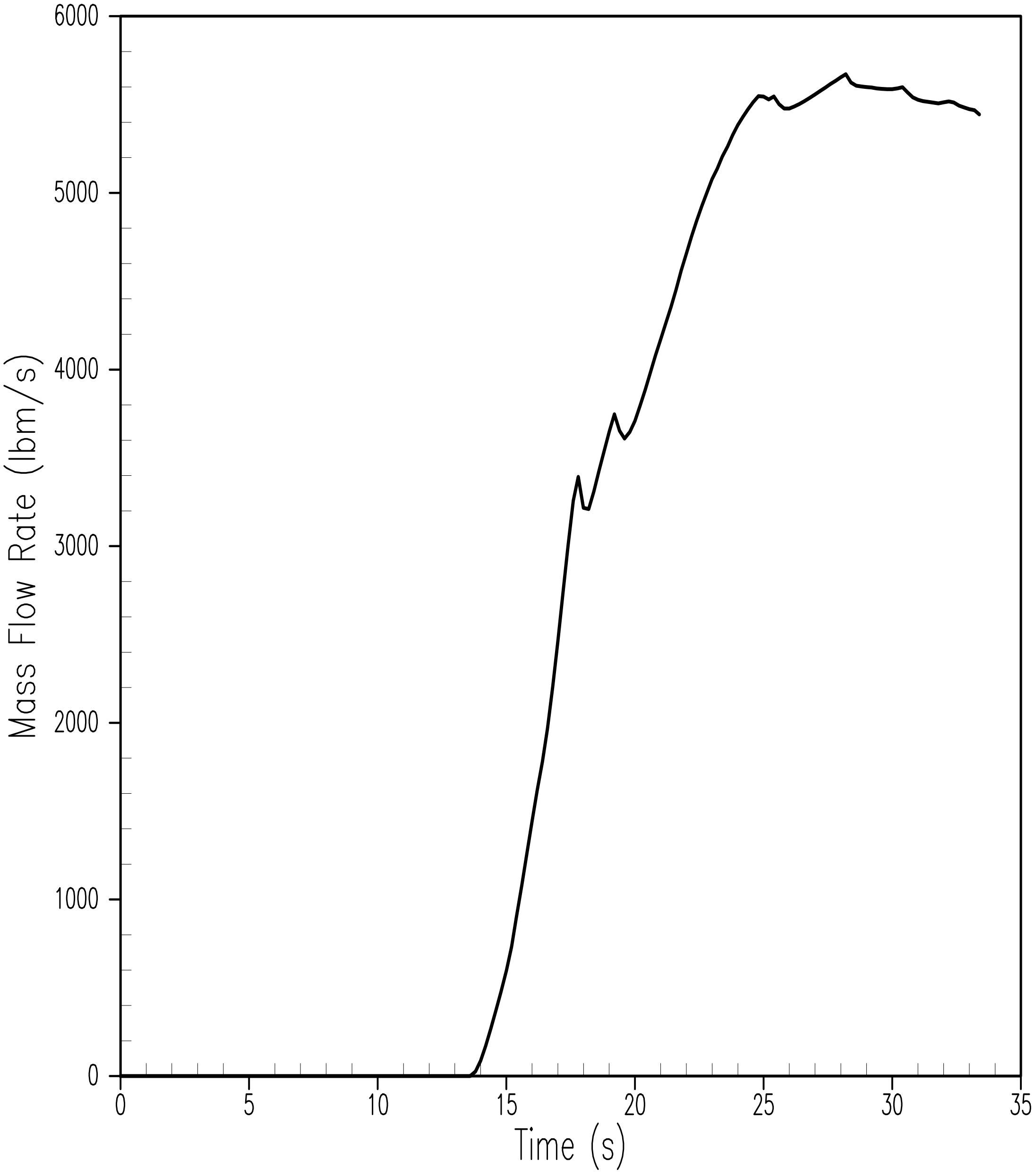
INTACT LOOP ACCUMULATOR MASS FLOW RATE DURING BLOWDOWN(C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–15 (SHEET 8 OF 9)



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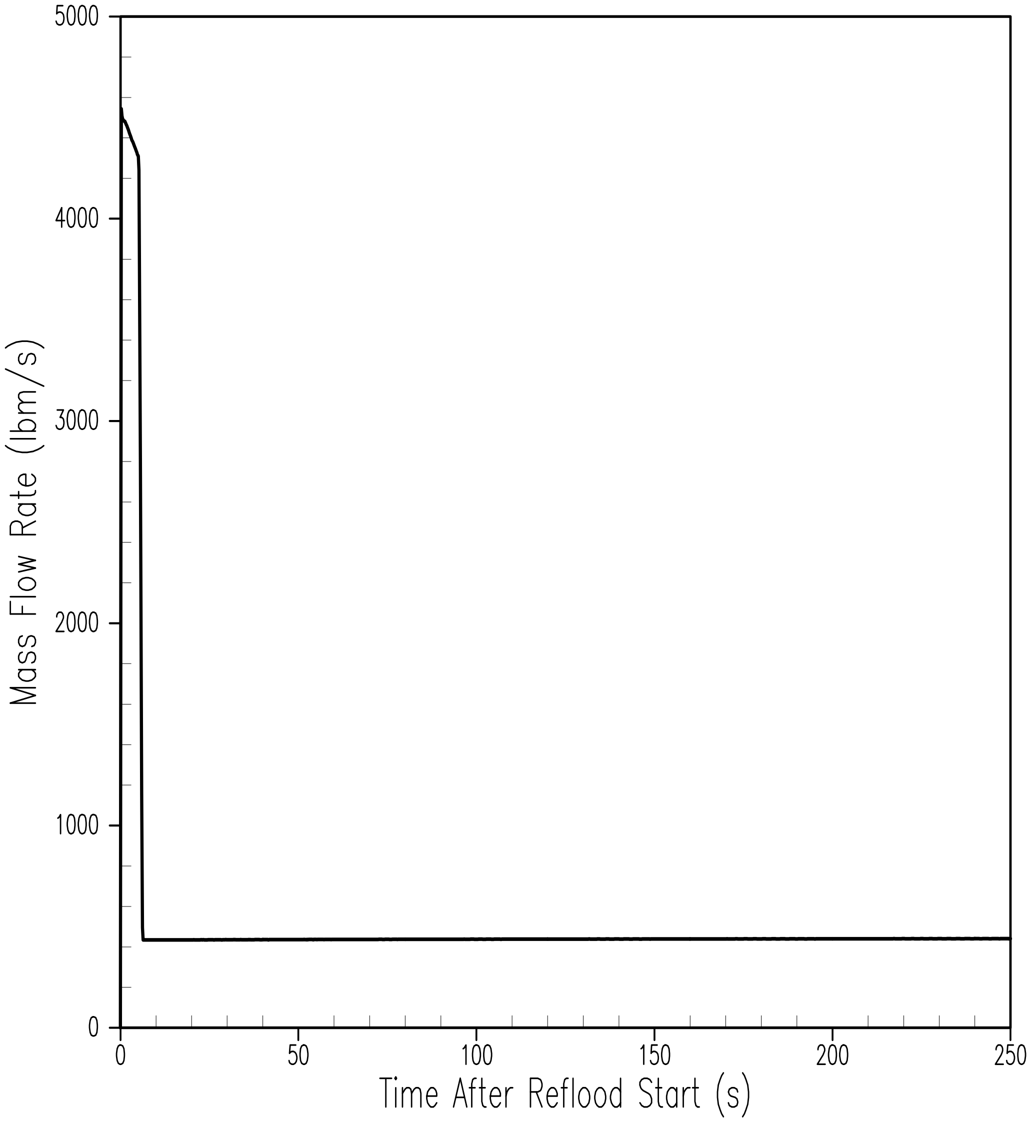
INTACT LOOP ACCUMULATOR MASS FLOW RATE DURING BLOWDOWN(C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 156-IFBA

FIGURE 15.6.5–15 (SHEET 9 OF 9)



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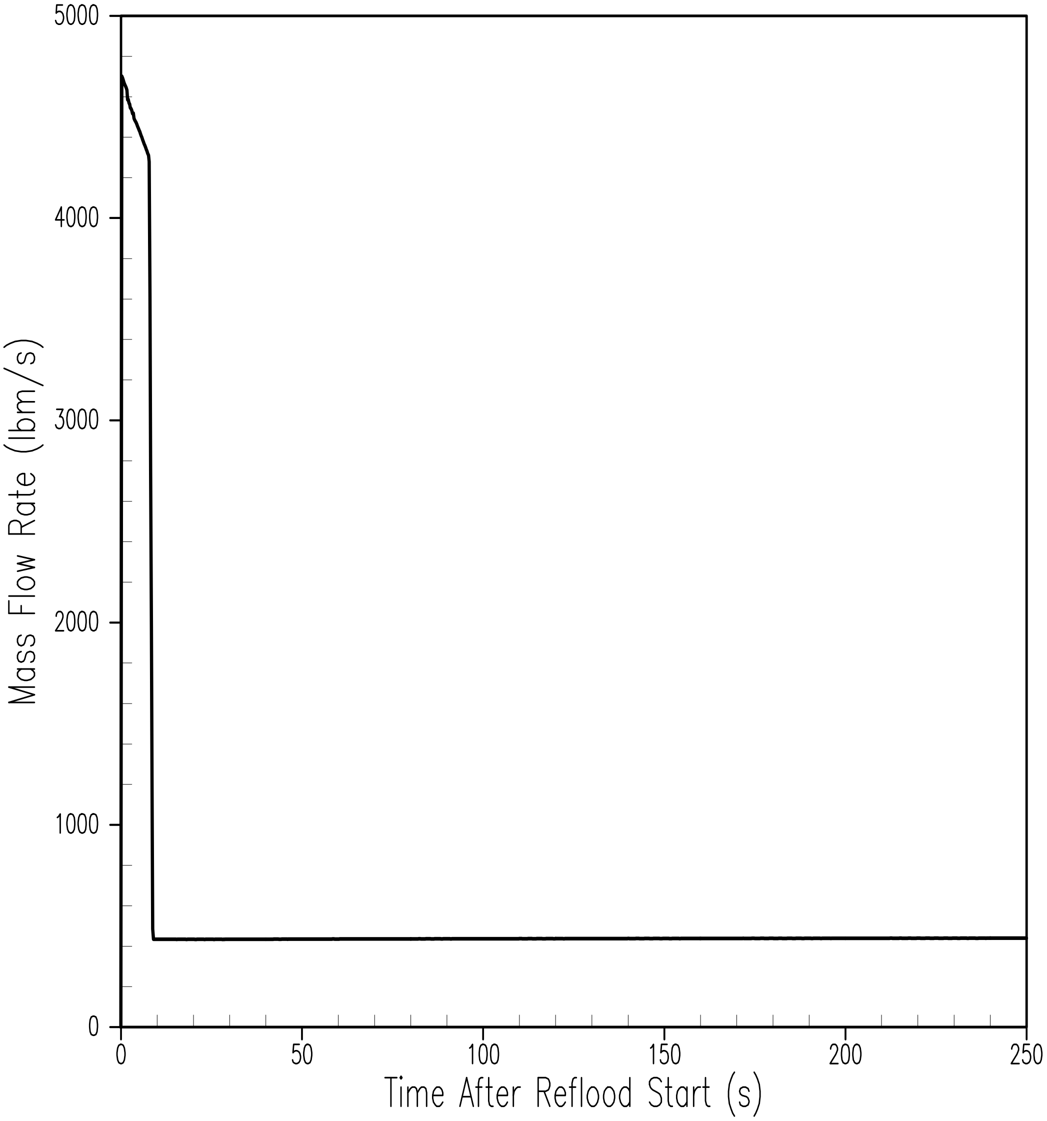
INTACT LEG ACCUMULATOR AND SI MASS FLOW RATE DURING REFLOOD (C_D = 0.4, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–16 (SHEET 1 OF 9)



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INTACT LEG ACCUMULATOR AND SI MASS FLOW RATE DURING REFLOOD (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, NON-IFBA)

FIGURE 15.6.5–16 (SHEET 2 OF 9)

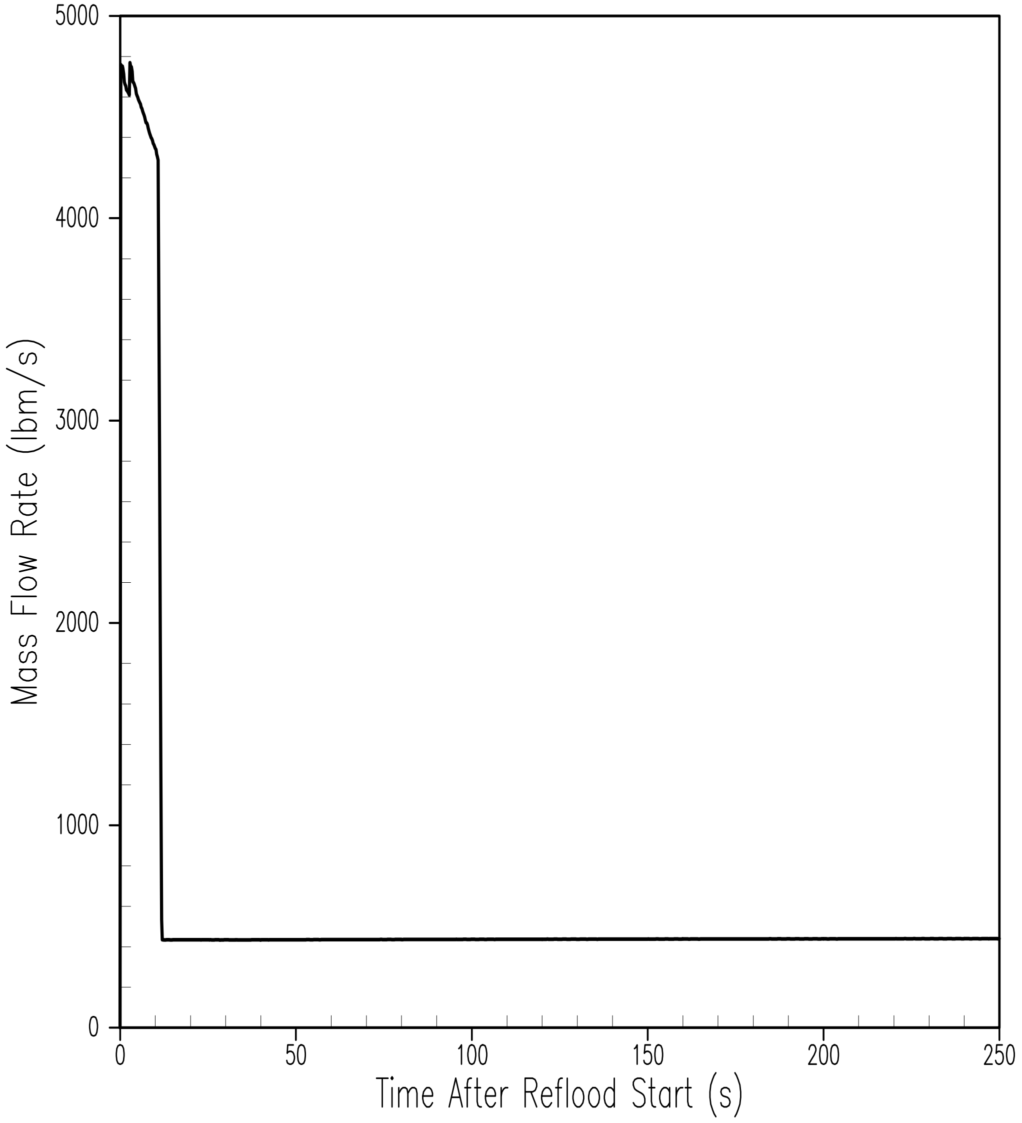

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FIGURE 15.6.5–16 (SHEET 3 OF 9)

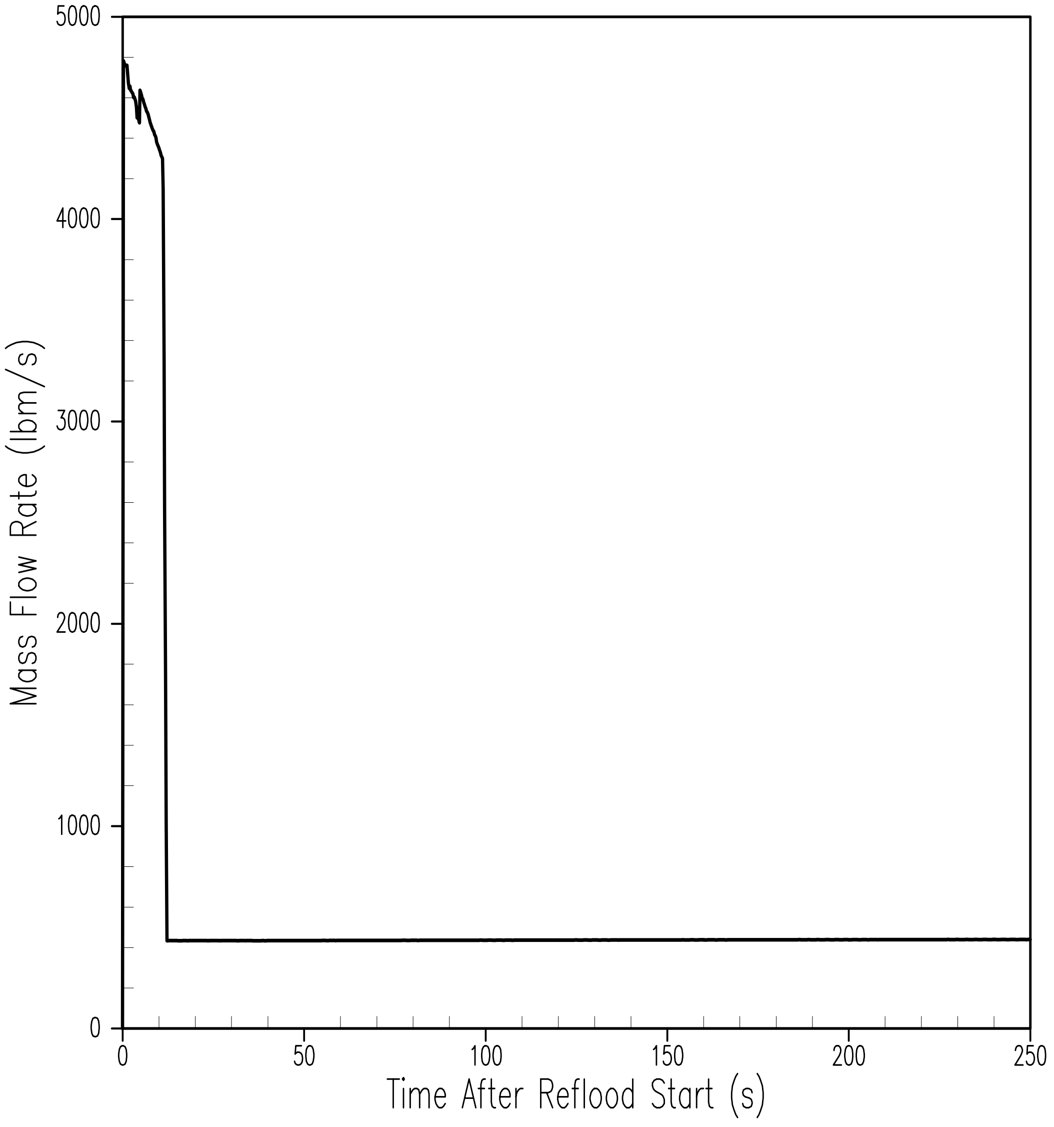

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FIGURE 15.6.5–16 (SHEET 4 OF 9)

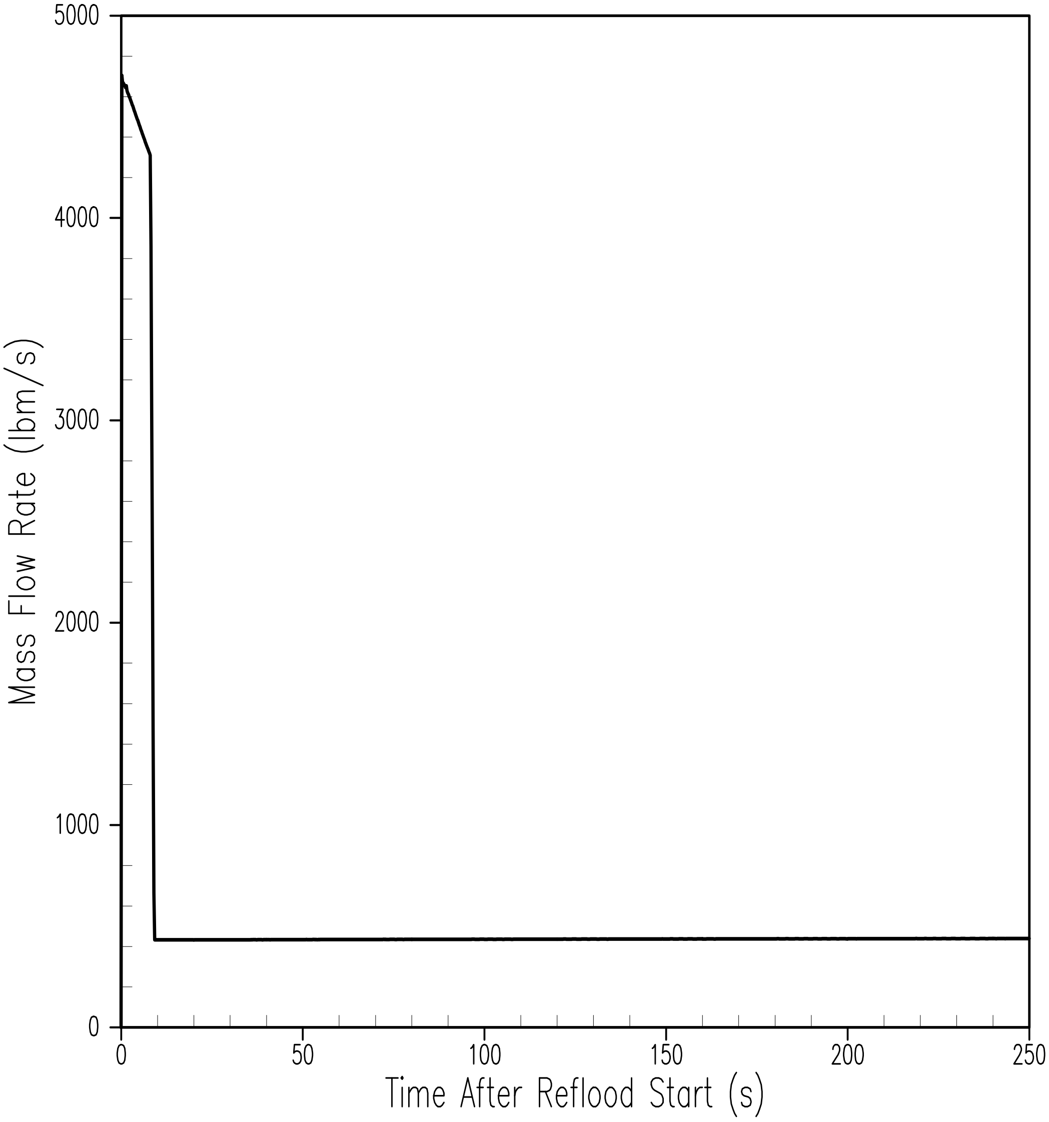

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FIGURE 15.6.5–16 (SHEET 5 OF 9)

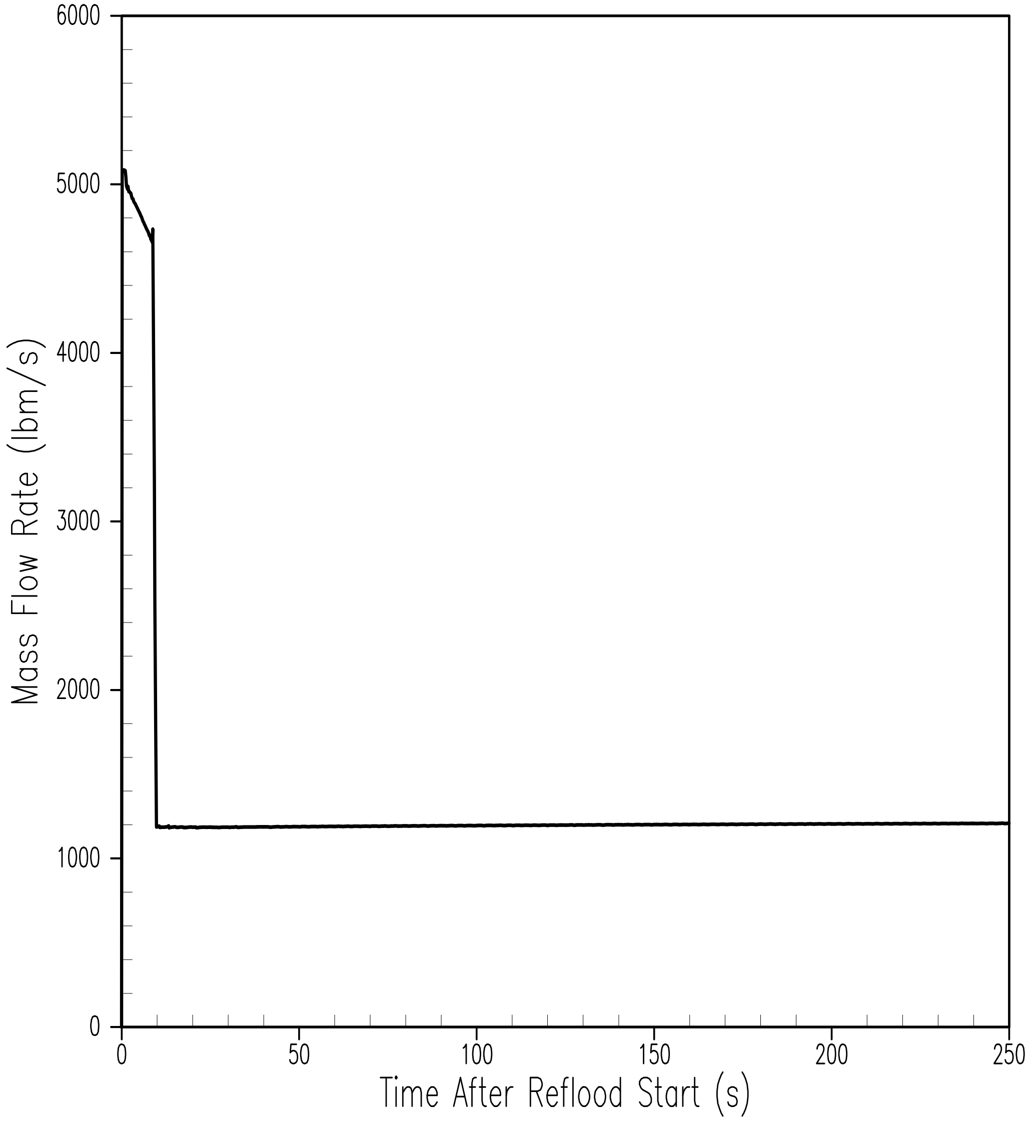

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FIGURE 15.6.5–16 (SHEET 6 OF 9)

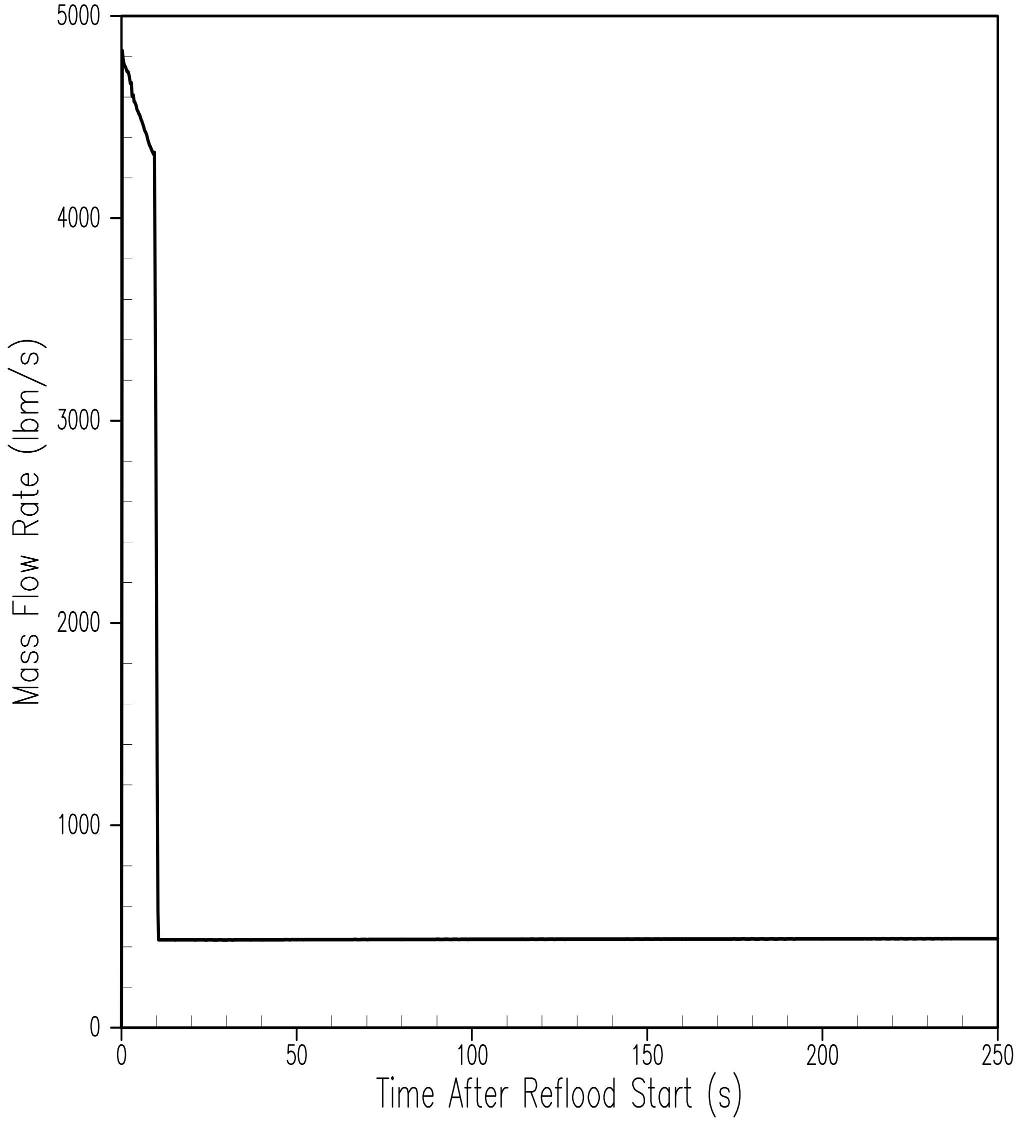

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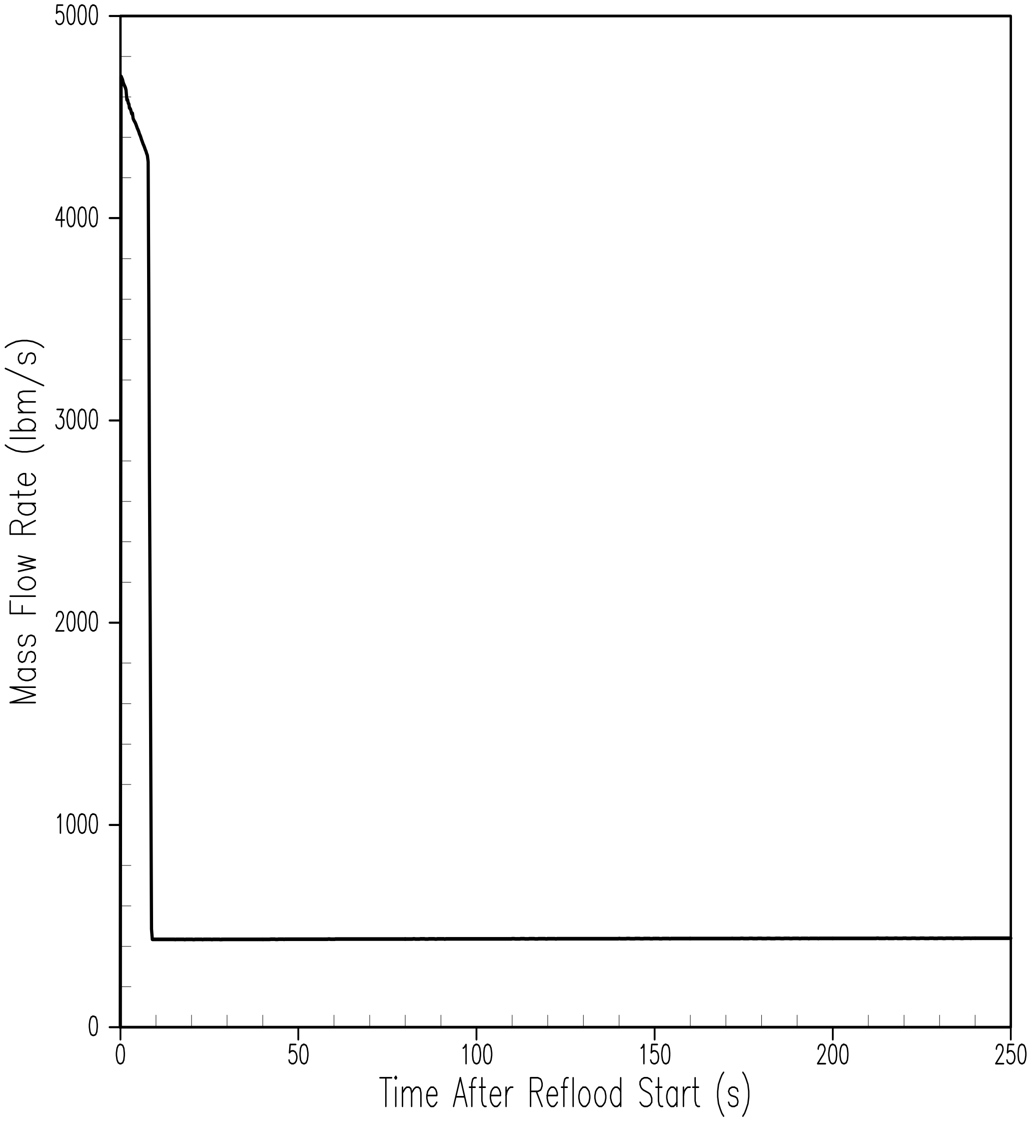
FIGURE 15.6.5–16 (SHEET 7 OF 9)



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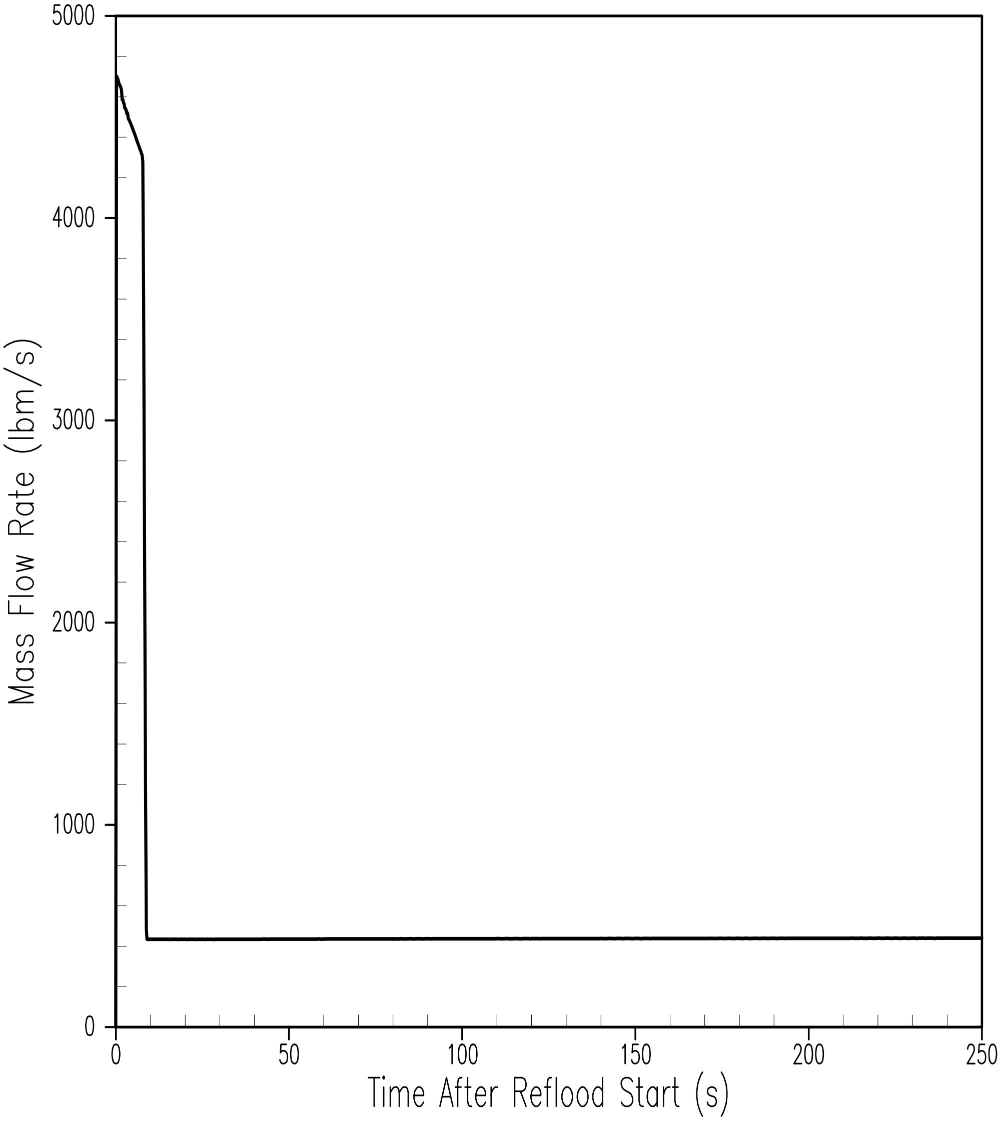
INTACT LEG ACCUMULATOR AND SI MASS FLOW RATE DURING REFLOOD (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 128-IFBA)

FIGURE 15.6.5–16 (SHEET 8 OF 9)



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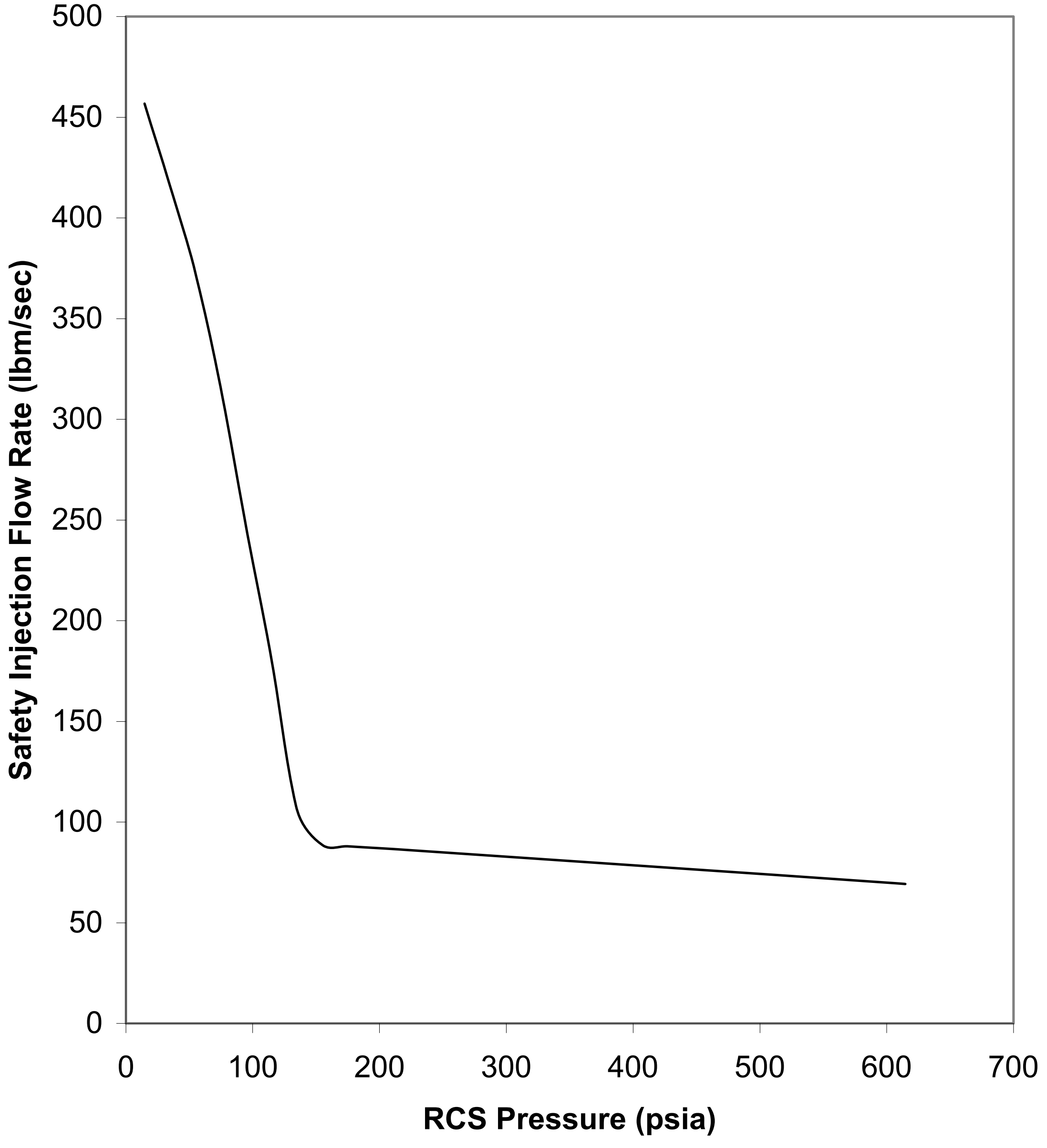
INTACT LEG ACCUMULATOR AND SI MASS FLOW RATE DURING REFLOOD (C_D = 0.6, LOW T_{AVG}, MIN SI, COSINE POWER SHAPE, 156-IFBA)

FIGURE 15.6.5–16 (SHEET 9 OF 9)



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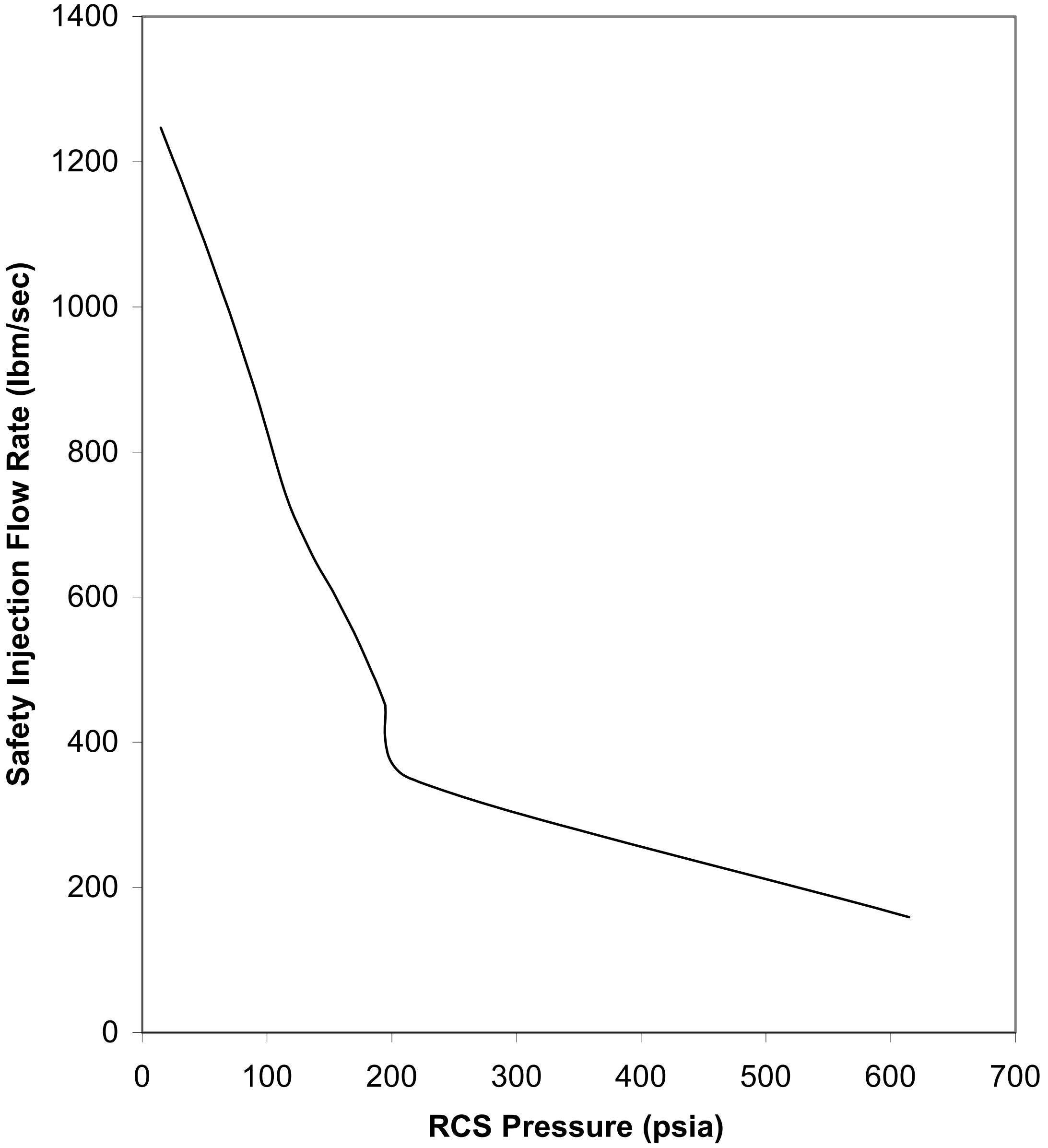
SAFETY INJECTION FLOW
(MINIMUM SAFETY INJECTION)

FIGURE 15.6.5–17



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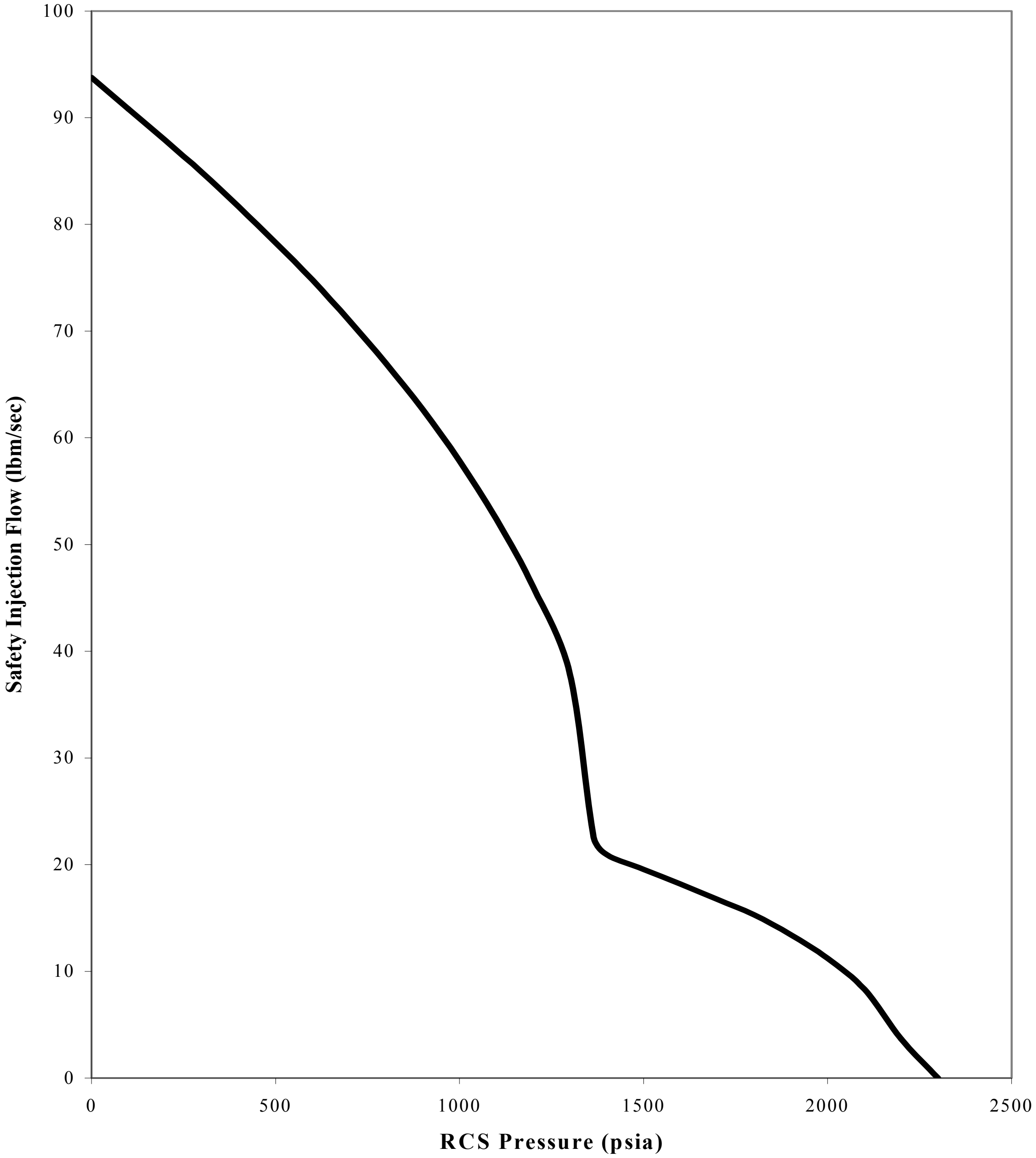
UNIT 1 AND UNIT 2

SAFETY INJECTION FLOW
(MAXIMUM SAFETY INJECTION)

FIGURE 15.6.5–18



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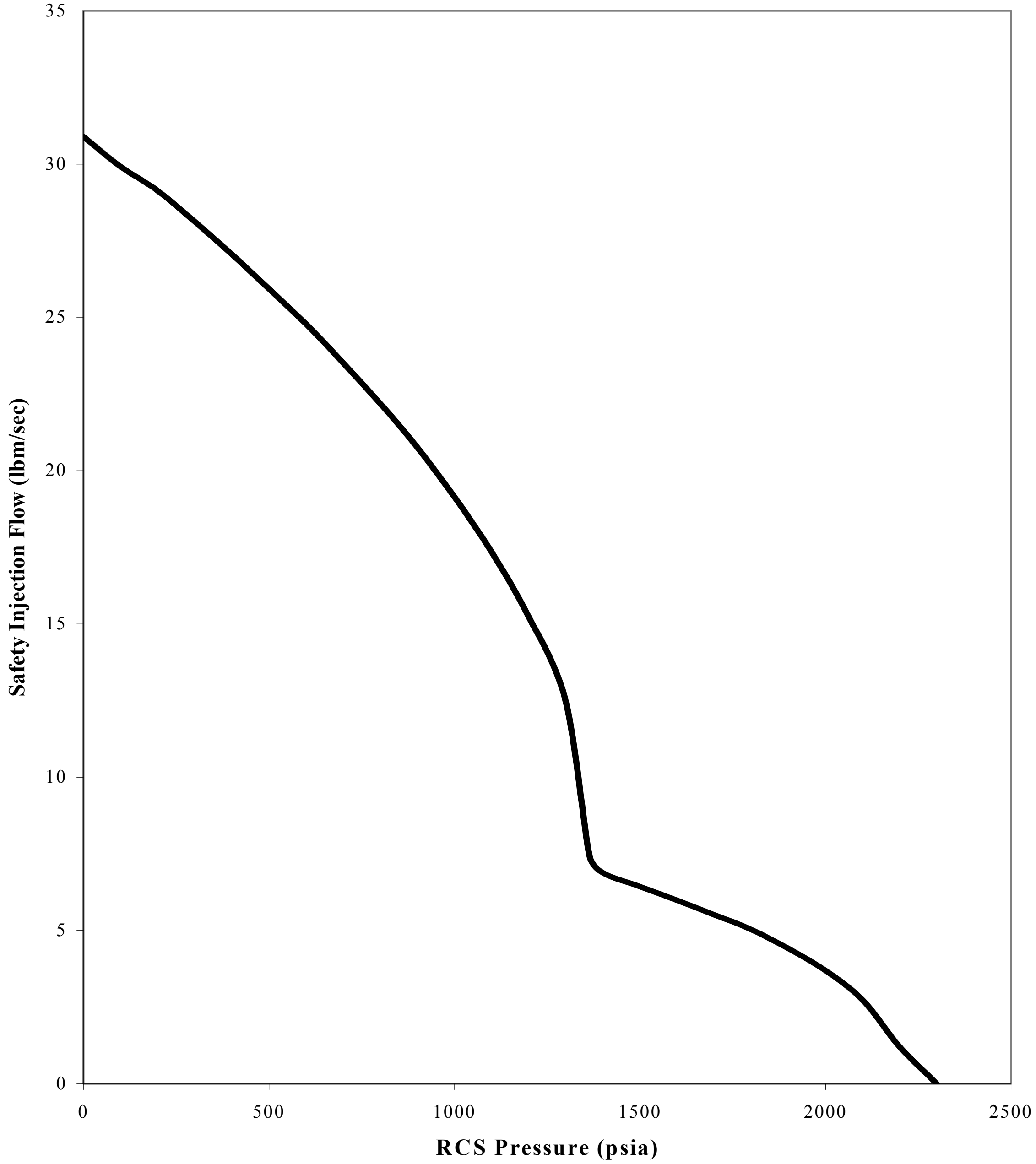
UNIT 1 AND UNIT 2

SMALL BREAK LOCA
INTACT LOOP SAFETY INJECTION FLOW

FIGURE 15.6.5–19



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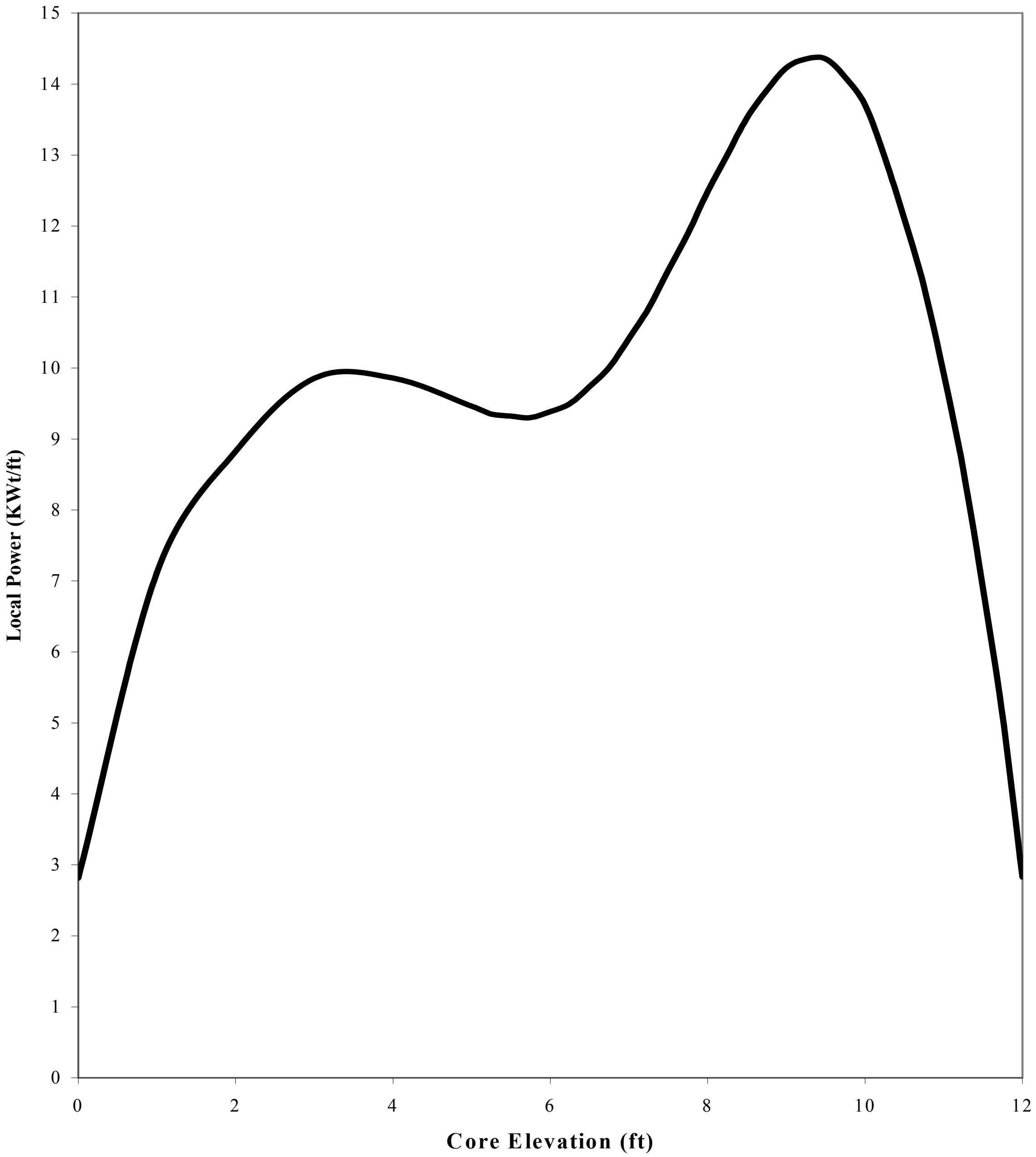
UNIT 1 AND UNIT 2

SMALL BREAK LOCA
BROKEN LOOP SAFETY INJECTION FLOW

FIGURE 15.6.5–20



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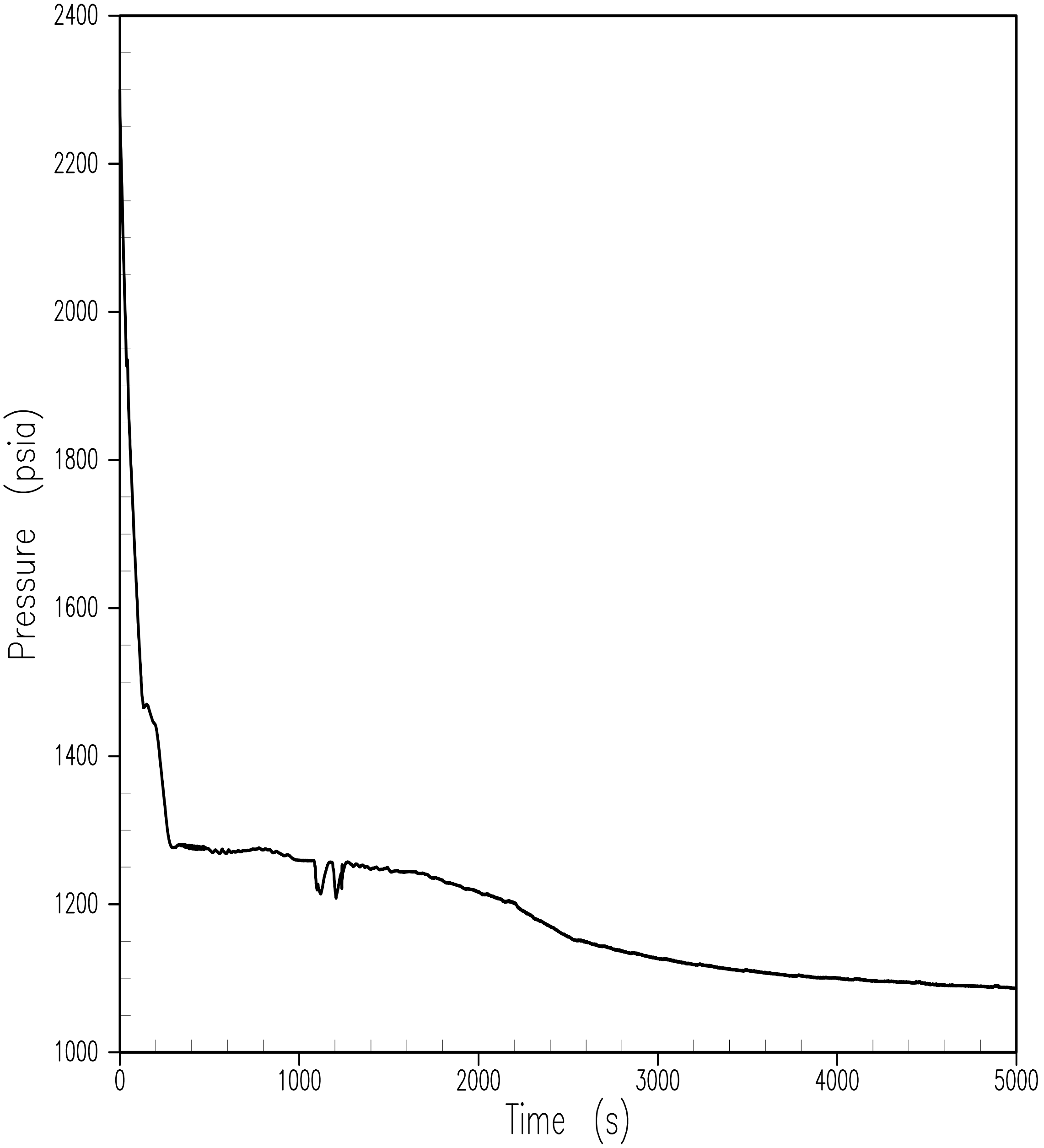
UNIT 1 AND UNIT 2

SMALL BREAK LOCA
POWER SHAPE

FIGURE 15.6.5–21



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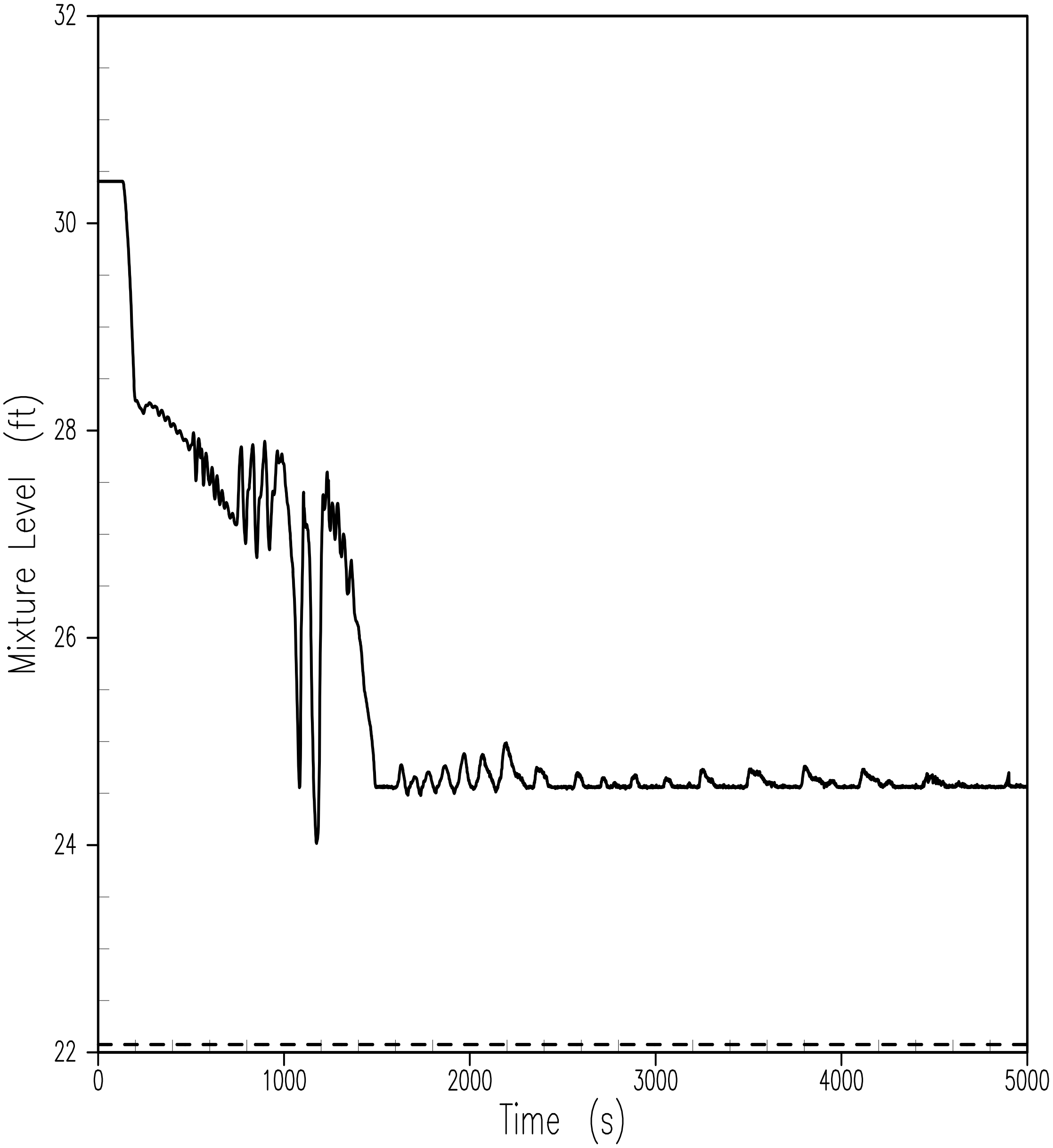
UNIT 1 AND UNIT 2

REACTOR COOLANT SYSTEM PRESSURIZER
PRESSURE 2-IN., LOW T_{AVG}

FIGURE 15.6.5–22



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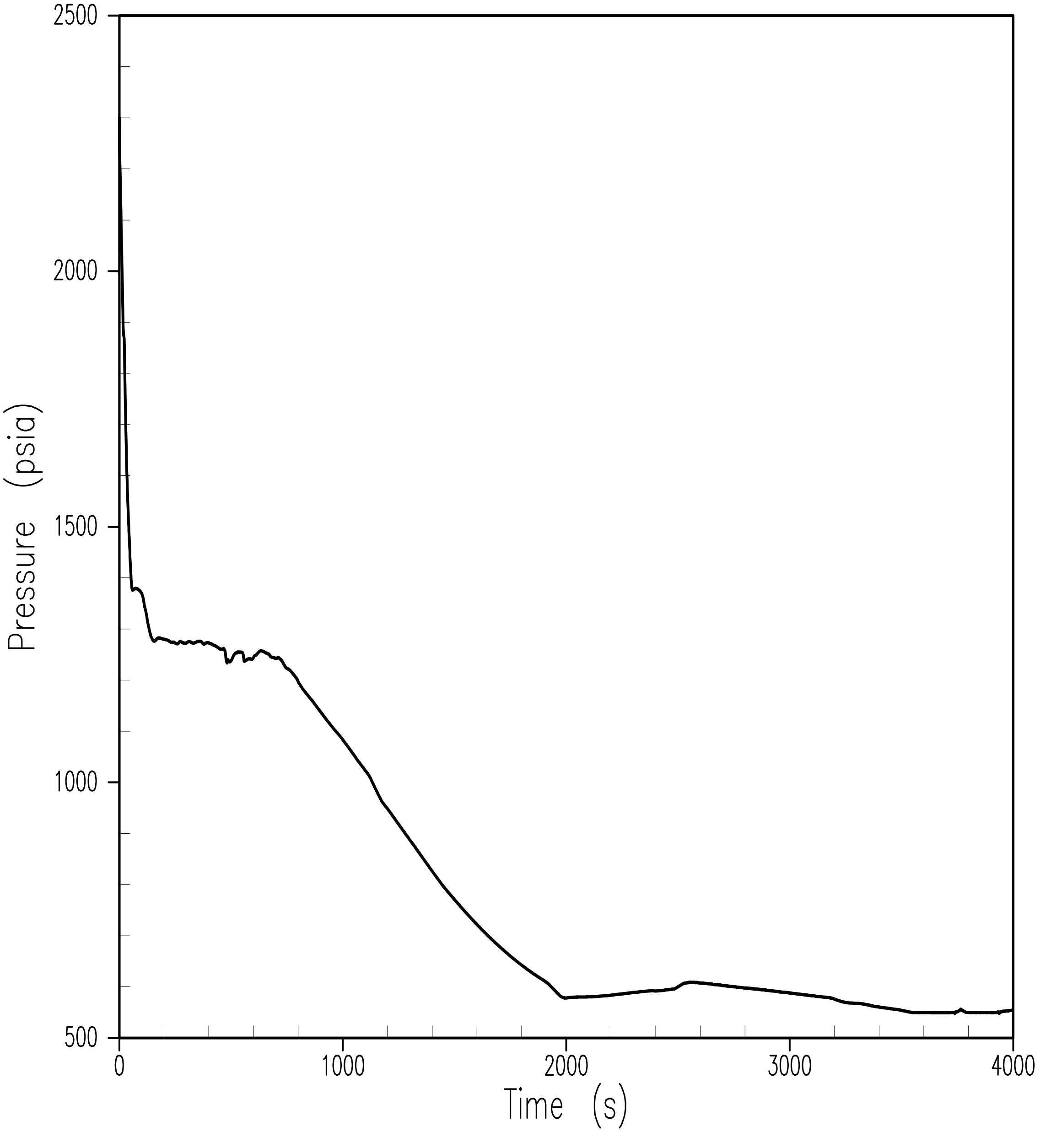
UNIT 1 AND UNIT 2

CORE MIXTURE LEVEL
2-IN., LOW T_{AVG}

FIGURE 15.6.5–23



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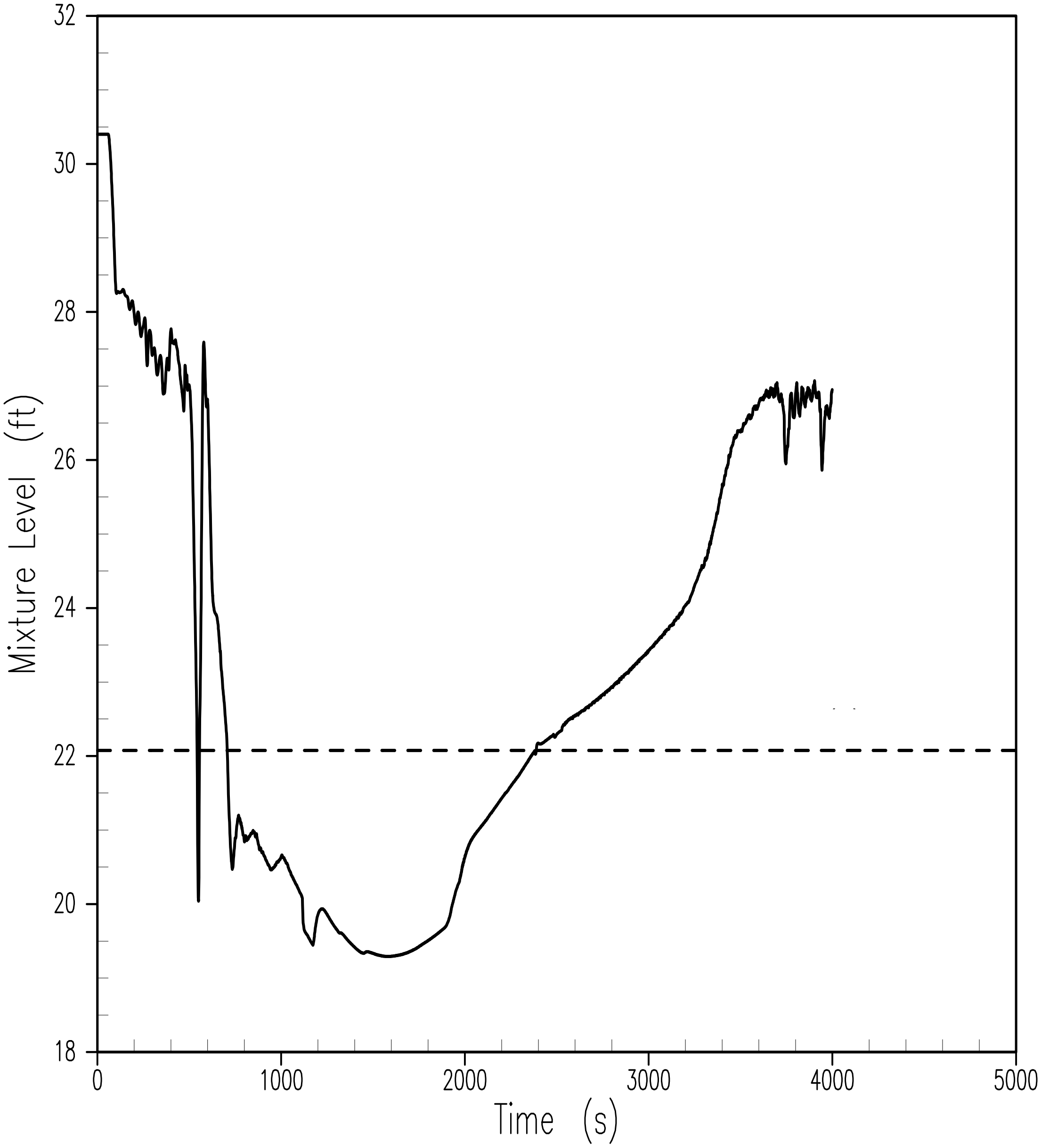
REACTOR COOLANT SYSTEM PRESSURIZER PRESSURE 3-IN., LOW T_{AVG}

FIGURE 15.6.5–24



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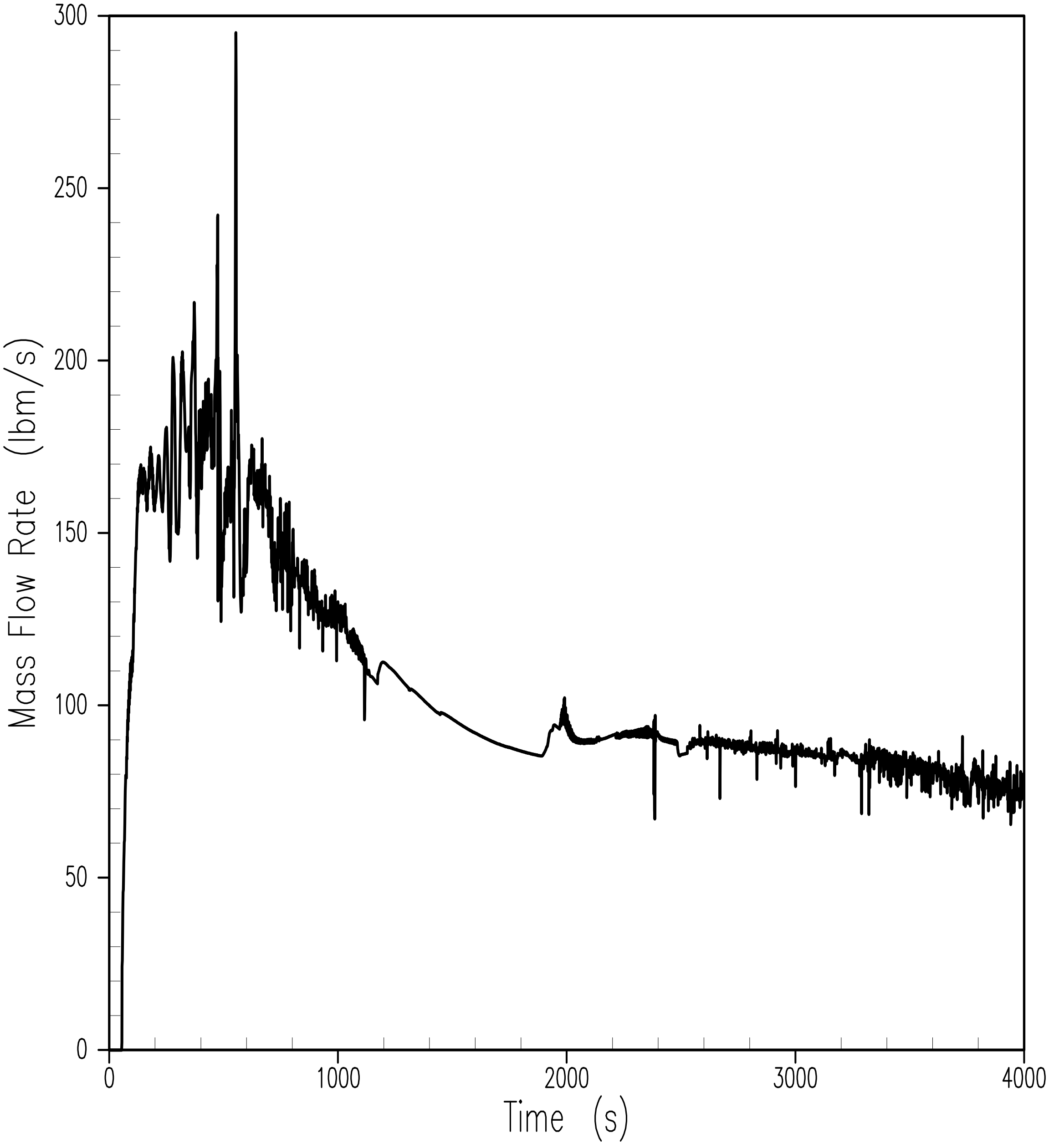
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE MIXTURE LEVEL
3-IN., LOW TAVG

FIGURE 15.6.5–25



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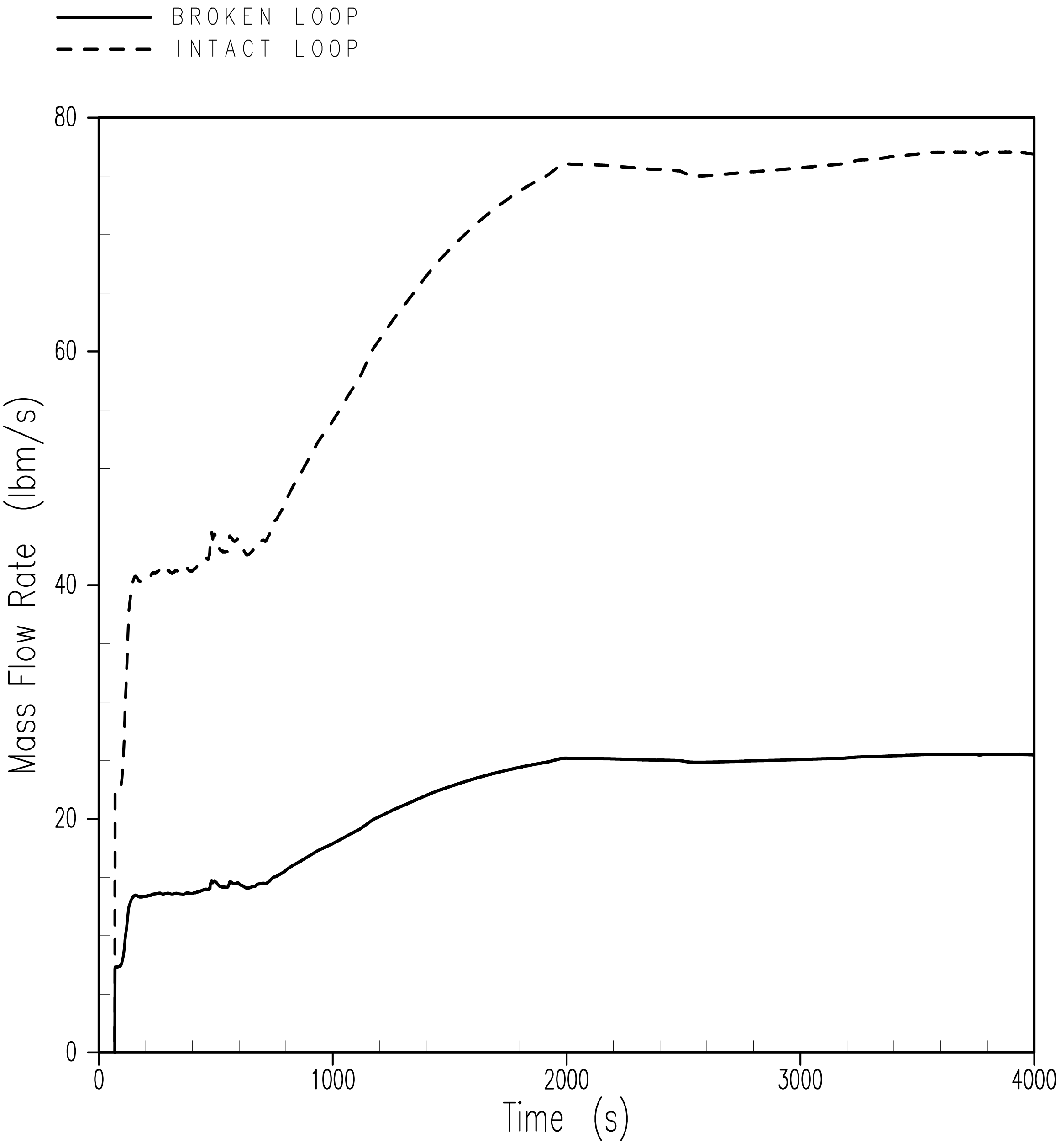
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE STEAM FLOW RATE
3-IN., LOW T_{AVG}

FIGURE 15.6.5–26



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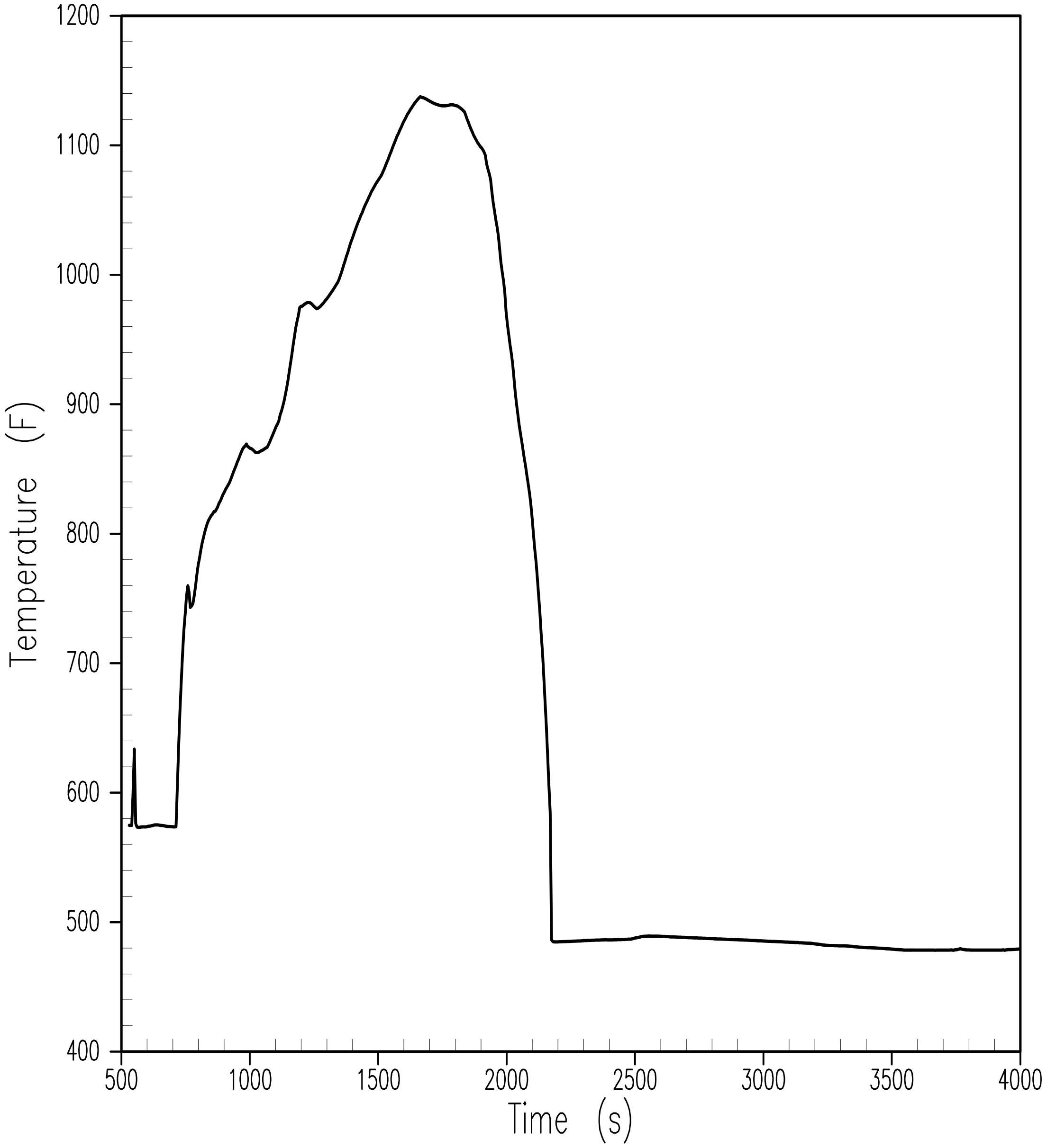
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PUMPED SAFETY INJECTION
3-IN., LOW T_{AVG}

FIGURE 15.6.5–27



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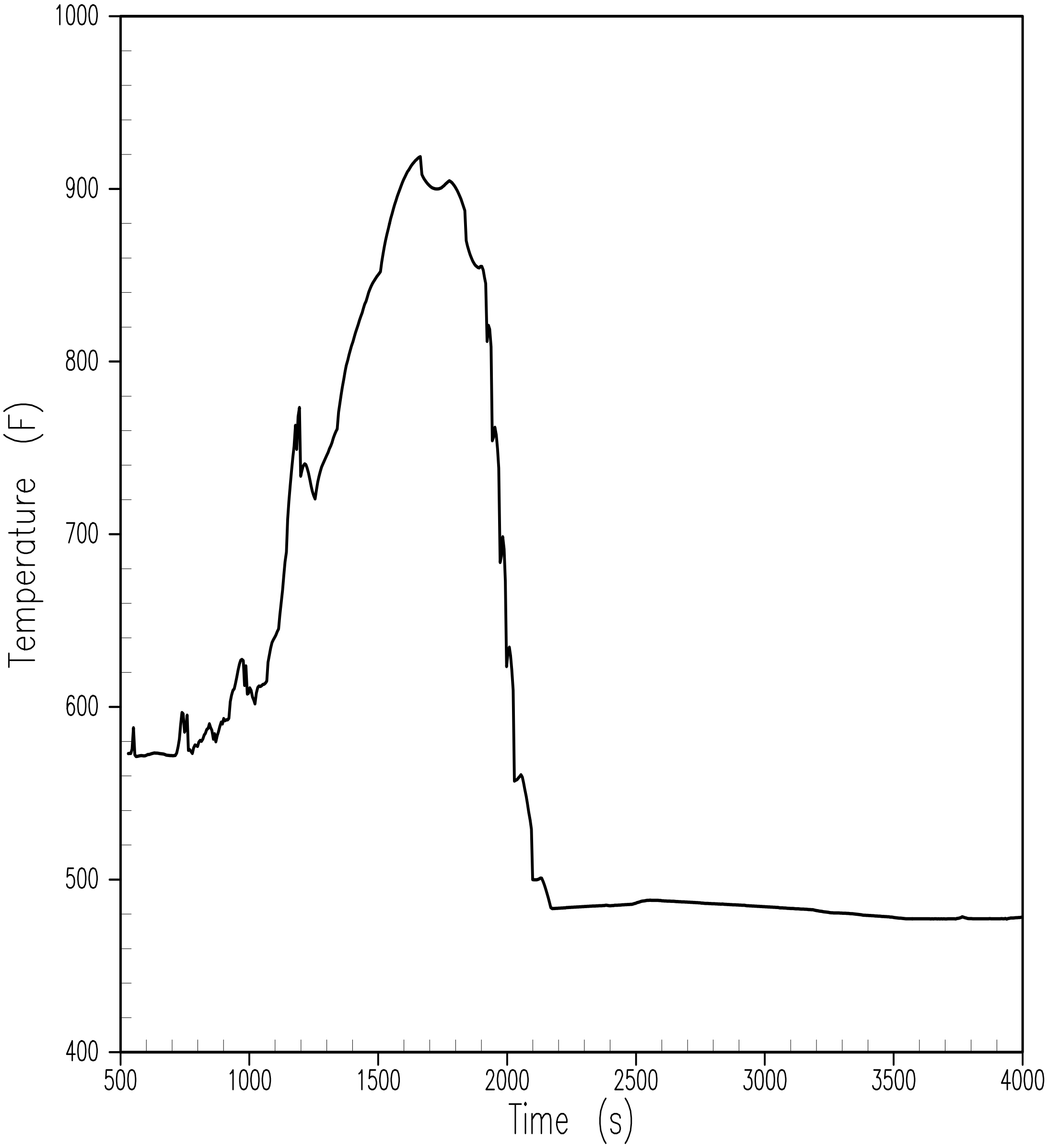
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PEAK CLAD TEMPERATURE AT 11.25 FT
3-IN., LOW T_{AVG}

FIGURE 15.6.5–28

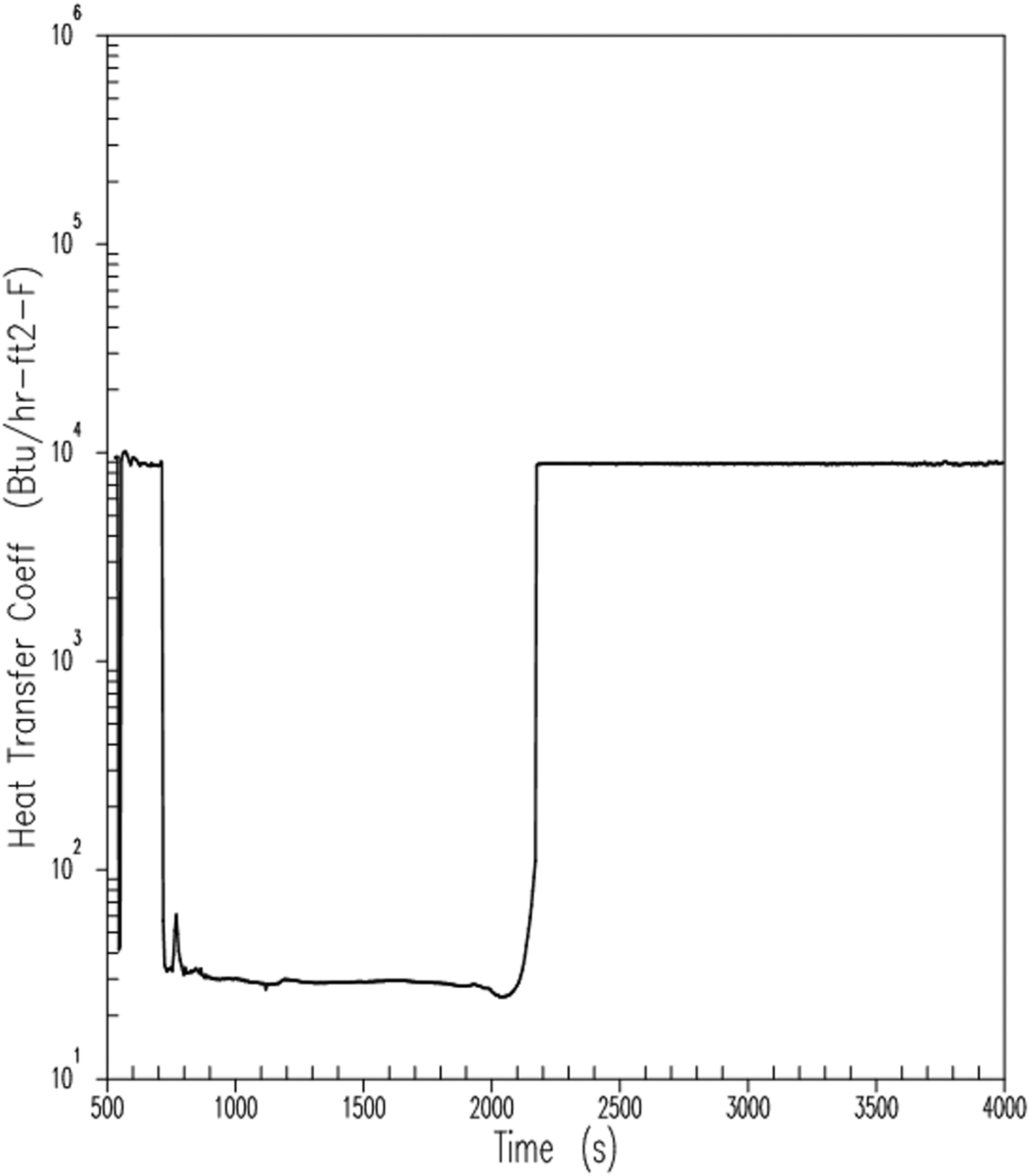


REV 14 10/07

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

HOT SPOT FLUID TEMPERATURE AT
11.25 FT 3-IN., LOW T_{AVG}

FIGURE 15.6.5–29



REV 19 4/15

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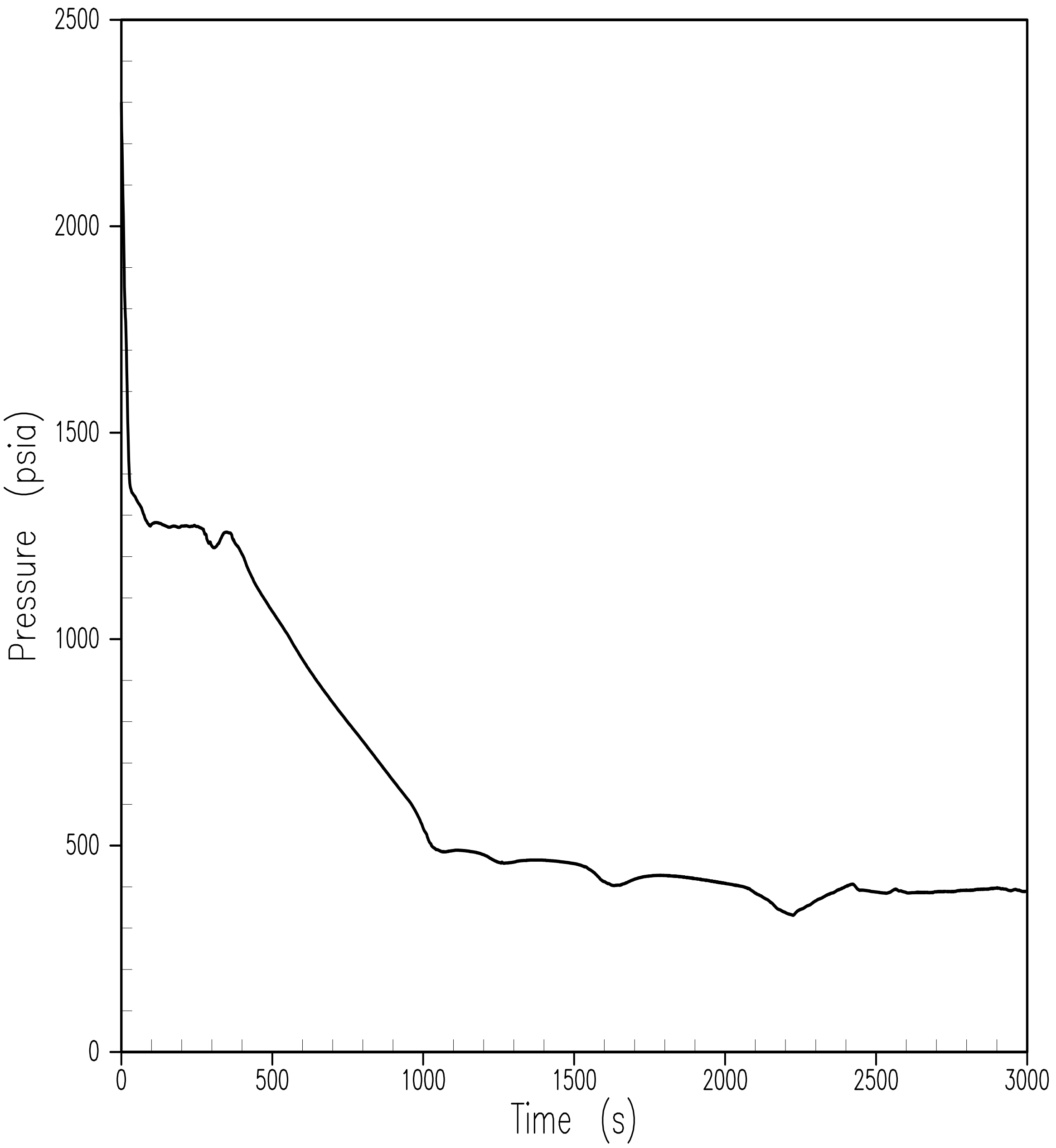
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

HOT ROD HEAT TRANSFER COEFFICIENT AT 11.25 FT 3-IN., LOW T_{AVG}

FIGURE 15.6.5–30

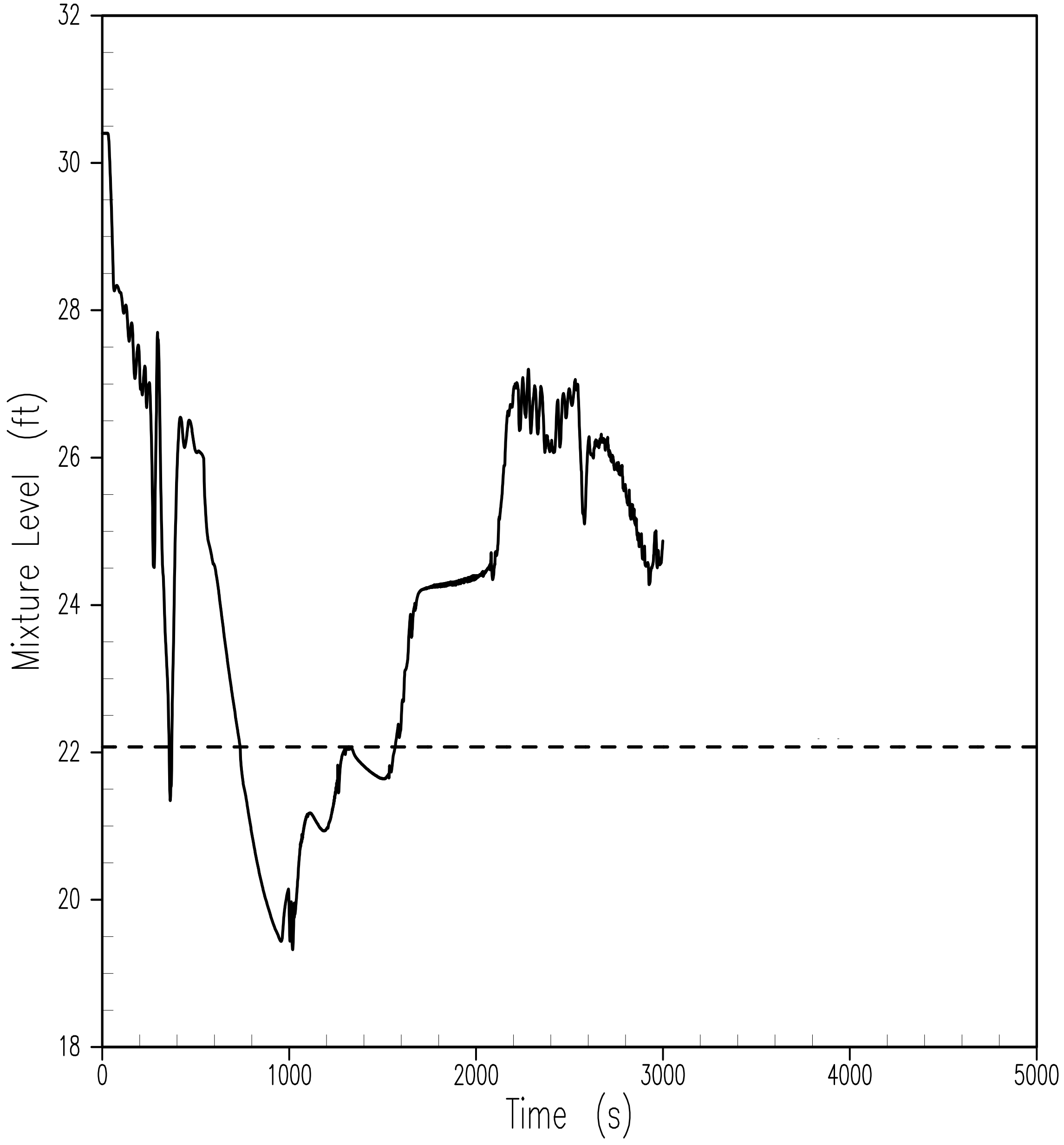


REV 14 10/07

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

REACTOR COOLANT SYSTEM PRESSURIZER PRESSURE 4 IN., LOW T_{AVG}

FIGURE 15.6.5–31

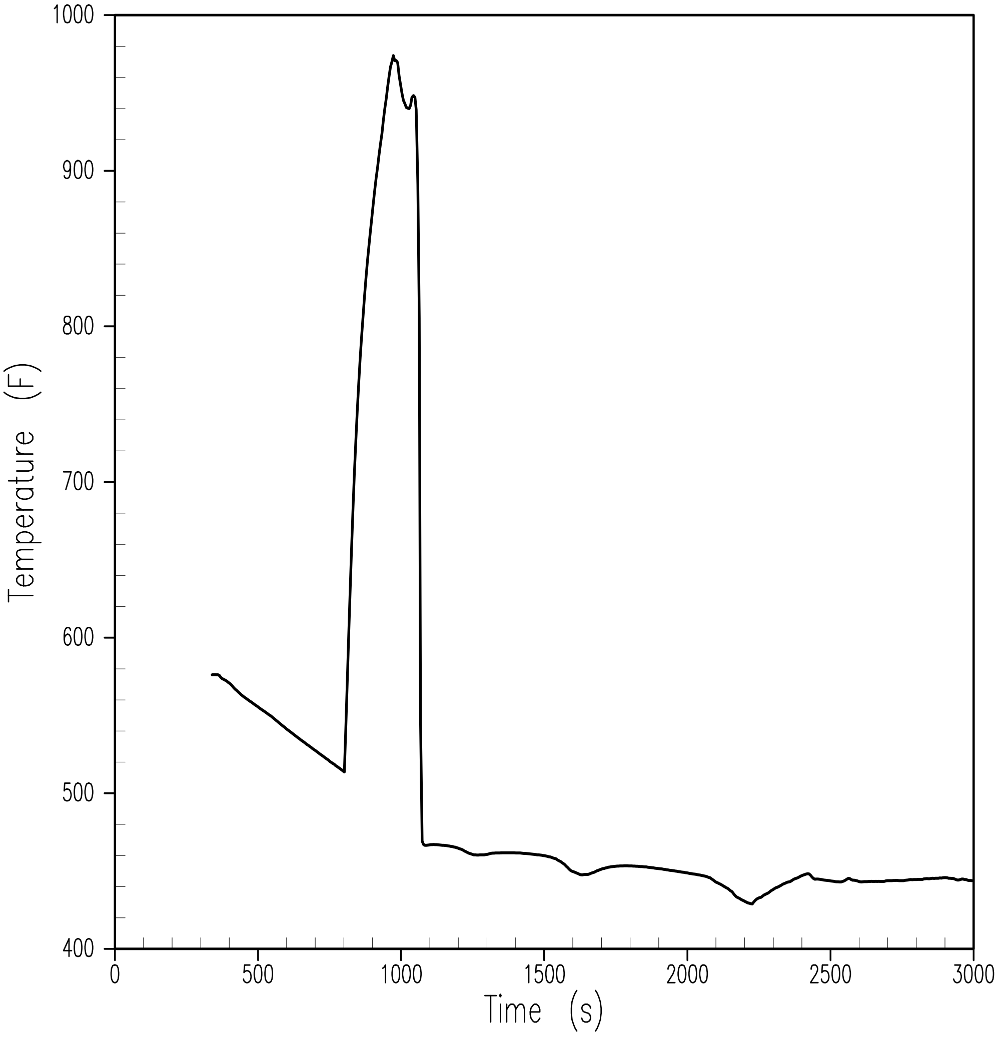


REV 14 10/07

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CORE MIXTURE LEVEL
4-IN., LOW T_{AVG}

FIGURE 15.6.5–32



REV 14 10/07

SOUTHERN COMPANY
Energy to Serve Your World®

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PEAK CLAD TEMPERATURE AT 10.75 FT
4-IN., LOW TAVG

FIGURE 15.6.5–33

15.7 RADIOACTIVE RELEASE FROM A SUBSYSTEM OR COMPONENT

This class of accident can be caused by any of the following events:

A. Radioactive gas waste system leak or failure--this is an American Nuclear Society (ANS) Condition III event.

B. Radioactive liquid waste system leak or failure--this is an ANS Condition III event.

C. Postulated radioactive release due to liquid tank failures--this is an ANS Condition III event.

D. Fuel handling accident--this is an ANS Condition IV event.

E. Spent fuel cask drop accidents--this is an ANS Condition III event.

All of the accidents in this section have been analyzed. It has been determined that the most severe radiological consequences will result from the fuel handling accident analyzed in subsection 15.7.4.

15.7.1 RADIOACTIVE WASTE GAS DECAY TANK FAILURE

15.7.1.1 Identification of Causes

This accident is an infrequent fault. Its consequences will be considered in this section. The accident is defined as an unexpected and uncontrolled release of radioactive iodine, xenon, and krypton fission product gases stored in a waste gas decay tank as a consequence of a failure of a single gas tank or associated piping.

15.7.1.2 Sequence of Events and System Operations

During a refueling shutdown, the radioactive gases are stripped from the primary coolant and are stored in the gas decay tanks. After the transfer has been completed, the tank is assumed to fail. This releases all of the contents of the tank to the auxiliary building. Also, since the tanks are isolated from each other, the only radioactivity released is from the failed tank. For conservatism, the tank is assumed to fail after 40 years[a], releasing the peak inventory expected in the tank.

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[a] The renewed operating licenses authorized a 20-year period of extended operation for both VEGP units, resulting in a total plant operating life of 60 years. Since the inventory in the Waste Gas Decay Tanks (WGDTs) has been routinely released during the first 20 years of operation and is expected to continue to be routinely released during future operation, the inventory of the WGDTs accumulated during the first 20 years of operation will be released prior to entering the period of extended operation. Therefore, the stated design capacity of the GWPS remains sufficient, and the analysis of the maximum fission product inventory in the GWPS over a 40-year plant life remains bounding for a 60-year plant life.

15.7.1.3 Core and System Performance

This accident occurs when the reactor is in the shutdown condition. There is no impact on the core or its system performance.

15.7.1.4 Barrier Performance

The only barrier between the released activity and the environment is the auxiliary building. During the course of this accident, the auxiliary building is assumed to remain intact. This means that the only method of release is through the auxiliary building ventilation system.

15.7.1.5 Radiological Consequences

15.7.1.5.1 Method of Analysis

15.7.1.5.1.1 Physical Model. Radioactive waste gas decay tanks (WGDTs) are used in the design to permit the decay of radioactive gases as a means of reducing or preventing the release of radioactive materials to the atmosphere. To evaluate the radiological consequences of the gaseous waste processing system, it is postulated that there is an accidental release of the contents of one of the WGDTs resulting from a rupture of the tank or from another cause, such as operator error or valve malfunction. The gaseous waste processing system (GWPS) is so designed that the tanks are isolated from each other during use, limiting the quantity of gas released in the event of an accident by preventing the flow of radioactive gas between the tanks.

The principal radioactive nuclides of the WGDTs are the noble gases krypton and xenon, the particulate daughters of some of the krypton and xenon isotopes, and trace quantities of halogens. The maximum amount of waste gases stored in any one tank occurs during a refueling shutdown, at which time the WGDTs store the radioactive gases stripped from the reactor coolant.

The maximum content of a gas decay tank given in table 15.7.1-1 is based on conservative assumptions used for the purpose of computing the noble gas and iodine inventory available for release. Rupture of the WGDT is assumed to occur immediately upon completion of the waste gas transfer, releasing the entire contents of the tank to the auxiliary building. For the purposes of evaluating the accident, it is assumed that all the activity is released directly to the environment during the 2-h period immediately following the accident.

15.7.1.5.1.2 Assumptions and Conditions. The major assumptions and parameters assumed in the analysis are itemized in table 15.7.1-1.

In the evaluation of the WGDT rupture, the fission product accumulation and release assumptions of Regulatory Guide 1.24 have been used. Table 15.7.1-2 provides a comparison of the assumptions used in the analysis to those of Regulatory Guide 1.24. The assumptions related to the release of radioactive gases from the postulated rupture of a WGDT are:

A. The iodine concentrations in the reactor coolant, prior to shutdown, are based on 1 μCi/g of dose equivalent I-131. Coincident with the shutdown, an iodine spike is created which increases the iodine release rate from the fuel to the primary coolant to a value 500 times greater than the release rate corresponding to the maximum equilibrium primary system iodine concentration of 1 μCi/g of dose equivalent I-131. The duration of the spike is assumed to be sufficient to raise the reactor coolant iodine concentration to 60 μCi/g of dose equivalent I-131 (approximately 2.5 h).

B. The noble gas concentrations in the primary coolant are based on 1-percent defective fuel.

C. All gaseous activity has been removed from the reactor coolant system (RCS) and transferred to the gas decay tank that is assumed to fail.

D. The maximum content of the WGDT was conservatively assumed to be the isotopic activities given in table 15.7.1-1 for the accumulated radioactivity in the GWPS after 40 years' operation[a] and immediately following plant shutdown and degasification of the RCS.

E. The failure is assumed to occur immediately upon completion of the waste gas transfer, releasing the entire contents of the tank to the auxiliary building.

F. The dose is calculated as if the release were from the auxiliary building at ground level during the 2-h period immediately following the accident. No credit for radioactive decay is taken.

15.7.1.5.1.3 Mathematical Models Used in the Analysis. The mathematical models used in the analysis are described in the following sections:

A. The mathematical models used to analyze the activity released during the course of the accident are described in appendix 15A.

B. The atmospheric dispersion factors used in the analysis were calculated based on the onsite meteorological measurement programs described in section 2.3.

C. The thyroid inhalation and total body gamma immersion doses to a receptor at the exclusion area boundary and outer boundary of the low population zone were analyzed, using the models described in appendix 15A, subsections 15A.2.4 and 15A.2.6, respectively.

15.7.1.5.1.4 Identification of Leakage Pathways and Resultant Leakage Activity. For the purpose of evaluating the radiological consequences due to the postulated WGDT rupture, the resultant activity is conservatively assumed to be released directly to the environment during the 2-h period immediately following the occurrence of the accident. This is a considerably higher release rate than that based on the actual building exhaust ventilation rate. Therefore, the results of the analysis are based on the most conservative pathway available.

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[a] The renewed operating licenses authorized a 20-year period of extended operation for both VEGP units, resulting in a total plant operating life of 60 years. Since the inventory in the WGDTs has been routinely released during the first 20 years of operation and is expected to continue to be routinely released during future operation, the inventory of the WGDTs accumulated during the first 20 years of operation will be released prior to entering the period of extended operation. Therefore, the stated design capacity of the GWPS remains sufficient, and the analysis of the maximum fission product inventory in the GWPS over a 40-year plant life remains bounding for a 60-year plant life.

15.7.1.5.2 Identification of Uncertainties and Conservatisms in the Analysis.

The uncertainties and conservatisms in the assumptions used to evaluate the radiological consequences of a WGDT rupture result from assumptions made involving the release of the waste gas from the decay tank and the meteorology present at the site during the course of the accident.

A. The iodine inventory in the GWPS is based on a reactor coolant concentration of 1 μCi/g of dose equivalent I-131 with extremely large iodine spike values, persisting for 2.5 h, and resulting in equivalent concentrations many times greater than the reactor coolant activities based on 0.12-percent defective fuel associated with normal operating conditions.

B. The noble gas inventory in the GWPS is based on a reactor coolant concentration corresponding to 1-percent defective fuel and 40 years of operation[a] (to maximize the Kr-85 inventory; all other nuclides equilibrate in approximately 60 days or less). Furthermore, 1-percent defects cannot exist simultaneously with 1.0 μCi/g of dose equivalent I-131. For iodines, 1-percent defects would be approximately three times the Technical Specification limit.

C. It is assumed that the WGDT fails immediately after the transfer of the noble gases and iodines from the reactor coolant to the WGDT is complete. These assumptions result in the greatest amount of gaseous activity available for release to the environment.

D. The gaseous activity contained in the ruptured WGDT was assumed to be released over a 2-h period immediately following the accident. This is a conservative assumption. If the contents of the tank were assumed to mix uniformly with the volume of air within the auxiliary building where the decay tanks are located, then, using the actual building exhaust ventilation rate, a considerable amount of holdup time would be gained. This reduces, by natural decay, the amount of gaseous activity available for release to the environment. However, no credit for radioactive decay is taken.

E. The meteorological conditions which may be present at the site during the course of the accident are uncertain. However, it is highly unlikely that meteorological conditions assumed will be present during the course of the accident for any extended period of time. Therefore, the radiological consequences evaluated, based on these meteorological conditions, will be conservative.

---

[a] The renewed operating licenses authorized a 20-year period of extended operation for both VEGP units, resulting in a total plant operating life of 60 years. Since the inventory in the WGDTs has been routinely released during the first 20 years of operation and is expected to continue to be routinely released during future operation, the inventory of the WGDTs accumulated during the first 20 years of operation will be released prior to entering the period of extended operation. Therefore, the stated design capacity of the GWPS remains sufficient, and the analysis of the maximum fission product inventory in the GWPS over a 40-year plant life remains bounding for a 60-year plant life.

15.7.1.5.3 Conclusions

15.7.1.5.3.1 Filter Loading. Since the accumulated iodine activity in the WGDTs is negligible, filter loading due to WGDT rupture does not establish the necessary design margin for the auxiliary building exhaust or the control room intake filters. Hence, the respective filter loadings were not evaluated.

15.7.1.5.3.2 Dose to Receptor at the Exclusion Area Boundary and the Low Population Zone Outer Boundary. The radiological consequences resulting from the occurrence of a postulated WGDT rupture have been conservatively analyzed, using assumptions and models described in previous sections.

The total body gamma dose due to immersion and the thyroid dose due to inhalation have been analyzed for the 0- to 2-h dose at the exclusion area boundary and for the duration of the accident at the low population zone outer boundary. The results are listed in table 15.7.1-3. The resultant doses are well within the guideline values of 10 CFR 100.

15.7.2 RADIOACTIVE LIQUID WASTE SYSTEM LEAK OR FAILURE

15.7.2.1 Identification of Causes

This is an infrequent fault, but the potential for release of significant amounts of radioactivity is present. The accident may be caused by an equipment malfunction or tank failure.

Liquid radwaste system leaks resulting in gaseous releases to the atmosphere and liquid releases to the ground water are bounded by the tank failure analyses presented in paragraphs 15.7.2.5 and 15.7.3.4, respectively. Accidental releases of radwaste processing facility liquid effluents to surface water are discussed in paragraph 2.4.13.2.

15.7.2.2 Sequence of Events and System Operation

The recycle holdup tank (RHT) is assumed to fail. This releases 100 percent of the tank capacity to the tank compartment.

15.7.2.3 Core and System Performance

This accident does not affect the core or the core system performance.

15.7.2.4 Barrier Performance

It is assumed that there are no barriers to the release of radioactivity from the auxiliary building.

15.7.2.5 Radiological Consequences

15.7.2.5.1 Method of Analysis

15.7.2.5.1.1 Physical Model. Reactor coolant shim bleed and some valve leakage is held in the RHT.

Table 15.7.3-1 provides an inventory and the concentrations of stored radioactivity in the tank. In the analyses, it is assumed that the liquid contents of the tank are released to the auxiliary building, and subsequently the airborne activity is released to the environment during the 2-h period immediately following the tank failure.

The RHT was selected because it contains the maximum total inventory.

15.7.2.5.1.2 Assumptions and Conditions. The major assumptions and parameters assumed in this analysis are listed below and in table 15.7.2-1.

A. The nuclide inventory of the failed tank is taken from table 15.7.3-1 and is based on 1-percent defective fuel.

B. The RHT failure is assumed to occur when the contents of the tank are at a maximum.

C. The doses are calculated as if the release were from the auxiliary building at ground level during the 2-h period immediately following the accident. No credit is taken for radioactive decay during holdup in the tank or in transit to the site boundary.

D. One-hundred percent of all noble gas activity in the tank is released while 1 percent of the iodine activity is released as airborne activity.

E. Credit is not taken for iodine removal by the nonsafety-grade auxiliary building heating, ventilation, and air-conditioning (HVAC) charcoal adsorber.

15.7.2.5.2 Mathematical Models Used in the Analysis.

A. The mathematical models used to analyze the activity released during the course of the accident are described in appendix 15A.

B. The atmospheric dispersion factors used in the analysis were calculated based on the onsite meteorological measurement program described in section 2.3; they are provided in table 15A-2.

C. The thyroid inhalation dose and total body immersion dose to a receptor at the exclusion area boundary or outer boundary of the low population zone were analyzed, using the models described in appendix 15A, sections 15A.2.4, and 15A.2.6, respectively.

15.7.2.5.2.1 Identification of Leakage Pathways and Resultant Leakage Activity. For the purpose of evaluating the radiological consequences due to the postulated RHT failure, the resultant activity is conservatively assumed to be released directly to the environment during the 2-h period immediately following the occurrence of the accident. This is a considerably higher release rate than that based on the actual building exhaust ventilation rate. Therefore, the results of the analysis are based on the most conservative pathway available.

15.7.2.5.3 Identification of Uncertainties and Conservatisms in the Analysis

The uncertainties and conservatisms in the assumptions used to evaluate the radiological consequences of the RHT failure result from assumptions made involving the release of the radioactivity from the tank and the meteorology assumed for the site.

A. It was assumed that the RHT fails when the inventory in the tank is a maximum. This assumption results in the greatest amount of activity available for release to the environment.

B. The contents of the failed tank are assumed to be released over a 2-h period immediately following the accident. If the contents of the tank were assumed to mix uniformly with the volume of air within the auxiliary building where the tank is located, then, using the actual building exhaust ventilation rate, a considerable amount of holdup time would be gained. This reduces the amount of activity released to the environment due to the natural decay. Also, no credit is taken for iodine removal by the auxiliary building HVAC charcoal adsorbers.

C. The meteorological conditions which may be present at the site during the course of the accident are uncertain. However, it is highly unlikely that meteorological conditions assumed will be present during the course of the accident for any extended period of time.

D. The RHT is assumed to have collected liquid waste based on operation at 100-percent power with 1-percent defective fuel for an extended period of time.

15.7.2.5.4 Conclusions

15.7.2.5.4.1 Filter Loadings. The filter loading due to an RHT failure does not establish the necessary design margin for the control room intake filters. Thus, the filter loading was not evaluated.

15.7.2.5.4.2 Doses to Receptor at the Exclusion Area Boundary and the Low Population Zone Outer Boundary. The radiological consequences resulting from the occurrence of a postulated liquid radwaste tank failure have been conservatively analyzed, using assumptions and models described in previous sections.

The total body dose due to immersion and the thyroid dose due to inhalation have been analyzed for the 0- to 2-h dose at the exclusion area boundary and for the duration of the accident at the low population zone outer boundary. The results are listed in table 15.7.2-2. The resultant dose is well within the guideline values of 10 CFR 100.

15.7.3 POSTULATED RADIOACTIVE RELEASE DUE TO LIQUID TANK FAILURE (GROUND RELEASE)

15.7.3.1 Identification of Causes and Frequency Classification

This accident is defined as an unexpected and uncontrolled postulated rupture of the recycle holdup tank (RHT). This tank is located in the Seismic Category 1 auxiliary building at el 119 ft 3 in. Since plant grade is at el 220 ft, the only way any effluents from the postulated rupture can be released accidentally is through postulated cracks in the auxiliary building, which would allow the contents of the tank to enter ground water. This accident is postulated to occur with the frequency of a limiting fault; in all other respects it is to be considered an infrequent, Condition III, event. (See paragraph 15.7.2.1.)

15.7.3.2 Sequence of Events and Systems Operation

See subsection 2.4.13.

15.7.3.3 Modeling of Accident Sequence

15.7.3.3.1 Mathematical Model

Subsection 2.4.13 gives the dispersion, dilution, and travel times of accidental releases of liquid effluents in surface water.

15.7.3.3.2 Input Parameters and Initial Conditions

The tank failure is evaluated in accordance with the following sets of assumptions and conditions:

A. One-hundred percent of the liquid volume of the RHT is released into the RHT cubicle.

B. The liquid enters the ground water environment through postulated cracks in the auxiliary building. RHT data is provided in table 15.7.3-1.

15.7.3.4 Radiological Consequences

The radiological consequences of this accident are presented in subsection 2.4.13.

The concentrations of any postulated accidental release of radioactive effluents from the RHT would not exceed 10 CFR 20 limits at the nearest surface water intake.

15.7.4 FUEL HANDLING ACCIDENTS

The postulated fuel handling accident has been analyzed for three cases: case 1, a fuel handling accident outside the containment in the fuel handling building; case 2, a fuel handling accident inside the reactor containment building with the containment airlocks and equipment hatch closed; and case 3, a fuel handling accident inside the containment with the personnel airlock doors and/or the equipment hatch open.

15.7.4.1 Identification of Causes and Accident Description

The accident is defined as dropping of a spent fuel assembly onto another fuel assembly in the fuel storage area or refueling pool, resulting in the rupture of the cladding of all the fuel rods in the dropped assembly plus additional rods in the struck assembly (for the accident inside containment), despite many administrative controls and physical limitations imposed on fuel handling operations. All refueling operations are conducted in accordance with prescribed procedures.

15.7.4.2 Sequence of Events and Systems Operations

The first step in fuel handling is the safe shutdown and cooldown of the reactor. After a radiation survey of the containment, the disassembly of the reactor vessel is started. After disassembly is complete, the first fuel handling is started. The first fuel transfer operation shall not begin until at least 90 h after shutdown.

The fuel handling accident is assumed to occur after a fuel assembly has been removed from the core but before it has been placed in its designated location in the spent fuel storage racks.

15.7.4.3 Core and System Performance

The fuel handling accident in the containment building or the fuel building does not impact the integrity of the core or its system performance.

15.7.4.4 Barrier Performance

The barriers between the released activity and the environment are the containment building or the fuel building. Since these buildings are designed Seismic Category 1, it is safe to assume that during the course of a fuel handling accident their integrity is maintained. Normally, release of radioactivity for a postulated accident in the fuel building is via the fuel building emergency filtration system. An open door in the fuel handling building pressure boundary could create another release path.

For a postulated accident in the containment building with the airlocks and equipment hatch closed, the release is limited to the minimal amount of radioactivity which could potentially be released prior to containment isolation. For a postulated accident in the containment building with the airlock and/or equipment hatch open, the limiting pathway for the release of activity is via the equipment building ventilation fan. During core alterations or movement of irradiated fuel assemblies within containment, the air lock door interlock mechanism may remain disabled, but the air lock must always be isolable by at lease one air lock door with a designated individual available to close the air lock door, or at least one air lock door must be closed. Similarly, the equipment hatch must be isolable and capable of being held in place by four bolts. The requirements for containment penetration closure are sufficient to ensure fission product radioactivity release from containment due to a fuel handling accident during refueling is maintained to within the acceptance criteria of Standard Review Plan subsection 15.7.4 and General Design Criteria 19.

The equipment hatch and the emergency air lock are farther away from the control room air intake than the personnel airlock. Therefore, the release path from the personnel airlock remains bounding for control room dose. Similarly, potential release paths from the purge supply and exhaust ductwork are no closer than the personnel airlock release path. Offsite dose is not affected by the relative locations of the personnel and emergency airlocks, the containment purge supply and exhaust ventilation, or the equipment hatch.

The spent fuel pool and the refueling pool provide a minimum decontamination factor of 200 for elemental iodine.

15.7.4.5 Radiological Consequences

15.7.4.5.1 Method of Analysis

15.7.4.5.1.1 Physical Model. The possibility of a fuel handling accident is remote because of the many administrative controls and physical limitations imposed on the fuel handling operations. (Refer to subsection 9.1.4.) All refueling operations are conducted in accordance with prescribed procedures.

When transferring irradiated fuel from the core to the spent fuel pool for storage, the reactor cavity and refueling pool are filled with borated water at a boron concentration equal to or greater than that concentration specified for the spent fuel pool or that concentration specified for refueling, whichever is highest, which ensures subcritical conditions in the core even if all rod cluster control (RCC) assemblies are withdrawn. After the reactor head and RCC drive shafts are removed, fuel assemblies are lifted from the core, transferred vertically to the upender, lowered to a horizontal position on the transfer car and pulled through the transfer tube and canal, upended and transferred through the spent fuel pool transfer gate, then lowered into steel racks for storage in the spent fuel pool in a pattern which precludes any possibility of a criticality accident.

Fuel handling manipulators and hoists are designed so that the fuel cannot be raised above a position that provides an adequate water shield depth for radiation protection of operation personnel.

The containment, fuel building, refueling cavity, refueling pool, and spent fuel pool are designed to Seismic Category 1 requirements, which prevent the structures themselves from failing in the event of a safe shutdown earthquake. The spent fuel storage racks are also located to prevent any credible external missile from reaching the stored irradiated fuel. The fuel handling manipulators, cranes, trollies, bridges, and associated equipment above the water cavities through which the fuel assemblies move are designed to prevent this equipment from generating missiles and damaging the fuel. The construction of the fuel assemblies precludes damage to the fuel should portable or hand tools drop on an assembly.

A fuel handling accident could occur during the transfer of a fuel assembly from the core to its storage position in the spent fuel pool. The facility is designed so that heavy objects, such as a spent fuel cask, cannot be carried over or tipped over onto the irradiated fuel stored in the spent fuel pool. Only one fuel assembly can be handled at a time. Movement of equipment handling the fuel is kept at low speeds, while exercising caution that the fuel assembly does not strike another object or structure during transfer from the core to its storage position. In the unlikely event that an assembly becomes stuck in the transfer tube, natural convection will maintain adequate cooling.

A. Containment Building Accident

During core alterations or movement of irradiated fuel assemblies inside containment, the containment may be either open or closed. If the containment is closed, the equipment hatch will be held in place with at least four bolts, the air locks will be isolated by at least one closed air lock door, and each penetration providing direct access from the containment atmosphere to the outside atmosphere (with the exception of the containment purge and exhaust penetrations) will be closed in accordance with the Technical Specifications. The containment purge and exhaust penetrations will be capable of being closed, by operator action, by at least two containment ventilation isolation valves. The containment radiation monitors (gaseous, particulate, iodine, and area low range) will be operable in accordance with the Technical Specifications. In addition, the Technical Requirements Manual requires that direct communications be maintained between the control room and personnel at the refueling station during core alterations. If a fuel handling accident were to occur inside containment with containment closed, the control room would be immediately aware of the event as a result of direct communication or a radiation alarm. Steps would be taken to isolate containment purge and exhaust, and personnel would be evacuated. With containment closed, the only potential release pathway would be via the containment purge and exhaust system. However, because of the gaseous, particulate, and iodine monitors in the exhaust portion of the system, the potential for an unmonitored release is minimized. In addition, the purge exhaust system is equipped with HEPA filters and charcoal adsorbers which will further minimize any radiological release. While no credit is taken for filtration by the purge exhaust system in the dose analyses, the availability of the filters will be maintained in accordance with NUMARC 93-01 guidance.

With containment open, the equipment hatch and/or the air lock doors may be open. The equipment hatch must be capable of being closed by at least four bolts and the air locks must be isolable by at least one door with a designated individual to close the open doors. A designated hatch closure crew and the necessary tools and equipment will be available to effect timely closure of the hatch. The equipment hatch will be capable of being cleared of obstructions so that closure can be achieved as soon as possible. The air lock doors will be closed within 15 minutes of a fuel handling accident. For the equipment hatch, the current commitment for closure time in response to a loss of decay removal capability during reduced inventory conditions is 25 minutes. This closure time is bounding for the case of a fuel handling accident inside containment with the equipment hatch open. Radiation monitor operability, requirements for other penetrations providing direct access from containment atmosphere to the outside atmosphere, communication requirements, and purge exhaust system availability is the same as for the case discussed above for containment closed. During core offload and reload with the equipment hatch open, the containment purge exhaust system will normally be operating providing an inward flow of air into containment. This is consistent with NUMARC 93-01, section 11.3.6.5, which states that the goal of maintaining ventilation system and radiation monitor availability is to reduce doses even further below that provided by natural decay and to avoid unmonitored releases. However, the purge exhaust system must be shut down during hatch closure activities, and it may be shut down during fuel handling while the hatch is open as required to maintain noise and comfort levels, etc. If for any reason operation of the purge exhaust system must be discontinued during core alterations/fuel movement with the hatch open, the opening will be monitored for radioactive releases via the health physics air monitoring station.

B. Fuel Building Accident

In the fuel building, a fuel assembly could be dropped in the transfer canal or in the spent fuel pool.

In addition to the area and effluent radiation monitors, portable radiation monitors capable of emitting audible alarms are located in this area during fuel handling operations. The doors in the fuel building are normally kept closed to ensure controlled leakage characteristics in the spent fuel pool region during operations involving irradiated fuel. Doors on the pressure boundary, except for the railroad bay door, may be held open during operations involving irradiated fuel. The fuel handling building normal and post-accident ventilation system function is not lost due to opening of personnel doors. Administrative controls are in place to close the doors after a fuel handling accident to minimize any potential release to the environment. Additionally, if none of the fuel handling building exhaust filter units are in service, one should be placed in service to ensure flow past the radiation monitors, or the doors should be closed. Should a fuel assembly be dropped in the canal or in the pool and release radioactivity above a prescribed level, the radiation monitors would sound an alarm. (See section 11.5 and subsection 12.3.4.) On alarm signal, the fuel building ventilation is switched to the emergency mode and exhausts through the engineered safety features (ESF) emergency filtration system charcoal and high-efficiency particulate air filters to remove most of the halogens and particulates prior to discharging to the atmosphere via the plant vent.

A radiation monitor located in the fuel handling building ventilation exhaust duct sounds an alarm if the radioactivity in the vent discharge exceeds the prescribed level.

The probability of a fuel handling accident is very low because of the safety features, administrative controls, and design characteristics of the facility, as previously mentioned.

15.7.4.5.1.2 Assumptions and Conditions. The major assumptions and parameters assumed in the analysis are itemized in tables 15.7.4-1 and 15A-1.

In the evaluation of the fuel handling accident, the fission product release assumptions of Regulatory Guide 1.25 are followed. Table 15.7.4-2 provides a comparison of the design to the requirements of Regulatory Guide 1.25. The following assumptions, related to the release of fission product gases from the damaged fuel assembly, are used in the analyses except as identified in table 15.7.4-2:

A. The dropped fuel assembly is assumed to be the assembly containing the peak fission product inventory. All the fuel rods contained in the dropped assembly are assumed to be damaged. In addition, for the analyses of the accident in the containment building the dropped assembly is assumed to damage 50 rods of an additional assembly.

B. The assembly fission product inventories are based on a radial peaking factor of 1.70.

C. The accident occurs 90 h after shutdown, which is the earliest time fuel handling operations can begin. Radioactive decay of the fission product inventories was taken into account during this time period.

D. Only that fraction of the fission products which migrates from the fuel matrix to the gap and plenum regions during normal operation is assumed to be available for immediate release to the water following clad damage.

E. The gap activity released to the fuel pool from the damaged fuel rods consists of 5% of the total noble gases and iodines, other than Kr-85 (10%) and I-131 which is 8% (Reg. Guide 1.195).

F. The pool decontamination factor is 1.0 for noble gases and organic iodine.

G. The effective pool decontamination factor is 200 for elemental iodine.

H. The iodine released from the fuel assembly is assumed to be composed of 99.75-percent inorganic and 0.25-percent organic species.

I. The activity which escapes from the pool is assumed to be available for release to the environment in a time period of 2 h.

J. No credit for decay or depletion during transit to the exclusion area boundary or the outer boundary of the low population zone is assumed.

K. No credit is taken for mixing or holdup in the fuel building atmosphere or equipment building.

L. For the case inside the reactor containment building, conservative credit is taken for mixing of the radioactivity released from the refueling pool with a minimum of the containment building free volume.

The mixing volume of 25 percent is assumed and is based on the normal airflow rate of four fan coolers.

M. The containment purge rate is 15,000 ft^3/min for the case with the containment airlocks and equipment hatch closed.

N. Automatic containment ventilation isolation capability is no longer required by the Technical Specifications. The limiting radiological consequences for a fuel handling accident inside containment as reported in table 15.7.4-4 are based on an open containment with no automatic isolation. However, the radiological consequences for a closed containment reported in table 15.7.4-4 are based on automatic containment ventilation isolation. If automatic containment ventilation isolation is available, it would be assumed to occur within 10 s from the time the containment isolation signal is generated with a 5-s signal generation time.

O. The control room emergency filtration system (CREFS) is initiated by RE-12116 and/or RE-12117 during a fuel handling accident in the fuel handling building.

P. For the case with the airlocks and/or equipment hatch open, the activity is assumed to be released from the containment to the outside atmosphere at a rate in which all the activity released from the damaged fuel assemblies would be released to the outside atmosphere in 2 hours if the containment airlocks and/or equipment hatch remain open. The radiological consequences of a fuel handling accident in containment have been evaluated assuming that the containment is open to the outside atmosphere. All airborne activity reaching the containment atmosphere is assumed to be exhausted to the environment within 2 hours of the accident. The calculated offsite and control room operator doses are within the acceptance criteria of Standard Review Plan 15.7.4 and General Design Criteria 19. Therefore, although the containment penetrations do not satisfy any of 10 CFR 50.36 (c)(2)(ii) criteria, Technical Specifications provide containment closure capability to minimize potential offsite doses. Procedures provide administrative controls to ensure that the designated person available to close the personnel and/or emergency air lock doors does not have other duties that would preclude the ability to operate the door in a timely manner. In addition, a designated hatch closure crew is available to effect a timely closure of the equipment hatch.

Q. The control room volume, normal and emergency mode flow rates, and emergency mode filter efficiencies for the control room ventilation system used to determine control room doses following a fuel handling accident with the containment airlocks and/or equipment hatch open are given in table 15A-1 of appendix 15A.

15.7.4.5.1.3 Mathematical Models Used in the Analysis. Mathematical models used in the analysis are described in the following sections:

A. The mathematical models used to analyze the activity released during the course of the accident are described in appendix 15A, section 15A.2.

B. The atmospheric dispersion factors are based on the onsite meteorological measurement described in section 2.3 and are provided in table 15A-2.

C. The thyroid inhalation and total-body immersion doses to a receptor located at the exclusion area boundary and outer boundary of the low population zone are analyzed using the models described in appendix 15A, subsections 15A.2.4 and 15A.2.6, respectively.

D. The thyroid inhalation, beta skin, and gamma body doses to personnel in the control room are analyzed using the models described in appendix 15A, and subsections 15A.3.3, 15A.3.4, and 15A.3.5.

15.7.4.5.1.4 Identification of Leakage Pathways and Resultant Leakage Activity. For evaluating the radiological consequences due to the postulated fuel handling accident in the fuel building, the resultant activity is conservatively assumed to be released to the environment during the 0- to 2-h period immediately following the occurrence of the accident. This is a considerably higher release rate than that based on the actual ventilation rate. Therefore, the results of the analysis are based on the most conservative pathway available. Only the limiting case of a fuel handling accident is shown in table 15.7.4-1.

15.7.4.5.2 Identification of Uncertainties and Conservatisms in Analysis

The uncertainties and conservatisms in the assumptions used to evaluate the radiological consequences of a fuel handling accident result from assumptions made involving the amount of fission product gases available for release to the environment and the meteorology present at the site during the course of the accident. The most significant of these assumptions are:

A. It is assumed in the analysis that all the fuel rods in the dropped assembly are damaged. This is a highly conservative assumption, since in transferring fuel under strict fuel handling procedures, only under the worst possible circumstances could the dropping of a spent fuel assembly result in damage to all the fuel rods contained in the assembly.

B. The fission product gap inventory in a fuel assembly is dependent on the power rating of the assembly and the temperature of the fuel. The gap fractions from Regulatory Guide 1.195 are conservatively assumed. Realistic calculations of gap fractions show less than 2% for all short lived isotopes.

C. Iodine removal from the released fission product gas takes place as the gas rises to the pool surface through the body of liquid in the spent fuel pool. The extent of elemental iodine removal is determined by mass transfer from the gas phase to the surrounding liquid and is controlled by the bubble diameter and contact time of the bubble in the solution. The values used in the analysis result in a release of elemental iodine approximately a factor of 3 greater than anticipated. The release of activity from the pool to the containment atmosphere is time dependent, and, consequently, there would be sufficient time for this activity to mix homogeneously in a significantly greater percent of the containment volume than assumed in the analysis.

D. Fuel handling building emergency filtration system charcoal filters are provided; however, no credit has been taken for their capability. This means a reduction in the iodine concentrations and, thus, a reduction in the thyroid doses at the exclusion area boundary and the outer boundary of the low population zone.

E. The containment purge exhaust system has charcoal adsorber units which filter any containment purge release. However, no credit has been taken for its capability (90% efficiency, minimum) since these units are not specifically designed to Seismic Category 1 criteria. It is expected that for any event which would produce a catastrophic failure of the charcoal adsorber unit to the extent that its filtering capability would be negated would also result in the purge exhaust fan becoming inoperable. Therefore, failure within the purge exhaust system would terminate any high-volume release from the containment. In fact, the purge exhaust fan is considerably more likely to be inoperable following any postulated event than the failure of a passive charcoal adsorber unit. Thus, although no credit in the analysis has been given for the normal purge exhaust filters, any release prior to containment isolation would be filtered, reducing the calculated releases by another factor of 10.

F. There is also conservatism in the time to first fuel transfer. Despite the fact that fuel could be transferred at 90 h, it is probable that fuel handling will begin sometime later.

G. The exhaust from the personnel airlock area is via the equipment building ventilation fan (1526-B7-00200). The distance from the equipment building ventilation exhaust to the control room (CR) intake is 190 ft. If both the intake and exhaust fans fail (loss of power to nonsafety-grade equipment), activity may exfiltrate through the equipment building intake. The distance from the equipment building ventilation intake to the CR intake is 90 ft. For the case of the fuel handling accident inside containment with the personnel airlock open, the activity is assumed to be released from the equipment building to the environment and from the environment to the CR intake. Furthermore, the CR dose analysis conservatively assumes that activity is released from the equipment building intake, which is closer to the CR than the equipment building exhaust. This assumption is limiting with respect to releases from the equipment hatch or the emergency air lock.

H. The distance from the CR intake to the nearest point on the containment is 70 ft. The atmospheric dispersion factors (χ/Q) at the CR intake used to determine the CR doses following a LOCA are based on this distance of 70 ft. The distance of 90 ft from the equipment building intake to the CR intake is comparable to the distance of 70 ft used in the LOCA CR dose analysis. Thus, the same χ/Q as used in the LOCA CR dose analysis, which are listed in table 15A-2, are conservatively used for the CR dose analysis for a fuel handling accident inside containment with the personnel airlock open.

I. The assumption that all radioactivity released due to the fuel handling accident is released from the containment and to the outside atmosphere in the initial 2 h following the accident if the containment remains open is conservative. There is no driving force to push this activity out of the containment. The bulk of the radioactivity would likely stay in the containment for much longer than 2 h, even if the containment remained open.

J. The meteorological conditions which may be present at the site during the course of the accident are uncertain. However, it is highly unlikely that meteorological conditions assumed will be present during the course of the accident for any extended period of time. Therefore, the radiological consequences evaluated, based on the meterological conditions assumed, are conservative.

15.7.4.5.2.1 Filter Loadings. The filtration systems which function to limit the consequences of a fuel handling accident in the fuel building are the fuel building emergency filtration system and the control room filtration system.

The activity loadings on the control room charcoal adsorbers as a function of time have been evaluated for the loss-of-coolant accident (LOCA), as described in subsection 15.6.5. Since these filters are capable of accommodating the design basis LOCA fission product iodine loadings, more than adequate design margin is available with respect to postulated fuel handling accident releases.

The activity loadings on the ESF filtration system charcoal adsorbers have been evaluated in accordance with Regulatory Guide 1.52, which limits the maximum loading to 2.5 mg iodine/g activated charcoal.

15.7.4.5.2.2 Doses to Receptor at the Exclusion Area Boundary and Low Population Zone Outer Boundary. The potential radiological consequences resulting from the occurrence of a postulated fuel handling accident occurring in the fuel building and in the reactor building have been conservatively analyzed, using assumptions and models described in previous sections. The total-body dose due to immersion from direct radiation and the thyroid dose due to inhalation have been analyzed for the 0- to 2-h dose at the exclusion area boundary and for the duration of the accident (0 to 2 h) at the low population zone outer boundary. The results are listed in table 15.7.4-4. The resultant doses are well within the guideline values of 10 CFR 100.

15.7.5 SPENT FUEL CASK DROP ACCIDENT

The spent fuel cask will follow the path outlined on drawing AX4DE501. Cask handling over the spent fuel pool or the new fuel pit is prevented by interlocks.

A Type 1 single-failure-proof crane designed according to NUREG-0554 is used in handling the spent fuel cask. Therefore, no cask drop will occur, and thus no radioactivity will be released. Refer to subsection 9.1.5 for a description of the spent fuel cask handling equipment.

TABLE 15.7.1-1

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A WASTE GAS DECAY TANK RUPTURE

I. Source Data	
A. Core power level (MWt)	3636
B. Reactor coolant iodine activity	Initial activity equal to 1.0 μCi/g of dose equivalent I-131 with a shutdown iodine spike that increases the activity to 60 μCi/g of dose equivalent I-131. (See tables 15A-6 and 15A-7.)
C. Volume control tank purge (sf^3/min)	0.7
D. Number of gas decay tanks per unit	7
E. Number of tanks shared by Units 1 and 2	2
F. Tank switching time for normal operation (days)	2
G. Shutdown degassing (h)	24
II. Atmospheric Dispersion Factors	See table 15A-2.

III. Activity Release Data (Maximum/Tank)

Nuclide	0 to 2 h (Ci)
Kr-85	6.42E+3
Kr-85m	1.33E+1
Kr-87	6.30E-4
Kr-88	2.66E+0
Xe-131m	1.65E+2
Xe-133	2.94E+4
Xe-133m	2.80E+3
Xe-135	4.15E+2
Xe-135m	Negligible
Xe-138	Negligible
I-131	3.71E+0
I-132	7.80E-1
I-133	3.59E+0
I-134	1.02E-1
I-135	1.16E+0

TABLE 15.7.1-2 (SHEET 1 OF 5)

DESIGN COMPARISON TO THE REGULATORY POSITIONS OF REGULATORY GUIDE 1.24, ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A PRESSURIZED WATER REACTOR RADIOACTIVE GAS STORAGE TANK FAILURE, REVISION 0, MARCH 23, 1972

Regulatory Guide 1.24 Position	Design
1. The assumptions related to the release of radioactive gases from the postulated failure of a gaseous waste storage tank are:	
A. The reactor has been operating at full power with 1 percent defective fuel and a shutdown to cold condition has been conducted near the end of an equilibrium core cycle. As soon as possible after shutdown, all noble gases have been removed from the primary cooling system and transferred to the gas decay tank that is assumed to fail.	1.A conforms.
B. The maximum content of the decay tank assumed to fail should be used for the purpose of computing the noble gas inventory in the tank. Radiological decay may be taken into account in the computation only for the minimum time period required to transfer the gases from the primary system to the decay tank.	1.B conforms.
C. The failure is assumed to occur immediately upon completion of the waste gas transfer, releasing the entire contents of the tank to the building. The assumption of the release of the noble gas inventory from only a single tank is based on the premise that all gas decay tanks will be isolated from each other whenever they are in use.	1.C conforms.

TABLE 15.7.1-2 (SHEET 2 OF 5)

Regulatory Guide 1.24 Position	Design
D. All of the noble gases are assumed to leak out of the building at ground level over a 2-h time period.	1.D conforms.
2. The atmospheric diffusion assumptions for ground level releases are:	2. Short-term atmospheric dispersion factors corresponding to a ground level release and accident conditions were calculated based on onsite meteorological measurement programs described in Regulatory Guide 1.1.45 and represent the worst of the 5-percent overall site meteorology and the 0.5-percent worst sector meteorology.
A. The basic equation for atmospheric diffusion from a ground level point source is $\chi/Q = \frac{1}{\pi u \sigma_y \sigma_z}$ where:	
χ = the short term average centerline value of the ground level concentration (Ci/s)	
Q = amount of material released (Ci/s)	
u = windspeed (m/s)	
σ_y = the horizontal standard deviation of the plume (m). See figure V-1, page 48, F. A. Gifford, Jr., Use of Routine Meteorological Observation for Estimating Atmospheric Dispersion, Nuclear Safety, Vol. II, No. 4, June 1961.	

TABLE 15.7.1-2 (SHEET 3 OF 5)

Regulatory Guide 1.24 Position	Design
σ_z = the vertical standard deviation of the plume (m). See figure V-2, page 48 in Gifford, Use of Routine Meteorological Observations…	
B. For ground level releases, atmospheric diffusion factors[a] used in evaluating the radiological consequences of the accident addressed in this guide are based on the following assumptions: 1. Windspeed of 1 m/s. 2. Uniform wind direction. 3. Pasquill diffusion category F.	
C. Figure 1 is a plot of atmospheric diffusion factors (χ/Q) versus distance derived by use of the equation for a ground level release given in regulatory position 2.A above under the meteorological conditions given in regulatory position 2.B above.	
3. The following assumptions and equations may be used to obtain conservative approximations of external whole body dose from radioactive clouds:	3. The dose models are described in Appendix 15A.
A. External whole body doses are calculated using "infinite cloud" assumptions; i.e., the dimensions of the cloud are assumed to be large compared to the distances that the gamma rays and beta particles travel. The dose at any	

TABLE 15.7.1-2 (SHEET 4 OF 5)

Regulatory Guide 1.24 Position	Design
A. distance from the reactor is calculated based on the maximum ground level concentration at that distance.	

For an infinite uniform cloud containing χ Ci of beta radioactivity/per m^3, the beta dose rate in air at the cloud center is:(b)

$$_{\beta}D'_{\infty} = 0.457\ \overline{E}_{\beta\chi}$$

where:

D'_{∞} = beta dose rate from an inifinite cloud (rad/s)

$\overline{E}_{\beta}$ = average beta energy per disintegration (MeV/dis)

χ = concentration of beta or gamma emitting isotope in the cloud (Ci/m^3)

Because of the limited range of beta particles in tissue, the surface body dose rate from beta emitters in the infinite cloud can be approximated as being one-half this amount or:

$$_{\beta}D'_{\infty} = 0.23\ \overline{E}_{\beta\chi}$$

For gamma-emitting material, the dose rate in air at the cloud center is :

$$_{\gamma}D'_{\beta} = 0.507\ \overline{E}_{\gamma\chi}$$

where:

TABLE 15.7.1-2 (SHEET 5 OF 5)

Regulatory Guide 1.24 Position	Design

$_{\chi}D'_{\beta}$ = Gamma dose rate from an infinite cloud (rad/s)

$\overline{E}_{\gamma}$ = average gamma energy per disintegration (MeV/dis)

However, because of the presence of the ground, the receptor is assumed to be exposed to only one-half of the cloud (semi-infinite) and the equation becomes:

$$_{\gamma}D'_{\beta} = 0.25\ \overline{E}_{\gamma\chi}$$

Thus, the total beta or gamma dose to an individual located at the center of the cloud path may be approximated as:

$$_{\beta}D_{\infty} = 0.23\ \overline{E}_{\beta\psi} \quad \text{or}$$

$$_{\gamma}D = 0.25\ \overline{E}_{\gamma\psi}$$

where ψ is the concentration time integral for the cloud (Ci/m^3)

B. The beta a gamma energies emitted per disintegration, as given in Table of Isotopes, © are averaged and used according to the methods described in ICRP Publication 2.

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a. These diffusion factors should be used until adequate site meteorological data are obtained. In some cases, available information on such site conditions as meteorology, topography and geographical location may dictate the use of more restrictive parameters to insure a conservative estimate of potential offsite exposures.

b. Meteorology and Atomic Energy, 1968, chapter 7.

c. C. M. Lederer, J. M. Hollander, and I. Perlman, Table of Isotopes, Sixth Edition, John Wiley and Sons, Inc., New York, 1967.

TABLE 15.7.1-3

RADIOLOGICAL CONSEQUENCES OF A WASTE GAS DECAY TANK RUPTURE

	Doses (rem)
Exclusion Area Boundary (0 to 2 h)	
Thyroid (rem)	0.3
Whole body (rem)	< 0.1
Low Population Zone Outer Boundary (duration)	
Thyroid (rem)	0.1
Whole body (rem)	< 0.1

TABLE 15.7.2-1

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A LIQUID RADWASTE TANK FAILURE

Source data	
Core power level (MWt)	3636
Defective fuel (%)	1
Atmospheric dispersion factors	See table 15A-2.
Activity release data	
Noble gas activity (percent of tank contents)	100
Iodine gas activity (percent of tank contents)	1
Tank contents	

Nuclide	Ci
Kr-87	5.42E+2
Kr-88	1.64E+3
Kr-89	--
Xe-133	1.04E+5
Xe-135	3.57E+3
Xe-138	3.12E+2
I-131	1.17E+2
I-132	1.18E+2
I-133	2.23E+2
I-135	1.10E+2

TABLE 15.7.2-2

RADIOLOGICAL CONSEQUENCES OF A LIQUID RADWASTE TANK FAILURE

	Doses (rem)
Exclusion area boundary (0 to 2 h)	
Thyroid (rem)	0.1
Whole body gamma (rem)	0.3
Low population zone outer boundary (duration)	
Thyroid (rem)	0.1
Whole body gamma (rem)	0.1

TABLE 15.7.3-1

RECYCLE HOLDUP TANK
DATA FOR FAILURE ANALYSIS

Volume of tank (gal)	112,000
Weight of liquid contained (g)	4.22×10^8

Radioactive contents

Nuclide	Activity (Ci)
Kr-87	5.49×10^2
Kr-88	1.56×10^3
Kr-89	4.64×10^1
Xe-133	1.14×10^5
Xe-135	3.08×10^3
Xe-138	2.7×10^2
I-131	1.18×10^2
I-132	1.18×10^2
I-133	1.77×10^2
I-135	9.7×10^1
Rb-88	2.03×10^2
Cs-136	1.22×10^2
Cs-138	4.05×10^1

TABLE 15.7.4-1 (SHEET 1 OF 2)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A FUEL HANDLING ACCIDENT

	Containment Open or In Fuel Building	*Containment Closed (HISTORICAL)*
Source Data		
Core power level (MWt)	3636	*3636*
Radial peaking factor	1.70	*1.70*
Decay time (h)	90	*100*
Number of fuel rods affected	314	*1.2 assemblies*
Fraction of fission product gases contained in the gap region of the fuel assembly	(Reg. Guide 1.195) 5% of the total noble gases and iodines except I-131 (8%) and Kr-85 (10%)	*RG 1.25 for all except I-131 a (fraction of 0.12)*
Atmospheric Dispersion Factors	Table 15A-2	*Table 15A-2*
Activity Release Data		
Percent of affected fuel assemblies gap activity released	100	*100*
Pool decontamination factors		
Elemental iodine	400	*200*
Organic iodine	1	*1*
Noble gas	1	*1*
Filter efficiency (%)	No credit	*0*
Building mixing volumes assumed (% total volume)	0	*25*

TABLE 15.7.4-1 (SHEET 2 OF 2)

	Containment Open or In Fuel Building	*Containment Closed (HISTORICAL)*
HVAC exhaust rate (ft^3/min)	N/A	*15,000*
Building isolation time (s)	No isolation	*10+5*
Activity release period (h)	2	*Release terminated 10 s after containment isolation signal with 5 s allowed for signal generation*

TABLE 15.7.4-2 (SHEET 1 OF 9)

REGULATORY GUIDE 1.25, ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A FUEL HANDLING ACCIDENT IN THE FUEL HANDLING AND STORAGE FACILITY FOR BOILING AND PRESSURIZED WATER REACTORS, REVISION 0, DATED MARCH 23, 1972

Regulatory Guide 1.25 Position	Case 1 (In Fuel Building or Open Containment)	*Case 2 (In Closed Containment Building) (HISTORICAL)*
The assumptions[(a)] related to the release of radioactive material from the fuel and fuel storage facility as a result of a fuel handling accident are:		
The accident occurs at a time after shutdown identified in the Technical Requirements Manual as the earliest time fuel handling operations may begin. Radioactive decay of the fission product inventory during the interval between shutdown and commencement of fuel handling operations is taken into consideration.	Conforms. Accident occurs 90 h after shutdown.	*Conforms. Accident occurs 100 h after shutdown.*
The maximum fuel rod pressurization[(b)] is 1200 psig.	Conforms.	*Conforms.*
The minimum water depth[(b)] between the top of the damaged fuel rods and the fuel pool surface is 23 ft.	Conforms. Water depth is greater than 23 ft.	*Conforms. Water depth is greater than 23 ft.*
All of the gap activity in the damaged rods is released and consists of 10% of the total noble gases other than Kr-85, 30% of the Kr-85, and 10% of the total radioactive iodine in the rods at the time of the accident. For the purpose of sizing filters for the fuel handling accident addressed in this guide, 30% of the I-127 and I-129 inventory is assumed to be released from the damaged rods.	Conforms, except for I-131 8%, Kr-85 10%, and 5% noble gases and other iodines; the gap is consistent with Reg. Guide 1.195 for lead rod average burnup to 62,000 MWd/Mtu.	*Conforms, except for I-131 which assumes 12%; the gap is consistent with NUREG CR-5009 for lead rod average burnup to 60,000 MWd/Mtu.*
The values assumed for individual fission product inventories are calculated assuming full-power operation at the end of core life immediately preceding shutdown, and such calculation should include an appropriate radial peaking factor. The minimum acceptable radial peaking factors are 1.5 for BWRs and 1.65 for PWRs.	A peaking factor of 1.70 is used since this is the maximum projected radial peaking factor. A value of 1.65 to 1.70 may be used for a cycle-specific core reload evaluation.	*A peaking factor of 1.70 is used since this is the maximum projected radial peaking factor. A value of 1.65 to 1.70 may be used for a cycle-specific core reload evaluation.*

TABLE 15.7.4-2 (SHEET 2 OF 9)

Regulatory Guide 1.25 Position	Case 1 (In Fuel Building or Open Containment)	*Case 2 (In Closed Containment Building) (HISTORICAL)*
The iodine gap inventory is composed of 99.75% inorganic species and 0.25% organic species.	Conforms.	*Conforms.*
The pool decontamination factors for the inorganic and organic species are 133 and 1, respectively, giving an overall effective decontamination factor of 100 (i.e., 99% of the total iodine released from the damaged rods is retained by the pool water). This difference in decontamination factors for inorganic and organic iodine above the fuel pool being composed of 75% inorganic and 25% organic species.	The pool decontamination factors for the inorganic and organic species are 400 and 1, respectively, giving an overall effective decontamination factor of 200 (i.e., 99.5% of the total iodine released from the damaged rods is retained by the pool). This difference in decontamination factors for inorganic and organic iodine above the fuel pool being composed of 50% inorganic and 50% organic species.	*The pool decontamination factors for the inorganic and organic species are 200 and 1, respectively, giving an overall effective decontamination factor of 133 (i.e., 99.25% of the total iodine released from the damaged rods is retained by the pool). This difference in decontamination factors for inorganic and organic iodine above the fuel pool being composed of 67% inorganic and 33% organic species.*
The retention of noble gases in the pool is negligible (i.e., decontamination factor of 1).	Conforms. A decontamination factor of 1 is used.	*Conforms. A decontamination factor of 1 is used.*
The radioactive material that escapes from the pool to the building is released from the building(c) over a 2-h time period.	Conforms. A 0- to 2-h release from the pool to the building to the environment is assumed.	*The release from pool to the building is automatically isolated upon detection of the first trace of release. Thus, the release is contained in the containment building after isolation.*
If it can be shown that the building atmosphere is exhausted through adsorbers designed to remove iodine, the removal efficiency is 90% for inorganic species and 70% for organic species.	No credit is taken for the FHB post-accident exhaust filters that conform to Regulatory Guide 1.52 as described in table 9.4.1-2.	*No credit is taken for the normal purge filters.*
The effluent from the filter system passes directly to the emergency exhaust system without mixing (e) in the surrounding building atmosphere and is then released (as an elevated plume for those facilities with stacks (f)).	Conforms.	*Conforms.*
The assumptions for atmospheric diffusion for: Ground level releases The basic equation for atmospheric diffusion from a ground level point source is: $\chi/Q = \frac{1}{\pi\mu\sigma_y\sigma_z}$ where:	Short-term atmospheric dispersion factors corresponding to ground level release and accident conditions were based on the meteorological measurements program described in section 2.3. The dispersion factors are in compliance with the methodology described in Regulatory Guide 1.145 and represent the worst of the 5% overall site meteorology and the 0.5% worst sector meteorology.	

TABLE 15.7.4-2 (SHEET 3 OF 9)

Regulatory Guide 1.25 Position	Case 1 (In Fuel Building or Open Containment)	*Case 2 (In Closed Containment Building) (HISTORICAL)*
χ = the short-term average centerline value of the ground level concentration (Ci/m).		
Q = amount of material released (Ci/s).		
μ = windspeed (m/s).		
σ_y = the horizontal standard deviation of the plume (m). See figure V-1, page 48, in F. A. Gifford, Jr., Use of Routine Meteorological Observation Estimating Atmospheric Dispersion, Nuclear Safety, Vol. II, No. 4, June 1961.		
σ_z = the vertical standard deviation of the plume (m). See figure V-2, page 48 in F. A. Gifford, Jr., Use of Routine Meteorological Observation for Estimating Atmospheric Dispersion, Nuclear Safety, Vol. II, No. 4, June 1961.		
For ground level releases, atmospheric diffusion factors(9) used in evaluating the radiological consequences of the accident addressed in this guide are based on the following assumptions: windspeed of 1 m/s, uniform wind direction, and Pasquill diffusion category F.		
Figure 1 is a plot of atmospheric diffusion factor (χ/Q) versus distance derived by use of the equation for a ground level release given in regulatory position 2.a.(1) and under the meteorological conditions given in regulatory position 2.a.(2).		
Atmospheric diffusion factors for ground level releases may be reduced by a factor ranging from 1 to a maximum of 3 (see figure 2) for additional dispersion produced by the turbulent wake of the reactor building. The volumetric building wake correction as defined in subsection 3-3.5.2 of		

TABLE 15.7.4-2 (SHEET 4 OF 9)

Regulatory Guide 1.25 Position	Case 1 (In Fuel Building or Open Containment)	*Case 2 (In Closed Containment Building) (HISTORICAL)*
Meteorology and Atomic Energy-1968 is used with a shape factor of ½ and the minimum cross-sectional area of the reactor building only.		
Elevated releases		
The basic equation for atmospheric diffusion from an elevated release is:	Not applicable; ground level releases were assumed.	*Not applicable; ground level releases were assumed.*
$\chi/Q = \frac{e^{-h^{2/z}}\sigma_z}{\pi\mu\sigma_y\sigma_z}$		
where:		
χ = the short-term average centerline value of the ground level concentration (Ci/m^3).		
Q = amount of material released (Ci/s).		
μ = windspeed (m/s).		
σ_y = the horizontal standard deviation of the plume (m). See figure V-1, page 48 in, F. A. Gifford, Jr., Use of Routine Meteorological Observations for Estimating Atmospheric Dispersion, Nuclear Safety, Vol. II. No. 4, June 1961.		
σ_z = the vertical standard deviation of the plume (m). See figure V-2, page 48 in, F. A. Gifford, Jr., Use of Routine Meteorological Observations for Estimating Atmospheric Dispersion, Nuclear Safety, Vol. II, No. 4, June 1961.		
h = effective height of release (m).		
For elevated releases, atmospheric diffusion factors(h) used in evaluating the radiological consequences of the accident addressed in this		

TABLE 15.7.4-2 (SHEET 5 OF 9)

Regulatory Guide 1.25 Position	Case 1 (In Fuel Building or Open Containment)	*Case 2 (In Closed Containment Building) (HISTORICAL)*
guide are based on the following assumptions: windspeed of 1 m/s, uniform wind direction, envelope of Pasquill diffusion categories for various release heights, and a fumigation condition existing at the time of the accident.(h)		
Figure 3 is a plot of atmospheric diffusion factors versus distance for an elevated release assuming no fumigation, and figure 4 is for an elevated release with fumigation.		
Elevated releases are considered to be at a height equal to no more than the actual stack height. Certain site conditions may exist, such as surrounding elevated topography or nearby structures, which will have the effect of reducing the effective stack height. The degree of stack height reduction will be evaluated on an individual case basis.		
The following assumptions and equations may be used to obtain conservative approximations of thyroid dose from the inhalation of radioiodine and external whole-body dose from radioactive clouds:		
The assumptions relative to inhalation thyroid dose approximations are:	Conforms. See appendix15A, subsection 15A.2.4.	*Conforms. See appendix15A, subsection 15A.2.4.*
The receptor is located at a point on or beyond the site boundary where the maximum ground level concentration is expected to occur.		
No correction is made for depletion of the effluent plume of radioiodine due to deposition on the ground or for the radiological decay of radioiodine in transit.		
Inhalation thyroid doses may be approximated by use of the following equation:		
$D = \frac{F_g I F P B R (\chi/Q)}{(DF_P)(DF_f)}$		
where:		

TABLE 15.7.4-2 (SHEET 6 OF 9)

Regulatory Guide 1.25 Position	Case 1 (In Fuel Building or Open Containment)	*Case 2 (In Closed Containment Building) (HISTORICAL)*
D = thyroid dose (rd). F_g = fraction of fuel rod iodine inventory in fuel rod void space (0.1). I = core iodine inventory at time of accident (Ci). F = fraction of core damaged so as to release void space iodine. P = fuel peaking factor. B = breathing rate = 3.47×10^{-4} m^3/s (i.e., 10 m^3/8-h workday as recommended by the ICRP). DF_p = effective iodine decontamination factor for pool water. DF_f = effective iodine decontamination factor for filters (if present). χ/Q = atmospheric diffusion factor at receptor location (s/m^3). R = adult thyroid dose conversion factor for the iodine isotope of interest (rd/Ci). Dose conversion factors for I-131 through I-135 are listed in the table below.(i) These values were derived from "standard man" parameters recommended in ICRP Publication 2.(j)		

TABLE 15.7.4-2 (SHEET 7 OF 9)

Regulatory Guide 1.25 Position	Case 1 (In Fuel Building or Open Containment)	*Case 2 (In Closed Containment Building) (HISTORICAL)*
Adult Inhalation Thyroid Dose Conversion Factors Iodine Isotope; Conversion Factor (R) (rd/Ci inhaled) 131 1.48×10^{6} 132 5.35×10^{4} 133 4.0×10^{5} 134 2.5×10^{4} 135 1.24×10^{5}	See table 15A-5 for dose conversion factors.	*See table 15A-5 for dose conversion factors.*
The assumptions relative to external whole-body dose approximations are: The receptor is located at a point on or beyond the site boundary where the maximum ground level concentration is expected to occur.	Conforms. See appendix 15A, subsection 15A.2.6	*Conforms. See appendix 15A, subsection 15A.2.6*
External whole-body doses are calculated using "infinite cloud" assumptions; i.e., the dimensions of the cloud are assumed to be large compared to the distances that the gamma rays and beta particles travel. The dose at any distance from the reactor is calculated based on the maximum ground level concentration at that distance. For an infinite uniform cloud containing χCi of beta radioactivity per m^3, the beta dose rate in air at the cloud center is: $\beta_{\infty}^{D'} = 0.457\ \overline{E}_{\beta}\,\chi$ where: $\beta_{\infty}^{D'}$ = beta dose rate from an infinite cloud (rd/s). $\overline{E}_{\beta}$ = average beta energy per disintegration (MeV/dis). χ = concentration of beta or gamma emitting isotope in the cloud (Ci/m^3).	See table 15A-5 for dose conversion factors.	*See table 15A-5 for dose conversion factors.*

TABLE 15.7.4-2 (SHEET 8 OF 9)

Regulatory Guide 1.25 Position	Case 1 (In Fuel Building or Open Containment)	*Case 2 (In Closed Containment Building) (HISTORICAL)*

Because of the limited range of beta particles in tissue, the surface-body dose rate from beta emitters in the infinite cloud can be approximated as being one-half this amount or:

$$\beta_{\infty}^{D'} = 0.23\ \overline{E}_{\beta}\,\chi$$

For gamma-emitting material the dose rate in tissue at the cloud center is:

$$\gamma_{\infty}^{D'} = 0.507\,\overline{E}_{\gamma}\,\chi$$

where:

$\gamma_{\infty}^{D'}$ = gamma dose rate from an infinite cloud (rd/s).

$E_{\gamma\chi}$ = average gamma energy per disintegration (MeV/disintegration).

However, because of the presence of the ground, the receptor is assumed to be exposed to only one-half of the cloud (semi-infinite) and the equation becomes:

$$\gamma^{D'} = 0.25\,\overline{E}_{\gamma}\,\chi$$

Thus, the total beta or gamma dose to an individual located at the center of the cloud path may be approximated as:

$$\beta_{\infty}^{D} = 0.23\ \overline{E}_{\beta}\ \psi \text{ or}$$

$$\gamma^{D} = 0.25\ \overline{E}_{\gamma}\ \psi$$

where ψ = the concentration time integral for the cloud (Ci s/m^3).

The beta and gamma energies emitted per disintegration, as given in Table of Isotopes,(i) are averaged and used according to the methods described in ICRP Publication 2.

TABLE 15.7.4-2 (SHEET 9 OF 9)

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a. The assumptions given are valid only for oxide fuels of the types currently in use and in cases where the following conditions are not exceeded:

1. Peak linear power density of 20.5 kW/ft for the highest power assembly discharged.
2. Maximum centerline operating fuel temperature less than 4500°F for this assembly.
3. Average burnup for the peak assembly of 25,000 MWd/t or less (this corresponds to a peak local burnup of about 45,000 MWd/t).

b. For release pressures greater than 1200 psig and water depths less than 23 ft, the iodine decontamination factors will be less than those assumed in this guide and must be calculated on an individual-case basis using assumptions comparable in conservatism to those of this guide.

c. The effectiveness of features provided to reduce the amount of radioactive material available for release to the environment will be evaluated on an individual-case basis.

d. These efficiencies are based upon a 2-in. charcoal bed depth with 1/4-s residence time. Efficiencies may be different for other systems and must be calculated on an individual-case basis.

e. Credit for mixing will be allowed in some cases; the amount of credit will be evaluated on an individual-case basis.

f. Credit for an elevated release will be given only if the point of release is more than 2 1/2 times the height of any structure close enough to affect the dispersion of the plume or located far enough from any structure which could affect the dispersion of the plume. For those plants without stacks the atmospheric diffusions factors assuming ground level release given in regulatory position 2.b should be used.

g. These diffusion factors should be used until adequate site meteorological data are obtained. In some cases, available information on such site conditions as meteorology, topography, and geographical location may dictate the use of more restrictive parameters to ensure a conservative estimate of potential offsite exposures.

h. For sites located more than 2 miles from large bodies of water such as oceans or one of the Great Lakes, a fumigation condition is assumed to exist at the time of the accident and continue for 1/2 h. For sites located less than 2 miles from large bodies of water a fumigation condition is assumed to exist at the time of the accident and continue for the duration of the release (2 h).

i. Dose conversion factors taken from F. D. Anderson, R. E. Baker, J. J. DiNunno, "Calculation of Distance Factors for Power and Test Reactor Site," TID-14844, 1962.

j. Recommendations of the International Commission on Radiological Protection, "Report of Committee II on Permissible Dose for Internal Radiation (1959)," ICRP Publication 2, Permagon Press, New York, 1960.

k. Meteorology and Atomic Energy-1968, chapter 7.

l. C. M. Lederer, J. M. Hollander, and I. Perlman, Table of Isotopes, sixth edition, John Wiley and Sons, Inc., New York, 1967.

TABLE 15.7.4-3

DELETED

TABLE 15.7.4-4

RADIOLOGICAL CONSEQUENCES OF A FUEL HANDLING ACCIDENT

	Doses (rem)
Fuel Building or Open Containment	
Exclusion area boundary (0 to 2 h)	
Thyroid	23.4
Whole body	1.1
Low population zone outer boundary (0 to 2 h)	
Thyroid	9.4
Whole body	0.4
Control Room[a]	
Thyroid	13.7
Whole body	0.6
Beta Skin	5.6
Containment Closed (HISTORICAL)	
Exclusion area boundary (0 to 2 h)	
Thyroid	*0.3*
Whole body	*< 0.1*
Low population zone outer boundary (0 to 2 h)	
Thyroid	*0.1*
Whole body	*< 0.1*

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[a] Doses from MURPU and Control Room Habitability (TSTF-448) implementation.

15.8 ANTICIPATED TRANSIENTS WITHOUT TRIP

The worst common mode failure which is postulated to occur is the failure to scram the reactor after an anticipated transient has occurred. A series of generic studies (1,2) on anticipated transients without scram (ATWS) showed acceptable consequences would result provided that the turbine trips and auxiliary feedwater flow is initiated in a timely manner. The effects of ATWS events are not considered as part of the design basis for transients analyzed in Chapter 15. The final NRC ATWS rule(3) requires that Westinghouse-designed plants install ATWS mitigation system circuitry (AMSAC) to initiate a turbine trip and actuate auxiliary feedwater flow independent of the reactor protection system. The Vogtle AMSAC design is described in section 7.7.

In support of the Measurement Uncertainty Recapture Power Uprate, a plant-specific evaluation was performed to demonstrate continued conformance with the analyses that formed the basis for the ATWS rule (Reference 4 and 5), at the uprated conditions.

15.8.1 REFERENCES

1. "Westinghouse Anticipated Transients Without Trip Analysis," WCAP-8330, August 1974.
2. Anderson, T. M., "ATWS Submittal," Westinghouse Letter NS-TMA-2182 to S. H. Hanauer of the NRC, December 1979.
3. ATWS Final Rule - Code of Federal Regulations 10 CFR 50.62 and Supplementary Information Package, "Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants."
4. NL-07-1010, “Vogtle Electric Generating Plant Request to Change Licensed Maximum Power Level,” L. M. Stinson to USNRC, August 28, 2007.
5. NL-08-0307, “Vogtle Electric Generating Plant, Units 1 and 2, Issuance of Amendments Regarding Measurement Uncertainty Recapture Power Uprate (TAC Nos. MD6625 and MD6626),” USNRC to T. E. Tynan, February 27, 2008.

APPENDIX 15A

ACCIDENT ANALYSIS RADIOLOGICAL CONSEQUENCES EVALUATION MODELS AND PARAMETERS

15A.1 GENERAL ACCIDENT PARAMETERS

This appendix contains the parameters used in analyzing the radiological consequences of postulated accidents. Table 15A-1 contains the general parameters used in all the accident analyses. For parameters specific only to particular accidents, refer to that accident parameter section. The site specific ground-level release short-term dispersion factors[a] are based on Regulatory Guide 1.145(1) methodology and represent the 0.5-percent worst sector meteorology; these factors are given in table 15A-2. (See subsection 2.3.4 for additional details on meteorology.) The core and gap inventories are given in table 15A-3. The thyroid (via inhalation pathway), beta skin, and gamma body (via submersion pathway) dose factors based on reference 2 are given in table 15A-5.

Reactor coolant iodine concentrations for the technical specification limit of 1 μCi/g of dose equivalent I-131 and for the assumed preaccident iodine spike concentration of 60 μCi/g of dose equivalent I-131 are presented in table 15A-6. Iodine appearance rates in the reactor coolant for normal steady-state operation at 1 μCi/g of dose equivalent I-131 and for an assumed accident-initiated iodine spike are presented in table 15A-7. Reactor coolant noble gas concentrations based on 1-percent fuel defects are presented in table 15A-4.

15A.2 OFFSITE RADIOLOGICAL CONSEQUENCES CALCULATIONAL MODELS

This section presents the models and equations used for calculating the integrated activity released to the environment, the accident flowpaths, and the equations for dose calculations. Two major release models are considered:

- A single holdup system with no internal cleanup.
- A holdup system wherein a two-region spray model is used for internal cleanup.

15A.2.1 ACCIDENT RELEASE PATHWAYS

The release pathways for the major accidents are given in figure 15A-1. The accidents and their pathways are as follows:

A. Loss-of-Coolant Accident (LOCA)

Immediately following a postulated LOCA, the release of radioactivity from the containment is to the environment with the containment spray and engineered safety features (ESF) systems in full operation. The release in this case is calculated using equations 6a and 6b, which take into account a two-region spray model within the containment. The release of radioactivity to the environment due to assumed ESF system leakages in the auxiliary building will be via ESF filters and is calculated using equation 5.

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[a] For accidents, ground-level releases are assumed.

B. Waste Gas Decay Tank Rupture (WGDTR)

The activity release to the environment due to WGDTR will be direct and unfiltered, with no holdup. The release pathway is A'-D. The total activity release in this case is therefore assumed to be the initial source activity itself.

C. Fuel Handling Accident

The release to the environment due to a fuel handling accident in the fuel building is via filters. The release pathway is B-C-D. Since the release is calculated without any credit for holdup in the fuel building, the total release will be the product of the initial activity and the filter nonremoval efficiency fraction. (For noble gases, the nonremoval efficiency fraction is 1.) The release of radioactivity to the environment due to a fuel handling accident inside the containment is direct and unfiltered via the A-D pathway and occurs only until the containment is isolated. (Actually, the release is via the nonsafety-grade filters.) The release is calculated using equation 5. No mixing in the containment volume is assumed.

D. Control Assembly Ejection

Radioactivity release to the environment due to the control assembly ejection accident is direct and unfiltered. The releases from the primary system are calculated using equation 5, which considers holdup in the single-region primary system. (The spray removal is not assumed.) The secondary (steam) releases via the relief valves are calculated without any holdup. The pathways for these releases are A-D and A'-D.

E. Main Steam Line Break (MSLB) or Steam Generator Tube Rupture (SGTR)

Radioactivity releases to the environment due to MSLB or SGTR accidents are direct and unfiltered with no holdup via the A'-D pathway. The activity release calculations for these accidents are complex, involving spiking effects, time-dependent flashing fractions, and scrubbing of flashed activities; the release calculations are described in the sections that address these accidents.

15A.2.2 SINGLE-REGION RELEASE MODEL

It is assumed that any activity released to the holdup system instantaneously diffuses to uniformly occupy the system volume.

The following equations are used to calculate the integrated activity released from postulated accidents.

$$A_1(t) \quad = \quad A\ (0)e^{-\lambda}1^{t} \qquad (1)$$

where:

$A_1(t)$ = source activity at time t, (Ci).

$A_1(0)$ = initial source activity at time t_o, (Ci).

λ_1 = total removal constant from primary holdup system (s^{-1}).

$$\lambda_1 \quad = \quad \lambda_d + \lambda_{1\ell} + \lambda_r \qquad (2)$$

where:

λ_d = decay removal constant (s^{-1}).

$\lambda_{1\ell}$ = primary holdup leak or release rate (s^{-1}).

λ_r = internal removal constant (i.e., sprays, plateout, etc. (s^{-1}).

thus, the direct release rate to the atmosphere from the primary holdup system

$$R_u(t) = \lambda_{1\ell}[A_1(t)] \qquad (3)$$

where:

$R_u(t)$ = unfiltered release rate (Ci/s).

The integrated activity release is the integral of the above equation.

$$\text{IAR (t)} = \int_o^t R_u(t)dt = \int_o^t \lambda_{1\ell} A_1(o) e^{-\lambda}l^t dt \qquad (4)$$

This yields:

$$\text{IAR (t)} = (\lambda_{1\ell} A_1(o)/\lambda_1)(1 - e^{-\lambda}l^t) \qquad (5)$$

15A.2.3 TWO-REGION SPRAY MODEL IN CONTAINMENT - LOCA

A two-region spray model is used to calculate the integrated activity released to the environment. The model consists of sprayed and unsprayed regions in containment and a constant mixing rate between them.

As it is assumed that there are no sources after initial release of the fission products, the remaining processes are removal and transfer so that the multivolume containment is described by a system of coupled first-order differential equations.

For a two-region model, the equations are:

$$\frac{dA_1}{dt} = -\sum_{j=1}^{K_1} \lambda_{1j}A_1 - Q_{12}\frac{A_1}{V_1} + Q_{21}\frac{A_2}{V_2} \qquad (6a)$$

$$\frac{dA_2}{dt} = -\sum_{j=1}^{K_2} \lambda_{2j}A_2 - Q_{21}\frac{A_2}{V_2} + Q_{12}\frac{A_1}{V_1} \qquad (6b)$$

where:

A_i = fission product activity in volume i (Ci).

$Q_{i\ell}$ = transfer rate from volume i to volume ℓ (cm^3/s).

V_i = volume of the ith compartment (cm^3).

λ_{ij} = removal rate of the jth removal process internal to volume i (s^{-1}).

K_i = total number of removal processes in volume i.

To calculate the integrated activity released to the atmosphere, the release rate of activity is first calculated. This is found from:

$$R(t) = \sum_{i=1}^{2} \lambda_{1\ell} A_i(t) \qquad (7)$$

The integrated activity released from time t_o - t_1 is then

$$IAR = \int_{t_0}^{t_1} R(t)\, dt$$

15A.2.4 OFFSITE THYROID DOSE CALCULATION MODEL

Offsite thyroid doses are calculated using the equation:

$$D_{TH} = \sum_{i} DCF_{THi} \sum_{j} (IAR)_{ij} (BR)_j \left(\chi/Q\right)_j \qquad (8)$$

where:

$(IAR)_{ij}$ = integrated activity of isotope i released(b) during the time interval j (Ci).

$(BR)_j$ = breathing rate during time interval j (m^3/s).

$(\chi/Q)_j$ = offsite atmospheric dispersion factor during time interval j (s/m^3).

DCF_{THi} = thyroid dose conversion factor via inhalation for isotope i (rem/Ci).

D_{TH} = thyroid dose via inhalation (rems).

15A.2.5 OFFSITE BETA SKIN DOSE CALCULATIONAL MODEL

Assuming a semi-infinite cloud of gamma emitters, offsite beta skin doses are calculated using the equation:

$$D_{\beta S} = \sum_{i} DCF_{\beta i} \sum_{j} (IAR)_{ij} \left(\chi/Q\right)_j$$

where:

$D_{\beta S}$ = beta skin dose (rem).

$DCF_{\beta i}$ = beta skin dose conversion factor for the I isotope ($rem\text{-}m^3/Ci\text{-}s$).

$(IAR)_{ij}$ = integrated activity of isotope released during the time interval j (Ci).

$(\chi/Q)_j$ = offsite atmospheric dispersion factor during time interval j (s/m^3).

15A.2.6 OFFSITE GAMMA BODY DOSE CALCULATIONAL MODEL

Assuming a semi-infinite cloud of gamma emitters, offsite gamma body doses are calculated using the equation:

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[b] No credit is taken for cloud depletion by ground deposition and radioactive decay during transport to the exclusion area boundary or the outer boundary of the low population zone.

$$D_{\gamma\beta} = \sum_i DCF_{\lambda i} \sum_j (IAR)_{ij} \left(\chi/Q\right)_j$$

where:

$D_{\gamma\beta}$ = gamma body dose (rem).

$DCF_{\gamma i}$ = gamma body dose conversion factor for the ith isotope (rem-m^3/Ci-s).

$(IAR)_{ij}$ = integrated activity of isotope is released during the time interval j (Ci).

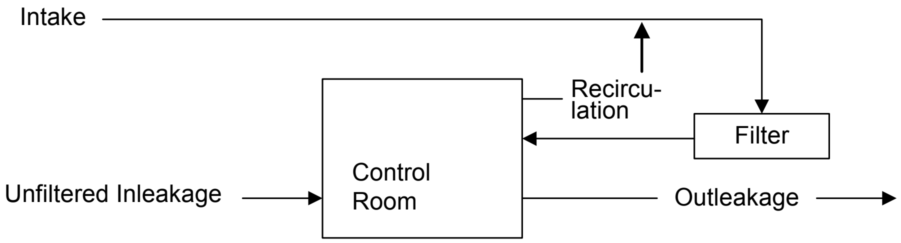
$(\chi/Q)_j$ = offsite atmospheric dispersion factor during time interval j (Ci).

15A.3 CONTROL ROOM RADIOLOGICAL CONSEQUENCES CALCULATIONAL MODELS

Radiation doses to a control room operator as a result of a postulated LOCA are presented in this chapter. (A study of the radiological consequences in the control room due to various postulated accidents indicate that the LOCA is the limiting case.)

15A.3.1 INTEGRATED ACTIVITY IN CONTROL ROOM

The integrated activity in the control room during each time interval is found by multiplying the release by the appropriate χ/Q to give the concentration at the control room intake. This activity is brought into the control room through the filtered intake valves and by unfiltered inleakage and is subjected to the control room ventilation system of recirculation through charcoal filters and exhaust to the atmosphere.



From this the total integrated activity in the control room during any time interval can be calculated.

The activity in the control room can be calculated by the same method used to calculate activity in the containment.

15A.3.2 INTEGRATED ACTIVITY CONCENTRATION IN CONTROL ROOM FROM SINGLE-REGION SYSTEM

To calculate the integrated activity concentration in the control room, the activity in the control room at any time, t, is calculated and then integrated again to find the integrated activity.

$$\frac{dA_{CR}(t)}{dt} = \left[F_2 R_{FIN} + R_{UIN}\right] \frac{\chi}{Q} R(t) - \lambda_3 A_{CR}(t)$$

where:

$A_{CR}(t)$ = activity in the control room at any time t (Ci).

F_2 = filter nonremoval fraction on intake.

R_{FIN} = filtered intake rate (m^3/s).

R_{UIN} = unfiltered intake rate (m^3/s).

R(t) = activity of release rate in Ci/s given in equation 3 of subsection 15A.2.2.

λ_3 = $\lambda_{3\ell} + \lambda_d + \lambda_r$.

where:

λ_3 = total removal rate from control room (s^{-1}).

$\lambda_{3\ell}$ = exhaust rate from control room (s^{-1}).

λ_d = isotopic decay constant (s^{-1}).

λ_r = recirculation removal rate (s^{-1}).

The integrated activity concentration in the control room (IA_{CR}) is determined by the expression

$$IA_{CR}(t) = \frac{1}{V_{CR}} \int_0^t A_{CR}(t)\, dt$$

where:

V_{CR} = control room volume.

This $IA_{CR}(t)$ is used to calculate the doses to the operator in the control room. This activity is multiplied by an occupancy factor which accounts for the time fraction the operator is in the control room.

15A.3.3 CONTROL ROOM THYROID DOSE CALCULATIONAL MODEL

Control room thyroid doses via inhalation pathway are calculated using the following equation:

$$D_{TH\text{-}CR} = BR \sum_i DCF_{THi} \sum_j (IA_{CRij}) \times o_j$$

where:

$D_{TH\text{-}CR}$ = control room thyroid dose (rem).

BR = breathing rate assumed to be always 3.47×10^{-4} m^3/s.

DCF_{THi} = thyroid dose conversion factor for adult via inhalation for isotope i (rem/Ci).

IA_{CRij} = integrated activity concentration in control room, Ci-s for isotope i during time interval jm^3

o_j = control room occupancy fraction during time interval j.

15A.3.4 CONTROL ROOM BETA SKIN DOSE CALCULATIONAL MODEL

The beta skin doses to a control room operator are calculated using the following equation:

where:

$D_{\beta\text{-CR}}$ = beta skin dose in the control room (rem).

$DCF_{\beta i}$ = beta skin dose conversion factor for isotope i (rem-m_3/Ci-s).

IA_{CRij} = integrated activity concentration in the control room, Ci-s for the isotope i during time interval jm^3

o_j = control room occupancy fraction during time interval j.

15A.3.5 CONTROL ROOM GAMMA BODY DOSE CALCULATION

Due to the finite size of the control room, the gamma body doses to a control room operator will be substantially less than what they would be due to immersion in an infinite cloud of gamma emitters. The finite cloud gamma doses are calculated using Murphy's method which models the control room as a hemisphere.$^{(3)}$ The following equation is used:

$$D_{\gamma\beta\text{-CR}} = \frac{1}{GF}\sum_i DCF_{\lambda i}\sum_j (IA_{CRij}) \times o_j$$

where:

$D_{\gamma\beta\text{-CR}}$ = gamma body dose in the control room (rem).

GF = dose reduction due to control room geometry factor.

GF = $1173/V_1^{0.338}$ (dimensionless).

V_1 = volume of the control room (ft^3).

$DCF_{\gamma i}$ = gamma body dose conversion factor for isotope i (rem-m^3/Ci-s).

IA_{CRij} = integrated activity concentration in control room, Ci-s for isotope i during time interval jm^3

o_j = control room occupancy fraction during time interval j.

15A.3.5.1 Model for Radiological Consequences Due to Radioactive Cloud External to the Control Room

This dose is calculated based on the semi-infinite cloud model which is modified using the protection factors described in subsection 7.5.4 of reference 4 to account for the control room walls.

15A.3.6 REFERENCES

1. "Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants," United States Nuclear Regulatory Commission (USNRC) Regulatory Guide 1.145, August 1979.
2. "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50 Appendix I," USNRC Regulatory Guide 1.109, Rev 1, October 1977.

3. Murphy, K. G., and Campe, K. M., "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Criterion 19," Paper presented at the 13th AEC Air Cleaning Conference.

4. "Meteorology and Atomic Energy 1968," D. H. Slade (ed.), USAEC Report, TID-24190, 1968.

TABLE 15A-1 (SHEET 1 OF 2)

PARAMETERS USED IN ACCIDENT ANALYSIS

General	
Core power level (MWt)	3636
Number of fuel assemblies in the core	193
Maximum radial peaking factor	1.70
Steam generator tube leak (gal/min)	1.0
Sources	
Core inventories (Ci)	Table 15A-3
Gap inventories (Ci)	Table 15A-3
Primary coolant specific activities for 1% fuel defects (μCi/g)	Table 15A-4
Primary coolant activity, Technical Specification limit for iodines - I-131 dose equivalent (μCi/g)	1.0 See table 15A-6.
Secondary coolant activity Technical Specification limit for iodines - I-131 dose equivalent (μCi/g)	0.1
Activity Release Parameters	
Free volume of containment (ft^3)	2.95 x 10^6
Containment leak rate	
0 to 24 h (percent per day)	0.2
After 24 h (percent per day)	0.1
Control room	
Free volume (ft^3)	1.72 x 10^5
Normal ventilation rate, unfiltered (ft^3/min)	3000
Time to isolate normal ventilation (s)	11.3
Time to establish emergency ventilation one unit operating (s)	99.3
Time to establish emergency ventilation, three units operating (s)	108
Emergency ventilation intake rate - one unit operating (ft^3/min)	1500
Emergency ventilation intake rate - three units operating (ft^3/min)	3870

TABLE 15A-1 (SHEET 2 OF 2)

Emergency ventilation rate, - one unit operating (ft^3/min)	17,100[(a)]
Emergency ventilation rate, - three units operating (ft^3/min)	47,500[(a)]
Unfiltered infiltration rate (ft^3/min) unpressurized control room	825 + 10[(b)]
pressurized control room	120 + 10[(c)]
Iodine removal efficiency for recirculation filters (all forms of iodine) (percent)	99
Iodine removal efficiency for intake filters (all forms of iodine) (percent)	99
High-efficiency particulate air filter efficiency (percent)	99
Miscellaneous	
Atmospheric dispersion factors (χ/Q)(s/m^3)	Table 15A-2
Dose conversion factors	
Gamma body and beta skin (rem-m^3/Ci-s)	Table 15A-5
Thyroid (rem/Ci)	Table 15A-5

---

a. The value is for combined intake and recirculation air flow. The value also reflects the Technical Specification acceptance criterion of ± 10% of the nominal flow for a single train.

b. 825 cfm unfiltered inleakage for inleakage testing. 10 cfm is for ingress/egress.

c. 120 cfm unfiltered inleakage for inleakage testing. 10 cfm is for ingress/egress.

TABLE 15A-2

LIMITING SHORT-TERM ATMOSPHERIC DISPERSION FACTORS FOR ACCIDENT ANALYSIS FOR VEGP

(s/m^3)

Location Type/ Time Interval	(χ/Q)
Site boundary	
0 to 2 h	1.8E-4
Low population zone	
0 to 2 h	7.2E-5
2 to 8 h	3.3E-5
8 to 24 h	2.2E-5
24 to 96 h	9.2E-6
96 to 720 h	2.7E-6
Control room	
0 to 2 h	1.0E-3
2 to 8 h	7.1E-4
8 to 24 h	3.1E-4
24 to 96 h	2.7E-4
96 to 720 h	2.1E-4

TABLE 15A-3

CORE FISSION PRODUCT INVENTORY[a]

Nuclide	Total Core Inventory (Ci)	Fuel Rod Gap Inventory (Ci)[b][c]
I-131	1.03E+08	1.03E+07
I-132	1.50E+08	1.50E+07
I-133	2.10E+08	2.10E+07
I-134	2.26E+08	2.26E+07
I-135	1.95E+08	1.95E+07
Kr-85m	2.68E+07	2.68E+06
Kr-85	1.04E+06	3.12E+05
Kr-87	4.93E+07	4.93E+06
Kr-88	7.02E+07	7.02E+06
Xe-131m	7.13E+05	7.13E+04
Xe-133m	3.01E+07	3.01E+06
Xe-133	2.12E+08	2.12E+07
Xe-135m	4.18E+07	4.18E+06
Xe-135	4.65E+07	4.65E+06
Xe-138	1.69E+08	1.69E+07
I-127	4.45 kg	1.34 kg
I-129	18.3 kg	5.49 kg

---

a. Source term at end of fuel cycle with zero decay.

b. The gap fractions are assumed to be 10% of the core activity for all isotopes except for Kr-85, I-127, and I-129 for which the gap fraction is assumed to be 30%. An exception to this is taken for the fuel handling accident which assumes a gap fraction of 12% for I-131, following the recommendation in NUREG/CR-5009.

c. The gap fractions assumed for the fuel handling accident analyses in subsection 15.7.4 are based on Regulatory Guide 1.195.

TABLE 15A-4

PRIMARY COOLANT NOBLE GAS CONCENTRATIONS[(a)]

Nuclide	Concentration (µCi/g)
Kr-85m	2.04
Kr-85	8.37
Kr-87	1.28
Kr-88	3.68
Xe-131m	2.02
Xe-133m	17.6
Xe-133	256
Xe-135m	0.56
Xe-135	8.30
Xe-138	0.74

---

a. Based on operation with 1.0% of power produced by fuel rods with cladding defects and with no purge of noble gas activity from the volume control tank to the gaseous waste processing system.

TABLE 15A-5

DOSE CONVERSION FACTORS USED IN ACCIDENT ANALYSIS[(a)]

Nuclide	Whole Body Dose Conversion Factor (rem-m^3/Ci-s)	Beta-Skin Dose Conversion Factor (rem-m^3/Ci-s)	Thyroid Dose Conversion Factor (rem/Ci)
I-131	6.73E-02	3.20E-02	1.08E+06
I-132	4.14E-01	1.12E-01	6.44E+03
I-133	1.09E-01	9.04E-02	1.80E+05
I-134	4.81E-01	1.43E-01	1.07E+03
I-135	2.95E-01	7.99E-02	3.13E+04
Kr-85m	2.77E-02	5.11E-02	NA
Kr-85	4.40E-04	4.98E-02	NA
Kr-87	1.52E-01	3.36E-01	NA
Kr-88	3.77E-01	7.90E-02	NA
Xe-131m	1.44E-03	1.51E-02	NA
Xe-133m	5.07E-03	3.13E-02	NA
Xe-133	5.77E-03	1.06E-02	NA
Xe-135m	7.55E-02	2.17E-02	NA
Xe-135	4.40E-02	6.47E-02	NA
Xe-138	2.13E-01	1.48E-01	NA

---

a. Whole body dose conversion factors are from Table III.1 of EPA Federal Guidance Report No. 12 (EPA 402-R-93-081, September 1993). Beta-skin dose conversion factors are from DOE/EH-0070, “External Dose-Rate Conversion Factors for Calculation of Dose to the Public,” July 1988. Thyroid dose conversion factors are from Table 2.1 of the EPA Federal Guidance Report 11 (EPA-520/1-88-020, September 1988).

TABLE 15A-6

REACTOR COOLANT IODINE CONCENTRATIONS FOR 1 μCi/g AND 60 μCi/g OF DOSE EQUIVALENT I-131[a]

	Reactor Coolant Concentration (μCi/g)	
Nuclide	1 μCi/g Dose Equivalent I-131	60 μCi/g Dose EquivalentI-131
I-131	0.74	44.4
I-132	0.75	45.0
I-133	1.41	84.6
I-134	0.18	10.8
I-135	0.69	41.4

---

a. Values are based on the thyroid dose conversion factors in table 15A-5.

TABLE 15A-7

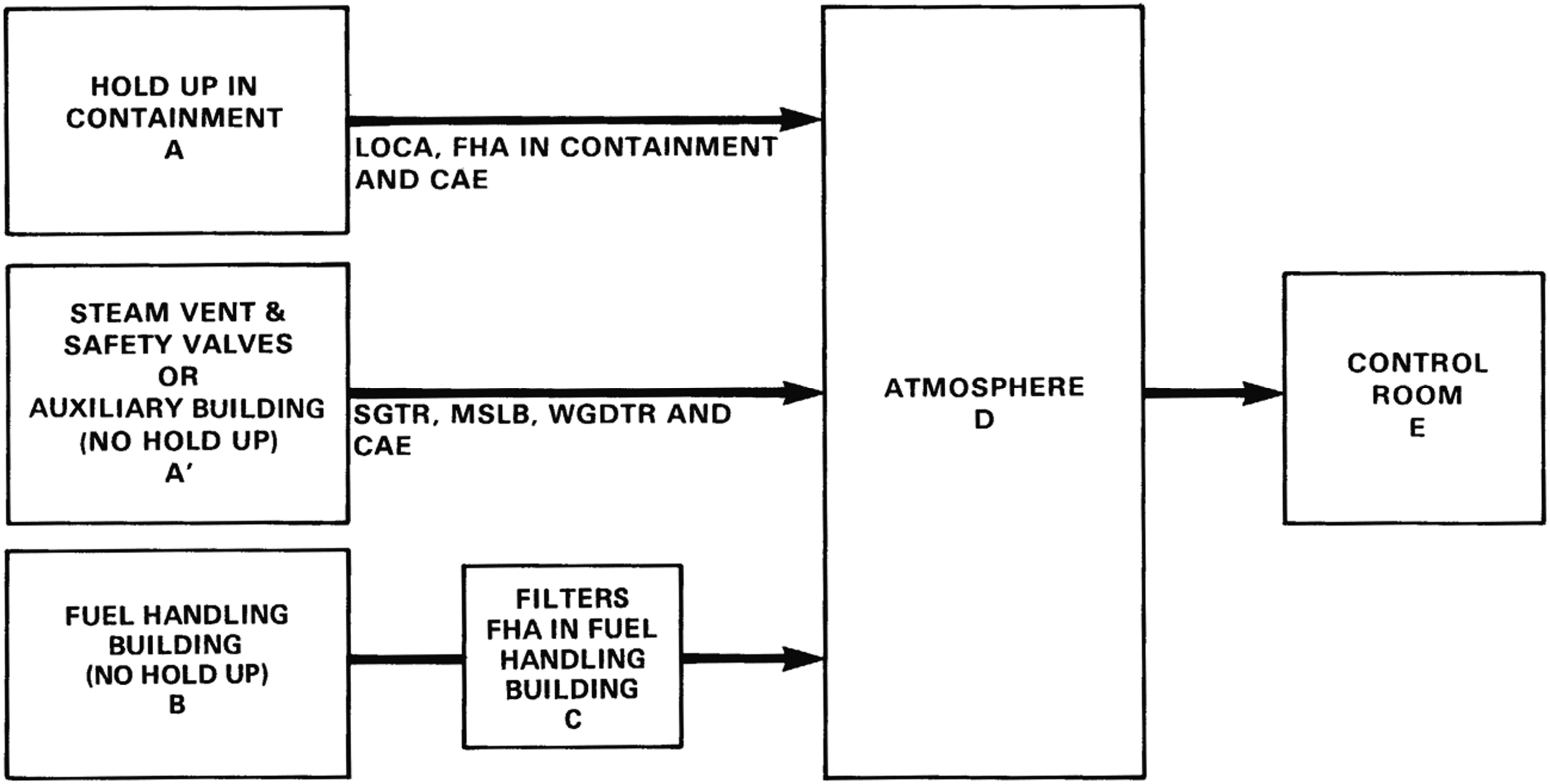
IODINE APPEARANCE RATES IN THE REACTOR COOLANT (Ci/s)

	Equilibrium Appearance Rates due to Fuel Defects[a]	Appearance Rates Due to an Accident-Initiated Iodine Spike[b]
I-131	7.3×10^{-3}	3.6
I-132	2.3×10^{-2}	11.5
I-133	1.7×10^{-2}	8.4
I-134	1.2×10^{-2}	5.9
I-135	1.2×10^{-2}	5.9

---

a. Based on RCS concentration of 1 μCi/g of dose equivalent I-131, an RCS leakage rate of 12 gpm and letdown flow of 140 gpm (130 gpm design letdown flow plus 10 gpm for instrument uncertainty) and dose conversion factors from table 15A-5.

b. 500 x equilibrium appearance rate.


HOLD UP IN CONTAINMENT
A
LOCA, FHA IN CONTAINMENT AND CAE
STEAM VENT & SAFETY VALVES
OR
AUXILIARY BUILDING (NO HOLD UP)
A'
SGTR, MSLB, WGDTR AND CAE
FUEL HANDLING BUILDING (NO HOLD UP)
B
FILTERS FHA IN FUEL HANDLING BUILDING
C
ATMOSPHERE
D
CONTROL ROOM
E

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UNIT 1 AND UNIT 2

RELEASE PATHWAYS

FIGURE 15A–1

APPENDIX 15B

(This appendix has been deleted)

TECHNICAL SPECIFICATIONS

16.1 PRELIMINARY TECHNICAL SPECIFICATIONS

The preliminary Technical Specifications were provided in the VEGP Preliminary Safety Analysis Report as part of an application for a construction permit. The construction permit for VEGP was issued on June 28, 1974. Therefore, this section is not applicable to the VEGP Final Safety Analysis Report.

16.2 PROPOSED FINAL TECHNICAL SPECIFICATIONS

16.2.1 FOREWORD

The following paragraphs briefly describe the applicability, format, and schedule for the development of the VEGP Technical Specifications.

16.2.2 APPLICABILITY

The Nuclear Regulatory Commission's (NRC's) Standard Technical Specifications for Westinghouse Pressurized Water Reactors (NUREG-0452) and Standard Radiological Effluent Technical Specifications for Pressurized Water Reactors (NUREG-0472) will be adapted to reflect the VEGP design.

16.2.3 FORMAT

The format of the Technical Specifications will address the categories required by 10 CFR 50 and will consist of six sections covering definitions, safety limits and limiting safety systems settings, limiting conditions for operation (LCOs), surveillance requirements, design features, and administrative controls. The LCOs and surveillance requirements (sections 3 and 4) will be presented in a combined format, with each LCO appearing first, followed immediately by the applicable surveillance requirements. The combined section 3/4 will be subdivided into 12 subsections covering the following areas:

- Reactivity control systems.
- Power distribution limits.
- Instrumentation.
- Reactor coolant system.
- Emergency core cooling systems.
- Containment systems.
- Plant systems.
- Electrical power systems.
- Refueling operations.
- Special test exceptions.
- Radioactive effluents.
- Radiological environmental monitoring.

16.2.4 SCHEDULE

The Technical Specifications for VEGP Units 1 and 2 will be submitted to the NRC approximately 15 months before the scheduled fuel load date of each unit. This submittal will be separate from the VEGP Final Safety Analysis Report but will be incorporated into the VEGP docket by confirmatory letter. The Technical Specifications for the VEGP will be based on the current version of the NRC's Standard Technical Specifications for Westinghouse Pressurized Water Reactors and Standard Radiological Effluent Technical Specifications for Pressurized Water Reactors.

16.3 TECHNICAL SPECIFICATION IMPROVEMENT PROGRAM

The Technical Specification Improvement Program for VEGP resulted in the inclusion of certain technical requirements into the FSAR. These improvements are provided below. Changes to these requirements shall be reviewed and approved in accordance with VEGP administrative procedures.

16.3.1 REQUIREMENT 1 - REACTOR TRIP SYSTEM RESPONSE TIMES

The reactor trip system response times are addressed in FSAR paragraph 7.2.1.2.6, Minimum Performance Requirements.

16.3.2 REQUIREMENT 2 - ENGINEERED SAFETY FEATURE ACTUATION SYSTEM RESPONSE TIMES

The engineered safety feature actuation system response times are addressed in FSAR paragraph 7.3.1.1.2.6, Minimum Performance Requirements.

16.3.3 REQUIREMENT 3 - LOOSE PART DETECTION SYSTEM

The loose part detection system requirements are addressed in the Technical Requirements Manual by TR 13.3.8, Loose Part Detection System.

16.3.4 REQUIREMENT 4 - REACTOR VESSEL MATERIAL IRRADIATION SPECIMENS

The reactor vessel material irradiation specimen requirements are addressed in FSAR paragraph 5.3.1.6, Material Surveillance.

16.3.5 REQUIREMENT 5 - CONTAINMENT ISOLATION VALVES

The containment isolation valve isolation time requirements of Technical Specification 3.6.3, Containment Isolation Valves, are addressed in FSAR paragraph 6.2.4.2.1, General Description.

16.3.6 REQUIREMENT 6 - CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTION

The containment penetration conductor overcurrent protection requirements are addressed in Technical Requirements Manual TR 13.8.1, Containment Penetration Conductor Overcurrent Protective Devices.

16.3.7 REQUIREMENT 7 - AREA TEMPERATURE MONITORING

The area temperature monitoring requirements are addressed in Technical Requirements Manual TR 13.7.5, Area Temperature Monitoring.

16.3.8 REQUIREMENT 8 - TURBINE OVERSPEED PROTECTION

The turbine overspeed protection requirements are addressed in the Technical Requirements Manual by TR 13.3.5, Turbine Overspeed Protection.

16.3.9 REQUIREMENT 9 - TECHNICAL REQUIREMENTS MANUAL

Technical requirements that are licensing commitments, but which may be controlled by the licensee in accordance with the process for changes, tests, and experiments as provided in 10 CFR 50.59, can be maintained in the Technical Requirements Manual (TRM).

The TRM contains selected requirements that apply to the operation of VEGP with the intent being to provide a single, prominent, and easily accessible document for operating staff to reference and which will support the operating staff's compliance with these requirements with a minimum of effort. These requirements are conditions for operation, associated action requirements, and surveillance requirements with the format for presentation of the requirements being the same as used in the VEGP NUREG-1431 based Technical Specifications.

The administrative controls for the TRM are the same as used for the control of the FSAR. These administrative controls ensure proposed TRM changes do not require prior NRC approval, or if prior approval is required, the controls ensure NRC review and approval are obtained, prior to implementation of the change. Additionally, other federal regulations may apply to the control of certain technical requirements and may be so stated at the appropriate location in the body of the TRM.

16.3.10 REQUIREMENT 10 - REACTOR COOLANT SYSTEM PRESSURE ISOLATION VALVES AND LEAKAGE LIMITS

The reactor coolant system pressure isolation valves and leakage limit requirements of Technical Specification 3.4.14, RCS Pressure Isolation Valve (PIV) Leakage, are addressed in FSAR paragraph 5.4.12.4, Tests and Inspections.

16.4 RISK MANAGED TECHNICAL SPECIFICATIONS

The Risk Managed Technical Specifications (RMTS) will allow the calculation of risk informed completion times (RICT) for certain LCO Conditions. Those are identified in the Completion Time column of the particular LCO Condition, with the phrase, "…or in accordance with the Risk Informed Completion Time Program". Without this phrase in the LCO Condition Completion Time column, the particular Condition is not in the program and a RICT cannot be calculated.

The program is consistent with the guidelines of NEI 06-09, Rev. 0, "Risk Informed Technical Specifications Initiative 4b, Risk Managed Technical Specifications (RMTS) Guidelines".

16.4.1 PRA FUNCTIONALITY

The RICT calculation performed depends on the configuration of the plant at the time of the inoperability of the component. Additionally, the inoperable component may be declared "PRA Functional" if the component's inoperability does not affect the PRA success criteria. For example, if an ECCS pump becomes inoperable, its PRA Functionality status would depend on the ability of the pump to meet the PRA flow rate success criteria. This is per the guidelines of NEI 06-09, section 11, which lists further requirements and restrictions on declaring a component PRA Functional.

PRA Functionality for a case of all trains and equipment required by the Technical Specifications inoperable has additional restrictions identified in Section 5.5.22 of the Technical Specifications.

16.4.2 PRA TECHNICAL ADEQUACY

The on-record PRA model that forms the basis for the VEGP Configuration Risk Management (CRM) Tool has been developed to the requirements of Reg. Guide 1.200, "An approach for determining the technical adequacy of probabilistic risk assessment results for risk-informed activities" and is subjected to peer reviews per the requirements of NRC endorsed applicable PRA standards and SNC procedures. These peer reviews are formally documented along with the findings and observations of the review, and their corresponding resolutions.

17.2 OPERATIONS QUALITY ASSURANCE PROGRAM

The operations phase quality assurance program for Vogtle Electric Generating Plant (VEGP) is designed to assure the plant's safe and reliable operation and to satisfy the quality assurance (QA) requirements of Appendix B to 10 CFR Part 50. The quality assurance program applicable to operation phase activities for VEGP is described in the Southern Nuclear Operating Company (SNC) Quality Assurance Topical Report (QATR). Quality assurance program requirements formerly contained in VEGP FSAR Section 17.2 are superseded by those contained in the SNC QATR.

FIGURE 17.2.1-1
DELETED

18.0 HUMAN FACTORS ENGINEERING

18.1 CONTROL ROOM DESIGN

18.1.1 CONTROL ROOM DESCRIPTION

18.1.1.1 Introduction

In accordance with the TMI Task Action Plan I.D.1 of NUREG-0660, NUREG-0694, and NUREG-0737 (references 1, 2, and 3, respectively) a control room design review was performed. The purpose of this review was the identification and analysis of human engineering deficiencies (HEDs) so they could be corrected in the final design or accommodated in the administrative and training procedures. This chapter presents the current control room design, the review procedures, and their results.

The preliminary control room design review included an assessment of the following:

- Control room layout.
- The adequacy of the information provided.
- The arrangement and identification of important controls and instrumentation displays.
- The usefulness of the audio and visual alarm systems.
- The information recording and recall capability.
- Other considerations of human factors that have an impact on operating effectiveness.

The final control room design review was conducted prior to licensing, as required by Supplement 1 to NUREG-0737, dated December 17, 1982. This review commenced approximately 1 year prior to Unit 1 fuel loading.

18.1.1.2 Description

The control room plan is shown in figure 18.1-1. The layouts of the Unit 1 main control board (QMCB); electrical auxiliary control board (QEAB); heating, ventilation, and air-conditioning systems panel (QHVC), and miscellaneous systems and equipment panel (QPCP) are shown in drawings 1X3AE01-20, 1X3AE01-21, 1X3AE01-24, 1X5AB01-66, 1X5AB01-67, 1X5AB01-557, 1X5AB01-560, 1X5AB01-563, 1X6AV02-46, 1X6AV02-47, 1X6AV02-48, 1X6AV02-49, 1X6AV02-50, 1X6AV02-60, and AX3D-CA-L50A.

A. QMCB

The QMCB is divided into groups of controls by black demarcation lines. These groups may be entire systems or could be divided into subsystems depending on the complexity of the system involved. The following are demarcation groups contained on each section of the QMCB:

1. QMCB Section A1
    a. Circulating water.
    b. Turbine plant cooling water.
    c. Turbine plant closed-loop cooling water.
    d. Instrument and service air.
    e. Nuclear service cooling water.
    f. Reactor makeup.
    g. Component cooling water.
    h. Auxiliary component cooling water.
    i. Containment spray system.
    j. Safety injection (SI) pumps.
2. QMCB Section A2
    a. Residual heat removal (RHR).
    b. Chemical and volume control system (CVCS) charging pumps.
    c. Waste processing system.
    d. CVCS letdown.
    e. CVCS seal injection.
    f. CVCS boron injection.
    g. CVCS boron meter.
    h. CVCS thermal regeneration.
3. QMCB Section B1
    a. Main steam isolation valves.
    b. Main steam, steam dump, and steam generator blowdown.
    c. Feedwater, steam generator feed pump turbine A.
    d. Feedwater, steam generator feed pump turbine B.
    e. Auxiliary feedwater.

f. Feedwater and condensate system.

g. Main steam and main steam relief drains.

4. QMCB Section B2
   - a. Main steam and main steam relief drains.
   - b. Extraction steam.
   - c. Turbine.
   - d. Generator.

5. QMCB Section C
   - a. Reactor control.
   - b. Reactor control and nuclear instrumentation.
   - c. Reactor coolant system (RCS) pressurizer pressure.
   - d. RCS pressurizer level.
   - e. RCS reactor coolant pumps.

6. QMCB Section D
   - a. Head vents.
   - b. Post-accident monitoring system (PAMS) plasma displays.
   - c. Main steam isolation valve bypass valves.

B. QEAB

1. QEAB Section A - Plant Auxiliaries

   QEAB section 1A covers electrical mimic boards for Unit 1 systems (common for both units on 1A and 1B). QEAB section 2A covers electrical mimic boards for Unit 2 systems.

2. QEAB Section B

   QEAB section 1B covers electrical mimic boards for Unit 1 system switchyards. QEAB section 2B covers electrical mimic boards for Unit 2 switchyard.

C. QHVC

1. QHVC Section 1
   - a. Control building and equipment room, level 4.
   - b. Control building auxiliary relay room and computer room exhaust.
   - c. Control building control room (normal), level 1.
   - d. Control building control room engineered safety features (ESF), level 1.
   - e. Equipment room ESF, level B.
   - f. Control building electrical penetration room, level B.

        g. Electrical tunnel ventilation.

    2. QHVC Section 2

        a. ESF coolers.

        b. Piping penetration area and recycle holdup tanks.

        c. Containment heat removal ESF.

        d. Containment heat removal (normal).

        e. Containment air purification.

        f. Containment air purification and post-accident cavity.

        g. Containment control rod drive mechanism cavity and reactor support.

        h. Diesel generator building.

        i. Control building levels A and B (normal) and lighting switchgear (normal).

    3. QHVC Section 3

        a. Auxiliary building (normal).

        b. Auxiliary feedwater pumphouse and control building control room chiller room.

        c. Piping penetration ventilation and turbine building exhaust fans.

        d. Control building cable spreading rooms, levels A2 and A3.

        e. Control building levels 1 and 2 smoke exhaust.

        f. Fuel handling building normal exhaust/air-conditioning units and fuel pool area ventilation.

        g. Fuel handling building system isolation and post-accident air-conditioning filter units.

        h. Fuel handling building normal air-conditioning units supply header isolation.

D. QPCP

    1. Section 1

        a. Plant demineralized water (Unit 1 only).

        b. Nuclear service cooling tower makeup water.

        c. River makeup water (Unit 1 only).

   d. Waste water.
   e. Turbine plant cooling water.
   f. Core monitor panel.
   g. Main steam atmospheric relief valve.
   h. Cooling water system temperature, train A.
   i. Cooling water system temperature, train B.

2. QPCP Section 2
   a. SI test line valves.
   b. Main steam.
   c. Steam generator feed pump turbine drains.
   d. Reheater drains.
   e. Auxiliary feedwater.
   f. Feedwater and condensate chemical injection.
   g. Containment building and auxiliary building drains.
   h. Fire protection.
   i. Refueling water storage tank sludge mixing.

3. QPCP Section 3
   a. Train A condensate and feedwater.
   b. Train A main steam.
   c. Train A steam generator blowdown sampling.
   d. Train A fire protection and containment service air.
   e. Train A line break monitors and CVCS letdown header.
   f. Train A containment hydrogen monitoring.
   g. Train A containment air monitoring.
   h. Train A pressurizer liquid.
   i. Train A SI sample.
   j. Train B condensate and feedwater.

k. Train B main steam.

l. Train B steam generator blowdown sampling.

m. Train B fire protection and containment service air.

n. Train B line break monitors and CVCS letdown header.

o. Train B containment hydrogen monitoring.

p. Train B containment air monitoring.

q. Train B pressurizer liquid.

r. Train B SI sample.

These control panels and their components provide display, control, alarm, and computer functions to assist in remote control, monitoring, and recording of plant operations during startup, normal, shutdown, and emergency operations. The control room and its boards are designed and configured to enable the operator to control the plant as required in an efficient manner without undue risk to public health and safety or potential problems to plant equipment. Should the need exist, the operator can take appropriate measures or can initiate protective action using the control room controls.

If the control room becomes uninhabitable, the necessary controls and displays for shutdown of the plant are provided at two secure, remotely located shutdown panels. (See section 7.4.)

18.1.2 DESIGN BASES

The following design bases constitute the design requirements for the control room evaluation.

18.1.2.1 Anthropometrics

This is defined as statistical data of physical dimensions for the control room personnel.

A. The QMCB is a combination bench-vertical type.

B. The remainder of the control boards are the vertical type.

18.1.2.2 Auditory Communications

This is defined as indications or displays for equipment or subsystem conditions as interpreted by the control room personnel in auditory modes.

A. The annunciator is designed to provide five mutually discriminable audible signals to allow the operator to be immediately cognizant of an alarm and to be able to distinguish the relative board location of that alarm based on sound characteristics. To ensure immediate notice by the operator, each audible alarm is designed to have a minimum sound level differential of 10 dBA above the ambient level.

1. The QMCB annunciator panels have a medium-pitched, medium-warble horn sound.
2. The QEAB has a low-pitched, low-warble horn sound.
3. The QHVC is designed to have its own horn with a low-pitched, high-warble sound.
4. The QPCP is designed to have a separate horn with a high-pitched, high warble sound.
5. The ring-back (reset of alarm) is common to all control boards, using a bell tone.
6. First-out panel on the QMCB has a high-pitch, high-warble sound (notably different than the QPCP).

18.1.2.3 Plant Communications

This is defined as the means provided for intercommunication between the control room, technical support center, emergency operations facility, and personnel on duty in various parts of the plant, as described below.

A. Communication to/from the control room is provided using sound-powered telephone systems. The equipment is available for maintenance (six jacks/box), refueling (two jacks/box), and shutdown purposes (two jacks/box).

B. The communication system within the plant is a public address system (one page line and party line common to all zones and four party lines). This system is for roving operator communications and is provided with the capability for the merger of four zones: Unit 1, Unit 2, administration building, and outside areas. This system provides remote merging in:

   1. Unit 1 control room.
   2. Unit 2 control room.
   3. Central alarm station.
   4. Secondary alarm station.
   5. Captain's office in the PESB.

   This also functions as an emergency alarm (supplied with emergency power from an uninterruptible power supply system). This system is actuated by a multi-tone generator applicable for discriminable tones. Capability for initiation and selection of the tone for the emergency alarm is provided in the control room.

C. Plant offsite communication system uses the public telephone systems.

D. Other communication facilities are:

   1. Microwave communications at 57 MHz.
   2. Walkie-talkie with external antenna for radio contact between the control room, technical support center, emergency operations facility, and field personnel.
   3. Security intercom linking control room, security subsystem, and security monitoring station.

4. Federal Telephone System (FTS) for the emergency notification system (ENS) and the health physics network.

Communications are further discussed in subsection 9.5.2.

18.1.2.4 Controls

Controls are defined as devices actuated by the control room personnel (manual mode) or by the systems (automatic mode) to influence system functioning.

A. The control devices used on the instrument panels are designed to minimize the size of the panels, while still allowing convenient and reliable operation. Insofar as is practicable, uniform types of control devices are used throughout the control room.

B. Control devices of redundant trains are designed for separation by physical barriers where there is an operational requirement for redundant trains to be close to each other.

C. Control devices for safety systems are designed to satisfy Seismic Category 1 requirements.

D. Control switches selected for the auxiliary board and panels are similar to those selected for the QMCBs (Electroswitch series 20 or equivalent).

E. Control switch development is designed to comply with the following:

1.	Left-right (right throw) or bottom-top (up-throw)	Start, close (circuit breaker), open (valve), on, raise, and other positive or increasing functions and associated indicating lights.
2.	Right-left (left throw) or top-bottom (down-throw)	Stop, trip (circuit breaker), close (valve), off, lower, and other negative or decreasing functions and associated indicating lights.

F. Where possible, automatic controls for parallel valves are designed to be kept in parallel (left to right). The series valves are designed to be kept in series (top to bottom) to make it compatible with the flow direction on the control board layout. Flow paths for system controls are designed for layout on the QMCB starting with suction, pump, and discharge going from top to bottom.

G. The analog control stations are Westinghouse 7300 series operator interface modules, which use Westinghouse-qualified designs for split architecture. Controls on the operator interface modules are marked to indicate in which direction to operate the controller to increase or decrease the variable to avoid operator errors.

H. Controls are designed for functional arrangement on control boards so that systems or equipment supporting or interacting with the desired function are located in the same general area on the control board for ease of operation.

I. The controls associated with core reactivity are located in the central area of the QMCB (section C) along with the other principal reactor controls.

J. Speed and flow controls for the charging pumps are located so that the flow control and pressurizer control are in the reactor control section of the QMCB (section C).

K. Controls for heating, ventilation, and air-conditioning (HVAC) and control rod drive motor fans are on the QHVC panel.

L. Control switches for rod motion are designed to have a clear line of vision to the rod step counters and count rate recorder so that the operator can continuously observe the effects of the rod motion.

M. Control switches for reactor trip and manual SI are located away from the other control switches to avoid inadvertent actuation.

N. Functional groups of controls are located in accordance with operational sequence having left-to-right order and/or top-to-bottom order of use based on the accepted operator compatibility principles, namely, spatial, movement, and conceptual (e.g., suction isolation valve, pump, and discharge isolation valve, in that order).

18.1.2.5 Control and Display Integration

This is defined as the relative locations of related control and display devices.

A. Controls and displays (including annunciators and recorders) are arranged in functional groups and in a functional sequence with the displays above their corresponding controls to prevent the arm of the operator from obscuring the indicated response to control adjustments.

B. Main feedwater and bypass feedwater valve controls and displays are located close to each other to facilitate transferring modes of operation as power level is changed.

C. Frequently used control and display systems are located on or near the central portion of the QMCBs to minimize operator movement.

18.1.2.6 Design for Maintainability

This is defined as the degree to which panels are designed to accommodate preventive maintenance and corrective repair or replacement functions as quickly as possible with minimum disturbance to operator functions.

A. Control boards in the control room are designed with split architecture controllers (controllers separate from process module) to facilitate maintenance and to reduce congestion in the operator's area of the control room.

B. Control panel components are primarily modular equipment to simplify maintenance as well as to reduce the maintenance time.

C. Maintenance accessibility is designed for minimum operator maintenance and technician interference by maintaining sufficient aisle clearance and by positioning panels so that there is adequate aisle space for panel back access.

18.1.2.7 Design for Personnel Requirements

This is defined as the norms in the power industry for control room personnel physical and mental capabilities.

A. A shift supervisor and operators are available in the control room for each shift as specified in Technical Specification 5.2.2, 10 CFR 50.54, and the Technical Requirements Manual.

B. A shift technical advisor or similarly qualified senior reactor operator is available to assist in the interpretation of information and control actions.

C. The qualifications for the operators are as specified in chapter 13.

18.1.2.8 Environment

This is defined as the external physical elements affecting the control room personnel in their performance of their functions. The environment for the main control room is designed for the following conditions:

A. Temperature of the control room is normally 75°±5°F with maximum allowable temperature of 85°F.

B. Pressure of the control room is slightly above atmospheric.

C. Relative humidity is maintained between 10 and 60 percent.

D. The fluorescent lighting in the control room is designed to provide a uniform horizontal intensity of 50 to 100 fc adjustable in the control room general area, 50 to 100 fc adjustable at the console surface, and approximately 30 fc during an emergency resulting from loss of normal 120-V ac lighting. The control room lighting system is further described in subsection 9.5.3.

E. Acoustical provisions are included in the design of the primary operating area of the control room to minimize the ambient noise to a sound level of 50 to 65 dBA.

18.1.2.9 Hazards/Safety

These are defined as the physical, chemical, and other hazards to control room personnel.

A. The HVAC system is designed to provide automatic protection against radiation and smoke. Manual operation provides protection against toxic chemicals.

B. The control room design includes protection against dangerous voltage and ground faults by appropriate use of fuses, breakers, and grounding techniques.

C. The control room is designed for operator warning should a hazardous situation arise.

D. The control room is provided, where required, with special ladders for bulb replacement.

E. Switch handles and other devices are designed so as not to protrude from boards and panels in a manner that could produce accidental actuation. A guard rail around the QMCB also prevents accidental activation.

F. The control room is provided with fire, smoke, and radiation detection. The fire hazard and protection analysis of the control room is provided in appendix 9A.

G. The control room is designed for automatic warnings against unsafe or emergency conditions in the plant by alarms.

H. Automatic actuation for control room isolation is also provided with operator actuation as a backup.

I. Accessibility of emergency and protective equipment to the control room operators is discussed in section 6.4.

J. Control room suspended ceiling is designed and constructed to ensure that the ceiling will not fall or compromise the functioning of safety-related equipment during or after a safe shutdown earthquake.

18.1.2.10 Information Utilization

This is defined as the information processing facility, such as entry, access, and retrieval, provided to improve control room personnel performance. The control room and boards are designed to have the following features:

A. Automated control of safety feature equipment if action is required within 10 min from the time indication is available for showing that action is required.

B. Operator involvement in selection of automatic versus manual control of loops.

C. Selection of Monitors and other computer display functions.

D. Operator involvement in:

  1. Startup.
  2. Shutdown.
  3. Load change.
  4. Base load.
  5. Trips.
  6. Accidents.
  7. Emergencies (including fire and security).

E. Selection of the particular train to use when a system has two trains.

F. Display, diagram, or information selection (including details of annunciated items if required).

G. Data handling and display (calculation, evaluation, and screening information before display).

H. Annunciator interpretation, alarm handling, and display.

I. Manual overrides for essential system.

J. Backup facility for highly significant parameter control.

K. Display of important parameters with the ability to call up backup information as needed by the operator to take any required action.

18.1.2.11 Labeling (Grouping, Marking)

This is defined as alphanumeric, color, and other visual methods used for controls and displays to improve the performance of control room personnel.

A color coding scheme for the switchplates on the QMCB, QEAB, QHVC, QPCP, PSDA, and PSDB is implemented in a plant procedure.

Additionally:

A. Controls located on the bench board section of the QMCB are grouped by subsystems divided by the demarcation lines (paragraph 18.1.1.2.A) and enveloped, where room permits, with hierarchical labels for subsystems at the top center of the envelopes to improve recognition of functional grouping.

B. Labels are located to minimize interference with operator view and to avoid interference with other control functions.

C. Labels are designed for legibility and visibility based on the contrast between the lettering and its background.

D. Labels are designed to have white letters on black tags. Black on white is sometimes used to highlight a display.

E. Labels are designed with 3/16-in. capital letters. Annunciator window engravings are designed with 1/4-in. or 3/16-in. letters. The 1/4-in. letters are used to improve readability when message length permits.

F. Controls and displays are labeled with service description and tag number engravings. In addition, the control switch modules shall contain engravings for switching development functions, equipment-actuated functions, and train, if applicable.

G. Labels are placed above the instruments and on the escutcheon plates for control switches to allow adequate viewing from a distance of about 3 ft.

H. Labels for similar devices throughout a board are designed to be uniform in style, size, lettering, and use of abbreviations, with the exception of integral panels supplied by the vendor and inserted into the boards or panels as a unit.

I. Labels are designed and mounted so that they cannot easily be damaged or removed.

J. Labels and tag numbers are designed for accessibility and visibility during maintenance.

K. Labels are concise with minimum repetitive information and are directly usable with minimum decoding and interpretation of the service descriptions and abbreviations. A hierarchical label is used to highlight functional grouping.

L. Labels are not designed to describe engineering characteristics, name of manufacturer, trademarks, or nonfunction-related nomenclatures of the equipment.

M. Shades of colors used for mimics on the QEABs are designed to have maximum contrast between the mimic bus and the boards.

N. Safety-related post-accident monitoring instrumentation is identified by a dark red line on the black bezel base of each instrument.

18.1.2.12 Visual Display (Meters, Recorders, Lights, Monitors, and Annunciators)

This is defined as indication and display of equipment or subsystem conditions in visual modes.

18.1.2.12.1 General

A. Where possible, displays are arranged in the sequence in which they are used.

B. Unusual aids, such as stools and ladders, extra lighting, etc., are not required to read or gain access to a display.

C. Information for different types of activation are not combined unless activation requires the same information.

D. In a standing position, the most frequently used displays are, insofar as possible, located at the eye level of the operator.

E. Displays frequently used in conjunction are grouped together.

F. Displays are located where they can be read with accuracy and minimum parallax.

G. Scale face and graduation markings are designed to have a high degree of contrast.

H. Displays are designed so that glare does not interfere with readability when viewed from a reasonable location.

I. Displays which cannot or may not be watched continuously, but which need vigilance in monitoring, are designed to have a suitable auditory or visual alarm.

J. Multiple displays grouped together are designed to have uniform brightness across the full range of the display faces.

18.1.2.12.2 Meters

A. Meters, dials, and instruments are designed for size and location so they can be read from normal operating positions.

B. Information presentations are designed in such a form that minimum interpretation or decoding is necessary for operator implementation.

C. The meter pointer is designed to extend to, but not obscure, the graduation marks.

D. The meter pointer is designed for mounting as close as possible to the dial face to reduce or eliminate parallax and shadows.

E. Meter scales generally have graduations of 1, 2, 5, 10, or any of their multiples.

F. The display indicator does not move after the control movement stops.

G. System indicators in a flow path are arranged in accordance with flow path from left to right; i.e., inlet temperature, flow, outlet temperature.

H. Meters have nonglare covers where needed.

I. The meter scales of selected instruments are color coded to indicate the normal operating region.

J. T_{avg}/T_{ref} indicators are located next to each other for easy comparisons.

18.1.2.12.3 Recorders

A. Whenever possible, small continuous multipen recorders, having dimensions of approximately 6 in. by 6 in. or 3 in. by 6 in. are used on the QMCB.

B. Scanning-type indicators are of the low-profile type to reduce panel dimensional requirements.

18.1.2.12.4 Lights

A. Indicating lights are designed to show information regarding equipment status.

B. Indicating lights are designed to show status derived from equipment response and not just to indicate control positions. They are designed to show information needed for effective system operation.

C. Both the red and the green lights are designed to be lit for motor-operated valves and other devices with considerable travel time while the device is in an intermediate position.

D. The indicating lights for different operational conditions are designed as follows:

    1. Red - Equipment or process operating, flowing, or in an increasing condition, breaker closed, valve open.
    2. Green - Equipment or process not operating, not flowing, or in a decreasing condition, breaker open, valve closed.
    3. Amber - Trip (automatic protection and not by operator action or process; exceptions exist for a few valve indications where it is necessary to heighten operator awareness of off-normal valve configurations).
    4. White - Electrical potential available or other special uses.

    Use of blue indicating lights is limited because of the low level of brightness obtained with this color.

E. Indicating lights are designed for showing the status of equipment interlocked with the controls of associated equipment.

F. Indicating lights installed on the control boards are designed for uniform size and use standard abbreviations for their engravings.

18.1.2.12.5 System Status Monitoring Panel

The system status monitoring panel (QBPS), shown in figure 18.1-1, is described in detail in subsection 7.5.5. All lights on the QBPS are white.

18.1.2.12.6 Annunciators

A. The annunciator displays alarms that denote an abnormal equipment status or plant condition. Nuisance alarms are kept to a minimum by suitable permissive interlocking contacts.

B. Annunciators are designed for high reliability, using solid state equipment.

C. The annunciator system is designed to provide reasonable assurance that failure of one alarm circuit does not disable any other alarm circuit. Preoperational testing verified that failure of one alarm card did not disable the adjacent alarm circuit. This was demonstrated by removing an alarm card and testing the adjacent circuit.

D. Annunciator and computer alarms are designed not to be duplicated, except for the QBPS and selected computer sequential alarms.

E. Each section of the QMCB or QEAB has a three-pushbutton station to acknowledge, test, and reset the annunciator windows located in that section of the board.

F. The HVAC panel and miscellaneous system/equipment panel have the capability to acknowledge, test, and reset the annunciator only by the pushbutton station located on their respective panels.

G. All annunciators are designed as non-Class 1E. The annunciator contacts accept signals from Class 1E circuits which are isolated from the Class 1E system.

H. The power supply for annunciators is obtained from a non-Class 1E battery.

I. Control room annunciator windows are designed for white opaque; colors are obtained by installing color lenses.

J. The alarm sequences for the main control room annunciator are designed as indicated in tables 18.1-1, 18.1-2, and 18.1-3.

K. The three-pushbutton stations have the following functions:

   1. Acknowledge - To silence the horn and put the alarm light on steady.
   2. Test - To sound the horn and put all alarm lights on a panel or control board section on fast (or gallop for first-out sequence alarms) flash.
   3. Reset - To silence the horn and extinguish the lamp.

L. Annunciator nominal window dimensions are 1.4 in. by 3 in.; letter size is 3/16 in. or 1/4-in.

M. Dual alarms (such as high-low, high-high, etc.) are only allocated a single alarm window, provided a second point of information is available to distinguish between the two conditions (such as an indicator, monitor lights, or recorder).

N. Each local annunciator panel is designed to have a common retransmitting contact to operate a single window in the control room annunciator (exceptions are the emergency diesel generator local annunciator panels which are duplicated on the QEABs).

O. Reflash (occurrence of another alarm on the same window after acknowledge) capability is provided in special cases for annunciator windows with multiple contacts if required for safe and reliable operation of the plant.

18.1.2.12.7 Monitors

These are defined as display devices with television-type screens to indicate a comprehensive group of information and with flexibility to call up any stored information as required.

A. The control board is designed to locate a Monitor on the display section of the QMCB board section C for displaying the annunciated parameters from the plant computer.

B. The control board is designed to locate a Monitor at the normal eye level on the display section of the QMCB section B2 for displaying parameters from the plant computer.

C. The control room is designed to mount one Monitor on the operator desks to provide graphic displays.

D. The control room is designed to mount two free-standing safety parameter display system Monitor consoles located near the QMCB, as shown in figure 18.1-1.

E. The vertical section of control board QMCB Section B2 is designed to locate three monitors along with keyboards and touch pads for providing operator interfaces to control the main turbine, feed pump turbines, and the generator excitation system.

18.1.2.12.8 Plasma Display Modules

Two redundant dot matrix-type graphic/alphanumeric displays shall be provided in section D of the QMCB. These modules shall display the process variables classified in Regulatory Guide 1.97, Revision 2, as Category 1, as well as other selected variables. Plasma displays are a part of the PAMS described in section 7.5. They interface with the redundant display processing units and meet the single failure requirements.

18.1.2.13 Workspace

This is defined as the space surrounding the area designated "at the controls."

A. The control room area is designed to include dual control rooms (one per unit) with a supervisor's area positioned to observe both central control areas.

   1. Arrangements of the most frequently used boards and displays are designed for location readily visible to the operator in the central control area. Control boards are designed to be arranged to provide the best accessibility; i.e., shortest walking distance.

   2. Layout designs of the QMCB, QEAB, desks, and other panels are arranged so that physical interference among operators working in the central control area is minimized.

   3. The design for the central control area space and aisles allows efficient movement of operators between areas during normal, emergency, startup, and shutdown operations.

   4. The lines of sight to a display are designed so as not to be obstructed by poor arrangement of equipment.

5. A restricted area between the operators’ desks and the QMCB and QEAB is designed for the use of licensed operators only.

18.1.2.14 References

1. U.S. Nuclear Regulatory Commission, "NRC Action Plan Developed as a Result of the TM1-2 Accident," NUREG-0660, May 1980.
2. U.S. Nuclear Regulatory Commission, "TMI Related Requirements for New Operating Licenses," NUREG-0694, June 1980.
3. U.S. Nuclear Regulatory Commission, "Clarification of TMI Action Plan Requirements," NUREG-0737, November 1980.

TABLE 18.1-1

MAIN CONTROL ROOM ANNUNCIATOR ALARM SEQUENCE FIRST-OUT SEQUENCE OF OPERATION (MODIFIED)[(a)]

Condition		Field Contact	Lamp	Horn 1	Horn 2
Normal		Normal	Off	Off	Off
Alarm	First	Abnormal	Gallop flash	On	Off
	Subsequent	Abnormal	Fast flash	On	Off
Return to normal before acknowledge	First	Normal	Gallop flash	On	Off
	Subsequent	Normal	Fast flash	On	Off
Acknowledge	First	Abnormal	Slow flash	Off	Off
	Subsequent	Abnormal	Steady	Off	Off
Return to normal	First	Normal	Slow flash	Off	On
	Subsequent	Normal	Slow flash	Off	On
Reset	First	Normal	Off	Off	Off
	Subsequent	Normal	Off	Off	Off
Test	First	Normal	Gallop flash	On	Off

---

a. All windows will be on a first-out condition during the test sequence.

TABLE 18.1-2

MAIN CONTROL ROOM ANNUNCIATOR ALARM SEQUENCE RING-BACK SEQUENCE OF OPERATION

Condition	Field Contact	Lamp	Horn 1	Horn 2
Normal	Normal	Off	Off	Off
Alarm	Abnormal	Fast flash	On	Off
Return to normal before acknowledge	Normal	Fast flash	On	Off
Acknowledge	Abnormal	Steady	Off	Off
Return to normal	Normal	Slow flash	Off	On
Reset	Normal	Off	Off	Off
Test	Normal	Fast flash	On	Off

TABLE 18.1-3 (SHEET 1 OF 2)

MAIN CONTROL ROOM ANNUNCIATOR ALARM SEQUENCE

Reflash Sequence of Operation - One Incoming Alarm Which Returns to Normal Before Being Acknowledged (Common Window)

Condition	Field Contact	Lamp	Horn 1	Horn 2
Normal	Normal	Off	Off	Off
Alarm[(a)]	Abnormal	Fast flash	On	Off
Return to norm before acknowledge	Normal	Fast flash	On	Off
Acknowledge	Normal	Slow flash	Off	On
Reset	Normal	Off	Off	Off

Reflash Sequence of Operation - Two or More Incoming Alarms (Common Window)

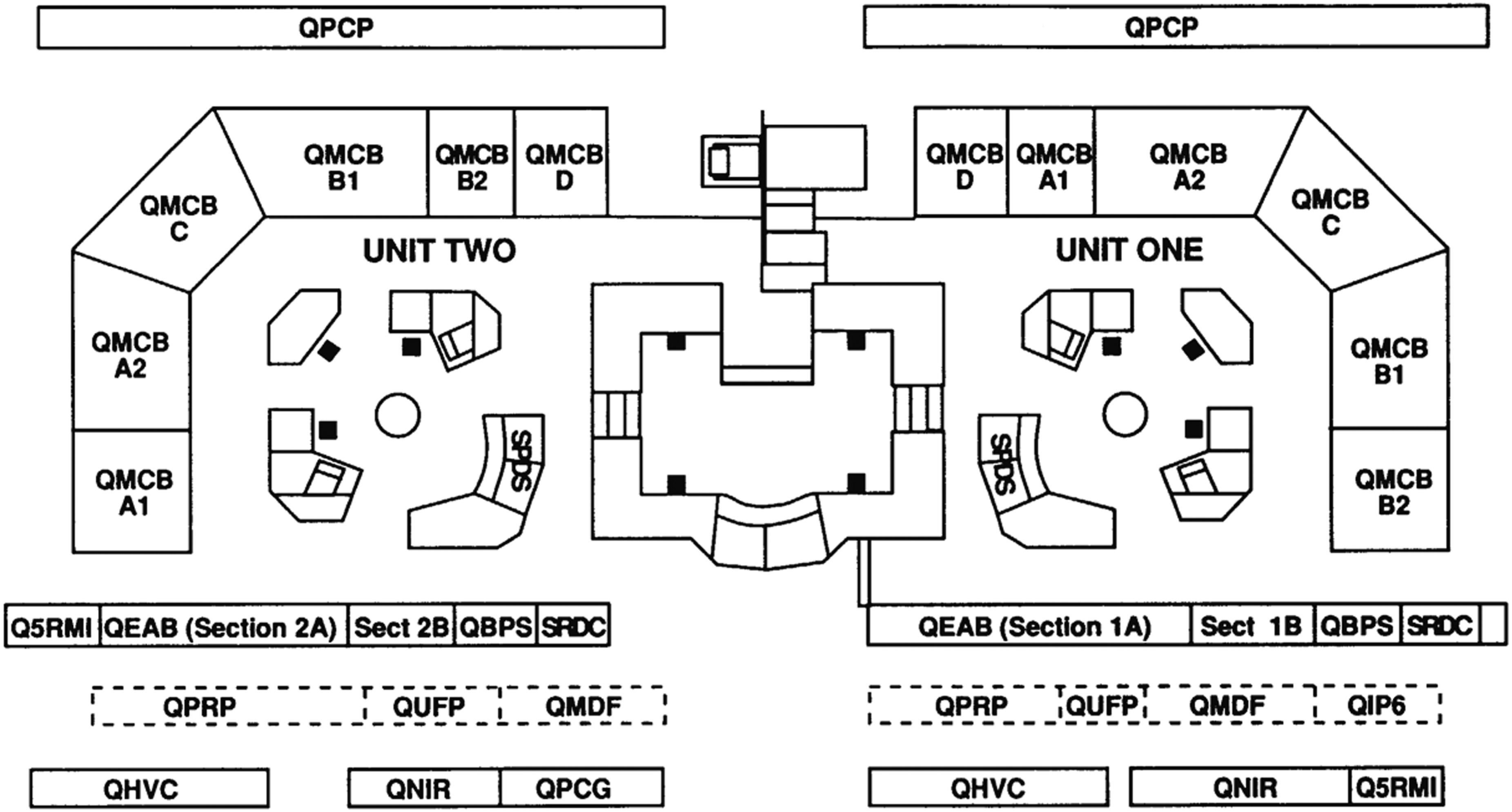
Condition	Field Contact	Lamp	Horn 1	Horn 2
Normal	Normal	Off	Off	Off
Alarm 1[(a)]	Abnormal	Fast flash	On	Off
Alarm 2[(a)]	Abnormal	Fast flash	On	Off
Acknowledge	Abnormal	Steady	Off	Off
Alarm 3[(a)]	Abnormal	Fast flash	On	Off
Alarm 1 returns to normal	Abnormal	Fast flash	On	Off
Acknowledge	Abnormal	Steady	Off	Off
Alarm 2 returns to normal	Abnormal	Steady	Off	Off

TABLE 18.1-3 (SHEET 2 OF 2)

Condition	Field Contact	Lamp	Horn 1	Horn 2
Alarm 3 returns to normal	Normal	Slow flash	Off	On
Reset	Normal	Off	Off	Off

---

a. Incoming alarm shall always have precedence over return to normal.


QPCP
QPCP
QMCB C
QMCB B1
QMCB B2
QMCB D
QMCB D
QMCB A1
QMCB A2
QMCB C
UNIT TWO
UNIT ONE
QMCB A2
QMCB A1
QMCB B1
QMCB B2
SPDS
SPDS
Q5RMI
QEAB (Section 2A)
Sect 2B
QBPS
SRDC
QEAB (Section 1A)
Sect 1B
QBPS
SRDC
QPRP
QUFP
QMDF
QPRP
QUFP
QMDF
QIP6
QHVC
QNIR
QPCG
QHVC
QNIR
Q5RMI

NOTE: DASHED LINE INDICATES EQUIPMENT SHOWN FOR LOCATION ONLY AND NOT PART OF DESIGN EVALUATION.

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VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTROL ROOM LAYOUT

FIGURE 18.1-1

18.2 PRELIMINARY REVIEW OF THE CONTROL ROOM AND CONTROL BOARD DESIGN

18.2.1 REVIEW PROCEDURES

18.2.1.1 Introduction

The preliminary review of the control room and control board design was conducted by the General Physics Corporation, with the primary objective of providing an adequate evaluation of the human factors.

The review included primarily those panels which comprised the inner ring of panels in the control room.

Certain additional panels which are not in the inner ring were also reviewed. A listing of the panels reviewed is given below:

Inner Ring Panels	Outer Ring Panels
QMCB A1	HVC
QMCB A2	QPCP
QMCB C	
QMCB B1	
QMCB B2	
QMCB D	
QEAB	

Figure 18.1-1 illustrates the layout of the panels in the main control room.

The review procedures and results are presented in detail in reference 1 and summarized in this section. The review was performed in accordance with the guidelines of NUREG/CR-1580.(2)

The use of engineering checklists provided standards of assessment of various properties of the control room including, among other aspects:

- Functional grouping.
- Anthropometrics.
- Readability of labels.
- Controls discrimination.

These checklists were developed based upon the latest established and recommended human factors engineering criteria.

Several techniques were employed in the review of the VEGP control room. Operators were used to determine how the VEGP control board stood in relationship to similar vintage control boards. Human factors specialists judged the control board against applicable guidelines. Engineering checklists were employed to evaluate individual controls and control/display layout. Scenario evaluations were performed to assess the operability of the board. Using the above methods, the human factors engineering group was able to make assessments of:

- Anthropometrics and panel elements.
- System layout.
- Component usage.
- Readability of displays and labels.
- Coding/discrimination methods.
- Environmental conditions.
- Operability of control board.

Below is a detailed description of methodologies used in anthropometrics and panel elements analysis, system evaluation, component evaluation, and scenario evaluation. The information gathered by use of these human factors methodologies served as a basis for the development of preliminary recommendations. The evaluation of these recommendations and their resolutions are provided in subsection 18.2.2.

18.2.1.2 Anthropometrics

Anthropometric evaluation was performed by comparing the control room design to established human factors guidelines. The main references used were Bechtel drawings, NUREG-1580,(2) and MIL-STD-1472B.(3)

The guidelines were applied three ways: by scale drawings, by use of a 1/4-in. scale panel silhouette and mannequins scaled for the 95th and 5th percentile male, and by actual measurements of reach and heights taken from the mockup.

Items examined were:

- Panel height.
- Distance of reach.
- Viewing distance.
- Viewing angle.
- Placement of controls and displays in relationship to anthropometric value.

18.2.1.3 System Evaluation

System evaluation was performed after developing engineering checklists from the current applicable human factors engineering guidelines, specifically NUREG/CR-1580.(2)

A separate set of questions was asked about each control and each display. A list of these questions is provided below. The questions were asked about each individual component with answers recorded as a yes or no.

A. Control Checklist

1. Are controls placed such that they may be easily operated?
2. Is control located to prevent inadvertent operation?
3. Does control give the information needed for operation of the equipment/system?
4. Is the control clearly marked as to what it does?
5. Do controls move in the culturally normal direction (clockwise for on)?
6. Is this control the best type of control for the function needed?
7. Are controls grouped in a consistent left-to-right, top-to-bottom order?
8. Is control not prone to be misread or its position misinterpreted?

B. Display Checklist

1. Is display prone to be misread or misinterpreted?
2. Is display the best type for indicating system/equipment function?
3. Does display give the type of information needed?
4. Does display movement correspond to the control movement?
5. Is display in reasonable proximity to the control?

18.2.1.4 Component Evaluation

Component evaluation was performed by reviewing all pertinent human factors guidelines, then developing a list of these guidelines applicable to components in the control room. Additions to this list draw heavily on Nuclear Regulatory Commission (NRC) Safety Evaluation Reports.(4)(5)(6)

These documents were reviewed:

- Electrical one-line diagrams.
- Piping and instrumentation diagrams.
- Control logic diagrams.
- Instrument specification sheets.
- Instrument index.
- Digital rod position indicator specification.
- Specification for the electrical auxiliary board and the miscellaneous control board.
- Various vendor documents were utilized.

Where possible, a hands-on evaluation of controls was performed. This entailed the use of testing devices such as a snap-on torque meter or an Amtex torsional testing machine. In addition, observation of equipment equivalent to that found in the VEGP control rooms was made at various operating simulators. In particular, the Sequoyah and McGuire simulators were used.

Safety evaluation reports were reviewed to determine how the NRC implemented the various guidelines.

18.2.1.5 Scenario Evaluation

Scenario walkthroughs were performed at the control room mockup for Unit 1 to gain an operational perspective on the proposed layout and to evaluate it from the operator's point of view. The primary purpose of this methodology was to assess the logical sequencing of all actions and the flow of required motions to perform the required actions in a timely manner.

This evaluation was performed in three phases. The first phase was the creation of operating procedures from Westinghouse generic procedures. The second phase was the actual walkthrough. The third phase was the scenario evaluation.

Nine scenarios were selected from Westinghouse generic procedures. Four nonprocedural scenarios were added during the review. The nine selected were chosen because they represent a wide variety of plant activities and contain the basic parameters for many more operating tasks. The four shorter scenarios were added to provide a review of observational tasks. The nine scenarios were:

- Immediate action and diagnostics.
- Steam generator tube rupture.
- Operation with natural circulation.
- Plant shutdown from minimum load to cold shutdown.
- Reactor coolant system leak.
- Station blackout.
- Plant startup from cold shutdown to minimum load.
- Loss of reactor coolant.
- Reactor trip.

The four additional scenarios performed were:

- Loss of secondary coolant.
- Starting the diesel generators.
- Controlling steam generator level.
- Changeover from recirculating mode to injection mode.

The information collected by use of these human factors methodologies served as a basis for the development of preliminary recommendations.

The evaluation of these recommendations is provided in subsection 18.2.2.

18.2.1.6 Reviewer Experience

General Physics Corporation, the prime control board reviewer, has had the following experience in design review:

- North Anna, Unit 2 Control Room Review.
- EPRI-RP769, Performance Measurement System for Training Simulators.
- Babcock & Wilcox and U.S. Department of Energy, Disturbance Analysis and Surveillance System.
- Clinch River Breeder Reactor Control Room Review.
- Edison Electric Institute, Operator Selection Study.
- Operability Assessment of Prototype Large Breeder Reactor Designs.
- Electric Power Research Institute, Survey and Analysis of Communication Problems in Nuclear Power Plants.

18.2.2 CONTROL ROOM AND CONTROL BOARD EVALUATION RESULTS

18.2.2.1 Human Factors Deficiencies Categories

The human factor deficiencies were categorized into five general groupings:

A. Administrative, where no hardware solutions were available.
B. Components, where the type of display, means and methods of manipulation, and elimination of the chances for inadvertant or accidental misoperation were considered.
C. Labeling, where the identifications of systems, trains, and devices were reviewed so that quick and easy identification by the operators would be enhanced.
D. Rearrangement of components, where component functional relationships were considered and their actual arrangement on the board was then critiqued.
E. Workshop/environment, where noise, temperature, lighting, and workspace definition were considered which would lead to increased operation effectiveness and reduced distraction; other deficiencies which would negatively affect operator performance.

18.2.2.2 Findings and the Resolutions Thereof

The preliminary control room design review identified human engineering deficiencies at an early stage in the design in order that they could be incorporated in design improvements, operator training, and plant operating and administrative procedures. When final NRC guidance was issued, the review process was repeated in the detailed control room design review, detailed in section 18.3.

18.2.2.3 References

1. General Physics Corporation, "Report on Human Factors Evaluation of Alvin W. Vogtle Nuclear Power Plant Control Room," GP-R-23003, Columbia, Maryland.
2. U.S. Nuclear Regulatory Commission, "Human Engineering Guide to Control Room Evaluation - Draft Report," NUREG/CR-1580, July 1980.
3. U.S. Department of Defense, "Human Engineering Design Criteria for Military Systems, Equipment, and Facilities," MIL-STD-1472B, Washington, D.C., May 1978.
4. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report, Supplement No. 1, Docket Nos. 50-327 and 50-328, Sequoyah Nuclear Plant Units 1 and 2," NUREG-0011, February 1980.
5. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report, Supplement No. 10, Docket No. 50-339, North Anna Power Station Unit 2," NUREG-0053, July 1980.
6. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report, Supplement No. 4, Docket No. 50-311, Salem Nuclear Generating Station Unit 2, NUREG-0512, January 1979.

18.3 DETAILED CONTROL ROOM DESIGN REVIEW

18.3.1 BACKGROUND

Guidance for the control room design review (CRDR) was provided by various NUREGs and Regulatory Guides. A Nuclear Utility Task Action Committee (NUTAC) with staff support from the Institute of Nuclear Power Operations (INPO) developed a generic control room design review implementation plan from these guidelines. NRC guidance and NUTAC guidelines were used by Georgia Power Company (GPC) for the development of the detailed CRDR process.

The detailed control room design review stands alone in documenting compliance with NRC requirements. Many design changes recommended in the preliminary review were already incorporated, resulting in fewer design deficiencies when reviewed by NUREG 0700 guidance. However, some items identified in the preliminary review had not been incorporated into the design. To assure problems were not overlooked, those items were incorporated in the review as human engineering discrepancies (HEDs) for review and resolution.

18.3.2 OBJECTIVES OF THE CRDR

The objective of the CRDR was to determine the extent to which the VEGP control room provides the operators with sufficient information to complete their required functions and task responsibilities efficiently under emergency conditions. The review also determined the human engineering suitability of the designs of the instrumentation and equipment in the VEGP control room.

To ensure that the CRDR fulfilled its stated purpose, several specific objectives were identified and met during the review. The following specific objectives were defined for the CRDR:

- To perform a control room survey that compares the existing control room with accepted human engineering criteria.
- To review relevant plant operational experience using appropriate documentation and operator questionnaires.
- To determine the information and control requirements of control room operator tasks during emergency conditions.
- To identify human engineering discrepancies.
- To evaluate the extent and importance of identified discrepancies.
- To formulate and implement solutions for significant discrepancies.
- To ensure that the proposed solutions do, in fact, eliminate or mitigate the discrepancies for which they are formulated without creating new discrepancies.
- To verify that implemented solutions eliminate or mitigate identified discrepancies.

18.3.3 CONTROL ROOM DESIGN REVIEW PROCESS

This section describes the process that was used to accomplish the objectives of the CRDR.

18.3.3.1 Preliminary CRDR Status Evaluation

Recognizing that the 1982 control room design review would provide valuable input to the current control room design review, each of the identified deficiencies/discrepancies was reviewed by the use of the following checklist:

- Action reflects the recommended intent and resolves the HED.
- Action reflects the recommended intent but does not resolve the HED.
- Action does not reflect the recommended intent.
- Actions taken create other HED(s).
- No action taken, deficiency remains.
- No action taken, deficiency resolved by resolution of HED.
- New HED(s) generated.
- Other (explain).

18.3.3.2 Operating Experience Review

The Vogtle Electric Generating Plant was under construction with no operating history, and the onsite experience of operational personnel and data from plant operating documents provided little information for the CRDR. Accordingly, the operating experience review focused primarily on industry experience at similar plants and considered the experience gained from the VEGP plant-specific simulator.

Two separate steps were involved in reviewing operating experience. The first was to review available and applicable historical documentation pertaining to plant-specific and generic occurrences. The second step was to survey operating personnel. Operating personnel surveys (operator questionnaire) identified specific problem areas in the VEGP control room that may occur during normal and emergency operation. The operator questionnaire was extracted from the Control Room Design Review Survey Development Guideline (INPO 83-014).

18.3.3.3 Problem Reports

An open ended control room design problem form was sent to all control room and simulator personnel. Copies were made available in the control room and the simulator. This allowed any problem noted to be promptly reported. These problem reports were evaluated for possible HEDs by the review team leader. In many cases, the problem reports identified items already documented by surveys or prior problem reports.

18.3.3.4 Control Room Surveys

Surveys of the existing VEGP control room were conducted during the CRDR. The purpose of the surveys was to compare the design features of the existing control room with applicable human engineering design guidelines. The surveys were conducted by the CRDR review team. The survey team used questionnaires, checklists, and surveys to compile information regarding the as-built characteristics of the VEGP control room.

Eleven separate surveys were completed during the CRDR survey activity. Some of the surveys consisted simply of recording (or determining) control room conventions, such as color usage and instrument arrangement. In general, HEDs were not written during the convention surveys. Instead, the information obtained was used in other CRDR activities to determine where particular instruments or systems departed from the overall convention.

Other surveys measured certain physical quantities, such as illumination and sound level, and compared these measurements to acceptable, or preferred, human engineering standards for such quantities. HEDs were written for characteristics that fell outside the acceptable band.

The individual surveys were:

- General design convention survey (NUTAC 83-042).
- Design convention survey for repetitive groupings (NUTAC 83-042).
- Lighting survey (NUREG 0700 Section 6.1.5).
- Noise survey (NUREG 0700 Appendix E).
- Anthropometric survey (NUTAC 83-042 and NUREG 0700 Section 6.1.2).
- Annunciator survey (NUREG 0700 Section 6.3).
- Communication survey (NUREG 0700 Section 6.2).
- Abbreviation and acronym survey (NUTAC 83-042).
- Color coding survey (NUTAC 83-042).
- Control room computer survey (NUREG 0700 Section 6.7).
- NUTAC 83-042 appendices B-H survey (using applicable NUREG 0700 guidelines).

18.3.3.5 Task Analysis

The operating experience review and the control room survey identified as HEDs those control room characteristics that had caused, or nearly caused, problems during normal operation and simulator exercises and those characteristics that did not conform to certain human engineering design criteria. The task analysis identified the tasks that operators must perform during emergency operation and determined whether the instrumentation, controls, and equipment were available and suitable to perform those tasks. In addition to determining the availability of suitable instrumentation, controls, and equipment, the task analysis validated that the emergency tasks identified could be performed in real time under simulated emergency conditions in the VEGP control room.

The task analysis used as its basis the Emergency Response Guidelines (ERGs) developed by the Westinghouse Owners Group (WOG).

18.3.3.6 Instrumentation and Control Characteristics Review

In response to the NRC in-progress audit concerns that the task analysis did not identify instrument and control (I&C) needs as compared to the I&C control room inventory, an independent review of the VEGP control room inventory, instrumentation and control characteristics was conducted. The instrumentation and control characteristics review program identified the instrumentation, controls, and characteristics necessary for proper operator response to emergency transients. This review program first identified generic characteristics based on the Westinghouse Owners Group high-pressure reference plant design, followed by the identification of plant-specific deviations. The characteristics of the installed control room instrumentation were justified with the development of or reference to appropriate generic or plant-specific basis documentation.

18.3.3.6.1 Identification of Required Instrumentation and Controls

The Emergency Response Guidelines and the ERG background documents were reviewed to identify:

- All operator tasks necessary to support the operator functions.
- Operator information and control needs necessary to support the operator functions and major actions.
- Plant systems necessary to provide information and control needs.
- Plant instrumentation and controls necessary to provide information and control needs.

For the required plant instrumentation and controls identified above, characteristics were determined based on the information and control needs. The characteristics for the instrumentation included the following:

- Setpoints.
- Units.
- Range.
- Resolution.
- Type of display.

Characteristics for controls included the following:

- Positions.

- Type of control (e.g., variable).

From the information gathered in the characteristics review, a required characteristics justification table was developed for required instrumentation. This table identified operator action categories and associated operator information needs, criteria, and characteristics. The basis for each action category or information need was described or a reference to other documentation was provided.

Following identification of the required characteristics, the VEGP specifics were identified. The VEGP-specific characteristics consisted of applicable generic characteristics and plant-specific deviations. To identify VEGP-specific instrumentation and controls and their associated required characteristics, the Vogtle Emergency Operating Procedures were reviewed to identify deviations from the Emergency Response Guidelines. These VEGP-specific characteristics were then entered in the required characteristics justification tables.

Generic and VEGP-specific required characteristics were reviewed and the limiting required characteristics were summarized in characteristics requirements tables.

18.3.3.6.2 Verification

Verification of the installed control board instrumentation with respect to the above defined required instrumentation and control characteristics was performed. The CRDR team developed an inventory of VEGP control board instrumentation and controls. The CRDR team then compared the inventory to the instrumentation and control characteristics requirements tables for consistency. No HEDs (not already identified in the original task analysis) were identified from this review. This verification provided assurance that the operator did in fact have the required instrumentation and controls assumed in the Westinghouse Owner's Group transient analysis for response to emergency transients.

18.3.4 EVALUATION OF HUMAN ENGINEERING DISCREPANCIES

18.3.4.1 Objectives of Evaluation Process

The objectives of this phase of the CRDR were:

- Evaluate the significance of the HEDs identified in the previous phases of the CRDR.
- Where HEDs were found to be of minor significance, describe the technical and operational basis for such a finding.
- Where the HEDs were found to be significant, formulate changes to the control room design, procedures, operator training, or any combination thereof to mitigate those HEDs.

18.3.4.2 Evaluation Criteria

Human engineering discrepancies found during the control room surveys, the operating experience review, and the task analysis were evaluated by the review team for their potential to adversely affect normal and emergency operation. A categorization scheme was used that required each HED to be assessed by the review team and prioritized for resolution. The following five categories were designed to be unique so a consensus could be obtained from the review team as to which category each HED should be assigned.

- Category 1 (Safety Significant) - HEDs that have caused errors in or are judged likely to adversely affect the management of emergency conditions by control room operators.
- Category 2 - HEDs that are known to have caused problems during normal operation.
- Category 3 - HEDs that can be fixed with simple and inexpensive enhancements, so called "paint, tape, and label" (PTL) fixes. This included HEDs that were easy to fix but difficult to assess as to the effect on emergency operation.
- Category 4 - These HEDs were judged by the review team as unlikely to affect emergency operation, not documented as causing problems during normal operation, and not easily corrected. However, corrective action was recommended.
- Category 4a - A minor deviation from standards not expected to cause a problem. No corrective action was recommended.

HEDs were initially categorized using a subjective approach that reflected the consensus judgment of the multidisciplinary CRDR team. This HED category review employed a systematic approach based on the assessment process identified in NUREG 0800 and NUREG 0801 (Draft).

HEDs were evaluated with respect to the following attributes and subjected to the algorithm presented in figure 18.3-1 to determine their significance and effects on plant safety.

Item 1 HEDs experienced (EOP validation) or assessed (surveys or checklists) as having a high probability of contributing to operator error.

Item 2 HEDs associated with engineered safety features (ESF) systems.

Item 3 HEDs that could result in unsafe operation or violation of the Technical Specifications.

Item 4 HEDs identified through the operating experience review or actual problems identified in the operator questionnaire.

Item 5 HEDs determined to be easily correctable with paint, tape, labels, engraving changes, or work space environment improvements.

Item 6 HEDs determined to contribute to the operator mental work load (cumulative effects) resulting in fatigue, confusion, or discomfort.

18.3.4.3 Resolution of Human Engineering Discrepancies

18.3.4.3.1 Approach to Correction

The correction of human engineering discrepancies was generally based on the following preferred order of approaches:

A. Guideline compliance - The first preference for correction of HEDs was to modify the control room to comply with the guidelines of NUREG 0700. This approach was used for labeling, procedural, and support equipment HEDs. Control board arrangement HEDs used this approach when consistent with regulatory (train separation) and physical (panel space) limitations.

B. Compensatory measures - When conflicting regulatory or physical constraints prevented a straightforward change to achieve guideline compliance, changes were used which eliminated or reduced the impact of an HED on the operators.

18.3.4.3.2 Engineering Consensus

The development and selection of corrections to HEDs was accomplished by group meetings of the detailed CRDR team. Alternate approaches, benefits, and costs were discussed, and an engineering consensus was arrived at on the recommended approach to correct each HED. The diverse backgrounds of team members were intended to provide input from all disciplines on the resolution of HEDs. The procedures in use called for final recording of the board recommendations. Brief summaries of the resolutions and supporting comments were reported in the Detailed CRDR Report of June 10, 1986.

18.3.4.3.3 Cost-Benefit Analysis

The engineering consensus approach considered costs vs. benefits but did not perform a detailed, documented cost-benefit analysis. The emphasis was on correction of the HEDs to enhance operator performance. The correction of safety significant HEDs was a commitment without regard to cost. In all cases the team members sought to develop the most practical solution balancing constructability, schedule, and cost to achieve the objective of enhanced operator performance.

Some example cost considerations were:

A. Labeling and procedure changes were always implemented to achieve compliance with NUREG 0700. These were typically less than $10,000-projects.

B. Panel rearrangements generally less than $100,000 were implemented.

C. A major control room layout modification of $300,000 was implemented.

D. Major control panel replacements which would cost several million dollars were not recommended. HEDs involving such changes for exact compliance with NUREG 0700 guidelines were addressed with alternate solutions.

18.3.5 COORDINATION WITH OTHER ACTIVITIES

The CRDR process was coordinated with other post-TMI activities in several ways. These activities included the following:

- Upgrading Emergency Operating Procedures.
- Detailed control room design review.
- Post-accident monitoring system (section 7.5).

- Safety parameter display system (subsection 9.5.10).
- Upgrading emergency response facilities.

The mechanism for coordination of control room improvements with other programs was the Emergency Operating Procedures validation program.

The coordination was achieved by: (1) having several members of the detailed CRDR team serve as members of the EOP observation teams during the EOP validation exercises, (2) the task analysis was a common basis for both the detailed CRDR and EOP programs, and (3) the findings or discrepancies identified during the validation exercises related to man and machine interface were processed via the detailed CRDR HED assessment process.

In addition, control room modifications that resulted from the Emergency Operating Procedures validation program were addressed in the detailed CRDR verification plan to ensure design improvements provided the necessary correction.

18.3.5.1 Emergency Operating Procedures

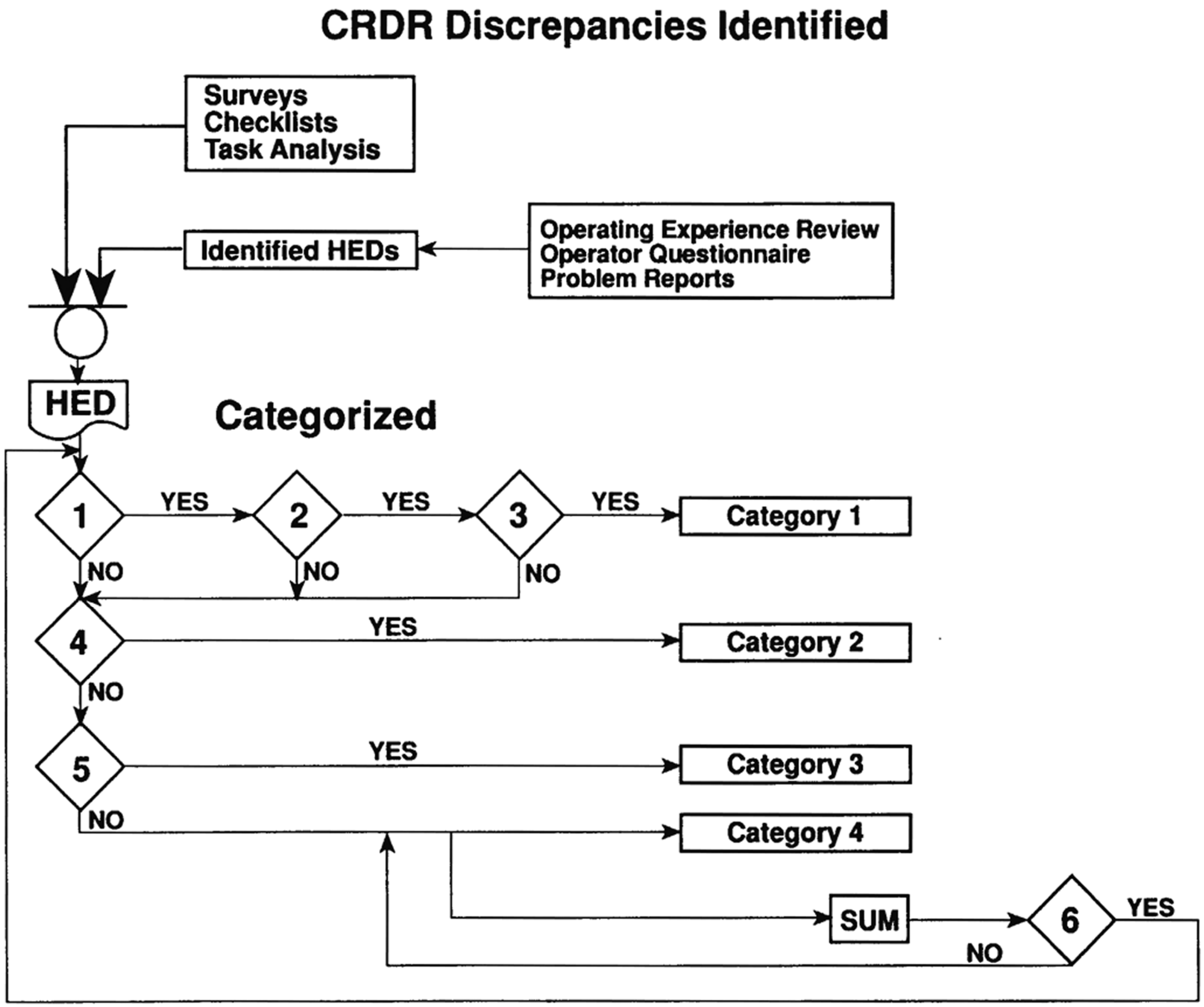
The task analysis portion of the detailed CRDR used the Westinghouse ERGs as plant-specific EOPs as its starting point. Thus, the task of upgrading emergency procedures is inherently integrated into the detailed CRDR. The simulator validation of the task analysis was combined with the VEGP EOP validation program.

18.3.5.2 Safety Parameter Display System (SPDS)

GPC used the SPDS during the EOP validation exercise, and evaluated it to NUREG 0700 Section 6.7 (process computer) guidelines. Some HEDs identified during the EOP validation exercise or the computer survey and judged to be significant by the review team were resolved by incorporating certain features into the SPDS and associated displays. In addition, the detailed CRDR team leader was chairman of a control room computer task force and participated in developing displays and board arrangements. This served to incorporate human engineering requirements into the design of the SPDS and further integrate them into the detailed CRDR process. (See the Emergency Plan, section H.4.5.)

18.3.5.3 Regulatory Guide 1.97

The design of Regulatory Guide 1.97 instrumentation was essentially complete at the time of this review. This instrumentation was evaluated in the detailed CRDR survey and task analysis.


CRDR Discrepancies Identified
Surveys
Checklists
Task Analysis
Identified HEDs
Operating Experience Review
Operator Questionnaire
Problem Reports
HED
Categorized
1
YES
2
YES
3
YES
Category 1
NO
NO
NO
4
YES
Category 2
NO
5
YES
Category 3
NO
Category 4
SUM
6
YES
NO

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HUMAN ENGINEERING DISCREPANCY EVALUATION ALGORITHM

FIGURE 18.3–1 (SHEET 1 OF 2)

Algorithm Attributes

ITEM 1

HEDs experienced or assessed as having a high probability of contributing to operator error.

ITEM 2

HEDs associated with engineered safety features systems.

ITEM 3

HEDs that could result in unsafe operation or violation of the Technical Specifications.

ITEM 4

HEDs identified through the operation experience review or actual problems identified in the operator questionnaire.

ITEM 5

HEDs determined to be easily correctable with paint, tape, labels, engraving changes, or work space environment improvements.

ITEM 6

HEDs determined to contribute to operator mental work load (cumulative effects) resulting in fatigue, confustion, or discomfort.

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UNIT 1 AND UNIT 2

HUMAN ENGINEERING DISCREPANCY EVALUATION ALGORITHM

FIGURE 18.3–1 (SHEET 2 OF 2)

19.0 LICENSE RENEWAL – AGING MANAGEMENT PROGRAMS AND ACTIVITIES

19.1 INTRODUCTION

19.1.1 BACKGROUND

Renewed operating licenses for Vogtle Electric Generating Plant (VEGP) Units 1 and 2 were issued on June 3, 2009, extending the original licensed operating term by 20 years. Units 1 and 2 will enter the period of extended operation on January 17, 2027 and February 10, 2029 for Units 1 and 2, respectively.

19.1.1.1 License Renewal Rule and Process

10 CFR Part 54, the license renewal rule, establishes the procedures, criteria, and standards governing nuclear plant license renewal.

Plant systems, structures, and components (SSCs) within the scope of license renewal are defined in 10 CFR 54.4(a) as:

- Safety-related SSCs (i.e., perform a safety-related function as defined in 10 CFR 54.4(a) (1)).
- Nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of safety-related functions.
- All SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).

The license renewal rule focuses on managing the effects of aging on the passive intended functions of long-lived structures and components, and on evaluation of time-limited aging analyses (TLAA), as defined in 10 CFR 54.21. (See paragraph 19.1.1.3 for a discussion of the definition of a TLAA.)

The license renewal rule generically excludes structures and components associated only with active functions from an aging management review. Functional degradation resulting from the effects of aging on active functions is more readily determinable and detectable, and existing programs and regulatory requirements are expected to directly detect the effects of aging. The license renewal rule credits the continued applicability of existing programs and regulatory requirements, and the maintenance rule requirements (10 CFR 50.65), to monitor the performance and condition of SSCs that perform active functions.

The license renewal process includes the identification of SSCs within the scope of the license renewal rule, determining the in-scope structures and components subject to aging management review (i.e., are passive and long-lived), and assuring the effects of aging on the intended functions are adequately managed through the identification and/or development of various aging management programs and activities. The process also includes the identification and evaluation of TLAAs, including any exemptions containing TLAAs.

The license renewal rule and the renewed operating licenses require that a summary description of the aging management programs and activities and the TLAA evaluations become part of the FSAR. To meet this requirement, sections 19.2 through 19.4 are incorporated into the FSAR. After issuance of the renewed license, 10 CFR 54.37(b) requires that, for newly identified SSCs that would have been subject to aging management review or evaluation of TLAAs in accordance with 10 CFR 54.21, the FSAR be updated to describe how the effects of aging will be managed such that the intended functions(s) in 10 CFR 54.4(b) will be effectively maintained during the period of extended operation.

19.1.1.2 Aging Management Programs

The NRC, in the Standard Review Plan for License Renewal (NUREG-1800), Appendix A.1, "Aging Management Review – Generic (Branch Technical Position RLSB-1)," describes the elements of an acceptable aging management program to the NRC staff. Additionally, NUREG-1801, "Generic Aging Lessons Learned Report," describes aging management programs that have been found acceptable to the NRC Staff to manage the aging effects of SSCs for license renewal.

In many cases, programs and activities existing at the time of the license renewal application were found adequate for managing aging for the period of extended operation. In some cases, the existing programs or activities required some degree of enhancement. Also, some new programs and activities were identified. It is important to note that only a portion of certain programs or activities may be relied upon for managing the effects of aging under the license renewal rule.

More than one program or activity may be credited to manage aging in a single system, structure, or component. Conversely, in other cases, one program or activity may manage the effects of aging in multiple systems.

19.1.1.3 Time-Limited Aging Analyses

The license renewal rule requires that TLAA be evaluated to capture certain plant-specific aging analyses explicitly based on the original 40-year operating life of the plant. In addition, the Rule requires that any exemptions based on TLAAs be identified and analyzed to justify extension of those exemptions through the renewal term.

TLAA evaluations are defined by the license renewal rule in 10 CFR 54.3 as those calculations and analyses that meet all of the following six criteria:

- Involve SSCs within the scope of license renewal.
- Consider the effects of aging.
- Involve time-limited assumptions defined by the operating term, e.g., 40 years.
- Were determined to be relevant in making a safety determination.
- Involve conclusions or provide the bases for conclusions related to the capability of the SSC to perform its intended functions, as delineated in the Rule.

- Are contained or incorporated by reference in the current licensing basis.

Once a TLAA has been identified, the Rule in 10 CFR 54.21 (c) requires it to be dispositioned by one of the following three specific criteria:

- The analyses remain valid for the period of extended operation.
- The analyses have been acceptably projected to the end of the period of extended operation.
- The effects of aging on the intended functions(s) will be adequately managed (e.g., programs or activities are in place) for the period of extended operation.

After the renewed license has been issued, 10 CFR 54.37 (b) requires that any newly identified calculations or analyses that would have been a TLAA be evaluated and a summary description placed in the FSAR.

19.1.2 AGING MANAGEMENT PROGRAMS

The following programs are credited to manage the effects of aging during the period of extended operation for license renewal and are described in section 19.2 as listed below:

- ACCW System Carbon Steel Components Program (19.2.1).
- Bolting Integrity Program (19.2.2).
- Boric Acid Corrosion Control Program (19.2.3).
- Buried Piping and Tanks Inspection Program (19.2.4).
- CASS RCS Fitting Evaluation Program (19.2.5).
- Closed Cooling Water Program (19.2.6).
- Diesel Fuel Oil Program (19.2.7).
- External Surfaces Monitoring Program (19.2.8).
- Fire Protection Program (19.2.9).
- Flow-Accelerated Corrosion Program (19.2.10).
- Flux Thimble Tube Inspection Program (19.2.11).
- Generic Letter 89-13 Program (19.2.12).
- Inservice Inspection Program (19.2.13).
- Nickel Alloy Management Program for Non-Reactor Vessel Closure Head Penetration Locations (19.2.14).

- Nickel Alloy Management Program for Reactor Vessel Closure Head Penetrations (19.2.15).
- Oil Analysis Program (19.2.16).
- One-Time Inspection Program (19.2.17).
- One-Time Inspection Program for ASME Class 1 Small Bore Piping (19.2.18).
- One-Time Inspection Program for Selective Leaching (19.2.19).
- Overhead and Refueling Crane Inspection Program (19.2.20).
- Periodic Surveillance and Preventive Maintenance Activities (19.2.21).
- Piping and Duct Internal Inspection Program (19.2.22).
- Reactor Vessel Closure Head Stud Program (19.2.23).
- Reactor Vessel Internals Program (19.2.24).
- Reactor Vessel Surveillance Program (19.2.25).
- Steam Generator Tubing Integrity Program (19.2.26).
- Steam Generator Program for Upper Internals (19.2.27).
- Water Chemistry Control Program (19.2.28).
- 10 CFR 50 Appendix J Program (19.2.29).
- Inservice Inspection Program – IWE (19.2.30).
- Inservice Inspection Program – IWL (19.2.31).
- Structural Monitoring Program (19.2.32).
- Structural Monitoring Program – Masonry Walls (19.2.33).
- Non-EQ Cables and Connections Program (19.2.34).
- Non-EQ Inaccessible Medium-Voltage Cables Program (19.2.35).
- Non-EQ Electrical Cable Connections One-Time Inspection Program (19.2.36).

19.1.3 AGING MANAGEMENT PROGRAMS – TIME LIMITED AGING ANALYSES (TLAA)

The aging management programs credited for managing the associated TLAAs during the period of extended operation are described in section 19.3 as listed below:

- Environmental Qualification Program (19.3.1).
- Fatigue Monitoring Program (19.3.2).

19.1.4 TLAA EVALUATIONS

The evaluation of TLAAs for the period of extended operation is provided in section 19.4. The TLAAs evaluated for the period of extended operation are listed below:

- Reactor Vessel Neutron Embrittlement Analyses (19.4.1).
- Metal Fatigue Analysis (19.4.2).
- Environmental Qualification Calculations (19.4.3).
- Containment Tendon Pre-Stress Analysis (19.4.4).
- Penetration Load Cycles (19.4.5).
- Other Plant Specific Analysis (19.4.6).

19.1.5 REFERENCES

1. NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, U.S. Nuclear Regulatory Commission (Rev. 1), September 2005.
2. NUREG-1801, Generic Aging Lessons Learned (GALL) Report, U.S. Nuclear Regulatory Commission, (Rev. 1), September 2005.
3. Vogtle Electric Generating Plant Technical Specifications, Units 1 and 2.

19.2 AGING MANAGEMENT PROGRAM DESCRIPTIONS

The VEGP integrated plant assessment for license renewal identified the aging management programs credited to provide reasonable assurance that structures and components requiring an aging management review will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation. This section describes the aging management programs and activities required to manage the effects of aging during the period of extended operation.

The aging management programs and activities in this section rely on the operations quality assurance program (OQAP) for VEGP and SNC for the elements of corrective action, confirmation process, and administrative controls. The VEGP quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B. Corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished per the existing corrective action program and document control program and are applicable to all aging management programs and activities that will be required during the period of extended operation. The confirmation process is part of the corrective action program and includes reviews to assure that corrective actions are adequate, tracking and reporting of corrective actions, and reviews of corrective action effectiveness. Any followup inspection required by the confirmation process is documented in accordance with the corrective action program. The corrective action, confirmation process, and administrative controls of the OQAP are applicable to all aging management programs and activities required during the period of extended operation.

19.2.1 ACCW SYSTEM CARBON STEEL COMPONENTS PROGRAM

The Auxiliary Component Cooling Water (ACCW) System Carbon Steel Components Program is a plant-specific program that manages cracking of carbon steel components exposed to ACCW through a combination of leakage monitoring and routine and periodic inspections. This includes the Units 1 and 2 ACCW systems, as well as carbon steel components serviced by these ACCW systems. The program is in response to operating experience related to nitrite-induced stress corrosion cracking (SCC) and subsequent component leakage in ACCW system components.

The program relies upon leakage detection monitoring, routine walkdowns, and periodic visual examinations. The program also includes preventive measures applicable to repairs and modifications intended to minimize crack initiation sites, lower stresses, and improve inspectability.

The ACCW System Carbon Steel Components Program will be implemented prior to the period of extended operation.

19.2.2 BOLTING INTEGRITY PROGRAM

The Bolting Integrity Program is a plant-specific program that manages cracking, loss of material, and loss of preload in mechanical bolted closures. The Bolting Integrity Program applies to safety-related and nonsafety-related bolting for pressure-retaining components within the scope of license renewal, with the exception of the reactor vessel head studs which are addressed by the Reactor Vessel Head Closure Stud Program.

Preventive aspects of the program include use of appropriate bolting and torquing practices, including control of thread lubricants. Periodic replacement of steam generator manway and handhole bolting is also included in the scope of the program as a preventive measure for managing cumulative fatigue damage for these fasteners. The program’s bolting and torquing practices are based on industry guidelines, vendor recommendations, and VEGP operating experience, as appropriate for VEGP applications. Consistent with NUREG-1339 recommendations, the use of lubricants containing molybdenum disulfide, which has been specifically implicated in SCC of bolting, is prohibited by the program.

The program also includes periodic inspection of closure bolting assemblies to detect signs of leakage that may be indicative of loss of preload, loss of material, or cracking. Periodic inspection of bolted closures in conjunction with the Inservice Inspection Program and External Surfaces Monitoring Program will detect the effects of aging and joint leakage. Operator rounds and system walkdowns also identify joint leakage.

19.2.3 BORIC ACID CORROSION CONTROL PROGRAM

The Boric Acid Corrosion Control Program monitors the condition of components on which borated water may leak to ensure that borated water leakage and associated boric acid residue are identified, evaluated, and removed before any loss of intended function of affected components. The program detects boric acid leakage by periodic visual inspection of systems containing borated water for evidence of leakage and by inspection of adjacent structures and components for evidence of leakage. The program was developed in response to the recommendations of Generic Letter 88-05 and addresses operating experience contained in recent NRC generic communications.

Prior to the period of extended operation, VEGP will enhance the Boric Acid Corrosion Control Program to address the effects of borated water leakage on materials other than steels, including electrical components (e.g., electrical connectors), that are susceptible to boric acid corrosion.

19.2.4 BURIED PIPING AND TANKS INSPECTION PROGRAM

The Buried Piping and Tanks Inspection Program manages loss of material from the external surfaces of buried carbon steel, cast iron, and stainless steel components. The program includes both preventive measures and visual inspections. Preventive measures consist of coatings and wrappings which are required by design in accordance with industry standards. Buried components in the scope of license renewal will be inspected when they are excavated for maintenance or when exposed for any other reason.

Prior to entering the period of extended operation, a review will be performed to determine if at least one opportunistic or focused inspection of buried piping and tanks has been performed within the 10-year period prior to the period of extended operation. If an inspection did not occur, a focused inspection will be performed prior to the period of extended operation.

In addition, a focused inspection of buried piping and tanks will be performed within 10 years after entering the period of extended operation, unless an engineering evaluation concludes that sufficient opportunistic and focused inspections have occurred during this time to demonstrate the ability of the underground coatings to protect the underground piping and tanks from degradation.

The Buried Piping and Tanks Inspection Program will be implemented prior to the period of extended operation.

19.2.5 CASS RCS FITTING EVALUATION PROGRAM

The Cast Austenitic Stainless Steel (CASS) Reactor Coolant System (RCS) Fitting Evaluation Program manages the effects of loss of fracture toughness due to thermal aging for susceptible CASS components in the RCS. This program augments VEGP Inservice Inspection Program requirements.

This aging management program evaluates the susceptibility of CASS components to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite. Screening for susceptibility to thermal aging is not required for pump casings and valve bodies, based on the assessment documented in the letter dated May 19, 2000, from Christopher Grimes, Nuclear Regulatory Commission (NRC), to Douglas Walters, Nuclear Energy Institute (NEI), ADAMS Accession No. ML003717179. The existing ASME Section XI inspection requirements, including the alternative requirements of ASME Code Case N-481 for pump casings, are adequate for all pump casings and valve bodies.

The program provides aging management through either a flaw tolerance evaluation or enhanced volumetric examination. Additional inspection or evaluations to demonstrate that the material has adequate fracture toughness are not required for components that are not susceptible to thermal aging embrittlement.

Based on screening consistent with the process specified in NUREG-1801, Rev. 1, Section XI.M12, the VEGP components that require additional aging management under this program are the VEGP Unit 1 Loop 4 and Unit 2 Loop 1 RCP inlet elbows. For these two casings, loss of fracture toughness due to thermal aging will be managed by component-specific flaw tolerance evaluation, additional inspections, or a combination of these techniques.

The CASS RCS Fitting Evaluation Program will be implemented prior to the period of extended operation.

19.2.6 CLOSED COOLING WATER PROGRAM

The Closed Cooling Water (CCW) Program manages loss of material, cracking, and reduction of heat transfer in closed-cycle cooling water systems and the components cooled by these systems. The program is based on the EPRI CCW chemistry guidelines.

The program includes maintenance of corrosion inhibitor, pH buffering agent, and biocide concentrations. Concentrations of detrimental ionic species are monitored and reduced if necessary. Important diagnostic parameters are monitored and evaluated for significant trends. The program also uses corrosion-monitoring activities including trending of iron and copper concentrations and component inspections. Corrosion rate monitoring methods may also be used.

Prior to the period of extended operation, VEGP will enhance the CCW Program to indicate the components in each system that are most susceptible to various corrosion mechanisms and to ensure that corrosion monitoring is appropriately accomplished. This qualitative assessment will be based on an understanding of corrosion principles associated with CCW chemistries and on review of system, plant, and industry operating experience. Parameters considered in the review will include system flow parameters (focusing on identification of stagnant regions and on intermittently operated systems), normal operating temperatures, and component geometries (e.g., creviced areas).

19.2.7 DIESEL FUEL OIL PROGRAM

The Diesel Fuel Oil Program is a plant-specific program that manages loss of material in the diesel fuel oil systems for the emergency diesel generators and the diesel engine-driven fire water pumps through monitoring and maintenance of diesel fuel oil quality. The program is based on VEGP Technical Specifications requirements and supplemental requirements. Draining, cleaning, and internal condition inspections of diesel fuel oil components are implemented under other VEGP aging management programs as noted below.

- Periodic cleaning and inspection of the interior of the EDG system's diesel fuel oil storage tanks is performed under the Periodic Surveillance and Preventive Maintenance Program.

- Visual inspection of the diesel engine-driven fire water pumps fuel supply lines for leakage during diesel operation is performed under the Fire Protection Program.

- The One-Time Inspection Program describes inspections to verify the effectiveness of the Diesel Fuel Oil Program. The inspections include thickness measurements of storage tank bottom surfaces to verify that significant degradation of the tank base material is not occurring.

19.2.8 EXTERNAL SURFACES MONITORING PROGRAM

The External Surfaces Monitoring Program inspects external surfaces of mechanical system components requiring aging management for license renewal in external air environments. Surfaces constructed from materials susceptible to aging in these environments are inspected at frequencies that assure the effects of aging are managed such that system components will perform their intended function during the period of extended operation.

The program detects corrosion, flange leakage, missing or damaged insulation, damaged coatings, and indications of fretting or wear. Inspections of insulated surfaces are performed on a sampling basis, targeting areas identified by baseline inspections and operating experience as most susceptible. Accessible polymers and elastomers are also inspected.

Systems and components which are normally inaccessible and therefore not readily available for inspection are inspected when they are made accessible during outages or routine maintenance or repair or they may be inspected by remote means.

The External Surfaces Monitoring Program will be implemented prior to the period of extended operation.

SNC will perform an inspection of an emergency diesel generator fuel oil day tank vent line. This inspection will determine whether a debris screen is installed on the open end of the vent line. If a screen is installed, the inspection will further determine the material of construction of the debris screen.

19.2.9 FIRE PROTECTION PROGRAM

The Fire Protection Program includes inspections, performance testing, and condition monitoring of water- and gas-based fire protection systems, fire barriers, and fire pump diesels and their fuel oil supply components. The program manages fire protection components relied upon for 10 CFR 50.48 compliance such that the intended functions will be maintained through the period of extended operation.

The water-based and gas-based fire suppression systems are tested and inspected in accordance with plant procedures based, in part, on the applicable National Fire Protection Association codes and standards. Periodic inspections, performance testing, and system monitoring provide an effective means to assure functionality of these components.

Diesel-driven fire pumps and fuel oil supply components are periodically inspected and tested to ensure that the diesels, pumps, and fuel oil supply components can perform their intended functions.

The fire barrier inspections include periodic visual inspection of structural fire barriers, including fire walls, floors, ceilings, fire penetration seals, and fire doors.

VEGP will implement the following enhancements to the Fire Protection Program:

- Wall thickness evaluations will be performed on water suppression piping systems using nonintrusive volumetric testing or visual inspections to ensure that wall thicknesses are within acceptable limits. Initial wall thickness evaluations will be performed before the end of the current operating term. Subsequent evaluations will be performed at plant-specific intervals during the period of extended operation. The plant-specific inspection intervals will be determined based on previous evaluations and site operating experience.

- A sample of sprinkler heads will be inspected using the guidance of NFPA 25 “Inspection, Testing and Maintenance of Water-Based Fire Protection Systems” (1998 Edition), Section 2-3.1.1 or NFPA 25 (2002 Edition), Section 5.3.1.1.1. Where sprinkler heads have been in service for 50 years, they will be replaced or representative samples from one or more sample areas will be submitted to a recognized testing laboratory for field service testing. This sampling will be performed every 10 years after the initial field service testing. The 50 years of time in service begins when the system was placed in service, not when the plant became operational.

- Prior to the period of extended operation, Fire Protection Program procedures will be revised to provide more detailed instructions for visual inspection of fire pump diesel fuel supply lines for leakage, corrosion, and general degradation while the engine is running during fire suppression system pump tests.

19.2.10 FLOW-ACCELERATED CORROSION PROGRAM

The Flow-Accelerated Corrosion (FAC) Program manages loss of material (wall thinning) due to FAC in susceptible plant piping and other components. The FAC Program is based on the guidance of NSAC-202L-R2, “Recommendations for an Effective Flow-Accelerated Corrosion Program,” including subsequent revisions. The program includes analysis to determine susceptible locations, predictive modeling techniques, baseline inspections of wall thickness, followup inspections, and repair or replacement of degraded components as necessary.

VEGP also uses the FAC Program and its inspection techniques to manage wall thinning that is occurring in piping components downstream of the steam generator blowdown demineralizers. The wall thinning has been attributed to the acidic conditions of the demineralizer effluent, not FAC.

19.2.11 FLUX THIMBLE TUBE INSPECTION PROGRAM

The Flux Thimble Tube Inspection Program manages loss of material due to fretting/wear of the incore flux detector thimble tubes. The program implements the VEGP response to NRC Bulletin No. 88-09, “Thimble Tube Thinning in Westinghouse Reactors.” The program uses proven nondestructive examination techniques to monitor for wear of the flux thimble tubes.

Wear rate predictions determine the need for corrective actions such as repositioning, capping, or replacement of a flux thimble tube. The wear-rate predictions are also used to establish the interval to the next inspection.

Prior to the period of extended operation, a VEGP program procedure will be issued documenting the Flux Thimble Tube Inspection Program administration and implementing activities credited for license renewal.

19.2.12 GENERIC LETTER 89-13 PROGRAM

The Generic Letter 89-13 Program includes the activities which implement the VEGP response to the NRC recommended actions contained in Generic Letter (GL) 89-13, “Service Water System Problems Affecting Safety-Related Equipment.” The Generic Letter 89-13 Program activities include mitigation, as well as performance and condition monitoring techniques, to ensure that the effects of aging on the Nuclear Service Cooling Water (NSCW) system, and on those components supplied by the NSCW system will be managed.

Prevention or mitigation of fouling and loss of material in the NSCW system and NSCW supplied components is accomplished, in part, by intermittent injection of appropriate water treatment chemicals. Other preventive and monitoring aspects of the VEGP Generic Letter 89-13 Program include periodic flushing of lines to mitigate or prevent fouling, periodic measurement of flow rates through selected components, periodic analysis of corrosion coupons, and cleaning of selected heat exchangers at regular intervals. Some components are visually inspected for fouling or loss of material. Volumetric examination may be used to detect degradation.

Prior to the period of extended operation, VEGP will implement the following enhancements to the Generic Letter 89-13 Program:

- An overall program procedure will be prepared which describes the various program activities that comprise the Generic Letter 89-13 Program and their implementing controls such as chemistry procedures, maintenance activities, scheduled surveillances, or other mechanisms.

- The VEGP Generic Letter 89-13 Program activities will include inspection of the NSCW transfer pumps’ casings and bolting and NSCW cooling tower spray nozzles.

19.2.13 INSERVICE INSPECTION PROGRAM

The VEGP Inservice Inspection Program is a plant-specific program that mandates examinations, testing, and inspections of components and systems to detect deterioration and manage aging effects. The program uses periodic visual, surface, and volumetric examination and leakage tests of Class 1, 2, and 3 pressure-retaining components, their integral attachments, and supports to detect and characterize flaws.

The program is implemented in accordance with 10 CFR 50.55(a), which imposes the inservice inspection requirements of ASME Section XI for Class 1, 2, and 3 pressure-retaining components, their integral attachments, and supports. Inspection, repair, and replacement of these components are covered in Subsections IWB, IWC, IWD, and IWF, respectively.

In conformance with 10 CFR 50.55a(g)(4)(ii), and as based on ASME Inservice Inspection Program B (IWA-2432), the VEGP Inservice Inspection Program is updated at the end of each inspection interval to the latest edition and addenda of the Code specified in 10 CFR 50.55a, 12 months before the start of the inspection interval.

19.2.14 NICKEL ALLOY MANAGEMENT PROGRAM FOR NONREACTOR VESSEL CLOSURE HEAD PENETRATION LOCATIONS

The Nickel Alloy Management Program for Nonreactor Vessel Closure Head Penetration Locations is a plant-specific program that manages cracking due to primary water stress corrosion cracking (PWSCC) for nonreactor vessel head nickel alloy component locations. The overall goal of the program is to maintain plant safety and minimize the impact of PWSCC on plant availability through assessment, inspection, mitigation, and repair or replacement of susceptible components. Program development is based on MRP-126, “Generic Guidance for Alloy 600 Management.”

The program is based on the following set of implementation commitments:

1. SNC will continue to participate in industry initiatives directed at resolving PWSCC issues, such as owners’ group programs and the EPRI Materials Reliability Program.
2. SNC will comply with applicable NRC orders.
3. SNC will submit a program inspection plan for VEGP that includes implementation of applicable NRC bulletins, generic letters, and staff-accepted industry guidance. The inspection plan will be submitted to the staff for review and approval not less than 24 months prior to entering the period of extended operation for VEGP Units 1 and 2. The inspection plan will include assessments of each of the 10 aging management program elements defined in Section A.1.2.3 of NUREG-1800, Revision 1.

Nickel Alloy Management Program for Nonreactor Vessel Closure Head Penetration Locations will be fully implemented prior to the period of extended operation.

19.2.15 NICKEL ALLOY MANAGEMENT PROGRAM FOR REACTOR VESSEL CLOSURE HEAD PENETRATIONS

The Nickel Alloy Management Program for Reactor Vessel Closure Head Penetrations addresses industry concerns regarding the potential for PWSCC in nickel alloy components exposed to the reactor coolant environment. The program is based upon the requirements of NRC First Revised Order EA-03-009, which establishes requirements for susceptibility ranking and inspections. Susceptibility ranking is based on calculated effective degradation years and the results of previous inspection findings. Inspection frequencies are determined by the susceptibility category. Inspections to detect cracking include bare metal visual examinations and nonvisual techniques.

The program implements commitments for reactor vessel closure head penetrations associated with nickel alloys from NRC orders, bulletins, and generic letters and staff-accepted industry guidelines.

19.2.16 OIL ANALYSIS PROGRAM

The VEGP Oil Analysis Program ensures that the lubricating oil and hydraulic fluid environments of in-scope mechanical systems are maintained to the required quality. The Oil Analysis Program maintains lubricating oil and hydraulic fluid system contaminants (primarily water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to deleterious aging effects. Program activities include sampling and analysis of lubricating oil and hydraulic fluid for detrimental contaminants.

The One-Time Inspection Program includes inspections planned to verify the effectiveness of the Oil Analysis Program.

Prior to the period of extended operation, VEGP will implement the following enhancements to the Oil Analysis Program:

- An overall program procedure or guideline will be prepared to formalize the sampling and analysis activities performed.

- Viscosity, relative level of oxidation, and flashpoint of lubricating oil samples will be determined for components where the lubricating oil is changed based on its analyzed condition (instead of being changed on a regular schedule regardless of condition). The relative level of oxidation of the lubricating oil will be monitored by analysis of the neutralization number or other appropriate parameters(s). Flashpoint monitoring will be performed for those components which have the potential for contamination of the lubricating oil with a light hydrocarbon such as fuel oil.

- When a lubricating oil sample’s wear metal content screening results exceed the limits established for the wear metal content screening, the lubricating oil from that component will be subjected to additional testing. The additional testing may include detailed particle counting, elemental analysis, or analytical ferrography as necessary to validate the initial screening results and to diagnose the source of the particulates.

19.2.17 ONE-TIME INSPECTION PROGRAM

The VEGP One-Time Inspection Program provides objective evidence that an aging effect is not occurring, or that the aging effect is occurring slowly enough to not affect the component or structure intended function during the period of extended operation, and therefore will not require additional aging management.

The program uses one-time inspections of plant piping and components to verify the effectiveness of aging management programs or to confirm the insignificance of potential aging effects where:

a. An aging effect is not expected to occur but there is insufficient data to rule it out with reasonable confidence,

b. An aging effect is expected to progress very slowly in a specified environment, but localized conditions may be more adverse than specified, or

c. The characteristics of the aging effect include a long incubation period relative to the operating life of the plant.

The inspections will be performed within a window of 10 years immediately preceding the period of extended operation.

The inspections will include a baseline and a followup inspection of the effectiveness of the Boral™ neutron-absorbing panels credited in the criticality analysis for the Unit 1 spent fuel storage racks to provide reasonable assurance that the panels will continue to perform their reactivity control function during the period of extended operation. The baseline inspection will be performed within a window of 10 years immediately preceding the period of extended operation. The followup inspection will be performed at a date to be determined based on the results of the baseline inspection and relevant industry guidance, not to exceed 10 years after the baseline inspection.

19.2.18 ONE-TIME INSPECTION PROGRAM FOR ASME CLASS 1 SMALL BORE PIPING

The VEGP One-Time Inspection Program for ASME Class 1 Small Bore Piping addresses NRC concerns on the potential for cracking of Class 1 piping with a diameter less than NPS 4.

To address SCC concerns, volumetric examination of a sample population of ASME Class 1 Piping butt welds less than NPS 4 will be performed. Examination locations will be selected using a risk-based approach that will consider susceptibility, inspectability, dose, and operating experience.

To address unanticipated thermal fatigue cracking of ASME Class 1 piping less than NPS 4, VEGP will screen and evaluate pipe lines using MRP-146, “Management of Thermal Fatigue in Normally Stagnant Nonisolable Reactor Coolant System Branch Lines,” or later updated guidance. Small bore piping inspections will be performed to detect thermal fatigue only at piping locations that fail screening and are not monitored for thermal cycling.

Examinations performed by the program may be incorporated into an NRC-approved Risk-Informed Inservice Inspection Program. The inspections will be performed within a window of 10 years immediately preceding the period of extended operation.

19.2.19 ONE-TIME INSPECTION PROGRAM FOR SELECTIVE LEACHING

The VEGP One-Time Inspection Program for Selective Leaching addresses selective leaching in susceptible cast iron and copper alloy components. The program includes a one-time examination of a sample population of components most likely to exhibit selective leaching. Initial examinations will be completed prior to entering the period of extended operation. If degradation due to selective leaching is identified, additional examinations will be performed.

Examination techniques may include hardness measurement (where feasible-based on form and configuration), visual examination, metallurgical evaluation, or other proven techniques determined to be effective in identifying and assessing the extent of selective leaching.

The inspections will be performed within a window of 10 years immediately preceding the period of extended operation.

19.2.20 OVERHEAD AND REFUELING CRANE INSPECTION PROGRAM

The VEGP Overhead and Refueling Crane Inspection Program manages the effects of general corrosion and wear of the crane bridge and trolley structural girders and beams and the crane rails and support girders in the scope of license renewal.

The Overhead and Refueling Crane Inspection Program is a condition monitoring program that includes the following nuclear safety-related and quality-related material handling systems: refueling machine, fuel handling machine bridge crane, spent fuel cask bridge crane, and the containment building (reactor) polar crane.

Prior to the period of extended operation, VEGP will enhance applicable plant procedures to explicitly identify inspection of crane rails and crane structural components for loss of material due to corrosion and wear and for indication of rail misalignment.

19.2.21 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE ACTIVITIES

The Periodic Surveillance and Preventive Maintenance Activities is a plant-specific program that includes existing and new periodic inspections and tests that are relied on by license renewal to manage the aging effects applicable to the components included in the program. The Periodic Surveillance and Preventive Maintenance Activities Program is generally implemented through repetitive tasks and surveillances.

Inspection and testing intervals are dependent on the component, material, and environment and take into consideration industry and plant-specific operating experience and manufacturer's recommendations.

The extent and schedule of inspections and testing assure detection of component degradation prior to loss of intended functions. Established techniques such as visual inspections are used. The following existing surveillance and maintenance activities are credited for license renewal:

- Control building control room filter unit seal inspections.
- Emergency diesel generator (EDG) diesel fuel oil storage tank cleaning and inspections.
- Steam generator blowdown trim heat exchanger inspections.
- NSCW cooling tower fill and drift eliminator testing.
- Diaphragm inspections for the boric acid storage tank, condensate storage tank, and reactor makeup water storage tank.

Prior to the period of extended operation, VEGP will enhance the Periodic Surveillance and Preventive Maintenance Activities to include the following additional surveillance and maintenance activities:

- Steam generator blowdown secondary sample bath shell inspections.

- Steam generator blowdown corrosion product monitor cooler shell inspections.
- Potable water system water heater housing inspections (for the in-scope water heaters).

19.2.22 PIPING AND DUCT INTERNAL INSPECTION PROGRAM

The VEGP Piping and Duct Internal Inspection Program manages corrosion of steel, stainless steel, and copper alloy components and degradation of elastomer components due to changes in material properties. Inspections are normally performed concurrent with scheduled preventive maintenance, surveillance testing, and corrective maintenance activities. Specific examinations not coordinated with existing work activities may also be performed at the discretion of the program owner. Inspection locations and intervals are dependent on assessments of the likelihood of significant degradation and on current industry and plant-specific operating experiences.

Examination techniques will be appropriate to detect and assess the aging mechanism of concern and may include visual examination, nonvisual NDE such as ultrasonic testing or radiography, physical manipulation of elastomers, etc.

The Piping and Duct Internal Inspection Program will be implemented prior to the period of extended operation.

19.2.23 REACTOR VESSEL CLOSURE HEAD STUD PROGRAM

The VEGP Reactor Vessel Closure Head Stud Program provides direction for loss of material and cracking in the reactor vessel closure head studs, nuts, and washers. Program aspects include preventive measures, as described in Regulatory Guide 1.65, and condition monitoring.

Preventive measures include material controls and the use of approved lubricants. The VEGP reactor vessel head studs are fabricated from modified SA-540 Grade B24 material as specified in ASME Boiler and Pressure Vessel Code case 1605. This Code case is not specified in Regulatory Guide 1.65 but has been approved by the NRC via Regulatory Guide 1.85. VEGP actual stud material properties have ultimate tensile strengths less than 170 ksi. Reactor vessel closure head studs and nuts are lubricated with an approved, stable lubricant at each reassembly.

Condition monitoring includes examination and leakage detection consistent with the VEGP Inservice Inspection Program.

19.2.24 REACTOR VESSEL INTERNALS PROGRAM

The Reactor Vessel Internals Program is a plant-specific program that addresses material degradation issues for the VEGP reactor vessel internals.

The program will be based on the following set of implementation commitments:

a. SNC will participate in the industry program for investigating and managing aging effects on reactor vessel internals.

b. SNC will evaluate and implement the results of the industry programs, such as the EPRI Material Reliability Program (MRP), as applicable to the VEGP reactor vessel internals.

c. SNC will submit an inspection plan for the VEGP reactor vessel internals to the NRC for review and approval not less than 24 months before entering the period of extended operation for VEGP Units 1 and 2. This inspection plan will address the bases, inspection methods, and acceptance criteria associated with aging management of the reactor vessel thermal sleeves and the core support lugs (along with the associated support pads and attachment welds).

The Reactor Vessel Internals Program will be implemented prior to the period of extended operation.

19.2.25 REACTOR VESSEL SURVEILLANCE PROGRAM

The Reactor Vessel Surveillance Program manages loss of fracture toughness due to neutron embrittlement in reactor vessel alloy steel materials exposed to neutron fluence exceeding 1 x 10^{17} n/cm^2 (E > 1.0 MeV). The program is based on 10 CFR 50, Appendix H, “Reactor Vessel Material Surveillance Requirements,” and ASTM E 185-82, “Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels.”

Capsules are periodically removed during the course of plant operating life. Neutron embrittlement is evaluated through surveillance capsule testing and evaluation, fluence calculations and benchmarking, and monitoring of effective full power years (EFPYs).

For both the VEGP Unit 1 and 2 reactor vessels, capsules with accumulated neutron fluence equivalent to 60 years of operation have already been pulled and tested. The remaining capsules (2 capsules in each unit) will be removed such that, at the time of removal, each of the remaining capsules will have accumulated neutron fluence that is not less than once, nor greater than twice, the peak end of life fluence expected for an additional 20-year license renewal term (80 years of operation).

The Reactor Vessel Surveillance Program will be enhanced as follows:

1. Prior to removal of the last surveillance capsule in each unit, program documents will be revised to require that tested and untested specimens from all capsules removed from the VEGP reactor vessels remain in storage.
2. Alternate dosimetry will be installed to monitor neutron fluence on the reactor vessel after removal of the last surveillance capsule in that unit. This enhancement will be implemented prior to removal of the last surveillance capsule in each unit.

19.2.26 STEAM GENERATOR TUBING INTEGRITY PROGRAM

The Steam Generator Tubing Integrity Program is a subprogram of the Steam Generator Program, which is an integrated program for managing the condition of the VEGP steam generators. The program focuses on steam generator tube integrity, tube planning, and the management and repair of steam generator tubing. The Steam Generator Program is in compliance with the program described in NEI 97-06, Steam Generator Program Guidelines, and VEGP Technical Specifications, subsection 5.5.9. Program deviations from NEI 97-06 are prepared and approved in accordance with NEI 97-06 and EPRI steam generator management program guidance.

The program includes a balance of prevention, inspection, evaluation and repair, and leakage monitoring. Major program elements include degradation assessments, inspection, integrity assessments, leakage monitoring, and chemistry controls.

19.2.27 STEAM GENERATOR PROGRAM FOR UPPER INTERNALS

The Steam Generator Program for Upper Internals is a plant-specific subprogram of the VEGP Steam Generator Program, which is an integrated program for managing the condition of the steam generators. The Steam Generator Program is in compliance with the program described in NEI 97-06, Steam Generator Program Guidelines.

The Steam Generator Program for Upper Internals includes VEGP Steam Generator Program activities associated with aging management of the steam generator upper internals components determined to be within the scope of license renewal. The program implements inspection activities intended to detect degradation of secondary side internals needed to maintain tubing integrity and accomplish steam generator intended functions. An assessment based upon steam generator design, potential degradation mechanisms, and related VEGP and industry operating experience is performed to establish inspection requirements for secondary side internals components. The resulting inspection requirements are incorporated into the steam generator inspection plans.

19.2.28 WATER CHEMISTRY CONTROL PROGRAM

The VEGP Water Chemistry Control Program mitigates loss of material, cracking, and reduction of heat transfer in system components and structures through the control of water chemistry. The program includes control of detrimental chemical species and the addition of chemical agents.

The VEGP Water Chemistry Control Program is based on the EPRI water chemistry guidelines for primary and secondary water chemistry control.

The One-Time Inspection Program includes inspections to verify the effectiveness of the Water Chemistry Control Program.

VEGP will monitor spent fuel pool aluminum concentrations to ensure the Boral spent fuel racks will continue to perform their intended function during the period of extended operation. If adverse trends are identified, SNC will implement corrective actions. Additionally, SNC will monitor industry experience related to Boral and will take appropriate actions if significant degradation of Boral is identified.

19.2.29 10 CFR 50 APPENDIX J PROGRAM

The 10 CFR 50 Appendix J Program monitors leakage rates through the containment pressure boundary, including penetrations and access openings. Containment leak rate tests assure that leakage through the primary containment and systems and components penetrating primary containment does not exceed the allowable leakage limits specified within the VEGP Technical Specifications. Corrective actions are taken if leakage rates exceed established administrative limits for individual penetrations or the overall containment pressure boundary.

19.2.30 INSERVICE INSPECTION PROGRAM – IWE

The VEGP Inservice Inspection Program – IWE is a plant-specific program implemented in accordance with 10 CFR 50.55(a), which imposes the inservice inspection requirements of ASME Section XI, Subsection IWE. The program manages aging effects for the containment liners and its integral attachments including connecting penetrations and parts forming the leaktight boundary. The primary inspection method for the program is periodic visual examination along with limited volumetric examinations utilizing ultrasonic thickness measurements as needed.

In conformance with 10 CFR 50.55a(g)(4)(ii) and as based on ASME Inservice Inspection Program B (IWA-2432), the VEGP Inservice Inspection Program – IWE is updated at the end of each 120-month inspection interval to the latest edition and addenda of the Code specified in 10 CFR 50.55a, 12 months before the start of the inspection interval.

Prior to the period of extended operation, the VEGP Inservice Inspection Program – IWE will be revised to provide more explicit direction to the registered professional engineer for trending and evaluating conditions identified during visual examinations.

19.2.31 INSERVICE INSPECTION PROGRAM – IWL

The VEGP Inservice Inspection Program – IWL is a plant-specific program implemented in accordance with 10 CFR 50.55(a), which imposes the inservice inspection requirements of ASME Section XI Subsection IWL, except where an exemption, relief, or an alternative has been authorized by the NRC, for Class CC components. The program manages the reinforced concrete and unbonded post-tensioning systems of the containment structures.

In conformance with 10 CFR 50.55a(g)(4)(ii) and as based on ASME Inservice Inspection Program B (IWA-2432), the VEGP Inservice Inspection Program – IWL is updated at the end of each 120-month inspection interval to the latest edition and addenda of the Code specified in 10 CFR 50.55a, 12 months before the start of the inspection interval.

Prior to the period of extended operation, the VEGP Inservice Inspection Program – IWL will be revised to provide more explicit direction to the registered professional engineer for trending and evaluating conditions identified during concrete visual examinations.

19.2.32 STRUCTURAL MONITORING PROGRAM

The VEGP Structural Monitoring Program is based on the requirements and guidance set forth in 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” and Regulatory Guide 1.160, Rev. 2, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” VEGP uses the Structural Monitoring Program to monitor the condition of structures and structural components within the scope of the Maintenance Rule, thereby providing reasonable assurance that there is no loss of structure or structural component intended function.

Prior to the period of extended operation, VEGP will implement the following enhancements to the Structural Monitoring Program:

- The scope of the Structural Monitoring Program will be expanded to include the additional structures that require monitoring for license renewal.

- The scope of inspection for structures that require monitoring for license renewal will be clarified. An area-based inspection will be performed unless a detailed inspection scope is provided.

- The Structural Monitoring Program scope for hangers and supports will be clarified.

- Program requirements will be revised to include periodic groundwater monitoring to confirm that groundwater chemistry remains nonaggressive as defined in NUREG 1801.

- Underwater inspection of the NSCW cooling tower basins, including appropriate inspection and acceptance criteria, will be added to the Structural Monitoring Program.

- Guidance will be given regarding proper documentation of condition adverse to quality and its probable causes for any CR written against a finding during Structural Monitoring Program walkdown.

- For any finding (e.g., crack, leakage, etc.) guidance will be given for data to be collected and evaluated.

- More explicit direction will be given for trending of the problems.

19.2.33 STRUCTURAL MONITORING PROGRAM – MASONRY WALLS

The Structural Monitoring Program – Masonry Walls is part of the VEGP Structural Monitoring Program that implements structures monitoring requirements as specified by 10 CFR 50.65. The Masonry Wall Program manages aging of masonry walls, and structural steel restraint systems of the masonry walls, within scope of license renewal. The program includes the concrete masonry units and restraint systems used to seal and provide radiation shielding of some access openings in the Seismic Category I structures.

The program contains inspection guidelines and lists attributes that cause aging of masonry walls, which are to be monitored during structural monitoring inspections, as well as establishes examination criteria, evaluation requirements, and acceptance criteria.

The Structural Monitoring Program – Masonry Walls will be enhanced prior to the period of extended operation to include monitoring of masonry walls in the structures which are in scope for license renewal but are not currently monitored under the program.

19.2.34 NON-EQ CABLES AND CONNECTIONS PROGRAM

The Non-EQ Cables and Connections Program will be used to maintain the function of electrical cables and connections, which are not subject to the environmental qualification requirements of 10 CFR 50.49, but are exposed to adverse localized environments caused by heat, radiation, or moisture. An adverse localized environment is an environment that is significantly more severe than the service condition for the insulated cable or connection.

A representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, and cracking. The technical basis for the sample selections of cables and connections to be inspected is provided. The scope of this sampling program includes electrical cables and connections in adverse localized environments.

The Non-EQ Cables and Connections Program will be implemented and the first inspection completed prior to the period of extended operation.

19.2.35 NON-EQ INACCESSIBLE MEDIUM-VOLTAGE CABLES PROGRAM

The Non-EQ Inaccessible Medium-Voltage Cables Program manages the aging effects for inaccessible medium-voltage cables (cables with operating voltage from 2 kV to 35 kV) in the scope of license renewal exposed to significant moisture and voltage. The aging effect of concern is “localized damage and breakdown of insulation.” The program includes periodic inspection and removal of water accumulation in cable manholes and periodic cable testing.

Manholes which retain water and contain medium-voltage cables in the scope of license renewal are periodically inspected for water collection and the accumulated water removed, as needed. The frequency of inspection is based on actual plant-experience but at least once every 2 years.

In-scope medium-voltage cables exposed to significant moisture and voltage are tested at least once every 10 years to provide an indication of the condition of the conductor insulation. The specific test performed is a proven test for detecting deterioration of the insulation system due to wetting.

The Non-EQ Inaccessible Medium-Voltage Cables Program will be implemented and the first inspections completed prior to the period of extended operation.

19.2.36 NON-EQ ELECTRICAL CABLE CONNECTIONS ONE-TIME INSPECTION PROGRAM

The Non-EQ Cable Connections One-Time Inspection Program is a plant-specific program that performs one-time inspections on a sample of bolted connections in the scope of license renewal to confirm that loosening of electrical connections is not an aging effect requiring additional aging management during the period of extended operation. The program inspects for loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation.

The factors considered for sample selection are application (medium and low voltage, defined as < 35 kV), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selections will be documented. Inspection methods may include thermography, contact resistance testing, or appropriate methods including visual inspection based on plant configuration and industry guidance.

The inspections will be performed within a window of 10 years immediately preceding the period of extended operation.

19.2.37 REFERENCES

1. NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, U. S. Nuclear Regulatory Commission, (Rev. 1), September 2005.
2. NUREG-1801, Generic Aging Lessons Learned (GALL) Report, U. S. Nuclear Regulatory Commission, (Rev. 1), September 2005.
3. Vogtle Electric Generating Plant Technical Specifications, Units 1 and 2.

19.3 AGING MANAGEMENT PROGRAMS – TIME LIMITED AGING ANALYSES (TLAA)

19.3.1 ENVIRONMENTAL QUALIFICATION PROGRAM

The Environmental Qualification (EQ) Program implements the requirements of 10 CFR 50.49. The EQ Program has been established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety functions in those harsh environments, consistent with 10 CFR 50.49 requirements. The EQ Program manages component thermal, radiation, and cyclical aging, as applicable, through the use of aging evaluations. The program requires action be taken before individual components in the scope of the program exceed their qualified life. Actions taken include replacement on a specified time interval of piece parts or complete components to maintain qualification and reanalysis.

As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Some aging evaluations for EQ components specify a qualification of at least 40 years and are considered TLAAs for license renewal. The EQ Program ensures that these EQ components are maintained within the bounds of their qualification bases.

19.3.2 FATIGUE MONITORING PROGRAM

The VEGP Fatigue Monitoring Program consists of two existing programs, which are the Fatigue and Cycle Monitoring Program and Thermal Stratification Data Collection. The Fatigue and Cycle Monitoring Program, also known as the VEGP Component or Cyclic Transient Limit Program (CCTLP), is described in subsection 5.5.5 of the Technical Specifications. This program provides controls to track the transient cycles to ensure that components are maintained within the design limit. The component cyclic or transient limits are provided in VEGP UFSAR paragraph 3.9.N.1. The Thermal Stratification Data Collection Program monitors for adverse thermal stratification and cycling resulting from isolation valve leakage in the normally stagnant nonisolable reactor coolant system (RCS) branch lines identified in the VEGP response to IEB 88-08. The VEGP Fatigue Monitoring Program uses a combination of cycle counting, cycle-based fatigue monitoring, and stress-based fatigue monitoring to monitor and track fatigue usage.

At least 2 years prior to the period of extended operation, the Fatigue Monitoring Program will be enhanced as follows:

1. Implementing documents will be revised to address the effect of the full structural weld overlays applied to the pressurizer spray and surge nozzles on the stress-based module calculation of cumulative usage factor (CUF).
2. The VEGP UFSAR will be revised to require fatigue monitoring of the accumulator/reactor heat removal (RHR) nozzles and pressurizer heater penetrations.
3. Implementing documents will be revised to reduce acceptable CUF values to account for environmental fatigue effects for those NUREG-6260 locations monitored for fatigue.

4. Implementing documents will be revised to explicitly require that the corrective actions initiated for exceeding an acceptance criterion include a review to identify and assess any additional affected reactor coolant pressure boundary locations.
5. SNC will revise the FatiguePro software to calculate a minimum projected value of 1 for any events that may potentially occur.
6. SNC will revise the FatiguePro initial CUF values for the Unit 1 and Unit 2 hot leg surge nozzles, pressurizer surge nozzles, and pressurizer heater penetrations to double the current values and recalculate the current and projected CUFs.
7. SNC will implement a fatigue management software program that uses six stress components in the stress-based fatigue calculation. The software will be appropriately benchmarked against an ASME NB-3200 fatigue analysis, and the stress-based fatigue monitoring locations will be modeled with the as-built configuration. The new software will be used to reproject 60-year CUF values for the monitored locations. When those locations were evaluated for environmental effects on fatigue, the new software will also be used to demonstrate that the environmental effects on fatigue will be adequately managed for those locations during the period of extended operation.

19.3.3 REFERENCES

1. NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, U. S. Nuclear Regulatory Commission (Rev. 1), September 2005.
2. NUREG-1801, Generic Aging Lessons Learned (GALL) Report, U. S. Nuclear Regulatory Commission (Rev. 1), September 2005.
3. Vogtle Electric Generating Plant Technical Specifications, Units 1 and 2.

19.4 EVALUATION OF TIME LIMITED AGING ANALYSES (TLAA)

In accordance with 10 CFR 54.21(c), an application for a renewed operating license must include evaluation of TLAAs for the period of extended operation. This section summarizes the TLAAs identified for VEGP license renewal.

19.4.1 REACTOR VESSEL NEUTRON EMBRITTLEMENT ANALYSES

Analyses associated with embrittlement of reactor vessel materials due to neutron irradiation are TLAAs. The end-of-life (EOL) bases for these analyses are selected to bound the projected effective full-power years (EFPY) for an operating term of 60 years.

The following VEGP analyses are TLAAs that address the effects of neutron embrittlement on the VEGP reactor vessels:

- Neutron fluence.
- Upper-Shelf Energy (USE).
- Pressurized Thermal Shock (PTS).
- Adjusted Reference Temperature (ART).
- Pressure-Temperature (P-T) limits.

19.4.1.1 Neutron Fluence Calculation

The VEGP reactor vessel neutron fluence calculations were projected out to EOL for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii). The reactor vessel neutron fluences, including extended beltline materials, were calculated using a method satisfying the requirements set forth in Regulatory Guide 1.90, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,” Revision 0 (March 2001). These projections are used in the USE, PTS, ART, and P-T analyses described in the sections that follow.

19.4.1.2 Upper-Shelf Energy (USE) Calculation

Charpy impact test upper-shelf absorbed energy (USE) of no less than 50 ft-lbs throughout the life of the reactor vessel, unless an approved analysis supports a lower value.

The VEGP analyses have been projected to the end of the period of extended operation for the reactor vessel materials (base materials and welds) with projected fluence exceeding 1 x 10^{17} n/cm^2 (MeV > 1.0). All Unit 1 and Unit 2 base materials and welds have a USE value at EOL of greater than 50 ft-lbs, which meets the acceptance criteria of 10 CFR 50, Appendix G. Therefore, these TLAAs have been shown to be acceptable for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

19.4.1.3 Pressurized Thermal Shock (PTS) Calculation

The requirements of 10 CFR 50.61 provide for protection against PTS events in pressurized water reactors. The screening criterion in 10 CFR 50.61 is 270°F for plates, forgings, and axial welds and 300°F for circumferential welds. According to this regulation, if the calculated RT_{PTS} for the reactor beltline materials is less than the specified screening criterion, then the vessel is acceptable with regard to the risk of vessel failure during postulated pressurized thermal shock transients.

The RT_{PTS} calculations for VEGP Units 1 and 2 have been projected to the end of the period of extended operation for all reactor vessel materials (base materials and welds) with projected fluence exceeding 1×10^{17} n/cm^2 (MeV > 1.0). All Unit 1 and Unit 2 base materials and welds meet the screening criteria contained in 10 CFR 50.61 at EOL. Therefore, these TLAAs have been shown to be acceptable for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

19.4.1.4 Adjusted Reference Temperature (ART) Calculation

The ART values are an input to the pressure-temperature (P-T) limit curves discussed in the following section. The calculations determining the ART for the critical locations of the reactor vessel meet the definition of the TLAA pursuant to the criteria of 10 CFR 54.3. These ART calculations have been projected through the end of the period of extended operation and the results demonstrate the beltline materials remain limiting, and the projected ART values permit adequate operating margins to P-T limits through the period of extended operation. Therefore, these TLAAs have been shown to be acceptable for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

19.4.1.5 Pressure-Temperature (P-T) Limits Calculation

Appendix G of 10 CFR Part 50 requires heatup and cooldown of the reactor pressure vessel be accomplished within established pressure and temperature limits. Plant-specific calculations establish these limits. The calculations utilize materials and fluence data obtained through plant-specific reactor surveillance capsule programs. The calculations for VEGP Units 1 and 2 meet the definition of a TLAA.

As described in the Pressure Temperature Limits Report (PTLR), the Reactor Vessel Surveillance Program updates the P-T limit curves considering the data gained from examination of surveillance specimens from capsules that SNC pulls. The content and update of the PTLR is in accordance with the requirements of subsection 5.6.6 of the VEGP Technical Specifications. When the operating conditions of each unit merit the use of a difference curve, the PTLR for that unit is updated to include P-T limit curves that bound the current level of neutron embrittlement (i.e., EFPY) for the unit. Therefore, this TLAA demonstration is made in accordance with 10 CFR 54.21(c)(1)(ii) and (iii).

The VEGP PTLR (for each unit) will be updated to address neutron embrittlement for the 60-year operating life prior to the unit entering the period of extended operation.

19.4.2 METAL FATIGUE ANALYSIS

The thermal fatigue analyses of the VEGP mechanical components have been identified as TLAAs.

19.4.2.1 ASME Section III, Class 1 Component Fatigue Analysis

The VEGP design incorporates the requirements of Section III Class 1 of the ASME Code, which requires a discrete analysis of the thermal, mechanical, and dynamic stress cycles on components that make up the reactor coolant pressure boundary. Although original design specifications commonly state that the transient conditions are for a 40-year design life, the fatigue analyses themselves are based on specified numbers of design transients, rather than on a specific operating life. Operating experience at VEGP and similar units has demonstrated that the analyzed numbers of design basis transients are, in general, conservative for a 40-year life. The Fatigue Monitoring Program monitors and tracks the transient cycles.

To address the additional operating term, the VEGP design transient cycles were projected through the period of extended operation. For the feedwater cycling, loss of charging flow, and loss of letdown and return to service transients, VEGP relies on cumulative usage factor (CUF) monitoring of the limiting component locations in lieu of cycle counting. Therefore, the CUFs were projected for these limiting locations in lieu of projecting their transient cycles. These limiting component locations are the steam generator main and auxiliary feedwater nozzles and the normal and alternate charging nozzles. The results of the cycles and CUF projections show that the original transient cycles were conservative and that the design fatigue analyses for Class 1 components and piping remain valid for 60 years.

In addition to the original design transients, fatigue loading transients and issues have been subsequently identified that are not part of the original fatigue analyses. For the pressurizer lower head and surge line, thermal stratification and insurge/outsurge transients are evaluated (IEB 88-11). Also, the impact of the reactor coolant system environment on the fatigue life of piping and components (GSI-190) requires specific evaluation for license renewal.

To address NRC IEB 88-11, the impact of thermal stratification on the fatigue usage in the surge line was evaluated for VEGP. The original evaluation showed that the surge line fatigue usage was acceptable for 40 years of operation, including the effects of thermal stratification due to insurge and outsurges from the pressurizer. For license renewal, stress-based fatigue monitoring is credited for managing the CUF of the surge line, including the effects of pressurizer insurge/outsurge and thermal stratification in both the pressurizer lower head and both surge line nozzles.

Generic Safety Issue (GSI) 190 addresses fatigue life of metal components and was closed by the NRC in December 1999. In the closure letter, however, the NRC concluded that licensees should address the effects of reactor coolant environment on the fatigue life of selected components as aging management programs are formulated in support of license renewal.

The effects of reactor coolant environment on component fatigue life for locations equivalent to those in Section 5.4 of NUREG/CR-6260 for the newer vintage Westinghouse plants have been evaluated for VEGP using the formulas from NUREG/CR-5704 for stainless steel components and from NUREG/CR-6583 for carbon and low-alloy steel components.

For the following locations, the application of the appropriate environmental factors to the design CUF values that were calculated based on the VEGP set of original design transients yielded acceptable results (e.g., CUF < 1.0):

- Reactor vessel shell and lower head.
- Reactor vessel inlet and outlet nozzles.

For the following locations, the application of the appropriate environmental factors to the CUF values that were calculated based on the VEGP set of original design transients yielded unacceptable results without additional management. VEGP manages the environmentally adjusted fatigue CUF values for these locations using fatigue monitoring implemented by the Fatigue Monitoring Program:

- Surge line hot leg nozzle.
- Pressurizer heater penetrations.
- Pressurizer surge line nozzles.
- Charging nozzles.
- Safety injection nozzles.
- Accumulator / RHR nozzles.

NRC Branch Technical Position MEB 3-1 is the basis for the VEGP criteria for the postulation of high-energy line breaks (HELBs) with the exception of lines that have eliminated postulated breaks based on leak-before-break analysis. One of the criteria in MEB 3-1 for Class 1 piping is postulating pipe breaks at any intermediate locations where the CUF exceeds 0.1. The NRC staff has determined that this analysis qualifies as a TLAA.

The existing VEGP HELB analyses have been shown to remain valid for the period of extended operation as long as the Fatigue Monitoring Program maintains the CUF of the charging nozzles less than or equal to 1.0. Therefore, this TLAA has been demonstrated to be acceptable for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i) and 10 CFR 54.21(c)(1)(iii).

Full structural weld overlays (FSWOL) have been installed on the pressurizer spray nozzles, pressurizer safety and relief nozzles, and the pressurizer surge nozzles. Fatigue crack growth analyses using ASME Code Section XI methodology were performed to demonstrate the fatigue qualification at the structural weld overlay regions. Reconciliation of the existing fatigue evaluation was performed for the limiting locations outside the FSWOL, and it was demonstrated that the pressurizer nozzles would still meet the applicable ASME Code Section III requirements. In summary, the reconciliation of the existing fatigue evaluation that was performed for the limiting locations outside the FSWOL is a TLAA that remains valid for the period of extended operation, because the cycles assumed will not be exceeded during 60 years of operation. Therefore, this TLAA has been demonstrated to be acceptable for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

In conclusion, the VEGP fatigue TLAAs for ASME Class 1 components have been evaluated and shown to remain valid or are adequately managed for the period of extended operation, in accordance with the demonstration methods of 10 CFR 54.21(c)(1)(i) and 10 CFR 54.21(c)(1)(iii). The Fatigue Monitoring Program monitors and tracks transient cycles and their severity and performs CUF monitoring of selected components to ensure that Class 1 components are maintained within their fatigue design limits.

19.4.2.2 ASME Section III, Non-Class 1 Component Fatigue Analysis

The design of ASME III Code Class 2 and 3 piping systems at VEGP incorporates stress reduction factors for determining the acceptability of the piping design with respect to thermal stresses. Those in-scope components that are designed in accordance with ANSI B31.1 requirements also incorporate stress-reduction factors based upon an assumed number of thermal expansion cycles. In general, 7000 full-temperature thermal cycles are assumed in the calculation of the thermal expansion stress, leading to a stress-reduction factor of 1.0 in the stress analyses.

SNC evaluated the validity of this assumption of 7000 full-temperature thermal cycles for 60 years of plant operation. The results of this evaluation indicate that the 7000-thermal cycle assumption remains valid and bounding for 60 years of operation. Therefore, the existing pipe stress calculations are valid for the extended period of operation in accordance with 10 CFR 54.21(c)(1)(i).

There are non-Class 1 fatigue evaluations that use a different method of analysis than the 7000 cycles described above. In general, those evaluations use the same cycles, or a subset of the cycles, used for the Class 1 piping. These analyses include the letdown heat exchangers, containment cooler cooling coils, and the main stream isolation valves. In each case, the analysis was determined to remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

19.4.2.3 Reactor Coolant Pump Flywheel Fatigue

A calculation was performed for the VEGP reactor coolant pump flywheels which assumes that each pump will be subjected to 6000 start/stop cycles over a 60-year life. Current projections indicate that the 6000 start/stop cycles will remain bounding for 60 years of operation by a large margin. Therefore, fatigue of the reactor coolant pump flywheels is demonstrated in accordance with 10 CFR 54.21(c)(1)(i).

19.4.2.4 Fatigue of Reactor Vessel Supports

The Westinghouse Generic Technical Report WCAP 14422, Revision 2a, identifies fatigue of reactor vessel supports as a potential TLAA if the supports of the reactor vessel were constructed in accordance with the 1963 version of the AISC Code.

The reactor pressure vessel supports embedded within the primary shield wall are procured in accordance with ASME Code, Section III, Division 1, Subsection NF; however, since they are outside the ASME jurisdictional boundary, their design follows AISC specifications. Therefore, both the 1969 version of the AISC Code and ASME Code, Section III, Division 1, Subsection NF apply to the supports.

In the SER for WCAP 14422, the NRC has indicated that licensees must ensure that a version of the AISC Code later than 1963 was used. Since the design used the 1969 version of the AISC Code, the existing analysis is demonstrated to be valid for the extended term of operation in accordance with 10 CFR 54.21(c)(1)(i).

19.4.2.5 Fatigue of Steam Generator Secondary Manway and Handhole Bolts

Westinghouse performed a fatigue calculation for steam generator secondary manway and handhole bolts that assumed the same cycles used for Class 1 component fatigue evaluations. That calculation resulted in a qualified life for the manway bolts of only 20 years. In 1993, it was determined that after low-temperature rerate, the qualified life of the manway bolts would be reduced to 14.5 years. A new secondary side manway and handhole bolts fatigue evaluation was performed based on actual cycles to qualify the bolts for 40 years with rerating.

To ensure that the cycle limits for these bolts are not exceeded, SNC will replace both the secondary side manway bolts and the handhole bolts after 35 years of service, unless a less restrictive replacement schedule is developed and documented based on potential updated analyses initiated by the Bolting Integrity Program. SNC considers this fatigue evaluation a TLAA that is managed by the Bolting Integrity Program. Therefore, this TLAA is demonstrated in accordance with 10 CFR 54.21(c)(1)(iii).

19.4.2.6 Fatigue of Reactor Vessel Internals

A fatigue analysis of the reactor vessel internals was not required when VEGP was originally designed. However, as part of rerating, Westinghouse performed a fatigue calculation for reactor vessel internals that assumed the same cycles used for Class 1 component fatigue evaluations and resulted in CUFs less than 1.0 for all subcomponents evaluated.

VEGP evaluated this TLAA for the extended period of operation. Since the analysis utilized the same design transients as the Class 1 component evaluations, the evaluation of the ASME Class 1 piping and component design transient cycles is also applicable to the reactor vessel internals. The design cycles for the transients applicable to the reactor vessel internals are bounded by the RCS design cycles, therefore the reactor vessel internals fatigue analysis remains valid for the period of extended operation. This TLAA is demonstrated in accordance with 10 CFR 54.21(c)(1)(i).

19.4.3 ENVIRONMENTAL QUALIFICATION CALCULATIONS

The NRC has established environmental qualification (EQ) requirements in 10 CFR Part 50 Appendix A and in 10 CFR 50.49. The Environmental Qualification Program for VEGP has been established to demonstrate that certain electrical components are qualified to perform safety functions in the harsh environment following a DBA. Elements of the proof of qualification involve the original 40-year license period. Hence, the qualification reports and calculations that comprise the EQ Program meet the definition of a TLAA. Qualified lives for EQ components have already been determined, and these components are tracked to determine when they are nearing the end of their qualified lives. For those components that are nearing the end of their qualified lives, the EQ Program has provisions for the component to be re-evaluated for longer service, refurbished, requalified, or replaced. The EQ Program will be continued through the period of extended operation. Therefore, this TLAA is demonstrated in accordance with 10 CFR 54.21(c)(1)(iii).

19.4.4 CONTAINMENT TENDON PRESTRESS ANALYSIS

To meet the requirements on 10 CFR 50.55a (b)(2)(ix)(B), SNC uses an analysis to predict the amount of residual prestress in the containment tendons for VEGP. This analysis meets the definition of a TLAA. SNC extended the analysis to estimate the amount of residual prestress on the tendons after 60 years of operation. The analysis results conclude that acceptable containment tendon prestress will be retained throughout the period of extended operation. Therefore, adequate containment prestress for the period of extended operation is demonstrated in accordance with 10 CFR 54.21(c)(1)(ii).

Results from containment tendon surveillances conducted under the Inservice Inspection Program – IWL periodically update the analysis and confirm prestresses remain above the minimum required values.

19.4.5 PENETRATION LOAD CYCLES

A fatigue analysis was required for some of the VEGP containment penetrations. Those analyses qualify as TLAAs. Review of the transient assumptions for those evaluations against the transient assumptions for Class 1 component fatigue determined that none of the cycles assumed in the penetration fatigue analyses will be exceeded within the period of extended operation. Therefore, fatigue analyses for containment penetrations are acceptable without revision, and the TLAAs are demonstrated in accordance with 10 CFR 54.21(c)(1)(i).

19.4.6 OTHER PLANT-SPECIFIC ANALYSIS

19.4.6.1 Leak-Before-Break Analysis

Plant-specific leak-before-break (LBB) analyses have been performed for both VEGP units. These analyses provide the technical justification for changes to the structural design basis involving protection against the effects of postulated pipe ruptures and are identified as TLAAs since they include assumptions regarding fatigue cycles and material fracture toughness properties.

VEGP LBB analyses exist for the Units 1 and 2 reactor coolant loop piping, the pressurizer surge line, and the Unit 2 accumulator injection and the RHR branch connection lines.

The LBB analyses for the pressurizer surge line and the Unit 2 RHR branch connection line were reviewed and determined to be acceptable without revision for the period of extended operation. Therefore, these LBB analyses are demonstrated in accordance with 10 CFR 54.21(c)(1)(i).

The analyses for the primary coolant loops and the Unit 2 accumulator line have been evaluated and updated to address operation through 60 years, including reductions in cast material fracture toughness properties due to thermal aging. Therefore, these LBB analyses are demonstrated in accordance with 10 CFR 54.21(c)(1)(ii).

WCAP-10551-P, Addendum 1 performed an LBB evaluation for the Units 1 and 2 primary loop piping that explicitly addressed the PWSCC concern for the Alloy 82/182 welds in this piping. However, the NRC has not yet accepted the process used as adequately addressing their concerns. Once the NRC has accepted a process for addressing PWSCC of Alloy 82/182 welds in LBB evaluations and at least 2 years prior to the period of extended operation, SNC will verify the LBB evaluation in WCAP-10551-P, Addendum 1 meets the conditions of that process or have it reperformed using the acceptable process.

19.4.6.2 Fuel Oil Storage Tank Corrosion Allowance

The VEGP diesel fuel oil storage tanks and associated piping are not provided with cathodic protection; therefore, a liberal corrosion allowance was included. A calculation performed to evaluate the corrosion allowance included a 40-year assumption and has been determined to be a TLAA.

The calculation determined the depth of penetration for a hole of approximately 1/32 in. diameter (0.001 in^2) in the coating. The calculation was reviewed for license renewal, and it was determined that depth of penetration due to corrosion would not exceed the corrosion allowance during a 60-year operating life. Specifically, consideration of 60 years instead of

40 years in the calculation increases the depth of penetration due to corrosion from 25% to 51% of the corrosion allowance for the tanks and from 50% to 76% of the corrosion allowance for the pipes.

Therefore, demonstration is in accordance with 10 CFR 54.21(c)(1)(ii).

19.4.6.3 Steam Generator Tube, Loss of Material

VEGP UFSAR subsection 5.4.2 describes allowances for erosion and corrosion that are partially based upon a measured loss of material rate for 40 years. These allowances are used as inputs to demonstrate that stress limits established by Regulatory Guide 1.121 continue to be satisfied. Subsection 5.4.2 demonstrates that a large margin exists between the allowable tube wall degradation which satisfies Regulatory Guide 1.121 limits and the tube plug limits established by the VEGP Steam Generator Tubing Integrity Program. Increasing the expected corrosion allowance to address the period of extended operation has an insignificant effect on this margin. Further, steam generator tubing wall loss is managed by the Steam Generator Tubing Integrity Program and the requirements of Regulatory Guide 1.121 are considered within that program.

Therefore, this TLAA is managed by the Steam Generator Tubing Integrity Program and is demonstrated in accordance with 10 CFR 54.21(c)(1)(iii).

19.4.6.4 Cold Overpressure Protection System

As described in paragraph 5.2.2.10 of the VEGP UFSAR, VEGP has a cold overpressure mitigation system (COPS). A calculation has been performed to confirm that the setpoints will maintain the system pressure within the established limits when the pressure difference between the pressure transmitter and reactor midplane and maximum temperature/pressure instrument uncertainties are applied to the setpoints. This calculation meets the definition of a TLAA.

The P-T limit curves in the VEGP PTLR have been evaluated for 36 EFPY. When a revision to the PTLR is issued, the cold overpressure mitigation system setpoints will also be updated to reflect the period covered by the PTLR revision. Therefore, this cold overpressure mitigation setpoint calculation TLAA is demonstrated in accordance with 10 CFR 54.21(c)(1)(ii).

As described in the PTLR, the Reactor Vessel Surveillance Program updates the P-T limit curves considering the data gained from capsules SNC pulls, and the content and update of the PTLR is in accordance with VEGP Technical Specifications, subsection 5.6.6. The associated COPS setpoints are also updated as operational needs dictate to bound the current level of neutron embrittlement (i.e., EFPY) for the unit. Therefore, this TLAA demonstration is made in accordance with 10 CFR 54.21(c)(1)(ii) and (iii).

The VEGP PTLR (for each unit) will be updated to address neutron embrittlement for a 60-year operating life, including any changes to the COPS setpoints, prior to the unit entering the period of extended operation.

19.4.6.5 Underclad Cracking of the Reactor Pressure Vessel

There is no plant-specific evaluation of underclad cracking at VEGP, and no such cracks have been identified. Freedom from underclad cracking is ensured by special evaluation of the procedure qualification for cladding applied on low-alloy steel (SA-508, Class 2) in accordance with Regulatory Guide 1.43. However, SNC conservatively includes underclad cracking as a TLAA. Analyses performed by Westinghouse in WCAP-15338 demonstrate that growth of underclad cracks in Westinghouse reactor pressure vessels (RPVs) does not represent a significant challenge to reactor vessel integrity for an operating term of 60 years. The assumptions used as inputs to WCAP-15338 are applicable to VEGP. The results of these analyses demonstrate that underclad cracking of reactor vessel components is not an aging effect requiring management for VEGP. TLAA disposition is in accordance with 10 CFR 54.21(c)(1)(i).

19.4.7 REFERENCES

1. NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, U. S. Nuclear Regulatory Commission (Rev. 1), September 2005.
2. NUREG-1801, Generic Aging Lessons Learned (GALL) Report, U. S. Nuclear Regulatory Commission (Rev. 1), September 2005.
3. Vogtle Electric Generating Plant Unit 1 & Unit 2 Technical Specifications.

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