6.3 EMERGENCY CORE COOLING SYSTEM

6.3.1 DESIGN

6.3.1.1 Summary Description

The Emergency Core Cooling System (ECCS) is the Safety Injection System (SIS). It is designed to provide core cooling in the unlikely event of a loss-of-coolant accident (LOCA). The SIS prevents significant alteration of core geometry, precludes fuel melting, limits the cladding metal-water reaction, removes the energy generated in the core and maintains the core subcritical during the extended period of time following a LOCA.

The SIS accomplishes these functional requirements by use of redundant active and passive injection subsystems. The active portion of the SIS consists of high pressure and low pressure safety injection pumps and associated control valves. The passive portion consists of nitrogen pressurized safety injection tanks (SIT).

In addition, the Safety Injection System functions to inject borated water into the Reactor Coolant System to add negative reactivity to the core in the unlikely event of a steam line break. Safety injection may also be initiated in the event of a steam generator tube rupture or a CEA ejection accident. The system is actuated automatically. The design of the SIS is functionally similar to St. Lucie Unit 1, Calvert Cliffs (Units 1 and 2) and Millstone (Unit 2).

6.3.1.2 Criteria

6.3.1.2.1 Functional Design Bases

a. The design parameters of the high pressure safety injection (HPSI) pump and low pressure safety injection (LPSI) pump are selected to insure that adequate flow is delivered to the Reactor Coolant System to accomplish the functional requirements of Subsection 6.3.1.1.

b. Borated water for the SIS is provided by the refueling water tank (RWT) to accomplish the functional requirements of Subsection 6.3.1.1.

c. The SIS is designed such that equal flows are delivered to each injection point, regardless of break location.

6.3.1.2.2 Reliability Design Bases

a. The safety function defined in Subsection 6.3.1.1 can be accomplished assuming the failure of a single active component during the injection mode of operation or the single active or limited leakage passive failure of a component during the recirculation mode of operation (refer to Subsection 6.3.2.5.4). A limited leakage passive failure is defined as the failure of a pump seal or a valve packing whichever is greater. The maximum leakage is expected to be from a failed LPSI pump seal.

b. Components of the SIS and instrumentation which must operate following a LOCA are designed to operate in the environment to which they would be

exposed in the unlikely event of a LOCA for the time they are required to operate (refer to Section 3.11).

c. The SIS is designed to seismic Category I requirements (refer to Section 3.2).

d. The SIS is protected against internally generated missiles and the dynamic effects associated with pipe breaks (as discussed in Sections 3.5 and 3.6 respectively).

e. The design of the SIS provides for inspection and testing of components and subsystems to ensure their availability and proper operation.

f. Valve motor operators inside containment are protected from flooding by locating them above the maximum post LOCA water level.

6.3.1.2.3 Environment Design Bases

Each SIS safeguards train is provided with an independent environmentally qualified control system such that the safety related equipment in each train operates within the environmental design limits specified in Section 3.11.

6.3.2 SYSTEM DESIGN

6.3.2.1 System Schematic

The SIS piping and instrumentation diagram (P&ID) is shown on Figures 6.3-1a, 1b and 1c. The major components of the system are the high pressure safety injection pumps, low pressure safety injection pumps, safety injection tanks, high pressure injection valves, low pressure injection valves and the refueling water tank. The major components are described in the following subsection. Figures 6.3-2a, 2b, 2c and 2d and Tables 6.3-4a, 4b, 4c and 4d show the various modes of operation of the system.

6.3.2.2 Component Description

A summary of the design parameters for the major components is given in Table 6.3-1. The shutdown cooling heat exchangers are discussed in Subsection 5.4.7. Details of instrumentation and controls associated with the SIS are provided in Subsection 6.3.5 and Sections 7.3, 7.5 and 7.6. Subsection 6.3.3 specifies the components used to provide core protection for the complete spectrum of reactor coolant pipe breaks.

The SIS components are designed, fabricated, inspected, tested and installed in accordance with the appropriate class of the ASME Code, Section III, (see Section 3.2). The design temperatures and pressures are selected to provide a generous margin above the highest anticipated component temperatures and pressures. Components are designed to provide a system whose design flowrate and net positive suction head (NPSH) meet acceptable values.

NPSH required for the safety injection pumps is shown on Figures 6.3-3a, 3b, 4a and 4b. A further discussion is provided in Subsection 6.3.2.2.3.

6.3.2.2.1 Safety Injection Tanks

The four safety injection tanks discharge their contents to the Reactor Coolant System following depressurization as a result of a loss-of-coolant accident. Each tank is connected to a cold leg of the Reactor Coolant System (RCS) via a safety injection nozzle located on the Reactor Coolant System (RCS) piping near the reactor vessel inlet. During normal plant operation each safety injection tank is isolated from the Reactor Coolant System by two check valves in series. The safety injection tanks automatically discharge into the Reactor Coolant System if Reactor Coolant System pressure decreases below safety injection tank pressure during reactor operation.

The motor operated isolation valves on the safety injection tank discharge are interlocked with pressurizer pressure signals to open automatically prior to an actual or simulated signal exceeding 515 psia, and to prevent inadvertent closure prior to or during an accident.

These isolation valve interlocks are uniquely identified as Class 1E circuits and are in conformance with the recommendations of Regulatory Guide 1.75 (R1) and the requirements of IEEE 384. After the valve is opened, it is locked open in the control room, and power to the motor is removed at the motor control center, outside the control room. The removal of electrical power (by opening and closing of the breakers) is to assure the open position of these valves (V3614, V3624, V3634, V3644) and to prevent, by single failure, isolation of the SITs. Also, each SIT isolation valve has two means of position indication displayed in the control room. There is an open and a closed light display for each, as well as a 0-100% position indicator, and the power supply to the position indicator is separate from control power. There is also an annunciator in the control room to alert the operator when the valve is in the "not full open position".

During plant cooldown, safety injection tank pressure is lowered by the operator in accordance with operating procedures during Reactor Coolant System pressure decreases. There are multiple ways to reduce the pressure of the safety injection tanks. Redundant safety grade vent valves (two in parallel) are provided to relieve the nitrogen cover gas. See Subsection 5.4.7.5 for a discussion of these vents and other means for reducing safety injection tank pressure. An interlock with pressurizer pressure prevents the safety injection tank isolation valves from being closed until Reactor Coolant system pressure drops to 276 psia. Following License Amendment No. 100, the SITs are not required to be operable in Modes 4,5 and 6. The SIT isolation valves may be closed when the RCS temperature is below Mode 3 temperature.

If Reactor Coolant System pressure is increased, and prior to an actual or simulated signal exceeding 515 psia, an interlock with pressurizer pressure automatically opens the safety injection tank isolation valves. The operator repressurizes the safety injection tanks after pressurizer pressure has been increased above the maximum safety injection tank pressure allowed by the operating procedures. The safety injection tank gas/water fractions, nitrogen gas pressure, and outlet pipe size are selected to allow three of the four safety injection tanks to assist in recovering the core before significant clad melting or zirconium-water reaction can occur following a LOCA.

The safety injection tanks contain borated water at the required Technical Specification concentration and are pressurized with nitrogen to the normal operating range of 540-570 psig (the Technical Specification operating range is 500 to 650 psig). Note that beginning with Cycle 7, the minimum safety injection tank operating pressure was reduced from 570 psig to 500 psig.

Redundant water level and pressure instrumentation is provided to monitor the condition of the safety injection tanks. This instrumentation is not utilized for SIT isolation valve interlocks. Therefore, these instruments are located on the control board in a non-safety section. However, the redundant instrument cables are routed in physically separate non-safety cable trays, and instrument power is supplied from a separate non-safety power source. The wide range water level instrumentation loop has been upgraded to receive a 120 Vac vital uninterrupted power source to meet the requirements of Regulatory Guide 1.97, Rev 3. (See Table 6.3-20). Sufficient visual and audible indication are available to the operator such that maintaining the safety injection tanks within the required Technical Specifications during various modes of plant operation is readily accomplished from the control room. Provisions are made for sampling, filling, draining, and adjusting boron concentration. Atmospheric vent valves are provided for safety injection tank venting, during both normal and post-accident conditions. These valves are safety-related valves (two valves per SIT, in parallel, powered from different safety buses). Power to those valves is removed (from the control room) during normal operation.

The RWT is not provided with missile shielding. The safety injection tanks are credited as a backup water source in the event the RWT is unavailable for safe shutdown due to a missile or tornadic wind event (see Section 9.3.4.3.1.3.5).

Safety injection tank data is summarized in Table 6.3-1.

6.3.2.2.2 Low-Pressure Safety Injection Pumps

The low pressure safety injection (LPSI) pumps serve two functions. One function is to inject large quantities of borated water into the Reactor Coolant System in the event of a large pipe break. Sufficient flow is delivered under these conditions to satisfy functional requirements described in Subsection 6.3.1. The other function of the low pressure safety injection pumps is to provide shutdown cooling flow through the reactor core and shutdown cooling heat exchanger for normal plant shutdown cooling operation or as required for long term core cooling. The low pressure safety injection pump characteristic curves are presented on Figures 6.3-3a and 3b. During normal operation the low pressure safety injection pumps are isolated from the Reactor Coolant System by motor-operated valves. During the injection mode, the LPSI pumps deliver water from the refueling water tank to the Reactor Coolant System via the Reactor Coolant System safety injection nozzles when Reactor Coolant System pressure falls below the low-pressure safety injection pump shutoff head.

Sizing of the low-pressure safety injection pump is governed by the shutdown cooling function. The flow available with a single low-pressure safety injection pump is sufficient to maintain a core ΔT at an acceptable level at the initiation of shutdown cooling.

The design temperature for the low pressure safety injection pumps is based upon the temperature of the reactor coolant at the initiation of shutdown cooling. The design pressure for the low pressure pumps is based on the sum of the maximum low pressure safety injection pump suction pressure, which occurs at the initiation of shutdown cooling, and the low pressure safety injection pump shutoff head (see Subsection 5.4.7).

The low-pressure safety injection pumps are vertical; single-stage centrifugal units equipped with mechanical face seals backed up by bushings with connections to collect the leakage past the seals. The low pressure safety injection pump motors are specified to have the capability of starting and accelerating the driven equipment, under load, to design point running speed within

eight seconds, based upon an initial voltage of 75 percent of the rated voltage at the motor terminals.

The low-pressure safety injection pumps are provided with minimum flow protection to prevent damage when starting against a closed system. The low-pressure safety injection pump data is summarized in Table 6.3-1 and Figures 6.3-3a and 3b. The shutdown cooling function of the low- pressure safety injection pumps is described in Subsection 5.4.7.

The LPSI pumps are supplied by Ingersoll-Rand, with NPSH characteristics confirmed by test. Both the St. Lucie Unit 2 LPSI pumps were tested using Hydraulic Institute Standards (see Table 6.3-22). These tests determined NPSH at approximately three- percent degradation.

The NPSH vs. flow curves for the LPSI pumps are shown on Figures 6.3-3a, and 6.3-3b. HPSI and LPSI pump descriptions, including runout flow, are provided in Table 6.3-1.

6.3.2.2.2a Generic Letter 98-04 Commitments

Generic Letter 98-04 was issued to address concerns related to potential for degradation of the emergency core cooling system and the containment spray system after Loss of Coolant Accidents because of construction and protective coating deficiencies and foreign material in containment. St. Lucie's response to GL 98-04 is documented in letter L-98-277 and is summarized below.

The plant has implemented controls for surface preparation, procurement, application, surveillance, and maintenance activities for Service Level 1 protective coatings used inside the containment in a manner that is consistent with applicable regulatory requirements. The requirements of 10 CFR 50 Appendix B are implemented through specification of appropriate technical and quality requirements for the Service Level 1 coatings program, which is considered a "Special Process" and is controlled in accordance with the requirements of ASME NQA-1-1994, Quality Assurance Requirements for Nuclear Applications. This program, which addresses both new and ongoing maintenance activities, is documented in the Service Level 1 Coatings Specification.

In addition to the above, the following items are discussed in the referenced St. Lucie response: (1) a safeguards sump inspection is performed every refueling outage; (2) the containment is thoroughly inspected for loose debris at the end of each outage prior to plant restart; (3) containment coatings are inspected at the end of each refueling outage to ensure that the coatings would not adversely affect the ECCS during design basis accidents; and (4) at the time of the Generic Letter review, St. Lucie did not employ commercial grade dedication for Service Level 1 coating inside the containment.

6.3.2.2.3 High Pressure Safety Injection Pumps

The primary function of a high-pressure safety injection (HPSI) pump is to inject borated water into the Reactor Coolant System if a break occurs in the Reactor Coolant System boundary. For small pipe breaks, the Reactor Coolant System pressure remains high for a long period of time following the accident, and the high pressure safety injection pumps ensure that the injected flow is sufficient to meet the criteria given in Subsection 6.3.1. The high-pressure safety injection pumps are also used during the recirculation mode to maintain a borated water cover over the core for extended periods of time. For long term core cooling, the HPSI pumps are manually realigned for simultaneous hot and cold leg injection. This insures flushing and

ultimate subcooling of the core coolant independent of break location. For small pipe breaks, the HPSI pumps continue injecting into the Reactor Coolant System to provide makeup for spillage out the break while a normal cooldown is implemented.

The St. Lucie 2 HPSI pumps are manufactured by Bingham-Willamette Company. These pumps are similar in design to conventional boiler feed pumps where continuous service over a broad range of temperature is required. Specific long-term testing of the HPSI pumps was not required because of the vendors experience with the design.

Operational testing is considered as part of the functional requirements of the pump. For the purpose of pump specification and design, the long-term LOCA requirement is defined as continuous operation for up to one year at runout conditions. The operational experience of the pump vendor on similar equipment is defined below.

The pumps for Units 1 and 2 have virtually identical performance curves, running clearances, and materials of construction.

St. Lucie Unit 2 pumps are designed to operate at a nominal 3600 rpm. The St. Lucie motors are 400 HP two-pole machines directly coupled to the pumps. For St. Lucie, anti-friction bearings of proven design are used.

Other Bingham-Willamette pumps of comparable size which have and are compiling significant operating hours include North Anna (Auxiliary Feedwater); Oyster Creek (Emergency Feedwater); Prairie Island (HPSI) and Point Beach (HPSI).

During normal operation the high-pressure safety injection pumps are isolated from the Reactor Coolant System by motor operated valves. During the injection mode, the HPSI pumps deliver water from the refueling water tank to the Reactor Coolant System via the cold leg safety injection nozzles when RCS pressure falls below the high pressure safety injection pump shutoff head. During the recirculation mode of operation, the high pressure safety injection pumps take suction from the containment sump.

The high pressure safety injection pumps are sized such that one HPSI pump (after consideration of spillage directly out the break) supplies adequate water to the core to match decay heat boiloff rates soon enough to minimize core uncovery and allow such small break LOCAs to meet the performance criteria of 10 CFR 50.46. The high-pressure safety injection pump characteristic curves are shown on Figures 6.3-4a and 4b.

The NPSH calculations for the HPSI pumps utilize the recommendations of Regulatory Guide 1.1, "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps," November 1970 (R0), as outlined in Subsection 6.2.2.3. The NPSH available to the HPSI pumps during recirculation (refer to Table 6.3-18) has been calculated based on "issued for construction" piping drawings and the following:

a. Crane Company Technical Paper No. 410, "Flow of Fluids Through Valves, Fittings, and Pipe," 1976.

b. System runout flow of one suction header of 5050 gpm, consisting of 4350 gpm for one containment spray pump and 700 gpm for one HPSI pump.

c. Containment pressure is equal to the saturation pressure of the containment sump water, as discussed in Subsection 6.2.2.

d. Containment sump water level at elevation 23.38.

e. HPSI pump suction nozzles are located at elevation -6.64 feet.

The minimum available NPSH at EPU conditions for the HPSI pumps during recirculation at the limiting plant specific containment sump water temperature of 192°F, operating at the system runout flow of 700 gpm for the design basis flow case, is 32.57 feet. Therefore, acceptable margin exists between the available NPSH and the NPSH required at pump runout. The NPSH required is determined from pump test curves furnished by the manufacturer.

The required NPSH of the St. Lucie 2 ECCS pumps has been confirmed by test, in accordance with the ASME Power Test Code 8.2 (centrifugal pumps).

Similar pumps were also supplied for St. Lucie Unit 1. Each of the St. Lucie Unit 1 pumps were also tested for the NPSH required. The results (see Table 6.3-23) show little variance between pumps for similar flow. The HPSI pumps were tested to produce NPSH at effectively zero percent degradation.

The NPSH vs flow curves for the HPSI pumps are shown on Figures 6.3-4a and 6.3-4b. HPSI and LPSI pump descriptions, including runout flow, are provided in Table 6.3-1.

Mechanical shaft seals are used and are provided with connections to collect any leakage past the seals. The HPSI pump motors are specified to have the capability of starting and accelerating the driven equipment, under load, to design point running speed within eight seconds based on an initial voltage of 75 percent of the rated voltage at the motor terminals. The HPSI pumps are provided with minimum flow protection to prevent damage resulting from operation against a closed discharge. The design temperature is based on the saturation temperature of the reactor coolant at the containment design pressure plus a design tolerance. The design pressure for the high pressure pumps is based on the shutoff head plus maximum containment pressure plus a design tolerance. The HPSI pump data is summarized in Table 6.3-1, and Figures 6.3-4a and 4b.

6.3.2.2.4 Refueling Water Tank

The refueling water tank (RWT) is an atmospheric tank containing water borated to between 1900 ppm and 2200 ppm for EPU operation. The RWT is equipped with a high water level alarm which, when actuated, alarms and annunciates in the control room thus identifying the condition. The over-flow alarm actuates at a level six inches below the RWT overflow nozzle which is 7350 gallons less than the spillover capacity. Assuming that the pump with the largest capacity is being used to fill the tank (primary water pumps @ 300 gpm) the operator has at least 24 minutes to shut the pump off before the RWT overflows. Operation of the RWT is not needed during normal operation, and use of it is under strict administrative control.

The possibility of RWT overflow from each of the fill lines was evaluated. The limiting RWT fill source is the 3,100 gpm from the LPSI pumps which allows the operator 2.4 minutes to respond before the tank overflow occurs. All other tank fill sources provide the operator a minimum of 20 minutes before any action is required. A tabulation of fill sources is presented in Table 6.3-21.

To limit the possibility of RWT overflow an air operated, fail-closed automatic block valve (LCV-07-12) on the LPSI fill line closes upon receipt of a high RWT level signal. In addition to the high RWT level alarm at 37.5 feet, annunciation of high-high RWT level at 37.75 feet, is

provided. The high-high level annunciation receives a signal from a source different from the present high-level alarm signal for additional reliability and is alarmed in the control room. This increases the operation response time margin and minimizes the potential for RWT overflow. See Figure 6.2-41 for RWT fill sources.

Should the RWT overflow, the discharge would flow to a local catch basin east of the RWT and then enter the plant storm drainage system.

The RWT is vented to the atmosphere through a mushroom vent on the top of the RWT.

The RWT is sized to contain sufficient water to fill the refueling water canal, transfer tube and the refueling cavity to a depth of 24 feet above the reactor vessel flange for refueling operation. This required volume is 500,000 gallons. Actual tank volume is 554,000 gallons.

The RWT also provides the reservoir of borated water for the injection mode operation of the Safety Injection System. The RWT is a seismic Category I, ASME III Class 2 structure designed to store borated water for use by the Containment Spray (CS), High Pressure Safety Injection (HPSI), and Low Pressure Safety Injection (LPSI) pumps. The Technical Specifications level accounts for the following volumes of water for EPU operation:

a. Injection Flow: A quantity of 386,735 gallons is maintained to provide a minimum of 20 minutes of injection flow for the CS, LPSI, and HPSI pumps. This quantity is determined using conservative maximum pump flows for EPU operation.

b. Unusable Volume: All stored water below a line six inches above the RAS setpoint is considered unusable. This quantity of 90,625 gallons is considered in the Technical Specifications determination.

c. Transfer Allowance: An additional volume of 10,586 gallons is stored to account for the time (90 seconds) required to transfer to the recirculation mode. This quantity conservatively assumed that a LPSI pump fails to stop on receipt of the Recirculation Actuation Signal (RAS) and continue to draw during the transfer process. Thus, no single failure can cause the tank to be drawn dry.

d. Instrument Error: An additional margin of five percent is added to the total of the above volumes to conservatively account for instrumentation error.

e. Working Allowance: The Technical Specification level based on the above requirements, including the instrumentation margin is 417,060 gallons. This will leave an approximate usable height of eight feet for working allowance.

In all determinations of the Net Positive Suction Head (NPSH) available to the CS, HPSI and LPSI pumps, no credit was taken for the height of the water in the RWT above the centerline of the supply line. Thus, safe pump operation is assured through the entire injection phase.

The RWT is not provided with missile shielding. The safety injection tanks are credited as a backup water source in the event the RWT is unavailable for safe shutdown due to a missile or tornadic wind event (see Section 9.3.4.3.1.3.5).

6.3.2.2.5 Piping

Piping is specified to deliver borated safety injection water from the safety injection tanks and from the refueling water tank via the safety injection pumps, to the safety injection nozzles in the Reactor Coolant System. The major piping sections are (refer to Figures 6.3-1a, b & c):

a. From each safety injection tank to its respective reactor coolant cold leg safety injection nozzle;

b. Separate piping from the refueling water tank and containment sump to the suction of each high and low pressure safety injection pump and discharge to separate high pressure injection headers each of which serves the four safety injection nozzles on the cold legs;

c. Separate piping from the low pressure safety injection pump discharge to each low pressure safety injection header each of which serves two of the four safety injection nozzles;

d. Separate piping from each high pressure safety injection pump discharge to the Reactor Coolant System hot legs.

The Safety Injection System piping is fabricated of austenitic stainless steel and is designed to ASME Code, Section III. Flexibility and seismic loading analyses are performed to confirm the structural adequacy of the system piping.

6.3.2.2.6 Valves

The location of valves, the type and size of the valve, type of operator, position of the valve during the normal operating mode of the plant and failure position of the valve are shown on Figures 6.3-1a, b & c. Design data for the major valves in the SIS are provided in Table 6.3-5. All valves are selected to ensure that the requirements of Subsection 6.3.1 are met.

6.3.2.2.6.1 Relief Valves

Protection against overpressure of components within the safety injection system is provided by relief valves. A description of relief valves is provided below (refer to Figures 6.3-1a, b & c).

a. Safety Injection Tank Relief Valves V3211, V3221, V3231, V3241

   The relief valves on the safety injection tanks discharge to the containment and are sized to protect the tanks against overpressure resulting from applying the maximum fill rate of liquid or gas into the safety injection tanks. The set pressure is 669 psig and the capacity is 800 cfm of nitrogen or 132 gpm of liquid.

b. Safety Injection Tank Outlet Drain to RWT Relief Valve V3466

   A relief valve is provided on the safety injection test and leakage return line. This relief valve is sized to protect against over- pressure of the line when filling a safety injection tank. Relief fluid is collected in the drain collection header. The set pressure is 700 psig and the capacity is 180 gpm.

c. Low Pressure Safety Injection Header Relief Valves V3439, V3507

These relief valves protect the low-pressure safety injection line and header against the pressure developed due to fluid thermal expansion. Relief fluid is collected in the drain collection header. The set pressure is 535 psig and the minimum required capacity is five gpm. This set pressure and capacity provides thermal overpressure protection consistent with the requirements of the piping design code.

d. High Pressure Safety Injection Relief Valve, V3412

This relief valve is sized to protect the high pressure safety injection header against overpressure due to thermal expansion of the fluid between the dual isolation valves. Relief fluid is collected in the holdup tank. The set pressure is 1585 psig and the capacity is five gpm.

e. Safety Injection Tank Outlet Drain to RWT Thermal Relief Valve, V3407

This relief valve is sized to protect the safety injection tank recirculation piping from pressure increases due to thermal expansion of the pipe contents. Relief fluid is collected in the drain collection header. The set pressure is 650 psig and capacity is five gpm.

f. High Pressure Safety Injection Relief Valve, V3417

The high pressure safety injection header to which the charging pumps discharge is protected from overpressure pressure by this valve. Relief fluid is collected in the holdup tank. The set pressure is 2485 psig with a capacity of 132 gpm.

g. Low Pressure Safety Injection Test Line Relief Valves, V3513, V3688

These relief valves are sized to protect the Low Pressure safety injection test line from overpressure due to thermal expansion in the line. Relief fluid is collected in the aerated waste storage tank. The set pressure is 500 psig and capacity is 180 gpm.

h. Hot Leg Injection Relief Valve, V3570

This relief valve is sized to protect the hot leg injection line from overpressure due to charging pump discharges. Relief fluid is collected in the holdup tank. The set pressure is 2400 psig and the capacity is 132 gpm.

i. Shutdown Cooling System Heat Exchanger Discharge Relief Valves, V3430, V3431

The relief valves on the SDCHX discharge are to protect the components and piping from thermal transient effects. Relief fluid is collected in the drain collection header. The set pressure and capacity are 500 psig and five gpm, respectively.

j. Shutdown Cooling System Suction Line Relief Valves, V3482, V3469, V3483, V3468, V3667, V3666

The relief valves on the SDC suction line are sized to protect the components and piping from overpressure due to thermal expansion of the fluid. Relief fluid is

collected in the quench tank for valves V3482 and V3469. These valves have a set pressure of 2485 psig and a capacity of five gpm. Relief fluid for valves V3483 and V3468 is collected in a holdup tank in the Waste Management System. These valves have a set pressure of 335 psig and a capacity of 155 gpm.

In addition to protecting the components from overpressure due to the thermal expansion of the fluid, valves V3666 and V3667 are sized to protect the components and piping from overpressure due to inadvertent starting of the charging pumps, HPSI pumps, and the pressurizer heaters. Relief fluid is collected in the containment sump for valves V3666 and V3667. These valves have a set pressure of 335 psig and a capacity of 2300 gpm.

6.3.2.2.6.2 Power Operated Valves

The type of valve, motor or air operated, and the position of each valve on loss of actuating signal or power supply (failure position) is selected to ensure safe operation. System redundancy is considered when defining the failure position of any given valve. Position indication of motor and air operated valves in the control room consists of position indicating lights and/or position indicators. A control switch in the control room and/or manual handwheel is provided on valves to permit manual control in the case of actuator failure.

Motor operated valves in the ECCS are equipped with motor operators which allow disengagement of the motor for handwheel operation but are automatically re-engaged when the motor is activated. As a result, it is not possible for the motor operated valves to be disabled from automatic operation due to a prior manual handwheel operation.

The following motor operated SI valves are subject to the requirements of NRC Generic Letter 89-10; V3432, V3444, V3523, V3540, V3550, V3551, HCV-3615, HCV-3625, HCV-3635, HCV-3645, HCV-3616, HCV-3617, HCV-3626, HCV-3627, HCV-3636, HCV-3637, HCV-3646, HCV-3647, V3654, V3656, V3659, V3660.

6.3.2.2.6.3 Check Valves

Check valves are provided in the system to prevent backflow. Refer to Figure 6.3-1(a through c) for locations.

6.3.2.2.6.4 Manual Valves

For the Safety Injection System, some manual valves exist in the flow paths of the trains, which, if improperly aligned, could prevent flow from that train. These are: V3206 and 3207, which are just downstream of the LPSI pumps; V3411 and 3470, which are upstream of the HPSI Pumps; V3414 and 3427, which are stop check valves downstream of the HPSI pumps; and valves V3202, 3203, 3767 and 3205 which are in the mini flow lines from the LPSI and HPSI pumps. Each of these are locked open and administrative procedures are used to assure their proper position. However, there is no single manual valve which if misaligned would disable both SIS trains.

6.3.2.3 Applicable Codes and Classifications

Refer to Section 3.2 for details.

6.3.2.4 Materials Specifications and Compatibility

The materials used in the construction of the Safety Injection System components are presented along with the component design parameters in Table 6.3-1. All materials in contact with reactor coolant are austenitic stainless steel. The materials selected are compatible with the most severe environmental condition to which they may be exposed. A detailed discussion is provided in Section 6.1.

6.3.2.5 System Reliability

6.3.2.5.1 Safety Injection Tanks

The safety injection tanks containing borated water pressurized by a nitrogen gas cover constitute a passive injection system because no operator action or electrical signal is required for operation. Each safety injection tank is connected to its associated Reactor Coolant System cold leg by a separate line containing two check valves which isolate the safety injection tank from the Reactor Coolant System during normal operation. When the reactor coolant pressure falls below the safety injection tank pressure, the check valves open discharging the contents of the safety injection tank into the Reactor Coolant System. The evaluation in Subsection 6.3.3 demonstrates the adequacy of the quantity of reactor coolant supplied. In order to prevent accidental overpressurization of the Shutdown Cooling System, safety injection tank pressure is decreased in accordance with operating procedures as Reactor Coolant System pressure is being reduced to shutdown cooling entry pressure. An interlock with pressurizer pressure prevents these valves from being closed if pressurizer pressure is greater than the shutdown cooling entry pressure. Following License Amendment no. 100, the SITs are not required to be operable in Modes 4,5 and 6. The SIT isolation valves may be closed when the RCS temperature is below Mode 3 temperature. The motor operated safety injection tank isolation valves are interlocked with pressurizer pressure to open the valves automatically prior to an actual or simulated signal exceeding 515 psia. After Reactor Coolant System pressure increases to above the maximum safety injection tank pressure allowed by the operating procedures, the operator will repressurize the safety injection tanks. Further details of valve control are provided in Section 7.6.

6.3.2.5.2 High Pressure and Low Pressure Safety Injection Subsystems

Redundant high pressure safety injection subsystems and redundant low pressure safety injection subsystem trains are provided. One HPSI and one LPSI pump and the associated valves operate from one emergency power supply, the other HPSI and LPSI pump and injection valves from a second independent source of emergency power. This provides automatic operation of one complete, full capacity subsystem in the unlikely event of a simultaneous loss of offsite power and the failure of an active component.

Valves in the injection paths not receiving a RAS or SIAS signal are maintained locked in the required position by administrative controls. Actuator operated valves are provided with key-operated control switches where considered necessary to prevent unintentional misalignment of safety injection flow paths during power operation. (See Subsections 6.3.2.2.6.2 and 6.3.2.2.6.4).

Prevention of flow blockage in small diameter pipes is accomplished by control of particle size and specific weight in the injection water through containment sump strainers and RWT exit screen designs.

6.3.2.5.3 Power Sources

In addition to the preferred sources of offsite power, independent onsite standby electrical power supplies are provided for the SIS equipment by emergency generators. The electrical power system is designed such that a single electrical failure can not initiate injection flow, nor prevent initiation of required injection flow of one train. A detailed description of the onsite standby power sources is given in Section 8.3. Diesel generator load sequencing is provided in Table 8.3-2.

6.3.2.5.4 Capacity to Maintain Cooling Following a Single Failure

The Safety Injection System is designed to meet its functional requirements even with the failure of a single active component during the injection mode of operation or with the single active or limited leakage passive failure of a component during the recirculation mode of operation. By providing redundancy of equipment, even with the single failure noted above, the minimum required safety injection equipment is always available. A failure modes and effects analysis demonstrating this is given in Table 6.3-2. Minimum operability requirements for components of the ECCS are delineated in the Technical Specifications. As discussed in NRC Generic Letter 2008-01 and INPO SER 2-05, the presence of unanticipated gas voids within fluid systems can challenge the ability of systems to perform their design functions due to issues such as gas binding, water hammer, injection delay times, etc. Requirements for maintaining Containment Spray system operability with respect to gas intrusion are contained within Technical Specifications and Gas Accumulation Management Program procedures. Consistent with these operability requirements and system failure modes, the minimum ECCS equipment that operates during postulated accidents is as discussed in Subsection 6.3.3. This complement of equipment is required to mitigate the consequences of a LOCA. SIS valve motor operators inside containment have been located above the maximum post LOCA water level to ensure they are not submerged. Containment isolation of ECCS lines is discussed in Subsection 6.2.4.

6.3.2.6 Protection Provisions

The Safety Injection System is protected from damage that could result from a LOCA by:

a. Designing components to withstand the design bases event environment including reactor coolant chemistry, radiation, temperature, humidity and pressure resulting from the accident,

b. protection from missiles as detailed in Subsection 3.5.1 and

c. a seismic design that withstands the stresses imposed by a safe shutdown earthquake occurring simultaneously with a LOCA.

6.3.2.6.1 Capability to Withstand Design Bases Environment

Components located in the containment, such as remote-operated valves and instrumentation and control equipment, required for operation of the Safety Injection System are designed to withstand the DBA conditions of temperature, pressure, humidity, chemistry and radiation for the extended period of time required as detailed in Section 3.11. Insofar as practical, Safety Injection System components required to maintain a functional status are located outside containment to eliminate exposure of the equipment to the post-DBA conditions. The equipment outside containment is designed in consideration of the chemical and radiation effects

associated with operation following a DBA. Figure 6.3-1 (a thru c) indicates the location of equipment inside and outside of containment.

Materials of construction for the pumps are compatible with the expected water-chemistry under normal and DBA conditions. A radiation resistance requirement is placed on the pumps consistent with Section 3.11.

6.3.2.6.2 Missile Protection

Protection from possible Reactor Coolant System generated missiles is afforded by locating all components outside the containment except for the safety injection tanks and discharge piping and valves. The tanks are located outside the biological shield such that protection from possible Reactor Coolant System missiles is provided (refer to Section 3.5).

6.3.2.6.3 Seismic Design

Since operation of the Safety Injection System is essential following a loss of coolant accident, it is seismic Category I design. The general design basis for seismic Category I equipment is that it be able to withstand the appropriate seismic loads plus other applicable loads without loss of design functions which are required to protect the public. For the Safety Injection System this means that the components are able to withstand the stresses resulting from emergency operation following a LOCA, simultaneously with the stresses resulting from the safe shutdown earthquake without loss of function.

Refer to Section 3.7 for details on seismic design and analysis.

6.3.2.7 Provisions for Performance Testing

The SIS is provided with the necessary connections such that proper operation of each active component can be determined. Recirculation lines are provided on each pump, such that the pumps can be started during normal operation and pump performance verified. The operability of all check valves can be verified by a variety of means including utilizing a SIT dump test during refueling, safety injection pump operation or by the charging pump connection to the high pressure header. Additionally, the motor-operated valves have position indication for testing.

The SITs are provided with sample connections and boron addition connections to control the boron content. This assures that fluid containing the proper boron content are injected in the event of a LOCA.

For further information on testing see Subsection 6.3.4.

6.3.2.8 Required Manual Actions

The two modes of operation, injection and recirculation, are automatically initiated by a safety injection actuation signal (SIAS) and a recirculation actuation signal (RAS) respectively.

Long term cooling is manually initiated when the entry conditions for shutdown cooling are met, generally within six hours following SIAS. If shutdown cooling entry conditions can not be met within six hours of SIAS, then simultaneous hot and cold leg high pressure safety injection will be initiated prior to the expiration of the six hours. Simultaneous hot and cold leg high pressure safety injection will not be initiated prior to two hours following SIAS. For small pipe breaks, the

HPSI pumps provide makeup for spillage, while the Reactor Coolant System is cooled down and depressurized to shutdown cooling initiation conditions utilizing the steam generator atmospheric dump valves and Auxiliary Feedwater System. For small LOCAs, the SITs are depressurized to allow Reactor Coolant System depressurization. This is followed by manual shutdown cooling operation.

The process instrumentation available to the operator in the control room to assist in assessing post-LOCA conditions is listed in Table 6.3-3.

6.3.3 PERFORMANCE EVALUATION

6.3.3.1 Introduction and Summary

10 CFR 50.46 provides the Acceptance Criteria for Emergency Core Cooling Systems for Light-Water-Cooled Reactors[(l)]. The analyses presented in this subsection, which were developed to support the original license of the plant, demonstrate that the design satisfies these criteria. These design bases and description of the Emergency Core Cooling System are presented in Subsections 6.3.1 and 6.3.2. The evaluation of these systems under current accident conditions is presented in Section 15.6.

Hot fuel rod temperature calculations were performed for a complete spectrum of break sizes. The most limiting break, that which limits the peak linear heat generation rate, has been identified as the 1.0 x double ended guillotine pump discharge. The results of these calculations demonstrate that the ECCS design meets the 10 CFR 50.46 acceptance criteria.

Conformance is as follows:

Criterion (1) Peak Clad Temperature. "The calculated maximum fuel element temperature shall not exceed 2200°F."

The spectrum analysis yielded a peak clad temperature of 2098°F for the 1.0 x double ended guillotine at the pump discharge.

Criterion (2) Maximum Cladding Oxidation. "The calculated total oxidation of the cladding shall nowhere exceed 17 percent of the total cladding thickness before oxidation."

The spectrum analysis yielded a local peak clad oxidation percentage less than 15.76 percent for the 1.0 x double ended guillotine at the pump discharge break.

Criterion (3) Maximum Hydrogen Generation. "The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 1 percent of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surround the plenum volume, were to react."

The spectrum analysis yielded a peak core-wide oxidation less than 0.62 percent for the 1.0 x double ended guillotine at the pump discharge break.

Criterion (4) Coolable Geometry. "Calculated changes in core geometry shall be such that the core remains amenable to cooling."

The clad swelling and rupture model which is part of the evaluation model (2,3) accounts for the effects of changes in core geometry if such changes are predicted to occur. With these core changes, core cooling was enough to lower temperatures. No further clad swelling and rupture can occur since the calculations were carried to the point at which the clad temperatures were decreasing and the system has been completely depressurized. Thus, a coolable geometry has been demonstrated.

Criterion (5) Long Term Cooling. "After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core".

The spectrum analysis shows that the rapid insertion of borated water from the ECCS will suitably limit the peak clad temperature and cool the core within a short period of time. Subsequently, the safety injection pumps will supply cooling water from the refueling water tank or the containment sump to remove decay heat resulting from the long-lived radioactivity remaining in the core. A detailed analysis and description of the long term cooling performance is given in Subsection 6.3.3.4.

6.3.3.2 Large Break Analysis (Cycle 1)
(See Chapter 15 for current analyses)

6.3.3.2.1 Mathematical Model

The calculations reported in this section were performed using the CE large break evaluation model which is described in Reference 2. In the CE model, the CEFLASH-4A[4] computer program is used to determine the primary system flow parameters during the blowdown phase, and the COMPERC-II[5] computer program is used to determine the system behavior during the refill and reflood phases. The core flow and thermodynamic parameters from these two codes are used as input to the STRIKIN-II[6] program, which is used to calculate the hot rod clad temperature transient. The peak clad temperature and peak local clad oxidation percentage are therefore obtained from the STRIKIN-II calculation. The core-wide clad oxidation percentage is obtained from the results of both the STRIKIN-II and COMPERC[5, Supp1.1] computer programs.

Supplemental ECCS analysis per NUREG-0630 is presented in Subsection 6.3.3.2.7.

6.3.3.2.2 Safety Injection System Assumptions

The Safety Injection System (SIS) consists of two high pressure pumps, two low pressure pumps and four safety injection tanks. Automatic operation of the pumps is actuated by either a low pressurizer pressure signal or a high containment pressure signal. Flow is initiated from the safety injection tanks by the opening of a check valve when the cold leg pressure drops below the tank pressure.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of safety injection flow. It is assumed that offsite power is lost and all pumps must await diesel startup before they can begin to deliver flow. (It is assumed, however, that offsite power is available for the Containment Heat Removal System.) For breaks in the reactor coolant pump (RCP) discharge leg, it is also assumed that all safety injection flow delivered to the broken cold leg spills into the containment.

An analysis of the possible single failures that can occur within the SIS has shown that the worst single failure for the large break spectrum is the failure of one of the low pressure pumps to start[(2)] . This results in the minimum amount of safety injection water available to the core without affecting the operation of the Containment Heat Removal System.

Therefore, based on the above assumptions, the following safety injection flows are credited for the large break analysis:

Two high pressure safety injection pumps are piped so that each one can feed all four cold leg injection points. Thus:

a. for a break in the RCP discharge leg; the safety injection flow credited is 75 percent of the flow from two HPSI pumps since it is assumed that all injection in the broken cold leg is spilled.

b. for breaks in other locations, the safety injection flow credited is 100 percent of two HPSI pumps.

Two low pressure safety injection pumps are piped so that each one feeds two cold leg injection points. Thus:

a. for a break in the RCP discharge leg; the safety injection flow credited is 50 percent of the flow from one LPSI pump. The bases for this flow is that only one LPSI pump is operable (worst single failure) and one of the two injection points for the operable pump is located in the broken loop and thus that flow is spilled.

b. for breaks in other locations, the safety injection flow is 100 percent of one LPSI pump.

Four safety injection tanks (SITs) are piped so that each SIT feeds a single cold leg injection point. Thus:

a. for a break in the RCP discharge leg; the safety injection flow credited is 100 percent flow from three SITs since it is assumed that all injection in the broken cold leg is spilled.

b. for breaks in other locations; the safety injection flow credited is 100 percent flow from four SITs.

The rate at which emergency cooling water is delivered to the reactor vessel downcomer for the limiting break is shown on Figure 6.3-9m. As shown in Table 6.3-6, no credit is taken for HPSI or LPSI pump flow until the tanks are empty, resulting in a minimum effective delay of over 70 seconds from the time the SIAS setpoints is reached until safety injection pump flow is credited.

The actual delay time will not exceed 30 seconds following a SIAS. In the large break analysis, no operator action has been assumed.

6.3.3.2.3 Core and System Parameters

The significant core and system parameters used in the large break calculations are presented in Table 6.3-7. The Peak Linear Heat Generation Rate was assumed to occur in the top of the core, the conservative location as identified in Section IV.A.4 of Reference 2. A conservative beginning-of-life moderator temperature coefficient ($+0.5 \times 10^{-4}$ $\Delta\rho/F$) was used in all large break cases.

Presently, St. Lucie Unit 2 has 47 steam generator tubes which have been plugged, representing approximately 0.6% of the unplugged total. The effect of tube plugging has been treated on an as needed basis for CE operating plants and to date tube plugging has been minimal. In one example, an ECCS analysis was performed assuming 500 tubes per SG plugged which represents approximately six percent of the unplugged total. The predicted ECCS performance changed very little and the allowable peak linear heat generation rate remained unchanged from the case with no SG tubes plugged. The method of analysis for the assessment of ECCS performance with a portion of the SG tubes plugged is provided in Reference 21.

Though the ECCS performance analyses for St. Lucie Unit 2 as performed do not explicitly account for steam generator tube plugging, the results of the analyses are applicable for the minimum amount of tubes plugged presently experienced by the plant. Based on the above, the current ECCS performance analysis remains applicable and no new analysis is required unless the plugging becomes more significant.

The initial steady state fill rod conditions were determined as a function of burnup using the FATES[7] computer program.

The ECCS performance analysis for St. Lucie Unit 2 Cycle 1 determined that the limiting burnup for ECCS performance for Cycle 1 is 620 Mwd/MTU. This is the hot rod average burnup yielding the maximum fuel stored energy. End-of-Cycle 1 conditions were investigated and found to be nonlimiting. At a hot rod average burnup of 16.4 Gwd/MTU the maximum fuel average temperature (stored energy) was approximately 220F less than the limiting burnup. The results of this study are presented on Figure 6.3-13.

ECCS performance is reevaluated prior to every core reload. As part of the analysis a study is performed to determine the burnup that is most limiting for ECCS performance. The study specifically investigates the burnup yielding the highest stored energy and the burnup yielding the highest fuel pin pressure.

To support the expectation that acceptable ECCS performance will be demonstrated for St. Lucie Unit 2 during Cycle 2 and 3 at the current peak linear heat generation rate (PLHGR) of 13.0 kw/ft, a preliminary cladding temperature/ oxidation calculation was performed for Cycles 2 and 3 using the STRIKIN-II computer code[6] and estimated fuel performance data. The calculation was performed in accordance with the NRC approved CE Large Break Evaluation Model.[2]. The calculation used fuel thermal performance data calculated by the FATES computer code[25], and included the use of the NRC fission gas release enhancement factor. The results of the calculation showed that the Cycle 2 and 3 peak cladding temperature and maximum local cladding oxidation remain below the values calculated for Cycle 1. At the

currently projected end of Cycle 3 (rod average burnup of 40.23 Gwd/MTU) the peak cladding temperature was calculated to be 2057F versus 2098F for Cycle 1 and the maximum local cladding oxidation was calculated to be 14.0 percent versus 15.76 percent for Cycle 1

6.3.3.2.4 Containment Parameters

Subsection 6.2-1.5 discusses in detail the containment parameters assumed in the ECCS analysis. The values for these parameters were chosen to minimize containment pressure such that a conservative determination of the core reflood rate was made. Pressure suppression equipment startup times were selected at their minimum values corresponding to offsite power being available.

6.3.3.2.5 Break Spectrum

In general, all possible break locations are considered in a LOCA analysis. However, as demonstrated in other Appendix K LOCA calculations (References 8 and 10 for example), hot leg ruptures and cold leg ruptures on the suction side of the reactor coolant pump, yield clad temperatures substantially lower than those observed for cold leg ruptures an the discharge side of the pump. Pump discharge leg ruptures are limiting due to the minimizing of blowdown core flow and reflood rate for the break location. Thus, only these breaks need to be considered in order to identify that rupture which results in the highest clad temperature or largest amount of clad oxidation. Since core flow is a function of break size, calculations have been performed for both guillotine and slot breaks over a range of break sizes up to twice the flow area of the cold leg. A list of the breaks examined for Cycle 1 appears in Table 6.3-8 which refer to Figures 6.3-5 through Figures 6.3-11.

6.3.3.2.6 Results and Conclusions

The important results of this analysis are summarized in Table 6.3-9 and the transient behavior of important NSSS parameters is shown in the figures listed in Tables 6.3-10 and 11 which refer to Figures 6.3-5 through 6.3-11 and Figures 6.3-9 respectively. Peak clad temperature vs. break size is presented in Figure 6.3-12. Times of interest for the various breaks analyzed are presented in Table 6.3-6. Fuel cladding rupture, occurs during the reflood period and the peak clad temperature is calculated to occur during late reflood.

These results demonstrate that the Emergency Core Cooling System is in compliance with the acceptance criteria of Reference 1, and is adequate to perform its intended function of maintaining the integrity of the core thereby limiting radiation release to the environment. Operational restrictions and limits on operation or maintenance that have been dictated by the results of this analysis are listed in the Technical Specifications.

6.3.3.2.7 Supplemental ECCS Analysis (NUREG-0630)

Prior to Cycle 1 operation a supplemental analysis[22] utilizing the material models of NUREG-0630 has been performed. This supplemental analysis also utilized the heat transfer portion of CE's alternate ECCS Evaluation Model which was described to NRC[25]. The combination of the NUREG-0630 material models and the alternate heat transfer model provides results which are less limiting than the results in Subsection 6.3.3.2.6 which were obtained by using CE's NRC approved ECCS Large Break Evaluation Model.[2]

For this analysis, the peak clad temperature decreased by 126F and the peak local clad oxidation decreased by 11.07 percent from the corresponding values reported in Subsection 6.3.3.2.6. Similar results were provided[24] to NRC for another Combustion Engineering designed PWR. As in this previous analysis, this analysis illustrates the overall conservatism of the CE flow blockage representation in its NRC approved ECCS Evaluation Model.[2]

6.3.3.2.7.1 Method of Analysis

The analysis used the three material models of NUREG-0630. Specifically, the models predict cladding rupture temperature, cladding burst strain and fuel assembly flow blockage. In addition, the analysis utilized the heat transfer portion of the alternate ECCS Model for the calculation of steam heat transfer coefficients for locations at and above the blockage plane. All other portions of the calculation used CE's NRC-approved ECCS Evaluation Model.

Figures 3, 8, and 16[22] present the NRC recommended rupture temperature, rupture strain, and reduction in fuel assembly flow area, respectively. This analysis assumed a heating ramp rate of 0 °C/sec and utilized the appropriate values from these three figures. The 0 °C/sec heating ramp rate predicts the earliest rupture and the maximum burst strain and maximum flow area reduction. Although this introduces additional, unnecessary conservatism into the analysis, it was done to remain consistent with the previous analysis performed.[24]

Since clad rupture occurred during reflood, the blowdown hydraulic transient is not sensitive to, and will not be affected by flow blockage modeling. Furthermore, calculation of reflood rates is based on the core average behavior and is not affected by local blockage. Therefore, the blowdown and reflood hydraulics calculated for the UFSAR analysis remain applicable and were used in this study. The hot rod clad temperature and oxidation values were recalculated using the NUREG-0630 clad material models and the alternate steam cooling heat transfer models. Other input assumptions remain the same. The calculation described above was performed for 1.0 DEG/PD* break, which is the limiting large break.

6.3.3.2.7.2 Results

Table 6.3-19 summarizes the significant input parameters and results of this supplemental analysis. The calculated rupture strain is 90 percent, which corresponds to a flow blockage of 71 percent. These are the maximum values predicted by the NUREG-0630 models. As mentioned earlier, rupture is predicted during reflood.

The rupture temperature of 1515°F is based on the 0°C/sec heating ramp rate curve. Use of a more representative heating ramp rate would calculate rupture at a higher temperature. The higher rupture temperature would result in a lower rupture strain and lower flow blockage than the maximum value calculated here.

As concluded previously, [24] the combination of the improved heat transfer of CE's alternate model with higher strain and flow blockage actually results in a significant decrease in both calculated peak clad temperature and peak clad oxidation. For this analysis, the peak clad temperature decreased by 126°F and the peak clad oxidation decreased by 11.07 percent from

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*DEG/PD - Double-Ended Guillotine/Pump Discharge

the corresponding results presented in Subsection 6.3.3.2.6 and presented graphically on Figures 6.3-27 and 6.3-28.

The results of this study demonstrate that the ECCS analysis results presented in Subsection 6.3.3.2.6 comply with the acceptance criteria of 10 CFR 50.46 at an estimated peak linear heat rate of 13.0 kW/ft.

6.3.3.3 Small Break Analysis

6.3.3.3.1 Evaluation Model

The calculations reported in this section were performed using the CE small break evaluation model which is described in Reference 3 and was approved by the NRC in Reference 12. In the summer of 1979, two reports, CEN-114-P[17] and CEN-115-P[18] were submitted which described small break behavior based on CE's Small Break Evaluation Model. In response to NUREG-0737, Item II.K.3.30[19] further clarification and justification of the Small Break LOCA methods were provided in CEN-203-P[20]. This document demonstrates that using the CE Small Break Evaluation model results in conservatively high cladding temperatures. Revisions to the present small break LOCA model are therefore unnecessary. In the CE model, the CEFLASH-4AS[13] computer program is used to determine the primary system hydraulic parameters during the blowdown phase, and the COMPERC-II[5] computer program is used to determine the system behavior during the reflood phase. Fuel rod temperatures and clad oxidation percentages are calculated using the STRIKIN-II[6] and PARCH[11] computer programs. The interfacing between these programs is discussed in detail in Reference 3.

6.3.3.3.2 Safety Injection System Assumptions

As discussed in Subsection 6.3.3.2.2, the safety injection system includes two high pressure pumps, two low pressure pumps and four safety injection tanks. It is conservatively assumed that offsite power is lost upon reactor trip and therefore all safety injection pumps must await diesel startup and load sequencing before they can start. The total time delay assumed is 30 seconds. For breaks in the pump discharge leg, it is also assumed that all safety injection flow delivered to the broken cold leg spills out the break.

An analysis of the possible single failures that can occur has shown that the worst single failure for the small break spectrum is the failure of one of the emergency diesels to start[3]. This failure causes the loss of one high pressure pump and one low pressure pump, thereby resulting in a minimum of safety injection water being supplied to cool the core. The available safety injection water is supplied by one HPSI pump which injects into each cold leg, one LPSI pump which injects into two cold legs and four safety injection tanks each of which injects into one cold leg.

In addition to the SIS flows, injection flow from a single charging pump is credited in the small break analysis for St. Lucie 2. Charging flow is supplied through the charging system piping which meets the requirements for a seismic Category I structure, (Table 3.2-1). Injection is into two cold legs in opposing loops (Figure 5.1-3). The charging pump is automatically started and loaded (Table 8.3-2) assuming a total delay time of 10 seconds after a safety injection actuation signal and a loss of offsite power. However, for ECCS analysis, a total delay time of 10 minutes was conservatively assumed. The analysis was also based on a value of 35 gpm for the injection flow rate of one charging pump (See Table 6.3-14).

An assumption of a single failure in the charging system would mean that credit for two operating diesel generators could be taken. Under this assumption more SI flow would be supplied to cool the core than would be available assuming a failed diesel generator. Therefore, the failure of a diesel generator to start, as assumed in this analysis, is the worst single failure for the small break spectrum.

Based on these assumptions, the following credit is taken for injection flow in the small break analysis. For a discharge leg break:

75% of the flow from one HPSI pump
50% of the flow from one LPSI pump
100% of the flow from three safety injection tanks
40% of the flow from one charging pump

and for breaks in other locations:

100% of the flow from one HPSI pump
100% of the flow from one LPSI pump
100% of the flow from four safety injection tanks
100% of the flow from one charging pump

Table 6.3-12 presents the high and low pressure safety injection pump flow rates assumed at each of the four injection points as a function of reactor coolant system pressure.

6.3.3.3.3 Core and System Parameters (Cycle 1)
(See Chapter 15 for the current analyses)

The significant core and system parameters used in the small break calculations are presented in Table 6.3-13. The peak linear heat generation rate of 15.0 kw/ft was assumed to occur 15 percent from the top of the active core. A conservative beginning-of-life moderator temperature coefficient of $+0.2 \times 10^{-4}$ $\Delta\rho/F$ was used.

Calculations were performed using two axial shape indices. A spectrum of break sizes was analyzed with an axial shape index (ASI) of -0.15 ASI units (ASIU); The limiting small break from that spectrum was also analyzed with an ASI of -0.25 ASIU.

The ECCS performance analyses, as performed, does not explicitly account for steam generator tube plugging which may occur during the plant's lifetime (See Subsection 6.3.3.2.3).

The initial steady state fuel rod conditions were obtained from the FATES[7] computer program. The small break analysis assumed the same hot rod average burnup as was found limiting in the large break analysis described in Subsection 6.3.3.2. However, since the small break analysis conservatively used a higher PLHGR than did the large break analysis (15.0 kW/ ft vs 13.0 kW/ft) the fuel rod parameter values given in Table 6.3-13 differ from those in Table 6.3-7.

6.3.3.3.4 Containment Parameters

The small break analysis does not credit any rise in containment pressure. Therefore, other than the initial containment pressure, which is assumed to remain constant, no containment parameters are employed for this analysis, The initial containment pressure was assumed to be 0.0 psig.

6.3.3.3.5 Break Spectrum (Cycle 1)

Five breaks were analyzed to characterize the small break spectrum. Four breaks, ranging in size from 0.5 ft^2 to 0.015 ft^2 were postulated to occur in the pump discharge leg. The 0.5 ft^2 break was also analyzed for the large break spectrum (Subsection 6.3.3.2) and is defined as the transition break size[3]. Breaks in the reactor vessel lower head were not considered since St. Lucie Unit 2 does not employ bottom mounted instrumentation and has no vessel penetrations in this region.

Leaks in the pressurizer relief valve with effective flow areas of 0.008 ft^2 and 0.0174 ft^2 were examined. Neither break demonstrated core uncovery or results that were more limiting than equivalent size cold leg breaks. This trend is further substantiated by other analysis yielding similar results for pressurizer relief valve leaks up to 0.03 ft^2 [10,16]. The spectrum of leak sizes examined thus far, 0.008 ft^2 to 0.03 ft^2, covers the range of typical pressurizer relief valve effective flow areas. Based on the results of these analyses it can be concluded that leaks from the pressurizer vapor space are less limiting than equivalent size cold leg breaks already covered as part of the small break spectrum. Table 6.3-14 lists the various break sizes and locations examined for this analysis.

6.3.3.3.6 Results (Cycle 1)

The transient behavior of important NSSS parameters is shown in the figures listed in Tables 6.3-14 and 6.3-15. Table 6.3-16 summarizes the important results of this analysis. Times of interest for the various breaks analyzed are presented in Table 6.3-17. A plot of Peak Clad Temperature (PCT) versus break size is presented on Figure 6.3-20. The 0.04 ft^2 break results in the highest clad temperature (1653°F) of the small breaks analyzed, which is over 400°F lower than that reported in Subsection 6.3.3.1 for the limiting large break. The break resulting in the next highest PCT of the small break spectrum is the 0.5 ft^2 break with a PCT of 1119°F.

For none of the breaks analyzed does the maximum clad temperature, maximum clad oxidation or core wide clad oxidation exceed the limits established by the acceptance criteria for ECCS Performance listed in Reference 1.

6.3.3.4 Post-LOCA Long Term Cooling (Cycle 1)
(See Chapter 15 for current analyses)

6.3.3.4.1 General Plan

The objective of Long Term Cooling (LTC) is to maintain the core at safe temperatures while avoiding the precipitation of boric acid in the core region. To accomplish this objective, the LTC analysis for St. Lucie 2 was performed using the codes and methods documented in CENPD-254-P-A, "Post-LOCA Long Term Cooling Evaluation Model," June, 1980 (Reference 14) as approved by NRC in Reference 15. Results of this analysis and CENPD-152, Emergency Procedure Guidelines are used in the development of emergency procedures.

Amendment 40 to the Operating License approved the reduction of the boric acid concentration in the Boric Acid Makeup system to 2.5 - 3.5 weight percent. The following analysis was performed based on a Boric Acid Makeup system boric acid concentration of 12 weight percent. The reduction results in a lower total boric acid concentration in the RCS. This provides an increased margin to avoid precipitation of boric acid and thus no revision was required or performed.

The LTC plan for St. Lucie Unit 2 employ either of two procedures, depending on the break size. Shutdown Cooling (SDC) is initiated if the break is sufficiently small such that successful operation is assured. However, for larger break LOCAs, simultaneous hot and cold leg injection will be employed to maintain core cooling and boric acid flushing. The plant operator initiates the appropriate procedure to be used based on the Reactor Coolant System (RCS) pressure at a specified time.

Figure 6.3-21 shows the basic sequence of events and the time schedule for operator actions for the St. Lucie 2 LTC plan. The time schedule provided gives a range in which the action is to be accomplished. That is, it is assumed that the specified functional requirement will be operational within the time range given. During the first hour operator action is limited to verifying the initiation of automatic safety actuation of the safety injection and auxiliary feedwater systems. Operator manual action is credited to initiate cooldown at one hour by releasing steam from the steam generators (SG). The steam is released through the turbine bypass system if ac power is available or through the atmospheric dump valves if power is unavailable. The cooldown rate should be controlled to maintain an RCS cooldown rate not to exceed 100F/hr. The operator also manually switches charging system suction to the Refueling Water Tank (RWT) no later than 1 1/2 hours post-LOCA. Switching charging system suction to the RWT terminates high concentration boric acid injection from the Boric Acid Makeup Tanks (BAMT). Post-LOCA pressurizer cooldown is initiated using the pressurizer main or auxiliary spray system, or charging and letdown control and/or throttling of the safety injection flow. Following License Amendment no. 100, the SITs are not required to be operable in Modes 4,5 and 6. The SIT isolation valves may be closed when the RCS temperature is below Mode 3 temperature. The isolation or venting of the SITs avoids injecting a large quantity of nitrogen (non-condensible) gas into the RCS. Then, if shutdown cooling can not be established within 6 hours, between two to six hours post-LOCA, the High Pressure Safety Injection Pump (HPSI) discharge lines are realigned so that the total injection flow is divided equally between the hot and cold legs to insure core cooling and boric acid flushing regardless of break location.

Cooling of the RCS via the steam generator atmospheric dump system and of the pressurizer by the auxiliary spray system continues until the SDC entry temperature is achieved. If the indicated RCS pressure is above 120 psia and the indicated RCS temperature is less than 332F at nine to 10 hours post-LOCA, the RCS is filled with liquid and there is assurance that all conditions for entering SDC mode of operation can be established. If the indicated RCS pressure is greater than shutdown cooling entry conditions, the HPSI pumps are throttled until RCS pressure is reduced to the SDC entry pressure. A prerequisite to throttling or terminating HPSI flow is that the system must be in a subcooled condition for the indicated RCS pressure. Therefore, while reducing RCS pressure and after shutdown cooling is initiated, it is essential that subcooling of the primary system, consistent with Emergency Operating Procedures, should be maintained.

If the indicated RCS pressure at nine to 10 hours has fallen below 120 psia, the break may be too large for absolute assurance that proper suction is available for the SDC mode of operation; however, in this event, there is complete assurance that simultaneous hot leg/cold leg injection alone will both cool the core and flush the reactor vessel indefinitely.

6.3.3.4.2 Assumptions Used in the Performance Evaluation of the LTC Plan (Cycle 1) (See Section 15 for current analyses)

The major assumptions used in performing the LTC analysis are listed below:

a. The worst single-failure assumed is the failure of one emergency diesel generator which results in the following:

   1) One HPSI pump is assumed to be operable.

   2) One LPSI pump is assumed to be operative during the short term ECCS injection phase taking suction from the Refueling Water Tank (RWT). The pump is not used for ECCS injection after the RWT is drained because of automatic termination upon a Recirculation Actuation Signal.

   3) Since there are two dump valves on each steam generator, failure of one diesel leaves one valve available on each steam generator and both steam generators are then used in cooling down the RCS.

   4) Auxiliary feedwater is supplied by two motor driven pumps and one steam driven pump. Due to the loss of one of the diesel generators, one of the two motor-driven auxiliary feedwater pumps is assumed to be unavailable (the steam driven pump by itself has sufficient flow to remove decay heat).

b. The SG steam dump and RCS cooldown are assumed to begin at one hour post-LOCA and the cooldown rate maintained at 75F/hr (analyzed cooldown rate). EC290592

c. Venting or isolation of the safety injection tanks is credited in establishing SDC conditions for the small break LTC procedures.

d. The pressurizer auxiliary spray is used to cooldown the pressurizer beginning between 1 1/2 and two hours post-LOCA, but is not terminated prior to five hours post-LOCA.

e. RCS cooldown via the SG atmospheric steam dump system is terminated when the hot leg temperature ≤ 332F and ≥ 300F.

f. Instrument error: Pressure ± 54 psi, Temperature: ± 10F.

6.3.3.4.3 Parameters Used in the Performance Evaluation of the LTC Plan (Cycle 1) (See Section 15 for current analyses)

	Parameter	Value
a)	Reactor Power Level (102% of Nominal)	2611 MWt
b)	SDC Entry Temperature	342F max. (including uncertainty)
c)	SDC Entry Pressure	300 psig max.
d)	SG Dump Valve Capacity per valve	15 lb/sec minimum at 55 psia
e)	Auxiliary Feedwater in Condensate minimum Storage Tank	149,600 gallons

f) The maximum possible boric acid concentration is assumed from each of these sources.

RCS = .7 wt %
RWT = 1.23 wt %
SIT = 1.23 wt %
BAMT = 12. wt %

g) The water inventories from each source are determined such that the effect of injection into the RCS maximizes the boric acid concentration in the RCS.

RCS = 495,347 lb - minimum
RWT = 4,325,565 lb - maximum
SIT = 384,910 lb - maximum
BAMT* = 157,700 lb - maximum

h) The following pump injection rates were assumed in the analysis.

PUMP	Source	Flow	Run Out Rate	(GPM)	Pump	No. Total Flow (GPM)
HPSI	RWT, sump	552	1	552		
LPSI	RWT 2794	1	2794			
CSP (via RWT, sump)			3450	1	3450	
CHARGING**	RWT	44	3	132		
			TOTAL	6928 gpm		

*BAMT injection is terminated no later than 1 1/2 hours post-LOCA.

**For conservation, boration with three charging pumps is used in determining the boric acid accumulation in the vessel.

6.3.3.4.4 Results of the LTC Performance Evaluation (Cycle 1)
(See Chapter 15 for current analyses)

The 9.8 ft^2 cold leg break is the limiting break in regard to long term boric acid accumulation in the inner vessel region. The initiation of simultaneous cold/hot side HPSI pump injection flow between two and six hours post-LOCA provides a substantial and increasing core flushing flow as shown on Figure 6.3-22. Figure 6.3-23 shows that with no core flushing flow, the boric acid would not begin to precipitate until after 12.0 hours post-LOCA. The margin provided for the prevention of boric acid accumulation by the net core flushing flow over the minimum flow of 10

gpm is also shown on Figure 6.3-23. The time at which hot leg steam entrainment of injection water is no longer a limiting factor has been calculated to be less than one hour post-LOCA. Therefore, the two - six hour cold/hot side injection time is initiated after hot leg entrainment has been reduced and well before the boric acid is predicted to precipitate.

The small break LTC plan applies to those break sizes for which the RCS refills before all of the auxiliary feedwater is consumed. The small break analysis determined that, with steam generator cooldown starting at one hour post-LOCA, 11 hours is the minimum time required to exhaust all of the auxiliary feedwater during the cooldown and post-cooldown decay heat removal period. Therefore, between nine and 10 hours post-LOCA, the operator decides which LTC procedure is appropriate according to the RCS pressure. At 10 hours post-LOCA, there is an additional hour of auxiliary feedwater supply available for continued decay heat removal. Using a plot of break area versus time-to-refill the RCS, Figure 6.3-24, and the range of decision time, it has been determined that, for a .030 ft^2 break, the RCS will be refilled and, therefore, the small break LTC plan can be applied.

The LTC analysis also determined that the LTC large break procedures can flush the core for break sizes down to .009 ft^2 . This overlap in break sizes for which either the large or small break procedures can be used is illustrated in tabular form on Figure 6.3-25 and graphically on Figure 6.3-26. Both figures indicate that the selected decision point pressure of 120 psia fits well within the break size range of .009 to .030 ft^2 for which both large and small break procedures are applicable.

6.3.4 TESTS AND INSPECTIONS

During fabrication of the SIS components, tests and inspections are performed and documented in accordance with ASME Code requirements. As necessary, performance tests of components are performed at the vendor's facility. The SIS is designed and installed to permit inservice inspections and tests in accordance with ASME Code Section XI.

6.3.4.1 ECCS Performance Tests

Prior to initial plant startup, a comprehensive series of ECCS system flow tests were performed to verify that the design performance of the ECCS system and individual components was attained.

6.3.4.2 Reliability Tests and Inspections

6.3.4.2.1 System Tests

After the plant is brought into operation, periodic tests and inspections of the SIS components and subsystems are performed to ensure proper operation in the event of an accident. The scheduled tests and inspections are necessary to verify system operability, since during normal plant operation, SIS components are aligned for emergency operation and serve no other function. The tests defined permit a complete checkout of the subsystem and components during normal plant operation. Satisfactory operability of the system is verified during normal scheduled refueling shutdown. The complete schedule of tests and inspections of the SIS is detailed in the Technical Specifications. As discussed in NRC Generic Letter 2008-01 and INPO SER 2-05, the presence of unanticipated gas voids within fluid systems can challenge the ability of systems to perform their design functions due to issues such as gas binding, water hammer, injection delay times, etc. Requirements for maintaining Emergency Core Cooling

System operability with respect to gas intrusion are contained within Technical Specifications and Gas Accumulation Management Program procedures.

6.3.4.2.2 Component Testing

In addition to the system tests, component tests are also conducted. These component tests supplement the system tests by verifying acceptable performance of each active component in the SIS. Pumps and valves are tested in accordance with ASME Code Section XI as described in Section 6.6. Motor operated valves in the High Pressure Safety Injection System identified in Table 6.3-5a would be tested using differential pressure stroke testing or other available and approved techniques to address IE Bulletin 85-03. A summary of the program to address IE Bulletin 85-03 is found in Reference 27.

Reports on ECCS outages will follow the guidelines of 10 CFR 50.73 for the development and content of License Event Reports which will document any significant problems with the ECCS equipment. Other ECCS equipment failures are reported via Institute of Nuclear Power Operations (INPO). These two methods provide an on-line reporting system which satisfies the requirements of NUREG-0737, item II.K.3.17.

These methods were accepted by the NRC in Reference 26.

6.3.5 INSTRUMENTATION

6.3.5.1 Design Criteria

The instruments and controls for the safety injection system are designed in accordance with the applicable portions of IEEE 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations". The instrumentation and controls which actuate and control the safety injection system are described in Section 7.3.

Discussion of the instrumentation and associated analog and logic channels employed for safety injection initiation is given in Section 7.3.

6.3.5.2 System Actuation Signals

Operation of the safety injection system is controlled by redundant actuation signals. The automatic actuation by the safety injection actuation signal (SIAS), initiates operation of the Safety Injection System in the event of low Reactor Coolant System pressure or high containment pressure. Either one of these parameters senses a loss-of-coolant accident that requires the Safety Injection System. SIAS can be manually initiated from the control room. The injection mode utilizes water either from the refueling water tank or through recirculation from the containment sump. The recirculation mode is initiated automatically by a recirculation actuation signal (RAS) on a low refueling water tank level. The transfer to an RAS occurs automatically, whether SIAS is initiated manually or automatically, thus permitting continuous flow of water to the core.

6.3.5.2.1 Safety Injection Actuation Signal (SIAS)

Initiation of safety injection is derived from independent pressurizer pressure sensors and independent containment pressure sensors. Coincident trip signals from either parameter automatically initiates safety injection. A further discussion of the SIAS is given in Section 7.3.

6.3.5.2.2 Recirculation Actuation Signal (RAS)

Initiation of RAS is derived from independent refueling water tank water level transmitters. Coincident trip signals of low water level at RWT or manual initiation provides an RAS. A further discussion of the RAS is provided in Section 7.3.

6.3.5.3 System Instrumentation

The instrumentation available for monitoring Safety Injection System components during Safety Injection System operation is discussed in this section. A summary of the process instrumentation available post accident is provided in Table 6.3-3.

6.3.5.3.1 Temperature

a. Shutdown Cooling Heat Exchanger Outlet

RTDs on each low pressure injection header are used to measure shutdown cooling water temperature as it leaves the shutdown heat exchanger. This readout is used to provide a measure of the overall system performance and provides information allowing the operator to adjust cooldown rate.

Indication is provided in the control room and locally. For further details see Table 6.3-3.

6.3.5.3.2 Pressure

a. High Pressure Safety Injection Header

A pressure transmitter mounted on each high pressure safety injection header permits readings of each header pressure in the control room. For further detail see Table 6.3-3.

6.3.5.3.3 Valve Position

a. Safety Injection Tank Isolation Valve

Valve position is indicated in the control room by redundant and diverse indicators. Indicator lights verify either the fully open or fully closed position.

In addition, continuous valve position monitoring indicates partially opened or partially closed valve position.

b. Shutdown Cooling System Valves

Valves that must be repositioned and valves used to control cooldown have position indication both inside the control room and at a location outside the

control room, with an alarm to indicate when the valve is not full open. (See Subsection 5.4.7.2.2.d).

c. Hot Leg Injection Valve

Hot leg injection valve position is indicated in the control room. Indicator lights verify either open or closed position.

d. LPSI Header Isolation Valve

Valve position is indicated both in the control room and at a location outside the control room.

e. HPSI Header Isolation Valve Position

Valve position is indicated in the control room.

f. LPSI Suction Isolation Valves

Valve position is indicated in the control room.

6.3.5.3.4 Flow

a. Shutdown Cooling/LPSI Flow

A shutdown cooling/LPSI flow indicator indicates total shutdown cooling flow.

The flow meter may also be used for backup flow rate data during safety injection and for testing the performance of the low pressure safety injection pumps. The flow rate is indicated in the control room and at a location outside the control room.

b. High Pressure Safety Injection Flow

The flow channels indicate the flow rate in each of the four high pressure safety injection lines to the cold legs. The flow elements for the flow meters are located in such a manner that they serve both high pressure manifolds. The flow meters are used to balance the high pressure safety injection flow rates in each of the lines. Readout is provided in the control room.

c. Hot Leg Injection Flow

These flow channels indicate the flow rate of injection fluid to the Reactor Coolant System hot legs. Readout is provided in the control room.

6.3.5.4 Post-Accident Instrumentation

The instrumentation available for evaluation and recording of post-accident performance is detailed in Section 7.5.

REFERENCES FOR SECTION 6.3

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12. Letter, 0. D. Parr (NRC) to F. M. Stern (CE), June 13, 1975.

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14. CENPD-254-P-A, Post-LOCA Long Term Cooling Evaluation Model, June 1980.

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16. "San Onofre Units 2 & 3 FSAR Section 15.6.3.4," Dockets 50-361 and 50-362.

17. CEN-114-P (Amendment 1-P), "Review of Small Break Transients in Combustion Engineering Nuclear Steam Supply Systems," July 1979 (Proprietary).

18. CEN-115-P "Response to NRC IE Bulletin 79-06C, Items 2 and 3 for CE Nuclear Steam Supply Systems," August 1979 (Proprietary).

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TABLE 6.3-1

SAFETY INJECTION SYSTEM

COMPONENTS DESIGN PARAMETERS

Low-Pressure Safety Injection Pumps

Quantity	2
Type	Single Stage, Centrifugal
Code	ASME III, Class 2 (Summer, 1974)
Design Pressure, psig	500
Maximum Suction Pressure, psig	350
Design Temperature, F	350
Rated Design Flow, gpm	3000*
Rated Design Head, Ft	350
Minimum Runout Flow Rate, gpm	4500*
Minimum Head at Runout Flow Rate, ft	235
Materials	Stainless steel type 304 or 316 or approved equivalent
Seals	Mechanical
Brake Horsepower	400

*Does not include 100 gpm by-pass flow

High-Pressure Safety Injection Pumps

Quantity	2
Type	Multistage, Centrifugal
Code	ASME Section III, Class 2 (Summer, 1973)
Design Pressure, psig	1600
Maximum Operating Suction Pressure, psig	250
Design Temperature, F	350
Rated Design Flow, gpm	315*

TABLE 6.3-1 (Cont'd)
High-Pressure Safety Injection Pumps (Cont'd)

Rated Design Head, ft	2500
Minimum runout flow rate, gpm	685
Minimum Head at Runout Flow Rate, ft	800
Materials	Stainless Steel, ASTM-A-351 GRCF8M
Shaft Seal	Mechanical
Brake Horsepower	400

* Does not include 30 gpm bypass flow

Safety Injection Tanks

Quantity	4
Code	ASME Section III, Class 2 (Winter, 1974)
Design Pressure, (Internal/External @ Design Temperature)	700psig/50 psig @ 40-200F 700psig/44 psig @ 300F
Operating Temperature, F	60-140
Normal Operating Pressure, psig	540-570
Minimum/Maximum Operating Pressure, psig	500/650*
Volume, Total, ft^3	1855
Liquid Volume	
Minimum, ft^3	1420
Maximum, ft^3	1556
Fluid	Borated Water, 2100 ppm maximum
Material	
Shell	SA516 GR70 with SA240 Type 304L Clad
Heads	SA516 GR70 with Austenitic SS Clad

* In Modes 1 through 3 with RCS pressure greater than or equal to 1750 psia.

TABLE 6.3-2

SAFETY INJECTION SYSTEM - FAILURE MODES AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
1.	HPSI pump 2A or 2B	a) Fail during operation	Elect. malf., Mech. malf., Seal failure	Reduction in flow to affected HPSI header (and hot leg injection line during core flushing operation).	Pump "run" light, Low flow indication from affected HPSI train flow indicator. Low HPSI pump discharge pressure from local indicator PI-3316 or PI-3318.	Redundant HPSI pump.	One HPSI pump will supply adequate borated water to the core to match decay heat boiloff rates soon enough to minimize core uncovery.
		b) Fails to start	Elect. malf., Mech. malf.	Loss of one HPSI pump.	Pump "run" light, Periodic testing, Low flow indication from affected HPSI train flow indicators.	Redundant HPSI pump.	See Item 1a.
2.	LPSI pump 2A or 2B	a) Fails during operation	Elect. malf., Mech. malf., Seal failure	Reduction of flow to affected LPSI header during injection and/or shutdown cooling operations.	Pump "run" light, low flow indication from FI-3301 or FI-3306.	Redundant LPSI	Generation of a Recirculation Actuation Signal (RAS) stops the operating LPSI pumps.
		b) Fails to start	Elect. malf., Mech. malf.	Loss of flow via one LPSI train during injection.	Pump "run" light, Periodic testing, Low LPSI pump discharge pressure from local indicator PI-3314 or PI-3315.	Redundant LPSI pump	

* The method of Detection column is used to show that it is possible to detect the failure during or before Safety Injection System operation.

TABLE 6.3-2 (Cont'd)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
2.		c) Fails to stop	Elect. malf.	Potential for dead loading affected pump	Pump "run" light, Low LPSI pump discharge pressure from local indicator PI-3314 or PI-3315. Flow indication from FR-3301 or FR-3306.	Redundant LPSI pump available for SDC operation.	Recirculation mode utilizes HPSI pumps only. RAS stops the operating LPSI pumps.
3.	Hot leg injection orifice bypass valve V3654 or V3656	a) Fails open	Elect. malf., Mech. malf.	Unable to realign affected HPSI pump for simultaneous hot and cold leg injection.	Low flow indication from FI-3315 or FI-3325, Periodic testing.	Valve in redundant HPSI train will not be affected.	
		b) Fails closed	Elect. malf., Mech. malf.	Reduction in flow rate to HPSI header during injection and short term recirculation.	Indication from periodic testing.	Redundant HPSI train will not be affected.	Each HPSI pump injects borated water into all of the four RCS cold legs. Also, see item 1a.
4.	LPSI/SDC Hx bypasses flow control valve FCV-3301 or FCV-3306	a) Fails open	Elect. malf., Mech. malf.	No impact during injection or recirculation.	Valve position indicator, Periodic testing.	None required	Power to valve operator is racked out during normal operation and SI mode.
		b) Fails closed	Elect. malf., Mech. malf.	Loss of flow via affected LPSI pump to two out of four RCS cold legs during long term cooling.	Valve position indicator, Periodic testing, No flow indication from FR-3301 or FR-3306.	Redundant LPSI train.	The mini-flow path protects the affected LPSI pump against operating dead-headed. Valves are locked open.
5.	SDC Hx inlet isolation valve V3517 or V3658	a) Fails open	Elect. malf., Mech. malf.	Possible diversion of flow from LPSI header to containment spray (CS) header. Possible reduction in CS pump performance.	periodic testing, Low flow indication from FR-3301 or FR-3306.	Redundant valve will not be affected	These valves are locked closed and are not required to open until the initiation of shutdown cooling operation.

* The Method of Detection column is used to show that it is possible to detect the failure during or before Safety Injection System operation.

TABLE 6.3-2 (Cont'd)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
		b) Fails closed	Elect. malf., Mech. malf.	No impact on injection. Unable to align one shutdown cooling Hx for long term cooling operation.	Periodic testing, Low shutdown cooling Hx inlet pressure from PI-3303X or PI-3303Y.	Crossover valve in redundant train will be unaffected.	
6.	Shutdown cooling flow control valve HCV-3512 or HCV-3657	a) Fails open	Elec. malf., Mech. malf.	No impact on injection. Unable to control cooldown rate during long term recirculation in affected train.	Periodic testing, Valve position indicator.	SDC Hx outlet valve V3456 or V3457 closed in series prevents flow to CS header during injection. Operator can manually adjust LPSI flow control valve to attain the required cooldown rate. Redundant LPSI train.	These valves are required to be closed during injection and short term recirculation.
		b) Fails closed	Elect. malf., Mech. malf.	No impact on injection. Unable to establish cooldown via one LPSI train during long term recirculation.	Periodic testing, valve position indicator.	Redundant LPSI train.	
7.	Hot leg injection line isolation valve V3550, V3551 or Hot leg injection line flow control valve V3523, V3540	a) Fails open	Elect. malf., Mech. malf.	Loss of double isolation capability during injection.	Valve position indicator, Periodic testing.	Series redundant iso-lation valve provides backup.	These valves are normally locked closed in the control room. During long term recirculation, the HPSI pumps are manually realigned for simultaneous hot and cold leg injection. This insures flushing and ultimate sub-cooling of the core independent of break location.

* The Method of Detection column is sued to show that is possible to detect the failure during or before Safety Injection System operation.

TABLE 6.3-2 (Cont'd)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
		b) Fails closed	Elect. malf., Mech. malf.	Loss of one hot leg injection flow path during long term recirculation. No impact on injection.	Valve position indicator, Periodic testing, Low flow indication from FI-3315 or FI-3325.	Redundant hot leg injection line.	These valves may be opened as early as two hours and prior to 6 hours following a LOCA. Therefore, operator action time of 4 to 6 hours for simultaneous hot and cold leg injection is acceptable. Also, see item 7a.
8.	HPSI header isolation valve HCV-3616, HCV-3617, HCV-3626, HCV-3627, HCV-3636, HCV-3637, HCV-3646, or HCV-3647	a) Fails closed	Elect. malf., Mech. malf.	Reduction in high pressure flow rate to the associated RCS cold leg during injection and recirculation.	Valve position indicator, Periodic testing, Low flow indication from FI-3311, FI-3321, FI-3331, or FI-3341	Parallel redundant HPSI header isolation valve will be unaffected.	These valves are closed during power operation. However, they are automatically opened upon generation of Safety Injection Actuation Signal (SIAS).
		b) Fails open	Elect. malf., Mech. malf.	No impact on injection or recirculation.	Valve position indicator, Periodic testing.	None required.	
9.	LPSI header isolation valve HCV-3615, HCV-3625, HCV-3635, or HCV-3645	a) Fails open	Elect. malf., Mech. malf.	No impact on injection or recirculation.	Valve position indicator, Periodic testing.	None required.	The low pressure header check valve prevents back flow through these valves during recirculation. See Item 8a.
		b) Fails closed	Elect. malf., Mech. malf.	Loss of low pressure flow to one RCS cold leg during injection.	Valve position indicator, Periodic testing, Low flow indication from FI-3312, FI-3322, FI-3332, or FI-3342	Redundant LPSI header valve will not be affected.	

* The Method of Detection column is used to show that it is possible to detect the failure during or before Safety Injection System operation.

TABLE 6.3-2(Cont'd)

No.	Name		Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks Other Effects
10.	SIT discharge isolation valve V3614, V3624, V3634, or V3644	a)	Fails open	Elect. malf., Mech. malf.	No impact on injection or recirculation. Unable to properly isolate affected tank during normal or small break post LOCA shutdown cooling.	Periodic testing, Valve position indicator.	The operator can depressurize the SIT by bleeding off nitrogen to minimize the discharging of its contents.	During normal cool-down, the operator will close the SIT isolation valves whenever the RCS pressure drops below 276 psia. An interlock with pressurizer pressure prevents closing of these valves whenever the RCS pressure is above 276 psia. **
		b)	Fails closed	Elect. malf., Mech. malf.	Isolation of one SIT from one RCS cold leg.	Valve position indicator, Periodic testing.	Redundant SIT. SIT dimensions and parameters are selected to allow three of the four tanks to recover the core following a LOCA, prior to establishing HPSI/LPSI flow.	These valves are interlocked with the pressurizer pressure measurement channels which open them automatically prior to an actual or simulated signal exceeding 515 psia and to prevent inadvertent closure prior to or during a LOCA.

* The method of Detection column is used to show that is possible to detect the failure during or before Safety Injection System operation.

** Following License Amendment No. 100, the SITs are not required to be operable when the RCS temperature is below Mode 3 temperature.

TABLE 6.3-2 (Cont'd)

No	Name		Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
								Once these valves are fully opened they are locked in the open position then the power to their motors is removed. Although locked open, they received a signal to open whenever a SIAS is initiated.
11.	SIT drain/fill line bypass valve V3611, V3621, V3631 or V3641	a)	Fails open	Elect. malf., Mech. malf., Faulty air supply	Possible reduction of inventory in affected tank. Possible diversion of affected tank content to the reactor drain tank during injection.	Low SIT level alarm from LIA-3311, LIA-3321, LIA-3331, LIA-3341, LIA-3312, LIA-3322, LIA-3332, or LIA-3342, Periodic testing, High level alarm in reactor drain tank.	The operator can isolate the flow path from the SIT to the reactor drain tank by manually closing Valve V3490, V3491, V3569 or V3914. Redundant SITs can provide borated water to the RCS.	These valves are normally closed. Initiation of SIAS will also close these valves.
		b)	Fails closed	Elect. malf., Mech. malf., Loss of air supply	Unable to fill and correct boron concentration of affected tank during maintenance. No impact during injection or recirculation.	Periodic testing, No flow indication from FI-3305 during filling operation, valve status indication.	None required.	
12.	Injection header loop check valve leakage valve HCV-3618, HCV-3628, HCV-3638, or HCV-3648	a)	Fails open	Elect. malf., Mech. malf., Faulty air supply	Unable to easily identify excessive cold leg check valve leakage. Possible reduction in pressurizer level.	Periodic testing, high level alarm in the reactor drain tank.	Operator can manually close valve V3118, V3128, V3138, or V3148 and also V3490, V3491, V3569, or V3914, to facilitate repair of affected valve. Operator can manually close valve V3661 to the reactor drain tank.	The pressurizer level controls will automatically start the standby charging pump in order to maintain the presurizer level within its specifications. Valves

* The Method of Detection column is used to show that it is possible to detect the failure during or before Safety Injection System operation.

TABLE 6.3-2 (Cont'd)

No.	Name		Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
								are normally closed, will fail closed, and close upon receipt of an SIAS.
		b)	Fails closed	Elect. malf., Mech. malf., Loss of air supply	Unable to properly drain cold leg check valve leakage fluid. Unable to test affected check valve for excessive leakage.	High pressure indication/alarm from PIA-3319, PIA-3329, PIA-3339 or PIA-3349, Periodic testing.	None required.	These valves are closed upon initiation of an SIAS.
13.	Nitrogen supply line isolation V3612, V3622, V3632, or V3642	a)	Fails open	Mech. malf., Faulty air supply Elect. malf.	Possible overpressurization of one SIT.	Periodic testing, High SIT pressure indication/alarm from PIA-3311, PIA-3321, PIA-3331, or PIA-3341. HH pressure alarm from PIS-3313, PIS-3323, PIS-3333 or PIS-3343. Actuation of SIT relief valve.	SIT relief valve protects the tank against overpressurization. Also the operator can gradually open the vent valve to relieve the excess pressure.	These valves are closed after pressurization of the SIT.
		b)	Fails closed	Elect. malf., Mech. malf., Loss of air supply	Inability to repressurize one SIT.	Periodic testing, Low SIT pressure indication/alarm from PIA-3311, PIA-3321, PIA-3331, or PIA-3341. LL pressure alarm from PIS-3312, PIS-3322, PIS-3332, or PIS-3342.	Operator can manually isolate the nitrogen supply line upstream to facilitate valve repair.	
14.	SIT vent line isolation valve V3733, V3734, V3735, V3736, V3737, V3738, V3739 or V3740	a)	Fails open	Elect. malf., Mech. malf.	Inadvertent depressurization of one SIT. Unable to repressurize affected tank.	Periodic testing, Low Pressure indication/alarm from PIA-3311, PIA-3321, PIA-3331, or PIA-3341.	Redundant SITs can provide borated water to the RCS.	These valves are locked closed in the control room during power operation.
		b)	Fails closed	Elect. malf., Mech. malf.	No impact on ability to vent affected SIT.	Periodic testing, valve position indication	Redundant vent valve. Operator can utilize redundant vent valve (in parallel) to vent affected SIT.	

*The Method of Detection column is used to show that it is possible to detect the failure during or before Safety Injection System operation.

TABLE 6.3-2 (Cont'd)

No.	Name		Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
15	Hot leg injection check valve leakage valve V3571 or V3572	a)	Fails open	Elect. malf., Mech. malf., Faulty air supply	Unable to easily identify excessive leakage through the hot leg injection check valve. Possible reduction in pressurizer level.	Periodic testing, High level alarm in the reactor drain tank.	Operator can isolate the drain line by manually closing valve V3573, V3574 or V3661 to drain tank.	These valves are normally closed. Also, they are closed upon initiation of SIAS. Also, see item 12a.
		b)	Fails closed	Mech. malf., Elect. malf., Loss of air supply	Unable to properly drain HPSI hot leg check valve leakage fluid. Unable to test hot leg check valve for excessive leakage.	Periodic testing, pressure indication, alarm from PIA-3310 or PIA-3320.	Operator can isolate the drain in order to facilitate valve repair.	
16.	Shutdown cooling suction line isolation valve V3480, or V3652.	a)	Fails open	Elect, malf., Mech. malf.	No impact during hot leg injection. Loss of redundancy for isolating one shutdown cooling train	Periodic testing. Valve position indication.	Redundant valve V3481 or V3651 prevents back flow to SDC line during hot leg injection. Redundant shutdown cooling isolation valve will not be affected.	These valves are interlocked with the pressurizer pressure measurement channel to prevent inadvertent opening and to automatically close whenever the RCS pressure exceeds the design pressure of the Shutdown Cooling System.
		b)	Fails closed	Elect. malf,, Mech. malf.	No impact during hot leg injection. Possible loss of one shutdown train following a small LOCA.	Periodic testing. Valve position indication.	Redundant shutdown cooling train will not be affected,	

*The Method of Detection column is used to show that it is possible to detect the failure during or before Safety Injection System operation.

TABLE 6.3-2 (Cont'd)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
17.	SIT drain/fill line containment isolation valve SE-03-2A or SE-03-2B	a) Fails open	Elect. malf., Mech. malf.	Loss of double redundant isolation capability.	Periodic testing.	Redundant series isolation valve V3463 provides backup capability. Valves SE-03-1A,B,C,D and V3611, 21, 31, 41 close on SIAS.	Valves are normally closed and are also closed by SIAS and CIAS.
		b) Fails closed	Elect. malf., Mech. malf.	No impact on system function.	Periodic testing.	Redundant valve provides for drain and fill and/or change of boric acid concentration in SITs.	Valves SE-03-2A and SE-03-2B are in parallel.
18.	SIT drain/fill line solenoid opr. isolation valve SE-03-1A, SE-03-1B, SE-03-1C, SE-03-1D	a) Fails open	Elect. malf., Mech. malf.	Same an item 11a.	Same as item 11a.	Same as item 11a.	Same as item 11a.
		b) Fails closed	Elect. malf., Mech. malf.	No impact an system operation.	Periodic testing, Valve status indication.	Parallel redundant drain/fill valve V3611, V3621, V3631 or V3641 provides an alternate path to drain the affected SIT.	
19.	LPSI Pump suction isolation valve V3432 or V3444	a) Fails open	Elect. malf., Mech. malf.	No impact on injection. Unable to establish shutdown cooling in affected train.	Periodic testing, valve status indication.	Redundant LPSI train for shutdown cooling.	Valves are opened from the control room.
		b) Fails closed	Elect. malf., Mech. malf.	Unable to establish LPSI flow in affected train, during injection.	Periodic testing, valve status indication.	Redundant LPSI train for injection.	These valves are normally locked open.

* The Method of Detection column is used to show that it is possible to detect the failure during or before Safety Injection System operation.

TABLE 6.3-2(Cont'd)

No.	Name	Failure Mode	Cause	Symptons and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
20.	Mini-flow line to RWT isolation valve V3495, V3496, V3659, or V3660	a) Fails open	Elect. malf., Mech. malf., Corrosion, Operator error.	No impact on injection. Loss of double isolation capability during recirculation.	Periodic testing. Valves status indication.	Series redundant valve provides adequate isolation during recirculation.	These valves are normally locked open but closed by RAS to assure that contaminants are not recirculated into the RWT during recirculation.
		b) Fails closed	Elect, malf., Mech. malf., Corrosion, Operator error	Loss of mini-flow protection for affected HPSI and LPSI pumps. Possible damage to affected HPSI and LPSI pumps during test.	Periodic testing. Valves status indication.	None	These valves are normally open during power operation to provide protection against the associated HPSI/ LPSI pump operating deadheaded.

*The Method of Detection column is used to show that it is possible to detect the failure during or before Safety Injection System operation.

TABLE 6.3-3

SAFETY RELATED PROCESS INSTRUMENTATION

System Parameter and Location	Indication: Local	Indication: Control Room	Indication: Alarm[1] High	Indication: Alarm[1] Low	Recording[1]	Identification No. Control Function	Instrument[3] Range	Normal Operating Range	Instrument[3] Accuracy(%)
Safety Injection System									
1) HPSI Cold Leg Flow Rate	x					F-3311,3321,3331,3341 Monitor HPSI cold leg injection flow		0-320 gpm	
2) HPSI Hot Leg Flow Rate	x		x			F-3315, 3325 Monitor HPSI hot leg injection flow		0-320 gpm	
3) HPSI Header Pressure	x					P-3308,3309 Monitor HPSI pressure		0-2400 psig	
4) LPSI Flow Rate	x		x			F-3312,3322,3332,3342 Monitor LPSI flow		0-2000 gpm	
5) Shutdown Cooling Flow Rate				x		F-3301,3306 Monitor shut-down cooling flowrate		0-3500 gpm	
6) Shutdown Cooling Temperatures	x[2]			x		T-3351X, -3352X, -3351Y, -3352Y Monitor Shutdown Cooling System Performance and Cooldown Rate		0-300°F	
Reactor Coolant System									
1) Pressurizer Pressure	x	x	x			P-1102A,1102B, 1102C,1102D Initiate SIAS		2225-2275 psia	
	x					P-1103,1104,1105 1106 Provides interlocks on RCS suction valves and SIT isolation valves.		100-750 psia	
	x[2]	x				P-1107,1108 Monitor RCS pres-sure.		0-2275 psia	

* Estimated values, may be less than indicated based on environmental qualification.

TABLE 6.3-3(Cont'd)

System Parameter and Location	Local	Indication Control Room	Alarm(1) High	Alarm(1) Low	Recording(1	Identification No. Control Function	Instrument(3) Range	Normal Operating Range	Instrument(3) Accuracy(%)
Reactor Coolant System									
2) Reactor Coolant Cold leg temperature	x(2)	x		None		T1115, 1125 Monitor cold leg temperatures. Used to determine when shutdown cooling can be initiated.		532-550°F	

* Estimated values, may be less than indicated based on environmental qualification.

(1) All alarms and recordings are in the control room unless otherwise indicated.
(2) These instruments are located on the hot shutdown panel.
(3) Instrument ranges are selected in accordance with standard engineering practices. Instrument accuracies are selected such that existing instrument loop performance and safety analysis assumptions remain valid. Where applicable, instrument accuracies are also evaluated for their impact on setpoints in accordance with the FPL Setpoint Methodology.

TABLE 6.3-4a

INJECTION MODE FLOWRATES*

NODE	FLOW, GPM
1	0
2	3580
3	2950
4	630
5	2950
6	630
7	100
8	30
9	2850
10	600
11	0
12	2850
13	2850
14	1425
15	600
16	150
17	300
18	1725
19	0
20	0
21	260

Note:

Refer to Figure 6.3-2A for mode diagram.

TABLE 6.3-4b

SHORT TERM RECIRCULATION MODE FLOWRATES*

NODE	FLOW, GPM
1	600
2	0
3	0
4	600
5	0
6	600
7	0
8	0
9	0
10	600
11	0
12	0
13	0
14	0
15	600
16	150
17	300
18	300
19	0
20	0
21	0

Note:

Refer to Figure 6.3-2b for Mode Diagram.

TABLE 6.3-4c

LONG TERM RECIRCULATION MODE FLOWRATES*

NODE	FLOW, GPM
1	600
2	0
3	0
4	600
5	0
6	600
7	0
8	0
9	0
10	600
11	0
12	0
13	0
14	0
15	300
16	75
17	150
18	150
19	300
20	0
21	0

Note:

Refer to Figure 6.3-2c for mode diagram.

TABLE 6.3-4d

SHUTDOWN COOLING MODE FLOWRATES*

NODE POINT	FLOW, GPM (start/end)**	PRESSURE, PSIG (start/end)**	TEMPERATURE F (start/end)**
1	0	-	-
2	0	-	-
3	0	-	-
4	0	-	-
5	3000	440 psig/150 psig	325 F/140 F
6	0	-	-
7	0	-	-
8	0	-	-
9	3000	438 psig/148 psig	325 F/140 F
10	0	-	-
11	0/3000	NA/148 psig	NA/140 F
12	3000/0	438 psig/NA	325 F/NA
13	3000	435 psig/134 psig	213 F/116 F
14	1500	435 psig/134 psig	213 F/116 F
15	0	-	-
16		-	-
17	0	-	-
18	1500	407 psig/104 psig	213 F/116 F
19	0	-	-
20	3000	261 psig/0 psig	325 F/140 F
21	0	-	-

Notes:

* Refer to Figure 6.3-2d for mode diagram.
** Start/end indicated flow, pressure or temperature at the start of SDC, and then at the end of SDC.

TABLE 6.3-5

POWER OPERATED VALVES

TAG NUMBER	VALVE SIZE, INCHES	VALVE TYPE	OPERATOR	ASME CLASS	OPERATING PRESSURE	OPERATING TEMPERATURE	DESIGN PRESSURE	DESIGN TEMPERATURE
FCV-3301	10	Butterfly	Motor	2	450	325	500	350
FCV-3306	10	Butterfly	Motor	2	450	325	500	350
V3456	10	Gate	Motor	2	450	325	500	350
V3457	10	Gate	Motor	2	450	325	500	350
V3480	10	Gate	Motor	1	2300	600	2485	650
V3481	10	Gate	Motor	1	2300	600	2485	650
V3495	6	Globe	Solenoid	2	1450	325	1750	350
V3496	6	Globe	Solenoid	2	1450	325	1750	350
HCV-3512	10	Butterfly	Motor	2	450	325	500	350
V3517	12	Gate	Motor	2	450	325	500	350
V3523	3	Globe	Motor	2	2400	300	2485	650
V3536	4	Globe	Motor	2	300	325	500	350
V3539	4	Globe	Motor	2	300	325	500	350
V3540	3	Globe	Motor	2	2400	300	2485	650
V3545	10	Gate	Motor	1	2235	600	2485	650
V3550	3	Globe	Motor	2	2400	300	2485	650
V3551	3	Globe	Motor	2	2400	300	2485	650
V3614	12	Gate	Motor	1	2235	330	2485	650
HCV-3615	6	Globe	Motor	2	2235	330	2485	650
HCV-3616	2	Globe	Motor	2	1485	300	2485	650
HCV-3617	2	Globe	Motor	2	2400	300	2485	650
V3624	12	Gate	Motor	1	2235	330	2485	650
HCV-3625	6	Globe	Motor	2	2235	330	2485	650

TABLE 6.3-5 (Cont'd)

TAG NUMBER	VALVE SIZE, INCHES	VALVE TYPE	OPERATOR	ASME CLASS	OPERATING PRESSURE	OPERATING TEMPERATURE	DESIGN PRESSURE	DESIGN TEMPERATURE
V3571	1	Globe	Pneu Diaph	1	2235	330	2485	650
SE-03-1A,B,C,D	1	Globe	Solenoid	2	555	300	700	350
V3572	1	Globe	Pneu Diaph	1	2400	330	2485	650
HCV-3626	2	Globe	Motor	2	1450	300	2485	650
HCV-3627	2	Globe	Motor	2	2400	300	2485	650
V3634	12	Gate	Motor	1	2235	330	2485	650
HCV-3635	6	Globe	Motor	2	2235	330	2485	650
HCV-3636	2	Globe	Motor	2	1450	300	2485	650
HCV-3637	2	Globe	Motor	2	2400	300	2485	650
V3644	12	Gate	Motor	1	2235	330	2485	650
HCV-3645	6	Globe	Motor	2	2235	330	2485	650
HCV-3646	2	Globe	Motor	2	1450	300	2485	650
HCV-3647	2	Globe	Motor	2	2400	300	2485	650
V3651	10	Gate	Motor	1	2300	600	2485	650
V3652	10	Gate	Motor	1	2300	600	2485	650
V3654	6	Gate	Motor	2	1450	300	1750	350
V3656	6	Gate	Motor	2	2400	300	2485	350
HCV-3657	10	Butterfly	Motor	2	450	325	500	350
V3658	12	Gate	Motor	2	450	325	500	350
V3659	3	Gate	Motor	2	1450	325	1750	350
V3660	3	Gate	Motor	2	1450	325	1750	350
V3661	3/4	Globe	Pneu Diaph	3	555	300	700	350
V3664	10	Gate	Motor	1	300	325	350	350
V3665	10	Gate	Motor	1	300	325	350	350

TABLE 6.3-5 (Cont'd)

TAG NUMBER	VALVE SIZE, INCHES	VALVE TYPE	OPERATOR	ASME CLASS	OPERATING PRESSURE	OPERATING TEMPERATURE	DESIGN PRESSURE	DESIGN TEMPERATURE
SE-03-2A, 2B	2	Globe	Solenoid	1	555	300	700	350
V3733, V3736	1	Globe	Solenoid	2	555	120	700	350
V3734, V3737 V3735, V3738	1	Globe	Solenoid	2	555	120	700	350
V3739, V3740	1	Globe	Solenoid	2	555	120	700	350
V3432, V3444	14	Gate	Motor	2	300	300	500	350
V3621, V3611 V3631, V3641	1	Globe	Pneu Diaph	2	555	300	700	350
V3642, V3632 V3622, V3612	0.5	Globe	Pneu Diaph	2	700	120	900	200
HCV-3638, 3628 3618, 3648	1	Globe	Pneu Diaph	1	2235	330	2485	650

TABLE 6.3-6

TIME SEQUENCE OF IMPORTANT EVENTS FOR A SPECTRUM OF LARGE LOCAs
(SECONDS AFTER BREAK)

Break*	SI Tanks On	End of Bypass	Start of Reflood	SI Tanks Empty	SI Pumps On	Hot Rod Rupture
1.0 DES/PD	13.8	21.1	34.8	71.9	71.9	94.5
0.8 DES/PD	13.8	21.3	35.1	72.0	72.0	95.8
0.6 DES/PD	14.8	22.3	36.1	73.0	73.0	99.0
0.5 ft^2 S/PD	122.5	135.0	148.6	187.3	187.3	273.6
1.0 DEG/PD	13.7	21.0	34.7	71.8	71.8	91.3
0.8 DEG/PD	13.9	21.4	35.1	72.2	72.2	93.9
0.6 DEG/PD	15.2	22.7	36.5	73.5	73.5	98.5

* DES/PD - Double Ended Slot Break In Pump Discharge Leg

S/PD - Slot Break In Pump Discharge Leg

DEG/PD - Double Ended Guillotine Break In Pump Discharge Leg

TABLE 6.3-7
GENERAL SYSTEM PARAMETERS AND INITIAL CONDITIONS
Cycle 1

Quantity	Value	
Reactor Power Level (102% of Nominal)	2611	Mwt
Average Linear Heat Generation Rate (102% of Nominal)	4.6	kw/ft
Peak Linear Heat Generation Rate	13.0	kw/ft
Gap Conductance at Peak Linear Heat Rate*	1262	BTU/hr-ft^2-F
Fuel Centerline Temperature at Peak Linear Heat Rate*	3285.6	F
Fuel Average Temperature at Peak Linear Heat Rate*	2133.5	
Hot Rod Gas Pressure	990.4	psia
Moderator Temperature Coefficient at Initial Density	$+0.5 \times 10^{-4}$	Δr/F
System Flow Rate (Total)	139.4×10^6	lbs/hr
Core Flow Rate	134.3×10^6	lbs/hr
Initial System Pressure	2250	psia
Core Inlet Temperature	550	F
Core Outlet Temperature	597	F
Active Core Height	11.39	ft
Fuel Rod OD	0.382	in
Number of Cold Legs	4	
Number of Hot Legs	2	
Cold Leg Diameter	30	in
Hot Leg Diameter	42	in
Safety Injection Tank Pressure	583	psia
Safety Injection Tank Gas/Water Volume	435/1420	ft^3

*These quantities correspond to the burnup (620 MWD/MTU, hot rod average) yielding the highest peak clad temperature.

TABLE 6.3-8

LARGE BREAK SPECTRUM

Cycle 1

Break Size, Type, and Location	Abbreviation	Figure No.
1.0 x Double Ended Slot Break In Pump Discharge Leg	1.0 DES/PD	6.3-5a to i
0.8 x Double Ended Slot Break In Pump Discharge Leg	0.8 DES/PD	6.3-6a to i
0.6 x Double Ended Slot Break In Pump Discharge Leg	0.6 DES/PD	6.3-7a to i
0.5 ft^2 Slot Break in Pump Discharge Leg	0.5 ft^2 S/PD	6.3-8a to i
1.0 x Double Ended Guillotine Break in Pump Discharge Leg	1.0 DEG/PD	6.3-9a to t
0.8 x Double Ended Guillotine Break in Pump Discharge Leg	0.8 DEG/PD	6.3-10a to i
0.6 x Double Ended Guillotine Break in Pump Discharge Leg	0.6 DEG/PD	6.3-11a to i

TABLE 6.3-9

PEAK CLAD TEMPERATURES AND OXIDATION PERCENTAGE
FOR THE LARGE BREAK SPECTRUM

Cycle 1

Break*	Peak Clad Temperature (°F)	Clad Oxidation (%) Local	Core-Wide
1.0 DES/PD	2085	15.27	0.569
0.8 DES/PD	2083	15.16	0.572
0.6 DES/PD	2075	14.82	0.540
0.5 ft^2 S/PD	1871	8.02	0.243
1.0 DEG/PD	2098	15.76	0.615
0.8 DEG/PD	2091	15.48	0.563
0.6 DEG/PD	2077	14.91	0.526

* DES/PD - Double Ended Slot Break In Pump Discharge Leg

S/PD - Slot Break In Pump Discharge Leg

DEG/PD - Double Ended Guillotine Break In Pump Discharge Leg

TABLE 6.3-10

VARIABLES PLOTTED AS A FUNCTION OF TIME
FOR EACH LARGE BREAK IN THE SPECTRUM

Cycle 1

Variable	Figure Designation
Core Power	6.3-5a, 6a, 7a, 8a, 9a, 10a and 11a
Pressure in Center Hot Assembly Node	6.3-5b, 6b, 7b, 8b, 9b, 10b and 11b
Leak Flow	6.3-5c, 6c, 7c, 8c, 9c, 10c and 11c
Hot Assembly Flow (below hot spot)	6.3-5d, 6d, 7d, 8d, 9d, 10d and 11d
Hot Assembly Flow (above hot spot)	6.3-5e, 6e, 7e, 8e, 9e, 10e and 11e
Hot Assembly Quality	6.3-5f, 6f, 7f, 8f, 9f, 10f and 11f
Containment Pressure	6.3-5g, 6g, 7g, 8g, 9g, 10g and 11g
Mass Added to Core During Reflood	6.3-5h, 6h, 7h, 8h, 9h, 10h and 11h
Peak Clad Temperature*	6.3-5i, 6i, 7i, 8i, 9i, 10i and 11i

* For the worst case, the temperature of the rupture node is also shown.

TABLE 6.3-11

ADDITIONAL VARIABLES PLOTTED AS A FUNCTION OF TIME FOR THE WORST LARGE BREAK

Cycle 1

Variable	Figure Designation
Mid Annulus Flow	6.3-9j
Qualities Above and Below the Core	6.3-9k
Core Pressure Drop	6.3-9l
Safety Injection Flow into Intact Discharge Legs	6.3-9m
Water Level in Downcomer During Reflood	6.3-9n
Hot Spot Gap Conductance	6.3-9o
Local Clad Oxidation	6.3-9p
Clad Temperature, Centerline Fuel Temperature, Average Fuel Temperature and Coolant Temperature for Hottest Node	6.3-9q
Hot Spot Heat Transfer Coefficient	6.3-9r
Hot Pin Pressure	6.3-9s
Core Bulk Channel Flow Rate	6.3-9t

TABLE 6.3-12

SAFETY INJECTION PUMPS
MINIMUM DELIVERED FLOW TO RCS FOR A
SMALL BREAK LOCA
(Assuming One Emergency Diesel Generator Failed)

RCS Pressure	Flow Rate Per Injection Point (gal/min)			
	(a), (c)	(a)	(b)	(b)
(psia)	A_1	A_2	B_1	B_2
1214	0.0	0.0	0.0	0.0
1192	25.0	25.0	25.0	25.0
1118	50.0	50.0	50.0	50.0
1048	62.5	62.5	62.5	62.5
955	75.0	75.0	75.0	75.0
840	87.5	87.5	87.5	87.5
708	100.0	100.0	100.0	100.0
558	112.5	112.5	112.5	112.5
398	125.0	125.0	125.0	125.0
220	137.5	137.5	137.5	137.5
167	140.8	140.8	140.8	140.8
105	909.6	909.6	144.6	144.6
0.0	1548.0	1548.0	151.0	151.0

(a) Delivered flow consists of 25% of the flow from one high pressure pump and 50% of the flow from one low pressure pump.

(b) Delivered flow consists of 25% of the flow from one high pressure pump.

(c) Injection point A_1 is assumed to be attached to the broken reactor coolant pump discharge leg.

TABLE 6.3-13

GENERAL SYSTEM PARAMETERS AND INITIAL CONDITIONS
SMALL BREAK ECCS PERFORMANCE ANALYSIS

Cycle 1

Quantity	Value
Reactor Power Level (102% of Nominal), MWt	2611
Average Linear Heat Rate (102% of Nominal), kw/ft	4.6
Peak Linear Heat Rate, kw/ft	15.0
Gap Conductance at Peak Linear Heat Rate, Btu/hr-ft^2-^{o}F	1514
Fuel Centerline Temperature at Peak Linear Heat Rate, ^{o}F	3658
Fuel Average Temperature at Peak Linear Heat Rate, ^{o}F	2304
Moderator Temperature Coefficient at Initial Density, $\Delta\rho/^o$F	$+0.2 \times 10^{-4}$
Axial Shape Index, ASIU	-0.25
System Flow Rate (total), lbs/hr	139.4×10^6
Core Flow Rate, lbs/hr	134.3×10^6
Initial System Pressure, psia	2250
Core Inlet Temperature, ^{o}F	550.0
Core Outlet Temperature, ^{o}F	598.6
Low Pressurizer Pressure Trip Setpoint, psia	1650
Safety Injection Actuation Signal Setpoint, psia	1500
Safety Injection Tank Pressure, psia	583
High Pressure Safety Injection Pump Shutoff Head, psia	1214
Low Pressure Safety Injection Pump Shutoff Head, psia	167

TABLE 6.3-14

SMALL BREAK SPECTRUM
(Cycle 1)

(See Chapter 15 for current analyses)

Break Size and Location	Abbreviation	Figure No.*
Breaks Analyzed with ASI of -0.15 ASIU and 50% charging pump flow of 40 gpm after 5 minute delay.		
0.5 ft^2 Break in Pump Discharge Leg	0.5 ft^2/PD	6.3-14
0.1 ft^2 Break in Pump Discharge Leg	0.1 ft^2/PD	6.3-15
0.04 ft^2 Break in Pump Discharge Leg	0.04 ft^2/PD	6.3-16
0.015 ft^2 Break in Pump Discharge Leg	0.015 ft^2/PD	6.3-17
0.008 ft^2 Break at Top of Pressurizer	0.008 ft^2/HL	6.3-18
Break Analyzed with ASI of -0.25 ASIU and 40% charging pump flow of 35 gpm after 10 minute delay.		
0.04 ft^2 Break in Pump Discharge Leg	0.04 ft^2/PD	6.3-19

* Refer to Table 6.3-15

TABLE 6.3-15

VARIABLES PLOTTED AS A FUNCTION
OF TIME FOR EACH SMALL BREAK
IN THE SPECTRUM
(Cycle 1)

(See Chapter 15 for current analyses)

Variable	Figure Designation *
Normalized Total Core Power	A
Inner Vessel Pressure	B
Break Flow Rate	C
Inner Vessel Inlet Flow Rate	D
Inner Vessel Two-Phase Mixture Volume	E
Heat Transfer Coefficient at Hot Spot	F
Coolant Temperature at Hot Spot	G
Hot Spot Clad Surface Temperature	H

* Refer to Figures 6.3-14a through 6.3-19h

TABLE 6.3-16

FUEL ROD PERFORMANCE SUMMARY
SMALL BREAK SPECTRUM

Break Size (ft^2)	Maximum Clad Surface Temperature (F)	Peak Local Zirconium Oxid. (%)	Hot Rod[c] Zirconium Oxid. (%)
0.5 ft^2/ID[a]	1119	<.0010	<.0002
0.1 ft^2/PD[a]	1019	<.0005	<.0001
0.04 ft^2/PD[a]	1547	<.75	<.11
0.015 ft^2/PD[a]	1093	<.0007	<.0002
0.008 ft^2/HL[a]	1005	<.0005	<.0002
0.04 ft^2/PD[b]	1653	<1.24	<.18

(a) Breaks analyzed with ASI of -0.15 ASIU and charging pump of 40 gpm after 5 minute delay.

(b) Break analyzed with ASI of -0.25 ASIU and charging pump flow of 35 gpm after 10 minute delay.

(c) Hot rod oxidation values are given as a conservative indication of core-wide oxidation.

TABLE 6.3-17

TIMES OF INTEREST FOR SMALL BREAKS
(seconds after break)

Break Size (ft^2)	HPSI Pump On	LPSI Pump On	SI Tanks On	Hot Spot Peak Clad Temp. Occurs
0.50 ft^2/PD[a]	42.8	(c)	102	6.4
0.10 ft^2/PD[a]	60.0	(c)	676	17.6
0.04 ft^2/PD[a]	90.0	(c)	2560	2514
0.015 ft^2/PD[a]	440.0	(c)	(d)	381
0.008 ft^2/HL[a]	285.0	(c)	(d)	167
0.04 ft^2/PD[b]	90.0	(c)	2490	2445

(a) Break analyzed with ASI of -0.15 ASIU and charging pump flow of 40 gpm after 5 minute delay.

(b) Break analyzed with ASI of -0.25 ASIU and charging pump flow of 35 gpm after 10 minute delay.

(c) Calculation terminated before time of LPSI pump activation.

(d) Calculation terminated before initiation of SI tank discharge.

TABLE 6.3-18

HPSI PUMP NPSH DATA

	Recirc Phase (Suction from Sump)
Elevation of Pump Suction, Ft	-6.64
Elevation of Source, Ft	23.38
Fluid Temperature, F	192
Fluid Vapor Pressure, Ft	23.3
Head Loss Due to Friction, Ft	3.79
NPSH Available, Ft	32.57
NPSH Required at Pump Runout, Ft	25.5
Sump Loss (Pb), Ft	2.79

The following formula is used:

NPSH (available) = Pt - Pv = Pa + Ps + Pe - Pi - Pv - Pb

where: Pt = pressure at pump suction centerline
Pv = vapor pressure of pumped water
Pa = air pressure
Ps = steam pressure
Pe = elevation pressure
Pi = head loss due to friction in the suction piping
Pb = head loss due to sump

NOTE: In accordance with SRP 6.2.2 the containment pressure is assumed equal to the fluid vapor pressure (i.e., $P_a + P_s = Pv$).

TABLE 6.3-19

I. INPUT PARAMETERS AND RESULTS OF THE ECCS SUPPLEMENTAL ANALYSIS

PARAMETER	SUPPLEMENTAL ANALYSIS
Rupture Strain Model	NUREG-0630 Models (1)
Steam Cooling Heat Transfer Model	CE's Alternate Model (2)
Model for Remainder of Calculation	"Calculation Method for the CE Large Break Evaluation Model"
Allowable Peak Linear Heat Generation Rate (kw/ft)	13.0
Rupture Strain (%)	90
Flow Blockage (%)	71
Hoop Stress at Rupture (KPSI)	5.63
Clad Temperature at Rupture (°F)	1515
Rupture Time	During Reflood

II. COMPARISON OF SUPPLEMENTAL AND SUBSECTION 6.3.3 ANALYSIS RESULTS

PARAMETERS	SUPPLEMENTAL ANALYSIS	SUBSECTION 6.3.3 ANALYSIS
Peak Clad Temperature (°F)	1972	2098
Location	Above Blockage	At Blockage
Peak Local Clad Oxidation (%)	4.69	15.76
Location	Above Blockage	At Blockage

TABLE 6.3-20

SIT INSTRUMENTS

SIT	TAG #	DESCRIPTION	POWER SOURCE	CABLE TRAY SYSTEMS	INSTRUMENT FUNCTION	CWD*	
2A2	LIA-3311	Level Wide Range	120 VAC 2MA-1 SA	SA	Indication & Hi-Low Alarm	280, 647	EC284924
	LIA-3312	Level Narrow Range	PP 221 (NB)	NB	Indication & Hi-LL Alarm	1521, 647	
	PIA-3311	Pressure	PP 220 (NA)	NA	Indication & H-L Alarm	280, 647	
	PIS-3312	Pressure	PP 209 (NB)	NB	LL Alarm	1522	
	PIS-3313	Pressure	PP 209 (NB)	NB	HH Alarm	1522	
2A1	LIA-3321	Level Wide Range	120 VAC 2MA-1 SA	SA	Indication & H-L Alarm	281, 647	EC284924
	LIA-3322	Level Narrow Range	PP 221 (NB)	NB	Indication & HH-LL Alarm	1521, 647	
	PIA-3321	Pressure	PP 220 (NA)	NA	Indication & H-L Alarm	281, 647	
	PIS-3322	Pressure	PP 209 (NB)	NB	LL Alarm	1522	
	PIS-3323	Pressure	PP 209 (NB)	NB	HH Alarm	1522	
2B1	LIA-3331	Level Wide Range	120 VAC 2MB-1 SB	SB	Indication & H-L Alarm	282, 647	EC284924
	LIA-3332	Level Narrow Range	PP 220 (NA)	NA	Indication & HH-LL Alarm	1521, 647	
	PIA-3331	Pressure	PP 221 (NB)	NB	Indication & H-L Alarm	282, 647	
	PIS-3332	Pressure	PP 220 (NA)	NA	LL Alarm	1522	
	PIS-3333	Pressure	PP 220 (NA)	NA	HH Alarm	1522	
2B2	LIA-3341	Level Wide Range	120 VAC 2MB-1 (SB)	SB	Indication & H-L Alarm	283, 647	EC284924
	LIA-3342	Level Narrow Range	PP 220 (NA)	NA	Indication & HH-LL Alarm	1521, 647	
	PIA-3341	Pressure	PP 221 (NB)	NB	indication & H-L Alarm	283, 647	
	PIS-3342	Pressure	PP 220 (NA)	NA	LL Alarm	1522	
	PIS-3343	Pressure	PP 220 (NA)	NA	HH Alarm	1522	

NA-Non-Nuclear Safety-Division A
NB-Non-Nuclear Safety-Division B
SA-Nuclear Safety-Division A
SB-Nuclear Safety-Division B
MA-Nuclear Safety-Division A
MB-Nuclear Safety-Division B

*CWD-Ebasco Drawing 2998-B-327

EC284924

TABLE 6.3-21
RWT FILL SOURCES

LINES TO RWT	SOURCE	RATED FLOW (gpm)	TIME ELAPSED BETWEEN HIGH ALARM AND OVERFLOW (MINUTES)
6"-CS-500	LPSI Pumps	3,100	2.4
6"-SI-154	HPSI Recirc.	30	250
	LPSI Recirc.	100	75
	CS Recirc.	150	50
3"-CS-62	Reactor Drain Pumps	50	150
3"-WM-A56	Hold Up Drain & Recirculation Pumps	80	94
3"-PMW-16	Primary Water Pumps	325	23
3"FS-556	Fuel Pool Purification Pump	150	50
I-3-CH-938	Boric Acid Makeup Pumps	143	50

TABLE 6.3-22

NET POSITIVE SUCTION HEAD

St. Lucie Unit 2 LPSI Pumps	GPM	NPSH (ft)
#1076149	3000	13.0
	3800	15.2
	4600	17.8
#1076150	3000	11.0
	3800	14.2
	4600	17.2

TABLE 6.3-23

NPSH TEST RESULTS FOR ST. LUCIE UNITS 1 AND 2

St. Lucie Unit 1 HPSI Pumps	GPM	NPSH (ft)
#200113	640	19.7
#200114	640	19.9
#200115	640	19.6
St. Lucie Unit 2 HPSI Pumps		
#14210014 (spare pump)	640	19.9
#14210015	631	19.0
#14210016	639	19.4

Refer to Drawings
2998-G-078, SH 130A & B

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW DIAGRAM
SAFETY INJECTION SYSTEM

FIGURE 6.3-1a

Refer to Drawing
2998-G-078 SH 131

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW DIAGRAM
SAFETY INJECTION SYSTEM

FIGURE 6.3-1b

Amendment No. 18 (01/08)

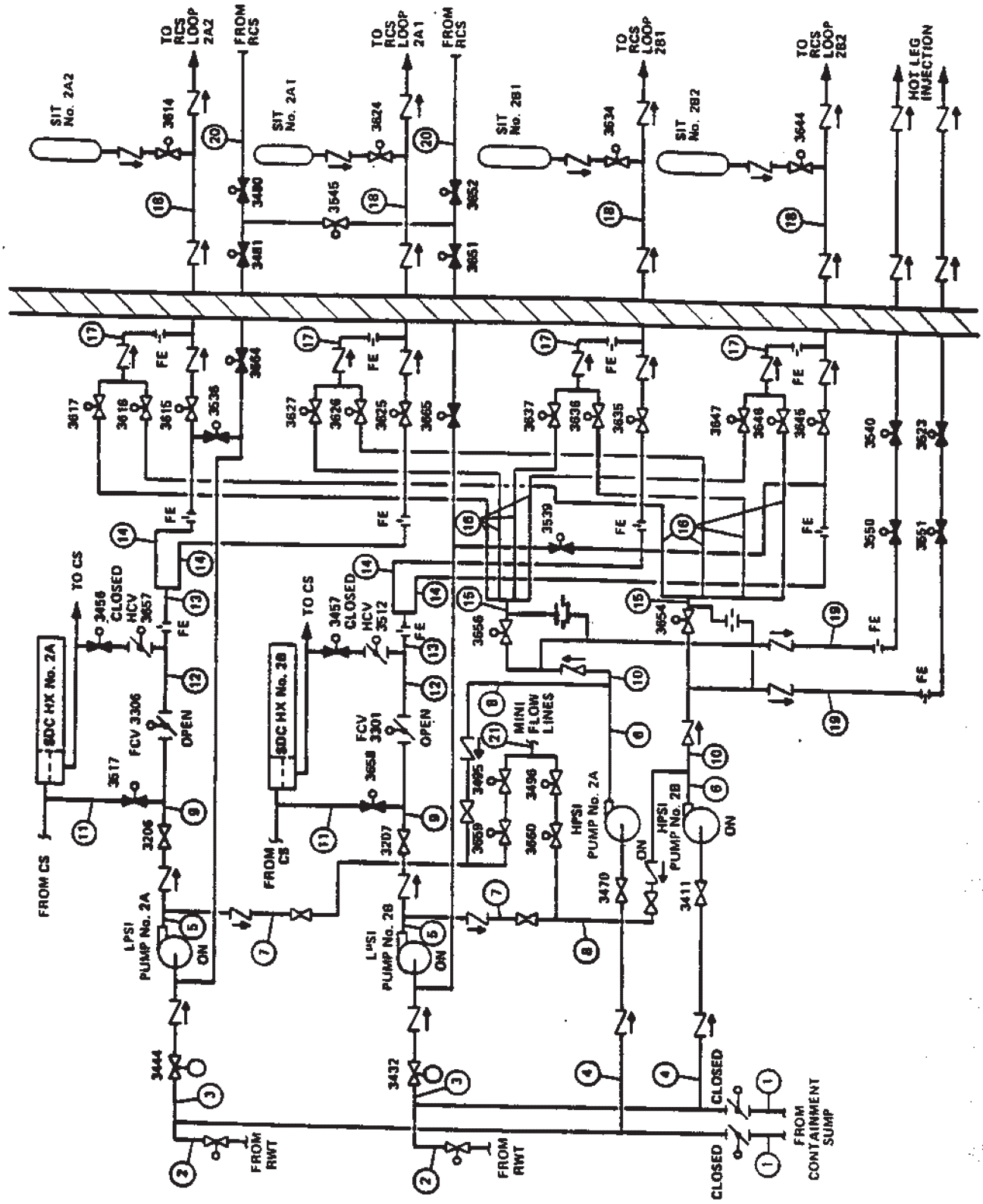
Refer to Drawing
2998-G-078 SH 132

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW DIAGRAM
SAFETY INJECTION SYSTEM

FIGURE 6.3-1c

Amendment No. 18 (01/08)



NOTES:

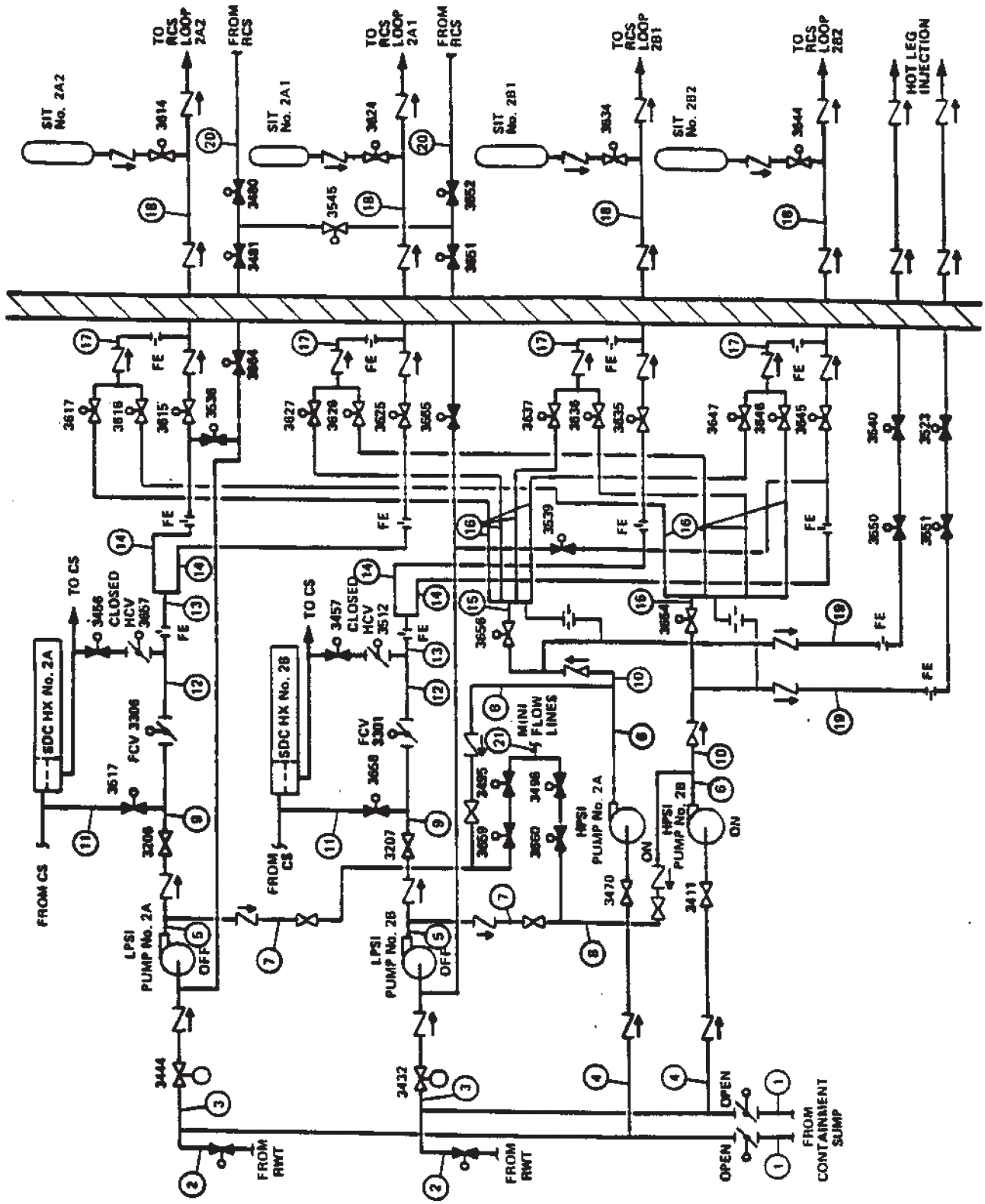
1) SEE TABLE 6.3-4a

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INJECTION MODE FLOW DIAGRAM[1]

FIGURE 6.3-2a

Amendment No. 10 (7/96)



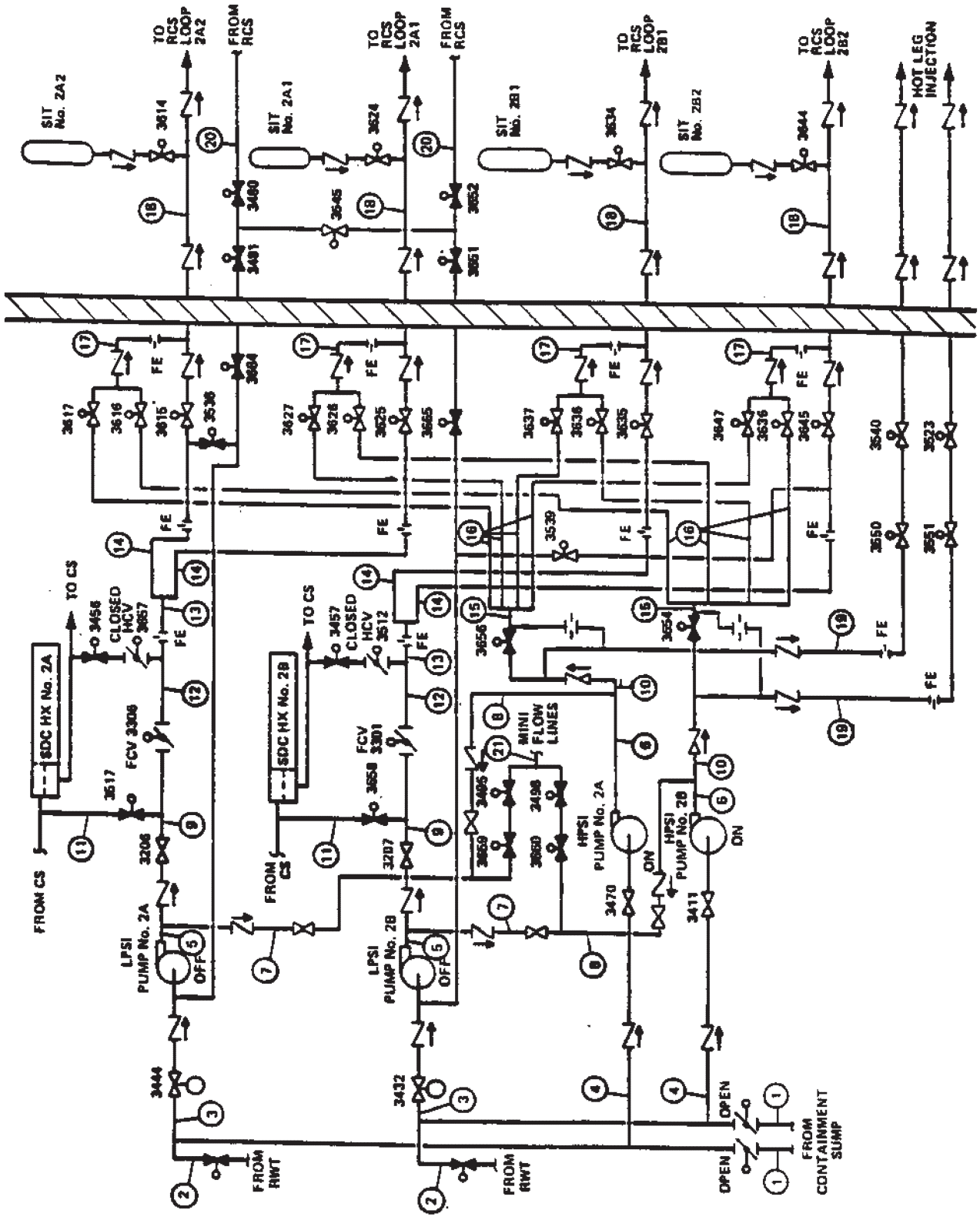
NOTES:

1) SEE TABLE 6.3-4b

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

SHORT-TERM RECIRCULATION MODE[1]
(LESS THAN 2 HOURS)

FIGURE 6.3-2b



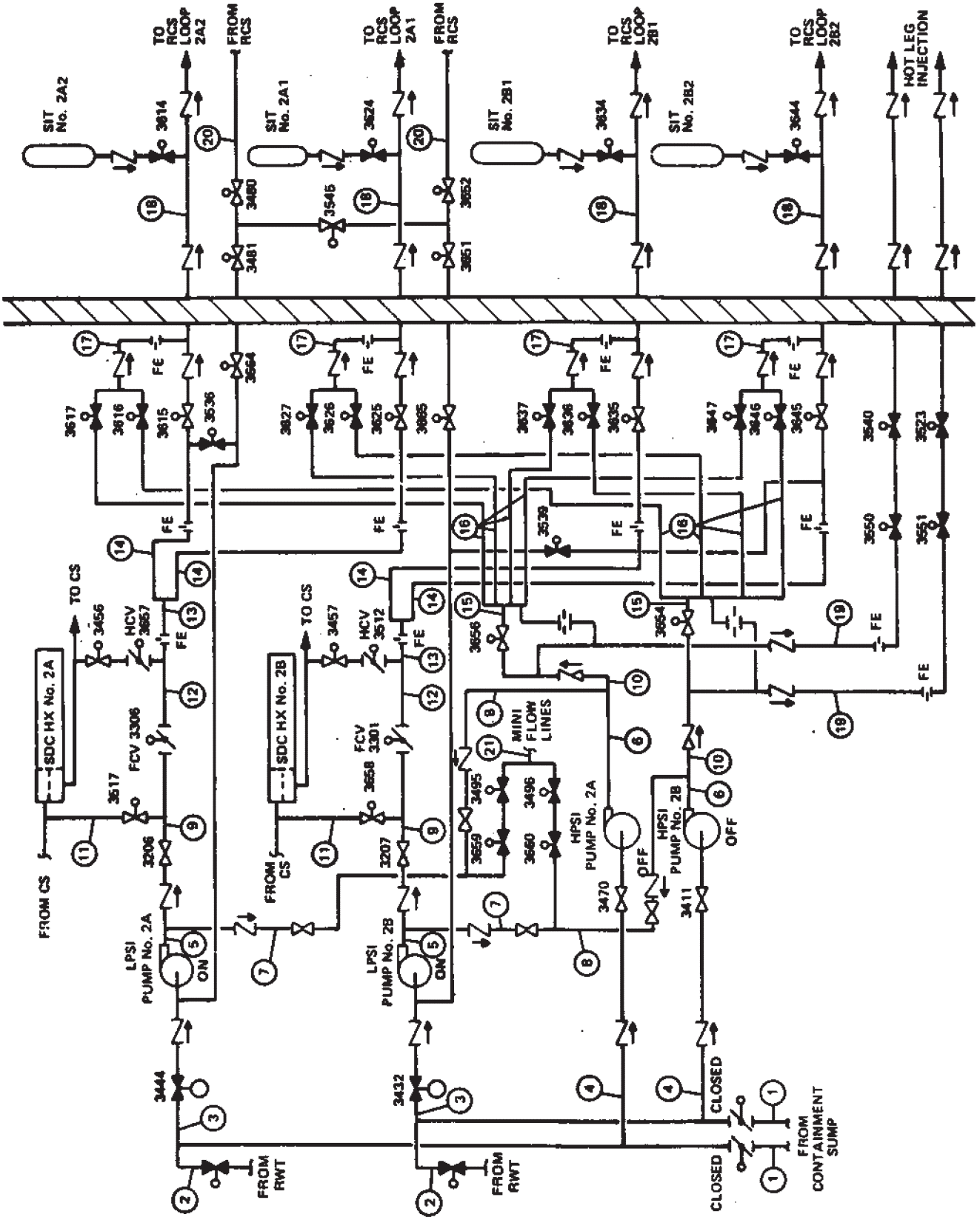
NOTES:

1) SEE TABLE 6.3-4c

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LONG-TERM RECIRCULATION MODE[1]
(HOT AND COLD LEG INJECTION)

FIGURE 6.3-2c



AMENDMENT NO. 1 (4/86)

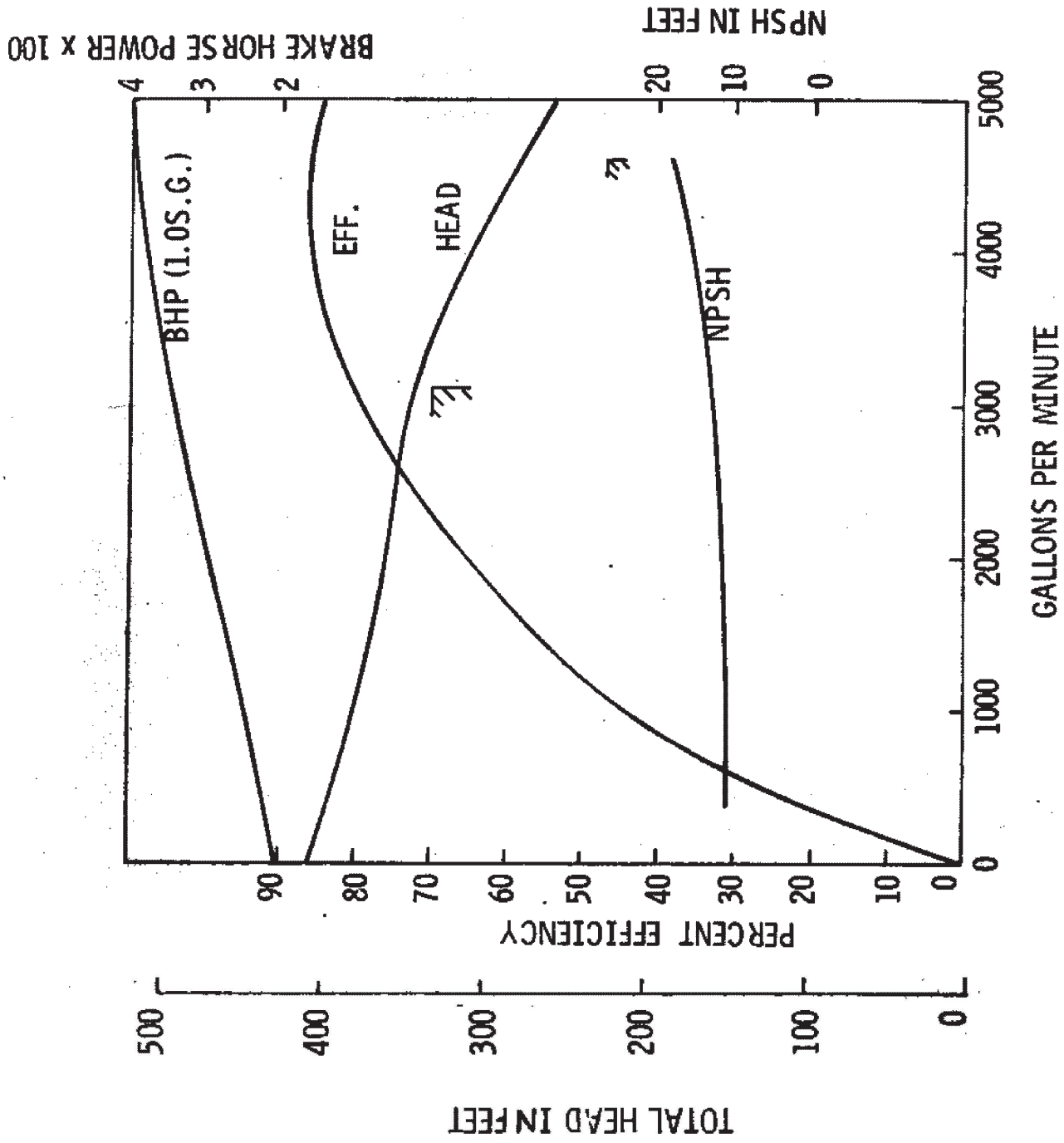
NOTES:

1) SEE TABLE 6.3-4d

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

NORMAL SHUTDOWN COOLING MODE (1)

FIGURE 6.3-2d

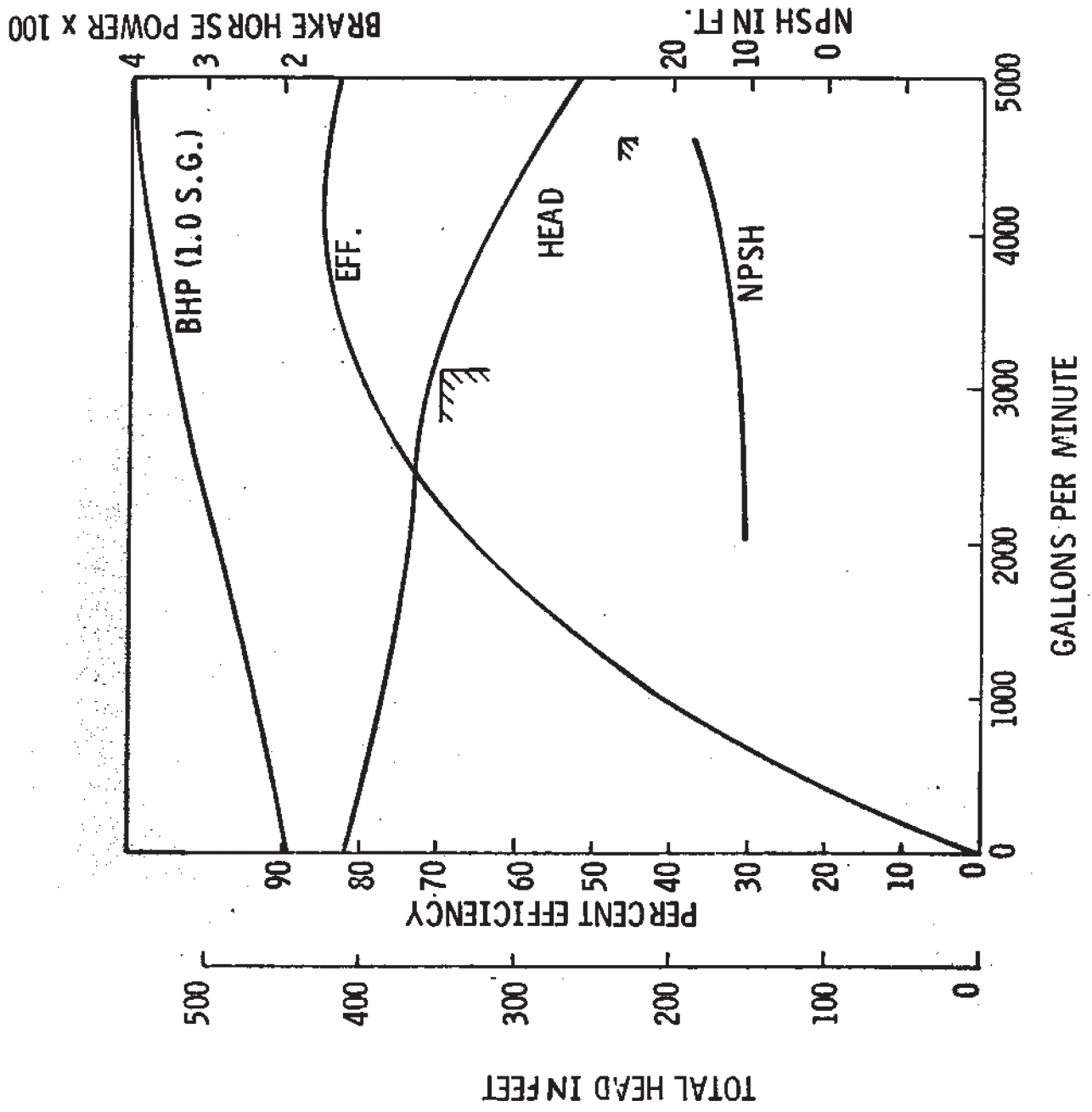


EC 290 023

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LOW-PRESSURE SAFETY INJECTION PUMP PERFORMANCE
PUMP NO. 1076149

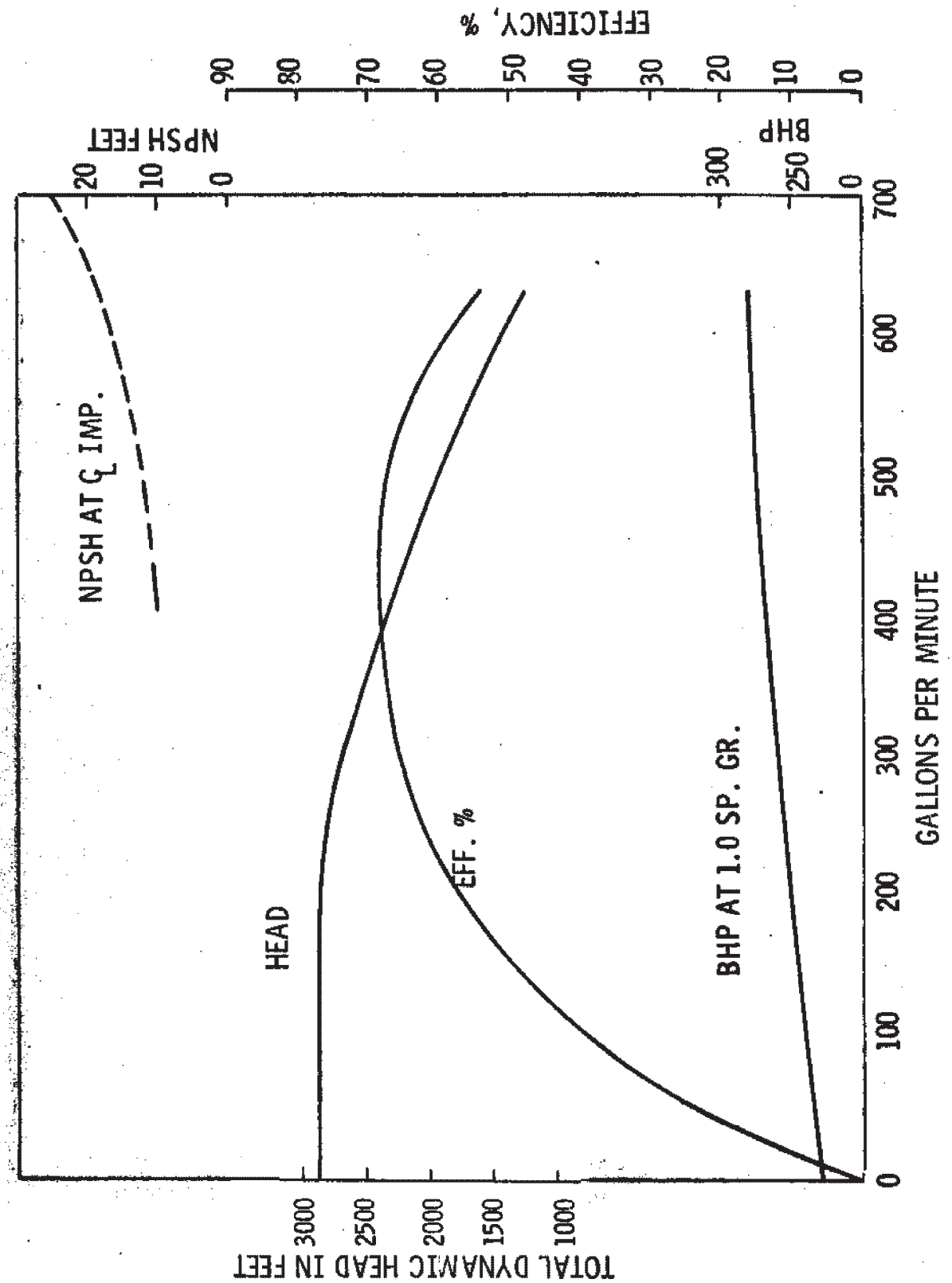
FIGURE 6.3-3a



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LOW-PRESSURE SAFETY INJECTION
PUMP PERFORMANCE
PUMP NO. 1076150

FIGURE 6.3-3b

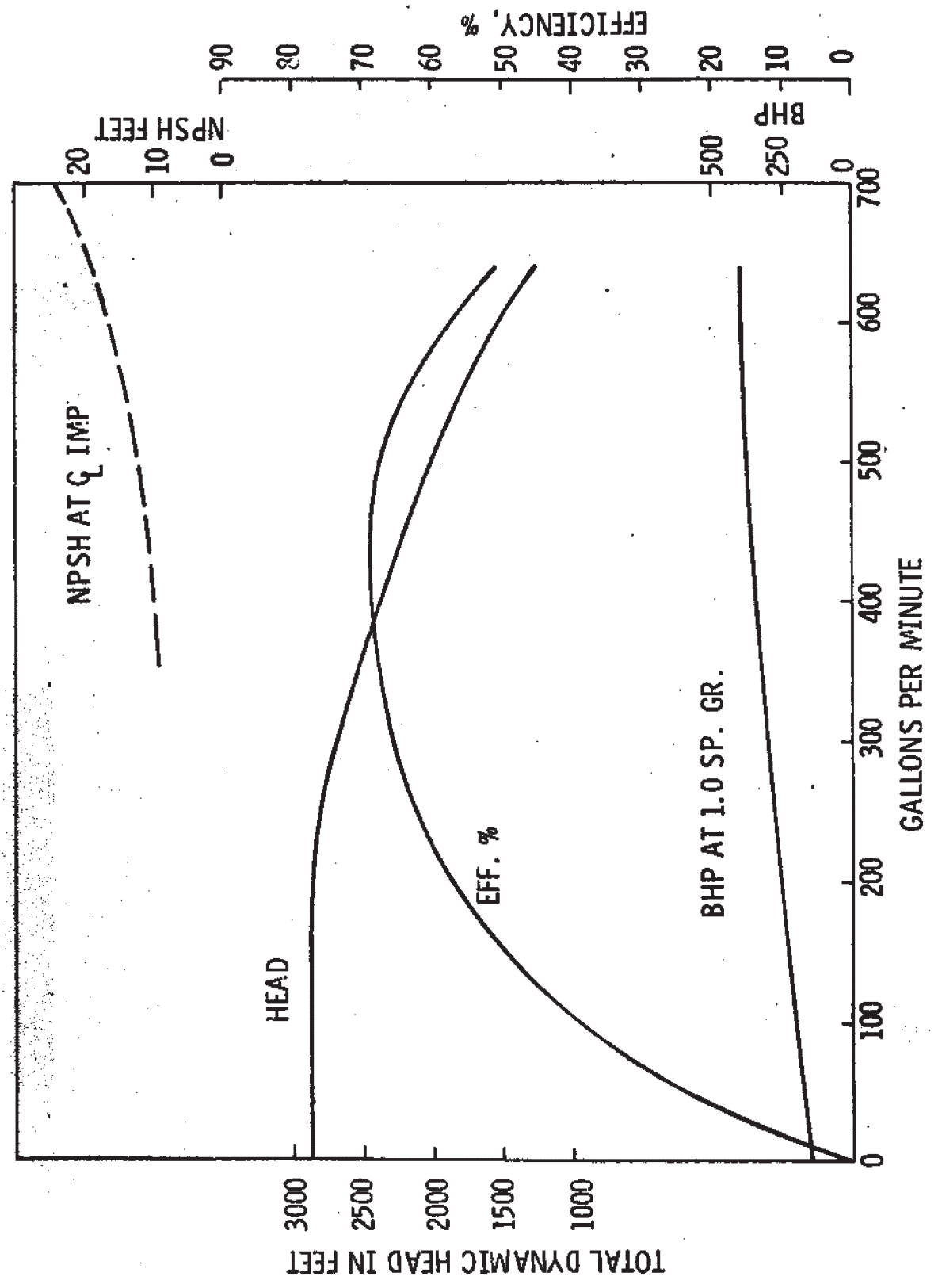


EC 290 023

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HIGH-PRESSURE SAFETY INJECTION PUMP PERFORMANCE
PUMP NO. 14210015

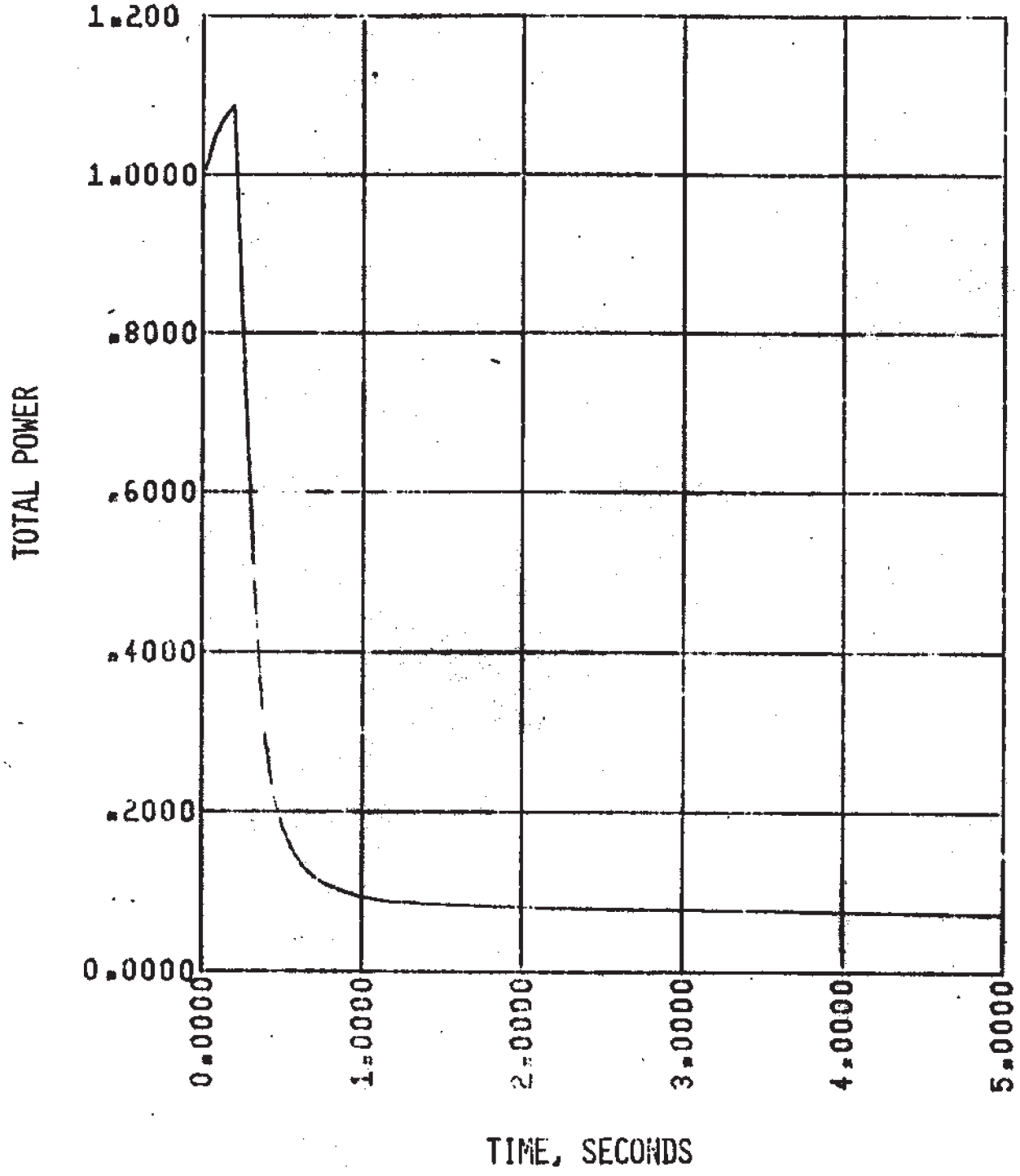
FIGURE 6.3-4a



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HIGH-PRESSURE SAFETY INJECTION
PUMP PERFORMANCE
PUMP NO. 14210016

FIGURE 6.3-4b



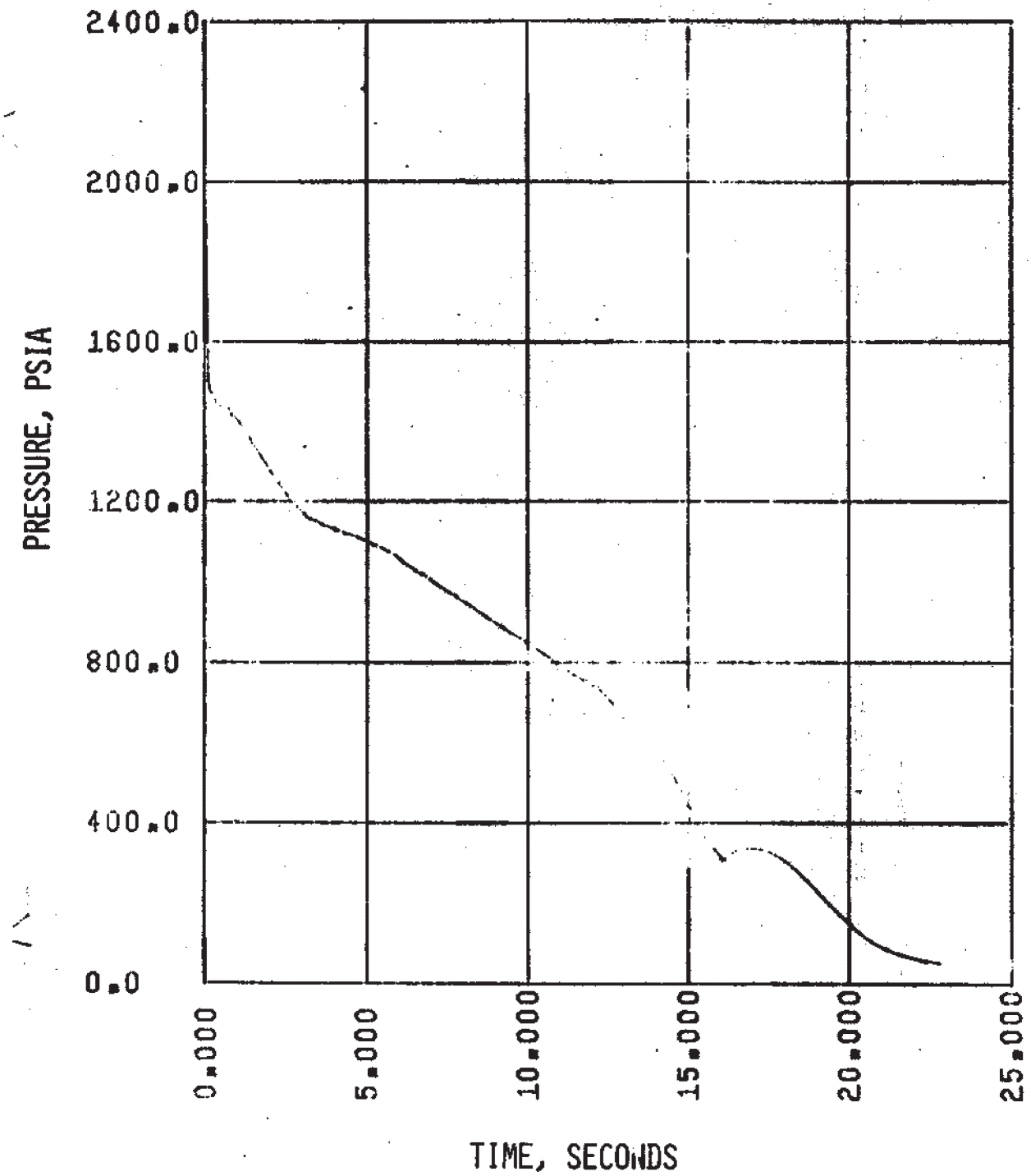
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE POWER - 1.0 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–5a

CYCLE 1



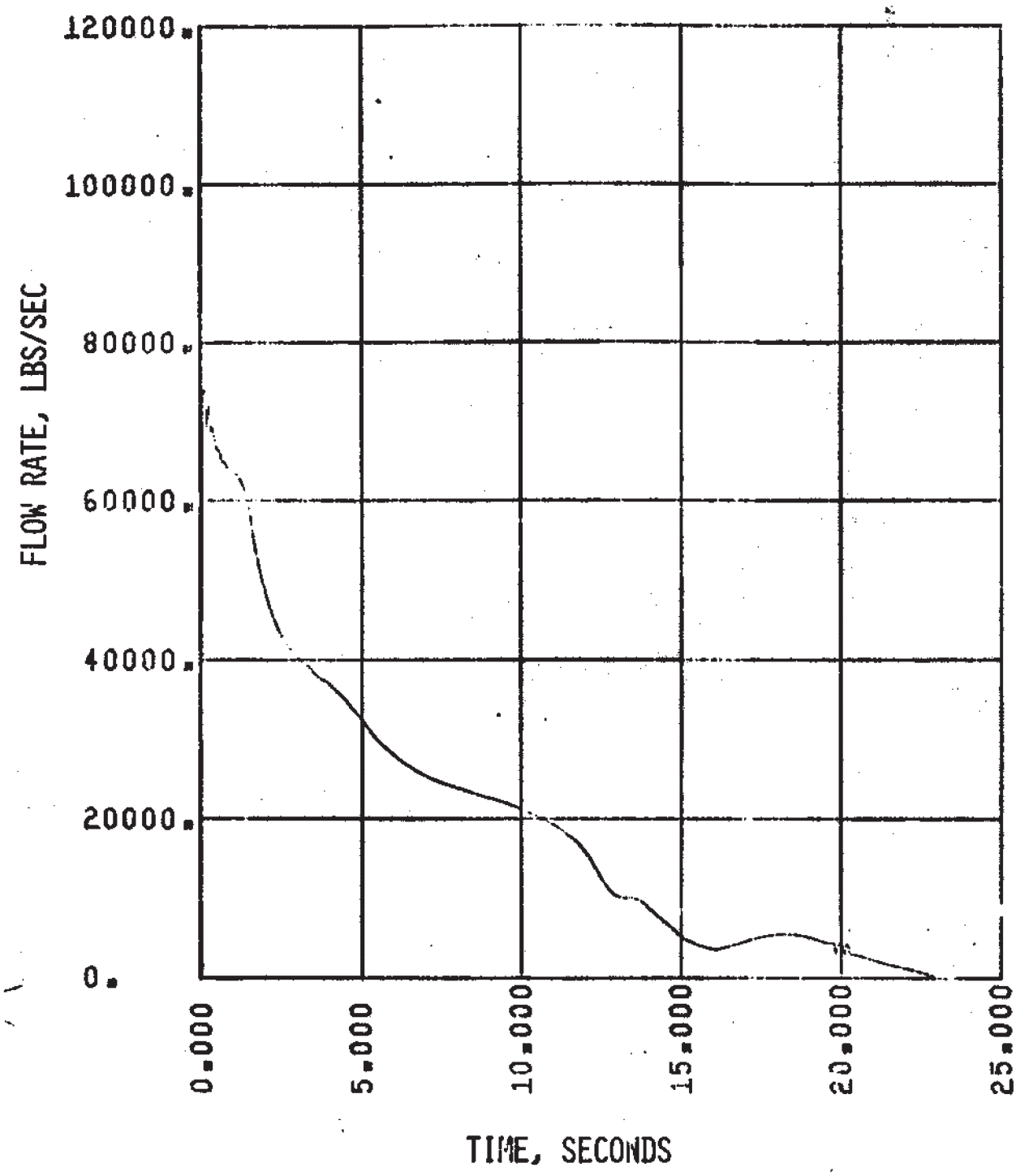
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PRESSURE IN CENTER HOT ASSEMBLY NODE - 1.0 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–5b

CYCLE 1



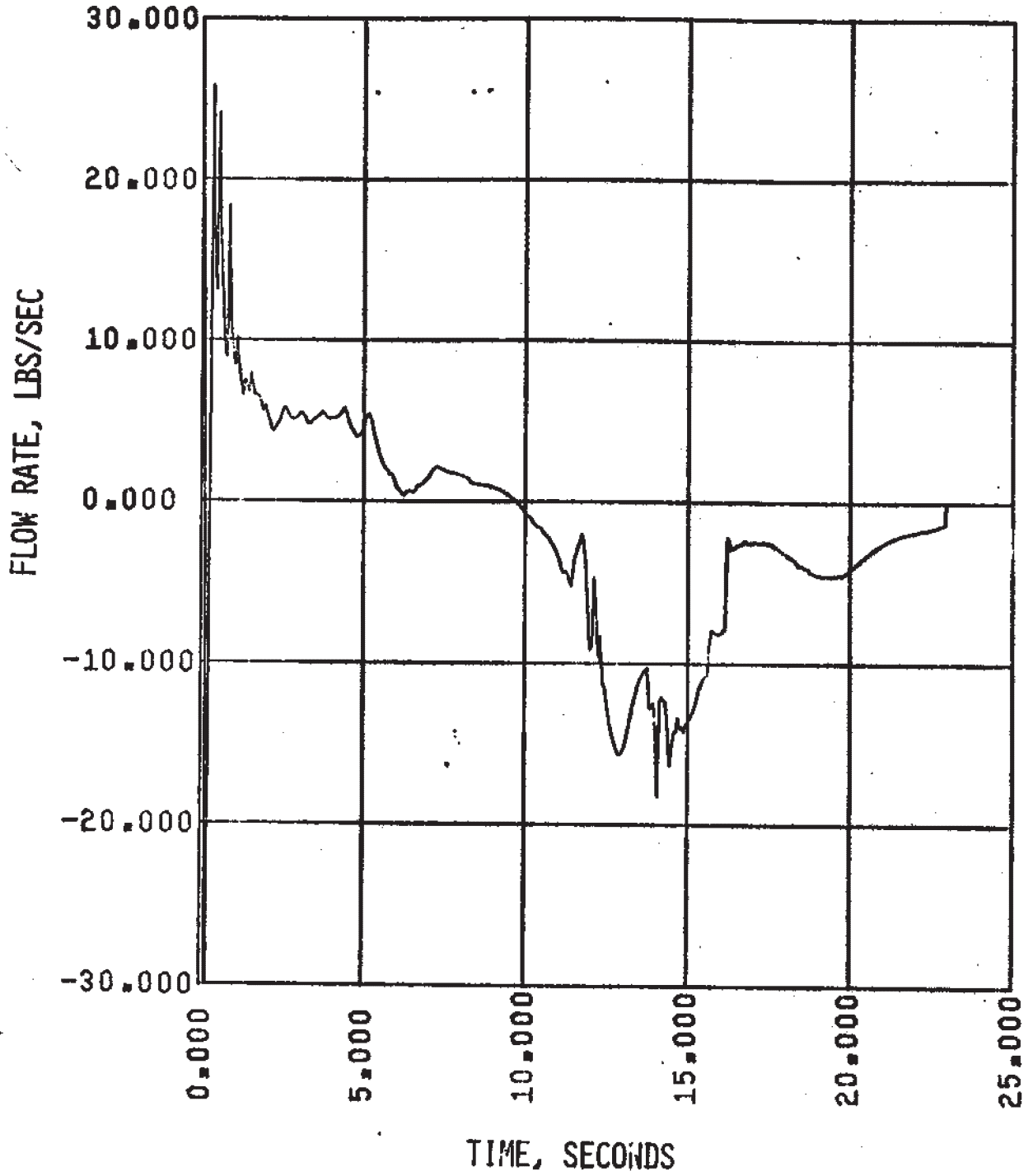
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LEAK FLOW - 1.0 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG

CYCLE 1

FIGURE 6.3–5c



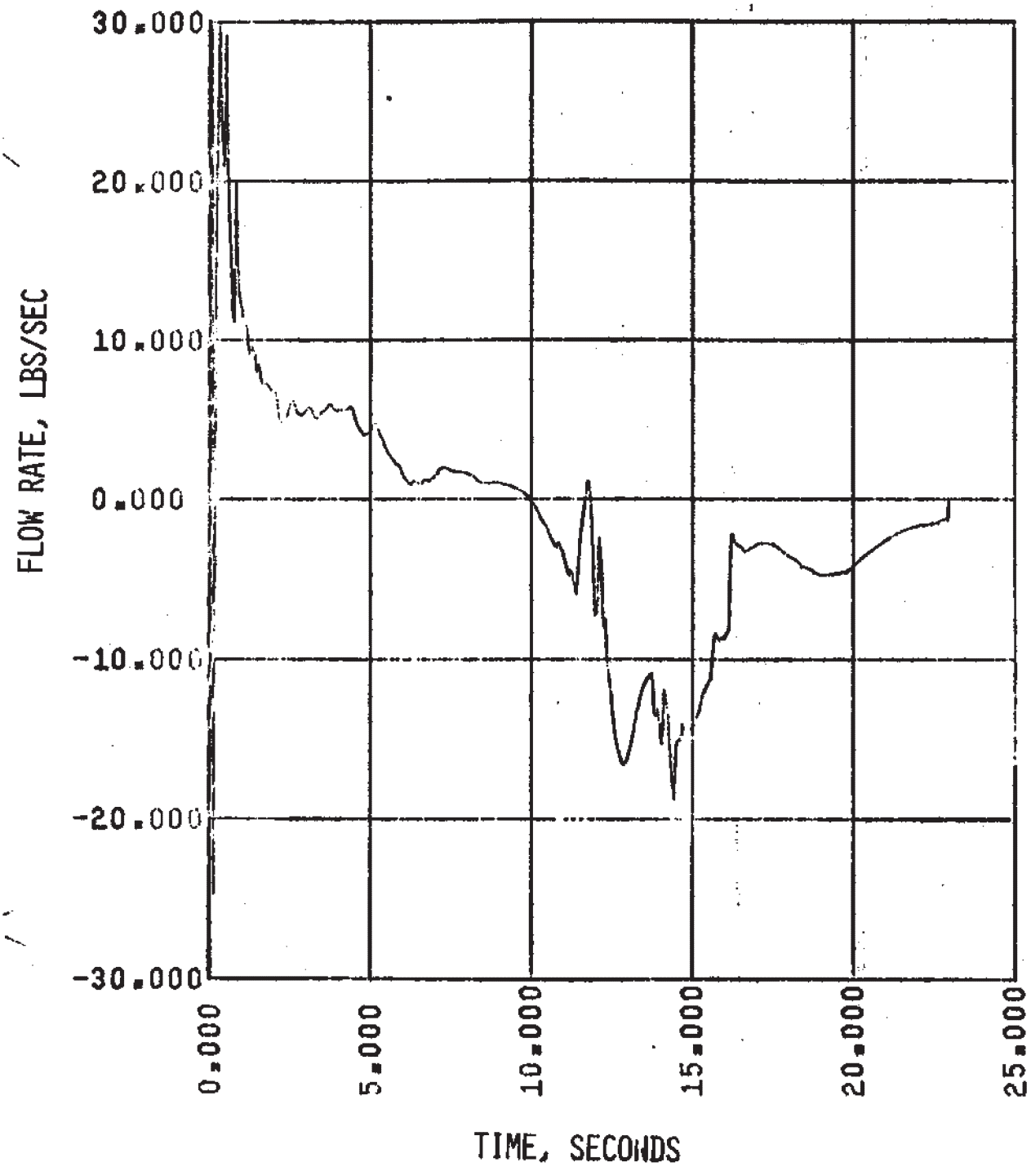
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 16, BELOW HOT SPOT - 1.0 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-5d

CYCLE 1

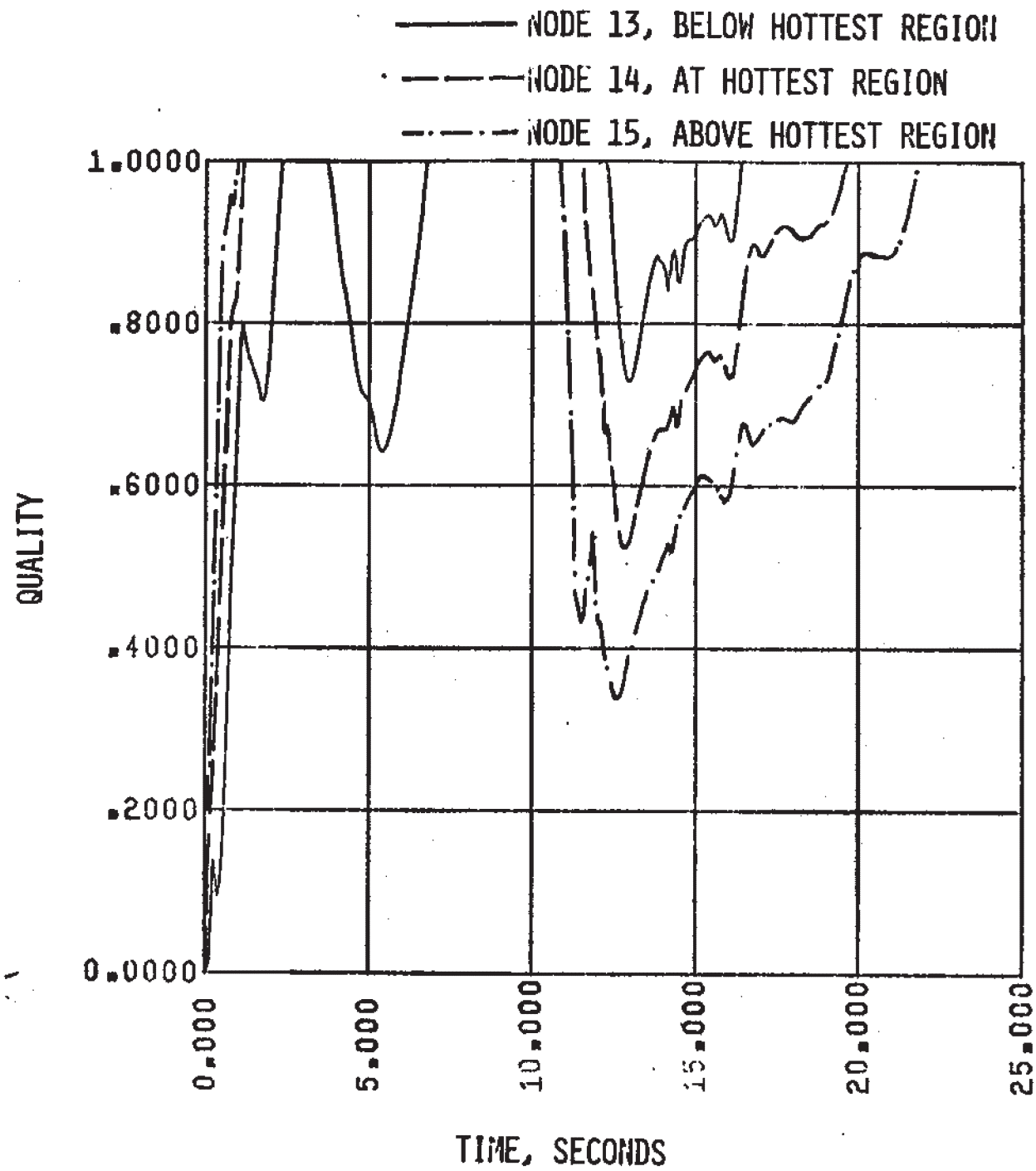


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 17, ABOVE HOT SPOT - 1.0 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–5e

CYCLE 1

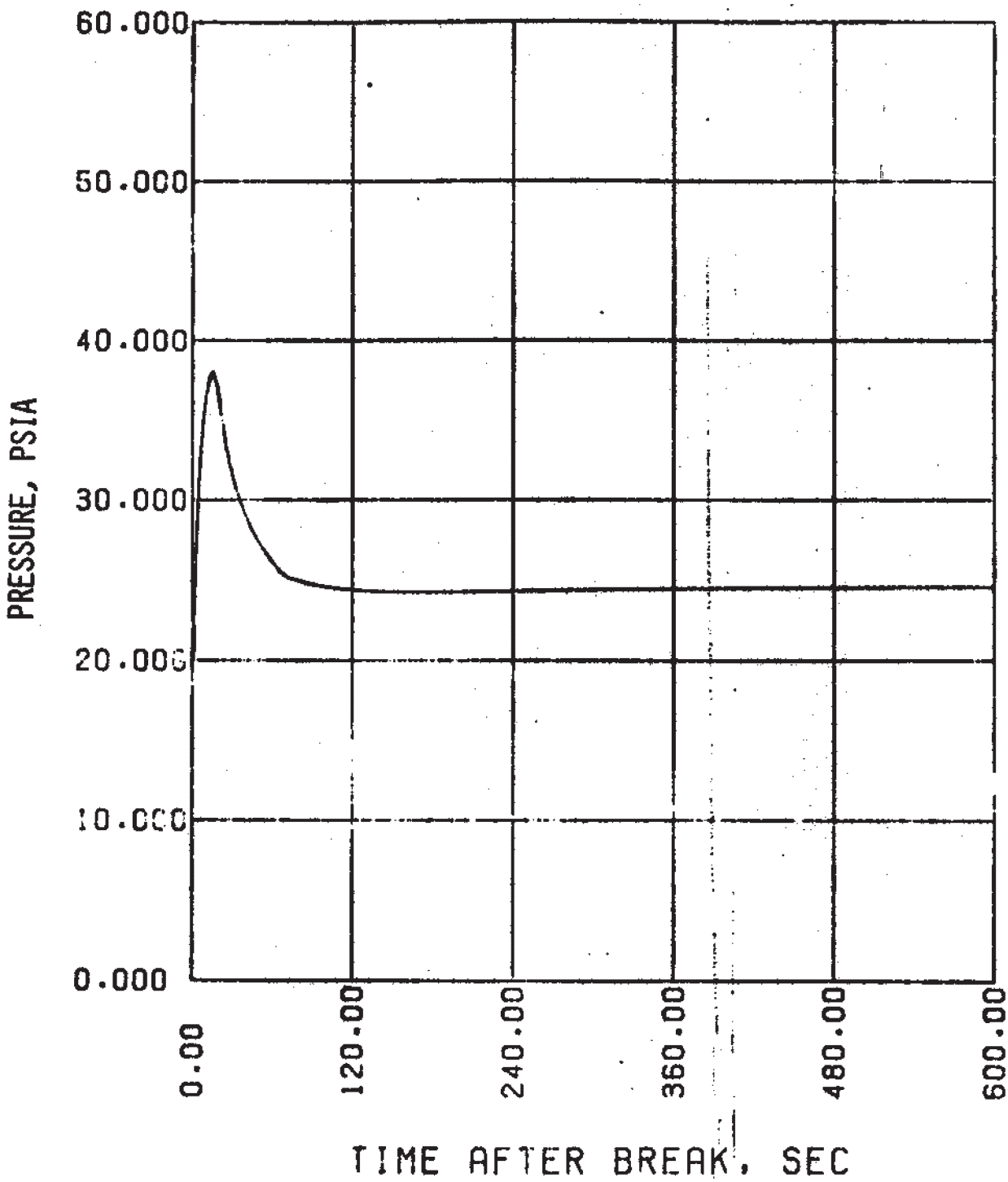


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT ASSEMBLY QUALITY - 1.0 X
DOUBLE ENDED SLOT BREAK IN
PUMP DISCHARGE LEG
FIGURE 6.3–5f

CYCLE 1

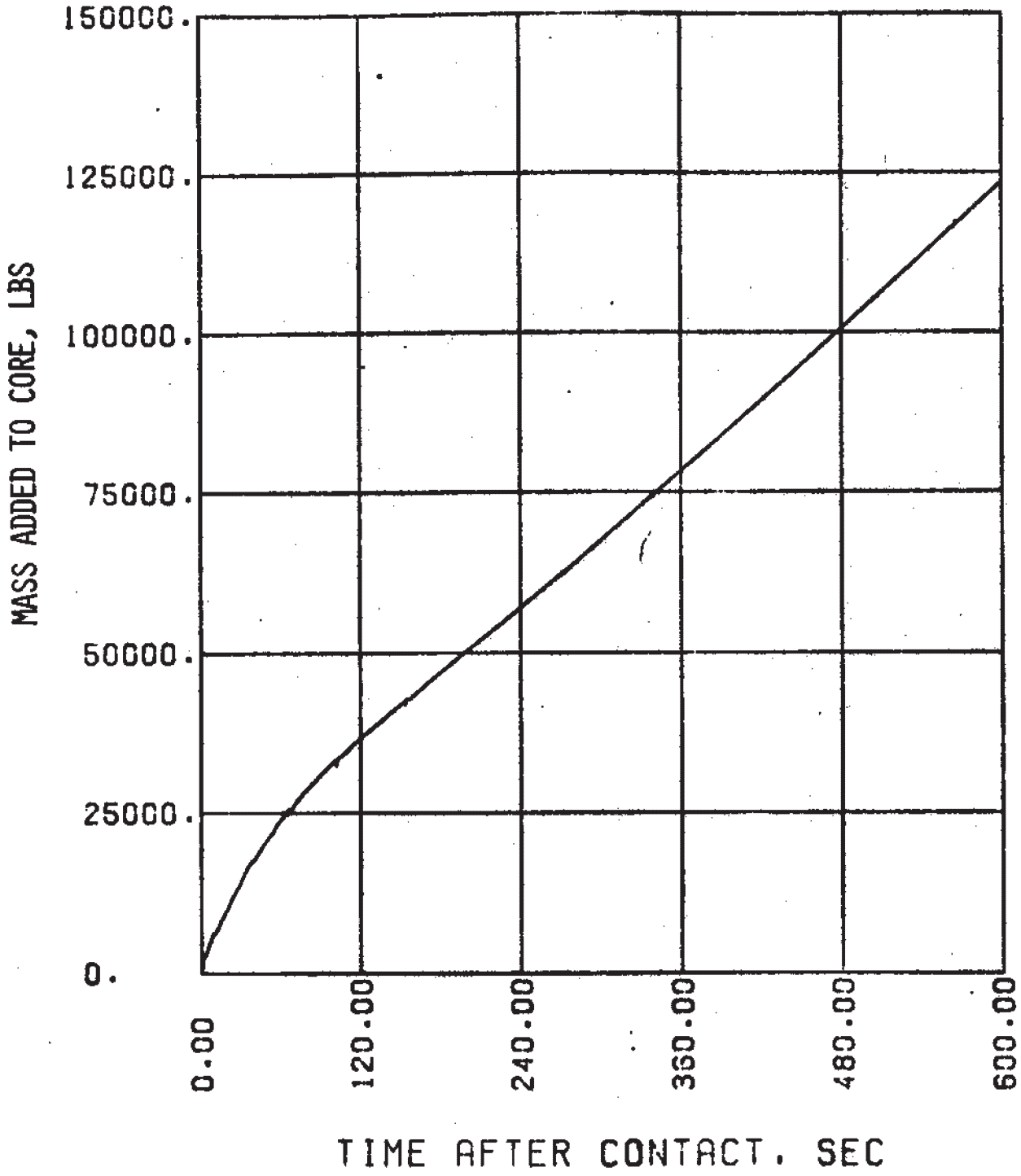


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CONTAINMENT PRESSURE - 1.0 X
DOUBLE ENDED SLOT BREAK
IN PUMP DISCHARGE LEG
FIGURE 6.3–5g

CYCLE 1

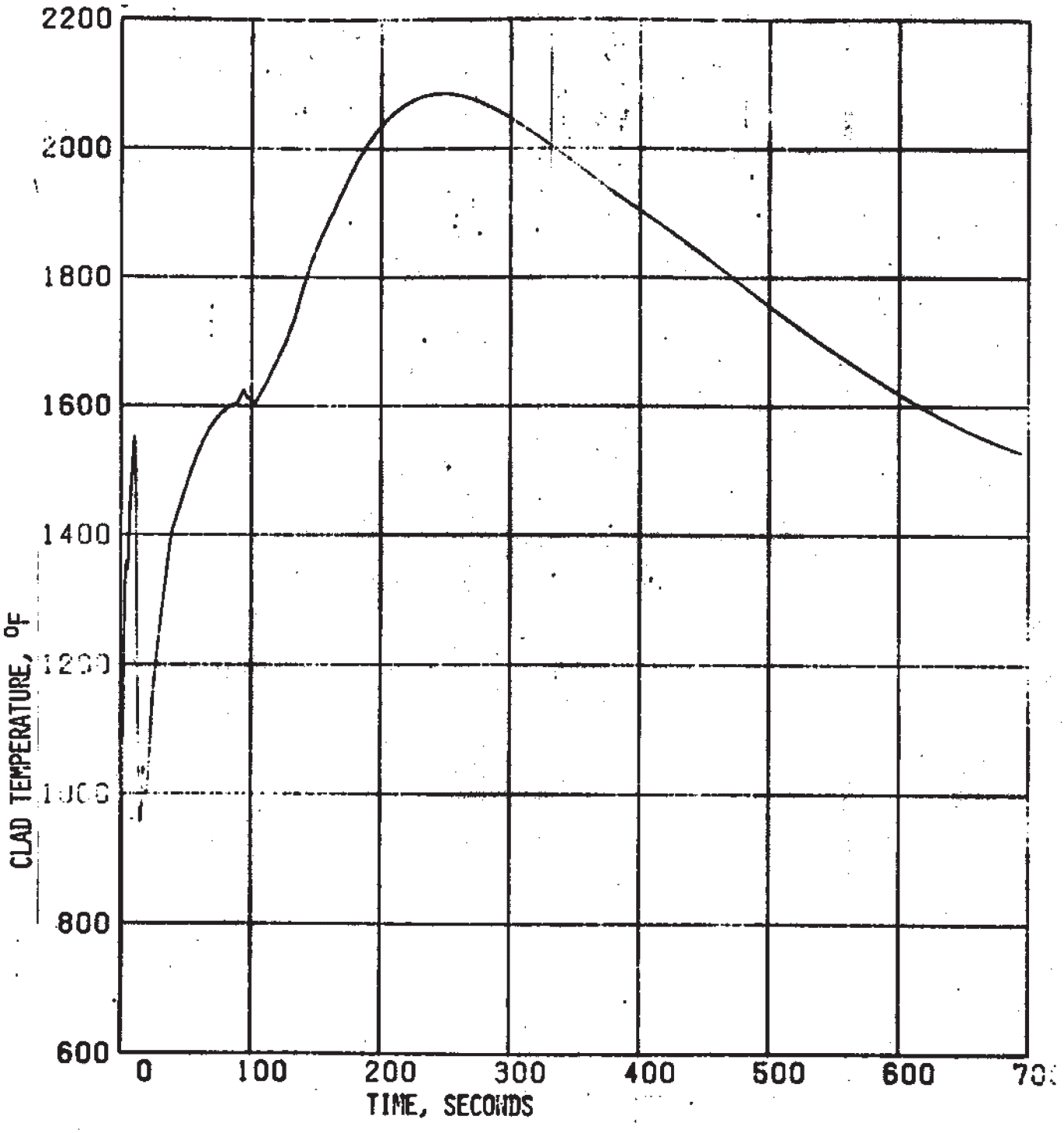


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

MASS ADDED TO CORE DURING REFLOOD
1.0 X DOUBLE ENDED SLOT BREAK
IN PUMP DISCHARGE LEG
FIGURE 6.3-5h

CYCLE 1



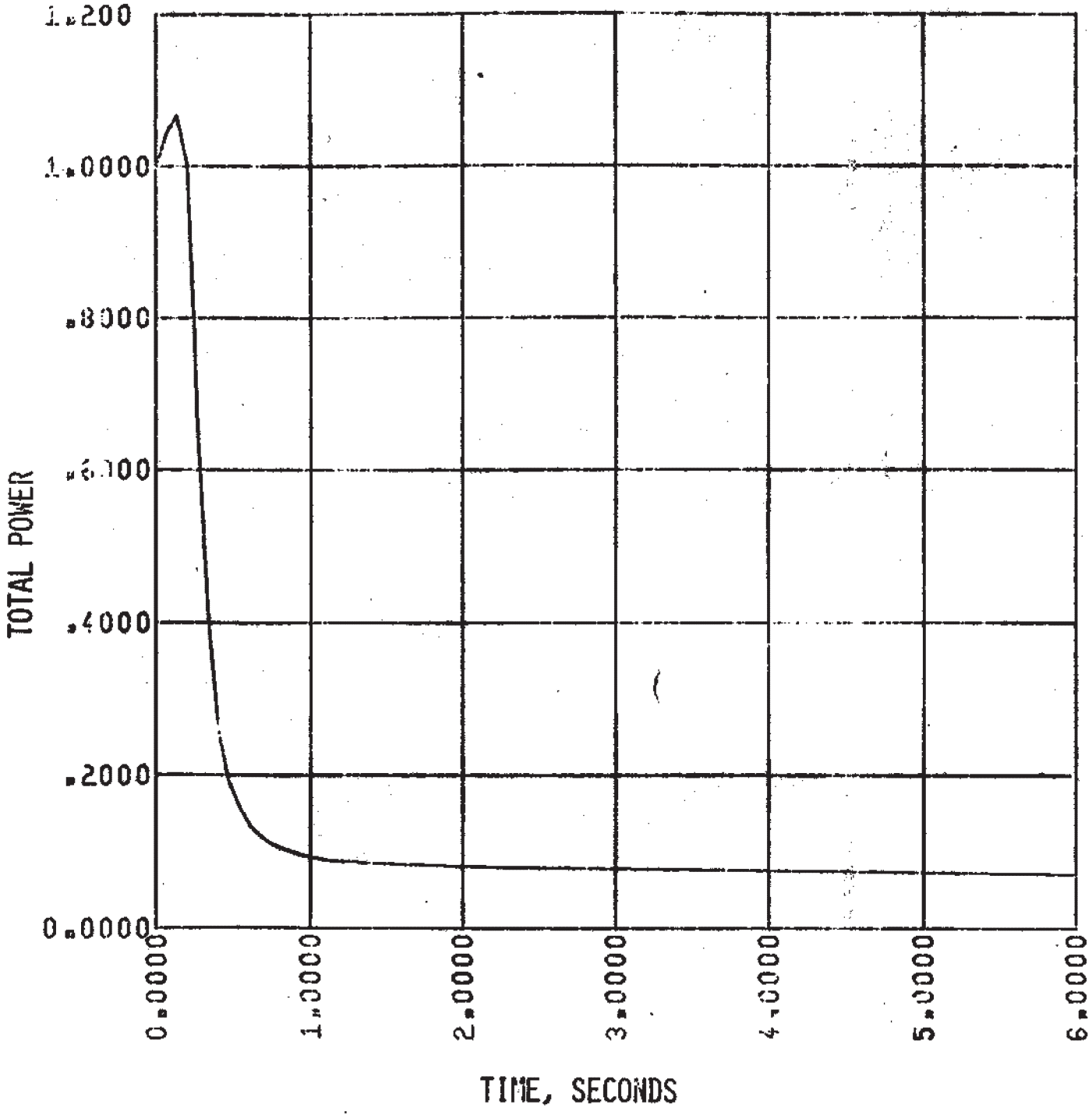
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PEAK CLAD TEMP. - 1.0 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–5i

CYCLE 1

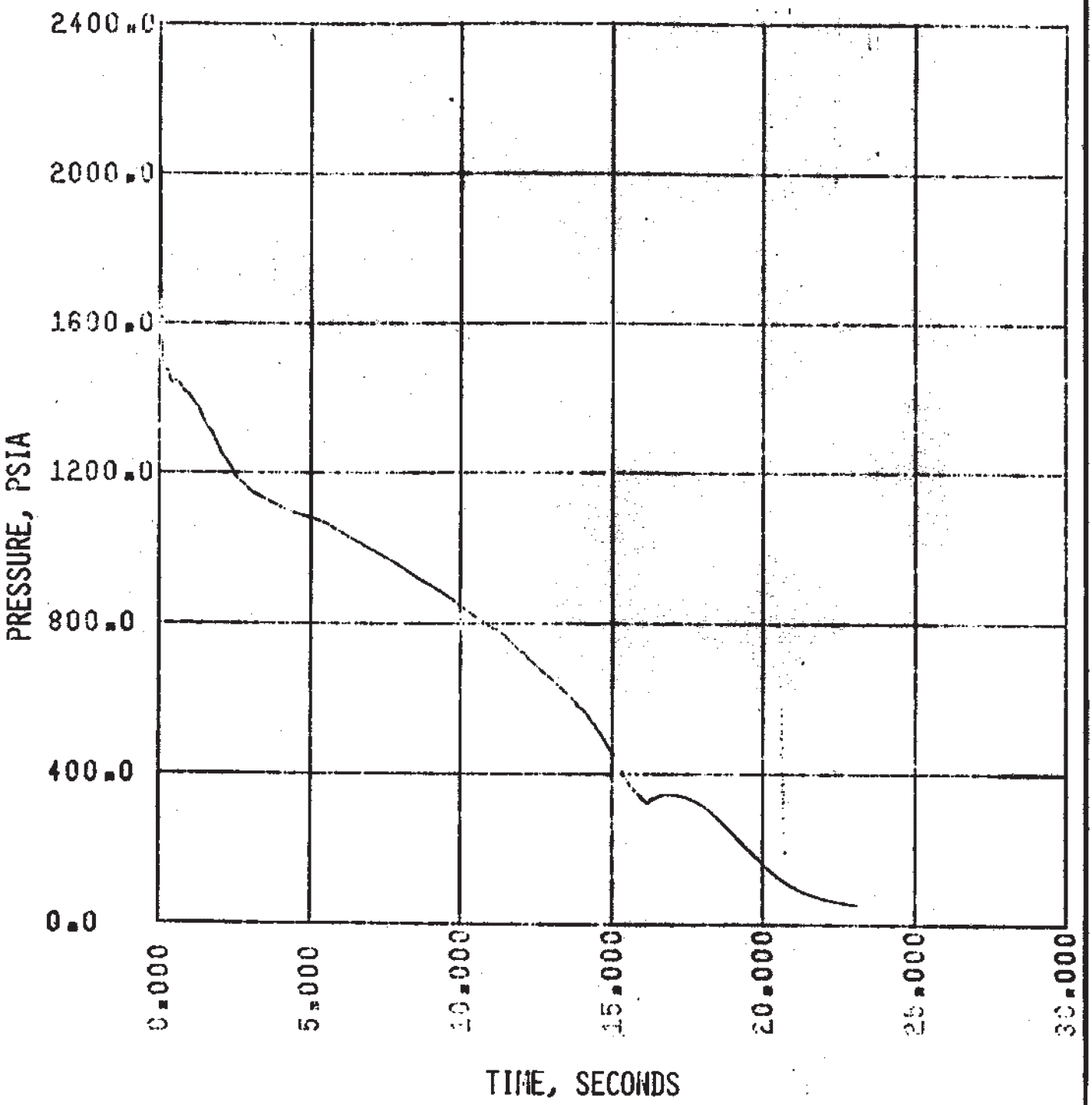


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE POWER - 0.8 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–6a

CYCLE 1

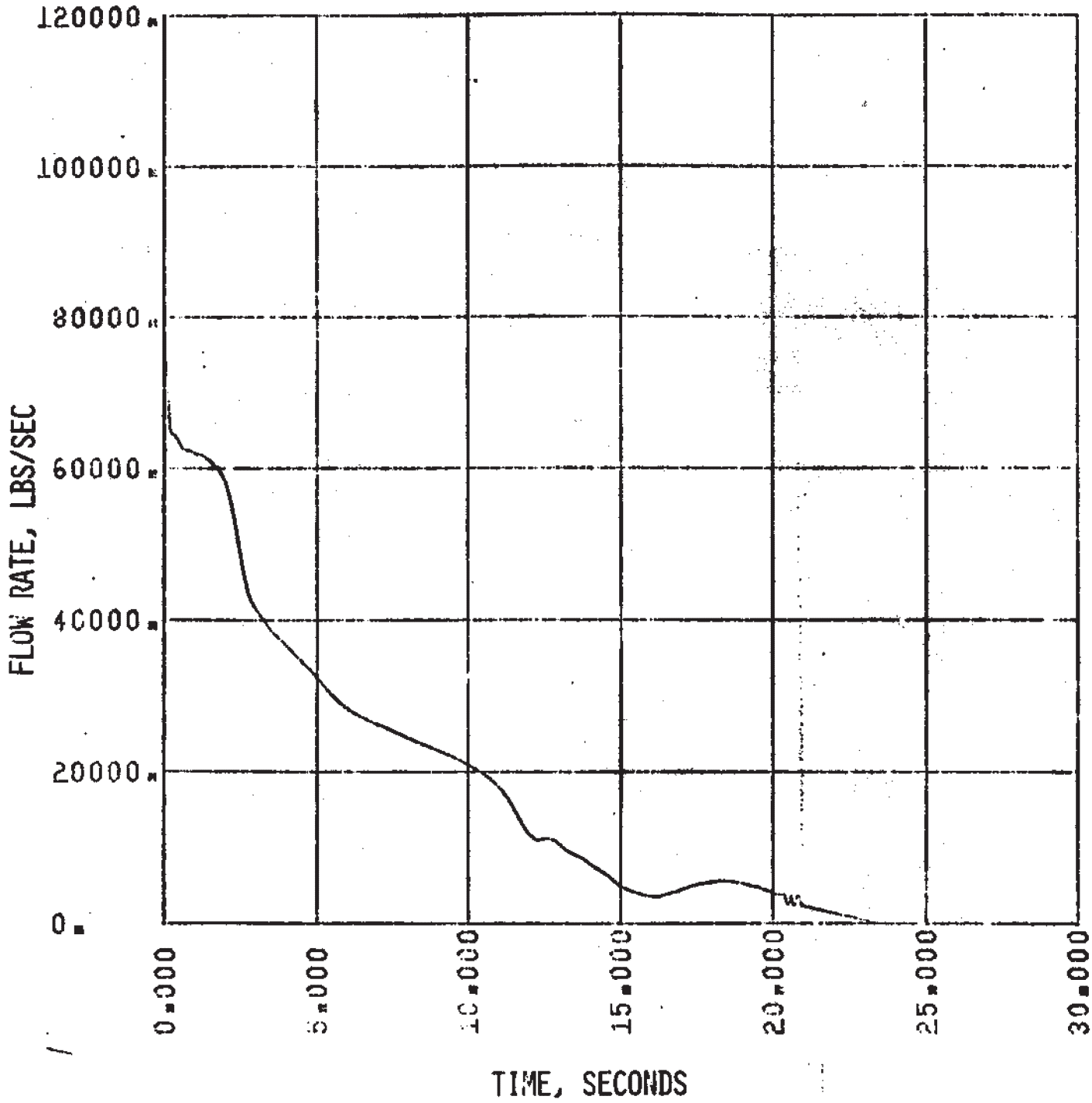


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PRESSURE IN CENTER HOT ASSEMBLY NODE - 0.8 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3-6b

CYCLE 1

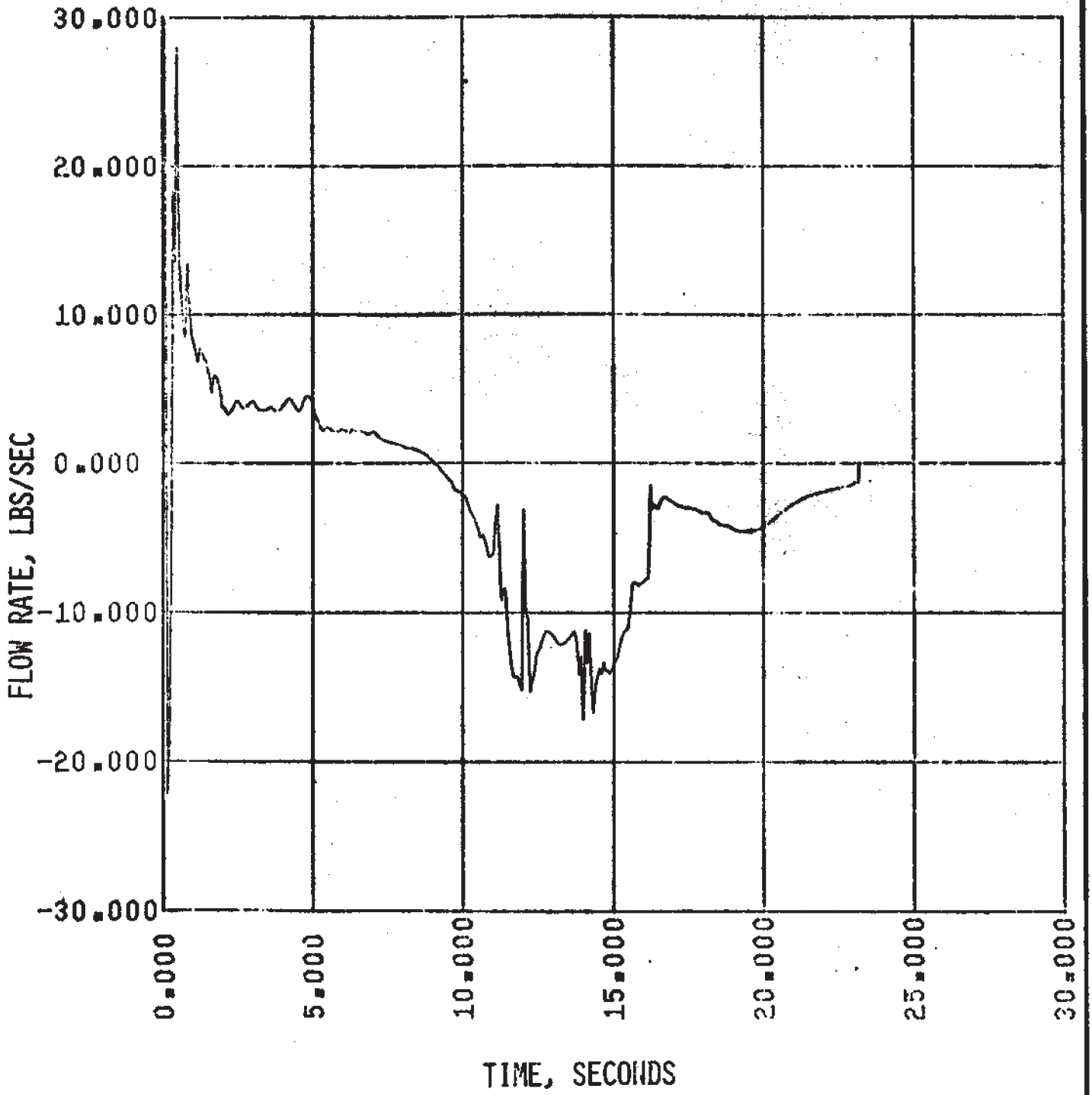


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LEAK FLOW - 0.8 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–6c

CYCLE 1



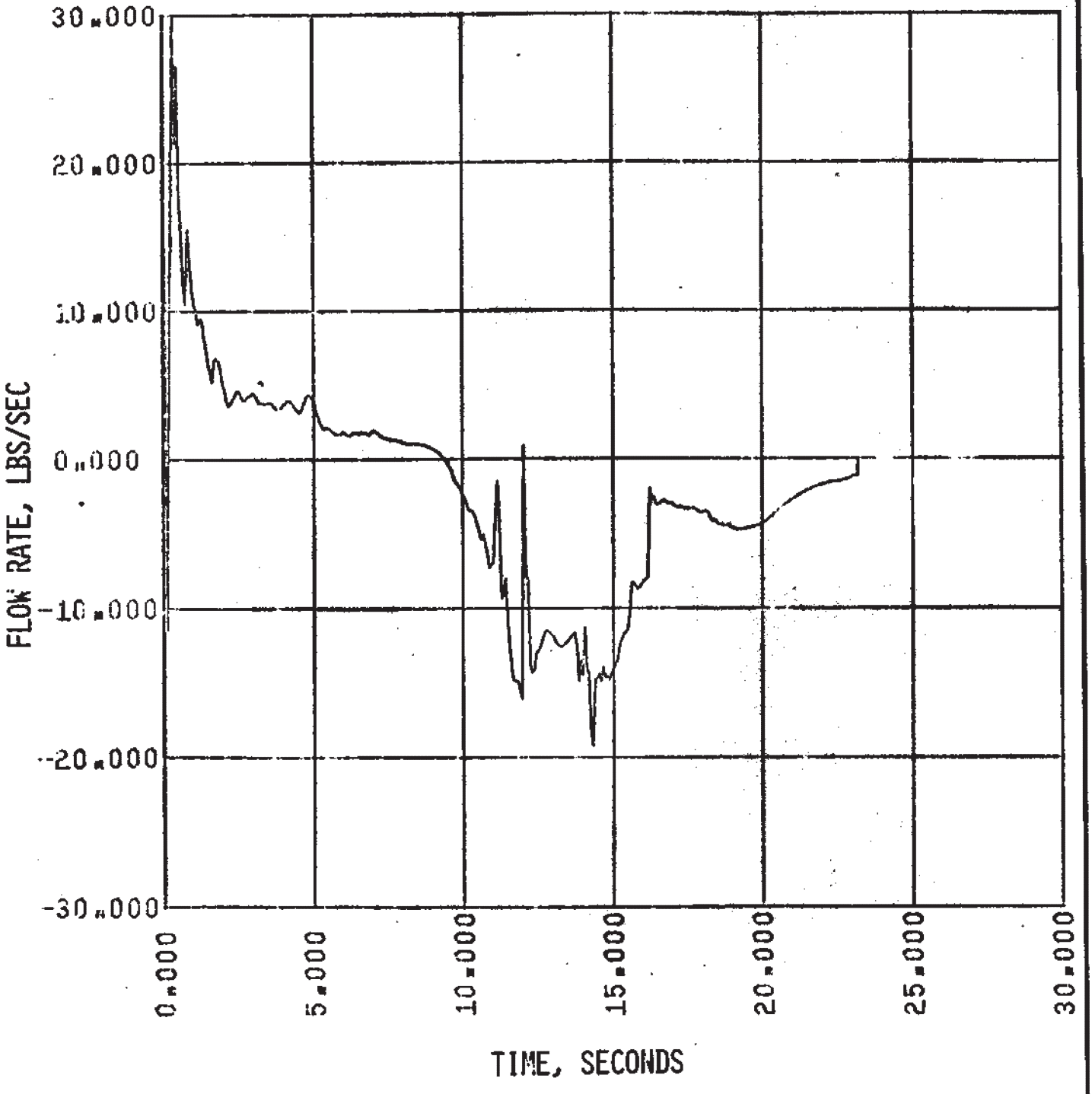
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 16, BELOW HOT SPOT - 0.8 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–6d

CYCLE 1

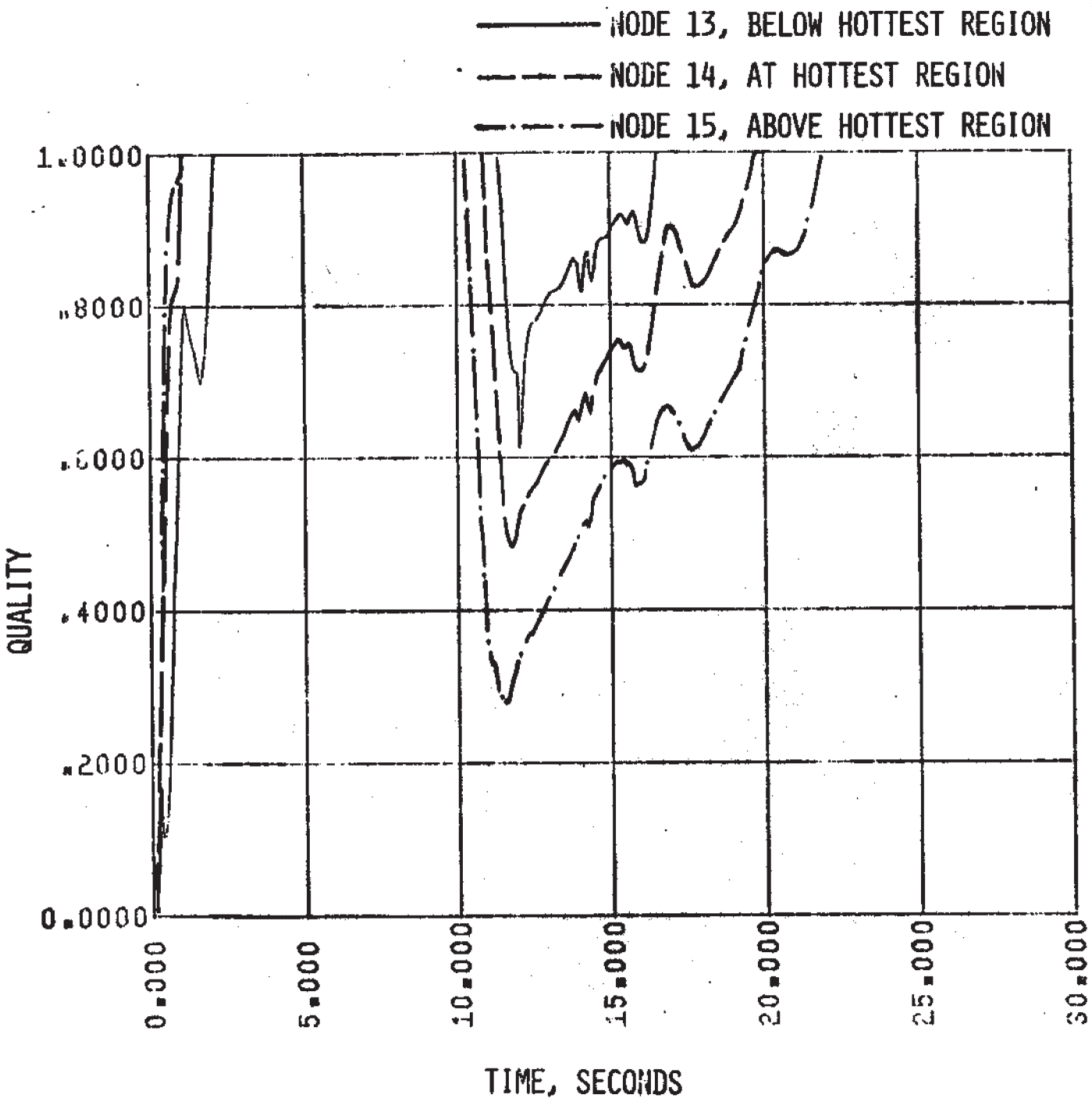


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 17, ABOVE HOT SPOT - 0.8 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–6e

CYCLE 1



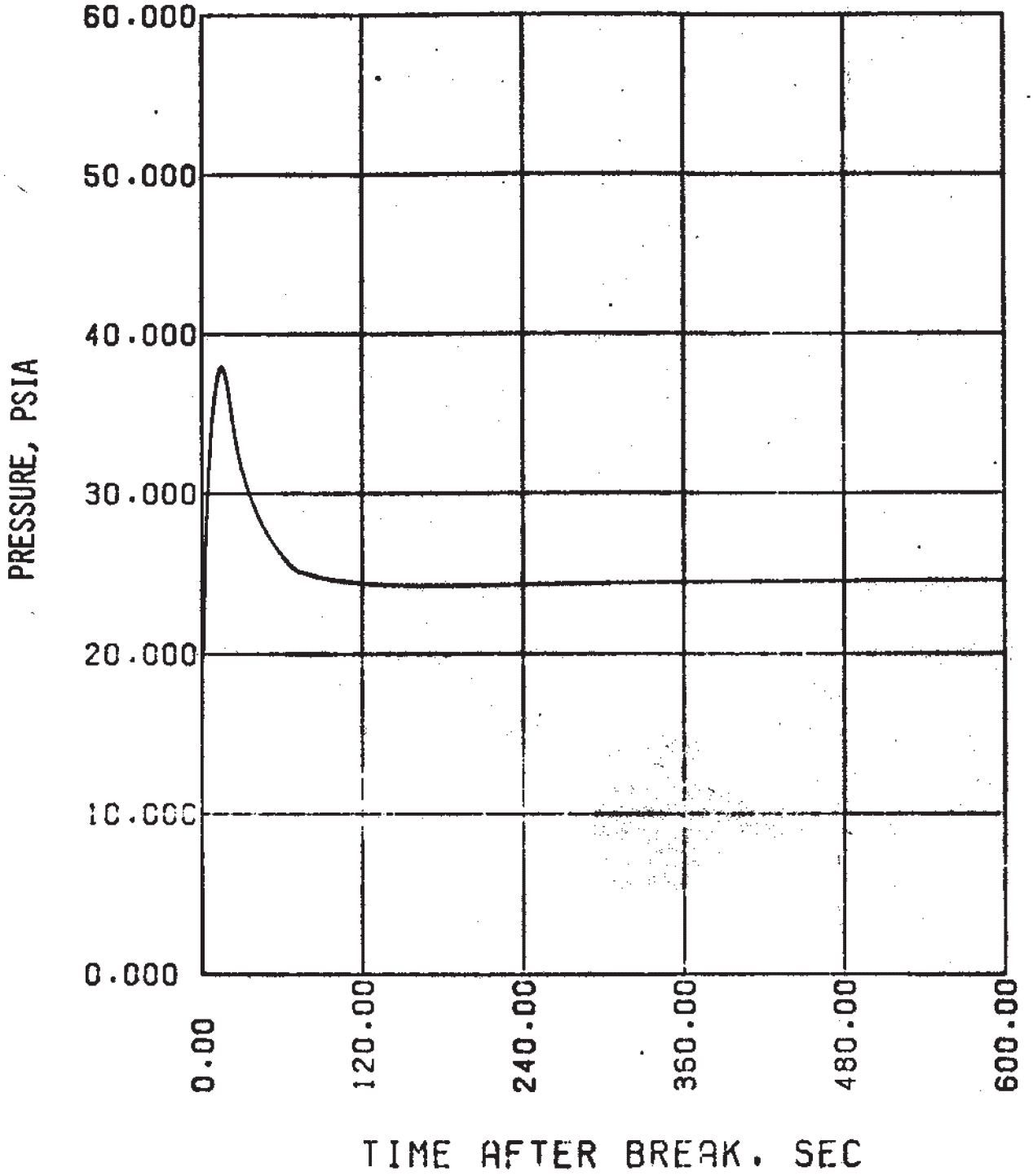
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT ASSEMBLY QUALITY - 0.8 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–6f

CYCLE 1



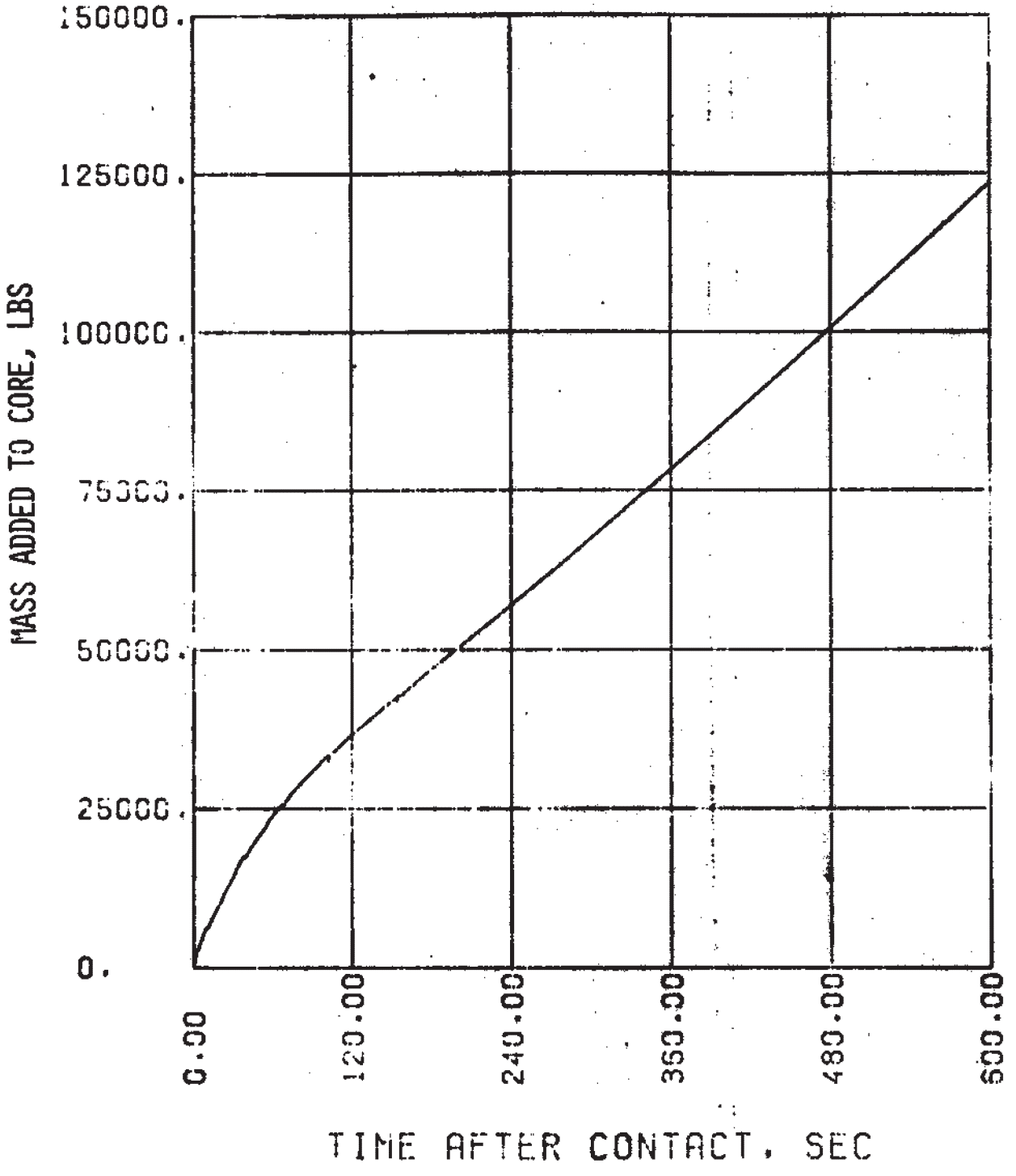
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CONTAINMENT PRESSURE - 0.8 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-6g

CYCLE 1

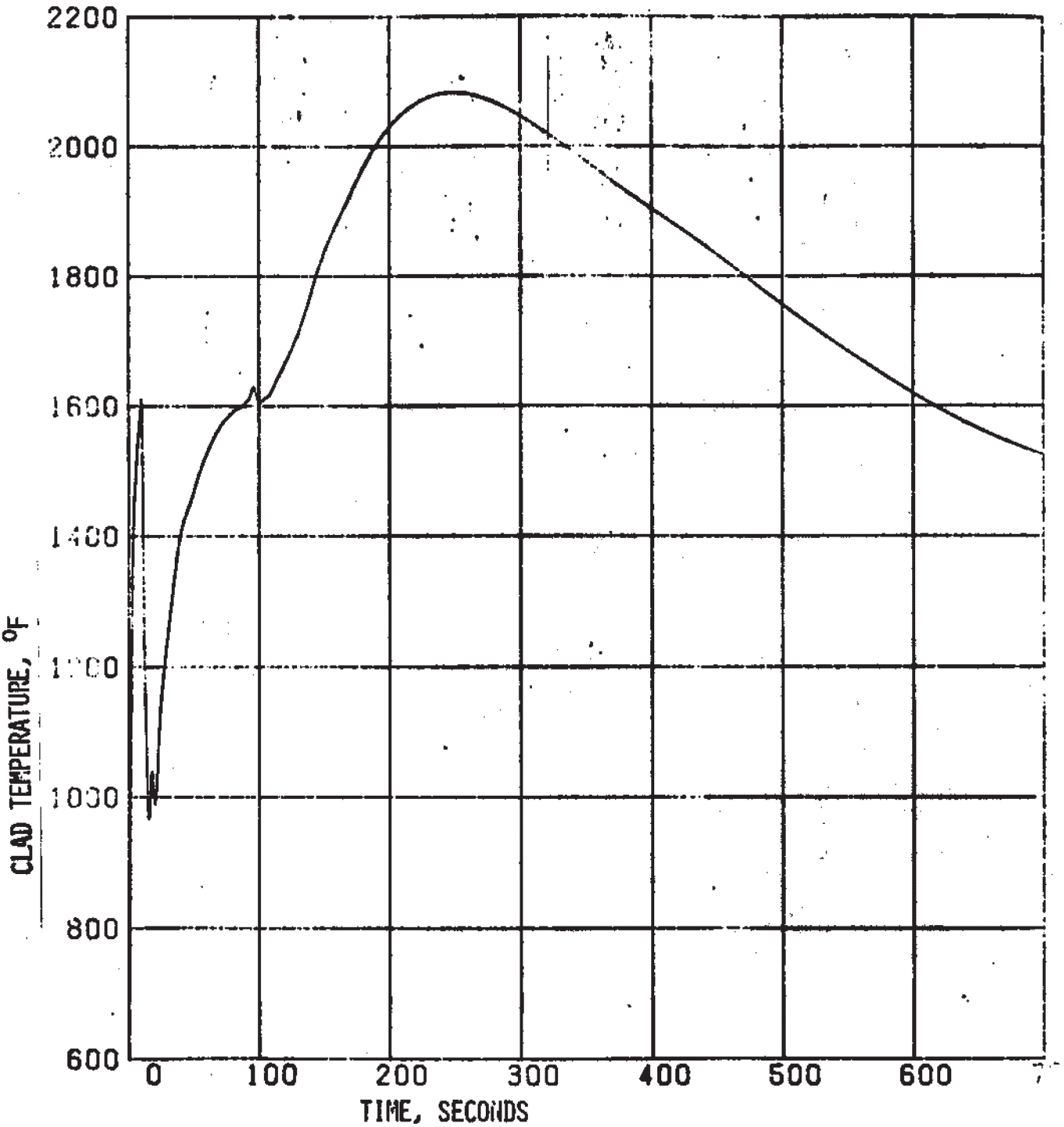


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

MASS ADDED TO CORE DURING REFLOOD
0.8 X DOUBLE ENDED SLOT BREAK
IN PUMP DISCHARGE LEG
FIGURE 6.3–6h

CYCLE 1

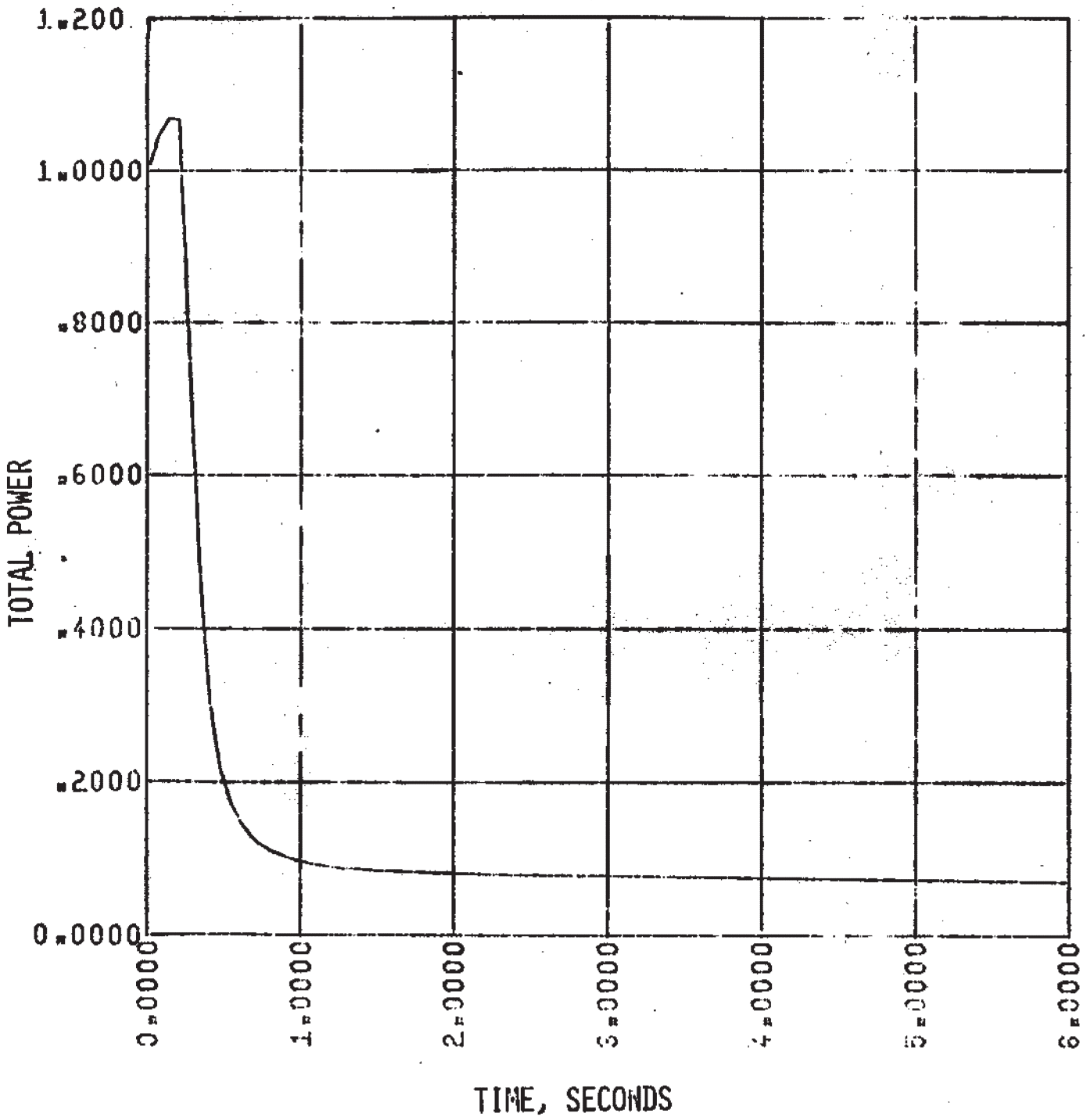


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PEAK CLAD TEMP. - 0.8 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–6i

CYCLE 1

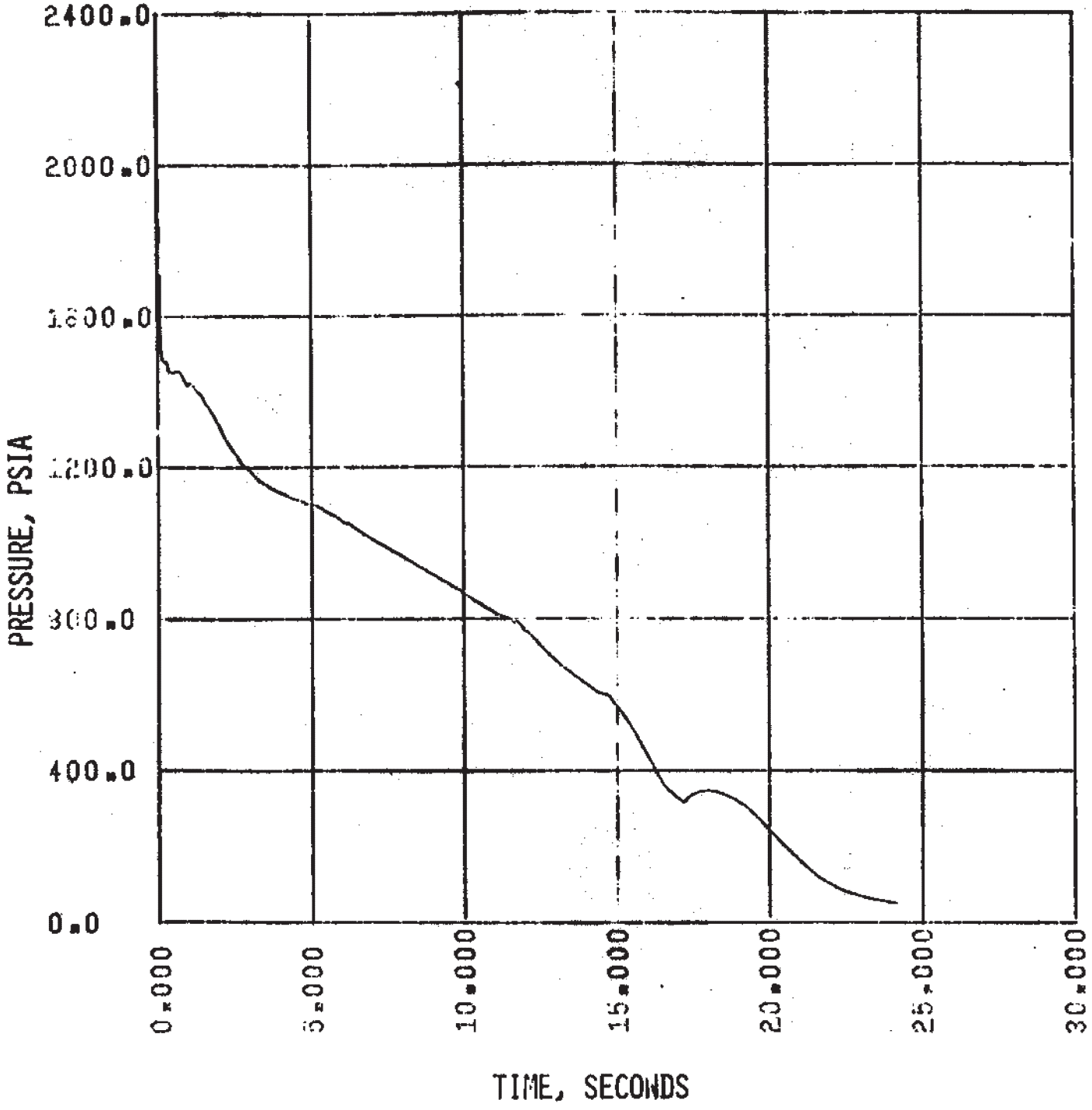


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE POWER - 0.6 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–7a

CYCLE 1

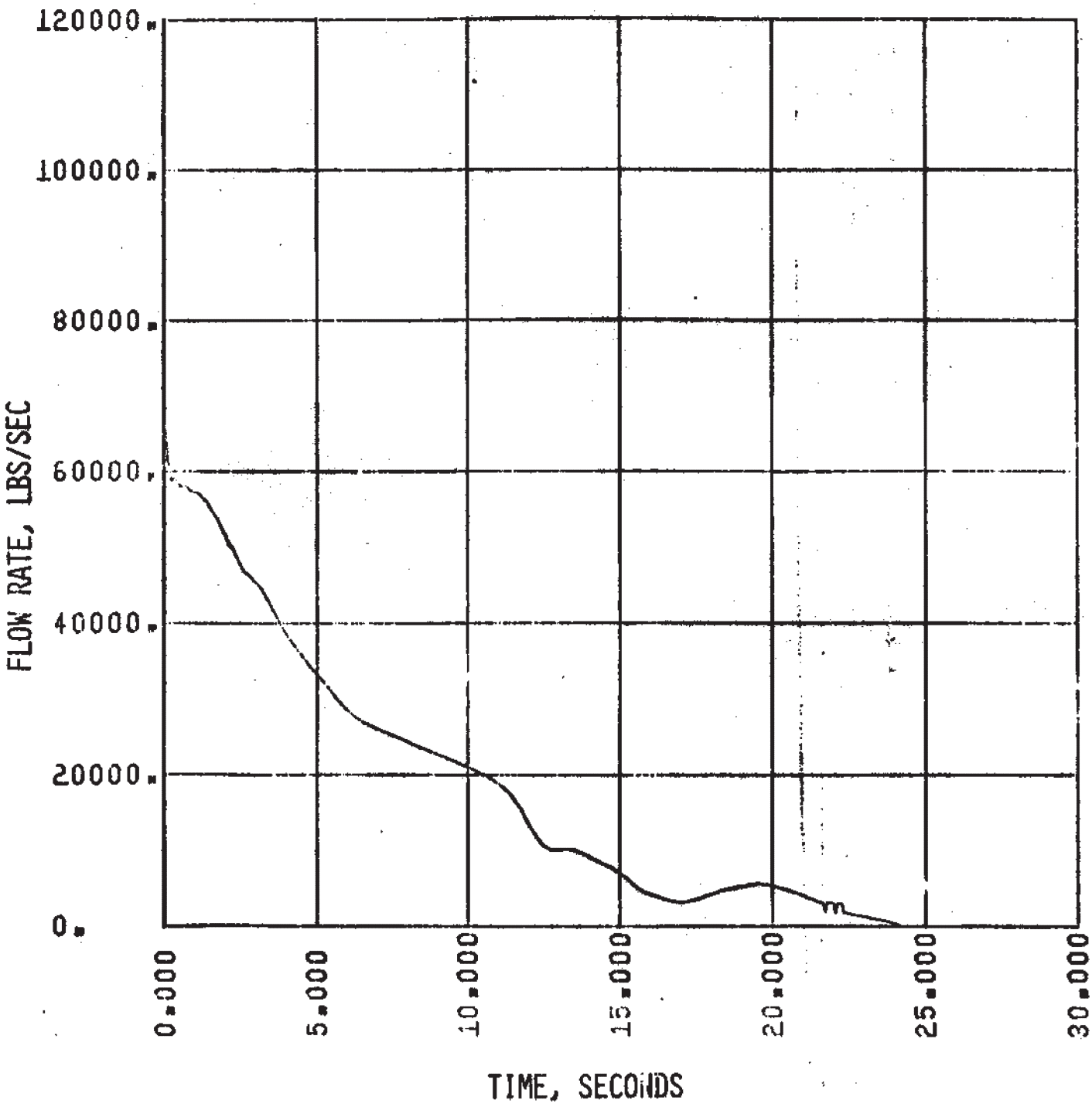


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PRESSURE IN CENTER HOT ASSEMBLY NODE - 0.6 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3-7b

CYCLE 1

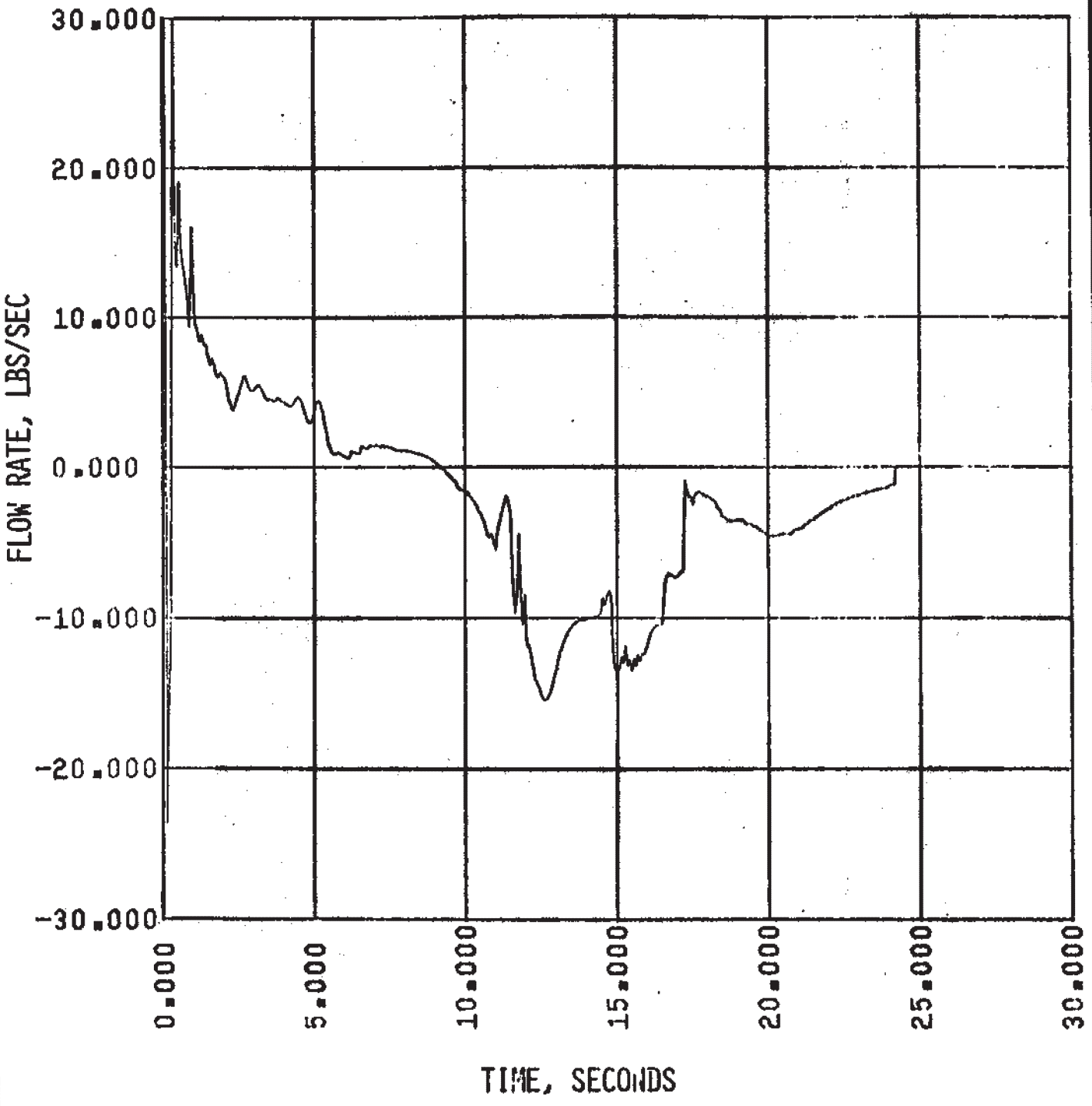


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LEAK FLOW - 0.6 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3-7c

CYCLE 1

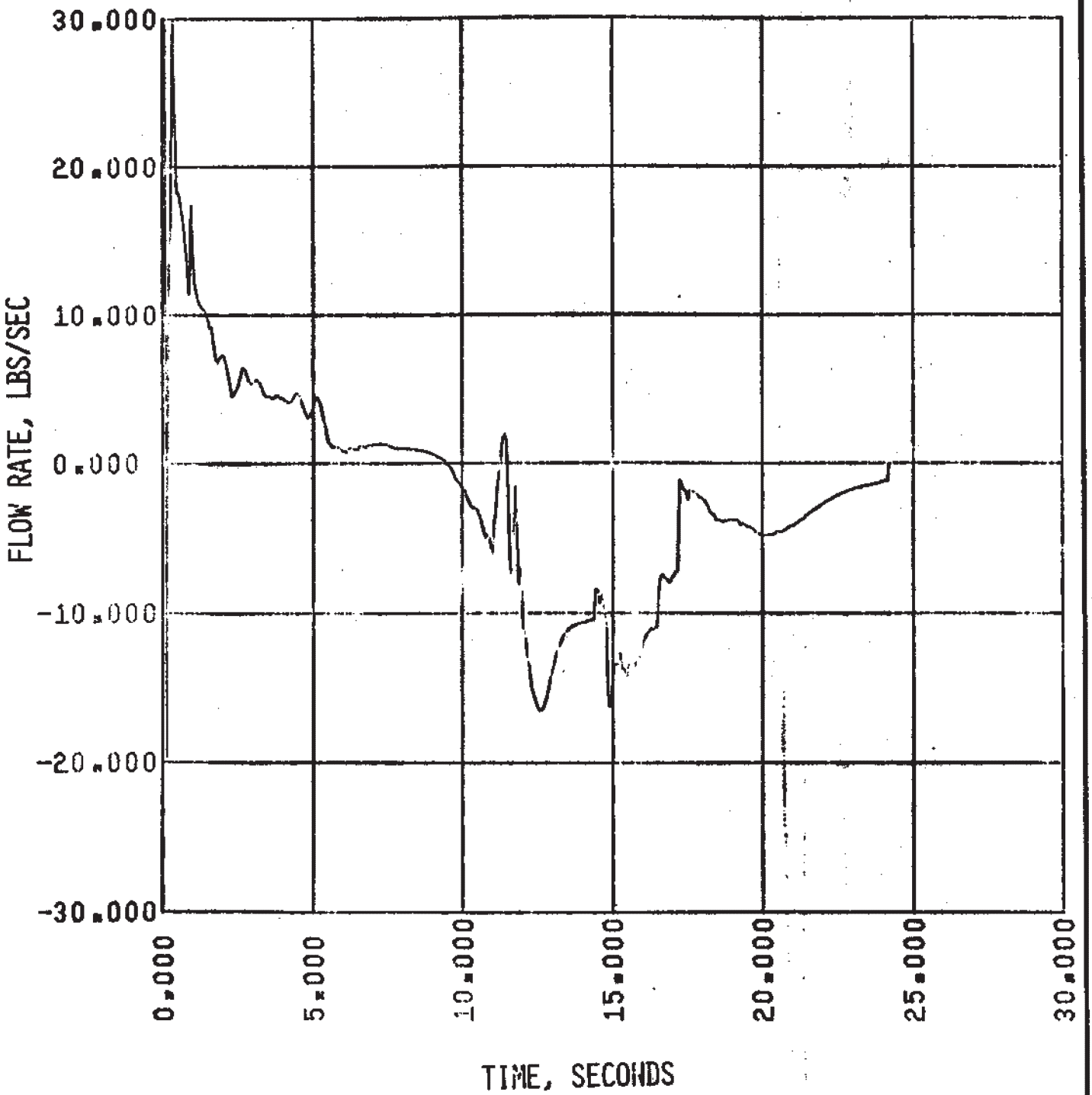


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 16, BELOW HOT SPOT - 0.6 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3-7d

CYCLE 1

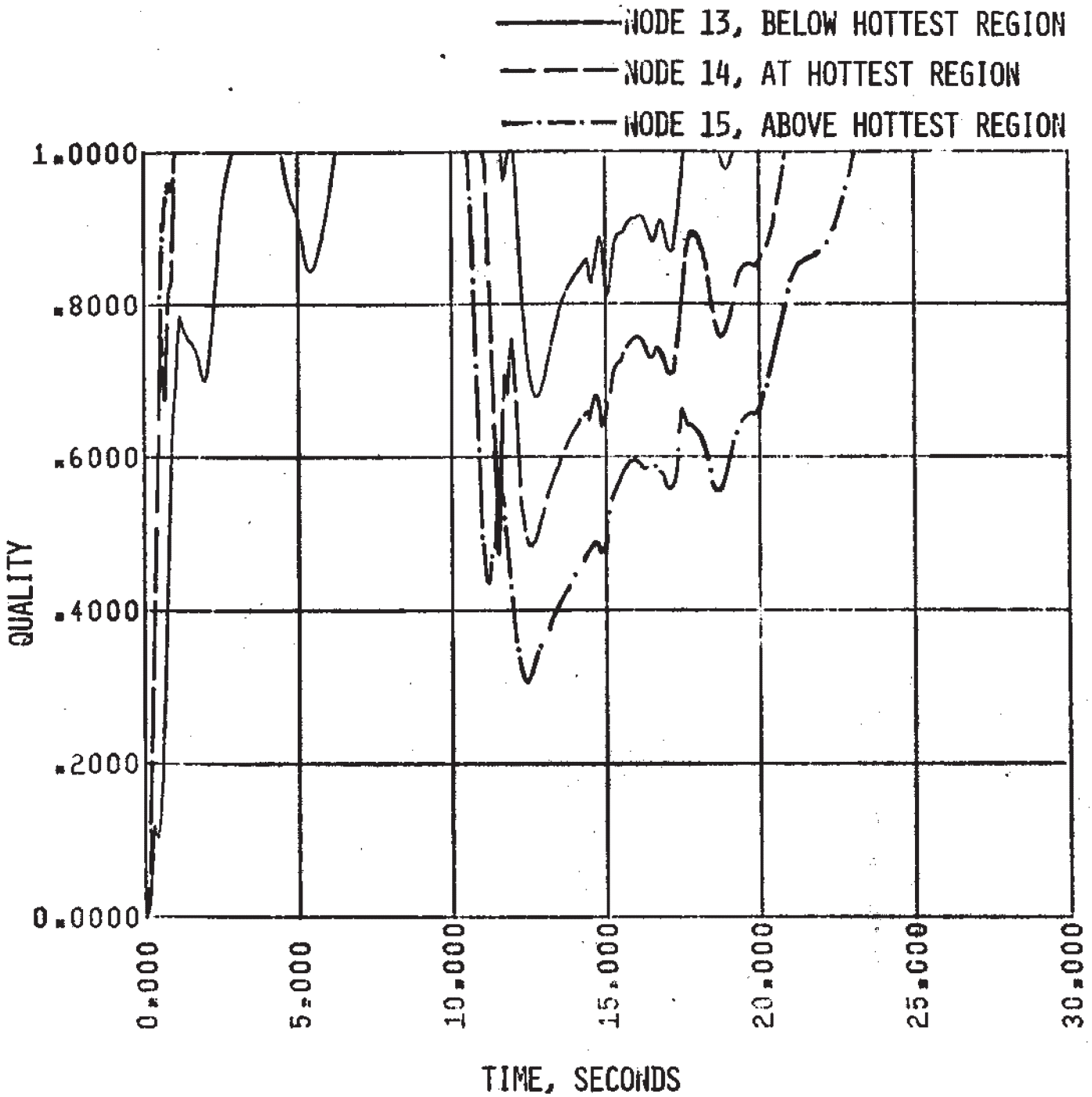


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 17, ABOVE HOT SPOT - 0.6 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3-7

CYCLE 1



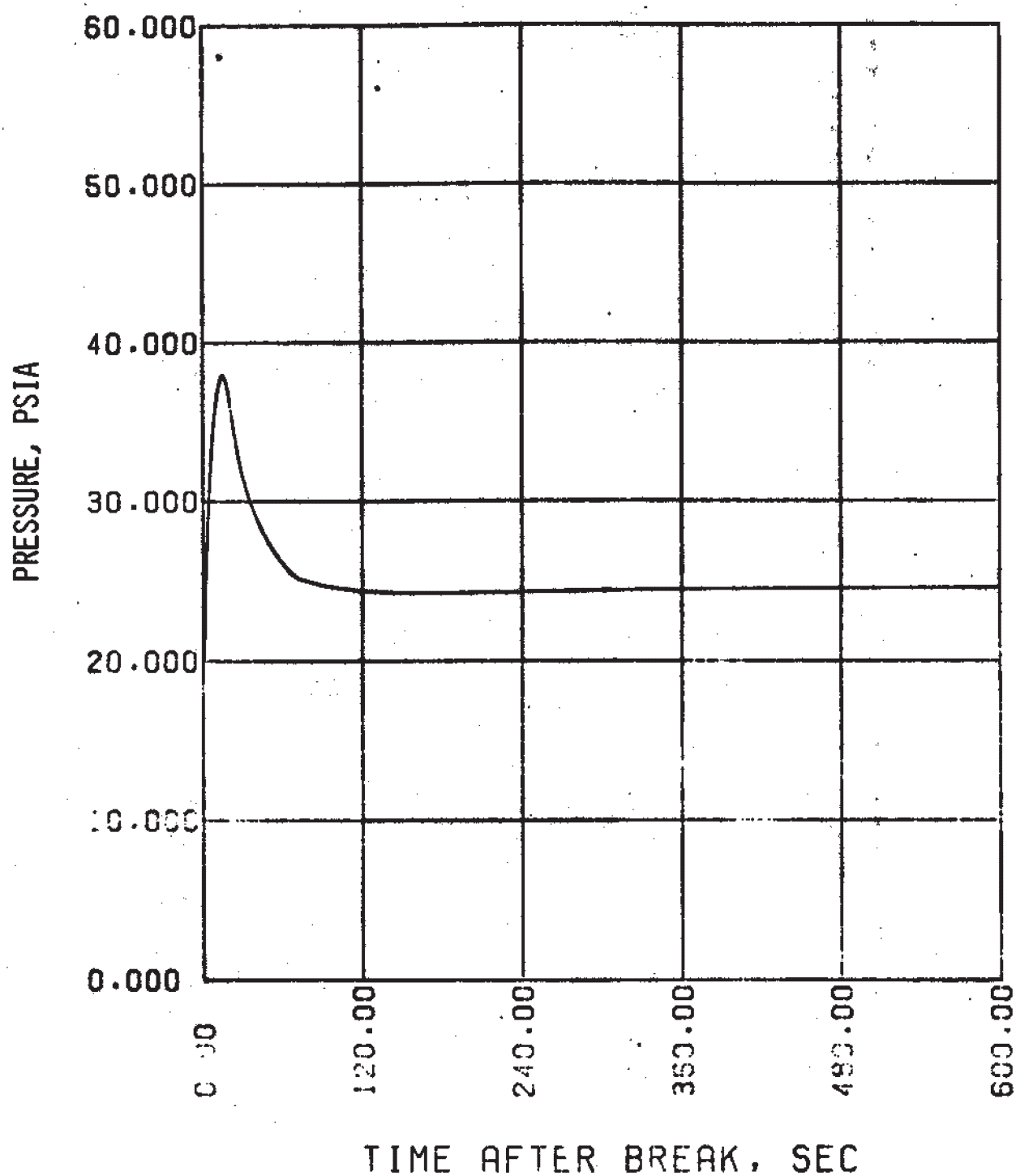
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT ASSEMBLY QUALITY - 0.6 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-7f

CYCLE 1

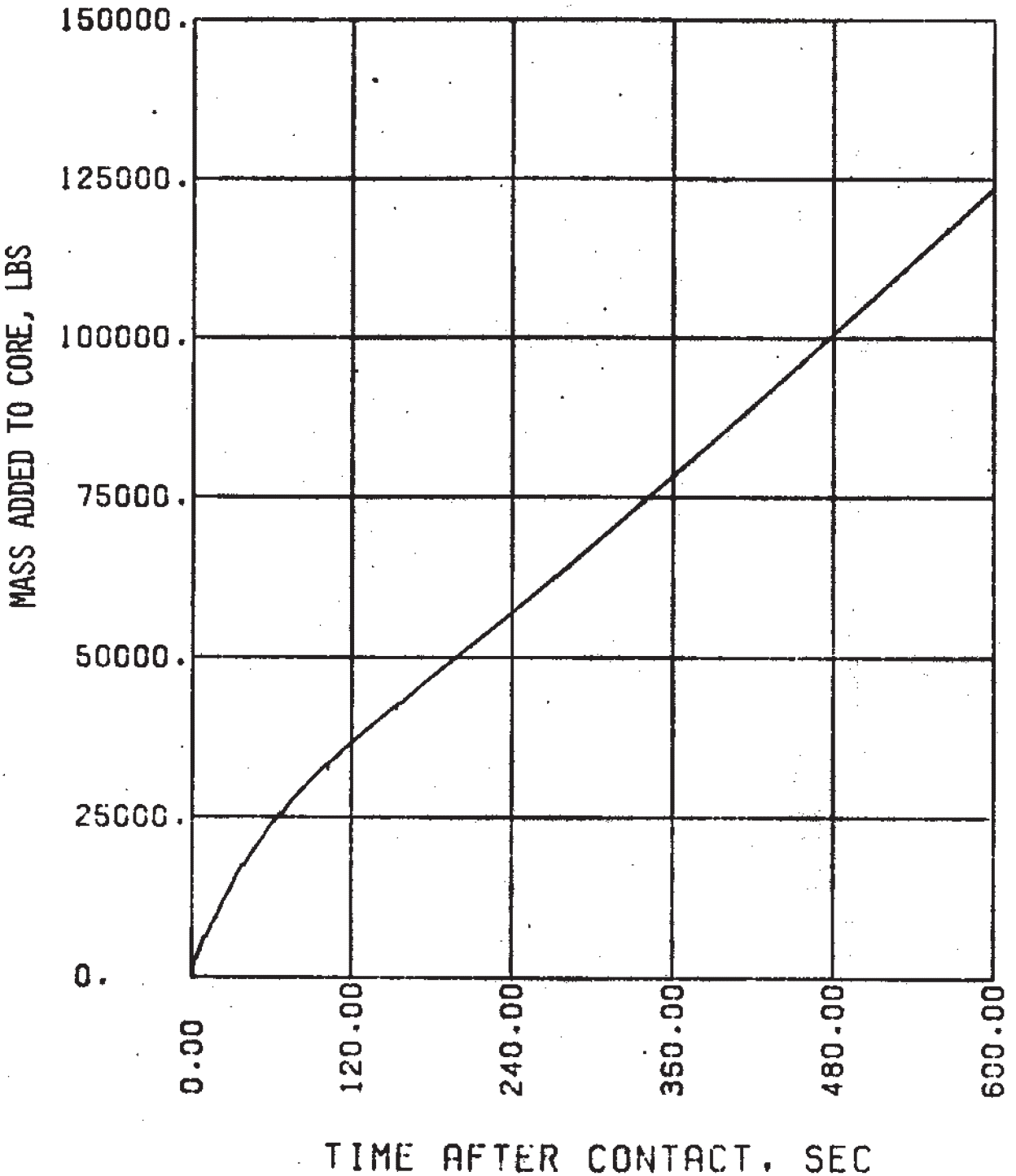


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CONTAINMENT PRESSURE - 0.6 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–7g

CYCLE 1

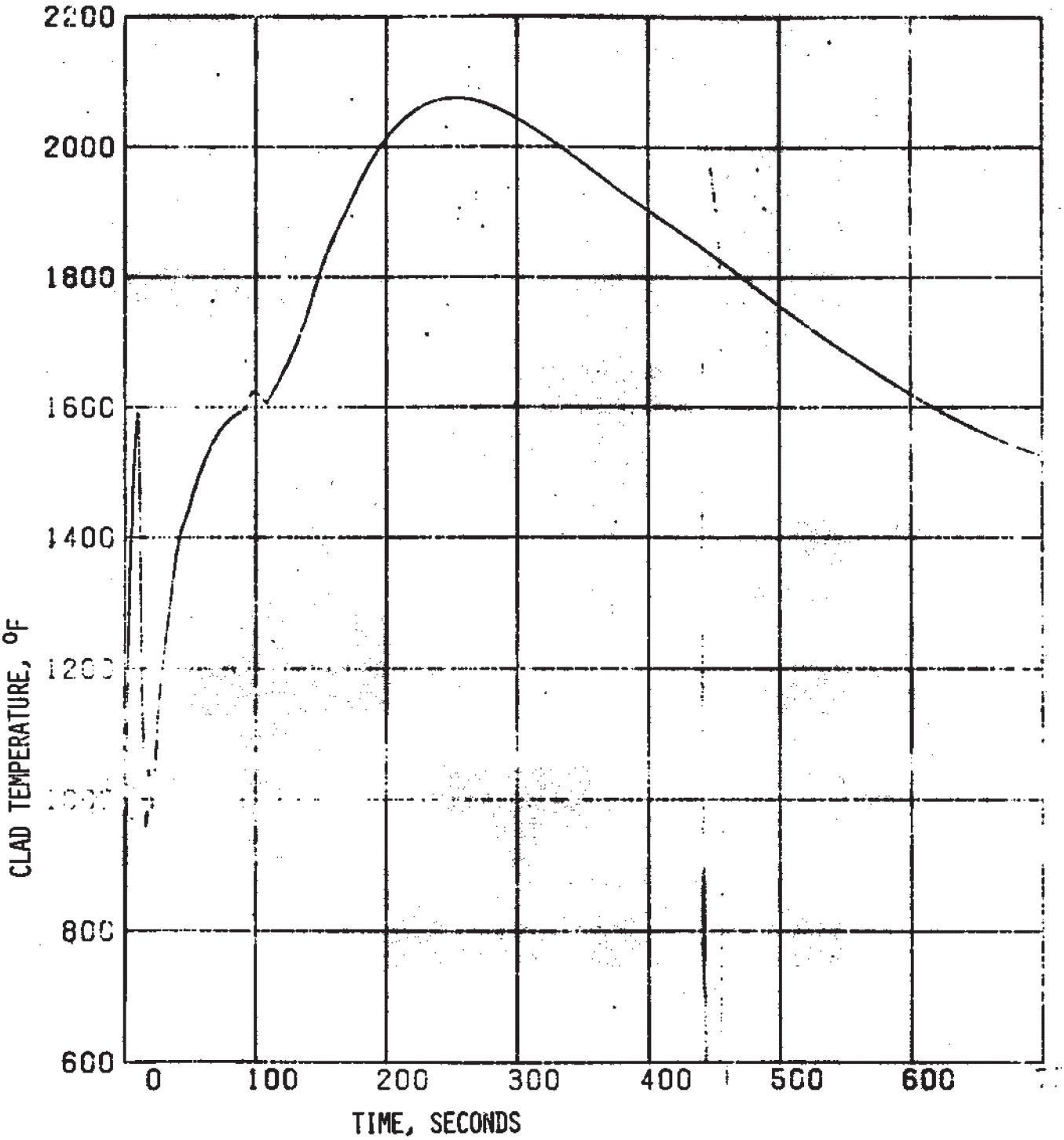


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

MASS ADDED TO CORE DURING REFLOOD
0.6 X DOUBLE ENDED SLOT BREAK
IN PUMP DISCHARGE LEG
FIGURE 6.3-7h

CYCLE 1

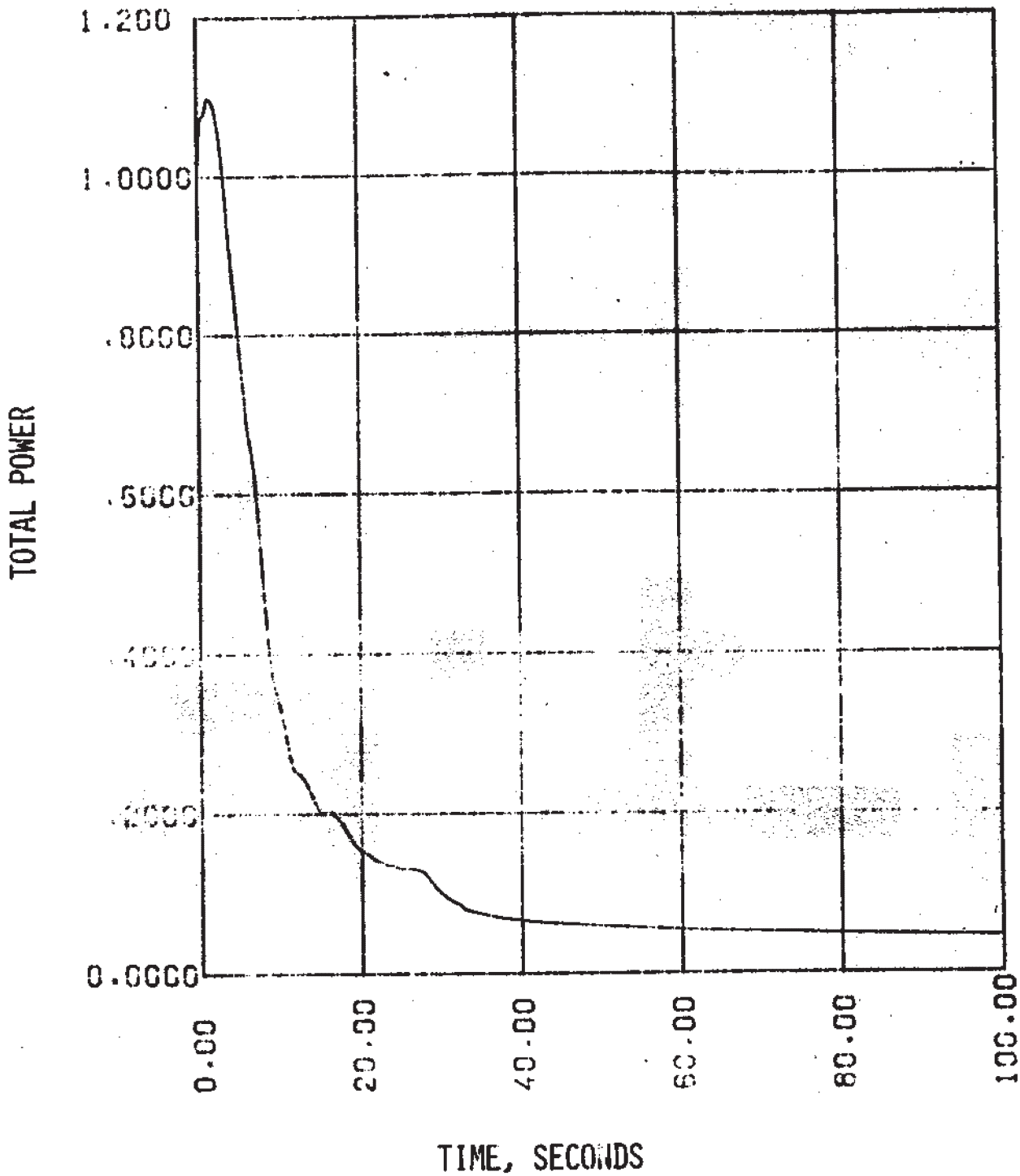


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PEAK CLAD TEMP. - 0.6 X DOUBLE ENDED SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3-7i

CYCLE 1



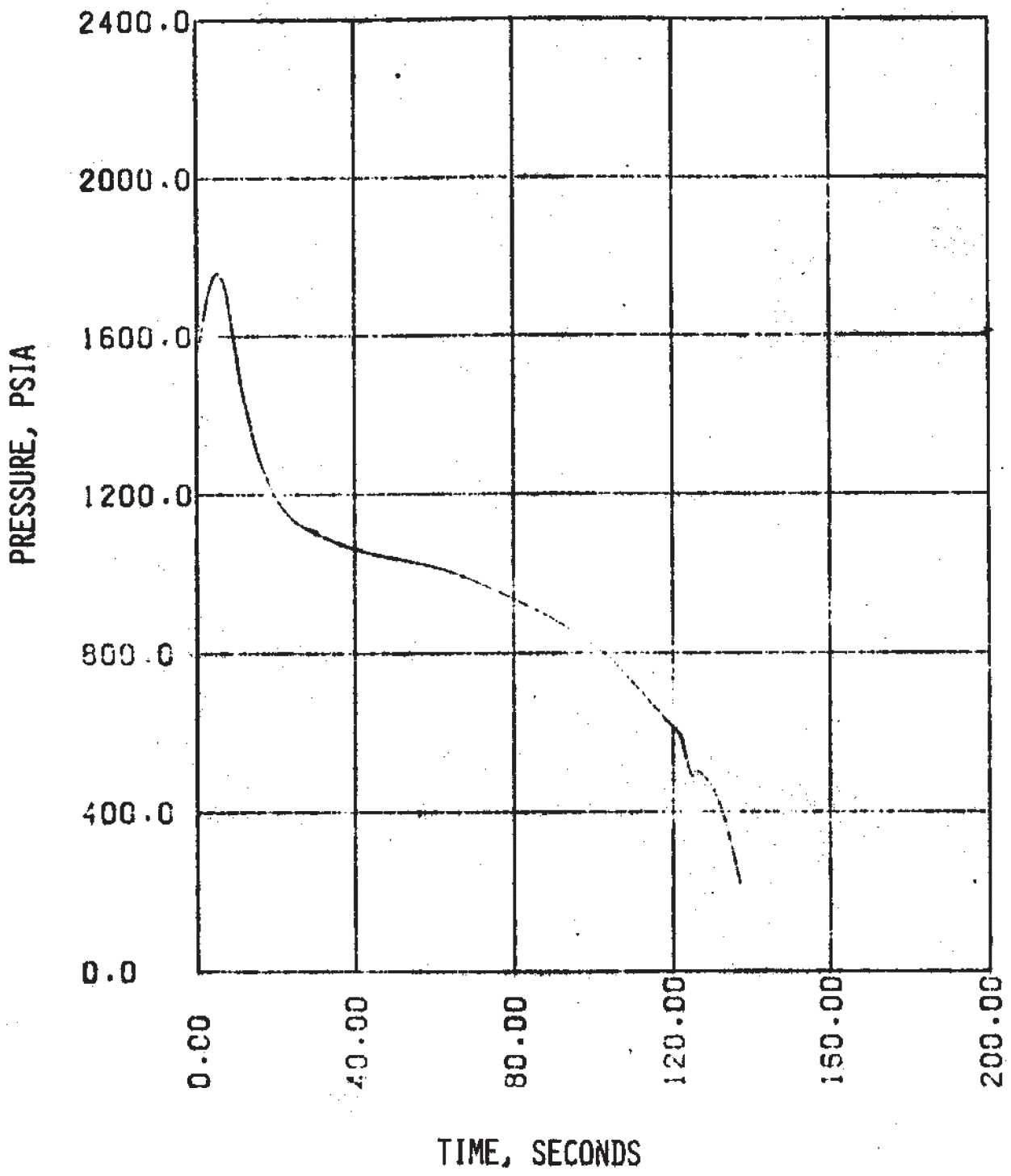
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE POWER - 0.5 FT^2 SLOT BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–8a

CYCLE 1



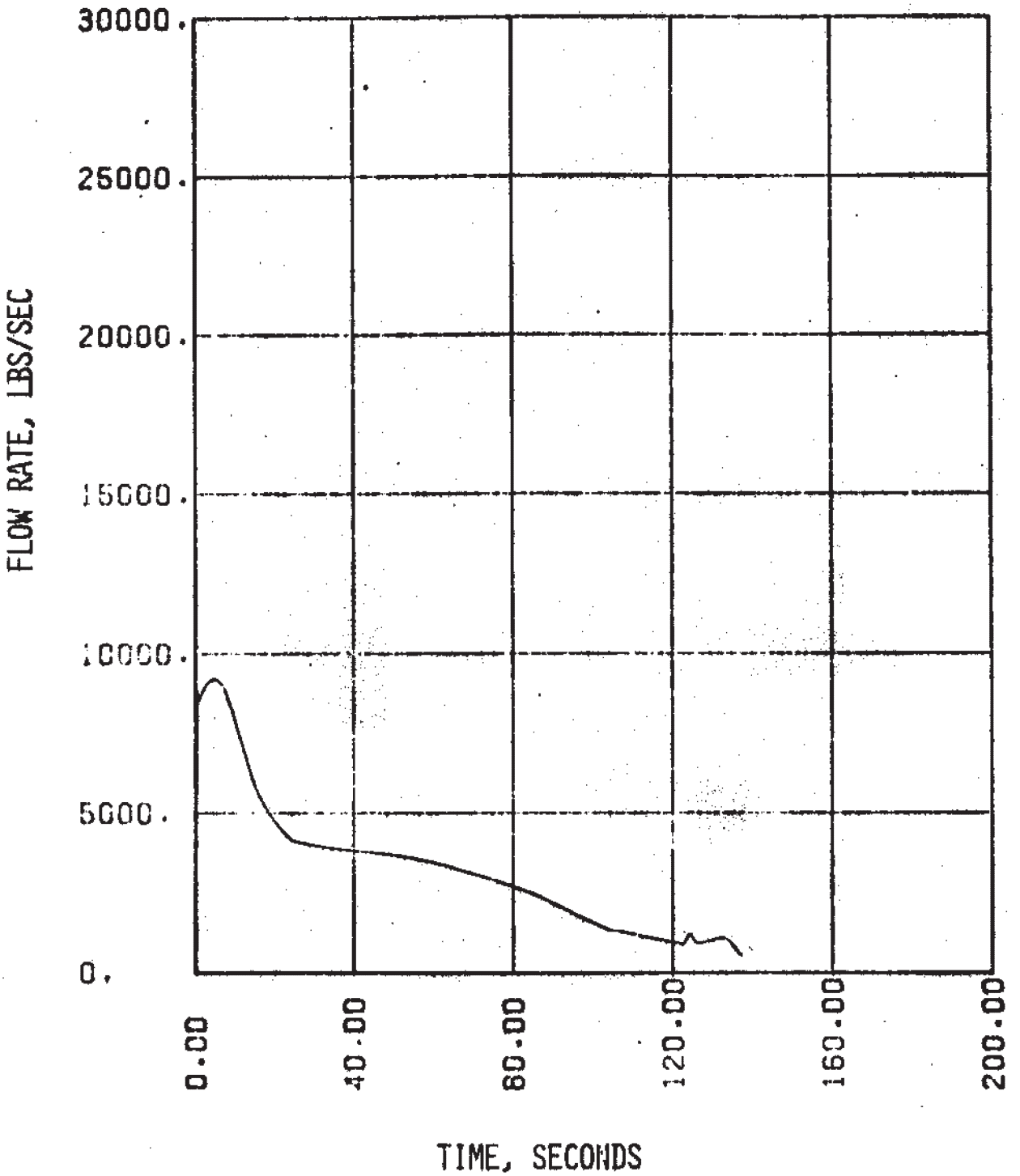
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PRESSURE IN CENTER HOT ASSEMBLY NODE - 0.5 FT^2 SLOT BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-8b

CYCLE 1



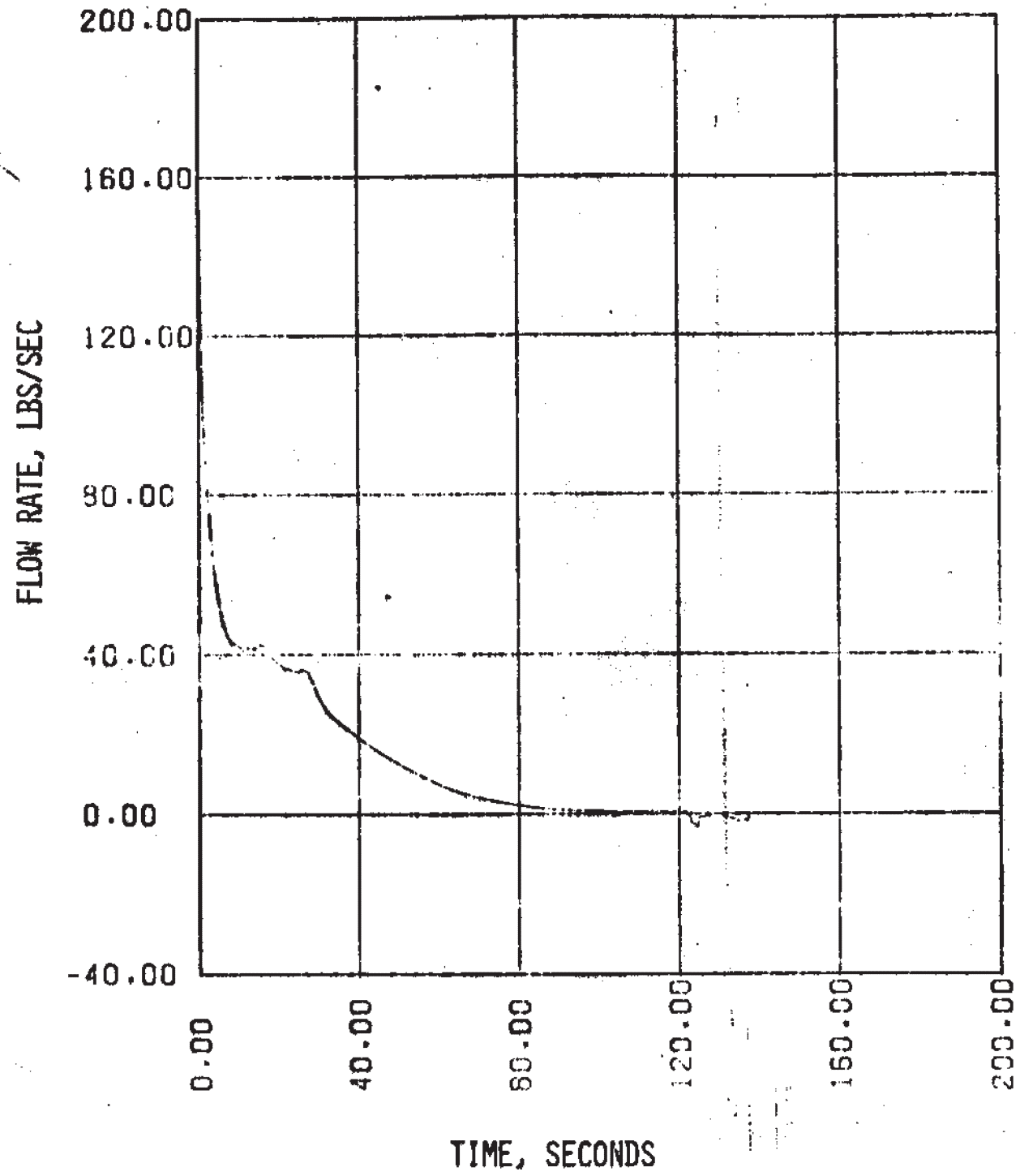
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LEAK FLOW - 0.5 FT^2 SLOT BREAK
IN PUMP DISCHARGE LEG

FIGURE 6.3–8c

CYCLE 1



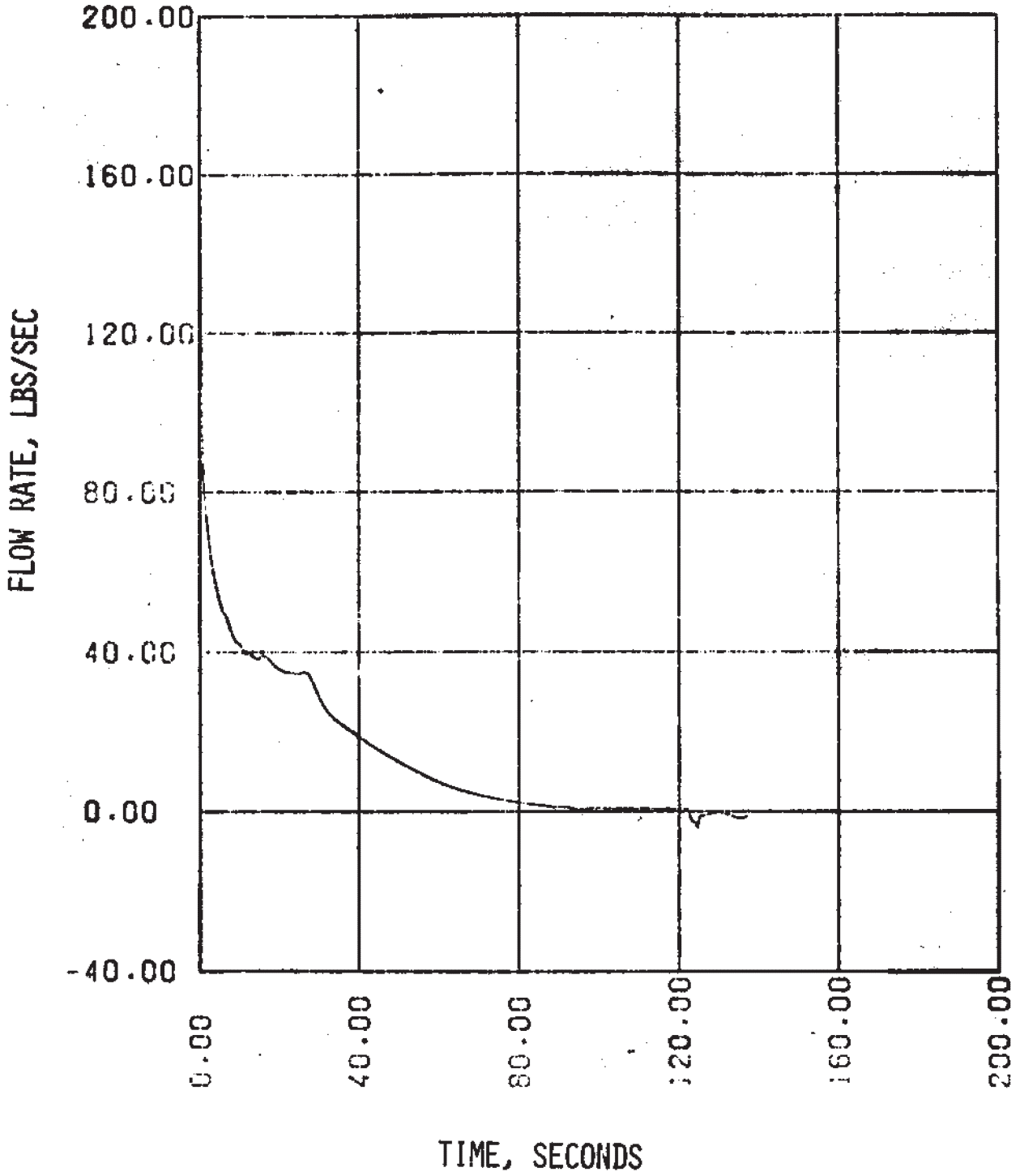
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 16, BELOW HOT SPOT - 0.5 FT^2 SLOT BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–8d

CYCLE 1



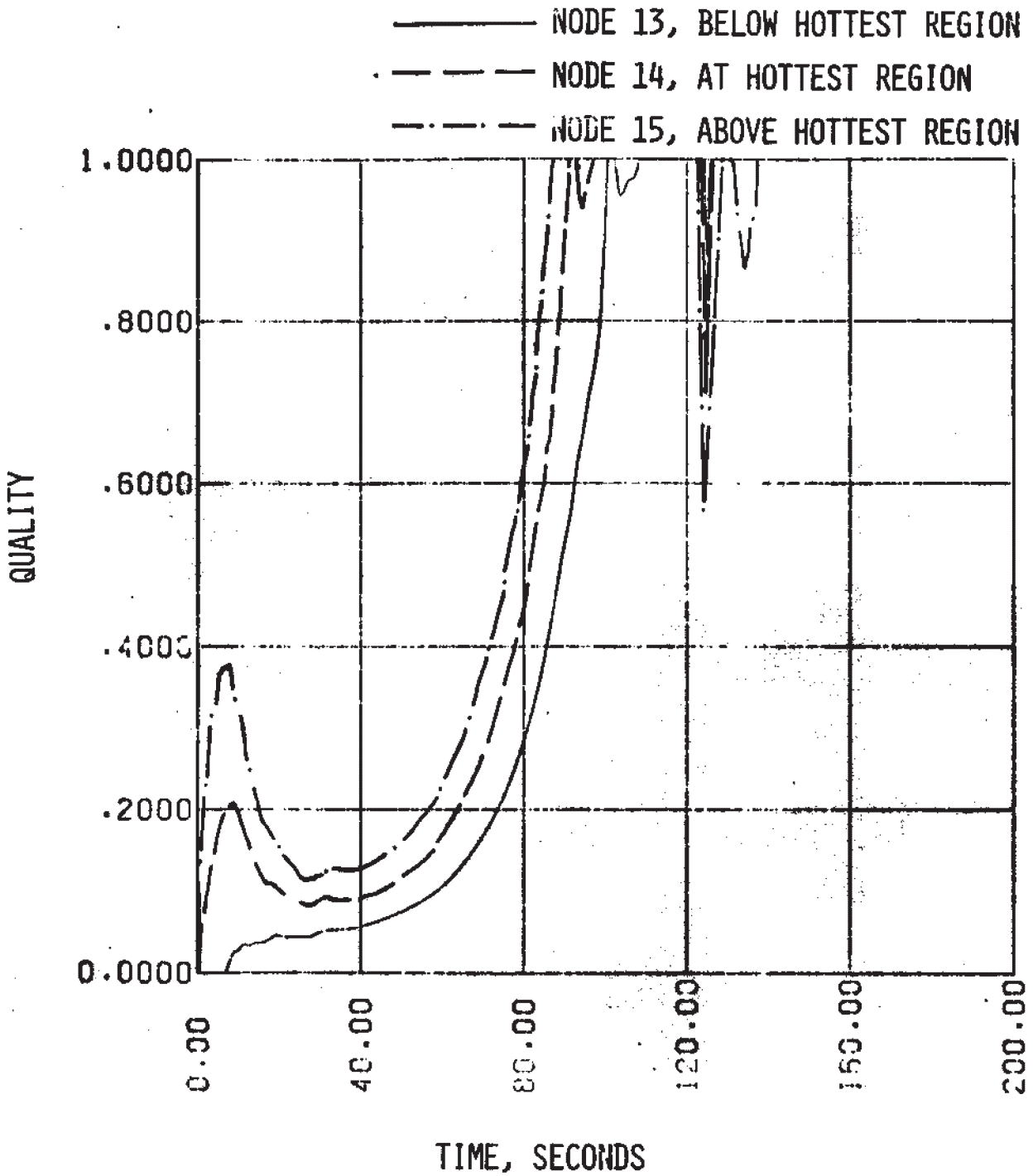
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 17, ABOVE HOT SPOT - 0.5 FT^2 SLOT BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–8e

CYCLE 1

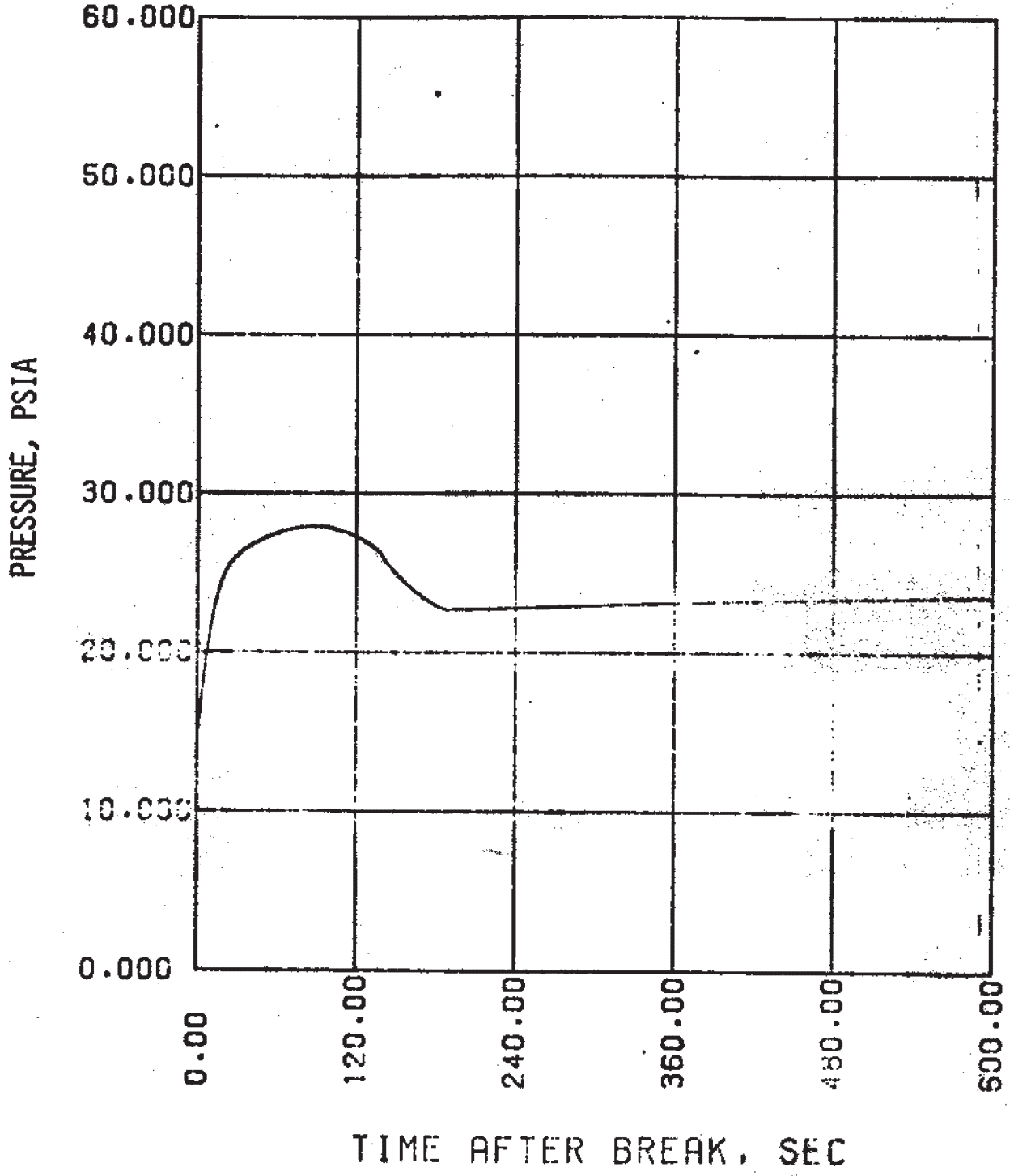


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT ASSEMBLY QUALITY - 0.5 FT^2 SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3-8f

CYCLE 1

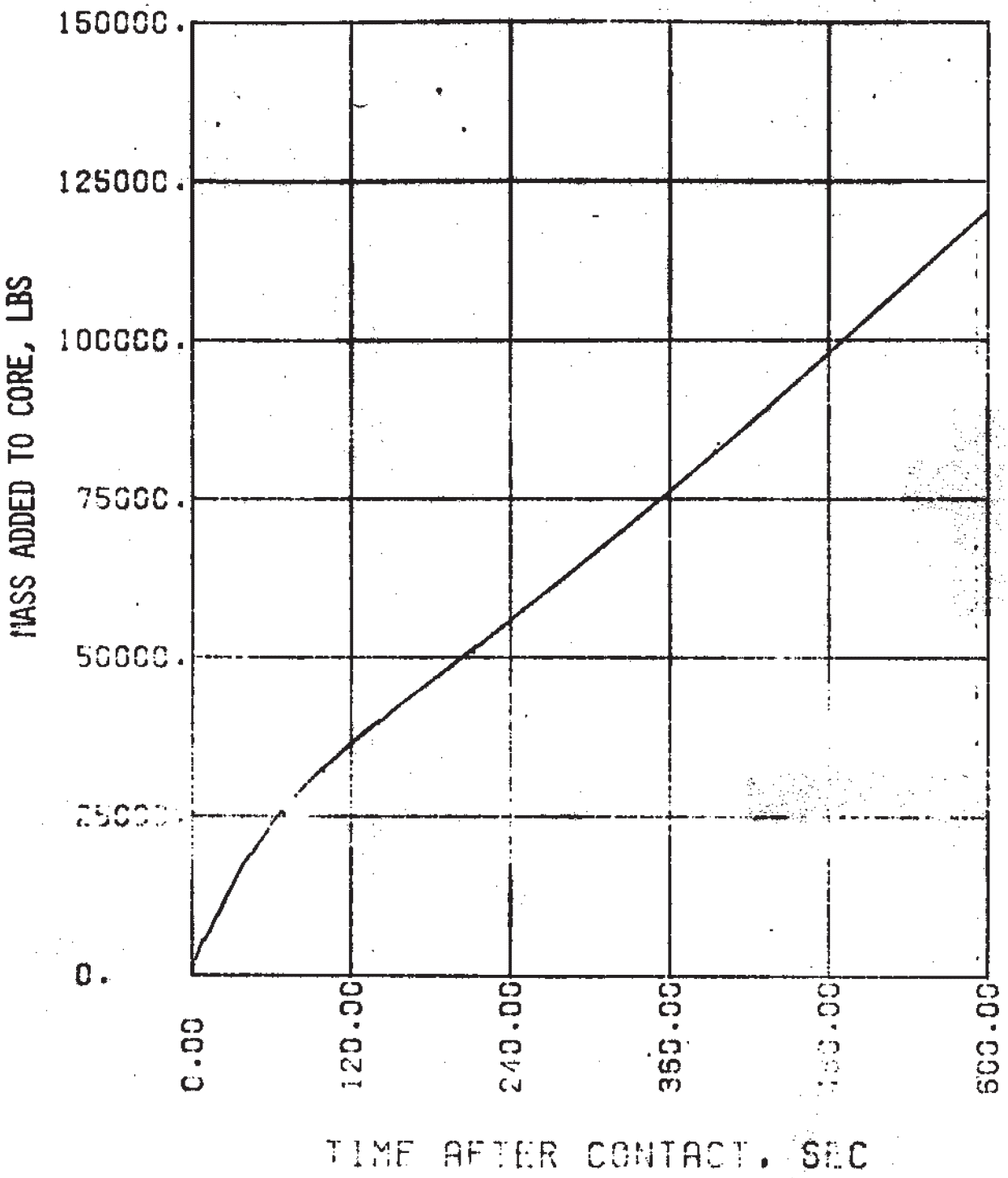


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CONTAINMENT PRESSURE - 0.5 FT^2 SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–8g

CYCLE 1

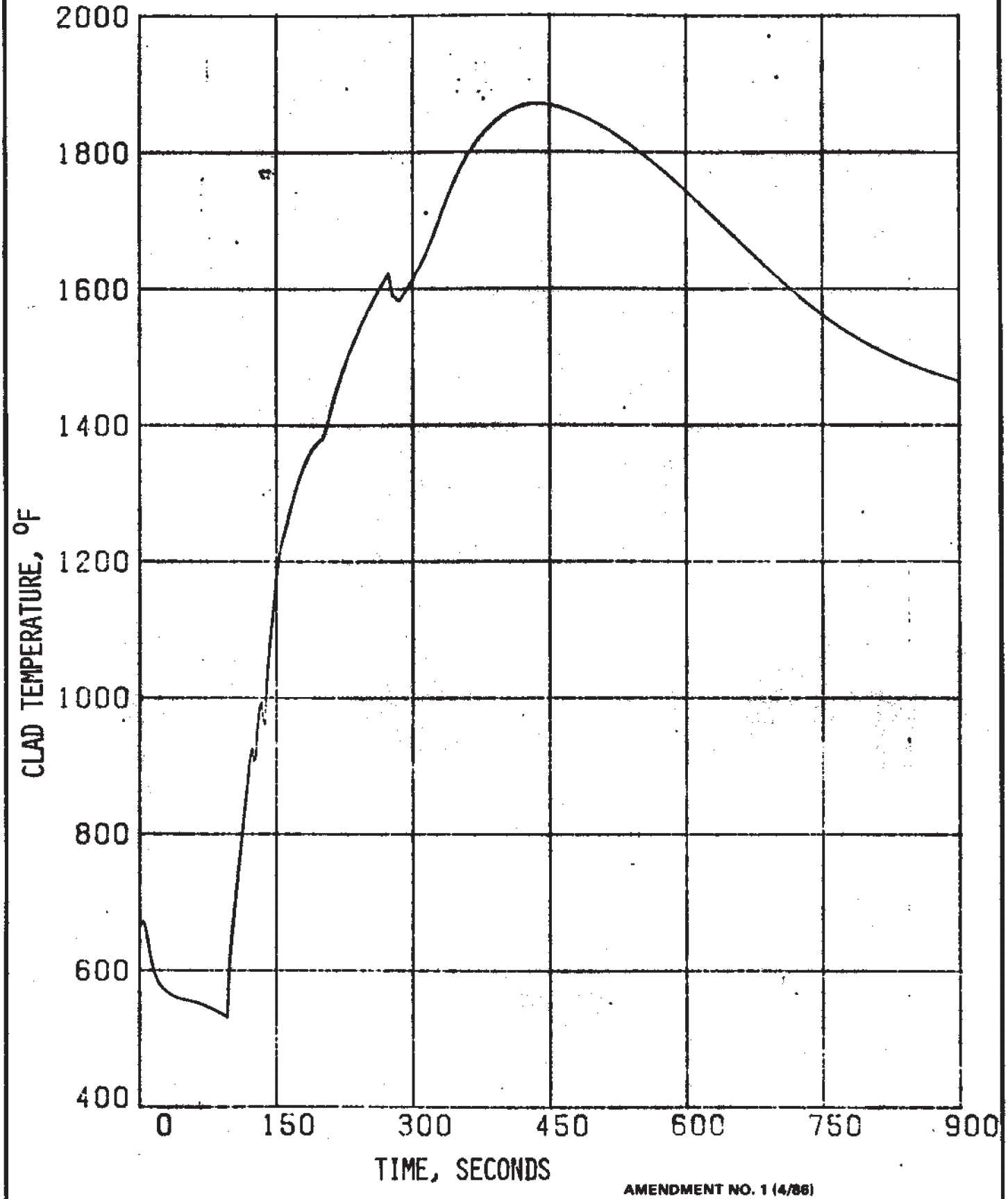


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

MASS ADDED TO CORE DURING REFLOOD
0.5 FT^2 SLOT BREAK
IN PUMP DISCHARGE LEG
FIGURE 6.3–8h

CYCLE 1

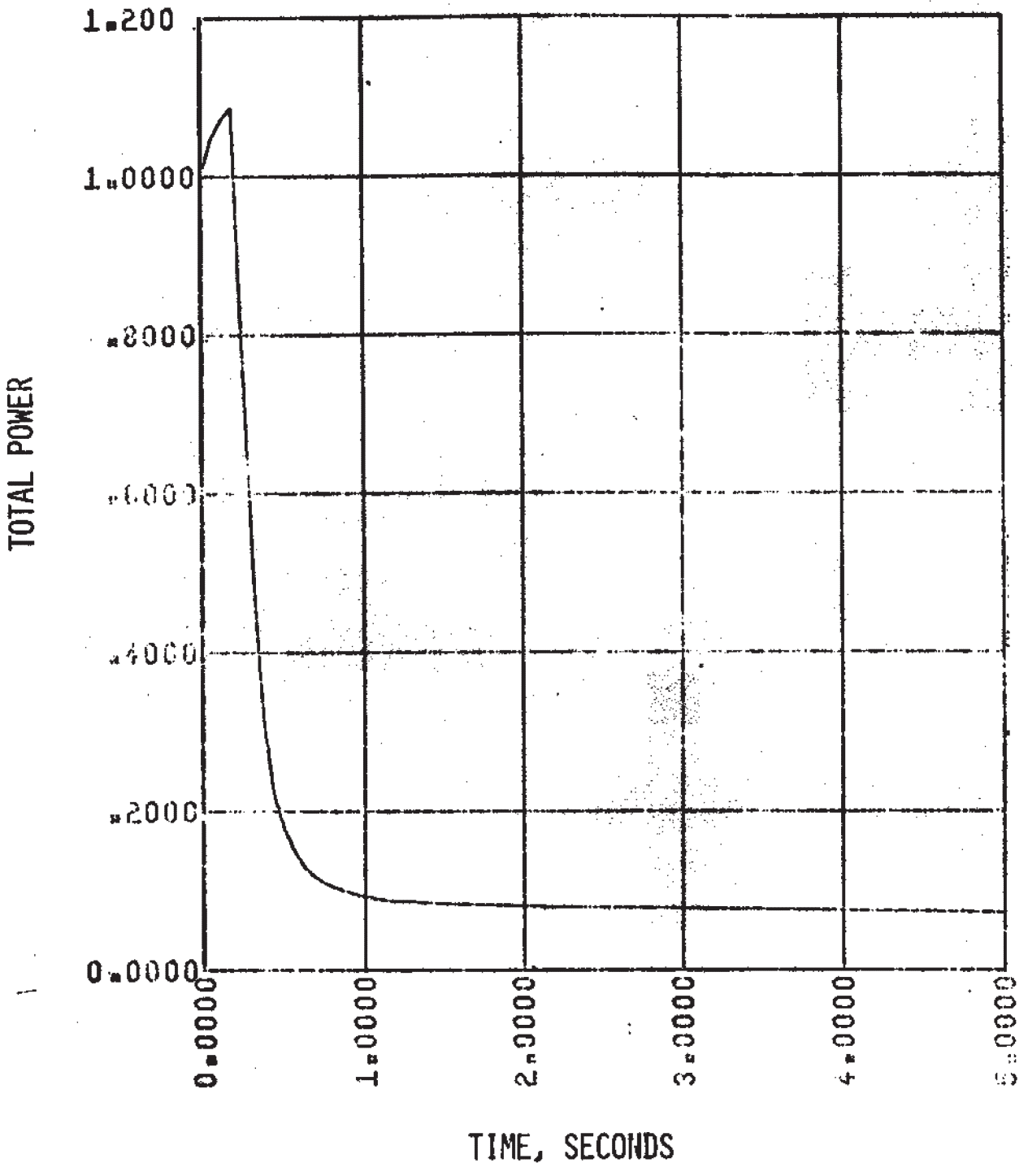


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PEAK CLAD TEMP. - 0.5 FT^2 SLOT BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3-8i

CYCLE 1



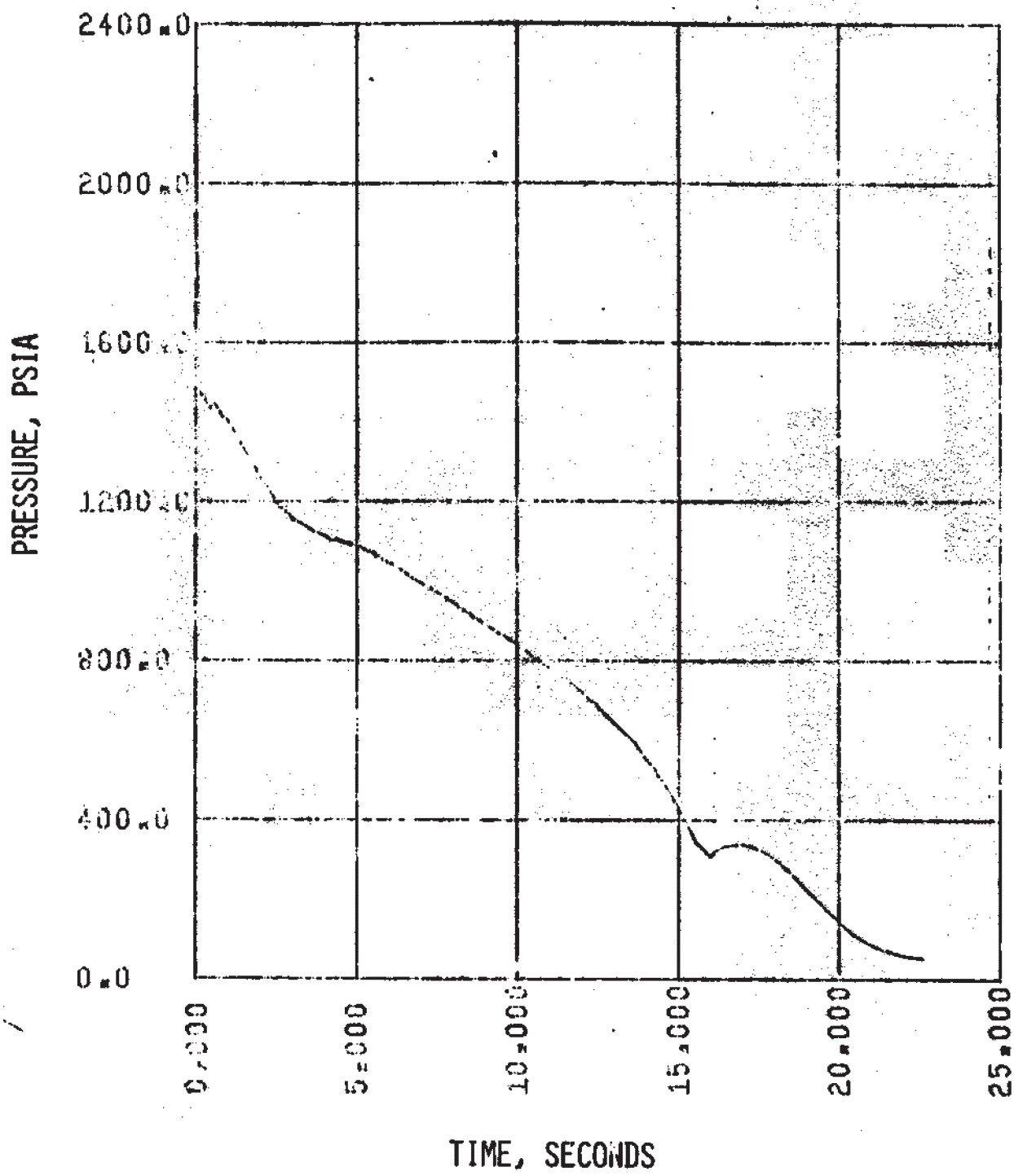
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE POWER - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-9a

CYCLE 1



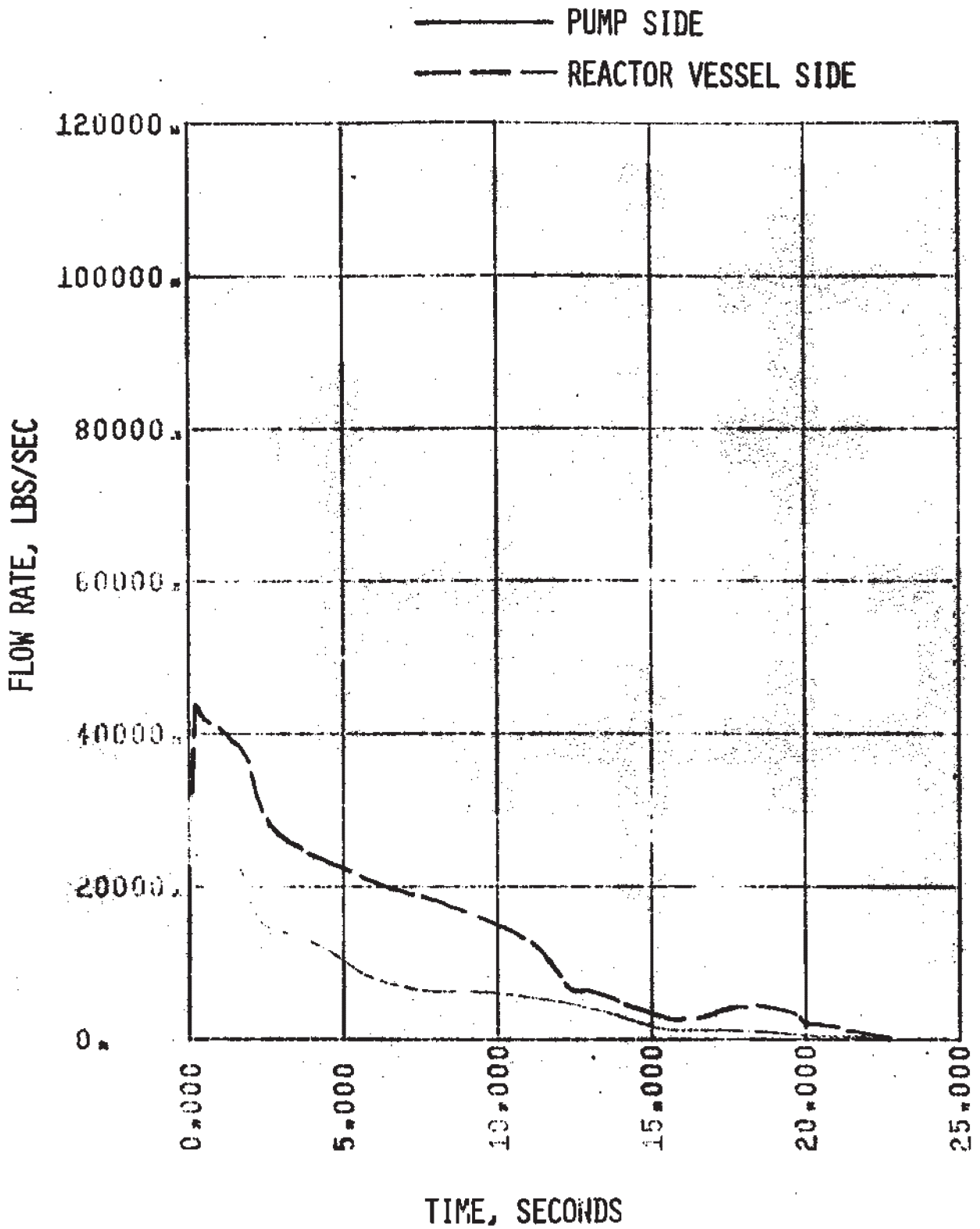
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PRESSURE IN CENTER HOT ASSEMBLY NODE - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-9b

CYCLE 1



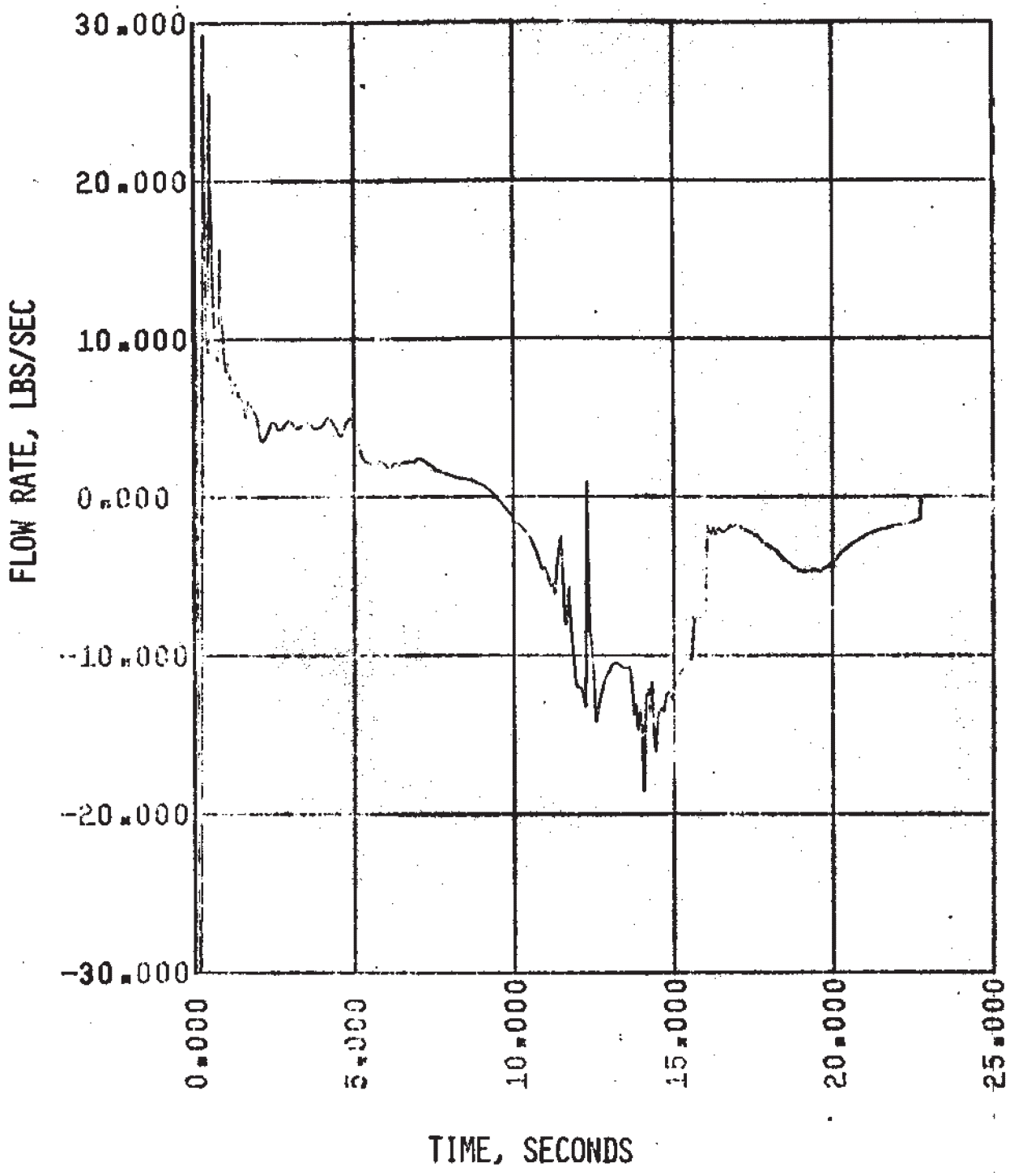
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LEAK FLOW - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-9c

CYCLE 1

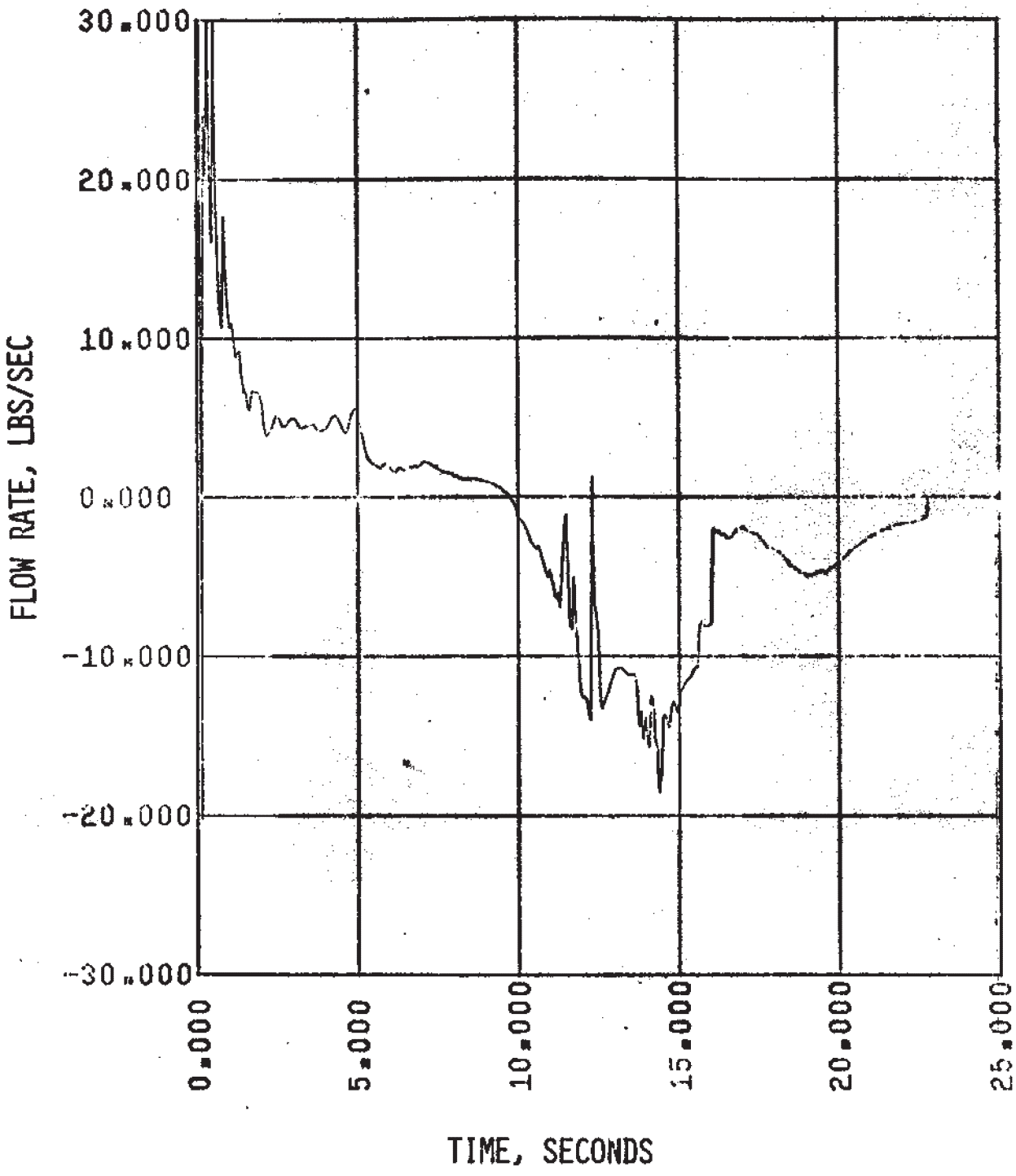


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 16, BELOW HOT SPOT - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCH. LEG
FIGURE 6.3–9d

CYCLE 1



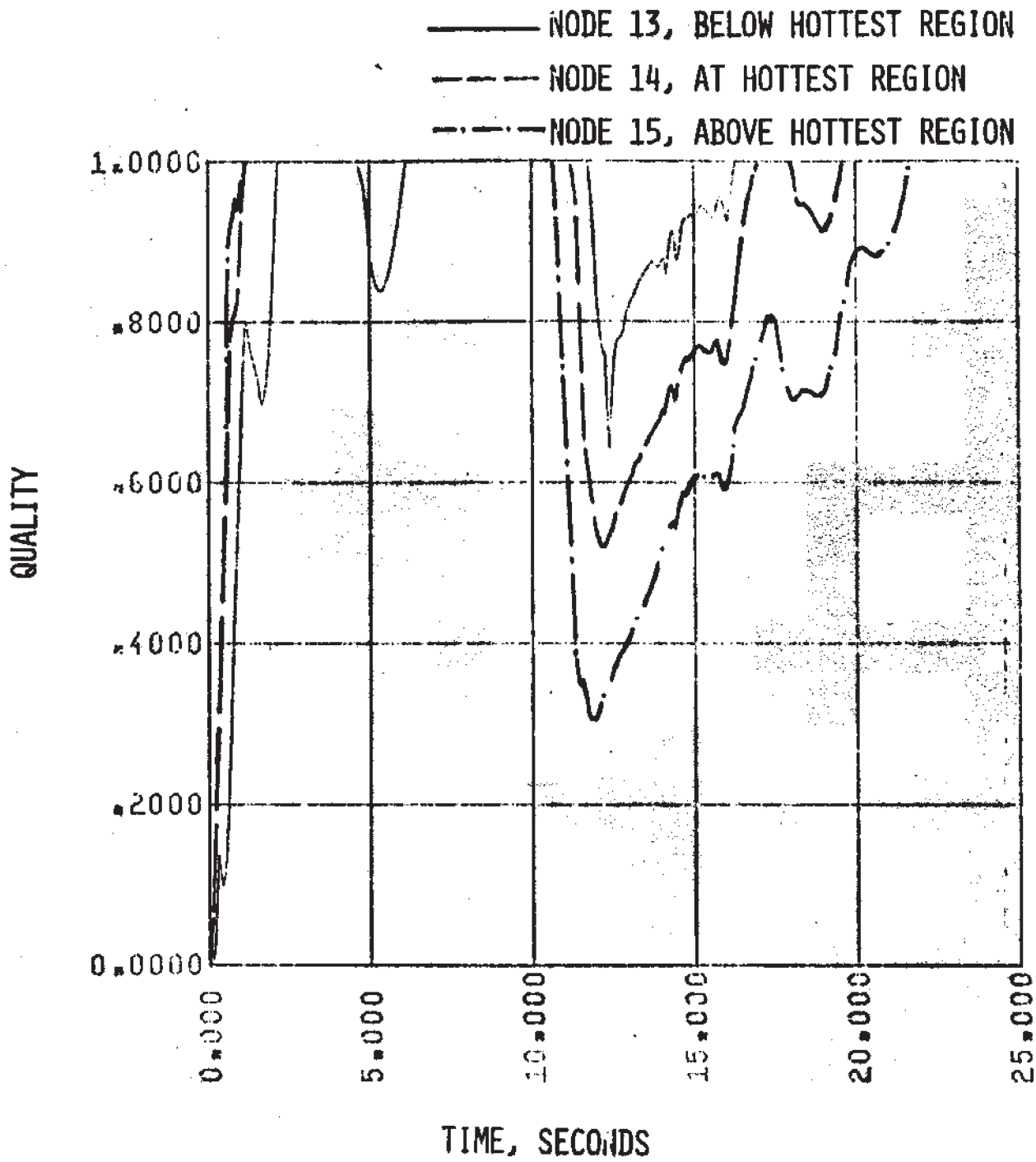
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 17 ABOVE HOT SPOT - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCH. LEG

FIGURE 6.3-9e

CYCLE 1



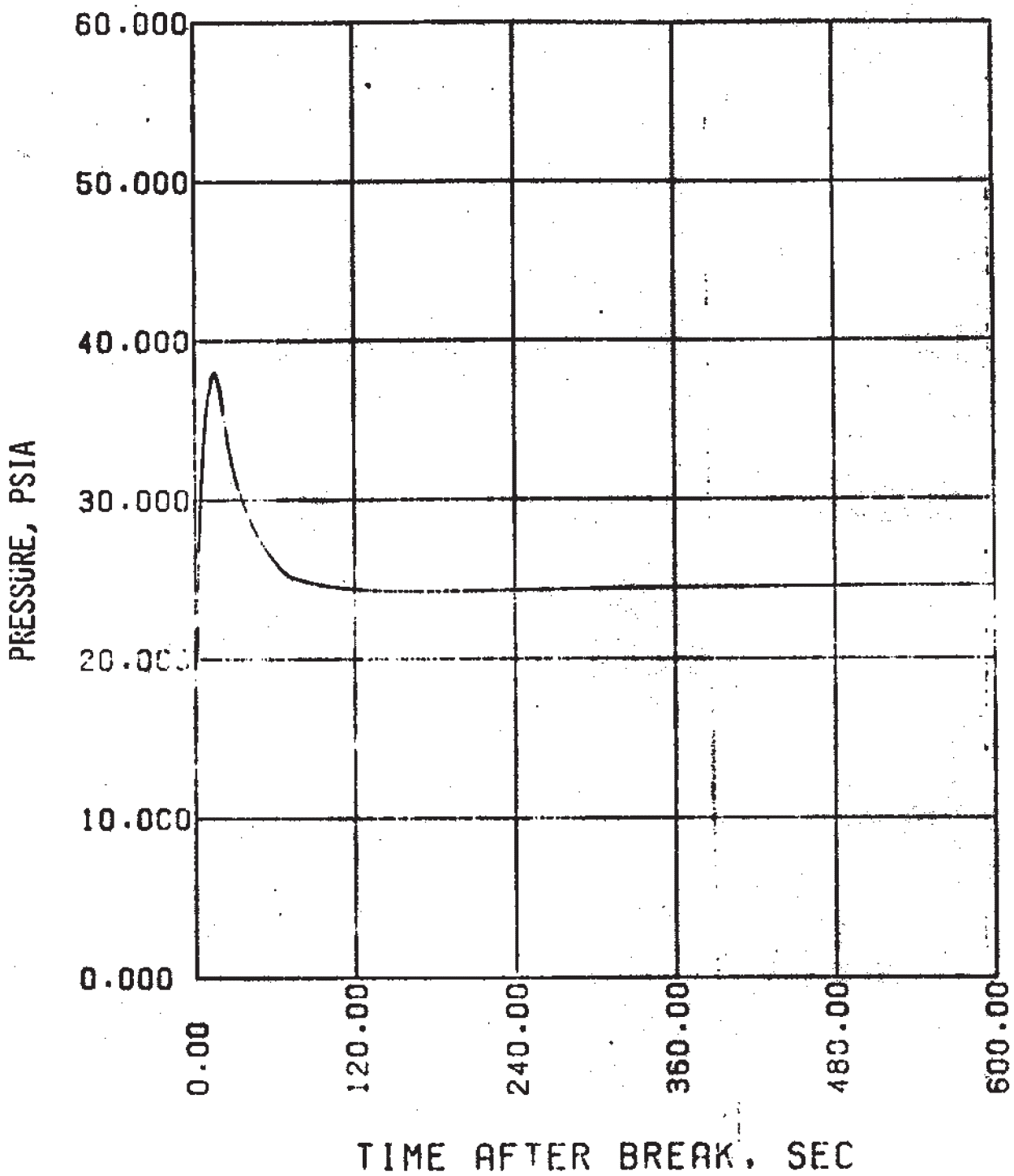
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT ASSEMBLY QUALITY - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-9f

CYCLE 1



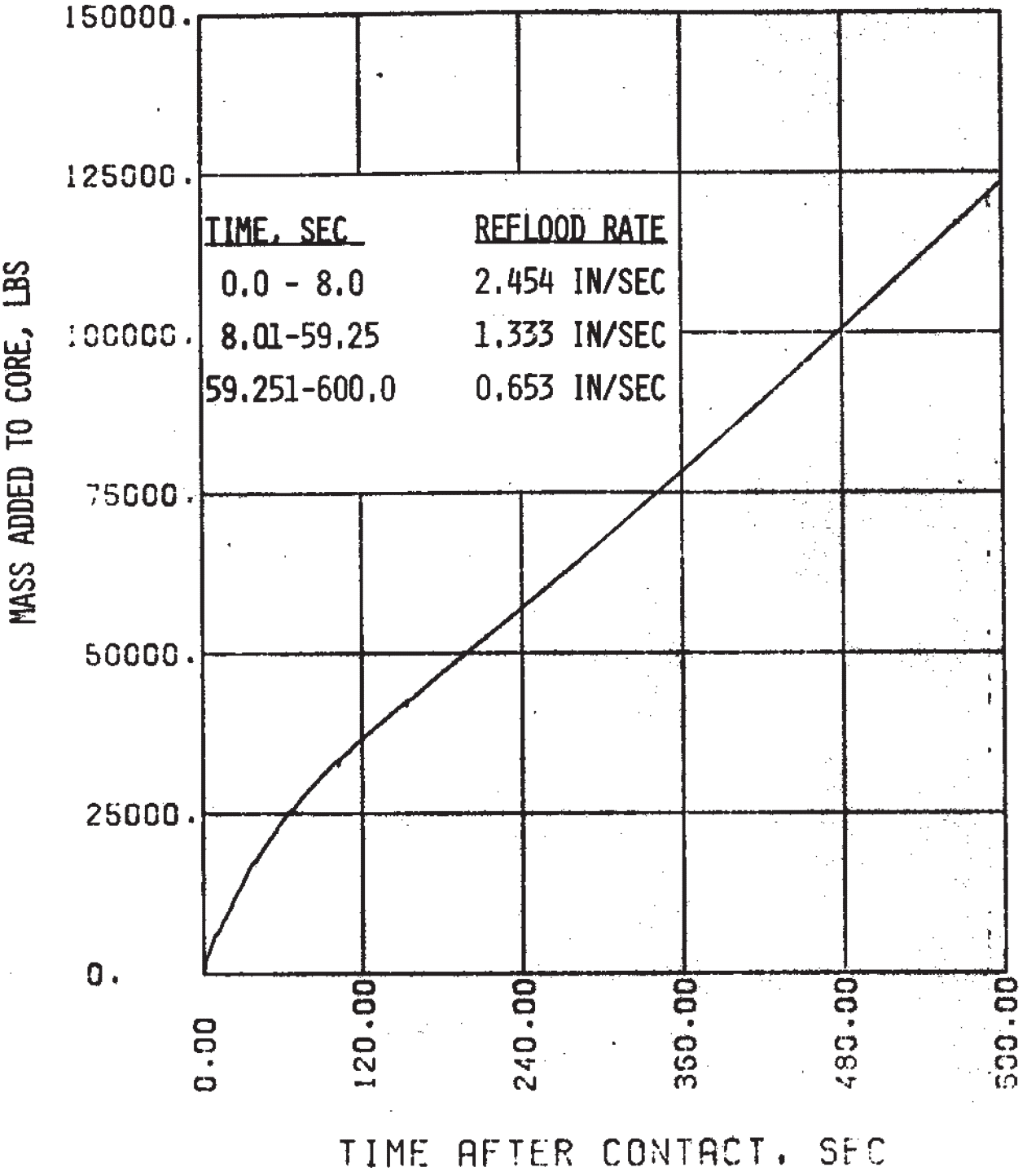
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CONTAINMENT PRESSURE - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–9g

CYCLE 1



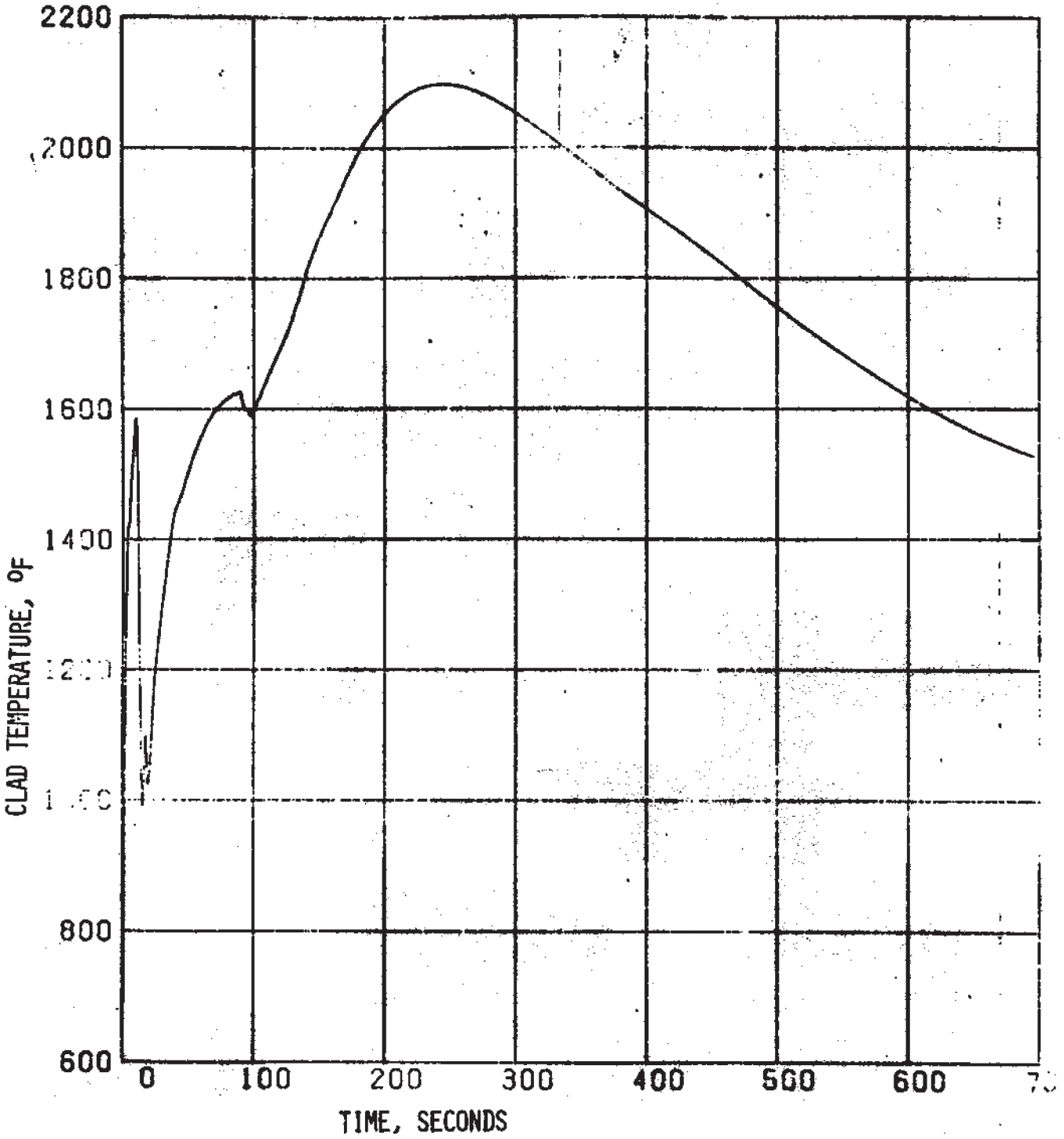
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

MASS ADDED TO CORE DURING REFLOOD
1.0 X DOUBLE ENDED GUILLOTINE BREAK
IN PUMP DISCHARGE LEG

FIGURE 6.3-9h

CYCLE 1



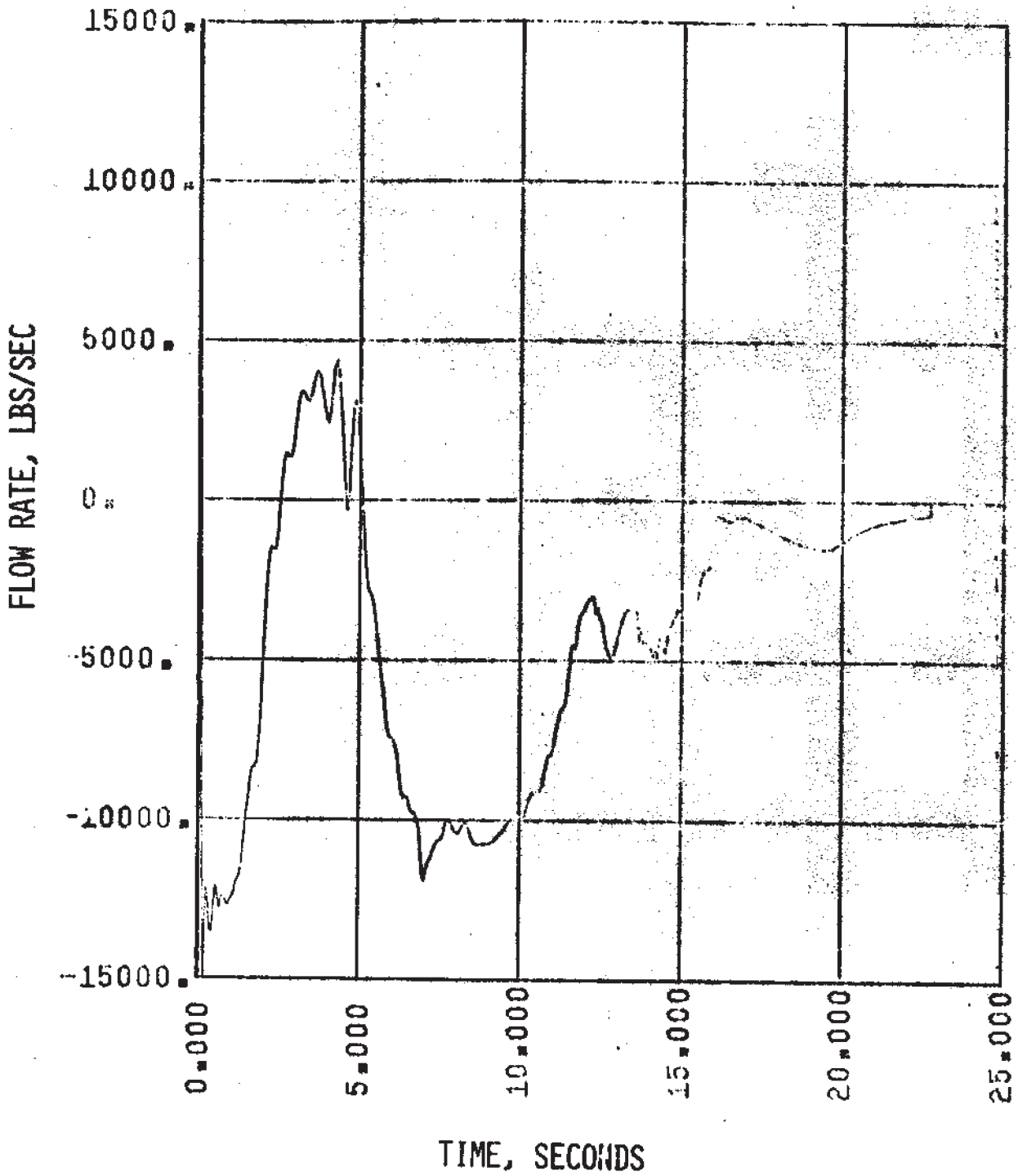
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PEAK CLAD TEMP. - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-9i

CYCLE 1

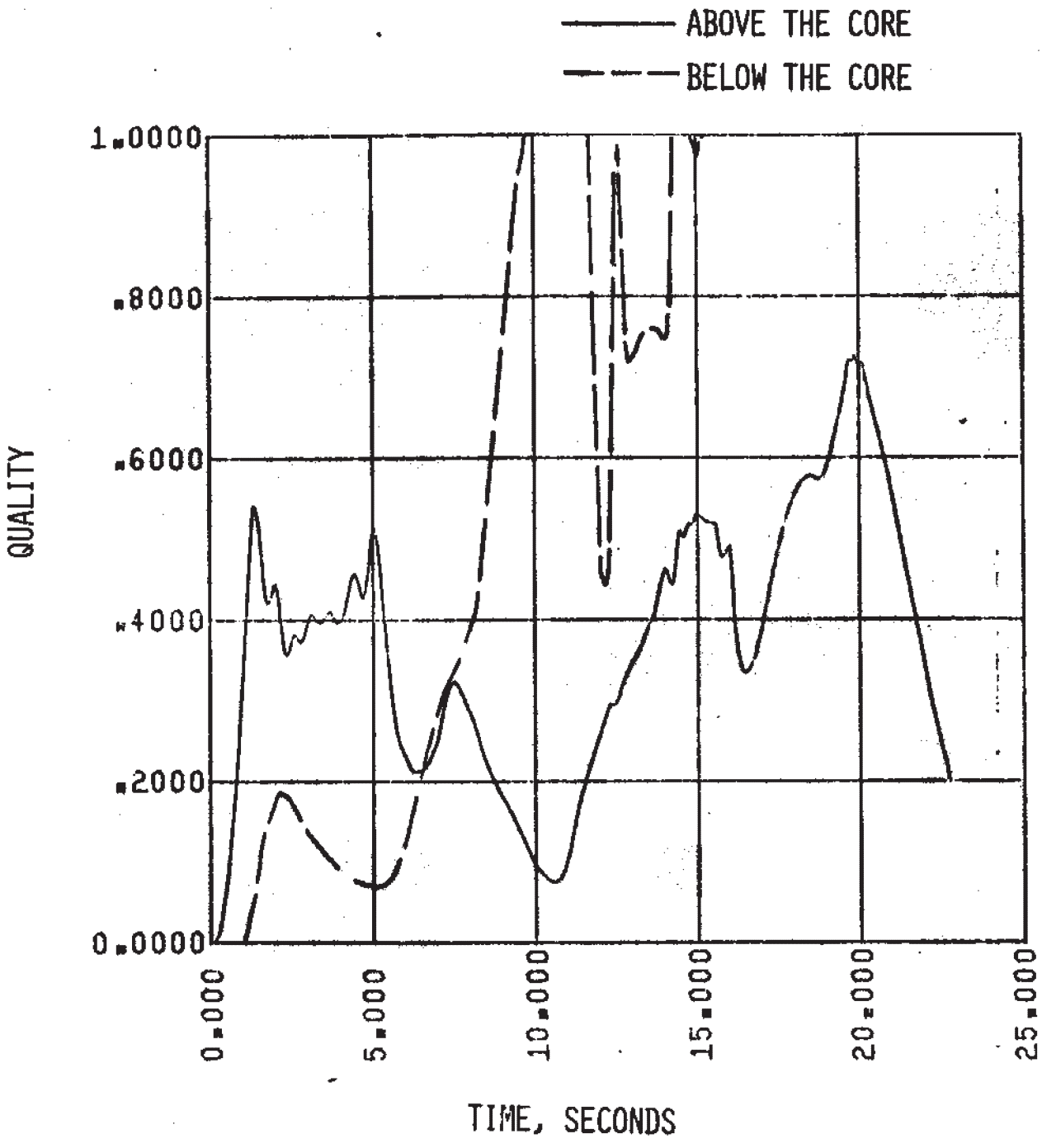


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

MID-ANNULUS FLOW - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3-9j

CYCLE 1

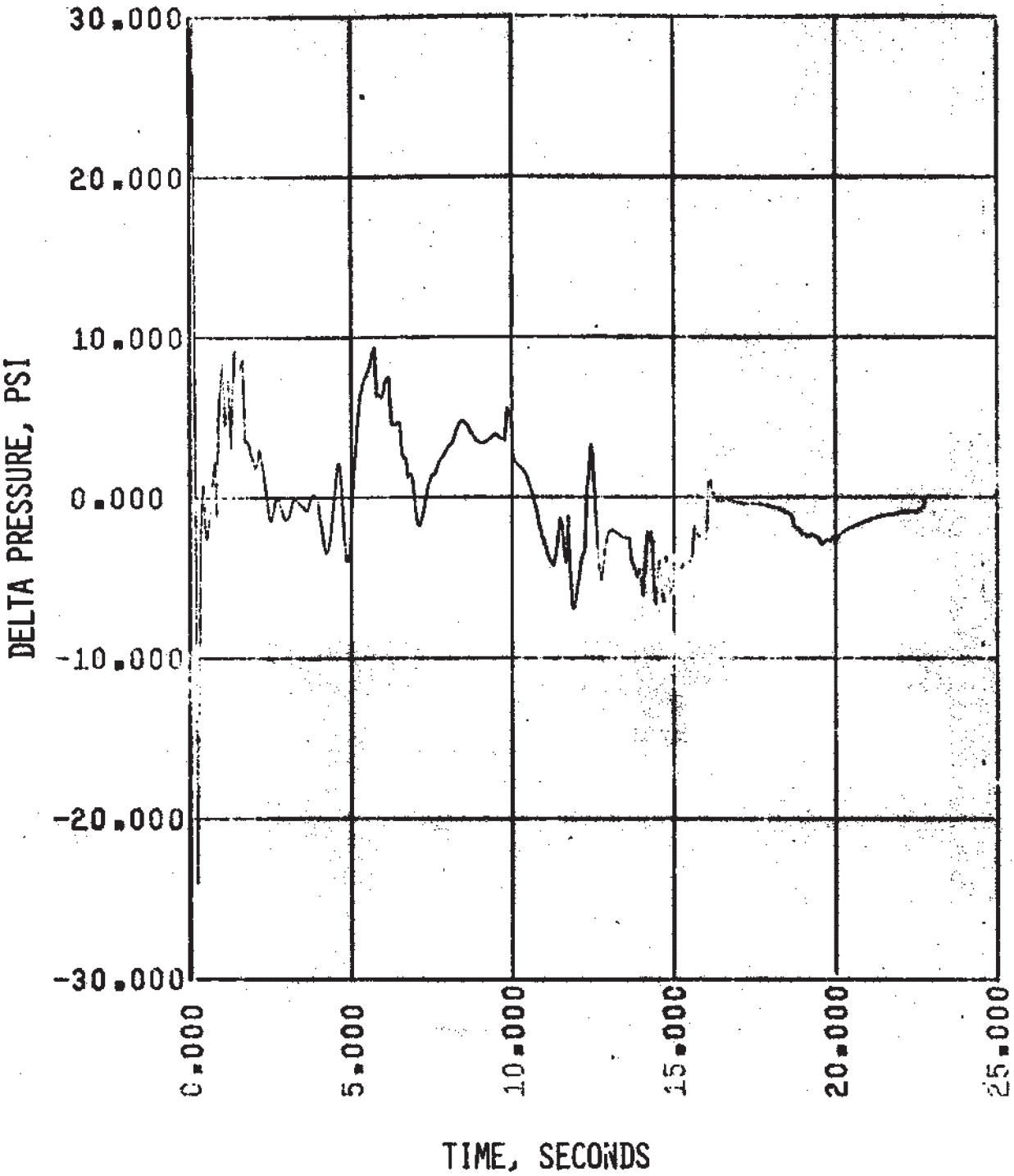


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

QUALITIES ABOVE & BELOW THE CORE - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3-9k

CYCLE 1



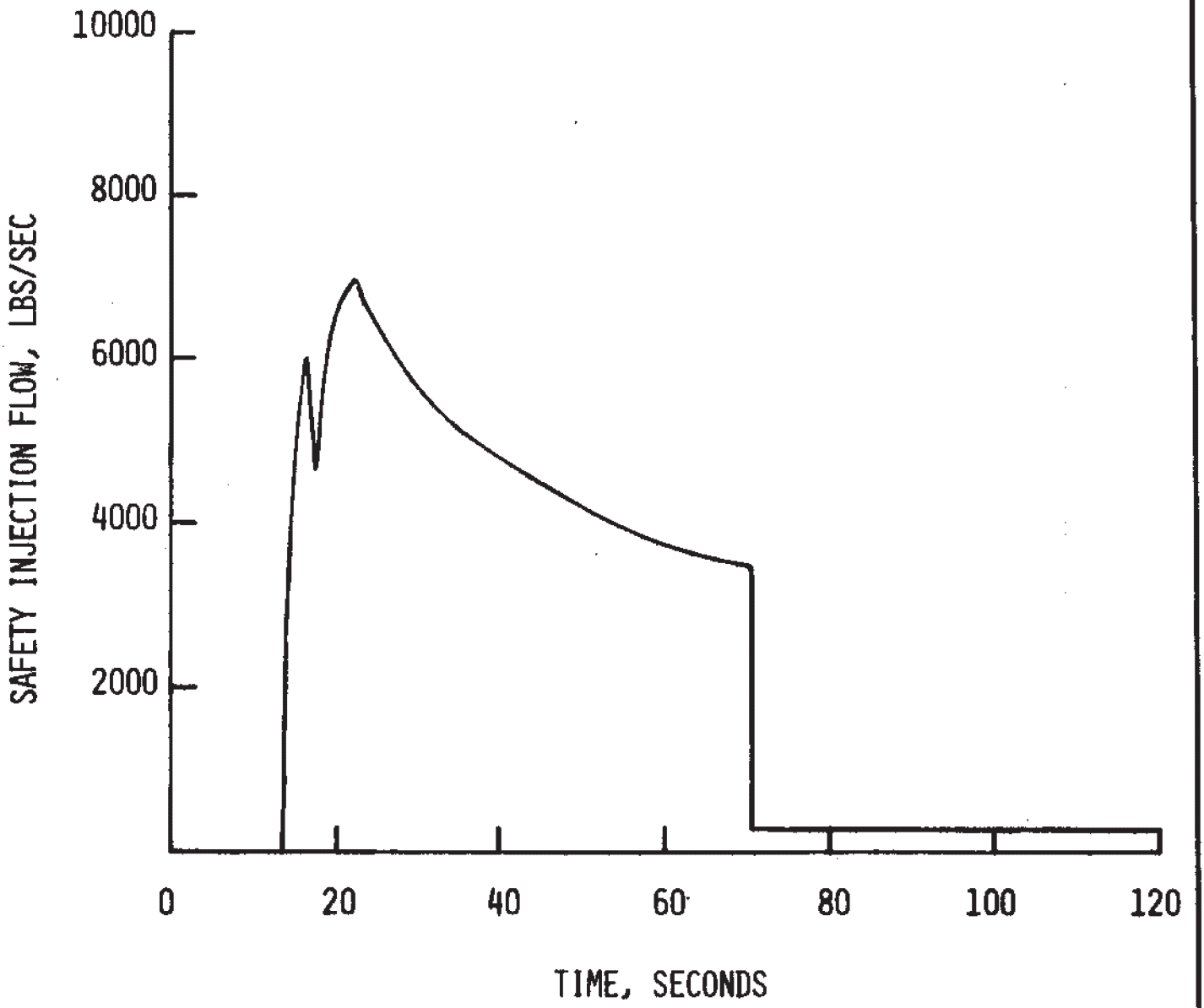
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE PRESSURE DROP - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

CYCLE 1

FIGURE 6.3-9I

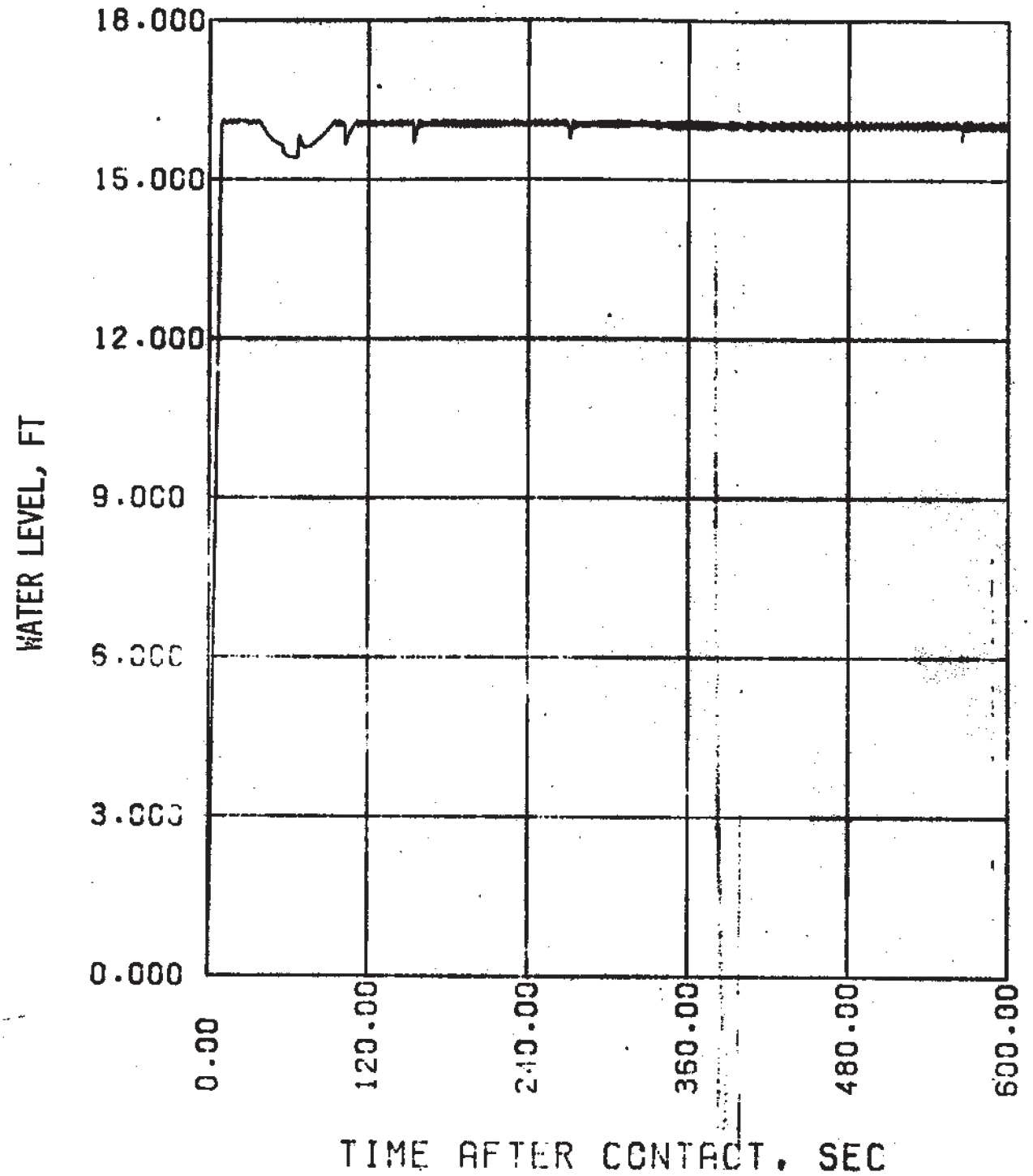


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

SAFETY INJECTION FLOW INTO INTACT DISCHARGE LEGS - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCH. LEG
FIGURE 6.3-9m

CYCLE 1



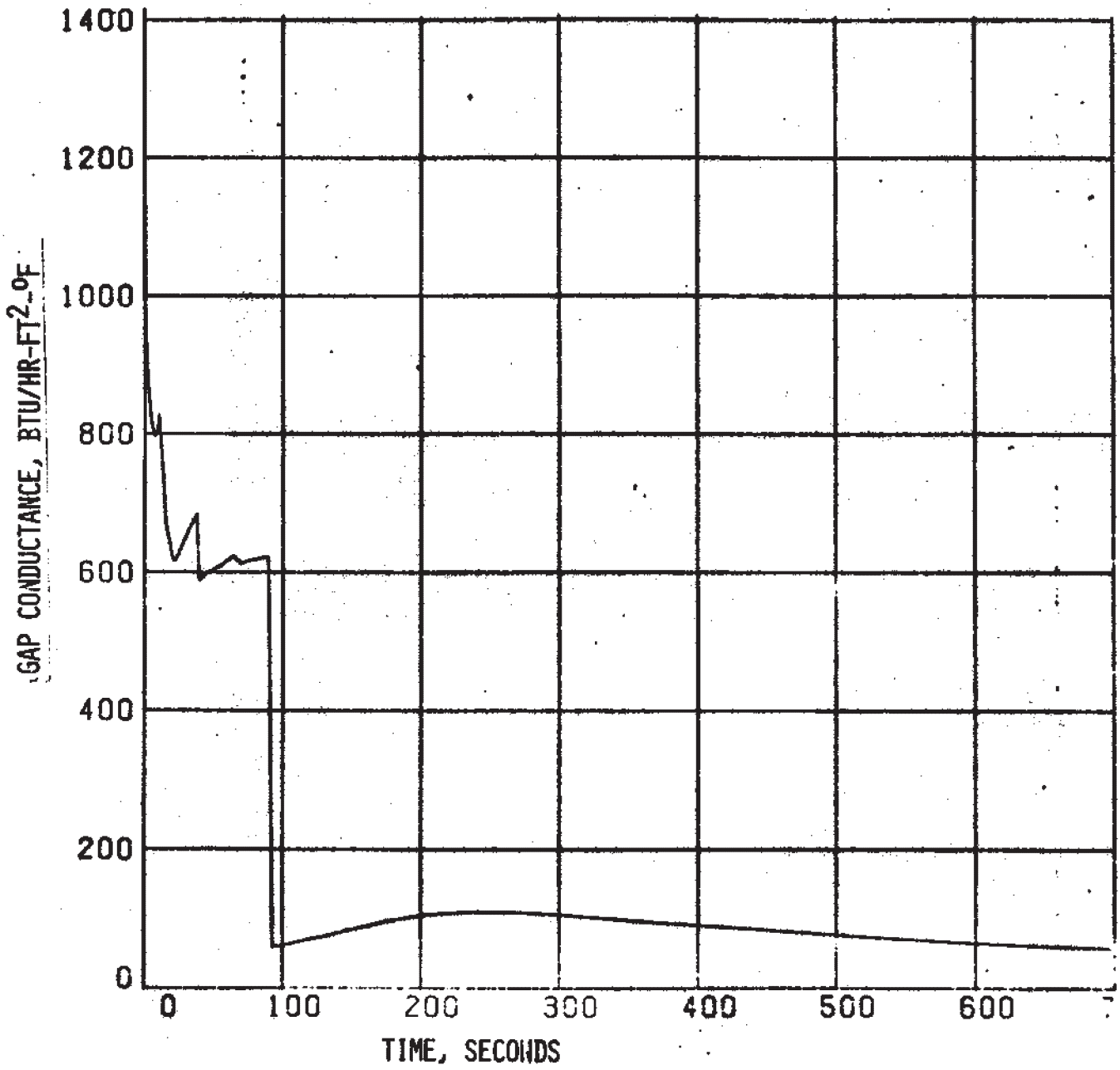
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

WATER LEVEL IN DOWNCOMER DURING REFLOOD - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCH. LEG

FIGURE 6.3–9n

CYCLE 1



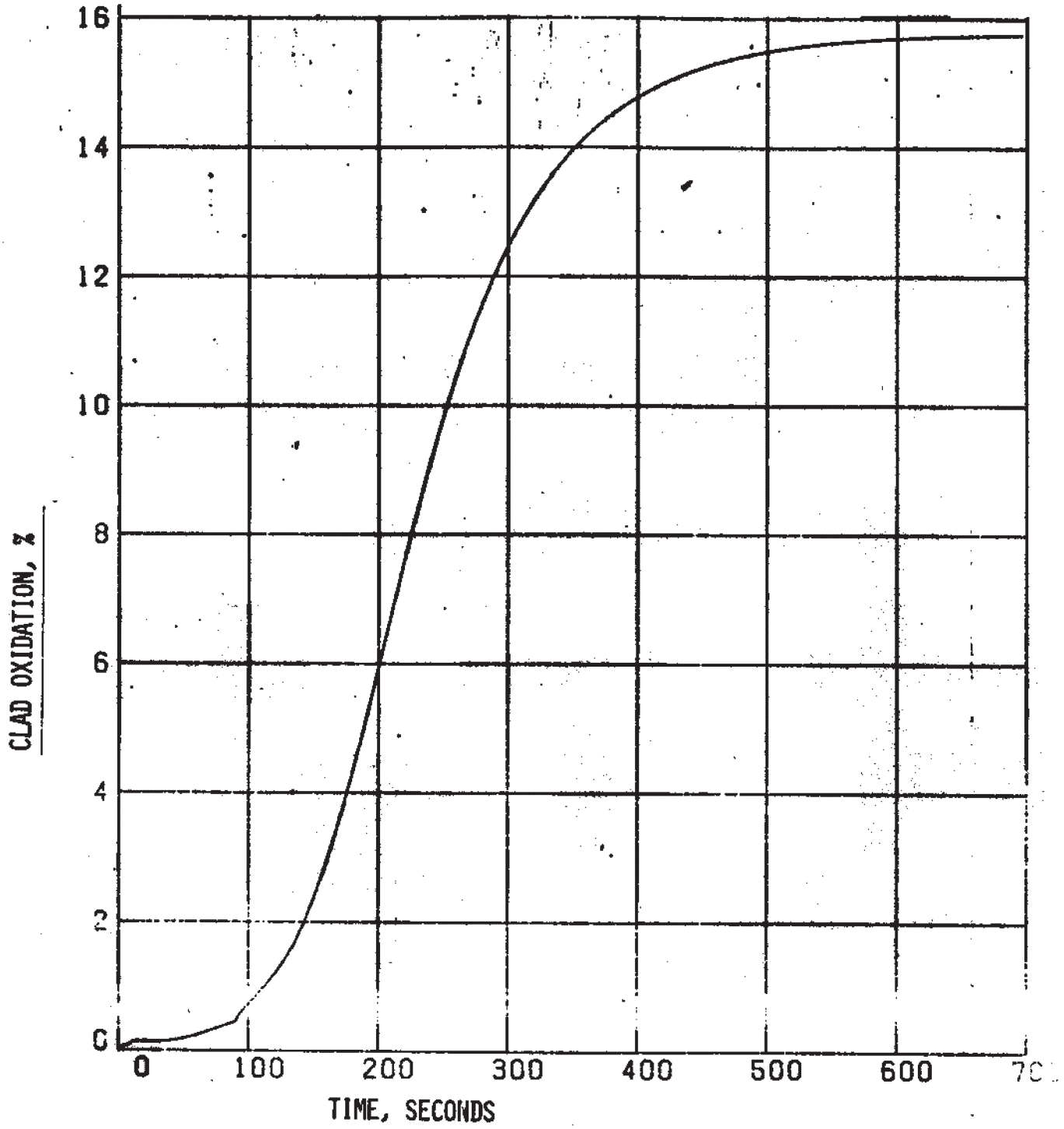
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT SPOT GAP CONDUCTANCE - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

CYCLE 1

FIGURE 6.3-9o



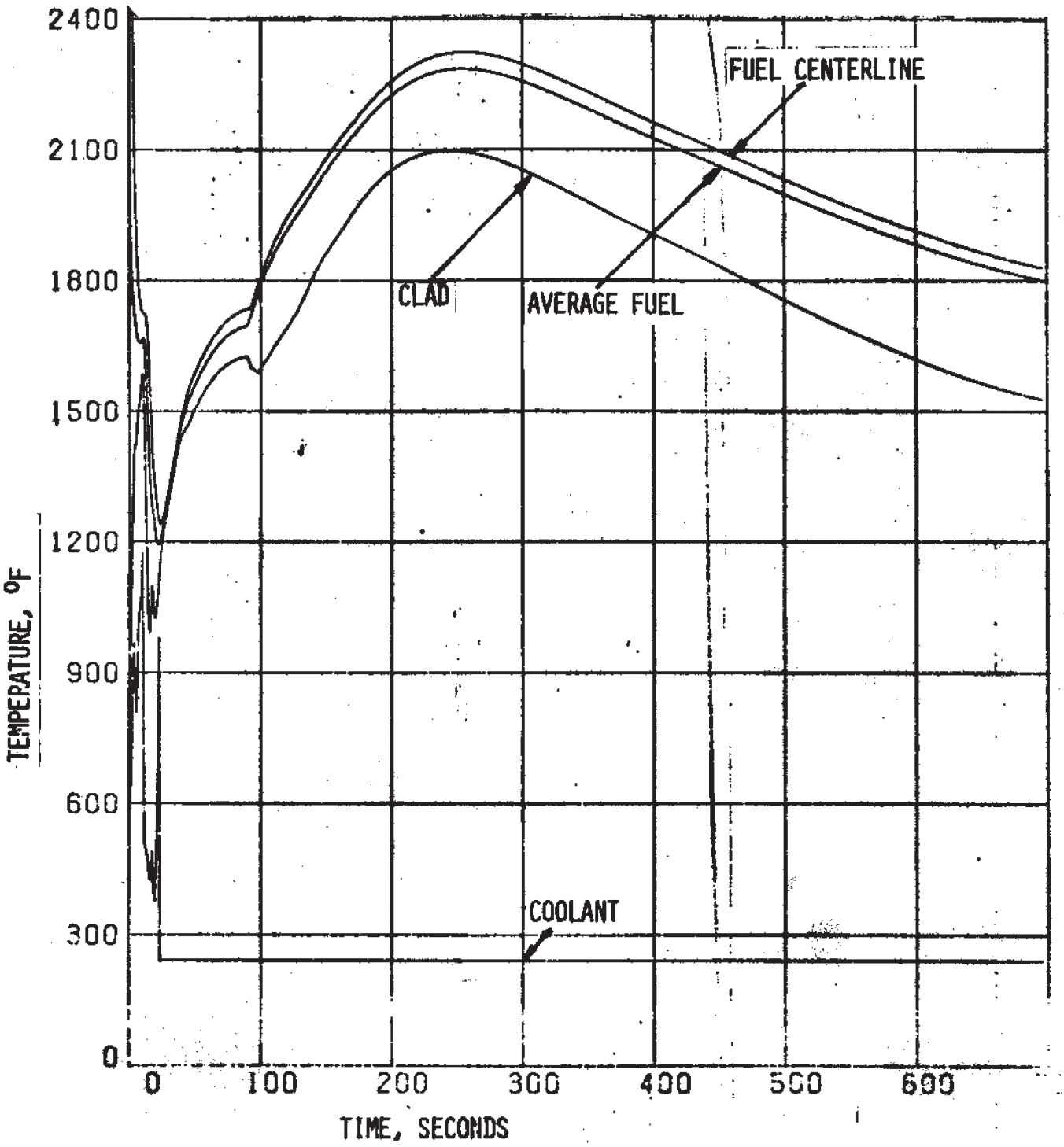
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LOCAL CLAD OXIDATION - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-9p

CYCLE 1

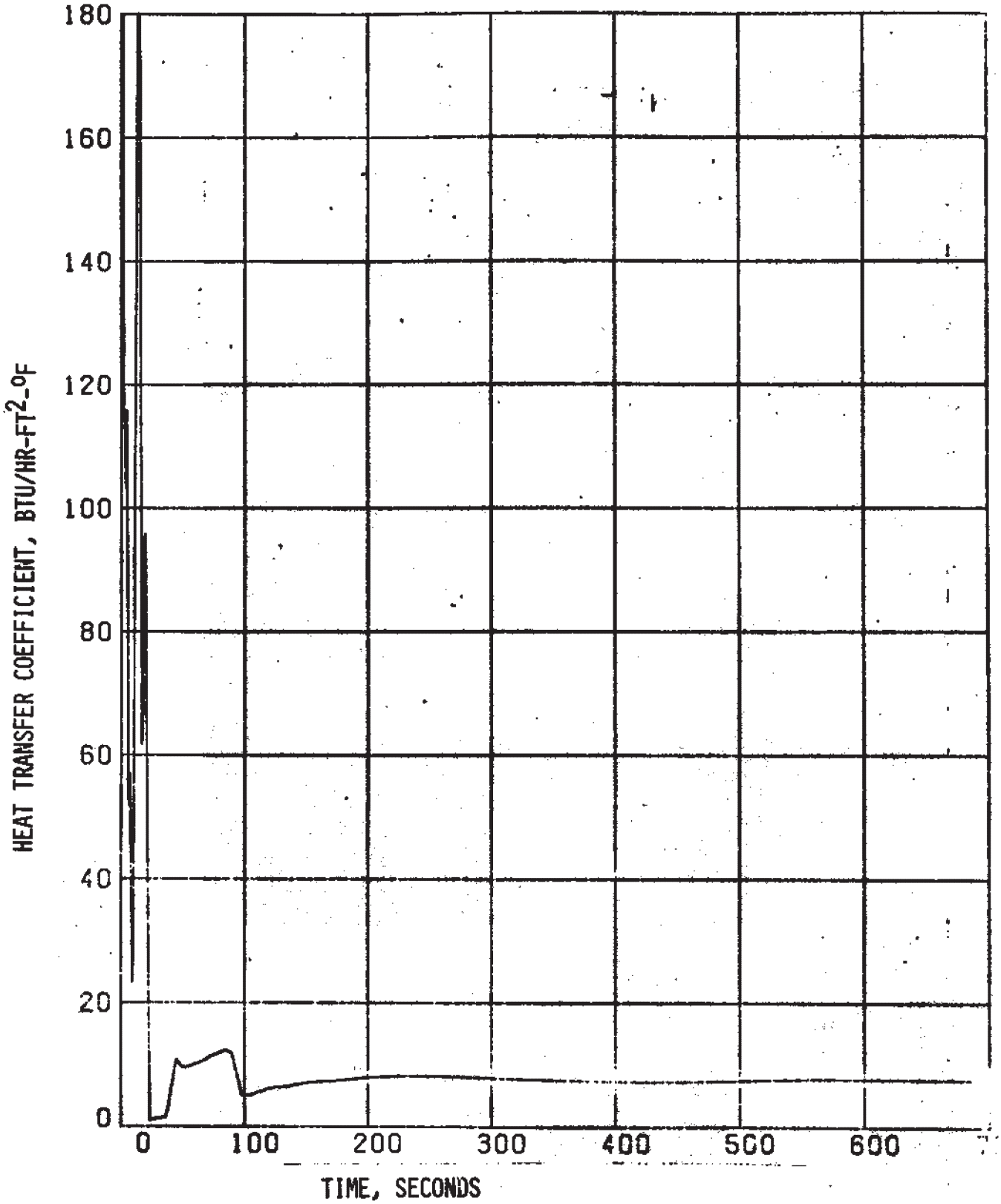


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CLAD, CENTERLINE, AVG. FUEL & COOL. TEMP. FOR HOTTEST NODE-1.0 X DOUBLE ENDED GUILL. BRK. IN PUMP DISCH. LEG
FIGURE 6.3–9q

CYCLE 1



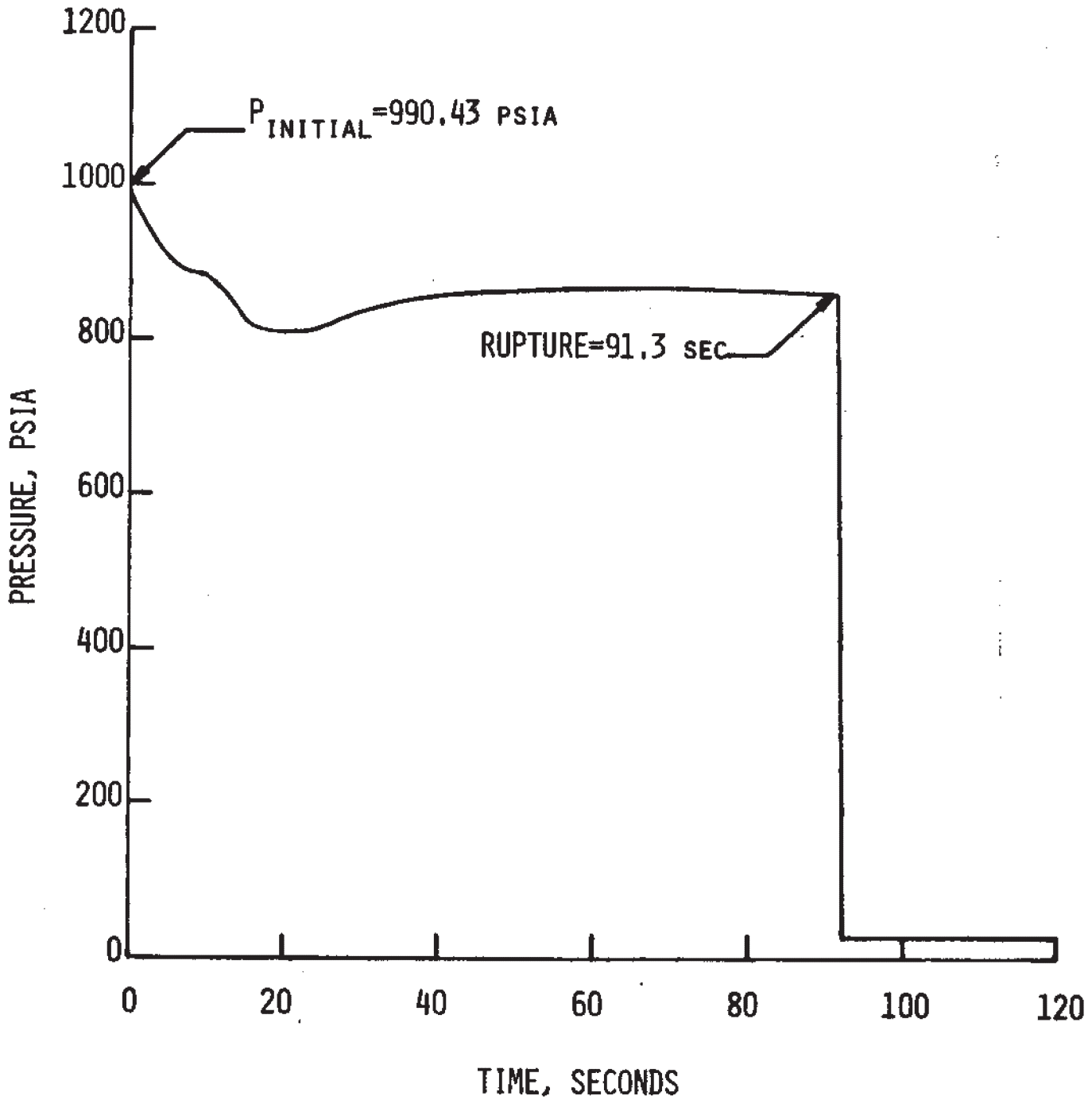
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT SPOT HEAT TRANSFER COEFFICIENT
1.0 X DOUBLE ENDED GUILLOTINE BREAK
IN PUMP DISCHARGE LEG

CYCLE 1

FIGURE 6.3-9r



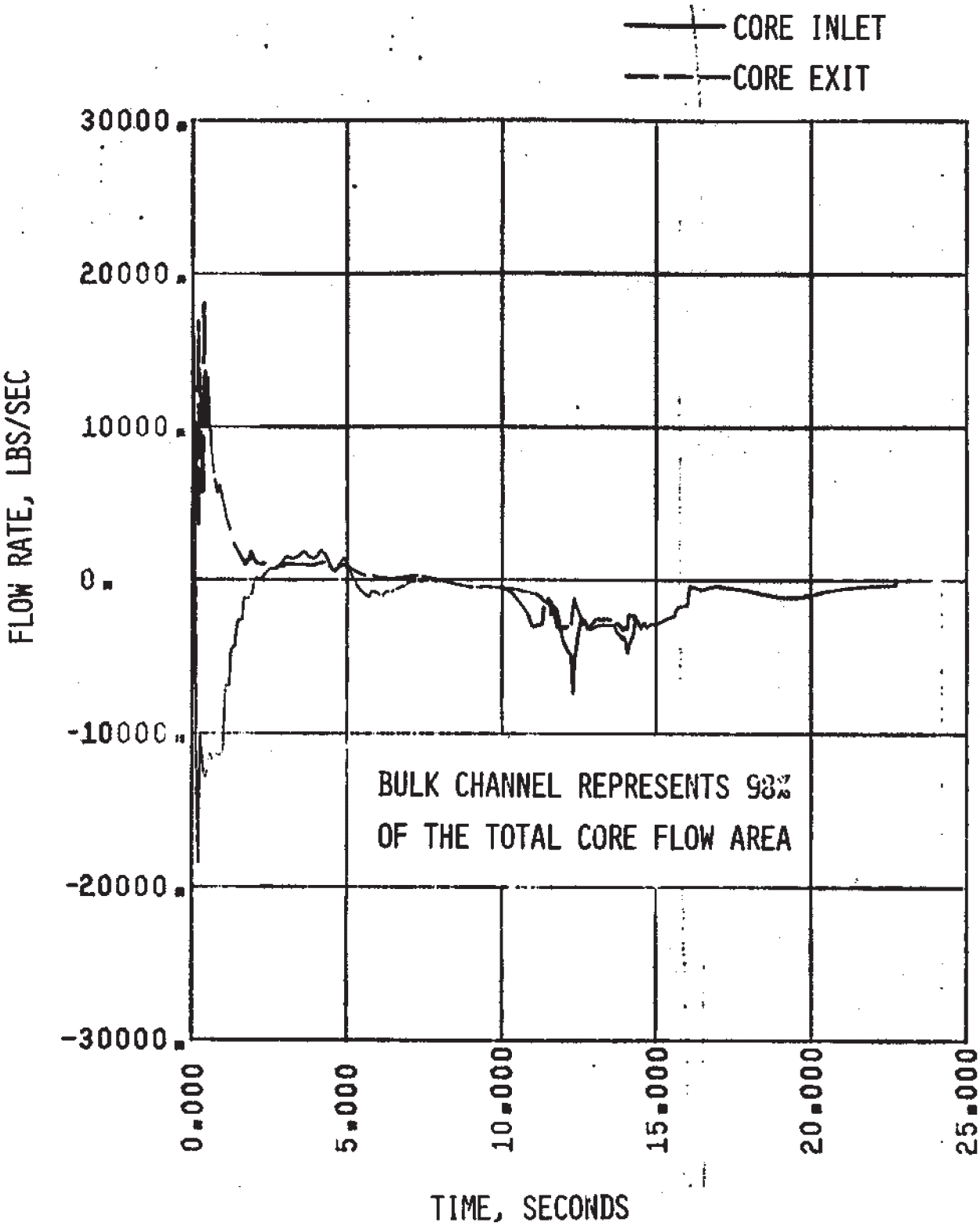
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT ROD INTERNAL GAS PRESSURE - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-9s

CYCLE 1



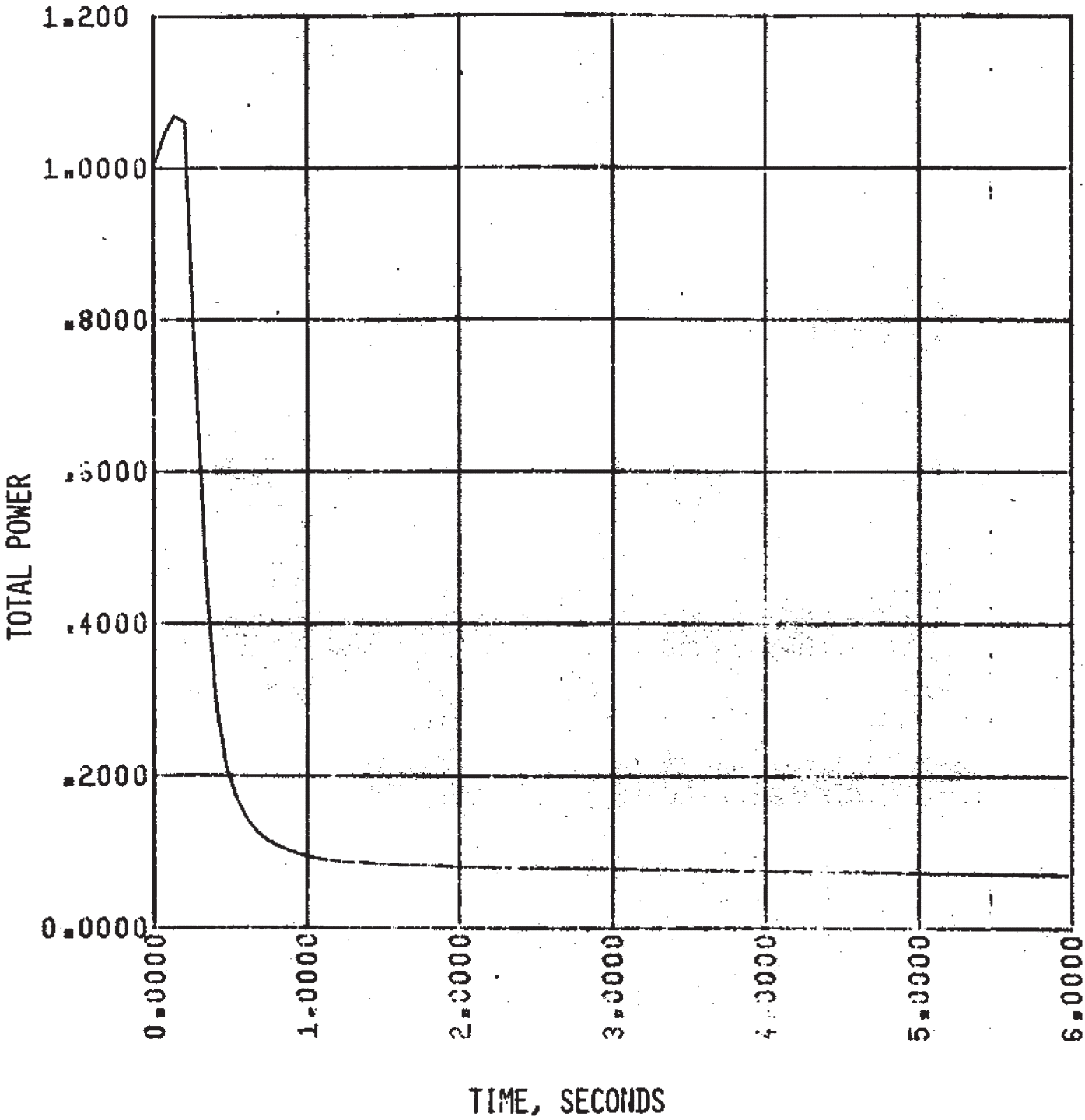
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE BULK CHANNEL FLOW RATE - 1.0 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–9t

CYCLE 1



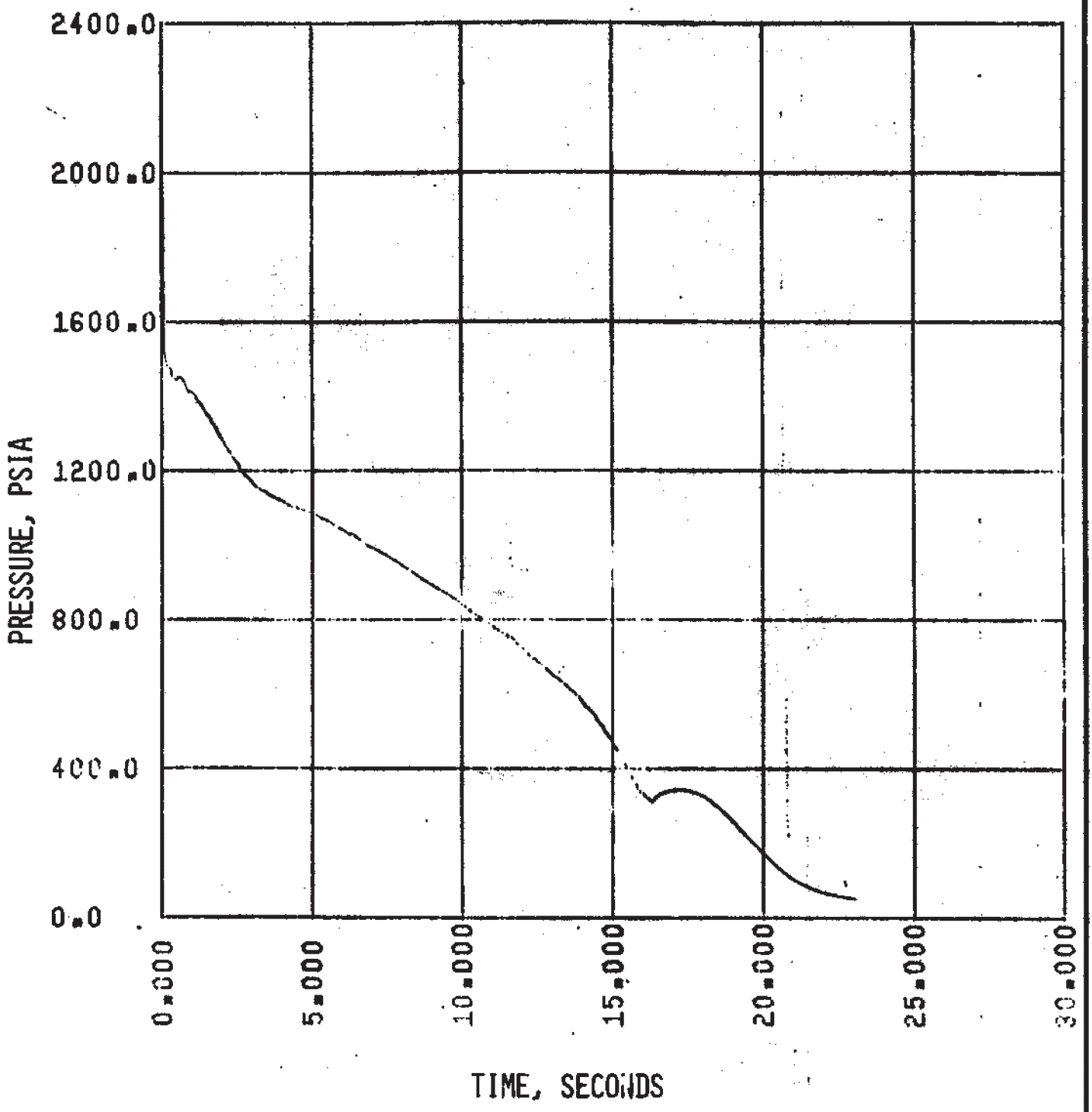
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE POWER - 0.8 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-10a

CYCLE 1



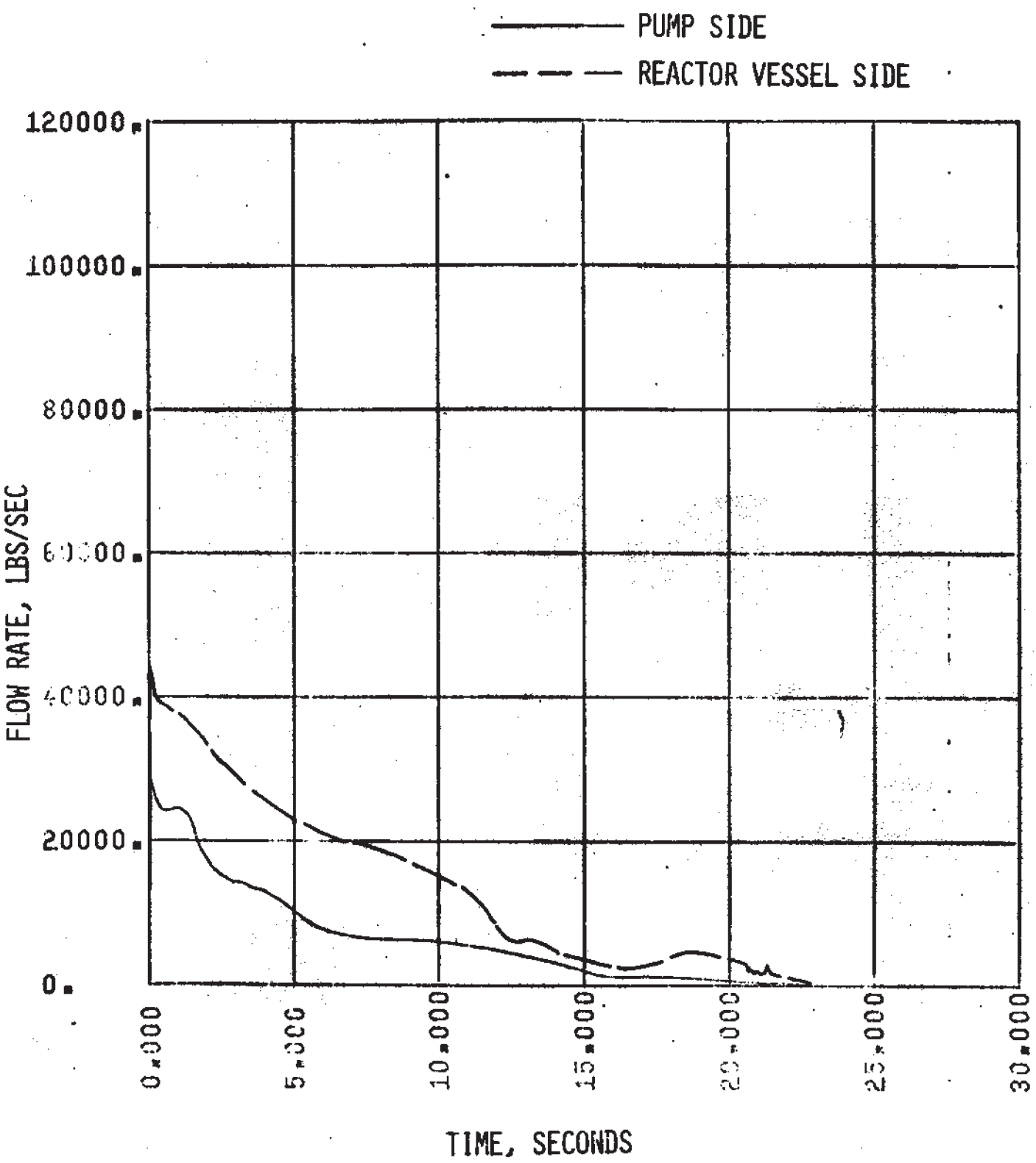
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PRESSURE IN CENTER HOT ASSEMBLY NODE - 0.8 X DOUBLE ENDED GUILLOTINE BRK. IN PUMP DISCH. LEG

FIGURE 6.3–10b

CYCLE 1



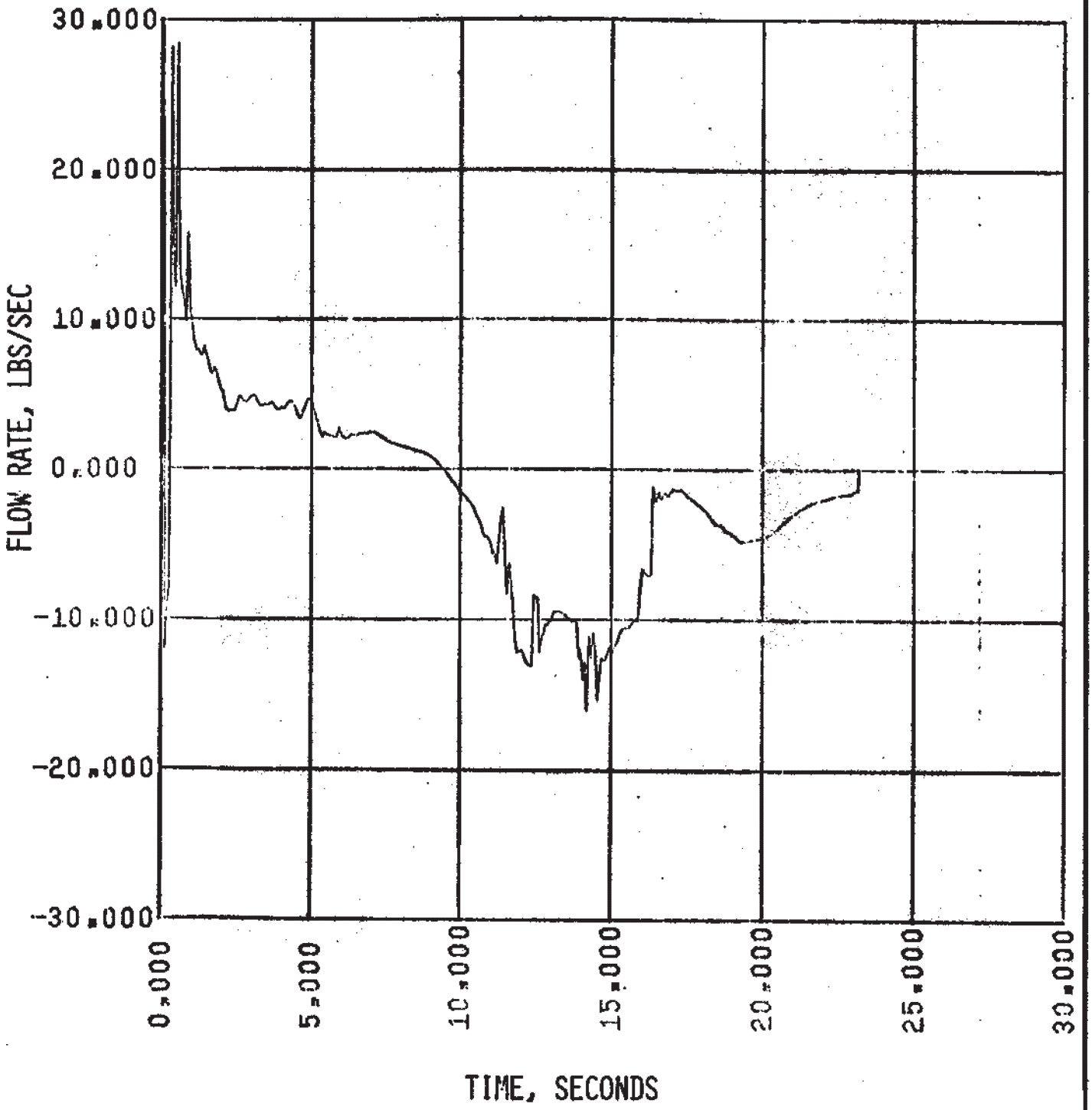
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LEAK FLOW - 0.8 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

CYCLE 1

FIGURE 6.3–10c



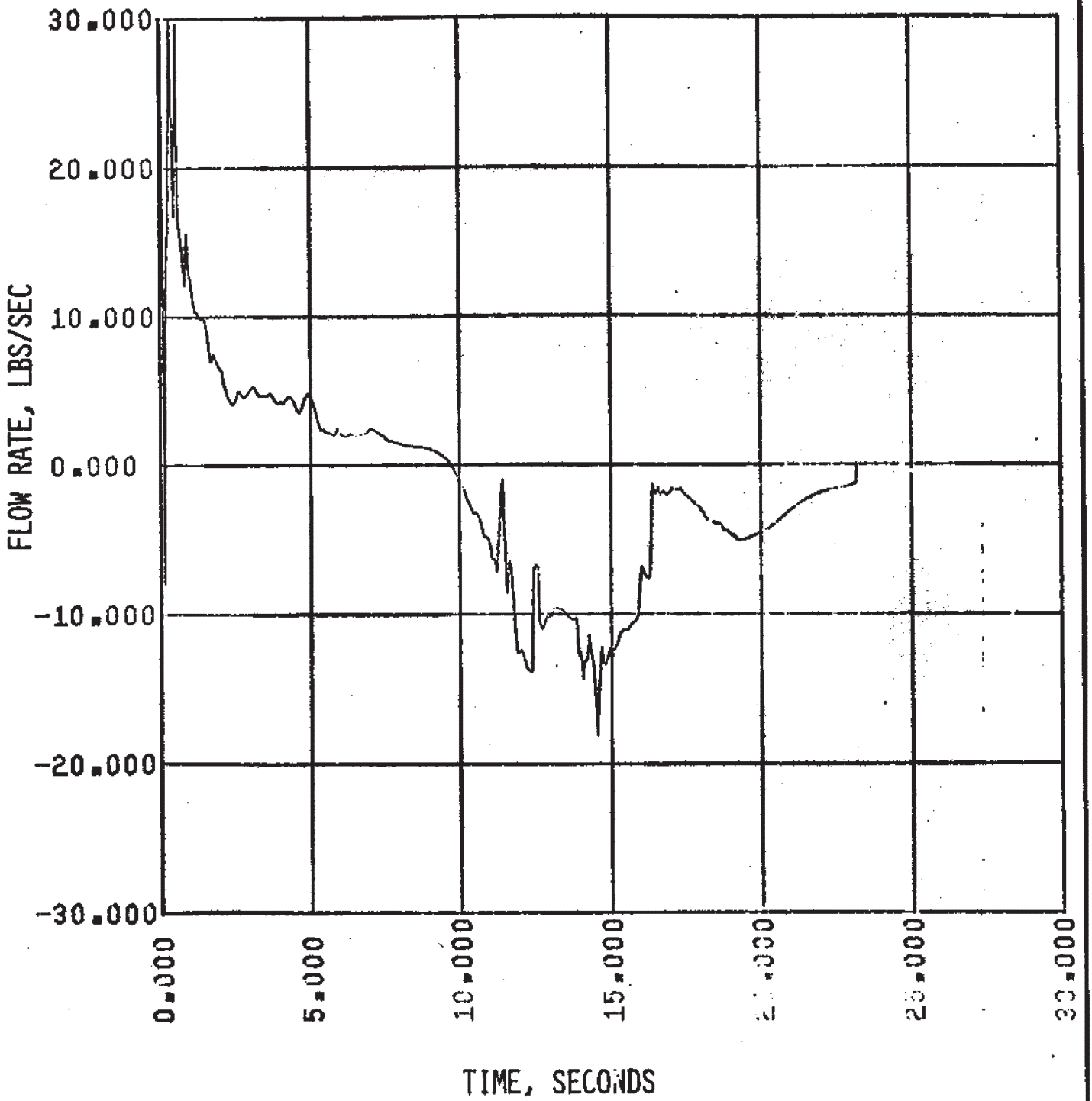
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 16, BELOW HOT SPOT - 0.8 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCH. LEG

FIGURE 6.3-10d

CYCLE 1



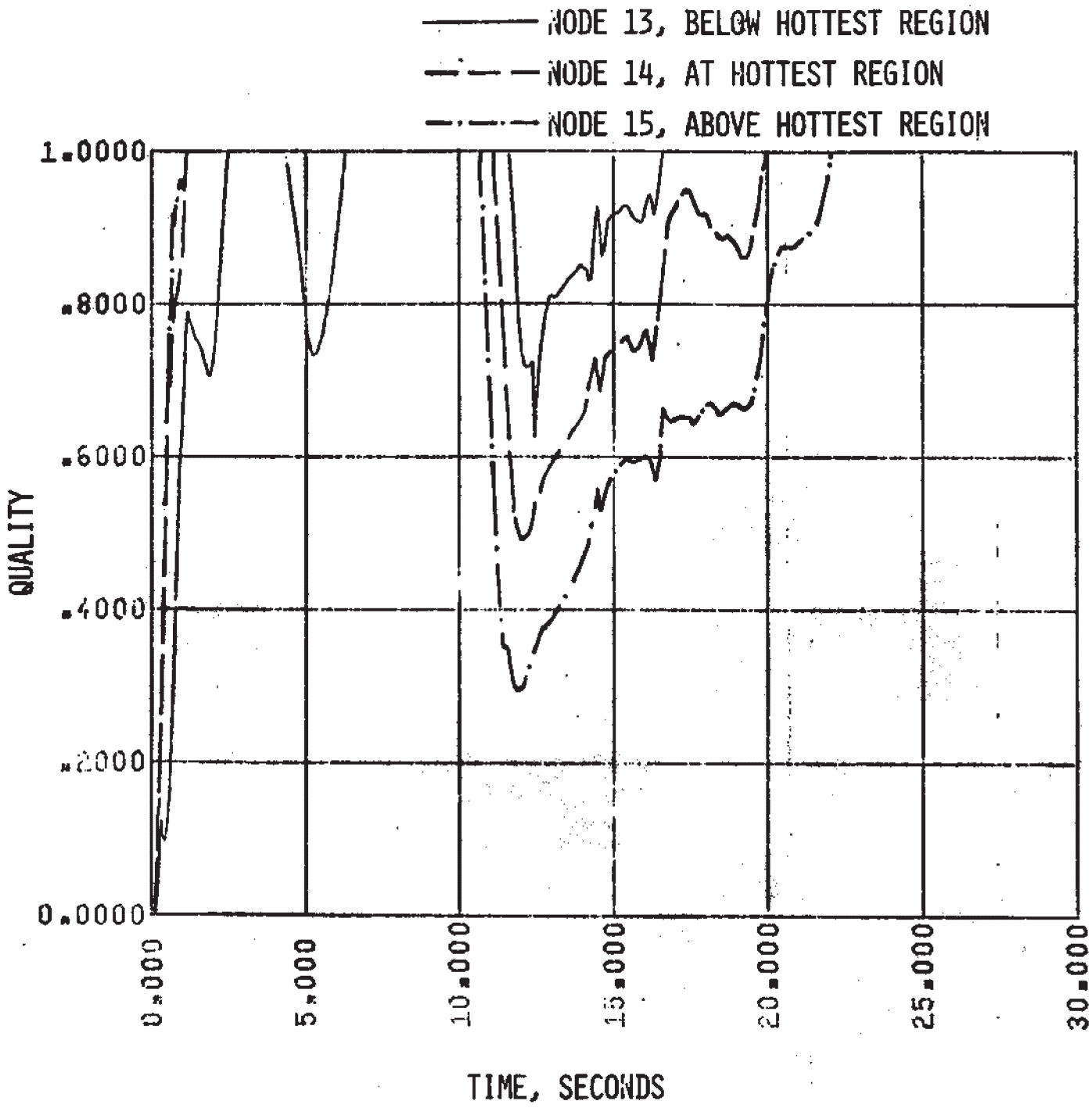
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 17, ABOVE HOT SPOT - 0.8 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCH. LEG

CYCLE 1

FIGURE 6.3-10e



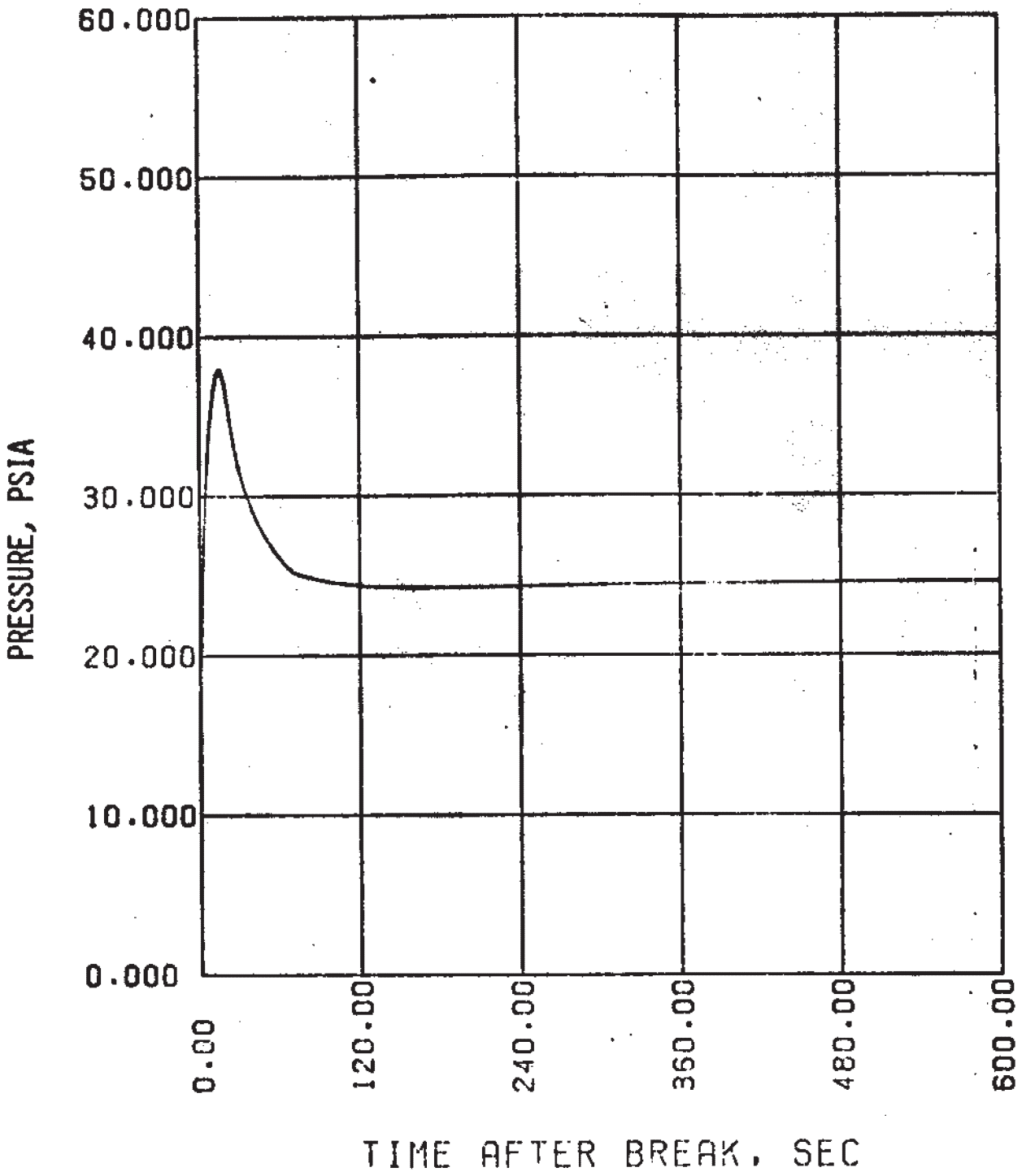
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT ASSEMBLY QUALITY - 0.8 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-10f

CYCLE 1



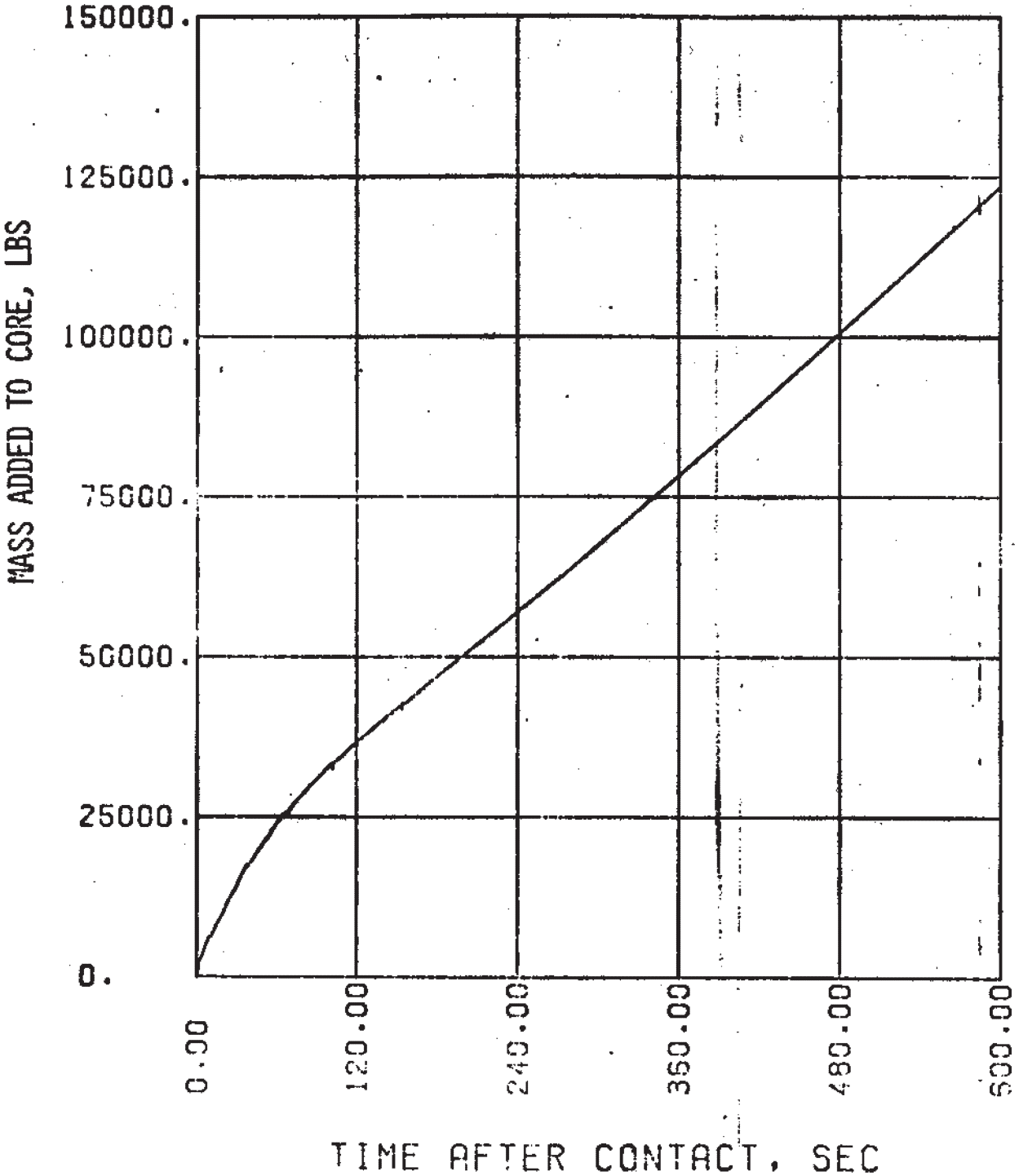
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CONTAINMENT PRESSURE - 0.8 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–10g

CYCLE 1

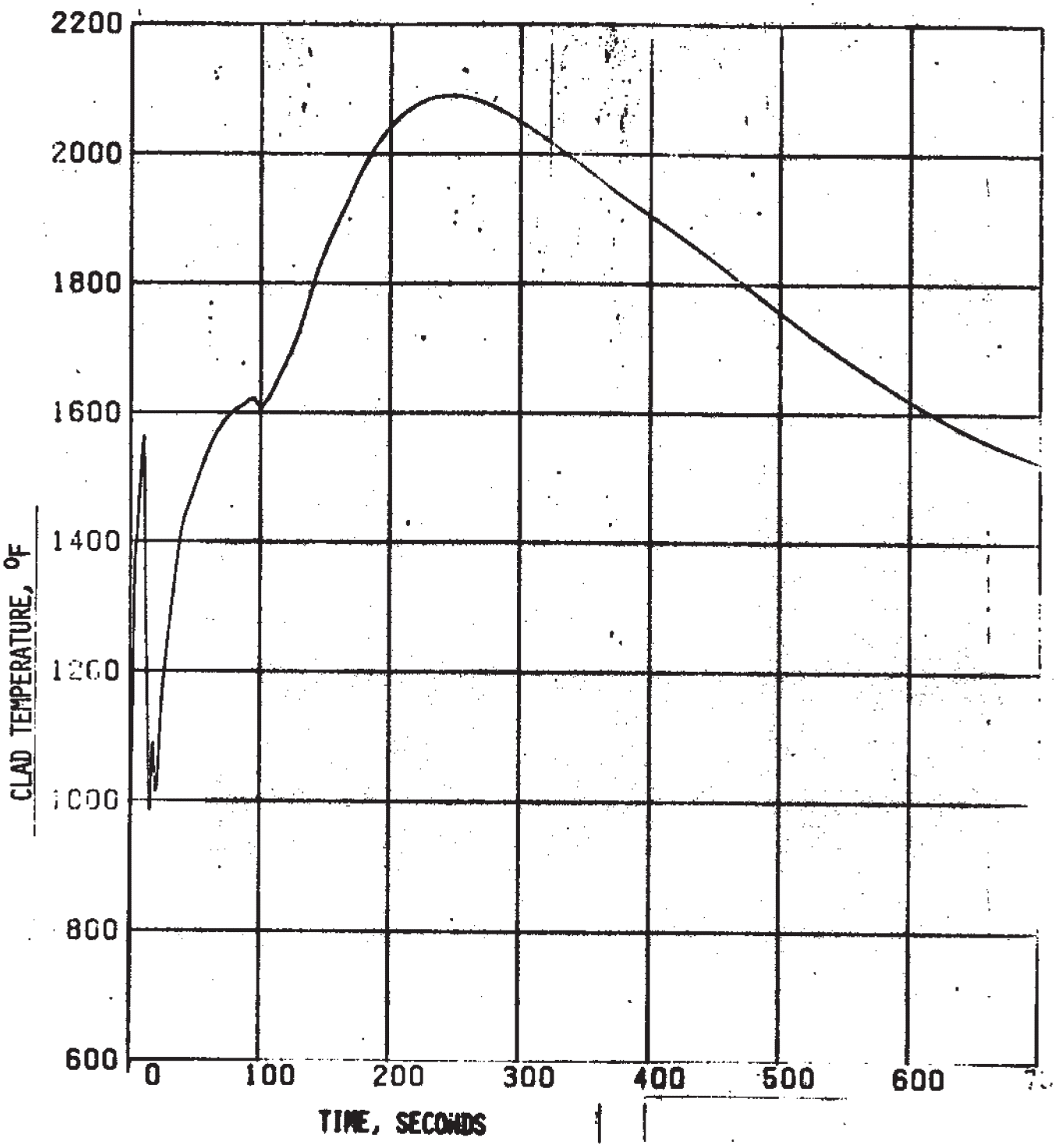


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

MASS ADDED TO CORE DURING REFLOOD
0.8 X DOUBLE ENDED GUILLOTINE BREAK
IN PUMP DISCHARGE LEG
FIGURE 6.3–10h

CYCLE 1



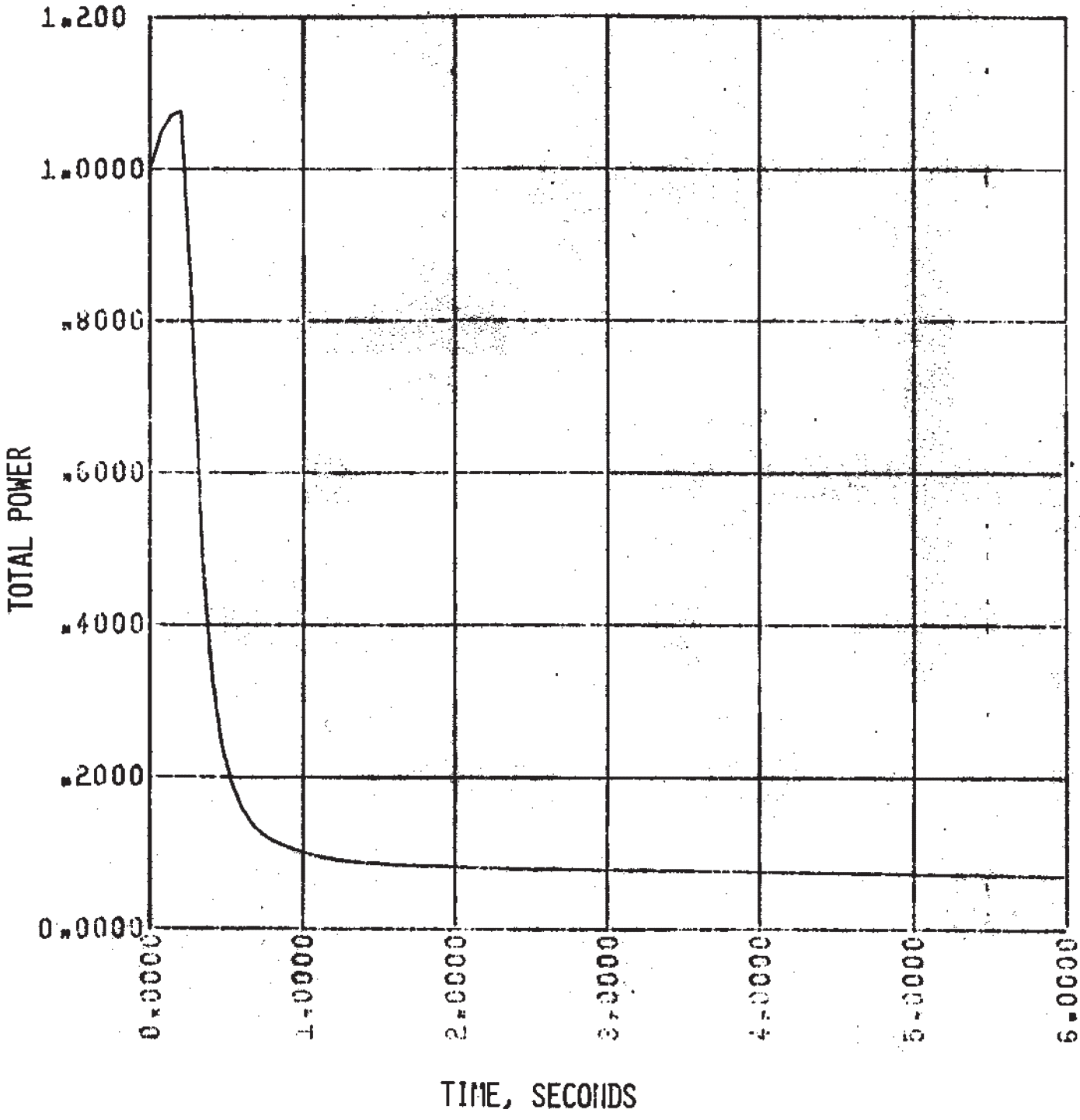
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PEAK CLAD TEMP. - 0.8 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3-10i

CYCLE 1



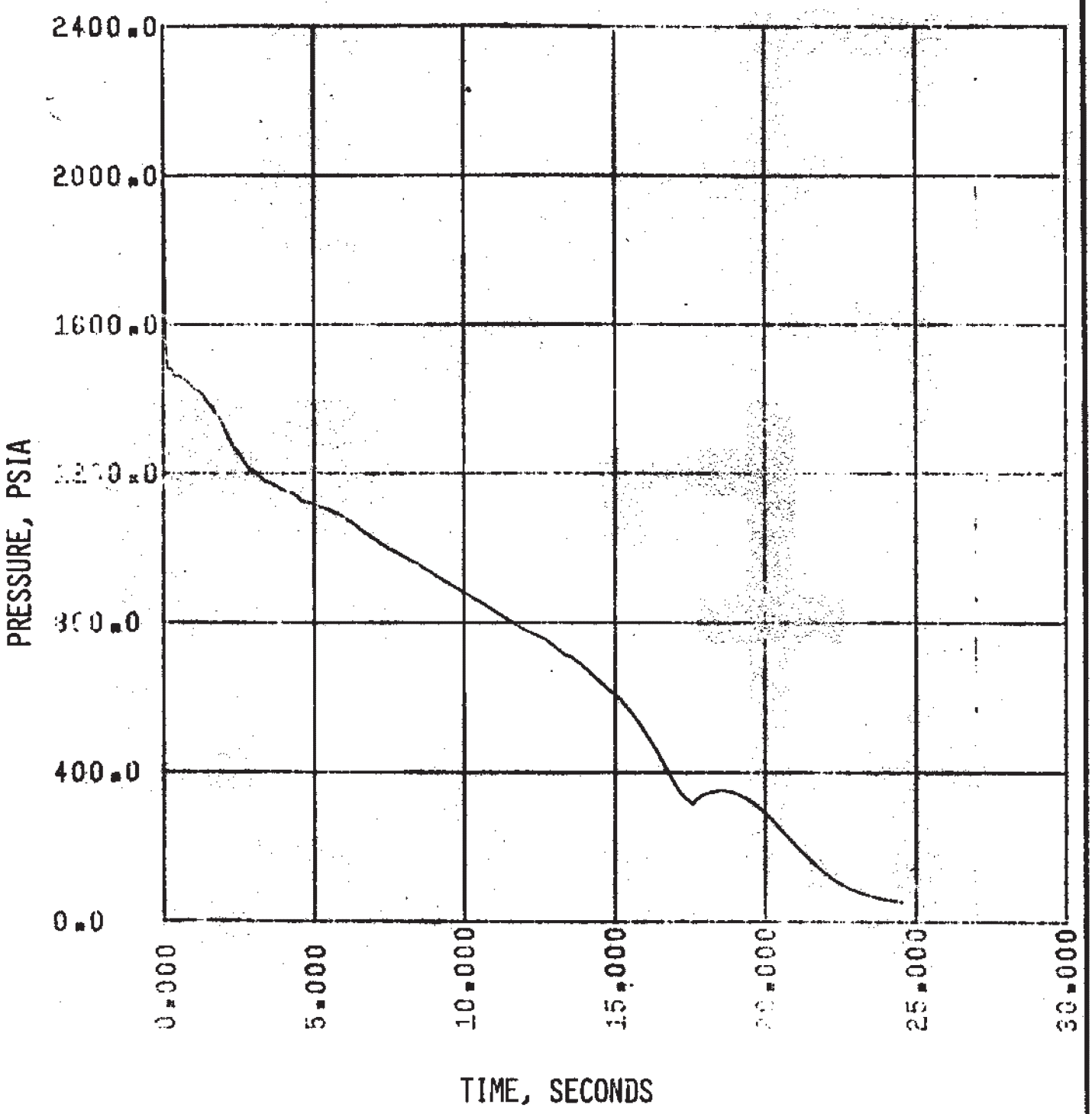
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE POWER - 0.6 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–11a

CYCLE 1

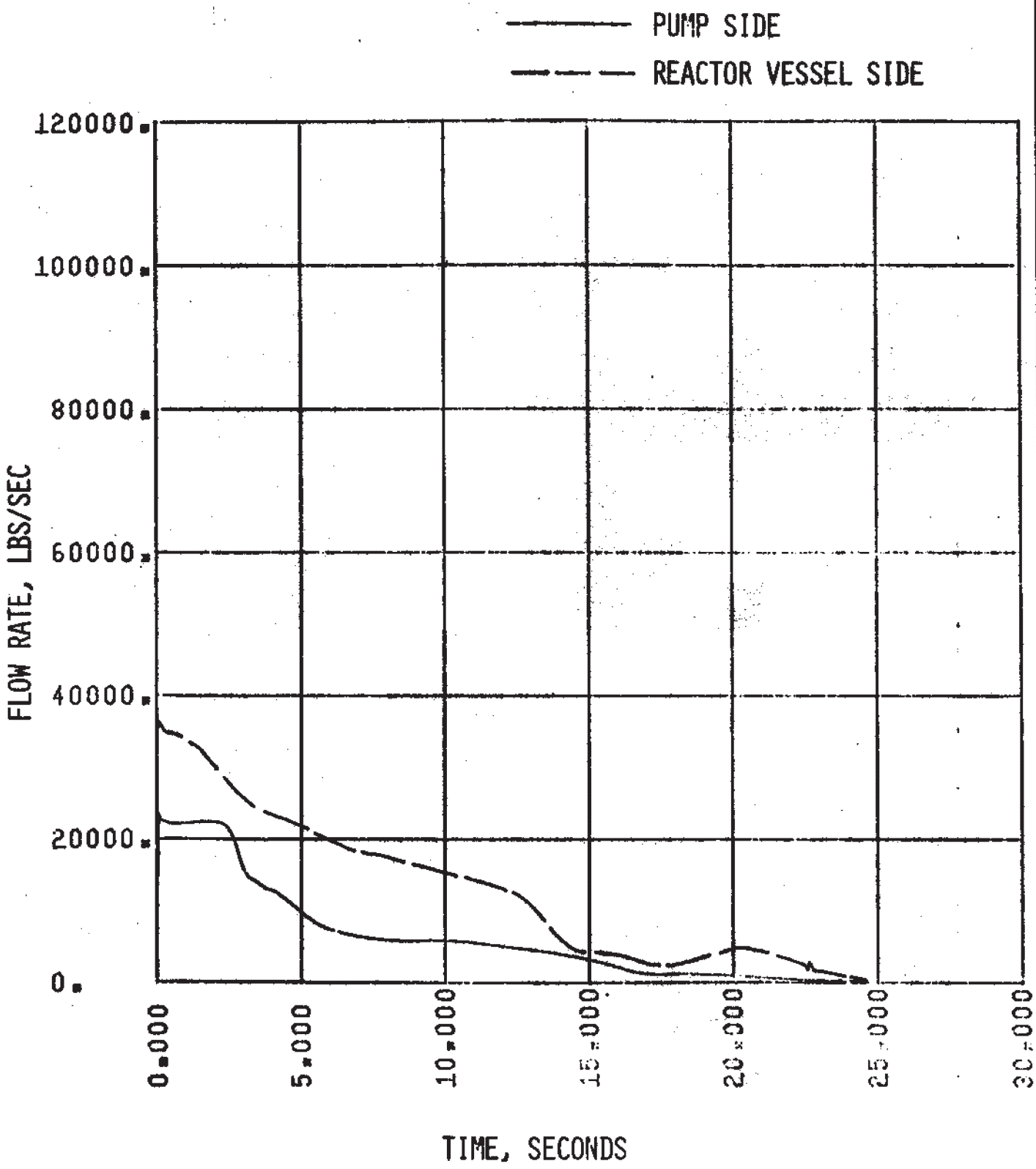


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PRESSURE IN CENTER HOT ASSEMBLY NODE-0.6X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–11b

CYCLE 1

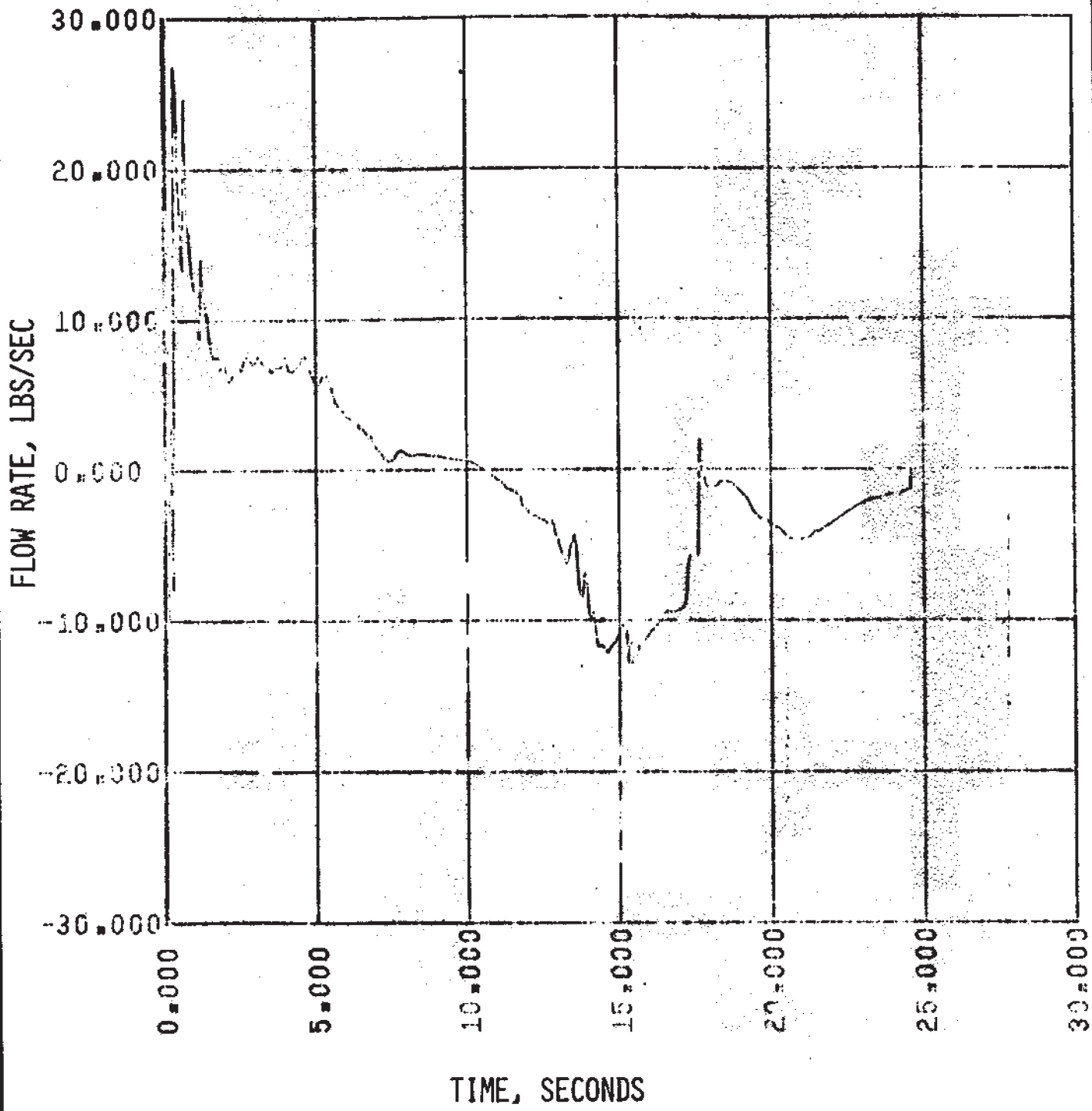


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LEAK FLOW - 0.6 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3-11c

CYCLE 1



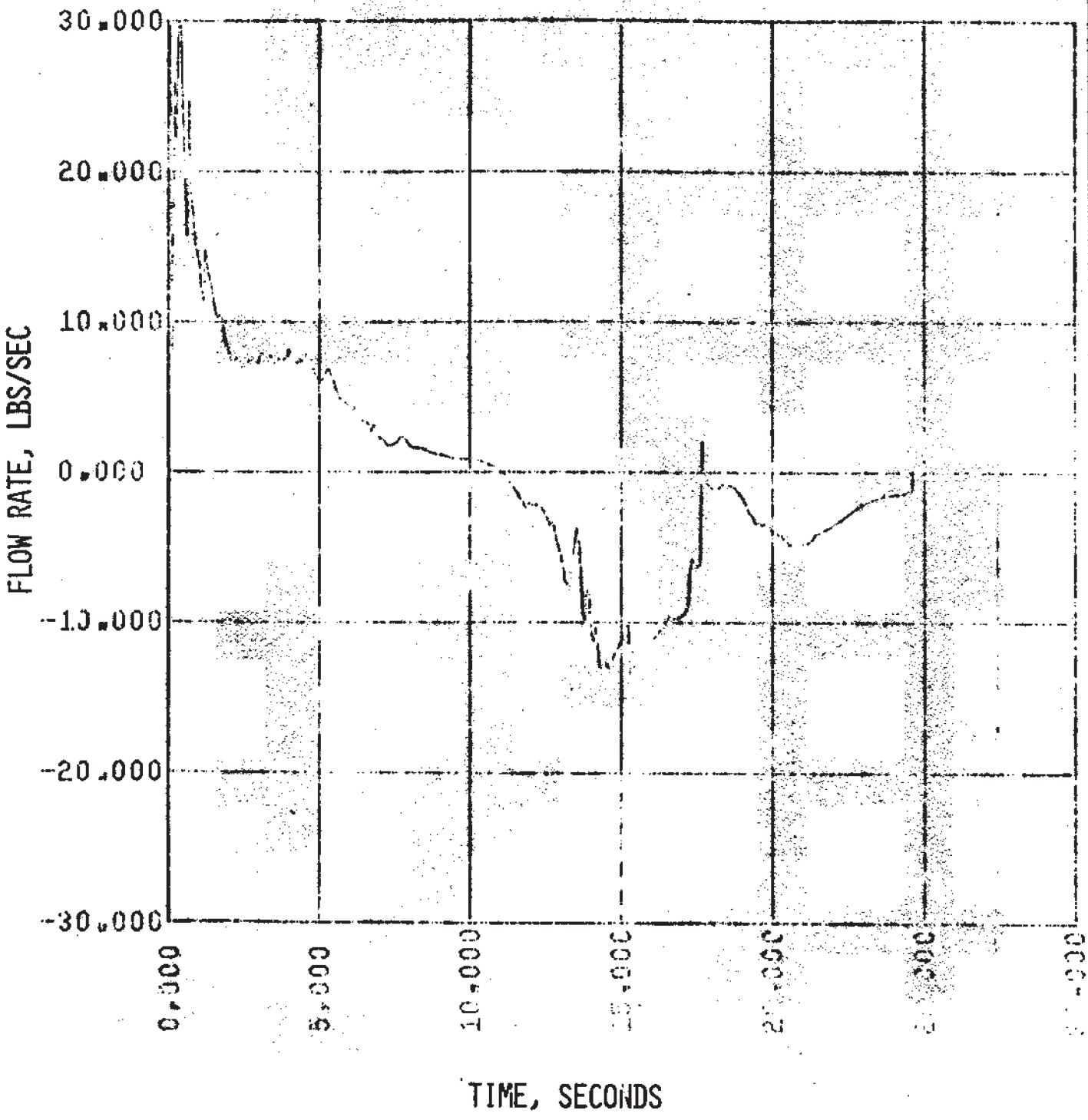
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 16, BELOW HOT SPOT - 0.6 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCH. LEG

FIGURE 6.3–11d

CYCLE 1



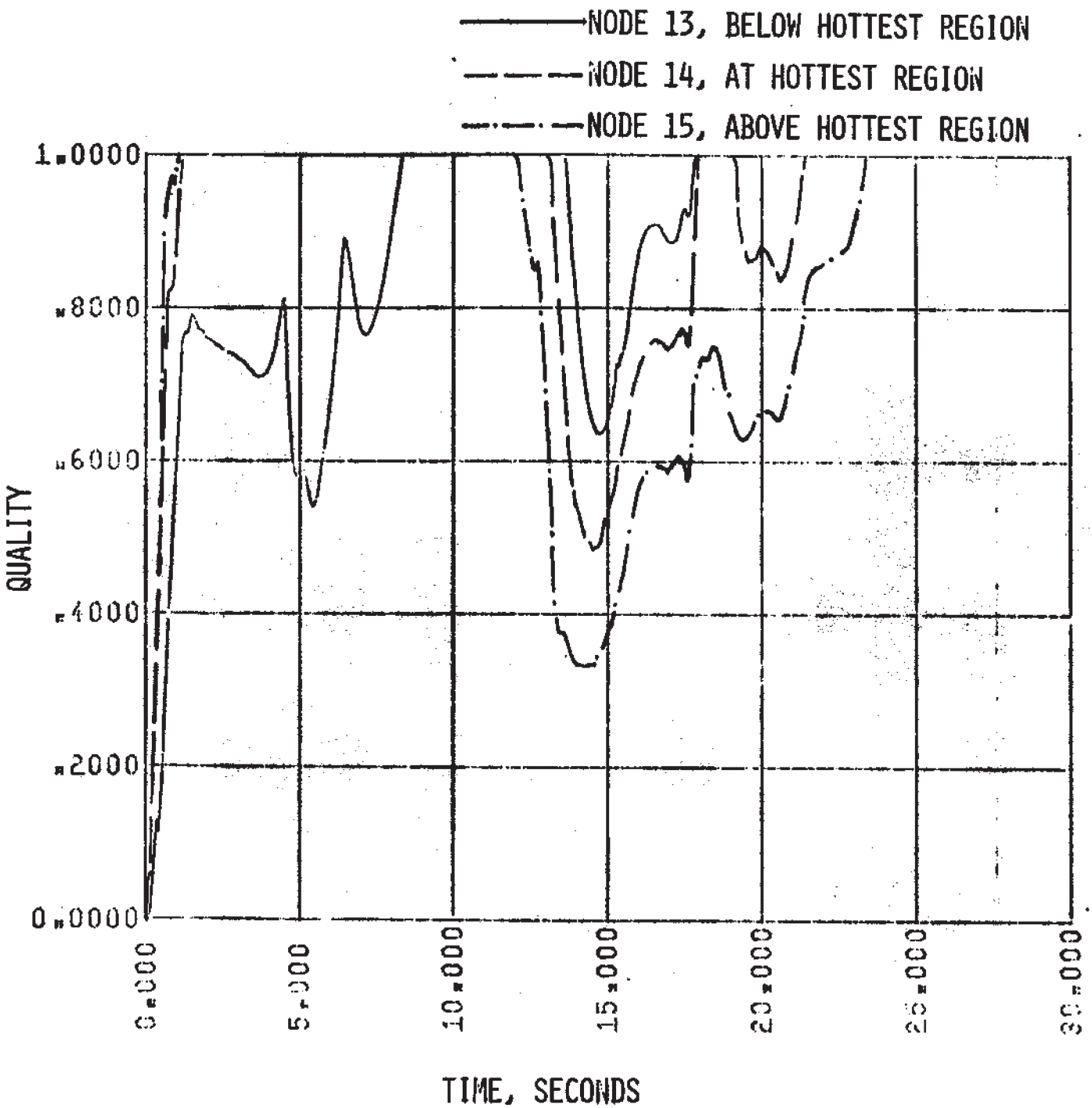
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FLOW IN HOT ASSEMBLY-PATH 17, ABOVE HOT SPOT - 0.6 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCH. LEG

CYCLE 1

FIGURE 6.3–11e



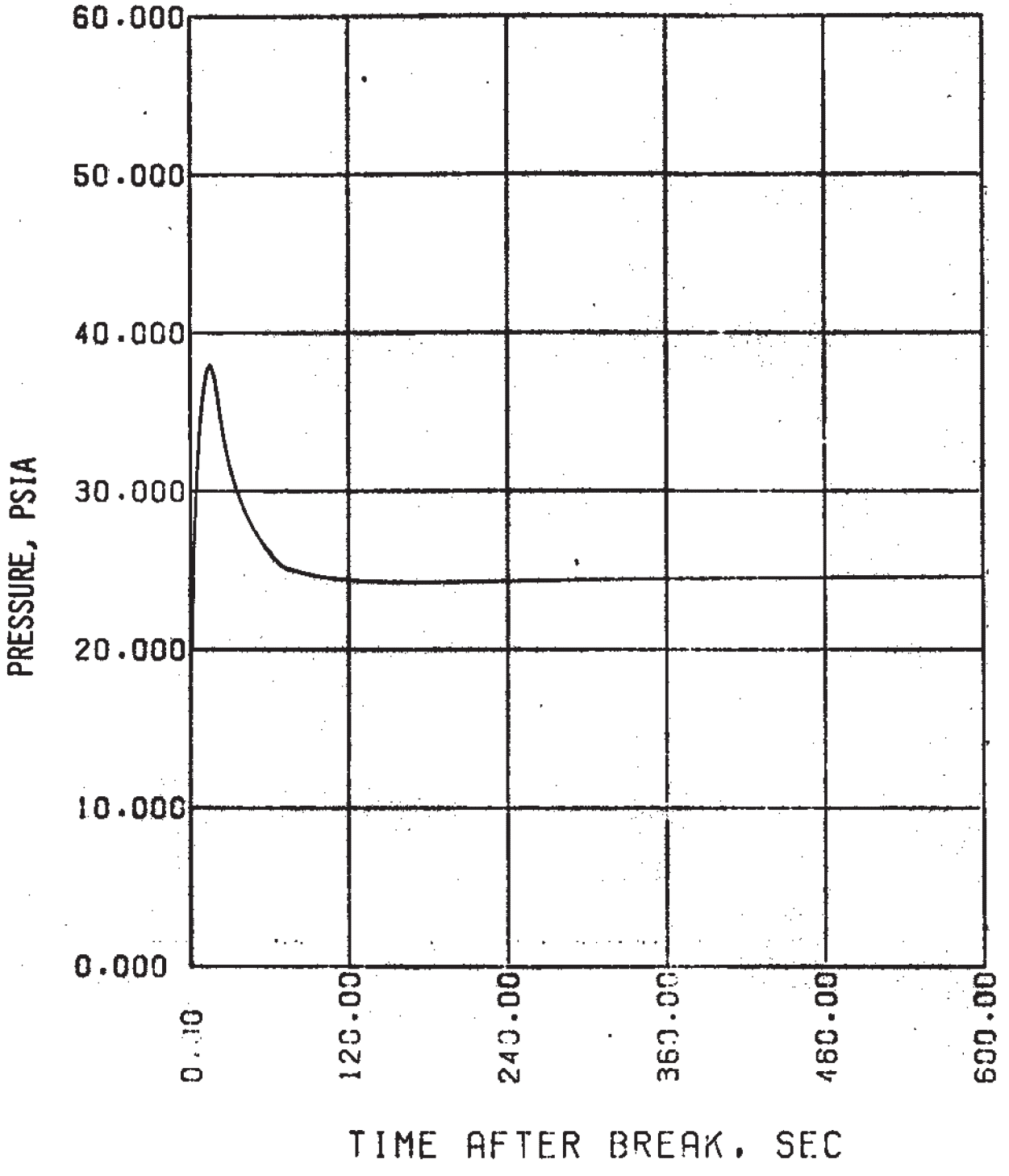
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT ASSEMBLY QUALITY - 0.6 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

CYCLE 1

FIGURE 6.3-11f



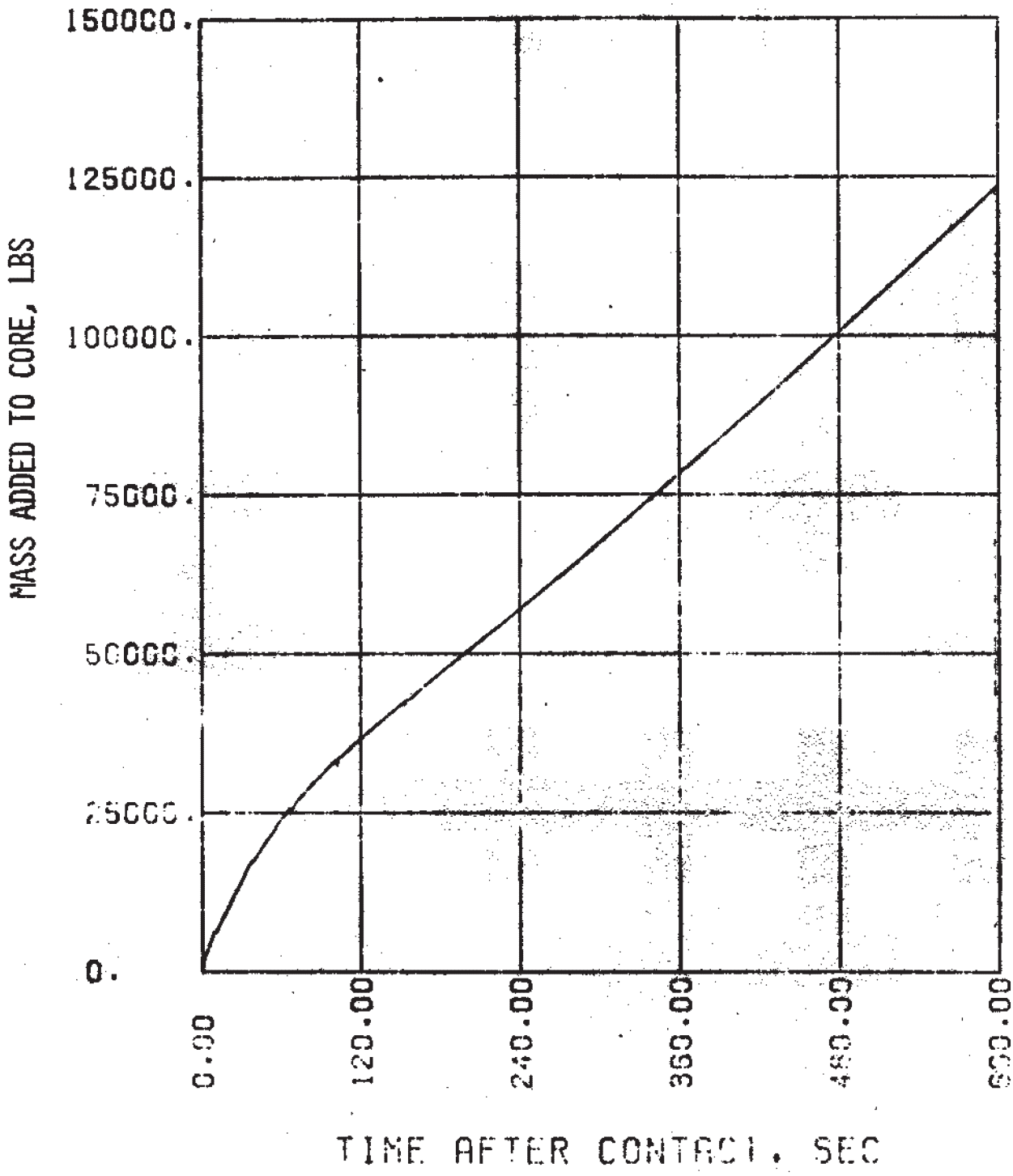
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CONTAINMENT PRESSURE - 0.6 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

CYCLE 1

FIGURE 6.3–11g



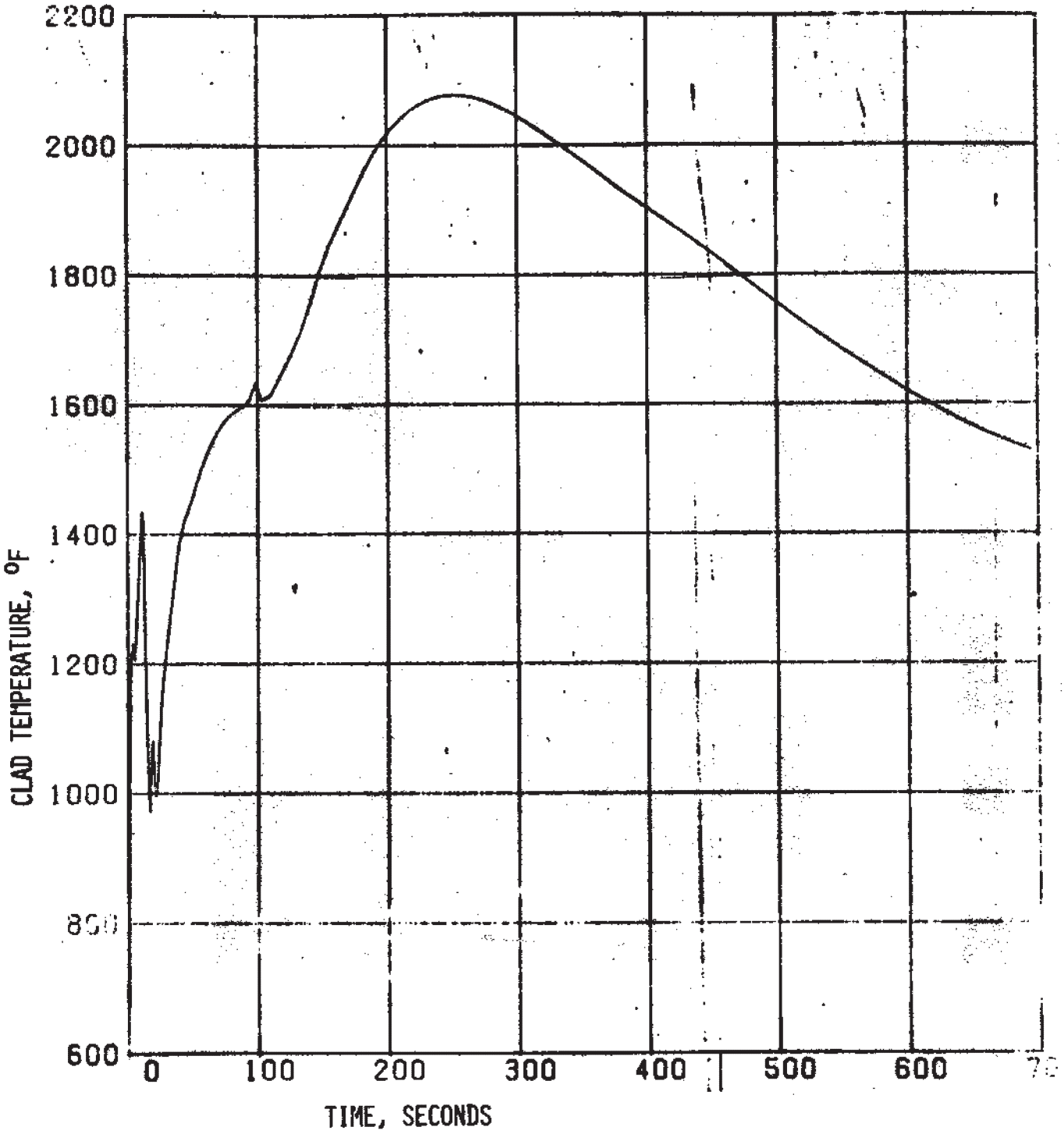
AMENDMENT NO. 1 (4/88)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

MASS ADDED TO CORE DURING REFLOOD
0.6 X DOUBLE ENDED GUILLOTINE BREAK
IN PUMP DISCHARGE LEG

CYCLE 1

FIGURE 6.3-11h



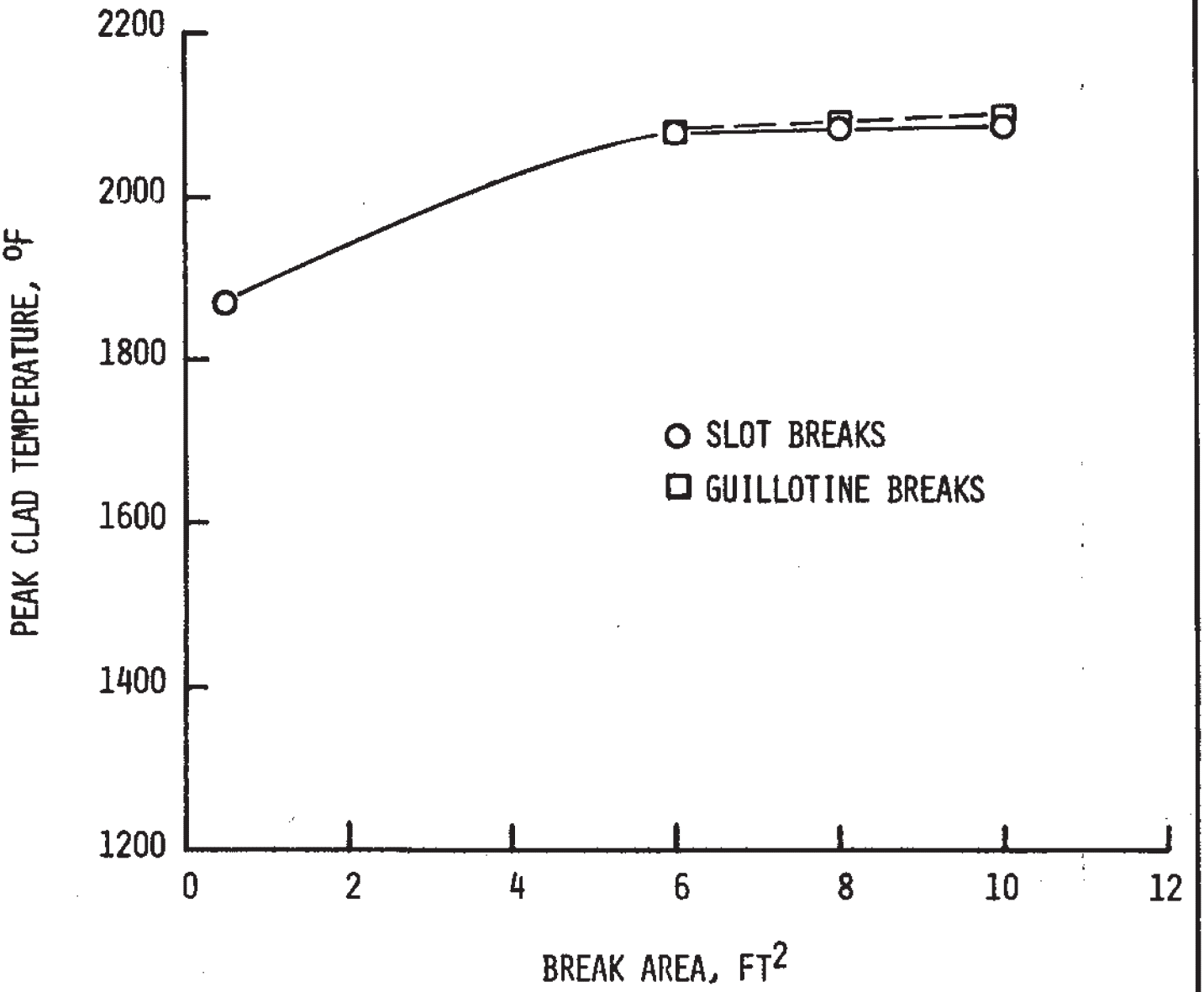
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PEAK CLAD TEMP -0.6 X DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–11i

CYCLE 1

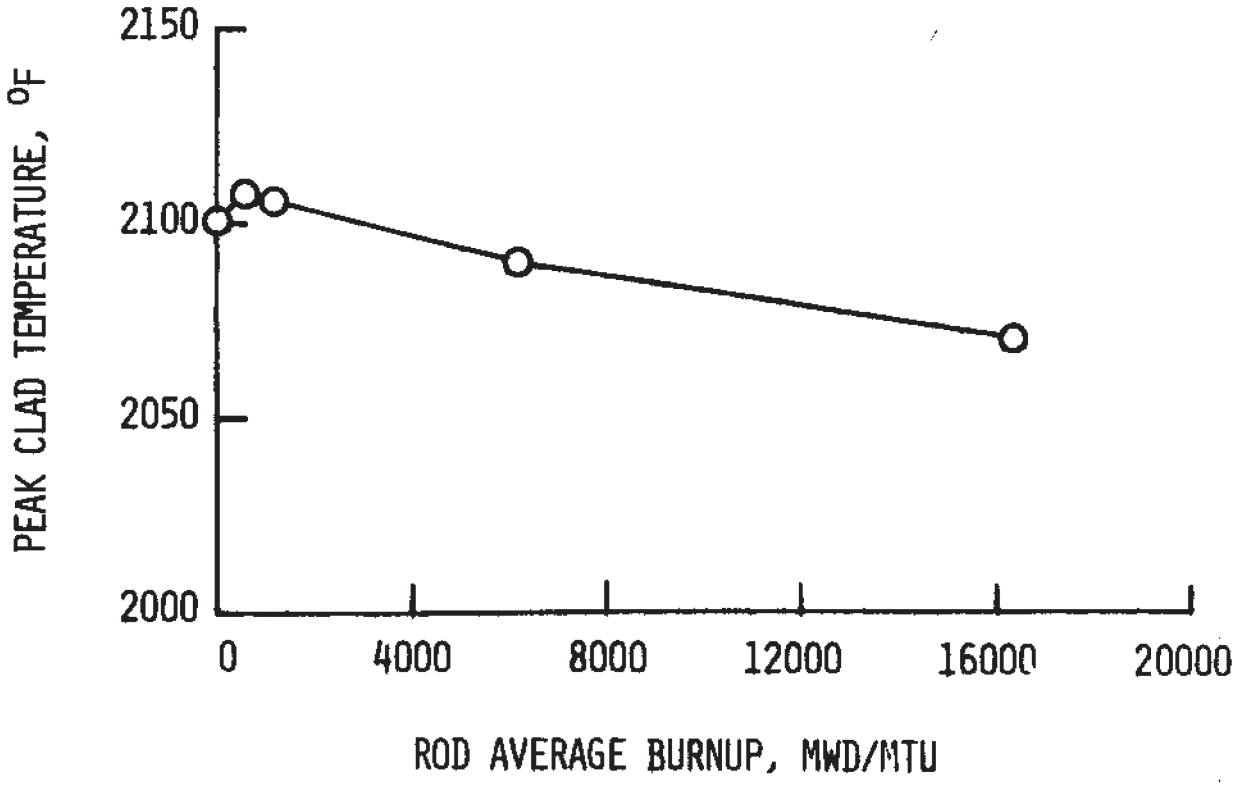


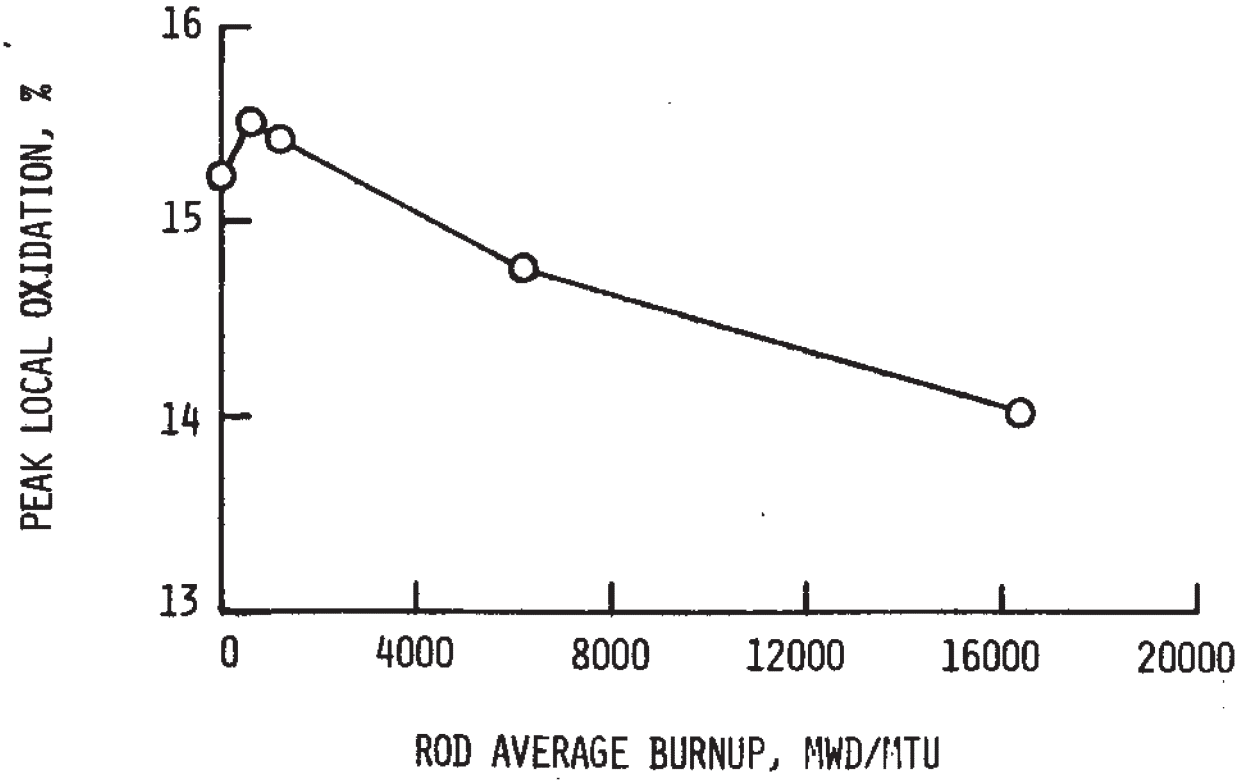
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PEAK CLAD TEMPERATURE
VS BREAK AREA
FIGURE 6.3–12

CYCLE 1





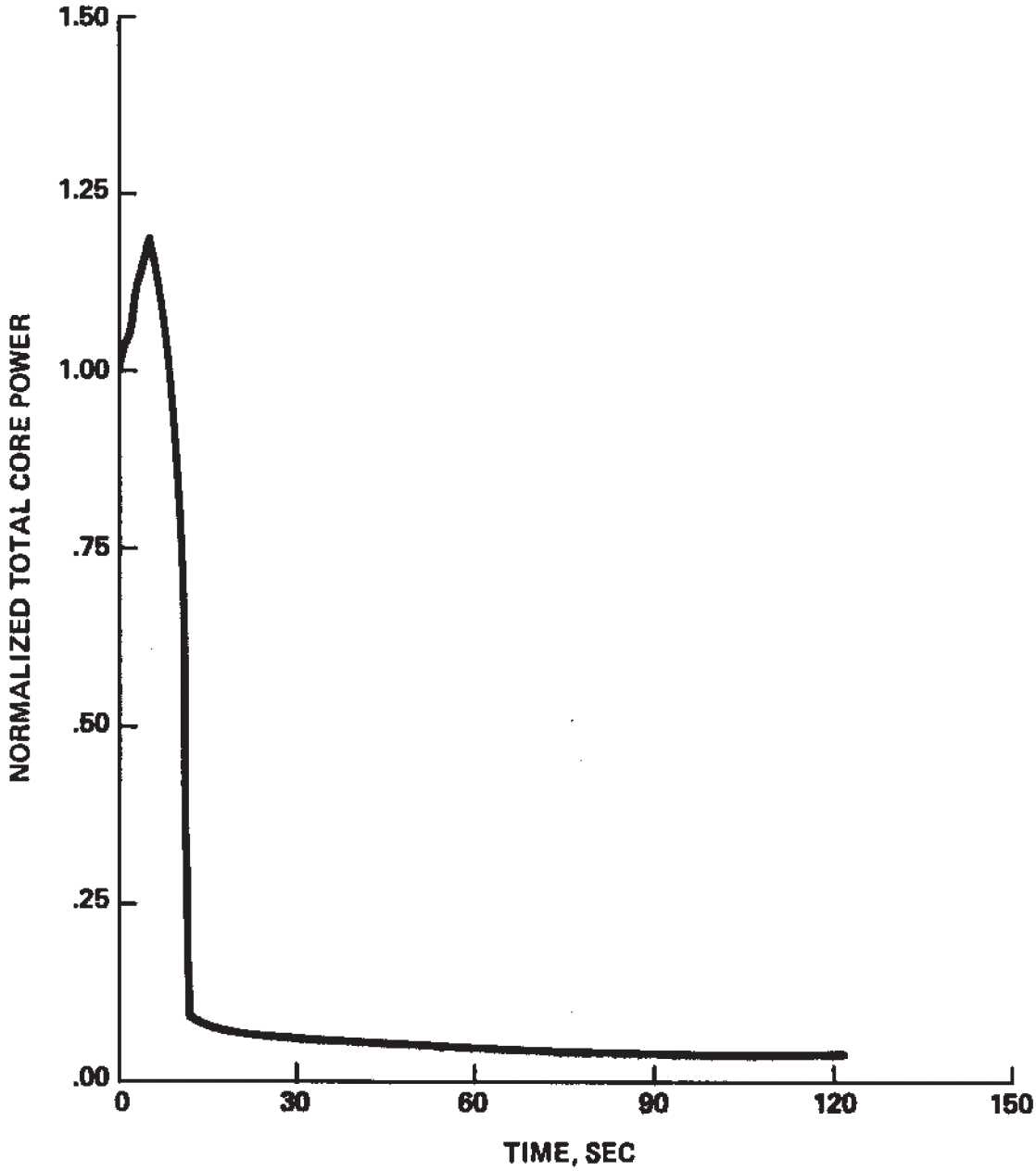
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PEAK CLAD TEMP AND PEAK LOCAL OXID VS ROD AVERAGE BURNUP

FIGURE 6.3-13

CYCLE 1

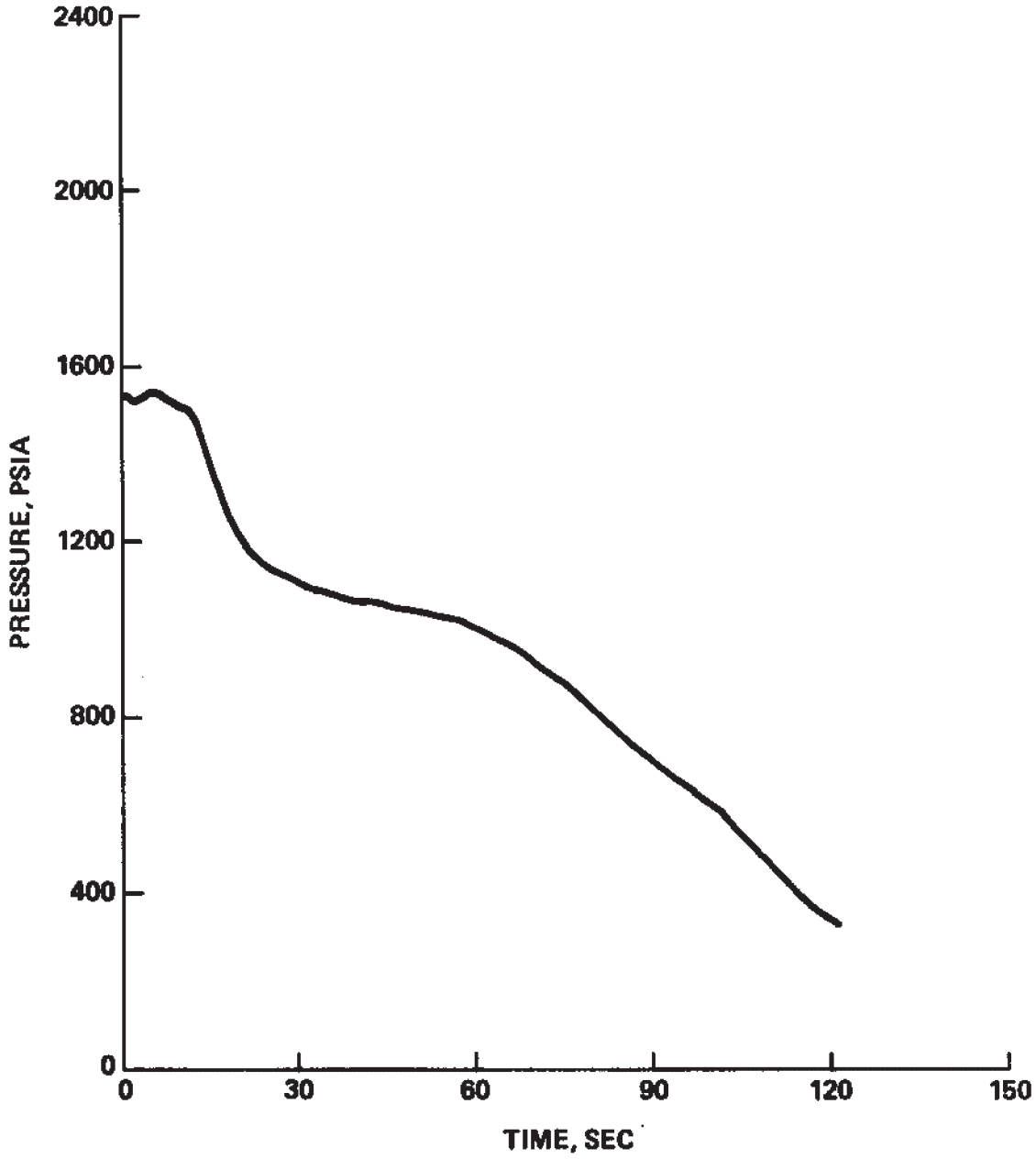


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE POWER 0.5 FT^2 BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–14a

CYCLE 1

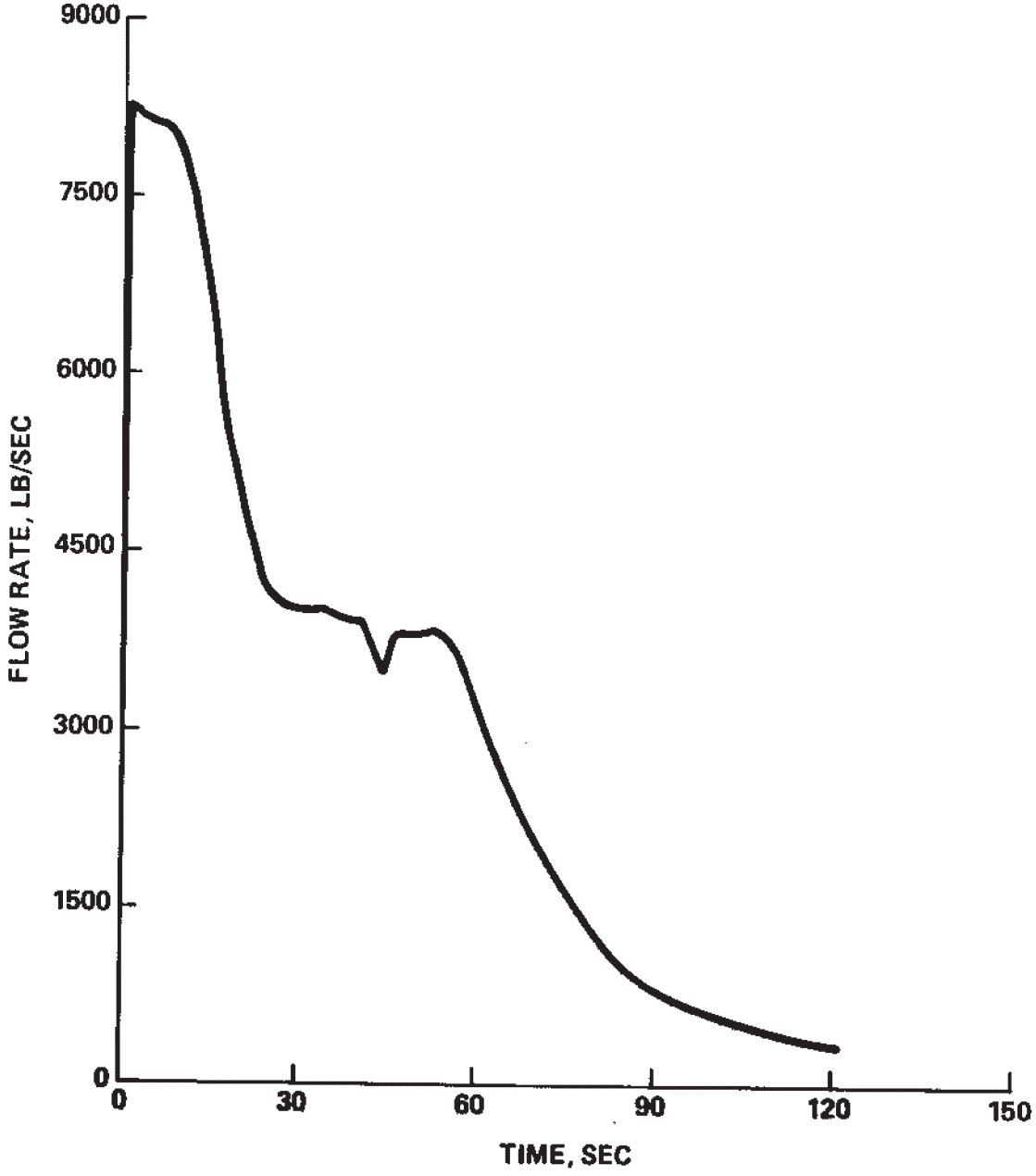


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL PRESSURE 0.5 FT^2 BREAK
IN PUMP DISCHARGE LEG
FIGURE 6.3–14b

CYCLE 1

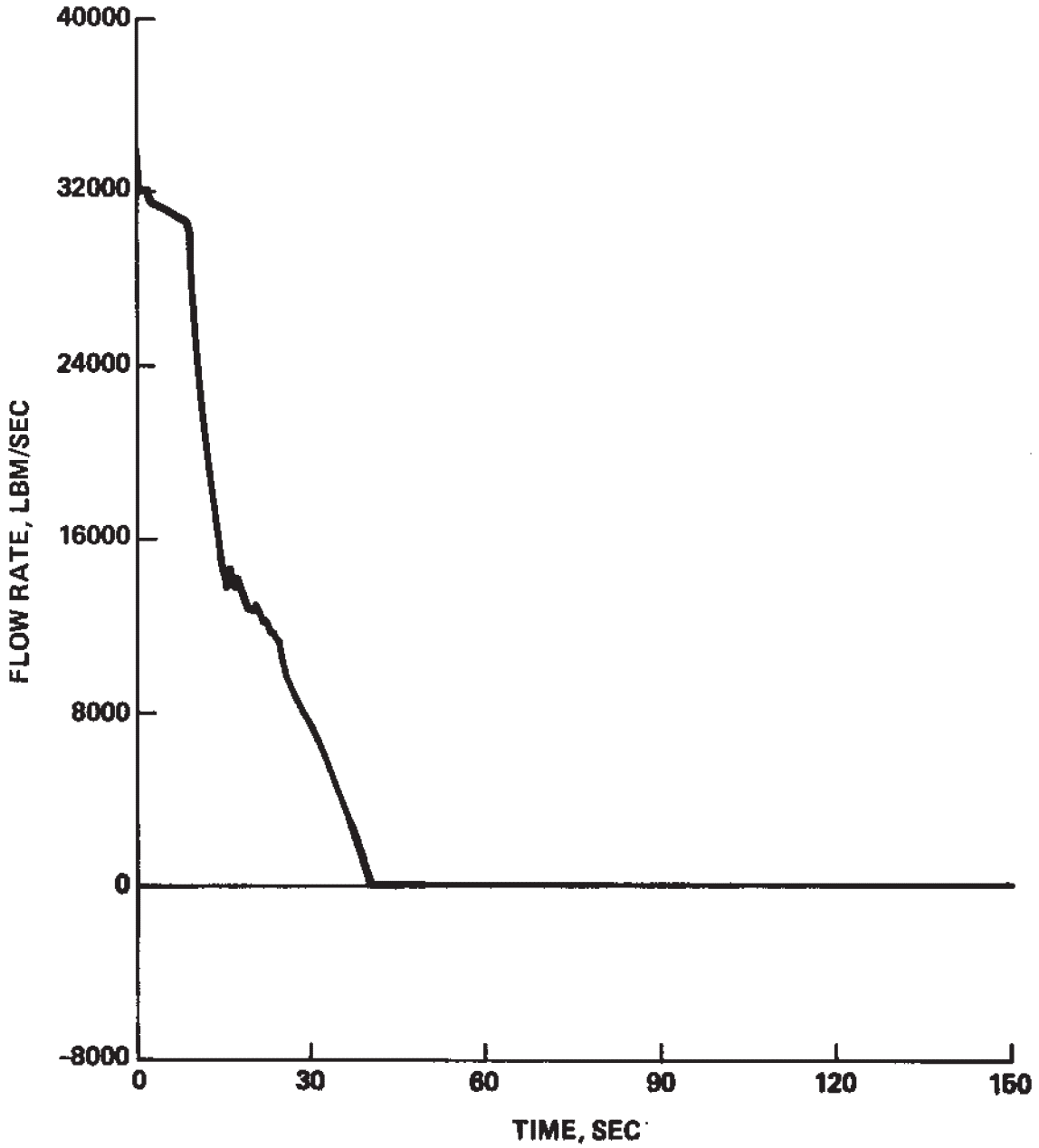


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

BREAK FLOW RATE 0.5 FT^2 BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–14c

CYCLE 1

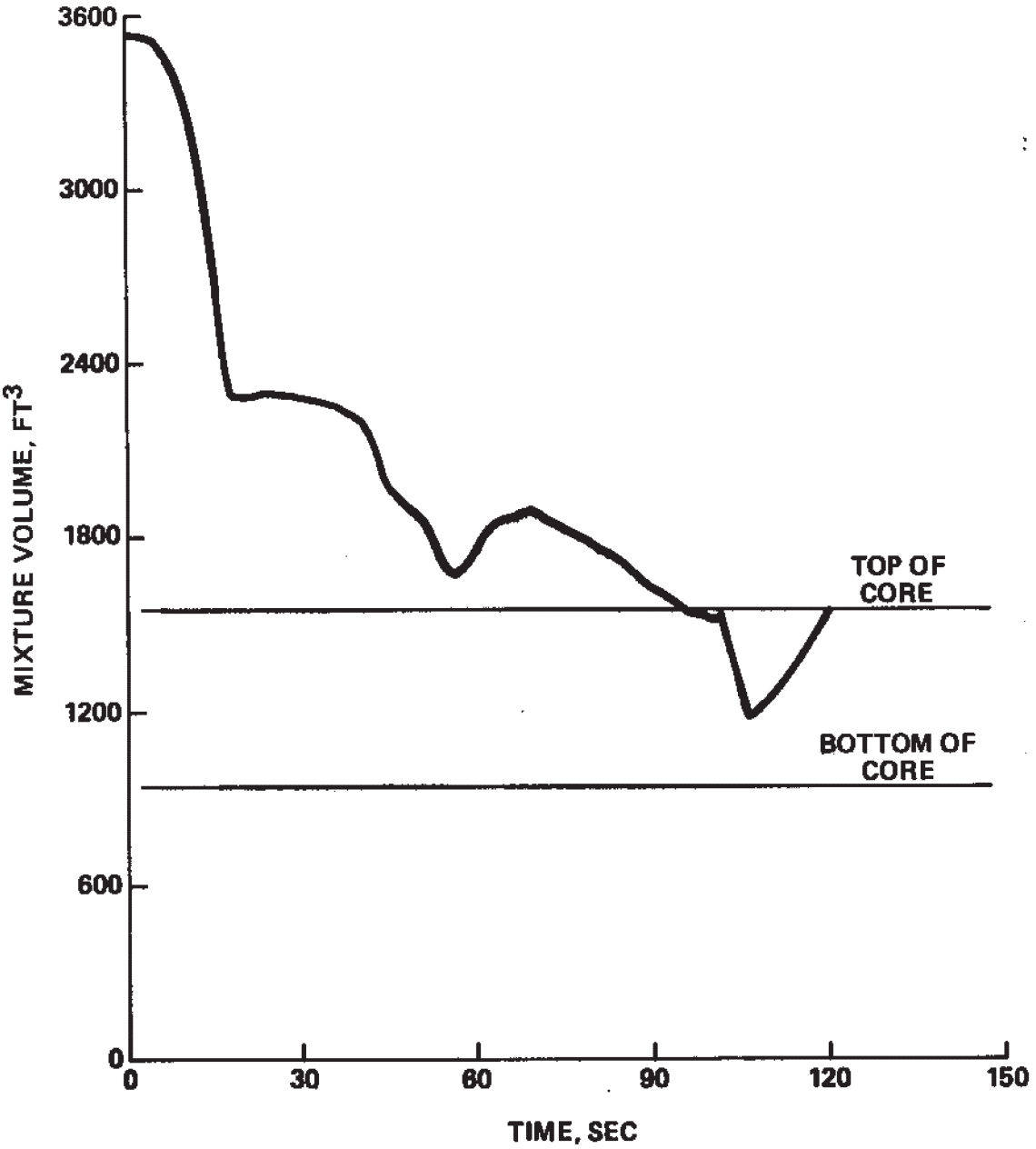


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL INLET FLOW RATE 0.5 FT^2
BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–14d

CYCLE 1

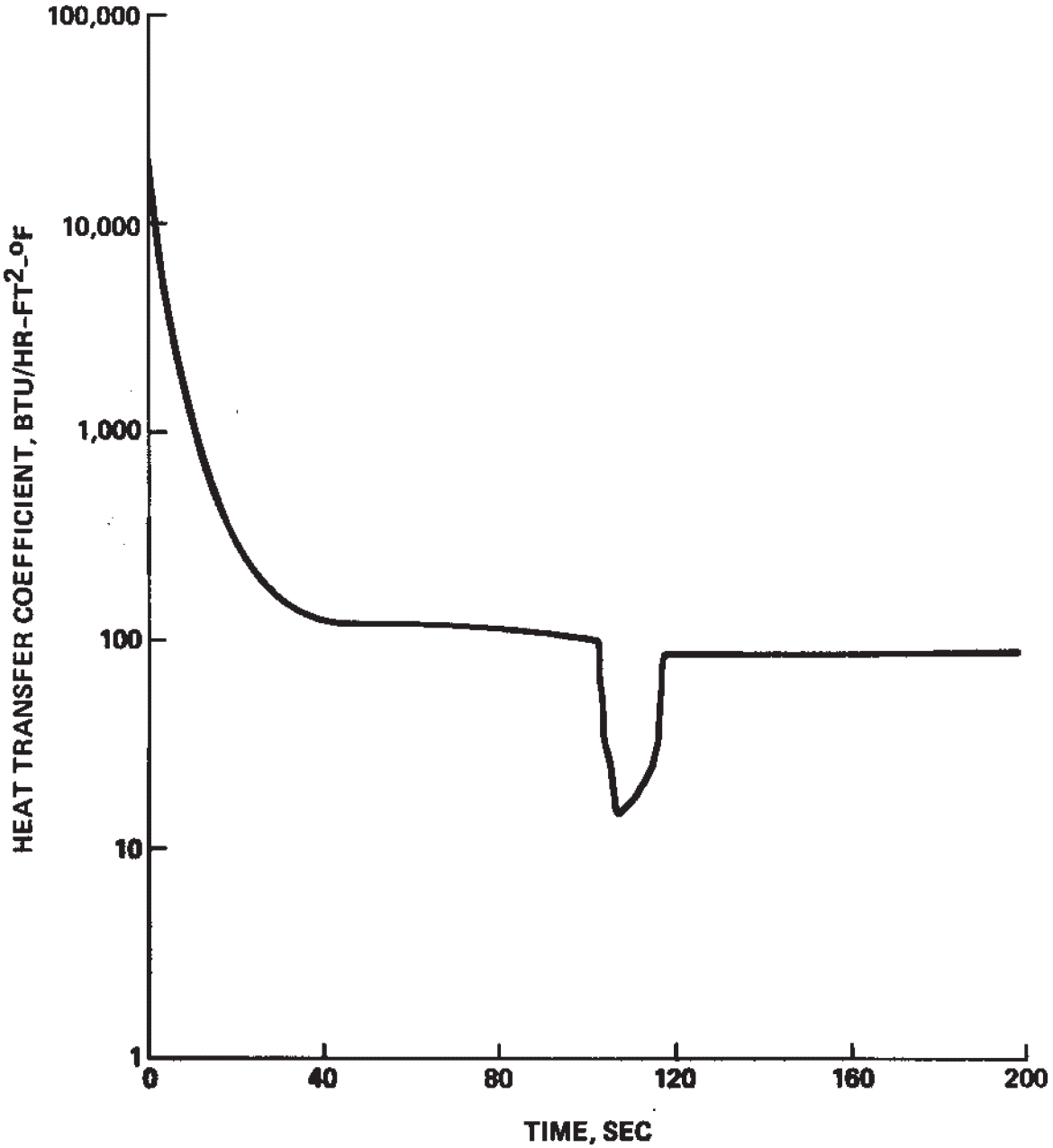


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL TWO-PHASE MIXTURE VOL.
0.5 FT^2 BREAK IN PUMP DISCH. LEG
FIGURE 6.3–14e

CYCLE 1

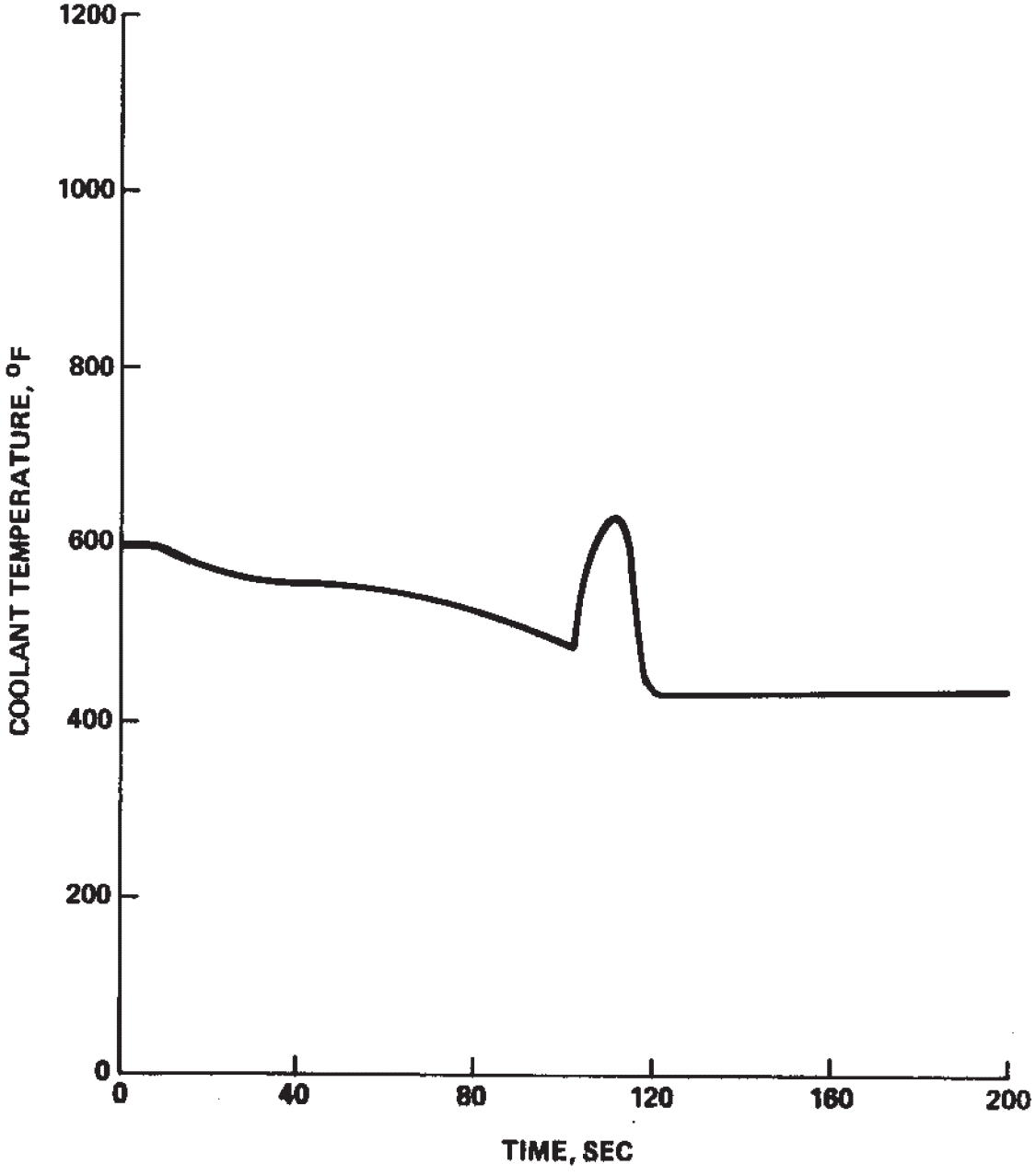


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HEAT TRANSFER COEFF. AT HOT SPOT
0.5 FT^2 BRK IN PUMP DISCHARGE LEG
FIGURE 6.3–14f

CYCLE 1

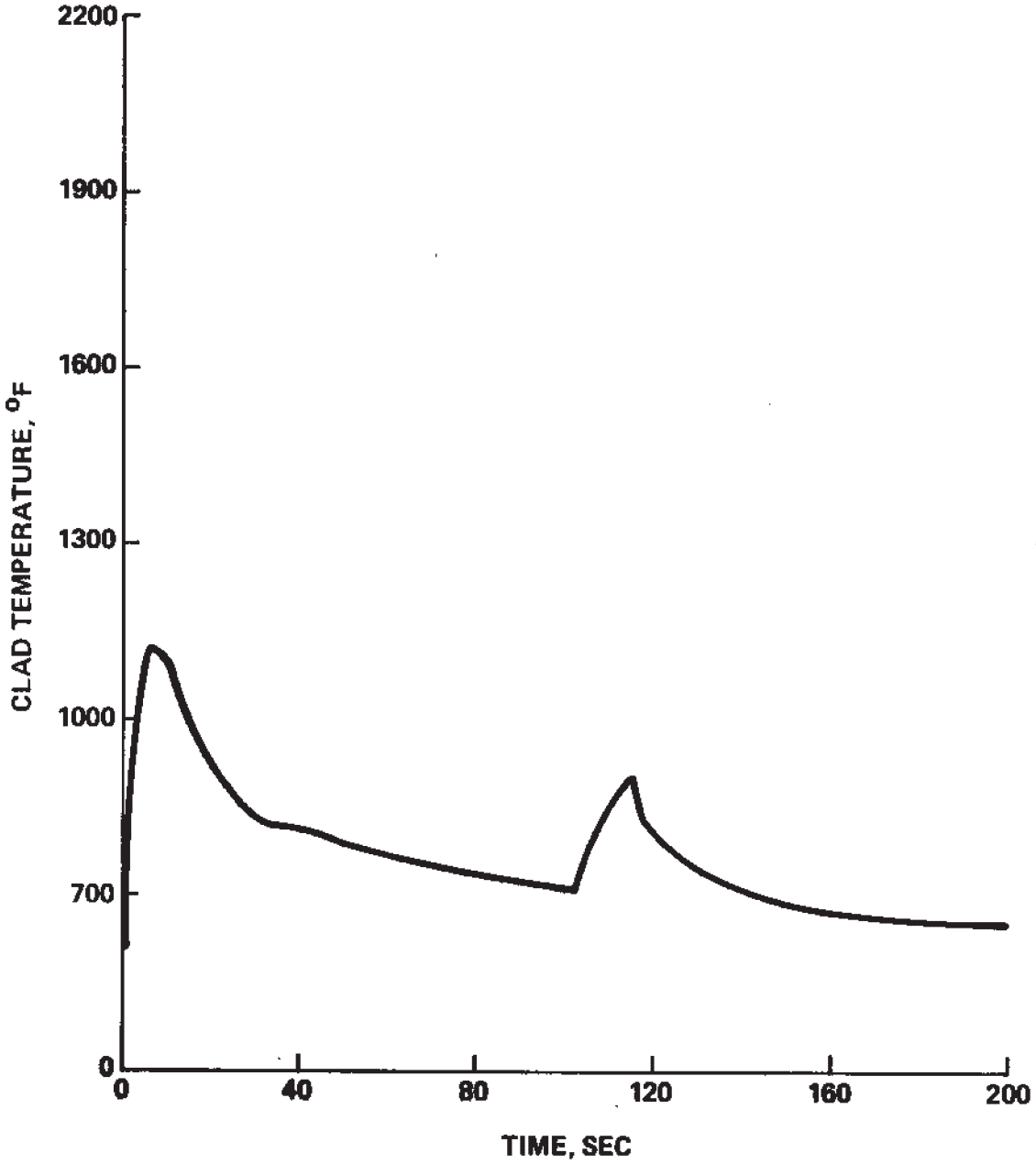


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

COOLANT TEMP. AT HOT SPOT 0.5 FT^2
BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–14g

CYCLE 1

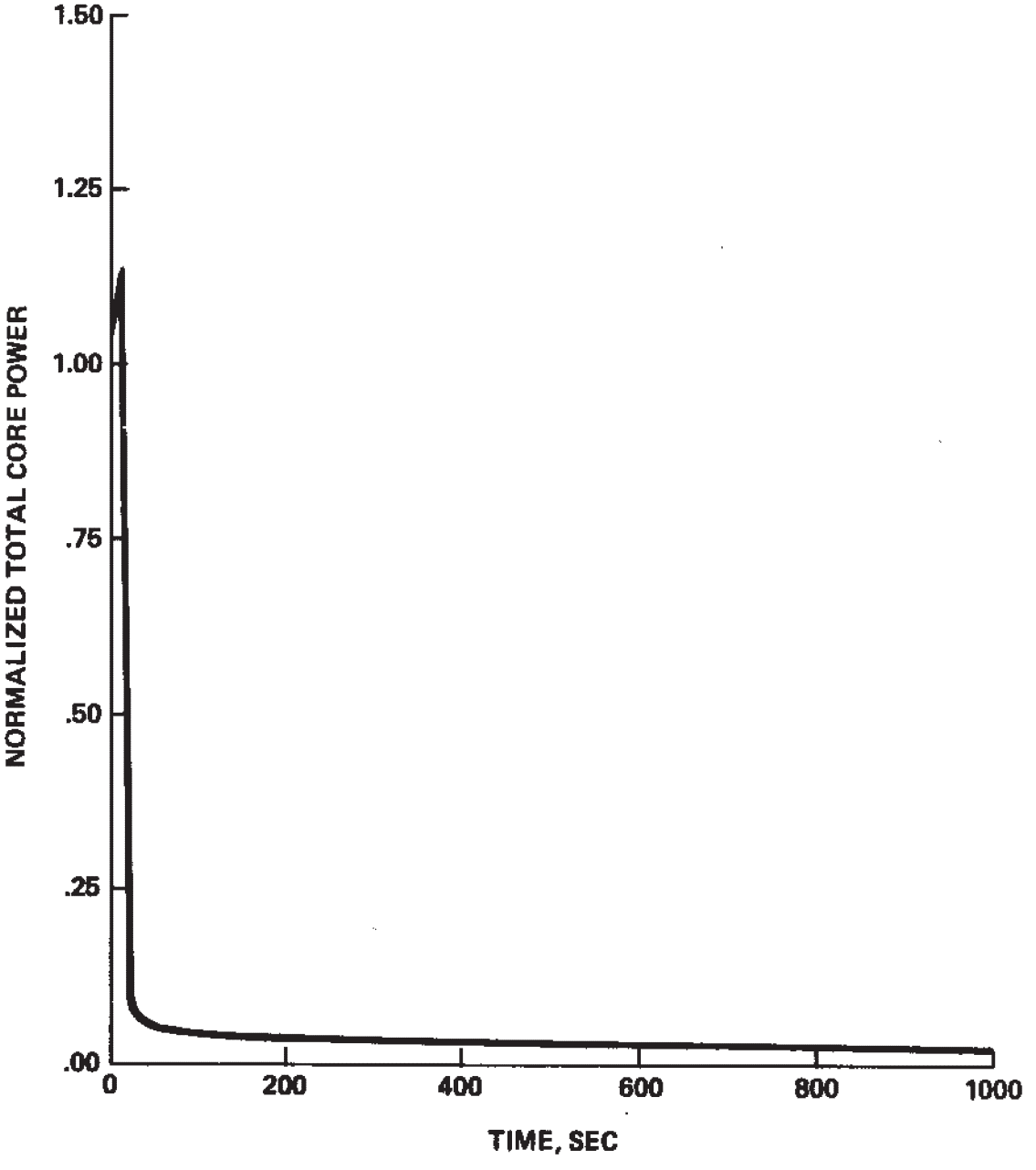


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT SPOT CLAD SURFACE TEMP. 0.5 FT^2
BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–14h

CYCLE 1

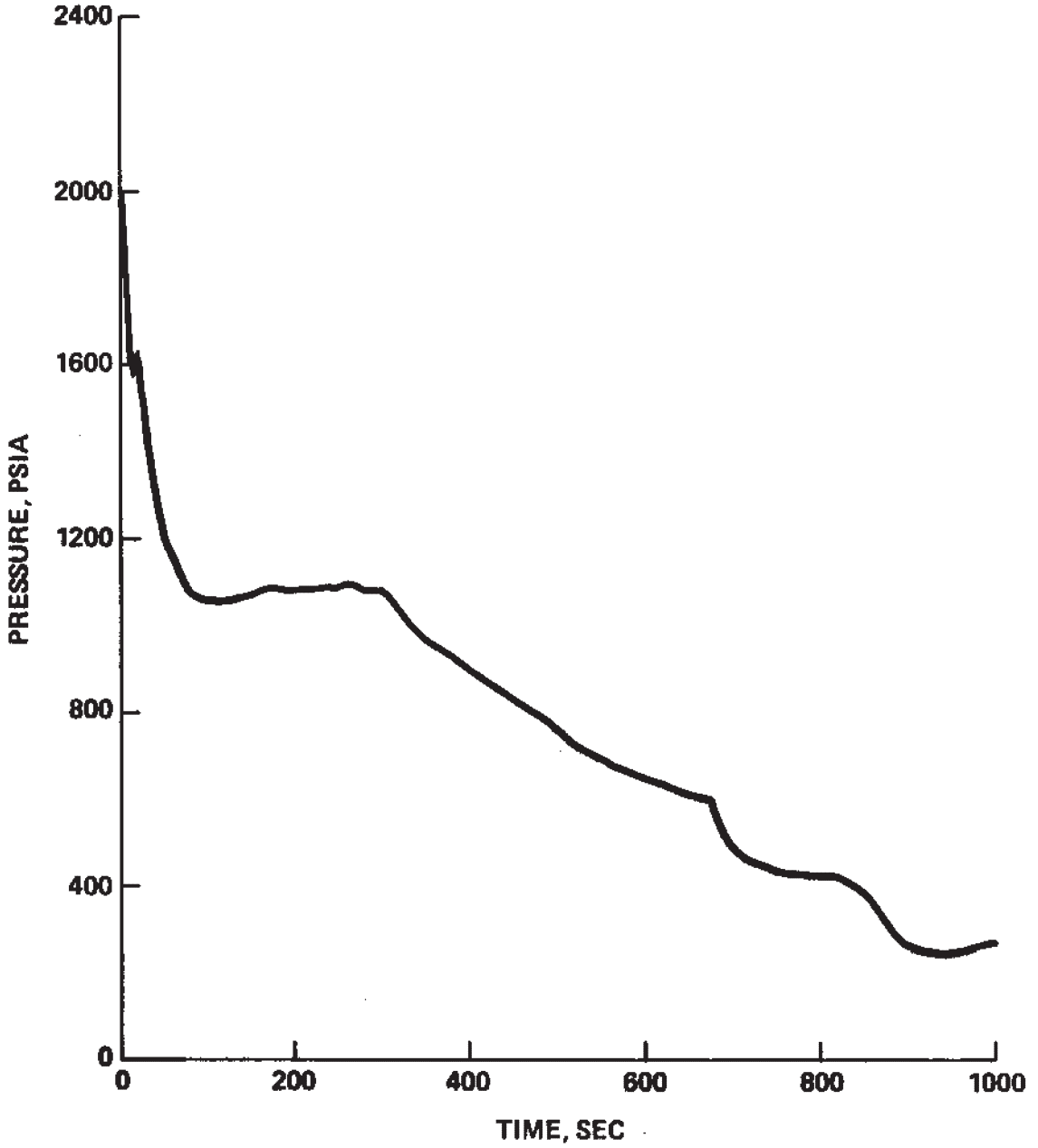


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE POWER 0.1 FT^2 BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–15a

CYCLE 1

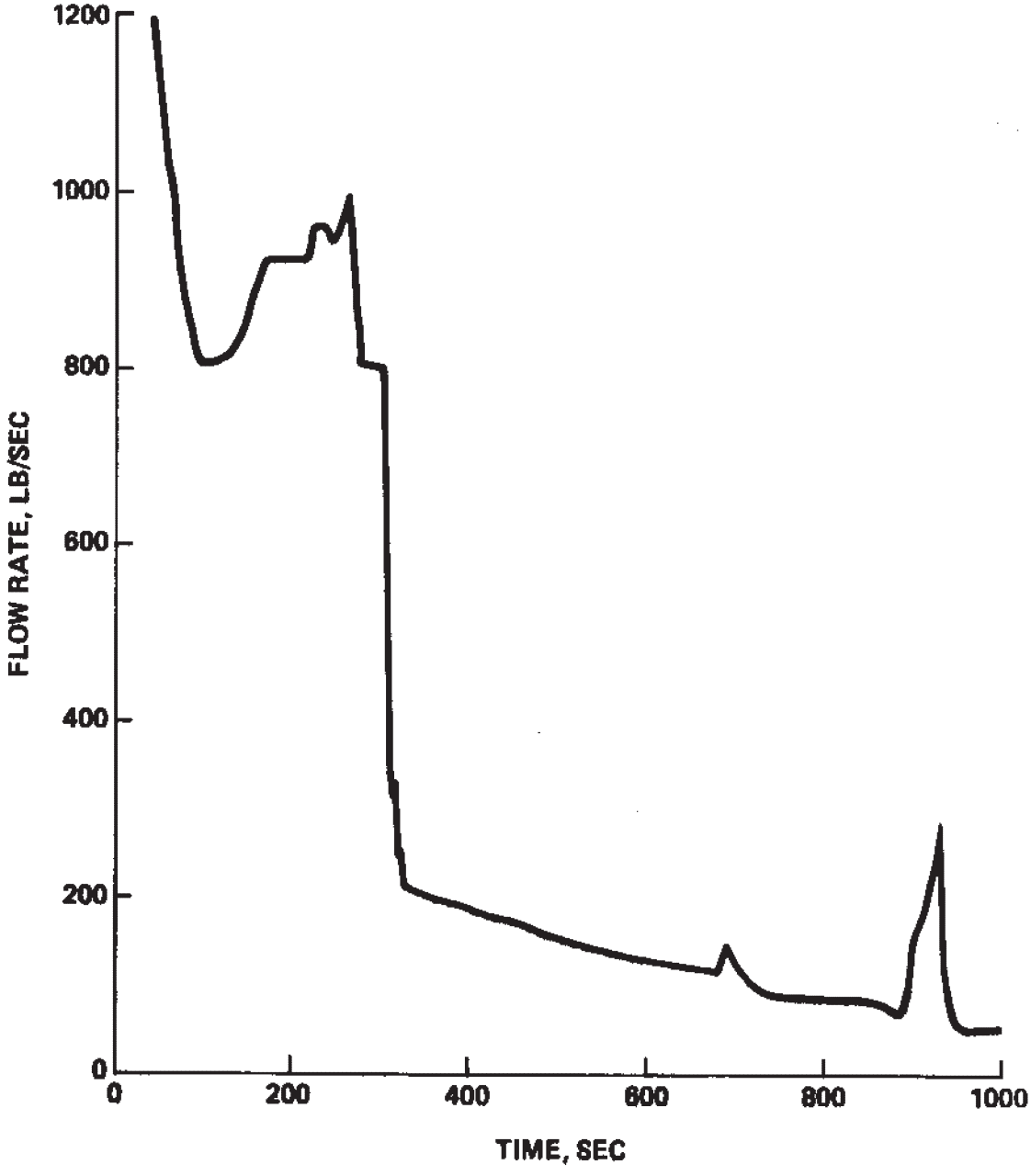


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL PRESSURE 0.1 FT^2
BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–15b

CYCLE 1

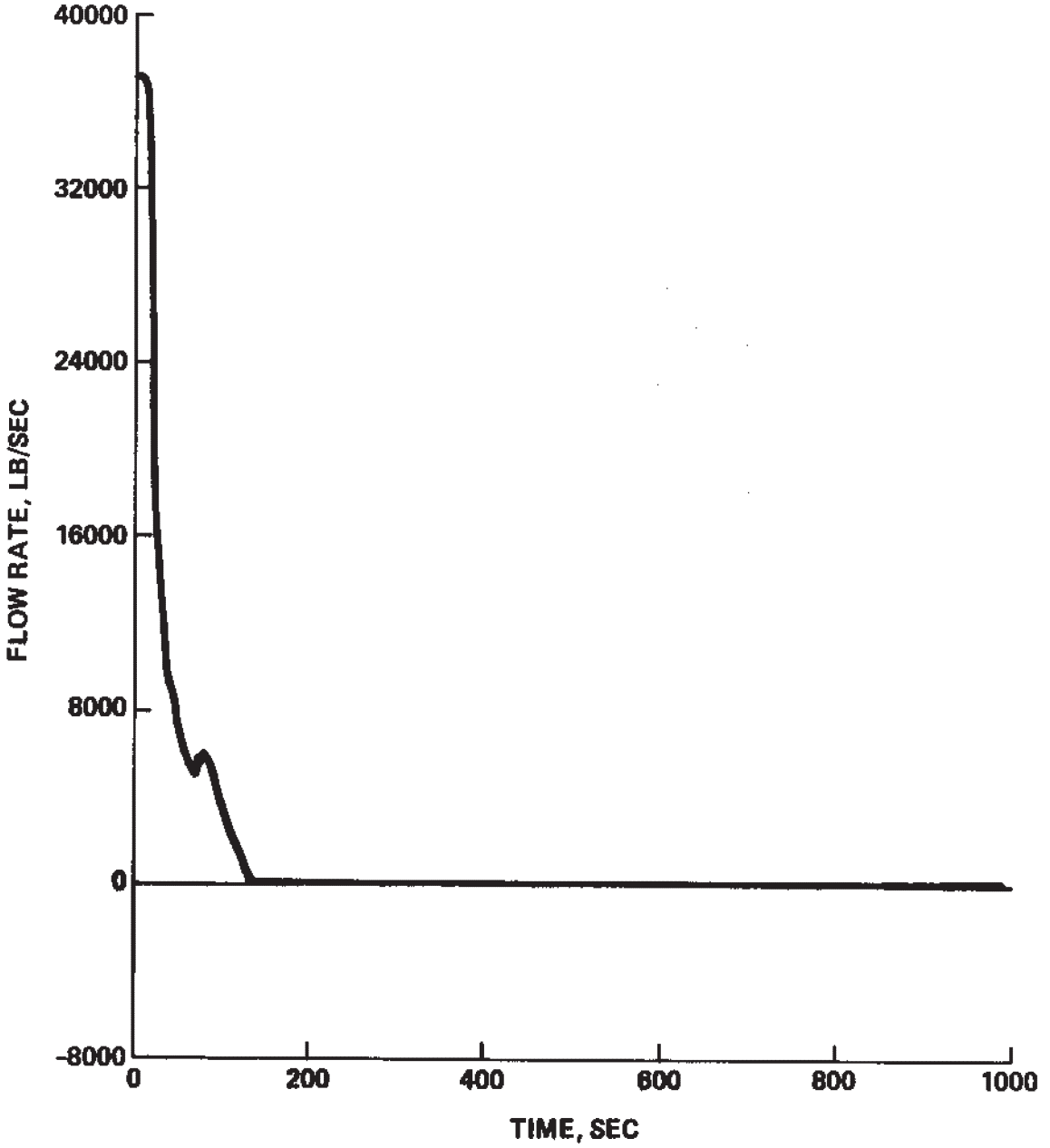


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

BREAK FLOW RATE 0.1 FT^2 BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–15c

CYCLE 1

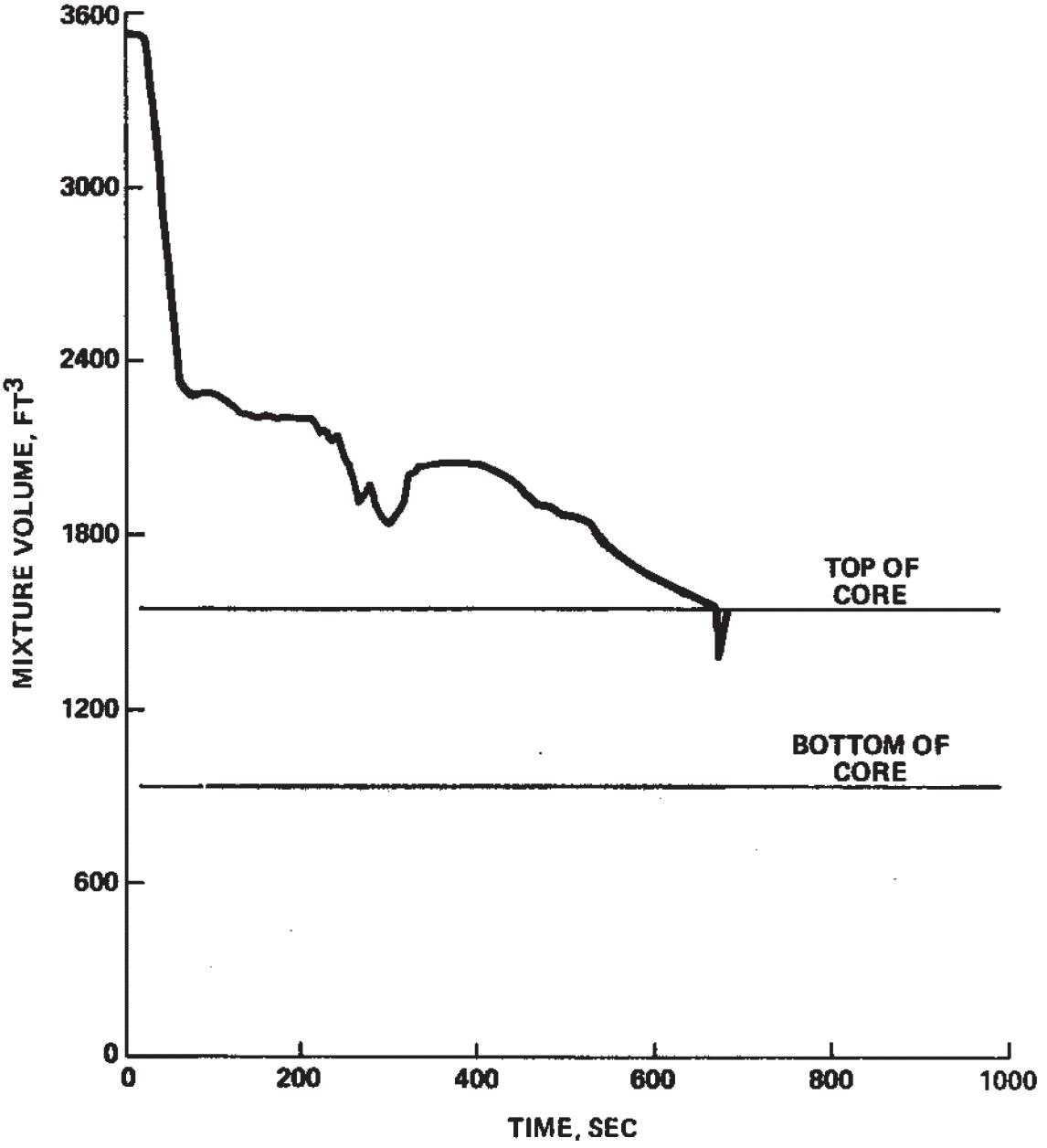


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL INLET FLOW RATE 0.1 FT^2
BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3-15d

CYCLE 1

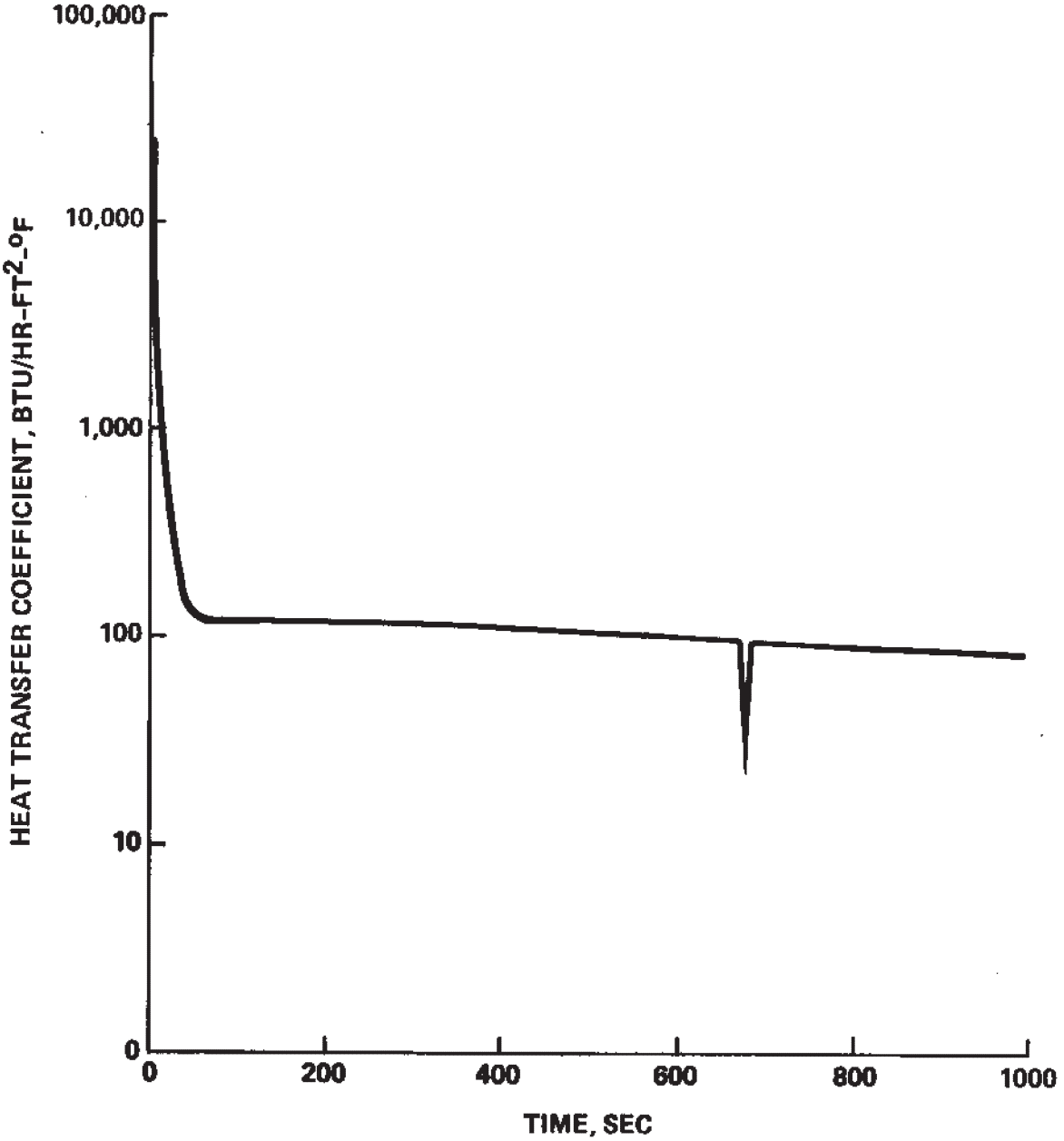


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL TWO-PHASE MIXTURE VOL.
0.1 FT^2 BREAK IN PUMP DISCH. LEG
FIGURE 6.3–15e

CYCLE 1

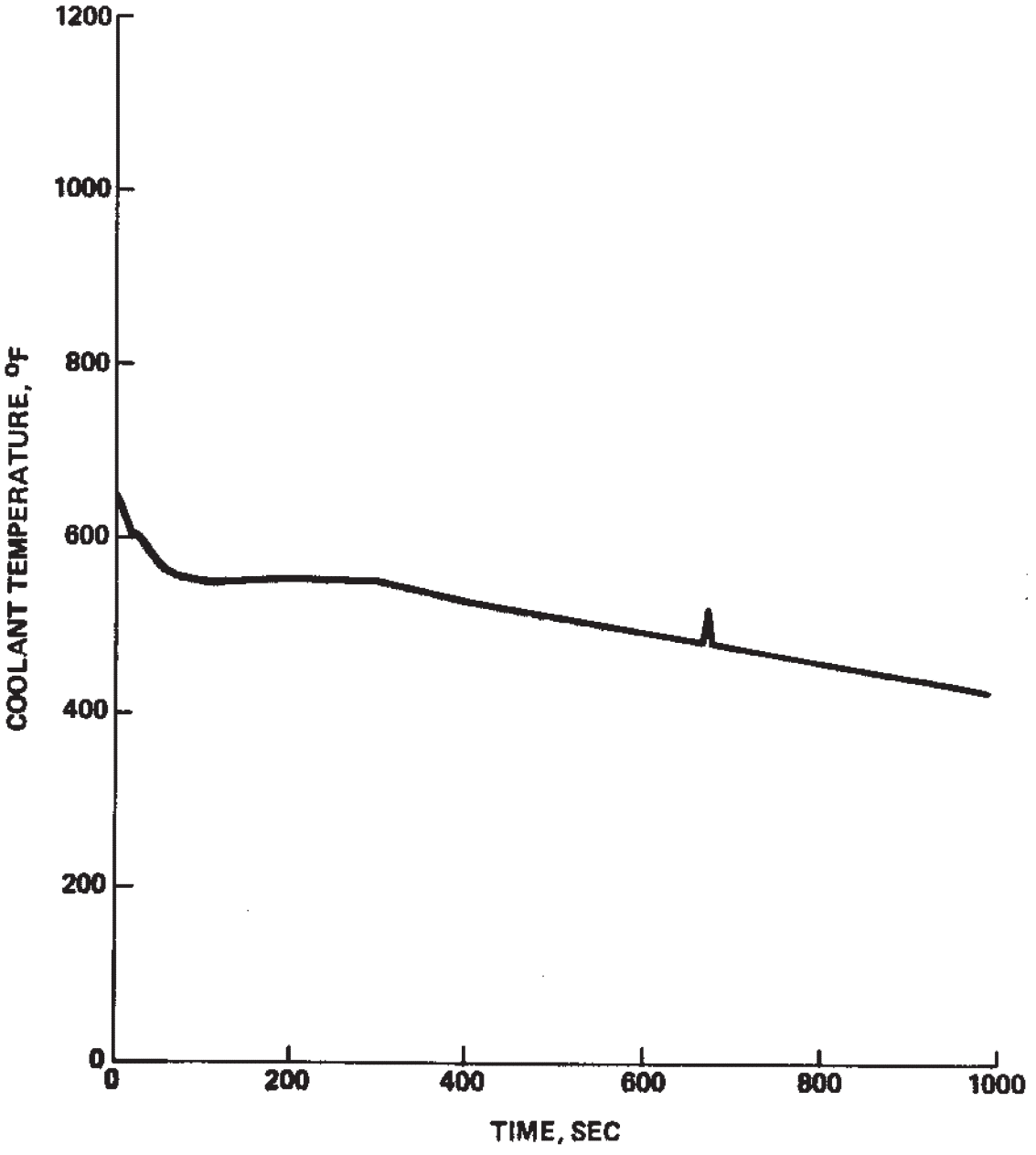


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HEAT TRANSFER COEFF. AT HOT SPOT
0.1 FT^2 BREAK IN PUMP DISCH. LEG
FIGURE 6.3–15f

CYCLE 1

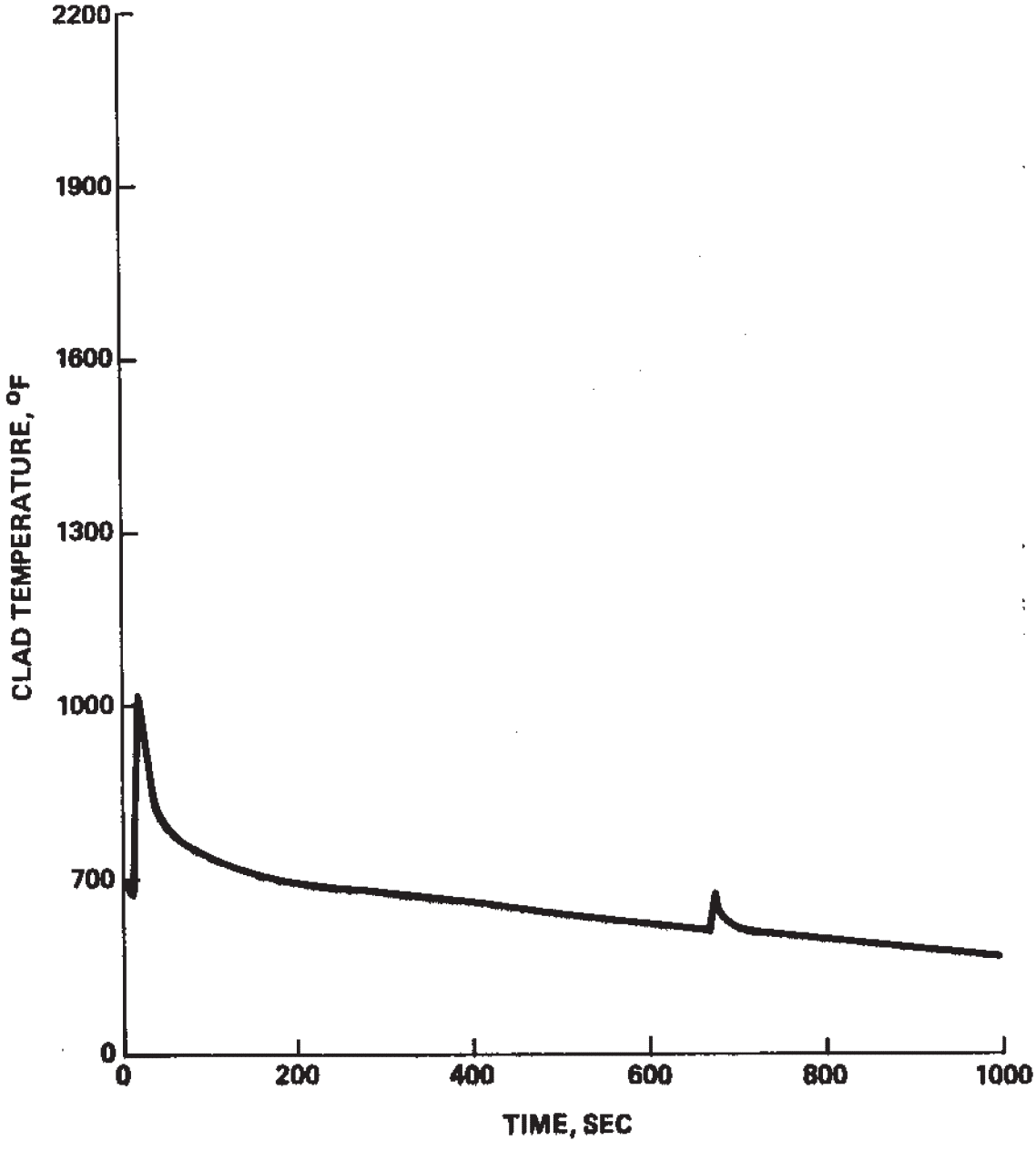


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

COOLANT TEMP. AT HOT SPOT 0.1 FT^2
BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–15g

CYCLE 1

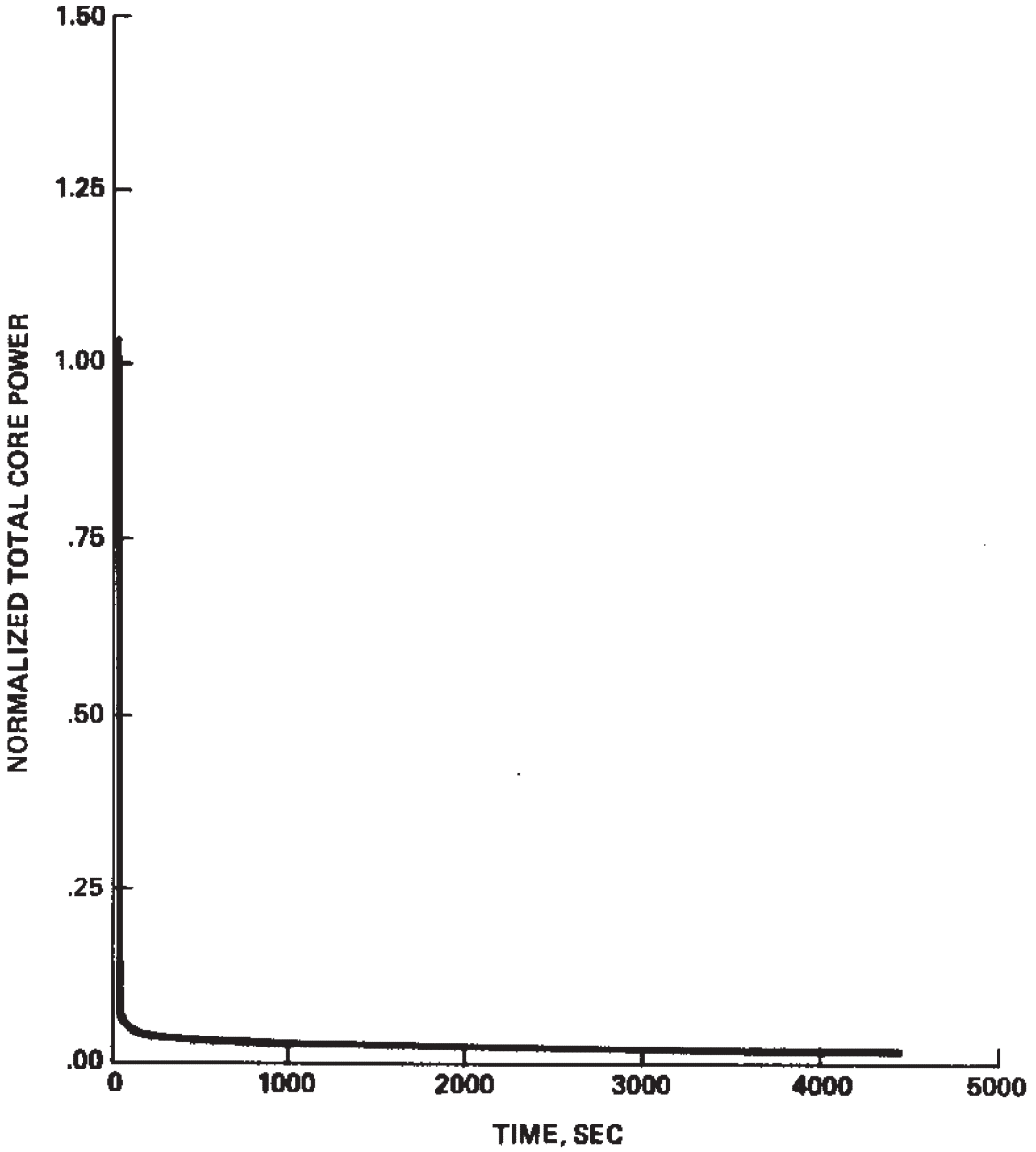


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT SPOT CLAD SURFACE TEMP.
0.1 FT^2 BREAK IN PUMP DISCH. LEG
FIGURE 6.3–15h

CYCLE 1

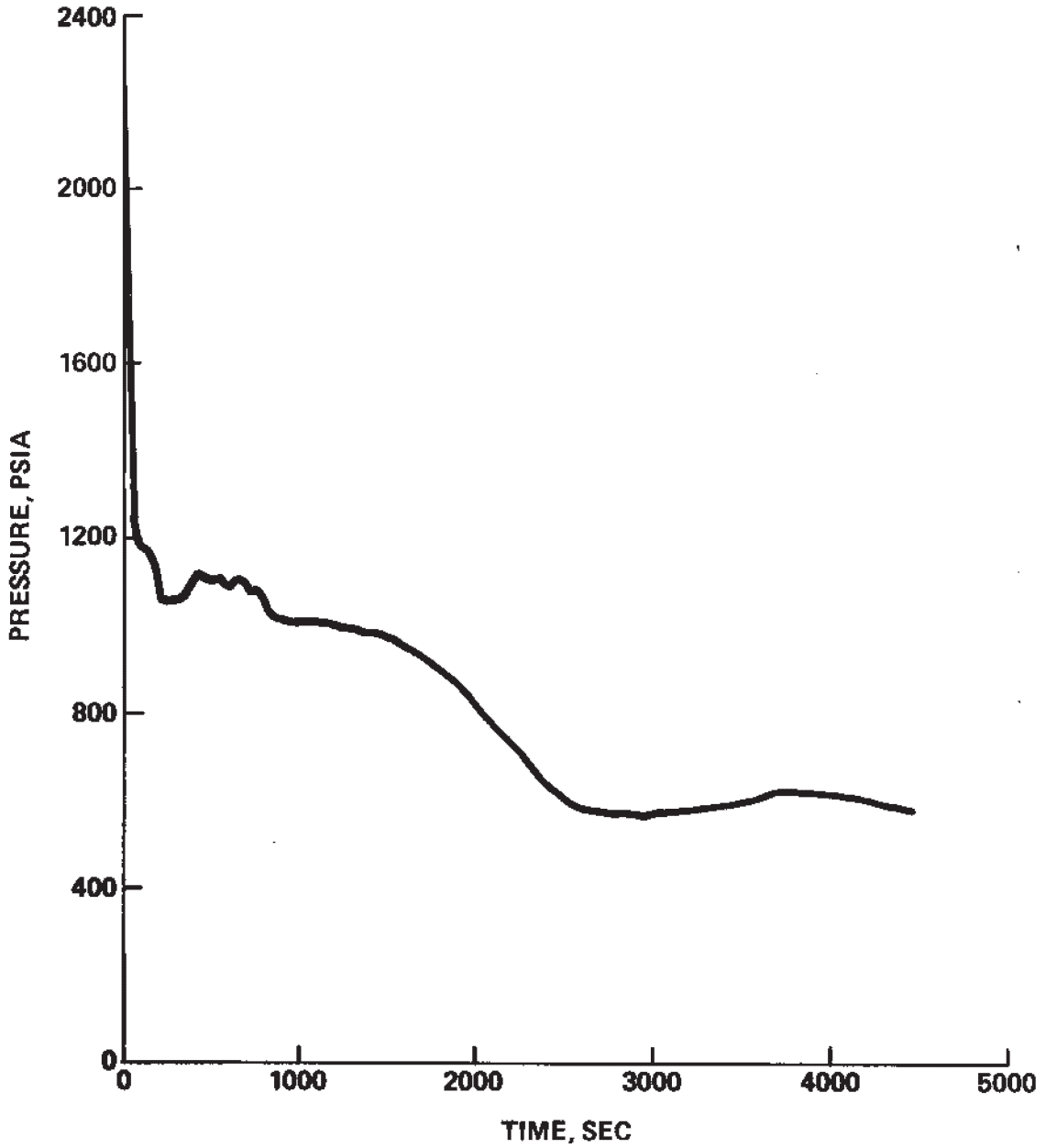


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE POWER 0.04 FT^2 BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–16a

CYCLE 1

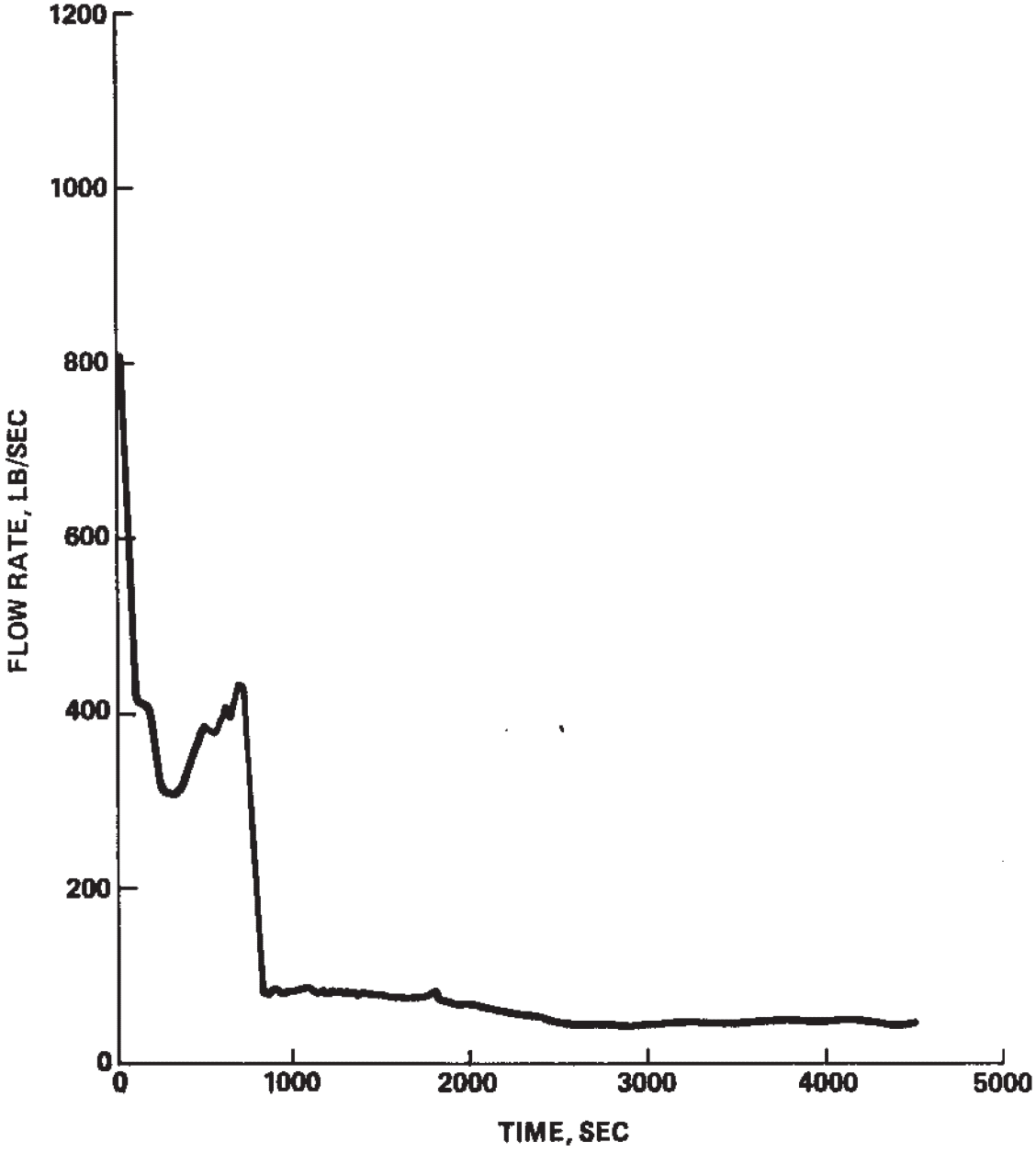


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL PRESSURE 0.04 FT^2
BREAK IN PUMP DISCH. LEG
FIGURE 6.3–16b

CYCLE 1

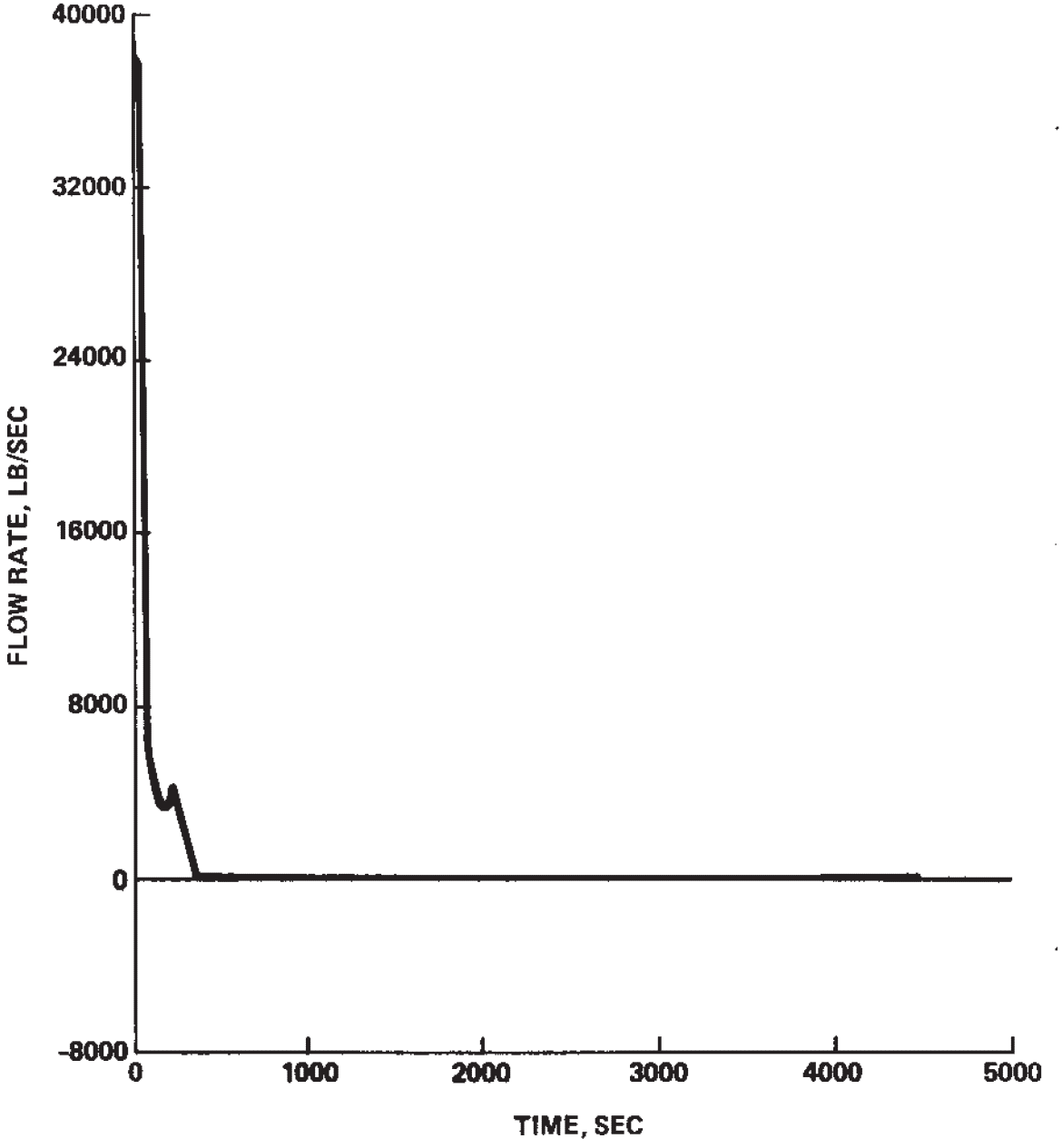


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

BREAK FLOW RATE 0.04 FT^2
BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–16c

CYCLE 1

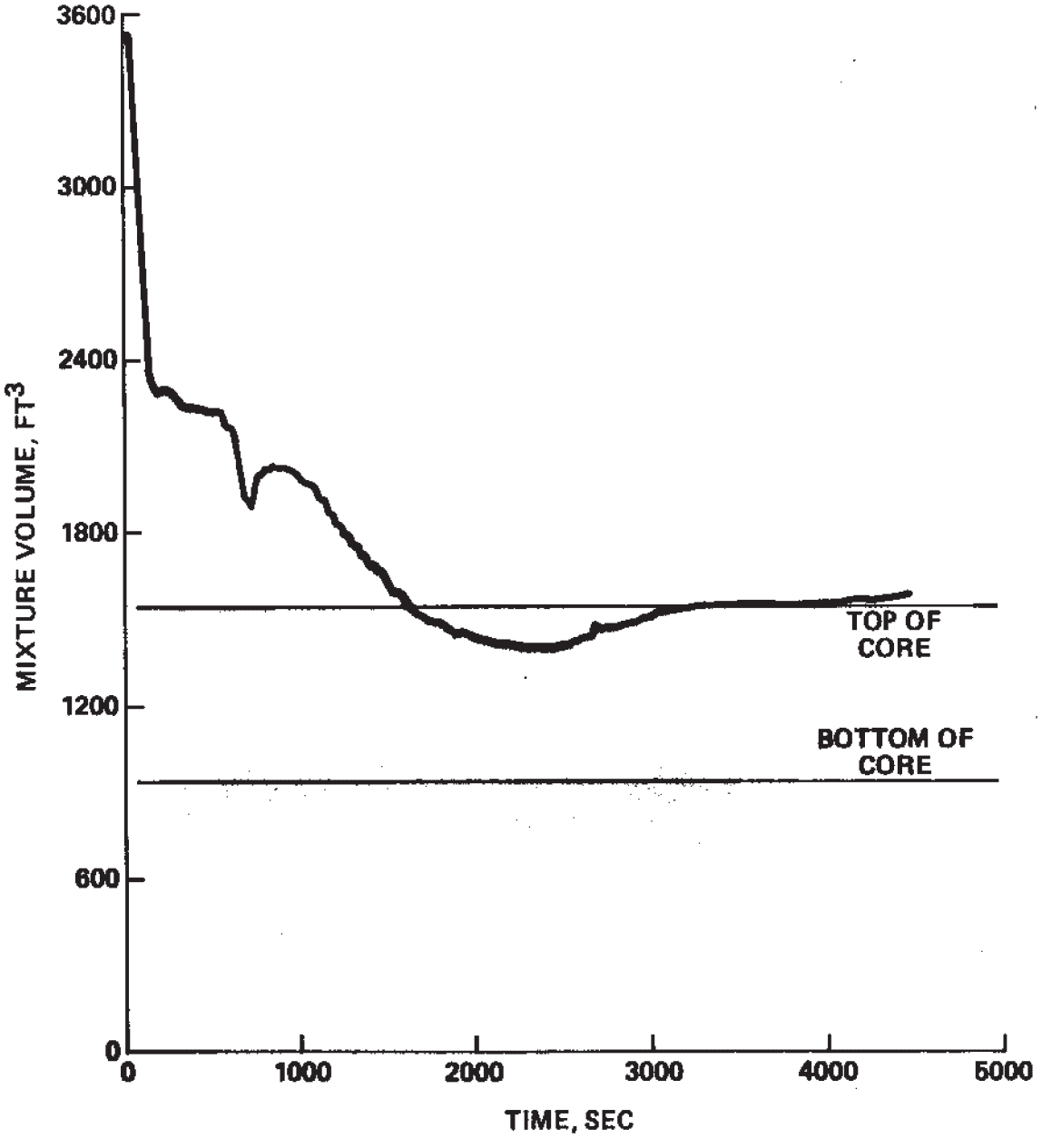


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL INLET FLOW RATE 0.04 FT^2
BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–16d

CYCLE 1

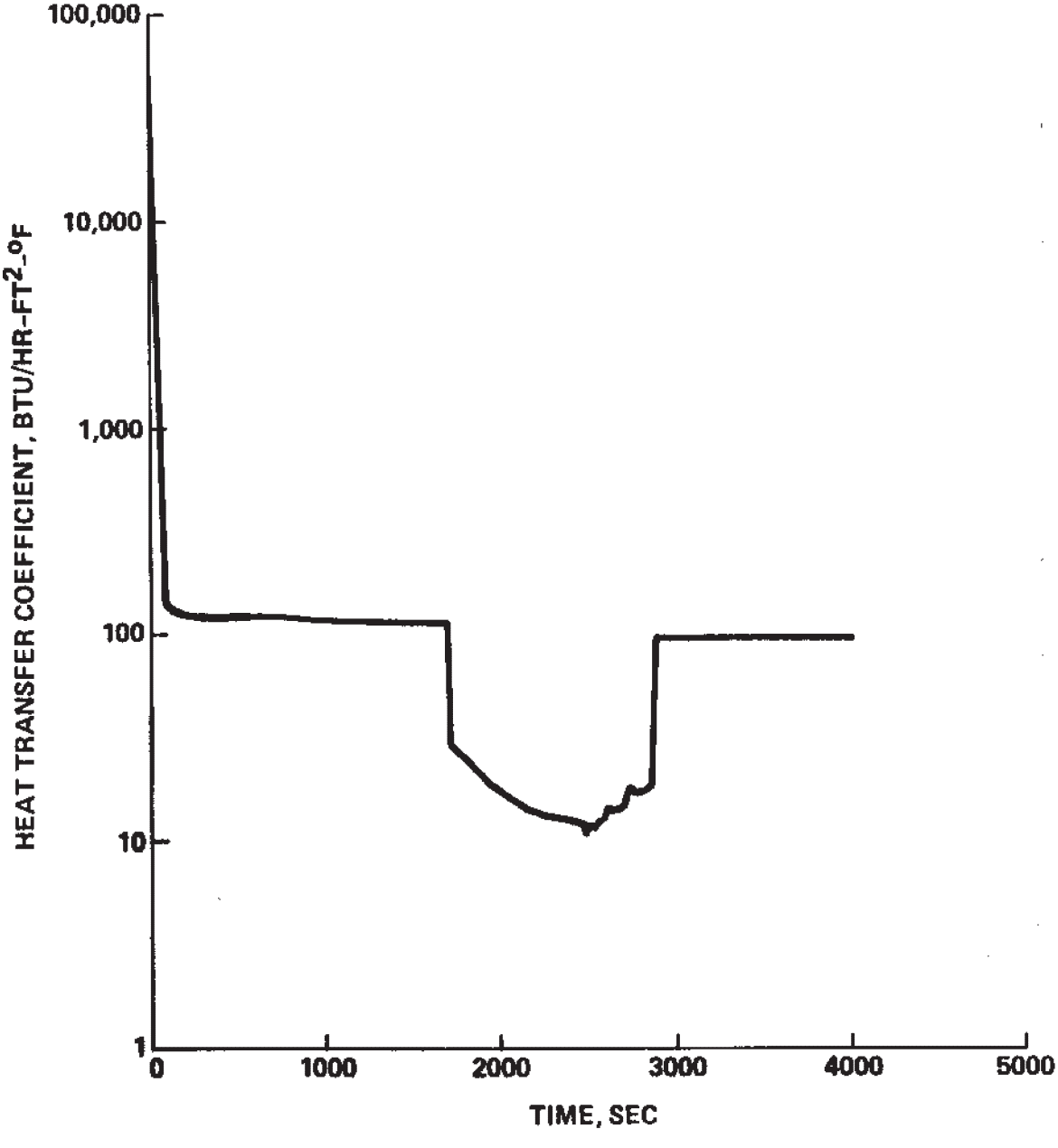


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL TWO-PHASE MIXTURE VOL.
0.04 FT^2 BREAK IN PUMP DISCH. LEG
FIGURE 6.3–16e

CYCLE 1

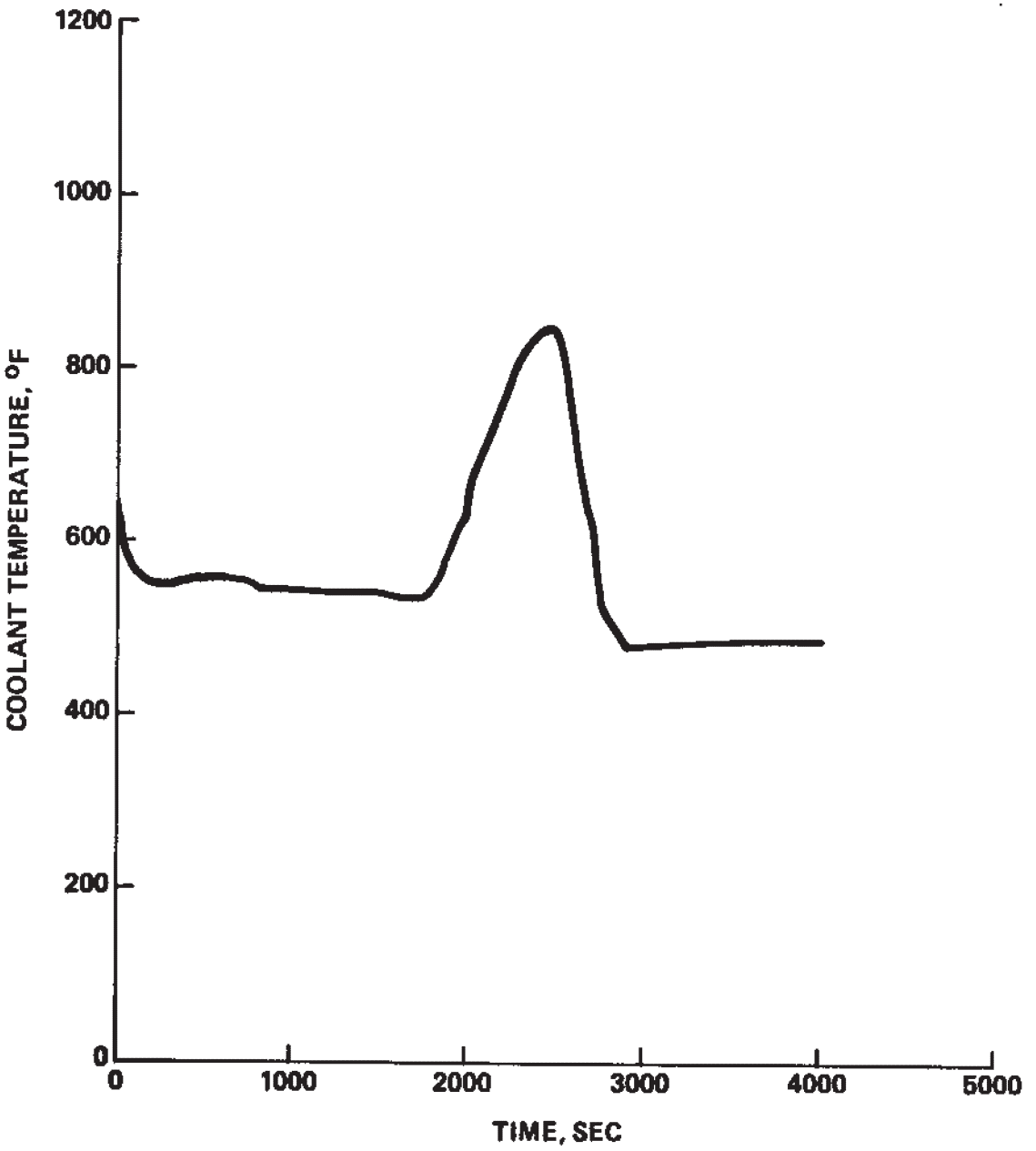


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HEAT TRANSFER COEFF. AT HOT SPOT
0.04 FT^2 BREAK IN PUMP DISCH. LEG
FIGURE 6.3-16f

CYCLE 1

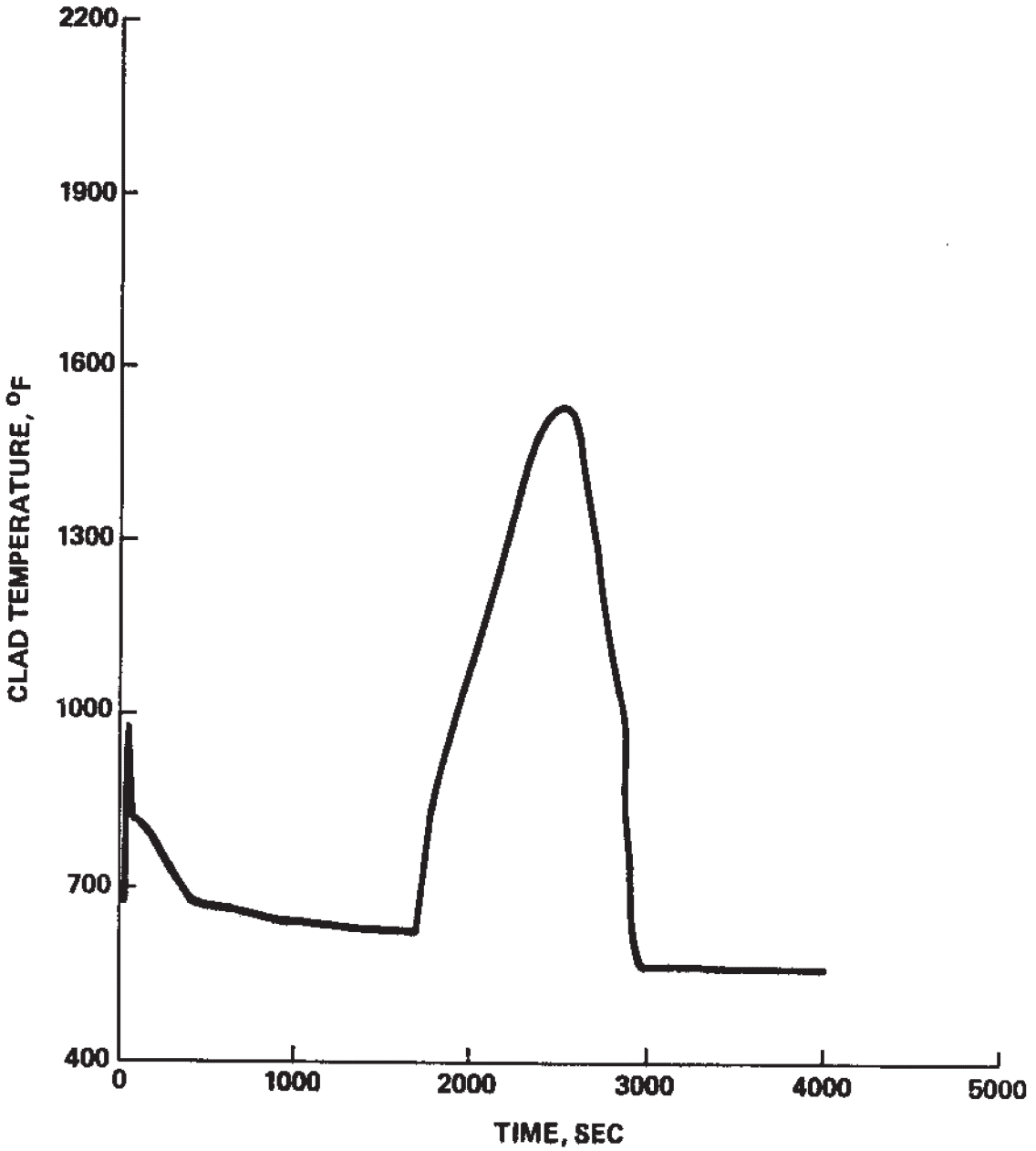


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

COOLANT TEMP. AT HOT SPOT
0.04 FT^2 BREAK IN PUMP DISCH. LEG
FIGURE 6.3–16g

CYCLE 1

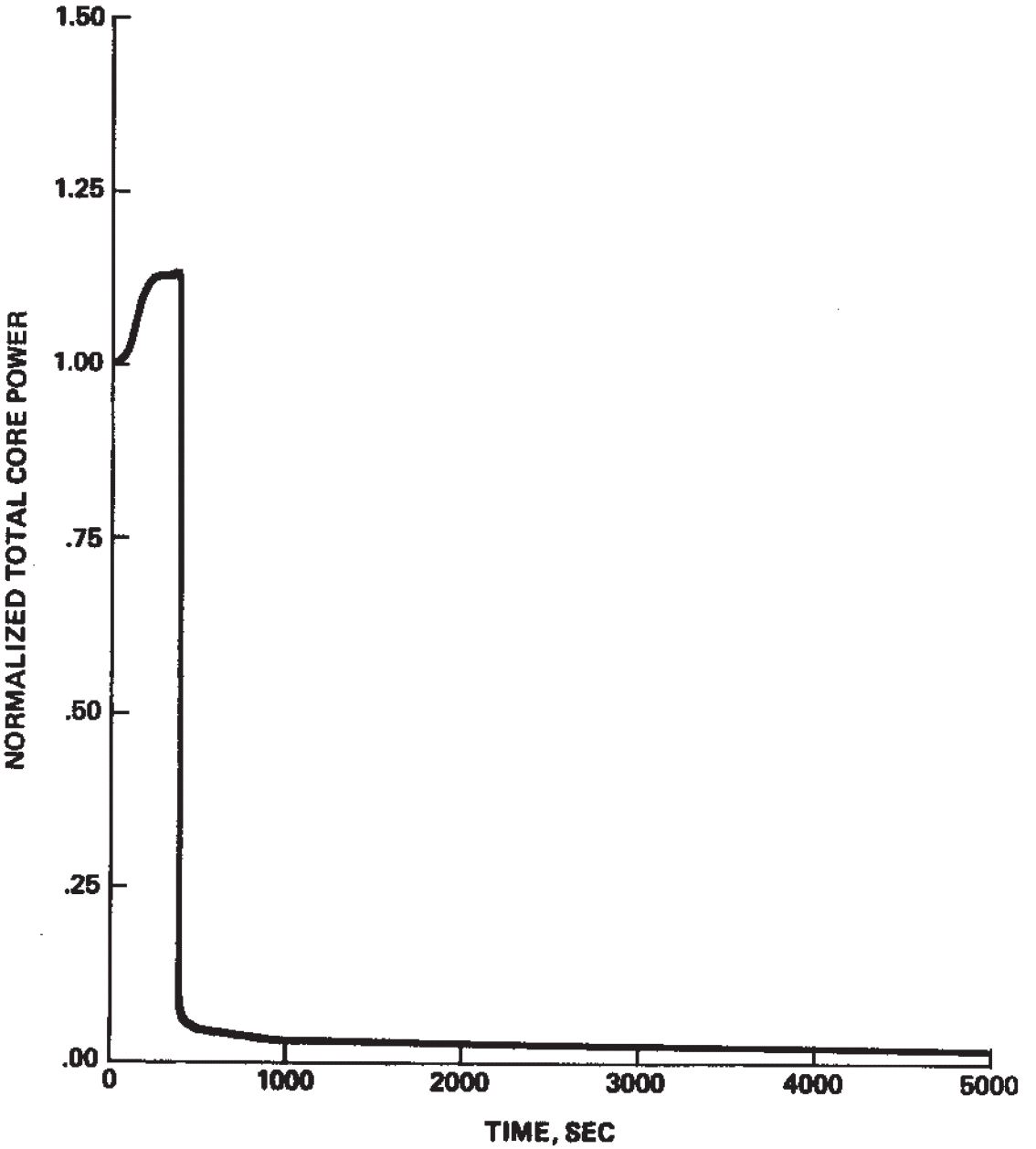


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT SPOT CLAD SURFACE TEMP.
0.04 FT^2 BREAK IN PUMP DISCH. LEG
FIGURE 6.3–16h

CYCLE 1

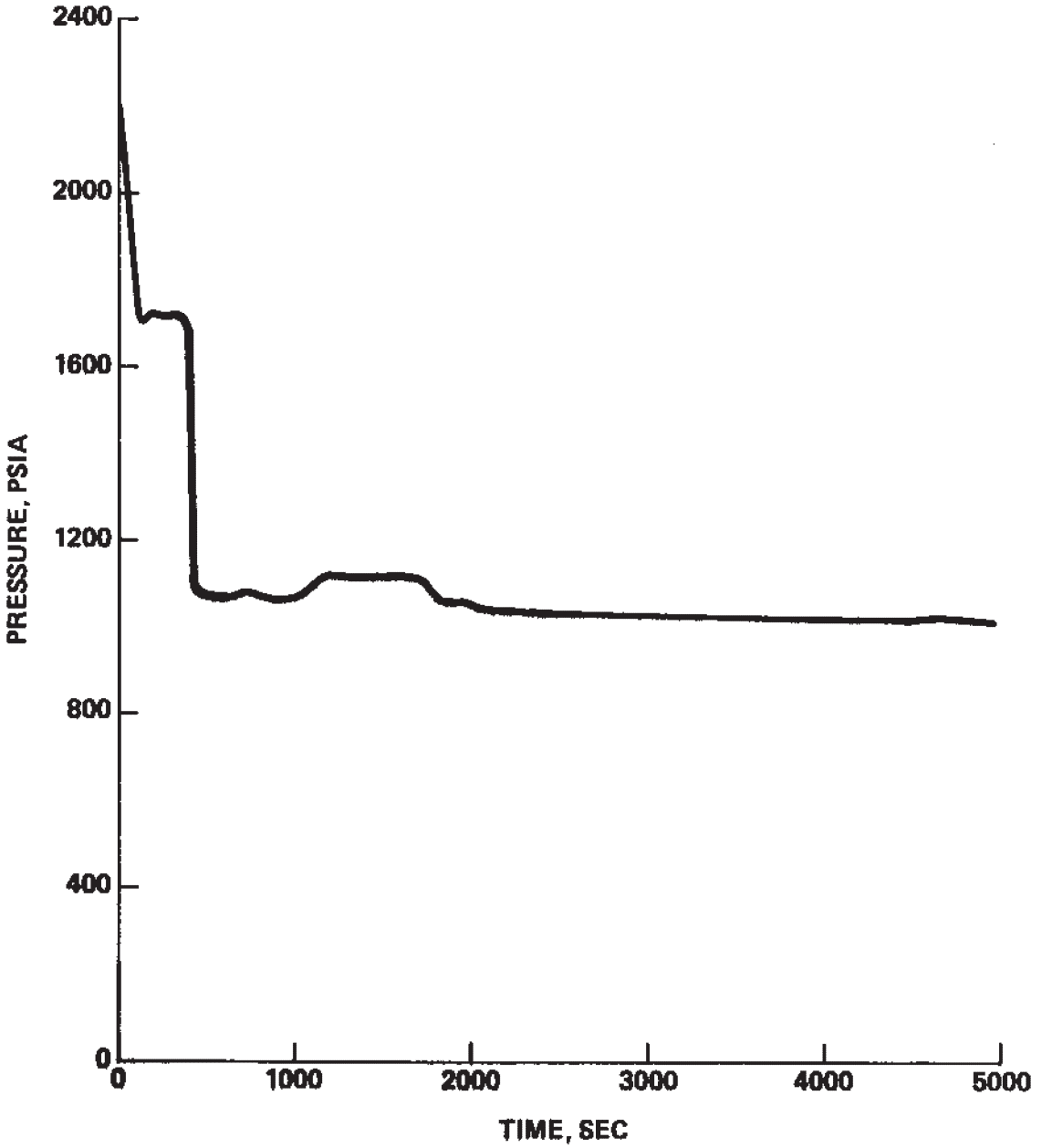


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE POWER 0.015 FT^2 BREAK
IN PUMP DISCH. LEG
FIGURE 6.3–17a

CYCLE 1

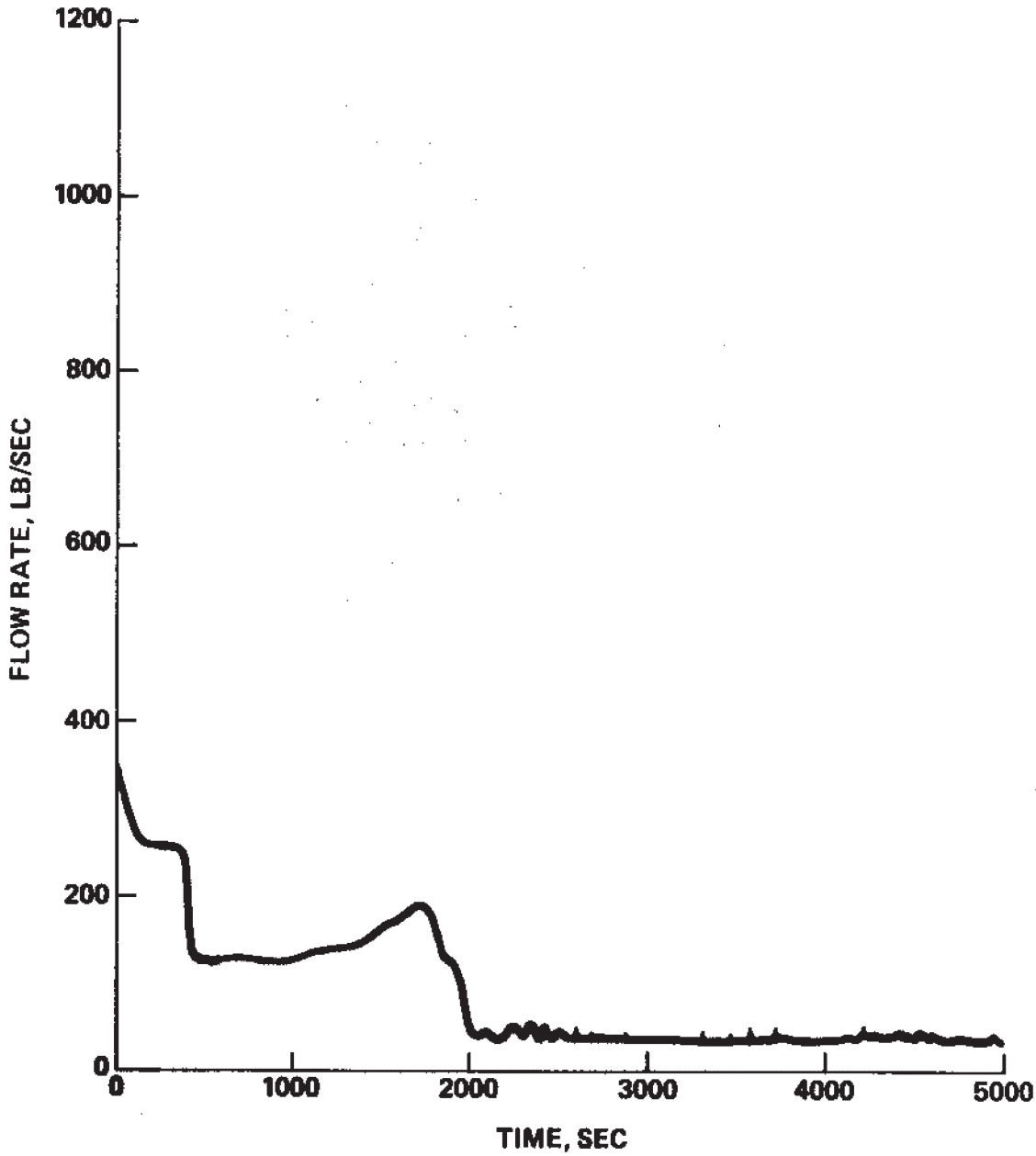


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL PRESSURE 0.015 FT^2
BREAK IN PUMP DISCHARGE LEG
FIGURE 6.3–17b

CYCLE 1



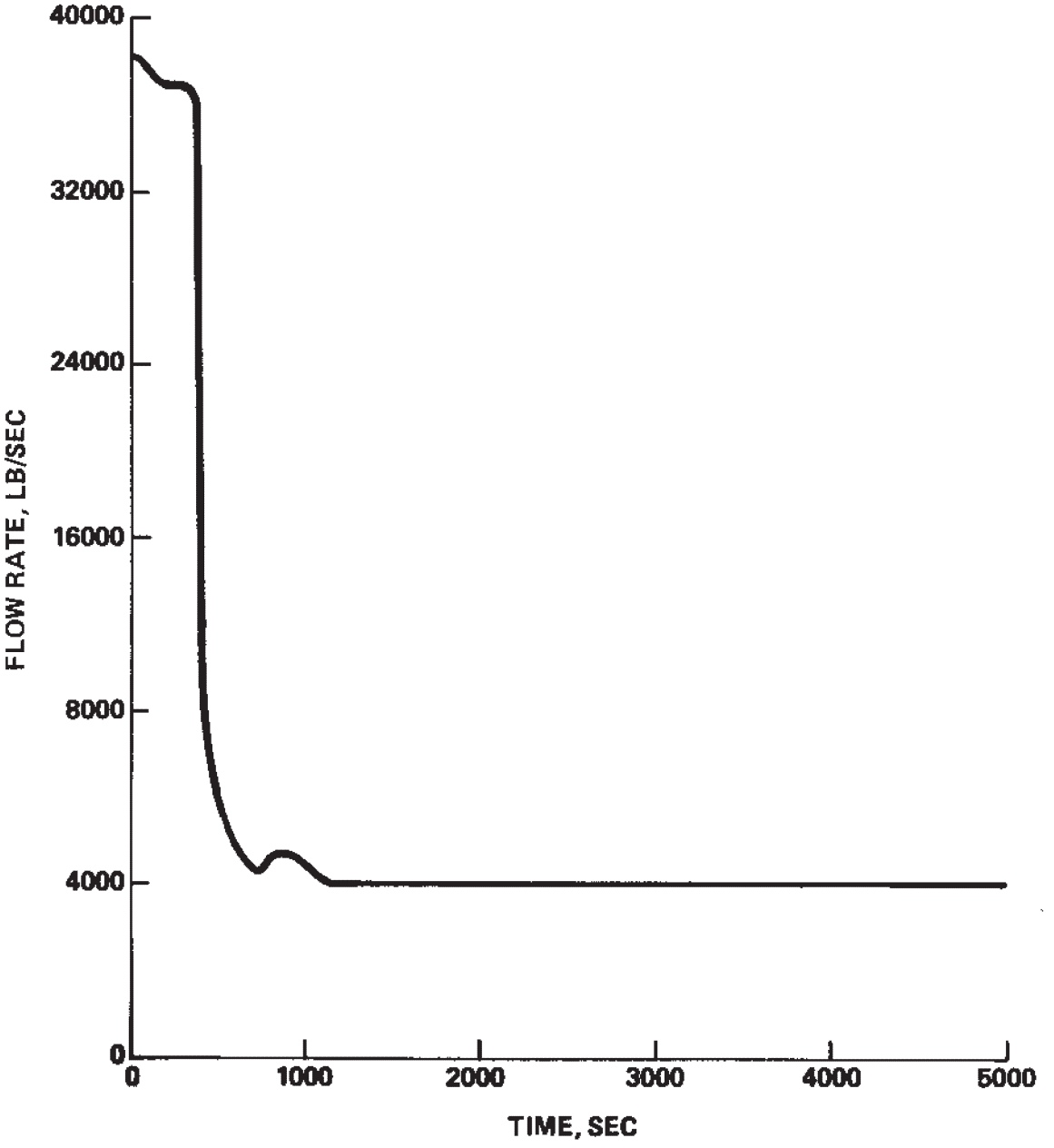
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

BREAK FLOW RATE 0.015 FT^2 BREAK IN PUMP DISCHARGE LEG

FIGURE 6.3–17c

CYCLE 1

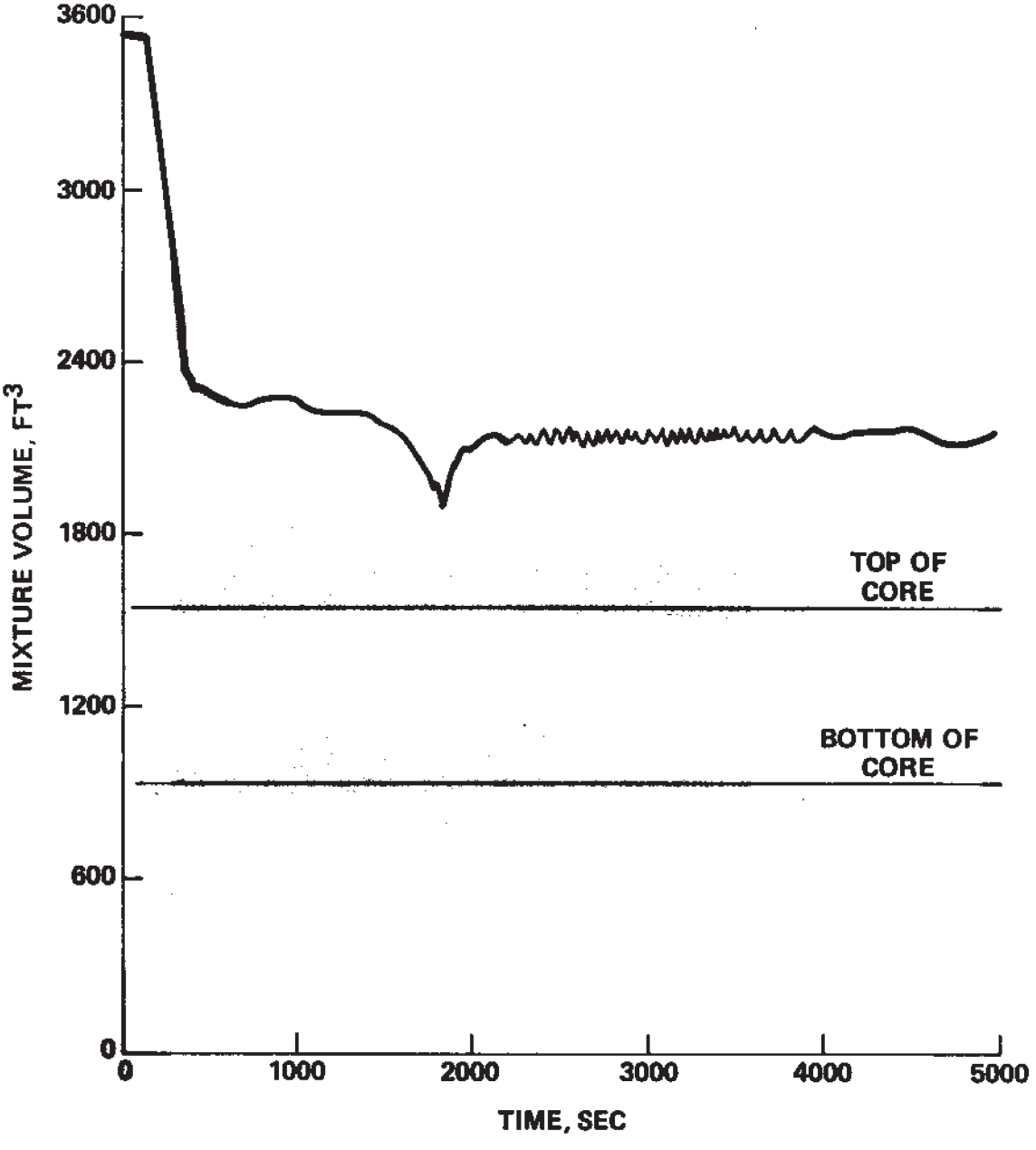


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL INLET FLOW RATE
0.015 FT^2 BREAK IN PUMP DISCH. LEG
FIGURE 6.3–17d

CYCLE 1



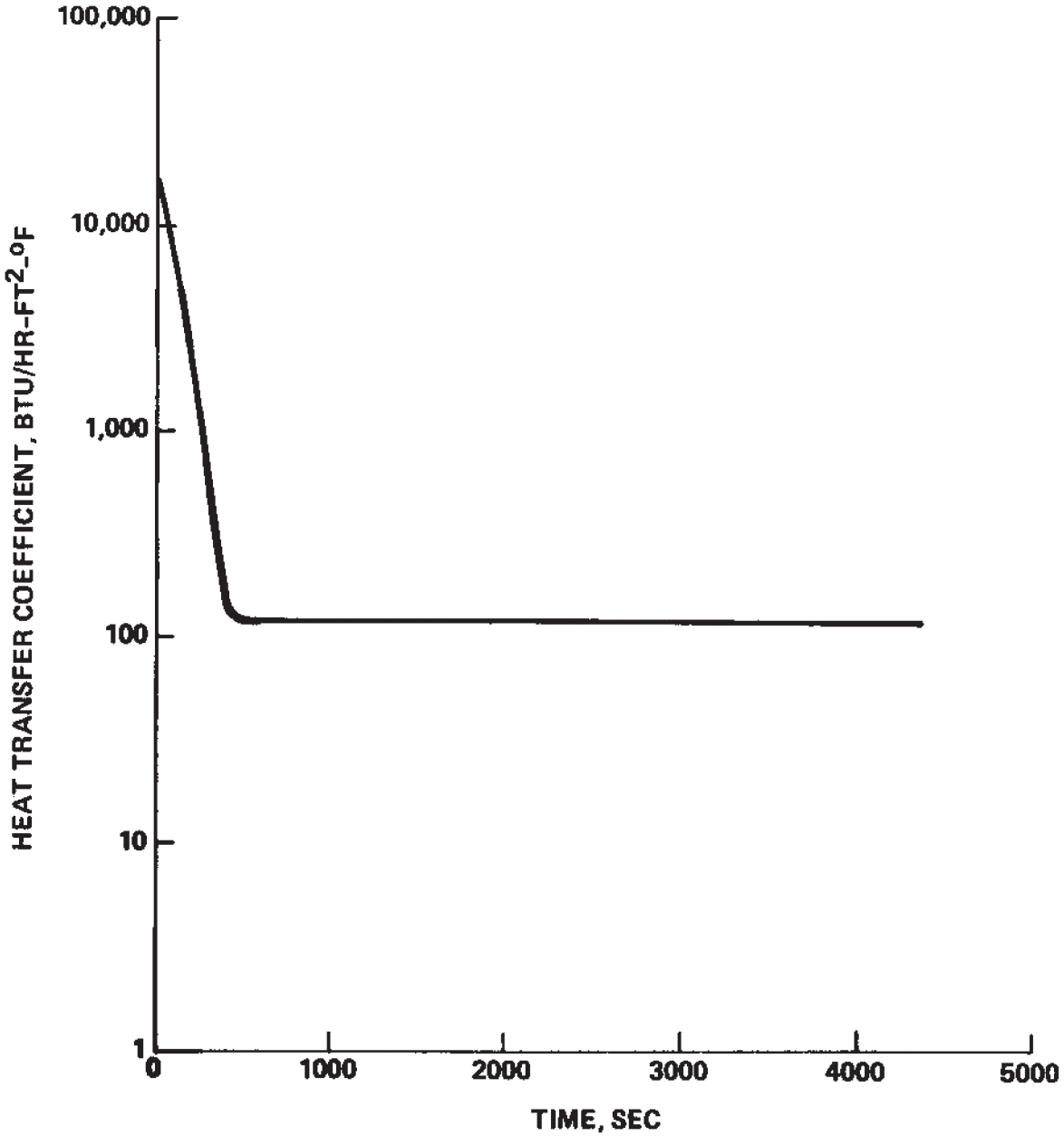
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL TWO-PHASE MIXTURE VOL.
0.015 FT^2 BREAK IN PUMP DISCH. LEG

FIGURE 6.3–17e

CYCLE 1

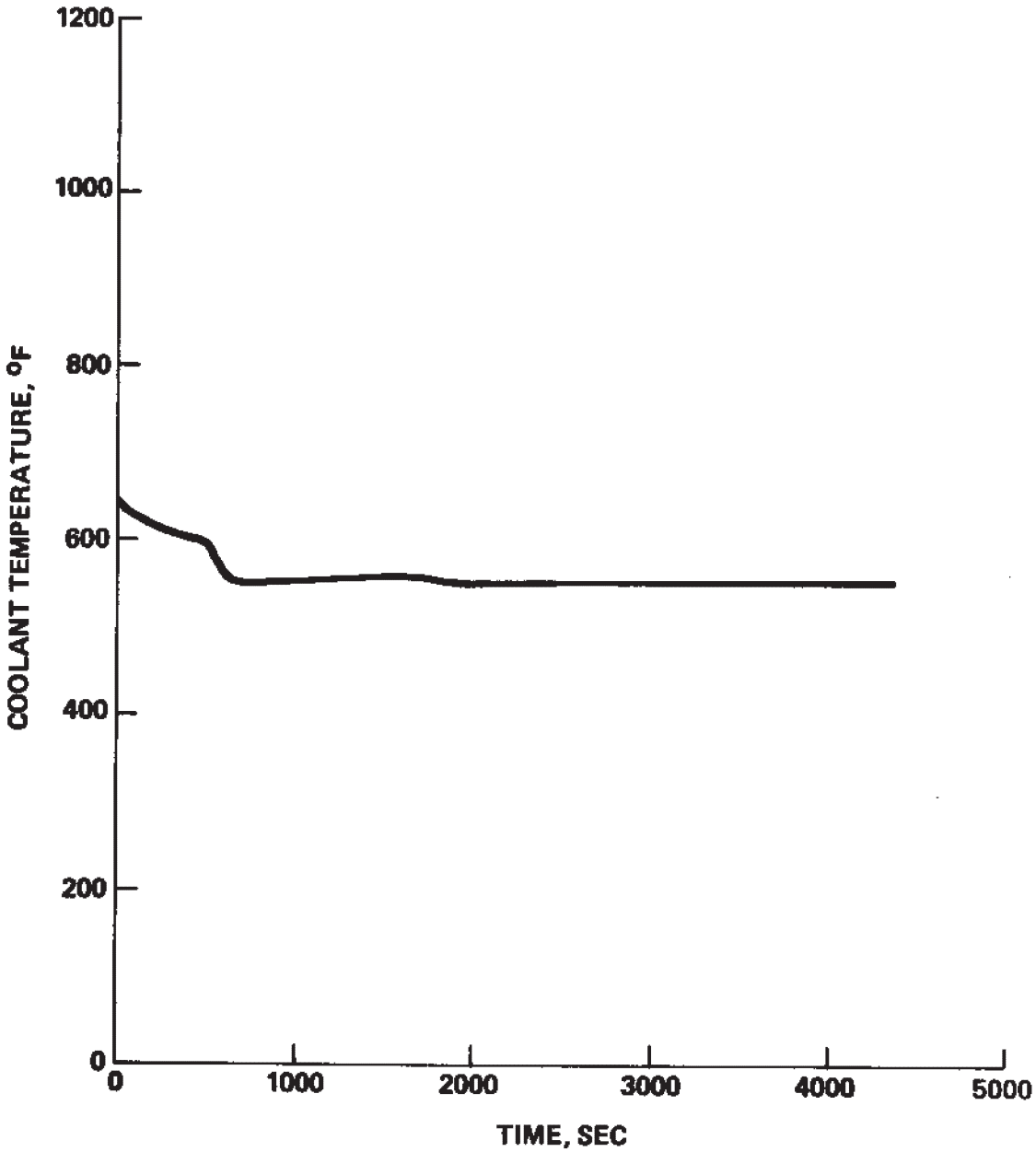


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HEAT TRANSFER COEFF. AT HOT SPOT
0.015 FT^2 BREAK IN PUMP DISCH. LEG
FIGURE 6.3–17f

CYCLE 1

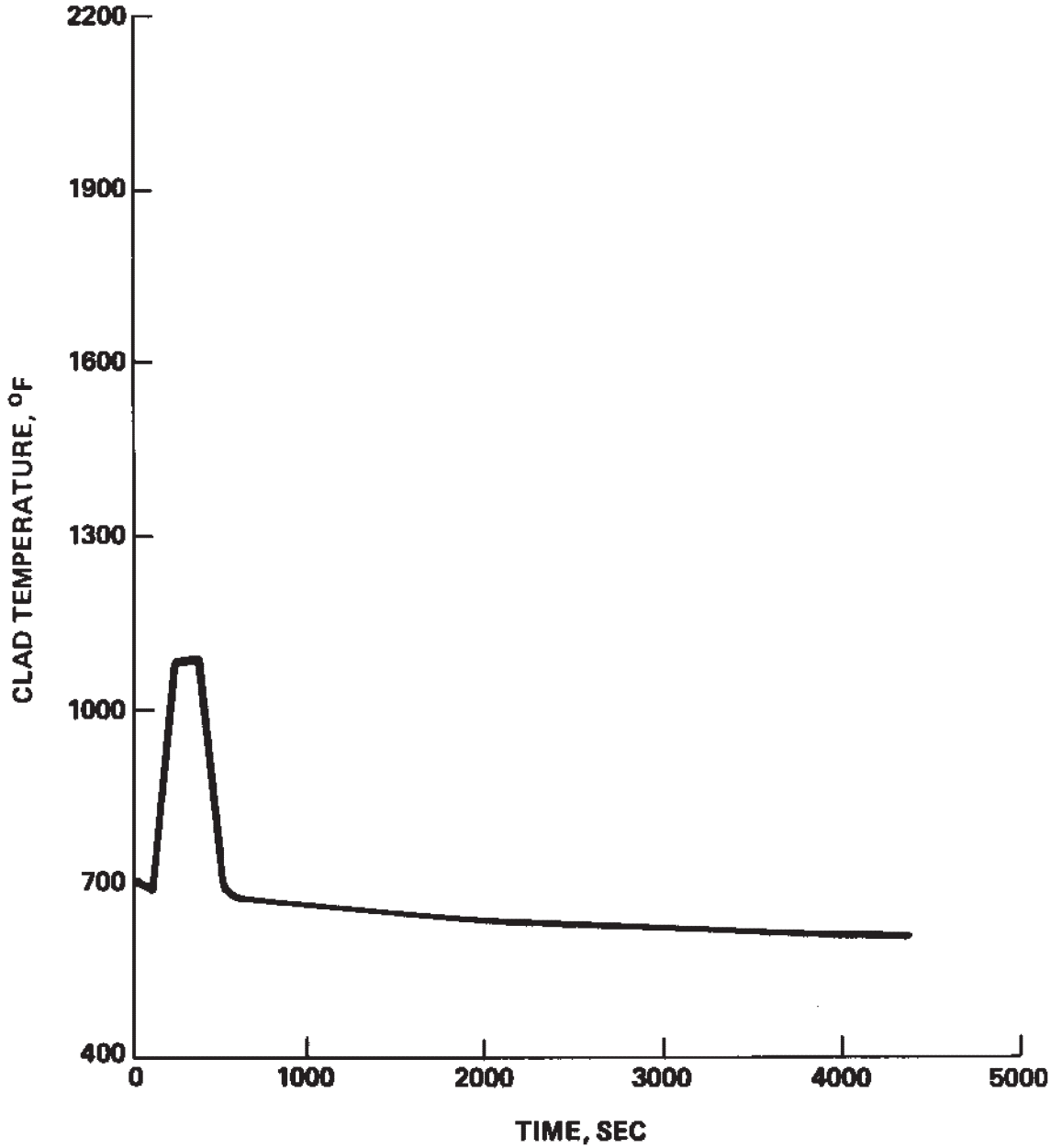


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

COOLANT TEMP. AT HOT SPOT
0.015 FT^2 BREAK IN PUMP DISCH. LEG
FIGURE 6.3–17g

CYCLE 1

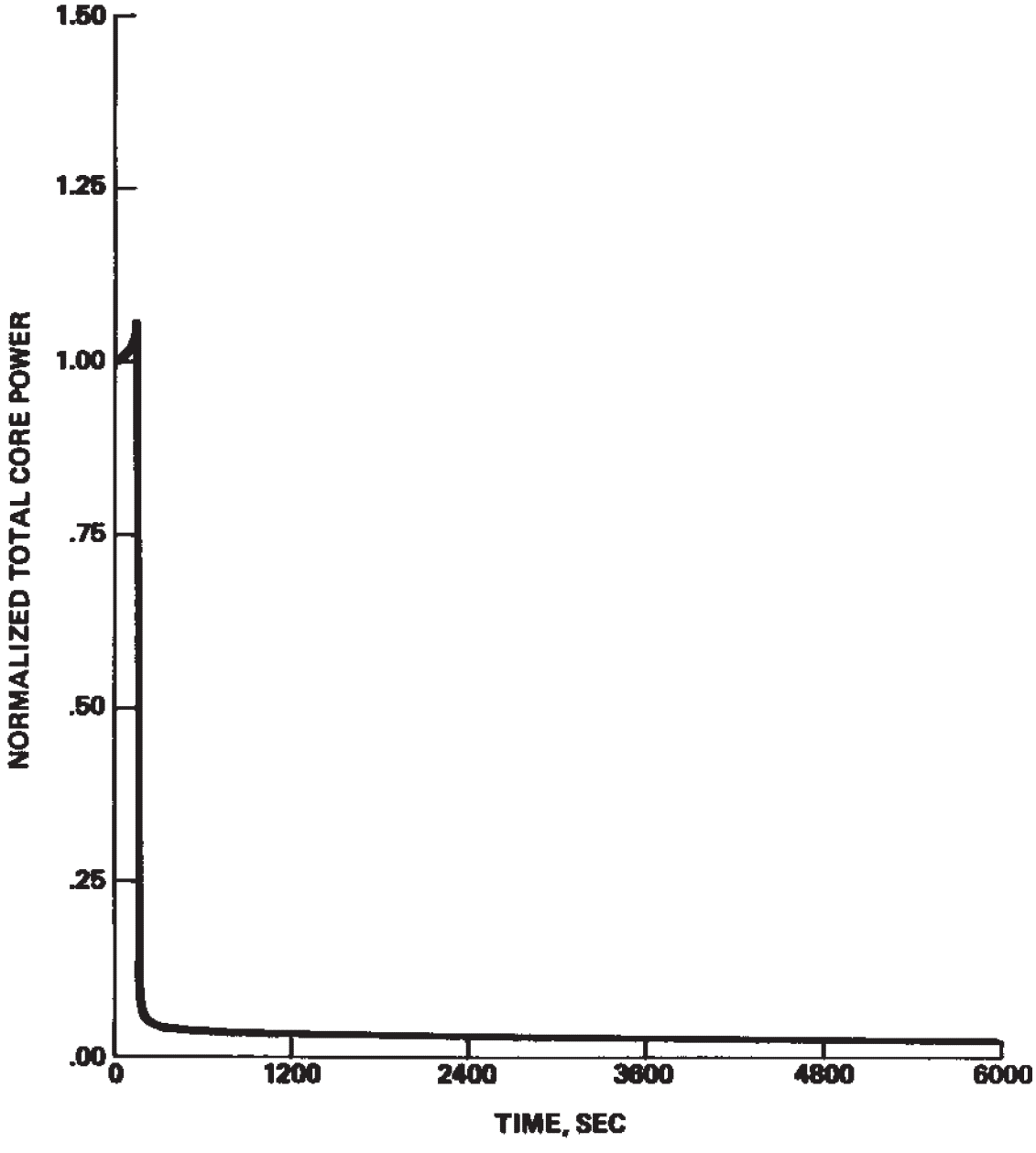


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT SPOT CLAD SURFACE TEMP.
0.015 FT^2 BREAK IN PUMP DISCH. LEG
FIGURE 6.3–17h

CYCLE 1

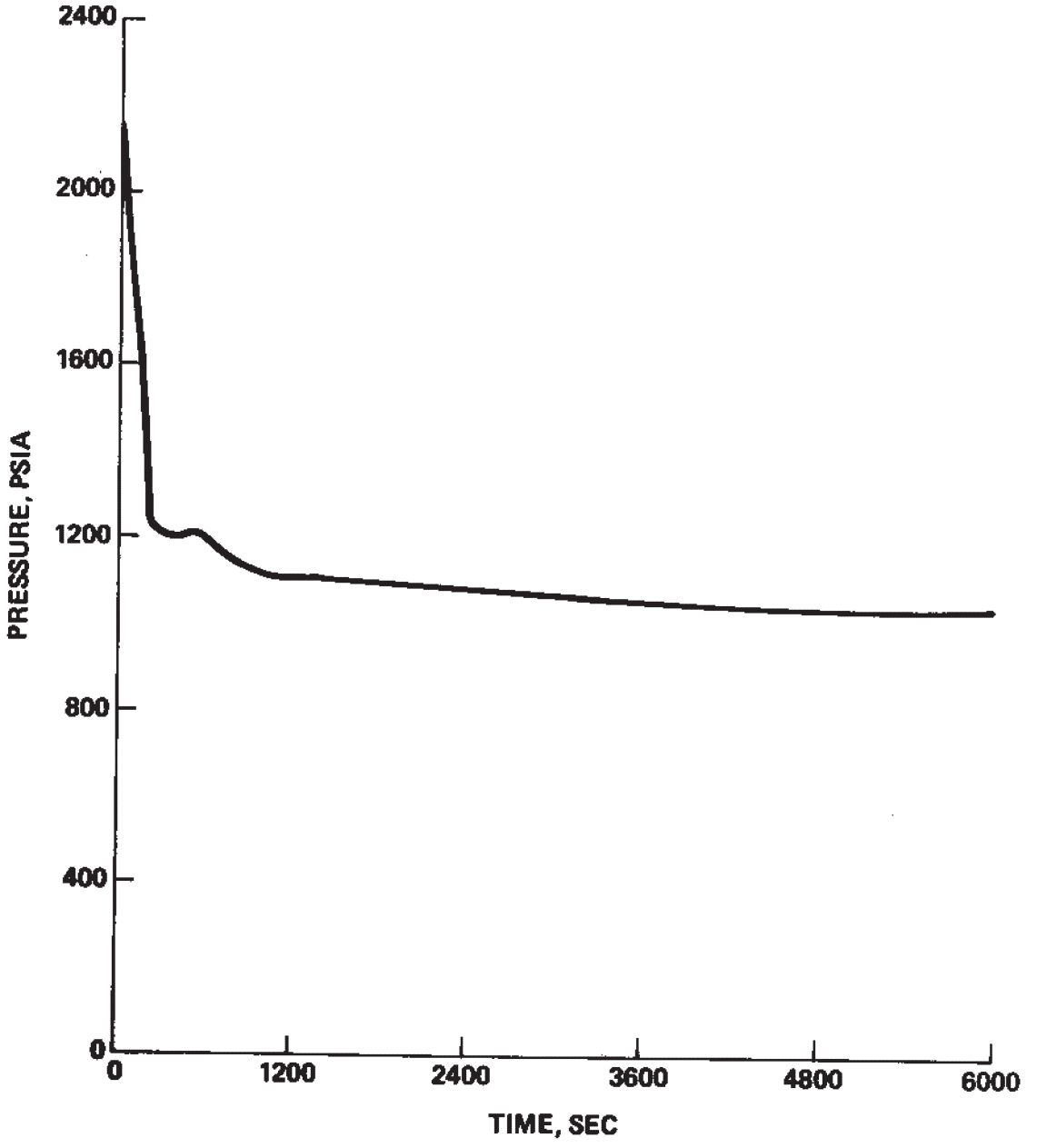


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE POWER 0.008 FT^2 BREAK
AT TOP OF PRESSURIZER
FIGURE 6.3–18a

CYCLE 1

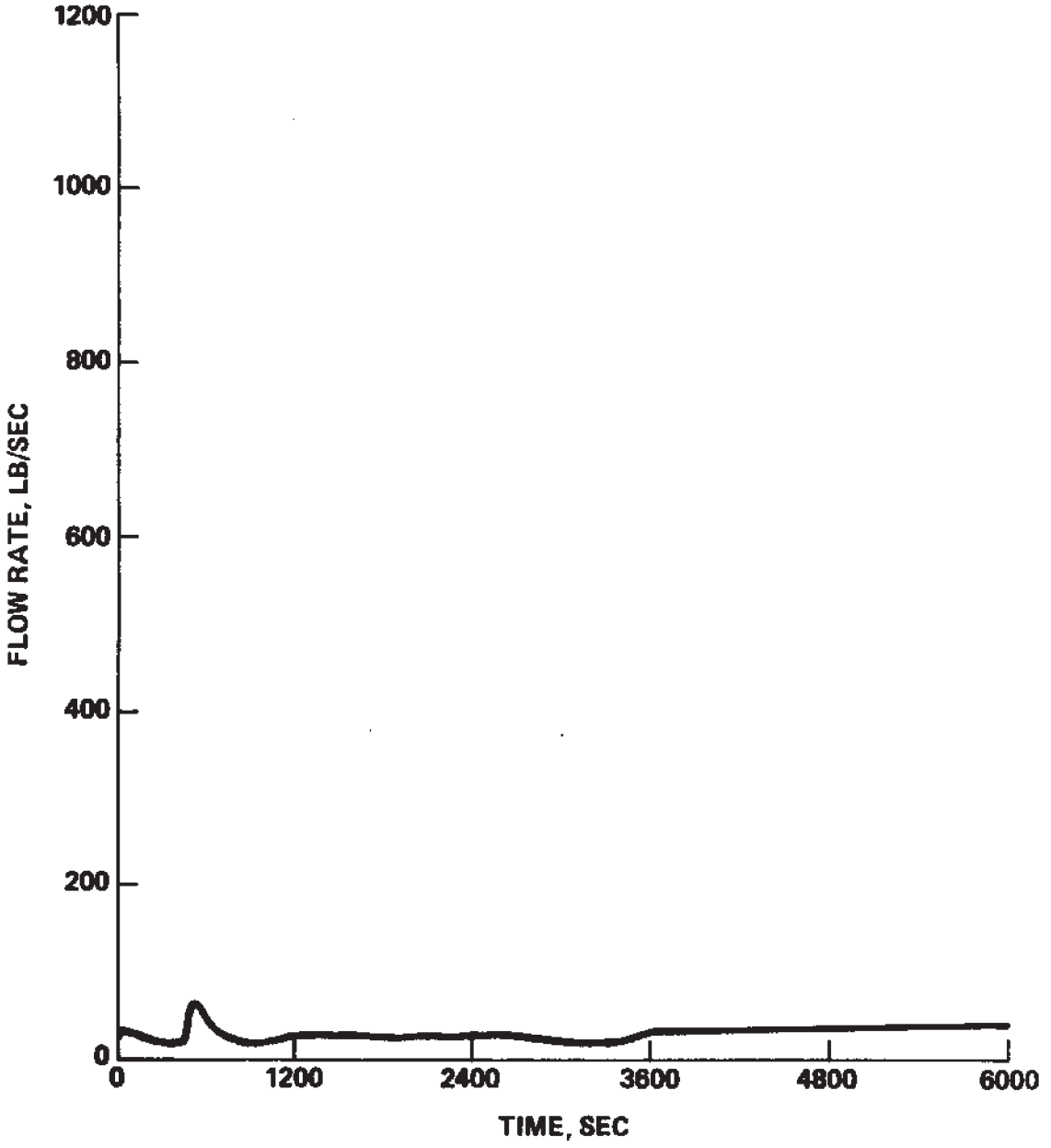


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL PRESSURE 0.008 FT^2
BREAK AT TOP OF PRESSURIZER
FIGURE 6.3–18b

CYCLE 1

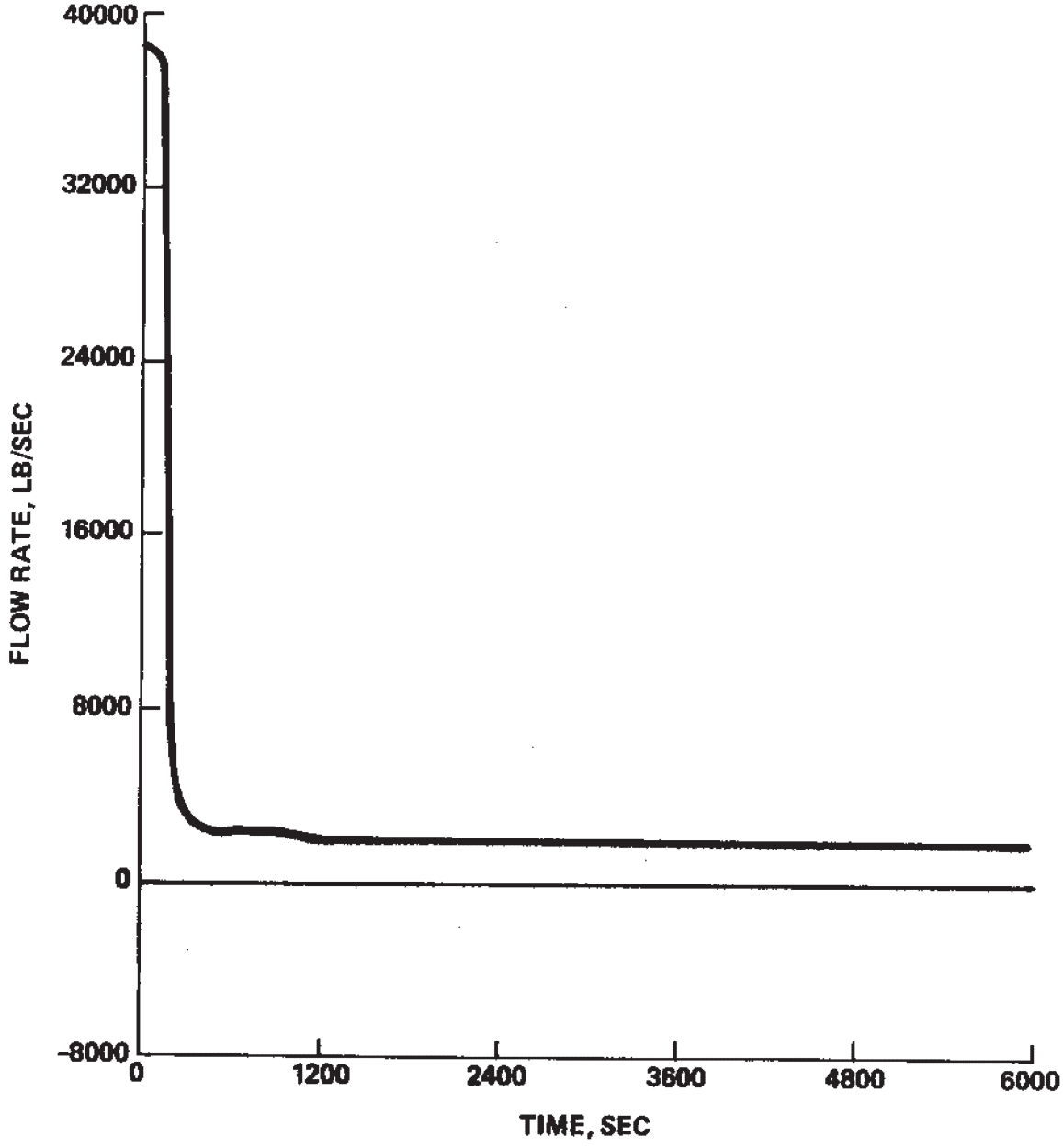


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

BREAK FLOW RATE 0.008 FT^2
BREAK AT TOP OF PRESSURIZER
FIGURE 6.3–18c

CYCLE 1

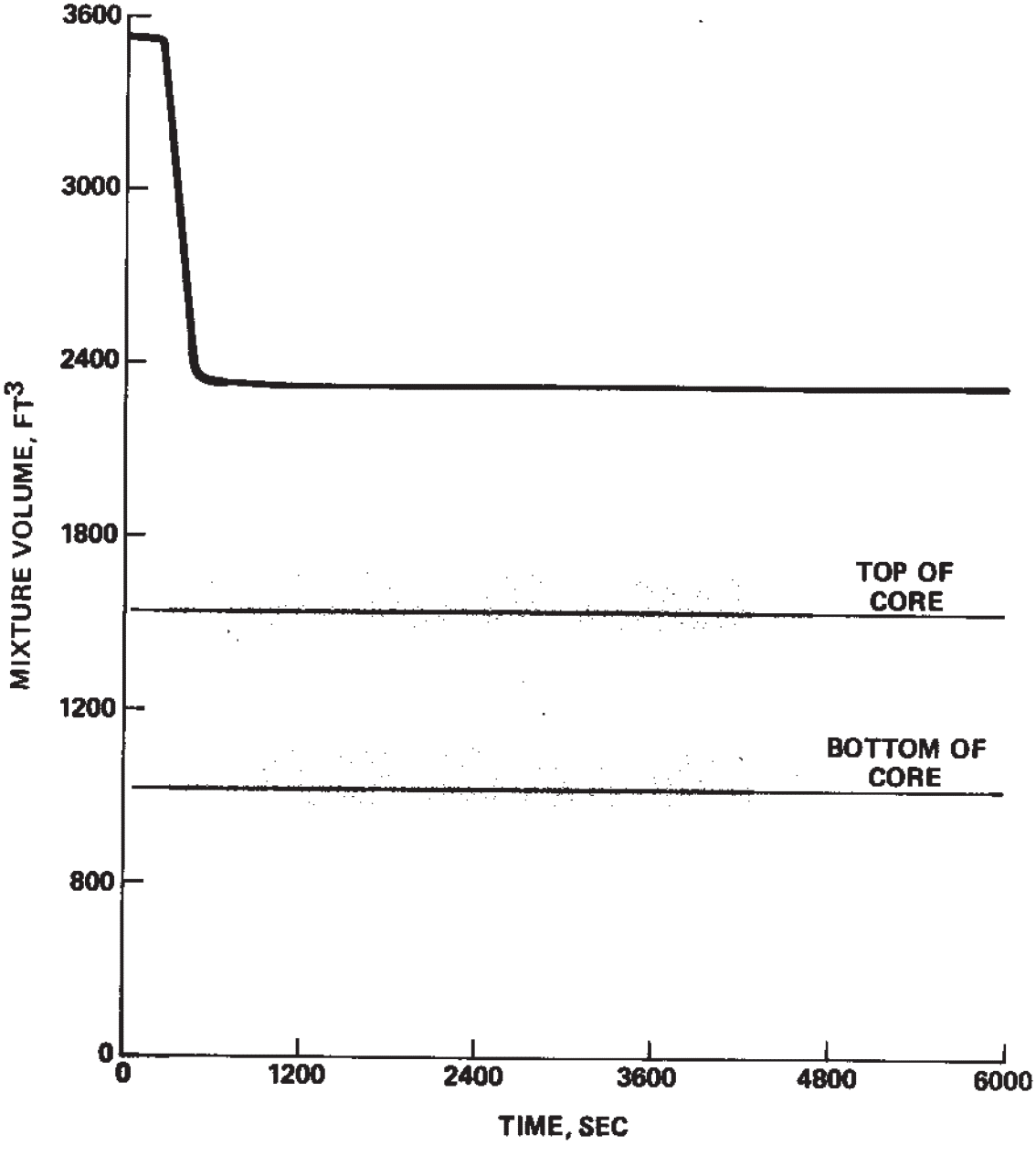


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL INLET FLOW RATE
0.008 FT^2 BRK. AT TOP OF PRESS.
FIGURE 6.3–18d

CYCLE 1

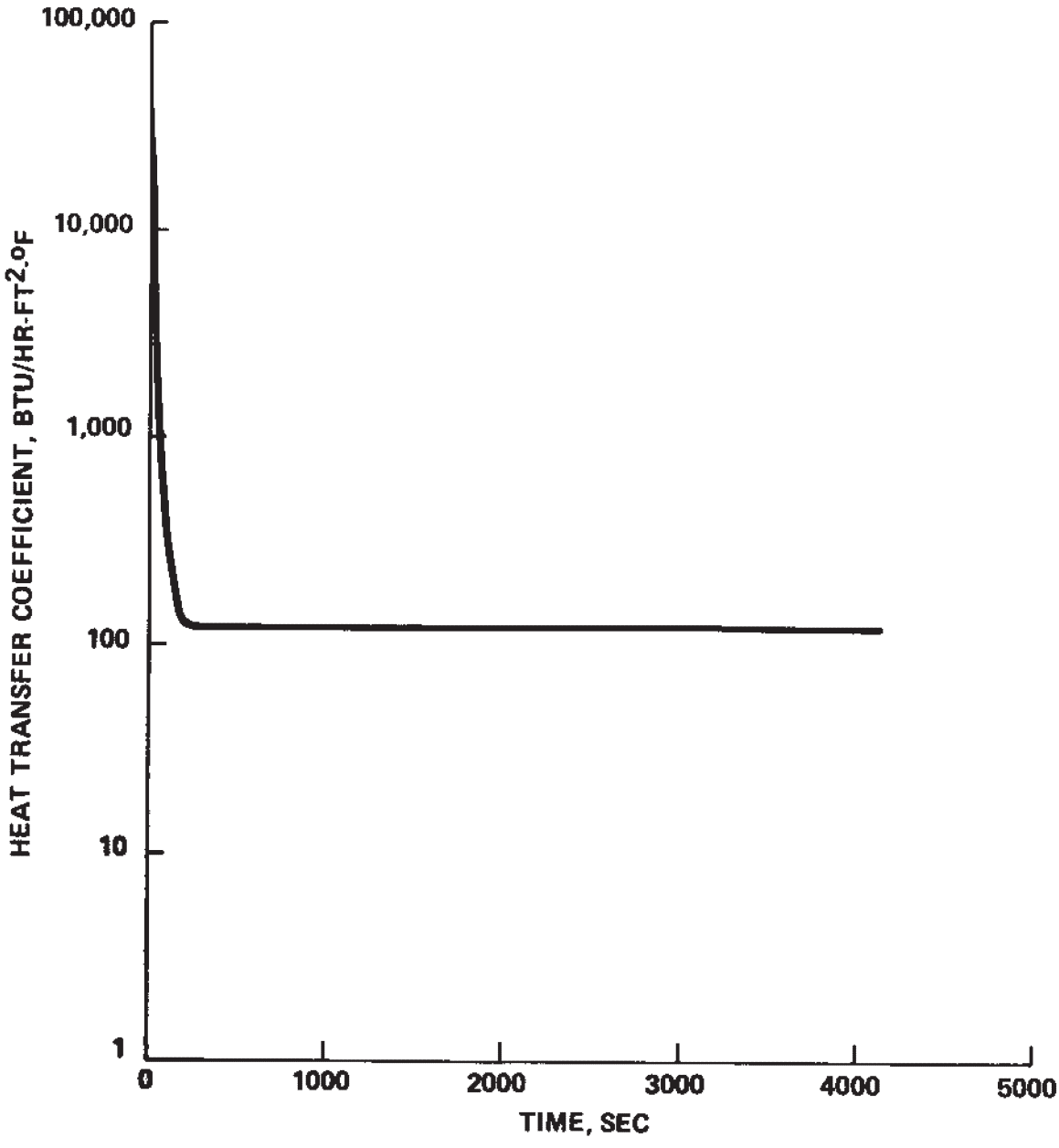


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL TWO-PHASE MIXTURE VOL.
0.008 FT^2 BRK. AT TOP OF PRESSURIZER
FIGURE 6.3–18e

CYCLE 1

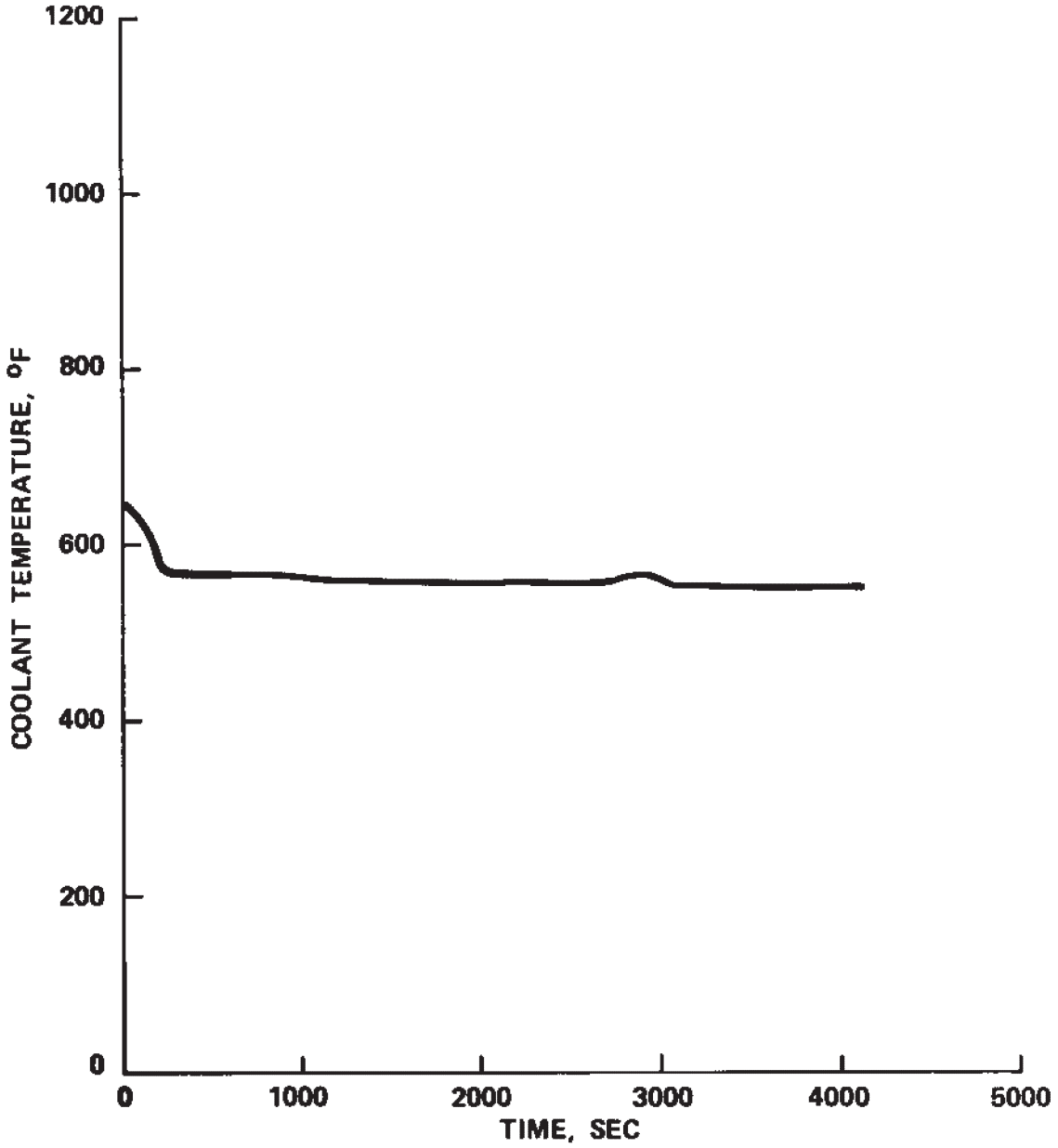


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HEAT TRANSFER COEFF. AT HOT SPOT
0.008 FT^2 BRK. AT TOP OF PRESSURIZER
FIGURE 6.3–18f

CYCLE 1

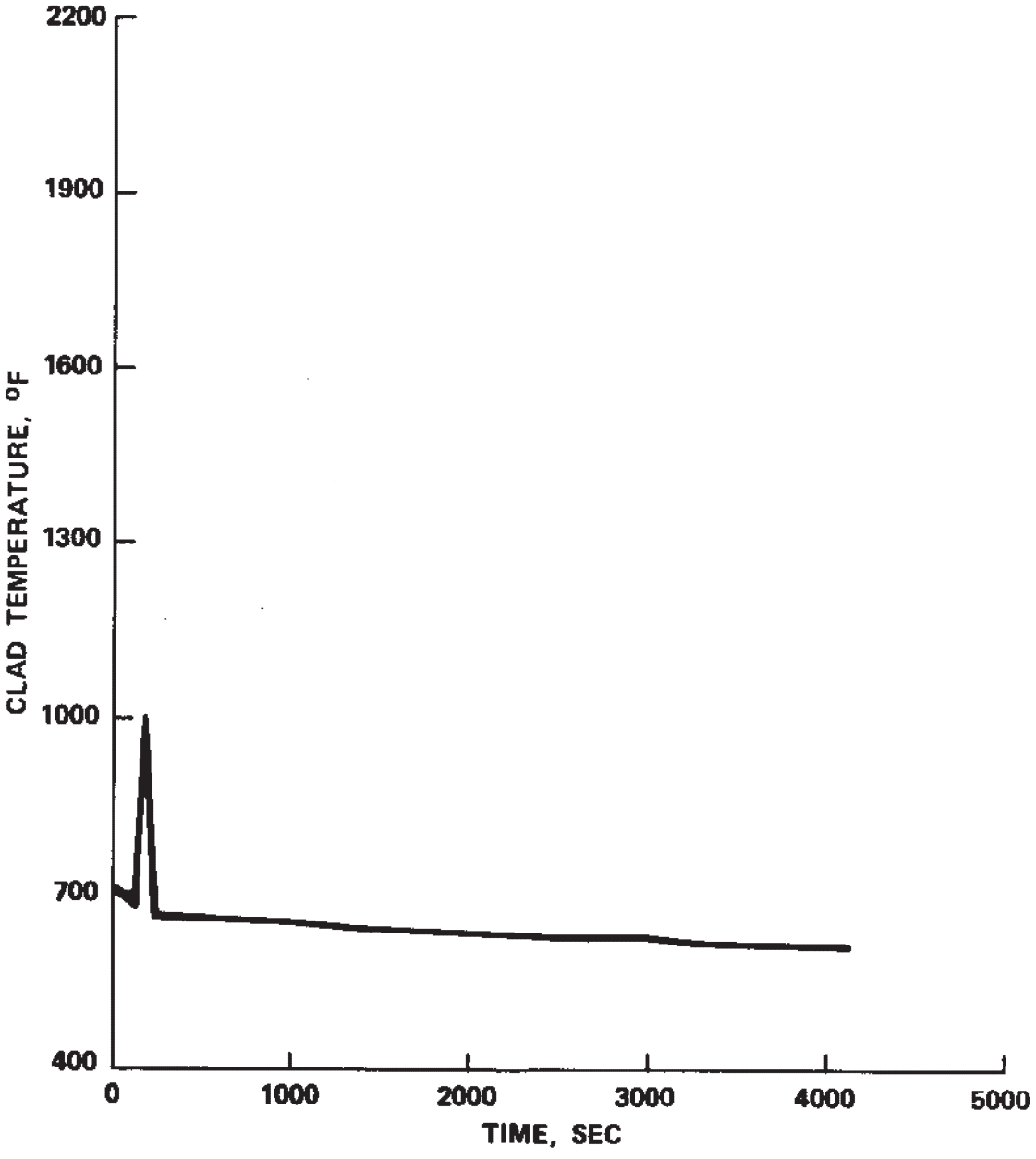


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

COOLANT TEMP. AT HOT SPOT 0.008 FT^2
BREAK AT TOP OF PRESSURIZER
FIGURE 6.3–18g

CYCLE 1

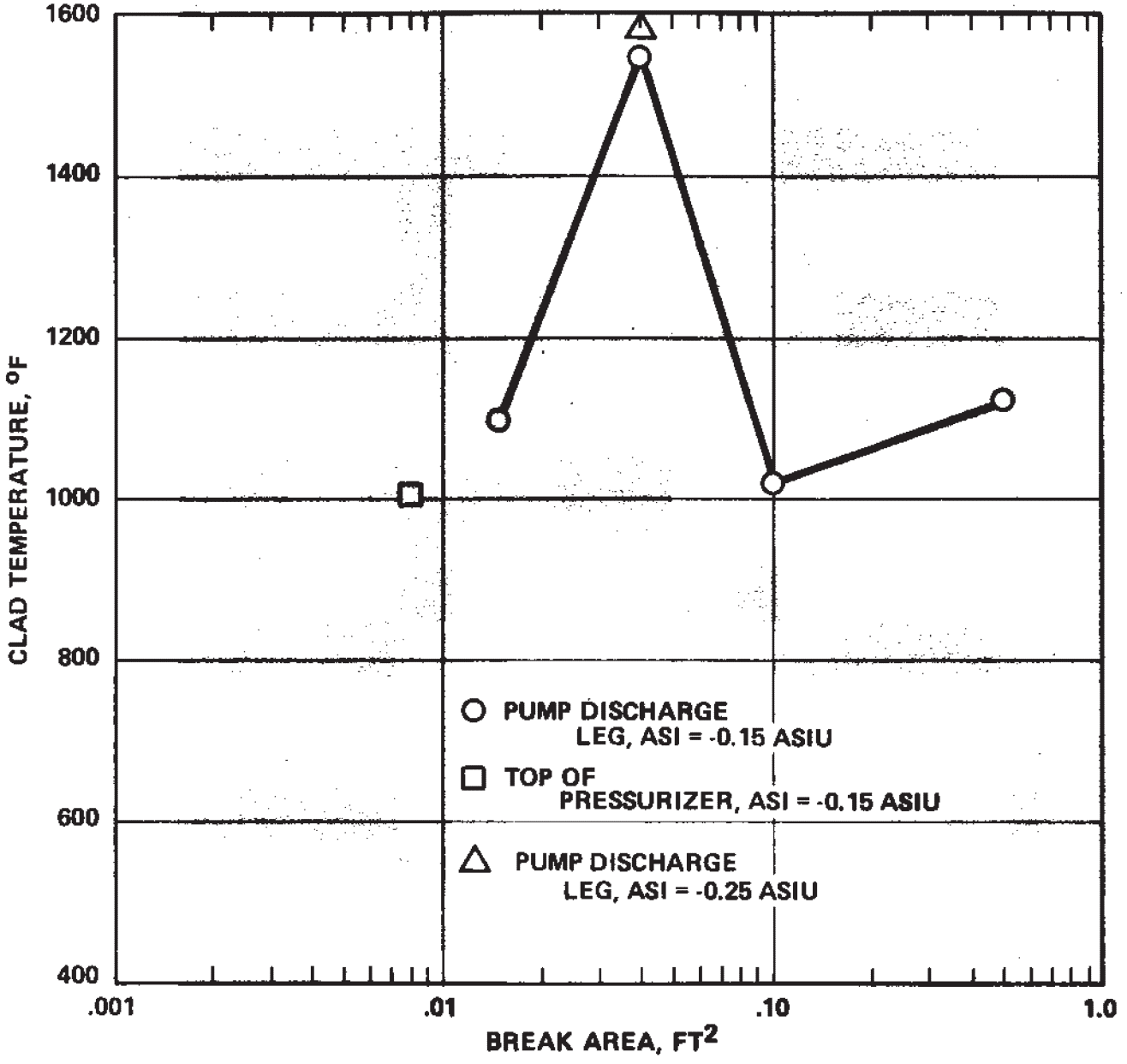


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HOT SPOT CLAD SURFACE TEMP. 0.008 FT^2
BREAK AT TOP OF PRESSURIZER
FIGURE 6.3–18h

CYCLE 1

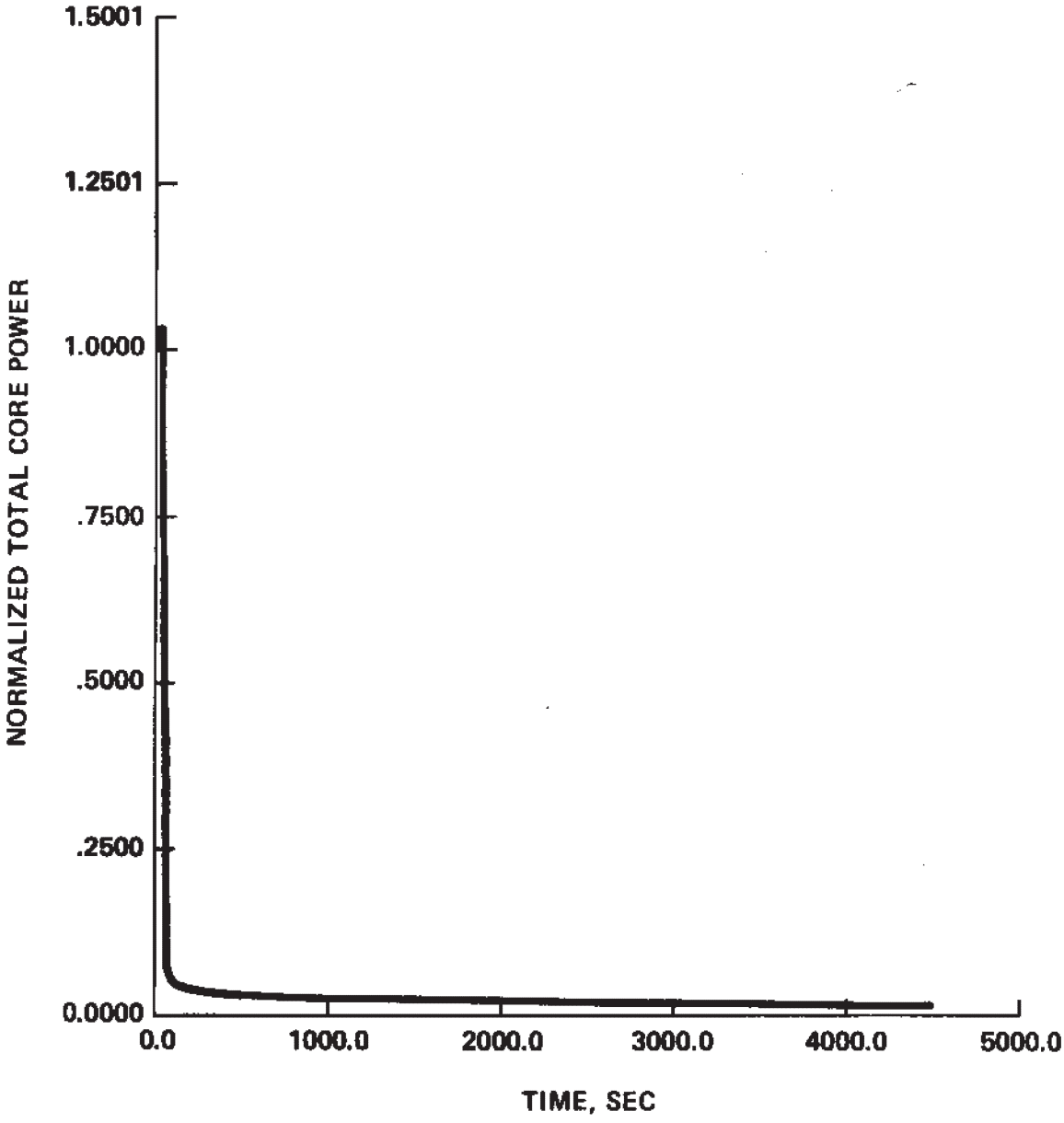


AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

MAXIMUM HOT SPOT CLAD TEMP.
VS. BREAK AREA
FIGURE 6.3–19

CYCLE 1



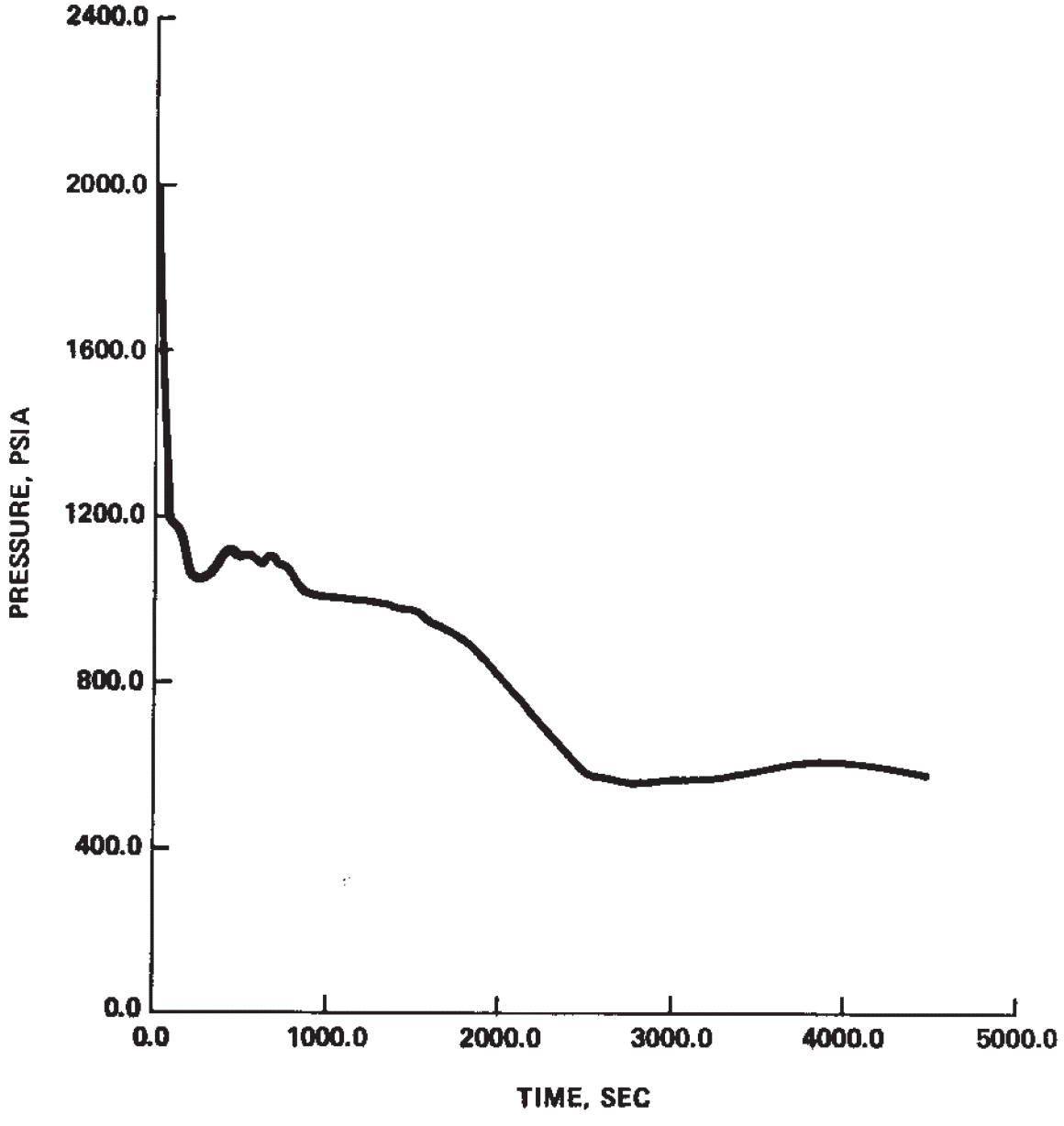
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

0.04 FT^2 BREAK IN PUMP DISCHARGE LEG
CORE POWER

FIGURE 6.3-19a

CYCLE 1



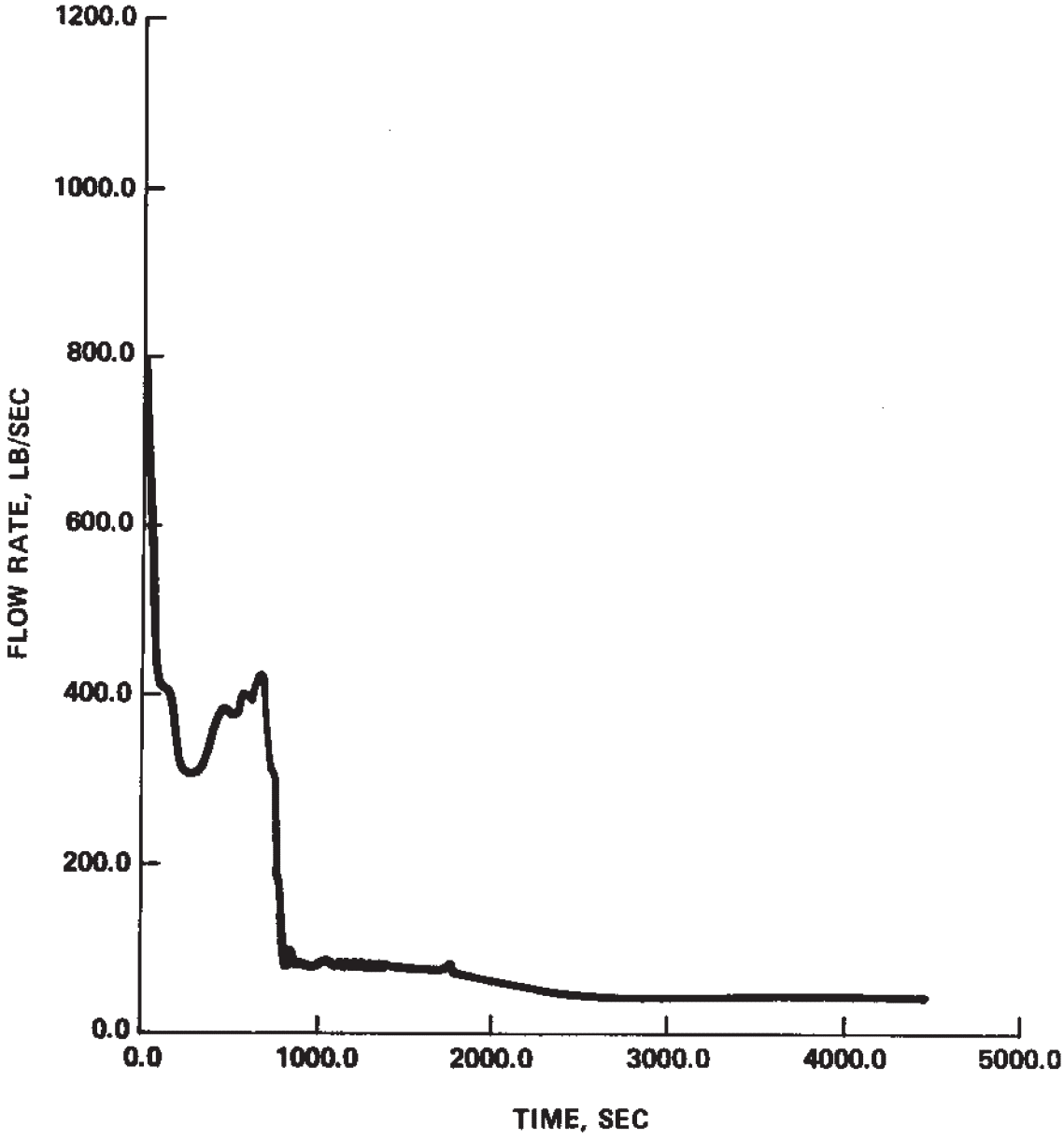
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

0.04 FT^2 BREAK IN PUMP DISCHARGE LEG
INNER VESSEL PRESSURE

CYCLE 1

FIGURE 6.3-19b



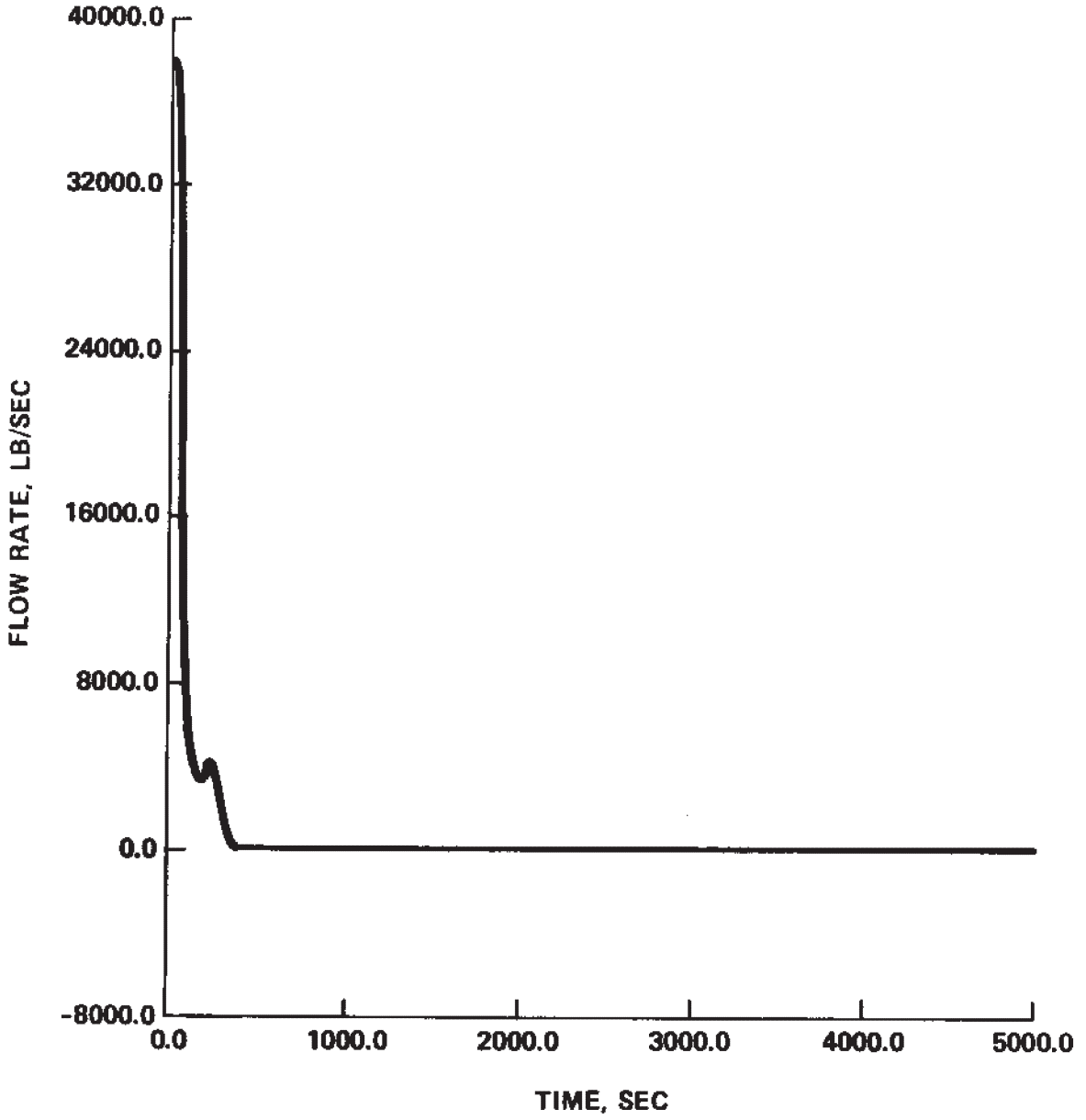
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

0.04 FT^2 BREAK IN PUMP DISCHARGE LEG
BREAK FLOW RATE

FIGURE 6.3-19c

CYCLE 1



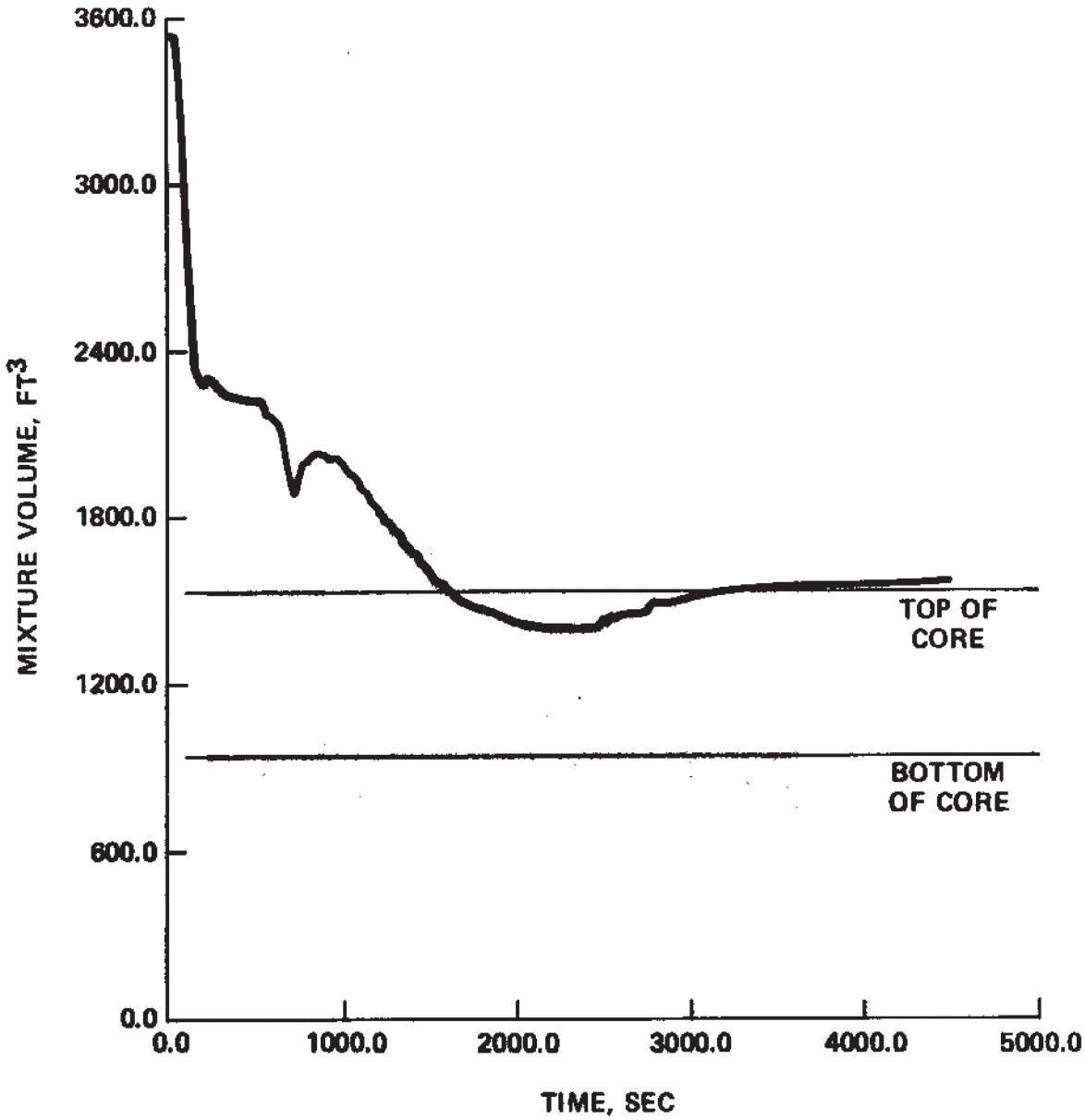
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

0.04 FT^2 BREAK IN PUMP DISCHARGE LEG
INNER VESSEL INLET FLOW RATE

FIGURE 6.3-19d

CYCLE 1



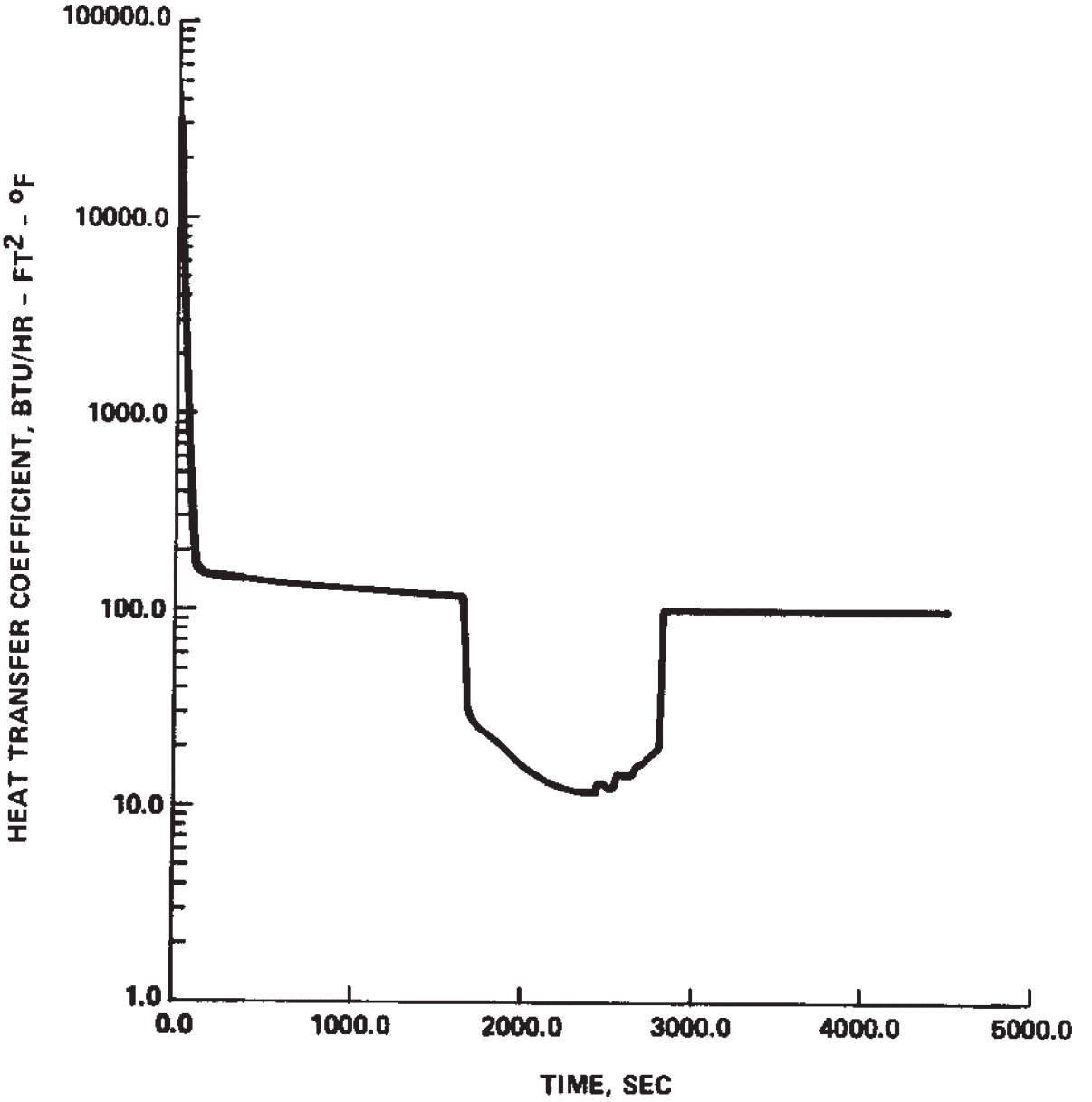
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

0.04 FT^2 BREAK IN PUMP DISCHARGE LEG
INNER VESSEL TWO-PHASE
MIXTURE VOLUME

FIGURE 6.3-19e

CYCLE 1



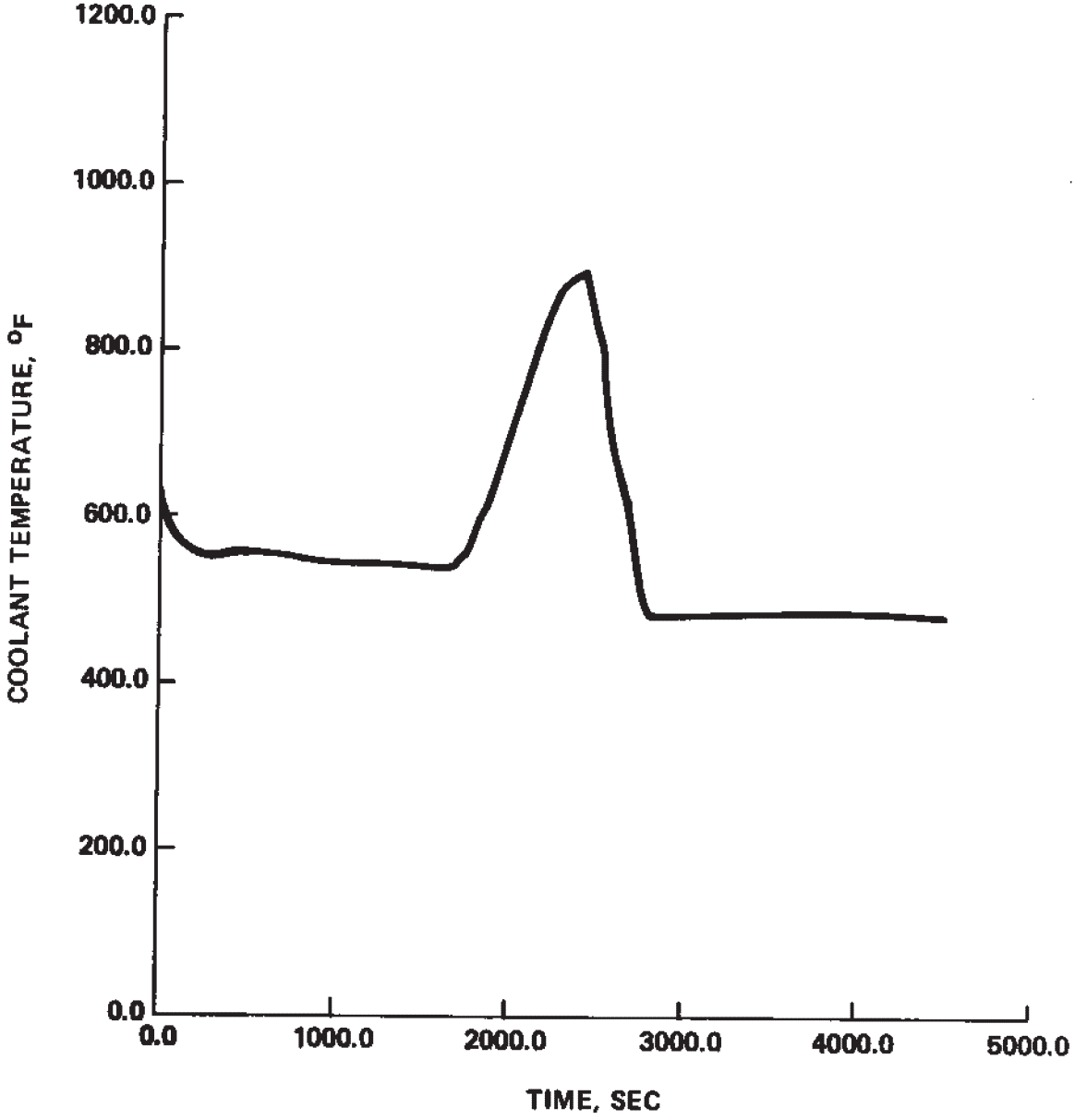
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

0.04 FT^2 BREAK IN PUMP DISCHARGE LEG
HEAT TRANSFER COEFFICIENT
AT HOT SPOT

CYCLE 1

FIGURE 6.3-19f



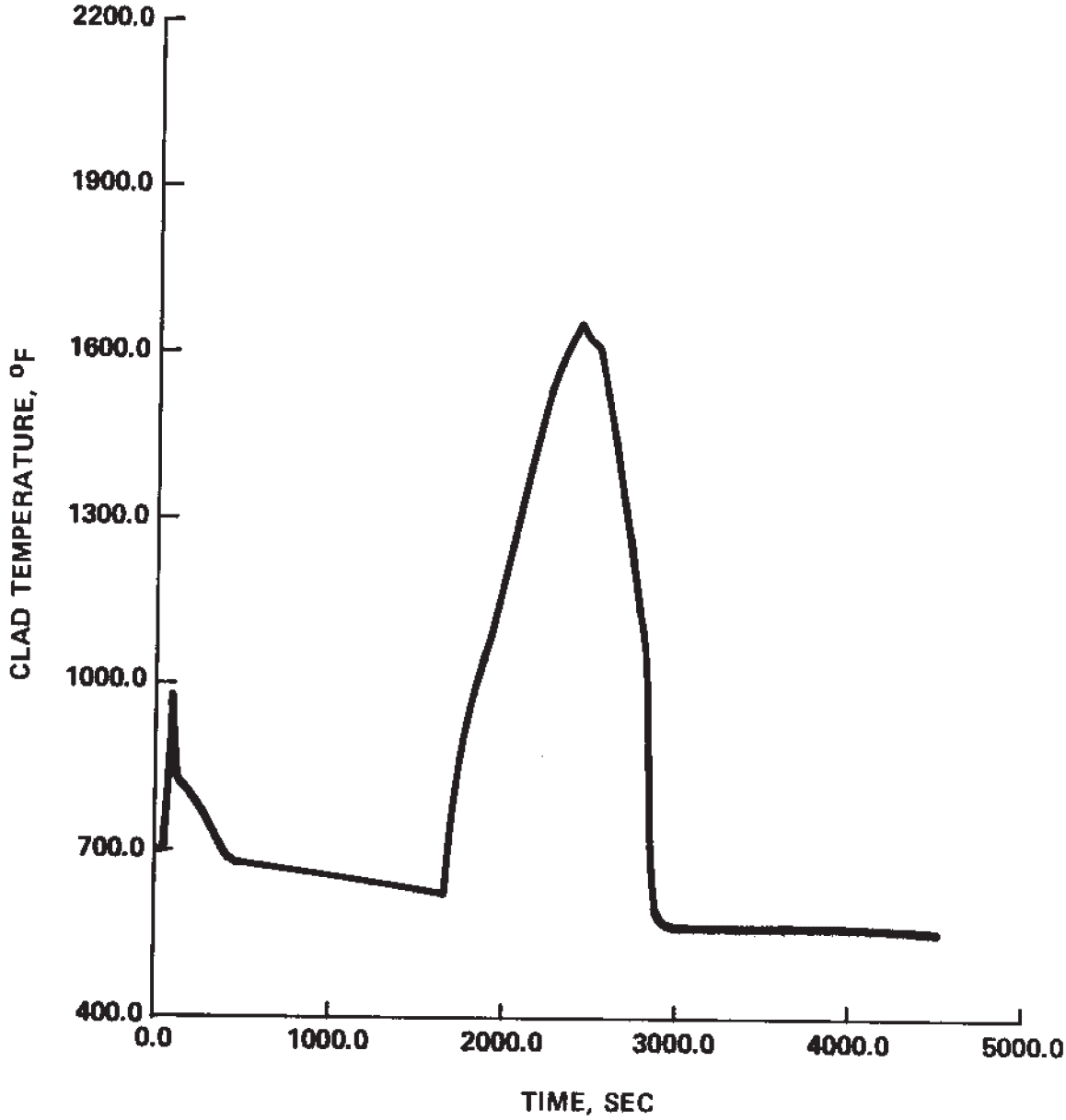
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

0.04 FT^2 BREAK IN PUMP DISCHARGE LEG
COOLANT TEMPERATURE AT HOT SPOT

CYCLE 1

FIGURE 6.3-19g



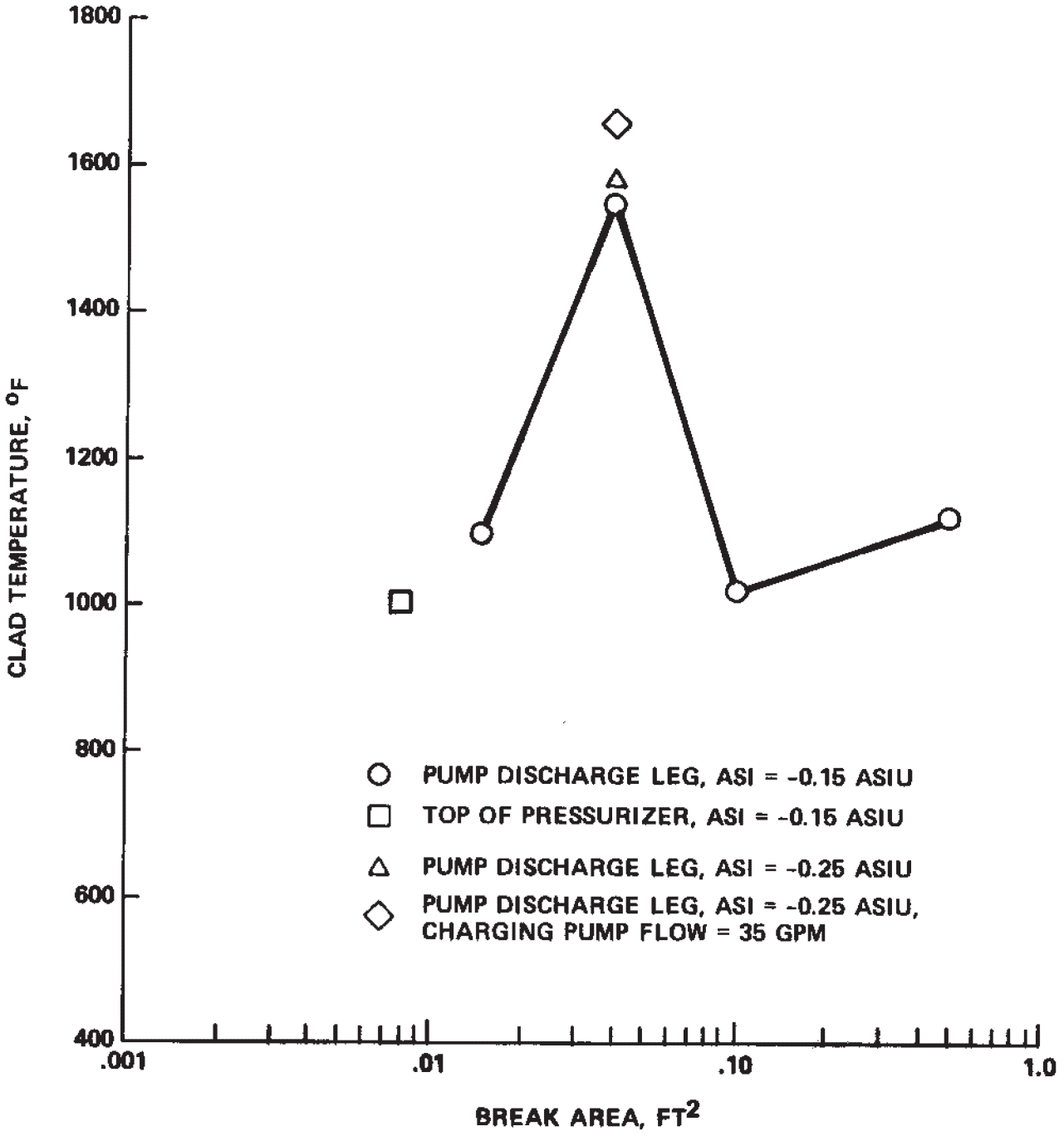
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

0.04 FT^2 BREAK IN PUMP DISCHARGE LEG
HOT SPOT CLAD SURFACE TEMPERATURE

CYCLE 1

FIGURE 6.3-19h



AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

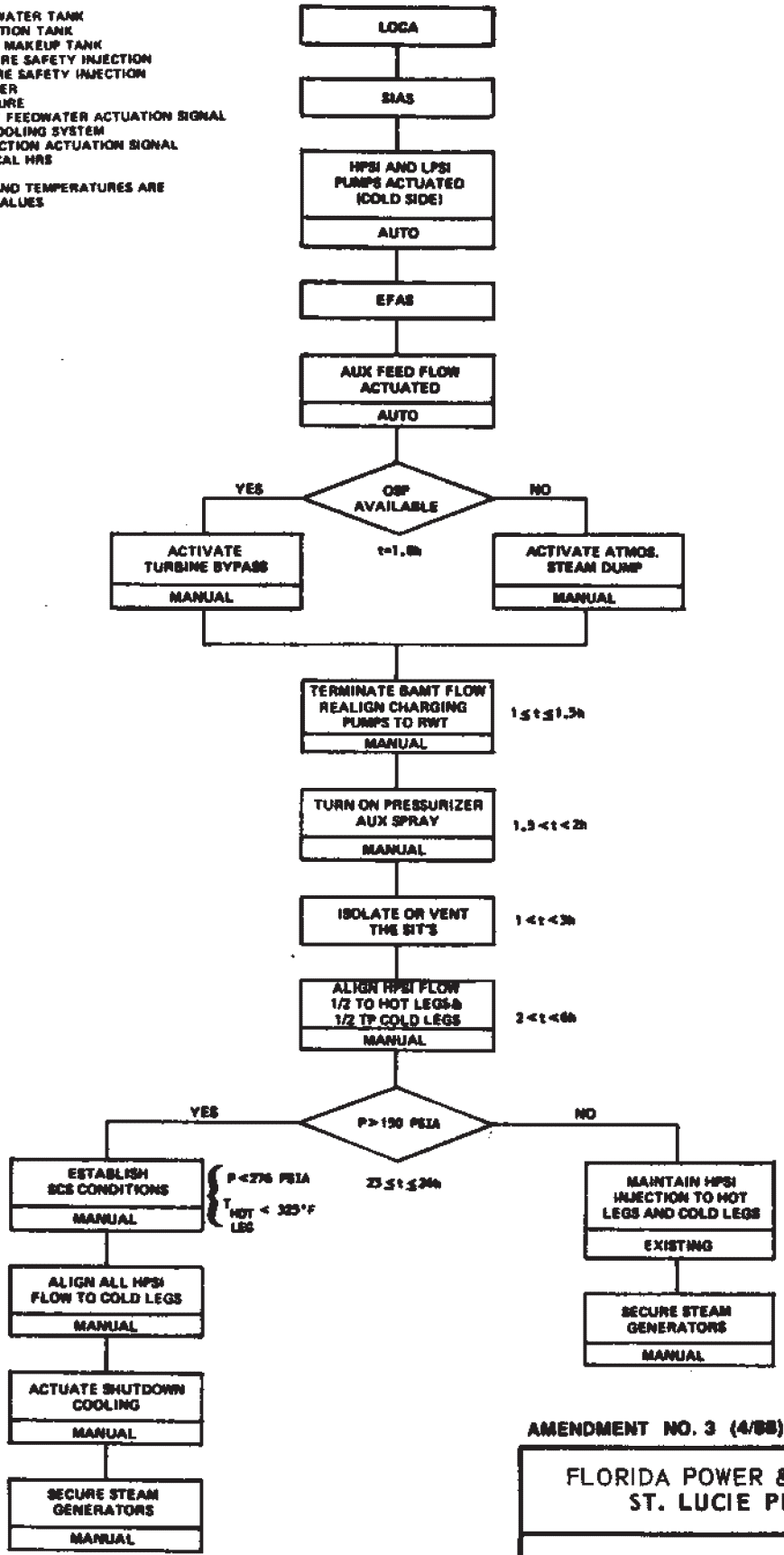
MAXIMUM HOT SPOT CLAD TEMPERATURE VS. BREAK AREA

FIGURE 6.3-20

CYCLE 1

RWT - REFUELING WATER TANK
SIT - SAFETY INJECTION TANK
BAMT - BORIC ACID MAKEUP TANK
HPSI - HIGH PRESSURE SAFETY INJECTION
LPSI - LOW PRESSURE SAFETY INJECTION
OSP - OFF-SITE POWER
P - PRIMARY PRESSURE
EFAS - EMERGENCY FEEDWATER ACTUATION SIGNAL
SCS - SHUTDOWN COOLING SYSTEM
SIAS - SAFETY INJECTION ACTUATION SIGNAL
t - TIME AFTER LOCAL HRS

NOTE: PRESSURES AND TEMPERATURES ARE INDICATED VALUES

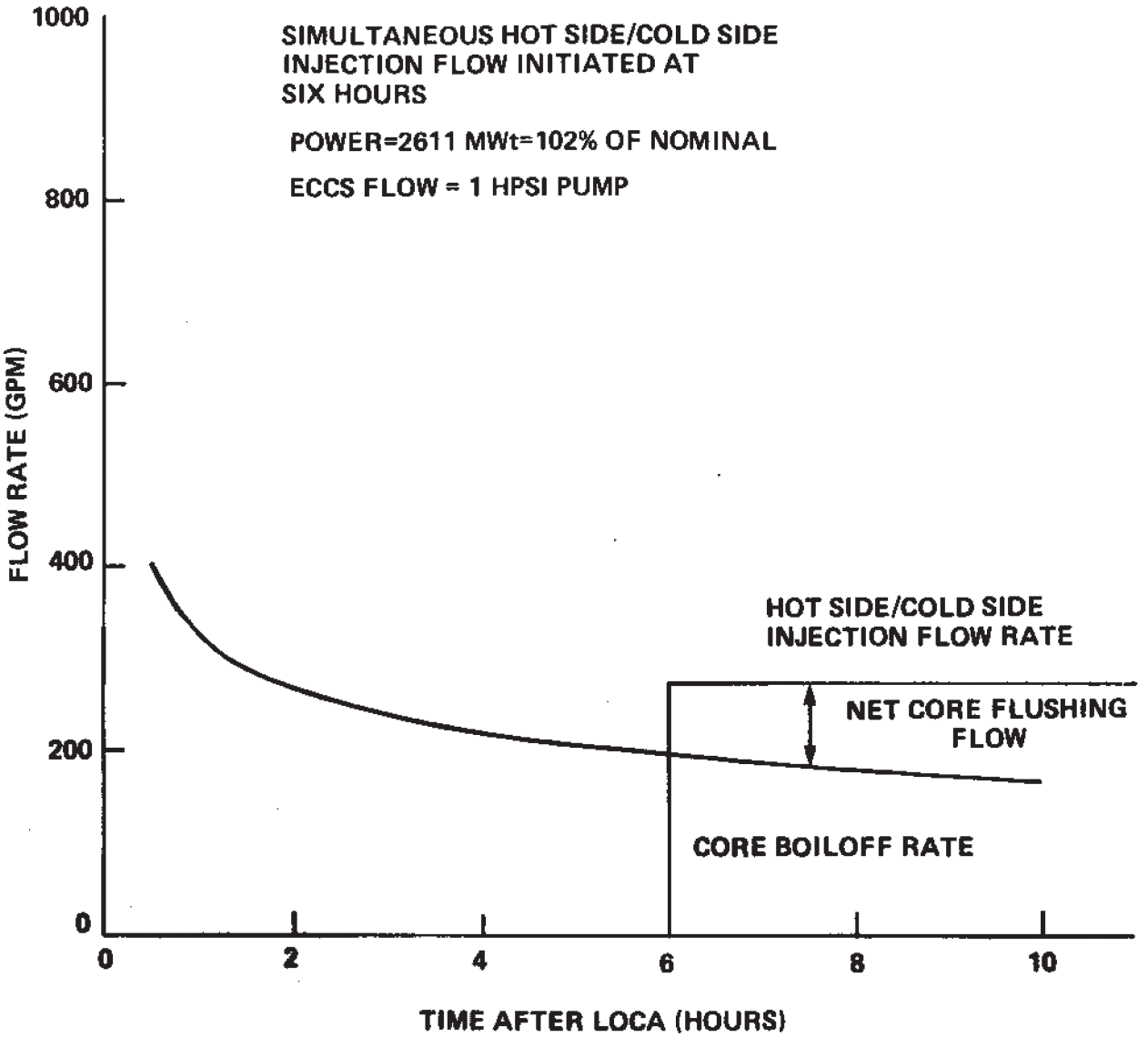


AMENDMENT NO. 3 (4/88)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LONG-TERM COOLING PLAN

FIGURE 6.3-21



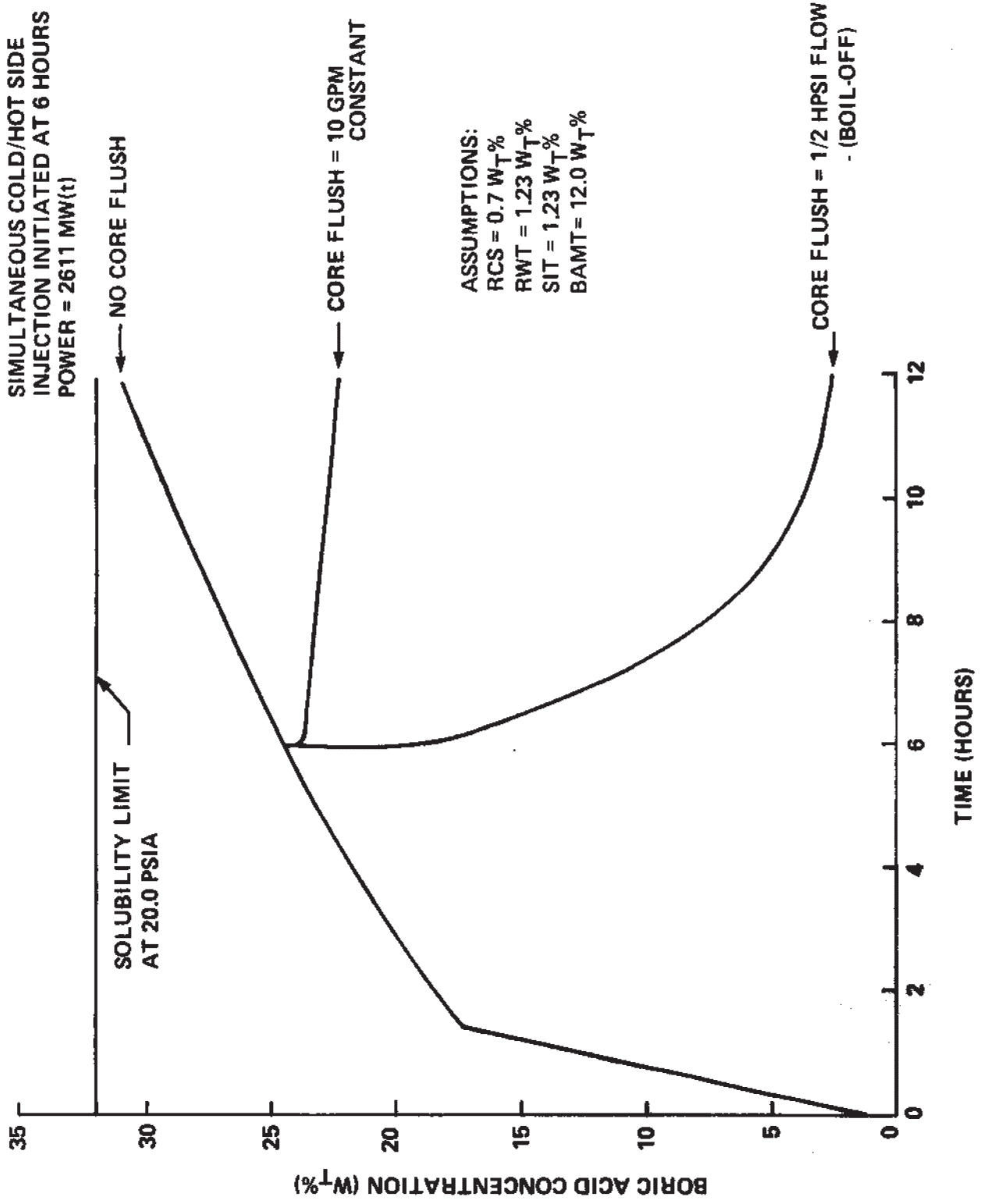
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CORE FLUSH BY HOT SIDE INJECTION
FOR 9.8 FT^2 COLD LEG BREAK

FIGURE 6.3-22

CYCLE 1



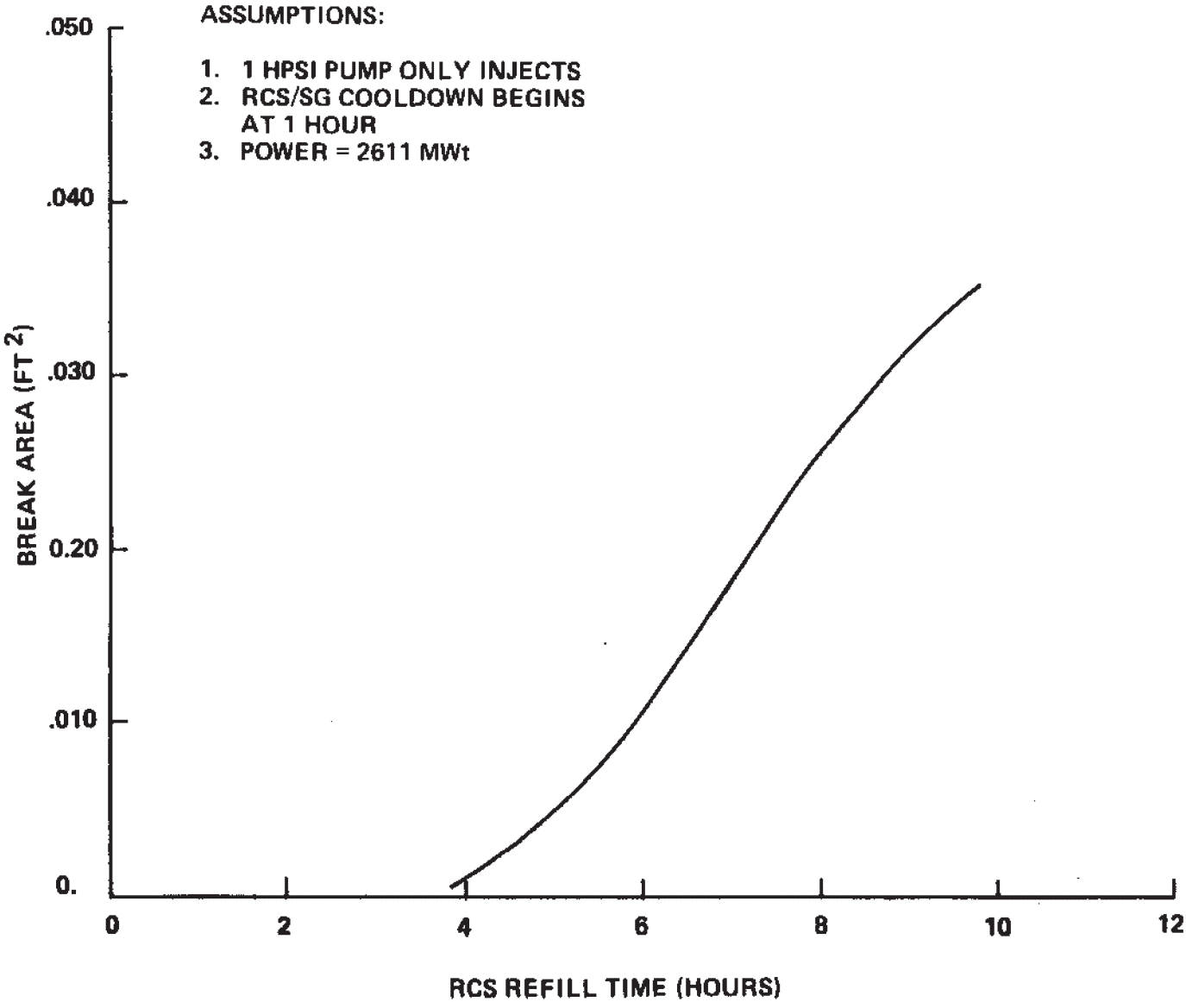
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

INNER VESSEL BORIC ACID
CONCENTRATION VS. TIME

FIGURE 6.3-23

CYCLE 1



AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ST. LUCIE 2 RCS REFILL TIME VERSUS BREAK AREA

FIGURE 6.3-24

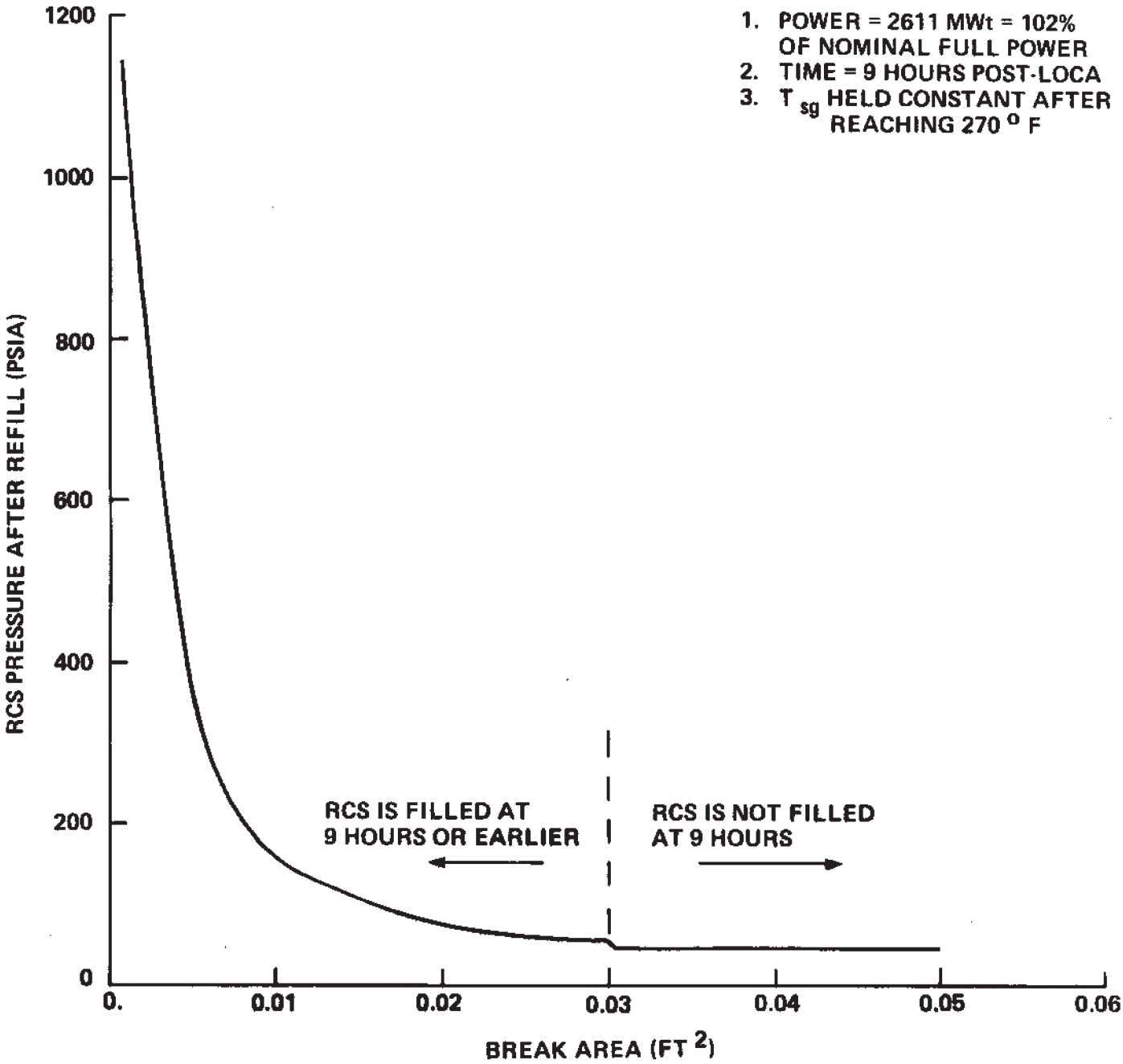
CYCLE 1

	BREAK SIZE (FT^2)	RCS PRESSURE AT t = 9 HOURS (PSIA)
SIMULTANEOUS HOT LEG/COLD LEG INJECTION COOLS CORE AND FLUSHES BORIC ACID FROM VESSEL	10	20
	5	20
	2	20
	1	20
	0.5	20
	0.2	20
	0.1	20
	0.05	20
	0.04	47
REFILL OF RCS DISPERSES BORIC ACID THROUGHOUT SYSTEM AND SGs ARE ABLE TO COOL RCS TO SDC TEMPERATURE	0.03	57
	0.02	73
	0.01	151
	0.009	174
	0.005	362
	0.002	859
	0.001	1077
	0.0005	1143

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

OVERLAP OF ACCEPTABLE LTC MODES IN TERMS OF COLD LEG BREAK SIZE

FIGURE 6.3-25



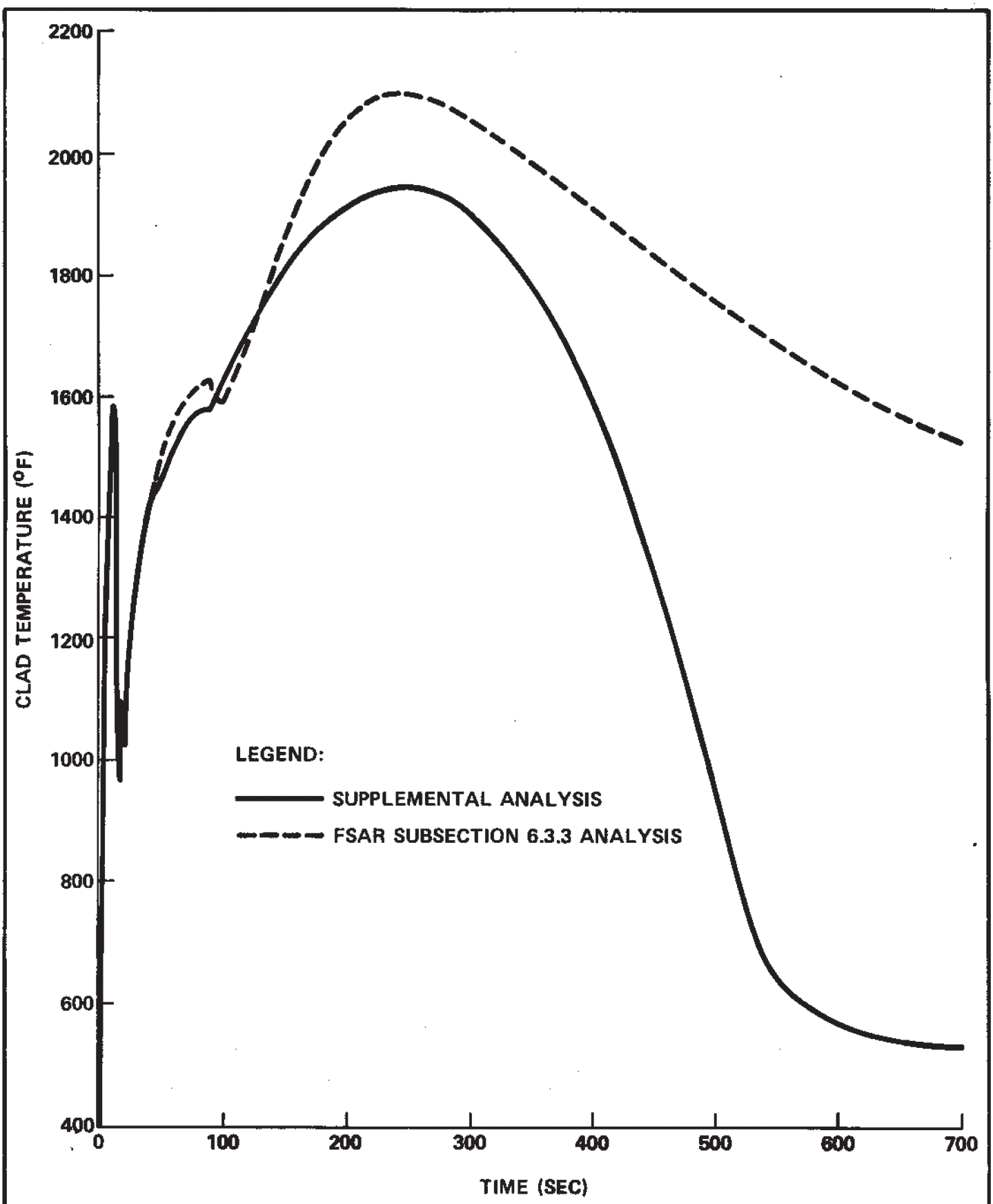
AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

RCS PRESSURE AFTER REFILL VERSUS BREAK AREA

FIGURE 6.3-26

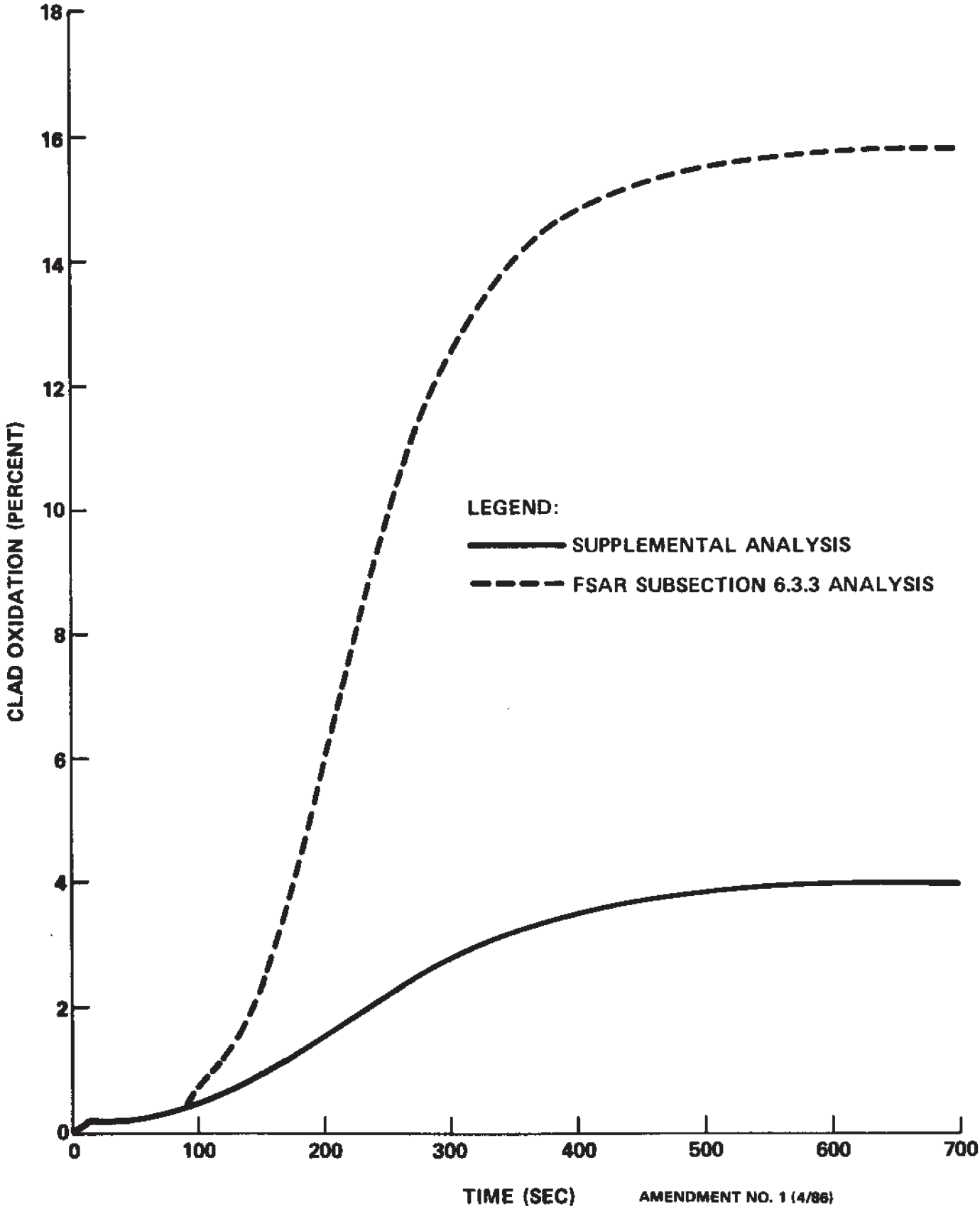
CYCLE 1



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CLAD TEMP. AT HOT SPOT

FIGURE 6.3-27



AMENDMENT NO. 1 (4/86)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PEAK LOCAL CLAD OXIDATION

FIGURE 6.3-28

CYCLE 1

6.4 HABITABILITY SYSTEMS

Habitability systems are provided to assure that the operators can remain in the control room and take effective actions to operate St. Lucie Unit 2 safely under normal conditions and maintain a safe condition post accident, as required by General Design Criterion 19 of Appendix A to 10 CFR 50.

The control room habitability systems include radiation shielding; air filtration and ventilation equipment with associated instrumentation and controls; missile protection; emergency lighting; food, water, kitchen and sanitary facilities; self contained breathing apparatus unit; fire protection equipment, and radiation monitors.

The Control Room Air Conditioning System is discussed in Subsection 9.4.1. Emergency lighting is described in Subsection 9.5.3. Protection of the control room from wind and tornado effects is covered in Section 3.3. Flood design is discussed in Section 3.4. Missile protection is described in Section 3.5. Protection against dynamic effects associated with pipe break is described in Section 3.6. Environmental design conditions are given in Section 3.11. Fire protection is discussed in Subsection 9.5.1 and Appendix 9.5A.

See Sections 9.4 and 15.6 for related information concerning the Control Room HVAC.

6.4.1 DESIGN BASES

Provisions for maintaining control room habitability and occupancy are based on the following:

a. A control room envelope, as defined in Subsection 6.4.2.1, is provided.

b. The control room environment is suitable for continuous occupancy during normal operation and occupancy throughout the duration (i.e. 30 days) of any one of the postulated accidents discussed in Chapter 15 without exceeding the guidelines (5 rem total effective dose equivalent) set forth in General Design Criterion 19 of Appendix A to 10 CFR 50.

c. During emergency conditions, food, water and other supplies will be provided to the control room (as necessary) in accordance with plant procedures.

d. Respiratory protection is provided for emergency use within the control room envelope.

e. The Control Room Air Conditioning System is capable of either automatic actuation (on a containment isolation actuation signal (CIAS) from St. Lucie Units 1 or 2 or high radiation signal from outside air intakes) or manual transfer from its normal operating mode to the pressurized or isolated modes, as necessary.

f. Radiation monitors and control equipment are provided at plant locations, as necessary, to ensure the ability to meet design bases b and e (see Section 12.3).

g. The control room envelope and the Control Room Air Conditioning Systems are designed to remain functional and maintain a room temperature of 80 ± 4°F during and after a safe shutdown earthquake.

h. The habitability systems (air filtration and ventilation equipment with associated instrumentation, controls and radiation monitoring) are capable of performing their functions assuming a single active component failure coincident with a loss of offsite power.

i. Additional design bases for the normal operation of the Control Room Air Conditioning System are given in Subsection 9.4.1.1.

6.4.2 SYSTEM DESIGN

6.4.2.1 Definition of Control Room Envelope

The control room envelope includes the control room, packaged air conditioning equipment room, emergency cleanup system equipment room, emergency food and water storage areas, toilet, kitchen/dining/conference room and supervisors office.

The entire envelope floor is at elevation 62 feet inside the Reactor Auxiliary Building.

Figure 1.2-19 is a layout drawing showing the control room envelope and the placement of equipment. Figure 6.4-2 shows the control room air conditioning equipment and its associated duct work.

6.4.2.2 Control Room Air Conditioning System

Subsection 9.4.1 contains an overall description of the Control Room Air Conditioning System and a system airflow diagram is shown on Figure 9.4-1.

The system is zone isolated, with filtered recirculated air, widely separated dual air inlets, and provisions for positive pressure (>1/8 inch wg). Makeup air for pressurization is filtered before entering the control room envelope.

The modes of operation of the Control Room Air Conditioning System are:

a. automatic isolation and automatic recirculation with partial filtration of recirculated air, or

b. automatic isolation with immediate manual and/or automatic filtered pressurization and recirculation with partial filtration.

The net volume of the control room envelope serviced by the Control Room Air Conditioning System is approximately 97,600 cubic feet.

The Control Room Air Conditioning System consists of three air conditioning units, designated as HVA/ACC-3A, HVA/ACC-3B, and HVA/ACC-3C, a toilet exhaust fan designated as HVE-14, and a conference room and kitchen exhaust fan designated as HVE-33.

Two full capacity, redundant Engineered Safety Feature emergency air filtration units HVE-13A and HVE-13B provide continuous filtration following a design basis accident.

Air conditioning unit capacity is 50 percent each during normal operation and 100 percent each during post LOCA operation. During normal plant operation, one or two out of three units are in

operation along with the toilet and kitchen exhaust systems. Under emergency conditions, only one out of three air conditioning units and one train of the Control Room Emergency Cleanup System are required to maintain the habitability of the control room envelope.

The action of the "nonessential" fans (toilet exhaust, and conference room and kitchen exhaust) is described in Subsection 9.4.1.

Design data for the Control Room Air Conditioning and Emergency Cleanup Systems components are given in Tables 9.4-1 and 9.4-2.

Automatically actuated, redundant isolation valves are provided at each outside air intake and exhaust air path so that the control room envelope is immediately isolated upon receipt of a CIAS, or outside air intake high radiation signal. The system is designed to perform its safety functions and maintain a habitable environment in the control room envelope during isolation.

Leakage characteristics of the isolation valves are given in Table 6.4-1. Automatic isolation of the control room via CIAS or a high radiation signal occurs within 30 seconds, with or without offsite power. This time includes instrument response time, valve closure time and EDG restoration of AC power if offsite power is not available.

The seismic classification of components, instrumentation and ductwork is indicated in Table 3.2-1.

The system is located within the Reactor Auxiliary Building which is designed to withstand the effects of tornado generated missiles. All outside air intakes are protected from entry of tornado generated missiles. Postulated internally generated missiles resulting from fan blades are stopped by its fan casing.

Figure 1.2-1 is a plot plan showing the plant layout, including the location of onsite potential radiological release points with respect to the control room air intakes. The elevations of release points and intakes are also indicated on Figure 1.2-1. Elevation and plan drawings showing building dimensions are given in Section 1.2. The potential for toxic gas release is discussed in Subsection 2.2.3.

A description of system controls and instrumentation is given in Subsection 9.4.1. Redundant radiation monitors are located at both outside air intakes. These Class 1E radiation monitors are discussed in Subsection 12.3.4.

During emergency conditions, pressurized air in the control complex is passed through high efficiency particulate filtration and charcoal absorption for removal of iodines, CO2, odor and other gaseous impurities.

Ionization type smoke detectors are provided within the control room envelope. They are located in the control room air conditioning equipment room, the emergency cleanup filter room, kitchen/dining/conference room and the two offices. In addition, two smoke detectors are provided in the supply duct of the air conditioning system. (See Fire Protection Design Basis Document, DBD-FP-1 (Reference 3)) EC282743

Design data for the HEPA and charcoal filter trains are given in Table 9.4-2. The degree to which the recommendations of Regulatory Guide 1.52, "Design, Testing, and Maintenance Criteria for Engineered Safety Feature Atmosphere Cleanup System Air Filtration and

Adsorption Units of Light Water Cooled Nuclear Power Plants", 3/78 (R2) are followed is discussed in Subsection 6.5.1.

The three redundant air conditioning units are served by the Component Cooling Water System such that loss of one active component of the Component Cooling Water System does not affect the ability of the air conditioning system to control the thermal environment in the control room envelope. The Component Cooling Water System is described in Subsection 9.2.2.

Redundant equipment which is essential to safety is powered from separate safety related buses such that loss of one bus does not prevent the Control Room Air Conditioning System from fulfilling its safety function.

6.4.2.3 Leak Tightness

Table 6.4-1 summarizes the exfiltration/infiltration analysis originally performed to determine control room envelope unfiltered inleakage and the pressurization air flow requirements. The leakage analysis is based on a 1/8 inch wg differential pressure and is in accordance with AEC R&D Report NAAA-SR-10100 (May, 1965)[(2)].

The control room envelope is pressurized to not less than 1/8 inch of water gauge relative to the surroundings at all times during normal plant operation. Outside air is continuously introduced to the control room envelope at an approximate rate of 1000 cfm. Following a design basis accident, the control room is pressurized at the rate of not more than 450 cfm to maintain a positive pressure differential of 1/8 inch of water gauge. This pressurization rate does not cause the doses to exceed the limit of General Design Criterion 19 of Appendix A to 10 CFR 50 and provides an air exchange rate of 0.276 per hour. The EPU control room dose assessment conservatively assumes a filtered inleakage of 504 cfm.

Current St. Lucie calculations assume a control room leakage rate of 395 cfm for normal plant operations and accident conditions.

As Table 6.4-1 indicates, the control room envelope is provided with selfclosing, double air lock doors. Therefore, the unfiltered inleakage resulting from controlled egress and ingress is considered to be zero in the evaluation of the control room personnel doses following a loss-of-coolant accident.

6.4.2.4 Interaction With Other Zones and Pressure-Containing Equipment

The ventilation zones adjacent to the control room envelope are either negative or atmospheric with respect to the envelope, thereby assuring control room outleakage only. No other area is served by the Control Room Air Conditioning and Emergency Cleanup Systems other than the control room envelope.

The closest main steam line is over 80 feet away from the north side of the control room. Steam jets resulting from a postulated main steam line break are not directed towards the northern outside air intake. The only high energy line in the proximity of the control room is the auxiliary steam line. Analyses presented in appendices in Section 3.6 verify that the consequences of a rupture in this line does not affect control room habitability. In addition, a temperature sensor is provided in the northern outside air intake to monitor the temperature of makeup air in the event of pipe break in the auxiliary steam lines. A high temperature setpoint automatically closes the isolation valves of the northern outside air intake.

6.4.2.5 Shielding Design

The control room is shielded against direct sources of radiation which are present during normal operating conditions and following a postulated accident.

There are no significant sources of radiation near the control room during normal operating conditions. The shielding walls and floor (at least two feet of concrete) are more than sufficient to limit the dose rate in the control room during normal operation to less than 0.25 mrem/hr (Zone 1).

In the event of a postulated accident (LOCA) there could be several major sources of direct radiation contributing to the dose in the control room. These sources and their dose contributions over a 30 day period following an accident are listed in Table 6.4-2. It is seen that the total direct dose from all sources is 0.15 rem TEDE. This, when combined with the dose to personnel from inhalation of and submersion in airborne radioactivity which may enter the control room, is within the limits set forth in 10 CFR 50.67.

A source of potential dose to the control room is the control room emergency filtration system which is located in a room adjacent to the control room kitchen/conference room, and is separated from it by a one foot thick concrete wall. This system could contribute as much as 0.033 rem over a 30 day period due to build up of radioactive material on its filters.

The potential dose from the external atmosphere surrounding the control room arises from assuming a 0.5 volume percent per day leakage rate of the containment atmosphere to the external atmosphere for the first day following a LOCA, and a 0.25 percent per day leakage rate for subsequent days. The control room is shielded from this source by at least two feet and as much as four feet of concrete. The time integrated dose calculated using an infinite cloud model, which overestimates the answer, amounts to 0.083 rem.

Potential dose also arises from the radioactive material released to the containment atmosphere following a LOCA. This source combines the dose from the material remaining in the atmosphere as well as that which plates out inside the containment. The activity at subsequent times was determined considering radioactive decay of the isotopes. The control room is shielded from these sources by at least the three feet thick concrete shield building wall, the two inch thick steel containment wall, and the two feet thick control room wall. The total dose then calculated, amounts to 0.029 rem.

The remaining sources of radiation, the Shield Building ventilation emergency filtration units, the atmosphere outside the control room but inside the Reactor Auxiliary Building, and the containment sump water, have a negligible contribution to the 30 day post-LOCA dose. The Shield Building ventilation emergency filtration units are separated from the control room by a distance of more than 63 feet and at least four to six feet of concrete shielding. The atmosphere inside the Reactor Auxiliary Building becomes radioactive from the relatively slow leakage of contamination from the containment. This low leak rate combined with concurrent radioactive decay, results in a low dose to the control room. The final source, the radioactive water in the containment sump, is separated from the control room by a distance of more than 98 feet and at least nine feet of concrete (measured perpendicular through the shield). As a consequence, its dose contribution is negligible under the most conservative shielding assumptions.

6.4.3 SYSTEM OPERATIONAL PROCEDURES

During normal operation the Control Room is air conditioned by one unit running with a second unit in Auto. The third unit is OFF available for manual use in the vent of a failure of one of the other two units. Fresh air is taken in through either the northern or the southern outside air intakes by remote manual opening of the redundant motor operated isolation valves.

Upon receipt of a CIAS or a high radiation signal, the redundant isolation valves on the fresh air intake, toilet exhaust, and conference/kitchen exhaust lines close automatically. The two control room emergency cleanup system filtration fans and the standby air conditioner start automatically while the running air conditioning unit remains running. Subsequently the operator initiates the following changes:

a. After determining which outside air intakes has the least, or zero, amount of radiation, the operator opens one of the two valves on that intake and adjusts the opening of the second valve for proper flow requirements.

b. Depending on the cooling required, the operator may stop or start air conditioning units.

c. The operator stops one of the two control room emergency cleanup system filtration fans.

6.4.4 DESIGN EVALUATION

6.4.4.1 Radiological Protection

The control room is designed to remain habitable for the duration of each of the accidents postulated in Chapter 15. A detailed analysis of the radiological exposures to control room personnel following the design basis loss of coolant accident is presented in Subsection 15.6.5.5. The analysis demonstrates that the total exposures from airborne activity within the control room are within the limits set forth in 10 CFR 50 Appendix A, General Design Criterion 19.

6.4.4.2 Toxic Gas Protection

Section 2.2 indicates that there are no stationary or mobile source of toxic chemicals offsite or located in the vicinity of the plant which could render the control room uninhabitable as a result of an accident.

A comparison of the potentially hazardous chemicals stored onsite with guidelines presented in Regulatory Guide 1.78, "Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release," 6/74 (R0) demonstrates that although there are chemicals stored onsite, none are of sufficient quantity or toxicity to pose a threat to control room habitability. Subsection 2.2.2.2.4 lists onsite products and materials. Table 2.2-8 presents a list of each of these chemicals along with their quantity and distance from the control room. Using the guidance of Regulatory Guide 1.78 (R0) and 1.95 (R0) an analysis was performed to evaluate an accidental release of chlorine and its effect on the control room habitability. Based on the failure of the nearest cylinder of Cl_2, the calculated peak concentration inside the control room was determined to be 23 percent of the toxicity limit listed

in Table C-1 of Regulatory Guide 1.78 (R0). (Note the chlorine cylinders have been removed. This information is retained as a historical record).

The circulating water system is treated with chlorine in the form of Sodium Hypochlorite by the use of a hypochlorite system which precludes the necessity of onsite chlorine storage. Subsection 10.4.5, which presents a description of the system, reveals that no toxic chemicals are required for this system.

6.4.5 TESTING AND INSPECTION OF CONTROL ROOM HABITABILITY SYSTEMS

Automatic and manual operations are tested periodically per plant procedures to ensure operation. The control room air conditioning is normally operating and consequently under continuous observation.

The control room is a totally enclosed structure with access provisions for personnel, HVAC penetrations, piping and electrical penetrations. HVAC penetrations are isolated on CIAS or high radiation signal by low leakage butterfly valves which are sealed against the concrete wall with rubber sleeves. Conduit and cable tray penetrations are sealed with air-tight fire stops. These features insure a low leakage structure. During preoperational testing, a survey was made by qualified personnel to insure that leakage barriers are in place and installed properly.

An initial test is conducted to ensure the capability to maintain the control room at a positive pressure during a postulated LOCA. The control room is pressurized to 1/8 in. wg or greater with an air inflow of up to 450 cfm. The control room leakage rate is acceptable if a 1/8 or greater in. wg pressure differential relative to the surroundings is maintained with up to 450 cfm.

Inservice surveillances are conducted in accordance with the Technical Specifications requirements.

6.4.6 INSTRUMENTATION REQUIREMENTS

The instrumentation for the Control Room Air Conditioning System and emergency filtration units are designed to maintain habitability conditions in the control room automatically with minimum attention from the operator. The Containment Isolation Actuation Signal (CIAS), which actuates the Control Room Air Conditioning System, is discussed in Subsection 7.3.1. The instrumentation and alarms on the HV control board associated with these systems provide the operator with the information concerning the status of the systems and enable the operators to take the proper course of action. Redundant instrumentation is provided for monitoring and controlling these systems as shown in Table 9.4-4.

SECTION 6.4: REFERENCES

1. Department of Defense, Office of Civil Defense, Shelter Design and Analysis, Volume 3, Chapter 9

2. AEC R&D Report NAAA-SR-10100 (May, 1965), "Conventional Buildings for Reactor Containment."

3. DBD-FP-1, Fire Protection Design Basis Document. EC282743

TABLE 6.4-1
CONTROL ROOM LEAKAGE CALCULATION

C0MPONENT	UNIT	NUMBER OF UNITS	LEAKAGE COEFFICIENT (NOTES 2 AND 3) A	B	LEAKAGE PER UNIT (= AP + $BP^{1/2}$) (NOTE 1)	TOTAL OUT LEAKAGE (cfm)
Electrical conduit penetrations	Each	270	10^{-9}	10^{-9}	4.786×10^{-10}	**12.921×10^{-8}**
Electrical tray penetrations	Each	77	10^{-9}	10^{-9}	4.786×10^{-10}	3.69×10^{-8}
Instrument & Control penetration - 6 in diameter pipe sl.	Each	2	2.1×10^{-3}	0	2.625×10^{-4}	5.25×10^{-4}
Lead wool packing	Each	2	-	-	1.8	3.6
Personnel access doors (airtight)	Each	3	4.3	22	8.316	24.95
Concrete block walls: surface	Sq. Ft.	524.4	1.5×10^{-6}	0	1.875×10^{-7}	9.833×10^{-5}
joints	LF	2354	2.4×10^{-4}	0	3.0×10^{-5}	**7.062×10^{-2}**
Slab: 1'-0" thick	Ft^2	3870	1.67×10^{-6}	0	2.0875×10^{-7}	8.0786×10^{-4}
3'-0" thick	Ft^2	1002	5.56×10^{-7}	0	6.95×10^{-8}	6.964×10^{-5}
3'-6" thick	Ft^2	513	4.76×10^{-7}	0	5.95×10^{-8}	3.052×10^{-5}
Wall: 0'-8" thick	Ft^2	207	2.5×10^{-6}	0	3.125×10^{-7}	6.469×10^{-5}
0'-10" thick	Ft^2	87	2.0×10^{-6}	0	2.5×10^{-7}	2.175×10^{-5}
1'- 0" thick	Ft^2	1651	1.67×10^{-6}	0	2.0875×10^{-7}	3.45×10^{-4}
1'- 1" thick	Ft^2	204	1.54×10^{-6}	0	1.925×10^{-7}	3.927×10^{-5}
2'- 0" thick	Ft^2	4710	8.33×10^{-7}	0	1.04125×10^{-7}	4.9043×10^{-4}
3'- 0" thick	Ft^2	108	5.56×10^{-7}	0	6.95×10^{-8}	7.51×10^{-6}
Roof 2'- 0" thick	Ft^2	5440	8.33×10^{-7}	0	1.0413×10^{-7}	5.66×10^{-4}
4'- 0" thick	Ft^2	190	4.17×10^{-7}	0	5.213×10^{-8}	9.905×10^{-6}
Construction joints	Ft	1261	2.4×10^{-4}	0	3.0×10^{-5}	3.783×10^{-2}
Plumbing penetration 3" floor 9.5" circum.	Each	19	9.5×10^{-6}	0	1.1875×10^{-6}	2.256×10^{-5}
4" floor 12.5" circum.	Each	1	12.5×10^{-6}	0	1.5625×10^{-6}	1.5625×10^{-6}
5" floor 15.7" circum.	Each	2	15.7×10^{-6}	0	1.9625×10^{-6}	3.925×10^{-6}
6" floor 18.8" circum.	Each	2	18.8×10^{-6}	0	2.35×10^{-6}	4.7×10^{-6}
4.725×10^{-8} 6" roof 18.9" circum.	Each	1	37.8×10^{-8}	0	4.725×10^{-8}	4.725×10^{-8}
3.925×10^{-8} 5" roof 15.7" circum.	Each	1	31.4×10^{-8}	0	3.925×10^{-8}	3.925×10^{-8}
2" floor 6.2" circum.	Each	2	6.2×10^{-6}	0	7.75×10^{-7}	1.55×10^{-6}
HVAC duct penetration						4.92
Butterfly valves	Each	4			0.0000125	0.000050
Electrical openings.						55.96
Subtotal						89.542
Safety factor for wear and tear and exposure to radiation	(11.68%)					10.458
TOTAL						100 cfm

Notes to Table 6.4-1

1. P = 1/8 in. wg
2. Source of empirical leakage coefficient is AEC R&D Report NAA-SR-10100
3. The empirical leakage coefficients are defined in Section II of AEC R&D Report NAA-SR-10100
4. Leakage from 12" butterfly valve is 0.018 ft^3/day at 13.8 psig and is proportional to the circumference based on LDS-A2 of AEC R&D report NAA SR-10100

TABLE 6.4-2

CONTROL ROOM 30 DAY POST-LOCA DOSES FROM
MAJOR EXTERNAL RADIATION SOURCES

	Radiation Source	Total Effective Dose Equivalent (Rem)
1.	Control Room Emergency Filtration System	0.033
2.	Environmental Atmosphere Outside the Control Room	0.083
3.	Containment Atmosphere and Plateout in Containment	0.029
4.	Shield Building Ventilation Emergency Filtration System	negligible
5.	Atmosphere Outside the Control Room but Inside the RAB	negligible
6.	Containment Sump Water	negligible
	Total	0.15

DELETED

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

FIGURE 6.4-1

Refer to Drawing
2998-G-873

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

HVAC - REACTOR AUXILIARY BUILDING
CONTROL ROOM AREA
FIGURE 6.4-2

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

Fission product removal systems are the engineered safety feature (ESF) filtration systems, and the Containment Spray System/Iodine Removal System described in Subsections 6.5.1 and 6.5.2. These systems remove fission products from the atmosphere via particulate filtration and adsorption, and by absorption in the containment spray.

Fission product control systems control the release of fission products by operating in conjunction with fission product removal systems following a design basis accident. These systems are described in Subsection 6.5.3.

6.5.1 ENGINEERED SAFETY FEATURE (ESF) FILTRATION SYSTEMS

The following ESF air filtration systems located outside containment mitigate the consequences of a postulated design basis loss-of-coolant accident (DBA-LOCA):

a. Control Room Emergency Cleanup System (CRECS)

b. Shield Building Ventilation System (SBVS)

c. Emergency Core Cooling System (ECCS) Area Ventilation System

6.5.1.1 Design Basis

The Control Room Emergency Cleanup System design basis are described in Subsection 9.4.1.1.

The Shield Building Ventilation System design basis are described in Subsection 6.2.3.

The ECCS Area Ventilation System design basis are described in Subsection 9.4.3.

In addition the following design bases are applicable to the above ESF air filtration systems:

a. The ESF air cleaning units are consistent with the recommendations of Regulatory Guide 1.52, "Design, Testing and Maintenance Criteria for Engineered Safety Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light Water Cooled Nuclear Power Plants," 3/78 (R2), as delineated in Table 6.5-1.

b. Perform their design functions assuming a single active component failure coincident with a loss of offsite power.

c. Perform continuously for at least 30 days following a DBA-LOCA and be capable of retaining radioactive material after the system is taken out of service.

d. Be designed to seismic Category I standards.

e. Withstand the post accident environmental conditions without loss of function.

f. Permit access for periodic inspection and testing to assure system integrity and functional capability.

The design basis for the Control Room Emergency Cleanup System (CRECS) along with the Control Room Air Conditioning System, is described in Subsection 9.4.1. A system air flow diagram is shown on Figure 9.4-1. The design basis for the SBVS and ECCS Area Ventilation System are described in Subsections 6.2.3 and 9.4.3 respectively.

6.5.1.2 Systems Design

A comparison between the design features and fission product removal capability of each filter system to the positions detailed in Regulatory Guide 1.52 (R2), is presented in Table 6.5-1.

6.5.1.3 Design Evaluation

Each ESF filtration system is provided with two 100 percent capacity ESF air filtration trains, either of which is capable of fulfilling its design bases. The trains are located within the Reactor Auxiliary Building which protects them from the effects of natural phenomena and missiles. The systems are seismic Category I, and components are qualified to meet the applicable environmental conditions specified in Section 3.11.

Instrumentation, controls and power to the redundant filter trains are electrically separated and powered from separate onsite power sources. The filter trains are actuated by their respective safety related actuation signals. Manual switches are provided in the control room for fans and motorized valves and dampers.

Failure modes and effects analyses for the Control Room Emergency Cleanup System, SBVS and ECCS Area Ventilation System are provided in Tables 9.4-3, 6.2-50, and 9.4-9, respectively. These tables demonstrate that the provision of fully redundant filter trains assures that a system can withstand a single active failure without impairing its functional capability.

Post accident fission product removal capability is assured by each air cleaning unit which is designed to be tested in place to verify that the unit meets the particulate filtration, iodine adsorption and leak tightness requirements. The test programs are discussed in Subsection 6.5.1.4.

The ECCS Area Ventilation System creates and maintains slightly a negative pressure relative to surrounding areas assuming a leakage of 0.54 gallons per hour in the ECCS areas from pump seals, valve stems, etc.

Temperature sensors located adjacent to and downstream of charcoal absorbers are provided to monitor the temperatures of the absorbers at all times. A cross connecting duct is provided on the SBVS allowing one exhaust fan to draw enough air through the second idle air cleaning unit to remove radioactive decay and oxidation heat. The iodine decay heat in the other air filtration systems is negligible.

Charcoal absorbers are designed and filled with activated charcoal having radioiodine removal efficiency of 99% minimum in accordance with ANSI N509-1976. The mass of activated charcoal in each air cleaning unit exceeds the basis of a loading of 2.5 mg of iodines per gram of activated charcoal.

Dose analysis of postulated accidents are discussed in Chapter 15. Offsite doses resulting from these accidents are shown to be within the guidelines established for design basis accidents.

The design and fabrication of ESF filtration systems are discussed in the CVI Topical Report No. CVI-TR-7301, "Design and Development of High Efficiency Charcoal Adsorber and Its Application in ESF Atmosphere Clean Up Systems," dated February, 1975. This report was accepted by the NRC in April, 1978.

6.5.1.4 Tests and Inspection

Functional testing is described in the Technical Specifications.

6.5.1.5 Instrumentation Requirements

Instrumentation for controlling and monitoring the ESF air filtration systems meets the applicable requirements of Regulatory Guide 1.52 (R2) position (2h). Each filter train is provided with instrumentation to indicate an alarm pressure drop at the control room. A control diagram showing instrumentation is provided on Figure 9.4-11 for the SBVS and on Figure 9.4-2 for the CRECS and for the ECCS Area Ventilation System.

a. Monitoring Instrumentation

   Instrumentation provided for sensing and transmitting abnormally high temperatures at the charcoal absorbers are as follows:

   The temperature of charcoal in each adsorber assembly within the unit is monitored by several thermocouples. Adsorber temperatures reaching the 200°F setpoint are annunciated in the control room for appropriate operator action.

   The pressure drops across each demister, heating coil, charcoal absorbers, prefilters, pre-HEPA and after HEPA filters are indicated locally. The pressure drop across filter trains are recorded in the control room. Differential pressure across pre-HEPA filters is indicated and recorded and high differential pressure is annunciated in the control room.

   Upon initiation of the SBVS exhaust fans the electric heating coils are energized and remain energized as long as the fan is running.

b. Actuating Instrumentation

   The CRECS trains are automatically started by either a containment isolation actuation signal (CIAS) (from either St. Lucie Units 1 or 2) or a control room air intake high radiation signal. One of the two emergency filtration fans can be manually deenergized and placed on standby.

   The ECCS Area Ventilation System is actuated by a safety injection actuation signal (SIAS). The ECCS area air is exhausted through the ECCS area filter train for filtering through charcoal absorbers prior to release to atmosphere.

   The SBVS is automatically actuated upon receipt of either a CIAS from containment or from a high radiation signal from the Fuel Handling Building. One fan can be manually shutdown and placed in the standby mode. The standby system is automatically restarted if the operating unit should fail. Actuation logic is discussed in Subsection 7.3.1 and monitoring instrumentation is discussed in Subsection 7.5.1.

6.5.1.6 Materials

Materials of construction of ESF filter trains are painted carbon steel and stainless steel. Demisters consist of fiberglass pads and stainless steel casings. Electric heating coils for SBVS have stainless steel finned tubes with terminals for wiring hermetically sealed in an external terminal box.

Pre-filters and mounting frames are made of fire resistant construction in accordance with UL-900, EC282656, with filter cells constructed of glass fiber media.

HEPA filters are fabricated by pleating a continuous sheet of molded or corrugated glass back and forth over itself so that the filter pack is self supporting without the use of separators and enclosing it within a frame. Filters assemblies are constructed of materials capable of withstanding a temperature of 250°F and 800 watts fission products decay heat for an indefinite period. Mounting frames are fabricated from a 1/4 inch carbon steel plate. The HEPA filter gaskets are flat closed cell type made from neoprene ASTM D1056 Grade SCE-43, 1/4 inch thick by 3/4 inch wide, which retain their integrity and resilience when subjected to air flow at 200°F and an integrated radiation exposure dose as high as $5.8x10^6$ rads.

The high efficiency charcoal adsorber filters are contained in an all welded gasketless stainless steel assembly. The radiation stability of coconut shell charcoal adsorbents has been demonstrated by tests. For example, coconut shell impregnated with potassium tri-iodide (KI_3) is reported in Table IV of a report by A. G. Evans entitled, "Effect of Intense Gamma Radiation on Radioiodine Retention by Activated Carbon," Proceedings of the 12th AEC Air Cleaning Conference (8/72).

Gasket materials used for casing access doors is neoprene ASTM D2000 BC 516 or ASTM D735 SCE 516 50 Durometer or ASTM D1056 Grade SCE-43 20/30 Durometer.

The ESF air filtration systems are located outside containment, in the Reactor Auxiliary Building. The systems operate at relatively low temperatures, therefore radiolytic or pyrolytic decomposition of system materials does not pose any problem.

6.5.2 CONTAINMENT SPRAY SYSTEM/IODINE REMOVAL SYSTEM (CSS/IRS)

The Containment Spray System (CSS) is provided to perform the dual functions of removing heat and fission products from a post-accident containment atmosphere. The heat removal capability of the CSS is discussed in Subsection 6.2.2. The fission product removal function is carried out by the Iodine Removal System (IRS), operating in conjunction with the Containment Spray System. The IRS removes radio-iodines from the containment atmosphere following a loss-of-coolant accident by adding controlled amounts of hydrazine to containment spray water.

6.5.2.1 Design Bases

The design bases for the CSS/IRS as a fission product removal system are as follows:

a. To provide capability for the fission product scrubbing of the containment atmosphere following a DBA-LOCA such that offsite doses, and doses to operators in the control room, are within the guidelines established for design basis accidents. The radioactive material release assumptions of Regulatory Guide 1.4, "Assumptions Used for Evaluating the Potential Radiological

Consequences of a Loss of Coolant Accident for Pressurized Water Reactors," 6/74 (R2) are used in determining system capability. The radioiodine and noble gas activity inventory in the containment atmosphere following a DBA-LOCA is given in Section 15.6.

b. To maintain a minimum hydrazine concentration of 50-65 ppm at the containment spray nozzles based on a storage concentration of 25.4 percent by weight in demineralized water. The EPU dose assessment does not credit hydrazine addition.

c. A minimum sump pH of 7.0 is required prior to the recirculation actuation signal (RAS) mode. The pH is controlled with baskets of TSP (trisodium phosphate dodecahydrate) in the containment sump which dissolves as the post-LOCA water level increases. The boron concentrations for the Refueling Water Tank (RWT), Safety Injection Tanks (SITs) and Reactor Coolant System (RCS) are considered. Hydrazine is not included in this analysis.

d. To remove elemental and particulate iodines with the following minimum first order removal coefficients.

Iodine Form	First Order Removal Coefficient
Elemental	20 $hours^{-1}$
Particulate	6.52 $hours^{-1}$

e. To meet iodine removal requirements based on an effective spray coverage of 85 percent of the containment free volume.

f. To perform its function following a LOCA, assuming a single active component failure coincident with loss of offsite power.

g. Be designed to seismic Category I, Quality Group B standards as applicable.

h. To perform its function under the post accident environmental conditions specified in Section 3.11.

i. To provide system materials which are compatible with fluid chemistry.

The Containment Spray/Iodine Removal Systems are designed to Quality Group B and seismic Category I requirements in accordance with the recommendations of Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," 2/76 (R3) and Regulatory Guide 1.29, "Seismic Design Classification," (R2), respectively.

6.5.2.2 System Design

6.5.2.2.1 Design Description

Both the CSS/IRS consist of two independent and redundant loops. Each CSS loop is made up of a spray pump, shutdown cooling heat exchanger, piping, valves, headers, and nozzles. Connected to each CSS loop is an independent train of the Iodine Removal System consisting of a constant volume metering pump, solenoid-operated isolation valve, IRS tank and

associated piping and valves. The flow diagrams for the CSS and IRS appear as Figure 6.2-41. The design data for IRS components is shown in Table 6.5-2. Similar data for the CVSS is given in Table 6.2-38.

The design of the IRS is based on the addition of hydrazine to the containment spray water at a rate that ensures a minimum hydrazine concentration of 50 ppm at the spray nozzles. Based on the offsite dose guidelines established for design basis accidents and a spray coverage of 85 percent of the total containment net free volume, hydrazine addition proceeds for a minimum period of 120 minutes. The EPU dose assessment does not credit the hydrazine addition and relies upon pH control with baskets of TSP (trisodium phosphate dodecahydrate) in the containment sump which dissolve as the post-LOCA water level increases.

A constant volume hydrazine addition pump is selected for system simplification and ease of operation. Over the entire range of spray flow rates the concentration of hydrazine is no less than 50 ppm and no greater than 65 ppm. Upon receipt of a containment spray actuation signal (CSAS) the solenoid-operated isolation valves open and the hydrazine pumps start.

Hydrazine is injected into the suction side of each containment spray pump at a rate of 0.71 to 0.82 gallons per minute (gpm) until a low level switch in the hydrazine storage tank simultaneously stops the pumps and closes the solenoid valves. The system is designed to be fully automatic yet is capable of local-manual control. As long as radiation levels are acceptable in this portion of the Reactor Auxiliary Building, there is the capability to permit the refilling of the hydrazine tank.

On initiation of the CSAS, the containment spray pumps take suction from the refueling water tank (RWT) and spray borated water directly into the containment atmosphere.

A low level in the RWT is reached in approximately 20 minutes (see Subsection 6.2.2). A low level switch initiates the recirculation actuation signal (RAS) transferring containment spray suction to the containment sump. Spray water in the sump is buffered with trisodium phosphate dodecahydrate (TSP) to maintain a minimum pH of 7.0. The Containment Spray System can function continuously in the recirculation mode. Refer to Subsection 6.5.2.3.2 for a discussion on spray and sump water pH history.

The spray header design is shown on Figures 6.5-4 and 6.5-5. There are two headers, one for each containment spray pump, each splitting up into four rings that line the inside of the steel containment structure at various elevations. There are a total of 357 nozzles with centerline-to-centerline spacing varying from approximately 40 to 75 inches depending on elevation and ring location. Three nozzle orientations are utilized as shown on Figure 6.5-5.

The nozzle design parameters are described in Table 6.5-2. Each spray nozzle is designed to produce a cone with an angle of approximately 62 degrees at the nozzle. The typical drop size distribution and pattern distribution of a nozzle spraying vertically down are shown in Figures 6.5-6 and 6.5-7. The effective mean fall height for the spray droplets is calculated to be approximately 140 feet taking into account the effective areas of equipment above and below the operating deck. These design parameters promote maximum coverage and mixture of the containment free volume.

The Containment Cooling System (see Subsection 6.2.2), (CCS), is also designed to promote mixing. The discharge of the fan coolers are connected to the ring header manifold to provide mixing of air high in the containment. Eighteen supply registers or air outlets are provided

around the periphery of the ring header blowing air toward the containment. To enhance mixing above the ring header, some of these air outlets are pointed upward towards the top of the dome. The remainder of the outlets are at various locations, including inside the secondary shield wall. All registers are sized to give a horizontal throw of 40 feet that covers a wide area. These design provisions, in addition to those of the CSS, assure that all areas of containment are contacted by the buffered spray solution. This eliminates the potential for areas to accumulate solutions of pH < 7.0, thus there are no dead volumes inside containment.

6.5.2.2.2 Modes of Operation

The modes of operation of the Iodine Removal System, conform to those of the Containment Spray System as follows:

a. Containment spray injection (suction from RWT), and

b. Long-term recirculation containment spray with limited chemical addition (suction from containment sump).

Spray initiation starts with receipt of a CSAS. Full spray flow at the nozzles commences within 80 seconds following CSAS assuming loss of offsite power. The time required for hydrazine addition is constant, and may occur during both injection and recirculation depending on the containment spray pumps operating mode. Three pump operating modes were investigated. The flow rates and corresponding cases for the containment spray are shown in Table 6.5-3.

Case 1: Minimum safeguard flow, minimum injection (i.e., one containment spray pump + one HPSI pump + one LPSI pump) with loss of offsite power and one diesel generator failure.

Case 2: Maximum safeguard flow (i.e., two HPSI + two LPSI pumps) and single failure of one containment spray pump, (i.e., only one containment spray pump operating) with offsite power available.

Case 3: Maximum safeguard flow, maximum injection (i.e., two containment spray pumps + two HPSI pumps + two LPSI pumps) with offsite power available.

6.5.2.3 Design Evaluation

No single active component failure can prevent the CSS and IRS from performing its fission product removal function. Table 6.5-4 demonstrates that a failure modes and effects analysis has been made on all active components of the Iodine Removal System to show that as a minimum there is available one 100 percent hydrazine spray additive subsystem after any single active failure. For a failure modes and effects analysis of the Containment Spray System see Table 6.2-41.

6.5.2.3.1 Theory of Iodine Removal by Containment Spray

The spray removal constant λ, for iodine is evaluated using the models described in NUREG/CR-009.[1] The model assumes a balance between iodine entering and leaving the containment atmosphere with first order removal produced by the spray. The resulting equation, as given in NUREG/CR-009, for the removal rate is:

$$\lambda = \frac{LEH}{v}$$

where: λ = iodine removal rate hr^{-1}
L = spray flow rate, ft^3/hr
E = absorption efficiency
H = equilibrium partition coefficient
V = net free volume of containment, ft^3

The absorption efficiency, E, is evaluated by using the stagnant film model. Further guidance on the determination of this parameter is given by Parsly and has been followed in this evaluation. The parameters used in the calculation are given in Table 6.5-5. For elemental iodine, a removal coefficient of 37 hr^{-1} has been calculated.

In the EPU evaluation of post-LOCA offsite doses, credit is taken for spray removal of elemental iodine until an elemental decontamination factor of 200 is reached. The removal of particulate iodine continues as long as spray is available; however, the removal rate is reduced by a factor of 10 when the particulate decontamination factor reaches a value of 50. The initial removal rates for elemental and particulate iodine used in the LOCA dose calculations are 20 hr^{-1} and 6.52 hr^{-1}, respectively.

6.5.2.3.2 Spray and Sump water pH History

The pH of liquid solutions that are recirculated within the containment following a design basis accident is stabilized at approximately 7.0 to 8.1. The pH is maintained with the use of trisodium phosphate dodecahydrate (TSP) which is stored in sixteen open baskets located in the vicinity of the containment sump (Figure 6.5-9). They are constructed of stainless steel with mesh screen sides, The TSP basket design will be such that an inadvertent containment spray will not dissolve the TSP. Borated water from the containment spray dissolves the TSP and thus raise the pH. Mixing is achieved as the solution is continuously recirculated from the sump to the spray nozzles. The spray water dissolves the TSP within three hours following CSAS. Approximately one-third of the TSP dissolves during the injection mode. For details of flow paths to the sump, see Subsection 6.2.2.

There are no significant quantities of acids or bases inside the containment which could affect the containment sump pH. For evaluating the post-LOCA sump pH the following chemical compounds are considered:

- Boron/Boric acid
- TSP (Trisodium Phosphate Dodecahydrate)
- Hydrocholoric acid
- Nitric acid

The minor contributions from other acidic and basic species are assumed to offset and are negligible compared to the chemicals above. The boron is introduced to the sump due to the borated water from the RCS, RWT, and other inventory sources which travel to the sump following a LOCA. In order to offset the effect of the boron, TSP is added to the sump to act as a buffer and raise the pH above 7.0. Hydrochloric acid is generated as a result of the irradiation of

the cable insulation in containment and tends to reduce the sump pH. Nitric acid is formed due to the irradiation of water in the sump and also decreases the pH. The relative concentration of these chemical species impacts the resulting sump pH. The acids are conservatively neglected in the maximum pH case.

Time histories of the minimum pH of the aqueous phase in the containment sump are shown on Figure 6.5-8a and 6.5-8b. The time-dependent post-Loss of Coolant Accident (LOCA) pH of the containment sump was assessed for the EPU dose assessment. A minimum sump pH of 7.0 is required prior to the recirculation actuation signal (RAS) mode. The pH is controlled with baskets of TSP (trisodium phosphate dodecahydrate) in the containment sump which dissolves as the post-LOCA water level increases. The boron concentrations for the Refueling Water Tank (RWT), Safety Injection Tanks (SITs) and Reactor Coolant System (RCS) are considered. Hydrazine is not included in this analysis.

The minimum and maximum cases were evaluated to determine the pH of the sump. Case 1 and Case 2 are parametric studies performed to determine the minimum pH in the sump up to 30 days (2592000 seconds). Case 1 (Figure 6.5-8a) incorporates the minimum water volume and minimum water level timing while Case 2 (Figure 6.5-8b) incorporates the maximum water volume and maximum water level timing. The recirculation actuation signal (RAS) mode occurs at 1338 seconds into the event based on a minimum RWT volume for Case 1. In Case 2 the RAS mode occurs at 1662 seconds based on a maximum RWT volume. This time represents the minimum time before containment spray will take suction from the containment sump. The sump pH value at recirculation is 6.971 and 7.073 for Case 1 and 2, respectively. In both cases the sump pH initially decreases due to hydrochloric and nitric acid generation then increases quickly when the water level reaches the bottom of the baskets and dissolves the TSP. The peak sump pH is reached when all of the TSP is dissolved and then begins to decline due to continued acid generation. Over 1/3 of the TSP dissolves upon recirculation. The maximum sump pH was also evaluated and was found to be 8.102.

6.5.2.3.3 Effective Containment Sprayed Volume

The spray nozzles are located and designed to promote uniform distribution of the sprayed water and provide adequate coverage of the containment. The EPU dose assessment assumes that 85% of the containment volume is effectively covered by containment sprays.

6.5.2.4 Testing and Inspections

The Containment Spray System/Iodine Removal System is designed to allow testing of components and actuation logic to the maximum extent practicable.

The design of the IRS allows for a full test of the actuation and control logic. The hydrazine metering pumps are shop tested to verify flow. A complete performance test is performed to measure capacity, total developed head, NPSH, power requirements and efficiency. The pump casing is hydrostatically tested. Calculations are performed to determine seat leakages, and the responses to a stringent vibration test. The active valves and chemical storage tanks are hydrostatically tested to ASME Code, Section III requirements. Valve seat leakage tests and vibration tests are performed at the manufacturers shop. Minimum wall thickness calculations are performed and verified by measurements at the shop. For further details concerning the operability of active IRS components see Subsection 3.9.3.

Design provisions are made to perform in situ tests. During normal plant operation the hydrazine pumps can take suction from the hydrazine storage tank and divert flow back to the tank via the recirculation line. Flow meters and pressure indicators are provided to verify operational capability of the system. The level indicators, pressure transmitters and temperature indicators and sample taps are provided on the storage tank in order to perform the surveillance requirements. The periodic testing and surveillance requirements for the Containment Spray and Iodine Removal Systems are part of the Technical Specifications.

The containment spray nozzles have been shop tested. Spray Engineering Company has conducted tests to verify the spray pattern and droplet sizes. Spray droplet measurement is done without the use of any collection medium which may interfere with effective collection of particle size data. This is accomplished with the use of a TV camera, a TV monitor, a strobe light and a computer console. The analyzer was used to count and measure the particles as follows;

a. A nozzle spray was positioned between the strobe light and the TV camera.

b. As the stroboscope flashes, the television camera receives the spray drop images whose motion is stopped by the rapid strobe light source.

c. The image that is now on the vidicon tube is scanned in the television camera and the electrical impulses formed by these images is sent to the electronic counting and measuring circuits housed in the console.

d. The console as it receives these impulses analyzes as follows:

    1. It determines whether a drop is in focus or out of focus; if it is out of focus, it is rejected and not counted.

    2. If the drop is in focus, its diameter is then determined by the number of TV scan lines that pass through the drop.

    3. The spray particle is counted by being recorded on one of the nine meters on the right side of the console. Each one of these meters represents a particular particle size range (20-25 microns, 25-30 microns, etc, all the way up to 20,000 microns) in steps of four magnification ranges.

e. Once the image on the television screen has been scanned and all of the spray particles in the image have been measured and counted by the electronic circuits, the image is erased and the strobe light flashes once more to put a new image on the television tube. The time element between light flashes, for all this to occur is, extremely short and approximates 1/3 of a second.

In order to obtain reasonably accurate particle size data, the analyzer is calibrated. This is accomplished with etched slides which contain images of particles of specific diameters which conform to specific channels in each magnification range. These slides are placed in the camera's field of view and the equipment is then adjusted until the proper count is obtained in the proper channel.

After the actual counting of particles is accomplished in one or more magnification ranges, certain constants and boundary conditions are applied to the data in order to apply drop velocity

corrections. Since the spray is composed of drops of many different sizes traveling at different velocities at the measuring zone, corrections must be applied to the data in order to obtain an accurate sampling. See Figure 6.5-6 for various typical droplet sizes.

6.5.2.5 Instrumentation Application

Instrumentation for the Containment Spray System is discussed in Subsection 6.2.2. Sufficient instrumentation is provided to enable the operator to assess the status of the system in the standby or operational mode.

Instrumentation provided for monitoring the actuation and performance of the IRS is shown in Table 6.5-6.

6.5.2.6 Materials

A discussion of the materials utilized in the engineered safety features systems is provided in Section 6.1. Materials of construction for the CSS are discussed in Subsection 6.2.2.

The materials used in the IRS are compatible with the hydrazine solution and the environment. The materials used are not subject to decomposition by the radiation or thermal environment. The specifications require that the materials be unaffected when exposed to the equipment design temperature, the total integrated radiation dose, and the boric acid and hydrazine solution.

A listing of the materials utilized in the Iodine Removal System is provided in Table 6.5-2.

6.5.3 FISSION PRODUCT CONTROL SYSTEMS

The fission product control systems are the primary containment vessel and the Shield Building.

6.5.3.1 Primary Containment

The primary containment structure consists of a cylindrical steel pressure vessel with hemispherical dome forming a continuous leak-tight freestanding steel shell. It is completely enclosed by the reinforced concrete Shield Building having a cylindrical shape with shallow dome roof. An annular space is provided between the primary containment vessel and the Shield Building and clearance is also provided between the containment vessel and the Shield Building dome. Long and short term containment response to the design basis accident is discussed in Subsection 6.2.1. Details of the containment vessel are discussed in Subsection 3.8.2.

The containment steel shell, mechanical penetrations, isolation valves, hatches, and locks function to limit release of radioactive materials subsequent to postulated accidents such that the resulting offsite doses are less than the guidelines established for design basis accidents. The containment isolation system is described in Subsection 6.2.4. Other containment penetration details are discussed in Subsection 3.8.2. Containment parameters affecting fission product release accident analyses are given in Section 15.6.5.5.2.

The operation of the Containment Spray System to reduce iodine concentrations and containment atmosphere temperature and pressure is discussed in Subsections 6.5.2 and 6.2.2 respectively.

Redundant safety related hydrogen recombiners are provided in the containment as the primary means of controlling post accident hydrogen concentrations. The hydrogen recombiners are discussed in Subsection 6.2.5.

The containment vacuum relief system is used to prevent excess external pressure on the primary containment steel shell. This system is described in Subsection 6.2-1.

The Containment Cooling, System is discussed in Subsection 6.2.2; normally three of four available containment fan coolers are used to cool the containment. Upon receipt of an SIAS all four fan coolers operate.

The Containment Main Purge System is discussed in Subsection 9.4.8.1.

The Continuous Containment/Hydrogen Purge System is discussed in Subsection 9.4.8.8.

6.5.3.2 Secondary Containment

Additional fission product control is achieved following a design basis accident by maintaining a negative pressure inside the Shield Building annulus by operation of the Shield Building Ventilation System. A partial vacuum inside the annulus prevents outleakage through the concrete structure and thus provides control over the release of fission products to the outside environment.

The cleanup of fission products in the annulus and the establishment of a negative pressure in the annulus area accomplished by the Shield Building Ventilation System and described in Subsections 6.2.3 and 6.5.1. The time sequence of events for the annulus transient and for performing the dose estimates are also described in Subsection 6.2.3.

A summary of Shield Building Ventilation System operation following a design basis accident is provided in Section 15.6.5.5.2. Secondary containment volume and the SBVS ductwork are shown in Figures 6.2-46 and 6.2-47.

SECTION 6.5: REFERENCES

1) NUREG/CR-009, "Technological Basis for Model of Spray Washout of Airborne Contaminants in Containment Vessels." October 1978

TABLE 6.5-1

COMPARISON OF SAFETY RELATED AIR FILTRATION SYSTEMS WITH REGULATORY POSITIONS OF REGULATORY GUIDE 1.52, (R2)

Regulatory Position	Control Room Emergency Cleanup System	Shield Building Ventilation System	ECCS Area Ventilation System[1]
1a	Comply	Comply	Comply
1b	Comply	Comply	Comply
1c	Comply	Comply	Comply
1d	Comply	Comply	Comply
1e	Comply	Comply	Comply
2a	No heater or demister: A demister and heater are not required because the recirculated air (1550 cfm) which picks up sensible heat from the equipment in the control room envelope carries no water particles. When this recirculated air is mixed with the outside air (450 cfm), the relative humidity of entering air to charcoal adsorbers is below 70%.	Comply	No demister, prefilter heater or HEPA afterfilter: A prefilter is provided in the supply air system (HVS-4A and 4B). Therefore, a prefilter in the emergency exhaust system is not required. A demister or moisture separator is not required because the atmosphere clean-up system is located at 60.0' away and 43.0' above from any source of moisture and the inlet velocity of the air stream is reduced from 2500 fpm to 700 fpm. With the distance, overhead location and reduction of air velocity, whatever moisture generated in the room is separated before the air stream reaches the HEPA and charcoal adsorber. Supply air to the ECCS areas picks up sensible heat from the equipment. This heat maintains an average relative humidity of 70%. A maximum relative humidity of 73.5% occurs for a very short duration when supply air 100% RH. Therefore, a heater is not required. The ECCS Area Ventilation system is not used in normal operation. It is operated during periodic testing or in the event of a LOCA. Therefore, the occurrence of adsorber releasing radioactive carbon particles is expected to be minimal. Should this condition occur during LOCA (as indicated by the downstream radiation monitor and/or a decrease in charcoal adsorbers pressure differential), the redundant train is available for filtration. Therefore, a HEPA after filter is not required.

Regulatory Position	Control Room Emergency Cleanup System	Shield Building Ventilation System	ECCS Area Ventilation System(1)
2b	Comply	Comply	Comply
2c	Comply	Comply	Comply
2d	Not applicable-located outside containment.	Not applicable-located outside containment.	Not applicable located outside containment.
2e	Comply	Comply	Comply
2f	Comply	Comply	Filters are 6 HEPA wide and 5 HEPA high. For service and maintenance, a hinged or removable platform is provided which limits the service height of HEPA filters to 3 high.
2g	Comply	Comply	Comply
2h	Comply	Comply	Comply
2i	Comply	Comply	Comply
2j	Comply	Comply	Comply
2k	Comply	Comply	Comply
2l	Comply	Comply	Comply
3a	Not applicable (no demister)	Comply	Not applicable (no demister)
3b	Not applicable (no heater)	Comply	Not applicable (no heater)
3c	Comply	Comply	Comply
3d	Comply	Comply	Comply
3e	Comply	Comply	Comply
3f	Comply	Comply	Comply
3g	Comply	Comply	Comply
3h	Comply	Comply	Comply
3i	Comply	Comply	Comply

TABLE 6.5-1 (Cont'd)

Regulatory Position	Control Room Emergency Cleanup System	Shield Building Ventilation System	ECCS Area Ventilation System(1)
3j	Tray or pleated-bed adsorbent cannisters are not used. The adsorber unites of ESF filtration systems are made of 2 inch (SBVS and ECCS Area Ventilation System) and 4 inch (Control Room Emergency Cleanup System) thick, gasketless, all welded construction vertical beds. The design and fabrication of ESF filtration systems are discussed in the CVI Topical Report No. CVI-TR-7301 dated February 2, 1975, "Design and Development of High Efficiency Charcoal Absorber and its Application in ESF Atmosphere Cleanup Systems."		
3k	Provision for cooling the iodine decay heat is not required because the maximum iodine filter loading is very small. Control room air is cooled and maintained at 81°F (during DBA). The temperature rise due to this decay heat is 1°F. Final adsorbent temperature is 82°F which is well below the ignition temperature of 626°F (330°C).	Comply	Provision for cooling the iodine decay heat is not required because the maximum iodine loading is small. Temperature rise due to this heat in 5400 lbs of charcoal is 84°F. The final temperature is well below the ignition temperature of 626°F (330°C).
3l	Comply	Comply	Comply
3m	Comply	Comply	Comply
3n	Comply	Comply	Comply
3o	Comply	Comply	Comply
3p	Comply	Comply	Comply
4a	Comply	SBVS HVE-6A has a permanent service gallery of 3 feet. Service is adequate for removal of largest component of the system.	Comply
4b	Comply	A minimum of three feet from mounting frame to mounting frame between banks of replaceable components is provided. This space is adequate for maintenance and servicing	Comply
4c	Comply	Comply	Comply
4d	Comply	Comply	Comply
4e	Comply	Comply	Comply
5a	Comply	Comply	Comply
5b	Comply	Comply	Comply
5c	Comply	Comply	Comply
5d	Comply	Comply	Comply

TABLE 6.5-1 (Cont'd)

Regulatory Position	Control Room Emergency Cleanup System	Shield Building Ventilation System	ECCS Area Ventilation System[1]
6a	All ESF filtration units comply with all criteria except Regulatory Position 6a(2) to Regulatory Guide 1.52 (R2). See 3i.		
6b	Six test canisters, in accordance with Appendix A of ANSI N509-1976 are provided in all ESF atmosphere cleanup systems.		

Notes: [1] This system is listed for information only. The ECCS area ventilation system is not credited as an ESF atmosphere clean-up system and testing in accordance with RG 1.52 is not required. Testing is performed in accordance with plant procedures.

TABLE 6.5-2

IODINE REMOVAL SYSTEM COMPONENTS**

A. Hydrazine Storage Tank

Volume, gallons		736
Minimum Required Usable Liquid Volume, gallons		675
Design Temperature, F		120
Design Pressure, psig		20
Operating Temperature, F		100
Operating Pressure, psig		10
Fluid	25.4% by weight hydrazine solution with nitrogen (N_2) cover gas	
Material		304 SS
Code	ASME III, Code Class 2	

B. Hydrazine Pumps

Quantity		2
Type	Positive Displacement, Metering	
Capacity, gpm		2.2 - 4.4
Discharge Pressure, psig		60
Design Temperature, F		120
Operating Temperature, F		100
$NPSH_A$, ft of water		30
Fluid	25.4% by weight hydrazine solution	
Material		304SS
Code	ASME III, Code Class 2	
Rating		480V, ac

C. Solenoid Valves

Quantity		2
Size, inches		1/2
Type		Globe
Design Pressure, psig		100
Design Temperature, F		120
ANSI Class		600
End Connection		SW
Pipe Schedule		80s
Material		304SS
Fluid	25.4% by weight hydrazine solution	
Operator	125V dc solenoid	
Code	ASME III, Code Class 2	

TABLE 6.5-2(Cont'd)

D. All Other Valves

ANSI Class	600
Material	304/316 SS
Code	ASME III, Code Class 2

EC 289343

All piping and fittings are of 304 SS and Quality Group B, seismic Category I

Spray Nozzles

Number	178 (minimum per train)
Type	1713 A, Spray Engineering Company
Mean Droplet Size	700 microns
Flow, per nozzle	15.2 gpm (40 psi drop)
Spray Velocity	44.25 ft/sec
Nozzle Diameter	0.375 in.

Spray Solution at Spray Nozzles*

Composition	0 to 1720 ppm boron 50 to 65 ppm hydrazine
pH	4.8 to 7.5

TSP Baskets

Number of Baskets	16 open baskets
Volume (total) of Baskets	189 ft^3
Total Quantity of TSP available	9700 lbs (173 ft^3)
Location	In the vicinity of the ECCS sump

*injection phase

**Hydrazine addition is not credited for the EPU dose assessment

TABLE 6.5-3

CONTAINMENT SPRAY AND SPRAY ADDITIVE FLOW RATES**

The flow rates for the containment spray and spray additive flow rates are given for the following three cases:

Case 1: Minimum safeguard flow, minimum injection (i.e., one containment spray pump + one HPSI pump + one LPSI pump) with loss of offsite power and one diesel generator failure.

Case 2: Maximum safeguard flow (i.e., two HPSI pump + two LPSI pumps) and single failure of one containment spray pump, (i.e., only one containment spray pump operating) with offsite power available.

Case 3: Maximum safeguard flow, maximum injection (i.e., two containment spray pumps + two HPSI pumps + two LPSI pumps) with offsite power available.

Case	Safeguard System Operation Mode	Total Containment Spray Flow (gpm)	Total Spray Additive Flow (gpm)	Total* Hydrazine Addition Time(minutes)
1	Injection	2800	0.8	40
	Long-Term Recirculation	3560	0.8	680
2	Injection	2800	0.8	27
	Long-Term Recirculation	3560	0.8	693
3	Injection	5600	1.6	20
	Long-Term Recirculation	7120	1.6-0.8	700

*Based on RWT at minimum Tech Spec level and runout flows for HPSI, LPSI and CS pumps. The containment spray flow of 2800 gpm includes a minimum recirculation flow of 150 gpm required during the injection phase. Operator action to turn off one hydrazine pump is initiated within one hour after the accident, resulting in a total hydrazine injection time of 12 hours.

**Hydrazine addition is not credited for the EPU dose assessment.

TABLE 6.5-4

FAILURE MODES AND EFFECTS ANALYSIS - IODINE-REMOVAL SYSTEM

Component Identification	Failure	Effect on System	Method of Detection	Monitor	Remarks
Hydrazine Addition Pump	One of two fails to start	Loss of one 100% capacity hydrazine additive subsystem	Flow element in hydrazine additive supply line registers half flow	CRI*	One 100% hydrazine subsystem remains
Solenoid Isolation Valve	One of two fails to open	Loss of one 100% capacity hydrazine additive subsystem	Indication light registers in the control room	CRI*	One 100% additive subsystem remains

* CRI-Control room indication

TABLE 6.5-5

IODINE REMOVAL RATE CONSTANT CALCULATION PARAMETER**

a.	K_g	Gas film mass transfer coefficient: $\frac{cm}{sec}$	16.4
b.	K_L	Liquid film mass transfer coefficient: $\frac{cm}{sec}$	6.58×10^{-4}
c.	H	Iodine partition:	10,000
d.	h	Droplet mean fall height: ft	140
e.	F	Spray flow rate: gpm	2800-3600*
f.	V	Net containment free volume: ft^3	2.5×10^6
g.	d	Droplet diameter:μ	700
h.	E	Adsorption efficiency of the spray droplet (2):	0.32

* The containment spray flow of 2800 gpm includes a minimum recirculation flow of 150 gpm required during the injection phase.

** Hydrazine addition is not credited for the EPU dose assessment.

TABLE 6.5-6

IODINE REMOVAL SYSTEM

System Local Parameter & Location	Indication Local	Indication Control Room	Alarm Local	Alarm Control Room	(1) Recording	Tag No./or Control Function	Instrument(2) Range	Normal Operating Range	Instrument(2) Accuracy
Hydrazine Storage Tank									
Cover Gas Pressure	*			LO/HI		PDIS-07-7		7 - 15 psig	
Level						LG-07-8		-	-
						LS-07-1OA,B stops IRSP - closes discharge valve on LL		2 - 42 in	
				LO/LO-LO		LIS-07-9		> 36.7 in	
Outlet Flow		*			FR-07-2-2	FT-07-2-2		0.8 gpm	
					FI-07-2-1	FI-07-2-1		0.8 gpm	
IRS Pump Discharge									
Pressure	*					PI-07-6A,B		15 - 100 psig	

(1) all recording in the control room

(2) Instrument ranges are selected in accordance with standard engineering practices. Instrument accuracies are selected such that existing instrument loop performance and safety analysis assumptions remain valid. Where applicable, instrument accuracies are also evaluated for their impact on setpoints in accordance with the FPL Setpoint Methodology.

DELETED

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ST. LUCIE PLANT UNIT 2

FIGURE 6.5-1

DELETED

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ST. LUCIE PLANT UNIT 2

FIGURE 6.5-2

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ST. LUCIE PLANT UNIT 2

FIGURE 6.5-3

Refer to Dwg.
2998-G-220

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CONTAINMENT SPRAY
PIPING PLAN
FIGURE 6.5-4

Refer to Dwg.
2998-G-221

FLORIDA POWER & LIGHT COMPANY
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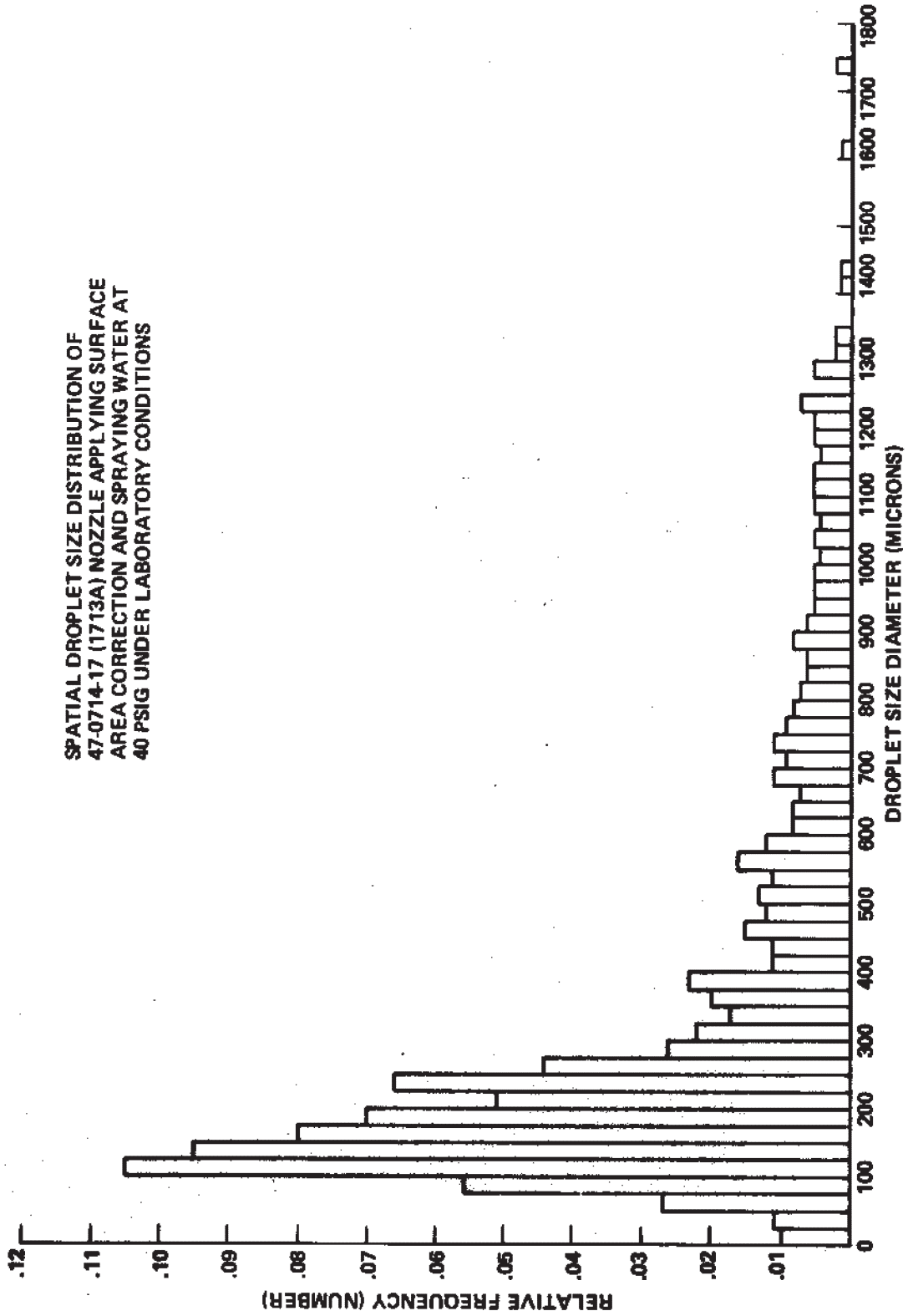
CONTAINMENT SPRAY
PIPING SECTION
FIGURE 6.5-5



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TYPICAL DROPLET SIZE

FIGURE 6.5–6

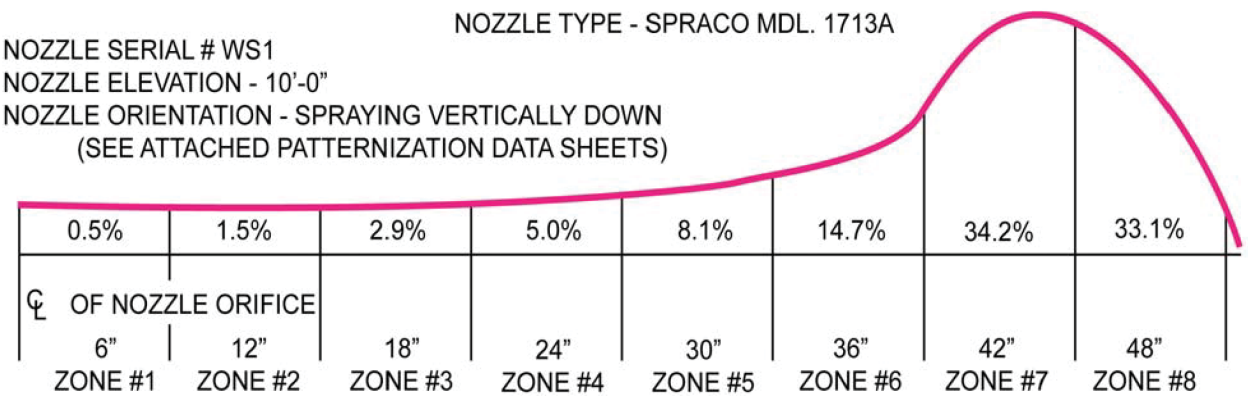
% OF TOTAL DISTRIBUTION FOR TYPICAL QUADRANT

ZONE #	SURFACE AREA (IN^2)	AVG. HEIGHT (IN)	VOLUME (IN^3)	% OF TOTAL VOLUME
1	113.1	1.30	147	0.5%
2	339.3	1.45	492	1.5%
3	565.5	1.68	950	2.9%
4	791.7	2.05	1623	5.0%
5	1017.8	2.61	2657	8.1%
6	1244.1	3.87	4815	14.7%
7	1470.3	7.60	11174	34.2%
8	1696.4	6.37	10806	33.1%

TOTAL VOLUME (IN^3) - 32664 ACCUMULATION TIME - 45 SEC.

NOZZLE TYPE - SPRACO MDL. 1713A

NOZZLE SERIAL # WS1
NOZZLE ELEVATION - 10'-0"
NOZZLE ORIENTATION - SPRAYING VERTICALLY DOWN
(SEE ATTACHED PATTERNIZATION DATA SHEETS)



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ST. LUCIE PLANT UNIT 2

TYPICAL SPRAY DISTRIBUTION

FIGURE 6.5-7

Figure 6.5-8a

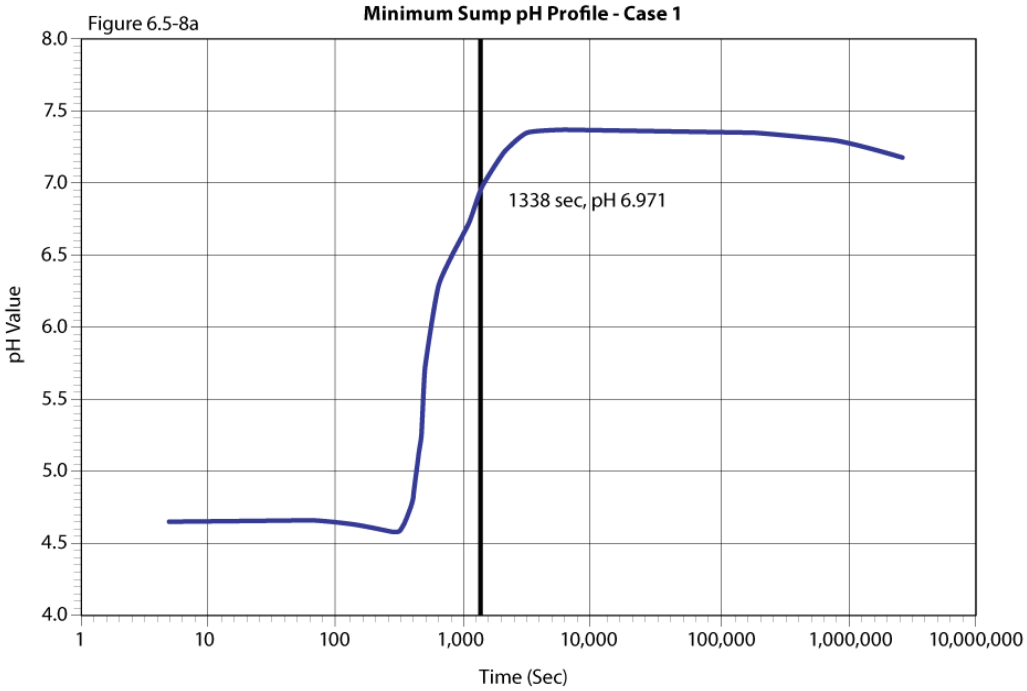
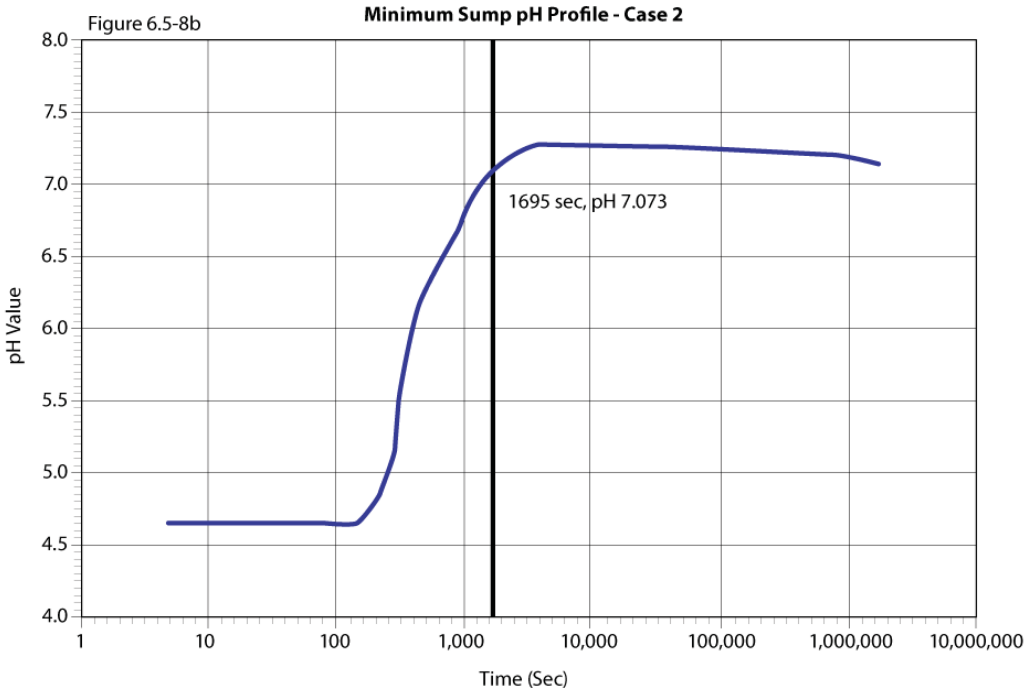


Figure 6.5-8b



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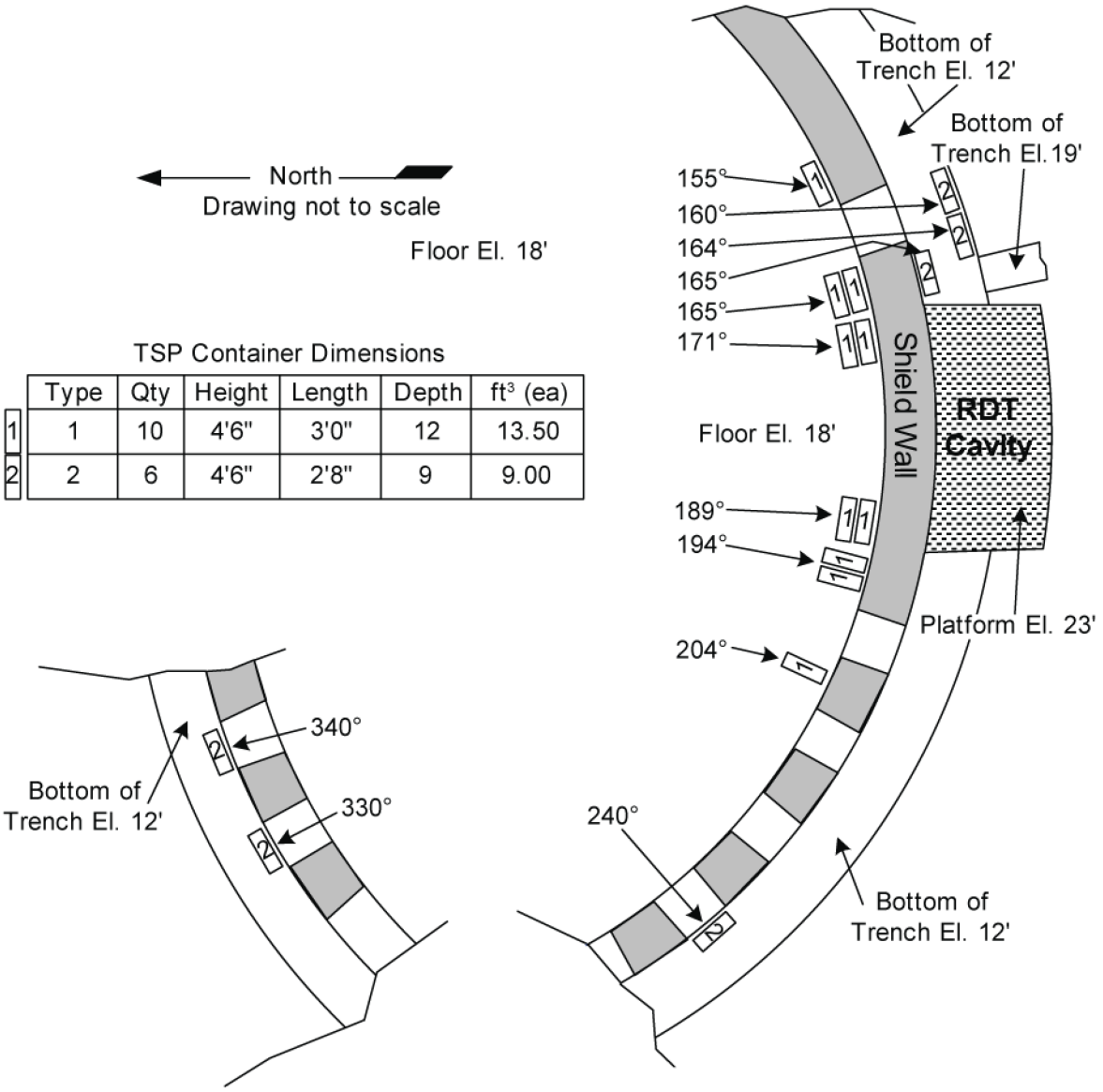
pH vs. TIME FOR CONTAINMENT SPRAY & CONTAINMENT SUMP

FIGURE 6.5-8



TSP Container Dimensions

	Type	Qty	Height	Length	Depth	ft³ (ea)
1	1	10	4'6"	3'0"	12	13.50
2	2	6	4'6"	2'8"	9	9.00

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PLAN @ EL. 11.00 & 18.00 FOR TRI-SODIUM PHOSPHATE CONTAINERS LOCATION
FIGURE 6.5-9

6.6 INSERVICE INSPECTION OF QUALITY GROUP B AND C COMPONENTS

6.6.1 COMPONENTS SUBJECT TO EXAMINATION

The system boundaries subject to inspection are defined in Regulatory Guide 1.26, "Quality Group Classifications, and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," February, 1976 (R3). An inservice program is provided for the examination of Quality Group B and C components including supports as defined by Code Class 2 and Code Class 3 in the ASME Code, Section XI.

A detailed inservice inspection program, including information on areas subject to examination, method of examination, and the extent of frequency of examination is provided in accordance with the ASME Code Section XI. The initial inservice inspection conducted to the first 120 month period following commercial plant operation is developed to the requirements of 10 CFR 50.55a(g), to the extent practical. The inservice inspection program is updated periodically to meet the 10 CFR 50.55a(g) requirements. Where it becomes impractical to meet this criterion, relief from requirements will be requested on a case-by-case basis. A list of these relief requests is provided in the inservice inspection program.

6.6.2 ACCESSIBILITY

Provisions are made in the design and layout of Code Class 2 and 3 systems to allow for compliance with the inservice inspection requirements contained in ASME Code, Section XI. However, where it becomes impractical to meet this criteria, relief from these requirements on a case-by-case basis, will be requested (e.g. type I penetrations).

6.6.3 EXAMINATION TECHNIQUES AND PROCEDURES

Examination techniques includes liquid penetrant magnetic particle when surface examination is specified and ultrasonic when volumetric examination is specified. Also visual inspection techniques are used to determine surface condition of components and for evidence of leakage. Specific techniques and procedures for performing examinations are defined in the inservice inspection program.

6.6.4 INSPECTION INTERVALS

The inspection interval for the examination program is defined in the inservice inspection program. The inservice inspection program for all ASME Code Class 2 and 3 systems and components are developed in accordance with the inspection intervals' guidance requirements of Sub-Articles IWC-2400 and IWD-2400 of the ASME Code, Section XI.

6.6.5 EXAMINATION CATEGORIES AND REQUIREMENTS

The ASME Code, Section XI code category inspection method for Code Class 2 components to be inspected complies with Section XI, Sub-Articles IWC-2520 and IWC-2600 of ASME Code, Section XI. The requirements for Class 3 components complies to Sub-Article IWD-2600 of the ASME Code, Section XI.

6.6.6 EVALUATION OF EXAMINATION RESULTS

Evaluation of nondestructive examination results for Code Class 2 and 3 system components are made in accordance with Article IWA-3000 of Section XI and as defined in the inservice inspection program. Where acceptance standards for a particular component examination category are in the course of preparation, evaluation will be based on acceptance standards for materials, and welds specified in the Section III edition applicable to the construction of the component. The results of the examination and evaluations are documented in accordance with article IWA-6000 of Section XI.

Repair procedures for Code Class 2 and Class 3 components and the extent of their agreement with IWC-4000 and IWD-4000 respectively are described in the inservice inspection program.

6.6.7 SYSTEM PRESSURE TESTS

Code Class 2 and 3 system pressure testing complies with the criteria of ASME Code, Section XI, Articles IWC-5000 and IWD-5000, respectively.

6.6.8 AUGMENTED INSERVICE INSPECTION TO PROTECT AGAINST POSTULATED PIPING FAILURES

The inservice inspection program discussed in Subsection 6.6.1 encompasses high energy fluid system piping between containment isolation valves or where no isolation valve is used inside containment, between the first rigid pipe connection to the containment penetration or the first pipe whip restraint inside containment and the outside isolation valve.