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January 10, 1989

Re: Indian Point Unit No. 2
Docket No. 50-247

Document Control Desk
U.S. Nuclear Regulatory Commission
Mail Station P1-137
Washington, DC 20555

SUBJECT: Supplemental Information to Increase Authorized Power Level (TAC No. 69542)

By letter dated September 30, 1988, we transmitted a document entitled "Application for License Amendment to Increase Authorized Power Level." The Application requested an amendment to Indian Point Unit 2 Technical Specifications to authorize operation of the plant at a Nuclear Steam Supply System (NSSS) power level up to 3083.4 Megawatt thermal (MWt), the power level originally guaranteed by the NSSS vendor.

As stated in our September 30 letter, we are transmitting herewith as Attachment I to this letter four (4) confirmatory analyses of the non-limiting evaluations. Included are: A.1 - Loss of External Electrical Load, A.2 - Excessive Load Increase Incident, A.3 - Rupture of a Steam Pipe, and A.4 - Excessive Heat Removal Due to Feedwater System Malfunctions.

The Nuclear Steam Supply System (NSSS) stretch rating licensing report (WCAP-11972; Enclosure 1 to Attachment B of the Application) will be revised by March 31st, 1989. In addition to the attached four analyses, the new revision will include other analyses and evaluations such as detailed short term subcompartment analysis mentioned on Page 17 of WCAP-11972.

Should you or your staff have any questions, please contact Mr. Jude G. Del Percio, Manager, Regulatory Affairs.

Very truly yours,

A001
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50-247 INDIAN POINT, UNIT 2 CEC

FORWARDS SUPPLEMENTAL INFO re 9/30/88 APPLICATION FOR AMENDMENT TO LIC. DPR-26

Ltr. dtd. 1/10/89 .... #8901230137

Attachment I

A.1 - Loss of External Electrical Load
A.2 - Excessive Load Increase Incident
A.3 - Rupture of a Steam Pipe
A.4 - Excessive Heat Removal Due to Feedwater System Malfunctions

Consolidated Edison Company of New York, Inc.
Indian Point Unit No. 2
Docket No. 50-247
January, 1989

A.1 LOSS OF EXTERNAL ELECTRICAL LOAD

Introduction

A major load loss on the plant can result from either a loss of external electrical load or from a turbine trip. For either case, offsite power is available for the continued operation of plant components such as the reactor coolant pumps. The case of loss of all ac power to station auxiliaries is discussed in Section A.2 of Reference 1.

For a turbine trip, the reactor would be tripped directly (unless below approximately 35% power) from a signal derived from the turbine autostop oil pressure. The automatic steam dump system accommodates the excess steam generation. Reactor coolant temperatures and pressure do not significantly increase if the steam dump system and pressurizer pressure control system are functioning properly. If the turbine condenser were not available, the excess steam generation would be dumped to the atmosphere. Additionally, main feedwater flow would be lost if the turbine condenser were not available. For this situation, steam generator level would be maintained by the auxiliary feedwater system.

The unit was originally designed to accept a step 50% loss of load without actuating a reactor trip. The automatic steam dump system, with 40% steam dump capacity to the condenser, was designed to accommodate this load rejection by reducing the severity of the transient imposed upon the RCS. The reactor power is reduced to the new equilibrium power level at a rate consistent with capability of the Rod Control System. The steam generator relief valves may be actuated, but the pressurizer relief valves and the steam generator safety valves do not lift for the 50% step loss of load with steam dump.

In the event the steam dump valves fail to open following a large loss of load or in the event of a complete loss of load with steam dump operating, 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/overpower delta-T signals. The steam generator shell-side

pressure and reactor coolant temperatures will increase rapidly. However, the pressurizer safety valves and steam generator safety valves are sized to protect the RCS and steam generator against overpressure for all load losses without assuming the operation of the steam dump system. The RCS and main steam supply relieving capacities were designed to ensure safety of the unit without requiring the automatic rod control, pressurizer pressure control and/or steam bypass control systems.

Method of Analysis

In this analysis, the behavior of the unit was evaluated for a complete loss of steam load from full power without a direct reactor trip. This was done to show the adequacy of the pressure relieving devices and to demonstrate core protection margins. The reactor is not tripped until conditions in the RCS result in a trip. The turbine was assumed to trip without actuating the turbine trip signal (low auto stop oil pressure). This assumption delays reactor trip until conditions in the RCS result in a trip due to other signals. Thus, the analysis assumes a worst case transient. In addition, for conservatism, no credit was taken for steam dump, main feedwater flow is terminated at the time of turbine trip, and no credit was taken for auxiliary feedwater (except for long-term recovery) to mitigate the consequences of the transient.

In addition to the specific analysis discussed above for a complete loss of steam load from full power, the acceptability of a loss of steam load without direct reactor trip on turbine trip below 35% of 3083.4 MWt NSSS full power was also evaluated.

The total loss of load transients were analyzed with the LOFTRAN computer program (Reference 2). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

This accident was analyzed using the Improved Thermal Design Procedure (ITDP) as discussed in Section 5.1.1 of Reference 6 (Attachment C). Initial reactor power, RCS pressure and temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in Reference 3.

Major assumptions are summarized below:

(1) Initial Operating Conditions

The initial reactor power, RCS pressure, and RCS temperatures are assumed at their nominal values consistent with steady state full power operation.

(2) Moderator and Doppler Coefficients of Reactivity

The turbine trip is analyzed with both maximum and minimum reactivity feedback. The maximum feedback (EOL) cases assume a large negative moderator temperature coefficient and the most negative Doppler power coefficient. The minimum feedback (BOL) cases assume a minimum moderator temperature coefficient and the least negative Doppler coefficient.

(3) Reactor Control

From the standpoint of the maximum pressures attained, it is conservative to assume that the reactor is in manual control. If the reactor were in automatic control, the control rod banks would move prior to trip and reduce the severity of the transient.

(4) Steam Release

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

(5) Pressurizer Spray and Power-operated Relief Valves

Two cases for both BOL and EOL reactivity feedback conditions were analyzed:

(a) Full credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Safety valves are also available.

(b) No credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Safety valves are operable.

(6) Feedwater Flow

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

Reactor trip is actuated by the first reactor protection system trip setpoint reached with no credit taken for the direct reactor trip on the turbine trip.

Results

The transient responses for a total loss of load from full power operation are shown on Figures A-1 through A-12 for four cases; two cases for the BOL and two cases for the EOL reactivity feedback conditions

Figures A-1 through A-3 show the transient responses for the total loss of steam load at BOL assuming full credit for the pressurizer spray and pressurizer power-operated relief valves. No credit is taken for the steam dump. The reactor is tripped by the high pressurizer pressure trip channel. The minimum DNBR is well above the limit value. The pressurizer safety valves are actuated for this case and maintain system pressure below 110 percent of the design value. The steam generator safety valves open and limit the secondary steam pressure increase.

Figures A-4 through A-6 show the transient responses for the total loss of steam load at EOL assuming a large (absolute valve) negative moderator temperature coefficient. All other plant parameters are the same as in the above case. The reactor is tripped by the high pressurizer pressure trip channel. The minimum DNBR is well above the limit value. The pressurizer safety valves are actuated for this case and maintain system pressure below 110 percent of the design value. The steam generator safety valves open and limit the secondary steam pressure increase.

The total loss of load event was also analyzed assuming the plant to be initially operating at full power with no credit taken for the pressurizer spray, pressurizer power-operated relief valves, or steam dump. The reactor is tripped on the high pressurizer pressure signal. Figures A-7 through A-9 show the BOL transients. The neutron flux remains essentially constant at full power until the reactor is tripped. The DNBR increases throughout the transient. In this case the pressurizer safety valves are actuated and maintain the system pressure below 110 percent of the design value.

Figures A-10 through A-12 show the transients at the EOL with the other assumptions being the same as on Figures A-7 through A-9. Again, the DNBR increases throughout the transient and the pressurizer safety valves are actuated to limit the primary system pressure.

Table A-1 summarizes the sequence of events for the various transients considered for the total loss of load cases presented above.

In the above analysis of a loss of load (turbine trip) event from full power four cases were analyzed; minimum and maximum moderator reactivity feedback, each considered with and without pressurizer pressure control. The analysis results for all four of these cases showed that a high pressurizer pressure reactor trip setpoint was reached within 10 seconds of the initiating loss of load event (i.e., a turbine trip). For determining the acceptability of no reactor trip on turbine trip below 35% power, each of these cases were also evaluated. However, before discussing the results of the evaluation for these cases, the following must be considered.

Normal power for the reactor coolant pumps is supplied through busses from a transformer connected to the generator. When the generator trip occurs, the busses are automatically transferred to a transformer supplied from external power lines, and the pumps will continue to supply coolant flow to the core.

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 (turbine-generator motoring). The turbine-generator motoring feature is required so that full reactor coolant flow is maintained to remove reactor core heat during Condition II overpower transients. The Reactor Protection System initiates a reactor trip as protection for an overpower event, and then the reactor trip signal initiates a turbine trip.

For no direct reactor trip on turbine trip function below 35% power, the first scenario which must be addressed is the failure of the 30 second time delay which results in an immediate generator trip on turbine trip. When this occurs, a fast bus transfer to offsite power will be initiated by the generator trip signal, thus insuring flow throughout the event. The other single failure scenario to consider is the failure of the fast bus transfer after the successful 30 seconds of turbine-generator motoring. If a failure of the network bus transfer occurs, a complete loss of forced reactor coolant flow would result approximately 30 seconds after the turbine trip. The immediate

effect of the loss of coolant flow is a more rapid increase in the coolant temperature compared to the increased coolant temperature as a result of the turbine trip by itself.

The following signals provide the necessary protection against a complete loss of flow accident:

1. Reactor coolant pump power supply undervoltage
2. 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., loss of AC power to station auxiliaries. This function is blocked below approximately 10 percent power (Permissive 7).

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.

Therefore, in the evaluations that follow for a loss of load (turbine trip) event below 35% power where there is no direct reactor trip function on turbine trip, the consequences of a loss of flow event 30 seconds into the event must also be considered. This loss of flow scenerio need not be considered for the turbine trip event from full power conditions since a reactor trip is reached well before the completion of the 30 second turbine-generator motoring period.

Without Pressurizer Pressure Control:

For the loss of load from full power without pressure control, both the minimum and maximum reactivity feedback cases result in a reactor trip on high pressurizer pressure within 6 seconds. For the same cases initiated from 50% of full power (which is conservative with respect to the actual 35% power permissive), reactor trip would occur within 20 seconds. The power and temperature conditions which exist at full power are more limiting than at partial powers with respect to the minimum DNBR reached during the transient

(in fact, the DNBR would increase throughout the transient). The pressurizer safety valve setpoint would be reached for both the full and partial power cases which assume no pressure control with the pressurizer PORVs or sprays. However, the event initiated from partial power would turn around faster due to the lower initial power and temperatures in addition to the lower amount of stored energy in the fuel. For both the full power and partial power cases, the reactor trip occurs long before any fast bus transfer is attempted. Thus, the loss of flow which may occur due to the fast bus transfer failure after the 30 seconds of turbine-generator motoring would have no effect on the transient for either the full or partial power cases. Therefore, the full power loss of load (turbine trip) event without pressurizer pressure control bounds any partial power initial condition without pressure control.

With Pressurizer Pressure Control:

The partial power, minimum and maximum moderator reactivity feedback cases with pressurizer pressure control may not trip until an undervoltage or low flow trip setpoint is reached after the failure of the fast bus transfer 30 seconds into the event. The power, temperature, and pressure conditions which exist at the time of the loss of flow for the partial power cases are much less severe with respect to minimum DNBR than those conditions which exist for the FSAR complete loss of flow event. The largest DNB benefit is, of course, due to the lower initial power level at the time of the loss of flow.

The minimum feedback case would essentially remain at the 50% power level until the reactor trip occurs on the reactor coolant pump undervoltage or low flow. The reactor coolant average temperature increases for the partial power loss of load (turbine trip) event, however, the RCS average temperature would not increase significantly above the nominal full power RCS average temperature (0 to 10 F) and thus would not offset the DNB benefit from the large difference in initial power level.

The power transient for the maximum reactivity feedback case would steadily decrease from the initial power level due to the heatup and moderator feedback effect. The RCS average temperature for this case would increase, but not above the nominal full power RCS average temperature, so the resultant minimum DNBR would be greater than the minimum DNBR for the loss of flow event.

Therefore, the FSAR full power complete loss of flow event bounds the partial power cases with respect to the minimum DNBR reached during the transient.

With pressurizer PORVs and sprays available for pressure control, both the full and partial power cases would show a pressure increase on the primary side to the PORV setpoint. After reactor trip, the pressure would decrease throughout the remainder of the transient. The cases without pressure control are always more limiting with respect to peak pressures and, as stated above, the UFSAR full power loss of load (turbine trip) event bounds any partial power event with respect to peak pressure.

Conclusion

The results of the analyses performed for a total loss of external electrical load without a direct or immediate reactor trip from full power (3083.4 MWt) conditions show that the plant design is such that there would be no challenge to the integrity of the RCS or the main steam system. Pressure relieving devices incorporated in the design of the plant would be adequate to limit the maximum pressures to within the design limits. In addition, the integrity of the core would be maintained by operation of the reactor protection system; i.e., the DNBR would be maintained above the safety analysis limit value. Thus, no core safety limit would be violated. Furthermore, these results, in conjunction with the results for the complete loss of flow event from full power, bound the results for a complete loss of load from 50% power without a direct reactor trip on turbine trip.

It is therefore concluded that the implementation of the Stretch Rating to a NSSS power of 3083.4 MWt is acceptable for the loss of external electrical load event.

A.2 EXCESSIVE LOAD INCREASE INCIDENT

Introduction

An excessive load increase incident as described in Section 14.1.11 of the Indian Point Unit 2 Updated FSAR is defined as a rapid increase in the steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The reactor control system is designed to accommodate a 10% step-load increase or a 5% per minute ramp load increase in the range of 15 to 100% of full power. Any loading rate in excess of these values may cause a reactor trip actuated by the reactor protection system.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam dump control or turbine speed control.

During power operation, steam dump to the condenser is controlled by reactor coolant condition signals: i.e., high reactor coolant temperature indicates a need for steam dump. A single controller malfunction does not cause steam dump; an interlock is provided that blocks the opening of the valves unless a large turbine load decrease or turbine trip has occurred.

Method of Analysis

This accident was analyzed using the LOFTRAN computer code (Reference 2).

Four cases were analyzed to demonstrate plant behavior following a 10% step load increase from rated load. These cases are as follows:

1. Reactor control in manual with beginning-of-life minimum moderator reactivity feedback.

2. Reactor control in manual with end-of-life maximum moderator reactivity feedback.

3. Reactor control in automatic with beginning-of-life minimum moderator reactivity feedback.

4. Reactor control in automatic with end-of-life maximum moderator reactivity feedback.

For the beginning-of-life minimum moderator feedback cases, the core has the least negative moderator temperature coefficient of reactivity and the least negative Doppler only power coefficient curve; therefore the least inherent transient response capability. For the end-of-life maximum moderator feedback cases, the moderator temperature coefficient of reactivity has its highest absolute value and the most negative Doppler only power coefficient curve. This results in the largest amount of reactivity feedback due to changes in coolant temperature.

A conservative limit on the turbine valve opening (equivalent to 120% turbine load) was assumed, and all cases were analyzed without credit being taken for pressurizer heaters.

This accident was analyzed using the Improved Thermal Design Procedure (ITDP) as discussed in Section 5.1.1 of Reference 6 (Attachment C). Initial reactor power, RCS pressure, and temperature were assumed to be at their nominal values. Uncertainties in initial conditions were included in the limit DNBR as described in Reference 3.

Normal reactor control systems and engineered safety systems were not required to function for this event. The reactor protection system was assumed to be operable; however, reactor trip was not encountered for most cases due to the error allowances assumed in the setpoints. No single active failure would prevent the reactor protection system from performing its intended function.

The cases which assume automatic rod control were analyzed to ensure that the worst case with respect to minimum DNBR is presented. The automatic rod control function is not required to mitigate the consequences of this event.

Results

The calculated sequence of events for the excessive load increase incident are shown in Table A-2.

Figures A-13 through A-16 illustrate the transient conditions with the reactor in the manual control mode. As expected, for the beginning-of-life minimum moderator feedback case, there is a slight power increase, and the core average coolant temperature shows a decrease. This results in a DNBR which increases above its initial value throughout the transient. For the end-of-life maximum moderator feedback case in manual control, there is a larger increase in reactor power due to the moderator feedback. A slight reduction in DNBR from its initial value is experienced but the minimum DNBR remains well above the limit DNBR value.

Figures A-17 through A-20 illustrate the transient conditions assuming the reactor is in the automatic control mode. Both the beginning-of-life minimum and end-of-life maximum moderator feedback cases show that the core power increases, thereby reducing the rate of decrease in coolant average temperature and pressurizer pressure. For both of these cases, the minimum DNBR remains above the limit DNBR value.

For all cases, the plant rapidly reaches a stabilized condition at the higher power level. Normal plant operating procedures would then be followed to reduce power.

The excessive load increase incident is an overpower transient for which the fuel temperatures will rise. Reactor trip does not occur for any of the cases analyzed, and the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in steam flow.

Since DNB does not occur at any time during the excessive load increase transients, the ability of the primary coolant to remove heat from the fuel rod is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

Conclusions

The analysis presented above shows that for a 10% step load increase, the DNBR remains above the safety analysis limit DNBR value, thereby precluding fuel or clad damage. The plant reaches a stabilized condition rapidly, following the load increase.

It is therefore concluded that the implementation of the Stretch Rating to a NSSS power of 3083.4 MWt is acceptable for the excessive load increase incident.

A.3 RUPTURE OF A STEAM PIPE

Introduction

A rupture of a steam pipe is assumed to include any accident that results in an uncontrolled steam release from a steam generator. The release can occur as a result of a break in a pipe or a valve malfunction. The steam release results in an initial increase in steam flow which decreases during the the accident as the steam pressure falls. The removal of energy from the reactor coolant system causes a reduction of coolant temperature and pressure. With a negative moderator temperature coefficient, the cooldown results in a reduction of core shutdown margin. If the most reactive control rod is assumed to be stuck in its fully withdrawn position, there is a possibility that the core may become critical and return to power even with the remaining control rod inserted. A return to power following a steam line rupture is a potential problem only because of the high hot-channel factors that may exist when the most reactive rod is assumed stuck in its fully withdrawn position. Even if the most pessimistic combination of circumstances that could lead to power generation following a steam line break are assumed, the core will ultimately be shut down by the boric acid in the safety injection system.

The analysis of a steam pipe rupture was made to show that assuming the most reactive RCCA stuck in its fully withdrawn position and assuming the worst single failure in the engineered safety features (ESFs), the core cooling capability is maintained and that radiation release dose rates do not exceed the guidelines of 10CRF100. In addition, the analysis considers conditions for both with and without offsite power available.

Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable, the following analysis shows that DNB does not occurs thus assuring clad integrity.

The following systems provide the necessary protection against a steam pipe rupture:

1. Safety Injection System actuation on one of the following signals:

   a. Two out of three channels with low pressurizer pressure signal.

   b. Two out of three high differential pressure signals between steam lines.

   c. High steam flow in two-out-of-four lines (one out of two per line) in coincidence with either low reactor coolant system average temperature (two-out-of-four) or low steam line pressure (two-out-of-four).

   d. Two-out-of-three high containment pressure signals.

   e. Manual.

2. Overpower reactor trips (nuclear flux and Delta-T) and the reactor trip occurring upon the actuation of the safety injection system.

3. Redundant isolation of the main feedwater lines. Sustained high feedwater flow would cause additional cooldown; however, in addition to the normal control action that would close the main feedwater valves, any safety injection signal would rapidly close all feedwater control valves and close the feedwater pump discharge valves which in turn would trip the main feedwater pumps.

4. Closing of the fast acting steam line stop valves (designed to close in 5 seconds or less) on:

   a. High steam flow in any two steam lines (one-out-of-two per line) in coincidence with either low reactor coolant system average temperature (two-out-of-four) or low steam line pressure (two-out-of-four).

   b. Two sets of two-out-of-three high-high containment pressure signals.

Each steam line has a fast-closing stop valve and check valve. These eight valves prevent blowdown of more than one steam generator for any break location even if one valve fails to close.

Method of Analysis

The analysis of a steam line rupture was performed to determine:

a. The core heat flux and RCS temperature and pressure resulting from the cooldown following the steam line break. These conditions were determined using the LOFTRAN code (Reference 2).

b. The thermal-hydraulic behavior of the core following a steam line break. A detailed thermal-hydraulic computer code, THINC (Reference 4), was used to determine if DNB occurs for the core conditions computed in the item (a) above.

The following conditions were assumed to exist at the time of a main steam line break accident:

1. The control rods give 1.3 % shutdown reactivity margin at end-of-life (EOL), no-load conditions with equilibrium xenon. This is the EOL design value including design margins with the most reactive stuck rod in its fully withdrawn position. The actual shutdown capability is expected to be significantly greater.

2. The moderator reactivity coefficient corresponding to the EOL rodded core with the most reactive rod in its fully withdrawn position. The variation of the coefficient with temperature and pressure is included.

3. Minimum capability of the safety injection system, corresponding to two-out-of-three safety injection pumps in operation and degraded system performance.

4. Power peaking factors corresponding to one stuck RCCA and non-uniform core inlet temperatures are determined at EOL. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck RCCA during the return to power phase following the steam line break.

5. The Moody curve for L/D = 0 reported in Figure 3 of Reference 5 was used to calculate the steam flow through a steam line break.

6. The determination of the critical heat flux is based on local coolant conditions.

Five separate steam line rupture cases initiated from EOL, hot standby conditions were analyzed to determine the resulting core power and reactor coolant system transient conditions. These cases are:

Case A - Steam pipe rupture outside containment (down stream of flow restrictor in faulted main steam line) with offsite power available.

Case B - Steam pipe rupture outside containment (down stream of flow restrictor in faulted main steam line) with a loss of offsite power.

Case C - Steam pipe rupture inside containment (up stream of flow restrictor in faulted main steam line) with offsite power.

Case D - Steam pipe rupture inside containment (up stream of flow restrictor in faulted main steam line) with loss of offsite power.

Case E - Steam release equivalent to one steam generator safety valve.

For the cases with offsite power, it is assumed that within 12 seconds following receipt of an safety injection signal (including appropriate delays for the instrumentation, logic, and signal transport), the appropriate realignment of valves and actuations have been completed and that the high head safety injection pump is at full speed.

In the cases where offsite power is not available, an additional 10 seconds delay is assumed to start the diesels and to load the necessary SI equipment on line.

Results

The results presented are a conservative indication of the events that would occur assuming a steam line rupture. The worst case assumes that the following occur simultaneously.

1. Minimum shutdown margin equal to 1.3 % delta-K.

2. The most negative moderator temperature coefficient for the rodded core at end of life.

3. The most reactive RCCA stuck in its fully withdrawn position.

4. One safety injection pump fails to function as designed.

The Time Sequence of the Events for all the cases analyzed is reported in Table A-3.

Core Power and Reactor Coolant System Transients

Case A - Steam pipe rupture outside containment (down stream of flow restrictor in faulted main steam line) with offsite power available.

Figures A-21 through A-23 show the reactor coolant system transient and core heat flux following a steam pipe rupture (complete severance of a pipe) outside the containment, downstream of the flow-measuring nozzle at the initial no-load conditions. Should the core be critical at near zero power when the rupture occurs, a reactor trip signal from the safety injection signal initiated on high differential pressure between steam lines or by high steam flow signals in coincidence with either low reactor coolant system temperature or low steam line pressure would trip the reactor.

The break assumed is the largest break that could occur anywhere outside the containment either upstream or downstream of the stop valves. Offsite power is assumed available such that full reactor coolant flow is maintained. Steam release out the break from the three intact steam generators would be prevented by the reverse flow check valve in the faulted loop or by the automatic closing of the fast-acting stop valves in the steam lines on a high steam flow signal in coincidence with low reactor coolant system temperature or low steam line pressure. Even with the failure of one valve, release from the three intact steam generators while the fourth steam generator blows down would be limited to the time required to obtain an isolation signal and to actuate steam line isolation via the fast-acting stop valves. The steam line stop valves are designed to be fully closed in less than 5 seconds with no flow through them. With the high flow that exists during a steam line rupture, the valves would close considerably faster.

For this case, a high steam flow condition in all four loops occurs almost immediately. A low average loop temperature condition (e.g., less than 536 degree F) is reached in 2 of 4 loops at 9.7 seconds. Two seconds later, at 11.7 seconds, signals to initiate SI, steam line isolation, and feedwater isolation are actuated. At 18.7 seconds, isolation of the main feedwater

system and isolation of the 3 intact steam generators by closure of the main steamline isolation valves is completed. The safety injection pumps which were started on the SI signal begin to deliver borated flow into the reactor core at approximately 47 seconds, after primary system pressure decreases below the SI pump head and the safety injection system lines purged of unborated water.

As shown in Figure A-21 the core becomes critical at 15.4 seconds. The peak core average heat flux of 18.6 % of the nominal core power value (3071.4 Mwt) is reached at 99.4 seconds.

Case B - Steam pipe rupture outside containment (down stream of flow restrictor in faulted main steam line) with a loss of offsite power.

Figures A-24 through A-26 show the response for the case assuming a break outside the containment with a loss of offsite power at the time zero which results in a subsequent reactor coolant system flow coastdown. For this case, a high steam flow condition in all four loops occurs almost immediately. A low steam line pressure condition (i.e., less than 460 psia) is reached in 2 of 4 loops at 10.2 seconds. Two seconds later, at 12.2 seconds, signals to initiate SI, steam line isolation, and feedwater isolation are actuated. At 24.2 seconds, isolation of the main feedwater system and the 3 intact steam generators is completed. Following the appropriate safety injection system delay time required to start the safety injection pumps on the diesels, the safety injection pumps begin to deliver borated flow into the reactor core at approximately 59 seconds.

As shown in Figure A-24 the core becomes critical at 19.6 seconds. The peak core average heat flux of 15.4 % of the nominal core power is reached at 194.4 seconds.

Case C - Steam pipe rupture inside containment (up stream of flow restrictor in faulted main steam line) with offsite power.

Figures A-27 through A-29 show the reactor coolant system transient and core heat flux following a steam pipe rupture (complete severance of a pipe) inside the containment, up stream of the flow-measuring nozzle at the initial no-load conditions.

The break assumed is the largest break that could occur anywhere inside the containment either upstream or downstream of the flow restrictor. Offsite power is assumed available such that full reactor coolant flow is maintained. Prolonged steam release out the break from the three intact steam generators is prevented by either closure of the reverse flow check valve in the faulted loop or by the automatic closing of the fast-acting stop valves in the intact steam lines on a high steam flow signal coincidence with low reactor coolant system temperature or low steam line pressure in two out of four loops.

For this case, the reverse flow check valve in the faulted loop is conservatively assumed to fail. A high steam flow condition in all four loops occurs almost immediately. Due to the location of the break with respect to the flow restrictor, a high differential steam pressure signal (i.e., greater than 215 psi) is reached at 1.4 seconds. This signal initiates SI and feedwater isolation. A low average loop temperature condition (i.e., less than 536 degree F) is reached in 2 of 4 loops at 12.3 seconds, coincident with the high steam flow conditions. Two seconds later, at 15.3 seconds, a signal to initiate steam line isolation is actuated. At 8.4 seconds, isolation of the main feedwater system occurs. At 21.3 seconds, isolation of the 3 intact steam generators by closure of the main steamline isolation valves is completed. The safety injection pumps which were started on the SI signal begin to deliver borated flow into the reactor core at approximately 48 seconds.

As shown in Figure A-27 the core becomes critical at approximately 14 seconds. The peak core average heat flux of 22.3 % of the nominal core power is reached at 149.2 seconds.

Case D - Steam pipe rupture inside containment (up stream of flow restrictor in faulted main steam line) with a loss of offsite power.

Figures A-30 through A-32 show the response for the same steam pipe rupture location and assumptions as those for Case C with the exception that offsite power is assumed to be lost at the time of the break. This loss of offsite power results in a subsequent reactor coolant system flow coastdown. For this case, a high steam flow condition in all four loops occurs almost immediately. A high differential steam pressure signal is reached at 1.4 seconds, initiating SI and feedwater isolation. Coastdown of the reactor coolant pumps begins at 3 seconds. A low average loop temperature condition is reached in 2 of 4 loops at 13.8 seconds, coincident with the high steam flow conditions. Two seconds later, at 15.8 seconds, a signal to initiate steam line isolation is actuated. At 8.4 seconds, isolation of the main feedwater system occurs. At 27.8 seconds, isolation of the 3 intact steam generators by closure of the main steamline isolation valves is completed. Following the appropriate safety injection system delay time required to start the safety injection pumps on the diesels, borated flow is delivered into the reactor core at approximately 54 seconds.

As shown in Figure A-30 the core becomes critical at approximately 18 seconds. The peak core average heat flux of 14.8 % of the nominal core power is reached at 253.2 seconds.

Case E - Steam release equivalent to one steam generator safety valve.

Figures A-33 and A-34 show the transient response following a break equivalent to the steam release through one steam generator safety valve (credible break) with steam release from one steam generator. The transient is initiated from a hot zero power condition. In this case, safety injection is initiated automatically by low pressurizer pressure signal at 285 seconds (the low pressurizer pressure setpoint is assumed to be at 1700 psig and is reached after the pressurizer is empty).

Borated flow reaches the core at about 420 seconds. Due to the relatively high reactor coolant system pressure the safety injection flow is very low such that the core remains stable at a power level of about 5% of 3071.4 Mwt.

The cooldown for the case shown in Figures A-34 is more rapid than the case of steam release from all steam generators through one safety valve. The transient is quite conservative with respect to cooldown, since no credit is taken for the energy stored in the system metal or energy stored in the other steam generators. Since the transient occurs over a period of 30 minutes, the neglected stored energy is likely to have a significant effect in slowing the cooldown. The conditions shown were computed assuming the design shutdown margin with all the rods inserted except one stuck rod inserted at time zero.

Margin to Critical Heat Flux

Using the transients of Cases A through E, DNB analyses were performed for each of the five steam line break cases. It was found that all the case have a minimum DNBR greater than the applicable safety analysis limit value.

Conclusion

The results of the analysis performed for the Rupture of a Steam Pipe show that all applicable safety criteria are met. In particular:

- DNBR is maintained above the applicable safety analysis limit value.

It is therefore concluded that the implementation of the stretch rating to a NSSS power of 3083.4 Mwt is acceptable for the Rupture of a Steam Pipe accident.

A.4 EXCESSIVE HEAT REMOVAL DUE TO FEEDWATER SYSTEM MALFUNCTIONS

Introduction

Excessive heat removal due to feedwater system malfunctions is a means of increasing core power above full power and can result from a decrease in feedwater enthalpy or excessive feedwater additions. Such transients are attenuated by the thermal capacity of the secondary plant and of the RCS. The overpower and overtemperature protection (high neutron flux, overtemperature delta-T, and overpower delta-T trips) prevent any power increase that could lead to a DNBR that is less than the DNBR limit.

An example of a feedwater control system malfunction that results in a decrease in feedwater enthaply is that of the inadvertent opening of the feedwater bypass valve which diverts flow around the low-pressure feedwater heaters. For this event, there is a sudden reduction in inlet feedwater temperature to the steam generator. The increased subcooling of the secondary side will create a greater load demand on the primary side which can lead to reactor trip conditions.

An example of excessive feedwater flow would be a full opening of a feedwater control valve due to a feedwater control system malfunction or an operator error. At power, these occurrences can also cause a greater load demand on the RCS due to increased subcooling in the steam generator. With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in RCS temperature and thus a reactivity insertion due to the effects of the negative moderator coefficient of reactivity. Continuous excessive feedwater addition is prevented by the steam generator high-high level trip, which closes the feedwater control valves.

Method of Analysis

The excessive heat removal due to feedwater system malfunction transients were analyzed with the LOFTRAN code (Reference 2).

As described in the UFSAR, the decrease in feedwater enthaply event is assumed to occur at hot full power initial conditions. As a result of opening the feedwater bypass valve and diverting the flow around the low-pressure feedwater heaters, the feedwater temperature at the inlet of the steam generator in the affected loop decreases from 430 degree F to 420 degree F. This results in a decrease in the feedwater enthalpy of less than 11 Btu/lbm. An evaluation performed shows that the reduction in feedwater enthalpy by 11 Btu/lbm is significantly less that that for excessive load increase events described in section A.2. Therefore, excessive load increase events (cases with manual reactor control at BOL and with automatic reactor contol at EOL) bound the feedwater enthalpy cases described in the FSAR.

Excessive feedwater addition due to a control system malfunction or operator error that allows a feedwater control valve to open fully is considered. Three cases were analyzed as follows:

1. Accidental opening of one feedwater control valve with the reactor just critical at zero load conditions assuming a conservatively large moderator density coefficient characteristic of end-of-life conditions and the reactor in manual rod control.

2. Accidental opening of one feedwater control valve from full power initial conditions and with the reactor in manual rod control.

3. Accidental opening of one feedwater control valve from full power initial conditions and with the reactor in automatic rod control.

The reactivity insertion rate following a feedwater system malfunction was calculated with the following assumptions:

1. For the feedwater control valve accident at full power, one feedwater control valve is assumed to malfunction, resulting in a step increase to 110% of nominal feedwater flow to one steam generator.

2. For the feedwater control valve accident at zero load conditions, a feedwater valve malfunction occurs that results in a ramp increase in flow to one steam generator from zero flow at time zero to 171% of the nominal full load value for one steam generator at 5 seconds.

3. For the zero load condition, a conservatively low feedwater enthalpy corresponding to a feedwater temperature of 90 degree F is assumed.

4. No credit is taken for the heat capacity of the RCS and steam generator thick metal in attenuating the resulting plant cooldown.

5. No credit is taken for the heat capacity of the steam and water in the unaffected steam generators.

Results

For the feedwater enthalpy reduction event, the reduction in feedwater enthalpy is less than that resulting for the same equivalent cases analyzed for the excessive load increase incident as described in Section A.2. Therefore, the results for the excessive load increase incident, which show considerable margin to the DNBR limit exist under these same conditions, bound the feedwater enthalpy reduction cases.

In the case of excessive feedwater flow resulting from an accidental full opening of one feedwater control valve with the reactor at zero power and the above mentioned assumptions, the maximum reactivity insertion rate is less than 80 pcm/sec, which is the maximum reactivity insertion rate analyzed in Section A.3.7 of Enclosure 1 to Attachment C of Reference 6 for the Uncontrolled RCCA Withdrawal from a Subcritical Condition events. Therefore, the excessive feedwater flow case with the reactor at zero power is bounded by the analysis presented in Section A.3.7. It should be noted that if the incident occurs with the unit just critical at no-load, the reactor may be tripped by the power range neutron flux trip (low setting).

For the full power cases, the results for with automatic rod control are identical to those with manual rod control assumed. This is because the small increase in feedwater flow (10% above nominal) results in a very small increase in RCS temperature which is within the dead band of the rod control system. Therefore, for the case with automatic rod control, the rod control system is not actuated.

Transient results showing the core heat flux, pressurizer pressure, T_{avg}, and DNBR, as well as the increase in nuclear power and loop delta-T associated with the increased thermal load on the reactor are given in Figure A-35 through Figure A-37 for the full power case with manual rod control. Steam generator water level rises until the feedwater is terminated as a result of the high-high steam generator water level trip. The DNBR does not fall below the safety analysis DNBR limit. The calculated sequence of events for the full power cases are shown in Table A-4.

Conclusions

For a decrease in feedwater enthalpy at initial hot full power (3083.4 MWt) conditions due to the inadvertant opening of the feedwater bypass valve, the feedwater enthalpy decrease is less than that which occurs as a result of an excessive load increase incident. Therefore, the results and conclusions for the Excessive Load Increase Incident as reported in Section A.2 bound those for the excessive heat removal due to a decrease in feedwater enthalpy.

At initial no-load conditions, the reactivity insertion rate that occurs following an excessive feedwater addition is less than the maximum value considered in the analysis of the rod withdrawal from a subcritical condition. Therefore, the results and conclusions for the Uncontrolled RCCA Withdrawal from a Subcritical Condition as reported in Section A.3.7 of Enclosure 1 to Attachment C of Reference 6 bound those for the Excessive Heat Removal Due to a Feedwater System Malfunction at no-load conditions.

For the cases of the excessive feedwater addition initiated from full power (3083.4 MWt) conditions with and without automatic rod control, the results show that all applicable design criteria are met.

It is therefore concluded that the implementation of the Stretch Rating to a NSSS power of 3083.4 MWt is acceptable for the excessive heat removal due to feedwater system malfunction events.

A.5 REFERENCES

1) "Application for License Amendment to Increase Authorized Power Level", S. B. Bram (Consolidated Edison) to Document Control Desk, U. S. Nuclear Regulatory Commission, September 30, 1988, Appendix 1 of Enclosure 1 to Attachment B.

2) T. W. T. Burnett, et. al., "LOFTRAN Code Description", WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-Proprietary), April 1984.

3) Chelemer, H. et. al., "Improved Thermal Design Procedure", WCAP-8667, July 1975.

4) Hochreiter, L. E., Chelmer, H., Chu, P. T., "THINC IV, An Improved Program for Thermal Hydraulic Analysis of Rod Bundle Cores", WCAP-7956, June 1973.

5) Moody, F. J., Transaction of the ASME, "Journal of Heat Transfer", p. 134, February, 1965.

6) "Application for Amendment to License to Incororate Westinghouse Optimized Fuel Assemblies (OFA)", S. B. Bram (Consolidated Edison) to Document Control Desk, U. S. Nuclear Regulatory Commission, September 30, 1988.

TABLE A-1

SEQUENCE OF EVENTS
FOR THE
LOSS OF EXTERNAL ELECTRICAL LOAD EVENT

Loss of External Electrical Load	Time of event, sec			
	With Pressurizer Control		Without Pressurizer Control	
Event	BOL	EOL	BOL	EOL
Loss of electrical load / turbine trip	0.0	0.0	0.0	0.0
Initiation of steam release from SG safety valves	10.5	10.5	10.5	10.5
High pressurizer pressure reactor trip point reached	8.7	10.0	5.5	5.4
Rods begin to fall	10.7	12.0	7.5	7.4
Minimum DNBR occurs	11.0	(a)	(a)	(a)
Peak pressurizer pressure occurs	11.5	12.0	8.5	8.0

(a) DNBR does not decrease below its initial value.

TABLE A-2

SEQUENCE OF EVENTS
FOR THE
EXCESSIVE LOAD INCREASE EVENT

Excessive Load Increase Event	Time of event, sec			
	Manual Rod Control		With Automatic Rod Control	
Event	BOL	EOL	BOL	EOL
10 percent step load increase occurs	0.01	0.01	0.01	0.01
Peak pressurizer pressure occurs	0.1	0.1	9.0	10.7
Minimum DNBR occurs	4.2	300.0	140.1	93.6
Peak nuclear power occurs	299.1	261.1	210.1	8.4

TABLE A-3

SEQUENCE OF EVENTS
FOR THE
RUPTURE OF A STEAM PIPE EVENTS

Case A and B
Steam pipe ruptures outside containment

Rupture of a Steam Pipe Event	Time of event, sec with offsite power	Time of event, sec with loss of offsite power
Steam line rupture occurs	0	0
RCPs Begin to coastdown	-	3.0
High Steam Flow coincident with Low Tavg reached	9.7	-
High Steam Flow coincident with low steam line pressure reached	-	10.2
Criticality attained	- 15.4	- 19.6
Feedwater Isolation occurs	18.7	24.2
Steam line isolation	18.7	24.2
Boron reaches the core	- 46.8	- 59.6

TABLE A-3 (Continued)

SEQUENCE OF EVENTS
FOR THE
RUPTURE OF A STEAM PIPE EVENTS

Case C and D
Steam pipe ruptures inside containment

Rupture of a Steam Pipe Event	Time of event, sec with offsite power	Time of event, sec with loss of offsite power
Steam line rupture occurs	0	0
High Steam line differential pressure reached	1.4	1.4
RCPs Begin to coastdown	-	3.0
Feedwater Isolation occurs	8.4	8.4
High Steam Flow coincident with Low Tavg reached	12.3	13.8
Steam line isolation	21.3	27.8
Criticality attained	~ 14.0	~ 18.0
Boron reaches the core	~ 47.6	~ 54.2

TABLE A-3 (Continued)

SEQUENCE OF EVENTS
FOR THE
RUPTURE OF A STEAM PIPE EVENTS

Case E
Steam release equivalent to
one steam generator safety valve

Rupture of a Steam Pipe Event	Time of event, seconds
Initial steam release occurs	0
Criticality attained	~ 264
Safety Injection Signal on low pressurizer pressure	~ 285
Boron reaches the core	~ 420

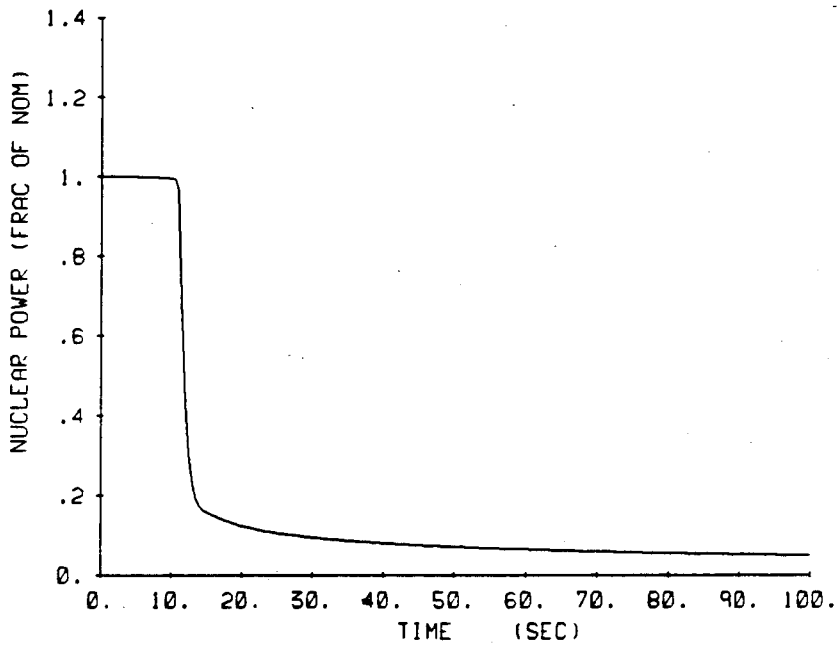
TABLE A-4

SEQUENCE OF EVENTS
FOR THE
FEEDWATER MALFUNCTION EVENT

Feedwater Malfunction at Full Power Event	Time of event, sec With Automatic Rod Control	Manual Rod Control
Feedwater flow to one SG increases to 110% of nominal	0.0	0.0
Peak pressurizer pressure occurs	4.5	4.5
Peak nuclear power occurs	131.5	131.5
Minimum DNBR occurs	194.0	194.0

Figure A-1

Loss of Load with Pressurizer Spray and
Power Operated Relief Valves
Beginning of Life
Nuclear Power and Pressurizer Pressure versus Time



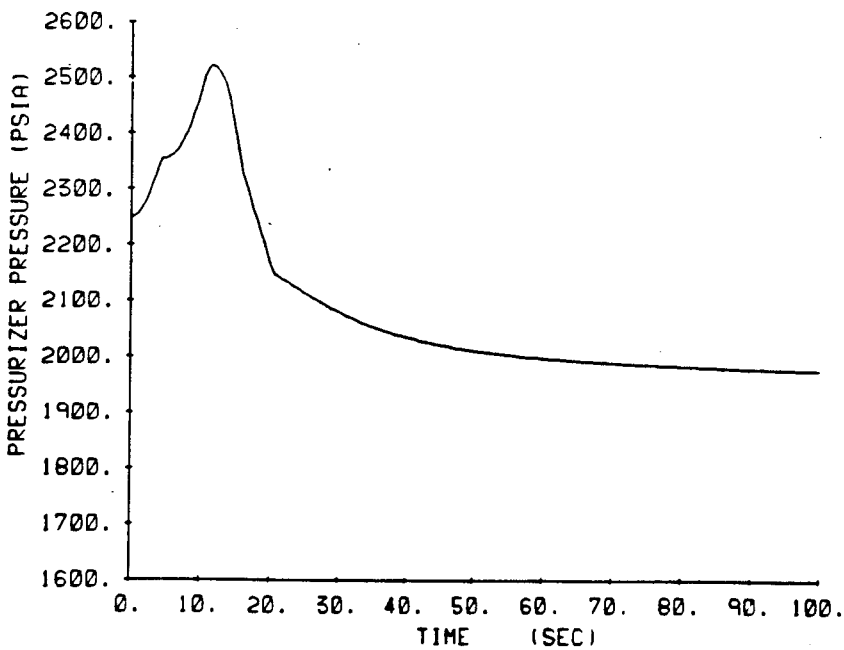
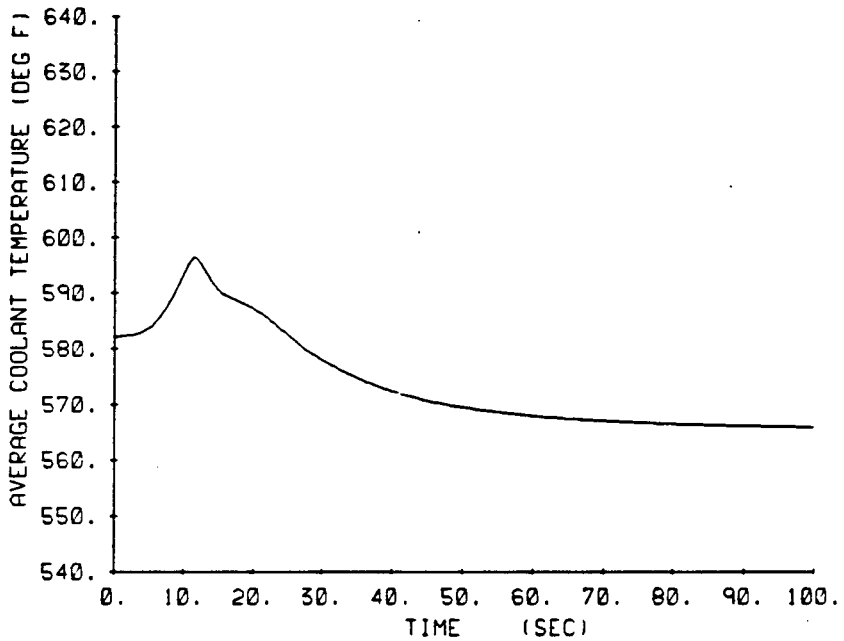


Figure A-2

Loss of Load with Pressurizer Spray and
Power Operated Relief Valves
Beginning of Life
Average Coolant Temperature and
Pressurizer Water Volume versus Time



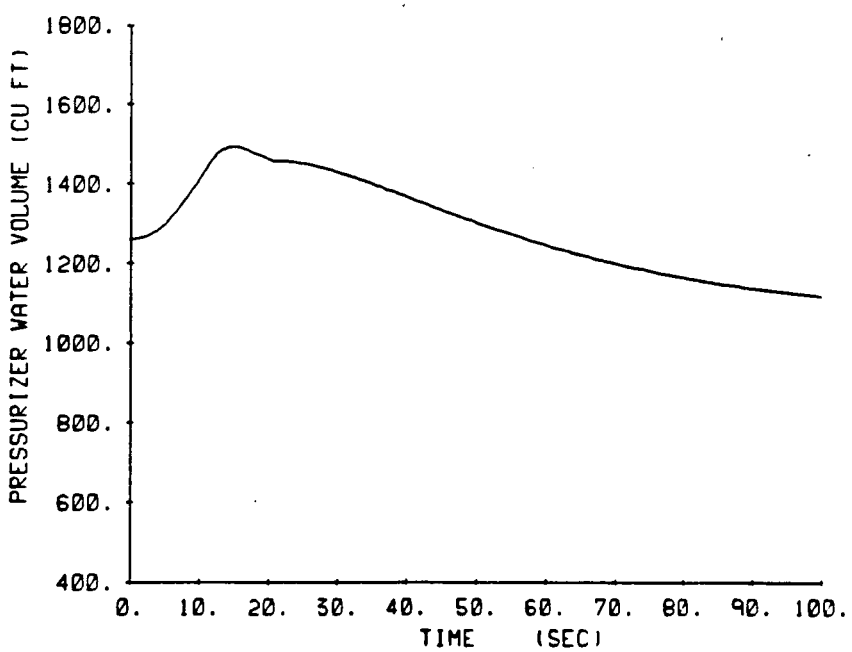
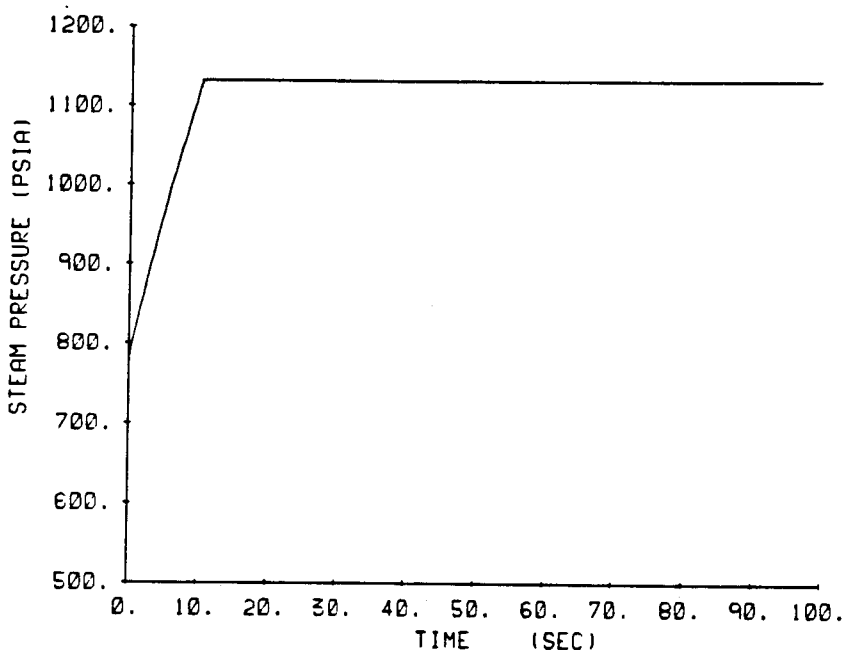


Figure A-3

Loss of Load with Pressurizer Spray and
Power Operated Relief Valves
Beginning of Life
Steam Pressure and DNBR versus Time



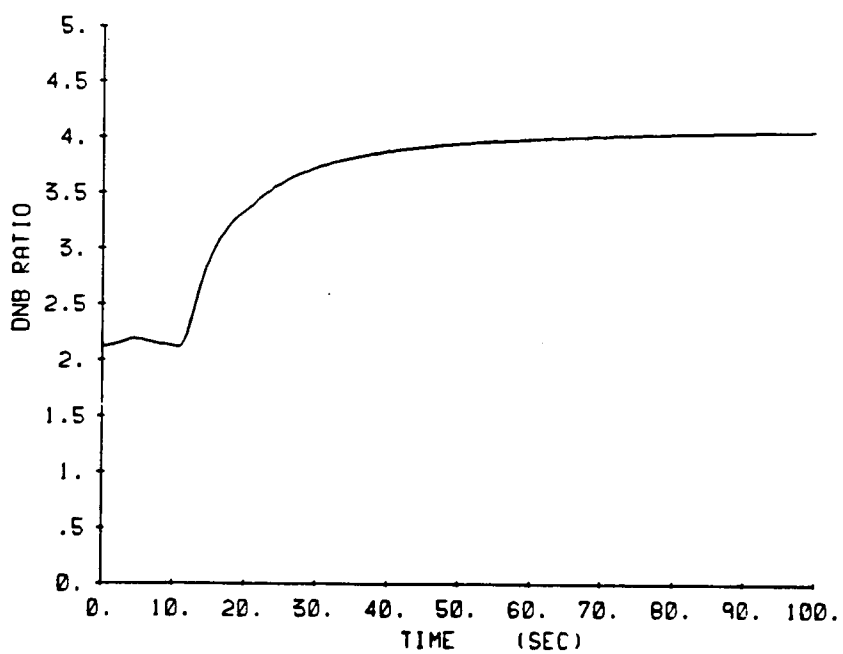
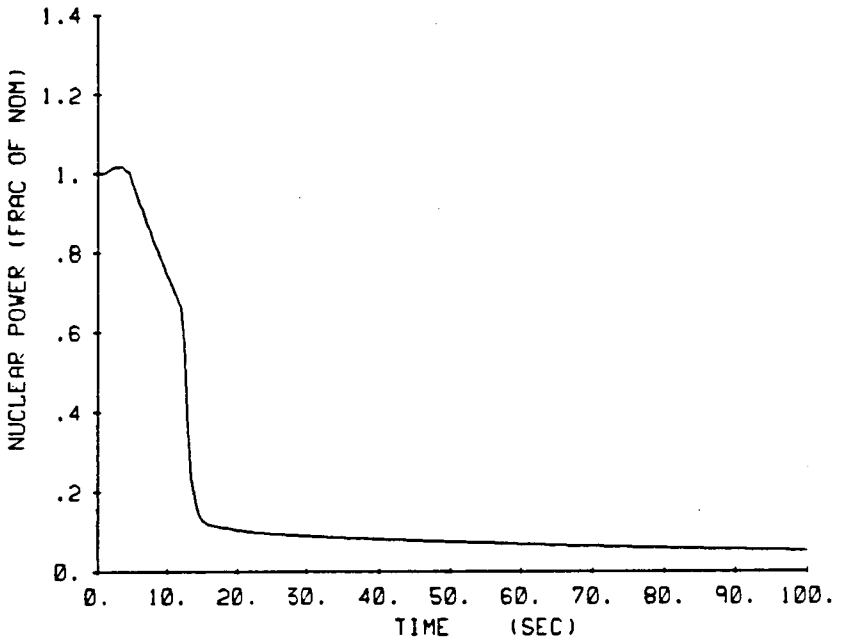


Figure A-4

Loss of Load with Pressurizer Spray and
Power Operated Relief Valves
End of Life
Nuclear Power and Pressurizer Pressure versus Time



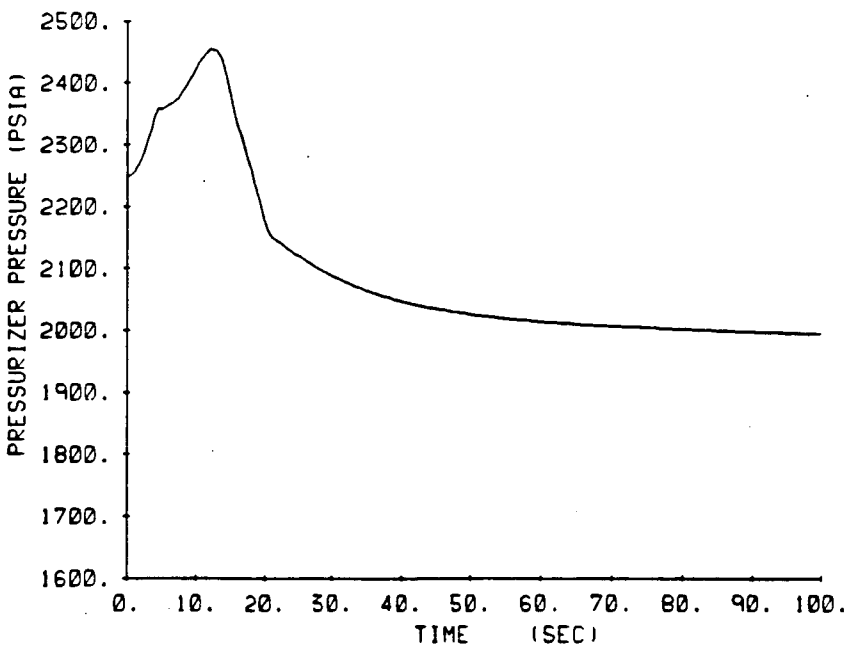
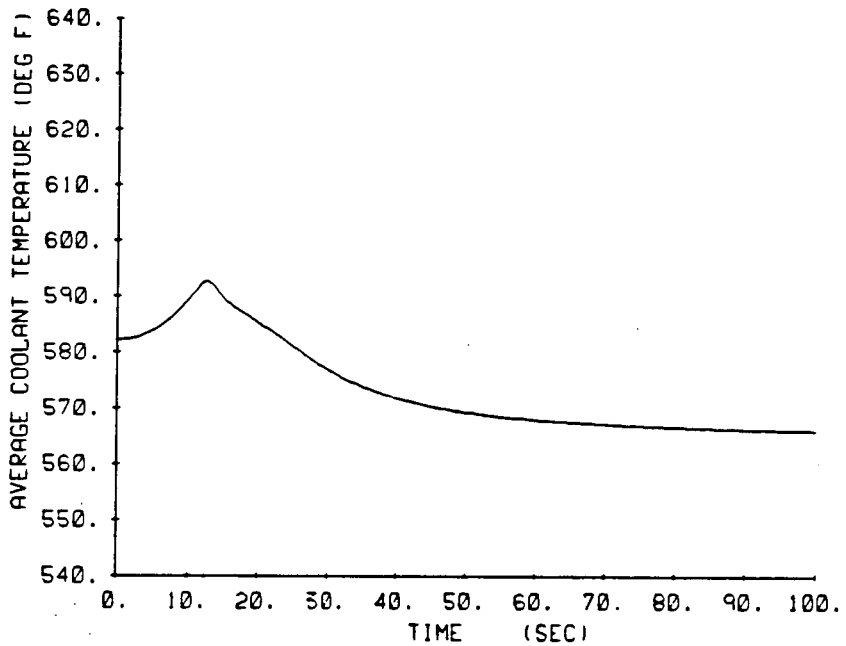


Figure A-5

Loss of Load with Pressurizer Spray and
Power Operated Relief Valves
End of Life
Average Coolant Temperature and
Pressurizer Water Volume versus Time



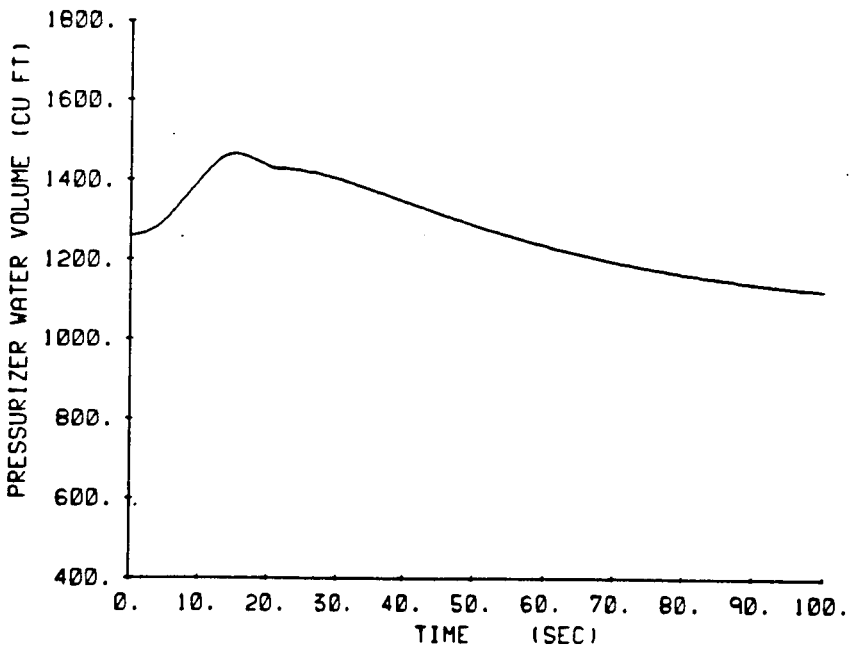
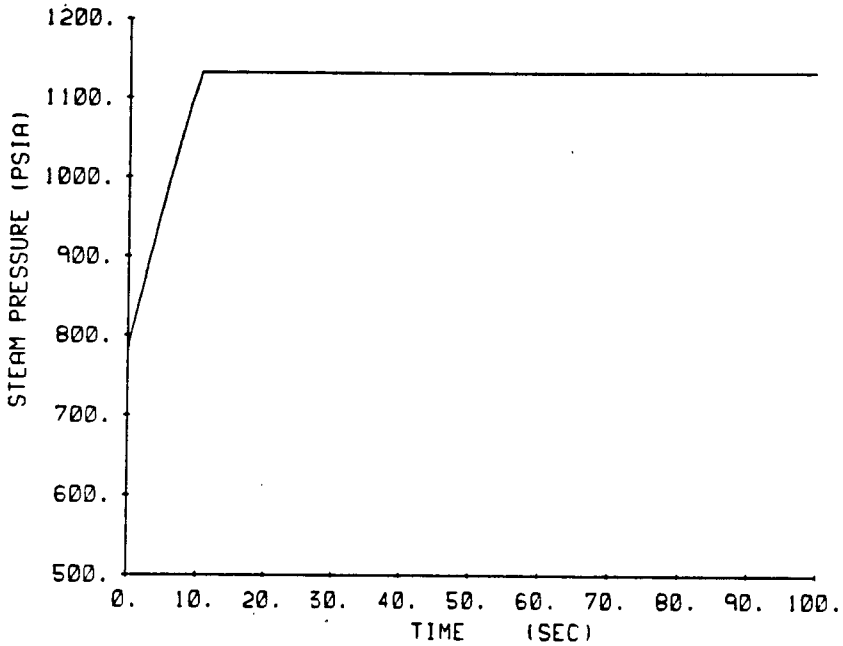


Figure A-6

Loss of Load with Pressurizer Spray and
Power Operated Relief Valves
End of Life
Steam Pressure and DNBR versus Time



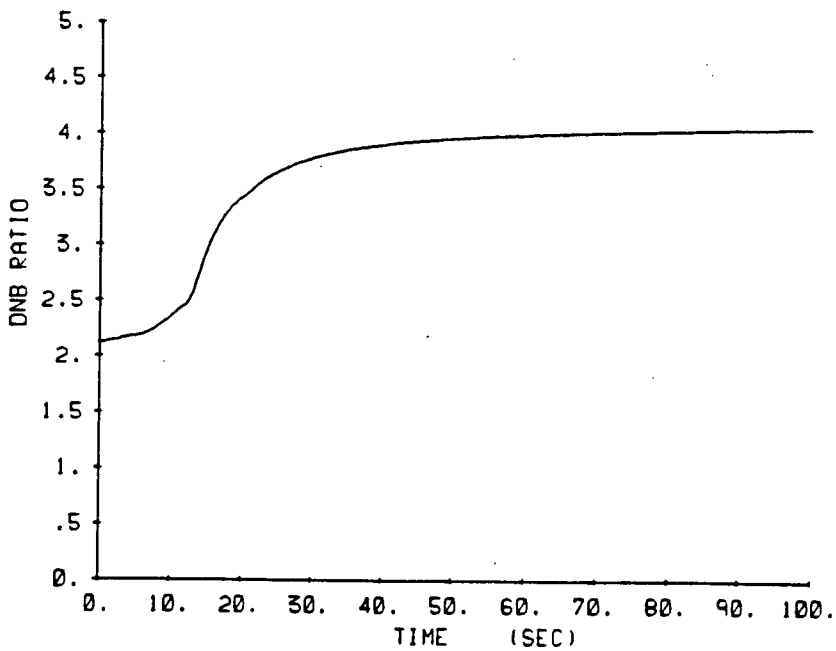
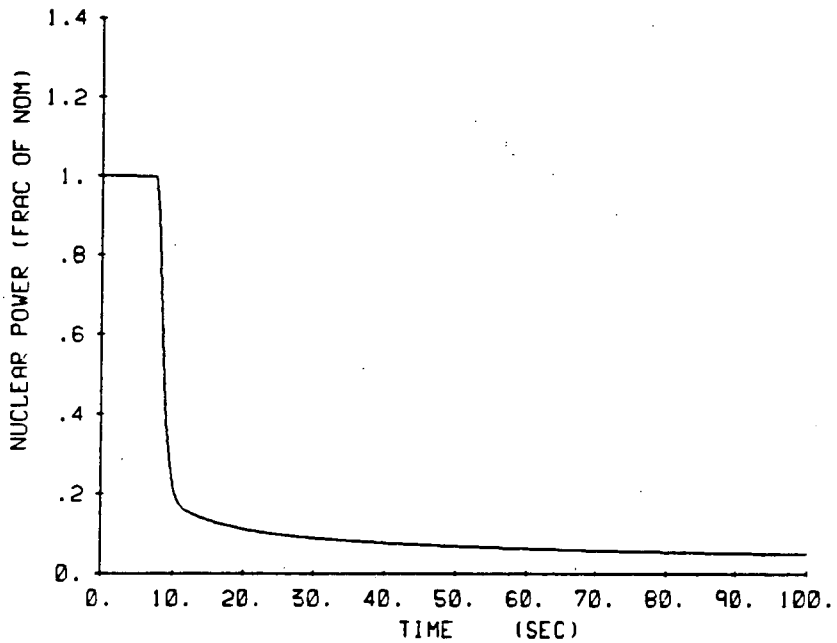


Figure A-7

Loss of Load without Pressurizer Spray and
Power Operated Relief Valves
Beginning of Life
Nuclear Power and Pressurizer Pressure versus Time



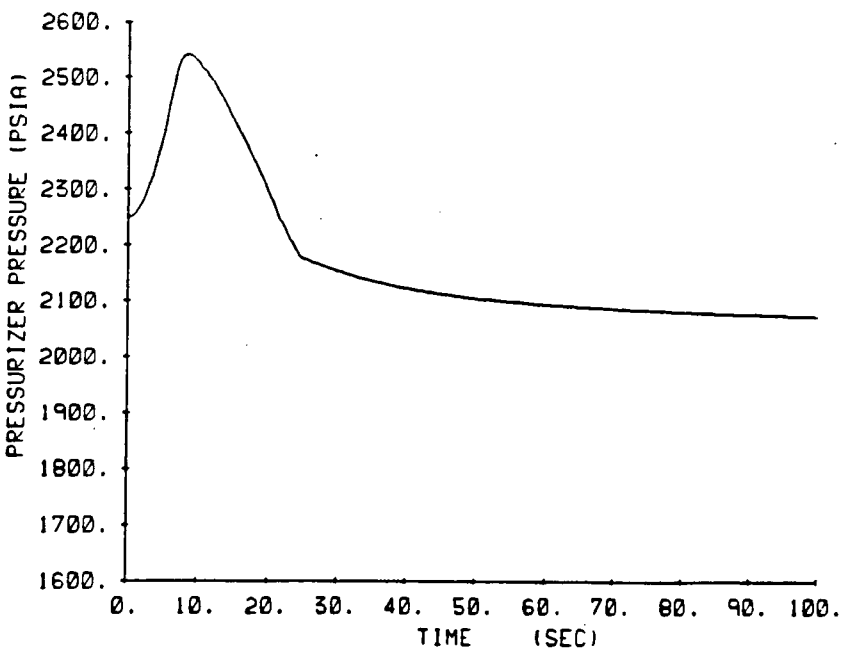
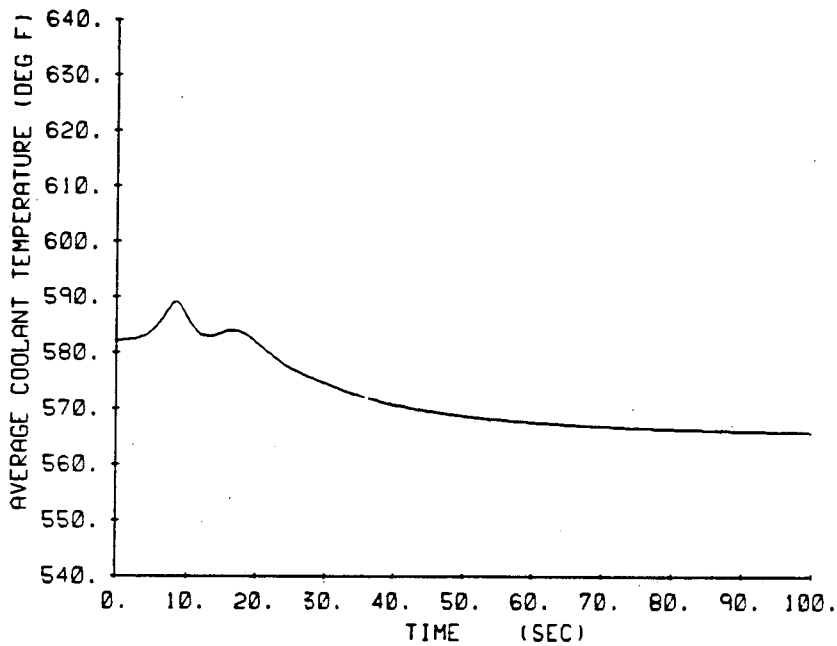


Figure A-8

Loss of Load without Pressurizer Spray and
Power Operated Relief Valves
Beginning of Life
Average Coolant Temperature and
Pressurizer Water Volume versus Time



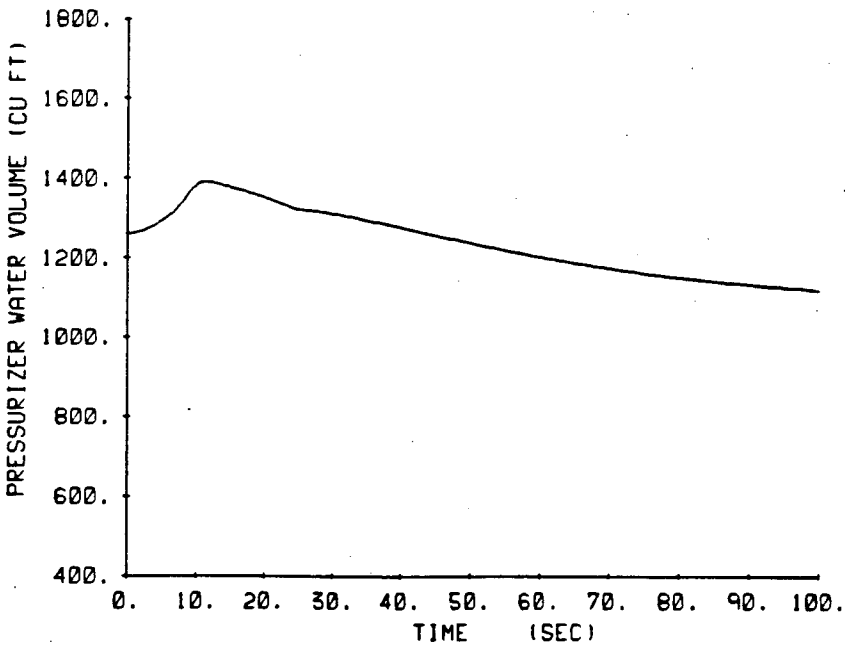
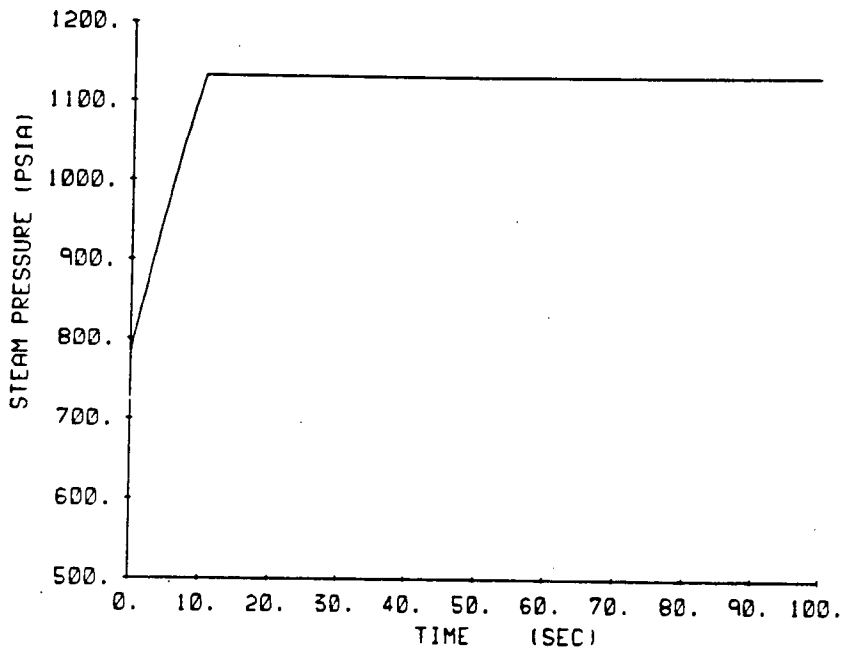


Figure A-9

Loss of Load without Pressurizer Spray and
Power Operated Relief Valves
Beginning of Life
Steam Pressure and DNBR versus Time



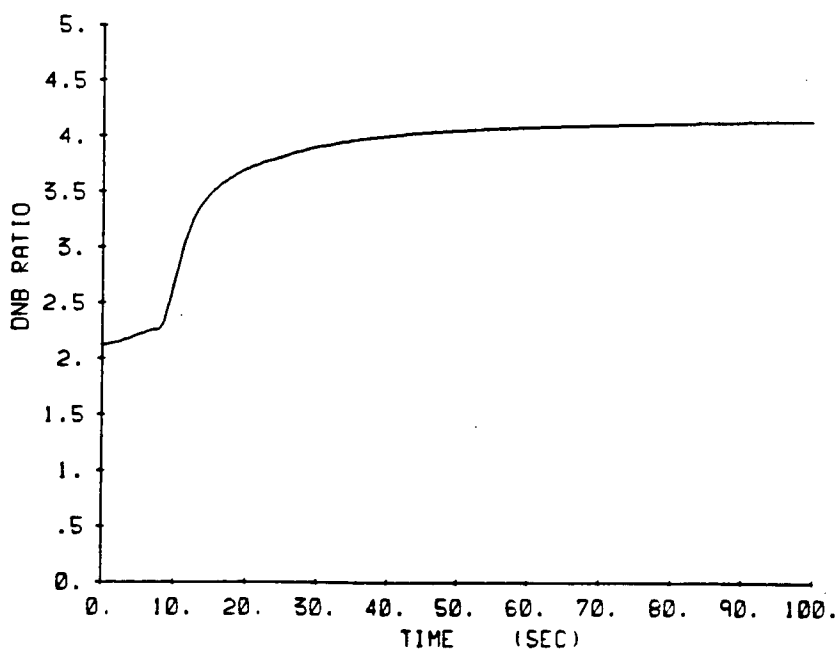
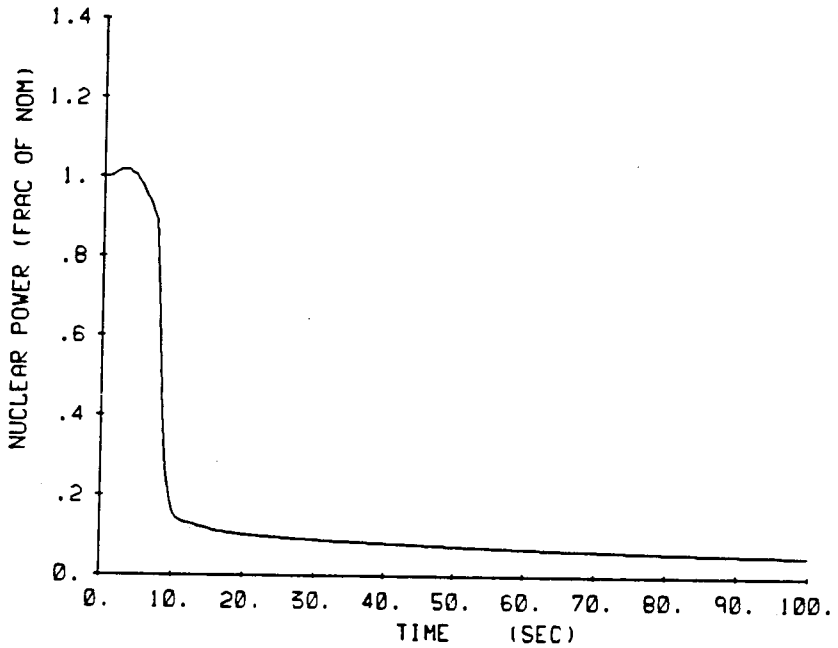


Figure A-10

Loss of Load without Pressurizer Spray and
Power Operated Relief Valves
End of Life
Nuclear Power and Pressurizer Pressure versus Time



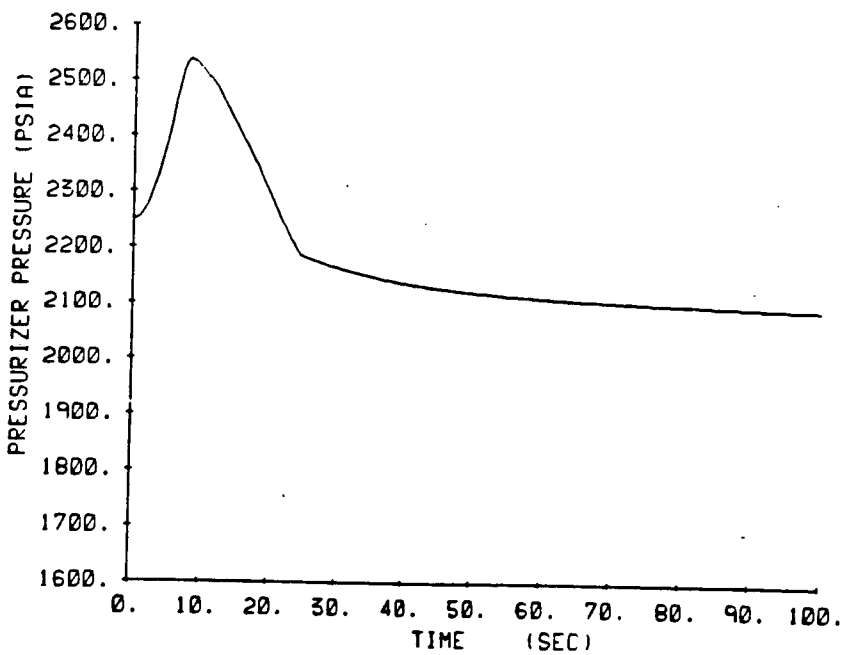
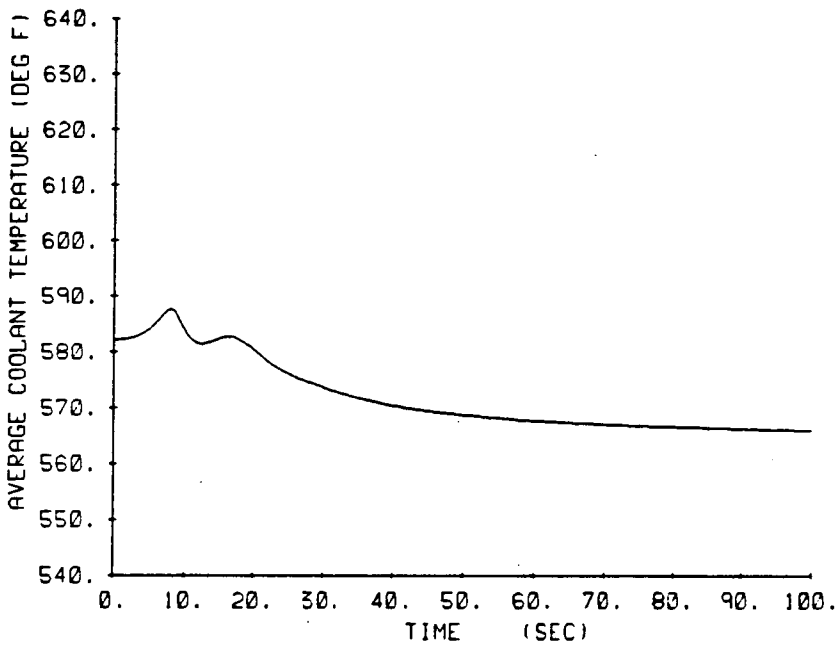


Figure A-11

Loss of Load without Pressurizer Spray and
Power Operated Relief Valves
End of Life
Average Coolant Temperature and
Pressurizer Water Volume versus Time



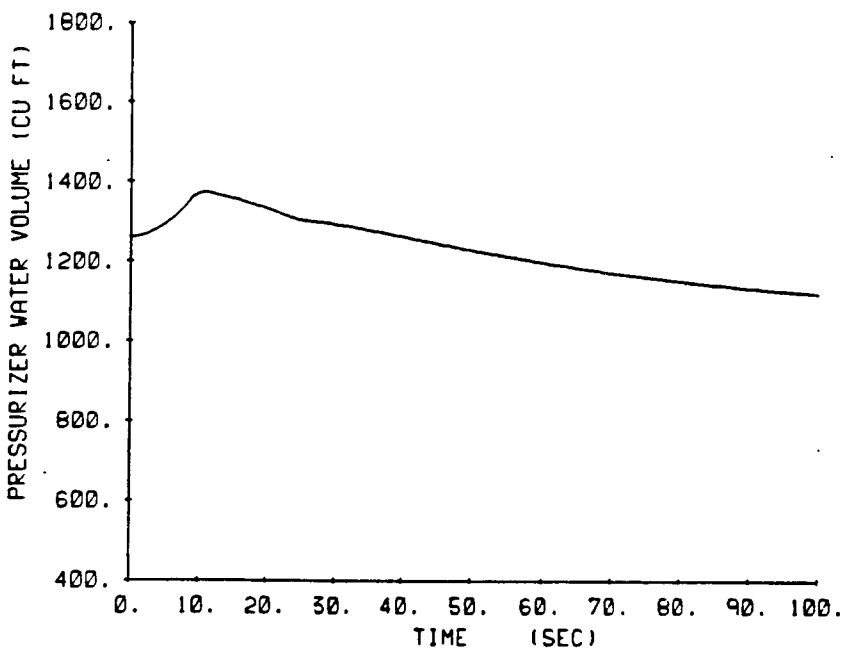
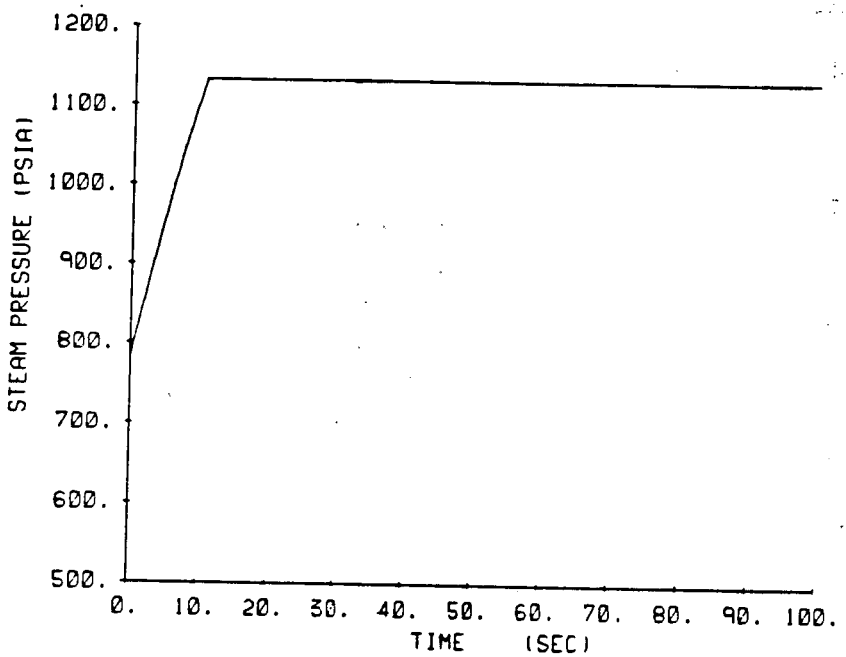


Figure A-12

Loss of Load without Pressurizer Spray and
Power Operated Relief Valves
End of Life
Steam Pressure and DNBR versus Time



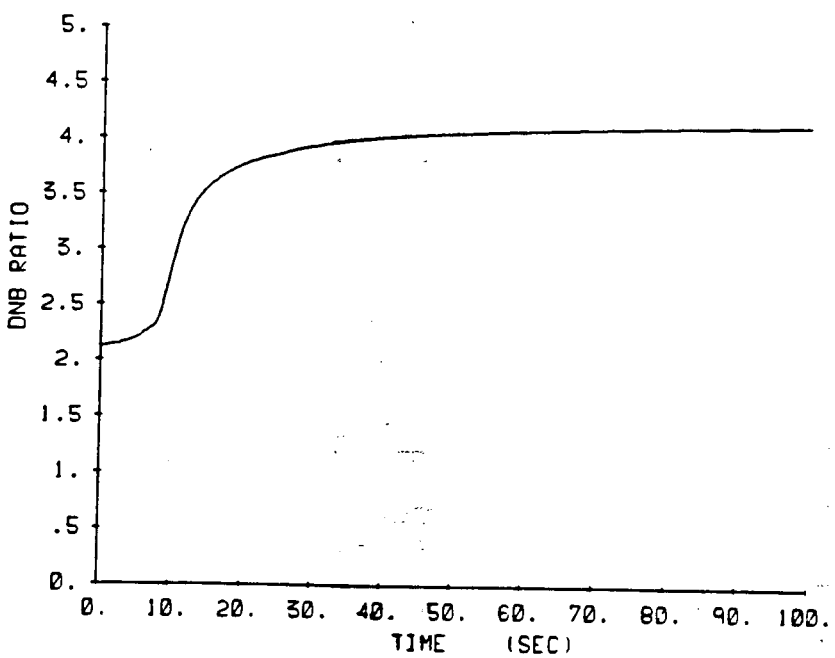
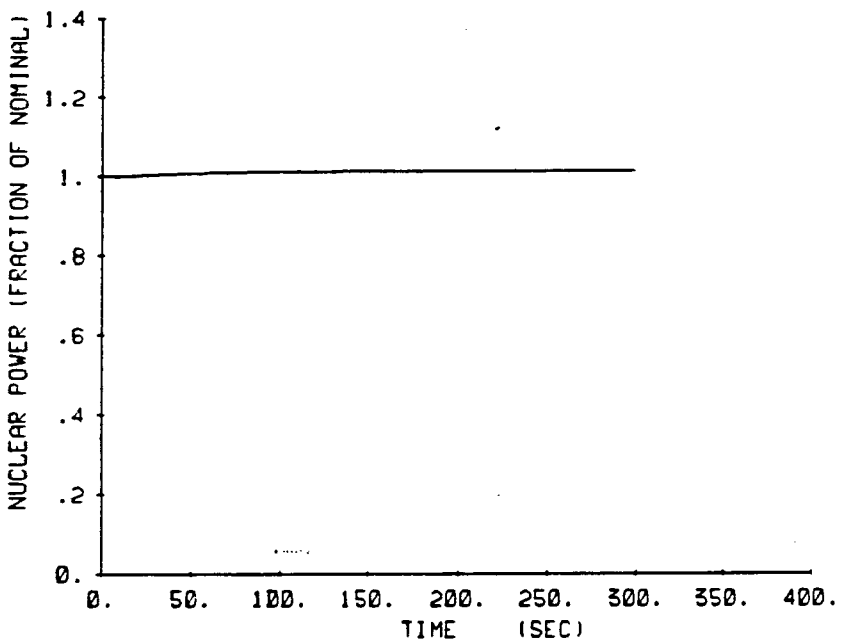


Figure A-13

Excessive Load Increase with
Manual Rod Control
Beginning of Life
Nuclear Power and Pressurizer Pressure versus Time



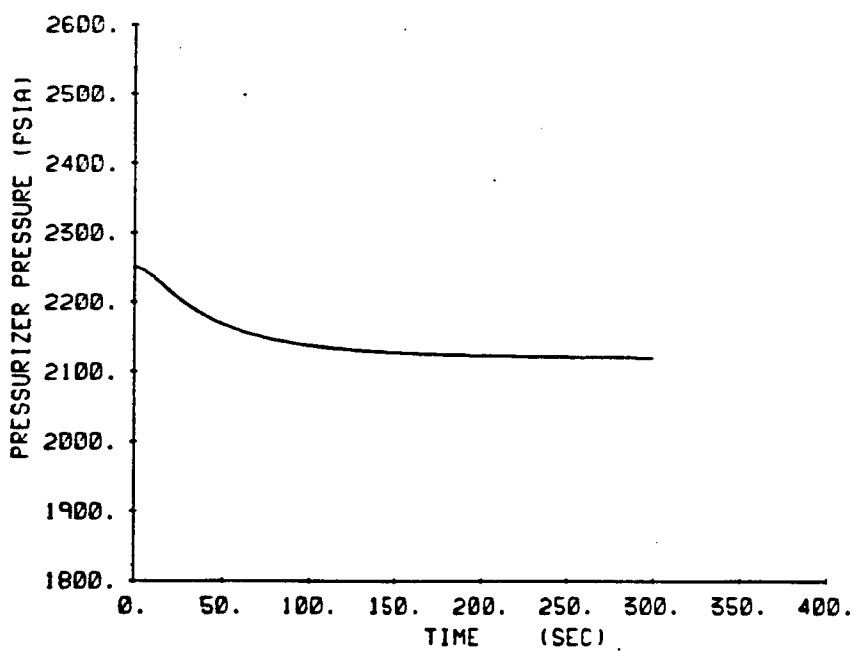
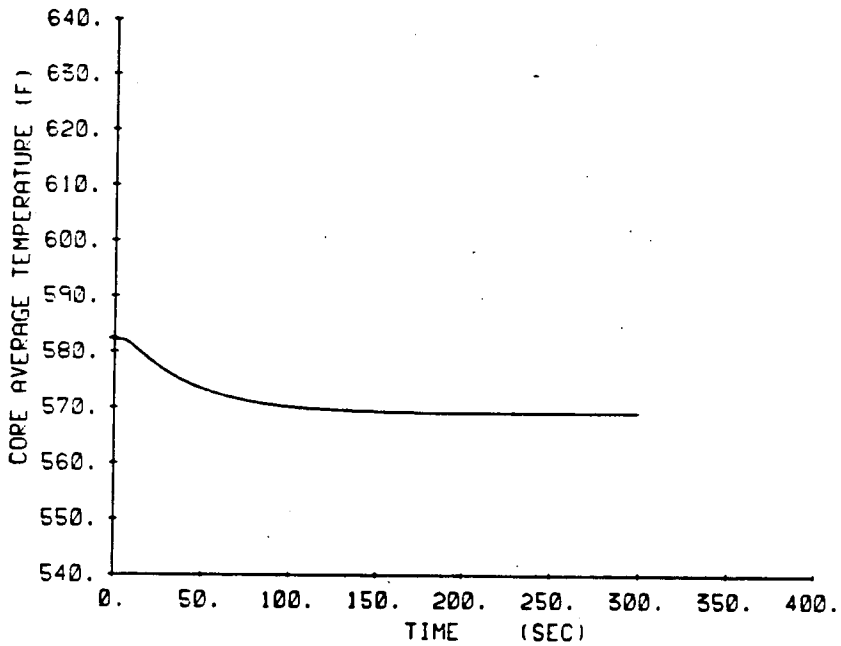


Figure A-14

Excessive Load Increase with
Manual Rod Control
Beginning of Life
Average Coolant Temperature and DNBR versus Time



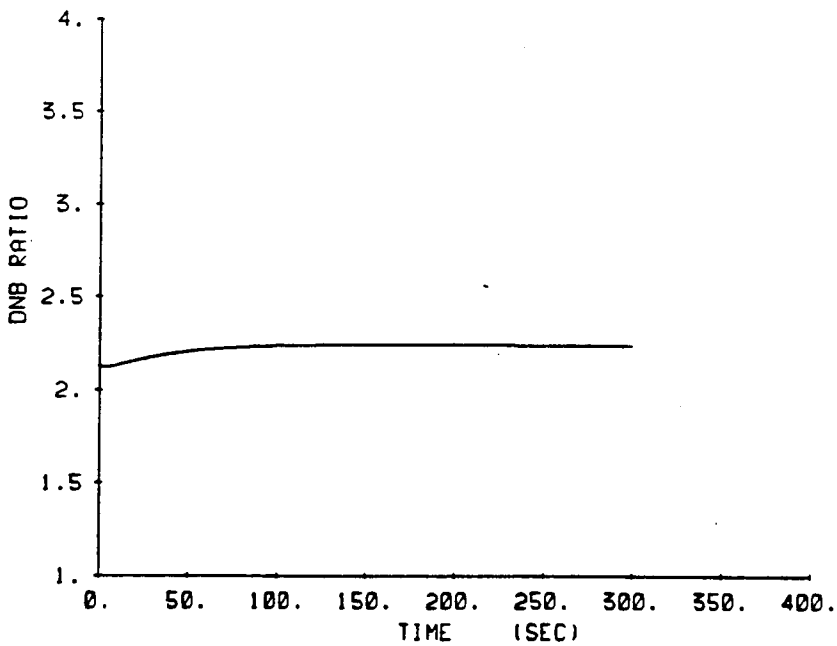
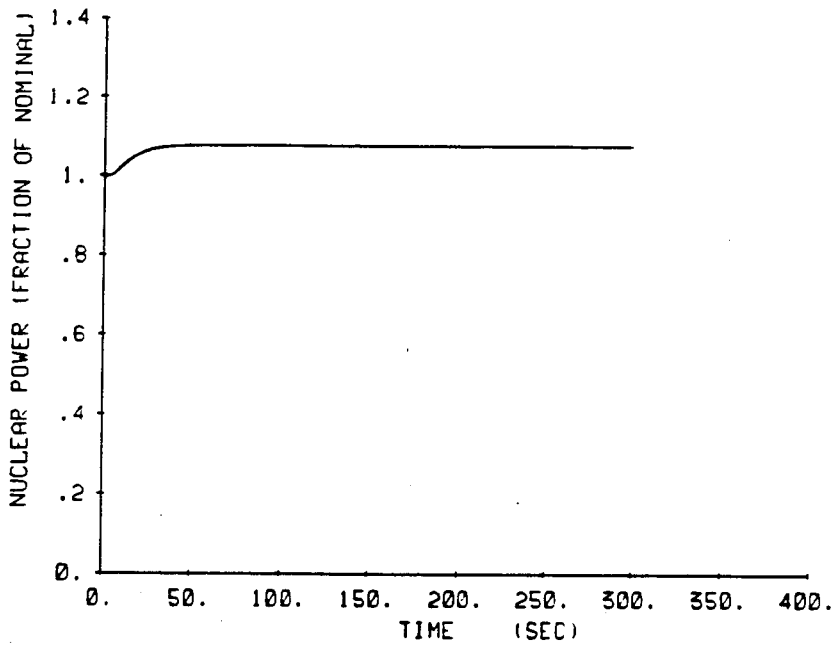


Figure A-15

Excessive Load Increase with
Manual Rod Control
End of Life
Nuclear Power and Pressurizer Pressure versus Time



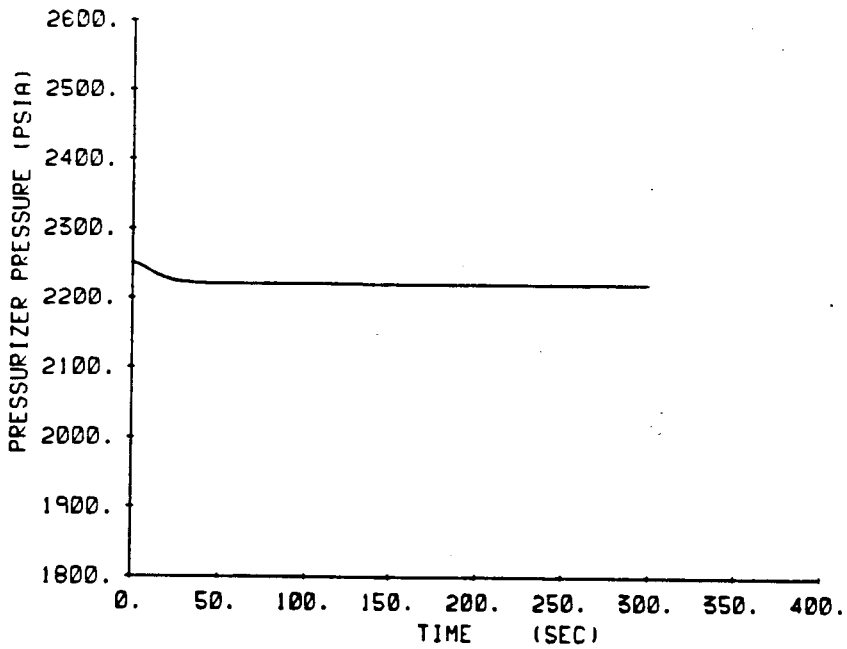
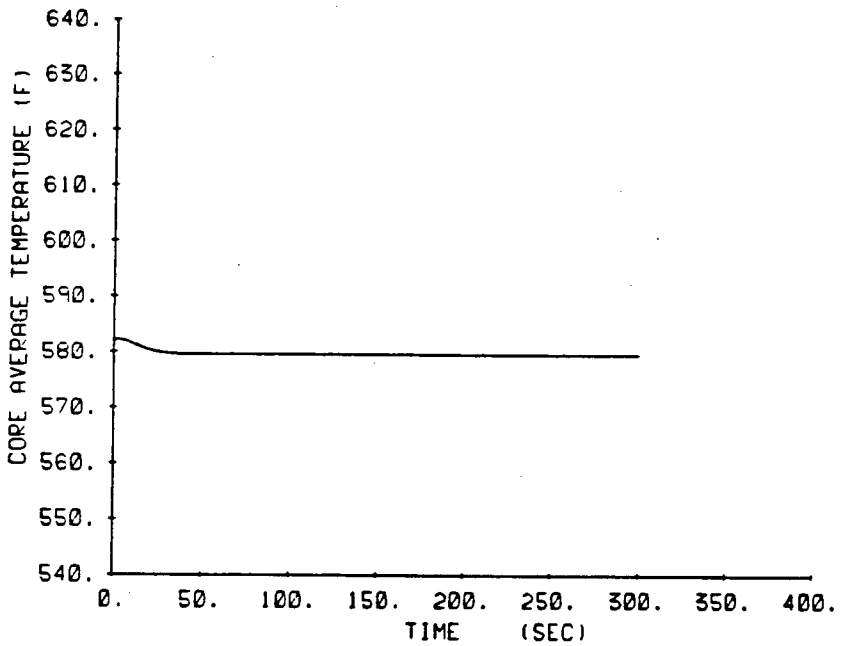


Figure A-16

Excessive Load Increase with
Manual Rod Control
End of Life
Average Coolant Temperature and DNBR versus Time



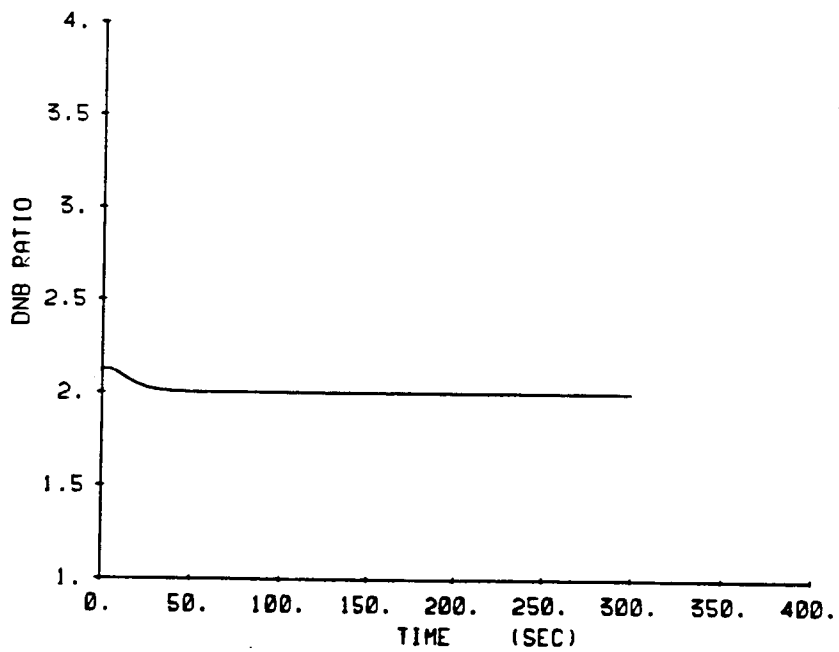
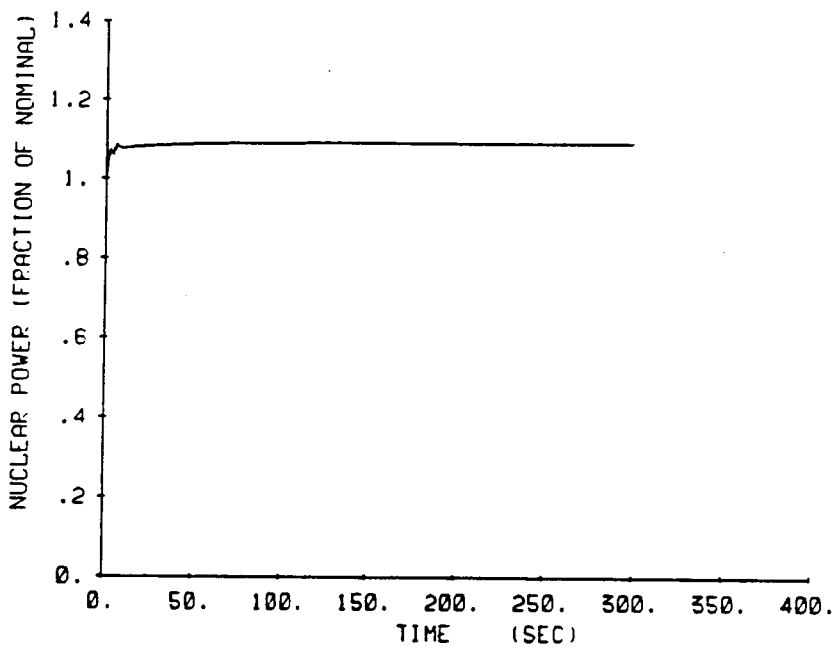


Figure A-17

Excessive Load Increase with
Automatic Rod Control
Beginning of Life
Nuclear Power and Pressurizer Pressure versus Time



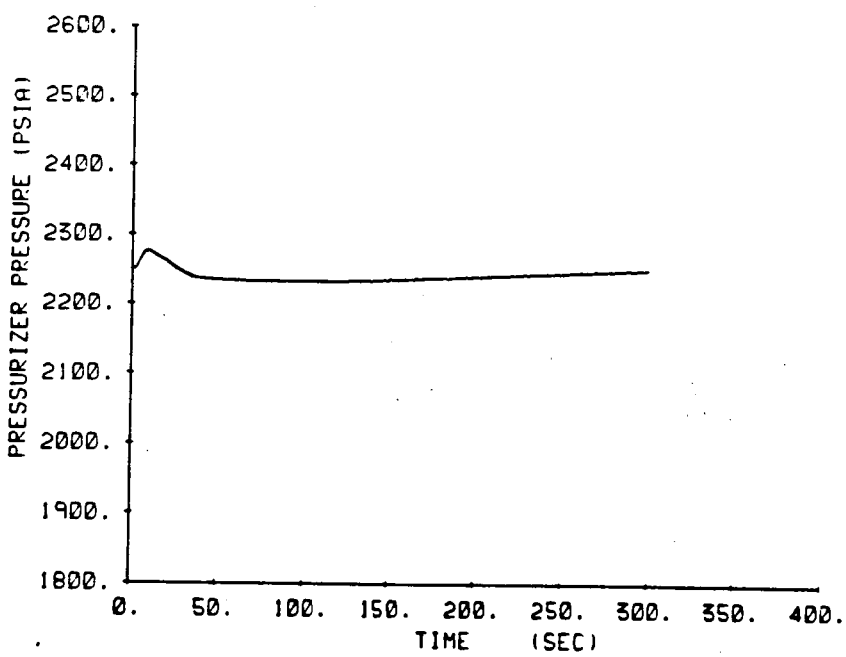
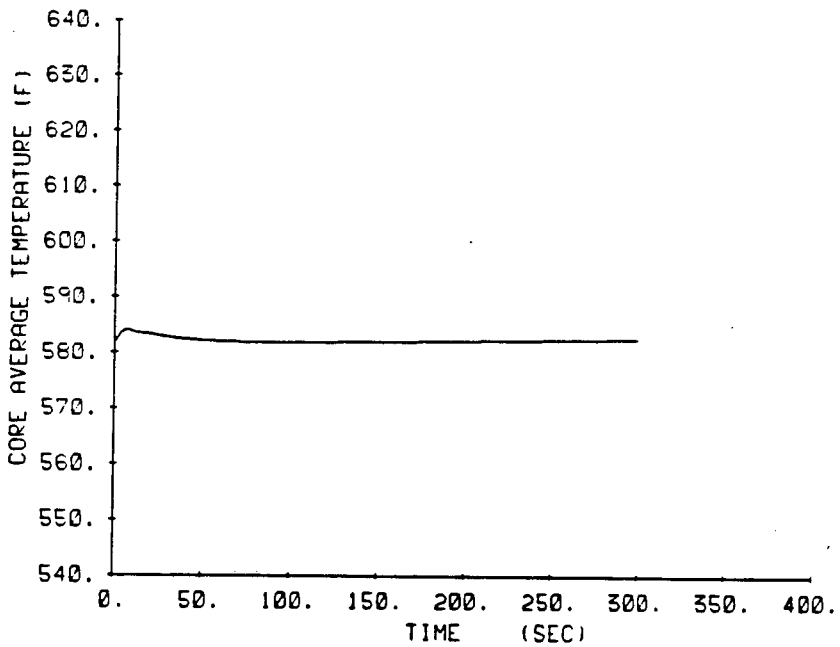


Figure A-18

Excessive Load Increase with
Automatic Rod Control
Beginning of Life
Average Coolant Temperature and DNBR versus Time



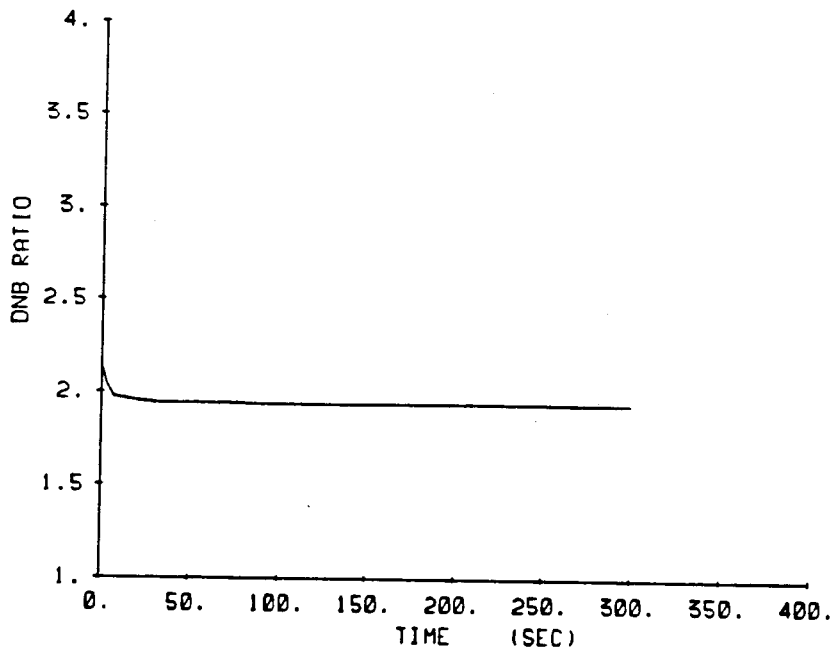
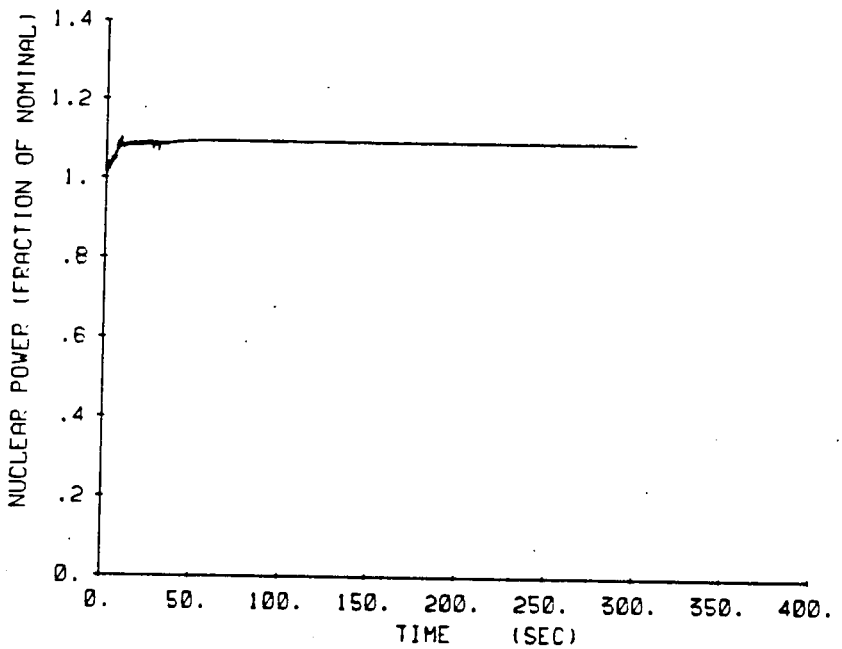


Figure A-19

Excessive Load Increase with
Automatic Rod Control
End of Life
Nuclear Power and Pressurizer Pressure versus Time



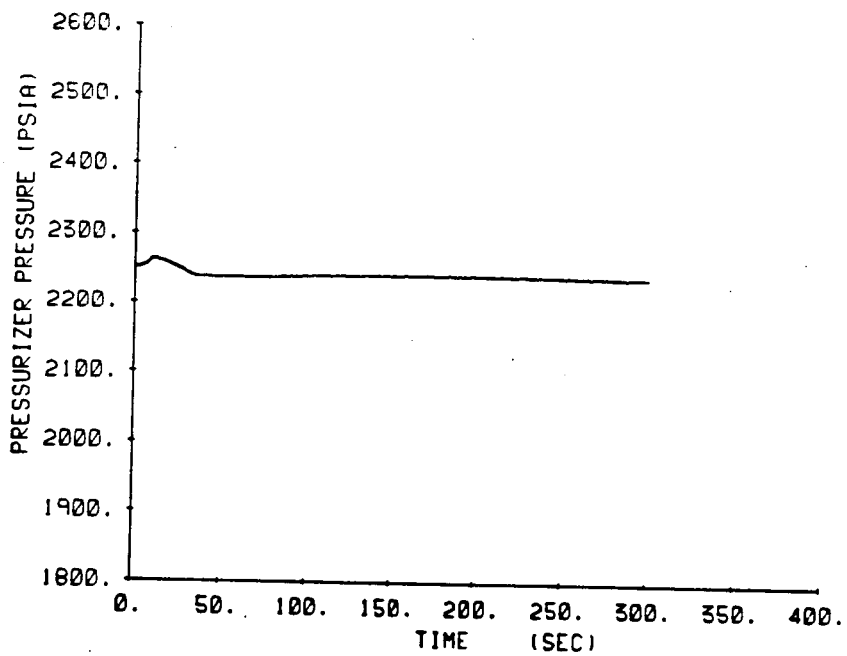
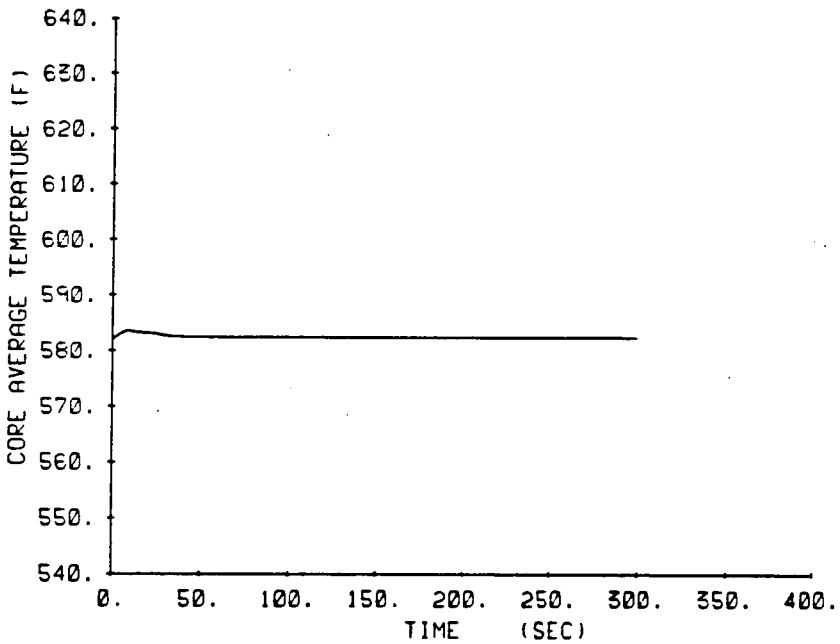


Figure A-20

Excessive Load Increase with
Automatic Rod Control
End of Life
Average Coolant Temperature and DNBR versus Time



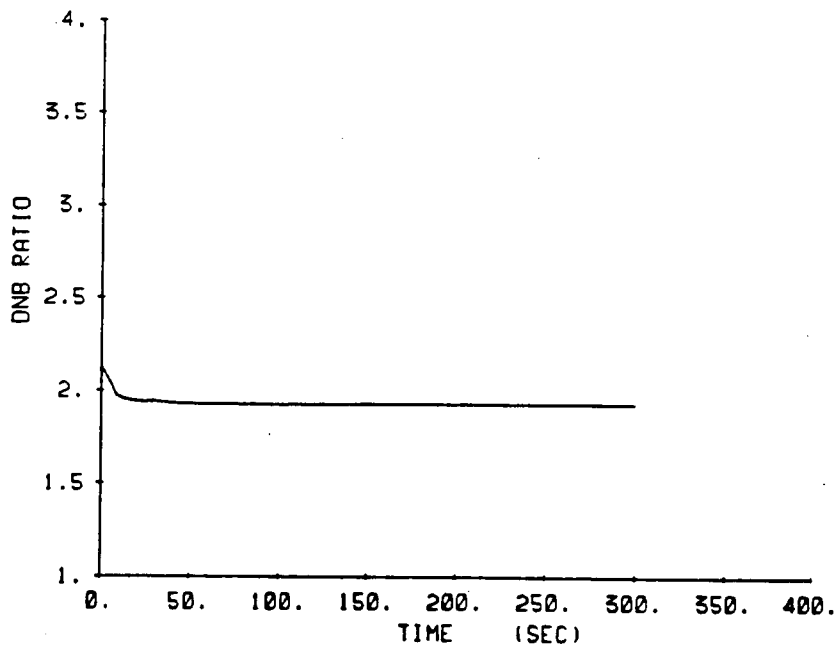
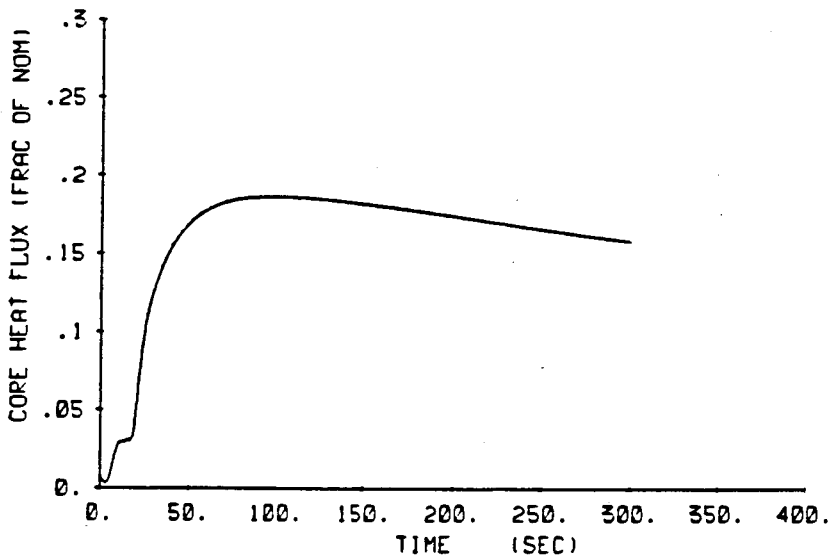


Figure A-21

Steam Line Rupture Inside Containment and Offsite Power Available
(Upstream of Flow Measuring Nozzle)
End of Life
Core Heat Flux and Core Reactivity versus Time



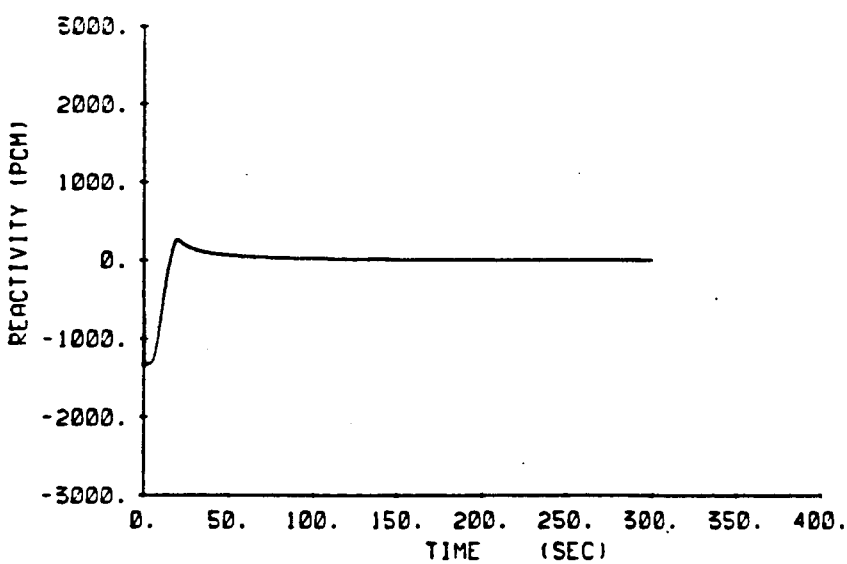
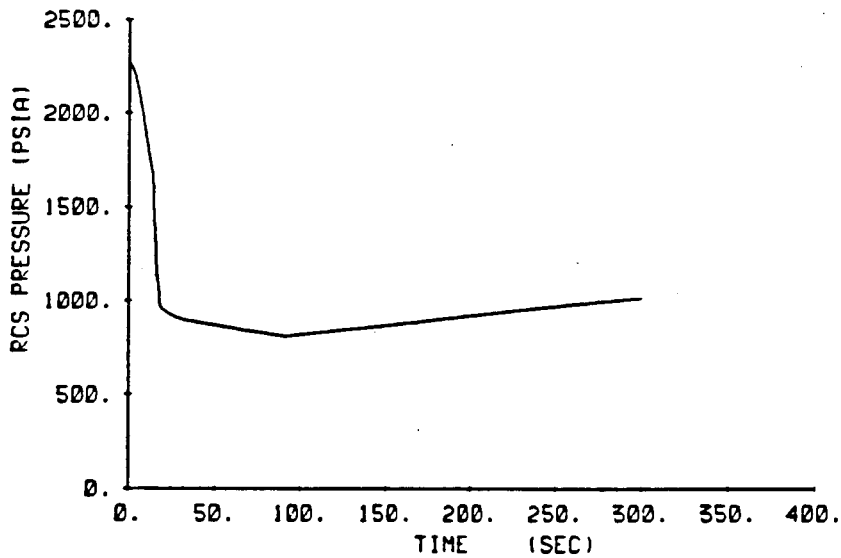


Figure A-22

Steam Line Rupture Inside Containment and Offsite Available
(Upstream of Flow Measuring Nozzle)
End of Life
Reactor Coolant Pressure and RV Inlet Temperatures



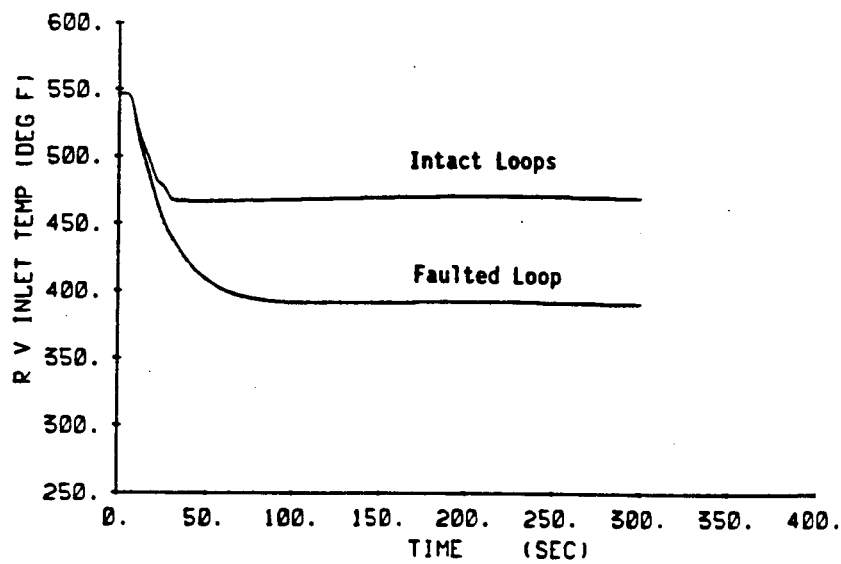


Figure A-23

Steam Line Rupture Inside Containment and Offsite Power Available
(Upstream of Flow Measuring Nozzle)
End of Life
Core Boron Concentration

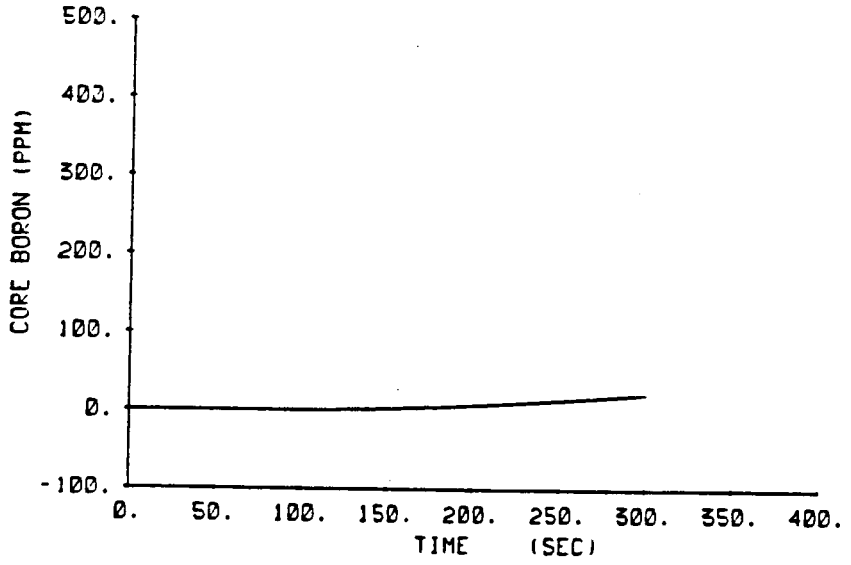
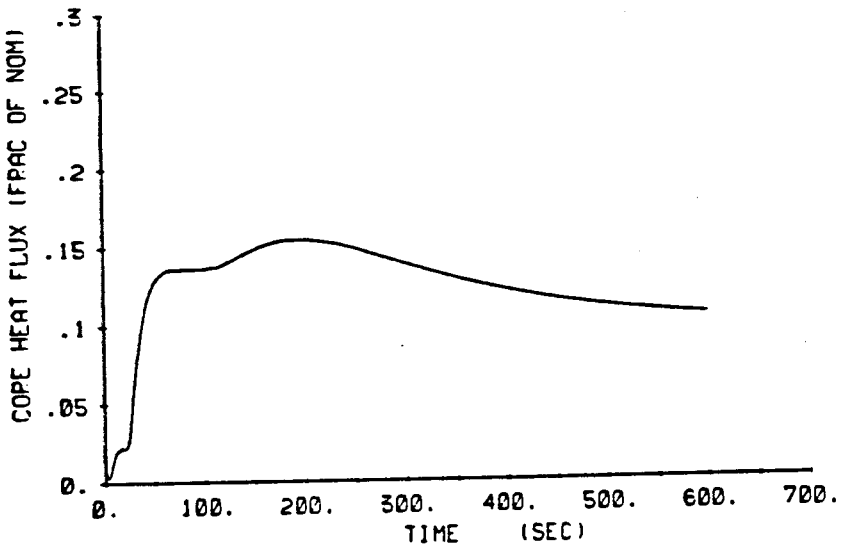


Figure A-24

Steam Line Rupture Inside Containment and Loss of Offsite Power
(Upstream of Flow Measuring Nozzle)
End of Life
Core Heat Flux and Core Reactivity versus Time



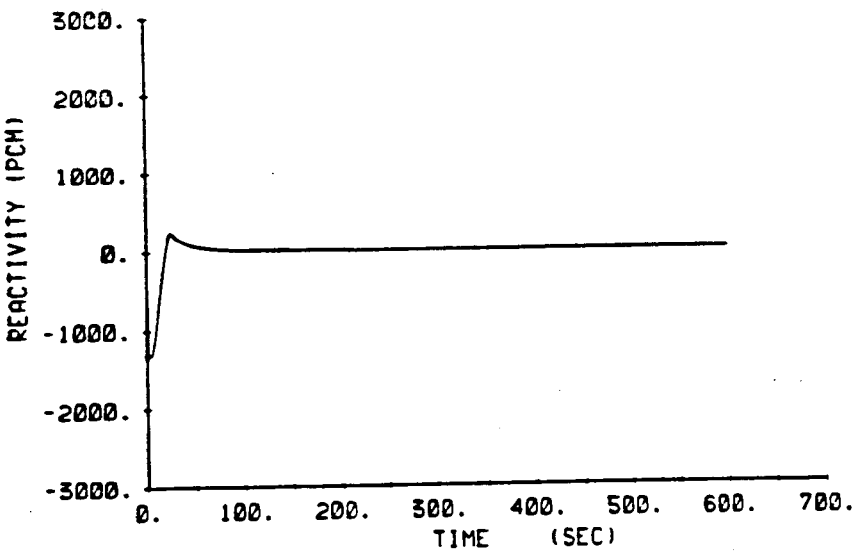
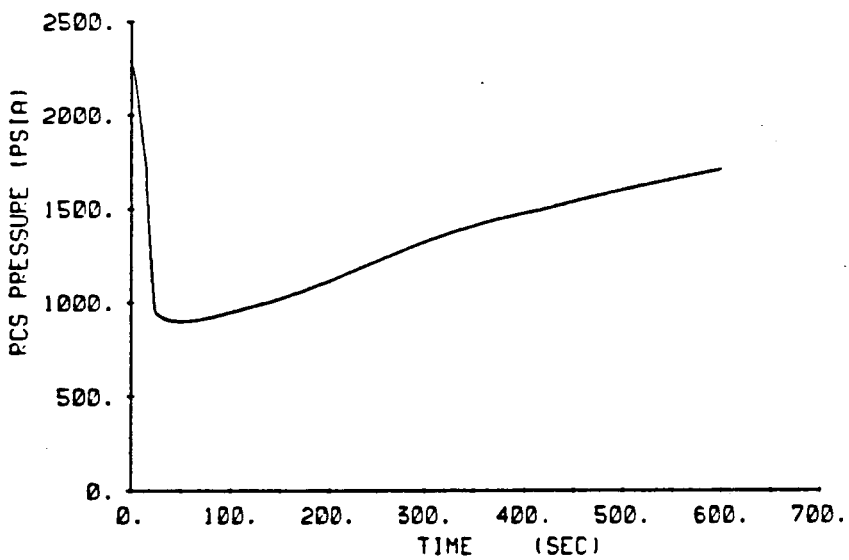


Figure A-25

Steam Line Rupture Inside Containment and Loss of Offsite
(Upstream of Flow Measuring Nozzle)
End of Life
Reactor Coolant Pressure and RV Inlet Temperatures



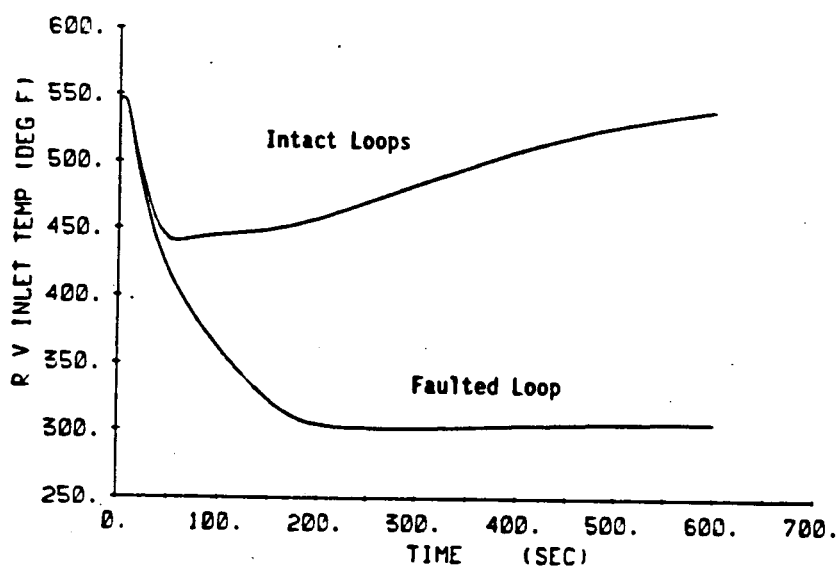
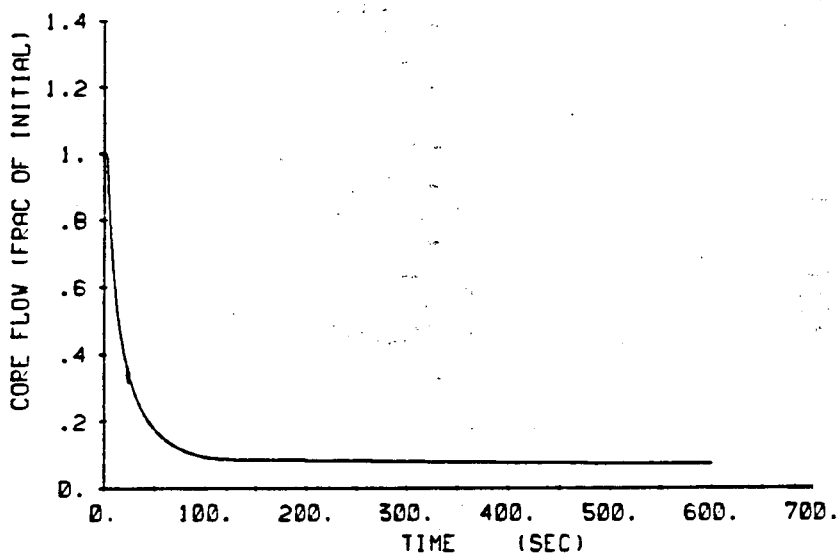


Figure A-26

Steam Line Rupture Inside Containment and Loss of Offsite Power
(Upstream of Flow Measuring Nozzle)
End of Life
Core Coolant Flow and Core Boron Concentration



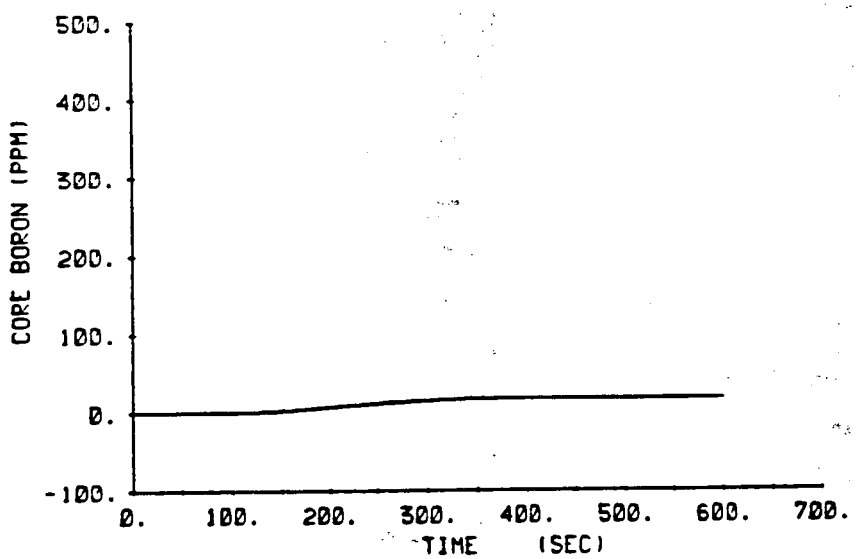
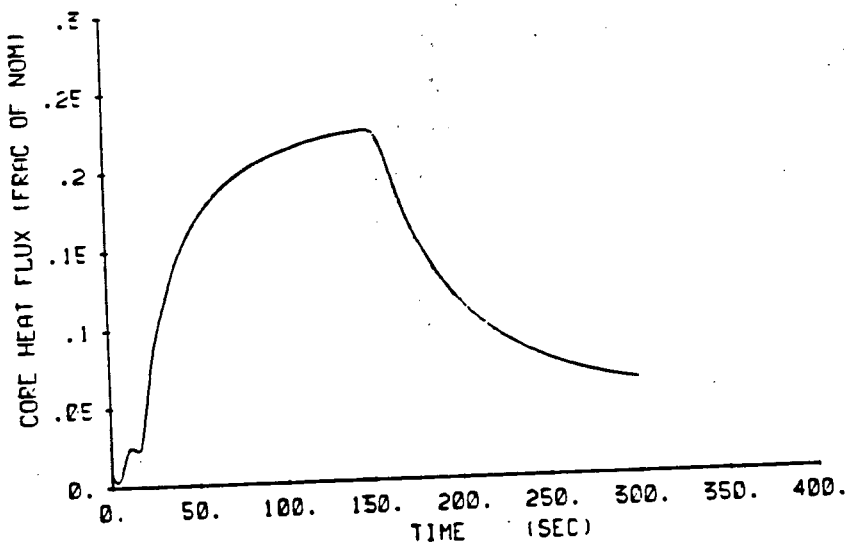


Figure A-27

Steam Line Rupture Outside Containment and Offsite Power Available
(Downstream of Flow Measuring Nozzle)
End of Life
Core Heat Flux and Core Reactivity versus Time



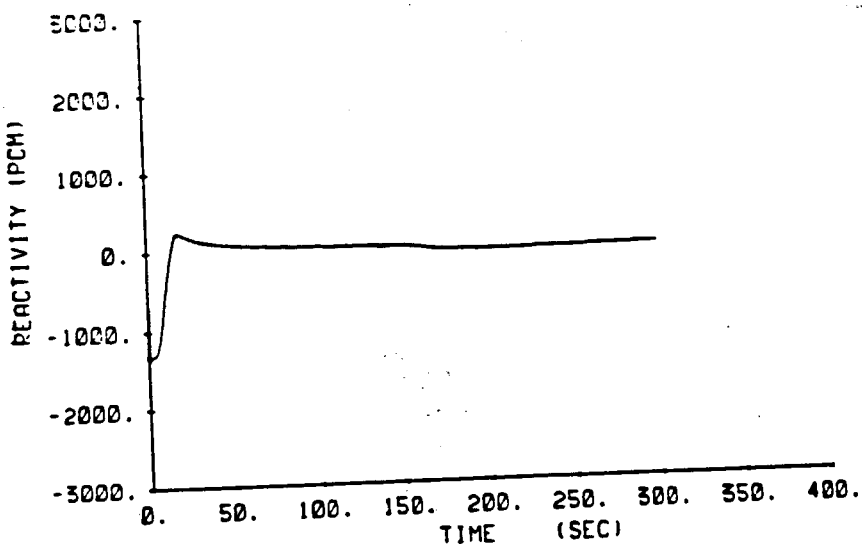
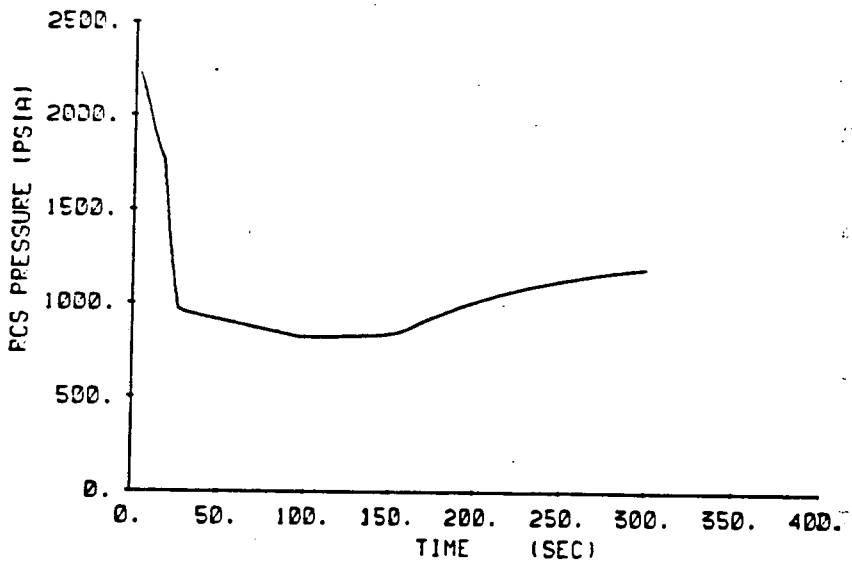


Figure A-28

Steam Line Rupture Outside Containment and Offsite Power Available
(Downstream of Flow Measuring Nozzle)
End of Life
Reactor Coolant Pressure and RV Inlet Temperatures



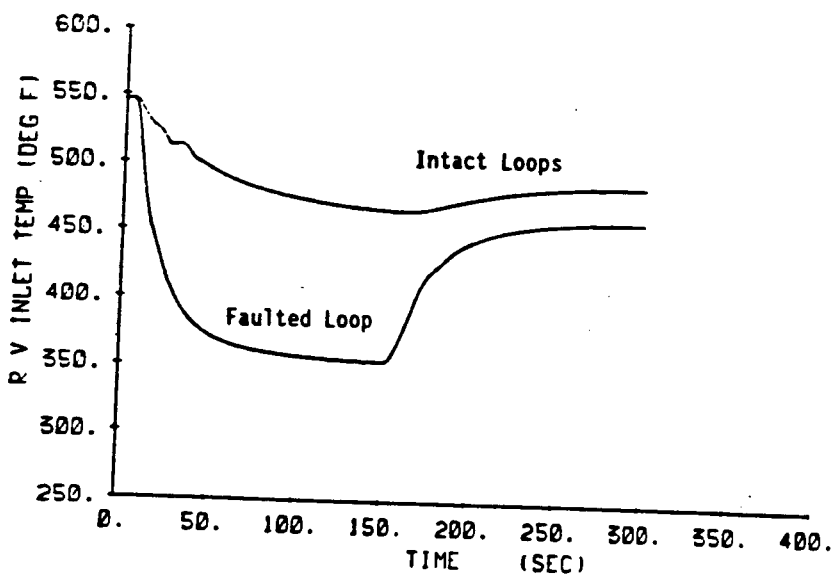


Figure A-29

Steam Line Rupture Outside Containment and Offsite Power Available
(Downstream of Flow Measuring Nozzle)
End of Life
Core Boron Concentration

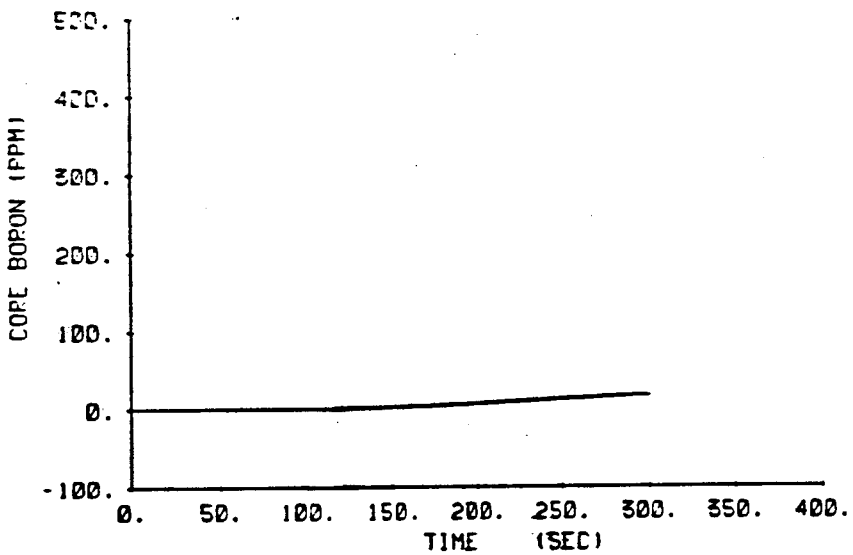
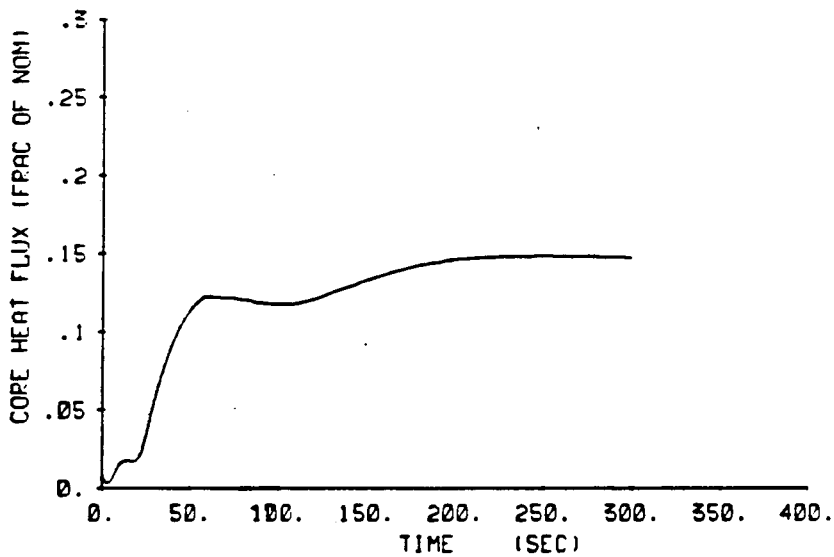


Figure A-30

Steam Line Rupture Outside Containment and Loss of Offsite Power
(Downstream of Flow Measuring Nozzle)
End of Life
Core Heat Flux and Core Reactivity versus Time



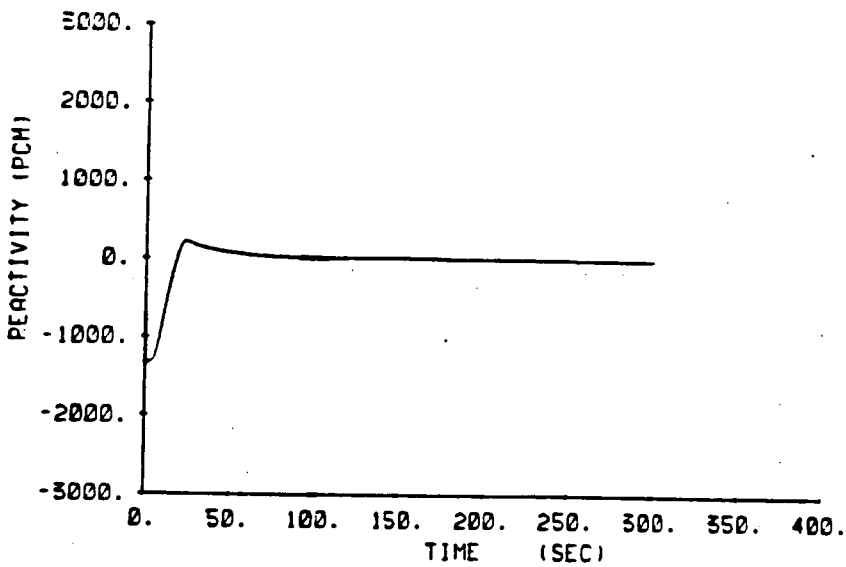
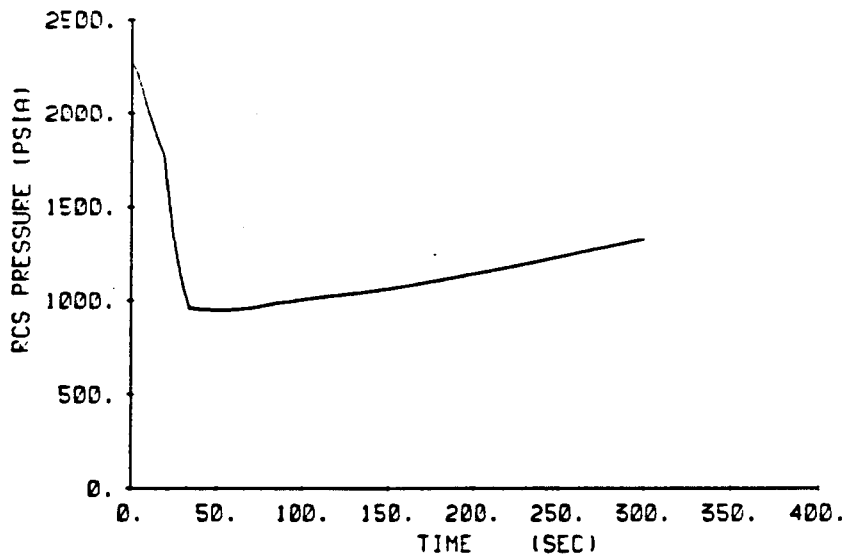


Figure A-31

Steam Line Rupture Inside Containment and Loss of Offsite
(Downstream of Flow Measuring Nozzle)
End of Life
Reactor Coolant Pressure and RV Inlet Temperatures



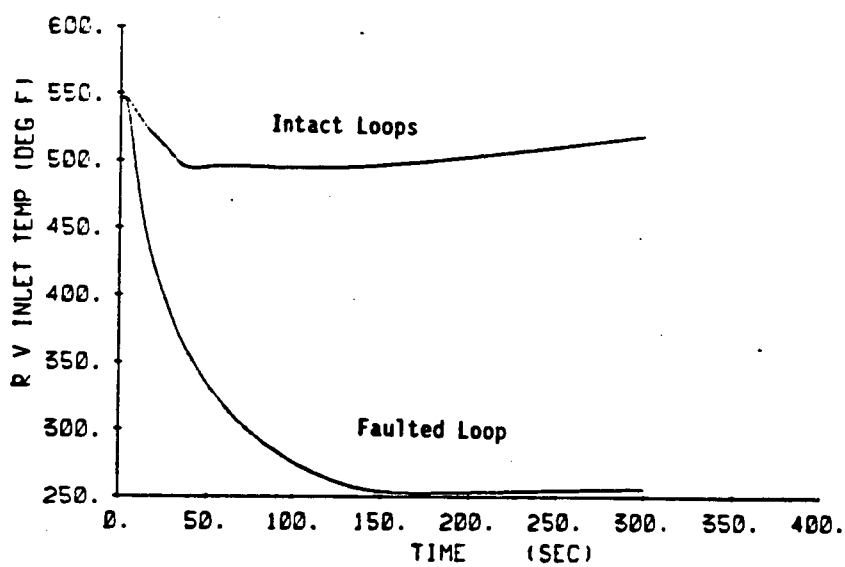
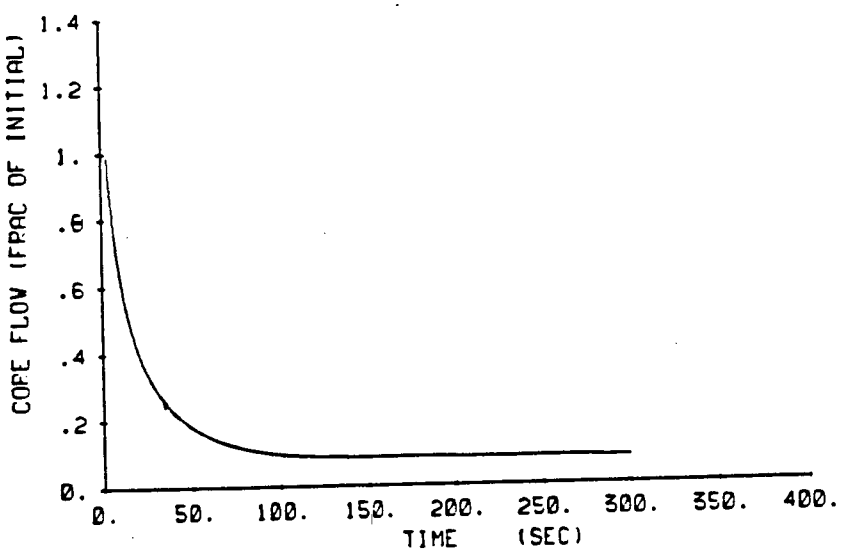


Figure A-32

Steam Line Rupture Inside Containment and Loss of Offsite Power
(Downstream of Flow Measuring Nozzle)
End of Life
Core Coolant Flow and Core Boron Concentration



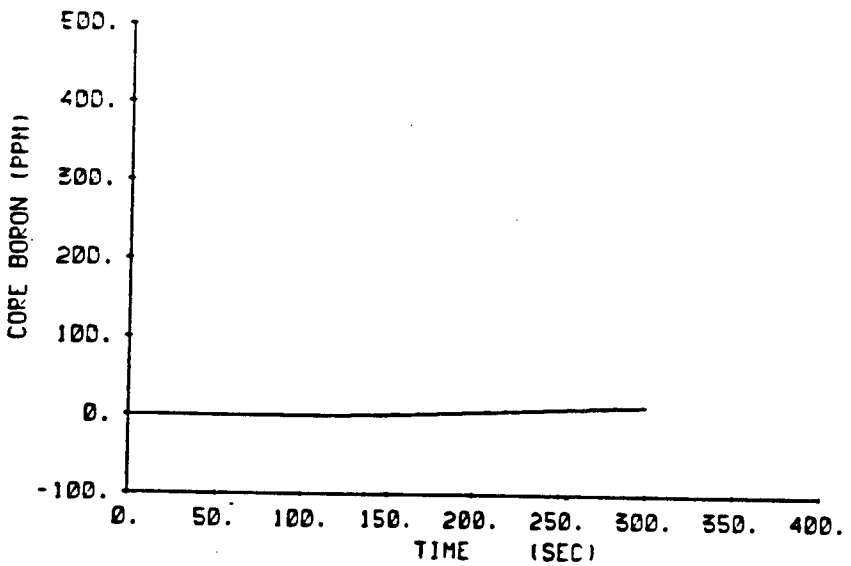
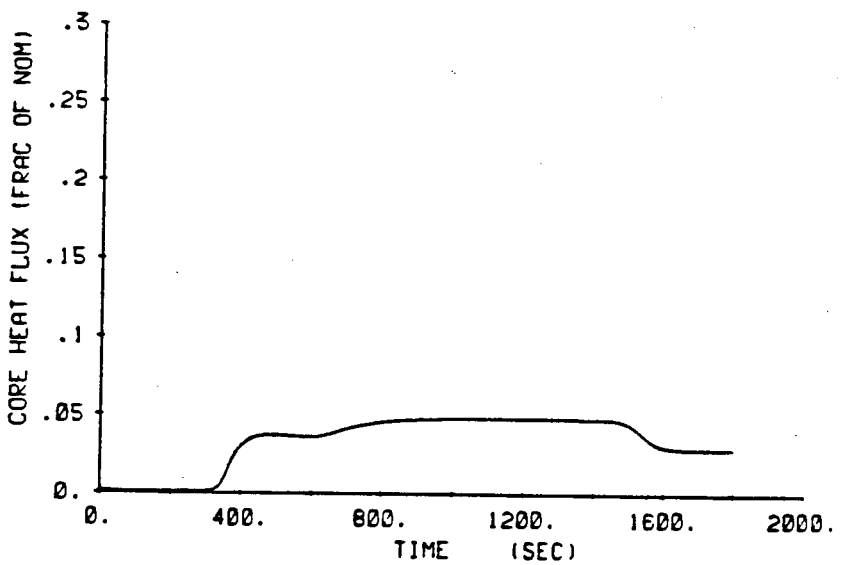


Figure A-33

Steam Line Rupture Equivalent to the Opening of
a Steam Generator Safety Valve and Offsite Power Available
End of Life
Core Heat Flux and Core Reactivity versus Time



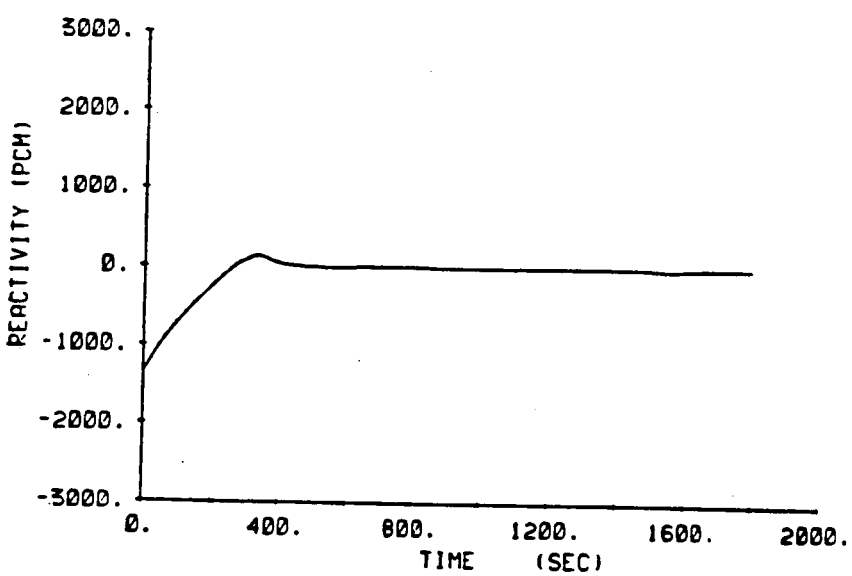
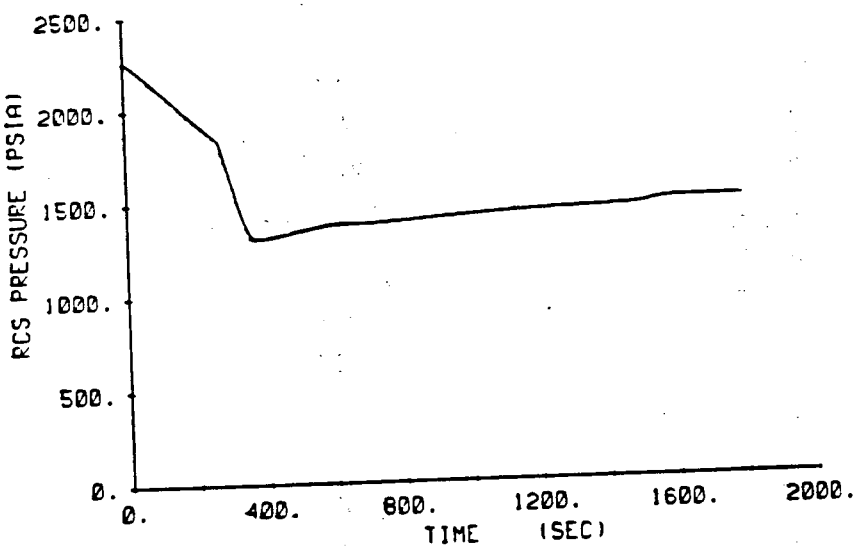


Figure A-34

Steam Line Rupture Equivalent to the Opening of
a Steam Generator Safety Valve and Offsite Power Available
End of Life
Reactor Coolant Pressure and RV Inlet Temperatures



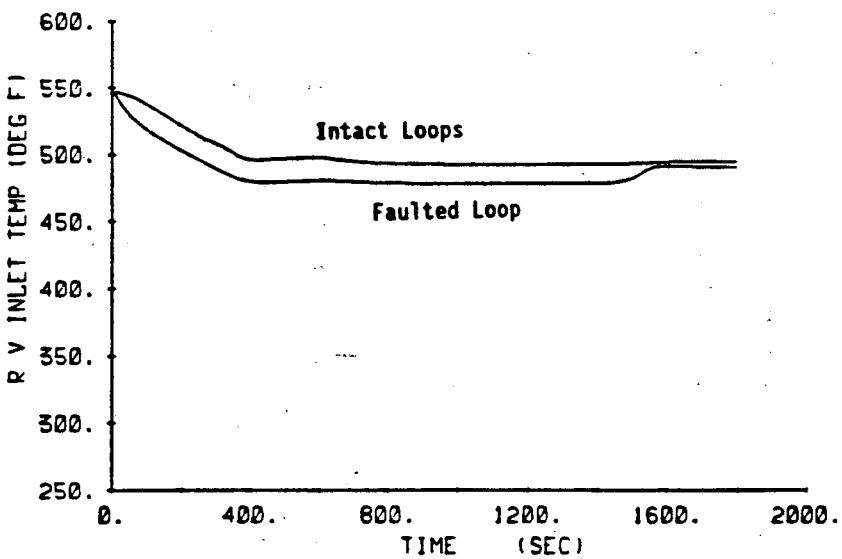
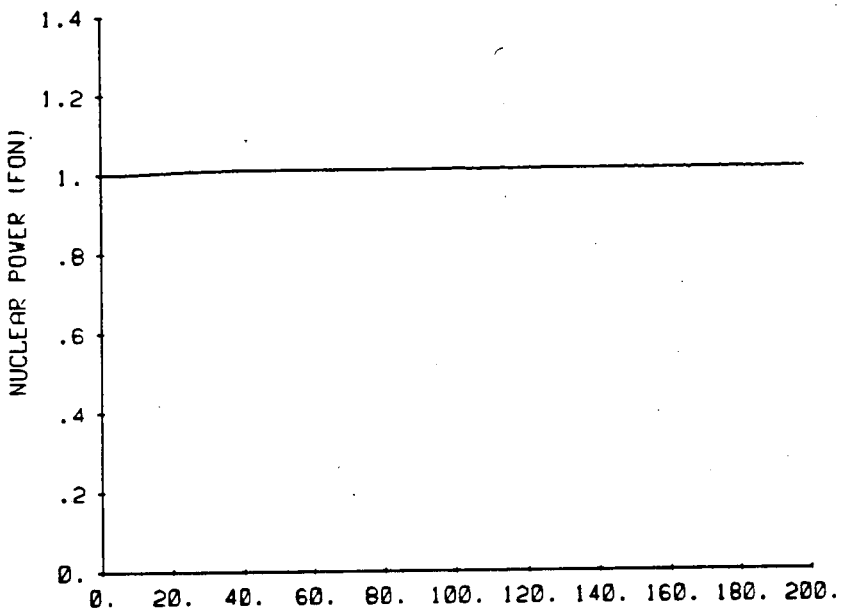


Figure A-35

Feedwater System Malfunction
Excessive Feedwater Flow at HFP conditions
Manual Rod Control

Nuclear power and Core Heat Flux Vs. Time



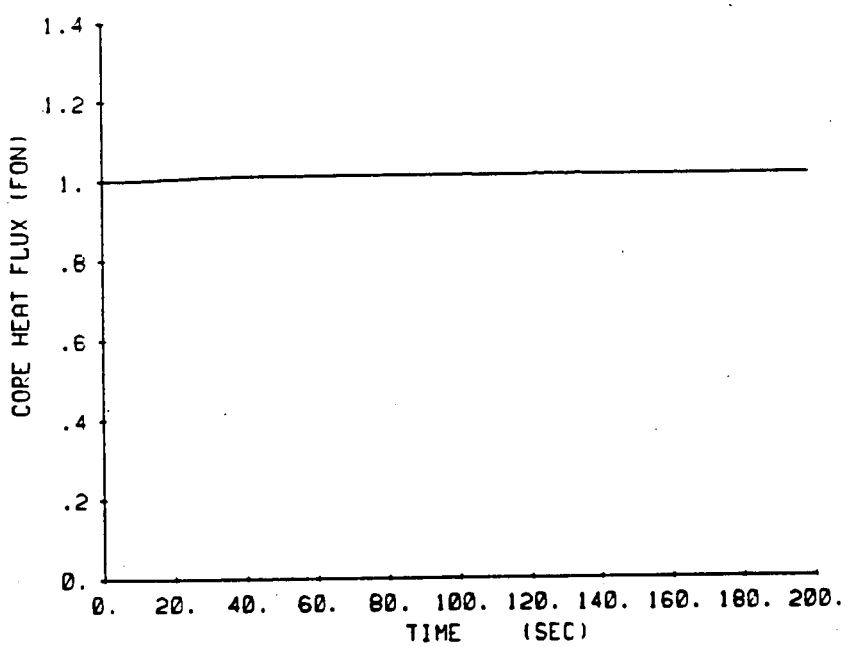
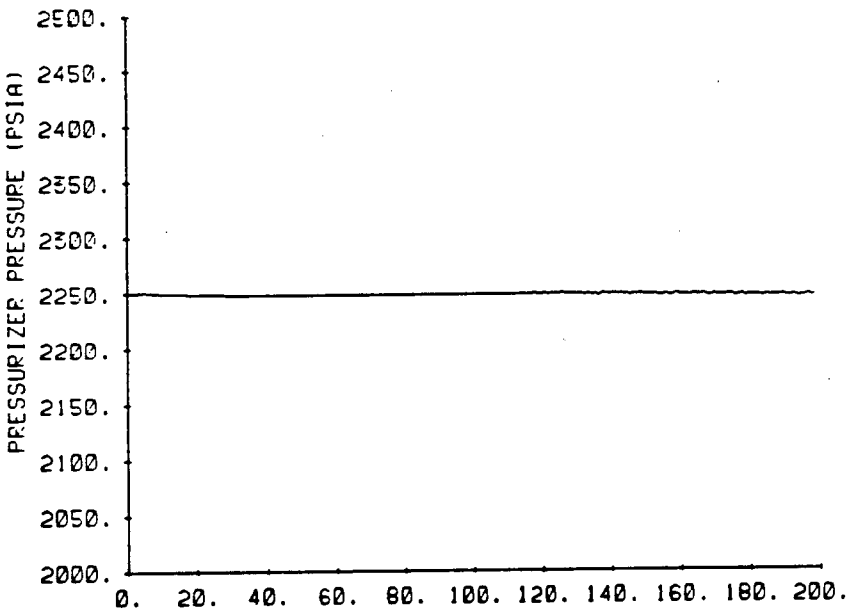


Figure A-36

Feedwater System Malfunction
Excessive Feedwater Flow at HFP conditions
Manual Rod Control

Pressurizer pressure and DNBR Vs. Time



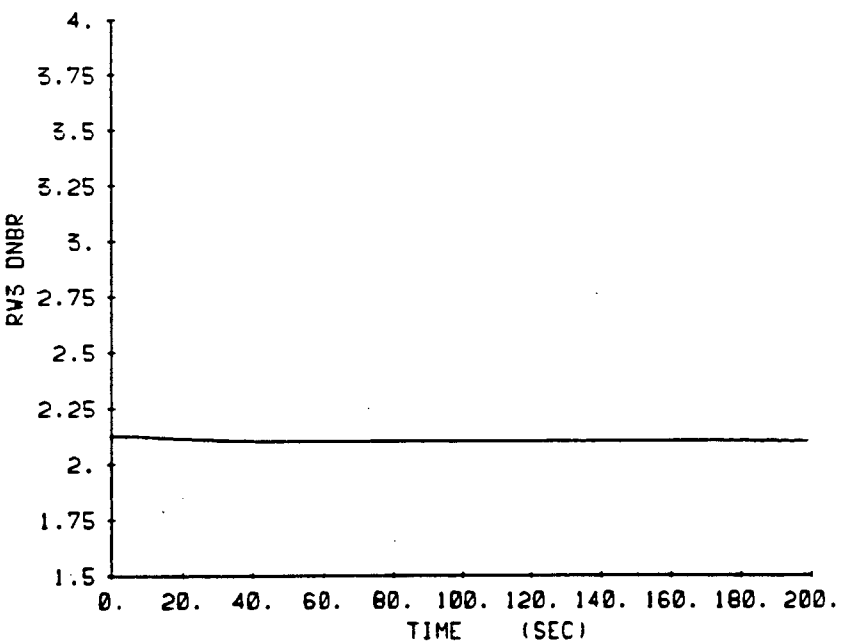


Figure A-37

Feedwater System Malfunction
Excessive Feedwater Flow at HFP conditions
Manual Rod Control

Loop Delta-T and Core Tavg Vs. Time